CLEAN DEVELOPMENT MECHANISM
PROJECT DESIGN DOCUMENT FORM (CDM-PDD)
Version 03 - in effect as of: 28 July 2006

CONTENTS

SECTION A. General description of project activity

A.1. Title of the project activity:

Project title: Associated Gas Recovery and Utilization at Block 9
PDD Version: 6.0

PDD completion date: 30/12/2012

A.2. Description of the project activity:

The Associated Gas Recovery and Utilization at Block 9 project consists of the recovery and utilization of natural gas found in association with oil at Block 9, Safah oil field, Sultanate of Oman. Block 9 is operated by Occidental of Oman Inc. under a development and production sharing agreement with the Ministry of Oil and Gas. The purpose of the project activity is to deliver recovered gas to the national gas pipeline to meet energy needs of end-users, and also to reduce local air pollution due to flaring.

The recovery process comprises three main stages including the separation stage where gas is separated from oil and water, the compression stage where gas is compressed for transportation to gas plant, and the processing stage where gas is processed to fit with conditions of gas pipeline for further transportation to end-users. Main equipment necessary for the proposed project activity comprises electric motor-driven reciprocating and screw compressors installed at several locations on site, and a network of pipelines for gas transportation.

The scenario existing prior to the start of the implementation of the proposed project activity is flaring of associated gas at the oil production site, the operation of the existing oil and gas infrastructure without processing of any recovered associated gas, and the use of gas-lift gas from the same source and quantity as under the project activity in the gas-lift system. The baseline scenario is the same as the scenario existing prior to the start of implementation of the proposed project activity. The project reduces greenhouse gases emissions as the utilization of recovered gas displaces the use of non associated gas or other fossil sources at end-users.

The total estimated amount of associated gas to be recovered during crediting period is about 2.1 billion m^3 while average methane content is estimated at about 70%. The project activity is expected to reduce emissions by approximately 775,250 tonnes of CO_2 equivalent annually over the crediting period.

The proposed project activity will contribute to the Oman national and local sustainable development and also generates the following benefits:

- Benefit the local air conditions by reducing the air pollution due to flaring.
- Efficient use of natural resources due to the utilization of the gas that would be flared in the absence of the project.
- New job opportunities due to the construction activities.
- Reduce the combustion of fossil fuels at end-users that are produced from non-associated gas or other fossil sources.

A.3. Project participants:

The parties involved in the project are shown in Table A.1:

Table A.1.Project participants

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)
The Sultanate of Oman (host)	The Government of the Sultanate of Oman, represented by the Ministry of Oil & Gas (public entity)	No
United Arab Emirates	Oman Trading International	No

For detailed information on participants in the project activities, please refer to Annex 1.

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

A.4.1.1. Host Party(ies):

The Sultanate of Oman

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

A'Dhahirah Region

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

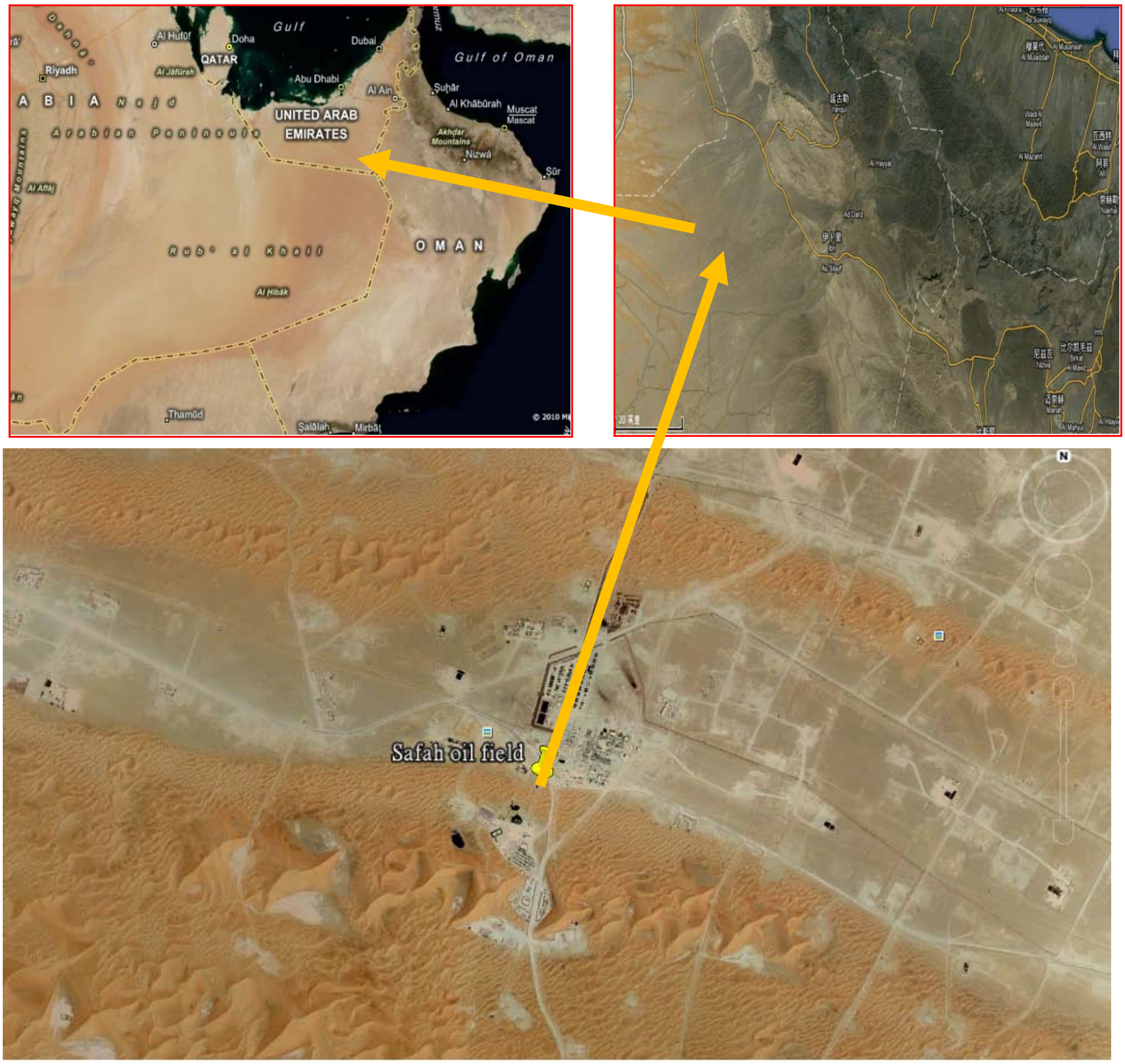
Safah oil field

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

The proposed project is located at Block 9, Safah oil field in A'Dhahirah Region of Northern Oman. Nearest town is Ibri which is about 50kilometres from the site. Approximate coordinates of Safah gas processing plant are east longitude of 55°27'40" and north latitude of 23°11'20". As further described in section A.4.3 the project includes four other locations: Far West (23°09'11"N, 55°27'03"E), Satellite (23°10'39"N, 55°29'52"E), Jalal (22°55'50"N, 55°48'16"E), and Wadi Latham (22°52'50"N, 55°48'16"E),

Figure A.1 shows the location of the project.

Figure A.1 Map of the project location



A.4.2. Category(ies) of project activity:

The project activity falls within Sectoral scope 10: Fugitive emission from fuels (solid, oil, gas). TA 10.2: Oil and gas industry, coal mine methane recovery and use (COMPLEX).

A.4.3. Technology to be employed by the project activity:

The proposed project activity aims to recover associated gas flow that is currently flared at 5 different locations in Safah oil field. When oil is extracted from the wells, it comes to the surface together with sands, water and gas. The mixture is then stored into tanks to rest for a period so that through gravity, oil, water and sands are recovered from the bottom of the tank and gas is recovered from the top of the tank. This is called the phase separation. Only oil, gas, sands and water are recovered during phase separation at each location. After that gas is compressed and transported to a processing plant on-site owned by onsite operator where it

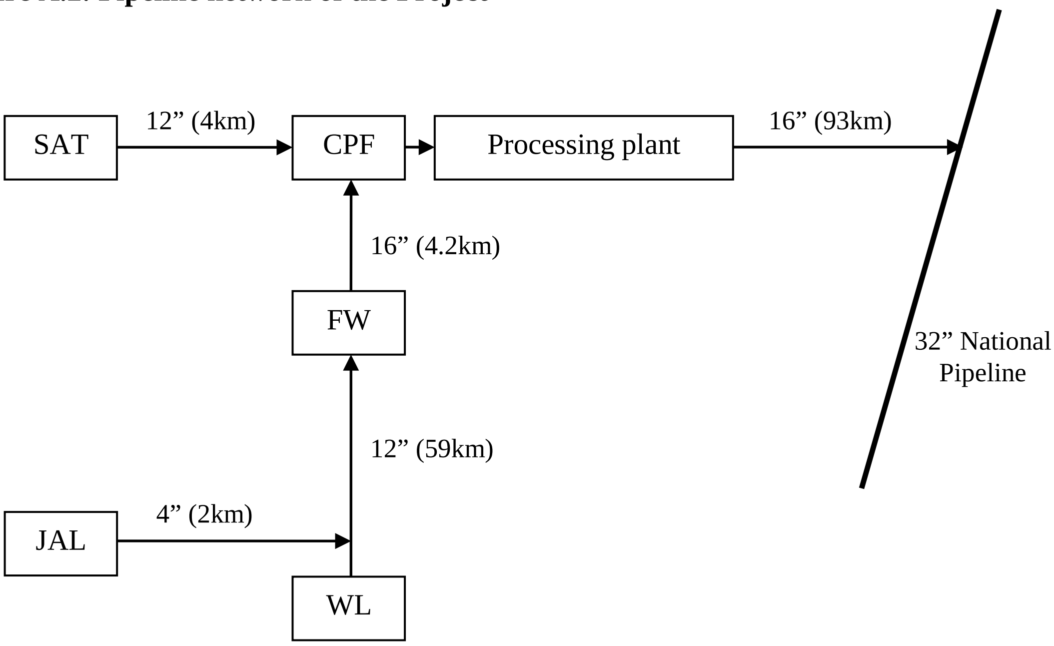
will be processed then further transported and sold by onsite operator to National Gas pipeline. Part of the gas is consumed onsite to provide electricity to the project activity. Expected annual gross gas volumes to be recovered as part of the project activity are on average 41.13 mmscfd over its lifetime. On average about 1.78 mmscfd of the recovered gas will be used annually in captive power plant on-site to supply electricity to the project activity. The captive gas power plant is owned and operated by on-site operator and the gas is delivered free of charge to the power plant. Expected average net gas volumes delivered to National pipeline is 37.02mmscfd after deduction of onsite gas consumption due to project activity and deduction of a shrinkage factor due to gas treatment at gas plant for the purpose of meeting the specifications of the National pipeline. This latter value corresponds to dry gas volumes after processing at gas plant. Detailed annual values per location from the start of crediting period are listed in Annex 3.

The project activity mainly comprises the installation of compressor packages at five different locations, including compressor, motor, scrubbers, suction and discharge bottles, coolers, as well as installation of a pipeline network. Technology employed by the proposed project activity mainly includes but is not limited to[1] the following equipment:

- Purchase and installation of a vapour recovery unit (VRU) for the central production boot flare (CPF) in Safah. The VRU package includes 4 screw compressors (2 prime units & 2 stand-by units) with associated knock out drums, lube oil systems and air coolers. The boot flare will be re-routed to the vapour recovery unit which will recover gas from the crude tank degassers and various other low pressure sources currently flared. The recovered gas will be sent to the gas plant for processing.
- Reduction of the Far West (FW) flare by a series of new pipelines and re-routes.
- Addition of electrical driven reciprocating compressor at the Satellite (SAT) facility as well as electrical infrastructures including transformers and relays to support the high voltage and low voltage demands of the compressor. A new motor control center and switch gear room will be installed. The recovered gas will be sent to the gas plant for processing.
- Addition of electrical motor driven reciprocating compressor at Jalal (JAL) as well as electrical infrastructure including transformers and relays to support the high voltage and low voltage demands of the compressor. The recovered gas will be sent to the gas plant for processing.
- Addition of electrical motor driven reciprocating compressors at Wadi Latham (WL) as well as electrical infrastructure including new motor control center and switch gear building, transformers and relays to facilitate the high voltage and low voltage demands of the compressors. The recovered gas will be sent to the gas plant for processing.
- Addition of electrical motor driven reciprocating compressors at Far West (FW) facility. The recovered gas will be sent to the gas plant for processing.
- The pipeline system mainly consists of a 16” 93.8km line from Safah to National pipeline and a 12” 58.2km line from Wadi Latham to Far West; 12” 4km line from Satellite to Central Production Flare; 16” 4.2km line from Far West to Central Production Flare; and 4” 2km line from Jalal connected to Wadi Latham-Far West line. The below figure provides an overview of the network.

[1] In accordance with the guidelines, “Information related to equipment, systems and measures that are auxiliary to the main scope of the project activity and do not interfere directly or indirectly with emissions of greenhouse gases and/or with mass and energy balances in the project activity should not be included”.

Figure A.2: Pipeline network of the Project



The Safah field produces oil before and after the project activity, the oil production process will remain unchanged. The scenario existing prior to the start of the implementation of the proposed project activity is that associated gas is flared on site, the existing oil and gas infrastructure operates without processing of any recovered associated gas and gas-lift gas from the same source and quantity as under the project activity is used in the gas-lift system. Non-associated gas or other fossil sources is combusted to meet energy needs of end-users in Oman. The baseline scenario is the same as the scenario existing prior to the start of implementation of the proposed project activity.

Baseline emissions source include CO_2 emissions from combustion of fossil fuels at end-users that are produced from non-associated gas and other fossil sources, and project emissions sources comprise CO_2 emissions from energy use for the recovery, pre-treatment including compression of the recovered gas.

The project installed new compressors with a maximum load factor of about 72%. According to manufacturer specifications, compressors lifetime should be of 15 years for products properly maintained and used according to instructions. Detailed information regarding compressors at each location is listed as follows:

Table A.2. Technical parameters of compressors:

Location	**Parameter**	**Value**
CPF	Capacity (MMSCFD)	4 * 5.399
	Manufacturer	Vilter
	Type	VSG-2101
	Rated Power (BHP)	541
FW	Capacity (MMSCFD)	2 * 12.5
	Manufacturer	Ariel Corporation
	Type	JGK/4
	Rated Power (BHP)	2540
SAT	Capacity (MMSCFD)	1 * 30

	Manufacturer	Ariel Corporation
	Type	JGD/4
	Rated Power (BHP)	4140
JAL	Capacity (MMSCFD)	1 * 12.5
	Manufacturer	Ariel Corporation
	Type	JGC/4
	Rated Power (BHP)	4140
WL	Capacity (MMSCFD)	3 * 12.5
	Manufacturer	Ariel Corporation
	Type	JGC/4
	Rated Power (BHP)	4140

Monitoring equipments and their location in the system:
Volume of the total recovered gas will be measured after pretreatment (phase separation and compression) and after the part of the recovered gas is used on-site by means of differential pressure flow meters providing values at normal temperature and pressure using the temperature and pressure at the time of measurement. Net calorific value of recovered gas will also be measured by qualified personnel from on-site lab by means of chromatography (gas composition analysis) through sampling at each location at point F in methodology AM0009 version 06.0.0 Figure 2. Project electricity consumption will be measured through standard electricity meters located on power line providing electricity to compressor packages. Detailed information for monitoring has been specified in Section B.7.2.

