JOINT IMPLEMENTATION PROJECT DESIGN DOCUMENT FORM
Version 01- in effect as of: 15 June 2006

CONTENTS

Annexes

SECTION A. General description of the project

A.1. Title of the project:

Associated Petroleum Gas Recovery for the Kharampur oil fields of "Rosneft"
Sectoral scopes: 1 (Energy industries) and 10 (Fugitive emissions from fuels)
Version 1.4
February 01, 2011

A.2. Description of the project:

Associated petroleum gas (APG) is a by-product of oil extraction. It is a mixture of volatile hydrocarbons – methane, ethane, propane and butane. It also contains light liquid-phase hydrocarbons, mainly, pentane and hexane. APG may be dissolved in underground oil reservoir, or accumulate in the upper layer of oil-bearing bed, forming a gas cap.

One of the main ways of useful utilization of associated petroleum gas is its separation into several commercial products: broad fraction of light hydrocarbons (BFLH), dry gas, which predominantly consists of methane, and casinghead gasoline – a mixture of heavier hydrocarbons, also known as condensate. Component composition of dry gas is similar to that of natural gas. Dry gas is similar to natural gas by its composition and used domestically as fuel for power plants and energy source in residential sector and industry. Dry gas is also exported abroad. Casinghead gasoline is either used directly as motor fuel or processed further. The BFLH is refined into ethane fraction and propane-butane fraction. Also BFLH is used in petrochemical industry as the primary source of raw materials, for production of liquefied propane-butane and high-octane petrol fractions.

The purpose of the proposed Joint Implementation project is useful utilization of the associated petroleum gas at the production sites of Kharampur group of oil-fields of Rosneft company, operated by its subsidiary, RN-Purneftegas, Ltd. This group of oil-fields includes North-Kharampur, South-Kharampur, and Festival oil-fields. Oil production at Kharampur group of oil-fields began in 1990. These oil-fields have high gas-oil ratios. Large volumes (about 1 billion cubic meters per year) of associated petroleum gas are historically flared and up to now. According to the subsoil user license, RN-Purneftegas has never been obliged to utilize any specified fraction of this gas.[1] Actually, environmental permits officially sanction the gas flaring.[2]

The proposed project includes the existing booster pump stations (BPS) with water discharge and preliminary water discharge units (PWDU): BPS "Festival", BPS-1 "South-Kharampur", PWDU-2 "South-Kharampur", BPS-2 "North-Kharampur", and PWDU "North-Kharampur" coupled with oil treatment facility (OTF) and central commercial tank (CCT). All facilities are equipped with high and low pressure flares. A small portion of APG is used for own needs of the facilities, while the remaining gas is flared. Nine of ten flares emit soot during APG flaring, because they operate under "carbon-black flaring" conditions, which are characterized by noticeable underfiring of methane. This has been proved by calculations of emission limits, and by remote photographs of the sites.

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[1] Licensing agreement about the terms of exploitation of subsoil of Kharampur oil-field, Annex I to the license held by OJSC "NK Rosneft" of 08.11.2006.

[2] Project of emission limits for facilities involved in preparation and transportation of oil, gas and condensate of RN-Purneftegas Ltd., issued by Ecoproject Ltd., Tumen. This document was approved by the State Environmental Expertise, the Decision No.794 of 30.10.2006, and by the Department for Technological and Environmental Surveillance of Rostechnadzor for Yamalo-Nenetsky Autonomous District, the Decision No.1231-e of 30.10.2006. The emission permit No. 162 is in effect till 31.12.2010.

Flaring of associated petroleum gas at the existing BPS and PWDU sites is considered as baseline scenario for the proposed project.

The project envisages the following activities:

- Recovery and delivery to the booster compressor station (BCS) the high-pressure associated petroleum gas under its own pressure and preliminary compressed low-pressure APG from the existing BPS "Festival", BPS-1 "South-Kharampur", PWDU-2 "South-Kharampur", BPS-2 "North-Kharampur", and PWDU "North-Kharampur".
- Low-temperature condensation of APG and its separation into the following commercial products: dry gas fraction, compliant to industry standard OST 51.40-93, and BFLH fraction (C_3 and higher extraction rate is at least 90%).
- Transportation of commercial BFLH through a multiphase pumping station (MPS) to Tarasovskoe oil-field, where the product is shipped to consumers.
- Injection of commercial dry gas through the injection wells into the Temporary underground gas storage (TUGS) at Cenomanian gas deposit of Kharampur gas condensate field.

The proposed project will utilize several infrastructure objects, of which only the multiphase pumping station currently exists. This MPS is temporarily dormant. It was constructed for collection and transportation of condensate from Kynsko-Chaselsky group of oil-gas-condensate field, but gas production has been suspended there.

The Temporary underground gas storage for commercial dry gas will be built near remotely located and yet unexplored Kharampur gas field. Rosneft company has the license for exploration of this gas deposit. The company is planning to drill the cluster of injections wells and to furnish all related infrastructure. Project documents have confirmed suitability of Cenomanian bed of gas deposit for dry gas storage.[3] According to the Technical Design Specifications of 2006, up to 7.5 billion cubic meters of associated gas could be injected in Cenomanian bed PK_1 during six-year period. This amount equals only to 3.8% of initial gas reserves in this large gas deposit. Daily injection rate could be 3.42 million m^3. In time of PDD development the initial plans were even corrected to decrease the amount of gas to be injected in TUGS.

After the gas is injected in TUGS, it may be topped immediately after the injection is finished (in 2013). Exploration of gas deposits of Kharampur gas field may begin at the same time.[4] The integrated gas transporting system of the Russian Federation shall be accessible at that time, after completion of 170 km connective gas main from Kharampur deposit to Purpeiskaya pumping station of OJSC "Gazprom". Topping of the injected gas and commercial exploration of Kharampur gas deposit may start even earlier, if the access to integrated gas transporting system is provided. At that time, the annual gas production at Kharampur gas field shall considerably exceed the annual volume of gas injection into TUGS.

Table A 2.1 Projected volumes of utilization of associated petroleum gas[5]

	2010	2011	2012	Total
Utilization of APG, million m^3	505. 135	958. 054	1031.140	2494.329

[3] "Project design documentation for construction and exploitation of Temporary underground gas storage in Cenomanian gas deposit at Kharampur oil-field, for storage of dry gas of Kharampur group of oil-fields", VNIIGAZ Ltd., Moscow Region, Razvilka Village, 2007.

[5] Business plan of RN-Purneftegas Ltd. for the period 2009-2013.

Project implementation became possible due to Joint Implementation (JI) mechanism under the Kyoto Protocol. An initial decision to implement the project was made by Rosneft company in 2006 after that a technical project design development had started. Construction of the gas collection pipelines begun in the middle of 2008 while main construction is planned to be fulfilled in 2009. The revenue from sales of the emission reduction units (ERU) increases the investment attractiveness of this project. In the absence of a project the associated petroleum gas would be continuously flared.

A.3. Project participants:

Table A 3.1. Project participants

Party involved	Legal entity project participants (as applicable)	Please indicate if the Party involved wishes to be considered as project participant (Yes/No)
Party A: (host) Russian Federation	OJSC "NK Rosneft"	No
Party B: to be determined at the later stage	Carbon Trade & Finance SICAR S.A.	No

OJSC "NK Rosneft" is the leader in Russian oil-and-gas sector. It is one of the largest publicly owned oil-and-gas companies in the world. The basic activities of OJSC "NK Rosneft" includes exploration and production of oil and gas, petrochemical processing and refining, and sales of petrochemical products. This company has been listed among strategic enterprises and organizations of the Russian Federation. The Russian Federation owns more than 75% of shares of OJSC "NK Rosneft", while 15% of shares are freely negotiable on the stock market.

The scope of oil and gas exploration and production activities of OJSC "NK Rosneft" includes all main oil and gas bearing provinces of the Russian Federation: West Siberia, South and Central Russia, Timano-Pechora, East Siberia and Far East. The company also operates in Kazakhstan, Algeria and Turkmenistan. Seven large refineries of OJSC "NK Rosneft" are evenly distributed over the territory of the Russian Federation from the shore of Black Sea to the Far East, while company sales network spreads over 36 regions.[6]

OJSC "NK Rosneft" owns RN-Purneftegas Ltd., which explores oil and gas fields in Yamalo-Nenetsky Autonomous District. RN-Purneftegas Ltd. is the second largest (after Yuganskneftegas) oil producer in the structure of Rosneft, and the largest gas producer. Purneftegas was established in 1986, and absorbed Selkupneftegas Company, which explores Kynsko-Chaselskaya group of fields.

In 2007, Purneftegas produced 9.2 million tons of oil and 7.6 billion m^3 of natural gas. The company accounted for the major increase of gas production of Rosneft, while its own gas production increased by 9.4%. The share of Purneftegas in total production of oil and gas condensate of Rosneft (including its share in production of subsidiaries) is 9.1%, and its share in natural gas production is 48.5%.

Oil and gas fields of Purneftegas are integrated in the regional transport infrastructure. The gas trunk pipeline Ust-Balyk – Omsk (owned by Transneft) runs through the company's oil and gas fields. Another accessible gas main is Urengoi-Chelyabinsk-Novopolotsk trunk line, which is owned by Gazprom.

[6] http://www.rosneft.ru/about/Glance/

Besides these pipelines, there is a railway, which connects Pur-Pe station with Surgut. This railway is used for transportation of gas condensate, produced by Purneftegas. Transportation by rail means that this condensate is not mixed with similar products of other producers, which always happens in Transneft pipelines.

Carbon Trade & Finance SICAR S.A. is a joint venture of Gazprombank (Russia) and Commerzbank (Germany). This joint venture was established to facilitate investments in rapidly developing greenhouse gas emission reduction markets. The company is registered in Luxemburg and invests in greenhouse gas emission reduction projects in Russia and CIS countries.

Carbon Trade & Finance SICAR S.A. offers complex solutions to its customers: from risk management to consultations on carbon project financing to direct procurement of emission reduction units. Carbon Trade & Finance SICAR S.A. develops financial derivative products for financial institutions, governments and buyers, which have accepted binding emission reduction obligations. Carbon Trade & Finance SICAR S.A. has established its daughter company CTF Consulting Ltd. in Moscow, which offers a comprehensive portfolio of consulting services in the area of JI project development, preparation and support.

Carbon Trade & Finance SICAR S.A. is a buyer of ERUs generated by the Project.

A.4. Technical description of the project:

A.4.1. Location of the project:

Yamalo-Nenetsky Autonomous District, Krasnoselkupsky and Purovsky municipal districts.

A.4.1.1. Host Party(ies):

The Russian Federation

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

Yamalo-Nenetsky Autonomous district, Tumen Region

Fig.A.4.1.2.1 Yamalo-Nenetsky Autonomous district on the map of the Russian Federation

Fig. A.4.1.2.2 Location of project facilities

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

130 km to the south of Tarko-Sale urban village, and 180 km to the east of Gubkinsky town.

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

Fig.A.4.1.4.1 Typical landscape on-site of the Kharampur group of oil-fields

Kharampur group of oil-fields (North-Kharampur, South-Kharampur, and Festival oil-fields) administratively belongs to Purovsky municipal district of Yamalo-Nenetsky Autonomous District of Tumen region. The administrative center of this municipality is Tarko-Sale urban village, which is some 130 km away from the project site. Tarko-Sale has an airstrip and regular air communication with Tumen and some other towns of Tumen region. Urengoi-Surgut-Chelyabinsk main gas transmission pipeline runs to the east of Kharampur site. The nearest railway station Purpe is situated some 150 km to the west from the site.

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

The proposed project involves recovery of low-pressure and high-pressure associate petroleum gas from the five existing production facilities of Kharampur group of oil-fields[7] (refer to Graph 3.1 in *Project Boundaries* section).

- BPS “Festival”,
- BPS-1 “South-Kharampur”,
- PWDU-2 “South-Kharampur”,
- BPS-2 “North-Kharampur”,
- PWDU-OTF-CCT “North-Kharampur”.

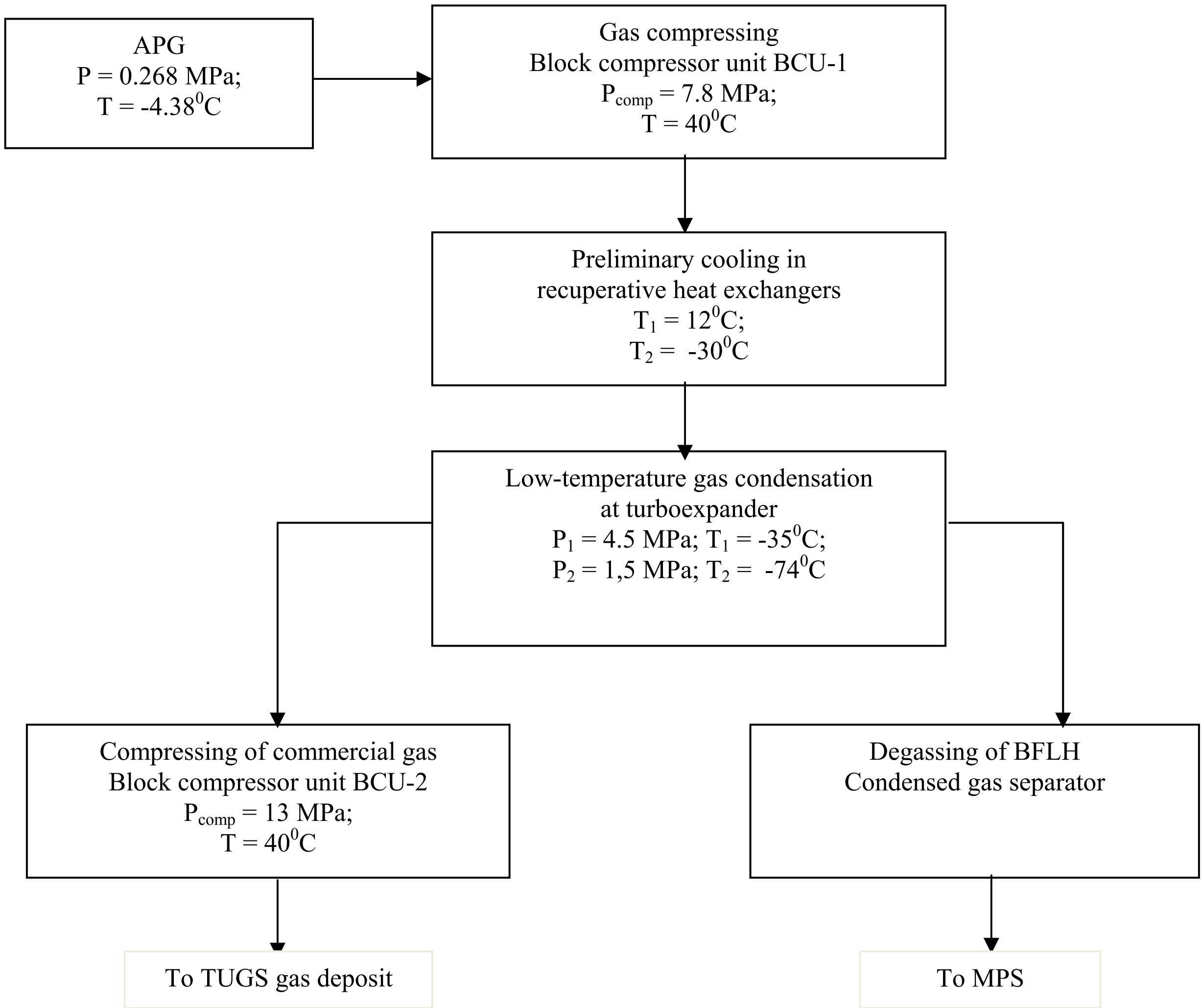
All installations are equipped with low-pressure and high-pressure flares. Project implementation requires several additions to the existing technological schemes.

[7] “Collection, treatment, compressing and injection of low-pressure gas of Kharampur group of oil-fields into Temporary underground gas storage (TUGS), in the amount of 1 billion m^3 per year”, Project Design Document, VolgoUralNIPIgaz Ltd., Orenburg, 2007.

Associated petroleum gas from the outlet oil and gas separators of BPS/PWDU that has been previously flared at the low-pressure flare is pressurized by block compressor up to 6.0 MPa and mixed with the high-pressure gas from inlet oil and gas separators. Then it passes gas meter point and is pumped through specially constructed collector pipelines to the projected BCS site, where the gas is separated into commercial fractions by low-temperature condensation (see the flowchart). This method uses a turboexpander. The output gas transmission pipe is equipped with cutoff valve, which closes during emergencies (gas inrush, fire or excess gassing).

Associated petroleum gas is separated at the BCS site into dry gas fraction, compliant to industry standard OST 51.40-93, and BFLH fraction (with C_3 extraction rate over 90%). Dry gas is pumped by the injection wells into the Temporary underground gas storage (TUGS). After Gazprom issues its permission to supply this gas into the integrated gas transporting system of the Russian Federation, these injection wells shall be transferred into the ‘gas production fund’ category.

Flowchart A.4.2.1: Gas processing at the BCS site



APG under pressure of 0.268 MPa and with temperature –4.38^{0}C flows from BPS and PWDU units to the gas separator unit (GSU) at the BCS site. The incoming gas transmission pipe is equipped with cutoff valve, which closes during emergencies (gas inrush, fire or excess gassing). All output pipes of gas recovery and processing units and the gas pipelines are equipped with cutoff valves, which isolate the sections of the gas pipeline during emergencies. All BPS and PWDU, dry gas injection wells and incoming/outcoming pipes, which transport the APG and products of gas processing, are equipped with operational metering device that control flow rates of APG, dry gas and BFLH, flow pressures and temperatures.

To prevent forming of hydrates in the intake gas pipe, a methanol solution is supplied through the metering unit.

During gas transportation, certain amount of liquid condenses in the pipeline. This liquid is collected in the separator, and then discharged into the water/methanol tank (WMT) through the liquid level controller. The gas, stripped from the bubbles of liquid, flows to the block compressing unit BCU-1, under pressure of 0.268 MPa and with temperature -4.38^{0}C.

Special equipment maintains the constant pressure in the suction pipe of BCU-1. When gas flow rates are insufficient, the gas pass-by automatically directs some gas from the compressor pipe to the suction pipe.

If the gas flow rate is too high, some gas is dumped to the flare through the controller valve. A special filter protects BCU-1 from contamination by mechanical impurities.

The gas is compressed in BCU-1 to 7.0–9.0 MPa and cooled down to 0- minus 40^0C in the air coolers. BCU-1 includes several gas separators: the intake filer-separator, the separators of intermediate stages and the end separator. They automatically divert liquid into WMT.

After the compressors the gas flows to the recuperative heat exchangers where it is cooled down by the flow of BFLH which runs through the shell side of heat exchangers.

Then the mixture of gas and liquid flows from the recuperative heat exchangers to the turboexpander where the gas is cooled for extraction of hydrocarbons. At the first stage, the pressure is reduced to 4.5 MPa, and the gas expands in the turbine and cools down to -35.21^0C. At the second stage, the pressure is reduced to 1.3-1.5 MPa and the gas cools down to -74.03^0C.

