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 treatment for further use at Yuzhno-Khylchuyuskoe field of LLC "Naryanmarneftegas", Russian Federation

Sector (category) of sources[1]:

(1) Energy industries (renewable/non-renewable sources),

(10) Fugitive emissions from fuels (solid, oil and gas).

Version: 1.4

Date: January 26, 2012

A.2. Description of the project:

The project is implemented at Yuzhno-Khylchuyuskoe oilfield in the Nenets Autonomous Okrug (NAO), Russian Federation. The field is developed by LLC "Naryanmarneftegas" (a joint venture between OJSC "LUKOIL" and ConocoPhillips) which started its development in February 2006. Commercial oil production at Yuzhno-Khylchuyuskoe field started in June 2008.

The distinctive feature of Yuzhno-Khylchuyuskoe field is the high content of hydrogen sulfide in crude oil and associated petroleum gas (APG). The volumetric fraction of hydrogen sulfide in APG is about 2.5%. Without pre-removal of hydrogen sulfide APG cannot be used for process needs of the field and so the only acceptable alternative for APG handling is its combustion in flare units.

The project involves removal of hydrogen sulfide from APG for the purpose of using treated APG for the field needs, producing elemental sulfur and reducing emissions of pollutants and greenhouse gases (GHG) into the atmosphere.

The main facilities to be put into operation under the project are a gas treatment plant (See Fig. A.2-1) and a sulfur recovery plant with a sulfur storage facility. An absorption method is used for removal of hydrogen sulfide and carbon dioxide from gas. The Claus process is used for sulfur recovery. The design gas treatment capacity of the plant is 586 million m^3 of APG per year. The design output of the sulfur recovery plant is 22.4 thousand tonnes of sulfur per year. The equipment was designed and supplied by OJSC "Giprogazoochistka".

Commissioning of the gas treatment plant allowed utilization of APG as a fuel for the needs of the Energy Center and also as a stripping agent for hydrogen sulfide removal from crude oil at the production site of Yuzhno-Khylchuyuskoe field. Part of treated APG is used for auxiliary needs of the project facilities (in desulfurization boiler house).

Up until that time natural gas from the neighbouring Yareyuskoe gas condensate field that is situated approximately 28 km south of the Central Oil Gathering Station of Yuzhno-Khylchuyuskoe field also developed by LLC "Naryanmarneftegas" had been used as fuel for the Energy Center and also for crude oil stripping. All of APG was flared. The baseline scenario assumes continuation of the APG flaring practice and use of natural gas for the needs of Yuzhno-Khylchuyuskoe field. It should be noted that since Yareyuskoe field is remote from the gas transmission system the company cannot sell natural gas to third-party consumers.

[1] In accordance with the list of sectoral scopes adopted by the Joint Implementation Supervisory Committee. http://ji.unfccc.int/Ref/Documents/List_Sectoral_Scopes.pdf

The GHG emission reduction is achieved through reduction in natural gas consumption and also due to far more complete oxidation of methane when APG is used as fuel than when it is flared. The field flare units serve to ensure the so-called soot combustion of gas characterized by a high unburnt carbon factor which leads to significant methane emissions. The expected GHG emission reductions over 2009-2012 are estimated at an average of 404 ktCO_2e per year.

Fig. A.2-1. General view of the gas treatment plant

On November 22, 2005 OJSC “LUKOIL” held the meeting on discussion of the Corporate Strategy for establishing an innovative investment promotion mechanism using the Kyoto mechanisms, where it was decided to approve the APG utilization project at Yuzhno-Khylchuyuskoe field. At that point in time the joint implementation plans envisaged APG utilization in the Energy Center (whose capacity at the first stage is 125 MW and after completion from 2010 onwards it was supposed to reach 250 MW) and also injection of APG surpluses to the Yareyu underground gas reservoir. The report of proceedings at the meeting also states that in the absence of the project electricity would be generated using natural gas and APG would be flared. The proposed APG handling was technically feasible given that gas treatment plants were available and such were planned to be commissioned in two stages: the 1st line and the 2nd line.

In practice the project has not been and will never be implemented in full because of a slump in crude oil and APG production volumes against the original projections. The company took a decision to implement the joint implementation project partially. The company dropped its plans for the Energy Center expansion, APG injection into the underground gas reservoir and gas treatment capacity enhancement.

The contract for supply of the equipment of the 1st gas treatment and sulfur recovery line was signed on June 19, 2006 which is considered the starting date of this project. The equipment of the 1st line started its pre-commissioning operation in October 2008 (order No.594 dated October 15, 2008).

A.3. Project participants:

Party involved	Legal entity, project participant (as applicable)	Please indicate if the Party involved wishes to be considered as project participant (Yes/No)
Russian Federation (Host Party)	Limited Liability Company "Naryanmarneftegas"	No
One of the Annex B Parties to the Kyoto Protocol	To be determined within 12 months upon approval of the project by the Russian Government	No

Limited Liability Company "Naryanmarneftegas"

LLC "Naryanmarneftegas" is a limited liability company established in 2005 as a joint venture between OJSC "LUKOIL" (70%) and ConocoPhillips (30%) for development of large oilfields in the Nenets Autonomous Okrug and for hydrocarbons export via a large marine terminal built in Varandey village.

A.4. Technical description of the project:

A.4.1. Location of the project:

Russian Federation, Arkhangelsk Region, Nenets Autonomous Okrug, Yuzhno-Khylchuyuskoe field

A.4.1.1. Host Party(ies):

Russian Federation

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

Arkhangelsk Region, Nenets Autonomous Okrug

Fig. A.4-1. The Nenets Autonomus Okrug on the map of the Russian Federation

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

Yuzhno-Khylchuyuskoe field

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

Yuzhno-Khylchuyuskoe field is a part of the Northern Territory fields group.

The construction site is located close to the Central Processing and Treatment Facility (CPF) of Yuzhno-Khylchuyuskoe field and lies approximately 120 km north-east of Naryan-Mar in the Nenets Autonomous Okrug, 38 km from the Barents Sea shore (Pechora bay) and approximately 250 km north of Usinsk.

The field is connected with the nearest settlements of Naryan-Mar and Usinsk by winter roads in winter (from December through April (inclusively)) and in summer time – by helicopter.

Naryan-Mar: 67°38′ N, 53°02′ E[2]. Time zone GMT: +3:00.

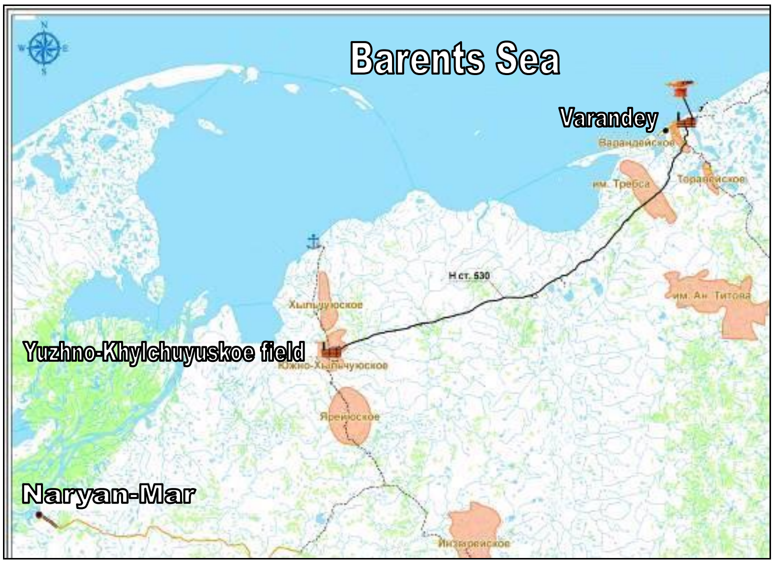

Fig. A.4-2. Yuzhno-Khylchuyuskoe field on the map of the Nenets Autonomous Okrug

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

Fig. A.4-3 shows the concept scheme of interconnections between various components covered by the project. Two main facilities are installed within the framework of the project: a gas treatment plant for removal of hydrogen sulfide and carbon dioxide and a sulfur recovery plant with a sulfur storage facility. The equipment was designed and supplied by OJSC "Giprogazoochistka".

Much of treated APG is used as fuel in the Energy Center situated on the same production site with the Gas Treatment Plant; some of it – in the desulfurization boiler house which is constructed under the project. There still remains a possibility to use natural gas as a backup fuel.

Crude oil stripping from hydrogen sulfide takes place in the stripping columns KO-24, 25 with the help of treated APG. Contaminated APG after stripping columns is flared.

The treated APG surpluses are flared.

[2] http://ru.wikipedia.org/wiki/%D0%9D%D0%B0%D1%80%D1%8C%D1%8F%D0%BD-%D0%9C%D0%B0%D1%80

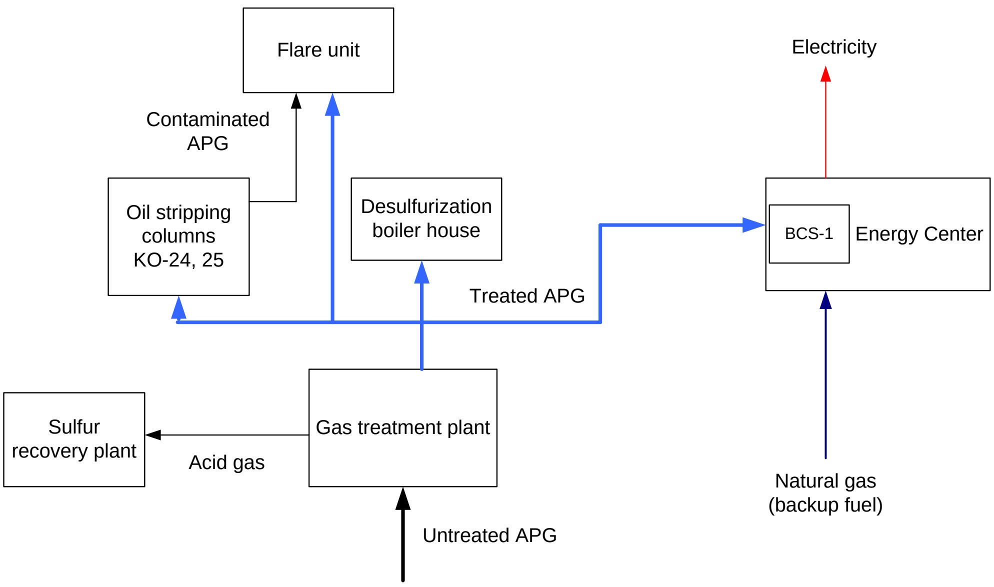

Fig. A.4-3. Concept scheme of interconnections between the components covered by the project

<u>Characteristics of the gas treatment and sulfur recovery plants</u>

The gas treatment plant is built to ensure removal of hydrogen sulfide and carbon dioxide from APG. The volumetric content of hydrogen sulfide and carbon dioxide in the untreated APG can reach 3% and 10% respectively.

The sulfur recovery plant is built to produce elemental sulfur using the Claus process.

The design throughput of the gas treatment plant is 20000-65000 m^3/h (at 0ºC and 101.3 kPa).

The raw material for the sulfur recovery plant is acid gas from the amine solution recovery unit of the gas treatment plant. The produced liquid sulfur is degassed and then supplied to the sulfur storage facility.

The sulfur recovery plant output is 18.8-64.3 tonnes of sulfur per day.

The plants operate continuously, 8400 hours per year.

Implementation of all technical solutions makes it possible to achieve a guaranteed sulfur recovery level of no less than 97.5-98.0%.

An absorption method is applied for removal of hydrogen sulfide and carbon dioxide from gas using a 33% solution of diethanolamine (DEA). Saturated DEA solution is recovered by heating it to the boiling temperature at regeneration pressure.

Acid gases absorption by secondary amines (DEA) results in production of chemically unstable compounds – water-soluble complex salts. These reactions are reversible. The chemical reaction equilibrium is ensured by maintenance of pressure and temperature parameters, by gas and liquid absorber properties, and by the design features of the equipment.

The absorption process takes place in a column – absorber. Chemical reactions take place in a liquid phase on contact absorber plates during countercurrent continuous contact of raw material (associated petroleum gas (flows from the bottom upward) with liquid absorber (DEA solution (flows from the top downward).

Regeneration of 33% DEA solution saturated with hydrogen sulfide and carbon dioxide is ensured by desorption process by means of heating the solution to the boiling temperature at working pressure in the plate absorber column. In the process of desorption chemical compounds degrade into DEA and gases. Desorption reactions take place with heat absorption which makes the process endothermic.

The sulfur recovery plant uses the Claus process which consists of one thermal step and there catalytic steps. To achieve the highest efficiency when using the state-of-the-art Claus process catalytists at least two conditions should be met. The first condition is the efficient operation of the thermal step, ensuring hydrogen sulfide conversion into sulfur of no less than 65%. The second condition is that the burning process in the thermal step should be organized in such a way as to ensure that the residual free oxygen in process gases does not exceed 100 ppm.

The thermal step is high-temperature combustion of hydrogen sulfide in a waste heat boiler furnace with supply of a certain air volume. In the catalytic process step at 200-300°C H_2S and SO_2 are converted into sulfur. As the reactions give off heat, decreasing the reaction temperature boosts the sulfur yield. Using three catalytic steps serves to boost the sulfur yield due to lower reaction temperature in the third step compared with the first and the second steps. More detailed information about the boiler units installed in the Energy Center is presented in Annex 2.6.

<u>The project implementation schedule</u>

Name	Date
Design	June 2006 – August 2008
Equipment supply	November 2006 – December 2008
Construction and installation	March 2007 – December 2008
Set up and start up	October 2008 – June 2009
Commissioning	December 2008

The actual operation of the plants was begun in a start-up mode in October 2008 (order of LLC “Naryanmarneftegas” No.594 dated October 15, 2008). By the end of 2008 the plants started routine operation.

The key consumer of APG after stripping of sour gases will be the Energy Center. The electric power generated by the Energy Center will be supplied to the oilfield facilities of Yuzhno-Khylchuyu and also to the marine oil handling terminal in Varandey which lies 158 km from Yuzhno-Khylchuyuskoe field. The Energy Center consists of 5 gas turbine units, 24.5 MW each.

The Energy Center was put into operation in stages:

- Unit No.1 SGT-600 – 24.5 MW – commissioned in January 2008;
- Unit No.2 SGT-600 24.5 MW – commissioned in June 2008;
- Unit No.3 SGT-600 24.5 MW – commissioned in December 2008;
- Unit No.4 SGT-600 24.5 MW – commissioned in December 2008;
- Unit No.5 SGT-600 24.5 MW – commissioned in June 2009.

Twin-shaft industrial gas turbine units SGT-600 serve to generate electricity. Gas turbine units are characterized by high efficiency and reliability and can operate on a wide range of gaseous and liquid fuels.

SGT-600 gas turbine unit manufactured by Siemens

Power output at generator terminals	– 24.5 MW (under ISO conditions)
Type of unit	– light industry
Number of shafts	– 2
Electrical efficiency	– 33.1% (ISO)
Exhaust gas flow	– 79.8 kg/s (ISO)
Gas temperature at the inlet to the power turbine (PT)	- 1115°C
Rated speed of PT	– 7700 rpm (ISO)
Combustion chamber type	– annular type, 2nd generation DLE (dry low emission reduction during gas fuel operation, water injection for NOx-reduction during liquid fuel operation)
Weight of PT	– 5.8 t
Operation on gas	Capacity – 25 MW Efficiency – 33.5% Per unit consumption of equivalent fuel – 501 g e.f./kWh Exhaust temperature – 540°C
Operation on diesel fuel	Capacity –25MBт Efficiency – 32.3% Fuel consumption – 1.77 kg/s Exhaust temperature – 543°C

The Energy Center also includes a booster compressor station (BCS) designed for compression of gas fed to the gas turbine units. The BCS consists of four gas booster compressor units of EGS-S-380/1600 WA type each capable of 11020 Nm^3/h (one standby) supplied by Sventa AG (Switzerland) with accessory equipment.

Technical data of EGS-S-380/1600 WA compressor units

Parameter	Unit	Nom.	Max.
Suction pressure (frame)	bar	3.5	4.5
Suction temperature	ºC	40	50
Discharge pressure (frame)	bar	28	28
Discharge temperature (frame)	ºC	60	120
Nominal output	Nm^3/h	11020	14000
Capacity	kW	1560	1595
Speed	min^{-1}	2980	
Electric motor			
Voltage	V	3x10000	
Frequency	Hz	50	50
Speed	min^{-1}	2980	2980
Nominal rating	kW	1600	1600

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:

Due to the project implementation LLC "Naryanmarneftegas" created conditions for APG utilisation at Yuzhno-Khylchuyuskoe field.