Training and maintenance requirements: The staff of the project activity will receive the appropriate training on the operation of the associated gas recovery equipment and CDM related knowledge.

Implementation schedule: More specific details on the implementation schedule in Table A.3, including the "starting date of the project activity" and CDM consideration are provided in Table B.14.

Table A.3. Implementation schedule

Location	Number of compressors	Start construction	Full commissioning
CPF	4	14-May-2009	08-Dec-2009
FW	2	02-Jan-2010	03-Jul-2010
SAT	1	14-Jan-2010	03-Sep-2010
JAL	1	19-Jan-2010	08-Aug-2010
WL	3	07-Jan-2010	29-Oct-2010

A.4.4. Estimated amount of emission reductions over the chosen crediting period:

The estimation of the emission reductions in the crediting period is presented in Table A.4.

Table A.4. The estimation of the emission reductions in first crediting period

Year	The estimation of annual emission reductions (tCO2e)
2013	1,327,326
2014	1,082,529
2015	816,065
2016	713,032
2017	567,231
2018	480,640
2019	439,930
Total estimated reductions (tonnes of CO2e)	**5,426,752**
Total number of crediting years	7 years
Annual average over the crediting period of estimated reductions (tonnes of CO2e)	775,250

A.4.5. Public funding of the project activity:

There is no public funding from Annex I countries available to the proposed project.

SECTION B. Application of a baseline and monitoring methodology

B.1. Title and reference of the approved baseline and monitoring methodology applied to the project activity:

The project activity uses the baseline and monitoring methodology AM0009/Version 06.0.0: "Recovery and utilization of gas from oil wells that would otherwise be flared or vented".

This methodology also refers to the latest approved versions of the following tools:
- "Tool to calculate project or leakage CO2 emissions from fossil fuel combustion" (not used in this PDD);
- "Tool to calculate baseline, project and/or leakage emissions from electricity consumption (Version 1)";
- "Assessment of the validity of the original/current baseline and update of the baseline at the renewal of the crediting period" (not used in this PDD);
- "Tool for the demonstration and assessment of additionality (Version 06.1.0)".

B.2. Justification of the choice of the methodology and why it is applicable to the project activity:

The baseline and monitoring methodology AM0009 Version 06.0.0 is applicable to the proposed project; because the project meets all the applicability criteria stated in the methodology:

The project activity aims to recover and utilise associated gas from oil wells (Block 9). Prior to the start of the project activity, part of the associated gas was used for the purpose of the gas-lift process and excess gas was flared on-site.

AM0009 Version 06.0.0 is applicable under the following conditions[2]:

- Under the project activity the recovered gas, after the pre-treatment (compression and phase separation) in movable or stationary equipment, is:
  - Consumed on-site to meet energy demands; and/or
  - Transported to a gas pipeline without prior processing; and/or
  - Transported to a processing plant where it is processed into hydrocarbon products (e.g. dry gas, liquefied petroleum gas (LPG) and condensates). The dry gas is either: (i) transported to a gas pipeline directly; or (ii) compressed to CNG first, then transported by trailers/trucks/carriers and then decompressed again, before it finally enters the gas pipeline;

- *The gas from the proposed CDM project activity will be transported to a processing plant and processed into hydrocarbon products (dry gas and condensate) while a small amount of recovered associated gas will be consumed on-site to meet energy demands of the proposed project activity. The dry gas will be transported to a gas pipeline directly.*

[2] Note that the documentation that has been used for justification of the applicability conditions consists of the description of the project activity in internal "project authorization request" provided by the entity operating Block 9.

- The project activity does not lead to changes in the process of oil-production, such as an increase - in the quantity or quality of oil extracted, in the oil-wells within the project boundaries;

- *The proposed project activity will utilise associated gas in excess of quantities of gas used as gas-lift gas. Excess gas will be compressed and sent to processing plant. Therefore, the project activity will have no impact on the quality or quantity of oil extracted in the oil wells within the project boundaries.*

- The injection of any gases into the oil reservoir and its production system is allowed in the project activity only for the purpose of the gas-lift process;

- *The project activity includes the injection of associated gas into oil reservoir for gas-lift proposes. Quantity of gas used in gas-lift system has been estimated by the reservoir management team on-site over the life time of the project and the project activity will only utilize associated gas in excess of quantities needed in gas-lift system. Evidence has been provided to DOE.*

- All recovered gas comes from oil wells that are in operation and are producing oil at the time of the recovery of the associated gas and/or gas-lift gas.

- *The project activity will be carried out at five different locations allowing recovery of associated gas across the Block 9, which has been in operation before the project design and which will continue to operate for at least as long as the proposed project activity.*

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

Tool to calculate baseline, project and/or leakage emissions from electricity consumption (Version 01)

- The tool is only applicable if one out of the following three scenarios applies to the sources of electricity consumption:
  Scenario A: Electricity consumption from the grid;
  Scenario B: Electricity consumption from (an) off-grid fossil fuel fired captive power plant(s): One or more fossil fuel fired captive power plants are installed at the site of the electricity consumption source and supply the source with electricity. The captive power plant(s) is/are not connected to the electricity grid.
  Scenario C: Electricity consumption from the grid and (a) fossil fuel fired captive power plant(s).

- *The project activity is applicable to Scenario B. Captive power plant using fossil fuel (i.e. natural gas) will supply the source with electricity. The captive power plant(s) is/are not connected to the electricity grid.*

- This tool is not applicable in cases where captive renewable power generation technologies are installed to provide electricity in the project activity, in the baseline scenario or to sources of leakage.

- *The captive power station which provides electricity uses natural gas as fuel; renewable resource will not be used as fuel.*

In conclusion, "*Tool to calculate baseline, project and/or leakage emissions from electricity consumption (Version 01)*" is applicable to this project.

Tool for the demonstration and assessment of additionality (Version 06.1.0)

The Tool mentions that "Once the additionality tool is included in an approved methodology, its application by project participants using the methodology is mandatory". Therefore the tool is applicable.

Finally, the methodology is only applicable if the identified baseline scenario is:

- The continuation of the current practice of either venting (scenario G1), flaring (scenario G2) of the associated gas and/or gas-lift gas or on-site use of the partial amount of associated and/or gas-lift gas to meet on-site energy demands and the rest of the gas are either vented or flared (scenario G3); and

- *The identified baseline scenario is the current practice of flaring (scenario G2) of the associated gas. Detailed description in section B.4.*

- The continued operation of the existing oil and gas infrastructure without any other significant changes (scenario P4);

- *The identified baseline scenario is the continued operation of the existing oil and gas infrastructure without any other significant changes (scenario P4). Detailed description is stated in section B.4.*

- In the case where gas-lift is used under the project activity: the gas-lift gas under the baseline uses the same source as under the project activity and the same quantity as under the project activity (scenario O1).

- *The identified baseline scenario uses the same source as under the project activity and the same quantity as under the project activity (scenario O1). Please refer to section B.4 for details.*

According to the above, the project is therefore justified to be applicable to the methodology.

B.3. Description of the sources and gases included in the project boundary:

The project boundary encompasses,

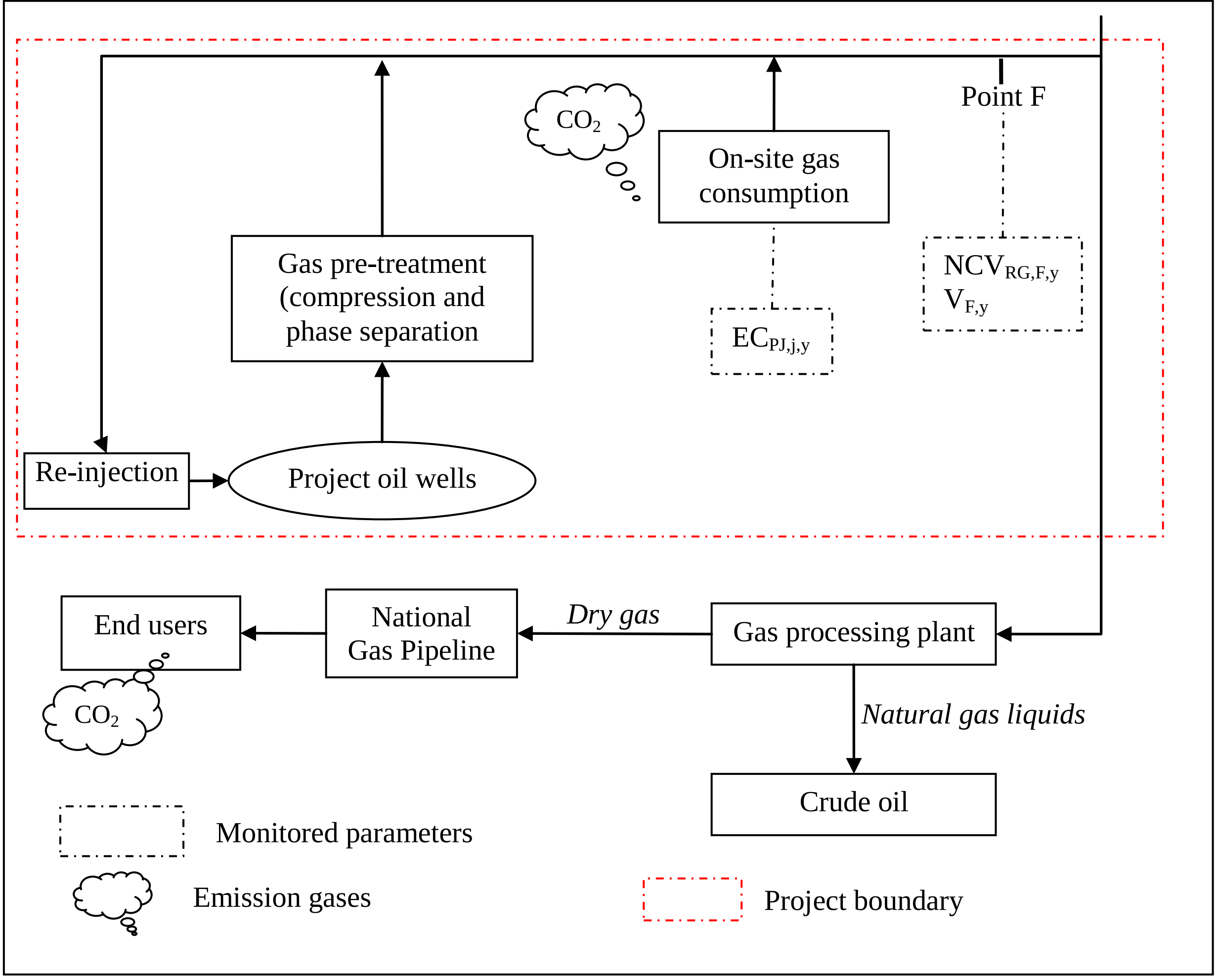
- The project oil reservoir and oil wells where the associated gas is collected;
- The site where the associated gas was flared or vented in the absence of the project activity;
- The gas recovery, pre-treatment, processing and transportation infrastructures, including where applicable, compressors;
- The source of gas-lift gas.

The greenhouse gases and emission sources included in or excluded from the project boundary are shown in Table B.1 below.

Table B.1. Emission sources included in or excluded from the project boundary

	Source	Gas	Included?	Justification / Explanation
Baseline	Combustion of fossil fuels at end-users that are produced from non-associated gas or other fossil sources	CO_2	Yes	Main source of emissions in the baseline
		CH_4	No	Excluded for simplification. This is conservative
		N_2O	No	Excluded for simplification. This is conservative
Project Activity	Energy use for the recovery, pre-treatment, transportation, and compression of the recovered gas	CO_2	Yes	Main source of emissions in the project. Part of the gas recovered is used for onsite power generation.
		CH_4	No	Excluded for simplification. This emission source is assumed negligible
		N_2O	No	Excluded for simplification. This emission source is assumed negligible

Figure B.1. Flow diagram of the project boundary



B.4. Description of how the baseline scenario is identified and description of the identified baseline scenario:

According to AM0009 version 06.0.0, the project participant shall apply the following steps to identify the baseline scenario:

Step 1: Identify plausible alternative scenarios
Step 2: Evaluate legal aspects
Step 3: Evaluate the economic attractiveness of alternatives
Step 4: Common practice analysis

Step 1: Identify plausible alternative scenarios

For the identification of plausible alternative scenarios for the production and utilization of gas from oil wells, realistic and credible alternatives should be separately determined regarding according to AM0009 version 06.0.0:

- Alternative baseline scenarios for the associated gas and gas-lift gas from project oil wells;
- Alternative baseline scenarios for oil and gas infrastructure;
- Alternative baseline scenarios for the use of gas-lift gas.

Realistic and credible alternatives for each of these components are presented below:

Alternatives baseline scenarios for the associated gas and gas-lift from project oil wells are analyzed as below in table below:

Table B.2. Alternative baseline scenarios for the associated gas and gas-lift from project oil wells:

NO.	*Scenario description*	*Relevance to the proposed project activity*
G1	Release of the associated gas and/or gas-lift gas into the atmosphere at the oil production site (venting)	**Not plausible.** Venting the associated gas from oil wells is not common practice for safety reasons (to avoid the risks of explosions and intoxication) and for environmental reasons (air pollution), as associated gas mainly consist of methane which is combustible, and mixtures of about 5 to 15 percent in air are explosive[3]. Thus, Option G1 is **not** considered a plausible alternative.
G2	Flaring of the associated gas and/or gas-lift gas at the oil production site	**Plausible.** Prior to the project, associated gas has been flared. There is no local or national regulation in Oman that restricts from flaring the gas. A World Bank Report shows Oman has an upward trend in gas flaring[4]. Thus, Option G2 is considered an alternative.