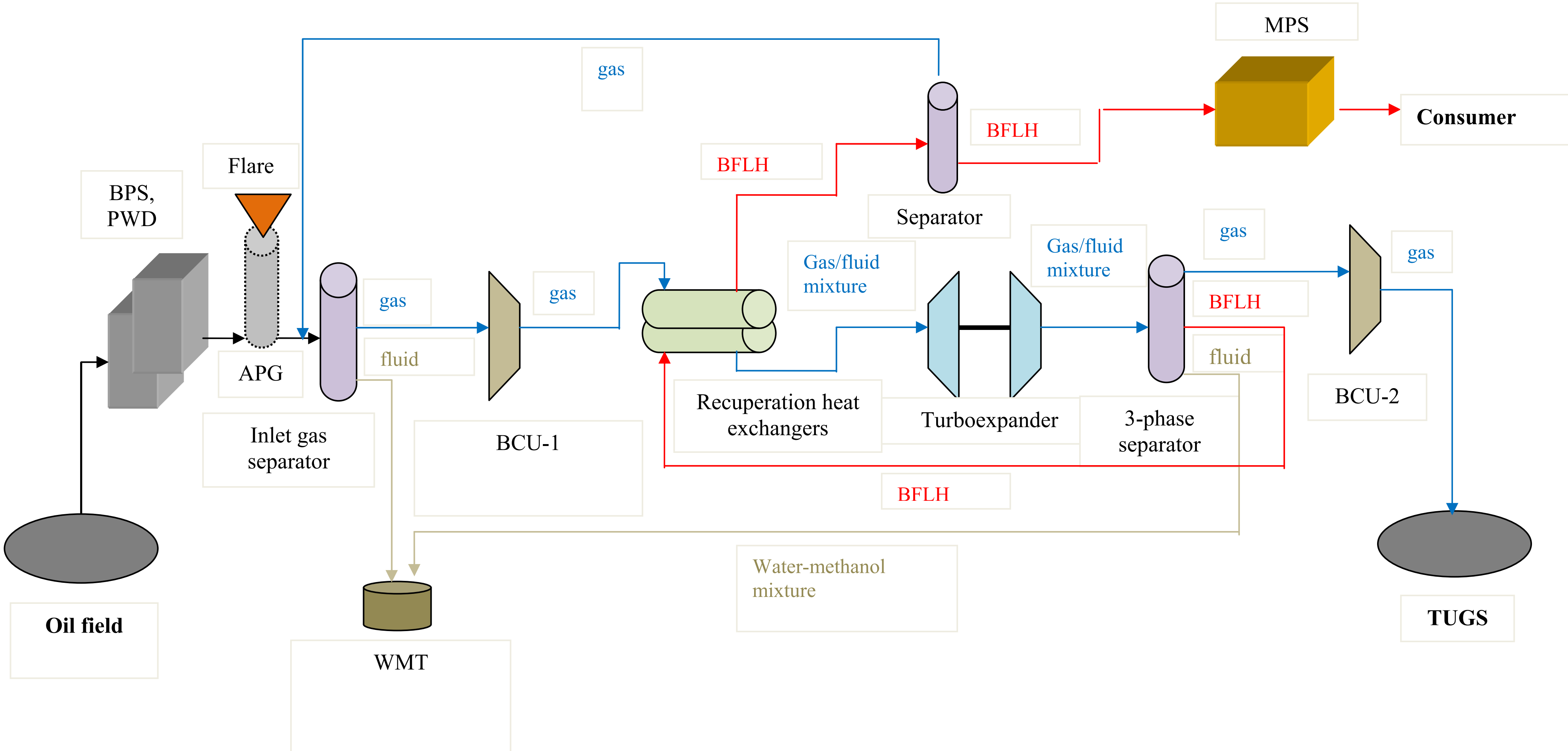
Cooled mixture of gas and liquid with temperature -74.03^0C under pressure of 1.5 MPa flows to three-phase gas separator unit, where water-methanol mixture and BFLH are separated. Water-methanol mixture direct to the WMT through the level controller.

BFLH with temperature -38^0C under pressure of 2.5-3.5 MPa from three-phase gas separator unit directs to the shell side of heat exchangers through the level controller, where it is warmed by initial gas. After the shell side of heat exchangers BFLH directs to liquefied gas separator unit, where it is additionally degassed. Pressure level controller keeps up the pressure. Gas from separator directs to inlet of BCS, while BFLH directs to MPS through the operational metering device. C_3 extraction rate is over 90%.

Precipitated gas from three-phase gas separator unit directs to inlet of BCU-2 through pressure level controller. Then gas is compressed in BCU-2 to 13.5 MPa and direct to gas pipeline for injection to the TUGS through the operational metering device.

Inlet and outlet collectors of BCS are equipped with electric-driven cut-off valves, which close during emergencies (gas inrush, fire or excess gassing). In such case APG from BPS, PWDU is burned at flare in the BCS site. To maintain the pressure in gas pipeline the gas directs to flare through controlling valve. In this case APG is used directly from main collector gas pipeline for uninterrupted delivery gas to flare, boiler house of BCS, emergency reservoirs, site of methanol storage.

Flowchart A.4.2.2: Schematic flows of APG, dry gas, BFLH, and water-methanol mixture at the booster compressor station site



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

The Ministry of Environmental Protection of Russia reported that 25-28% of APG, recovered in Russia, is being flared. It amounts to 15-17 billion m^3 out of 60 billion m^3 of annual APG recovery. About one-third of the remaining gas is processed, while the rest is either charged off as technological losses, or used as fuel in energy sector. However, energy sector experts believe that the share of flared gas is even greater.[8]

Almost one half of recovered associated gas is being flared in Russia, as reported by the World Bank upon the results of the study made by PFC Energy under the auspices of Global Partnership for Gas Flaring Reduction[9]. According to the results of this study, Russian oil-producing companies flare about 38 billion m^3 of associated gas annually, which is about 45% of APG recovery in Russia. Besides, an estimated 10 billion m^3 of associated gas is being flared during extraction of gas condensate.

As Section B.2 shows, at the moment when the decision on the project was made in 2006, Rosneft Company could not implement this project without additional financing sources, such as Joint Implementation Mechanism. Economic efficiency of this project was and still remains quite low, especially taking in account the lack of opportunities to sell dry gas right away (the project payback period without ERU sales is more than 15 years).

Besides, the effective subsoil user license for Kharampur group of oil-fields (expiration date 06.06.2013) does not require mandatory utilization of APG, and the existing environmental permits[10] explicitly confirm the practice of gas flaring. Federal law of the Russian Federation does not explicitly prohibit APG flaring, neither such prohibition is anticipated in the near future.

In view of increasing pressure of the state on oil companies, with the goal to make them utilize APG, one may hypothesize that Rosneft might have initiated project of APG utilization unilaterally. In such a case, actual project implementation cycle would have taken at least four years. It means that flaring practice would have been stopped in 2013, after the end of the first commitment period of the Kyoto Protocol[11]. The proposed project generates emission reduction units for Rosneft, which is an important incentive for early project implementation, even though other companies presently cannot avoid APG flaring because of the existing economic barriers (more detailed discussion of economic situation is provided in Section B.2).

Therefore, one may conclude that, in the absence of this project, almost all APG would have been flared, with the exception of small amount of gas, used as heating fuel for own needs of the facilities (in boilers, oil heating furnaces, etc.). High-pressure and low-pressure gas flaring installations at the booster pump stations and preliminary water discharge units are the sources of emissions of CO_2 and methane (see the

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[8] http://www.finmarket.ru/z/nws/news.asp?id=894722

[10] The approved Project of emission limits for facilities involved in preparation and transportation of oil, gas and condensate of RN-Purneftegas Ltd., issued by Ecoproject Ltd., Tumen. The emission permit No. 162 is in effect till 31.12.2010.

[10] The approved Project of emission limits for facilities involved in preparation and transportation of oil, gas and condensate of RN-Purneftegas Ltd., issued by Ecoproject Ltd., Tumen. The emission permit No. 162 is in effect till 31.12.2010.

[11] http://www.rbcdaily.ru/2008/12/05/tek/393401

picture below).[12] The latter is emitted because of underfiring during carbon-black flaring conditions. The estimates of methane emissions are available in the approved 'Emission Limits' document.

The purpose of the proposed project is APG recovery, treatment and separation by low-temperature condensation techniques into the two commercial fractions:

- Dry gas, which is injected into temporary underground gas storage constructed in the Cenomanian gas deposit of yet unexplored large gas field. Gas injection will continue until 2013, after that dry gas will be supplied to the integrated gas transporting system of the Russian Federation.
- Broad fraction of light hydrocarbons, which contains at least 90% of C_3 and heavier hydrocarbons. BFLH will be shipped to the consumers.

Therefore, project implementation will result in useful utilization of large volumes of APG (almost 1 billion m^3) instead of the gas flaring and in total reduction of air emissions by more than 6.8 million tCO_2 (additional analysis on emission reduction is done in Section B.2).

[12] The photo was taken during the site inspection visit at North-Kharampur oil-field in August of 2008. Similar flaring conditions may be observed at the other flaring installations.

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

	Years
Length of the commitment period:	3 years
Year	**Estimate of annual emission reductions in tones of CO_2 equivalent**
2008	0
2009	0
2010	1 393 969
2011	2 650 962
2012	2 795 576
Total estimated emission reductions over the crediting period (tones of CO_2 equivalent)	6 840 507
Annual average of estimated emission reductions over the crediting period (tones of CO_2 equivalent)	2 280 169

A.5. Project approval by the Parties involved:

The project was approved in Russia (Host party) by the Order of the Russian Ministry of Economic Development №709 dated 30th of December 2010.

The approval of the second Party is pending and will be received before first issuance of ERUs.

SECTION B. Baseline

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

The approach chosen by the developer for baseline description and justification uses principles of approved CDM methodology AM0009 "Recovery and utilization of gas from oil wells that would otherwise be flared" version 2.1 (for description of the monitoring plan, calculation formulae for estimation of the emission reductions) and "Recovery and utilization of gas from oil wells that would otherwise be flared or vented" version 3.3[13] (for justification of the baseline choice and additionality argumentation) that is based on the analyses of available alternatives from the standpoint of their economic and legal viability. Thus, the selected project baseline corresponds to the most economically efficient activity, in comparison with the other available alternatives. As Section B.2 shows, the baseline scenario for the proposed project corresponds to flaring of associated petroleum gas at the existing BPS and PWDU sites.

Separately, for calculation of methane emissions during carbon-black flaring conditions in the baseline the domestic methodology "Guidelines for calculation of air emissions from APG flaring" is used, issued by the Research Institute of Air Protection, Saint Petersburg, in 1998. These guidelines were approved by the State Committee for Environmental Protection", the Decision No. 199 of 08.04.98.

Let us describe the applicability of methodology AM0009 v. 2.1 and 3.3. (jointly) in the context of the proposed project.

Methodology applicability conditions	Does the project meet this condition?
APG is recovered and transported: -to gas processing installation, where the gas is separated into dry gas, BFLH and condensate -to the existing natural gas pipeline without processing	Collected APG is transported to BCS where it is processed with production of dry gas and BFLH
Gas is recovered from the active oil wells, which produce oil and associated gas	APG comes from the existing oil wells of Kharampur group of oil-fields: North-Kharampur, South-Kharampur and Festival deposits
The recovered gas and processing products (dry gas, BFLH and condensate) are the most likely substitutes for marketable fuels with the same or higher carbon content	The component composition of dry gas is similar to that of natural gas. Its injection in underground gas storage will only increase the reserves of natural gas in the Cenomanian gas bed, substituting for the extracted gas after the exploration of the gas field starts in 2013. Alternative role of dry gas is substitution of the natural gas in the integrated gas transporting system of the Russian Federation. Despite the temporary storing of the dry gas in the underground storage, the project is by no means a carbon capture and storage activity. BFLH shall be shipped to consumers for production of condensed propane-butane fraction, and used as motor fuel and household fuel.
APG utilization after project implementation will not result in increased fuel consumption at the relevant markets	Taking into account limited throughput capacity of the integrated gas transporting system, the injection of dry gas in the underground gas-holder will lead to reduction of gas recovery at the production sites of Gazprom or

[13] http://cdm.unfccc.int/methodologies/PAmethodologies/approved.html

	independent gas producers. Domestic and export demand for natural and condensed gas in Russia do not depend upon the rate of utilization of associated petroleum gas, because this rate has remained quite low during several past years.
Project activity will not affect (positively or negatively) the volumes of production and consumption of oil and high-pressure gas	Project activities (recovery, transportation and refining of associated gas) belong to the category of “end-of-pipe” technologies and shall not affect oil production at Kharampur group of oil-fields. Project implementation cannot affect gas-oil ratio which depends upon natural factors.
Energy required for transport and processing of the gas is generated by using the recovered gas	Objects are to be used in the project activity for transportation and processing of the APG consume only electricity for technological purposes except of turboexpander at the BCS site fed by recovered APG. A heating is provided with use of only the recovered gas as a fuel. The electricity consumption is accounted which is conservative.
The data on quantity of carbon and carbon content in the products of APG processing are available	The data about volume and component composition of APG and the products of its processing shall be available to project participants. Project monitoring system enables project participants to measure these parameters.
The project does not include gas from gas-lift systems	Gas-lift systems are not utilized at Kharampur group of oil-fields.

Following deviations are made from the used CDM methodology AM0009 version 3.3 “Recovery and utilization of gas from oil wells that would otherwise be flared or vented”:

a. Instead of prescribed CDM “Combined tool to identify the baseline scenario and demonstrate additionality” a CDM “Tool for demonstration and assessment of additionality”, version 05.2 was used.
b. Formulae for calculation of the baseline emissions, project emissions, leakages and emission reductions are taken from AM0009 version 2.1
c. Monitoring methodology including monitoring plan is taken from AM0009 version 2.1

A main reason for the project developer not to apply AM0009 v. 3.3 equations for calculation is the accounting of the balance difference of carbon between APG and products of its processing as methane (CH_4) emissions from its venting, leaks through stop valves and joint leakiness or flaring which may result in large potential uncertainty in ERUs estimation.

- In time of PDD development only the technical design documentation was available where the modelled projection of amounts of dry gas and BFLH was made, based on APG composition test. However the composition of APG changes slightly and amount of APG that really will be fed for the processing also differs from initially designed.
- Since the version 3.3 of AM0009 accounts all the difference in the carbon balance between APG and products for CH_4 emissions with respective multiplication factor 21 it has a significant influence of uncertainty between estimated and really received ERUs. At the same time, the CH_4 leakages on the pipelines during transportation and due to emergency situation are not accounted in version 3.3. while in the project there are long gas pipelines.

To avoid the unwanted uncertainly in ERUs estimation and to ensure conservativeness the version 2.1 was used.

Key information and data used to establish the baseline

Data/Parameter	$V_{A\ APG}$
Data unit	m^3
Description	The volume of APG recovered at the sites of Kharampur group of oil-fields which enters the BCS.
Time of determination/ monitoring	Continuously during project activity
Source of data (to be) used	APG flow measurement at BCS entry point A at graph D.1.1. Data is stored in the Automated data collection and transmission system
Value of data applied (for ex ante calculation/ determinations)	Monitored ex-post
Justification of the choice of data or description of measurement methods and procedures (to be) applied	The parameter is defined in line with AM0009 v. 2.1. The volume is measured at the entry point of BCS where the collected APG is further processed. In the baseline the equivalent amount of the APG would be flared.
QA/QC procedures (to be) applied	See section D.2.
Any comment	

Data/Parameter	$w_{A\ APG}$
Data unit	vol.%; mass %
Description	The component composition of APG is monitored at the entry point of BCS site.
Time of determination/ monitoring	Each 10 days during the project activity
Source of data (to be) used	APG composition sample measurement at BCS entry point A at graph D.1.1.
Value of data applied (for ex ante calculation/ determinations)	Monitored ex-post
Justification of the choice of data or description of measurement methods and procedures (to be) applied	The parameter is defined in line with AM0009 v. 2.1. The APG composition at the entry point of BCS is measured by chromatograph where the collected APG is further processed. Then the carbon content is calculated. Average data for 1 year is taken for baseline emissions calculation.
QA/QC procedures (to be) applied	See section D.2.
Any comment	

Data/Parameter	ρ_{APG}
Data unit	kg/m^3
Description	APG density
Time of determination/ monitoring	Each 10 days during the project activity
Source of data (to be) used	APG composition measurement at BCS entry point A at graph D.1.1.
Value of data applied (for ex ante calculation/ determinations)	Monitored ex-post
Justification of the choice of data or description of measurement methods and procedures (to be) applied.	The parameter is defined to calculate the mass of APG for further calculation of the mass of carbon in it.
QA/QC procedures (to be) applied	See section D.2.
Any comment	Calculated on the basis of APG component composition data

Analysis of available alternatives and baseline selection

Baseline selection and justification of additionality are based on the strict observance of national legislation, economic attractiveness and existing barriers. We analyzed following alternatives defined in methodology AM0009 v.3.3 for identification of the baseline scenario:

Alternative (1) Ventilation (release) of APG to the atmosphere at the oil production site;

Alternative (2) On-site APG flaring;

Alternative (3) Utilization of APG for heat and electricity generation;

Alternative (4) Utilization of APG for on-site production of liquefied gas;

Alternative (5) Injection of APG in oil or gas bed;

Alternative (6) Recovery and transportation of APG and the products of its processing to final consumers, without JI project registration;

Alternative (7) Recovery, transportation and utilization of APG as raw material for production of commercial products.

Alternative (1) Ventilation (release) of APG to the atmosphere at the oil production site

Release of APG to the atmosphere is prohibited by Preventive fire-fighting regulations for oil and gas industry[14]. Moreover taking into account volume of the recovered APG the venting of the high-explosive gas would be quite dangerous. Gas release is also prohibited by environmental legislation and is not justified in "Emission limits" document. Gas venting would have caused the company to pay unreasonably high penalties for release of methane and other hydrocarbons to the atmosphere.

Alternative (2) On-site APG flaring

This scenario is currently implemented at Kharampur group of oil-fields. Since the beginning of oil production and until today, the subsoil user of Kharampur group was not obliged to utilize any specified fraction of this gas, according to its user license.[15] Actually, environmental permits officially sanction gas flaring.[16] Besides, the current Russian legislation does not prohibit APG flaring.

By 28 March 2008 the State Commission on fuel and energy sector sent for redrafting the proposals of Ministry of Industry and Energy "On utilization of associated petroleum gas (APG)". This document set the target to bring the level of APG utilization to 95% by 2011, when all production wells shall have to be equipped with meters. Earlier, Ministry of Natural Resources proposed to suspend (by mid-2008) the operations at all wells that did not have meters. The Proposals of Ministry of Industry and Energy also required that dry gas, which is produced during APG processing, should be preferentially supplied to Gazprom gas transporting system. However, the State commission was of opinion that the Proposals did not provide enough incentives for APG utilization.