APG burns up in any case, however due to the project treated APG is used as fuel for the Energy Centre and also as an agent for removal of hydrogen oxide from crude oil. Without the project natural gas would have been used for this purpose. Thus the project results in substitution of natural gas which ensures CO_2 emission reductions.

Besides gas combustion in flare units is characterised by a high unburnt carbon factor which is responsible for significant methane emissions. Gas flaring is significantly reduced as result of the project. Thus in addition to CO_2 emission reduction the project also results in mitigation of CH_4 emissions.

As the government does not provide proper incentives and there are significant barriers towards implementation of APG utilisation projects in the areas with poorly developed infrastructure, flaring has been and still remains common practice for the majority of Russian oil companies. There is still no rigid legislative and regulatory framework aimed at boosting APG processing and utilisation. Historically the size of penalties for APG flaring has been incomparable with the revenues from oil sales.

At the time when the decision was taken the main factors which constrained implementation of similar projects were: lack of economic interest on behalf of oil companies in solving the APG utilisation issue and low investment attractiveness of projects dealing with effective use of APG.

Since LLC “Naryanmarneftegas” has no liabilities to the government in respect of APG utilisation rate at Yuzhno-Khylchuyuskoe field (the license agreements for use of natural resources do not include APG utilisation requirements) it was difficult for the company to decide to venture upon implementation of the expensive project. It is important to note that the company has vast reserves of natural gas which does not need any special retreatment. Because the Yareyuskoe field is located far from the gas transmission system the company cannot sell its natural gas to third-party consumers. The only remaining option is using natural gas for in-house needs. This option is much less expensive compared with the APG utilisation option. The situation and the regulatory framework in the country did not facilitate nor create conditions for implementation of projects related to APG effective use.

Without the project the investment risks could be avoided. The investment risks are the actual project investments being higher than the originally planned level. This could be due to mistakes in design, need to purchase additional equipment or undertake unscheduled works, rising prices for equipment, mounting and setup works, etc.

With this in view the project implementation was only reasonable with allowance for the possibility to offset some of the investments by selling the achieved GHG emission reductions.

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

	Years
Length of the crediting period	4
Year	Estimate of annual emission reductions in tonnes of CO_2 equivalent
2009	345 351
2010	463 937
2011	483 245
2012	322 578
Total estimated emission reductions over the crediting period (tonnes of CO_2 equivalent)	**1 615 111**
Annual average of estimated emission reductions over the crediting period (tonnes of CO_2 equivalent)	403 778

A.5. Project approval by the Parties involved:

The letters of approval by the Parties will be received later.

SECTION B. Baseline

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

Selection of the baseline setting approach

For baseline setting and greenhouse gas emission reductions estimation the PDD developer used a JI-specific approach based on paragraph 9 (a) of the "Guidance on criteria for baseline setting and monitoring" [R2] and agreeing with the requirements of *Decision 9/CMP.1, Appendix B* [R3].

The most likely baseline scenario was selected through analysis of the project alternatives that suggest different options for APG handling and hydrogen sulfide stripping from crude oil. Selection of the baseline scenario was justified taking into account Annex 1 to the "Guidance on criteria for baseline setting and monitoring" [R2].

The baseline setting took into account that construction and installation, set up and start up works under the project have already been completed and the project is a reality which is right now generating actual greenhouse gas emission reductions. Therefore, it is deemed reasonable to determine quantitative baseline parameters that affect the projected value of emission reductions up to 2012 by using the available actual project data (up to and including 2010).

Methane emissions from APG combustion in flare units were calculated basing on the "Guidelines for Calculation of Air Pollutant Emission from APG Flaring" developed by the Scientific Research Institute for Atmospheric Air Protection in Saint-Petersburg (approved by the Order of the National Environmental Protection Committee (Goskomecologia) of the Russian Federation dated 08.04.1998 No.199) [R1].

All key data, factors and assumptions affecting the greenhouse gas emission reduction value are considered on a transparent and conservative basis.

Identification of the plausible scenarios and selection of the baseline scenario

The groups of scenarios were considered separately for the following types of project activity:

- APG handling;
- Hydrogen sulfide removal from crude oil.

The following APG handling alternatives for Yuzhno-Khylchuyuskoe field have been suggested:

Alternative H1: Venting of APG;

Alternative H2: Further flaring of APG;

Alternative H3: Reduction of APG flaring volume by gas injection;

Alternative H4: Transportation, processing and distribution of gas between end-users;

Alternative H5: APG consumption for process needs of the field without hydrogen sulfide removal from APG;

Alternative H6: The project activity without the joint implementation mechanism (JI).

The following alternatives for hydrogen sulfide removal from crude oil have been suggested:

Alternative R1: Hydrogen sulfide removal from crude oil by stripping with chemical agents;

Alternative R2: Hydrogen sulfide removal from crude oil by stripping with natural gas;

Alternative R3: The project activity without JI.

APG handling alternatives

Alternative H1: Venting of APG

This scenario is unacceptable as safety requirements prohibit free venting of APG at oil fields. Thus, *Alternative H1 is excluded from further consideration*.

Alternative H2: Further flaring of APG

When the decision regarding the project implementation was taken, APG flaring at oil fields was common practice in Russia. Russian legislative framework at that time did not provide for any pre-requisites nor encourage oil companies to practice APG utilization. In spite of all efforts to create legal incentives for effective use of APG, as well as to raise penalties for its wasteful combustion, flaring is still the simplest and the cheapest way of APG utilization in Russia as it doesn't require additional investment.

Besides untreated APG containing hydrogen sulfide cannot be used directly as fuel or agent for oil stripping. The company has its own natural gas field and so natural gas is always available for energy generation and process needs of the field.

Thus, *Alternative H2*, involving further flaring of APG at Yuzhno-Khylchuyuskoe field, is the most acceptable one for the oil company, both technically and economically, and *it is considered as the most likely baseline scenario for APG handling.*

Alternative H3. Reduction of APG flaring volume by gas injection

Originally the Kyoto project suggested injection of treated APG surpluses into the bed of the neighbouring Yareyu gas condensate reservoir so that when there is shortage of APG (due to reduction in oil and APG volumes) this gas could be pumped out to meet the needs of Yuzhno-Khylchuyuskoe field. As oil and gas production volumes decreased compared with the original projected levels the company gave up its plans to inject APG into the bed.

In any case without H_2S removal from APG, APG injection to the bed is not feasible as it would cause contamination of clean natural gas of Yareyu reservoir with hydrogen sulfide.

Alternative H3 is excluded from further consideration.

Alternative H4: Transportation, processing and distribution of gas between end-users

Gas transmission infrastructure is non-existent; besides APG that is contaminated with hydrogen sulfide is of no interest for potential consumers.

Alternative H4 is excluded from further consideration.

Alternative H5: APG consumption for process needs of the field without hydrogen sulfide removal from APG

Consumption of untreated APG at the field production site is not feasible. If H_2S-contaminated gas is used as fuel for the boiler house or the Energy Center in case of long-term exposure it may cause hydrogen embrittlement, sulfide stress cracking and/or stress corrosion cracking of ferroalloys, in other words, quick wear and tear of the equipment. It is absolutely unfeasible to use contaminated gas for hydrogen sulfide stripping from crude oil. Thus, *Alternative H5 is excluded from further consideration.*

Alternative H6. The project activity without JI

This alternative suggests construction of a gas treatment plant and a sulfur recovery plant with further use of treated APG as a fuel and a stripping agent for hydrogen sulfide stripping from crude oil at the production site of Yuzhno-Khylchuyuskoe field. The recovered sulfur can be considered as commercial product. Natural gas is used for backup purposes only.

Based on the investment analysis given in Section B.2 it can be concluded that the project activity without selling emission reductions has unacceptably low economic attractiveness. Thus, *Alternative H6 cannot be considered as a likely baseline scenario.*

Alternatives for hydrogen sulfide removal from crude oil

Alternative R1: Hydrogen sulfide removal from crude oil by stripping with chemical agents

The process of hydrogen sulfide stripping from crude oil with chemical agents is very expensive. As there is a cheap stripping agent (natural gas), LLC "Naryanmarneftegas" has not considered the option of hydrogen sulfide removal from crude oil by stripping with chemical agents as a reasonable alternative.

Alternative R1 is excluded from further consideration.

Alternative R2: Hydrogen sulfide removal from crude oil by stripping with natural gas

For removal of hydrogen sulfide from crude oil many companies use the process of hydrogen sulfide stripping from crude oil with a H_2S-free gas. This method is one of the most effective and less expensive technologies[3]. LLC "Naryanmarneftegas" has at its disposal its own source of clean natural gas therefore this alternative is the most acceptable both technologically and economically.

In view of the above, Alternative R2 can be considered as the most likely baseline scenario.

Alternative R3: The project activity without JI

This alternative suggests construction of a gas treatment plant and a sulfur recovery plant for further use of APG as a fuel and a stripping agent for hydrogen sulfide stripping from crude oil at the production site of Yuzhno-Khylchuyuskoe field. The recovered sulfur can be considered as commercial product. Natural gas is used for backup purposes only.

As stated above for Alternative H6, the project activity is not economically attractive. Thus, *Alternative R3 cannot be considered as a likely baseline scenario.*

The undertaken analysis shows that the most likely baseline scenario, both in terms of process and economics, is the combination of Alternatives H2 and R2 which suggests APG flaring practice coupled with using natural gas at the production site of Yuzhno-Khylchuyuskoe field as a fuel and a stripping agent for hydrogen sulfide removal from crude oil.

Description of GHG emission estimation methodology

GHG emission reduction

GHG emission reduction in the year *y* is calculated as follows, tCO_2e:

$$ER_y = BE_y - PE_y, \tag{B.1-1}$$

where ER_y is the GHG emission reduction during the year *y*, tCO_2e;

BE_y is the baseline GHG emissions during the year *y*, tCO_2e;

PE_y is the project GHG emissions during the year *y*, tCO_2e;

Baseline GHG emissions

$$BE_y = BE_{NG,y} + BE_{CH4,y}^{APG} + BE_{CH4,y}^{NG}, \tag{B.1-2}$$

[3] http://www.tatneft.ru/wps/tatneft/htmleditor/file/0cc734fe30df43909bda98d62b67a16cae5144e6.doc

where $BE_{NG,y}$ is the baseline carbon dioxide emissions due to combustion of natural gas during the year y, tCO_2e;

$BE_{CH4,y}^{APG}$ is the baseline methane emissions due to soot flaring of APG which under the project is combusted with complete oxidation during the year y, tCO_2e;

$BE_{CH4,y}^{NG}$ is the baseline methane emissions due to soot flaring of contaminated natural gas after stripping columns for crude oil during the year y, tCO_2e.

$$BE_{NG,y} = BE_{NG,y}^{GTPP} + BE_{NG,y}^{SC}, \quad \text{(B.1-3)}$$

where $BE_{NG,y}^{GTPP}$ is the baseline carbon dioxide emissions due to combustion of natural gas in the Energy Center during the year y, tCO_2e;

$BE_{NG,y}^{SC}$ is the baseline carbon dioxide emissions due to flaring of natural gas after stripping columns for crude oil during the year y, tCO_2e.

$$BE_{NG,y}^{GTPP} = 10^3 \times FC_{GTPP,PJ,y} \times \frac{EG_{GTPP,PJ,y} - EC_{DU,y} - EC_{BCS,y}}{EG_{GTPP,PJ,y}} \times \frac{EF_{EC,y}}{NCV_{NG,y}}, \quad \text{(B.1-4)}$$

where $EG_{GTPP,PJ,y}$ is the project electricity generation by the Energy Center during the year y, MWh;

$EC_{DU,y}$ is the consumption of electricity by gas treatment and sulfur recovery plants during the year y, MWh;

$EC_{BCS,y}$ is the consumption of electricity by BCS during the year y, MWh;

$EF_{EC,y}$ is the CO_2 emission factor for natural gas combustion in the Energy Center during the year y, tCO_2/thousand m^3;

$NCV_{NG,y}$ is the net calorific value of natural gas in the year y, GJ/thousand m^3;

$FC_{GTPP,PJ,y}$ is the total project fuel consumption by the Energy Center during the year y, TJ.

$$EC_{DU,y} = SEC_{DU} \times \frac{V_{DU,y}^{APG}}{10^3}, \quad \text{(B.1-5)}$$

where SEC_{DU} is the specific electricity consumption by the gas treatment and sulfur recovery plants during the year y, MWh/million m^3;

$V_{DU,y}^{APG}$ is the volume of untreated APG supply to the gas treatment plant during the year y, thousand m^3.

$$FC_{GTPP,PJ,y} = V_{GTPP,y}^{APG} \times NCV_{APG,y} + V_{GTPP,PJ,y}^{NG} \times NCV_{NG,y}, \quad \text{(B.1-6)}$$

where $NCV_{APG,y}$ is the net calorific value of treated APG of the year y, GJ/thousand m^3.

$$EF_{EC,y} = \frac{44.011}{12.011} \times \sum_i \left(v_i \times C_i \times \rho_i \times \frac{w_{NG,y}^i}{10^2} \right), \quad \text{(B.1-7)}$$

where $\frac{44.011}{12.011}$ is the emission factor for carbon combustion, tCO_2/tC;

ν_i is the efficiency of combustion of *i*-component of natural gas in the Energy Center. $\nu_i = 1$. See Annex 2.5;

$w^i_{NG,y}$ is the volumetric fraction of *i*-component in natural gas in the year *y*, %;

ρ_i is the density of *i*-component of gas at standard conditions, kg/m^3. See Annex 2.3;

C_i is the carbon fraction in *i*-component of gas. See Annex 2.3;

Only carbon-bearing components of gas are considered.

$$BE^{SC}_{NG,y} = V^{NG}_{SC,BL,y} \times EF_{CO2,y}, \tag{B.1-8}$$

where $V^{NG}_{SC,BL,y}$ is the baseline volume of natural gas supply to the hydrogen sulfide stripping columns for crude oil of the year *y*, thousand m^3;

$EF_{CO2,y}$ is the CO_2 emission factor for natural gas flaring *y*, tCO_2/thousand m^3.

$$V^{NG}_{SC,BL,y} = V^{APG}_{SC,y}, \tag{B.1-9}$$

where $V^{APG}_{SC,y}$ is the volume of APG supply to the hydrogen sulfide stripping columns for crude oil of the year *y*, thousand m^3.

$$EF_{CO2,y} = \frac{44.011}{12.011} \times \sum_i \left(\mu_i \times C_i \times \rho_i \times \frac{w^i_{NG,y}}{10^2} \right), \tag{B.1-10}$$

where μ_i is the efficiency of combustion of *i*-component of natural gas in flare. $\mu_i = (1-\varepsilon)$ - for hydrocarbons. $\mu_i = 1$ - for carbon dioxide. Only carbon-bearing components are considered.

$$BE^{APG}_{CH4,y} = \rho_{CH4} \times \varepsilon \times GWP_{CH4} \times \left(V^{APG}_{GTPP,y} + V^{APG}_{boilerS,y} \right) \times w^{CH4}_{APG,y}, \tag{B.1-11}$$

where ρ_{CH4} is the methane density at standard conditions, kg/m^3;

GWP_{CH4} is the Global Warming Potential for methane, tCO_2e/tCH_4. GWP_{CH4} = 21 tCO_2e/tCH_4;

$w^{CH4}_{APG,y}$ is the volumetric fraction of methane in treated APG of the year *y*, %.

$$BE^{NG}_{CH4,y} = V^{NG}_{SC,BL,y} \times EF_{CH4,y}, \tag{B.1-12}$$

where $EF_{CH4,y}$ is the CH_4 emission factor for natural gas flaring in the year *y*, tCO_2e/thousand m^3.

$$EF_{CH4,y} = \frac{w^{CH4}_{NG,y}}{10^2} \times \rho_{CH4} \times \varepsilon \times GWP_{CH4}, \tag{B.1-13}$$

where $w^{CH4}_{NG,y}$ is the volumetric fraction of methane in natural gas in the year *y*, %.