[3] http://scifun.chem.wisc.edu/chemweek/methane/methane.html

[4] http://siteresources.worldbank.org/INTGGFR/Resources/DMSP_flares_20070530_b-sm.pdf

G3	On-site use of the partial amount of associated gas and/or gas-lift gas to meet on-site energy and rest of the gas are either vented (G1) or flared (G2)	**Not plausible.** The electricity demand is limited at the project site. There is no need for more electricity generation. In addition, there are no connection structures between the proposed project and the power grid or other users, as the site is located in a deserted area about 50km from the nearest town (see section A.4.1.4 for details) Thus, Option G3 is **not** considered an alternative.
G4	Injection of the associated gas and/or gas-lift gas into an oil or gas reservoir	**Not Plausible.** The purpose of gas re-injection is either for gas-lift application or for gas storage. Gas-lift application: In the scenario existing prior to the proposed project activity, part of the gas is re-injected for gas-lift process and the rest is flared. Volumes of gas required for gas-lift process are calculated by field operator for efficient oil production. Existence of gas flaring prior to the start of the project activity demonstrates that excess gas exists after determination of gas-lift gas volumes for efficient oil production. Recovered associated gas volumes as part of the proposed CDM project activity have been estimated after deduction of projected gas volumes for gas-lift gas. Evidence is provided to DOE. Gas storage: Oil and gas production from Block 9 is off-taken easily through the Fahud-Sohar pipeline located near project site while the operator is a private company which aims at maximising profits. There is no justification for gas storage on-site. Thus, Option G4 is **not** considered a plausible alternative.
G5	The proposed project activity without being registered as a CDM project activity	**Plausible.** This option is technically and legally possible but economically unattractive considering projected gas volumes to be recovered and sold (120,385.54 mmscf) and maximum net calorific value of the recovered gas (43MJ/m3) as per specifications of National gas line where the gas will be sold; full details on economic attractiveness have been discussed in section B.5.
G6	Recovery, transportation and utilization of the associated gas and/or gas-lift gas as feedstock for manufacturing of useful products	**Not Plausible.** A factory which utilizes gas as feedstock for manufacturing of a useful product tends to require large investments and a stable gas supply. However, as per gas gains provided in Annex 3 Table 1 of this PDD, the associated gas from the proposed project will decrease year by year and does not guarantee such a stable and long-lasting supply. Besides, there is no manufacturing industry near project location as detailed in section E of the

		PDD. This option is **not** considered a plausible alternative

<u>Alternatives baseline scenarios for oil and gas infrastructure are analyzed as below in Table B.3</u>:

Table B.3. Alternative baseline scenarios for the oil and gas infrastructure:

NO.	*Scenario description*	*Relevance to the proposed project activity*
P1	Construction of a processing plant for the purpose of processing the recovered gas, in the same way as in the project activity, without being registered as a CDM project activity;	**Not Plausible.** Gas processing plant already exists on site.
P2	Construction of a processing plant of a lower capacity than under the project activity, which processes only non-associated gas and no recovered gas;	**Not Plausible.** Gas processing plant already exists on site.
P3	Supplying recovered gas to an existing gas processing plant and constructing the necessary infrastructure, without being registered as a CDM project activity;	**Plausible.** Supplying recovered gas to an existing gas processing plant and constructing the necessary infrastructure leads to the proposed project activity scenario. Thus, Option P3 is considered an alternative, yet not financially attractive considering projected gas volumes to be recovered and sold (120,385.54 mmscf) and maximum net calorific value of the recovered gas (43MJ/m3) as per specifications of National gas line where the gas will be sold; full details on economic attractiveness are provided in section B.5
P4	Continuation of the operation of the existing oil and gas infrastructure without any other significant changes;	**Plausible.** The continuation of the operation of the existing oil and gas infrastructure without gas any other significant changes does not require any investment and is consistent with existing regulations which do not prohibit flaring of associated gas; refer to step “legal aspects” for further legal information. Thus, Option P4 is considered an alternative.
P5	Supplying recovered gas to a gas pipeline without prior processing and without being registered as a CDM project activity.	**Not Plausible.** This option is not plausible as the gas must be processed to meet quality requirements of the gas pipeline. Any gas not meeting standard requirements of gas pipeline will be rejected. National gas pipeline specifications are provided to

DOE.

Plausible alternative baseline scenarios for the use of gas-lift could include, inter alia:

Table B.4. Alternative baseline scenarios for the use of gas-lift:

NO.	*Scenario description*	*Relevance to the proposed project activity*
O1	Gas from the same source as under the project activity and in the same quantity as under the project activity is used for the gas-lift system;	**Plausible.** The injection of gas into the oil reservoir and its production process for the purpose of the gas-lift process is common production practice at Block 9. Gas used as gas-lift gas originates from the wells where it is reinjected, while volumes of gas required for gas-lift process are calculated by field operator for efficient oil production.
O2	Gas from a different source than under the project activity but using the same quantity of gas-lift gas as under the project activity, is used for the gas-lift system;	**Not plausible.** Gas used as gas-lift gas originates from the wells where it is reinjected, as natural gas is found in association with oil at Block 9. Related equipment is installed at each location.
O3	Gas from the same source as under the project activity but using a different quantity of gas-lift gas, is used for the gas-lift system;	**Not plausible.** Volumes of gas required for gas-lift process are calculated by field operator for efficient oil production, regardless of the proposed project activity. Recovered associated gas volumes as part of the proposed CDM project activity have been estimated after deduction of projected gas volumes for gas-lift gas. Evidence is provided to DOE.
O4	Gas from a different source than under the project activity and in a different quantity than under the project activity, is used for the gas-lift system;	**Not plausible.** Gas used as gas-lift gas originates from the wells where it is reinjected. Related equipment is installed at each location. Volumes of gas required for gas-lift process are calculated by field operator for efficient oil production, regardless of the proposed project activity.
O5	No gas-lift system is utilized.	**Not plausible.** As stated in scenario O1 above, The injection of gas into the oil reservoir and its production process for the purpose of the gas-lift process is common production practice at Block 9.

Outcome of Step 1: The above analysis results in realistic combination of baseline alternative scenario as:

Option 1: G2+P4+O1, flaring of the associated gas at the oil production site; continuation of the operation of the existing oil and gas infrastructure without any other significant changes; and gas from the same source as under the project activity and in the same quantity as under the project activity is used for the gas-lift system.

Option 1 is the continuation of the scenario existing prior to the start of the proposed project activity

> ***Option 2***: G5+P3+O1, the proposed project activity without being registered as a CDM project activity; supplying recovered gas to an existing gas processing plant and constructing the necessary infrastructure, without been registered as CDM project activity; and gas from the same source as under the project activity and in the same quantity as under the project activity is used for the gas-lift system.

Option 2 is the proposed project activity without being registered as a CDM project activity.

Step 2: Evaluate legal aspects:
All the realistic and credible alternative scenarios (G2, G5, P3, P4, and O1) outlined above are permitted by law or other (industrial agreements and standards. There are no laws or other regulations (e.g. environmental regulations) which implicitly restrict some of the alternatives. This is evidenced in the report "Regulation of Associated Gas Flaring and Venting, A Global Overview and Lessons from International Experience" published by the Global Gas Flaring Reduction Public-Private Partnership of the World Bank[5], which states that for the Sultanate of Oman: The operator may "lift, process, and market associated gas jointly with the national oil company, subject to a negotiated gas agreement" and "use associated gas in operations or reinject or flare gas, subject to relevant consents". Besides, the report further explains that: "Permission to flare gas that cannot be marketed and that exceeds operational requirements is granted by the minister's written consent. Permission is not required to flare during normal well testing".
In addition, associated gas flaring at Block 9 (existing scenario prior to the proposed project activity) does not violate the emissions standards as prescribed by the Ministerial Decision 5/86 of May 17th 1986 that "Dark Smoke-products of combustion shall not emit smoke as dark as or darker than shade 1 on the Ringelmann Scale. (20% opacity)", and that "sulfur recovery units must achieve at least 95% efficiency", as evidenced by the renewal of environmental permit (7th renewal) issued by the Ministry of Environment and Climate affairs on July 25th 2010.

Outcome of Step 2:
All the realistic and credible alternative scenarios (G2, G5, P3, P4, and O1) outlined above are in compliance with mandatory legislation and regulations taking into account the enforcement in Oman and EB decisions on national and/or sectoral policies and regulations.

Step 3 and Step 4 will be carried out in the Section B.5.

As detailed in section B.5, the outcome of the investment analysis shows that Option 2 above (i.e. the proposed project activity without being registered as a CDM project activity) is not considered economically attractive by the project participants. Therefore, the most plausible baseline scenario for the Project is identified as ***Option 1***: G2+P4+O1, flaring of the associated gas at the oil production site; continuation of the operation of the existing oil and gas infrastructure without any other significant changes; and gas from the same source as under the project activity and in the same quantity as under the project activity is used for the gas-lift system.

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[5] http://go.worldbank.org/NEBP6PEHS0

Methodology AM0009 is applicable to the proposed project activity as the identified baseline scenario is scenario G2, P4 and O1.

B.5. Description of how the anthropogenic emissions of GHG by sources are reduced below those that would have occurred in the absence of the registered CDM project activity (assessment and demonstration of additionality):

Step 3: Evaluate the economic attractiveness of alternatives

According to AM0009 (version 06.0.0), the economic attractiveness is assessed for those alternative scenarios that are feasible in technical terms and that are identified as permitted by law or other (industrial) agreements and standards in Step 2. The economic attractiveness is assessed by determining an expected Internal Rate of Return (IRR) of each alternative scenario.

As required by methodology, the IRR should be determined using, inter alia, the following parameters as applicable to the relevant scenario:

- Overall projected production of associated gas and/or gas-lift gas;
- The projected quantity of gas recovered, gas flared, vented, consumed on-site, processed in a gas processing plant and/or compressed into a pipeline;
- The agreed price for the delivery of recovered gas (e.g. from a Production Sharing Contract) to the gas pipeline or gas processing plant (if operated by a third party);
- The net calorific value of the recovered gas;
- Capital expenditure for all oil and gas infrastructure needed in the relevant scenario, such as gas recovery facilities, pipelines, and gas processing plant (if applicable) etc. (CAPEX);
- All operational expenditure associated with the respective scenario (OPEX);
- All revenues from the operation of the alternative scenario, such as revenues from selling processed gas or other products of the gas processing plant or electricity;
- Any profit sharing agreements and cost recovery, such as cost savings through the substitution of products by the recovered gas, if applicable.

In the proposed project activity, the combinations of alternative scenarios left after ***step 2*** are:

Option 1: G2+P4+O1, flaring of the associated gas at the oil production site; continuation of the operation of the existing oil and gas infrastructure without any other significant changes; and gas from the same source as under the project activity and in the same quantity as under the project activity is used for the gas-lift system.

Option 1 is the continuation of the existing scenario or the scenario occurring prior to the start of the proposed project activity. This alternative scenario does not involve any investment and no additional revenues are generated from the operations of such scenario. Associated gas flaring and the use of gas-lift are common production practices at Block 9. Note that venting or flaring of associated gas at a given location is not subject to taxes or fine (see section B.4 step 2 for legal aspects).

Option 2: G5+P3+O1, the proposed project without being registered as a CDM project activity; supplying recovered gas to an existing gas processing plant and constructing the necessary infrastructure, without been registered as CDM project activity; and gas from the same source as under the project activity and in the same quantity as under the project activity is used for the gas-lift system.

Option 2 is the proposed project activity without being registered as a CDM project activity. This option requires capital investment and generates revenues from the sales of gas and by-products. The following investment analysis is conducted for this alternative. The IRR is determined following the guidance for the investment analysis in the latest approved version of the "Tool for the demonstration and assessment of additionality (Version 06.1.0)".

Table B.5. Basic data for Equity IRR calculation

Parameter	Data	Unit	Source
Capital expenditures (100% equity)	86,066,460	US$	Project Authorization Request provided by onsite operator
Annual Operational expenditures	1,017,105	US$	Calculated by Operator on-site. The value is discounted over lifetime in IRR analysis to reflect expected cessation of gas recovery activities at some locations
Projected quantity of gas recovered over the project life time	133,885.73	mmscf	On-site operator. Detailed values in Annex 3, Table 2
Projected quantity of gas used internally over the project life time	5,707.72	mmscf	Calculated considering energy content in recovered gas and electrical efficiency of turbines installed on-site. See detailed calculations in Annex 3, Table 11.
Projected quantity of gas sold over the project life time	120,385.54	mmscf	On-site operator. Detailed values in Annex 3, Table 12, after deduction of a shrinkage factor (see suitability of input values below).
Agreed price for the delivery of recovered gas	996 (incremental +1.5% per year)	US$/mmscf	Gas Purchase Agreement. Evidence provided to DOE
Net calorific value of the recovered gas	43	MJ/m^3	Maximum value acceptable at gas selling point as per gas purchase agreement (or 1154 BTU per SCF). Evidence provided to DOE. Note that here the Gross Heating Value is used for conservativeness.
Expected price for liquid gains	45	US$/Brl	Official oil price for budget purpose at investment decision, as per Oman State General 2008 Budget published on January 1st 2008. Evidence provided to DOE
Expected gross annual average revenues for the Operator as per cost	4,424,462	US$	From IRR calculations sheet. Calculated in accordance with the terms of the Exploration

recovery and production sharing agreements			& Production Sharing Agreement. Evidence is provided to DOE.
Income tax rate for Operator	55	%	Oman Tax Law; Tax receipts. Depreciation is not taken into account in the calculations of taxable income to avoid double-counting, as the operator is allowed to recover all costs including equipment costs.

Determination of the benchmark
Following the Guidelines on the Assessment of Investment Analysis Version 5 and as the project could only be implemented by the current Block 9 operator, the operator's internal benchmark applies and the cost of equity is determined by selecting the simple default option value provided in Appendix A of the above mentioned UNFCCC Guidelines, in line with Guidelines section IV paragraph 15. The project belongs to Sectoral Scope 10 "Fugitive Emissions from fuels" and therefore falls under project category Group 2. The default value for the expected return on equity calculated after taxes for the Sultanate of Oman is 11.5%. Thus, the investment analysis compares the equity Internal Rate of Return after tax (IRR) with the 11.5% benchmark. The main results of the investment analysis are presented in Table B.6,

Table B.6. Comparison of the financial indicator for the proposed project activity and the financial benchmark

Equity IRR after taxes	8.65%
Financial benchmark	11.5%

It is concluded that the project activity has a less favourable indicator than the benchmark, therefore the proposed project activity without being registered as CDM (alternative baseline scenario Option 2 as per Section B.4 step 2) is not considered financially attractive.

Suitability of key input values:

- *<u>CAPEX</u>*:
Capital expenditures for the project are taken from the operator's internal *Project Authorization Request*. They are detailed in the Table B.7 below:

Table B.7. Capital Expenditures

Location	Costs (USD)	Main equipment
CPF	17,225,443	- Screw compressors - Electric Motors - Pipelines
FW	25,846,713	- Reciprocating compression - Motor - Air cooled exchanger - Scrubbers and discharge scrubbers - Suction bottles - Pipelines
WL	17,459,163	- Reciprocating compression - Motor - Air cooled exchanger

		- Scrubbers and discharge scrubbers - Suction bottles - Pipelines
JAL	14,801,350	- Reciprocating compression - Motor - Air cooled exchanger - Scrubbers and discharge scrubbers - Suction bottles
SAT	10,733,793	- Reciprocating compression - Motor - Air cooled exchanger - Scrubbers and discharge scrubbers - Suction bottles
Total	**86,066,460**	

The total value has been cross-checked with actual invoices related to the implementation of the proposed project activity. Actual invoices amount to 88,859,850 USD, of which around 85% relates to equipment, 8% to construction and 8% to electrical works. Design phase related invoices are not provided which is conservative. Hence, the capital costs used in PDD's investment analysis are in line with actual costs.