Rostechnadzor has proposed to increase the penalties for APG flaring, and to use economic incentives for APG utilization. One of such incentives is abatement of export tax for condensed hydrocarbons –

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[14] Preventive fire-fighting regulations for oil and gas industry 08-624-03, This document was approved by Gosgortephnadzor (State Mining Technical Supervision), the Regulation No.56 of 05.05.2003, p.3.5.4.112.

[15] Licensing agreement about the terms of exploitation of subsoil of Kharampur oil-field, Annex I to the license held by OJSC "NK Rosneft" of 08.11.2006.

[16] Project of emission limits for facilities involved in preparation and transportation of oil, gas and condensate of "RN-Purneftegas" Ltd., issued by "Ecoproject" Ltd., Tumen. This document was approved by State Environmental Expertise, the Decision No.794 of 30.10.2006, and by Department for Technological and Environmental Surveillance of Rostechnadzor for Yamalo-Nenetsky Autonomous District, the Decision No.1231-e of 30.10.2006. The emission permit No. 162 is in effect till 31.12.2010.

products of APG processing. Gazprom has recently proposed this initiative to the Government, Ministry of Fuel and Energy, and Ministry of Industrial Development. Today, gas export tax is tied to the international price of Urals oil brand. At the same time, Russian gas transportation system can hardly offer preferential acceptance to dry gas suppliers. The reason is that dry gas, produced from APG, comes from remote production sites, where inter-site infrastructure is often lacking. So far, Russian Government has made only one real step to provide incentives for APG utilization: in February of 2008, it decided to liberalize prices for APG, which is supplied to gas-processing plants.[17]

Despite all attempts of the legislators to create incentives for APG utilization, APG flaring still remains the most economically attractive option, because flaring does not require additional investments. The decision about implementation of this project was made in 2006, when alternative (2) seemed the most likely baseline scenario.

Alternative (3) Utilization of APG for on-site heat and electricity generation
BPS and PWDU sites currently use APG as fuel to cover their heating demands. APG is burned in gas boilers and in the furnaces for oil preheating, which prepare oil for transportation.

Kharampur oil production facilities receive grid electricity from "Tumen Energo" power lines. Annual electricity consumption of booster pump stations at Kharampur group of oil-fields is 4,269,159 kWh/year.[18] Formation of large amounts of recovered APG (1 billion m^3 in 2012) means that this gas cannot be fully utilized for on-site electricity generation if only to cover own needs. To solve the problem of APG flaring for the whole volume of the recovered gas a big power plant needs to be constructed. The company does not want to sell electricity to the grid, because of the following reasons:

- It does not correspond with the company's business objectives: the company has to cover in the first place its own energy demands for oil production, but not to be independent power generation company.
- When on-site power station operates in parallel with the grid, fixed frequency and dispatched controlled rate of production of electric current has to be maintained, which is not always possible because of variations in component composition of APG at Kharampur group of oil-fields. To ensure a stable burning of the gas in turbine or combined cycle unit the APG needs to be processed into dry gas, i.e. capital expenses has to be made for APG collection and processing and then another expenses will be needed for power station implementation.
- Electricity sales to the grid require complex bureaucratic procedures of approvals

A General Scheme of Electricity Generation Objects Placement until 2020 approved by Russian Government Decree #215 by 22.02.2008 contains only one greenfield power station in Yamalo-Nenets Autonomous District for implementation in 2008-2015 – this is combined cycle heat and power plant at Tarko-Sale town, which is 130 km from Kharampur site, to be commissioned in 2011-2015. However this station will be fired with natural gas which is abundant in that area and produced at many of the natural gas fields located in proximity of Tarko-Sale.

A small gas-piston power station (GPPS) has been installed at the MPS site, to cover own needs of the facility and to save on external electricity purchases. This power station could also act as a back-up electricity source in case of emergency or cut-offs. This power station is now conserved. According to the original project, GPPS should use APG, but the gas from Kharampur group of oil-fields is rather "fat", with high content of propane and butane fraction. Because this gas contains only 80% of methane, it is not suitable for fueling GPPS. In the result, a rather expensive GPPS remains idle. According to RN-Purneftegas business plan for 2009-2013, the company will invest additional resources in this power plant, improve its design, and fuel it with APG.

[17] http://gasforum.ru/novosti/1336/

[18] Source: RN-Purneftegas data

Nevertheless, large-scale on-site electricity generation and full utilization of co-produced APG cannot be considered a viable alternative.

In the existing legislation, there are no barriers or significant incentives for implementation of this alternative.

Alternative (4) Utilization of APG for on-site production of liquefied gas

Liquefied gas is a cryogenic liquid, which consists of hydrocarbons C_1-C_{10} and nitrogen, with dominating share of methane (85-99%).

Liquefied gas is produced from natural gas by cooling it down to cryogenic temperatures: -130ºC … -160ºC. Its boiling point under atmospheric pressure is -160ºC…-162ºC.

Associated petroleum gas is a “fat” gas with high content of heavy hydrocarbons (propane, butane and heavier). This property of APG makes it a valuable resource for BFLH extraction. For this purpose, a special installation for separation of APG into dry gas fraction (similar to natural gas) and BFLH fraction is needed.

Handling and shipment of cryogenic gas require special containers for low-temperature transportation. Additional investments in construction of condensation plant and shipment terminal will be required in this scenario. On the other hand, it is very hard to make projections about future demand for liquefied gas in Russia, because this fuel is still quite new.

Large volumes of co-produced APG (1 billion m^3 in 2012) render pipeline transportation to be the only viable transportation option. Rosneft has not studied the feasibility of construction of liquefied gas plant.

In the existing legislation, there are no barriers or significant incentives for implementation of this alternative.

Alternative (5) Injection of APG in oil or gas bed

Backward injection of associated petroleum gas into oil or gas bed allows maintaining the output of oil wells. The reservoir pressure at Kharampur group of oil-fields is historically maintained by pumping the water. For oil production are used the bore-hole pumps and sucker-rod pumps while gas-lift systems is not utilized.

The project proposes to inject dry gas to TUGS, but this measure is not aimed at maintaining reservoir pressure, or increasing well production. TUGS shall be constructed in a separate and yet unexplored Cenomanian gas deposit, with the sole intent to preserve dry gas until it can be delivered to the integrated gas transporting system of the Russian Federation.

Alternative (6) Recovery and transportation of APG and the products of its processing to final consumers, without JI project registration

This option is a project scenario at Kharampur group of oil-fields. The following objects will have to be constructed for its implementation:

- Pipelines and infrastructure for recovery and transportation of APG to the BCS site, where the gas is separated into fractions;
- The installation for gas treatment and fractionalization into dry gas and BFLH (BCS site);

- The cluster of injections wells and all related infrastructure because the gas will be injected in temporary gas storage during the first few years, and after that it will be supplied to Gazprom gas pipeline system;
- Pipelines and infrastructure for transportation of dry gas and BFLH.

According to project design, total length of the pipelines shall be 97.829 km, of which 85.229 km will connect the existing production sites of Kharampur group to the newly constructed BCS, and 12.6 km pipeline will connect the BCS site with gas-distributing points of well clusters.

As Section B.2 shows, this alternative can be economically sustainable only with sales of ERU via JI mechanism. Without such mechanism, the company does not have enough economic and legal incentives to implement this project.

***Alternative (7) Recovery, transportation and utilization of APG as raw material for production of commercial products*.**

Remote location of oil production sites in West Siberia historically dictated fractionalization of APG and transportation of the products of APG processing primary by pipelines to south regions of Siberia and European part of Russia, closer to producers and final consumers of higher transformation levels of the hydrocarbon feedstock. Moreover, cold northern climate requires higher fuel consumption for technological needs and transportation costs for commercial gas conversion products.

Rosneft considered the option to build a methanol production facility at Kharampur site in 2006, but decided against it by commercial reasons.[19]

In the existing legislation, there are no barriers or significant incentives for implementation of this alternative.

Conclusions

Among the described above alternatives, alternative (2) is most economically and technically feasible. It does not violate the norms of Russian legislation. This option is simply a continuation of the existing practice of gas flaring. This is why we have selected it as the baseline scenario. The project scenario is alternative (6). We rejected the other considered options because of the following reasons. Alternative (1) contradicts Russian legislation. Alternative (5) is technically inappropriate. Alternatives (3), (4) and (7) are quite unlikely because they cannot fully solve the problem of APG utilization or demand as a first step the APG collection and processing, (proposed project) apart from the other costs related to the technology and therefore are more costly than alternative (6).

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

We used the approach described in Methodology AM0009 v.3.3 to demonstrate that GHG emission levels will be lower in the project scenario, than in the business-as-usual scenario. The CDM "Tool for demonstration and assessment of additionality", version 05.2 was used which consists of the four steps:

STEP 1. Identification of alternative scenarios;
STEP 2. Investment analysis;
STEP 3. Barrier analysis;

[19] The meeting journal of Investment committee of OJSC "NK Rosneft" of 15.09.2006.

STEP 4. Common practice analysis.

The first step was described in Section B.1.

Description of the baseline scenario
Continuation of on-site APG flaring at the existing PWDU and BPS sites of Kharampur group of oil-fields.

Description of the project scenario

Recovery, collection, treatment and fractionalization of APG from Kharampur group of oil-fields by low-temperature condensation techniques into the two commercial fractions: dry gas and BFLH. Dry gas will be compressed and injected into temporary underground storage constructed in Cenomanian gas deposit of yet unexplored large gas field until 2013. This gas will be then supplied to the integrated gas transporting system of the Russian Federation. Broad fraction of light hydrocarbons will be shipped to the consumers immediately after its production.

A component composition of dry gas is similar to that of natural gas. Its injection in underground gas storage will only increase the reserves of natural gas in the gas bed, substituting for the recovered gas after the exploration of the gas field starts in 2013. After that the dry gas will substitute the natural gas in the integrated gas transporting system of the Russian Federation. Because of limited throughput capacity of this system, the injection of dry gas in the underground gas-holder will lead to reduction of gas extraction at the production sites of Gazprom or independent gas producers.[20]

In both of these scenarios, dry gas, which was previously flared, will replace a natural gas – the fuel with the same carbon content.

In any case even though the dry gas during first years of the project operation does not enter the gas transportation system operated by Gazprom and thus, during these years there is no immediate replacement of the natural gas in the pipeline by the dry gas from processed APG, the CO_2 and CH_4 emissions due to flaring no more takes place and thus, emissions previously existed are actually prevented already in 2010-2012. However, to be in line with logic of the applied methodology AM0009 and since the project activity is by no means a carbon capture and storage activity and temporary storing of the dry gas in the underground storage is considered as a deferred replacement of the natural gas in the integrated gas transportation system during 2010-2012, which actually will happen for the dry gas already pumped into TUGS, when the access to the trunk gas pipeline would be open in 2013.

BFLH has many uses. This product is a valuable raw material for petrochemical industry, where it is used for production of polymers, plastics, rubber articles, etc. Its utilization by petrochemical industry means that its carbon content is mostly transferred to these petrochemical products. BFLH mainly consists of the light propane-butane fraction, and may be processed into condensed gas, which is used as motor fuel and household fuel.

Recent rise of oil prices resulted in increase of prices of petrochemical products. The propane-butane fraction has become an attractive substitute for traditional gasoline and diesel fuel. Its attractiveness increases rapidly, because it is two times cheaper than gasoline. Many vertically integrated oil companies (TNK BP, Gazprom Neft, Tatneft, Lukoil and others) plan to invest considerable financial resources in development of the existing sales networks (or in construction of new networks). These plans include

[20] http://www.barrel.ru/news/2007/08/20/news_7.html

construction of multifuel gas stations, which sell propane-butane mixture along with gasoline and diesel fuel.[21]

The conservative estimates show that utilization of BFLH results in substitution of propane-butane motor fuel (with the same carbon content) or traditional gasoline and diesel motor fuels (with even higher carbon content).

Additionality
To prove project additionality we used investment analysis and analysis of barriers. Then we considered common practice for such type of the projects.

Investment analysis
We will compare two scenarios of project implementation:

- Without registration under JI mechanism
- With registration under JI mechanism.

Table B.2.1 Main project indicators without registration under JI mechanism

Capital costs with VAT	million RUR	**7 434**
Operational costs	million RUR	**2 489**
Internal rate of return (IRR)	**%**	**12.6%**
Net present value NPV (10%)	million RUR	**1 049**
Discounted payback period DPP (10%)	**years**	**15.7**

Rosneft conducted internal economic evaluation of project activities in 2006, for the period 2006-2030, before making an investment decision. Project evaluation was based on the existed capital costs and the prices for commercial products: dry gas and BFLH. Rosneft assumed that dry gas would be initially injected into underground storage, and there would be no sales of dry gas during the first few years of project implementation. Furthermore, it was assumed that the operation of underground gas-holder would begin in 2013 and all accumulated gas would be sold on the market during that year.

Rosneft considered the plans of utilization of associated gas at Kharampur group of oil-fields several times.[22] The initial estimates of economic efficiency of this project were rejected by the company's Investment Committee and sent for revision. Closely after that the company became interested in JI mechanism and decided to collaborate with the World Bank on APG utilization projects, for instance on Purneftegaz operated Komsomolskoe oil field.[23] The Kharampur project has been approved for implementation after inclusion of potential profits from ERU sales in the economic analysis, assuming that the project would be registered under JI mechanism.

The basic economic indicators of JI project at Kharampur site are shown in Table B.2.2, under the following assumptions:

- ERU price is 8 Euro per ton of CO_2-eq.

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[21] http://www.kommersant.ru/doc.aspx?DocsID=797533

[22] The meeting journal of Investment committee of OJSC "NK Rosneft" of 15.09.2006

[23] http://ji.unfccc.int/JI_Projects/DeterAndVerif/Verification/PDD/index.html Project #108

- The exchange rate is 34.29 RUR/Euro.[24]
- The discount rate is 10%.

For estimation of the total emission reduction potential the initial plans to start APG recovery in 2009 were taken into account. In this scenario, annual revenue from ERU sales was 732.4 million RUR.

Table B.2.2 Main project indicators with registration under JI mechanism

Capital costs with VAT	million RUR	**7 434**
Operational costs	million RUR	**2 489**
Internal rate of return (IRR)	**%**	**15.7%**
Net present value NPV (10%)	million RUR	**2 293**
Discounted payback period DPP (10%)	**years**	**11.3**

The above analysis proves that registration under JI mechanism considerably increases the investment attractiveness of the project. Since only Rosneft company can implement the considered project the developer applied for comparison the internal IRR benchmark of 15% existed in Rosneft for the past years, before the global economic crises begun in autumn 2008.

For demonstration of reasonableness of this internal benchmark in Russian circumstances it should be noted that the discount rate of Central Bank of Russian Federation in 2006 was 11-11.5%[25] and a wide-spread interest rate of banks for long-term credits in RUR was 14-16%.

ERUs sales increased IRR to make it higher than required 15% and payback period of 15 years became rather shorter, because of the additional carbon revenue.

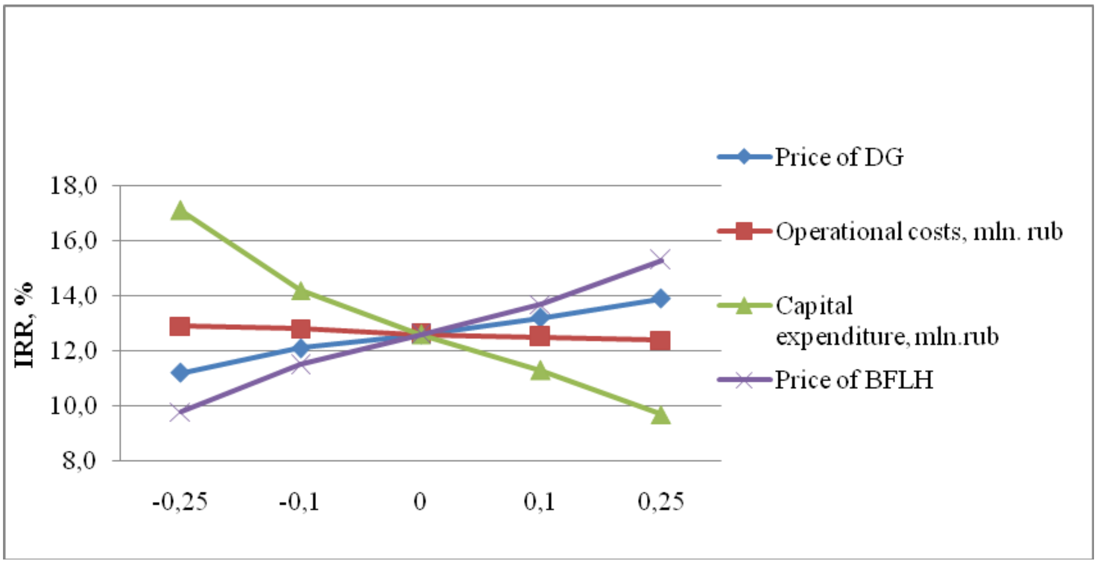
Project developer performed a sensitivity analysis study for situation when the project is implemented without registration under JI mechanism. The purpose of sensitivity analysis was to compare relative influence of various assumptions on the key economic effectiveness indicators (IRR and DPP).

Sensitivity analysis involved small changes in the input parameters: prices of dry gas and BFLH, capital and operational costs. These changes were assumed to be in the range from –25% to +25%. Varying each input parameter, we measured the consequent changes of IRR. The results of sensitivity analysis are summarized on Graphs B.2.1 and B.2.2.

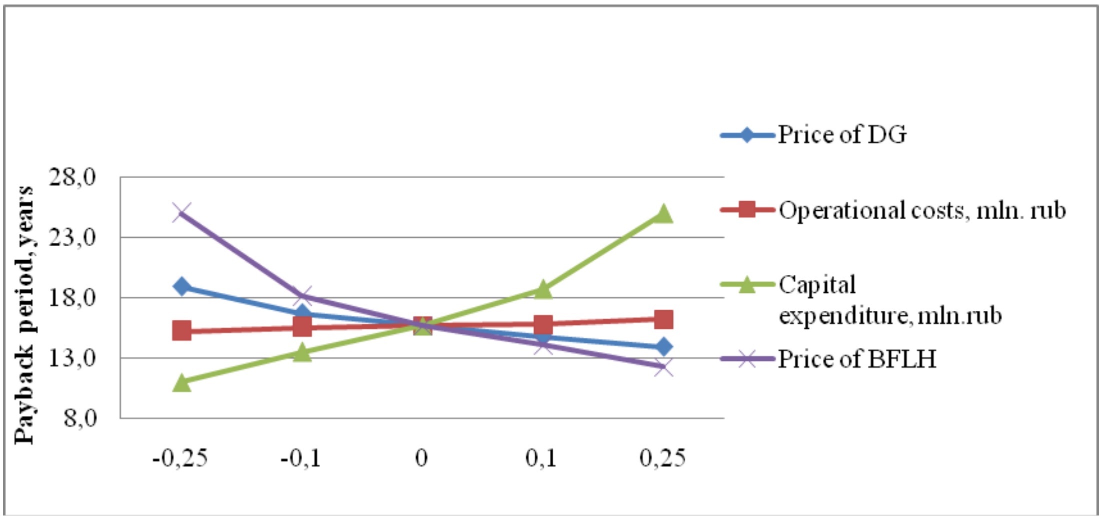
[24] As of January 2006, http://www.kurs.metrinfo.ru/kurs/2006-1-3/

[25] http://www.arbis1c.ru/useful/22.shtml

Graph B.2.1 Sensitivity analysis: IRR response to variations of the input parameters



Graph B.2.2 Sensitivity analysis: Response of investment project payback period to variations of the input parameters



Sensitivity analysis showed that IRR and DPP are more sensitive to the changes in capital costs and BFLH price, than to the changes of operating costs and dry gas price. The variation of capital costs in the range from –25% to +25% resulted in the change of IRR ~7%, while the difference between maximum and minimum value of project payback period is 14 years. Similarly, 25% decrease of BFLH price brought IRR down to 9.8%, which was less than the discounting rate, while the project payback period increased to 25 years. 25% increase of capital costs had almost the same effect on IRR and DPP. In other words, such changes in BFLH price or capital costs rendered this project unprofitable.