Project GHG Emissions

$$PE_y = PE_{CO2,EC,y} + PE_{ox\_HC,y}, \tag{B.1-14}$$

where $PE_{CO2,EC,y}$ is the project carbon dioxide emissions due to use of natural gas for the needs of the Energy Center during of the year *y*, tCO_2e;

$PE_{ox\_HC,y}$ is the project carbon dioxide emissions due to complete oxidation of hydrocarbons in the Energy Center and the desulfurization boiler house, which otherwise would have been released into the atmosphere as a result of incomplete oxidation during soot flaring of the year *y*, tCO_2e.

$$PE_{CO2,EC,y} = V^{NG}_{GTPP,PJ,y} \times EF_{EC,y}, \tag{B.1-15}$$

where $V^{NG}_{GTPP,PJ,y}$ is the project volumetric consumption of natural gas in the Energy Center of the year *y*, thousand m^3.

$$PE_{ox\_HC,y} = \frac{44.011}{12.011} \times \frac{\varepsilon}{10^2} \times \sum_i \left(V^{APG}_{GTPP,y} + V^{APG}_{boilerS,y} \right) \times \left(\rho_i \cdot C_i \cdot w^i_{APG,y} \right), \tag{B.1-16}$$

where $V^{APG}_{GTPP,y}$ is the volumetric consumption of APG in the Energy Center of the year *y*, thousand m^3;

$V^{APG}_{boilerS,y}$ is the volumetric consumption of APG in the desulfurization boiler house of the year *y*, thousand m^3;

$w^i_{APG,y}$ is the volumetric fraction of *i*-hydrocarbon in the treated APG of the year *y*, %;

ε is the unburned carbon factor for soot combustion of APG in flare units. ε = 0.035 [R1].

Justification of soot flaring under the baseline scenario is given in Annex 2.7. The calculations take account of the gas flows chanelled to the high- and low-pressure flares under the baseline scenario.

__Key factors determining GHG emission reductions__

All key factors are considered and necessary data for calculation of the project GHG emission reductions are provided below. See also Annex 2. The gas treatment plant was put into operation to reach the operating mode by the end of 2008. Emission reductions are calculated for four full years from 2009 through 2012.

Crude oil production

Oil production data are not directly used for calculation of GHG emission reductions. However the total amount of APG and also the required volume to be fed to the hydrogen sulfide stripping columns depend on the production volumes. The crude oil production volumes are the same for the project and the baseline scenarios.

The table below shows actual oil production data for 2009-2010 and also the planned oil production in 2011-1012. As seen from the table the crude oil production is diminishing.

Data/Parameter	$P_{oil,y}$
Data unit	Thousand tonnes
Description	Quantity of produced crude oil at Yuzhno-Khylchuyuskoe during the year *y*
Time of	August 2011

determination/monitoring	
Source of data (to be) used	Reported and projected data of LLC "Naryanmarneftegas"
Value of data applied (for ex ante calculations/determinations)	2009: 6 961.62; 2010: 6 888.21; 2011: 4 946.30; 2012: 1 848.4
Justification of the choice of data or description of measurement methods and procedures (to be) applied	For 2009-2010 – actual data, for 2011-2012 – projected data provided by LLC "Naryanmarneftegas"
QA/QC procedures (to be) applied	Not required
Any comment	Used only for projection of GHG emission reductions. This parameter doesn't need to be monitored.

APG utilization in the Energy Center

As a result of the project activity most of treated APG is channeled to the Energy Center where it substitutes natural gas which under the baseline scenario would have been combusted. Besides APG is combusted in gas-turbine units with full oxidation of hydrocarbons, including methane. Hence methane emissions are also reduced due to APG utilization in the Energy Center instead of its flaring.

The table below shows actual data on APG utilization for the needs of the Energy Center over 2009-2010, as well as projected utilization volumes in 2011-2012.

Data/Parameter	$V_{GTPP,y}^{APG}$
Data unit	Thousand m^3
Description	Volumetric consumption of APG in the Energy Center during the year *y*
Time of determination/monitoring	August 2011
Source of data (to be) used	Reported and projected data of LLC "Naryanmarneftegas"
Value of data applied (for ex ante calculations/determinations)	2009: 78 252.69; 2010: 137 757.00; 2011: 164 263.03; 2012: 123 720.65
Justification of the choice of data or description of measurement methods and procedures (to be) applied	For 2009-2010 – actual data, for 2011-2012 – projected data provided by LLC "Naryanmarneftegas" Actual values are determined based on gas flow meter readings.
QA/QC procedures (to be) applied	Determined based on actual and projected data. The gas flow meter is verified regularly.
Any comment	-

APG supply to hydrogen sulfide stripping columns for crude oil

The peculiarity of the Yuzhno-Khylchuyuskoe field is that the produced crude oil is heavily contaminated with hydrogen sulfide, therefore pre-purification is required. As has been mentioned, the most likely option of hydrogen sulfide removal from oil under the baseline scenario is its stripping with natural gas followed by flaring of the contaminated gas. Natural gas is substituted with treated APG under the project.

The table below shows actual data on APG supply to the oil stripping columns in 2009-2010, and also projected supply in 2011-2012.

Data/Parameter	$V_{SC,y}^{APG}$
Data unit	Thousand m^3
Description	APG supply to hydrogen sulfide stripping columns for crude oil during the year *y*
Time of determination/monitoring	August 2011
Source of data (to be) used	Reported and projected data of LLC "Naryanmarneftegas"
Value of data applied (for ex ante calculations/determinations)	<table><tr><th>2009</th><th>2010</th><th>2011</th><th>2012</th></tr><tr><td>76 156.64</td><td>70 458.25</td><td>50 594.81</td><td>18 907.90</td></tr></table>
Justification of the choice of data or description of measurement methods and procedures (to be) applied	For 2009-2010 – actual data, for 2011-2012 – projected data provided by LLC "Naryanmarneftegas" Actual values are determined based on gas flow meters readings. For 2011-2012 calculations were made as follows: $V_{SC,y}^{APG} = k \cdot P_{oil,y}$ where k is the ratio between treated APG volume supplied to stripping columns and oil production volume in 2010, m^3/t, $k = \frac{V_{SC,2010}^{APG}}{P_{oil,2010}} = \frac{70458.25}{6888.21} = 10.23;$ $P_{oil,y}$ is the crude oil production volume during the year *y*, thousand t.
QA/QC procedures (to be) applied	Determined based on actual and projected data. The gas flow meters are verified regularly.
Any comment	-

APG combustion in desulfurization boiler house

The desulfurization boiler house appears under the project. It is worthwhile to include this boiler house in the project boundary as APG is combusted here with full oxidation. Therefore operation of the boiler house leads to additional methane emission reductions as opposed to flaring.

The table below shows actual data on APG utilization in the desulfurization boiler house over 2009-2010, and also projected utilization in 2011-2012.

Data/Parameter	$V_{boilerS,y}^{APG}$
Data unit	Thousand m^3
Description	Volumetric consumption of APG in the desulfurization boiler house during the year *y*
Time of determination/monitoring	August 2011
Source of data (to be) used	Reported and projected data of LLC "Naryanmarneftegas"
Value of data applied (for ex ante calculations/determinations)	<table><tr><th>2009</th><th>2010</th><th>2011</th><th>2012</th></tr><tr><td>12 237.04</td><td>11 676.46</td><td>10 131.29</td><td>9 576.15</td></tr></table>

Justification of the choice of data or description of measurement methods and procedures (to be) applied	For 2009-2010 – actual data, for 2011-2012 – projected data provided by LLC “Naryanmarneftegas” Actual values are determined based on gas flow meter readings.
QA/QC procedures (to be) applied	Determined based on actual and projected data. The gas flow meter is verified regularly.
Any comment	-

Untreated APG supply to the gas treatment plant

This parameter is used to determine electricity consumption by the gas treatment and sulfur recovery plants.

Data/Parameter	$V_{DU,y}^{APG}$
Data unit	Thousand m^3
Description	Volume of untreated APG supply to the gas treatment plant during the year *y*
Time of determination/monitoring	August 2011
Source of data (to be) used	Reported and projected data of LLC “Naryanmarneftegas”
Value of data applied (for ex ante calculations/determinations)	**2009**: 253 016.16; **2010**: 330 634.33; **2011**: 217 652.44; **2012**: 157 229.31
Justification of the choice of data or description of measurement methods and procedures (to be) applied	For 2009-2010 – actual data, for 2011-2012 – projected data provided by LLC “Naryanmarneftegas” Actual values are determined based on gas flow meter readings
QA/QC procedures (to be) applied	Determined based on actual and projected data. The gas flow meter is verified regularly.
Any comment	-

Use of natural gas in the Energy Center under the project

After the project implementation natural gas ceases to be used as main fuel. Nonetheless, natural gas can be used in the required volume as a backup fuel in case of emergency or when the gas treatment plant is shut down for repair. As shown in the table below, in 2009-2010 natural gas was used, however the consumption volume cannot be accurately foreseen for 2011-2012, therefore in estimations it is assumed that natural gas is not used in the Energy Center. Anyway monitoring is carried out and actual consumption of natural gas will be duly taken into account.

Data/Parameter	$V_{GTPP,PJ,y}^{NG}$
Data unit	Thousand m^3
Description	Volumetric consumption of natural gas in the Energy Center under the project during the year *y*
Time of determination/monitoring	August 2011
Source of data (to be) used	Reported and projected data of LLC “Naryanmarneftegas”
Value of data applied	**2009** **2010** **2011** **2012**

(for ex ante calculations/determinations)		39 870.17	18 556.89	0	0
Justification of the choice of data or description of measurement methods and procedures (to be) applied	For 2009-2010 – actual data provided by LLC "Naryanmarneftegas" Actual values are determined based on gas flow meters readings. For 2011-2012 it is assumed at zero level as the backup fuel consumption volume cannot be foreseen.				
QA/QC procedures (to be) applied	Determined based on actual and projected data. The gas flow meters are verified regularly.				
Any comment	-				

Use of natural gas in the Energy Center under the baseline scenario

According to the baseline scenario the only fuel for the Energy Center is natural gas. This being said, its consumption in energy equivalent would have been lower than the overall consumption of fuel in the Energy Center under the project (APG plus natural gas). This is due to the fact that under the baseline scenario it would have been necessary to generate less electricity (such amount being smaller by the value equal to electricity consumption for auxiliary needs of the gas treatment and sulfur recovery plants).

Data/Parameter	$FC^{NG}_{GTPP,BL,y}$
Data unit	TJ
Description	Consumption of natural gas in the Energy Center under the baseline scenario during the year *y*
Time of determination/monitoring	August 2011
Source of data (to be) used	Calculated
Value of data applied (for ex ante calculations/determinations)	**2009**: 3 926.70; **2010**: 5 210.46; **2011**: 5 576.97; **2012**: 4 202.50
Justification of the choice of data or description of measurement methods and procedures (to be) applied	$FC^{NG}_{GTPP,BL,y} = \frac{EG_{GTPP,PJ,y} - EC_{DU,y} - EC_{BCS,y}}{EG_{GTPP,PJ,y}} \cdot FC_{GTPP,PJ,y}$, where $EG_{GTPP,PJ,y}$ is the electricity generation by the Energy Center under the project during the year *y*, MWh; $EC_{DU,y}$ is the electricity consumption by the gas treatment and sulfur recovery plants during the year *y*, MWh; $EC_{BCS,y}$ is the consumption of electricity by BCS during the year *y*, MWh; $FC_{GTPP,PJ,y}$ is the total consumption of fuel by the Energy Center under the project scenario during the year *y*, TJ.
QA/QC procedures (to be) applied	Not required
Any comment	-

Natural gas supply to hydrogen sulfide stripping columns for crude oil under the baseline scenario

Under the baseline scenario hydrogen sulfide is removed from crude oil by stripping with natural gas. The volume of natural gas is equivalent to the volume of APG supplied to the oil stripping under the project scenario.

Data/Parameter	$V_{SC,BL,y}^{NG}$
Data unit	Thousand m^3
Description	Volume of natural gas supply to hydrogen sulfide stripping columns for crude oil under the baseline scenario during the year *y*
Time of determination/monitoring	August 2011
Source of data (to be) used	Calculated
Value of data applied (for ex ante calculations/determinations)	**2009**: 76 156.64; **2010**: 70 458.25; **2011**: 50 594.81; **2012**: 18 907.90
Justification of the choice of data or description of measurement methods and procedures (to be) applied	$V_{SC,BL,y}^{NG} = V_{SC,y}^{APG}$, where $V_{SC,y}^{APG}$ is the volume of APG supplied to hydrogen sulfide stripping columns for crude oil during the year *y*, thousand m^3
QA/QC procedures (to be) applied	Not required
Any comment	-

Total fuel consumption by the Energy Center under the project

Total consumption of fuel by the Energy Center under the project scenario is made up of APG and natural gas consumption taking into account net calorific values of these two fuels.

Data/Parameter	$FC_{GTPP,PJ,y}$
Data unit	TJ
Description	Total consumption of fuel by the Energy Center under the project during the year *y*
Time of determination/monitoring	August 2011
Source of data (to be) used	Calculated
Value of data applied (for ex ante calculations/determinations)	**2009**: 4 140.49; **2010**: 5 595.47; **2011**: 5 946.32; **2012**: 4 478.69
Justification of the choice of data or description of measurement methods and procedures (to be) applied	$FC_{GTPP,PJ,y} = \frac{\left(V_{GTPP,y}^{APG} \cdot NCV_{APG}\right) + \left(V_{GTPP,PJ,y}^{NG} \cdot NCV_{NG}\right)}{10^3}$, where $V_{GTPP,y}^{APG}$ is the volumetric consumption of APG in the Energy Center during the year *y*, thousand m^3; NCV_{APG} is the net calorific value of treated APG, GJ/thousand m^3; $V_{GTPP,PJ,y}^{NG}$ is the volumetric consumption of natural gas in the Energy Center under the project during the year *y*, thousand m^3;

	NCV_{NG} is the net calorific value of natural gas, GJ/thousand m^3.
QA/QC procedures (to be) applied	Not required
Any comment	-

Data/Parameter	NCV_{APG}
Data unit	GJ/thousand m^3
Description	Net calorific value of treated APG
Time of determination/monitoring	August 2011
Source of data (to be) used	Chemical and analytical laboratory of LLC “Naryanmarneftegas”
Value of data applied (for ex ante calculations/determinations)	36.2
Justification of the choice of data or description of measurement methods and procedures (to be) applied	The value of one of the results of treated APG compositional analyses was assumed for projection purposes: protocol No.641 dated 25.06.2011.
QA/QC procedures (to be) applied	Measurements and calculations are made by a specialized licensed laboratory using the corresponding gas analyzing equipment, chromatograph. Verification (calibration) of all devices is made in accordance with the requirements of normative technical documentations and with the instrumentation verification schedule and procedure adopted at the company.
Any comment	This value is to be monitored on a monthly basis. When the actual emission reductions quantity is calculated the corresponding values shall be used.

Data/Parameter	NCV_{NG}
Data unit	GJ/thousand m^3
Description	Net calorific value of natural gas
Time of determination/monitoring	August 2011
Source of data (to be) used	Chemical and analytical laboratory of LLC “Naryanmarneftegas”
Value of data applied (for ex ante calculations/determinations)	32.8
Justification of the choice of data or description of measurement methods and procedures (to be) applied	The value of one of the results of compositional analyses of natural gas supplied from Yareyu field was assumed for projection purposes: protocol No.642 dated 25.06.2011.
QA/QC procedures (to be) applied	Measurements and calculations are made by a specialized licensed laboratory using the corresponding gas analyzing equipment, chromatograph. Verification (calibration) of all devices is made in accordance with the requirements of normative technical documentations and with the instrumentation verification schedule and procedure adopted

	at the company.
Any comment	This value is to be monitored on a monthly basis. When the actual emission reductions quantity is calculated the corresponding values shall be used.

Electricity generation by the Energy Center under the project

As shown above, this parameter is used to determine natural gas consumption in the Energy Center under the baseline scenario. The table below shows actual data on electricity generation by the Energy Center in 2009-2010, as well as projected generation in 2011-2012.