- *OPEX*:
Operational expenses have been calculated by the on-site operator and correspond to around 1.2% of CAPEX. Table below provides the breakdown:

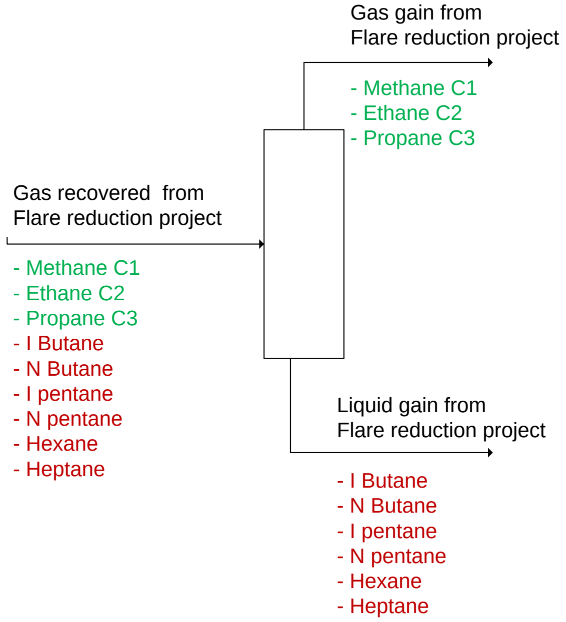
Table B.8. Annual operational expenditures

	Labour	Maintenance	Materials	Support & others	Total
CPF	200,000	9,302	52,436	50,000	311,738
FW & SAT	200,000	21,391	29,316	50,000	300,707
WL & JAL	200,000	38,987	115,673	50,000	404,660
Total					1,017,105

The value was cross-checked with actual O&M costs which amount to 1,155,674 USD.

Expected volumes of gas and liquids
Gas gains are assumed to methane C1, ethane C2 and propane C3. The liquid gains are assumed to be the remaining heavy components of the recovered gas a shown in the below figure:

Figure B.2. Gas and liquid gains composition



Source: operator, 'liquid gain from flare reduction project' report.

Recovered gas: Volumes detailed in Annex 3 Table 1 were calculated by the reservoir management team and served as the basis of investment decision. As projections of the oil production, the expected gas volumes involve a considerable degree of uncertainty. In accordance with recommendation of the monitoring methodology, the quantity of recovered gas will be monitored ex-post. A shrinkage factor during processing at gas plant was estimated by operator through computerized model using HYSYS software. The following shrinkage factors values have been used in IRR calculations:

Table B.9. Gas Shrinkage factor

Location	Shrinkage factor
CPF	11%
FW	5%
WL	4%
JAL	4%
SAT	4%

Source: operator, 'liquid gain from flare reduction project' report.

Moreover, values have been cross-checked with actual data at CPF location where specific measuring equipment is already installed. At other locations, actual volumes have been derived based on measured oil production volumes and Gas/Oil Ratio (GOR) at Block 9. Actual values have been provided to DOE. Projected values used in IRR calculations are deemed conservative.

Recovered liquids: The recovered gas is treated at processing plant located after methodology Point F as described in PDD Figure B.1 for the purpose of meeting specifications of the national pipeline where it is sold. The treatment generates condensate as by-product (also referred to as 'Natural Gas Liquids' or NGL). The condensate is swollen into the crude oil for sales therefore revenues from condensate are estimated at crude oil price. There is no LNG production. Liquid volumes were estimated by the operator through complex modelling using HYSYS software based on gas composition at each location. A separate report prepared by

operator named ‘liquid gain from flare reduction project’ detailing the liquid gains estimation process and original HYSYS files have been provided to DOE.

Table B.10. Liquid gains

Location	**Expected liquid gains (brls per mmscf recovered)**
CPF	81.67
FW	40.41
WL	27.19
JAL	33.94
SAT	31.9

Source: operator, ‘liquid gain from flare reduction project’ report.

Moreover, considering that NGL volumes are a direct function of gas volumes and that actual recovered gas volumes have been cross-checked as being on the conservative side from an additionality point of view compared with projected data, actual projected NGL volumes are deemed to reflect actual NGL volumes in an equally conservative manner.

- ***Agreed price for the delivery of recovered gas***

According to Article 5 of the Gas Purchase Agreement (GPA) effective April 29th 2003, which was provided to DOE, the agreed price for the delivery of recovered gas at the delivery point is set at USD 0.85 per MMBTU escalated at 1.5% per annum with the first escalation effective the first day of the 49th ‘Contract Month’.
As per GPA Article 1, paragraph 1.1, ‘Contract Month’ starts from the 'First Gas Date'. The definition of ‘First Gas Date’ as per GPA Article 2, paragraph 2.2 is as follows: The date of first delivery of natural gas, but no later than January 1st 2004.
As evidenced by actual gas invoice dated December 1st 2012 and provided to DOE, the current gas price is **0.91569 US$ per MMBTU (**or 1056.70787941018 US$ per MMSCF). It confirms that the ‘First Gas Date’ was January 1st 2004 and that first escalation occurred in 2008.

- ***Expected price for liquid gains***

As mentioned above, the recovered condensate is swollen into crude oil. Assumed US$45/Brl oil price is strictly in line with Oman Ministry of Finance’s official budgeted oil price for 2008, made publicly available in January 2008. Evidence is provided to DOE. Official budgeted oil price in the State General Budget for the subsequent Financial Year 2009 was also 45$/brl.

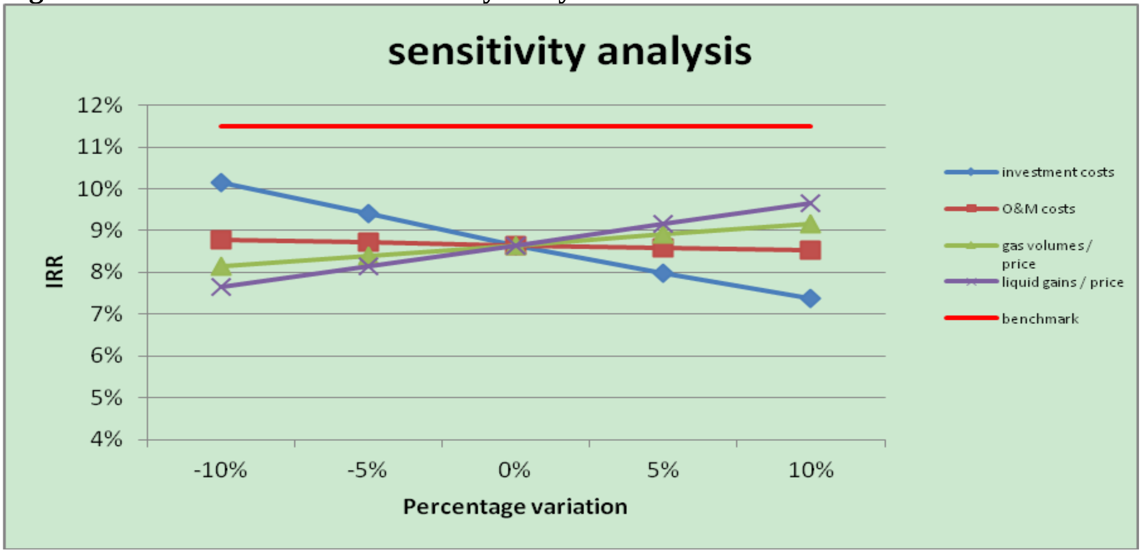
Sensitivity Analysis (step 2d of the “Tool for the demonstration and assessment of additionality” (Version 06.1.0)

A sensitivity analysis is performed to show whether the conclusion regarding the financial/economic attractiveness is robust to reasonable variations in the critical assumptions. The range of +10% and -10% is standard for this type of projects and in line with the Guidelines on the assessment of investment analysis (version 05) paragraph 21. Variables listed in Table below have been considered in the sensitivity analysis:

Table B.11. Sensitivity analysis; impact of variations in assumptions on the IRR

Percentage Variation / Critical assumption	-10%	-5%	0%	+5%	+10%
Investment costs	10.16%	9.40%	8.65%	7.98%	7.39%
O&M costs	8.77%	8.71%	8.65%	8.60%	8.54%
gas volumes / price	8.15%	8.40%	8.65%	8.91%	9.17%
liquid gains / price	7.65%	8.15%	8.65%	9.17%	9.66%

Figure B.3. Results of the sensitivity analysis



The sensitivity analysis of the Internal Rate of Return confirms that the proposed project after realistic modifications to the critical assumptions remains commercially is unlikely to be financially/economically attractive without CDM revenues. The Internal Rate of Return of the proposed project activity without CDM revenues remains below the 11.5% benchmark.

The conclusion is clear that with reasonable modifications in the critical assumptions, the main results remain unaltered. The results of the sensitivity analysis therefore confirm that the ***Option 2***: G5+P3+O1 is not economically attractive for the Operator without CDM support.

Outcome of step 3:
As per AM0009 methodology, the alternative scenario that is economically the most attractive course of action is considered as the baseline scenario. Consequently, Option 2 is eliminated and Option 1 is the baseline scenario.

Step 4 Common practice analysis

Methodology AM0009 assumes that the use of recovered gas displaces the use of methane, the fossil fuel with the lowest direct CO2 emissions. Hence, and in line with email clarification from the UNFCCC CDM Helpdesk (provided to DOE), greenhouse gas emission reduction activities as part of the proposed project fall within Measure type (a) "Fuel and feedstock switch" listed in paragraph 6 of the "Tool for the demonstration and assessment of additionality" (Version 06.1.0). Consequently, the existing common practice should be identified and discussed through the following sub-steps:

Sub-step 1*: Calculate applicable output range as +/-50% of the design output or capacity of the proposed project activity.*

As per EB69 Annex 8 “Guidelines on Common Practice” the output is defined as “goods/services produced by the project activity including, among other things, heat, steam, electricity, methane and biogas unless otherwise specified in the applied methodology”. In the project activity context the output is the recovered gas as sold to gas pipeline. The design output, i.e. the expected average net gas volumes to be transported and delivered to National pipeline, is 37.02mmscfd over the lifetime.

Outcome of sub-step 1*:* The applicable output range is between 18.5 mmscfd and 55.52 mmscfd.

Sub-step 2*: In the applicable geographical area, identify all plants that deliver the same output or capacity, within the applicable output range calculated in Step 1, as the proposed project activity and have started commercial operation before the start date of the project. Note their number* N_{all}*. Registered CDM project activities and projects activities undergoing validation shall not be included in this step.*

As per EB69 Annex 8 “Guidelines on Common Practice” and the “Tool for the demonstration and assessment of additionality” (Version 06.1.0), the applicable geographical area is the entire Host Country as a default. In order to identify all plants delivering the same output as the proposed project, we have reviewed oil and gas concessions and companies active in the Sultanate of Oman, based on concession boundaries and operators list provided by the Ministry of Oil & Gas and information publicly available. We first considered the status of each concession, i.e. whether oil and/or gas are currently being produced. The table below summarizes the findings. Note that the original source of information is indicated in Annex 3, Table 13.

Table B.12. Active petroleum companies in the Sultanate of Oman

Company	Country of origin	Oman concession block #	Status	EPSA[6] date
Occidental of Oman	U.S.A	9	production	1983
Circle oil	Ireland	52, 49	exploration	2005
BP	UK	61	test production	2007
Petronas	Malaysia	63	exploration	2009
RAK Petroleum	UAE	8	production	2009
		30	appraisal	2009
		31	exploration	2009
		47	exploration	2009
CC Energy	Lebanon	3, 4	test production	2005
Thetys	Sweden	15	test production	2007
Petrotel	Oman	40	exploration	2011
Petrogas	Oman	7	production	1999
Maersk	Denmark	48	appraisal	2001
Epsilon Energy	Canada	55	exploration	2009
Oilex	Australia	56	relinquished	2006
Reliance industries	India	18, 41	relinquished	2005

[6] Exploration and Production Sharing Agreement between company and Oman Government

Hunt Oil	U.S.A	51	exploration	2002
MOL	Hungary	43B	exploration	2008
Daleel	Oman	5	production	2002
Harvest	U.S.A	64	exploration	2008
PDO	Oman	6	production	1974

Source: concession boundaries and operators provided by Ministry of Oil & Gas; other information source please refer to Annex 3 Table 13.

From the table above and with the exception of Block 9, only four concessions are currently producing oil and/or gas. Others are at either earlier stages of development or relinquished, and can be excluded from the analysis. Concessions producing oil and/or gas are operated by RAK Petroleum (Block 8), Petrogas (Block 7), Daleel (Block 5) and PDO (Block 6).

Block 8: RAK Petroleum Public Company Limited reports on its website that it is producing 40 million cubic feet a day of gas from its two operated offshore fields in Oman Block 8, as of June 2010, which falls within the defined output range in Step 1. However, commercial operation commenced on 16 February 2009, as per a press release from the company, which is after the start date of the proposed CDM project (See weblinks in Annex 3 Table 13). Moreover, the gas produced is delivered outside the applicable geographical area directly to a foreign country, the United Arab Emirates.

Block 7: Publicly available information[7] from Petrogas which operates Block 7 reports that *"Production from the Contract Area peaked in mid 1992 (while operated by previous operator), with production achieving an annual average rate of some 14,000 barrels a day. Production in 2006 averaged 1,655 barrels a day. At the end of 2007, the total cumulative production from the Sahmah field was 53.0 million barrels. The forecast production rate for 2008 including Ramlat and Rija fields is 1,850 barrels a day"*.
Besides, Petrogas indicates that *"All producing wells in the Sahmah field are artificially lifted. Three wells are produced using electric submersible pumps and the remainder and majority of the wells are artificially lifted by gas lift. Sahmah has its own dedicated surface facilities which include power generation and gas compression for gas lift"*.
Considering that no gas production is reported by Petrogas (See also Annex 3 Table 13) and since production has been declining since 1992, it is reasonable to conclude that associated gas recovery, if any, is taking place at Block 7 only for gas lift purpose and does not fall within the output range defined in sub-step 1. Absence of associated gas in oil wells located in South Oman is confirmed by Petroleum Development Oman which states: *"The character of Oman's oil changes between the north and south, posing different production problems. In the north the crude is light and normally recovered with gas. Some wells produce simply using the natural reservoir pressure to push the oil to the surface. Others need additional help from the injection of water and gas (gaslift). In the south there is little gas associated with oil which is heavy and viscous and will not flow readily"*[8].