Economic indicators of investment projects are usually quite sensitive to the increase in capital costs, because of observed until a middle of 2008 prices increase in Russia and elsewhere, especially the increase of prices for metals. Even small changes in capital costs may significantly worsen economic indicators of investment projects with low efficiency (i.e., the projects without ERU sales). This really happened in 2007 after metal and compressor equipment price leap that increased capital investment into the project more than two times in comparison with 2006 estimates on the moment of investment decision making[26]. Thus, the demonstrated analysis is conservatively and reasonably describes the economic attractiveness of the project which is in past time turned out to be even worse.

Barrier analysis

Addressing the Federal Assembly in April of 2007, Russian President Vladimir Putin mentioned that flaring of large volumes of APG is a big problem of Russian fuel and energy sector. According to official estimates, 57.9 billion m^3 of APG was annually recovered 24.4% of which was flared in Russia[27].

After the President's declaration, Russian ministries and agencies put forward several initiatives in this area. To prevent flaring, they proposed several mandatory measures for the companies. Despite the political will to solve this problem, one may hardly expect that the government plan to raise the share of APG utilization up to 95% will be accomplished in the near future, as Russian ministers pointed out.[28] The Government so far has been largely unsuccessful in its efforts to propose a countrywide policy to reach this ambitious goal. Technical design cycle for projects of APG utilization may take between 3 and 5 years.[29]

APG utilization in 1990s was difficult because of gas processing industry crisis. Russian oil companies did not have enough funds in the conditions of unprecedentedly low oil prices. Rapid growth of oil prices in early 2000s and governmental efforts boosted oil production volumes. In 2006, Russia became the unofficial world leader in the volumes of flared APG, because of numerous barriers to APG utilization (which the Government addresses today). At that time, Rosneft decided to utilize APG at Kharampur group of oil-fields. Hence, this document analyzes the barriers that existed in 2006.

Barrier No.1 Associated gas price regulation and price disproportions

The net cost of APG recovery is initially higher than that of natural gas, because of high capital costs of construction of infrastructure for collection, transportation and processing of APG, and because of technological complexity of APG recovery. The abovementioned obstacles make APG utilization activities unprofitable for oil producing companies, especially at small and remote oil fields with limited APG resources.

In the 1990s, after the collapse of Soviet economic system and transition to market economy, the problem of APG utilization shifted from macroeconomic level of "national economic efficiency" to microeconomic level of company's cost-effectiveness. The production capacities of Siberian gas-processing plants became underused after oil production fell down at many large but exhausted oil fields, and because oil companies did not have the system of APG recovery and transportation from the distant oil fields. Some gas-processing facilities were temporarily abandoned.

At the same time, low oil prices and economic instability provided disincentives to utilize APG at newly explored oil-fields. In 1995, Siberian state-owned gas processing plants merged into SIBUR company, which had the authority and responsibility to address gas processing problems. SIBUR proved itself unprofitable, because the government, in its attempt to save a petrochemical complex from collapse, regulated the disbursing prices for BFLH (the main product of gas processing) and liberated the prices for

[26] Economic part of Technical project "Collection, preparation, compressing and injection of low-pressure gas of Kharampur group of oil-fields into Temporary underground gas storage (TUGS), in the amount of 1 billion m^3 per year" (by VolgaUralNIPIgas Ltd., 2007)

[27] http://www.lawtek.ru/news/tek/40363.html

[28] http://www.lawtek.ru/news/tek/40363.html

[29] http://www.erta-consult.ru/index.php?option=com_content&task=view&id=289&Itemid=62

associated gas, the raw material purchased by gas processing plants, which made this price plummet with inflation.

After this, the State reintroduced regulation of APG and dry gas price (Decree No. 239 of 7 March 1995).[30]. Between 2002 and 2008, during price regulation period, the price for APG remained practically the same. The disproportion of prices is illustrated by the following fact: the maximum state regulated price for APG was $17 per 1000 m^3 (depending on content of the heavier hydrocarbons it varied from 73 to 442 RUR per 1000 m^3), while the price of the two main products of its processing (natural gas and propane-butane) was over $85[31].

According to the estimates of oil companies, the transportation of APG from remote fields to gas-processing stations increases APG price to $30 per 1000 m^3, rendering its processing unprofitable, because the net cost of natural gas recovery is only $4-7 per 1000 m^3 (Gazprom estimate). This is why oil companies prefer to flare APG.

The Government abolished the severance tax with the goal to stimulate subsoil users to utilize APG in 2001. At the same time, the penalties for the gas flaring were quite low (50 RUR per ton of methane within the maximum permissible emission limit and 250 RUR per ton of methane for emissions within the temporary approved emission limit,[32] and the sale price of APG for gas-processing plants was regulated by state. Oil companies had more incentives to flare APG than to process it. Between 2000 and 2005, the volume of flared APG increased from 6.6 billion m^3 to 14.9 billion m^3, according to official data. It means more than two-fold increase, while oil production in Russia increased only by 50% during the same period.

Barrier No.2 Limited access to the integrated gas transporting system

Russia produced 346 billion m^3 of natural gas in the first half of 2008. During the same period, Gazprom produced 289.6 billion m3, and the largest independent gas producer NOVATEC supplied only 15 billion m^3 to the integrated gas transporting system (the data reported by state enterprise CDU TEC). Oil companies produced 28.4 billion m^3 of gas, of which LUKOIL and Surgutneftegas produced 7 billion m^3, Rosneft produced 6.6 billion m^3, and TNK-BP produced 4.9 billion m^3. Today, independent gas producers supply only 14-16% of total gas production volume, but in principle their share may increase to 30%.[33]

According to the existing rules, Gazprom may limit the supply of gas of independent producers to the gas transporting system, if the system lacks free volume for pumping. Because the oil-producing regions of Yamalo-Nenetsky Autonomous District lie to the south of main gas reserves of Gazprom and other gas suppliers, the local oil producers gain access to the gas transporting system in the last turn. Moreover, RN-Purneftegas works in the most congested (from transportation viewpoint) region: Nadym-Pur-Tazovsky.

Gazprom assessed the capacity of other gas producers to act as co-investors during upgrading and extension of gas transporting infrastructure in 2003.[34] But the anticipated investments only increase

[30] tarif.kurganobl.ru/assets/files/laws/Postanovlenie_N239_07.03.1995.pdf

[31] http://www.expert.ru/printissues/expert/2007/30/sankcii_protiv_gazovyh_fakelov/print

[32] The Decree of the Government of the Russian Federation No. 410 of 01.07.05 “On amendments to annex 1 to the Decree of the Russian Government No. 344 of 12.06.03”.

[33] http://www.kommersant.ru/doc.aspx?DocsID=909849&NodesID=4

[34] http://www.avias.com/news/2003/06/18/54143.html

capital costs of facilities for recovery and utilization of associated gas, and these costs are already high enough. Besides, Gazprom retains some freedom to play with the tariffs for gas transportation.

The former deputy minister of economic development Andrey Sharonov said: "Independent producers tried to gain access to Gazprom pipelines during 15 years, and failed".[35]

These two main barriers for implementation of Kharampur project hindered Rosneft's approval of this project. At the same time, the possibility to capitalize the proceeds from ERU sales enables the company to insure certain fraction of its financial risks. This is a serious argument in favor of implementation of APG utilization project in its current form.

Common practice analysis

According to Russian Ministry of Natural Resources, only 26% of 55-60 billion m^3 of annually recovered APG is being processed, about 27% is flared, and the remaining 47% is used by subsoil exploration companies for their own needs, or reported as technological losses in Russia. Therefore, the rate of APG utilization varies between 50 and 70%.

Gas flaring poses a risk for the environment because of large emissions of combustion products and unburnt gas. Annual emissions from flaring reached 1.8 million tons.[36]

Another source of official data reported that Russian oil companies flare about 14 billion m^3 of associated petroleum gas, of which 92% is flared by the five largest oil producers: Rosneft, LUKOIL, TNK-BP, "Gazprom Neft" and Surgutneftegas. Even Surgutneftegas, which may utilize 95% of its APG at its own gas processing plant, flares over 1 billion m^3 of the gas every year. The leaders in APG flaring are "Rosneft" with 5 billion m^3 and "Gazprom Neft" with 3.5 billion m^3.

The differences in official estimates of the rates of APG flaring are caused by inadequate monitoring. Many oil wells do not have flared gas meters. The problem of accounting for flared APG has never been a priority for oil companies and regulating agencies until very recently.

The Russian APG is processed mainly by SIBUR company which is a petrochemical holding. However large gas processing plants (GPP) of SIBUR located in Khany-Mansiisky and Yamalo-Nenetsky autonomous districts are constructed 30 and more years ago during Soviet Union time. The last gas processing plant in USSR and Russia was commissioned in 1989[37].It means that those plants cannot be considered in common practice analysis because were implemented in absolutely other economic circumstances and time.

There are no examples of large scale greenfield APG processing implemented so far. There are a number of examples of small scale APG processing plants owned as, as a rule, by the specialized independent companies. For large scale processing there is one recent example of commissioning the previously inoperative gas processing installation MAU-3 at Nizhnevartovsky GPP performed by specially created TNK-BP-SIBUR joint venture[38]. However this project is not a greenfield but only recovery of previously abandoned equipment.

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[35] http://www.minenergopress.ru/monitoring/11226/

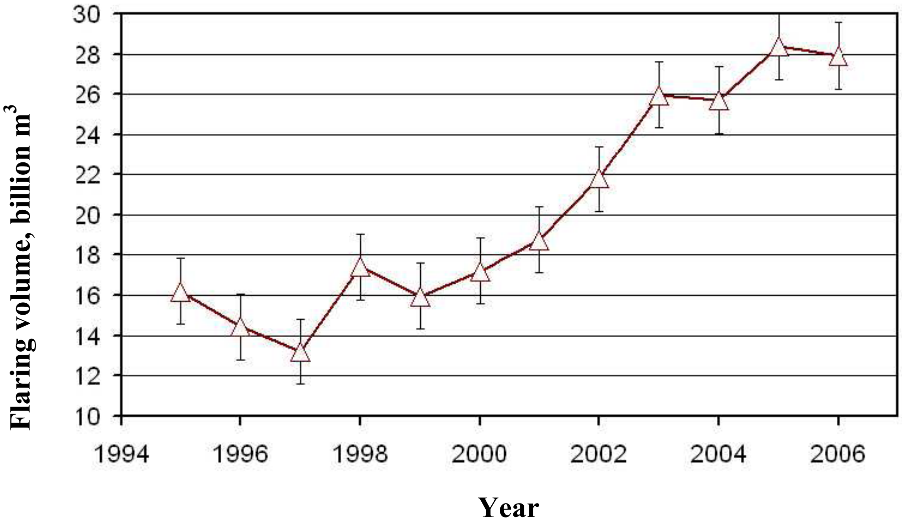
[36] http://www.prime-tass.ru/news/show.asp?id=695594&ct=news

[37] http://www.nisse.ru/analitics.html?id=gas-IV-karisalov

[38] http://www.sibur.ru/112/179/140/index.shtml?id=3621

The other main difference is that in most of the cases oil companies realize their APG utilization programmes because of mandatory APG useful utilization percent rate prescribed in the license for oil field exploration. However as it mentioned before Rosneft does not have a mandatory APG utilization rate for Kharampur group of oilfields and preformed project is a voluntary activity.

Graph B.2.3: APG flaring in Russia, billion m^3 per year (excluding Khanty-Mansijsky Autonomous Okrug)[39]



The analysis of project indicators of 2006, when Rosneft considered utilization of APG at Kharampur group of oil-fields, shows that the project economic efficiency was indeed very low, and investment payback period was quite long, because Rosneft could not hook up to Gazprom gas transportation system to sell commercial dry gas. This will not be possible at least until 2013. Therefore, APG flaring was the most economically viable option at that time, and, moreover, this practice was widespread and common in the Russian Federation.

The decision about project implementation was taken with the hope to attain very significant additional investments in the form of revenue from ERU sales (an estimated 60 million EUR in 2006). Implementation of this project would be possible only in the framework of Joint Implementation mechanism under Article 6 of the Kyoto Protocol[40].

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

The project is defined within the following boundaries:

- Oil wells producing the mixture of associated gas, oil and water;
- Facilities for initial oil treatment (BPS and PWDU at Festival, South-Kharampur, and North-Kharampur oil-fields equipped with flares).
- Infrastructure for collection and transportation of APG and processing products, including APG collecting pipelines at Kharampur group of oil-fields, compressors, and line stop valves
- BCS site with gas treatment facilities
- Facilities for gas injection in TUGS and the storage itself

[39] NOAA, 2007. A Twelve Year Record of National and Global Gas Flaring Volumes Estimated Using Satellite Data. Final Report to the World Bank - May 30, 2007.

[40] http://www.ks.yanao.ru/15/1/271/

- MPS for delivery of BFLH to consumers.

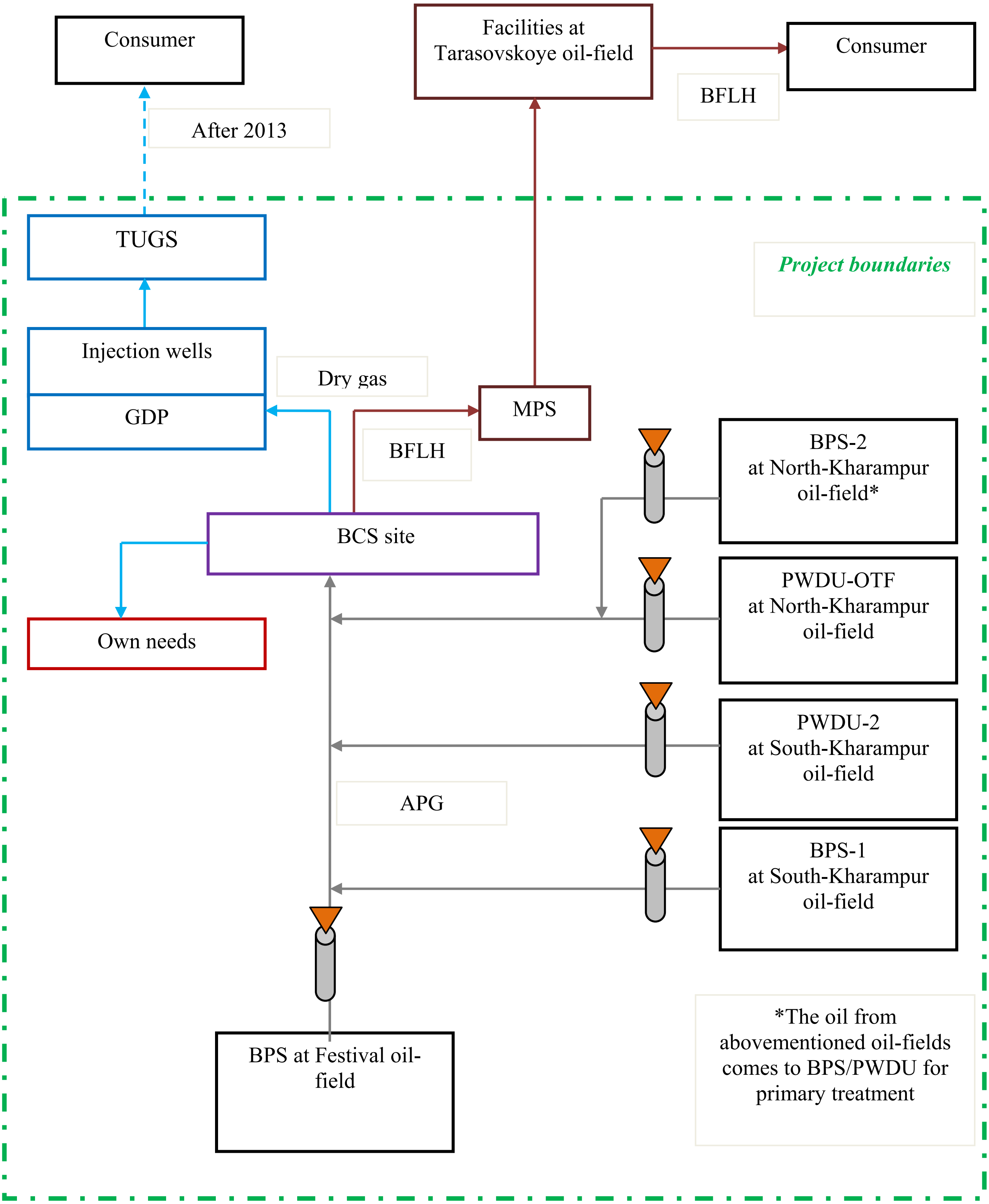
Table B.3.1: Emission sources under baseline and project scenarios

	Emission source	Gas	Included/not included	Comments
Baseline scenario	APG flaring	CO_2	Included	Principal emission source in the baseline scenario
		CH_4	Included	The existing flares underfire methane and emit soot
		N_2O	Not included	Assumed negligible
Project scenario	Emissions from use of APG and other fuels within project boundaries	CO_2	Included	Principal emission source in the project scenario. Use of the fuel other than APG and dry gas produced from it is not envisaged in the project.
		CH_4	Not included	Excluding methane emissions from joint leakages, during blowing, etc. (leaks are listed separately)
		N_2O	Not included	Assumed negligible
	Gas leaks from joint leakiness, during pipeline transportation, and during storage in TUGS	CO_2	Not included	Assumed negligible
		CH_4	Included	Calculations are based on gas blowing volumes and IPCC-2006 emission factors
		N_2O	Not included	Assumed negligible
	Emergency leaks of gas	CO_2	Not included	Assumed negligible
		CH_4	Included	Emergencies in gas mains or installations may lead to significant emissions of methane to the atmosphere
		N_2O	Not included	Assumed negligible
	Emissions from energy consumption within project boundaries	CO_2	Included	CO_2 emissions during mains electricity generation
		CH_4	Not included	Assumed negligible
		N_2O	Not included	Assumed negligible

CO_2 emission sources within project boundaries include facilities to be constructed during project implementation, for collection and utilization of APG (see Annex 5). Under conservative approach, energy consumption by the existing BPS and PWDU is included in emission sources, because additional compressors will be installed there during project implementation.

