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:

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Verkh-Tarskoye Oilfield (VTOF) Gas Utilization
Version 02
09 June 2008

A.2. Description of the project:

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Purpose:
The purpose of LLC SP Sibgazpererabotka's (SP SGP's) proposed JI project is to build and operate a gas processing plant to process Associated Petroleum Gases (APG) from Verkh-Tarskoye Oilfield (VTOF), 100% owned by TNK-BP, to be operated by Novosibirskneftegas (NNG), thus reducing flaring of APG in the oil field and emissions of GHG to the atmosphere.

Current status:
NNG has flared APG not required for on-site power generation in VTOF since the field was commissioned in 2001. The amount of APG produced is related to the rate of oil production, and is estimated to be 254 million cubic meters (MMCM/yr) in 2008.

VTOF is undergoing field development, and a drilling program is in place to increase oil production from the northern part of the field and extend the plateau production. APG production is estimated to increase to 256 MMCM/yr in 2009 and then enter a natural decline. The consumption of APG for on-site energy generation is currently about 78 MMCM/yr, and this is estimated to increase to 102 MMCM/yr in 2011 due to the oil field development, after which it then stabilizes. The majority of energy consumption is related to water flooding of the oil field to provide pressure support for the oil production.

APG is currently flared at the Central Processing Facility (CPF) where the gas undergoes 2-stage separation. First stage separation gas is used for on-site power with any excess flared, and all second stage separation gas is flared. New gas turbines that can be operated on liquid fuels (e.g. second stage separation gas) are under installation to meet the expected increase in on-site energy demand and deal effectively with the future levels of APG production. Within a relatively short time horizon, the majority of the produced APG will be required to meet the increasing on-site energy demand in VTOF. Flaring of APG in VTOF can thus be considered to be a temporal issue.

Project activity:
TNK-BP has as the field owner evaluated several options to maximize utilization of the APG produced from VTOF and thus reduce flaring at the CPF. Options evaluated have included gas processing facilities, gas processing facilities with methanol production, gas processing with LNG production, power generation on-site for grid export, gas re-injection and gas pipeline transport. Given the limited amount of gas available and the distance to markets, the most feasible of the options evaluated was the installation of a gas treatment and processing facility for production of LPGs, condensate and dry gas. This option is the proposed JI project activity.

Installation of a gas processing plant (GPP) for subtraction of liquids from the APG has been studied in detail for a long time by TNK-BP. TNK-BP is the project developer of the proposed JI project.

The APG currently flared contains considerable natural gas liquids (the APG composition can be found in Annex 4). The primary change in energy utilization due to the proposed JI project activity is extraction of these liquids from the gas stream produced at VTOF (and potentially Maloicheskoe oil field[1]) and their use as a commercial and productive resource. The gas processing facility will produce dry gas, LPGs (i.e. fuel liquefied hydrocarbon gas for household consumption (SPBT) and liquefied hydrocarbon gas for automotive vehicles (C3)) and stable gas condensate (SNG). SPBT, C3 and SNG will be transported from the VTOF plant gate by trucks and sold in the market by SP SGP. The liquid extraction in itself substantially decreases the amount of gas flared at VTOF[2]. In addition, dry gas will be used as a fuel for the GPP and to substitute consumption of wet gas (first-stage separation gas) for power generation at VTOF. The amount of dry gas available from the GPP to VTOF is not expected to be sufficient to run the gas generators and turbines from 2011 onwards, and other fuels (e.g. diesel) will be utilized to compensate for the deficit in energy at the field.

The effect of the project activity, the GPP, is increased productive use of APG and thereby a significant and measurable reduction of GHG emissions from flaring at VTOF.

Contribution to sustainable development:
The proposed JI project activity will contribute positively to sustainable development as following:

- LPGs and natural gasoline currently flared will be used productively and provide economic benefits;
- Local production, distribution and sale of gas liquids will create local employment opportunities (SP SGP will employ about 150 people to operate the GPP);
- Immediate elimination of C3+ in the flare gas and eventually minimization of the flaring of APG will both contribute to mitigate the effect of climate change and reduce emissions of particulates

A.3. Project participants:

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Name of Party involved (*) ((host) indicates a host Party)	Private and/or public entity(ies) project participants (*) (as applicable)	Kindly indicate if the Party involved wishes to be considered as project participant (Yes/No)
Russian Federation (host) Kingdom of Norway	TNK-BP Carbon Limits AS	No No

A.4. Technical description of the project:

A.4.1. Location of the project:

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A.4.1.1. Host Party(ies):

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The Russian Federation

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

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Novosibirsk Region

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[1] Another oil field operated by TNK-BP in the region where APG recovery, transportation and processing in the new plant is evaluated as one opportunity to eliminate flaring (the amount of APG produced is however limited).

[2] The extraction of liquids from the APG results in shrinkage of the gas as it goes from a "wet" to a "dry" composition, thereby reducing the amount of flared carbon-based energy.

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

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Severny District, Severny Village

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

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The GPP will be located in close proximity (<500 m) to the Verkh-Tarskoye Oilfield CPF, which is located in the northern part of Novosibirsk region, in the South of Western Siberia. VTOF is situated 180 km north from the city of Barabinsk, which lies between the towns of Novosibirsk and Omsk on the Trans-Siberian rail road running along the Omsk-Irkutsk export pipeline.

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

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The production stream from oil wells in VTOF is sent to a Central Processing Facility (CPF) where APG is separated in a two-stage process. Gas from 1st stage separation is predominately light components (methane and ethane) while gas from the 2nd stage separation has a higher composition of heavy (C3+) components (see Annex 4 for gas compositions). At present APG is used as fuel gas for the on-site, stand-alone power plant and heaters to meet the energy demand of the oil field while the remaining gas is flared. The power supply of the overall oil field is provided by gas piston power units (GPPU) and gas turbine power units located at the CPF fuelled with own associated gas recovered at the 1st separation phase of CPF and free water knock-out unit (FWCU).

The proposed JI project activity consists of installing an APG processing plant (GPP) and pipelines so as to produce dry gas (which is transported back to the field), and NGLs which are marketed for final use.

Gas transportation infrastructure:

To recover and transport APG from the CPF and the FWCU to the GPP, a 505 meter pipeline with internal diameter 530 mm will be constructed. The pipeline will operate at a pressure of maximum 6.9 atm and supply gas to the GPP at a single inlet at 3 atm.

To transport dry gas produced in the GPP to the GPPU for fuel, a 960 meter pipeline with an internal diameter of 273 mm will be constructed. The pipeline will operate at an outlet pressure of 4.8 atm, with a pressure drop of 0.79 atm during transportation to the GPPU. A flare header at the GPP will be installed in the event of excess supply of dry gas and of emergencies.

Pipeline fittings recommended for the proposed JI project are manufactured by JSC Ikar, Kurgan. Pipes will be constructed to meet the manufacturing specifications, delivery standards and have certificates of conformity with the Russian state standard and permits for application in the oil and gas industry. Used fittings (taps, valves and stoppers) are designed to meet the estimated pipeline pressure. Service life of used pipeline fittings (Kurgan pipeline plant JSC Ikar manufacture) is 20 years. All applied fittings shall meet class A under GOST 9544-93[3].

Gas processing plant:

The design of the GPP is based on the Terms of Reference for design of the facility "System of associated petroleum gas gathering, transportation and processing facilities at the Verkh-Tarskoye oil field". Inputs for the design were accepted under the Protocol of the OJSC "Novosibirskneftegaz" Technical Council of January 19, 2007 upon review of the "System of associated petroleum gas gathering, transportation and processing facilities at the Verkh-Tarskoye oil field" project concept.

The general developer of technology and equipment for the APG processing is JSC "Gazprom" subsidiary JSC Tsentralnoye Konstruktorskoe Buro Nefteapparatury/CKBN in Podolsk.

The proposed GPP includes two processing lines:

- Low-temperature separation line (LTS) that will produce dry lean gas according to GOST 5542-78 for use as fuel to operate the GPP and with the excess exported to the gas power piston units so as to provide energy to the oil field (currently utilizing 1st stage APG as fuel gas)
- Line producing propane-butane technical mix (SPBT, i.e. primarily C_3 and C_4) according to GOST 20448-90[4], automobile propane (C_3) under TU 38-101490-79 and stable natural gasoline (SNG, i.e. primarily C_5+) under TU 39-1340-89[5] using the liquid condensate produced in the LTS line as feedstock

As the project is in Siberia, the huge temperature differences between the summer and the winter[6] requite the plant to be run in different seasonal operational modes. The following sections describe the production process during the summer and winter, respectively, with indication of production streams and compositions:

Summer operations:

Summer operations are expected to operate for 5 months each calendar year.

Low temperature separation line:
After preliminary treatment, recovered flared gas from CPF and FWCU is passed into the GPP. The gas (at T=16^{0}C and 3 atm) enters into a separator where liquids are measured and removed. The separator gas will also be measured and mixed with gas from a later stage separator prior to entering a filter separator. The separator gas exits the filter separator at 14^{0}C and 2 atm into a compressor. The compressed gas (at T=186^{0}C and 34 atm) then passes an air cooler and is transported to a heat-exchanger where its temperature is dropped to 36^{0}C with partial condensation of hydrocarbon gas.

A second separator then removes the liquid phase from the gas, where 90 % methanol will be injected into the separator gas to prevent formation of hydrates. This mixture passes into another heat-exchanger

[3] Russian standard for "Pipeline gate valves – rates of gates sealibility"

[4] Russian standard for "Fuel Liquefied Hydrocarbon Gas for Household Consumption"

[5] Russian standard for "Stable gas benzene"

[6] The absolute minimum temperature in the construction area is -52^{0}C, with average temperature in January lying between -16^{0}C and -20^{0}C. The maximum air temperature in the area is 37^{0}C, with average July temperatures ranging from 18^{0}C to 20^{0}C.

followed by a propane cooler for further cooling. After cooling, the mixture (at T=-30^{0}C and 32 atm) will be passed into a third separator.

Downstream of the third separator the gas is throttled to 6.6 atm and -53.5^{0}C where it mixes with gas recovered from the liquid processing line and pass into another heat-exchanger to cool liquids entering into the liquid processing line. Downstream of the heat exchanger the (dry) gas goes to a metering unit before the gas (at T=10.1^{0}C and 4.8 atm) is transported to end users (GPP power unit and subsequently GPPU).

Liquid treatment line:
The liquids removed from the low-temperature separation line (at T=-30^{0}C) go to the liquid processing line, where residual gas, condensate and water-methanol solution is extracted from the liquid phase. The condensate (at T=25.7^{0}C and 30 atm) is segregated into two streams (product and reflux) which enter the 1st stage liquid treatment column in equal portions. The reflux portion is passed into a propane cooler and is cooled to -10^{0}C before being passed into the 1st stage liquid treatment unit. The product portion is cooled to 20.3^{0}C and 27 atm and passed into the column as a product.

The condensate from the 1st stage liquid treatment unit (at T=92.1^{0}C and 27 atm) goes to the 2nd treatment column, where stable gas-condensate (SNG) is removed from the bottom of the column and passed into an air cooler. After cooling, the SNG will go to the metering unit and be pumped out of the facility at 40^{0}C and 13.5 atm. The stream from the top of the 2nd column will go to an air cooling unit and be stored in a tank after condensation. Any residual gas is flared. Liquid will then be pumped from the storage tank in two portions; one as a reflux to the 2nd stage liquid treatment column and the other for measurement and export as a commercial propane-butane mix (SPBT) at 48.1^{0}C and 12.5 atm.

The relevant units and product flows within the GPP during summer operations are depicted in Figure 1 below:

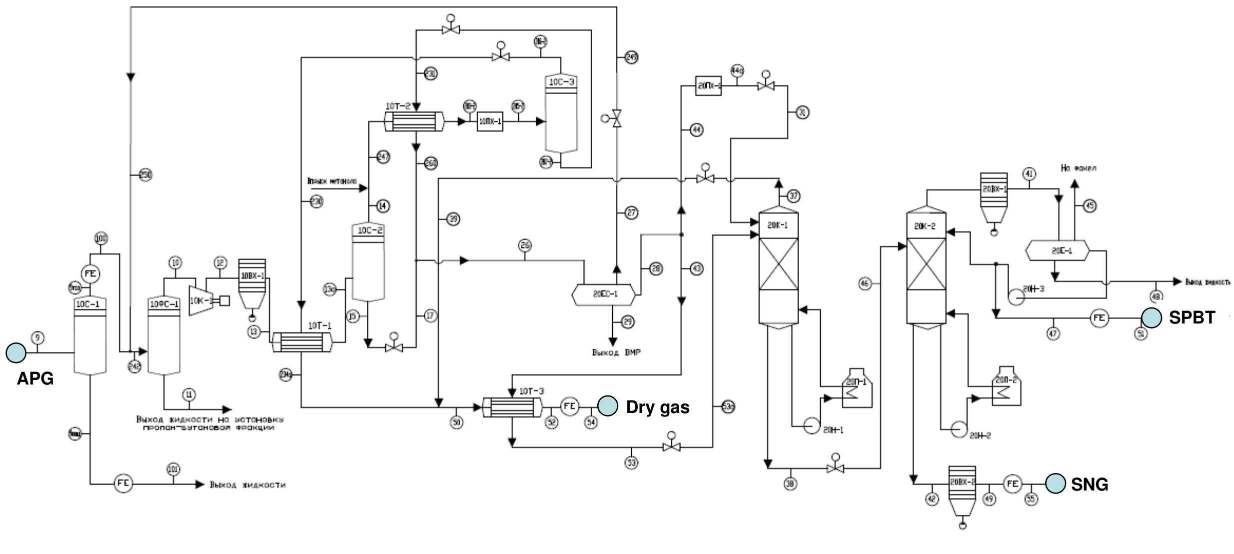

Figure 1: Product flows during summer operations

Winter operations:

Winter operations are expected for 7 months each calendar year.

Low temperature separation line:

Recovered flared gas from CPF and FWCU will be passed into the GPP after preliminary treatment. The gas (at T=16^{0}C and 3 atm) will enter into a separator where liquids are measured and removed from the separator. The separator gas will also be measured and mixed with gas from a later stage separator prior to entering a filter separator. The separator gas will leave the filter separator at 14.4^{0}C and 3 atm and enter into a compressor. The compressed gas (at T=180^{0}C and 30.5 atm) will then be passed into a heat-exchanger and subsequently cooled in an air cooler where its temperature is dropped to 15^{0}C. After cooling, the gas is transported to a heat-exchanger where its temperature is dropped further to 12.5^{0}C with partial condensation of hydrocarbon gas.

A second separator then removes the liquid phase from the gas, where 90 % methanol will be injected into the separator gas to prevent formation of hydrates. This mixture passes into another heat-exchanger followed by a propane cooler for further cooling. After cooling, the mixture (at T=-30^{0}C and 28 atm) is passed into a third separator.

Downstream of the third separator the gas is throttled to 6.6 atm and -50.3^{0}C where it will mix with gas recovered from the liquid processing line and pass into another heat-exchanger used to cool liquids entering into the liquid processing line. Downstream of the heat exchanger the (dry) gas will go to a metering unit before the gas (at T=19.6^{0}C and 5.0 atm) is transported to end users.

Liquid treatment line:
The liquids removed from the low-temperature separation line (at T=-30^{0}C) go to the liquid processing line, where residual gas, condensate and water-methanol solution is extracted from the liquid phase. The condensate is segregated into two streams (product and reflux) which enter the 1st stage liquid treatment column in equal portions. The reflux portion is passed into a propane cooler to reach -10^{0}C before being passed into the 1st stage liquid treatment column. The product portion (at 7.8^{0}C and 23 atm) is passed into the column directly as a product. To maintain the required temperature in the treatment column, the liquid is heated in a heating circuit.

The condensate from the 1st stage liquid treatment unit (at 83.7^{0}C and 23 atm) goes to the 2nd treatment column, where stable gas-condensate (SNG) is removed from the bottom of the column and passed into an air cooler. The SNG then goes to the metering unit and is pumped out of the facility at 40^{0}C and 15 atm. The stream from the top of the 2nd column goes to an air cooling unit to be stored in a tank after condensation. Any residual gas from this stage is flared. The liquid is pumped from the storage tank to a heat-exchanger where it is heated to 68^{0}C and the majority of the liquid is pumped to the third liquid treatment column.