Block 5: Petrogas has also 50% working interest in the Block-5 Contract Area held by their wholly owned subsidiary Mazoon Petrogas SAOC. Mazoon Petrogas SAOC has a 50% ownership of the Daleel Petroleum Co. LLC, a joint venture with the China National Petroleum Corporation (CNPC). Daleel Petroleum Co. LLC is the operator in Block 5 and has managed operations since Year 2002[9]. The CNPC website[10] indicates that a processing plant

[7] http://www.petrogasllc.com/Backup/operations_petroleum_agreements_b07.shtml

[8] http://www.pdo.co.om/expatriate_site/operations.htm

[9] http://www.petrogasllc.com/Backup/operations_petroleum_agreements_b05.shtml

was constructed onsite to allow the recovery and treatment of 20 mmscfd of associated gas, which falls within the output range defined in sub-step 1. Information regarding the start date of the project and the actual volumes of gas processed is not publicly available, but for conservativeness in this analysis it is assumed that commercial operations started prior to the proposed CDM project.

Block 6: Petroleum Development Oman (PDO) which operates Block 6 is according to the latest (2008) Trade Policy Review of the World Trade Organization[11] the *"major state-owned company that dominates oil and natural gas activities"*. PDO is majority-owned (60%) by the Oman Government. According to The Geological Society of Oman, an organization declared by a Ministerial Order issued by the Ministry of Social Affairs of Oman, *"Block 6 contains almost all of Oman's oil and gas producing reserves (95%). Industry perceptions are that Block 6 contains most of the oil and gas prone basins, with the peripheral blocks available to others having minor potential"*[12]. In a press release dated 20th February 2012, the company announced *"Daily oil and condensate production in 2011 stood at 549,280 and 93,600 barrels per day respectively and non-associated and associated gas production at 463,000 and 85,000 barrels of oil equivalent per day respectively"* (see Annex 3 Table 13). This is equivalent[13] to 493 mmscfd associated gas and 2,685mmscfd non-associated gas which is out of the range defined in sub-step 1.

Outcome of sub-step 2: In the applicable geographical area, only Block 5 delivers an output within the applicable output range defined in sub-step 1 and has started commercial operation before the start date of the proposed CDM project is. Therefore N_{all} = 1.

Sub-step 3*: Within plants identified in Step 2, identify those that apply technologies different that the technology applied in the proposed project activity. Note their number* N_{diff}*;*

As per additionality tool (version 06.1.0), different technologies in the context of common practice are technologies that deliver the same output and differ by at least one of the following (as appropriate in the context of the measure applied in the proposed CDM project and applicable geographical area):
(a) Energy source/fuel;
(b) Feed stock;
(c) Size of installation (power capacity):
  (i) Micro (as defined in paragraph 24 of Decision 2/CMP.5 and paragraph 39 of Decision 3/CMP.6);
  (ii) Small (as defined in paragraph 28 of Decision 1/CMP.2);
  (iii) Large;
(d) Investment climate in the date of the investment decision, inter alia:
  (i) Access to technology;
  (ii) Subsidies or other financial flows;
  (iii) Promotional policies;

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[10] http://www.cnpc.com.cn/NR/exeres/7F35D277-53A6-44DB-A028-34DE66DF167D.htm?COLLCC=547061880&NRMODE=Unpublished&wbc_purpose=Basic&WBCMODE=PresentationUnpublished

[13] http://www.natgas.info/html/natgasunitscalculator.html

[13] http://www.natgas.info/html/natgasunitscalculator.html

[13] http://www.natgas.info/html/natgasunitscalculator.html

(iv) Legal regulations;
(e) Other features, inter alia:
(i) Unit cost of output (unit costs are considered different if they differ by at least 20 %).

Gas recovery and utilization activities at Block 5 differ from the proposed CDM project by the 'investment climate in the date of the investment decision' with regard to 'subsidies or other financial flows' because the operator of Block-5 benefited from a US$40 Million from the International Finance Corporation as *"international banks have shied away from extending long-term financing at reasonable rates to small local private players in the region following the events of September 11th"*. IFC also states that *"IFC's participation with a longer maturity will afford the Project with greater flexibility"*[14], and that *"IFC plans to monitor the Operator's progress towards the reduction/elimination of gas flaring"*.

Outcome of sub-step 3: Block 5 applies a technology different than the technology applied in the proposed project activity. $N_{diff} = 1$

Sub-step 4: *Calculate factor $F=1-N_{diff}/N_{all}$ representing the share of plants using technology similar to the technology used in the proposed project activity in all plants that deliver the same output or capacity as the proposed project activity.*
The proposed project activity is a "common practice" within a sector in the applicable geographical area if both the following conditions are fulfilled:
(a) The factor F is greater than 0.2; and
(b) $N_{all}-N_{diff}$ is greater than 3.

$F = 1- (1/1)$
$F= 1-1 = 0$

$N_{all} – N_{diff} = 1-1 = 0$

Outcome of sub-step 4: The factor F is 0 and N_{all} minus N_{diff} is 0.

Outcome of Step 4: The proposed project is not a 'common practice' within the sector in the applicable geographical area because both condition (a) and condition (b) in sub-step 4 above are not fulfilled. The requirements of the common practice analysis are fulfilled and the project is additional.

<u>Prior consideration of the CDM</u>

CDM was a decisive factor in the decision to proceed with the project. An overview of key events is given in Table below, indicating continuing and real actions to secure CDM status for the project in parallel with its implementation with no gap greater than 2 years between these actions to secure CDM status:

Table B.13. Timeline of CDM consideration

Date	Key events	Evidence
Feb. 12th 2008	**Early CDM consideration –** Decision to develop the project under the Clean Development Mechanism	Official correspondence

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14 http://www.ifc.org/ifcext/spiwebsite1.nsf/2bc34f011b50ff6e85256a550073ff1c/2da4cf88b1048a13852576ba000e266e?OpenDocument&Highlight=0,Hungary

Apr. 1st 2008	**Start of the project activity** – A Project Authorization Request is approved internally for the reduction of the FW flare and the purchase of a series of new pipeline and re-routes.	Project Authorization Request
May 2008	The Oman Authority for Electricity Regulation recommends that Oman establish a Designated National Authority (DNA) to facilitate and administer incentives for Clean Development Mechanisms (CDM).	Study on Renewable Energy Resources, Oman, Final Report[15]
4th Aug. 2008	The Ministry of Oil & Gas contacts the Ministry of Environment & Climate Affairs (MECA) to inform about the progress of the project and inquire about establishment of the Designated National Authority	Letter
24th May 2009	A Memorandum of Understanding is drafted between Operator on-site and CER buyer	MoU
6th July 2009	MECA issue a statement in the press confirming that DNA is at final stage of establishment	Oman Daily Observer Newspaper
30th Sep 2009	Following MECA statement clarifying the status of Omani DNA establishment process, CDM consultant is hired and starts work	Email correspondence
15th Dec 2009	Meeting is organized between project participants and CDM consultant at Occidental of Oman	Email correspondence
May 10th 2010	Signature of a term sheet for the purchase of carbon credits	Term sheet
Jun. 2010	A CDM-related stakeholder consultation is organized	Questionnaire survey
Sep. 2010	Omani Government names the Directorate General of Climate Affairs (Ministry of Environment and Climate Affairs) as the statutory body with responsibility to serve as the DNA in Oman.	Ministerial Decree 30/2010
Nov. 2010	ERPA is signed with CER buyer	ERPA
28th Jun. 2011	On-site validation	Email correspondence
30th Jul. 2011	No-Objection Letter is issued by the Ministry of Environment and Climate Affairs in relation to the proposed CDM project	Letter

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

In accordance with AM0009 Version 06.0.0, baseline is calculated as below,

Baseline emissions
Project activities under this methodology reduce emissions by recovering and utilizing the recovered gas. The utilization of the recovered gas displaces the use of other fossil fuel sources.

Baseline emissions are calculated as follows:

[15] http://www.aer-oman.org/pdf/studyreport.pdf

$$BE_y = V_{F,y} \cdot NCV_{RG,F,y} \cdot EF_{CO2,Methane} \tag{1}$$

Where:

BE_y	= Baseline emissions in year *y*, (tCO_2e)
$V_{F,y}$	= Volume of total recovered gas measured at point F in methodology AM0009 version 06.0.0 Figure 2 in year *y*, (Nm^3)
$NCV_{RG,F,y}$	= Net calorific value of recovered gas measured at point F in methodology AM0009 version 06.0.0 Figure 2 in year y, (TJ/Nm^3)
$EF_{CO2, Methane}$	= CO_2 emission factor for methane (tCO_2/TJ)

Project emissions

The following sources[16] of project emissions are accounted in this methodology:

- CO2 emissions due to consumption of fossil fuels for the recovery, pre-treatment, transportation, and, if applicable, compression of the recovered gas up to the point F in F methodology Figure 2;
- CO2 emissions due to the use of electricity for the recovery, pre-treatment, transportation, and, if applicable, compression of the recovered gas up to the point F in methodology Figure 2.

Project emissions are calculated as follows:

$$PE_y = PE_{CO2,fossilfuels,y} + PE_{CO2,elec,y} \tag{2}$$

Where:

PE_y	= Project emissions in the period y, (tCO_2e)
$PE_{CO2,fossilfuels,y}$	= CO_2 emissions due to consumption of fossil fuels for the recovery, pre-treatment, transportation, and, if applicable, compression of the recovered gas up to the points F in methodology AM0009 version 06.0.0 Figure 2 during the period y, (tCO_2e)
$PE_{CO2,elec,y}$	= CO2 emissions due to the use of electricity for recovery, pre-treatment, transportation and, if applicable, compression of the recovered gas up to the points F in methodology AM0009 version 06.0.0 Figure 2 during the period y, (tCO_2e)

(i) $PE_{CO2,fossilfuels,y}$ *Project emissions from the consumption of fossil fuels*:

Project emissions $PE_{CO2, fossilfuels, y}$ due to the consumption of fossil fuels, including the recovered gas, if applicable for the recovery, pre-treatment, transportation and, if applicable, compression of the recovered gas are calculated applying the latest approved version of the "*Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion*" where $PE_{CO2,fossilfuels,y}$ corresponds to $PE_{FC,j,y}$ in the tool and process *j* corresponds to all sources of fuel combustion (e.g. a compressor, etc) up to point F in methodology Figure 2. All applicable emission sources should be documented transparently in the CDM-PDD and in monitoring reports.
Energy use due to the project activity consists of the power required to run the compression, pre-treatment and transportation equipment. The equipment is all electricity-driven, the

[16] Other sources of project emissions such as emissions from leaks, venting and flaring during the recovery, transportation and processing of recovered gas are assumed to be of similar magnitude in the baseline scenario.

electricity consumption is monitored and the project emissions from the consumption of electricity are estimated using the conservative default factor of the applicable tool, and consequently the emissions from the fossil fuel consumed by the electricity generators as part of project activity is: $PE_{CO2, fossilfuels, y} = 0$.

(ii) $PE_{CO2,elec,y}$ *Project emissions from consumption of electricity:*

Project emissions $PE_{CO2, elec, y}$ due to the use of electricity for the recovery, pre-treatment, transportation, and, if applicable, compression of the recovered gas are calculated applying the latest approved version of the "*Tool to calculate baseline, project and/or leakage emissions from electricity consumption*" where $PE_{CO2,elec,y}$ corresponds to $PE_{EC,y}$ in the tool and the electricity consumption sources *j* in the tool correspond to all sources of electricity consumption (e.g. a compressor, etc) up to point F in methodology Figure 2.
Applicable sources of electricity consumption as part of the project activity consists of the power required to run the compression, pre-treatment and transportation equipment. Electricity is produced in on-site captive power plant.

As per above mentioned Tool, the generic approach for project emissions is based on the quantity of electricity consumed, an emission factor for electricity generation and a factor to account for transmission losses:

$PE_{CO2,elec,y} = PE_{EC,y}$

$$PE_{EC,y} = \sum_j EC_{PJ,j,y} \times EF_{EL,j,y} \times (1 + TDL_{j,y}) \quad (3)$$

Where:

$PE_{EC,y}$ = Project emissions from electricity consumption in year y (tCO2/yr);

$EC_{PJ,j,y}$ = Quantity of electricity consumed by the project electricity consumption source j in year y (MWh/yr);
$EF_{EL,j,y}$ = Emission factor for electricity generation for source j in year y (tCO2/MWh)
$TDL_{j,y}$ = Average technical transmission and distribution losses for providing electricity to source *j* in year *y*

j = Sources of electricity consumption in the project

Determination of quantity of electricity consumed by the project electricity consumption source j in year y ($EC_{PJ,j,y}$)
Sources of electricity consumption in the project include vapour recovery unit at CPF and reciprocating compression units at WL, JAL, SAT and FW. Vapour recovery unit and reciprocating compression packages include compressors but also motors, air cooled exchangers, scrubbers, discharge scrubbers and suction bottles. The electricity consumption for each unit is estimated ex-ante through multiplying the total power capacity of the units at each location by the expected operating hours. Please refer to Annex 3 Table 8 for detailed values. Expected operating hours are calculated as gross gas gains at each location divided by total installed compression capacity at each location, and then multiplied by 24 hours and 350 days, considering annual downtime for maintenance (evidence provided to DOE). Please refer to Annex 3 Table 7 for detailed values.

Determination of the emission factor for electricity generation ($EF_{EL,j,y}$)
Scenario B "Electricity consumption from an off-grid captive power plant" of the "Tool to calculate baseline, project and/or leakage emissions from electricity consumption" applies. Option B1 is not applicable as the captive power plant does not monitor the quantity of fossil fuel fired to generate electricity. Therefore Option B2 is selected and the conservative value of 1.3tCO2/MWh is applied as the electricity consumption source is a project electricity consumption source. Application of this conservative value results in overestimation of project emissions compared to the fuel gas consumption. Evidence has been provided to DOE.

Leakage
Leakage emissions shall be accounted for project activities where the recovered gas is transported to a processing plant where it is processed into hydrocarbon products (e.g. dry gas, LPG and condensates) and the dry gas is compressed to CNG first, then transported by trailers/trucks/carriers and then decompressed again, before it finally enters the gas pipeline. For other types of project activities, leakage emissions need not to be considered.

As described in sections A.4.3 and B.2, in the proposed project activity the dry gas is directly sold to the pipeline without being compressed to CNG first then transported by trailers/trucks/carriers and then decompressed again before entering the pipeline. Consequently, leakage emissions need not to be considered.

Thus, $LE_y = 0$.