The project does not include emissions from energy consumption by other facilities (well pumps, etc.) and from APG consumption for own needs of the existing and newly constructed installations (BPS, PWDU, boilers), because project implementation will not affect operations of these facilities.

Flowchart B 3.1 Project boundaries



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

Baseline setting date: 15/09/2008.

Baseline calculations were performed by:

"CTF Consulting Ltd."
Moscow, Balchug street 7, Business-center "Balchug Plaza", office 629;
Contact person: Konstantin Myachin, Carbon Project Manager
Ph: +7 495 984 59 51
Fax: +7 495 984 59 52
e-mail: konstantin.myachin@carbontradefinance.com

SECTION C. Duration of the project / crediting period

C.1. Starting date of the project:

July of 2008.

C.2. Expected operational lifetime of the project:

30 years between 2010 and 2040.

C.3. Length of the crediting period:

3 years 0 months from 01.01.2010 to 31.12.2012.

SECTION D. Monitoring plan

D.1. Description of monitoring plan chosen:

Monitoring plan is based on methodology AM0009 v.2.1[41] "Recovery utilization of gas from oil wells that would otherwise be flared". This approach is based on calculation of carbon balance before and after APG utilization.
The applicability of methodology AM0009 v. 2.1 jointly with 3.3 (applied for justification of the baseline choice and additionality argumentation) in the context of the proposed project was described in section B.1.Following deviations are made from the used CDM methodology AM0009 version 2.1 "Recovery and utilization of gas from oil wells that would otherwise be flared":

a. Analysis of alternatives of the project activity, identification of the baseline scenario and project scenario and additionality argumentation is provided according to AM0009 version 3.3
b. Formula 12 to account emission reduction include one more parameter – CO_2 emission from consumption of electricity (calculated via multiplication of actual electricity consumption and grid emission factor described in Annex 4 of this PDD), which was not taken into consideration in the methodology. Thus, monitoring plan included project CO_2 emissions connected with electricity consumption that is conservative.
c. Instead of EPA methodology contained methane emission factors for each individual equipment type, the more comprehensive IPCC based approach for fugitive emissions of CH4 in oil and gas sector was used.

Using conservative approach, project developer applies corresponding emission factors for oil and gas industry, as prescribed by IPCC Guidelines for National Greenhouse Gas Inventories 2006.

IPCC Guidelines estimate methane emissions from technological systems of gas treatment to be higher, by an order of magnitude, than estimated by EPA, which used previous versions of AM0009 methodology. Project developer decided that IPCC approach would describe fugitive emissions more adequately, because it is tied to the volumes of methane flow through the system, instead of being based on individual emission factors for each equipment type.

d. In contrast to AM0009 provision the fugitive emissions of CH4 due to carbon-black firing conditions were accounted.

According to the emission limits document for Kharampur group of oil-fields, one of ten flares of South-Kharampur group does not have carbon-black conditions, whereas all other flares operate under carbon-black firing conditions[42]. Carbon-black firing conditions are characterized by inderfiring of methane, which has been taken in account during baseline emission calculations.

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[41] http://cdm.unfccc.int/methodologies/PAmethodologies/approved.html

[42] Emission limits for facilities involved in preparation and transportation of oil, gas and condensate of RN-Purneftegas Ltd., issued by Ecoproject Ltd., Tumen. This document was approved by the Department for Technological and Environmental Surveillance of Rostechnadzor for Yamalo-Nenetsky Autonomous District, the Decision No.1231-e of 30.10.2006.

The reason for transition to soot-forming flaring conditions is a long history of exploitation of Kharampur group of oil-fields, which has been in active exploration for 15 years. During this period, the gas-oil ratio decreased considerably, along with the decrease in oil production volumes, and, consequently, in the volumes of flared APG. Because the nozzle diameters were initially designed to burn large volumes of flared gas, the outflow velocity of gas at the nozzle has fallen down, which caused underfiring of methane.

Methane emissions during carbon-black flaring conditions were calculated in accordance with the "Guidelines for calculation of air emissions from APG flaring", issued by the Research Institute of Air Protection, Saint Petersburg, in 1998. These guidelines were approved by the State Committee for Environmental Protection", the Decision No. 199 of 08.04.98.

Description of monitoring methodology

In line with AM0009 methodology v. 2.1, this project involves *ex post* monitoring to determine carbon balance between the flow of raw APG entering the BCS site, which would have been flared without this project, and the flows of commercial products of gas separation: dry gas and BFLH. The difference between the two is attributed to on-site APG consumption for own needs of the facility, i.e., project emissions.

Carbon balance is calculated on the basis of continuous monitoring of gas volume and regular measurements of component composition of APG and the products of its processing. The project also deals with emergencies at APG processing site and in the pipelines. Monitoring data are used to calculate baseline emissions of CO_2 and methane (due to underfiring), because without the project all processed APG would have been flared.

All monitoring data should be stored in electronic and hardcopy formats, and be available for 2 years after the end of the credit period. All measurements are performed by calibrated meters compliant with the applicable industry standards.

All monitoring endpoints and metering device s are shown on the graph D.1.1.

We suggest to organize three monitoring points: A, B, and X, to monitor the following parameters

- A: composition and volume of APG incoming to the BCS site;
- B: composition and volume of dry gas and BFLH;
- X: composition and volume of APG supplied from another oil-field (not present in the project, because all oil-fields are combined into Kharampur group, and there are no external gas supplies).

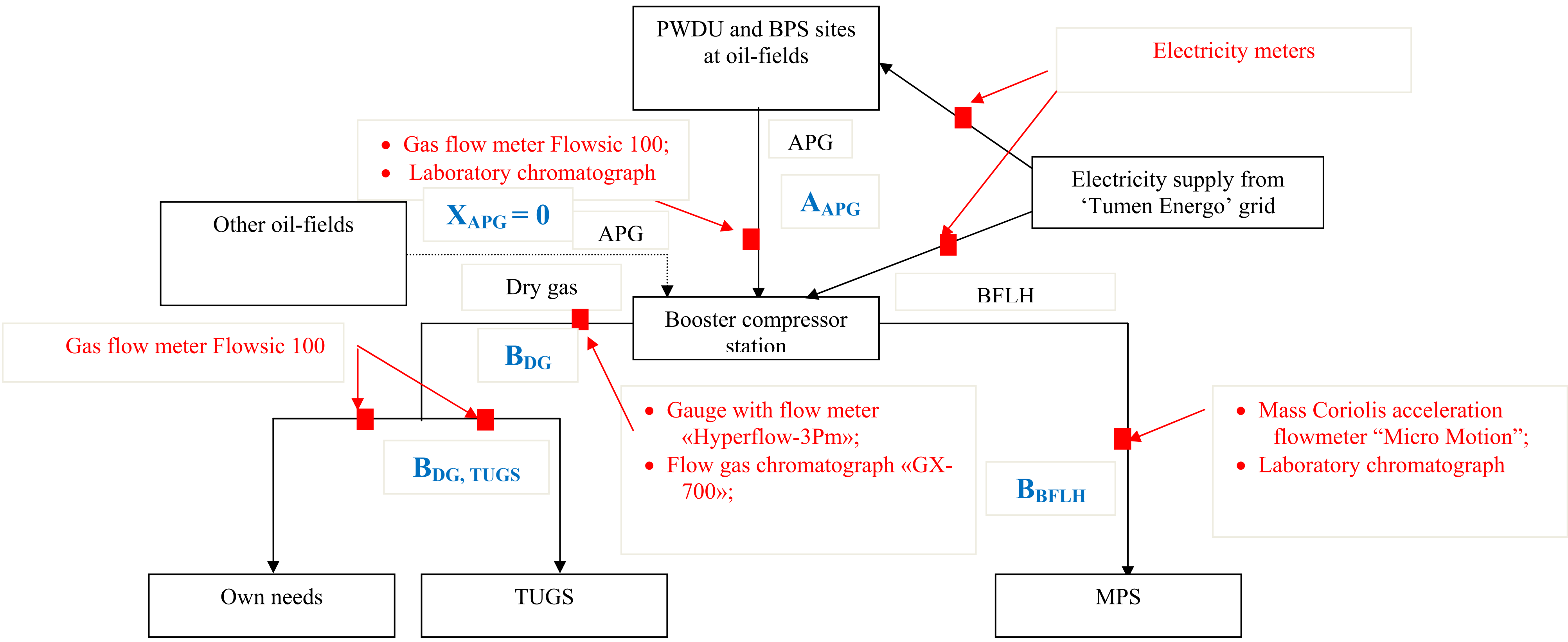
Along with these parameters, electricity consumption during all project activities shall be continuously monitored. During emergencies, special emergency monitoring plan provides for calculation of accidentally released gases, on the basis of other monitoring parameters (temperature, pressure, and time period), gas pressure in the system, and mass-balance equations.

Forecast and correction of baseline and project emissions due to changes in oil production volumes

Baseline and project emissions depend upon the volumes of APG that in turn are determined by the volumes of extracted oil. These volumes change every year. The emission estimates were based on the forecast of oil production and APG recovery reported in the operating company's business plan.[43] Later, during the project implementation stage, the volumes of recovered and processed APG will be monitored.

[43] Business plan of RN-Purneftegas Ltd. for 2009-2013.

Graph D.1.1: Monitoring endpoints



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

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

ID number *(should be the same as in D.2)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment
1.	$V_{A\ APG}$	APG flow measurement at BCS entry point A	m^3	m	Continuously	All	Electronic and hard copy for 2 years after the end of the credit period	
2.	$w_{A\ APG}$	APG composition measurement at BCS entry point A	vol.%; mass %	m	Every 10 days	Sample	Electronic and hard copy for 2 years after the end of the credit period	Fairly stable component composition of APG allows to measure it once every 10 days, conversion to kg of carbon per m^3
3.	$V_{B\ DG,\ TUGS}$	Dry gas flow meter, at TUGS entry point $B_{DG\ TUGS}$	m^3	m	Continuously	All	Electronic and hard copy for 2 years after the end of the credit period	
4.	$w_{B\ DG}$	Dry gas composition analysis at BCS out gate (point B_{DG})	vol.%; mass %	m	Continuously	All	Electronic and hard copy for 2 years after the end of the credit period	Dry gas composition is measured by flow chromatograph
5.	$V_{B\ BFLH}$	BFLH flow meter (point B_{BFLH})	kg, m^3	m	Continuously	All	Electronic and hard copy for 2 years after the end of the credit period	
6.	$w_{B\ BFLH}$	BFLH composition analysis at BCS exit point B_{BFLH}	vol.%; mass %	m	Every 10 days	Sample	Electronic and hard copy for 2 years after the end of the credit period	
7.	t_1, t_2	The period of emergency situation at the pipeline	seconds/minutes	m	During emergency	All	Electronic and hard copy for 2 years after the end of the credit period	Automated system of control of technological processes (ASC TP) measures the period of time from emergency alarm to full closing of valve

8.	P_P	Pressure in the pipeline after cutoff valves closed the emergency section of the pipe	Pa	m	During emergency	All	Electronic and hard copy for 2 years after the end of the credit period	ASC TP gauges at the gas treatment sites entry/exit gates, BCS entry/exit gates, injection well cluster
9.	T_p	Temperature in the pipeline after cutoff valves closed the emergency section of the pipe	^0C	m	During emergency	All	Electronic and hard copy for 2 years after the end of the credit period	ASC TP gauges at the gas treatment sites entry/exit gates, BCS entry/exit gates, injection well cluster
10.	d	Pipe radius	m	m	If changes	All	Hard copy	Pipeline passport
11.	L	Pipe length	m	m	If changes	All	Hard copy	Pipeline passport
12.	EC	Electricity consumption for project needs	MWh	m	Continuously	All	Electronic and hard copy for 2 years after the end of the credit period	
13.	m_{fuel}	Consumption of other fuel for project needs	kg	m	Continuously (if needed)	All	Electronic and hard copy for 2 years after the end of the credit period	Other fuel is not used in this project. If the situation changes, this parameter shall be accounted for.

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

An emission calculation applies AM0009 v.2.1 methodology. Project emissions were calculated using carbon balance method. This method estimates carbon content in APG flow which enters BCS gas treatment facility, and carbon content in processing products: dry gas and BFLH.

Project emissions are calculated by the following equation:

$$\mathbf{PE_y = PE_{CO2gas,y} + PE_{CH4,\ plants+\ pipeline,y} + PE_{CH4,\ pipeline,\ accident} + PE_{EC,y} + PE_{CO2,\ otherfuels,y} + L_y}, \textbf{ tonnes of } \mathbf{CO_2}\textbf{-eq.} \quad \mathbf{(D.1.1.2.\text{-}1)}$$

Where:
PE_y – project emissions
$PE_{CO2gas,y}$ –CO_2 emissions from the combustion or flaring of APG at BCS site during period y, tonnes of CO_2

$PE_{CH4,\ plants+pipeline,y}$ –fugitive emissions of CH_4 from project activities during operations at BCS site, at the cluster of TUGS injection wells, and during gas transportation during the project period, tonnes of CO_2-eq.

$PE_{CH4,\ pipeline,\ accident}$ - CH_4 emissions from project activities during emergencies at the gas mains, tonnes of CO_2-eq.

$PE_{EC,y}$ – CO_2 emissions from project activities in the result of electricity consumption, tonnes of CO_2-eq.

$PE_{CO2,\ other\ fuels,y}$ – CO_2 emissions from project activities in the result of combustion of other fuels, tonnes of CO_2-eq.

L_y – leaks during project activities, tonnes of CO_2-eq.

CO_2 emissions from the combustion or flaring of APG at BCS site during period y are estimated by the following equation:

$$\mathbf{PE_{CO2gas,y} = [m_{carbon,\ A,\ y} * (m_{carbon,\ A,\ y} + m_{carbon,\ X,\ y} - m_{carbon,\ B,\ y})] / (m_{carbon,\ A,\ y} + m_{carbon,\ X,\ y})*44/12*1/1000}, \textbf{ tonnes of } \mathbf{CO_2}\textbf{-eq.} \quad \textbf{(D.1.1.2.-2)}$$

In this project $\mathbf{m_{carbon,\ X} = 0}$, because APG is supplied only from Kharampur group of oil-fields. In this case, Eq. D.1.1.2-2 may be simplified:

$$\mathbf{PE_{CO2gas,y} = (m_{carbon,\ A,\ y} - m_{carbon,\ B,\ y})*44/12*1/1000}, \textbf{ тCO}_\mathbf{2}\textbf{-eq.} \quad \textbf{(D.1.1.2.-3)}$$

Where

$$\mathbf{m_{carbon,\ A,\ y} = V_{A,\ APG,\ y} * w_{A,\ APG,\ y.}} \quad \textbf{(D.1.1.2.-4)}$$

APG is collected from the five oil-production sites of Kharampur group, owned by RN-Purneftegas Ltd. Gas flow is measured at BCS entry point. All oil fields are equipped with integrated system of gas collection.

$$\mathbf{m_{carbon,\ B,\ y} = (V_{B,\ BFLH,y} * w_{B,\ BFLH,y}) + (V_{B,\ DG,\ TUGSy} * w_{B,\ DG,\ p})} \quad \textbf{(D.1.1.2.-5)}$$

$$\mathbf{m_{carbon,\ X,\ y} = V_{X,y} * w_{X,y}} \quad \textbf{(D.1.1.2.-6)}$$

$m_{carbon,\ A,\ y}$ – the quantity of carbon in the APG from Kharampur group of oil-fields during the period y, kg (measured in point A on Graph D.1)

$m_{carbon,\ B,\ y}$ – the quantity of carbon in the products of APG processing (in dry gas and BFLH) during the period y, kg (measured in point B on Graph D.1)

$m_{carbon,\ X,\ y}$ – the quantity of carbon in APG delivered to BCS from other oil fields, which do not belong to Kharampur group (measured in point A on Graph D.1)

$V_{A,y}$ – APG volume, delivered to BCS from oil production site during the period y, m^3 (measured in point A on Graph D.1)

$w_{A,\ APG,y}$ – the average carbon content in APG, recovered from the oil production sites of Kharampur group during the period y, kg/m^3

$V_{B,\ BFLH,y}$ – the volume of BFLH produced by BCS during the period y, kg or m^3 (measured in point B_{BFLH} on Graph D.1)

$w_{B,\ BFLH,y}$ – the average carbon content in BFLH, produced by BCS during the period y, kg/ m^3 or kg/kg (measured in point B_{BFLH} on Graph D.1)

$V_{B,\ DG,\ TUGS,y}$ – the volume of stripped gas, injected in TUGS during the period y, m^3 (measured in point $B_{DG,\ TUGS}$ on Graph D.1)

$w_{B,\,DG,y}$ – the average carbon content in dry gas, produced by BCS during the period y, kg/ m^3 (measured in point B_{DG} on Graph D.1).

CH_4 emissions from project activities at BCS site, during injection to TUGS and gas transportation during the project period are estimated by the following equation:

$$PE_{CH4,\,plants+\,pipeline,y} = GWP_{CH4} * EF_{CH4} * V_A(V_{B\,DG,\,TUGS}) * 10^{-3}, \text{ tonnes of } CO_2\text{-eq.} \qquad \textbf{(D.1.1.2.-7)}$$

Where:

GWP_{CH4} – global warming potential of methane, $GWP_{CH4} = 21$

EF_{CH4} – emission factor of volatile gases during treatment, transportation and storage (IPCC Guidelines for National Greenhouse Gas Inventories 2006, chapter 4, 4.2. Table 4.2.5)

V_A ($V_{B\,DG,\,TUGS}$) – the volume of APG or dry gas, depending upon the source of fugitive emissions.

This approach was described in IPCC Guidelines for National Greenhouse Gas Inventories 2006, chapter 4, 4.2. We used the emission factor of volatile gases for countries with developing economies from Table 4.2.5.

GHG Inventory Guidelines offer three Tiers to calculate emissions of volatile gases from oil and gas systems. The choice of a particular tier depends upon availability of initial data for calculation of fugitive emissions. Tier 1 is the simplest and the most conservative tier, for calculation of project emissions. We used this Tier to calculate fugitive emissions, but this tier has large uncertainties. The inaccuracy of the estimate may be the order of magnitude and even higher.

In line with the conservative approach, we used average emission factor, because the lowest value with 100% relative inaccuracy would result in lower emission factor. We didn’t use the highest value of the emission factor because a brand new and modern gas compressor equipment and new pipelines will be mounted at Kharampur site but the IPCC Guidelines coefficient refers to the whole oil and gas development, processing and transportation system in countries with economy in transitions (including Russia) which is considered enough old and outworn. There are two reasons for using Tier 1 to calculate emissions: Firstly, we did not have detailed statistics on production and infrastructure. Secondly, this tier maximally accounted for fugitive emissions of APG and dry gas. We also assumed equal methane content in APG and in dry gas, in line with the conservative approach.