The third treatment column requires a heating circuit to maintain the necessary temperature. The steam from the top of the column goes to an air cooling unit, where condensate is sent to the second storage tank and the residual gas is flared. Liquid from the storage tank is divided into three portions; one portion being sent back to the third treatment column as a reflux, one portion being measured and pumped into an automobile propane line at 39^{0}C and 20 atm for export, and the last portion being sent to the third storage tank. The bottom-end liquid from the third treatment column goes to a heat-exchanger and is then dumped into the third storage tank. The blend of the two liquid flows in the third storage tank is commercial propane-butane (SPBT), and is cooled in an air cooler to 40^{0}C and measured prior to leaving the unit. The SPBT complies with the requirements of GOST 20448-90.

The relevant units and product flows within the GPP during winter operations are depicted in Figure 2:

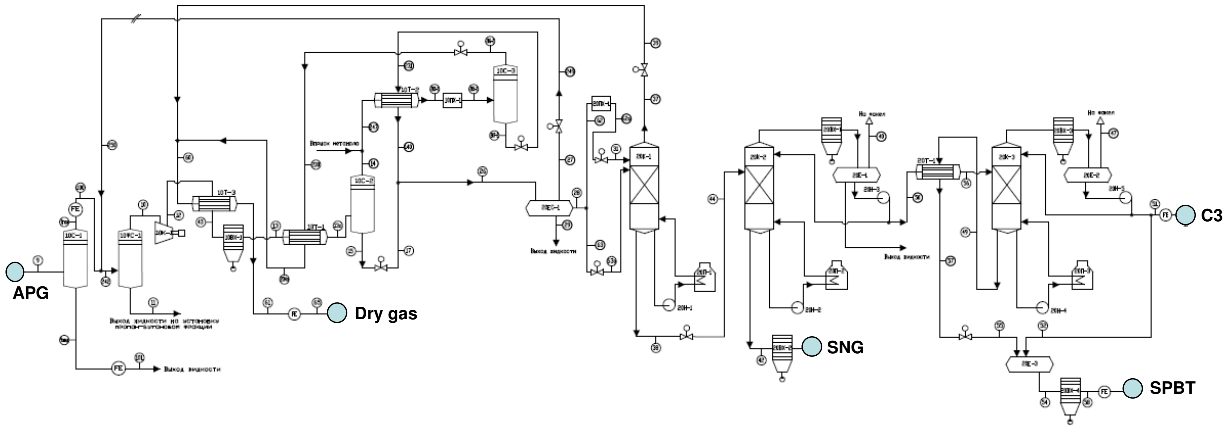

Figure 2: Product flows during winter operations

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:

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The purpose of SP SGP's proposed JI project is to build and operate a gas processing plant to process Associated Petroleum Gases from Verkh-Tarskoye Oilfield. The GPP will produce dry gas, LPGs (i.e. fuel liquefied hydrocarbon gas for household consumption (SPBT) and liquefied hydrocarbon gas for automotive vehicles (C3)) and stable gas condensate (SNG). SPBT, C3 and SNG will be transported from the VTOF plant gate by trucks and sold on the market by SP SGP. The liquid extraction in itself substantially decreases the amount of gas flared at VTOF[7]. In addition, dry gas will be used as a fuel for the GPP and to substitute consumption of wet gas (first-stage separation gas) for power generation at VTOF. The amount of dry gas available from the GPP to VTOF is not expected to be sufficient to run the gas generators and turbines from 2011 onwards, and other fuels (e.g. diesel) will be utilized to compensate for the deficit in energy at the field.

The effect of the project activity, the GPP, is increased productive use of APG and thereby a significant and measurable reduction of GHG emissions from flaring at VTOF.

In the absence of the proposed project, the most economic option would be to continue to utilize APG to meet the on-site energy demand with the excess amount being flared. The energy balance of VTOF is expected to change over the next few years, naturally leading to a higher utilization level absent the project activity. The proposed JI project serves to essentially eliminate flaring at VTOF in the short term. The ability to monetize the resulting GHG emission reductions provides an essential incentive to implement the project.

APG flaring in Russia:

In 2006, the US National Oceanic and Atmospheric Administration (NOAA) estimated that Russia flared approximately 52 bcm/yr of gas, up from a figure of 37 bcm/yr in 1996. Although the Russian authorities do not acknowledge this estimate, the Ministry of Industry and Energy has recognized that oil and gas companies in Russia produced 55 bcm associated gas in 2005, of which 40 bcm was vented or flared[8]. Other Russian sources state that the gas flaring levels are around half this figure. Still, at a level

[7] The extraction of liquids from the APG results in shrinkage of the gas as it goes from a "wet" to a "dry" composition, thereby reducing the amount of flared carbon-based energy.

[8] RBK daily, 15 December 2006

of 25 bcm/yr, Russia flares more associated gas than any other country. The World Bank has estimated that only 41.4% of associated gas in Russia was utilized in 2005[9]. This compares poorly to "best practice" countries and regions such as Norway (98%), the UK (97%) and Alberta (96%).

The utilization of associated gas in Russia is therefore relatively low, and this is primarily due to physical and economic barriers. Historically, Russian oil companies have had little incentive to recover and utilize associated petroleum gases. This has partly been related to the availability of relatively low-cost non-associated natural gas. As a result of the relative abundance of non-associated gas, some oil fields have been developed without the required infrastructure to recover and utilize APG due to significantly higher investment costs.

The great distance to market is a significant barrier to investment in infrastructure viable. Most Russian oil producing regions have sparse populations and little local demand. Small volumes can be used locally, if there is local demand, but larger volumes need to be shipped off, and for most distances, pipelines constitute the only realistic alternative. A lack of investment in infrastructure and access to the existing Gazprom network is, however, a major barrier in marketing associated gas in Russia. Although Gazprom is legally obliged to offer spare transportation capacity to third parties, few transit agreements have been reached, due to low prices and a claimed capacity shortage.

Currently, no secondary legislation (such as codes, guidelines) exists at the federal level that deals specifically with operational processes or regulatory procedures related to gas flaring and venting. Some general requirements at the regional level are in place, specifically in Khanty-Mansijsk and Yamal-Nenets, but these do not apply to the project activity situated in the Novosibirsk region.

Government Resolution N 344 of June 12, 2003, updated by the Government Resolution N 410 of July 1, 2005 introduces taxes on emissions of environmentally damaging substances. The list includes methane, SO_X, NO_X, sulfur, and ashes, but not CO_2. These taxes apply for each harmful pollutant depending on whether the operator stays within "established emission limits"[10], within "temporarily agreed emission limits" or "above-limit emissions". Methane is the main pollutant relevant to flaring of APG. The tax rates for methane contained in APG flared by stationary sources[11] are 50 roubles/tonne (USD 2/tonne), 250 roubles/tonne (USD 10/tonne) or 1250 roubles/tonne (USD 50/tonne) respectively.

With the current taxation of emissions companies have limited direct fiscal incentives to increase utilization of associated gas, apart from the value of the gas itself and taxes on incomplete combustion of methane. In the case of VTOF, annual payments of taxes on harmful pollutants from flaring of APG could in theory reach 400,000 USD if the highest tax levels for the various types of emissions are applied. The potential saving on taxes on harmful pollutants is in this particular instance insignificant compared to the required capital expenditures to increase APG utilization in the oil field (estimated to 132.5 million USD).

In a public address in April 2007, the President of the Russian Federation named APG flaring as one of the main problems facing Russia's energy industry. Despite high economic losses and increasing concerns at the highest political level, substantial improvements in the Russian regulatory framework and national policies have yet to be substantially improved to stimulate more effective usage of APG and create the necessary conditions for a significant reduction in flaring. Plans to increase the regulated

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9 www.worldbank.org/html/fpd/ggfrforum06/gasflaringthecountriesexperienceandbestpractices.ppt#285

10 The Maximum Permissible Concentration (MPC) of emissions is established by the Ministry of Health.

11 The tax is applicable for methane emissions resulting from incomplete combustion of APG in stationary sources (e.g. flares).

wholesale prices for APG and flaring fees have been announced recently, but even with stronger economic incentives in place it is not expect to reach the government's objective of 95%-rate of utilization for APG before 2015[12]. The JI Mechanism could provide an effective incentive to reach this stated objective.

Conclusion on why the emission reduction would not occur in the absence of the project activity:
Associated gas is increasingly recognized to be of considerable economic value, but various barriers often hinder its productive use.

One obvious reason for the flaring practise in Russia is the long distance between production sites for associated gas and consumption points, which makes treatment and transport of the gas uneconomic. APG is furthermore technically more difficult to treat and has more uncertain delivery than non-associated natural gas, making investments in transport infrastructure and treatment facilities more risky. Low domestic gas prices are also a barrier to productive use of associated gas. In other cases gas producers are not granted access to third party infrastructure due to a stated lack of pipeline capacity.

A lack of secondary legislation (such as codes, guidelines) at the federal level is also a further disincentive to invest in gas recovery technology. The current emissions tax also gives limited direct fiscal incentives to increase utilization of associated gas.

It can therefore be concluded that flaring is common practise in Russia, and APG recovery remains relatively low.

The implementation of the proposed JI project faces significant economic barriers and would not be implemented without the contribution of the JI component. Carbon finance will contribute to the implementation of a short-term measure to eliminate flaring at VTOF, clearly contributing to the objective of the national energy strategy. The project will when implemented recover and utilize a valuable energy resource that would otherwise be wasted. The project will also lead to a significant reduction in regional volumes of gas flaring and will allow significant mitigation of local polluting emissions.

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

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Years	**Annual estimation of emission reductions in tonnes of CO_{2e}**
2010	157,960
2011	516,392
2012	414,196
2013	261,389
2014	224,768
2015	161,372
2016	0
2017	0
2018	0
2019	0
Total estimated reductions for crediting period 01 Oct 2010 to 30 Sept 2020 (tonnes of CO_{2e})	**1,736,077**

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

Total estimated reductions for crediting period 01 Oct 2010 to 31 Dec 2012 (tonnes of CO_{2e})	**1,088,548**
Annual average over the crediting period of estimated reductions (tonnes of CO_{2e})	**173,608**

The first crediting period of the JI project starts on 01 October 2010 and ends on 31 December 2012. The second crediting period of the JI project could be from 01 January 2013 to 30 September 2020.

Any carbon credits for the project after 2012 is dependent on approval by host party, the Russian Federation, and any relevant international policies.

During the part of the crediting period during the Kyoto Protocol, the project will generate emission reductions estimated to be 1,088,548 tonnes of CO_2 equivalent (for the period from 01 October 2010 to 31 December 2012), for which ERUs will be requested.

Beyond 2012, emission reductions generated by the project are estimated to be 647,529 tonnes of CO_2 equivalent. It is possible that such reductions will be eligible to be marketed as carbon credits and this PDD allows for the monitoring of such reductions and their certification as carbon credits.

A.5. Project approval by the Parties involved:

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Approvals by the Russian and other Annex B country UNFCC Focal Points are pending.

SECTION B. Baseline

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

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The baseline for a JI project is the scenario that reasonably represents the anthropogenic emissions by source or anthropogenic emissions by sinks of GHGs that would occur in the absence of the proposed project.

The baseline of this PDD is established on a project-specific basis with respect to the requirements of the JI guidelines as specified in the *"Guidance on criteria for baseline setting and monitoring (version 01)"*. In doing so, the approved CDM baseline and monitoring methodology AM0009 *"Recovery and utilization of gas from oil wells that would otherwise be flared"* is applied in accordance with the provisions made in option 20 (a) of the JI guidelines. All explanations, descriptions and analysis related to the identification of a baseline are made following the chosen methodology.

As specified in AM0009, the baseline is selected based on legal applicability and economic analysis of alternatives. Thus, the baseline represents utilization of a technology that represents a preferred course of action taking into account barriers to investment. It will be demonstrated below that continued flaring of APG in VTOF is the baseline scenario.

The approach selected allows for a transparent determination of the baseline with regard to the choice of approaches, assumptions, parameters, data sources and key factors. Uncertainties are accounted for in accordance with AM0009, i.e. by utilizing conservative assumptions.

For the selection of a baseline scenario and demonstration and assessment of additionality, version 03 of AM0009 is applied. For the purpose of calculating and monitoring emission reductions, version 02.1 of AM0009 is applied due to the unsuitability of version 03 for this specific component.

Demonstration of applicability of the selected CDM methodology (AM0009 - version 03)*:*

The selected CDM methodology is applicable to project activities that recover and utilize associated gas that was previously flared or vented from oil wells. In addition, the JI project has to meet the following applicability conditions:

1. Associated gas at oil wells is recovered and transported to:
    a. A processing plant where dry gas, liquefied petroleum gas (LPG) and condensate are produced; and/or,
    b. An existing natural gas pipeline without processing.
2. All associated gas recovered comes from oil wells that are in operation and are producing oil at the time of the recovery of the associated gas;
3. The recovered gas and the products (dry gas, LPG and condensate) are likely to substitute in the market only the same type of fuels or fuels with a higher carbon content per unit of energy;
4. The utilization of the associated gas due to the project activity is unlikely to lead to an increase of fuel consumption in the respective market;
5. The project activity does not lead to changes (negative or positive) in the volume or composition of oil or high-pressure gas extracted at the production site;
6. Data (quantity and fraction of carbon) are accessible on the products of the gas processing plant and on the gas recovered from other oil exploration facilities in cases where these facilities supply recovered gas to the same gas processing plant;
7. No gas coming from a gas lift system is used by the project activity.

In addition, the applicability conditions included in the tools mentioned in AM0009 apply. The methodology is only applicable if the identified baseline scenario is the continuation of the current practice of either flaring or venting of the associated gas.

The proposed JI project meets all the applicability conditions in AM0009. The objective of the Verkh-Tarskoye Oilfield (VTOF) Gas Utilization project is to recover APG that is currently flared from oil wells as has been the practice since the field was commissioned. The primary change in energy utilization due to the proposed JI project activity is extraction of liquids from the gas stream and their use as a commercial and productive resource.

In particular, the JI project meets the above mentioned applicability conditions as follows:

1. APG from oil wells is recovered after each of the two stages of well-stream separation and transported to a gas processing plant (GPP) where dry gas, LPGs (SPBT and C3) and condensate (SNG) is produced;
2. All the APG recovered is produced from oil wells that are in operation at the time of recovery of the associated gas;
3. The products produced in the GPP will substitute in the market the same type of fuels or fuels with a higher carbon content per unit of energy. The products will compete with other suppliers in the domestic markets, and the small amounts added by the JI project activity will have no impact on the global markets in terms of price or inter-fuel competition. In particular, the dry gas produced will be utilized as fuel for the GPP and to meet on-site energy demand at VTOF as a substitute for APG (which has considerable higher carbon content per unit of energy). LPGs will be transported from the GPP by trucks and sold in the local market. The market size of the local market is about 400,000 tons per year. The local market comprises parts of the Omsk, Altai and Novosibirsk region, and is currently supplied by LPGs imported from other regions by railroad[13]. The LPGs sold are expected to replace part of the imported LPGs and to convert part of the car park to run on propane rather than gasoline (which has an equivalent or higher carbon content per unit of energy). SNG will be sold in the spot market and is expected to replace products with an equivalent carbon content per unit of energy;
4. The absolute amount of LPGs and condensate marketed is not significant compared to the total size of the domestic markets. Marketing of LPGs and condensate is thus not expected to lead to any increase of fuel consumption due to altering marketing conditions;
5. The proposed JI project activity will not affect the extraction of oil or high-pressure gas in VTOF. The project does not remove any constraints related to optimization of production from the field, and the value added by recovery and sale of APG to SP SGP is negligible compared to the value of oil production;
6. All data required for monitoring of the project in accordance with AM0009 will be readily available via SP SGP and NNG (upstream operator of VTOF). No other oil exploration facilities are expected to supply recovered gas to the GPP, and if this occurs in the future, data on gas recovered from such facilities will be available through installation of appropriate monitoring equipment;
7. Gas lift systems are not utilized in VTOF (which utilizes water flooding), and no gas will thus come from a gas lift system used by the project activity.

[13] LPGs are imported by railroad and trucks from Omsk, Tomsk and Irkutsk, with sources of supply located more than 1,000 km from the local market which will be supplied by the proposed JI project activity.

The application of the procedure to identify the baseline scenario and demonstrate additionality specified in AM0009 demonstrates that the identified baseline scenario is the continuation of the current practice of flaring (see analysis below and in Section B.2). The proposed JI project activity is thus found to meet all applicability conditions specified in AM0009.

Identification of the baseline scenario

AM0009 lists seven options by which associated gas is likely to be treated at oil fields. After applying the analytical steps proposed in the selected methodology to identify the baseline scenario, these options and the relevance to this project activity are:

Option 1: Release of the associated gas into the atmosphere at the oil production site (venting)

Venting of the gas in such quantities as produced at VTOF would be extremely dangerous to the workers due to the likelihood of explosion at the risk of life and property and for environmental health by inhaling methane and other gases. This option has never been considered viable for these reasons and is not considered.