Data/Parameter	$EG_{GTPP,PJ,y}$
Data unit	MWh
Description	Electricity generation by the Energy Center under the project during the year *y*
Time of determination/monitoring	August 2011
Source of data (to be) used	Reported and projected data of LLC “Naryanmarneftegas”
Value of data applied (for ex ante calculations/determinations)	**2009**: 295 914.36; **2010**: 402 846.00; **2011**: 428 105.63; **2012**: 322 443.26
Justification of the choice of data or description of measurement methods and procedures (to be) applied	For 2009-2010 – actual data provided by LLC “Naryanmarneftegas” Actual values are determined based on the electric meters readings. For 2011-2012 calculations were made as follows: $EG_{GTPP,PJ,y} = g \cdot FC_{GTPP,PJ,y}$, where g is the ratio between the electricity generation and total fuel consumption by the Energy Center in 2010, MWh/TJ, $g = \frac{EG_{GTPP,PJ,2010}}{FC_{GTPP,PJ,2010}} = \frac{402846.00}{5595.47} = 72.00$; $FC_{GTPP,PJ,y}$ is the total consumption of fuel by the Energy Center (natural gas and associated petroleum gas) during the year *y*, TJ.
QA/QC procedures (to be) applied	Determined based on actual and projected data. The electric meters are verified regularly.
Any comment	-

Electricity consumption for auxiliary needs of the gas treatment and sulfur recovery plants

This parameter is also used to determine the consumption of natural gas by the Energy Center under the baseline scenario. The project implementation brought about additional electricity consumers, namely the gas treatment plant and the sulfur recovery plant. These consumers do not have separate electric meters therefore electricity consumption is calculated on the basis of design data.

Data/Parameter	$EC_{DU,y}$
Data unit	MWh
Description	Electricity consumption by the gas treatment and sulfur recovery plants

	during the year *y*
Time of determination/monitoring	August 2011
Source of data (to be) used	Calculated
Value of data applied (for ex ante calculations/determinations)	**2009**: 5 422.35; **2010**: 7 085.77; **2011**: 4 664.47; **2012**: 3 369.56
Justification of the choice of data or description of measurement methods and procedures (to be) applied	$EC_{DU,y} = SEC_{DU} \cdot V_{DU,y}^{APG}$ where SEC_{DU} is the specific electricity consumption by the gas treatment and sulfur recovery plants, MWh/million m^3; SEC_{DU} =21.43 MWh/million m^3; $V_{DU,y}^{APG}$ is the volume of untreated APG supply to the gas treatment plant during the year *y*, thousand m^3
QA/QC procedures (to be) applied	Not required
Any comment	-

Data/Parameter	$EC_{BCS,y}$
Data unit	MWh
Description	Electricity consumption by BCS during the year *y*
Time of determination/monitoring	Continuously
Source of data (to be) used	Actual historical data for 2009-2010 provided by LLC “Naryanmarneftegas”, the values for 2011-2012 are derived by calculations.
Value of data applied (for ex ante calculations/determinations)	**2009**: 9 857; **2010**: 20 633; **2011**: 21 927; **2012**: 16 515
Justification of the choice of data or description of measurement methods and procedures (to be) applied	For the period 2009-2010 actual historical data are given. For 2011-2012 the electricity consumption by BCS is derived from the following equation: $EC_{BCS,y} = \frac{EC_{BCS2010}}{FC_{GTPP,PJ,2010}} \times FC_{GTPP,PJ,y} =$ $= \frac{20633}{5595.47} \times FC_{GTPP,PJ,y}$, where $EC_{BCS2010}$ is the electricity consumption by BCS in 2010; $FC_{GTPP,PJ,2010}$ is the total project fuel consumption by the Energy Center in 2010.
QA/QC procedures (to be) applied	Determined on the basis of actual and estimated data.
Any comment	-

Data/Parameter	SEC_{DU}
Data unit	MWh/million m^3
Description	Specific electricity consumption by the gas treatment and sulfur recovery plants during the year *y*
Time of determination/monitoring	August 2011
Source of data (to be) used	"Construction and completion of wells of Yuzhno-Khylchuyuskoe oil and gas field. Gas treatment plant. Sulfur recovery and storage facility" OJSC "GIPROGAZOOCHISTKA", 2006 [R5], Table 5.8.1
Value of data applied (for ex ante calculations/determinations)	21.43
Justification of the choice of data or description of measurement methods and procedures (to be) applied	Table 5.8.1 [R5] shows a specific value of 23.0 MWh/million m^3, which corresponds to normal conditions (0 °C and 101.3 kPa) to which the gas volume is adjusted in [R5]. However the volume of gas at the field is adjusted to standard conditions (20 °C and 101.3 kPa). Therefore this value was recalculated: 23.0·273.15/293.15=21.43 MWh/million m^3
QA/QC procedures (to be) applied	Determined on the basis of design data
Any comment	-

Parameters required for calculation of GHG emission reductions

The calculation of GHG emission reductions is given in Section E. The required parameters for estimations are described in the tables below.

Data/Parameter	ε
Data unit	-
Description	Unburnt carbon factor for soot flaring of APG
Time of determination/monitoring	August 2011
Source of data (to be) used	"Guidelines for Calculation of Air Pollutant Emissions from APG Flaring" developed by the Scientific Research Institute for Atmospheric Air Protection in Saint-Petersburg, 1998 [R1].
Value of data applied (for ex ante calculations/determinations)	0.035
Justification of the choice of data or description of measurement methods and procedures (to be) applied	Recommended by the calculation guidelines
QA/QC procedures (to be) applied	Reference data
Any comment	-

Data/Parameter	$w^{i}_{APG,y}$
Data unit	%
Description	Average volumetric fraction of *i*-hydrocarbon in treated APG during the year *y*;
Time of determination/monitoring	Monthly
Source of data (to be) used	Chemical and analytical laboratory of LLC "Naryanmarneftegas"
Value of data applied (for ex ante calculations/determinations)	Methane 89.96% Ethane 3.00% Propane 1.86% Isobutane 0.42% Butane 0.90% Isopentane 0.31% Pentane 0.34% Hexane 0.13% Heptane+ higher hydrocarbons 0.06%
Justification of the choice of data or description of measurement methods and procedures (to be) applied	At the PDD development stage calculations are based on the results of one of the treated APG composition tests – test protocol No.641 dated 25.06.2011. In the course of the project monitoring the gas composition is analyzed on a monthly basis.
QA/QC procedures (to be) applied	Measurements and calculations are made by a specialized licensed laboratory using the corresponding gas analyzing equipment, chromatograph. Verification (calibration) of all devices is made in accordance with the requirements of normative technical documentations and with the instrumentation verification schedule and procedure adopted at the company.
Any comment	This value is to be monitored on a monthly basis. When the actual emission reductions quantity is calculated the corresponding values shall be used.

Data/Parameter	$w^{i}_{NG,y}$
Data unit	%
Description	Average volumetric fraction of *i*-component in natural gas during the year *y*;
Time of determination/monitoring	Monthly
Source of data (to be) used	Chemical and analytical laboratory of LLC "Naryanmarneftegas"
Value of data applied (for ex ante calculations/determinations)	Methane 92.66% Ethane 1.56% Propane 0.54% Isobutane 0.09% Butane 0.16%

	Isopentane 0.04% Pentane 0.04% Hexane 0.00% Heptane+ higher hydrocarbons 0.00% Carbon dioxide 0.00%
Justification of the choice of data or description of measurement methods and procedures (to be) applied	The value of one of the results of natural gas compositional analyses was assumed for projections: protocol No.642 dated 25.06.2011. In the course of the project monitoring the gas composition is analyzed on a monthly basis.
QA/QC procedures (to be) applied	Measurements and calculations are made by a specialized licensed laboratory using the corresponding gas analyzing equipment, chromatograph. Verification (calibration) of all devices is made in accordance with the requirements of normative technical documentations and with the instrumentation verification schedule and procedure adopted at the company.
Any comment	This value is to be monitored on a monthly basis. When the actual emission reductions quantity is calculated the corresponding values shall be used.

Data/Parameter	C_i
Data unit	-
Description	Carbon fraction of *i*-component
Time of determination/monitoring	August 2011
Source of data (to be) used	"Guidelines for Calculation of Air Pollutant Emissions from APG Flaring" developed by the Scientific Research Institute for Atmospheric Air Protection in Saint-Petersburg, 1998 [R1], Annex A1, table 4.
Value of data applied (for ex ante calculations/determinations)	Methane 0.7487 Ethane 0.7989 Propane 0.8171 Isobutane 0.8266 Butane 0.8266 Isopentane 0.8324 Pentane 0.8324 Hexane 0.8373 Heptane higher hydrocarbons 0.8401 Carbon dioxide 0.2729
Justification of the choice of data or description of measurement methods and procedures (to be) applied	Based on reference data.
QA/QC procedures (to be) applied	Reference data.
Any comment	-

<table>
<tr><th>Data/Parameter</th><th>ρ_i</th></tr>
<tr><td>Data unit</td><td>kg/m^3</td></tr>
<tr><td>Description</td><td>Density of i-component at standard conditions, kg/m^3</td></tr>
<tr><td>Time of determination/monitoring</td><td>August 2011</td></tr>
<tr><td>Source of data (to be) used</td><td>“Guidelines for Calculation of Air Pollutant Emissions from APG Flaring” developed by the Scientific Research Institute for Atmospheric Air Protection in Saint-Petersburg, 1998 [R1], Annex A1, table 3.</td></tr>
<tr><td>Value of data applied
(for ex ante calculations/determinations)</td><td>
<table>
<tr><td>Methane</td><td>0.667</td></tr>
<tr><td>Ethane</td><td>1.250</td></tr>
<tr><td>Propane</td><td>1.835</td></tr>
<tr><td>I obutane</td><td>2.418</td></tr>
<tr><td>Butane</td><td>2.418</td></tr>
<tr><td>Isopentane</td><td>3.001</td></tr>
<tr><td>Pentane</td><td>3.001</td></tr>
<tr><td>Hexane</td><td>3.580</td></tr>
<tr><td>Heptane+ higher hydrocarbons</td><td>4.163</td></tr>
<tr><td>Carbon dioxide</td><td>1.831</td></tr>
</table>
</td></tr>
<tr><td>Justification of the choice of data or description of measurement methods and procedures (to be) applied</td><td>Reference data were used. Under guidelines density of gases is given at normal conditions. To adjust them to standard conditions the values that are given in this reference source are multiplied by the conversion factor $\frac{273.15}{293.15}$</td></tr>
<tr><td>QA/QC procedures (to be) applied</td><td>Reference data.</td></tr>
<tr><td>Any comment</td><td>-</td></tr>
</table>

Data/Parameter	$EF_{CO2,y}$
Data unit	tCO_2/thousand m^3
Description	Average CO_2 emission factor for flaring of natural gas in the year y
Time of determination/monitoring	Monthly
Source of data (to be) used	Calculated
Value of data applied (for ex ante calculations/determinations)	1.745
Justification of the choice of data or description of measurement methods and procedures (to be) applied	At the PDD development stage the constant value is calculated using formula (B.1-10) on the basis of one of the natural gas composition tests – protocol dated 25.06.2011. See also Annex 2.3. In the course of the monitoring this parameter is calculated every month on the basis of natural gas composition data
QA/QC procedures (to be) applied	The value of this parameter is calculated
Any comment	-

Data/Parameter	$EF_{CH4,y}$
Data unit	tCO_2e/thousand m^3
Description	Average CH_4 emission factor for natural gas flaring in the year y
Time of determination/monitoring	Monthly
Source of data (to be) used	Calculated
Value of data applied (for ex ante calculations/determinations)	0.454
Justification of the choice of data or description of measurement methods and procedures (to be) applied	At the PDD development stage the constant value is calculated using formula (B.1-13) on the basis of one of the natural gas composition tests – protocol dated 25.06.2011. See also Annex 2.4. In the course of the monitoring this parameter is calculated every month on the basis of natural gas composition data.
QA/QC procedures (to be) applied	The value of this parameter is calculated
Any comment	-

Data/Parameter	$EF_{EC,y}$
Data unit	tCO_2/thousand m^3
Description	Average CO_2 emission factor for combustion of natural gas in the Energy Center in the year y
Time of determination/monitoring	Monthly
Source of data (to be) used	Calculated
Value of data applied (for ex ante calculations/determinations)	1.808
Justification of the choice of data or description of measurement methods and procedures (to be) applied	At the PDD development stage the constant value is calculated using formula (B.1-7) on the basis of one of the natural gas composition tests – protocol dated 25.06.2011. See also Annex 2.5. In the course of the monitoring this parameter is calculated every month on the basis of natural gas composition data
QA/QC procedures (to be) applied	The value of this parameter is calculated
Any comment	-

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

The approach described in paragraph 2 (a) of Annex 1 to the “Guidance on criteria for baseline setting and monitoring” [R2] was selected to demonstrate that the reductions of greenhouse gas emissions from sources achieved due to the project implementation are additional to those that might have otherwise occurred in the absence of the project.

Within the framework of the selected approach the project additionality was proved using the project alternatives analysis, the investment analysis and the common practice analysis.

Analysis of the project alternatives

Alternatives were considered separately for APG handling and for hydrogen sulfide removal from crude oil. The description of the alternatives and their analysis are given in Section B.1.

Based on the analysis of the project alternatives it was concluded that the most likely baseline scenario is the scenario that suggests flaring of APG combined with using natural gas at the production site of Yuzhno-Khylchuyuskoe field as fuel (in the Energy Center) and for removal of hydrogen sulfide from crude oil.

The analysis makes a reference to the below investment analysis which demonstrates that the project activity without the joint implementation mechanism cannot be considered as a baseline scenario.

Investment analysis

The economic parameters of the project were compared for the two project implementation options:

(a) without selling GHG emission reductions;

(b) with selling GHG emission reductions.

The investment analysis was undertaken using data and assumptions valid as of the start of the project implementation (June 2006).

The expected capital investment to the project which included construction of the 1st line of the gas treatment plant, the 1st line of sulfur recovery plant and a sulfur storage facility was estimated at RUR 1.8 billion.

The rated annual output of the equipment according to the design data [R5] is: untreated gas intake – 586 million m^3/year, elemental sulfur production – 22.4 thousand tonnes per year. The treated gas with virtually zero hydrogen sulfide content is used in the Energy Center (1st start-up complex), in the desulfurization boiler house and also in the hydrogen sulfide stripping columns for crude oil. The remaining treated gas is flared.

The service life of the equipment is 20 years starting from 2008.

The time horizon is limited to 2020.

The revenues from the project activity are made up of reduced payments for pollutant emissions than in case of untreated APG flaring, reduced costs of natural gas production (the natural gas field belongs to LLC “Naryanmarneftegas”, therefore only natural resources production tax is taken into account) and revenues from sale of sulfur. As for the second project implementation option, here also revenues from sale of GHG emission reductions are taken into consideration. The costs include payroll expenses for the staff of the gas treatment and sulfur recovery plants, repair costs and other operating expenses. The electricity costs are considered in calculation of natural gas savings for the needs of the Energy Center.

The expected selling price of emission reduction unit (ERU) for the 1st crediting period of the Kyoto Protocol (2008-2012) was assumed at 500 RUR/tCO_2e, for the post-Kyoto period (2013-2020) – 250 RUR/tCO_2e.

The discount rate was determined using the “Methodological recommendations on evaluation of investment projects efficiency…”[4].

According to this methodology the discount rate is calculated as follows:

[4]Methodological recommendations on evaluation of investment projects efficiency. Approved by Ministry of Economy of the RF, Ministry of Finance of the RF, State Committee of the RF on Construction, Architecture and Housing Policy dd. 21.06.1999 N BK 477

$$r = R_{real} + R_{risk}\ , \tag{B.2-1}$$

where r is the nominal discount rate, %;

R_{real} is the real risk-free discount rate, %;

R_{risk} is the allowance for risk, %.

Freed from inflation or real risk-free discount rate R_{real}, which is used for estimation of commercial efficiency of the project on the whole, can be set in accordance with the requirements to the minimum allowable future return on investments, freed from inflation, in practice 4-6%. Let us assume minimum real risk-free rate at 4%.

The risk of not getting the expected project income is assessed to be not less than medium (in accordance with Table 11.1 from the "Methodological recommendations on evaluation of investment projects efficiency…"). The risk premium is assumed at 8%.

The final discount rate was assumed at 12%.

The results of calculation of the net present value (NPV) for the two project implementation options are given in Table B.2-1.

Table B.2-1. Calculation of the net present value (NPV) for the two project implementation options

Parameter	Unit	Without sale of GHG emission reductions	With sale of GHG emission reductions
NPV	Thousand RUR	-1 583 061	132 666

The economic parameters of the project without the joint implementation mechanism are unacceptably low (NPV<0). Due to the revenues received from sale of ERUs the project becomes more commercially attractive, NPV becomes positive. Moreover, the project option with sale of GHG emission reductions shows robust sustainability to risks (See the results of the sensitivity analysis in Table B.2-2).