Emission reductions

Emission reductions are calculated as follows:

$$ERy = BEy - PEy - LEy \qquad (3)$$

Where:

ERy = Emission reductions in the period *y*, (tCO_2e)

BEy = Baseline emissions in the period *y*, (tCO_2e)

PEy = Project emissions in the period *y*, (tCO_2e)

LEy = Leakage emissions in year y (tCO_2e)

B.6.2. Data and parameters that are available at validation:

Data / Parameter:	EFCO2,Methane
Data unit:	tCO2/TJ
Description:	CO2 emission factor for methane
Source of data used:	Calculated in line with procedures and data presented in ISO 6976: <table><tr><th>Unit</th><th>Value</th><th>Source</th></tr><tr><td>Carbon Content of Methane</td><td>12,011 kg/kmol</td><td>ISO 6976: Table 1</td></tr><tr><td>CO₂ Emission Factor for</td><td>44.01 kg/kmol</td><td>ISO 6976: Table 1</td></tr></table>

	Methane | | NCV of Methane (at 25^{0}C) | 802.60 kJ/mol | ISO 6976: Table 3
Value applied:	54.834 tCO_2/TJ
Justification of the choice of data or description of measurement methods and procedures actually applied :	---
Any comment:	---

Data / Parameter:	$TDL_{j,y}$
Data unit:	-
Description:	Average technical transmission and distribution losses for providing electricity to source *j* year *y*
Source of data used:	"Tool to calculate baseline, project and/or leakage emissions from electricity consumption";
Value applied:	0
Justification of the choice of data or description of measurement methods and procedures actually applied :	Scenario B "Electricity consumption from an off-grid captive power plant" of the "Tool to calculate baseline, project and/or leakage emission from electricity consumption" applies.
Any comment:	-

Data / Parameter:	$EF_{EL,j,y}$
Data unit:	tCO2/yr
Description:	Emission factor for electricity generation for source j in year y
Source of data used:	"Tool to calculate baseline, project and/or leakage emissions from electricity consumption";
Value applied:	1.3
Justification of the choice of data or description of measurement methods and procedures actually applied :	Scenario B, Option B2 is applied.
Any comment:	-

B.6.3. Ex-ante calculation of emission reductions:

The following section gives details about the ex-ante estimation of emission reduction based on the equations laid out in section B.6.1 above and the ex-ante values available at the time of CDM project developing.

Baseline emissions

Volume of the total recovered gas and NCV of recovered gas at each location have been provided by the project entity and are detailed in Annex 3. $EF_{CO2, Methane}$ uses the default value 54.834 tCO2/TJ according to methodology AM0009 (version 06.0.0). Applying formula (1) presented in Section B.6.1, we obtain the values for the baseline emissions during crediting period provided in Tables below:

Table B.14. CPF

CPF	$V_{F,y}$	$NCV_{RG,F,y}$	$EF_{CO2,Methane}$	BE_y
year	**Volume of total recovered gas (Nm³)**	**Net calorific value of recovered gas (TJ/Nm3)**	**CO2 emission factor for methane (tCO2/TJ)**	**Estimation of baseline emissions (tCO2e)**
01/01/2013 – 31/12/2013	97,682,967	0.00006358	54.834	340,532
01/01/2014 – 31/12/2014	97,682,967	0.00006358	54.834	340,532
01/01/2015 – 31/12/2015	97,682,967	0.00006358	54.834	340,532
01/01/2016 – 31/12/2016	97,682,967	0.00006358	54.834	340,532
01/01/2017 – 31/12/2017	97,682,967	0.00006358	54.834	340,532
01/01/2018 – 31/12/2018	97,682,967	0.00006358	54.834	340,532
01/01/2019 – 31/12/2019	97,682,967	0.00006358	54.834	340,532
total	683,780,772			2,383,722

Table B.15. FW

FW	$V_{F,y}$	$NCV_{RG,F,y}$	$EF_{CO2,Methane}$	BE_y
year	**Volume of total recovered gas (Nm³)**	**Net calorific value of recovered gas (TJ/Nm3)**	**CO2 emission factor for methane (tCO2/TJ)**	**Estimation of baseline emissions (tCO2e)**
01/01/2013 – 31/12/2013	140,064,641	0.00004547	54.834	349,194
01/01/2014 – 31/12/2014	94,015,570	0.00004547	54.834	234,390
01/01/2015 – 31/12/2015	37,790,854	0.00004547	54.834	94,216
01/01/2016 – 31/12/2016	29,002,937	0.00004547	54.834	72,307
01/01/2017 – 31/12/2017	11,272,517	0.00004547	54.834	28,103
01/01/2018 – 31/12/2018	-	0.00004547	54.834	-
01/01/2019 – 31/12/2019	-	0.00004547	54.834	-
total	312,146,519			778,210

Table B.16. WL

WL	$V_{F,y}$	$NCV_{RG,F,y}$	$EF_{CO2,Methane}$	BE_y
year	**Volume of total recovered gas (Nm³)**	**Net calorific value of recovered gas (TJ/Nm3)**	**CO2 emission factor for methane (tCO2/TJ)**	**Estimation of baseline emissions (tCO2e)**
01/01/2013 – 31/12/2013	261,153,249	0.00004172	54.834	597,378
01/01/2014 – 31/12/2014	214,403,902	0.00004172	54.834	490,441
01/01/2015 – 31/12/2015	167,413,432	0.00004172	54.834	382,952
01/01/2016 – 31/12/2016	145,585,639	0.00004172	54.834	333,022
01/01/2017 – 31/12/2017	104,544,880	0.00004172	54.834	239,142
01/01/2018 – 31/12/2018	74,269,205	0.00004172	54.834	169,888

01/01/2019 – 31/12/2019	53,877,291	0.00004172	54.834	123,242
total	1,021,247,597			2,336,066

Table B.17. JAL

JAL	**$V_{F,y}$**	**$NCV_{RG,F,y}$**	**$EF_{CO2,Methane}$**	**BE_y**
year	**Volume of total recovered gas (Nm^3)**	**Net calorific value of recovered gas (TJ/Nm3)**	**CO2 emission factor for methane (tCO2/TJ)**	**Estimation of baseline emissions (tCO2e)**
01/01/2013 – 31/12/2013	66,849,208	0.00004584	54.834	168,034
01/01/2014 – 31/12/2014	46,775,553	0.00004584	54.834	117,577
01/01/2015 – 31/12/2015	27,788,555	0.00004584	54.834	69,850
01/01/2016 – 31/12/2016	10,223,193	0.00004584	54.834	25,697
01/01/2017 – 31/12/2017	-	0.00004584	54.834	-
01/01/2018 – 31/12/2018	-	0.00004584	54.834	-
01/01/2019 – 31/12/2019	-	0.00004584	54.834	-
total	151,636,509			381,159

Table B.18. SAT

SAT	**$V_{F,y}$**	**$NCV_{RG,F,y}$**	**$EF_{CO2,Methane}$**	**BE_y**
year	**Volume of total recovered gas (Nm^3)**	**Net calorific value of recovered gas (TJ/Nm3)**	**CO2 emission factor for methane (tCO2/TJ)**	**Estimation of baseline emissions (tCO2e)**
01/01/2013 – 31/12/2013	-	0.00004417	54.834	-
01/01/2014 – 31/12/2014	-	0.00004417	54.834	-
01/01/2015 – 31/12/2015	-	0.00004417	54.834	-
01/01/2016 – 31/12/2016	-	0.00004417	54.834	-
01/01/2017 – 31/12/2017	-	0.00004417	54.834	-
01/01/2018 – 31/12/2018	-	0.00004417	54.834	-
01/01/2019 – 31/12/2019	-	0.00004417	54.834	-
total	-			0

SAT Gains are realized prior to the start of crediting period.

Table B.19. Total all locations

Total all locations	**BE_y**
year	**Estimation of baseline emissions (tCO2e)**
01/01/2013 – 31/12/2013	1,455,139
01/01/2014 – 31/12/2014	1,182,939
01/01/2015 – 31/12/2015	887,550
01/01/2016 – 31/12/2016	771,558
01/01/2017 – 31/12/2017	607,778
01/01/2018 – 31/12/2018	510,420
01/01/2019 – 31/12/2019	463,774
total	5,879,156

Project emissions

$PE_y = PE_{CO2,fossilfuels,y} + PE_{CO2,elec,y}$

As explained in section B.6.1, there is no direct consumption of fossil fuels as part of the Project activity therefore above equation can be simplified as:

$PE_y = PE_{CO2,elec,y} = PE_{EC,y}$

$$PE_{EC,y} = \sum_j EC_{PJ,j,y} \times EF_{EL,j,y} \times \left(1 + TDL_{j,y}\right)$$

Calculation of $EC_{PJ,j,y}$

As detailed in section B.6.1, electricity use consists of power required to run the pre-treatment, compression and transportation equipment. Equipment power ratings at each location are detailed in section A.4.3 and amount to 20.85MW. Expected operating hours have been calculated through dividing the total compression installed capacity by the expected gas gains at each location, see Annex 3 for details. $EC_{PJ,j,y}$ is equal to installed capacity multiplied by operating hours.

Average technical transmission and distribution losses for providing electricity to source *j* in year *y* (TDLj,y) is set at 0% as the project consumes electricity from an off-grid captive power plant, and $EF_{EL,j,y}$ is set at 1.3tCO2/MWh as it is a project electricity consumption source, which is the conservative default value set in the tool. Application of this value results in overestimation of project emissions of 133% on average per year over the crediting period of the project activity. Evidence has been provided to DOE. Both values are strictly in line with Option B of the “Tool to calculate baseline, project and/or leakage emissions from electricity consumption”.

Table B.20. Emissions from consumption of electricity in the project case

	$EC_{PJ,j,y}$	**$EF_{EL,j,y}$**	**$TDL_{j,y}$**	**$PE_{EC,y}$**
Year	Quantity of electricity consumed by the project electricity consumption source j in year y (MWh/yr)	Emission factor for electricity generation for source j in year y (tCO2/MWh)	Average technical transmission and distribution losses for providing electricity to source j in year y	Project emissions from electricity consumption (tCO2/yr)
2013	98,317	1.3	0%	127,813
2014	77,238	1.3	0%	100,410
2015	54,989	1.3	0%	71,485
2016	45,020	1.3	0%	58,526
2017	31,190	1.3	0%	40,547
2018	22,907	1.3	0%	29,780
2019	18,342	1.3	0%	23,844

As been specified in part B.6.1, $PE_{CO2, fossilfuels, y} = 0$.

PE_y has been calculated based on $PE_{CO2, elec, y}$ (= $PE_{EC,y}$) as in the following table:

Table B.21. The estimation of project emissions during crediting period

year	$PE_{CO2,fossilfuels,y}$ CO2 emissions due to consumption of fossil fuels (tCO2e)	$PE_{CO2,elec,y}$ CO2 emissions du to the use of electricity (tCO2e)	PE_y Project emissions in the period y, (tCO2e)
01/01/2013 – 31/12/2013	0.00	127,813	127,813
01/01/2014 – 31/12/2014	0.00	100,410	100,410
01/01/2015 – 31/12/2015	0.00	71,485	71,485
01/01/2016 – 31/12/2016	0.00	58,526	58,526
01/01/2017 – 31/12/2017	0.00	40,547	40,547
01/01/2018 – 31/12/2018	0.00	29,780	29,780
01/01/2019 – 31/12/2019	0.00	23,844	23,844
Total			**452,405**

Leakage
There is no leakage emission considered, thus $LE_y = 0$.

B.6.4 Summary of the ex-ante estimation of emission reductions:

The table below provides the annual emission reductions in tabular form.

Table B.22. Estimate of emission reductions due to the project in crediting period

Year	Estimation of project activity emissions (tCO_2e)	Estimation of baseline emissions (tCO2e)	Estimation of leakage (tCO_2e)	Estimation of overall emission reductions (tCO_2e)
01/01/2013 – 31/12/2013	127,813	1,455,139	0	1,327,326
01/01/2014 – 31/12/2014	100,410	1,182,939	0	1,082,529
01/01/2015 – 31/12/2015	71,485	887,550	0	816,065
01/01/2016 – 31/12/2016	58,526	771,558	0	713,032
01/01/2017 – 31/12/2017	40,547	607,778	0	567,231
01/01/2018 – 31/12/2018	29,780	510,420	0	480,640
01/01/2019 – 31/12/2019	23,844	463,774	0	439,930
Total (tons of CO_2e)				**5,426,752**

B.7 Application of a monitoring methodology and description of the monitoring plan:

B.7.1 Data and parameters monitored:

Data / Parameter:	$V_{F,y}$
Data unit:	Nm³
Description:	Volume of the total recovered gas measured at point F in methodology

	Figure 2 in year *y*.
Source of data to be used:	Flow meter installed by project entity
Value of data applied for the purpose of calculating expected emission reductions in section B.6	See Annex 3 for detailed values per location
Description of measurement methods and procedures to be applied:	Data will be measured continuously using calibrated flow meters. Measurements will be taken at the point(s) where recovered gas exits the pretreatment plant.
QA/QC procedures to be applied:	Volume of gas will be metered through a differential pressure (or equivalent) flow meter installed at each different location. Calibration frequency is annual. Accuracy is ±2% of reading typical or more accurate. Lead operators at each location are responsible for monitoring and reporting to Central Production Facility.
Any comment:	The total value for parameter $V_{F,y}$ will be equal to the sum of volumes of recovered gas at each 5 locations. See section B.7.2 for further details.

Data / Parameter:	$NCV_{RG,F,y}$
Data unit:	TJ/Nm3
Description:	Average net calorific value of recovered gas at point F in methodology Figure 2 in year *y*
Source of data to be used:	On site measurement
Value of data applied for the purpose of calculating expected emission reductions in section B.6	See Annex 3 for detailed value per location. Values used to calculate expected emissions reductions are the latest available at the time of investment decision.
Description of measurement methods and procedures to be applied:	Gas composition measurements will be undertaken in line with national or international fuel standards under the responsibility of the on-site lab located at Safah gas plant. Samples will be taken at least monthly through chromatography gas analyzer (or equivalent). Calibration frequency is at minimum annual using standard gas. NCV will be calculated as the sum of molar fraction of each individual component in the natural gas sample multiplied by net calorific value of each individual component in the natural gas sample as referenced in ISO/DP 6976:1995 standard for a combustion reference temperature of 25^0C and the same reference condition used for parameter $V_{F,y}$. The average NCV during the period y is defined as the arithmetic average of NCVs for the samples taken during the same period. See section B.7.2 for details.
QA/QC procedures to be applied:	Measurements will be done as per ISO10715 or equivalent standard, in strict accordance with requirements listed in gas purchase agreement provided to DOE. Compositional analysis in accordance with ISO 6974 or equivalent standard. Routine maintenance and calibration in accordance with ISO 10723 or equivalent standard. GC calibration gases certified to ISO 6141 or equivalent standard. Annual manufacturer servicing and calibration to ISO17025 or equivalent standard. In case third party laboratories are used, these should as a minimum have ISO17025 accreditation or justify that they can comply with similar quality standards

Any comment:	For the purpose of this methodology, the qualifier "net" is synonymous with "lower" and "inferior", and the term "calorific value" is synonymous with "heating value"