Option 2: Flaring of the associated gas at the oil production site

This is the option used since the field began production in 2001 and represents the “business as usual” case. The very low value of gas in the domestic market and the costs related to processing and marketing of LPGs and condensates have always caused this option to be uneconomic from the oil field operator’s perspective. The Russian authorities impose a fine for the flaring of gas, but the payment of the fine is economically preferable to investing in any other option. In that the APG will soon be on decline and the energy needs at the field will increase, a projection of the energy balance at VTOF shows that any investments to reduce flaring are both costly and have a very short operating life, thereby being economically unattractive. As a result, this option represents the business as usual case and is considered the baseline scenario.

Option 3: On-site use of the associated gas for power production

Associated gas is used to meet the majority of on-site energy demand at VTOF. About 30 % of the APG produced is currently required as fuel for on-site gas fired generators and heaters, and this serves all feasible power needs[14]. Alternatives to expand the power production on-site by installing a grid-connected power plant have been considered. Given the high cost of equipment and transmission lines (remote location), the rapidly declining amount of excess gas, and the low value of produced electricity, this option is very unattractive economically and has not been considered feasible (see Annex 5 for a more detailed analysis).

Option 4: On-site use of the associated gas for liquefied natural gas production

The option to install a gas processing facility with LNG production facilities and invest in transport trucks and a re-gasification terminal has been studied. Given the limited and rapidly declining volume of APG that can be recovered and the limited net-back value of LNG the option is highly uneconomic and has previously been considered unfeasible by TNK-BP (see Annex 5 for economic analysis). At this point in time there is absolutely no rationale to install any LNG facility as all the dry gas produced in a

[14] Diesel is utilized to operate drilling rigs, but it is not feasible to replace this source of fuel by natural gas

gas processing facility will essentially be required to meet the energy requirements of the GPP and VTOF.

Option 5: Injection of the associated gas into an oil or gas reservoir

The option to re-inject APG for partial pressure maintenance has been studied both geologically and commercially. VTOF is currently subject to extensive water flooding, and natural gas is not expected to provide any value added. Capital expenditures to allow for a suitable gas injection scheme are estimated to lie in the range of 170 million USD, and the option is considered to be very unattractive by the oil field operator. This is thus not considered to be a feasible option.

Option 6: Recovery, transportation, processing and distribution of the associated gas and products thereof to end-users without being registered as a (JI) CDM project

Two alternative options to recover, transport, process and distribute the associated gas and related products have been evaluated by TNK-BP:

i. Construction of a 160 km gas pipeline and required gas treatment infrastructure for recovery and sale of APG to a power plant in Barabinsk
ii. Construction of a GPP in VTOF for recovery of APG and extraction of LPGs, condensate and dry gas. This is the proposed JI project activity.

Option 6 (i) requires significant investments in a long distance gas pipeline and gas treatment facilities (approximately 114 million USD). This option faces technical barriers associated with APG transport in the relevant climate conditions, which implies that substantial gas treatment is required prior to transportation. Given the very small amount of excess APG that can be exported over time and the limited value associated with sale of APG to Barabinskaya, this option is considered to be economically unfeasible (see Annex 5).

Option 6 (ii) is described in detail in this PDD. The project is economically unattractive for the project developer without income from sale of ERUs, and is thus considered unfeasible without being registered as a JI project activity. The economic assessment of this option is presented in detail in Section B.2.

Option 7: Recovery, transportation and utilization of the associated gas as feedstock for manufacturing of a useful product

TNK-BP has studied an option to recover APG for processing of NGLs and production of methanol on-site. This option requires installation of a gas processing plant, a methanol plant, purchase of trucks and installation of methanol related infrastructure. There are no regulatory or legal requirements that would prevent this option, but the project has a highly negative NPV and has thus been considered to be unfeasible by the project developer (see Section B.2 for more details). At this point there is no rationale to install a methanol plant as all the dry gas produced in a potential gas processing facility will essentially be required to meet the energy requirements of the GPP and VTOF and is further on rapid decline.

Summary of identification of the baseline scenario

From the seven options discussed above, the one that represents the most attractive economic course of action, is technically feasible and in compliance with the relevant legislation will be the baseline scenario. As is demonstrated in detail in Section B.2, the baseline scenario for the VTOF Gas Utilization project is to continue current practice, i.e. flaring of APG not required to meet on-site energy demand.

Explanation of methodological choices

The methodology used to determine the emission reductions resulting from this JI project activity is that contained in the approved CDM methodology “Recovery and utilization of gas from oil wells that would otherwise be flared”, AM0009 (Version 02.1). The reason for utilizing AM0009 version 02.1 rather than the more recent AM0009 version 03 is that the new version of the methodology contains formulas that results in an inaccurate determination of the emission reductions from the proposed JI project activity. This is primarily a result of the way the new version calculates fugitive emissions and how all produced products (dry gas, LPGs and condensate) are implicitly assumed to be used for productive purposes, rather than monitoring the extent to which these are put into productive use. All references to AM0009 in the calculations below are made to version 02.1 of this document.

Project Area

The project is located in close proximity to the Verkh-Tarskoye Oilfield (VTOF), which is the supplier of APG to the GPP. VTOF is one of the new TNK-BP fields located in the northern part of Novosibirsk region, in the South of Western Siberia. The field was discovered in the 1970s, and 14 exploratory wells were drilled by 1974. The fist development well (well #111) was drilled in 2000, and the field began production in 2001. The field is still undergoing development and additional wells are being added over time[15]. All current and future associated gas production within this specific concession area is considered within the project activity. The APG production from Maloicheskoe oil field is also considered as a potential source of supply to the GPP which will result in reductions of GHG emissions as a result of APG recovery, but this is only a possibility as proved reserves of APG at Maloicheskoe do not now justify any connection.

The JI project infrastructure will be built within the VTOF concession area adjacent to the Central Processing Facilities (approx. 500 meters away). The gas pipelines to transfer the APG from the points of flaring to the GPP and the GPP itself are all located within the concession area.

The physical design of the project allows for the straightforward application of AM0009. The project boundary is defined in Section A.4.1 and B.3.

Definition of Project Activity

The project activity encompasses the recovery of associated petroleum gases from VTOF and transport to and processing in a new GPP built and operated by TNK-BP. Specifically the infrastructure consists of:

- the connection of the gas from the CPF (LP and HP flare systems at the CPF) to the gas processing plant
- the gas processing plant
- the connection of the GPP to the power generation units at VTOF (GPPU)
- the connection of the GPP to the oil pipeline (for preliminary heavy condensate extraction)[16]

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[15] By the time of the completion of the ongoing drilling program VTOF well count will be 268 wells, including 145 producing wells and 123 injectors. All production wells are based on artificial lift (ESP).

[16] This recovery of heavy condensates is not measured as a beneficial use of recovered gas, and is not explicitly included in the project boundary.

The reduction of flaring by extraction and marketing of liquids from the APG is the mean by which GHG emissions are reduced. The JI project activity is illustrated in Figure 3

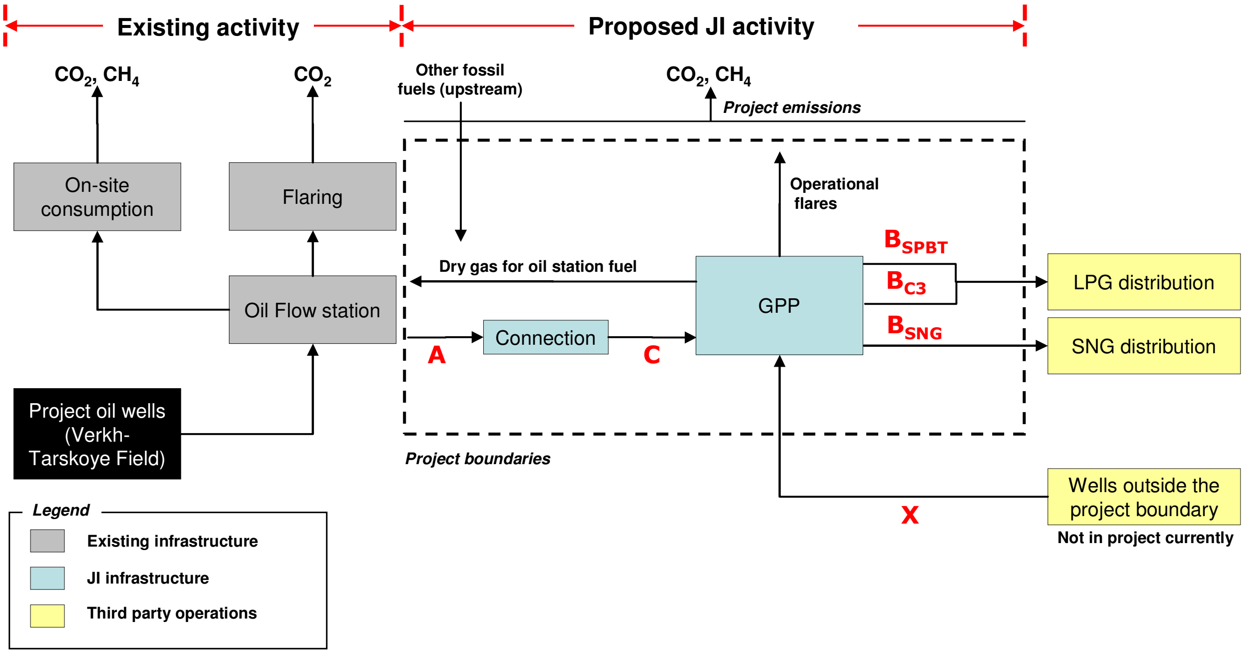

Figure 3: Illustration of the project boundary

Projection and adjustment of baseline and project emissions

Baseline emissions are based on the quantity of gas recovered as measured at the in-take of the gas at the Gas Processing Plant (Point A in Figure 3). (If there are more than one in-take points, all will be metered). This gas is precisely the gas that would be flared (and at this location) absent this project. The quantity of recovered gas is directly linked to the oil production. The associated gas production forecast in this PDD is based on TNK-BP's reservoir engineering studies and is directly related to the oil production vis-à-vis a gas-to-oil ratio of the oil produced.

The production of associated gas is estimated to grow along with the increase in oil production, reaching a maximum level of about 256 MMCM in 2009. The oil field (and thus the APG) is then expected to enter a natural decline, with APG production reducing to approximately 99 MMCM in 2015 (see Section E.1). While forecasts are used in the PDD, the quantity and composition of the recovered gas are monitored ex-post and baseline and project emissions are actual reductions that are monitored as described in the monitoring plan. The project emissions are those that occur in the infrastructure built for this project by the project developer and under his control.

Please refer to Figure 3 for the Points A, B, C and X referred to in this PDD. These points are as defined in AM0009.

Baseline Emissions

The baseline emissions are those that would occur from the flaring of the APG absent this project activity.

The Verkh-Tarskoye Oilfield utilizes modern low-pressure and high-pressure flares at the flow station where flaring of APG currently occurs. Flaring is often conducted under sub-optimal combustion conditions and part of the gas is not combusted, but released as methane and other volatile gases. However, measurement of the quantity of methane released from flaring is difficult and in this instance not considered significant enough to justify inclusion. Hence, for the purpose of determining baseline emissions, it is assumed that all carbon in the gas is converted into carbon dioxide. This is a conservative estimate.

As all flaring is done at the oil flow stations, the reduction in gas flaring is quite straightforward. The mass of carbon in the APG entering the GPP via the gas pipeline is equivalent to the carbon that would have been released as CO_2 through flaring of APG absent this project activity.

Sources of project emissions

The following sources of project emissions are accounted for in AM0009:

- CO_2 emissions due to fuel combustion for recovery, transport and processing of the gas (on-site power);
- CO_2 emission due to consumption of other fuels in place of the recovered gas (substitution);
- CH_4 and CO_2 emissions from leaks, venting and flaring during the recovery, transport and processing of recovered gas.

These emission sources are all under the control of the project participants and are contained within the project boundary. It should be noted that in AM0009, the gas transmission and the gas processing plant are separate and distant facilities and therefore the calculations adjust for gas not involved in the flare reduction. In this project activity however, the connection between the oil processing and gas processing plants, and the gas processing plant and all other facilities, are built specifically for the gas from the flare reduction activity. While this implies that some of the variables in the AM0009 calculations are zero in this instance, these calculations are still accurate and are maintained as is. This allows for gas not related to this project to utilize the gas processing facility at some future date.

CO_2 Emissions

The calculation for the CO_2 emissions from on-site fuel combustion, leaks, flaring and venting during transport and processing of recovered gas are calculated by equations 1, 2, 3, and 4 in AM0009. In essence carbon is tracked from Point A (entry of the gas into the project activity) through Point B (the exit of the liquids from the gas processing facility. The calculations are based on the volume of the entering and leaving stream into the project activity and the carbon content of the gas and liquids at the entry and exit points, over the time interval.

It should be noted that currently wet gas (APG) is used for on-site power in VTOF (GPPU). Once the GPP is completed, a connection will take dry gas to the power generating units (GPPU) to replace the wet gas[17]. This connection will be taken from the GPP before point B so as to ensure correct determination of the emission reductions.

[17] In essence, the current power supply of wet gas at the oil flow station will be replaced with dry gas that is somewhat lower in carbon content.

As noted previously, all gas is from the project activity[18] and therefore all variables related to Point X are zero at this time. Nevertheless the formula is maintained in case gas from outside the project activity is processed at this gas processing plant at some future date.

CO_2 emission due to consumption of other fuels in place of the recovered gas (substitution)

The new GPP will utilize dry natural gas produced in the facility as fuel for the gas turbines and furnaces. Emissions caused by this consumption of dry gas are taken into account in the carbon mass balance described in the previous paragraph as dry gas used for this purpose is taken out before measurement at point B. The gas power piston units (GPPU) in VTOF providing the overall oilfield with energy is currently utilizing 1st stage APG as a fuel. After implementation of the project activity, dry gas will be sent from the GPP to the GPPU to provide energy for the oil field. This consumption of dry gas is taken out before point B, and is thus also included in the carbon mass balance described above. As the amount of dry gas available from the GPP for fuel to the GPPU is forecasted to be less than the amount of energy required to provide VTOF with energy in the future (expected to occur from 2011 onwards), it is expected that another source of fuel (diesel) will be required to run upstream generators. The amount of energy used upstream in the form of fossil fuels other than dry gas produced in the GPP will be monitored by NNG (TNK-BP) and the resulting GHG emissions will be subtracted as project emissions according to Equation 5 in AM0009.

CH_4 emissions from leaks, venting and flaring during the recovery, transport and processing of recovered gas

These emissions can occur principally at two stages within the VTOF project activity: 1) transportation lines for the gas and 2) within the GPP. The first of the stages, the transportation, is a minor portion in this project activity in that the flare points (CPF) and the GPP are in close proximity; the gas pipelines from the CPF to the GPP will be about 0.5 km in length[19]. The connection line from the GPP to the power generation units in VTOF will be about 1.0 km. As the pipelines will be relatively short, it is likely they will be seamless thus minimizing any potential emissions.

CH_4 emissions from recovery and processing of the gas

All infrastructure built for the VTOF project activity will use modern equipment and conform to international best practice. In this regard emissions during operations are expected to be very minor. Since the measurement of such emissions at each potential source is impractical, the average emission factors included in AM0009 Version 02.1 will be utilized. These emission factors are taken from the IPCC Good Practice Guidance and/or from the 1995 Protocol for Equipment Leak Emission Estimates, published by EPA. This will likely provide greater estimated emissions than would occur, but this is done under the conservative principle suggested by the Executive Board. These sources are cited by AM0009.

Upon the physical completion of the project, a complete data base of all relevant equipment installed (such as valves, pump seals, connectors, flanges, open-ended lines, etc.) will be made and the conversation factors applied. The data base will include:

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[18] This will also be the case if APG from Maloicheskoe oil field is recovered and transported to the GPP. This source of gas would if recovered be treated as gas entering at point A.

[19] It should be noted that on the PDD accompanying the AM0009 methodology, the pipeline was much longer and thus it was a more important potential source of emissions.

- The number of each type of component in a unit (valve, connector, etc.).
- The service each component is in (gas, light liquid or heavy liquid).
- The total organic compound and methane concentration of the stream, and
- The time period each component is in that service.

This data base will be maintained throughout the crediting period of the project activity.

Using this approach, methane emissions are calculated for all relevant equipment by multiplying the CH_4 concentration in the respective stream with the appropriate emission factors.