Table D.1.1.2.1. Emission factors calculated under IPCC Guidelines for National Greenhouse Gas Inventories 2006, chapter 4.4.2

Category	***Subcategory***	***EF_{CH4}***	***Units***
Gas recovery	Plant for sweet gas (leaks from	7.9E-04	Gg per 10^6 m^3 of APG

	compressor)		
Transportation and storage of gas	Transportation (leaks from compressor)	1.1E-03[44]	Gg per 10^6 m^3 of dry gas
	Transportation (leaks from stop valves)	39.2E-05	Gg per 10^6 m^3 of dry gas
	Storage	4.15E-05	Gg per 10^6 m^3 of dry gas

Emission factors are expressed in Gg per 10^6 m^3 = tonnes per 10^3 m^3

CH_4 emissions from project activities during emergencies at gas mains are calculated as follows:

$$PE_{CH4,\ pipeline,\ accident} = GWP_{CH4} * 1/1000 * (V_{A,\ accident} + V_{remain,\ accident}) * w_{CH4,\ pipeline,\ accident},\ \text{tonnes of } CO_2\text{-eq.} \quad \text{(D.1.1.2.-8)}$$

CH_4 emissions from project activities during emergencies at gas mains were calculated using methodology AM0009, v. 2.1.
Where:

$$V_{A,\ accident} = t_{accident} * F = (t_2 - t_1) * F \quad \text{(D.1.1.2.-9)}$$

$$V_{remain,\ accident} = d^2 * \pi * L * P_P / P_S * T_S / T_P * V_{A,\ d,\ accident} / \sum V_{Xi,\ d,\ accident} \quad \text{(D.1.1.2.-10)}$$

$V_{A,\ accident}$ – the volume of gas supplied in the pipeline at the time when the accidental gas leakage commenced until the shutdown valves isolated the pipeline, m^3
$V_{remain,\ accident}$ – the volume of the remaining gas after the shutdown valves isolate the pipeline, m^3
$t_{accident}$ – time difference between t1 and t2 determined as "retention time" in seconds
t_2 – time that the shutdown valves isolate the section of the pipe where the leak is occurring (both upstream and downstream), based on operational data
t_1 – time that gas leakage caused by the accident occurred, determined through continuous pipeline pressure monitoring
F – gas flow, m^3/s
d - pipe radius, m
L – pipe length, m
P_P – pressure in the pipeline when the valves isolate the pipeline leak, Pa
P_S – standard pressure in the pipeline, Pa

[44] We used the maximum value of emission factor to calculate emissions from piston compressors.

T_S – standard temperature in the pipeline, ^0C
T_P temperature in the pipeline, when the shutdown valves isolate the leak in degrees Centigrade (ºC)
$V_{A, d, accident}$ – volume of gas pumped through the pipeline before the accident, m^3
$V_{Xi, d, accident}$ – volume of gas supplied from other deposits before the accident, m^3
$\mathbf{V_{Xi, d, accident} = 1}$, because APG is supplied only from Kharampur group of oil-fields.

CO_2 emissions from project activities in the result of electricity consumption during the project period

We took the formula from the latest approved version of «Tool to calculate project emissions from electricity consumption» v. 01 to calculate CO_2 emissions from project activities in the result of electricity consumption:

$$\mathbf{PE_{EC,y} = EG_{PJ, y} * EF_{grid, y} * (1+ TDL_y)}, \textbf{ tonnes of } \mathbf{CO_2} \qquad \textbf{(D.1.1.2.-11)}$$

Where:
$EG_{PJ, p}$ – electricity consumption by project activities during the period y, MW
$EF_{grid, y}$ – emission factor for the grid electricity during the project period, tonnes of CO_2/MW[45]
TDL_y – average losses during transportation and distribution of electricity in the grid in year y for the voltage level at which electricity is obtained from the grid at the project site, $TDL_p = 20\%$[46].

CO_2 emissions from combustion of other fuel for project activities during the project period

We took the formula from the latest version of CDM «Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion» to calculate CO_2 emissions from combustion of other fuels for project activities:

$$\mathbf{PE_{CO2, otherfuels,y} = 1/1000 * \sum m_{fuel, y} * NCV_{fuel} * EF_{CO2, fuel}}, \textbf{ tonnes of } \mathbf{CO_2} \qquad \textbf{(D.1.1.2.-12)}$$

Where:
$m_{fuel, y}$ – quantity of a specific fuel type that is consumed due to the project activity during the period y, kg

[45] See Annex 4

[46] See Annex 4

NCV_{fuel} – net calorific value of the respective fuel type, kJ/kg
$EF_{CO2,\ fuel}$ – CO_2 emission factor for the respective fuel type, kg CO_2/kJ.

$PE_{CO2,\ otherfuels,y}$ = 0, because this project does not plan to use other fuels except APG and dry gas to be produced from it.

Leakages from project activities

To calculate leakages, methodology AM0009 v. 2.1 proposes to calculate changes of CO_2 emissions in the result of substitution of fuel consumed by final consumers:

- Will additional fuel supplies from project activities lead to increase of fuel consumption at corresponding markets?
- Can the products, produced by project activities, substitute for fuel with lower carbon content (for example, electricity from APG substitutes for electricity from renewables)

APG is separated in dry gas (92% methane and 5% ethane) and BFLH (37% propane, 16% ethane, 15% n-butane, 12% iso-butane, 9% methane, 5% iso-pentane, 4% n-pentane, 2% n-hexane) at the BCS plant. Dry gas mainly consists of methane, while BFLH mainly consists of propane and butane. Commercial uses of these products as fuel substitutes will depend upon their component composition.

Dry gas will be supplied to the integrated gas transporting system after 2013. It will substitute for natural gas. BFLH will be used as a raw material for production of condensed propane-butane fuel, substituting for similar or more carbon-intensive motor fuel.

Having said this, and taking in account limited throughput capacity of integrated gas transporting system of the Russian Federation, we conclude that the products of APG processing shall substitute for some kind of fossil fuels. Consumption of these products will not increase fuel consumption on the market. The component composition of these products is similar or the same as that of substituted fuels, with roughly the same carbon content. Therefore, fuel substitution will not increase CO_2 emissions of final consumers, and conservative estimate will not consider this kind of losses.

D.1.1.3. Relevant data necessary for determining the baseline of anthropogenic emissions of greenhouse gases by sources within the project boundary, and how such data will be collected and archived:								
ID number *(should be the same as in D.2)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment
1.	$V_{A\ APG}$	APG flow measurement at BCS entry point A	m^3	m	Continuously	All	Electronic and hard copy for 2 years after the end of the credit period	This indicator is the same for project and baseline scenarios
2.	$w_{A\ APG}$	APG composition measurement at BCS entry point A	vol.%; mass %	m	Every 10 days	Sample	Electronic and hard copy for 2 years after the end of the credit period	Fairly stable componentcomposition of APG allows to measure it once every 10 days, conversion to kg of carbon per m^3
14.	ρ_{APG}	APG density in point A	kg/m^3	m	Every 10 days	Sample	Electronic and hard copy for 2 years after the end of the credit period	Calculated on the basis of APG component composition data

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

Baseline emissions calculations are based on the volume of APG that would have been flared in the absence of the project. Baseline emissions consist of two parts: (1) CO_2 emissions, which were calculated using AM0009 v. 2.1 methodology, and (2) CH_4 emissions due to underfiring of APG in flares. Methane emissions during carbon-black flaring conditions were calculated in accordance with the “Guidelines for calculation of air emissions from APG flaring”, issued by the Research Institute of Air Protection, Saint Petersburg, in 1998. These guidelines were approved by the State Committee for Environmental Protection”, the Decision No. 199 of 08.04.98.

$$\mathbf{BE_Y = BE_{,CO2} + BE_{,CH4}} \qquad \textbf{(D.1.1.4.-1)}$$

$$\mathbf{BE_{,CO2} = V_{A,APG,y} * w_{A,APG,y} * 44/12 * 1/1000}, \textbf{ tonnes of } \mathbf{CO_2}\textbf{-eq.} \qquad \textbf{(D.1.1.4.-2)}$$

Where:

$V_{A,APG,y}$ – The volume of APG, recovered at the sites of Kharampur group of oil-fields during the project period, m^3 (in point A at the graph D.1.)

$w_{A,APG,y}$ – the average carbon content in APG, recovered at the sites of Kharampur group of oil-fields during the project period, kg of carbon per m^3 (in point A at the graph D.1.)

According to the emission limits document for Kharampur group of oil-fields, one of ten flares of South-Kharampur group does not have carbon-black conditions, whereas all other flares operate under carbon-black firing conditions[47]. Carbon-black firing conditions are characterized by inderfiring of methane, which has been taken in account during baseline emission calculations. Methane emissions were converted to CO_2-equivalent and summed with total baseline emissions.

$$\mathbf{BE_{,CH4} = 0.001 * q_{CH4} * V_{A\ APG} * \rho_{APG}} \qquad \textbf{(D.1.1.4.-3)}$$

Where:

q_{CH4} unit emissions of methane, $kgCH_4/APG$

$V_{A,\ APG,\ y}$ – The volume of APG, recovered at the sites of Kharampur group of oil-fields during the project period, m^3 (in point A at the graph D.1.)

$\rho_{\ APG}$ – APG density, kg/ m^3, calculated on the basis of component composition of APG, which is measured in Point A on the graph D.1 once every ten days.

The following equation was used to calculate unit emissions of methane:

$$\mathbf{q_{CH4} = 0.01 * 0.035 * б_{CH4},\ kgCH_4/APG} \qquad \textbf{(D.1.1.4.-4)}$$

Where:

0.035 – underfiring coefficient during carbon-black conditions of APG flaring

$б_{CH4}$ – methane content by mass (%), calculated on the basis of component composition of APG.

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

D.1.2.1. Data to be collected in order to monitor emission reductions from the project, and how these data will be archived:								
ID number *(should be the same as in D.2)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

[47] Emission limits for facilities involved in preparation and transportation of oil, gas and condensate of RN-Purneftegas Ltd., issued by Ecoproject Ltd., Tumen. This document was approved by the Department for Technological and Environmental Surveillance of Rostechnadzor for Yamalo-Nenetsky Autonomous District, the Decision No.1231-e of 30.10.2006.

Not applicable.

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

Not applicable.

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

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

ID number *(should be the same as in D.2)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

Project boundaries should include all infrastructure for recovery, transportation and processing of APG. Fugitive emissions due to fuel substitution by final consumers are not considered.

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

Not applicable.

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

Methodology AM0009 v. 2.1 provides the following equation for calculation of emission reductions:

$$EF_p = BE_p - PE_p, \text{ tonnes of } CO_2\text{-eq.} \qquad \text{(D.1.4.-1)}$$

Where:
BE_p – baseline emissions during the project period, in tonnes of CO_2-eq.
PE_p – project emissions during the project period, in tonnes of CO_2-eq.

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

The Russian environmental legislation requires RN-Purneftegas Ltd. approve "Project of emission limits for facilities involved in preparation and transportation of oil, gas and condensate of RN-Purneftegas".[48] Apon the approval of this document, the company obtained the Emission Permit No. 162, which quantifies its environmental impacts. The company regularly monitors its emission parameters, according to the schedule of environmental impact monitoring.

[48] This document was approved by the Decision No. 794 of State Environmental Expertise on 30.10.2006. The document's effective period is 5 years. The authority to issue such decisions in Yamalo-Nenetsky Autonomous District (YNAD) rests with the District Department of Technological and Environmental Surveillance of Federal Agency for Environmental, Technological and Nuclear Surveillance.

D.2. Quality control (QC) and quality assurance (QA) procedures undertaken for data monitored:		
Data *(Please specify table and ID)*	Data uncertainty level (high/medium/low)	Describe planned QA/QC procedures or explain why are such procedures not applicable
1. $V_{A\ APG}$	Low	APG flow is continuously monitored by ultrasonic flow meter Flowsic 100 and recorded in automated regime. Relative measurement error is ± 1.0-1.5%. Ultrasonic flow meters are also installed at the out gates of PWDU and BPS sites. Once every two years Laboratory of Metrology of "RN-Purneftegas Ltd." calibrates and services these meters. The laboratory holds the license for such services. As specified in the license, in special cases the lab sends the meters to Gubkinsky district department of Tumen Regional Center for standardization, metrology and certification for state inspection. After such inspection, each device is stamped with the inspection date and signature of the inspector, and sealed.
2. $w_{A\ APG}$	Medium	Component composition of APG is measured by gas chromatographer in "RN-Purneftegas Ltd." Lab. Then the carbon content is calculated. The lab holds al necessary licenses. The procedure of equipment servicing and certification is described above.
3. $V_{B\ DG}$, $V_{B\ DG,\ TUGS}$	Low	Dry gas volume is continuously monitored by flow meter "Hyperflow-3Pm". This device automatically calculates the flow and quantity of dry gas on the basis of measurements of excess pressure, pressure differential, and temperature in the orifice. The measurements are recorded in automatic regime. Relative measurement error is ± 0.5%. The flow meter is serviced once every three years. The procedure of equipment servicing and certification is described above.
4. $w_{B\ DG}$	Medium	Component composition of dry gas is measured by flow gas chromatographer GCX. Then the carbon content is calculated .The measurements are recorded in automatic regime and stored in Automated data collection and transmission system. Reproducibility of measurements is ± 0.05%. The procedure of equipment servicing and certification is described above. The volumes of dry gas injected in TUGS and consumed for own needs are continuously monitored by ultrasonic flow meter Flowsic 100 and recorded in automated regime. Relative measurement error is ± 1.0-1.5%. Reproducibility of measurements is ± 1.0%. The procedure of equipment servicing and certification is described above.
5. $V_{B\ BFLH}$	Low	The volume of BFLH is continuously monitored by Coriolis acceleration flowmeter Micro Motion. The measurements are recorded in automatic regime. The relative measurement error of this device depends upon its sensor. Typically, it is ± 0.5-2.0%. The flow meter is serviced once every two years. The procedure of equipment servicing and certification is described above.
6. $w_{B\ BFLH}$	Medium	Component composition of BFLH is measured by chromatograph in "RN-Purneftegas Ltd." Lab. The lab holds al necessary licenses. The chromatograph is calibrated in Metrology Lab. The procedure of equipment servicing and certification is described above.

7. t_1, t_2	Low	These parameters are measured and recorded by Automated System of Control of Technological Processes (ASC TP) only in case of emergency or contingency.
8. P_P	Low	These parameters are measured and recorded by Automated System of Control of Technological Processes (ASC TP) only in case of emergency or contingency.
9. T_p	Low	These parameters are measured and recorded by Automated System of Control of Technological Processes (ASC TP) only in case of emergency or contingency.
10. d	Low	This parameter is measured only once during commissioning of the pipeline. The measurement results are entered into the pipeline passport.
11. L	Low	This parameter is measured only once during commissioning of the pipeline. The measurement results are entered into the pipeline passport.
12. EC	Low	This parameter is continuously monitored and recorded by the standard electricity consumption meters. The measurement results are recorded according to the existing commercial accounting standards.
13. m_{fuel}	Low	This parameter is controlled only in case of fuel substitution. Fuel flow is continuously monitored and recorded by the standard flow meters. The measurement results are recorded according to the existing commercial accounting standards.
14. ρ_{APG}	Medium	Calculated on the basis of APG component composition data.

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

Flowchart D.3.1: Current system of APG monitoring at RN-Purneftegas Ltd.

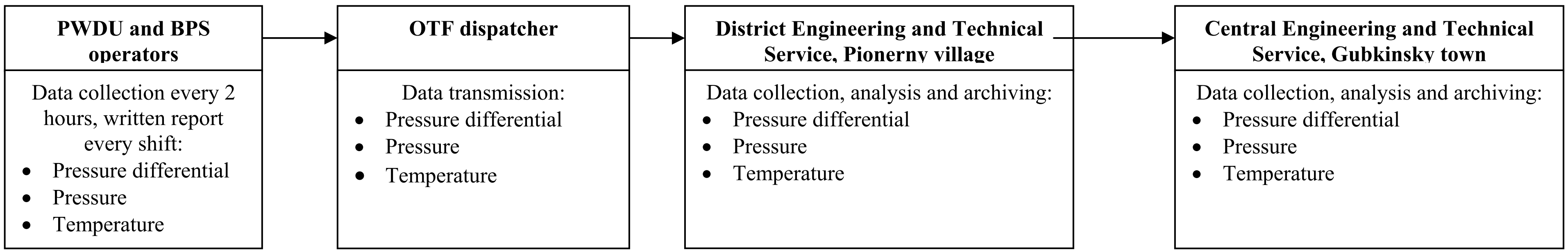
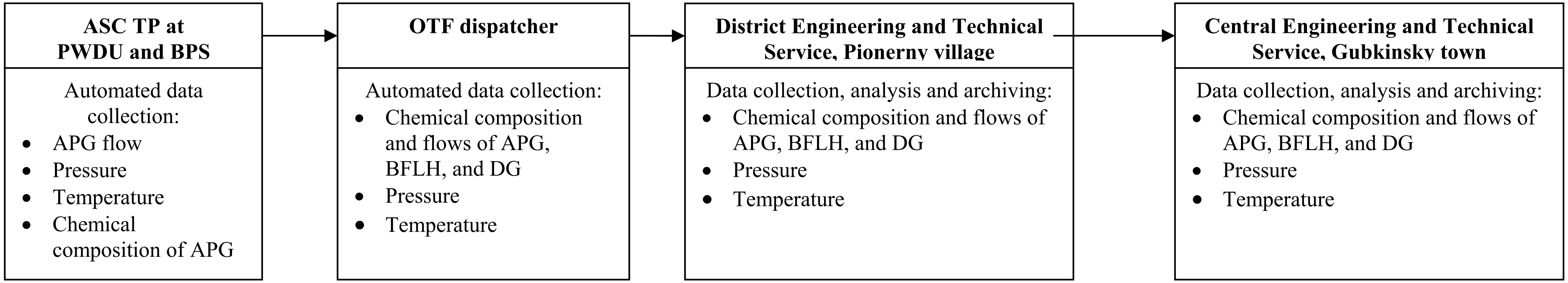


Table D.3.1: Procedure of data collection to be implemented in the project: APG, dry gas and BFLH flow

Equipment and technology	Automated data collection and transmission
The existing compressors at PWDU and BPS sites	Automated data collection and transmission system consists of the following elements: • Station of operative accounting for gas • Controller of ASC TP • Workstation of engineer-operator of each BPS and PWDU. When APG is transported to BCS, gas flow is measured by ultrasonic meter as well as the temperature and pressure, and the measured data are transmitted to ASC TP. The metrology Lab of RN-Purneftegas also periodically measures component composition of APG samples.
BCS	ASC TP manages operations of all equipment at BCS. ASC TP performs automatic measurements, calculations and registration of technological parameters of BCS operations. ASC TP consists of the following elements: • Data collection and processing center • Controllers • Workstation of engineer-operator The following data are transmitted to the controller: • APG pressure, flow and temperature in the APG feeder pipe, • BFLH mass and volume flow in operational BFLH control unit, the temperature in BFLH pipe The metrology lab of RN-Purneftegas also periodically measures component composition of BFLH samples.
GDP	The current gas pressure, pressure differential, and temperature data are transmitted to the controller.