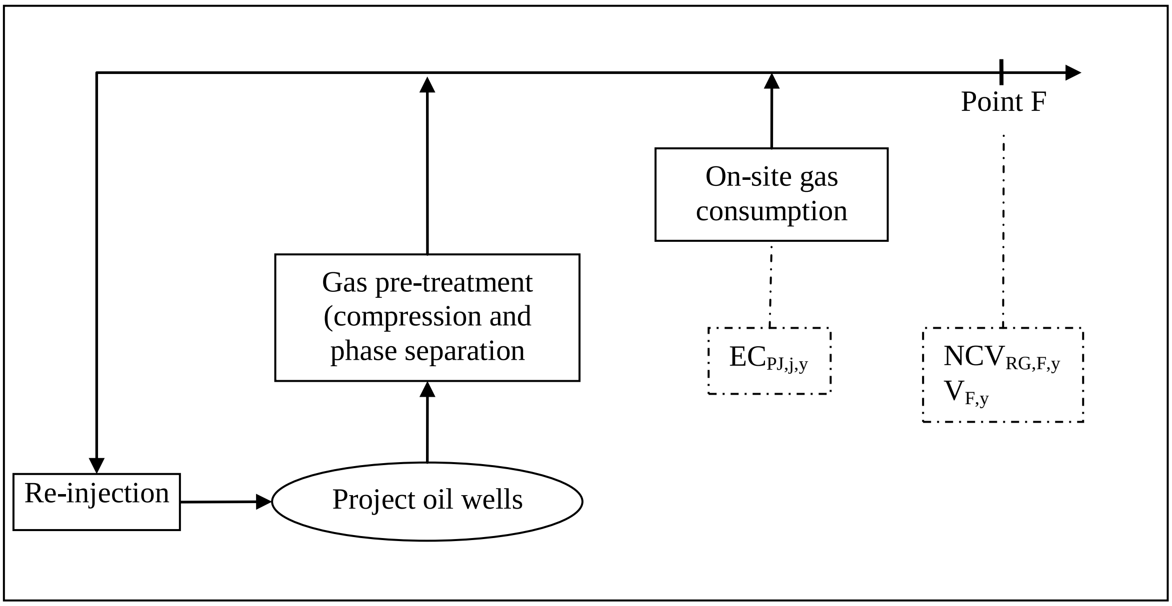
Data / Parameter:	$EC_{PJ,j,y}$
Data unit:	MWh/yr
Description:	Quantity of electricity consumed by the project electricity consumption source j in year y
Source of data to be used:	Electricity meter
Value of data applied for the purpose of calculating expected emission reductions in section B.6	See Annex 3 for detailed values per location
Description of measurement methods and procedures to be applied:	Continuous measurement with national standard metering equipment located at each location
QA/QC procedures to be applied:	Accuracy Class 2 or more accurate. Instrument will be calibrated periodically in accordance with local requirements
Any comment:	-

B.7.2. Description of the monitoring plan:

The objective of the monitoring plan is to ensure the complete, consistent, clear, and accurate monitoring and calculation of the emissions reductions during the whole crediting period. Monitoring procedures may be adjusted from time to time but will not deviate from the principles described in the monitoring plan below.

Figure below shows the location of monitoring points within project boundary.

Figure B.4. General monitoring plan at each location



Operational procedures:

Monitoring of volume of recovered gas *($V_{F,y}$)*
Gas flow meters at each location will measure volumes of recovered gas after pre-treatment and after part of the recovered gas is used on-site. The total value for parameter $V_{F,y}$ will be equal to the sum of volumes of recovered gas at each 5 locations.

Monitoring Net calorific value of recovered gas ($NCV_{RG,F,y}$)
The net calorific value (volume based) of the recovered gas in TJ/standard cubic meter will be calculated according to the following method:

$$NCV_{RG,F,y} = \frac{\Sigma(X_i \times NCV_i)}{\Sigma(X_i)}$$

X_i = molar fraction of the individual component i in the recovered gas sample provided by Safah Lab using chromatography gas analyzer at least monthly.
NCV_i = Net Calorific Value (volume based) of the individual component i as per ISO/DP 6976:1995 standard for a combustion reference temperature of 25^0C and the same metering reference condition used for parameter VF,y, as indicated in below table:

Table B.23. Values of NCV_i

	Net calorific value (MJ/Sm3) of component (25^0C combustion reference temperature and 0^0C metering reference temperature)
hydrogen	10.788
nitrogen	0
C6 group	173.41
methane	35.808
co2	0
ethane	63.74
propane	91.15
i-butane	118.15
n-butane	118.56
i-pentane	145.66
n-pentane	145.96
C7+	200.82

Source: ISO 6976:1995

Molar fraction of recovered gas will be measured separately at each location at least monthly by staff of Safah Lab located on-site.

Monitoring of electricity consumption $EC_{PJ,j,y}$
Electricity meters will measure electricity consumed by equipment at the each project location. The total value for parameter $EC_{PJ,j,y}$ will be equal to the sum of electricity consumption at each 5 locations.

Emergencies:

In case of emergencies[17], the project entity will not claim emission reductions due to the project activity for the duration of the emergency. The project entity will follow the following procedure for declaring the emergency period to be over:

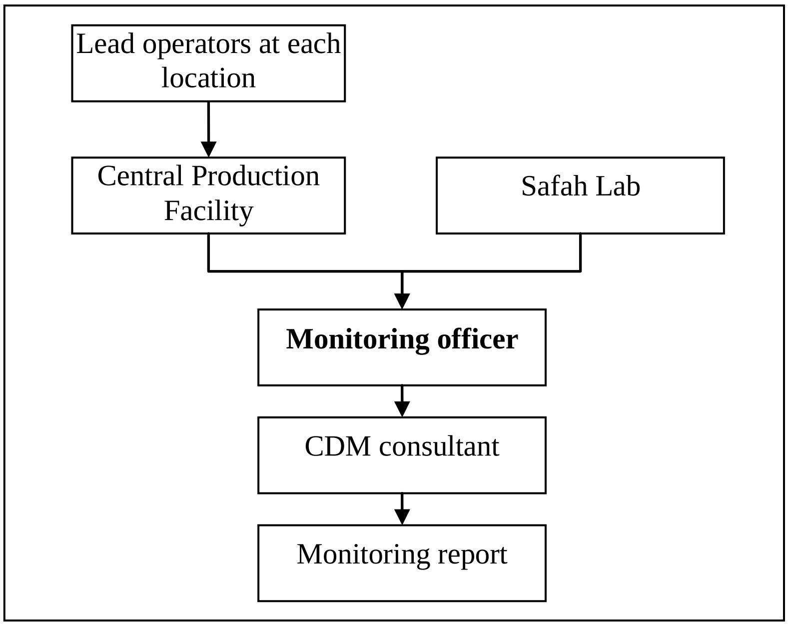
1. The project entity will ensure that all requirements for monitoring of emission reductions have been re-established.
2. The monitoring officer will sign a statement declaring the emergency situation has ended and normal operations have resumed.

OPERATIONAL AND MANAGEMENT STRUCTURE FOR MONITORING

The monitoring of the emission reductions will be carried out according to the scheme shown in **Error! Reference source not found.**. The overall responsibility for the monitoring process will be held by the Monitoring Officer which will be selected among senior staff of the operating entity on-site. Some of the monitoring tasks will be delegated as indicated in **Error! Reference source not found.**. Measurements of the associated gas volumes recovered and project electricity consumption will fall under the responsibility of lead operators at each location who report to the Central Production Facility. Measurement of NCV of the recovered gas will be performed by the Safah lab located on-site.

The monitoring officer will be responsible for collecting and performing plausibility check of the measurements. The monitoring reports and calculation of emission reductions will be prepared by experienced CDM consultant. The selection procedure, tasks and responsibilities of the monitoring officer are detailed in Annex 4.

Figure B.5. Responsibilities for measurements and reporting emission reductions



<u>Data management</u>

[17] Emergencies are defined as conditions under which monitoring is not possible due to an unexpected incident.

All electronic and hard copy records of the metering devices, relevant documentation and the proof of calibration will be collated by monitoring officer and electronic copy will be provided to CDM consultant. All Data collected as part of monitoring will be archived electronically and kept at least 2 years after the end of the crediting period.

B.8. Date of completion of the application of the baseline study and monitoring methodology and the name of the responsible person(s)/entity(ies):

Date of completion of the baseline study and monitoring methodology: 31/10/2012

Name of person determining the baseline study and the monitoring methodology:
Caspervandertak Consulting
Christophe Assicot; Yin Li; Deng Ping
Tel: +86-10-84505756
Fax: +86-10-84505758
Email: christophe@cdmasia.org, yinli@cdmasia.org, dengping@cdmasia.org

Caspervandertak Consulting is not project participant.

SECTION C. Duration of the project activity / crediting period

C.1. Duration of the project activity:

C.1.1. Starting date of the project activity:

01/04/2008

This date marks financial controller approval (final internal approval) of earliest significant capital expenditures in relation to the proposed project activity, i.e. the purchase of new pipelines and re-routes at Far West location, as per internal project authorization request.

C.1.2. Expected operational lifetime of the project activity:

10y-0m

C.2. Choice of the crediting period and related information:

C.2.1. Renewable crediting period:

C.2.1.1. Starting date of the first crediting period:

Not applicable

C.2.1.2. Length of the first crediting period:

Not applicable

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

01/01/2013

C.2.2.2. Length:

7y

SECTION D. Environmental impacts

D.1. Documentation on the analysis of the environmental impacts, including transboundary impacts:

There is no binding national/regional regulation in Oman as to undertake an environmental impact assessment for the proposed project. The environmental permit granted to the operator of Block 9 for the Exploration & Production of Oil & Gas was renewed for the 7^{th} time on 25/07/2010 by Ministry of Environment and Climate Affairs according to Law on Conservation of Environment and Prevention of Pollution promulgated by Royal Decree 114/2001.

The project is located in landscape which has high sand dune area and gravel plains. There are no local residents next to the project site. Thus, the project has limited impacts on local residents. Furthermore, the project has been built on an existing oil field for which an environmental impact assessment had already been approved by Omani Government. Still, the following has been identified as key possible environmental impacts:

1. Air quality:
Due to the general low industrial emission sources and low population density, air quality in Oman is good. Air pollution will be significantly reduced due to the project activity as a result of associated gas recovery.

2. Noise
The noise during the operation period is mainly from compressors. However, the project is located in remote area, where no surrounding resident. Therefore, noise from the project activity is not significant harmful to the environment. During construction phase, no significant impact on the environment is expected as the proposed project is implemented on existing clusters where oil extraction activities are taking place on daily basis.

3. Solid waste
The Block 9 field itself already has a treatment system for solid waste, which will be applied to the proposed project as well; the impact of solid waste on the environment is limited.

In light of the above analysis, it is concluded that the proposed project activity has no significant negative impacts on the ambient environment during the construction and operation period. Some impacts are short-term, and others are mitigated through appropriate preventive and mitigation measures. Therefore, this project does not have significant negative environmental impact.

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

It is concluded that the proposed project will have no significant environmental impacts.

SECTION E. Stakeholders' comments

E.1. Brief description how comments by local stakeholders have been invited and compiled:

In order to confirm the impact of the project on local stakeholders, the project entity carried out a separate consultation of local stakeholders near the project site on July 2nd and 4th 2010. We will describe in this section how comments were invited and compiled while the results of the consultations are provided in section E.2.

As described in sections A.4, the project is located in the middle of the Omani desert on an existing oil field, while the nearest town is about 50 km away. Only one small tribe leaves nearby. All men from the tribe are employed on project site at the block 9 oil field and the tribe mainly consists of members of the same family. Therefore no formal written invitation for comments was considered necessary nor practical or most efficient, and the members of the tribe were informed orally in an open and transparent manner by the Health and Safety Department of the Operator on-site. Questionnaires were distributed that contained a description of the project activity and reasonable time for comments was given.

The questionnaire survey included the following elements:
- An introduction of the project
- An introduction of the Clean Development Mechanism
- An explanation of the purpose of the stakeholder consultation process
- A set of questions to assess the impacts of the project

A total number of 20 questionnaires have been filled in and outcome of the survey is provided in section E.2.

E.2. Summary of the comments received:

The results of the questionnaire surveys among project participants are presented in Table E.1. The results of the questionnaire surveys show that all respondents fully support the project without any negative opinion towards the project.

Table E.1. Summary of questionnaire results

<table>
<tr><th>NO.</th><th colspan="3">Impacts of the project</th><th>Results</th><th>Number of total interviewees</th><th>Percentage</th></tr>
<tr><td rowspan="13">1</td><td rowspan="13">Environment</td><td rowspan="3">Construction of associated gas utilization project</td><td>Benefit local environment</td><td>20</td><td rowspan="3">20</td><td>100%</td></tr>
<tr><td>No benefit</td><td>0</td><td>0%</td></tr>
<tr><td>Not sure</td><td>0</td><td>0%</td></tr>
<tr><td>Current practice of gas flaring</td><td>Benefit local environment</td><td>0</td><td>20</td><td>0%</td></tr>
<tr><td rowspan="3">Global warming</td><td>No benefit</td><td>0</td><td rowspan="3">20</td><td>0%</td></tr>
<tr><td>Not sure</td><td>0</td><td>0%</td></tr>
<tr><td>Reduce</td><td>20</td><td>100%</td></tr>
<tr><td rowspan="4">Any negative impact</td><td>No effect</td><td>0</td><td rowspan="4">20</td><td>0%</td></tr>
<tr><td>Not sure</td><td>0</td><td>0%</td></tr>
<tr><td>Yes</td><td>0</td><td>0%</td></tr>
<tr><td>No</td><td>20</td><td>100%</td></tr>
<tr><td rowspan="3">2</td><td rowspan="3" colspan="2">Local economy</td><td>Benefit local economy</td><td>20</td><td rowspan="3">20</td><td>100%</td></tr>
<tr><td>No benefit</td><td>0</td><td>0%</td></tr>
<tr><td>Not sure</td><td>0</td><td>0%</td></tr>
<tr><td rowspan="3">3</td><td rowspan="3">General opinion</td><td rowspan="3">Regarding the project construction</td><td>Fully support</td><td>20</td><td rowspan="3">20</td><td>100%</td></tr>
<tr><td>Not support</td><td>0</td><td>0%</td></tr>
<tr><td>Not sure</td><td>0</td><td>0%</td></tr>
</table>

Conclusion for questionnaire survey:

The results show that the 100% of the stakeholders support the gas recovery project for its contribution to environment. All of the participants agreed that the project will bring no negative impact on economy, environment or society.

After all, the project is an energy efficiency project on existing facilities. The project plant was located in desert area thus will have limited impact on local residents during construction and operation period. Local stakeholders consider that the project will be bring benefit and support the project implementation.

E.3. Report on how due account was taken of any comments received:

Given the generally positive nature of the comments received, no further action is considered necessary.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Organization:	MINISTRY OF OIL & GAS
Street/P.O.Box:	P O BOX 551
Building:	MINISTRY OF OIL & GAS
City:	MUSCAT
State/Region:	
Postfix/ZIP:	113
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URL:	
Represented by:	ZAID AL SIYABI
Title:	DIRECTOR GENERAL OF OIL & GAS EXPLORATION & PRODUCTION
Salutation:	DR.
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State/Region:	
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Annex 2

INFORMATION REGARDING PUBLIC FUNDING

No public funding from Annex I Party is involved in this project.