CH_4 emissions from recovery and processing of the gas are calculated based on equation 6 in AM0009:

CH_4 emissions from transport of the gas in pipelines under the normal operation condition

As noted, the pipeline system for the JI project activity comprise the gas gathering lines from the points of flaring (CPF) to the GPP and the gas pipeline for transportation of dry gas from the GPP to the power generation units upstream. No significant emissions are expected from this system due to the limited distances.

For this component, equation 7 from AM0009 is used.

CH_4 emissions from transport of the gas in pipelines when accidental event occurred

In the event of a pipeline accident, methane will be released to the atmosphere. Again because of the short length of the project pipelines, automatic cut-off valves, and that they are completely within NNG's concession area thus assuring continuous surveillance, the likelihood of any such accidental leaks are anticipated to be very small.

For this component, AM0009 version 02.1 equations 8, 9 and 10 are used to estimate any emissions from this type of event. When an accident causes gas leakage from the pipeline, the gas volume is calculated as the sum of (1) the total amount of gas flow from the time the accident occurred until gas flow was shut off, and (2) the total amount of gas remaining in the pipeline at time of shut off. In the original design of AM0009, the origin of the pipeline is at point A in Figure 3, but in this project activity the origin of the pipelines is at point B (exit of the dry gas from the GPP).

Parameters required to calculate CH_4 emissions from transport of the gas in pipelines when accidental events occurs will be monitored by NNG (TNK-BP) and collected by SP SGP as part of the monitoring plan.

Leakage

As noted in AM0009, three categories of leakage can typically occur with gas-flare reduction projects:

- CO_2 emissions due to fuel combustion for transport and processing of the gas, where the transport and processing of the gas is not under control of project participants;
- CH_4 and CO_2 emissions from leaks, venting and flaring during transport and processing of recovered gas, where the transport and processing is not under control of project participants, and
- Changes in CO_2 emissions due to the substitution of fuels or additional fuel consumption at end-users, where these effects occur.

Concerning the first two categories, all significant infrastructure related to transport and processing of the gas is under the control of the project participants and therefore fully captured in the project emissions described previously.

Concerning transportation of LPGs and SNG, it is anticipated that the produced volumes will be transported from the GPP by trucks and sold in the local market. As the volume of LPGs and SNG supplied from this project activity is not significant in relation to the domestic market size, no demand or supply impacts are anticipated.

The size of the local market is about 400,000 tons per year. The local market is defined as the market comprising parts of the Omsk, Altai and Novosibirsk region, and is currently supplied by LPGs imported at considerable distance from other regions by railroad and trucks[20]. The LPGs sold from the GPP are expected to replace part of the imported LPGs and enable conversion of part of the car park to run on propane rather than gasoline (which has an equivalent or higher carbon content per unit of energy) in line with the transport policy of the regional government.

Transport costs account for about 10-15% of the local wholesale price of imported LPGs and these costs are primarily driven by energy related costs. By significantly reducing the required transport distance of LPGs sold locally, the GHG emissions associated with transportation is expected to reduce. This is a positive leakage, but is not included for conservativeness. The significant reduction of transport related costs achieved through local marketing of processed products is an important contribution to achieve attractive net-back prices for LPGs and SNG. Without a competitive advantage in transport costs relative to other LPG suppliers, the economics of the proposed JI project activity would be even more marginal.

Based on this discussion, no significant leakage is anticipated from this project activity. Indeed should leakage occur it is likely to be positive, not negative, by reducing GHG emissions. Utilizing the principle of conservatism, the leakage for this project activity is estimated at zero.

Emission Reductions

Based on the forgoing discussion, the emission reductions for the project are straightforward and equal to the Baseline Emissions minus all Project Related Emissions and Leakage – all being converted to tons of CO_2 equivalent. As explained, leakage is assumed to be zero. Equation number 12 in AM0009 is used to determine the emission reductions.

Monitoring

As stated in the monitoring methodology of AM0009 version 02.1, the following data are needed to correctly determine the emission reductions:

- The composition and quantity of recovered gas at point A and all points X_i as well as the composition and quantity of products (LPGs and condensate) from the gas processing plant at point B;
- The quantity of gas provided to the gas processing plant at point C;
- The quantity of any additional consumption of other fossil fuels than the recovered gas;
- Based on the EPA approach in AM0009 to estimate fugitive CH_4 emissions in the gas recovery facility and the gas processing plant: The approximate methane content of streams and the

[20] LPGs are imported by railroad and trucks from Omsk, Tomsk and Irkutsk, with sources of supply located more than 1,000 km from the local market which will be supplied by the proposed JI project activity.

approximate operation time of equipment subject to leakage of CH_4 emissions in the gas recovery facility and the gas processing plant.

These data needs are met by this project activity. Indeed, care has been taken to assure that the project design and schematic for this project activity overlay that in AM0009 thereby making points A, B, and C directly equivalent. Point X is also designated in this project activity, albeit at this time, point X is equal to zero and thus does not impact the calculations, but could in the future be utilized.

Once the GPP is completed, a connection will take dry gas to the upstream power generation units (GPPU) to replace the wet gas currently consumed for upstream energy needs. Although dry gas from the GPP will be utilized to substitute wet gas upstream, the amount and composition of dry gas utilized for this purpose is not required. The processing of wet gas currently utilized upstream will increase the baseline emissions, but project emissions will be increased by the same quantity when applying AM0009 as the dry gas sent back to the oil flow station is taken out pre point B. The emission reductions can thus be calculated correctly utilizing AM0009 directly.

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:

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To demonstrate that the anthropogenic emissions of greenhouse gases are reduced below those that would have occurred in the absence of the JI project, the stepwise procedure described in AM0009 version 03 is followed. These steps are:

Step 1. Identify plausible alternative scenarios
Step 2. Evaluate legal aspects
Step 3. Evaluate the economic attractiveness of alternatives

The first two steps were carried out in Section B.1. Out of the seven alternative scenarios analyzed in Section B.1, only two plausible alternative scenarios that are in compliance with all applicable legal and regulatory requirements were identified.

TNK-BP carried out a comprehensive economic comparison of all the alternatives specified in Section B.1 in 2006 as part of a SELECT study aimed at identifying attractive options to increase utilization of APG at VTOF. The preliminary economic assessment of alternatives not studied further in this Section can be found in Annex 5. Production estimates, investment and operating costs and price assumptions used to assess the economic attractiveness of these alternatives, all aimed at complete recovery of APG currently flared on-site, have not been updated since the SELECT study was finalized. However, the study clearly illustrates the highly negative value associated with these schemes. Since the SELECT study was undertaken, the APG production forecast (declined), the implementation timing (delayed), market prices (increased) and investment costs (increased) have changed significantly. The economic assessments illustrated in Annex 5 can thus not be compared to the economics of the alternatives studied in detail in this Section.

Apart from continuation of current practice, the proposed JI project activity was found to provide the most attractive option to increase utilization of APG at VTOF. The economic attractiveness of these two alternatives has been compared to demonstrate additionality:

i. *Flaring of the associated gas at the oil production site*
ii. *The proposed JI project activity*

The figures presented below represents the most recent data available within SP SGP, NNG and TNK-BP.

The evaluation of the two plausible alternatives has been done based on generally acceptable methods and principles used within the oil and gas industry as well as the fiscal regime under which the project developer operates in Russia. The project financial returns are calculated on a project, stand alone basis, as is normal for such evaluation. The opportunity to secure project finance is under evaluation by TNK-BP, but specific financial structures and sources of finance are not known at this moment.

The continuation of current practice is used as a baseline when determining the economic attractiveness of the two alternatives, and the outcome of the economic analysis will show which of the alternatives is most economic. The economics is assessed on a Net Present Value (NPV) basis, utilizing a weighted average cost of capital of 12 % (which is TNK-BP's standard discount rate used for investment analysis).

i. Flaring of the associated gas at the oil production site (Option 2 in Section B.1)

Flaring at the oil production site is the current practice, and the economics of this alternative will not be evaluated specifically (NPV equals zero by definition). Savings related to reduced payments of flaring fees are included in the economic analysis of the alternative to continuation of current practice.

ii. The proposed JI project activity (Option 6-ii in Section B.1)

The comprehensive SELECT study carried out by TNK-BP indicated that a scheme similar to the proposed JI project activity would represent the most attractive alternative option to increase utilization of APG at VTOF. The economic assessment of this alternative has thus been revised along with changes in the design of the proposed JI project, and the analysis shown below is based on the most recent estimates available. SP SGP was set up in October 2007 to complete the project design and manage the project development. The economics presented below represent the view of the project developer (SP SGP) at the time of submission of the PDD.

The economics of the proposed JI project activity relies on the processing of APG and sale of SPBT and C3 (LPGs) and SNG (condensate), specifically:

- The LPGs and SNG will be sold to the local market. SP SGP will be responsible for production, storage and transportation of the LPGs to the local distribution centers.
- The reduction in flaring will result in a reduction of flaring fines to be paid by the operator of VTOF, NNG/TNK-BP. The economic impacts upstream are included in the economic analysis.

As will be shown below, the financial returns earned by the project developer and its owners for implementing the proposed JI project are marginal.

As identified in AM0009 the following parameters are used in calculating the financial returns:

- The overall projected gas production
- The projected quantity of gas recovered, excluding gas flared, vented or consumed on-site
- The net calorific value of the gas
- Capital expenditures for gas recovery facilities, pipelines, etc.
- Operational costs
- Any cost recovery or profit sharing agreements

In addition because of the specifics of this project, the following parameters are also used:

- The overall projected production of LPGs and condensates, based on the forecasted APG production and the material balance of the GPP
- Within the operating costs:
  - An overall amount equal to 5.2% of the capital for the operation and maintenance of the new gas related facilities
  - An annual operating expense for maintenance of trucks and fuel for the transport of LPGs and condensate
  - Net back price received by the project developer for the LPGs and condensate marketed. This net back price reflects the structure of the regional LPG market

Concerning the analysis, all costs and prices are treated in terms of 2008 USD and the analysis is done in this currency independent of any changes in real inflation or exchange rates. The prices used are the current generally accepted long-term prices within the oil and gas industry for the relevant region.

The major variables expressed in terms of 2008 USD are:

Capital expenditures (CAPEX):
Capital costs of 132.5 million USD which covers the gas gathering network, the GPP, loading station and trucks. A breakdown of CAPEX is available for validation. The fair value of the assets at the end of the assessment period has been included as a cash inflow in the final year, and is calculated based on the book value of assets at that time with a 15 year depreciation period.

Operating costs:
Operating costs of the GPP are estimated at 5.2% of capital. Fuel costs and operating costs for trucks are estimated to peak in 2012[21]. Total operating costs thus peak in 2012 and are then declining as a result of reduced export of LPGs and condensate.

Calculation of net-back prices:
The prices used in the analysis are the corporate price assumptions for TNK-BP for SNG and LPGs in the relevant region. Net-back prices are calculated from regional market price assumptions provided by ARGUS.

Reduction in fines for stationary combustion:
The implementation of the JI project activity will reduce the payment of fines for stationary combustion of gas within the oil field. Therefore the financial analysis of the project specifically includes this benefit.

The key financial indicators for the Verkh-Tarskoye Gas Utilization Project are:

Proposed JI project activity	**NPV$_{2008}$ (USD):**
Capital expenditures:	-107,600,000
Operating expenses:	-48,400,000
Revenues (SPBT, C3 and SNG):	179,100,000

[21] The emissions from consumption of fuel for truck transport are not included as project emissions as marketed products will substitute similar projects with considerable longer transport distances and thus emissions. This is as conservative measure.

Taxes (property tax, income tax, VAT payable): Upstream implications:	-28,500,000 -18,900,000
Total NPV@12%:	**-24,300,000**
IRR:	**5.9 %**

Source: SP SGP/TNK-BP

As can be seen from the table above, the financial returns earned by the project developer for implementing the proposed JI project are substantially below what is normally required for investments (12%).

A sensitivity analysis has been conducted by varying the production profile of APG, the price assumptions of processed products, operational and capital expenditures by +/- 10%. The results can be found in the table below:

Parameter name:	NPV (-10%[22])	Base case parameter value	NPV (+10%[16])
APG production forecast	-35,841,000	980.3 MMCM over the lifetime	-12,698,000
CAPEX	-11,538,000	132.5 million USD	-37,001,000
OPEX	-20,590,000	15.9 million USD in 2012	-27,949,000
SBPT, C3 and SNG prices	-35,841,000	See above	-12,698,000

While the technologies to be utilized in the proposed project are well known, there are risks associated with the physical implementation of the project. The most serious of these is associated with transportation of equipment to the site. Due to the climate conditions in the area and the standard of available infrastructure (dirt roads, bridges, etc.), heavy equipment has to be transported to the site during winter months when the ground is frozen. TNK-BP hope to be able to select a general subcontractor for construction works in 2008. Supply of equipment is expected to take 10 to 14 months, and the target is to transport parts to the site for assembly during 2009. The world market for relevant equipment (especially compressors) is tight, and a delay in delivery could imply that the project will be significantly delayed. The latest month of relatively safe climate conditions for transportation is April. Construction and assembly of equipment has to take place during summer months (impossible earlier than May and later than November).

As a result of the particular climate conditions on-site, a relatively small delay in delivery and/or assembly could lead to a significant delay in commissioning of the project. As an illustration, the NPV of the project is found to deteriorate by 11.9 million USD to minus 36.1 million USD if commissioning is delayed by one year (i.e. Q3 2011).

The sensitivity analysis above shows that the conclusion regarding the financial attractiveness is robust to reasonable variations in critical assumptions.

Baseline and additionality summary:

According to AM0009, *"the alternative scenario that is economically the most attractive course of action is considered as the baseline scenario"*. In this context, the continuation of current practice, i.e. flaring of associated gas not required to meet on-site energy demand, is found to be the most economically attractive option by TNK-BP.

Option:	Legal issues:	Economic	Conclusion:

[22] Refers to a % change in parameter value(s) applied for sensitivity analysis.

		attractiveness:	
Flaring of the gas at the oil production site	Not prohibited by law	Attractive	Most attractive course of action
On-site use of the associated gas for power production	Not prohibited by law	Highly unattractive	Not a feasible option
On-site use of the associated gas for LNG production	Not prohibited by law	Highly unattractive	Not a feasible option
Injection of the associated gas into the producing oil reservoir	Not prohibited by law	Highly unattractive	Not a feasible option
Recovery and transportation of the associated gas via pipelines to an existing GPP	Not prohibited by law	Highly unattractive	Not a feasible option
Recovery and processing of associated gas in a new GPP	Not prohibited by law	Unattractive	Not a feasible option.
Recovery and utilization of the associated gas as feedstock for methanol production	Not prohibited by law	Highly unattractive	Not a feasible option

The proposed JI project activity is evaluated as the most attractive alternative to the continuation of current practice (baseline scenario). Without revenues from sale of ERUs the project economics of this option are however unattractive, with a negative NPV of 24.3 million USD. The proposed project has an IRR (5.9%) considerably lower than the hurdle rate of the project participants (12 %)[23].

Given that the proposed JI project would not be implemented without the JI component and taking into account that the project allows for a significant reduction in GHG emissions below the baseline level, the project activity is considered to be additional.

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

>>

The project boundary encompasses all new gas related infrastructure under the control of the project developer that is constructed and relevant for this project activity (see Figure 3). Therefore it includes:

- The pipeline connections between the oil flow stations (the sites of the current flaring) and the gas processing plant
- The gas processing plant
- The gas pipelines that transports the dry gas from the GPP to the gas generators upstream

The table below presents the gases and their sources which are included in the project boundary.

	Source	Gas	Included?	Justification / Explanation
	Flaring	CO_2	Yes	Main source of emissions in baseline

[23] It is expected that the additional income from sale of ERUs will contribute to make the project economically viable for the developer.

		CH_4	No	Flaring does not achieve complete oxidation, so that some CH_4 is released in the atmosphere. As in AM0009, the flare efficiency is assumed to be 100%, and no CH_4 emitted. This is a conservative assumption.
		N_2O	No	Assumed negligible
Project Activity	Fuel consumption by gas processing facilities and upstream generators	CO_2	Yes	Emissions from natural gas (or any other fossil fuel) used in these facilities
		CH_4	Yes	Minor leakages can occur at valves and flanges within the facility
		N_2O	No	Assumed negligible
	Fugitive Emissions from Gas Pipelines	CO_2	No	Assumed negligible
		CH_4	Yes	Fugitive emissions can occur at valves and flanges in the pipeline
		N_2O	No	Assumed negligible
	Fugitive Emissions from accidents	CO_2	No	Assumed negligible
		CH_4	Yes	Fugitive emissions can occur if there is a pipeline failure
		N_2O	No	Assumed negligible

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

>>

Carbon Limits is the entity determining the baseline and participating in the project as JI developer. The baseline calculations are based on the most recent data available. The baseline development was finalized June 09, 2008. The person in charge of its development is:

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Please see Annex 2 for further details on baseline development.