Table B.2-2. The sensitivity analysis of the main economic parameters of the project

Parameter	Unit	Without sale of GHG emission reductions	With sale of GHG emission reductions
1) Increase in investment costs by 10%			
NPV	Thousand RUR	-1 776 352	-60 626
2) Reduction in investment costs by 10%			
NPV	Thousand RUR	-1 389 769	325 957
3) Increase in gas treatment and sulfur recovery volumes by 10%			
NPV	Thousand RUR	-1 559 742	177 772
4) Reduction in gas treatment and sulfur recovery volumes by 10%			
NPV	Thousand RUR	-1 606 379	87 560
5) Increase in savings of pollutant emission payments by10%			
NPV	Thousand RUR	-1 580 287	135 439
6) Reduction in savings of pollutant emission payments by 10%			
NPV	Thousand RUR	-1 585 834	129 892
7) Increase in savings of natural gas costs by 10%			
NPV	Thousand RUR	-1 560 173	155 554
8) Reduction in savings of natural gas costs by 10%			
NPV	Thousand RUR	1 605 948	109 778

It is important to note, that the project is aimed at mitigation of anthropogenic environmental impact and it couldn't have been implemented in the context of usual business practice (without sale of ERUs).

Common practice analysis

According to the official data about 15-20 billion m^3 of APG per year are flared in Russia (See Table N.2-3). However there are more radical estimations. For example, in 2007 the results of the research carried out by the US National Oceanic and Atmospheric Association (NOAA) and commissioned by the World Bank were published. To estimate the volume and the dynamics of APG flaring from 1995 to 2006 the military metrological survey data were used. The findings of the analyses show that in Russia the official statistic data differ considerably from the results of the space survey.

Table B.2-4. Parameters of APG use in Russia from 2001 to 2007*

Parameter	2001	2002	2003	2004	2005	2006	2007
APG output, bln. m^3	35.9	42.6	48.5	54.9	57.6	57.9	61.2
Burnt in flare devices, bln. m^3	7.1	11.1	11.1	14.7	15.00	14.7	16.7
Utilization level, %	80.1	73.8	77.2	73.3	74.0	75.6	72.6

*Source: data of the Fuel and Energy Industry Central Dispatch Service (FEI CDS)

As the statistics of FEI CDS for the period 2001-2007 indicate, 14.7 billion m^3 of APG were burnt in the flare devices in 2004; but according to the NOAA research this figure is considerably higher and is approximately 50.7 billion m^3. Thus, information regarding APG handling by oil companies is very controversial; however, the fact of country-wide flaring of APG at the fields of Russia is undeniable.

Undoubtedly, APG is utilized by the oil companies, but in most cases it happens only at those fields where it is economically feasible. In the regions, where the beneficial use of APG is impeded due to objective causes, gas is diverted to flare devices for burning.

APG utilization doesn't bring much profit to oil companies because of low APG rates. The fixed payments (penalties) for APG flaring are incomparable with the oil revenue, that is why oil producing companies mostly prefer "to finance the existence of the problem" rather than spend money on finding a solution to it. At the present moment the government doesn't take any really drastic measures to reduce APG flaring. Even the increase of air emission charges expected in 2012[5] by no means stimulates speedy development of infrastructure for APG processing; the government themselves admit that it will be impossible to achieve the 95% level of APG utilization earlier than in 2014-2015.[6]

It is evident that even the direct statutory bar against APG flaring (except for emergencies) existing in a number of developed countries is not applicable in Russia as it can become a fatal blow for the *whole* Russian oil industry, that is why such option won't be even considered by the government whose revenues depend heavily on petrodollars. Getting extra revenue from sale of ERUs generated as a result of the projects implemented within the framework of joint implementation mechanism can become one of the few efficient incentives towards increase in APG utilization. An additional obstacle to APG utilization at Yuzhno-Khylchuyuskoe field of LLC "Naryanmarneftegas" is that the untreated hydrocarbon gas with high content of hydrogen sulfide cannot be directly used for the field process needs. The implemented project is unique for the Nenets Autonomous Okrug. In view of the above and also considering the significant amount of capital investment into the construction of gas treatment and sulfur recovery plants at Yuzhno-Khylchuyuskoe field, the project implementation was worth-while only in view of the possibility to cover some of the investment costs by selling the achieved GHG emission reductions.

Hence, GHG emission reductions achieved as a result of the project implementation are additional to those that might have otherwise occurred.

[5] http://www.globotek.ru/news/archive/news_100531
[6] http://www.nakanune.ru/news/2011/4/12/22228021

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

Fig. B.3-1 shows the main components and emission sources for the baseline scenario. Fig. B.3-2 shows the main components and emission sources included in the project boundary. Table B.3-1 indicates which sources and gases are included into the project boundary and which are excluded.

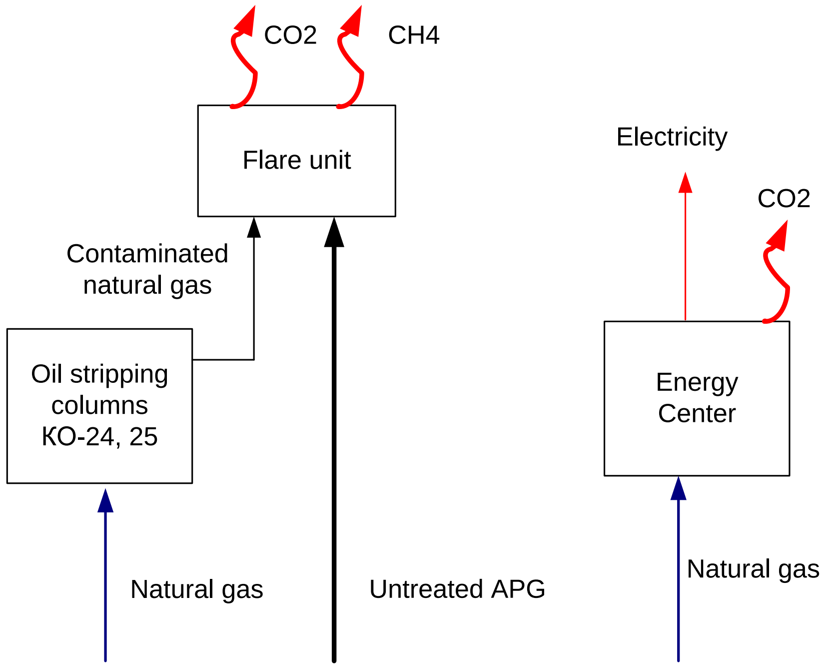

Fig. B.3-1. Main components and emission sources for the baseline scenario

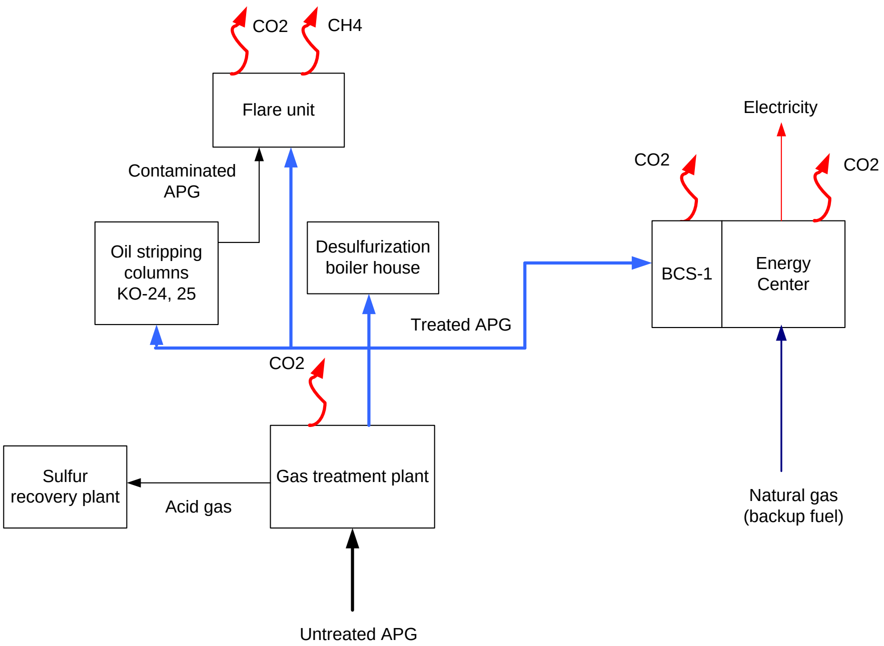

Fig. B.3-2. Main components and emission sources included in the project boundary

Table B.3-1. Emission sources included in and excluded from consideration

	Source	Gas	Incl./ Excl.	Justification/Explanation
Baseline	APG combustion in flare units	CO_2	No	Excluded from consideration because the bulk of CO_2 generation during APG flaring is the same as under the project, whereas a correction for more complete oxidation in the Energy Center and desulfurization boiler house was made for the project emissions
		CH_4	**Yes**	**Main emission source**
		N_2O	No	Considered negligible. This is conservative
	Combustion of contaminated natural gas in flare unit after hydrogen sulfide stripping columns for crude oil	**CO_2**	**Yes**	**Main emission source**
		CH_4	**Yes**	**Main emission source**
		N_2O	No	Considered negligible. This is conservative
	Combustion of natural gas in the Energy Center	**CO_2**	**Yes**	**Main emission source**
		CH_4	No	Considered negligible. This is conservative
		N_2O	No	Considered negligible. This is conservative
Project activity	APG combustion in the Energy Center and desulfurization boiler house	**CO_2**	**Yes**	**Main emission source.** Only CO_2 generated due to complete oxidation of hydrocarbons (which under the baseline scenario would not be afterburnt in flare units) in the Energy Center and desulfurization boiler house are taken into account
		CH_4	No	Considered negligible by virtue of complete burning of gas in the Energy Center and in the boiler house
		N_2O	No	Considered negligible by virtue of complete burning of gas in the Energy Center and in the boiler house
	Use of backup fuel (natural gas) in the Energy Center	**CO_2**	**Yes**	**Main emission source**
		CH_4	No	Considered negligible by virtue of complete burning of gas in the Energy Center
		N_2O	No	Considered negligible by virtue of complete burning of gas in the Energy Center
Leakages	Fugitive emissions of APG at the field caused by the project activity	CO_2	No	Any possible fugitive emissions of APG caused by the project activity are invariably less than fugitive emissions at extraction and use of natural gas replaced as a result of the project
		CH_4	No	
		N_2O	No	

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

The date of the baseline setting: 31/08/2011

The baseline were developed by CCGS LLC (CCGS LLC is not a project participant and is not listed in Annex 1 hereto).

The persons responsible for baseline setting::

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SECTION C. Duration of the project / crediting period

C.1. Starting date of the project:

June 19, 2006 (the date of the contract for designing and supply of the gas treatment and sulfur recovery plants)

C.2. Expected operational lifetime of the project:

20 years / 240 months

C.3. Length of the crediting period:

4 years / 48 months (from January 1, 2009 to December 31, 2012)

SECTION D. Monitoring plan

D.1. Description of monitoring plan chosen:

When developing the monitoring plan the PDD developer used a JI-specific approach based on Paragraph 9 (a) of the "Guidance on criteria for baseline setting and monitoring" [R2].

The data (registered in any case) required for determination of GHG emission reductions are collected in accordance with the best industry standards and practices of fuel, energy and environmental impact monitoring.

All data required for monitoring will be kept in the company's archive in paper and electronic form for at least two years after the end of the crediting period or after the last transfer of ERUs.

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 *(Please use numbers to ease cross-referencing to D.2.)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment
1. $V_{GTPP,PJ,m,y}^{NG}$	Volumetric consumption of natural gas in the Energy Center under the project in the month *m* of the year *y*	Oil and Gas Treatment Department	Thousand m^3	m	Continuously	100 %	Electronic and paper	Readings of flow meters
2. $V_{GTPP,m,y}^{APG}$	Volumetric consumption of APG in the Energy Center in the month *m* of the year *y*	Oil and Gas Treatment Department	Thousand m^3	m	Continuously	100 %	Electronic and paper	Readings of flow meter

3. $V^{APG}_{boilerS,m,y}$	Volumetric consumption of APG in the desulfurization boiler house in month *m* of the year *y*	Oil and Gas Treatment Department	Thousand m^3	m	Continuously	100 %	Electronic and paper	Readings of flow meter
4. $w^{i}_{APG,m,y}$	Volumetric fraction of *i*-hydrocarbon in treated APG in the month *m* of the year *y*	Oil and Gas Treatment Department	%	m	Once per month	100 %	Electronic and paper	Findings of laboratory analyses
5. $w^{i}_{NG,m,y}$	Volumetric fraction of *i*-component in natural gas in the month *m* of the year *y*	Oil and Gas Treatment Department	%	m	Once per month	100 %	Electronic and paper	Findings of laboratory analyses

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

The project GHG emissions during the year *y*, tCO_2e:

$$PE_y = PE_{CO2,EC,y} + PE_{ox\_HC,y}, \qquad \text{(D.1-1)}$$

where $PE_{CO2,EC,y}$ is the project carbon dioxide emissions due to use of natural gas for the needs of the Energy Center during the year *y*, tCO_2e;

$PE_{ox\_HC,y}$ is the project carbon dioxide emissions due to complete oxidation of hydrocarbons in the Energy Center and the desulfurization boiler house, which otherwise would have been released into the atmosphere as a result of incomplete oxidation during soot flaring in the year *y*, tCO_2e.

$$PE_{CO2,EC,y} = \sum_m \left(V^{NG}_{GTPP,PJ,m,y} \times EF_{EC,m,y} \right), \qquad \text{(D.1-2)}$$

where $EF_{EC,m,y}$ is the CO_2 emission factor for natural gas combustion in the Energy Center in the month *m* during the year *y*, tCO_2/thousand m^3;

$V^{NG}_{GTPP,PJ,m,y}$ is the project volumetric consumption of natural gas in the Energy Center in the month *m* of the year *y*, thousand m^3.

$$EF_{EC,m,y} = \frac{44.011}{12.011} \times \sum_m \sum_i \left(\nu_i \times C_i \times \rho_i \times \frac{w^i_{NG,m,y}}{10^2} \right), \quad \text{(D.1-3)}$$

where $\frac{44.011}{12.011}$ is the emission factor for carbon combustion, tCO_2/tC;

ν_i is the efficiency of combustion of *i*-component of natural gas in the Energy Center. $\nu_i = 1$. See Annex 2.5;

$w^i_{NG,m,y}$ is the volumetric fraction of *i*-component in natural gas in the month *m* during the year *y*, %;

ρ_i is the density of *i*-component of gas at standard conditions, kg/m^3. See Annex 2.5;

C_i is the carbon fraction in *i*-component of gas. See Annex 2.5;

Only carbon-bearing components of gas are considered.

$$PE_{ox\_HC,y} = \frac{44.011}{12.011} \times \frac{\varepsilon}{10^2} \times \sum_m \sum_i \left[\left(V^{APG}_{GTPP,m,y} + V^{APG}_{boilerS,m,y} \right) \times \left(\rho_i \cdot C_i \cdot w^i_{APG,m,y} \right) \right], \quad \text{(D.1-4)}$$

where $V^{APG}_{GTPP,m,y}$ is the volumetric consumption of APG in the Energy Center in the month *m* of the year *y*, thousand m^3;

$V^{APG}_{boilerS,m,y}$ is the volumetric consumption of APG in the desulfurization boiler house in the month *m* of the year *y*, thousand m^3;

$w^i_{APG,m,y}$ is the volumetric fraction of *i*-hydrocarbon in the treated APG in the month *m* of the year *y*, %;

ε is the unburned carbon factor for soot combustion of APG in flare units. ε = 0.035 according to [R1]. Please see also Annex 2.7.