Flowchart D.3.2: Monitoring system during project implementation: component composition and flows of APG, DG and BFLH

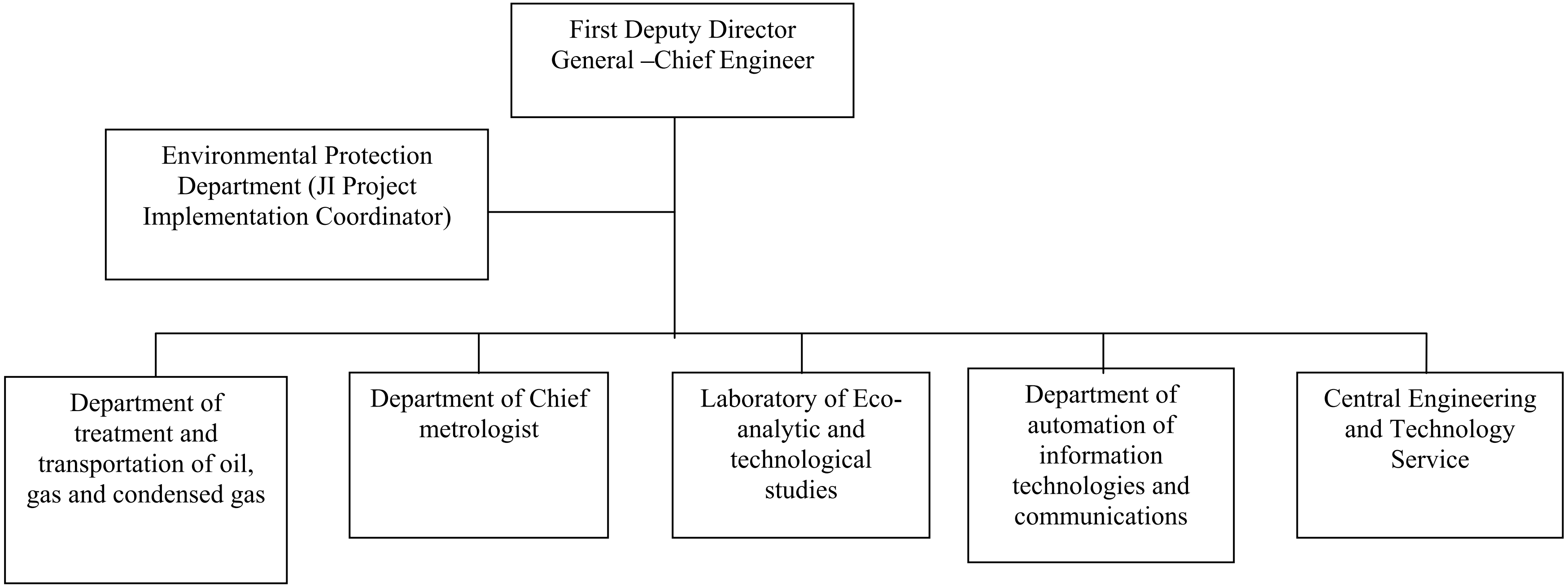


Organization of monitoring system

Monitoring team shall be formed, and monitoring coordinator shall be appointed before project implementation. The members of JI project monitoring team shall have specified responsibilities. JI project coordination center shall bear full responsibility for implementation of the project monitoring plan. It is expected that Environmental Protection Department shall assume the functions of the coordination center. Several other departments of RN-Purneftegas Ltd. Shall also participate in organization of monitoring system.

JI project coordination center shall train new employees and divide responsibilities among the staff members, for integrated operation of monitoring system and coordination of various divisions of RN-Purneftegas Ltd. Annex 3 specifies the responsibilities of each division.

Graph D.3.3: Management structure of monitoring system



There are several monitoring procedures that will have to be implemented prior to project implementation period. These procedures should specify:

- Training of personnel who participates in JI project implementation
- Collection and transmission of data
- Data of QA/QC
- Equipment maintenance and calibration
- Emission reduction calculation procedures
- Emergency situation response measures
- Other

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

CTF Consulting Ltd. (Moscow);
Contact person: Konstantin Myachin, Carbon project manager;
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Fax +7 495 984 59 52
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SECTION E. Estimation of greenhouse gas emission reductions

E.1. Estimated project emissions:

Section D specified the equations used for calculation of project emissions.

The initial volume of processed associated gas was taken from the Business plan of RN-Purneftegas Ltd. for the period 2009-2013. The volumes of processing products and carbon content were calculated using proportions equations for the initial figures in technical design document and corrected for volumes of gas processing based on the business plan.

Fugitive emissions of CH_4 during project implementation at BCS site, the cluster of TUGS injection wells, and during gas transportation were estimated on the basis of corresponding emission factors as provided in IPCC Guidelines for National Greenhouse Gas Inventories 2006, Chapter 4, 4.2., Table 4.2.5.

For conservative estimates, we also accounted for fugitive emissions during backpumping of dry gas out of TUGS after 2013. These emissions were summed up with 2012 emissions.

Table E.1.1: Estimates of project emissions

Parameter	Measurement Unit	Data variable	Estimated value		
			2010	2011	2012
Volume of APG flow to BCS	m^3/year	V_{APG}	505 134 583	958 054 000	1 031 140 000
Average carbon content in APG pumped to BCS	kgC/m^3	w_A	0.7049	0.7049	0.7049
Quantity of carbon in APG pumped to BCS	**kgC**	$m_{carbon\ A}$	**356 069 566**	**675 332 640**	**726 850 990**
Volume of dry gas injected in TUGS	m^3/year	$V_{DG,\ TUGS}$	411 867 226	781 160 223	840 751 724
Average carbon content in dry gas	kgC/m^3	$w_{B\ DG}$	0.5654	0.5654	0.5654
Quantity of carbon in dry gas	**kgC**	$m_{B\ DG,\ TUGS}$	**232 871 114**	**441 670 615**	**475 363 849**
Volume of BFLH which flows from BCS to MPS	kg/year	$V_{B\ BFLH}$	130 476 805	247 466 377	266 344 569
Average carbon content in BFLH	kgC/kg	$w_{B\ BFLH}$	0.819	0.819	0.819
Quantity of carbon in BFLH	**kgC**	$m_{B\ BFLH}$	**106 853 346**	**202 661 387**	**218 121 591**
Project CO_2 emissions from combustion, flaring or venting of APG	***tCO_2/year***	$PE_{CO2\ gas}$	***59 932.1***	***113 669***	***122 340.4***
Fugitive emissions					
Fugitive emission factor for gas transportation from the compressors	tCH_4/tDG	EF_{CH4}	0.0011	0.0011	0.0011
Project emissions during gas transportation by the compressors	*tCO_2/year*		*9 514.1*	*18 044.8*	*19 421.4*
Fugitive emission factor for gas transportation from the valves	tCH_4/tDG	EF_{CH4}	0.000392	0.000392	0.000392

Parameter	**Measurement Unit**	**Data variable**	**Estimated value**		
			2010	**2011**	**2012**
Project emissions during gas transportation	*tCO_2/year*		*3 390.5*	*6 430.5*	*6 921.1*
Fugitive emission factor for gas treatment at the compressors	tCH_4/tAPG	EF_{CH4}	0.000790	0.000790	0.000790
Project emissions during gas treatment	*tCO_2/year*		*8 380.2*	*15 894.1*	*17 106.6*
Fugitive emission factor for dry gas storage in TUGS	tCH_4/tDG	EF_{CH4}	0.0000415	0.0000415	0.0000415
Project emissions during dry gas storage in TUGS	*tCO_2/year*		*358.94*	*680.78*	*732.72*
Fugitive emissions during underground gas storage in 2013-2015	tCO_2/3 years				2 198.1
Annual fugitive emissions during backpumping of dry gas					
Fugitive emission factor for gas transportation from the compressors	tCH_4/tDG	EF_{CH4}			0.0011
Project emissions during gas transportation by the compressors	*tCO_2/year*				*46 980. 2*
Fugitive emission factor for gas transportation from the valves	tCH_4/tDG	EF_{CH4}			0.000392
Project emissions during gas transportation	*tCO_2/year*				*16 742.1*
Project fugitive emissions during operation of equipment and gas transportation	*tCO_2/year*	$PE_{CH4, plants}$ (CH4, pipeline)	***21 643.8***	***41 050.2***	***107 904.1***
Electricity consumption	MW	EG_{PJ}	6808.9	13 617.7	13 617.7
Emission factor[49]	tCO_2/MW	EFgrid	0.541	0.541	0.541
Grid losses		TDL	0.200	0.200	0.200
Project emissions from electricity consumption	*tCO_2/year*	***PEec***	***4 420***	***8 841***	***8 841***
Total project emissions	*tCO_2/year*	***PE***	***85 996***	***163 560***	***239 085***

E.2. Estimated leakage:

We did not estimate fugitive emissions, see the comment to Section D.1.1.2.

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

Because fugitive emissions are not considered, project emissions are presented in Table E.1.1.

[49] See Annex 4.

E.4. Estimated baseline emissions:

Baseline emissions were calculated using the equations in Section D.1.1.4.

Table E.4.1. Baseline emissions

Parameter	Measurement Unit	Data variable	Estimated value		
			2010	2011	2012
Volume of APG flow to BCS	m^3/year	V_{APG}	505 134 583	958 054 000	1 031 140 000
Average carbon content in APG pumped to BCS	kgC/m^3	w_A	0.7049	0.7049	0.7049
Quantity of carbon in APG pumped to BCS	**kgC**	$\mathbf{m_A}$	**356 069 565**	**675 332 639**	**726 850 989**
Baseline CO_2 emissions	tCO_2/year	BE CO_2	1 305 588	2 476 219	2 665 120
Baseline emissions of CH_4 due to underfiring, in CO_2-eq.	tCO_2/year	BE CH_4	174 376	338 301	369 541
Total baseline emissions	***tCO_2/year***	***BE CO_2***	***1 479 965***	***2 814 521***	***3 034 661***

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

Project emission reductions were calculated using the equation D.1.4.-1.
Total emission reductions for the period 2010-2012 are equal to **6 840 507 tonnes of CO_2-eq.**
Average annual emission reductions are equal to **2 280 169 tonnes of CO_2-eq.**

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

Table E.6.1 shows the project emission reductions.

Table E.6.1: Project and baseline emissions, emission reductions

Year	Estimated project emissions (tonnes of CO_2 equivalent)	Estimated leakage (tonnes of CO_2 equivalent)	Estimated baseline emissions (tonnes of CO_2 equivalent)	Estimated emission reductions (tonnes of CO_2 equivalent)
2010	85 996	0	1 479 965	1 393 969
2011	163 560	0	2 814 521	2 650 961
2012	239 085	0	3 034 661	2 795 576
Total (tones of CO_2 equivalent)	**488 641**	**0**	**7 329 147**	**6 840 506**

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:

Article 32 of the Federal Law on environmental protection No.7-FZ provides that:

"Environmental impact assessment is conducted for economic and other projects, which may directly or indirectly influence the state of the environment, irrespective of ownership type of the subjects of economic and other activities."

Under this Law, two environmental impact assessments (EIA) has already developed by Tyumen research and development and engineering centre of oil and gas technology for the following projects:

- Technical project "Collection, preparation, compressing and injection of low-pressure gas of Kharampur group of oil-fields into Temporary underground gas storage (TUGS), in the amount of 1 billion m^3 per year" (by VolgaUralNIPIgas Ltd., 2007);
- Technical project "Construction and operation of Temporary underground gas storage for natural gas at Kharampur oil-production site on the basis of Cenomanian gas deposit for storage of dry gas of Kharampur group of oil-fields" (by VNIIGAZ Ltd., 2007).

These documents shall be submitted to State expertise before project implementation for approval. The Expertise shall decide if the project design documents meet all requirements of currently enforced normative acts.

On the whole, utilization of associated dissolved gas at Kharampur group of oil-fields will result in considerable reductions of negative environmental impacts, because flaring will be discontinued. Project implementation will bring about considerable reductions of emissions of soot, nitrous oxides, hydrocarbons and other air pollutants, typical for gas flaring.

In the result of realization of the project activity a value of such resources as soil-vegetable cover, water resources, land resources, hunting resources, fish resources is reduced. Reasons of reduction are destruction the growth, changing hydrologic system of swamp, changing catchment area of water resources, sewage pollution, disturbance ecotope of animals and fishes.

Following types of anthropogenic impacts were marked out:

1. mechanical factors
2. technological factors

Mechanical factors associate with construction work – surface layout, filling road, pipelining, building and construction works. One of the main mechanical factors during building and construction works is unregulated thoroughfare transport. Technological factors associate with environmental pollution. The pollution of landscape takes place at all stages of life cycle of the objects (BPS, PWD, BCS, MPS, etc). Emergency will be the reason for environmental pollution. Noise pollution renders considerable contribution in the whole of environmental pollution.

However using up-to-date technology during building and construction works and operation objects environmental impact will be minimal.

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 city-building Code of the Russian Federation RF No.190-FZ provides in Article 49, Para 1,4,5:

"Technical design documentation for capital construction projects is subject to state expertise. State expertise of project documentation is carried out by specially designated Federal executive authority, or another agency under its jurisdiction. State expertise of project documentation establishes if the project meets the requirements of technical regulations, sanitary, epidemiological, environmental norms, the requirements in the area of protection of cultural heritage, fire safety, industrial, nuclear and radiation safety. State expertise of project documentation also establishes if the project conforms with the results of engineering survey."

Construction of the booster compressor station (BCS) and engineering infrastructure shall begin only if the State expertise formally approves the following projects:

- Technical project "Collection, preparation, compressing and injection of low-pressure gas of Kharampur group of oil-fields into Temporary underground gas storage (TUGS), in the amount of 1 billion m^3 per year" (by VolgaUralNIPIgas Ltd., 2007);
- Technical project "Construction and operation of Temporary underground gas storage for natural gas at Kharampur oil-production site on the basis of Cenomanian gas deposit for storage of dry gas of Kharampur group of oil-fields" (by VNIIGAZ Ltd., 2007).

SECTION G. Stakeholders' comments

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

Federal Law on environmental protection No.7-FZ defined the procedure of participation of citizens and public organizations in the public environmental expertise.

Public hearings on the project "Collection, preparation, compressing and injection of low-pressure gas of Kharampur group of oil-fields into Temporary underground gas storage (TUGS), in the amount of 1 billion m^3 per year" were held on 21.02.2008. The participants included project developers from RN-Purneftegas Ltd., the President of municipal administration of Purovsky municipal district, journalists and representatives of independent association.

The participants of the public hearings issued the Protocol on the hearing results. This Protocol has been attached to project design documents to be submitted for the State environmental expertise. This protocol has been signed by all interested parties.

During the public hearings the stakeholders touched following topics:
1. Taking building and construction works by local organization. This makes supplement for local budget and gives additional employment of local labor force.
2. Training of local labor force and employment in the objects.
3. Construction of museum in Kharampur village and other social and cultural objects.
4. Noise pollution of pipelining through the rivers will be considerable.
5. Unauthorized access to the protected territory for fishing.

All above-listed opinions were taken into account by specialists of RN Purneftegas.

Annex 1

CONTACT INFORMATION ON PROJECT PARTICIPANTS

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Annex 2

BASELINE INFORMATION

Table 2.1: Component composition of APG incoming to BCS

Component	*Molar ratio*
N_2	0.0165432
CH_4	0.8122044
CO_2	0.0026458
C_2H_6	0.0636023
C_3H_8	0.0552443
i-C_4H_{10}	0.0156802
n-C_4H_{10}	0.0187103
i-C_5H_{12}	0.0058861
n-C_5H_{12}	0.0044293
n-C_6H_{14}	0.0026415
O_2	0.0003550
H_2O	0.0020576

Table 2.2: APG volume flared in flares with carbon-black firing conditions

	2010	*2011*	*2012*
APG flaring volumes			
APG volume flared at HPF of South-Kharampur BPS-1, m^3/year*	97 167 583	166 573 000	166 573 000
APG volume flared at HPF of South-Kharampur BPS-1, kg/year*	90 773 956	155 612 496	155 612 496
APG volume flared in flares with carbon-black firing conditions, kg/year	381 113 223	739 383 440	807 659 000

**)According to Project of Emission Limits document of RN-Purneftegas Ltd., only this flare does not operate under carbon-black (soot-forming) firing conditions. Following conservative approach, we took maximum projected amount of flared gas.*
HPF= high pressure flare.

Annex 3

MONITORING PLAN

The monitoring plan specifies:
- Monitored parameters, and procedures of measurement of these parameters;
- Measuring equipment;
- Monitoring procedures and distribution of responsibilities for data collection, storage and processing.

Data collection procedures should be simple and transparent. The monitoring plan may be corrected according to operational requirements in case of need. All changes shall be approved during annual verification by independent organization in accordance with the existing procedures.

Project monitoring shall begin immediately after project commission in January of 2010. Section D describes the monitoring system. The Table below follows methodology AM0009 v.2.1. All monitoring data shall be archived in electronic and paper copy formats, and be available for 2 years after the end of the credit period. All indicators will be automatically controlled by ASC TP. All measuring device s shall be calibrated according the existing industry standards.

Table 3.1 Matrix of responsibilities

Task	Operator	Department of treatment and transportation of gas, oil and condensed gas	Department of chief metrologist	Laboratory of eco-analytical and technological research	Department of automation of information technologies and communications	Central service of engineering and technology	Department of environmental protection	The first deputy of Director General - Chief Engineer
Collection of measured data	E	R	I				I/C	
Data transmission					E		I/C	
Approval of data flows and preparation of reports						E	I/R/C	
Random sampling of data flow	I			I/R			I/C	
Analysis of composition				E			I/C	
Calibration and maintenance	I	R	E				I/C	

Preparation of monthly and annual reports						E	E/R/C	I
Archiving of data and reports							E/R/C	I
Calculation of emission reductions	I	I	I	I	I	I	E/R/C	I

E = collection of existing data,
R = quality control,
I = informing,
C = coordination.

Annex 4

EMISSION FACTORS

Emission factors (EFs) for grid electricity generation by Ural Regional Energy system of the Russian Federation were developed under the "Guidelines for calculation of emission factors for energy systems" (EB-35, October 2007) by Carbon Investments Ltd. Co., Moscow (contact person is Mikhail Rogankov). This work was commissioned by Carbon Trade and Finance SICAR S.A. These EFs should be used by JI project initiators and independent organizations involved in preparation of PDD for JI projects. The same EFs will be used in PIN documents, in research and development activities, and for other purposes.

The EFs study has been a subject for verification performed by Bureau Veritas Certification Holding SAS in October-November 2008. The official approval for the EFs used in this PDD was received by 10.11.2008. We give beneath the extracts from the study.