SECTION C. Duration of the project / crediting period

C.1. Starting date of the project:

>>

The definition of the start date of the project activity is according to the definition determined in EB 33 *"the dates at which the implementation or construction or real action of the project activity begins"*.

The proposed JI project is currently in TNK-BP's DEFINE stage, and SP SGP was set up in October 2007 to finalize the design and manage the project development. The only action taken so far is site preparation, i.e. land reclamation. Ordering of equipment and construction is estimated to start in mid-

2008. If the project is developed according to the current schedule, the gas processing plant is estimated to be commissioned in October 2010.

C.2. Expected operational lifetime of the project:

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Given the rapidly declining volumes of associated gas that will be produced at VTOF, the project activity has a limited economical lifetime. Based on current production forecasts, the gas processing plant may be commercially operated for a period of 5 to 6 years. In 2015-2016 the energy balance at VTOF is expected to reach a point where it is no longer attractive to operate the GPP to recover and process associated petroleum gas.

C.3. Length of the crediting period:

>>
The starting date of the crediting period for the JI project is set to 01 October 2010. The end of the first crediting period (taking into account the first commitment period of the Kyoto Protocol which is determined as the possible period of generation of ERUs under JI projects) is the end of 2012 and the end of the second crediting period is 30 September 2020. Thus, the length of the two crediting periods is 10 years and the entire period during which emission reductions are generated is 120 months.

Emission Reduction Units generated for the period after the first commitment period of the Kyoto Protocol (2008 to 2012) is pending on any relevant agreement under the UNFCCC and approval by the Russian Federation.

SECTION D. Monitoring plan

D.1. Description of monitoring plan chosen:

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The monitoring methodology for this project activity is that contained in the approved methodology used for this project activity, "Recovery and utilization of gas from oil wells that would otherwise be flared", AM0009 (Version 02.1).

As is clearly stated, this methodology should be used in "conjunction with the approved baseline methodology AM0009 (Version 02.1), "Recovery and utilization of gas from oil wells that would otherwise be flared".

Further the physical design of the project allows for the straightforward application of this methodology. As stated in the monitoring methodology the following data are needed:

- The composition and quantity of recovered gas at point A and all points X_i as well as the composition and quantity of products (dry gas, LPGs and condensate) from the gas processing plant at point B;
- The quantity of gas provided to the gas processing plant at point C;
- The quantity of any additional consumption of other fossil fuels than the recovered gas, both for the operation of the GPP and the oil field;
- Based on the EPA approach in AM0009 to estimate fugitive CH_4 emissions in the gas recovery facility and the gas processing plant: The approximate methane content of streams and the approximate operation time of equipment subject to leakage of CH_4 emissions in the gas recovery facility and the gas processing plant.

All these four data needs are met by this project activity. Indeed, care has been taken to assure that the project design and schematic for this project activity overlay that in AM0009 thereby making points A, B, and C directly equivalent. Point X is also designated in this project activity, albeit at this time, point X is equal to zero and thus does not impact the calculations, but could in the future be utilized.

Once the GPP is completed, a connection will take dry gas to the on-site gas generators to replace the wet gas currently consumed for on-site needs. Although dry gas from the GPP will be utilized to substitute wet gas at the oil flow station, the amount and composition of dry gas utilized for this purpose is not required. The processing of wet gas currently utilized in the oil flow station will increase the baseline emissions, but project emissions will be increased by the same quantity when applying AM0009 as the dry gas sent back to the oil flow station is taken out pre point B. As the project activity does not comprise any external marketing of dry gas, the amount of dry gas at point B will in essence be zero throughout the crediting period and no flow meter will be installed for this product. The emission reductions can thus be calculated correctly utilizing AM0009 directly.

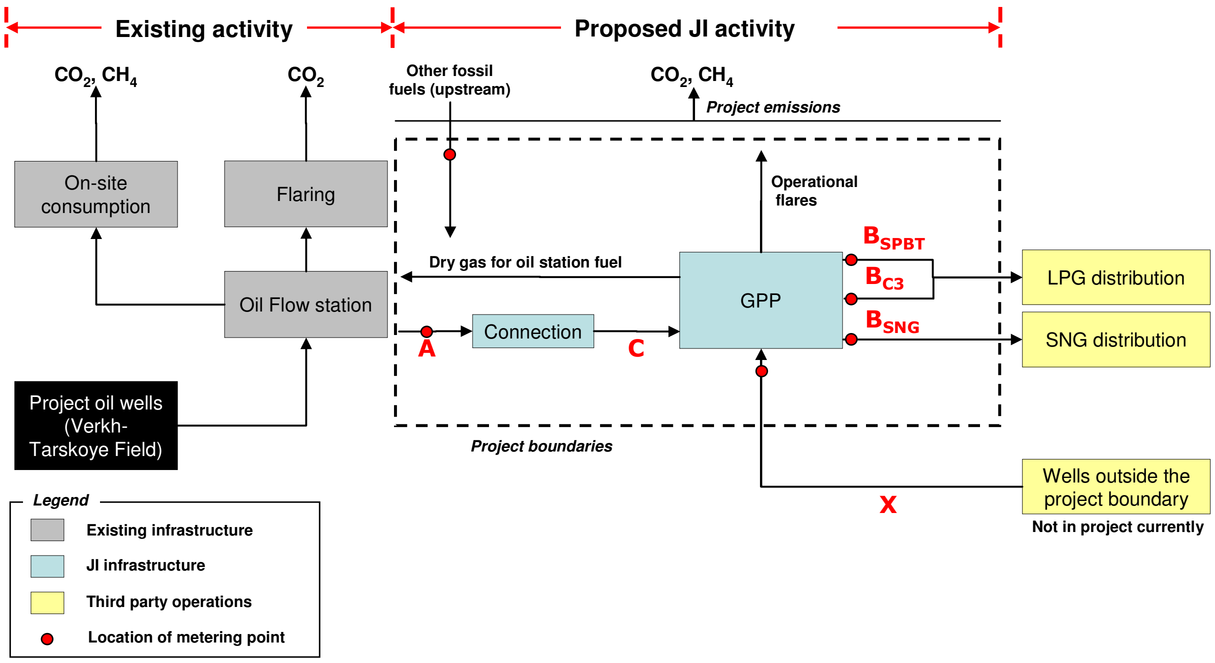


Figure 4: Physical layout of monitoring points

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	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment
1.	$V_{A,y}$	*Flow meter*	*m3*	*m*	*Continuous*	*All*	*Electronic and paper*	

2.	$w_{carbon,A,y}$	*Composition analysis at point A*	*kgC/m3*	*m*	*Sampled monthly*	*Sampled*	*Electronic and paper*	
3.	$V_{dry-gas,B,y}$	*No monitoring required*	*m3*	*m*	*Continuous*	*All*	*Electronic and paper*	*Will be zero throughout the crediting period*
4.	$w_{carbon,dry-gas,B,y}$	*Composition analysis at outlet of GPP*	*kgC/m3*	*m*	*Sampled monthly*	*Sampled*	*Electronic and paper*	*Dry gas composition is sampled at the GPP outlet*
5.	$m_{SPBT,B,y}$	*Liquefied gas metering at point* B_{LPG}	*kg*	*m*	*Continuous*	*All*	*Electronic and paper*	*Amount of SPBT produced by the GPP*
6.	$w_{carbon,SPBT,B,y}$	*Composition analysis at outlet of GPP*	*kgC/kg*	*m*	*Sampled monthly*	*Sampled*	*Electronic and paper*	
7.	$m_{C3,B,y}$	*Liquefied gas metering at point* B_{LPG}	*kg*	*m*	*Continuous*	*All*	*Electronic and paper*	*Amount of* C_3 *produced by the GPP*
8.	$w_{carbon,C3,B,y}$	*Composition analysis at outlet of GPP*	*kgC/kg*	*m*	*Sampled monthly*	*Sampled*	*Electronic and paper*	
9.	$m_{condensate,B,y}$	*Flow meter at point* B_{cond}	*kg*	*m*	*Continuous*	*All*	*Electronic and paper*	
10.	$w_{carbon,condensate,B,y}$	*Composition analysis at outlet of GPP*	*kgC/kg*	*m*	*Sampled monthly*	*Sampled*	*Electronic and paper*	
11.	$V_{Xi,y}$	*Flow meter if required*	*m3*	*m*	*Continuous*	*All*	*Electronic and paper*	*No other sources of gas is expected to deliver to the GPP*
12.	$w_{carbon,Xi,y}$	*Composition analysis at point X*	*kgC/m3*	*m*	*Sampled monthly*	*Sampled*	*Electronic and paper*	*No monitoring required until additional gas is processed*
13.	$m_{fuel,y}$	*Quantity of other fossil fuels used due to PA*	*Kg*	*m*	*Continuous*	*All*	*Electronic and paper*	
14.	NCV_{fuel}	*Standards from suppliers or IPCC*	*KJ/kg*	*m*	*Estimated*	*Standard or sample*	*Electronic and paper*	*Supply data preferred, alternatively IPCC standards*
15.	$EF_{CO2,fuel}$	*Standards from suppliers or IPCC*	*kg* CO_2*/KJ*	*m*	*Estimated*	*Standard or sample*	*Electronic and paper*	*Supply data preferred, alternatively IPCC standards*
16.	GWP_{CH4}	*IPCC, Third Assessment Report*	-	*m*	*Estimated*	*Standard*	*Electronic and paper*	*21 (Standard value chosen as determined by the IPCC)*
17.	$w_{CH4,A,y}$	*Composition analysis at point A*	*kg*CH_4*/kg*	*m*	*Sampled monthly*	*Sampled*	*Electronic and paper*	*Measured in conjunction with* $w_{carbon,A,y}$
18.	$EF_{equipment}$	*Emission factor of GPP*	*kg*CH_4*/hr*	*m*	*Estimated*	*All*	*Electronic and paper*	*Average emission factor for equipment installed (P&I)*

19.	$EF_{pipeline}$	*Emission factor of gas pipelines*	*kgCH$_4$/hr*	*m*	*Estimated*	*All*	*Electronic and paper*	*Average emission factor for equipment installed (P&I)*
20.	$T_{equipment}$	*Operating time of the GPP*	*hr*	*m*	*Continuous*	*All*	*Electronic and paper*	*8760 hr minus downtime of the plant in each year*
21.	$T_{pipeline}$	*Operating time of the pipeline(s)*	*hr*	*m*	*Continuous*	*All*	*Electronic and paper*	*8760 hr minus downtime of the pipeline in each year*
22.	$w_{CH4,pipeline}$	*Composition analysis at outlet of GPP*	*kgC/m3*	*m*	*Sampled monthly*	*Sampled*	*Electronic and paper*	*Dry gas composition is sampled at the GPP outlet*
23.	t_1 and t_2	*Time of accidental pipeline release*	*Seconds*	*m*	*Continuous*	*All*	*Electronic and paper*	*Calculated by monitoring the pressure drop in the pipeline. t_1 is the time the pressure drop occurs, t_2 is the time at which the upstream and downstream valves are closed*
24.	F	*Flow rate of gas out from the GPP*	*m3/sec*	*m*	*Continuous*	*All*	*Electronic and paper*	*Regularly calibrated flow meter at the outlet of the GPP*
25.	d	*Radius of the pipeline(s)*	*meters*	*m*	*Measured once before start-up*		*Electronic and paper*	*Data derived from P&I diagrams once before start-up*
26.	π	*Standard value*	*-*	*m*	*Estimated*	*Standard*	*Electronic and paper*	*3.1416 (On-line encyclopedia of integer sequences)*
27.	L	*Length of pipeline(s)*	*meters*	*m*	*Measured once before start-up*	*All*	*Electronic and paper*	*Data derived from P&I diagrams once before start-up*
28.	P_P and P_S	*Monitoring of gas pressure in pipelines*	*atm*	*m/e*	*Continuous*	*All*	*Electronic and paper*	*Pressure measured when up- and downstream valves are closed. Standard pressure 1 atm.*
29.	T_P and T_S	*Monitoring of gas temperature in pipelines*	*K*	*m/e*	*Continuous*	*All*	*Electronic and paper*	*Temperature measured when up- and downstream valves are closed. Standard temperature 273.15 K*
30.	$V_{d,accident}$	*Volume of gas supplied at point A before accident occur*	*m3*	*m*	*Continuous*	*All*	*Electronic and paper*	
31.	$V_{Xi,d,accident}$	*Volume of gas*	*m3*	*m*	*Continuous*	*All*	*Electronic*	

		supplied from all sources to GPP before accident occur					*and paper*	

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

>>

Sources of project emissions

The following sources of project emissions are accounted for in AM0009:

- CO_2 emissions due to fuel combustion for recovery, transport and processing of the gas (on-site power);
- CO_2 emission due to consumption of other fuels in place of the recovered gas (substitution);
- CH_4 and CO_2 emissions from leaks, venting and flaring during the recovery, transport and processing of recovered gas.

These emission sources are all under the control of the project participants and are contained within the project boundary. It should be noted that in AM0009, the gas transmission and the gas processing plant are joint facilities and therefore the calculations adjust for gas not involved in the flare reduction. In this project activity however, the connection between the oil processing and gas processing plants, and the gas processing plant and all other facilities, are built specifically for the gas from the flare reduction activity. While this implies that some of the variables in the AM0009 calculations are zero in this instance, these calculations are still accurate and are maintained as is. This allows for gas not related to this project to utilize the gas processing facility at some future date.

CO_2 Emissions

The calculation for the CO_2 emissions from on-site fuel combustion, leaks, flaring and venting during transport and processing of recovered gas are calculated by equations 1, 2, 3, and 4 in AM0009. In essence carbon is tracked from Point A (entry of the gas into the project activity) through Point B (the exit of the liquids from the gas processing facility. The calculations are based on the volume of the entering and leaving stream into the project activity and the carbon content of the gas (and liquids) at the entry and exit points, over the time interval.

It should be noted that currently wet gas (APG) is used for on-site power in VTOF. Once the GPP is completed, a connection will take dry gas to the power generating units on site to replace the wet gas[24]. This connection will be taken from the GPP before point B so as to ensure correct determination of the emission reductions.

As noted previously, all gas is from the project activity and therefore all variables related to Point X are zero at this time. Nevertheless the formula is maintained in case gas from outside the project activity is processed at this gas processing plant at some future date.

The calculation of CO_2 emissions from on-site fuel combustion, leaks, flaring and venting during transport and processing of recovered gas are calculated by equations 1, 2, 3, and 4 in AM0009. As two types of LPG will be produced by the GPP (GOST 20448-90 and TU 38-101490-79), each stream will be monitored separately.

(1) $$PE_{CO2,gas,y} = \frac{m_{carbon,A,y}}{m_{carbon,A,y} + m_{carbon,X,y}} \cdot (m_{carbon,A,y} + m_{carbon,X,y} - m_{carbon,B,y}) \cdot \frac{44}{12} \cdot \frac{1}{1000}$$

With:

(2) $$m_{carbon,A,y} = V_{A,y} \cdot w_{carbon,A,y}$$

(3) $$m_{carbon,B,y} = V_{dry-gas,B,y} \cdot w_{carbon,dry-gas,B,y} + m_{SPBT,B,y} \cdot w_{carbon,SPBT,B,y} + m_{C3,B,y} \cdot w_{carbon,C3,B,y} + m_{condensate,B,y} \cdot w_{carbon,condensate,B,y}$$

(4) $$m_{carbon,X,y} = \sum_i V_{Xi,y} \cdot w_{carbon,Xi,y}$$

Where:

$PE_{CO2,gas,y}$	CO_2 emissions from the project activity due to combustion, flaring or venting of recovered gas during the period y, in tons of CO_2
$m_{carbon,A,y}$	Quantity of carbon in the recovered gas from the project area at point A in Figure 4 during the period y, in kg C

[24] In essence, the current power supply of wet gas at the oil flow station will be replaced with dry gas that is somewhat lower in carbon content.