D.1.1.3. Relevant data necessary for determining the baseline of anthropogenic emissions of greenhouse gases by sources within the project boundary, and how such data will be collected and archived:								
ID number *(Please use numbers to ease cross-referencing to D.2.)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment
6. $EG_{GTPP,PJ,y}$	Electricity generation by the Energy Center under the project during the year y	Chief Power Engineer Department	MWh	m	Continuously	100%	Electronic and paper	Readings of electric meters
7. $V_{DU,y}^{APG}$	Volume of untreated APG supplied to the gas treatment plant during the year *y*	Oil and Gas Treatment Department	Thousand m^3	m	Continuously	100%	Electronic and paper	Readings of flow meter
8. $NCV_{APG,m,y}$	Net calorific value of treated APG in the month *m* of the year *y*	Oil and Gas Treatment Department	GJ/thousand m^3	m, c	Once per month	100 %	Electronic and paper	Findings of laboratory analyses
9. $V_{SC,m,y}^{APG}$	Volume of APG supplied to the hydrogen sulfide stripping columns for crude oil in the month *m* of the year *y*	Oil and Gas Treatment Department	Thousand m^3	m	Continuously	100 %	Electronic and paper	Readings of flow meters

10. $NCV_{NG,m,y}$	Net calorific value of natural gas in the month *m* of the year *y*	Oil and Gas Treatment Department	GJ/thousand m^3	m, c	Once per month	100 %	Electronic and paper	Findings of laboratory analyses
11. $EC_{BCS,m,y}$	Electricity consumption by BCS in the month *m* of the year *y*	Chief Power Engineer Department	MWh	m	Continuously	100%	Electronic and paper	Readings of electric meters

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

The baseline GHG emissions during the year *y*, tCO_2e:

$$BE_y = BE_{NG,y} + BE_{CH4,y}^{APG} + BE_{CH4,y}^{NG}, \qquad \text{(D.1-5)}$$

where $BE_{NG,y}$ is the baseline carbon dioxide emissions due to combustion of natural gas during the year *y*, tCO_2e;

$BE_{CH4,y}^{APG}$ is the baseline methane emissions due to soot flaring of APG which under the project is combusted with complete oxidation during the year *y*, tCO_2e;

$BE_{CH4,y}^{NG}$ is the baseline methane emissions due to soot flaring of contaminated natural gas after stripping columns for crude oil during the year *y*, tCO_2e.

$$BE_{NG,y} = BE_{NG,y}^{GTPP} + BE_{NG,y}^{SC}, \qquad \text{(D.1-6)}$$

where $BE_{NG,y}^{GTPP}$ is the baseline carbon dioxide emissions due to combustion of natural gas in the Energy Center during the year *y*, tCO_2e;

$BE_{NG,y}^{SC}$ is the baseline carbon dioxide emissions due to flaring of natural gas after stripping columns for crude oil during the year *y*, tCO_2e.

$$BE_{NG,y}^{GTPP} = 10^3 \times FC_{GTPP,PJ,y} \times \sum_m \left(\frac{EG_{GTPP,PJ,y} - EC_{DU,y} - EC_{BCS,m,y}}{EG_{GTPP,PJ,y}} \times \frac{EF_{EC,m,y}}{NCV_{NG,m,y}} \right), \qquad \text{(D.1-7)}$$

where $FC_{GTPP,PJ,y}$ is the total project fuel consumption by the Energy Center during the year *y*, TJ;

$EC_{BCS,m,y}$ is the electricity consumption by BCS in the month *m* of the year *y*, MWh;

$EG_{GTPP,PJ,y}$ is the project electric power generation in the Energy Center during the year y, MWh;

$EC_{DU,y}$ is the electric power consumption by the gas treatment and sulfur recovery units during the year y, MWh;

$NCV_{NG,m,y}$ is the net calorific value of natural gas in the month m of the year y, GJ/thousand m^3.

$$EC_{DU,y} = SEC_{DU} \cdot \frac{V_{DU,y}^{APG}}{10^3}, \quad \text{(D.1-8)}$$

where SEC_{DU} is the specific electric power consumption by gas treatment and sulfur recovery units in the year y, MWh/million m^3. According to [R5] $SEC_{DU} = 21.43$ MWh/million m^3;

$V_{DU,y}^{APG}$ is the volume of untreated APG supply to the gas treatment and during the year y, thousand m^3.

$$FC_{GTPP,PJ,y} = \sum_m \left(V_{GTPP,m,y}^{APG} \times NCV_{APG,m,y}\right) + \sum_m \left(V_{GTPP,PJ,m,y}^{NG} \times NCV_{NG,m,y}\right), \quad \text{(D.1-9)}$$

where $NCV_{APG,m,y}$ is the net calorific value of treated APG in the month m of the year y, GJ/thousand m^3.

$$BE_{NG,y}^{SC} = \sum_m \left(V_{SC,BL,m,y}^{NG} \times EF_{CO2,m,y}\right), \quad \text{(D.1-10)}$$

where $EF_{CO2,m,y}$ is the CO_2 emission factor for natural gas flaring in the month m during the year y, tCO_2/ thousand m^3.

$V_{SC,BL,m,y}^{NG}$ is the baseline volume of natural gas supply to the hydrogen sulfide stripping columns for crude oil in the month m of the year y, thousand m^3.

$$V_{SC,BL,m,y}^{NG} = V_{SC,m,y}^{APG}, \quad \text{(D.1-11)}$$

where $V_{SC,m,y}^{APG}$ is the volume of APG supply to the hydrogen sulfide stripping columns for crude oil in the month m of the year y, thousand m^3.

$$EF_{CO2,m,y} = \frac{44.011}{12.011} \times \sum_m \sum_i \left(\mu_i \times C_i \times \rho_i \times \frac{w_{NG,m,y}^i}{10^2}\right), \quad \text{(D.1-12)}$$

where μ_i is the efficiency of flaring of *i*-component of natural gas. $\mu_i = (1-\varepsilon)$ - for hydrocarbons. $\mu_i = 1$ - for carbon dioxide. Only carbon-bearing component are considered. See Annex 2.3.

$$BE_{CH4,y}^{APG} = \rho_{CH4} \times \varepsilon \times GWP_{CH4} \times \sum_m \left[\left(V_{GTPP,m,y}^{APG} + V_{boilerS,m,y}^{APG} \right) \times w_{APG,m,y}^{CH4} \right], \quad \text{(D.1-13)}$$

where ρ_{CH4} is the methane density at standard conditions, kg/m^3. $\rho_{CH4} = 0.667$ kg/m^3, See Annex 2.2;

GWP_{CH4} is the Global Warming Potential for methane, $tCO_2e/\ tCH_4$. GWP_{CH4} = 21 $tCO_2e/\ tCH_4$;

$w_{APG,m,y}^{CH4}$ is the volumetric fraction of methane in treated APG in the month *m* of the year *y*, %.

$$BE_{CH4,y}^{NG} = \sum_m \left(V_{SC,BL,m,y}^{NG} \times EF_{CH4,m,y} \right), \quad \text{(D.1-14)}$$

where $EF_{CH4,m,y}$ is the CH_4 emission factor for natural gas flaring in the month *m* during the year *y*, tCO_2e/thousand m^3.

$$EF_{CH4,m,y} = \frac{w_{NG,m,y}^{CH4}}{10^2} \times \rho_{CH4} \times \varepsilon \times GWP_{CH4}, \quad \text{(D.1-15)}$$

where $w_{NG,m,y}^{CH4}$ is the volumetric fraction of methane in natural gas in the month *m* during the year *y*, %.

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

This option is not applied to the project monitoring.

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

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):

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

Leakages are assumed to be zero.

D.1.3.1. If applicable, please describe the data and information that will be collected in order to monitor leakage effects of the project:								
ID number *(Please use numbers to ease cross-referencing to D.2.)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

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

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):

The GHG emission reductions during the year *y*, tCO_2e:

$$ER_y = BE_y - PE_y \quad (D.1\text{-}16)$$

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:

LLC "Naryanmarneftegas" pays much attention to environmental issues and rational use of natural resources and energy.

Industrial environmental monitoring within LLC "Naryanmarneftegas" is carried out for the company on the whole.

The company's priority targets and commitments in the sphere of environmental protection are laid out in the "Policy in the sphere of industrial safety, labour and environment protection" approved by the Director General of LLC "Naryanmarneftegas" on May 8, 2008[7]. Each employee of the company embraces the Policy and clearly understands their environmental liability striving to preserve the virgin beauty and grandeur of nature.

The environmental targets of the Company Policy are implemented within the framework of the strategic environmental safety programme and environmental action plans developed annually. The programme is agreed with the environment supervisory authorities and sets out clear timeframes for implementation of top-priority tasks.

Achievement of the set targets became possible due to stable funding of the planned measures.

In order to estimate and forecast the company's environmental impact within the boundary of all license areas, environmental monitoring is carried out and the projects of local environmental monitoring systems have been developed and approved by the respective supervisory bodies.

In 2008 LLC "Naryanmarneftegas" was awarded a certificate confirming that its environmental and occupational health and safety management systems comply with the requirements of international standards: ISO14001:2004 and OHSAS 18001:2007.

The quality of treated APG is monitored by regular taking of samples. The analyses are carried out by the chemical and analytical laboratory of the Yuzhnoe Khylchuyu Central Production Facility (CPF). All analyses are carried out in accordance with GOST 23781, GOST 22667, GOST 22387.2, and GOST 22387.2.

The reports are provided in paper form and contain chemical composition of fuel and its other physical and chemical characteristics (moisture, calorific value, Wobbe index) and also record the sampling time and point.

All reports on the fuels used as well as environmental impact data are sent directly to the production and to the company office.

The environmental department of LLC "Naryanmarneftegas" regularly draws up and submits to the supervisory authorities the reports as per statistic forms which cover all aspects of the company's environmental impact.

[7] http://www.nmng.ru/Environment.aspx?Lang=ru

кмD.2. Quality control (QC) and quality assurance (QA) procedures undertaken for data monitored:		
Data *(Indicate table and ID number)*	Uncertainty level of data (high/medium/low)	Explain QA/QC procedures planned for these data, or why such procedures are not necessary.
Table D.1.1.1. ID 1, 2, 3 Table D. 1.1.3. ID 7, 9	Low	Flow meters are used to monitor volumes of associated petroleum gas and natural gas. Measurement error is 1.0%. Verification (calibration) of measuring devices is carried out in accordance with the requirements of normative documents and with the schedule and procedure for instrumentation and control verification adopted by the company.
Table D.1.1.1. ID 4, 5 Table D 1.1.3. ID 8,10	Low	The APG and natural gas composition, including methane and other hydrocarbons fractions, as well as calorific values, is analyzed by a specialized licensed chemical and analytical laboratory with the help of corresponding gas analyzing equipment, chromatograph. Verification (calibration) of measuring devices is carried out in accordance with the requirements of normative documents and with the schedule and procedure for instrumentation and control verification adopted by the company.
Table D. 1.1.3. ID 6, 11	Low	Electric meters which monitor electricity generation by the Energy Center and electricity consumption by BCS are regularly verified (calibrated) in accordance with the requirements of normative documents and with the schedule and procedure for instrumentation and control verification adopted by the company.

Data storage

All input data and the project monitoring reports will be stored in the archives of LLC “Naryanmarneftegas” and “CCGS” LLC in electronic and paper form for at least 2 years after the end of the crediting period or the last transfer of ERUs.

Emergency monitoring procedures

In case of emergencies affecting the project monitoring system (equipment or measurement instrumentation breakdown, etc.) specialists of LLC “Naryanmarneftegas” and “CCGS” LLC shall analyze the situation, work out alternative monitoring and measurement plans for the duration of such emergency situations, as well as corrective actions for the equipment and/or the monitoring plan.

Actions undertaken during calibration of measuring instruments

The measuring instruments are calibrated during the periods of scheduled shutdown of the equipment. If necessary the removed measuring device is replaced with a backup calibrated instrument. Operation of the equipment without calibrated measuring instruments is not allowed.

Cross-checking

Cross-checking is a procedure consisting of two stages. At the first stage the monitoring report is checked by “CCGS” LLC, while at the second stage it is checked by LLC “Naryanmarneftegas”.

The primary cross-check of the monitoring report is done by the Director of Energy and Greenhouse Gas Emissions Management Department or on his instructions by an employee of the said Department who has no direct connection to preparation of the report.

Additional cross-check is done by the Director of the Project Development Department of "CCGS" LLC or on his instructions by another employee of this Department.

The procedures for quality control of calculations are laid out in detail in the "Regulations on the procedure for quality control of GHG emission reduction project design documents and monitoring reports at CCGS LLC".

Training

All employees of LLC "Naryanmarneftegas" have appropriate qualification and valid permissions to operate certain machines and equipment. New employees and those members of the staff, who need to confirm that they belong to a certain eligibility group, have to take a corresponding training course, pass an exam and receive a permit. The personnel department is responsible for staff training. The contract for training upon requisition of the supervisory authorities (Rostechnnadzor) has been concluded with the NP "Center for personnel development Perm-oil". The personnel get on-the-job training at the field and in the office of LLC "Naryanmarneftegas".

Besides LLC "Naryanmarneftegas" concluded a contract with the Training Centre of Gubkin Russian State University of Oil and Gas for professional skills upgrading on applications of the heads of subdivisions.

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

CCGS LLC is responsible for:

- preparation of the project monitoring report;
- preparation and organisation of training sessions for the company's personnel related to collection of data required for monitoring (in cooperation with LLC "Naryanmarneftegas").

LLC "Naryanmarneftegas" is responsible for:

- normal operation of the equipment;
- timely check, calibration and proper maintenance of instrumentation;
- collection, storage and reporting of all data required for GHG emission reductions monitoring;
- arranging and holding training sessions for the company's staff regarding collection of data required for the GHG emissions monitoring (in cooperation with "CCGS" LLC).

Collection and recording of data necessary for calculation of GHG emission reductions will be carried out in accordance with the monitoring points location scheme as shown in Fig. D.3-1.

Input data for emission reduction monitoring will be provided by the Chief Power Engineer Department and Oil and Gas Treatment Department of LLC "Naryanmarneftegas" to "CCGS" LLC.

"CCGS" LLC based on the received data shall prepare the project monitoring report and shall submit it for review to LLC "Naryanmarneftegas". After all comments received from the company have been accommodated, the report is submitted for approval to LLC "Naryanmarneftegas".

The management of CCGS LLC is responsible for:

- drawing up of the monitoring reports (Director of Energy and GHG Emissions Management Department);
- interaction with the independent expert organization concerning verification of GHG emissions reductions (Director of Energy and GHG Emissions Management Department);
- arranging and holding training sessions regarding collection of data required for the GHG emissions monitoring under the project (Director of Energy and GHG Emissions Management Department).

The management of LLC "Naryanmarneftegas" is responsible for:

- coordination and control of monitoring (Deputy General Director for Health and Safety Executive);
- verification of input monitoring data (Head of the Oil and Gas Treatment Department);
- collection, storage and transfer of primary data (Head of the Fuel Gas Treatment Unit of Oilfield №3);
- internal audit of monitoring procedures observance, training sessions for the personnel regarding collection of primary data (Oilfield №3 Director);
- check-out of the monitoring reports (Head of the Environmental Department);
- metrological assurance (Chief Metrologist - Head of the Automation Department).

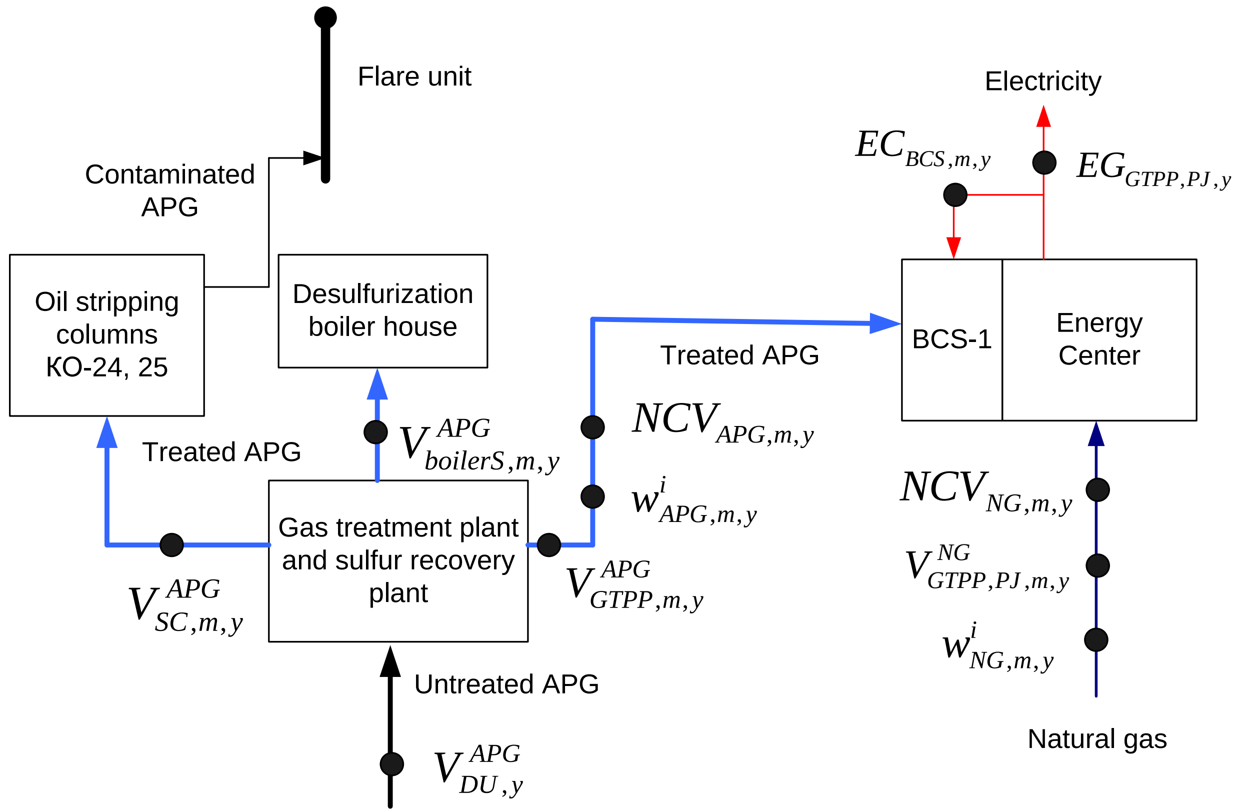

Fig. D.3-1. Location of monitoring points

Organizational scheme of the monitoring is shown in Fig. D.3-2.