CO_2 emission factors were estimated for the situations when grid electricity is substituted by electricity generated at the existing power stations ("operating margin" - OM), by newly constructed plants ("built margin" - BM) or their combination ("combined margin" - CM). These three categories refer to the power plants, which may be influenced by the JI project.

The following sources of information were used to calculate EF_{OM}:
- Official information of Federal Statistical Service (Rosstat),
- Information published by Russian Open Joint-Stock Company "Integrated Power Systems of Russia" (RES),
- Information published by OJSC "System Operator of RES",
- Data of regional energy dispatching departments,
- Data of energy companies reported in annual statistical reports No.6-TP.

The following sources of information were used to calculate EF_{BM}:
- Official annual reports of RES and regional energy companies which listed recently commissioned power plants,
- "General scheme of location of power plants until 2020", approved by the Government of the Russian Federation (Decision No. 215 of 22.02.2008),
- Investment programs of regional energy companies.

The electric power industry of Russian Federation comprises 319 thermal power plants (TPPs), 61 hydro power stations (HPSs) and 9 nuclear power stations (NPSs) (data of 2006 from JSC UES of Russia) related to the «electric power sector» and some block-units being shops of industrial enterprises (mainly, of metallurgical plants) and some municipal electric power stations. The capacity of municipal power plants constitutes an insignificant part in the power balance of the country. The power stations are unified by transmission lines in 60 provincial electricity systems (PESs), while these systems have in its turn the electric connections with the neighbor ones (excluding some isolated provincial systems). Provincial electricity systems (PESs) are unified in 7 regional systems (RESs), which have the connections between themselves through backbone and interconnection networks. All together these power plants, transmission lines, distribution networks and power systems constitute the national energy system (UES of Russia).

Thermal and hydro plants of electric power industry appertain to 6 generating companies of the wholesale electricity market (OGCs), 14 territorial generating companies (TGCs), JSC "Irkutskenergo", JSC "Novosibirskenergo", "JSC "Tatenergo", JSC "Bashkirenergo", provincial power companies of isolated territories, hydrogenerating OGC (JSC "RusHydro"), nuclear plants belong to the State concern «RosEnergoAtom». The backbone (main) networks are in the maintenance of JSC «Federal Network Company of UES», distribution networks in the maintenance of more than 50 distributional companies.

For decades the national Unified Energy System is functioning as a centralized, 3 level dispatched system "from top to the bottom" and strict discipline of all of the participants to provide reliable, safe and optimal power supply in the country. Along with this "command" system wholesale power market which was launched in Russia several years ago is functioning. The structure of UES and subordination of its component entities are presented in Figure 3-1.

Figure 3-1. Structure of UES and dispatch management.

UES The dispatch management is carried out by JSC "SO UES"

RES of Center	RES of North-West	RES of Mid- Volga	RES of South	RES of the Urals	RES of Siberia	RES of East
The dispatch management is carried out by the corresponding branch of JSC "SO UES" (SO ODU)						

16 PESs	7 PESs	8 PESs	6 PESs	8 PESs	8 PESs	3 PESs + 4 isolated ones
The dispatch management is carried out by the corresponding branch of JSC "SO UES" (SO RDU)						

JSC «System Operator of Unified Energy System» (JSC «SO UES») was launched in June 2002 (as the successor of the former Central Dispatch Operator of UES acting as a department of JSC "UES of Russia"). It is the superior body of operative-dispatching management in electric power industry. JSC «SO UES» was first created as 100%-affilated company of JSC "UES of Russia". 64 branches (7 branches – SO ODU and 57 branches – SO RDU) are functioning as a part of JSC "SO UES". From July 2008 JSC «SO UES» is transformed in 100%-state company (owned by the Government of Russia).

JSC «SO UES» is continuously forming operational tasks and regimes of RESs and some large-scale power plants of federal significance and define optimal power transmission between RESs. "SO ODU" branches provide fulfillment of those tasks on a regional level and form tasks, regimes of PESs and transmission between them. "SO RDU" branches fulfill those tasks and dispatch the loads of related power plants.

Such a structure of power systems in Russia and regimes of their operation as referred to the choice of the project electricity system which must meet the condition of being dispatched "without significant transmission constraints" mean the following. Large and mid-scale JI project activity will physically cause changes in transmission, especially in small and mid-scale provincial power systems though these impulses may be smoothed down by the dispatch general policy and decisions. But obviously the larger the system is the lower the probability of constraints (e.g. for RESs the probability of transmission constraints from even large-scale JI projects activity will be minimal while for small and mid-scale PESs for each JI project this must be the subject of discussions with the corresponding system operator).

RESs "Center", "North-West", "South", "Siberia" and "East" coincide with the Federal districts of the Russian Federation (okrugs). 4 PESs "Udmurt", "Perm", "Kirov" and "Orenburg" are referred to RES "Urals" while the 4 corresponding subjects of Russia are component parts of the Volga Federal District. As for the PESs they coincide with the corresponding subjects of the Russian Federation; some of them with one or two provinces of the Russian Federation.

PESs vary a great deal by their capacities, lack or redundancy of capacities, import/export rates, shares of thermal, hydro and nuclear capacities, fuel mix, degree of interrelations. For instance, PES "Kurgan" (in the Urals) comprises only one TPP 480 MW, some transmission lines and distribution network while in Moscow PES the capacity of power plants constitutes 15 560 MW. Thus developing EFs for PESs will need taking into consideration peculiarities of each system while RESs are more or less universal for this task.

United energy system of Urals (RES Urals) includes Yamalo-Nenetsky Autonomous District, Sverdlov, Chelyabinsk, Perm, Orenburg, Tumen, Kirov and Kurgan regions, Udmurtia and Bashkortostan. RES Urals has more than 106,000 km of power lines (about ¼ of Russian high-voltage power lines), with voltages 500 – 110 kV. This grid unites 111 power plants, with total installed capacity over 42,000 MW, or 21% of total installed capacity of the Russian Federation. Annual electricity generation is over 210 billion kWh, or 25% of total electricity generation in the Russian Federation. About 55% of this electricity is consumed by industrial consumers, which is 30% of electricity consumption by industrial consumers in the Russian Federation. RES Urals is situated in the center of the country, between RES of Siberia, Central European Part, Middle Volga and Kazakhstan.

The following equation was used to calculate the operating margin (OM) emission factor:

$EF_{grid,OMsimple,y} = b_{weight,\ y} \times EF_{CO2,weight}$ (4.1.)

where
$EF_{grid,OMsimple,y}$ - simple emission factor EF_{OM} in the year ***y*** (tons of CO_2 per MWh)
$b_{weight,\ y}$ – unit consumption of fuel per 1 kWh of net electricity generation, averaged for the whole RES (t.c.e. per MWh);
$EF_{CO2,weight}$ – weighted average emission factor for the fuel mix (tons of CO_2 per t.c.e.).

It should be noted that in Russian Federation historically for measurement of thermal energy produced or consumed the non SI values are used, i.e. tonne of equivalent fuel (1 t.c.e*0.0293076=1 TJ). Every Russian power plant is legally obliged to submit production information (6-TP report form) to Federal Statistical Service (Rosstat) which is then aggregate each individual report to unit consumption of fuel per 1 kWh of net electricity generation, averaged for the whole RES. The same aggregation for scale of RES is done for consumed fuel share in the mix and electricity generation. Thus, to avoid extensive work the developer decided to use aggregated data which already includes info about each power plant.

The data for calculation of $EF_{grid,OMsimple,y}$ were taken from Rosstat reports. The regional shares of various fuels ***a*** were calculated using the regional-level fuel consumption data (reported by Rosstat in t.c.e).
Table 4.1. IPCC default emission factors for stationary combustion in the energy industries

Fuel	Default emission factor in tCO_2/TJ	Default emission factor in tCO_2/t c.e. (converted from tCO_2/TJ)
Sub-bituminous coal	96.1	2.775
Lignite (brown coal)	101.0	2.962
Residual fuel oil (mazut)	77.4	2.270
Natural gas	56.1	1.645

Source: 2006 IPCC Guidelines for National GHG Inventories

Table 4.2 The results of calculation of EF_{OM}

RES Urals			
$b_{.weight}$ (t c.e./MWh)	0.3414	0.3325	0.3226
$EF_{CO2,average}$ (tCO_2/t c.e.)	1.8732	1.9387	1.880
$EF_{grid,OMsimple,y}$ (tCO_2/MWh)	0.6395	0.6446	0.6064
Net generation by TPPs (thous.	124564.2	149426.2	138016.6

MWh)			
3 years average electricity weighted EF_{OM} (tCO_2/MWh)	**0.630**		

Then we identified the set of new power plants to be included in "BM" category.

The main principle stated by the Tool is that the cohort should reasonably "reflect the power plants that would likely be built in the absence of the project activity" (*quoted from the Tool*) which means that the BM capacity is a virtual one (though the most probable) and the cohort is assembled just to determine the parameters of such a capacity to calculate GHG emissions.

The sample group of power units used to calculate the BM consists of either:
- (a) The set of 5 power units that have been built most recently (in 10 years period), or
- (b) The set of power capacity additions in the electricity system that comprise 20% of the system generation (in MWh) and that have been built most recently.

Capacity additions from retrofits of power plants should not be included in the calculations of $EF_{grid,BM,y}$.
In case it is impossible to fulfill conditions (a) and (b) the Tool recommends to increase the 10 year period for the new capacities so that 5 new plants (a) or 20% additions (b) are available.
In terms of vintage of data, projects participants can choose between one of the following 2 options:
Option 1.
For the first crediting period, calculate the BM emission factor ex-ante based on the most recent information on units already built for the sample group ***m*** at the time of PDD submission for determination. This option does not require monitoring of the EF.
Option 2.
For the first crediting period, the BM emission factor shall be updated annually, ex-post, including those units built up to the year of registration of the project activity or, if this information is not available, including those units built up to the latest year for which information is available.

Power plants with higher capacities should be included in the cohort of 5 plants/units.

The Tool states that if this approach does not reasonably reflect the power plants that would likely be built in the absence of the project activity, project participants are encouraged to propose an alternative.

From mid '90s Russia was recovering after a long and deep economic crisis, construction of new power capacities were very rare and in some RESs one or two new capacities are lacking for the cohort of 5 plants. In this case we increased the 10 years period to 15 years as recommended by the Tool. If this didn't work we had to include a new plant(s)/unit(s) which are under construction.

Table 4.3. RES Urals. Power plants/units commissioned from 1993

Power plant/unit	Year of commissioning	Capacity, MW	Technology	Fuel
Commissioned in 1996-2008				
Nizhne-Vartovsk TPP, unit # 2	2003	800	New steam unit	Gas
Nizhne-Vartovsk TPP, unit # 1	1993	800	New steam unit	Gas
Tchaikovsky CHP	2007	50	Additional steam turbine	Gas
Kizelovsk TPP-3	2005	26	Additional steam turbine	Coal/ gas
Kizelovsk TPP-3	2006	26	Additional steam turbine	Coal/ gas
Berezniky CHP-2	2005	30	Additional steam turbine	Coal/

				gas
Berezniky CHP-2	2003	12	Additional steam turbine	Coal/ gas
Tumen CHP-1	2003	190	CC GT	Gas
Cheliabinsk CHP-3 (unit No.2)	2006	180	New steam unit	Gas
Cheliabinsk CHP-3 (unit No.1)	1996	180	New steam unit	Gas
Total		Less than 20% of RES's capacity		

Small-scale (12-30 MW) steam turbines that have been commissioned at Tchaikovsky CHP, Kizelovsky and Bereznikovsky CHP plants can't be related to the "new" capacities, because these projects are either direct or delayed substitution of obsolete turbines, while capacity additions from retrofits are not recommended by the Tool for calculating the build margin EF. They are not included in the group of 5 units. The cohort of 5 plants comprises:

- 2 x 800 MW steam unit
- 190 MW CC GT unit that has been commissioned;
- 2 steam units by 180 MW

The BM emission factor is the generated-weighted average emission factor of all power units ***m*** during the year y calculated as follows:

$$EF_{grid,BM,y} = \frac{\sum_m EG_{m,y} \text{ x } EF_{EL,m,y}}{\sum_5 EG_y} \quad (6)$$

Where:
$EF_{grid,BM,y}$ = BM emission factor in year ***y*** (tCO_2/MWh)
$EG_{m,y}$ = net quantity of electricity generated and delivered to the grid by power unit ***m*** in year ***y***
$\sum_5 EG_y$ = net quantity of electricity generated and delivered to the grid by the cohort of 5 units in year ***y***
$EF_{EL,m,y}$ = CO_2 emission factor of power unit ***m*** in year ***y*** (tCO_2/MWh)
m = power units included in the BM
y = year for which power generation data is available.

The method of calculation of $EF_{EL,m,y}$ here is the same as for EF_{OM} described under Step 3, i.e. by using specific fuel consumption per 1 kWh of energy output b_m (kg c.e./kWh).

$EF_{EL,m,y} = EF_{CO2fuel}$ x $b_{m,y}$

Where

$EF_{CO2fuel}$ – fuel emission factor (fuel type weighted) in tCO_2/MJ or tCO_2/t c.e; the IPCC factors for main types of fuel values are presented in Table 4-4.
b_m – specific fuel consumption by unit ***m*** (MJ/MWh or t c.e./MWh)

b_m is accepted according either to the operational reports, or from the projects' designs or from the standards established by the "Concept of Technical Policy of JSC UES" (2005) for new equipment.

The results of EF_{BM} calculation for RESs are presented in Table 4-16.

Table 4.4. Calculation of $EF_{grid,BM}$ for RES "Urals"

Description	Natural gas-fired 800 MW steam unit*	Natural gas-fired 800 MW steam unit*	Natural gas-fired CC GT 190 MW unit **	Natural gas-fired steam unit 180 MW **	Natural gas-fired steam unit 180 MW**
Electric capacity, MW	800	800	190	180	180
Capacity utilization, %***			52	52	52
Annual net generation of electricity, MWh	5817000	5817000	865488	819936	819936
Specific fuel consumption, b_m (kg c.e./kWh)	0.3045	0.3045	0.2399	0.330	0.330
The same in MJ/MWh	$8.931x\ 10^3$	$8.931x\ 10^3$	$7.0363x10^3$	$9.679\ x\ 10^3$	$9.679x10^3$
Fuel	Natural gas	Natural gas	Natural gas	Natural gas	Natural gas
Fuel emission factor, $EF_{CO2fuel}$ (tCO_2/MJ)	$0.0561.10^{-3}$	$0.0561.10^{-3}$	$0.0561.10^{-3}$	$0.0561.10^{-3}$	$0.0561.10^{-3}$
Results of calculations					
$EF_{EL,m,}$ (tCO_2/MWh)	0.501	0.501	0.3947	0.5430	0.5430
Average weighted EF_{gridBM}, tCO_2/MWh	**0.501**				

* based on the reported data of operational Nijne-Vartovsk TPP with 2 x 800 MW units
** based on the reported data of analogs
*** assumed based on the 2007 figure from Rosstat of 52 % for TPPs; for high capacity and TPPs of condensed type assumed as 60 %

The $EF_{grid,CM,y}$ is calculated as follows:

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

Where:

$EF_{grid,OM,y}$ – OM emission factor in year y (tCO_2/MWh)
$EF_{grid,BM,y}$ - BM emission factor in year y (tCO_2/MWh)
w_{OM} – weighting of OM emission factor (equals 0.5 for the first crediting period as recommended by the Tool);
w_{BM} - weighting of OM emission factor.

Table 4.5. Final EF_{CM} values for the case of increase of power delivery to the grid or/and increase of electricity consumption from the grid.

Regional power system	**Amendment of EF_{CM} (taking into account uncertainty)**	**EF_{CM} (tCO_2/MWh)**
"Urals"	0.566 - 4.4%	0.541

As recommended in the "Tool to calculate baseline, project and/or leakage emissions from electricity consumption, EB 39 Report, version 1)", this emission factor EF_{CM} should be used to calculate baseline emissions and fugitive emissions of greenhouse gases, if electricity consumption from the grid increases as a direct result of JI project activities.

We assumed 20% leakage of electricity during transmission (the default value from IPCC Guidelines). We used the default value for 2 reasons: (1) we did not have domestic data and (2) electricity is transmitted via RES Urals grid over long distances.

Annex 5

PROJECT INFORMATION

Table 5.1. Adjusted material balance of BSC

	2010		*2011*		*2012*	
	Value	***%***	***Value***	***%***	***Value***	***%***
Receipts						
APG, m^3/year	505 134 583	100.0	958 054 000	100.0	1 031 140 000	100.0
APG (specific density 0.93 kg/ m^3), kg/year	471 887 179	100.0	894 995 937	100.0	963 271 497	100.0
Expenditures						
Dry gas to TUGS (specific density 0.769 kg/ m^3), m^3/year	411 867 226		781 160 223		840 751 724	
Dry gas to TUGS, kg/year	316 777 863	67.13	600 810 772	67.13	646 644 156	67.13
BFLH, kg/year	130 476 805	27.65	247 466 377	27.65	266 344 569	27.65
Dry gas for own needs, kg/year	22 178 697	4.70	42 064 809	4.70	45 273 760	4.70
Losses, kg/year	2 359 435	0.50	4 474 979	0.50	4 816 357	0.50
Content of C_3+ in APG, kg/year	121 936 417		231 268 411		248 910 927	
Content of C_3+ in BFLH, kg/year	112 364 457		213 113 933		229 371 519	
Rate of BFLH recovery, %	92.2		92.2		92.2	

Source: Business Plan of RN-Purneftegas Ltd. for 2009-2013

Table 5.2. Annual electricity consumption by the project

Production site	Annual electricity consumption, kWh
PWDU-OTF site of North-Kharampur oil-field	391 563
BPS-2 site of North-Kharampur oil-field	659 663
BPS-1 site of South-Kharampur oil-field	771 103
PWDU-2 site of South-Kharampur oil-field	882 543

BPS site of Festival oil-field	554 223
MPS site	272 791
Gas-distributing station	99 383
Cluster of injection wells	155 230
Stop valves	464 826
Cathodic protection devices	360 000
BCS site with water supply wells	9 006 387
Total:	**13 617 712**

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Annex 6

LIST OF ABBREVIATIONS

BPS	Booster pump station
PWDU	Preliminary water discharge unit
APG	Associated petroleum gas
GSU	Gas separator unit
BCS	Booster compressor station
BFLH	Broad fraction of light hydrocarbons
BCU	Block compressing unit
WMT	Water/methanol tank
MPS	Multiphase pumping station
TUGS	Temporary underground gas storage
OTF	Oil treatment facility
CCT	Central commercial tank
GDP	Gas distributing point
ASC TP	Automated system of control of technological processes
OJSC	Open joint-stock company
RES	Integrated power system
EF	Emission factor
Rostechnadzor	State Commitee for Technical Surveillance
JI	Joint implementation
ERU	Emission reduction unit
VRC	Vapour recovery compressor
GPPS	Gas-piston power station
DG	Dry gas
PDD	Project Design Document