$m_{carbon,B,y}$	Quantity of carbon in the products (LPG and naphtha) leaving the gas processing plant at point B in Figure 4 during the period y, in kg C
$m_{carbon,X,y}$	Quantity of carbon in recovered gas from other oil wells at all points X_i in Figure 4 during the period y, in kg C
$V_{A,y}$	Volume of gas recovered at point A in Figure 4 during the period y, in m^3
$V_{dry-gas,B,y}$	Volume of dry gas that is produced in the gas processing plant measured at point B in Figure 4 during the period y, in m^3
$m_{SPBT,B,y}$	Quantity of SPBT (GOST 20448-90) that is produced in the gas processing plant at point B in Figure 4 during the period y, in kg
$m_{C3,B,y}$	Quantity of C_3 (TU 38-101490-79) that is produced in the gas processing plant at point B in Figure 4 during the period y, in kg
$m_{condensate,B,y}$	Quantity of naphtha that is produced in the gas processing plant at point B in Figure 4 during the period y, in kg
$V_{Xi,y}$	Volume of gas recovered from oil well *i* at point X in Figure 4 during the period y, in m^3
$w_{carbon,A,y}$	Average carbon content of wet gas at point A in Figure 4, in kgC/m^3
$w_{carbon,dry-gas,B,y}$	Average carbon content of dry gas (GOST 5542-78) at point B in Figure 4, in kgC/m^3
$w_{carbon,SPBT,B,y}$	Average carbon content of SPBT (GOST 20448-90) at point B in Figure 4, in kgC/kg
$w_{carbon,C3,B,y}$	Average carbon content of C_3 (TU 38-101490-79) at point B in Figure 4, in kgC/kg
$w_{carbon,condensate,B,y}$	Average carbon content of naphtha at point B in Figure 4, in kgC/kg
$w_{carbon,Xi,y}$	Average carbon content of the gas recovered from oil well *i* at point X in Figure 4 during the period y, in kgC/m^3

CO_2 emission due to consumption of other fuels in place of the recovered gas (substitution)

The new GPP will utilize dry natural gas produced in the facility as fuel. Emissions from this consumption is taken into account in the material balance in Equation 2 above, as dry gas used for this purpose is taken out before point B. The gas power piston units (GPPU) providing the overall oilfield with energy is currently utilizing 1st stage APG as a fuel. After implementation of the project activity, dry gas will be sent from the GPP to the GPPU to provide energy for the oil field. This consumption of dry gas is taken out before point B, and is thus included in Equation 2 above. As the amount of dry gas available from the GPP for fuel to the GPPU is expected to be less than the amount of energy required to run the GPPU after some years, it is expected that another source of fuel (diesel) will be required to run the upstream generators. It is however likely that this happens after the end of the crediting period. The amount of energy used in the GPPU in the form of fossil fuels other than dry gas produced in the GPP will be monitored and the resulting GHG emissions will be subtracted as project emissions according to Equation 6 below.

Should other fuels be used in place of gas in the GPPU or the GPP, equation 5 from AM0009 will be used to calculate project emissions:

(5) $$PE_{CO2,other-fuels,y} = \frac{1}{1000} \cdot \sum_{fuels} m_{fuel,y} \cdot NCV_{fuel} \cdot EF_{CO2,fuel}$$

Where:

$PE_{CO2,other-fuels,y}$ CO_2 emissions due to consumption of other fuels than the recovered gas due to the project activity during the period y, in tons of CO_2

$m_{fuel,y}$ Quantity of a specific fuel type that is consumed due to the project activity during the period y, in kg

NCV_{fuel} Net calorific value of the respective fuel type, in KJ/kg

$EF_{CO2,fuel}$ CO_2 emission factor of the respective fuel type, in kg CO_2/KJ

CH_4 emissions from leaks, venting and flaring during the recovery, transport and processing of recovered gas

These emissions can occur principally at two stages within the VTOF project activity: 1) transportation lines for the gas and 2) within the GPP. The first of the stages, the transportation, is a minor portion in this project activity in that the flare points and the GPP are in close proximity; therefore the gas pipelines from the CPF to the GPP will be about 0.5 km in length[25]. The connection line from the GPP to the power generation units (GPPU) will be about 1.0 km. As the pipelines will be relatively short, it is likely they will be seamless thus minimizing any potential emissions.

CH_4 emissions from recovery and processing of the gas

All infrastructure built for the VTOF project activity will use modern equipment and conform to international best practice. In this regard emissions during operations are expected to be very minor. Since the measurement of such emissions at each potential source is impractical, the average emission factors included in AM0009 will be utilized. These emission factors are taken from the IPCC Good Practice Guidance and/or from the 1995 Protocol for Equipment Leak Emission Estimates, published by EPA. This will likely provide greater estimated emissions than would occur, but this is done under the conservative principle suggested by the Executive Board. These sources are cited by AM0009.

[25] It should be noted that on the PDD accompanying the AM0009 methodology, the pipeline was much longer and thus it was a more important potential source of emissions.

Upon the physical completion of the project, a complete data base of all relevant equipment installed (such as valves, pump seals, connectors, flanges, open-ended lines, etc.) will be made and the conversation factors applied. The data base will include:

- The number of each type of component in a unit (valve, connector, etc.).
- The service each component is in (gas, light liquid or heavy liquid).
- The total organic compound and methane concentration of the stream, and
- The time period each component is in that service.

This data base will be maintained throughout the crediting period of the project activity.

Using this approach, methane emissions are calculated for all relevant equipment by multiplying the CH_4 concentration in the respective stream with the appropriate emission factors.

CH_4 emissions from recovery and processing of the gas are calculated based on equation 6 in AM0009:

(6) $$PE_{CH4,plants,y} = GWP_{CH4} \cdot \frac{1}{1000} \cdot \sum_{equipment} w_{CH4,A,y} \cdot EF_{equipment} \cdot T_{equipment}$$

Where:

$PE_{CH4,plants,y}$	CH_4 emissions from the project activity at the gas processing plant during the period y, in tons of CO_{2e}
GWP_{CH4}	The approved Global Warming Potential for methane
$w_{CH4,A,y}$	Average methane weight fraction of recovered gas, in kg-CH_4/kg
$EF_{equipment}$	The appropriate emission factor from Table 1 below, in kg/hour/equipment
$T_{equipment}$	The operating time of the equipment, in hours (in absence of further information, the monitoring period could be used as a conservative approach)

For the purpose of calculating the appropriate emission factor in Equation 8, the table extracted from the EPA protocol presented in AM0009 will be used (see Table 1 below).

Table 1: Oil and natural gas production average emission factors

Equipment Type	Service	Emission Factor (EF) (kg/hour/equipment item) for TOC
Valves	Gas	4.5E-3
Pump seals	Gas	2.4E-3
Others*	Gas	8.8E-3
Connectors	Gas	2.0E-4
Flanges	Gas	3.9E-4
Open-ended lines	Gas	2.0E-3

TOC: Total Organic compound
Source: US EPA-453/R-95-017 Table 2.4, page 2-15
*"Other" equipment type was derived from compressors, diaphragms, drains, dump arms, hatches, instruments, meters, pressure relief valves, polished rods, relief valves and vents. This "other" equipment type should be applied for any equipment type other than connectors, flanges, open-ended lines, pumps or valves.

CH_4 emissions from transport of the gas in pipelines under the normal operation condition

As noted, the pipeline system for the VTOF project activity comprise the gas gathering lines from the points of flaring to the GPP and the gas pipeline for transportation of dry gas from the GPP to the power generation units. No significant emissions are expected from this system due to the limited distances.

For this component, equation 7 from AM0009 is used:

(7) $$PE_{CH4,pipeline,y} = GWP_{CH4} \cdot \frac{1}{1000} \cdot \sum_{equipment} w_{CH4,pipeline} \cdot EF_{pipeline} \cdot T_{pipeline}$$

Where:

$PE_{CH4,pipeline,y}$ CH_4 emissions from the project activity during the transportation of the gas in pipelines under normal operating during the period y, in tons of CO_{2e}

GWP_{CH4}	The approved Global Warming Potential for methane
$w_{CH4,pipeline,y}$	Average methane weight fraction in the pipeline, in kg-CH_4/kg
$EF_{equipment}$	The appropriate emission factor from Table 1, in kg/hour/pipeline
$T_{pipeline}$	The operating time of the pipeline, in hours (in absence of further information, the monitoring period could be used as a conservative approach)

CH_4 emissions from transport of the gas in pipelines when accidental event occurred

In the event of a pipeline accident, methane will be released to the atmosphere. Again because of the short length of the project pipelines and that they are completely within the concession area thus assuring continuous surveillance, the likelihood of any such accidental leaks are anticipated to be very small.

For this component, AM0009 version 02.1 equations 8, 9 and 10 are used to estimate any emissions from this type of event. When an accident causes gas leakage from the pipeline, the gas volume is calculated as the sum of (1) the total amount of gas flow from the time the accident occurred until gas flow was shut off, and (2) the total amount of gas remaining in the pipeline at time of shut off. In the original design of AM0009, the origin of the pipeline is at point A in Figure 3, but in this project activity the origin of the pipelines is at point B (exit of the dry gas from the GPP).

Accidental release of methane from the pipeline is calculated as:

(8) $$PE_{CH4,pipeline,accident} = GWP_{CH4} \cdot \frac{1}{1000} \cdot (V_{B,accident} + V_{remain,accident}) \cdot w_{CH4,pipeline,accident}$$

With:

(9) $$V_{B,accident} = t_{accident} \cdot F = (t_2 - t_1) \cdot F$$

(10) $$V_{remain,accident} = d^2 \cdot \pi \cdot L \cdot \frac{P_P}{P_S} \cdot \frac{T_S}{T_P} \cdot \frac{V_{d,accident}}{\sum_i V_{Xi,d,accident}}$$

Where:

$PE_{CH4,pipeline,accident}$ Methane emissions from the transport pipeline due to an accidental event, in tCO_{2e}

GWP_{CH4} The approved Global Warming Potential for methane

$V_{B,accident}$ The volume of associated gas supplied to the pipeline from the time the gas leakage started until the shutdown valves were closed, in m^3

$V_{remain,accident}$ The volume of gas remaining in the pipeline after the shutdown valves have been closed, in m^3

$w_{CH4,pipeline,accident}$ The fraction of methane in the associated gas on a mass basis, in kg CH_4/kg

t_1 The time the gas leakage caused by the accident occurred, in sec

t_2 The time that the shutdown valves closed both the upstream and downstream pipeline, in sec

F The flow rate of gas supplied from the GPP at point B in Figure 3, in m^3/sec

d The radius of the pipeline, in meters

π The ratio of the circumference of a circle to its diameter

L The length of the pipeline, in meters

P_P The pressure in the pipeline when the shutdown valves close both the upstream and downstream of the pipeline, in atm

P_S Standard pressure, in atm

T_P The temperature in the pipeline when the shutdown valves close both the upstream and downstream of the pipeline, in K

T_S Standard temperature, in K

$V_{d,accident}$ The volume of associated gas supplied to the pipeline at point A in Figure 3 before the accident occurs during the period, in m^3

$V_{Xi,d,accident}$ The volume of gas supplied to the pipeline from all sources before the accident occurs during the period, in m^3

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

1.	$V_{A,y}$	*Flow meter*	*m3*	*m*	*Continuous*	*All*	*Electronic and paper*	
2.	$w_{carbon,A,y}$	*Composition analysis at point A*	*kgC/m3*	*m*	*Sampled monthly*	*Sampled*	*Electronic and paper*	

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 emissions are calculated based on equation 11 in AM0009:

(11) $$BL_y = \frac{44}{12} \cdot \frac{1}{1000} \cdot V_{A,y} \cdot w_{carbon,A,y}$$

Where:

BL_y Baseline emissions in year y, in tCO_2
$V_{A,y}$ Volume of APG recovered at point A in Figure 4 during the period y, in m^3
$w_{carbon,A,y}$ Average carbon content of wet gas at point A in Figure 4, in kgC/m^3

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

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

ID number *(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

>>
Not applicable.

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

>>
Not applicable.

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

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

ID number *(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

>>
Not applicable.

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

>>
Not applicable.

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

>>
Equation 12 in AM0009 is used to determine the emission reduction:

(12)
$$EF_y = BL_y - PE_{CO2,gas,y} - PE_{CO2,other-fuels,y} - PE_{CH4,plants,y} - PE_{CH4,pipeline,y} - PE_{CH4,pipeline,accident}$$

Where:

EF_y	Emission reductions of the project activity during the period y, in tons of CO_{2e}
BL_y	Baseline emissions in year y, in tCO_2
$PE_{CO2,gas,y}$	CO_2 emissions from the project activity due to combustion, flaring or venting of recovered gas during the period y, in tons of CO_2
$PE_{CO2,other-fuels,y}$	CO_2 emissions due to consumption of other fuels than the recovered gas due to the project activity during the period y, in tons of CO_2
$PE_{CH4,plants,y}$	CH_4 emissions from the project activity at the gas recovery facility and the gas processing plant during the period y, in tons of CO_{2e}
$PE_{CH4,pipeline,y}$	CH_4 emissions from the project activity during the transportation of the gas in pipelines under normal operating during the period y, in tons of CO_{2e}
$PE_{CH4,pipeline,accident}$	Methane emissions from the transport pipeline due to an accidental event, in tCO_{2e}

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:

>>
Not applicable.

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

Data *(Indicate table and ID number)*	Uncertainty level of data (high/medium/ low)	Explain QA/QC procedures planned for these data, or why such procedures are not necessary.
D.1.1.1 – 1 *D.1.1.3 – 1*	*Medium (+/-5%)*	*This parameter is continuously monitored from the flow meter and controlled by electronic systems. Calibration and maintenance are executed according to national and manufacturer norms. Cross check via mass balance calculations for GPP.*
D.1.1.1 – 2 *D.1.1.3 - 2*	*Medium*	*The gas is sampled using chromatography and is most likely analyzed within the labs of Tomsk scientific research and project institute of oil and gas (TomskNIPIneft). Laboratory procedures, norms, certifications and standards are within national regulations. Data could be compared with historical records.*
D.1.1.1 – 3	*Low*	*No dry gas will be exported from the GPP to the market (only for internal use as a substitute for APG currently utilized in GPPU and for new Rolls-Royce Ellison gas turbine power units serving the new GPP), and no monitoring it thus required.*
D.1.1.1 – 4	*Medium*	*The gas is sampled using chromatography and is most likely analyzed within the labs of TomskNIPIneft. Laboratory procedures, norms, certifications and standards asre within national regulations. Product shall meet Russian standard GOST 5542-78.*

D.1.1.1 – 5	*Low (+/- 0.25 %)*	*The data is continuously monitored from the liquid gas meter and controlled by electronic systems. Calibration and maintenance are executed according to national and manufacturer norms. Cross check via mass balance calculations for GPP and sales records*
D.1.1.1 – 6	*Medium*	*The SPBT is most likely analyzed within the labs of TomskNIPIneft. Laboratory procedures, norms, certifications and standards are within national regulations. Product shall meet Russian standard GOST 20448-90.*
D.1.1.1 – 7	*Low (+/- 0.25 %)*	*The data is continuously monitored from the liquid gas meter and controlled by electronic systems. Calibration and maintenance are executed according to national and manufacturer norms. Cross check via mass balance calculations for GPP and sales records.*
D.1.1.1 – 8	*Medium*	*The C3 most likely analyzed within the labs of TomskNIPIneft. Laboratory procedures, norms, certifications and standards are within national regulations. Product shall meet Russian standard TU 38-101490-79.*
D.1.1.1 – 9	*Low (+/- 0.25 %)*	*The data is continuously monitored from the flow meter and controlled by electronic systems. Calibration and maintenance are executed according to national and manufacturer norms. Cross check via mass balance calculations for GPP and sales records*
D.1.1.1 - 10	*Medium*	*The condensate is most likely analyzed within the labs of TomskNIPIneft. Laboratory procedures, norms, certifications and standards are within national regulations.*
D.1.1.1 – 11	*Low*	*The data will be continuously monitored from flow meters and controlled by electronic systems if additional sources of gas are processed at the GPP in the future.*
D.1.1.1 – 12	*Low*	*The gas will most likely be analyzed within the labs of TomskNIPIneft if additional sources of gas are processed at the GPP in the future. Laboratory procedures, norms, certifications and standards are within national regulations.*
D.1.1.1 – 13	*Low*	*This parameter will be continuously monitored and recorded as part of standard operations.*
D.1.1.1 – 14	*Low*	*Parameter is taken from fuel suppliers based on laboratory measurement, with procedures, norms, certifications and standards within national regulations. IPCC values used as cross check. Alternatively default values estimated by IPCC are used directly.*
D.1.1.1 – 15	*Low*	*Parameter is taken from fuel suppliers based on laboratory measurement, with procedures, norms, certifications and standards within national regulations. IPCC values used as cross check. Alternatively default values estimated by IPCC are used directly.*
D.1.1.1 – 16	*Low*	*Standard value (21) from IPCC's Third Assessment Report is used throughout the crediting period. No QA/QC required by developer.*
D.1.1.1 – 17	*Medium*	*The gas at the inlet of the GPP is sampled using chromatography and is most likely analyzed within the labs of Institute of oil chemistry in Tomsk. Laboratory procedures, norms, certifications and standards are within national regulations. Data could be compared with historical records.*
D.1.1.1 – 18	*Low*	*Equipment will be counted and the inventory is to be verified during the first verification period based on installed equipment taken from the P&I documentation.*
D.1.1.1 – 19	*Low*	*Equipment will be counted and the inventory is to be verified during the first verification period based on installed equipment taken from the P&I documentation.*
D.1.1.1 – 20	*Low*	*The operating time of the equipment installed in the GPP is determined as 8760 hours minus downtime of the plant in each year. The downtime is monitored and recorded as part of standard operations.*