The Deputy General Director for Health and Safety Executive is in charge of the JI project implementation on the part of LLC “Naryanmarneftegas” (Order No.302 of 16.12.2011).

Original request for primary GHG emission reductions monitoring data is made by the Director of Energy and GHG Emissions Management Department of CCGS LLC to the LLC "Naryanmarneftegas" namely to the Deputy General Director for Health and Safety Executive, who in his turn gives instructions to the enterprise to collect the requested data. The enterprise has specific persons (a working group) that responsible for collection, control and transfer of monitoring data. At LLC "Naryanmarneftegas" the responsibility of such persons is set forth in Order No.302 of 16.12.2011.

Collection of all primary data is carried out in accordance with the enterprise's existing practice of fuel, energy and feedstock monitoring. The monitoring does not require to make any changes in the company's existing monitoring and data collection system. All necessary data are determined and registered in any case.

The information collected at the enterprise is transferred to the Deputy General Director for Health and Safety Executive of LLC "Naryanmarneftegas", who in his turn transfers it to the Director of Energy and GHG Emissions Management Department of CCGS LLC. All information is transferred by e-mail.

On the basis of the received data the Department of Energy and GHG Emissions Management of CCGS LLC prepares a GHG emission reduction monitoring report and submits it for additional cross-check to the Project Development Department of CCGS LLC. As soon as all comments made by the Project Development Department are incorporated or resolved the monitoring report is submitted for verification at LLC "Naryanmarneftegas".

At CCGS LLC the procedure for verification of the monitoring reports are laid down in "Regulations on quality check and control of GHG emission reduction project design documents (PDD) and monitoring reports at CCGS LLC".

After the report is verified and amended as necessary, the Director of Department of Energy and GHG Emissions Management of CCGS LLC informs the Deputy General Director for Health and Safety Executive of LLC "Naryanmarneftegas" about preliminary monitoring results and, if there are no comments on his part, the Director General of CCGS LLC takes the final decision to submit the monitoring report for verification to an independent expert organization.

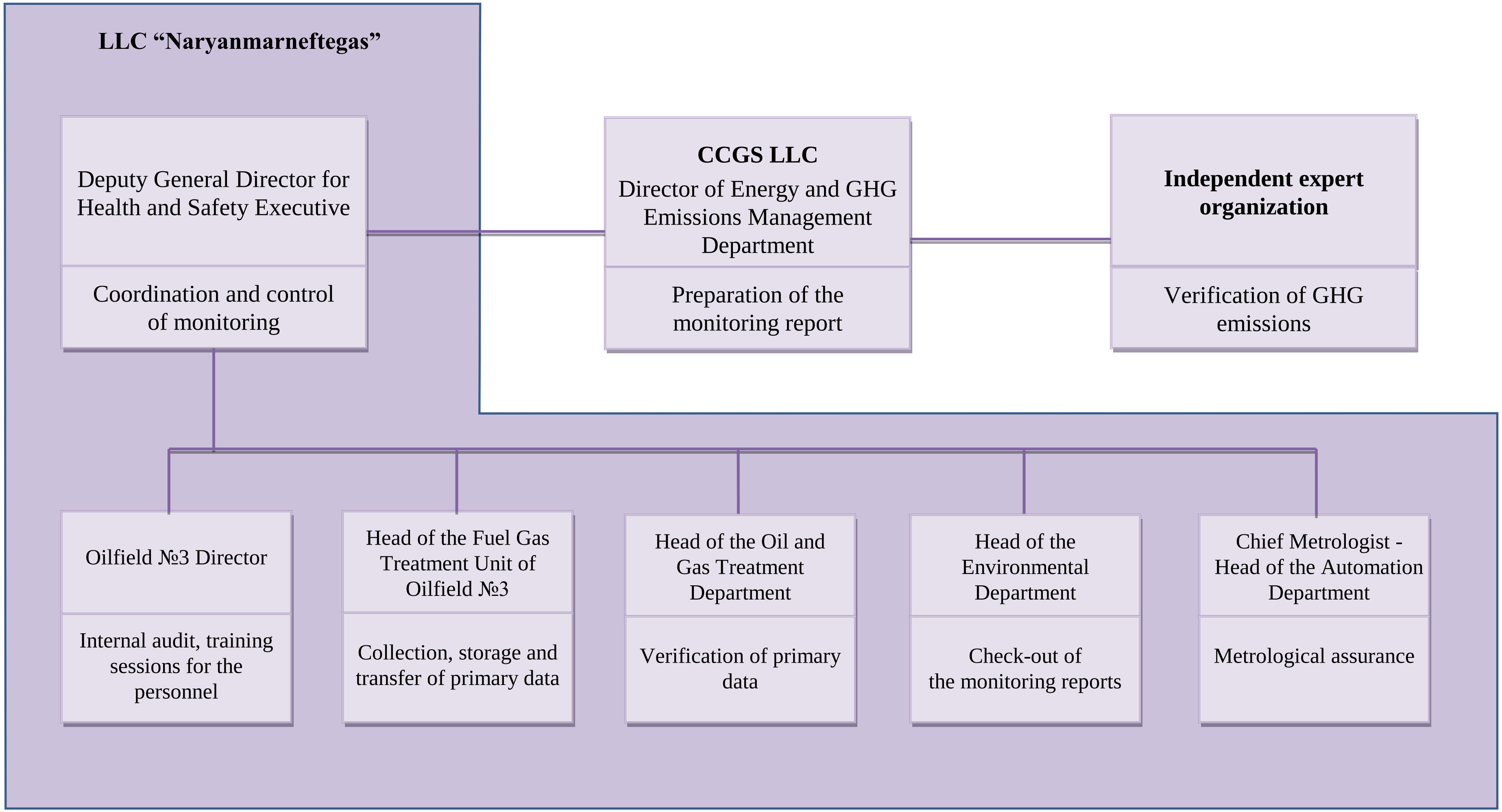

Fig. D.3-2. Organizational scheme of the monitoring

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

The monitoring plan is developed by "CCGS" LLC ("CCGS" LLC is not the project participant and is not listed in Annex 1 hereto).

The person responsible for development of the project monitoring plan:

The persons responsible for baseline setting::

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SECTION E. Estimation of greenhouse gas emission reductions

E.1. Estimated project emissions:

Table E.1-1. GHG emissions under the project

Year	$PE_{NG,y}$, tCO_2e	$PE_{ox\_HC,y}$, tCO_2e	Estimate of project GHG emissions, tCO_2e
2009	72 097	6 446	78 543
2010	33 556	10 645	44 201
2011	0	12 423	12 423
2012	0	9 495	9 495
Total	**105 653**	**39 009**	**144 662**

E.2. Estimated leakage:

Leakages are assumed to be zero.

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

Since there are no leakages then E.1+E.2=E.1

E.4. Estimated baseline emissions:

Table E.4-2. GHG emissions under the baseline scenario, tCO_2e

Year	$BE_{NG,y}^{GTPP}$, tCO_2e	$BE_{NG,y}^{SC}$, tCO_2e	$BE_{CH4,y}^{APG}$, tCO_2e	$BE_{CH4.y}^{NG}$, tCO_2e	Estimate of baseline GHG emissions, tCO_2e
2009	216 481	132 893	39 917	34 603	423 894
2010	287 256	122 949	65 919	32 014	508 138
2011	307 462	88 288	76 930	22 988	495 668
2012	231 687	32 994	58 801	8 591	332 073
Total	**1 042 886**	**377 124**	**241 567**	**98 196**	**1 759 773**

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

Table E.5-1. Results of GHG emission reductions estimation, tCO_2e

Parameter	Reporting years				2009-2012
	2009	2010	2011	2012	
Total GHG emission reduction	**345 351**	**463 937**	**483 245**	**322 578**	**1 615 111**

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

Year	Estimated project emissions (tonnes of CO_2 equivalent)	Estimated leakage (tonnes of CO_2 equivalent)	Estimated baseline emissions (tonnes of CO_2 equivalent)	Estimated emission reductions (tonnes of CO_2 equivalent)
2009	78 543	0	423 894	**345 351**
2010	44 201	0	508 138	**463 937**
2011	12 423	0	495 668	**483 245**
2012	9 495	0	332 073	**322 578**
Total (tonnes of CO_2 equivalent)	**144 662**	**0**	**1 759 773**	**1 615 111**

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:

Within the framework of development of the design documentation for "Construction and completion of wells of Yuzhno-Khylchuyuskoe oil and gas field. Gas treatment plant. Sulfur recovery and storage facility" [R5] Section 11 "Environment Protection" was developed.

Actions aimed at prevention and mitigation of pollutant emissions were developed within the framework of the project.

The principal action aimed at pollutant emissions mitigation is application of a technology that shall ensure the overall level of hydrogen sulfide utilization at the sulfur recovery and storage facility of no less than 97.5-98.0%.

Actions which allow additional pollutant emission reduction are as follows:

- receiver tanks for diethanolamine (DEA) solution have "nitrogen breathing";
- elimination of relief valves on pressure apparatuses with hydrosulfuric medium by adopting the rated pressure of base apparatuses at a level higher or equal to the feeding sources pressure;
- providing plugs on air and vent lines of hydrosulfuric medium pipelines;
- using canned pumps which rules out emission of pollutants into the environment;
- using an incinerator operating at ~750-800 °C and due to such temperature making it possible to achieve complete afterburning of hydrogen sulfide, carbon monoxide, carbon disulfide and carbon oxysulfide;
- installation of a liquid sulfur degassing unit to ensure safe handling of sulfur during transportation and pelletization;
- installation of ejectors for draining air-gas medium from sulfur degassing tank and channeling it to afterburning;
- availability of a warning alarm signaling any disturbances in the operation mode;
- providing for gas alarm devices detecting methane and hydrogen sulfide in the air of the working area;
- the sulfur recovery unit is fitted with gas alarm device for composition of flue gases in the flue stack to ensure monitoring of defined-source pollutant emissions after the incinerator;
- using explosion-proof version of electric equipment for the facility;
- using closed drainage of apparatuses and pipelines.

The project has the following emission permits:

- Permit No.115 dated 27.06.2006 (valid from 27.06.2006 through 01.07.2011) for emissions of pollutants from stationary sources during construction and operation of Yuzhnoe Khylchuyu field issued by Russian Technical Inspection (Rostechnadzor).

- Permit No.16 dated 03.08.2009 (valid from 03.08.2009 through 31.12.2011) for pollutant emissions in the area of Yuzhno-Khylchuyuskoe oil field issued by Rostechnadzor.

The environmental impact assessment developed within the framework of the project demonstrates that as long as there are no emergency situations and the environment protection actions are undertaken, gas treatment and sulfur recovery units will not have any measurable impact upon environmental components. Moreover, the project measures are environment-oriented and make it possible to significantly reduce sulfur dioxide and hydrogen sulfide emissions to the atmosphere from stationary sources at Yuzhno-Khylchuyuskoe field.

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 working design "Construction and completion of wells of Yuzhnoe Khylchuyu during commercial exploitation" within which framework the construction of APG treatment unit and sulfur recovery unit is envisaged, was submitted for review to the expert commission of the State Expert Committee of the Federal Natural Resources Supervision Service (Rosprirodnadzor) in the Nenets Autonomous Okrug. According to the opinion of the expert committee No.229-P dated 12.09.2005 the planned project measures comply with the requirements set to the facilities of this kind, and the environmental impact level is acceptable.

SECTION G. Stakeholders' comments

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

Since the APG treatment and sulphur recovery plants are the facilities of Yuzhno-Khylchuyuskoe field, the stakeholders' comments were received as a part of comments to the Yuzhno-Khylchuyuskoe field infrastructure development project.

According to the minutes of the public hearings for the project "Construction and completion of wells of Yuzhnoe Khylchuyu during commercial exploitation" dated 22.09.2005, the administration of the Nenets Autonomous Okrug, specialists, environment protection authorities, public organizations and residents of the Okrug participated in the discussion of the project. It was noted that successful implementation of the project was beneficial for all participants: additional jobs, social and economic benefits for the Nenets Autonomous Okrug and the city of Naryan-Mar.

Annex 1

CONTACT INFORMATION ON PROJECT PARTICIPANTS

Organisation:	Limited Liability Company “Naryanmarneftegas”
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Building:	16
City:	Iskateley Settlement
State/Region:	Nenets Autonomous Okrug
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Country:	Russia
Phone:	(81853) 6-40-04
Fax:	(81853) 6-43-99
E-mail:	sgoloushkin@nmng.ru
URL:	http://www.nmng.ru/
Represented by:	
Title:	Deputy Director General for Occupational Health and Safety
Salutation:	Mr.
Last name:	Goloushkin
Middle name:	
First name:	Sergey
Department:	
Phone (direct):	(81853) 6-40-04
Fax (direct):	(81853) 6-43-99
Mobile:	
Personal e-mail:	sgoloushkin@nmng.ru

Annex 2

BASELINE INFORMATION

Annex 2.1

Calculation model with main parameters

Methane content in natural gas	%	92,66%				
Methane content in APG	%	89,96%				
Methane density	kg/m3	0,667				
Incomplete burning in flare unit	%	3,5%				
Net calorific value of APG	GJ/thousand m3	36,2				
Net calorific value of natural gas	GJ/thousand m3	32,8				
Specific consumpiton of electricity for gas treatment (GTP) and sulfur recovery plants (SRP)	MWh/million m3	21,43				
Project scenario						
Parameter	Unit	2009	2010	2011	2012	2009-2012
Oil production	thousand t	6 961,62	6 888,21	4 946,30	1 848,49	**20 644,62**
Supply of untreated APG to GTP	thousand m3	253 016,16	330 634,33	217 652,44	157 229,31	**958 532,24**
APG consumption in Energy Center	thousand m3	78 252,69	137 757,00	164 263,03	123 720,65	**503 993,37**
Supply of APG to oil stripping columns	thousand m3	76 156,64	70 458,25	50 594,81	18 907,90	**216 117,60**
Consumption of APG in desulfurization boiler house	thousand m3	12 237,04	11 676,46	10 131,29	9 576,15	**43 620,94**
Consumption of natural gas in Energy Center	thousand m3	39 870,17	18 556,89	0,00	0,00	**58 427,06**
Generation of electricity in Energy Center	MWh	295 914,36	402 846,00	428 105,63	322 443,26	**1 449 309,24**
Consumption of electricity by GTP and SRP	MWh	5 422,35	7 085,77	4 664,47	3 369,56	**20 542,15**
Consumption of electricity by BCS	MWh	9 857,00	20 633,00	21 926,75	16 514,93	**68 931,68**
Total consumption of fuel by Energy Center	TJ	4 140,49	5 595,47	5 946,32	4 478,69	**20 160,97**
Total volume of APG burned with complete oxidation	thousand m3	90 489,73	149 433,46	174 394,32	133 296,80	**547 614,31**
CO2 emission factor for natural gas combustion in Energy Center	tCO2/thousand m3	1,808	1,808	1,808	1,808	**1,808**
CO2 emissions from natural gas combustion in Energy Center	tCO2e	72 097	33 556	0	0	**105 653**
CO2 emissions related to complete oxidation of hydrocarbons which without the project would be emitted into the atmosphere through flaring	tCO2e	6 446	10 645	12 423	9 495	**39 009**
Overall GHG emissions	tCO2e	78 543	44 201	12 423	9 495	**144 662**
Baseline scenario						
Parameter	Unit	2009	2010	2011	2012	2009-2012
Oil production	thousand t	6 961,62	6 888,21	4 946,30	1 848,49	**20 644,62**
Supply of natural gas to oil stripping columns	thousand m3	76 156,64	70 458,25	50 594,81	18 907,90	**216 117,60**
Consumption of natural gas in Energy Center	TJ	3 926,70	5 210,46	5 576,97	4 202,50	**18 916,63**
CO2 emission factor for natural gas flaring	tCO2/thousand m3	1,745	1,745	1,745	1,745	**1,745**
CH4 emission factor for natural gas flaring	tCO2/thousand m3	0,454	0,454	0,454	0,454	**0,454**
CO2 emissions from natural gas flaring after oil stripping columns	tCO2e	132 893	122 949	88 288	32 994	**377 124**
CO2 emissions from natural gas combustion in Energy Center	tCO2e	216 481	287 256	307 462	231 687	**1 042 886**
CH4 emissions due to flaring of APG which inder the project is burned with complete oxidation	tCO2e	39 917	65 919	76 930	58 801	**241 567**
CH4 emissions due to flaring of natural gas after oil stripping columns	tCO2e	34 603	32 014	22 988	8 591	**98 196**
Overall GHG emissions	tCO2e	423 894	508 138	495 668	332 073	**1 759 773**
Total GHG emission reductions	tCO2e	345 351	463 937	483 245	322 578	**1 615 111**