D.1.1.1 – 21	*Low*	*The operating time of the pipelines is determined as 8760 hours minus downtime of the pipelines in each year. The downtime is monitored and recorded as part of standard operations.*
D.1.1.1 – 22	*Medium*	*The dry gas produced in the GPP is sampled using chromatography and is most likely analyzed within the labs of TomskNIPIneft. Laboratory procedures, norms, certifications and standards are within national regulations. Data could be compared with historical records.*
D.1.1.1 – 23	*Low*	*These parameters will be continuously monitored and recorded as part of standard operations.*
D.1.1.1 – 24	*Medium (+/-5%)*	*The data is continuously monitored from the flow meter and controlled by electronic systems. Calibration and maintenance are executed according to national and manufacturer norms.*
D.1.1.1 – 25	*Low*	*This parameter is a physical characteristic of the pipelines installed and will remain fixed throughout the crediting period. Radius is taken from P&I documents before start-up, and no QA/QC is required.*
D.1.1.1 – 26	*Low*	*A standard value of 3.1416 taken from the "On-line encyclopedia of integer sequences" is used throughout the crediting period, and no QA/QC is required.*
D.1.1.1 – 27	*Low*	*This parameter is a physical characteristic of the pipelines installed and will remain fixed throughout the crediting period. Radius is taken from P&I documents before start-up, and no QA/QC is required.*
D.1.1.1 – 28	*Low*	*This parameter will be continuously monitored and recorded as part of standard operations. Standard pressure remains constant at 1 atm, and no QA/QC is required for this parameter.*
D.1.1.1 – 29	*Low*	*This parameter will be continuously monitored and recorded as part of standard operations. Standard temperature remains constant at 273.15 K, and no QA/QC is required for this parameter.*
D.1.1.1 – 30	*Medium (+/-5%)*	*The data is continuously monitored from the flow meter and controlled by electronic systems. Calibration and maintenance are executed according to national and manufacturer norms.*
D.1.1.1 – 31	*Medium (+/-5%)*	*The data is continuously monitored from the flow meter(s) and controlled by electronic systems. Calibration and maintenance are executed according to national and manufacturer norms. Additional meters will be installed if other gas sources are supplying the GPP.*

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

>>

Data collection

Data to be collected for the purposes of monitoring of the JI activity includes parameters described in detail in Section D.1.

The management structure will have the Technical Director of SP SGP assuring that the data is collected as required. He will report to the General Director of SP SGP who has the overall responsibility for the monitoring.

Data collection will be recorded according to the following frequency:

Data variable:	Recording frequency:
$V_{A,y}$, $V_{B,dry-gas,y}$, $m_{SPBT,B,y}$, $m_{C3,B,y}$, $m_{condensate,B,y}$, $V_{Xi,y}$, $m_{fuel,y}$, F , $T_{equipment}$, $T_{pipeline}$, t_1, t_2 , P_P, T_P	Continuous
$w_{carbon,A,y}$, $w_{carbon,dry-gas,B,y}$, $w_{carbon,SPBT,B,y}$, $w_{carbon,C3,B,y}$, $w_{carbon,condensate,B,y}$, $w_{carbon,Xi,y}$, $w_{CH4,A,y}$, $w_{CH4,pipeline,y}$, $w_{CH4,pipeline,accident}$	Monthly
NCV_{fuel} , $EF_{CO2,fuel}$	Yearly

A monthly report will be prepared by the 10th of each subsequent month. The report will be used for QA by the General Director of SP SGP, who will undertake all necessary consistency checks with operational and commercial data by the 15th of each subsequent month. The monthly report, following QA procedures, will be sent to Carbon Limits for final QC.

Data calculation
The operator will install all necessary meters and assure that a software program is installed so as to record the data and generate the monthly monitoring reports. The monitoring equipment and software will be integral to the newly constructed gas processing plant. The following variables will be calculated:

1. $m_{carbon,A,y}$ (Equation 2)
2. $m_{carbon,B,y}$ (Equation 3)
3. $m_{carbon,X,y}$ (Equation 4)
4. $PE_{CO2,gas,y}$ (Equation 1)
5. $PE_{CO2,other-fuels,y}$ (Equation 5)
6. $PE_{CH4,plants,y}$ (Equation 6)
7. $PE_{CH4,pipeline,y}$ (Equation 7)
8. $V_{B,accident}$ (Equation 9)
9. $V_{remain,accident}$ (Equation 10)
10. $PE_{CH4,pipeline,accident}$ (Equation 8)
11. BL_y (Equation 11)

12. EF_y (Equation 12)

QA of the calculations will be the responsibility of the General Director of SP SGP. A final monthly report will be sent to Carbon Limits for final QC.

Data storage and archiving
All data will be archived electronically and stored by SP SGP. An electronic copy of all relevant data aggregated on a monthly basis will be sent along with the monthly report to Carbon Limits.

The monthly monitoring reports will be stored at SP SGP's Novosibirsk office to allow easy access for certification until 2 years after the end of the crediting period.

Data verification

The General Director of SP SGP will be responsible for making all relevant information available for verification procedures.

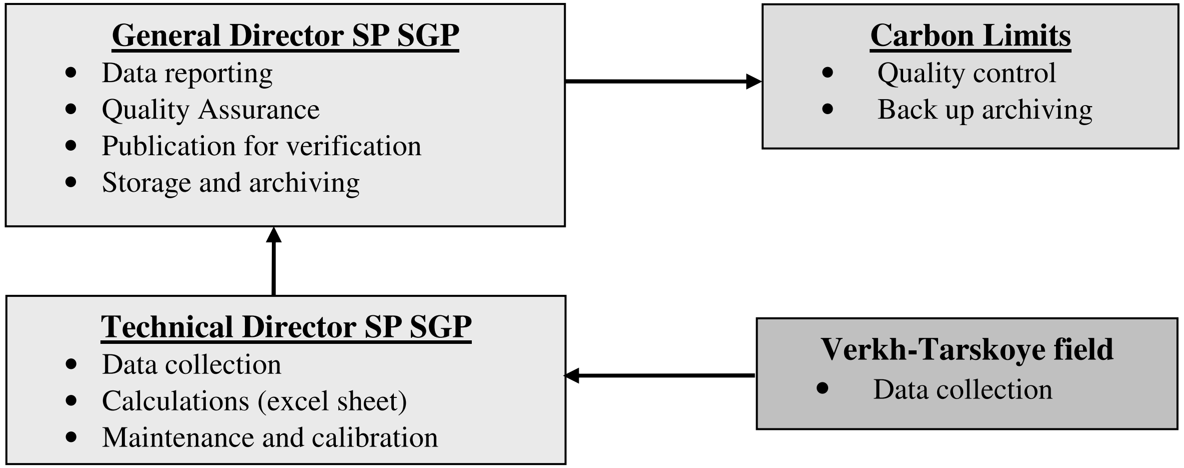
Maintenance and calibration

All meters used in this project activity will be of international standards and will be maintained as discussed in the monitoring plan. All data will be of high quality with low levels of uncertainty. There is no significant variation in data quality level or uncertainly level in the variables measured. The standards used are also international standards, and thus are of high quality and low levels of uncertainty.

An annual report will be sent to Carbon Limits detailing when all relevant monitoring and measurement equipment was last calibrated for quality control.

Management structure for monitoring plan

The management structure will have the Technical Director of SP SGP assuring that the data is collected as required. He will report to the General Director of SP SGP at the Headquarters in Novosibirsk. See figure below for schematic overview of responsibilities.



Staff training

Prior to starting up project monitoring, training of relevant staff will be provided as follows:

Relevant staff:	JI related training:
Operational staff	Data collection Maintenance and calibration
Technical Director SP SGP	Data collection Calculations Maintenance and calibration Data reporting
Headquarters staff Novosibirsk	Quality Assurance Data reporting Storage and archiving Publication for verification

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

>>

Carbon Limits is the entity establishing the monitoring plan and participating in the project as JI developer. The monitoring plan was finalized March 6, 2008. The person in charge of its development is:

Anders Pederstad
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SECTION E. Estimation of greenhouse gas emission reductions

E.1. Estimated project emissions:

>>

Project emissions are estimated to be:

CO_2 Emissions

The calculation for the CO_2 emissions from on-site fuel combustion, leaks, flaring and venting during transport and processing of recovered gas are calculated according to Equation 2 in Section D.1.1.2. The calculations are based on the volume of the entering and leaving stream into the project activity and the carbon content of the gas and liquids at the entry and exit points, over the time interval.

The carbon contents of the APG and the processed products from the GPP are estimated to be constant over the crediting period, but will be monitored with regular intervals:

Variable:	Value:
$w_{carbon,A,y}$	0.9715 kgC/m3
$w_{carbon,dry-gas,B,y}$	0.5931 kgC/m3
$w_{carbon,SPBT,B,y}$	0.8109 kgC/kg
$w_{carbon,C3,B,y}$	0.8077 kgC/kg
$w_{carbon,condensate,B,y}$	0.8311 kgC/kg
$w_{carbon,Xi,y}$	NA

The volume of APG recovered by the project activity and the annual sale of processed products from the GPP are estimated to be:

Year:	$V_{A,y}$ (m^3)	$V_{Xi,y}$ (m^3)	$m_{SPBT,B,y}$ (kg)	$m_{C3,B,y}$ (kg)	$m_{condensate,B,y}$ (kg)	$V_{dry-gas,B,y}$ (m^3)
2010	63,070,383	0	40,388,606	5,302,291	7,284,681	0
2011	209,532,494	0	134,179,068	17,615,276	24,201,176	0
2012	169,771,890	0	108,717,429	14,272,625	19,608,794	0
2013	131,400,376	0	84,145,325	11,046,754	15,176,852	0
2014	118,339,174	0	75,781,277	9,948,706	13,668,272	0
2015	98,899,299	0	63,332,495	8,314,407	11,422,951	0

By applying Equation 2 in Section D.1.1.2, the CO_2 emissions from on-site fuel combustion, leaks, flaring and venting during transport and processing of recovered gas are estimated to be:

Year:	$m_{carbon,A,y}$ (kgC)	$m_{carbon,B,y}$ (kgC)	$m_{carbon,X,y}$ (kgC)	$PE_{CO2,gas,y}$ (ton CO_{2e})
2010	61,274,139	43,088,412	0	66,681
2011	203,565,009	143,148,367	0	221,528
2012	164,936,787	115,984,725	0	179,491
2013	127,658,093	89,770,082	0	138,923
2014	114,968,874	80,846,932	0	125,114

2015	96,082,647	67,566,003	0	104,561

CO_2 emission due to consumption of other fuels in place of the recovered gas (substitution)

The emissions from other fuels used in place of the recovered gas are calculated based on Equation 5. It is expected that diesel fuel will be utilized in VTOF to supply energy to meet the deficit in energy caused by switching from utilizing APG to dry gas from the GPP in the project scenario. The emissions from consumption of diesel fuel in the gas turbines in VTOF/GPPU are estimated to be:

Year:	$m_{fuel,y}$ (kg)	NCV_{fuel}* (KJ/kg)	$EF_{CO2,fuel}$** (kg CO_2/KJ)	$PE_{CO2,other-fuels,y}$ (tCO_{2e})
2010	0	43,330	74.1*10^(-6)	0
2011	2,605,363	43,330	74.1*10^(-6)	8,361
2012	3,414,184	43,330	74.1*10^(-6)	10,957
2013	21,077,563	43,330	74.1*10^(-6)	67,644
2014	22,293,601	43,330	74.1*10^(-6)	71,547
2015	26,873,744	43,330	74.1*10^(-6)	86,246

* *Default value for diesel, from Revised 1996 IPCC Guidelines for National GHG Inventories: Workbook, Table 1.3*

** *Default value for diesel, from Revised 1996 IPCC Guidelines for National GHG Inventories: Workbook, Table 1.2 multiplied by 44/12*

CH_4 emissions from recovery and processing of the gas

All infrastructure built for the VTOF project activity will use modern equipment and conform to international best practice. In this regard emissions during operations are expected to be very minor. CH_4 emissions from recovery and processing of the gas are calculated based on Equation 7.

For the purpose of calculating the appropriate emission factor in Equation 7, an inventory of the installed equipment in the GPP will be summarized once before the start of the crediting period. A preliminary estimate of the number of items installed in the GPP is as follows:

Table 1: Oil and natural gas production average emission factors

Equipment Type	Service	Emission Factor (EF) (kg/hour/equipment item) for TOC	Number of items	Total EF GPP
Valves	Gas	4.5E-3	15	0.0675
Pump seals	Gas	2.4E-3	0	0.0000
Others*	Gas	8.8E-3	78	0.6864
Connectors	Gas	2.0E-4	700	0.1400
Flanges	Gas	3.9E-4	1,021	0.3982
Open-ended lines	Gas	2.0E-3	745	1.4900
Total GPP	**Gas**		**2,782**	**2.7821**

Based on the preliminary estimate of the number of equipment of each type that will be installed in the GPP if the project is implemented (numbers will be verified before the initial verification period based on the P&I diagram), the GHG emissions from leaks in the GPP are estimated to be:

Year:	GWP_{CH4}	$w_{CH4,A,y}$ (kg CH4/kg)	$EF_{equipment}$ (kg/hour)	$T_{equipment}$ (kg)	$PE_{CH4,plants,y}$ (tCO_2)

2010	21	0.2499	2.7821	2,100	31
2011	21	0.2499	2.7821	8,400	123
2012	21	0.2499	2.7821	8,400	123
2013	21	0.2499	2.7821	8,400	123
2014	21	0.2499	2.7821	8,400	123
2015	21	0.2499	2.7821	8,400	123

CH_4 emissions from transport of the gas in pipelines under the normal operation condition

As noted, the pipeline system for the VTOF project activity comprise the gas gathering line from the CPF to the GPP and the gas pipeline for transportation of dry gas from the GPP to the GPPU. No significant emissions are expected from this system due to the limited distances. Fugitive emissions of CH_4 are calculated based on Equation 8.

For the purpose of calculating the appropriate emission factor in Equation 8, an inventory of the equipment installed in the project pipelines will be summarized once before the start of the crediting period. A preliminary estimate of the number of items installed in the pipelines is as follows:

Table 1: Oil and natural gas production average emission factors

Equipment Type	Service	Emission Factor (EF) (kg/hour/equipment item) for TOC	Number of items	Total EF GPP
Valves	Gas	4.5E-3	2	0.0090
Pump seals	Gas	2.4E-3	0	0.0000
Others*	Gas	8.8E-3	0	0.0000
Connectors	Gas	2.0E-4	0	0.0000
Flanges	Gas	3.9E-4	2	0.0008
Open-ended lines	Gas	2.0E-3	0	0.0000
Total GPP	**Gas**		**4**	**0.0098**

Based on the preliminary estimate of the number of equipment of each type that will be installed in the GPP if the project is implemented (numbers will be verified before the initial verification period based on the P&I diagram), the GHG emissions from leaks in the GPP are estimated to be:

Year:	GWP_{CH4}	$w_{CH4,A,y}$ (kg CH4/kg)	$EF_{equipment}$ (kg/hour)	$T_{equipment}$ (kg)	$PE_{CH4,plants,y}$ (tCO_2)
2010	21	0.6622	0.0098	2,100	0
2011	21	0.6622	0.0098	8,400	1
2012	21	0.6622	0.0098	8,400	1
2013	21	0.6622	0.0098	8,400	1
2014	21	0.6622	0.0098	8,400	1
2015	21	0.6622	0.0098	8,400	1

CH_4 emissions from transport of the gas in pipelines when accidental event occurred

Pipeline operations will be closely monitored, and emissions from accidental events will be subtracted as project emissions if required.

E.2. Estimated leakage:

>>
There is no leakage from the proposed project activity.

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

>>
The sum of E.1. and E.2. is the same as E.1. since leakage is zero.

E.4. Estimated baseline emissions:

>>
Baseline emissions are calculated according to Equation 11. The baseline emissions are expected to be:

Year:	$V_{A,y}$ (m^3)	$w_{carbon,A,y}$ (kgC/m^3)	BL_y (tCO_{2e})
2010	63,070,383	0.9715	224,672
2011	209,532,494	0.9715	746,405
2012	169,771,890	0.9715	604,768
2013	131,400,376	0.9715	468,080
2014	118,339,174	0.9715	421,553
2015	98,899,299	0.9715	352,303

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

>>
The emission reductions are calculated according to Equation 12. The ex-ante estimation of emission reductions can be summarized as:

Year:	2010	2011	2012	2013	2014	2015
BL_y	224,672	746,405	604,768	468,080	421,553	352,303
$PE_{CO2,gas,y}$	66,681	221,528	179,491	138,923	125,114	104,561
$PE_{CO2,other-fuels,y}$	0	8,361	10,957	67,664	71,547	86,246
$PE_{CH4,plants,y}$	31	123	123	123	123	123
$PE_{CH4,pipeline,y}$	0	1	1	1	1	1
$PE_{CH4,pipeline,accident}$	0	0	0	0	0	0
EF_y	**157,960**	**516,392**	**414,196**	**261,389**	**224,768**	**161,372**

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

>>

Year	Estimation of project activity emissions (tonnes of CO_{2e})	Estimation of baseline emissions (tonnes of CO_{2e})	Estimation of leakage (tonnes of CO_{2e})	Estimation of overall emission reductions (tonnes of CO_{2e})
2010	66,712	224,672	0	157,960
2011	230,013	746,405	0	516,392
2012	190,572	604,768	0	414,196
2013	206,691	468,080	0	261,389

2014	196,785	421,553	0	224,768
2015	190,931	352,303	0	161,372
2016	0	0	0	0
2017	0	0	0	0
2018	0	0	0	0
2019	0	0	0	0
Total 10 yr crediting period	**1,081,730**	**2,817,780**	**0**	**1,736,077**

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:

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The environmental review stage is mandatory to obtain a construction permit from the public oversight authorities. An operating permit will be obtained before start of operation. The provisions of the national legislation (Federal Law on Environmental Reviews (1995); Federal Law on Environmental Protection (1991); Ordinance on the Environmental Impact Assessment in the Russian Federation (1994), as well as other relevant national regulations) should be enforced.

As part of getting State approvals for the proposed JI project, SP SGP have documented the environmental impacts of the project as part of the document pack submitted to the Russian state expertise in accordance to the Russian guidelines for this type of procedure, i.e. OVOS (environmental impact assessment, 498 pages) and OOS (defence of the environment, 98 pages). These can be made available for validation if necessary.

The regional Governor has expressed interest in starting utilizing propane produced by the project activity as a fuel for municipal vehicles. This will substitute fossil fuels with a higher carbon impact and particulate emissions, and thus has a positive impact on the environment.

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 project participants do not consider the environmental impacts to be significant, and a positive approval from the Russian state expertise of the project documentation pack is expected in June 2008.

SECTION G. Stakeholders' comments

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

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The project developers have discussed the project idea with the regional authorities in a meeting held 23 November 2007. The regional Governor is very interested in rapid implementation of the project, and their preliminary response indicates that the project developers will be granted tax exemptions due to the projects desirability. A formal response from the stakeholder consultations with the Administration of the Novosibirsk region was obtained in April 2008.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

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Represented by:	Marat Yunirovich Ibragimov
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Annex 2

BASELINE INFORMATION

The stationary combustion of APG produced at VTOF over the last three years is:

	2005:	2006:	2007:
Stationary combustion of APG (m^3):	84,652,909	99,561,635	215,553,400

The above figures comprise all stationary combustion sources. An exact split of various types of stationary combustion sources is not available historically.

Production forecasts used to determine the amount of APG that will be produced in VTOF was developed by chief geologists Alexandr B. Grishkevich in Novosibirskneftegas (NNG) 26 February 2008. The APG forecast is developed based on a stable Gas-to-Oil (GOR) ratio.

Annex 3

MONITORING PLAN

A monitoring report (excel sheet) will be filled out monthly by Technical Director SP SGP, controlled by General Director SP SGP and sent to Carbon Limits head office in Oslo.

Annex 4

PRODUCT COMPOSITIONS VTOF

The compositions of the product streams at the inlet and outlet of the GPP are taken from the material stream analysis developed by Hyprotech (Canada). Summer and winter operations are treated separately, and compositions used to estimate emission reductions are taken as winter compositions. Compositions will be monitored with regular intervals as part of the monitoring plan.

Expected APG composition at intake to GPP:

The composition of the APG (mix) at the intake of the GPP is taken from the technical project documents. The APG (mix) is equivalent to material stream no. 9 (both summer and winter) in the material stream analysis developed by Hyprotech, Canada.

Fuel source	**APG – summer (9)**		**APG – winter (9)**	
	Component	**Wi %**	**Component**	**Wi %**
Composition	Nitrogen	1.03	Nitrogen	1.03
	Methane	25.00	Methane	24.99
	Ethane	6.25	Ethane	6.24
	Propane	22.70	Propane	22.68
	Butanes	23.51	Butanes	23.49
	Pentanes	9.02	Pentanes	9.01
	Hexanes	3.11	Hexanes	3.10
	Heptanes	1.01	Heptanes	1.01
	Octanes	0.17	Octanes	0.17
	C9+	0.00	C9+	0.00
	CO_2	3.42	CO_2	3.42
Net Calorific Value (MJ/Nm^3)		**56.4**		**56.4**
Carbon Intensity Fuel (kg C/MJ)		**0.0172**		**0.0172**
Carbon Content (kg C/Nm^3)		**0.9723**		**0.9715**
Mass fraction of methane (kg CH4/kg)		**0.2500**		**0.2499**

Expected dry gas composition at outlet of GPP:

The composition of the processed products produced by the GPP is taken from the technical project documents. The dry gas composition is determined as material stream no. 54 (summer) and no. 65 (winter) in the material stream analysis developed by Hyprotech, Canada. The product will meet standard GOST 5542-78.

Fuel source	**Dry gas – summer (54)**		**Dry gas – winter (65)**	
	Component	**Wi %**	**Component**	**Wi %**
Composition	Nitrogen	2.78	Nitrogen	2.72
	Methane	67.73	Methane	66.22
	Ethane	8.86	Ethane	9.48
	Propane	9.47	Propane	10.50
	Butanes	2.48	Butanes	2.44
	Pentanes	0.18	Pentanes	0.15
	Hexanes	0.01	Hexanes	0.01
	Heptanes	0.00	Heptanes	0.00
	Octanes	0.00	Octanes	0.00
	C9+	0.00	C9+	0.00
	CO_2	8.45	CO_2	8.45
Net Calorific Value (MJ/Nm^3)		**36.6**		**37.0**
Carbon Intensity Fuel (kg C/MJ)		**0.0160**		**0.0161**
Carbon Content (kg C/Nm^3)		**0.5856**		**0.5931**
Mass fraction of methane (kg CH4/kg)		**0.6773**		**0.6622**

Expected SPBT composition at outlet of GPP:

The propane-butane mix composition is determined from material stream no. 51 (summer) and no. 58 (winter) in the material stream analysis developed by Hyprotech, Canada. The product will meet standard GOST 20448-90.

Fuel source	**SPBT – summer (51)**		**SPBT – winter (58)**	
	Component	**Wi %**	**Component**	**Wi %**
Composition	Nitrogen	0.00	Nitrogen	0.00
	Methane	0.00	Methane	0.00
	Ethane	5.56	Ethane	3.52
	Propane	35.86	Propane	27.85
	Butanes	42.13	Butanes	58.54
	Pentanes	14.45	Pentanes	8.56
	Hexanes	0.03	Hexanes	0.00
	Heptanes	0.00	Heptanes	0.00
	Octanes	0.00	Octanes	0.00
	C9+	0.00	C9+	0.00
	CO_2	0.56	CO_2	0.30
Net Calorific Value (MJ/Nm^3)		**99.5**		**103.0**
Carbon Intensity Fuel (kg C/MJ)		**0.0178**		**0.0178**
Carbon Content (kg C/kg)		**0.8070**		**0.8109**
Mass fraction of methane (kg CH4/kg)		**0.00**		**0.00**

Expected SNG composition at outlet of GPP:

The composition of stable natural gasoline (SNG) is determined from material stream no. 55 (summer) and no. 42 (winter) in the material stream analysis developed by Hyprotech, Canada. The product will meet standard TU 39.1340-89.

Fuel source	**SNG – summer (55)**		**SNG – winter (42)**	
	Component	**Wi %**	**Component**	**Wi %**
Composition	Nitrogen	0.00	Nitrogen	0.00
	Methane	0.00	Methane	0.00
	Ethane	0.00	Ethane	0.00
	Propane	0.00	Propane	0.00
	Butanes	0.12	Butanes	0.77
	Pentanes	22.15	Pentanes	57.47
	Hexanes	57.49	Hexanes	30.70
	Heptanes	17.71	Heptanes	9.44
	Octanes	2.48	Octanes	1.33
	C9+	0.00	C9+	0.00
	CO_2	0.00	CO_2	0.00
Net Calorific Value (MJ/Nm^3)		**177.7**		**160.5**
Carbon Intensity Fuel (kg C/MJ)		**0.0185**		**0.0184**
Carbon Content (kg C/kg)		**0.8348**		**0.8311**
Mass fraction of methane (kg CH4/kg)		**0.00**		**0.00**

Expected C3 composition at outlet of GPP:

The composition of automobile propane (C3) is determined from material stream no. 51 (winter) in the material stream analysis developed by Hyprotech, Canada. The product will meet standard TU 38.101490-79.

Fuel source	**C3 – winter (51)**	
	Component	**Wi %**
Composition	Nitrogen	0.00
	Methane	0.00
	Ethane	13.48
	Propane	82.58
	Butanes	2.77
	Pentanes	0.00
	Hexanes	0.00
	Heptanes	0.00
	Octanes	0.00
	C9+	0.00
	CO_2	1.14
Net Calorific Value (MJ/Nm^3)		**82.4**
Carbon Intensity Fuel (kg C/MJ)		**0.0176**
Carbon Content (kg C/kg)		**0.8077**
Mass fraction of methane (kg CH4/kg)		**0.00**

Annex 5

Brief economic overview of non-plausible alternative scenarios

TNK-BP carried out a comprehensive economic comparison of alternative scenarios to increase utilization of APG at VTOF as part of a SELECT study in 2006/2007. A preliminary economic assessment of alternatives not evaluated as plausible can be found below. Production estimates, investment and operating costs and price assumptions used to assess the economic attractiveness of these alternatives, all aimed at complete recovery of APG currently flared on-site, have not been updated since the SELECT study was finalized. The alternatives below can thus not be compared with the alternatives studied in detail during the DEFINE stage presented in this PDD.

On-site use of the associated gas for power production (Option 3 in Section B.1)

To fully recover the APG currently flared on-site, alternative options to generate power for export into the regional grid was studied by TNK-BP. The economics of this opportunity relies on the cost of installing power generation units, the cost of connecting the power plant to the regional grid and the price that can be obtained for electricity and extracted by-products. The price of electricity was estimated to be 36.4 USD per MWh. Of the various alternative power generation schemes evaluated, the most economic option was found to be generation of dry gas for production of electricity in gas turbines[26]. The NPV of this alternative was found to be:

On-site use of the associated gas for power production	NPV_{2007} (USD):
Capital expenditures:	-90,152,856
Operating expenses:	-46,413,482
Revenues (electricity, LPG, C5+, flaring fines):	106,141,991
Taxes (property tax and profit tax):	-16,052,295
Total NPV:	**-46,476,641**

This alternative was considerably less economic than continuation of current practice, and economics has since deteriorated due to lower APG production forecasts, increased on-site power demand at VTOF and implementation delays.

On-site use of the associated gas for LNG production (Option 4 in Section B.1)

The option to build a GPP with LNG production for export of excess dry gas was evaluated as another option to fully recover the APG currently flared at VTOF. The economics of this option is dependent on the cost of adding LNG production, transportation and regasification and the net-back value of LNG. With a net-back price of APG that could be obtained from LNG of 34.2 USD/000m^3 (2007 USD), the NPV was found to be:

On-site use of the associated gas for LNG production	NPV_{2007} (USD):
Capital expenditures:	-88,296,606
Operating expenses:	-45,904,711
Revenues (LNG, LPG, C5+, flaring fines):	97,137,175

[26] Both APG and dry gas were evaluated as fuels for power production on-site. The value added by extraction and marketing of liquids was found to be offset by the reduced scale of power production if dry gas were to be used. Use of dry gas as fuel for power production on-site is equivalent to an expansion of the proposed JI project activity to fully utilize dry gas on-site.

Taxes (property tax and profit tax):	-14,623,937
Total NPV:	**-51,688,079**

This alternative was considerably less economic than continuation of current practice, and economics has since deteriorated due to lower APG production forecasts, elimination of excess amounts of dry gas available for LNG export post 2011 and delays in the potential implementation schedule.

Injection of the associated gas into the producing oil reservoir (Option 5 in Section B.1)

The economics of re-injection of APG for partial pressure maintenance of producing reservoirs is dependent on the expected EOR response in the relevant reservoirs, the cost of installing compression facilities and required investments in pipelines and injection wells. The EOR response is expected to be marginal by TNK-BP engineers as the field is currently being water flooded, with all necessary equipment installed. The complete recovery, compression and re-injection of the amount of APG that would be flared in the future was found to have a NPV of:

Injection of the associated gas into the producing oil reservoir	**NPV_{2007} (USD):**
Capital expenditures:	-149,584,308
Operating expenses:	-12,543,980
Taxes (property tax and profit tax):	-14,864,999
Total NPV:	**-176,993,287**

The expected amount of APG flared at VTOF in the future has since reduced due to lower APG production forecasts and increased on-site power demand, and the economics of this alternative is expected to be very unattractive.

Recovery and transportation of the associated gas via pipelines to an existing power plant (Option 6-i in Section B.1)

The option to tie-in the APG produced at VTOF via pipelines to an existing power plant in Barabinsk was evaluated as a technically simple scheme to completely eliminate APG flaring. The economics of this alternative is dependent on the cost of installing treatment facilities, a compressor station and long distance pipelines to the existing power plant and the net-back price of APG. The net-back price of APG that could be obtained from the power plant in Barabinsk was estimated to be 45.9 USD/000m^3 (2007 USD). It should be noted that this was an optimistic assumption, and the price would be subject to negotiations with the owner of the power plant. The NPV of this alternative was at the time of the study found to be:

Recovery and transportation of the APG via pipelines to end-user	**NPV_{2007} (USD):**
Capital expenditures:	-97,159,762
Operating expenses:	-11,498,367
Revenues (APG, flaring fines):	18,878,861
Taxes (property tax and profit tax):	-9,470,460
Total NPV:	**-99,249,729**

As this alternative was considerably less economic than continuation of current practice, it was not studied further by TNK-BP.

Recovery and utilization of the associated gas as feedstock for methanol production (Option 7 in Section B.1)

The opportunity to install a GPP with an adjacent methanol plant at VTOF was investigated as another alternative option to fully recover APG currently being flared. The economics of this alternative is dependent on the cost of installing a gas processing plant and a methanol plant and the value of processed products and methanol. Due to the high cost of adding the required methanol infrastructure (estimated to 34 million USD) and the limited value added by marketing of methanol, the project economics were found to be highly unattractive. This can be seen in the table below:

Recovery and utilization of APG as feedstock for methanol prod.	**NPV_{2007} (USD):**
Capital expenditures:	-94,250,570
Operating expenses:	-50,209,797
Revenues (APG, flaring fines):	93,113,599
Taxes (property tax and profit tax):	-11,209,939
Total NPV:	**-62,556,708**

This alternative was considerably less economic than continuation of current practice, and economics has since deteriorated due to lower APG production forecasts, elimination of excess amounts of dry gas available for methanol production post 2011 and delays in the potential implementation schedule.

Annex 6

Abbreviations used in PDD

APG	Associated Petroleum Gas
BCM	Billion Cubic Meter
CPF	Central Processing Facility
FWCU	Free Water Knock-out Unit
GHG	Green House Gases
GPP	Gas Processing Plant
GPPU	Gas Power Piston Units
HP	High Pressure
SP SGP	LLC SP Sibgazpererabotka
LNG	Liquefied Natural Gas
LP	Low Pressure
MMCM	Million Cubic Meter
NGL	Natural Gas Liquids
NNG	Novosibirskneftegas
NOAA	U.S. National Oceanic and Atmospheric Administration
NPV	Net Present Value
SNG	Stable Gas Condensate
SPBT	Fuel Liquefied Hydrocarbon Gas for Household consumption
VTOF	Verkh-Tarskoye Oil Field

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