Annex 2.2

Estimation of project CO_2 emissions from afterburning of APG which under the baseline scenario would have been released in the atmosphere during soot flaring

APG,thousand m3			
2009	2010	2011	2012
3 167	5 230	6 104	4 665

* Density at 20 0C and 101325 Pa

Gas component	Composition,%	Carbon content in component	*Density, kg/m3	Volume of component, thousand m3	Mass of component, tonnes	Specific carbon content, kgC/m3	Carbon content in gas, kgC/m3	CO2 content, kg CO2/m3	CO2 Emissions, t CO2
2009									
methane	89,96%	0,7487	0,667	2849	1901	0,499	0,449	1,647	5215
ethane	3,00%	0,7989	1,250	95	119	0,999	0,030	0,110	348
propane	1,86%	0,8171	1,835	59	108	1,499	0,028	0,102	324
isobutane	0,42%	0,8266	2,418	13	32	1,999	0,008	0,031	97
butane	0,90%	0,8266	2,418	29	69	1,999	0,018	0,066	209
isopentane	0,31%	0,8324	3,001	10	29	2,498	0,008	0,028	89
pentane	0,34%	0,8324	3,001	11	32	2,498	0,008	0,031	97
hexane	0,13%	0,8373	3,580	4	14	2,997	0,004	0,014	44
heptane+higher hydrocarbons	0,06%	0,8401	4,163	2	8	3,497	0,002	0,007	24
nitrogen	2,08%	-	-	-	-	-	-	-	
carbon dioxide	0,94%	-	-	-	-	-	-	-	
hydrogen sulfide	0,00%	-	-	-	-	-	-	-	
oxygen	0,00%	-	-	-	-	-	-	-	
helium	0,02%	-	-	-	-	-	-	-	
Total	**100%**			**3071**	**2312**		**0,555**	**2,035**	**6446**
2010									
methane	89,96%	0,7487	0,667	4705	3139	0,499	0,449	1,647	8612
ethane	3,00%	0,7989	1,250	157	196	0,999	0,030	0,110	574
propane	1,86%	0,8171	1,835	97	179	1,499	0,028	0,102	536
isobutane	0,42%	0,8266	2,418	22	53	1,999	0,008	0,031	160
butane	0,90%	0,8266	2,418	47	114	1,999	0,018	0,066	345
isopentane	0,31%	0,8324	3,001	16	48	2,498	0,008	0,028	147
pentane	0,34%	0,8324	3,001	18	53	2,498	0,008	0,031	161
hexane	0,13%	0,8373	3,580	7	24	2,997	0,004	0,014	72
heptane+higher hydrocarbons	0,06%	0,8401	4,163	3	13	3,497	0,002	0,007	39
nitrogen	2,08%	-	-	-	-	-	-	-	
carbon dioxide	0,94%	-	-	-	-	-	-	-	
hydrogen sulfide	0,00%	-	-	-	-	-	-	-	
oxygen	0,00%	-	-	-	-	-	-	-	
helium	0,02%	-	-	-	-	-	-	-	
Total	**100%**			**5072**	**3818**		**0,555**	**2,035**	**10645**
2011									
methane	89,96%	0,7487	0,667	5491	3663	0,499	0,449	1,647	10050
ethane	3,00%	0,7989	1,250	183	229	0,999	0,030	0,110	670
propane	1,86%	0,8171	1,835	114	209	1,499	0,028	0,102	625
isobutane	0,42%	0,8266	2,418	26	62	1,999	0,008	0,031	187
butane	0,90%	0,8266	2,418	55	133	1,999	0,018	0,066	403
isopentane	0,31%	0,8324	3,001	19	56	2,498	0,008	0,028	171
pentane	0,34%	0,8324	3,001	21	62	2,498	0,008	0,031	188
hexane	0,13%	0,8373	3,580	7	24	2,997	0,004	0,014	84
heptane+higher hydrocarbons	0,06%	0,8401	4,163	3	13	3,497	0,002	0,007	45
nitrogen	2,08%	-	-	-	-	-	-	-	
carbon dioxide	0,94%	-	-	-	-	-	-	-	
hydrogen sulfide	0,00%	-	-	-	-	-	-	-	
oxygen	0,00%	-	-	-	-	-	-	-	
helium	0,02%	-	-	-	-	-	-	-	
Total	**100%**			**5917**	**4449**		**0,555**	**2,035**	**12423**

2012									
methane	89,96%	0,7487	0,667	4197	2800	0,499	0,449	1,647	7682
ethane	3,00%	0,7989	1,250	140	175	0,999	0,030	0,110	512
propane	1,86%	0,8171	1,835	87	160	1,499	0,028	0,102	478
isobutane	0,42%	0,8266	2,418	20	47	1,999	0,008	0,031	143
butane	0,90%	0,8266	2,418	42	102	1,999	0,018	0,066	308
isopentane	0,31%	0,8324	3,001	14	43	2,498	0,008	0,028	131
pentane	0,34%	0,8324	3,001	16	47	2,498	0,008	0,031	143
hexane	0,13%	0,8373	3,580	7	24	2,997	0,004	0,014	65
heptane+higher hydrocarbons	0,06%	0,8401	4,163	3	13	3,497	0,002	0,007	35
nitrogen	2,08%	-	-	-	-	-	-	-	
carbon dioxide	0,94%	-	-	-	-	-	-	-	
hydrogen sulfide	0,00%	-	-	-	-	-	-	-	
oxygen	0,00%	-	-	-	-	-	-	-	
helium	0,02%	-	-	-	-	-	-	-	
Total	**100%**			**4525**	**3409**		**0,555**	**2,035**	**9495**

Annex 2.3

Calculation of CO_2 emission factor for natural gas flaring

Calculation of CO2 emission factor for natural gas flaring						
Gas component	**Composition,%**	**Carbon content in component**	**Component density, kg/m3**	**Specific carbon content in component, kgC/m3**	**Efficiency of flaring of component, %**	**CO2 emission factor for component flaring, tCO2/thou. m3**
methane	92,66%	0,7487	0,667	0,463	0,965	1,637
ethane	1,56%	0,7989	1,250	0,016	0,965	0,055
propane	0,54%	0,8171	1,835	0,008	0,965	0,029
isobutane	0,09%	0,8266	2,418	0,002	0,965	0,007
butane	0,16%	0,8266	2,418	0,003	0,965	0,011
isopentane	0,04%	0,8324	3,001	0,001	0,965	0,003
pentane	0,04%	0,8324	3,001	0,001	0,965	0,003
hexane	0,00%	0,8373	3,580	0,000	0,965	0,000
heptane+higher hydrocarbons	0,00%	0,8401	4,163	0,000	0,965	0,000
carbon dioxide	0,00%	0,2729	1,831	0,000	1	0,000
nitrogen	4,89%	-	-	-	-	-
hydrogen sulfide	0,00%	-	-	-	-	-
helium	0,02%	-	-	-	-	-
Total	**100%**			**0,493**		**1,745**

Annex 2.4

Calculation of CH_4 emission factor for natural gas flaring

Calculation of CH4 emission factor for natural gas flaring					
Parameter	**Volume fraction of methane in natural gas, %**	**Methane density, kg/m3**	**Unburned carbon factor**	**GWP for methane, tCO2/tCH4**	**Methane emission factor (in CO2 equivalent), tCO2/thous. m3**
Value	92,66%	0,667	0,035	21	**0,454**

Annex 2.5

Calculation of CO_2 emission factor for natural gas combustion in the Energy Center

Calculation of CO2 emission factor for natural gas combustion in the Energy Center						
Gas component	Composition,%	Carbon content in component	Component density, kg/m3	Specific carbon content in component, kgC/m3	Efficiency of component combustion in Energy Center, %	CO2 emission factor for component combustion in Energy Center, tCO2/thou.m3
methane	92,66%	0,7487	0,667	0,463	1	1,696
ethane	1,56%	0,7989	1,250	0,016	1	0,057
propane	0,54%	0,8171	1,835	0,008	1	0,030
isobutane	0,09%	0,8266	2,418	0,002	1	0,007
butane	0,16%	0,8266	2,418	0,003	1	0,012
isopentane	0,04%	0,8324	3,001	0,001	1	0,004
pentane	0,04%	0,8324	3,001	0,001	1	0,004
hexane	0,00%	0,8373	3,580	0,000	1	0,000
heptane+higher hydrocarbons	0,00%	0,8401	4,163	0,000	1	0,000
carbon dioxide	0,00%	0,2729	1,831	0,000	1	0,000
nitrogen	4,89%	-	-	-	-	-
hydrogen sulfide	0,00%	-	-	-	-	-
helium	0,02%	-	-	-	-	-
Total	**100%**			**0,493**		**1,808**

Annex 2.6

Information about the boiler units installed in the Energy Center

1.Waste heat recovery hot water boiler (KU-V)

Waste heat recovery hot water boiler (KU-V) serves to produce hot water by recovering heat of exhaust gases coming from the gas turbine. KU-V is gas-tight and made of finned tubes, it also has a bypass gas duct. In order to ensure the hot water demand the heat recovery boiler is supplied with shutoff valves installed along the gas turbine exhaust duct. Operational reliability of the hot water recovery boiler will be ensured by the required quality of the circulating water.

Main technical details of the recovery boiler:

1. Thermal capacity of KU-V	~ 25 MW
2. Combustion products flow at the inlet to KU-V	~ 93÷75 kg/s
3. Gas temperature at the inlet to KU-V	485÷560°C
4. Maximum gas temperature at the inlet to KU-V	600°C
5. Operating water temperatures in KU-V	150/70°C
6. Water temperature at the inlet to KU-V	70°C
7. Outlet water temperature	150°C
8. Heated water flow in KU-V	~270 m^3/h
9. Temperature of exhaust gases after KU-V/bypass (max)	270/600°C

2.Peak-load hot water boilers

Peak-load hot water boilers are designed to meet the in-house heat demand of the Energy Center in the period of set up and start up operations of the main and auxiliary equipment of the Energy Center, and also to cover the heat demand of the external consumers under such load conditions when it is not reasonable to operate heat recovery boilers. Peak-load hot water boilers must ensure heating of the circulating water for external consumers to the specified temperatures 150/70°C. Peak-load hot water boilers shall operate in a closed circuit via plate-type heat exchangers. Heat supply regulation is ensured by the output of the boilers with modulated burners and by a device on the heated side. The output of the boiler circuit will be determined by the load of the external circuit.

Temperatures of the boiler circuit – 160/80°C.

The output of each peak-load hot water boiler was defined by the in-house heat demand of the Energy Center at the initial stage of set up and start up works.

Total output of hot water boilers is 14.4 MW (2x7.7 MW).

Rated pressure of circulating water in the closed circuit is 16 bar.

The boilers are supplied together with a gas manifold for ≤ 3 bar pressure, which determines the quantity of gas fed to the boilers. The diesel fuel is fed to the boilers from fuel consumed tanks installed in the main building of the Energy Center.

Main technical details of the boiler:

1. Thermal capacity	7.7 MW
2. Temperatures	160/120°C
3. Maximum water temperature at the outlet from the boiler	200°C

Annex 2.7

Soot flaring proof

The calculations rely on the gas flows fed to the high- and low-pressure flares. It is also taken into account that natural gas, which would be used in the oil stripping columns under the baseline scenario, would be fed from the columns to the low-pressure flare (See the Table below).

Parameter	2009*
APG production volume, thousand m3	804 763,27
Gas volume fed to the stripping columns KO-24,25, thousand m3	76 156,64
Gas volume fed to the low-pressure flare under the project, thousand m3	246 617,31
Gas volume supplied from BRTG-1 to the low-pressure flare seal under the project, thousand m3	816,17
Gas volume supplied from BRTG-1 to the low-pressure flare ignitor under the project, thousand m3	0,00
Low-pressure APG volume from the end stages of oil separation, thousand m3	169 644,50
High-pressure APG volume from the 1st stage of oil separation, thousand m3	635 118,77

* according to the data of LLC "Naryanmarneftegas"

Then, calculations were made in accordance with the "Guidelines for Calculation of Air Pollutant Emissions from APG Flaring" developed by the Scientific Research Institute for Atmospheric Air Protection in Saint-Petersburg, 1998 in order to check the compliance with the APG soot flaring conditions. The volume of gas combusted in a flare unit is given for the year 2009, because it is in this year when the gas production was at the maximum level. Composition of gas from the oil stripping columns has been used because this adds conservativity here (protocol of analysis from 10/04/2011). The calculation results are presented in the Tables below.

Gas component	Composition,%	Adiabatic exponent	Coefficient	Molecular weight	Coefficient
1	2	3	4=2*3	5	6=2*5
methane	79,790%	1,31	1,045	16,043	12,8007097
ethane	2,690%	1,21	0,033	30,07	0,808883
propane	3,593%	1,13	0,041	44,097	1,58440521
isobutane	1,419%	1,1	0,016	58,124	0,82477956
butane	3,477%	1,1	0,038	58,124	2,02097148
isopentane	1,428%	1,08	0,015	72,151	1,03031628
pentane	1,672%	1,08	0,018	72,151	1,20636472
hexane	0,744%	1,07	0,008	86,066	0,64033104
heptane+higher hydrocarbons	0,173%	1,06	0,002	100,077	0,17313321
carbon dioxide	1,709%	1,3	0,022	44,011	0,75214799
nitrogen	1,647%	1,4	0,023	28,016	0,46142352
H2S	1,640%	1,34	0,022	34,082	0,5589448
Helium	0,018%	1,666	0,000	4,003	0,00072054
Total	100,00%	-	1,283	-	22,86313105

Conditional adiabatic exponent (4)	1,283	-
Conditional molecular weight (6)	22,8631	-
Gas temperature	20	˚C
Sound speed	371,0	m/s
Volume of flared gas*	635 118,77	thousand m3
Volumetric flow of gas	20,14	m3/s
Diameter of discharge nozzle	0,60	m
Velocity of gas exhaust from the discharge nozzle of flare unit	**71,3**	m/s

Critical speed of soot flaring	**74,2**	m/s
Conclusion:	**Soot flaring**	

Thus it could be concluded that soot flaring of gas takes place under the baseline scenario.

Annex 3

MONITORING PLAN

See Section D of the PDD.

Annex 4

REFERENCE LIST

[R1] Guidelines for Calculation of Air Pollutant Emission from APG Flaring, developed by the Scientific Research Institute for Atmospheric Air Protection in Saint-Petersburg, 1998 (approved by the Order of the National Environmental Protection Committee (Goskomecologia) of the Russian Federation dated 08.04.1998 No.199)

[R2] Guidance on criteria for baseline setting and monitoring, Version 03, JISC (http://ji.unfccc.int/Ref/Documents/Baseline_setting_and_monitoring.pdf)

[R3] Decision 9/CMP.1. Guidelines for the implementation of Article 6 of the Kyoto Protocol. FCCC/KP/CMP/2005/8/Add.2. 30 March 2006

[R4] 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2.

[R5] "Construction and completion of wells of Yuzhno-Khylchuyuskoe oil and gas field. Gas treatment plant. Sulfur recovery and storage facility" OJSC "GIPROGAZOOCHISTKA", 2006