Annex 3

BASELINE INFORMATION

The calculation for emission reductions following AM0009 (Version 06.0.0) has been listed as follow:

Baseline emissions:

Table 1. Gross gas gains (mmscf per day)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CPF	0.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
FW	0.00	0.00	10.21	13.58	16.65	14.68	9.85	3.96	3.04	1.18	0.00	0.00
WL	0.00	0.00	18.45	24.35	28.35	28.17	23.13	18.06	15.71	11.28	8.01	5.81
JAL	0.00	0.00	6.56	5.34	6.99	7.17	5.02	2.98	1.10	0.00	0.00	0.00
SAT	0.00	0.00	8.16	9.36	4.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00
total	**0.00**	**10.00**	**53.37**	**62.63**	**66.19**	**60.02**	**48.00**	**35.00**	**29.84**	**22.46**	**18.01**	**15.81**

Source: operator

Table 2. Yearly gross gas gains (mmscf**) on a 350 days per year basis**

The use of 350 days annually is operator's common practice and reflects annual downtime of on-site operations. Evidence is provided to DOE.

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total
CPF	0.00	230.00	3500.00	3500.00	3500.00	3500.00	3500.00	3500.00	3500.00	3500.00	3500.00	3500.00	
FW	0.00	0.00	1816.70	4753.86	5826.51	5137.74	3448.60	1386.21	1063.86	413.49	0.00	0.00	
WL	0.00	0.00	1162.07	8520.95	9923.03	9860.30	8095.20	6320.99	5496.84	3947.28	2804.16	2034.23	
JAL	0.00	0.00	938.26	1868.80	2448.15	2508.86	1755.50	1042.91	383.68	0.00	0.00	0.00	
SAT	0.00	0.00	954.28	3275.22	1468.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
total	**0.00**	**230.00**	**8371.30**	**21918.83**	**23165.75**	**21006.90**	**16799.29**	**12250.11**	**10444.38**	**7860.76**	**6304.16**	**5534.23**	**133,885.73**

Table 3. Conversions

Parameters	Value	Units
1 Ft^3 =	0.02826216	m^3
1 kJ =	0.947817	BTU
1 TJ =	1000000000	kJ

Table 4. Yearly gas gains at methodology Figure 2 Point F (Nm3)

	2012	2013	2014	2015	2016	2017	2018	2019
CPF	97,682,967	97,682,967	97,682,967	97,682,967	97,682,967	97,682,967	97,682,967	97,682,967
FW	158,841,999	140,064,641	94,015,570	37,790,854	29,002,937	11,272,517	0.00	0.00
WL	262,814,576	261,153,249	214,403,902	167,413,432	145,585,639	104,544,880	74,269,205	53,877,291
JAL	65,231,382	66,849,208	46,775,553	27,788,555	10,223,193	0.00	0.00	0.00
SAT	40,464,223	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**625,035,147**	**565,750,065**	**452,877,993**	**330,675,808**	**282,494,736**	**213,500,365**	**171,952,172**	**151,560,258**

Table 5. Mole fraction and NCV of gas component

Molar fractions of recovered gas were taken by onsite lab personnel at the time of investment decision at each location, after pre-treatment (compression and phase separation).

	Molar % of recovered gas					
	WL	**FW**	**CPF**	**SAT**	**JAL**	**Net** calorific value (MJ/m3) of component
hydrogen	0.0000	0.0000	0.0000	0.0000	0.0000	10.788
nitrogen	2.0300	0.8900	0.2000	1.0400	1.3400	0
C6 group	0.3200	0.3700	0.5000	0.2800	0.2100	173.41

methane	80.9900	77.4500	39.8600	78.6900	75.9700	35.808
co2	2.2400	1.4300	1.9000	1.5100	0.6000	0
ethane	7.4600	9.6300	26.0700	9.5000	11.0300	63.74
propane	3.8900	5.5500	21.5700	5.2700	6.7600	91.15
i-butane	0.8700	1.3900	3.9000	1.1800	1.2400	118.15
n-butane	1.3800	2.0000	4.4000	1.6100	1.9800	118.56
i-pentane	0.4400	0.6900	0.9000	0.4900	0.4600	145.66
n-pentane	0.3800	0.6000	0.7000	0.4300	0.4100	145.96
C7+	0.0000	0.0000	0.0000	0.0000	0.0000	200.82
	100	100	100	100	100	

Source: Molar fractions from Safah Lab; NCVs from ISO 6976:1995

Table 6. Calculation of $NCV_{RG,F,y}$ (TJ/Nm^3)

Net Calorific values of recovered gas at each location are calculated by multiplying molar fraction by net calorific value of each component

	WL	**FW**	**CPF**	**SAT**	**JAL**
hydrogen	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
nitrogen	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
C6 group	0.0000006	0.0000006	0.0000009	0.0000005	0.0000004
methane	0.0000290	0.0000277	0.0000143	0.0000282	0.0000272
co2	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
ethane	0.0000048	0.0000061	0.0000166	0.0000061	0.0000070
propane	0.0000035	0.0000051	0.0000197	0.0000048	0.0000062
i-butane	0.0000010	0.0000016	0.0000046	0.0000014	0.0000015
n-butane	0.0000016	0.0000024	0.0000052	0.0000019	0.0000023
i-pentane	0.0000006	0.0000010	0.0000013	0.0000007	0.0000007
n-pentane	0.0000006	0.0000009	0.0000010	0.0000006	0.0000006
C7+	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
total	**0.0000417**	**0.0000455**	**0.0000636**	**0.0000442**	**0.0000458**

Project emissions:

Calculation of $EC_{PJ,j,y}$

The electricity consumption for each unit is estimated ex-ante through multiplying the total power capacity of the units at each location by the expected operating hours, based on expected volumes of gas recovered.

Table 6. System rated power and compression capacity

	# compressors	Rated Power (KW) per compressor	total rated power (MW)	compression capacity per compressor (mmscfd)	total compression capacity (mmscfd)
CPF	4	403.59	1.61	5.399	21.596
FW	2	1.894.84	3.79	12.5	25
SAT	1	3,088.44	3.09	30	30
JAL	1	3,088.44	3.09	12.5	12.5
WL	3	3,088.44	9.27	12.5	37.5
total rated power (MW)			**20.85**		

Table 7. Estimation of annual operating hours (gross gas gains as per Annex 3 Table 1/total compression capacity at each location in Table 6 above*24*350)

	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
CPF	3890	3890	3890	3890	3890	3890	3890	3890
FW	5593	4932	3311	1331	1021	397	0	0
WL	6351	6311	5181	4045	3518	2526	1795	1302
JAL	4700	4817	3371	2002	737	0	0	0

SAT	1174	0	0	0	0	0	0	0
average	4342	3990	3150	2254	1833	1363	1137	1038

Table 8. $EC_{PJ,j,y}$ (installed total rated power capacity at each location in Table 6 above in MW *operating hours)

	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
CPF	6,279	6,279	6,279	6,279	6,279	6,279	6,279	6,279
FW	21,197	18,692	12,546	5,043	3,870	1,504	0.00	0.00
WL	58,842	58,470	48,003	37,482	32,595	23,407	16,628	12,063
JAL	14,517	14,877	10,410	6,184	2,275	0.00	0.00	0.00
SAT	3,627	0.00	0.00	0.00	0.00	0.00	0.00	0.00
total	104,462	98,317	77,238	54,989	45,020	31,190	22,907	18,342

Estimation of recovered gas consumption for internal power generation:

Volumes of recovered gas utilized for the purpose of generating power and provide electricity to the project activity are calculated as per the following approach. Net gas volumes sales to the national gas pipeline are taken into account in the financial analysis in section B.5.

Table 9. fuel gas consumption per compressor package

Parameter	**Value**	**Unit**	**Source**
η off-grid gas turbine system	28.8	%	turbine specifications, corrected for ambient temperature as per US EPA guidance
		CPF	
Rate power per compressor	403.586	kW	equipment specs

Energy needed	1,401.34	kW per comp	calculated as rated power/efficiency
NCV of fuel gas	1703.02	BTU/CF	Annex 3 Table 6
total fuel gas needed/comp	0.0674	MMSCFD	calculated
FW			
Rate power per compressor	1,894.84	kW	equipment specs
Energy needed	6,579.31	kW per comp	calculated as rated power/efficiency
NCV of fuel gas	1,217.92	BTU/CF	Annex 3 Table 6
total fuel gas needed/comp	0.4424	MMSCFD	calculated
SAT			
Rate power per compressor	3,088.44	kW	equipment specs
Energy needed	10,723.75	kW per comp	calculated as rated power/efficiency
NCV of fuel gas	1,183.09	BTU/CF	Annex 3 Table 6
total fuel gas needed/comp	0.7423	MMSCFD	calculated
JAL			
Rate power per compressor	3,088.44	kW	equipment specs
Energy needed	10,723.75	kW per comp	calculated as rated power/efficiency
NCV of fuel gas	1,227.95	BTU/CF	Annex 3 Table 6
total fuel gas needed/comp	0.7152	MMSCFD	calculated
WL			
Rate power per compressor	3,088.44	KW	equipment specs

Energy needed	10,723.75	Kwh per comp	calculated as rated power/efficiency
NCV of fuel gas	1,117.46	BTU/CF	Annex 3 Table 6
total fuel gas needed/comp	0.7859	MMSCFD	calculated

Table 10. Recovered gas internal consumption for electricity generation (mmscfd)

Projected quantity of gas used internally over the project life time is calculated as gross gas gains (as per Annex 3 Table 1) divided by single compression capacity (mmscfd) as per equipment specs in PDD section A.4.3 Table A.2, then multiplied by total fuel gas needed per compressor per location as per Annex 3 Table 9 above.

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CPF	0.00	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
FW	0.00	0.00	0.36	0.48	0.59	0.52	0.35	0.14	0.11	0.04	0.00	0.00
WL	0.00	0.00	1.16	1.53	1.78	1.77	1.45	1.14	0.99	0.71	0.50	0.37
JAL	0.00	0.00	0.38	0.31	0.40	0.41	0.29	0.17	0.06	0.00	0.00	0.00
SAT	0.00	0.00	0.20	0.23	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00
total	0.00	0.12	2.22	2.67	3.00	2.83	2.21	1.57	1.28	0.88	0.63	0.49

Table 11. Projected quantity of gas used internally over the project life time (mmscf per year on a 350 days per year basis).

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total
CPF	0.00	2.87	43.68	43.68	43.68	43.68	43.68	43.68	43.68	43.68	43.68	43.68	
FW	0.00	0.00	64.29	168.24	206.20	181.83	122.05	49.06	37.65	14.63	0.00	0.00	
WL	0.00	0.00	73.06	535.71	623.86	619.91	508.94	397.40	345.58	248.16	176.30	127.89	
JAL	0.00	0.00	53.68	106.92	140.07	143.54	100.44	59.67	21.95	0.00	0.00	0.00	

SAT	0.00	0.00	23.61	81.04	36.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
total	**0.00**	**2.87**	**258.33**	935.59	1050.13	988.96	775.11	549.81	448.87	306.48	219.98	171.57	**5,707.72**

Source: calculated

<u>Net gas gains:</u>

Table 12. Projected quantity of gas sold over the project life time (mmscf)

Besides the deduction of gas used internally, a shrinkage factor was applied to obtain net gas gains from gross gas gains. See shrinkage factors at each location in section B.5 under "justification of gas gains".

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
CPF	0.00	202.15	3076.12	3076.12	3076.12	3076.12	3076.12	3076.12	3076.12	3076.12	3076.12	3076.12	
FW	0.00	0.00	1664.78	4356.34	5339.29	4708.11	3160.23	1270.30	974.90	378.91	0.00	0.00	
WL	0.00	0.00	1045.45	7665.83	8927.20	8870.77	7282.80	5686.65	4945.21	3551.15	2522.75	1830.09	
JAL	0.00	0.00	849.20	1691.41	2215.76	2270.71	1588.86	943.91	347.26	0.00	0.00	0.00	
SAT	0.00	0.00	893.44	3066.41	1374.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Total	**0.00**	**202.15**	**7528.99**	**19856.11**	**20932.85**	**18925.72**	**15108.01**	**10976.98**	**9343.49**	**7006.18**	**5598.87**	**4906.21**	**120,385.54**

Source: calculated

Background information for the assessment and demonstration of additionality:

Table 13. Source of data in common practice analysis

Company	source
Circle oil	http://www.circleoil.net/oman.aspx
BP	http://www.bp.com/sectiongenericarticle.do?categoryId=721&contentId=7034195
Petronas	http://www.petronas.com.my/about_us/milestone/2009.aspx; http://www.reuters.com/article/2009/04/20/petronas-oman-idUSKLR42692020090420
RAK Petroleum	http://www.rakpetroleum.ae/en/our-business/assets.aspx http://www.rakpetroleum.ae/en/media/ninterest.aspx http://www.rakpetroleum.ae/en/media/pressreleases/newsdetails/FIRST_OIL_PRODUCTION_ANNOUNCED_FROM_OFFSHORE_OMAN_BLOCK.aspx
CC Energy	http://www.tethysoil.com/page.php?view=verksamhet&content=2_8_oman-block-3&PHPSESSID=0c5e18d021d34679773da23d2e5d93f
Thetys	http://www.tethysoil.com/page.php?view=verksamhet&content=2_10_oman-block-15&PHPSESSID=0c5e18d021d34679773da23d2e5d93f http://www.oilvoice.com/n/Tethys_Signs_Agreement_to_Increase_Acerage_Position_Onshore_Oman/047bb80a.aspx
Petrotel	http://www.oman.petrotel.com/?page=news-oman&lang=en
Petrogas	http://www.petrogasllc.com/our_company.html
Maersk	http://www.maerskoil.com/GlobalOperations/Oman/Pages/Oman.aspx
Epsilon Energy	http://www.epsilonenergyltd.com/areas_oman.html
Oilex	http://www.oilex.com.au/index.cfm?objectId=51965D94-C09F-1F3C-C8C5376B105C72C0 http://www.oilvoice.com/n/Oilex_Announces_Relinquishment_of_Oman_Block_56/9a956a658.aspx
Reliance industries	http://articles.economictimes.indiatimes.com/2011-08-23/news/29918933_1_exploration-and-production-dmcc-oil-exploration-block-offshore-block http://www.gulfoilandgas.com/webpro1/MAIN/Mainnews.asp?id=1251
Hunt Oil	http://www.huntoil.com/IntlOps.aspx http://www.wintershall.com/pi-09-03.html
MOL	http://ir.mol.hu/sites/default/files/hu/down/befektetoi/MOL%20-%20Drilling%20update%20-%2027%20February%202009.pdf
Daleel	http://www.dapeco.com.om/AboutDaleel.shtml
Harvest	http://www.harvestnr.com/operations/oman.html
PDO	http://pdointernet.pdo.co.om/Press%20Releases/_PressReleaseFile_PDO%20Announces%20Strong%202011%20Results%20in%20Production-%20Reserves-%20Safety%20and%20Omani%20National%20Employment20127287370.pdf

Annex 4

MONITORING INFORMATION

Selection procedure:
The monitoring officer will be appointed by the general manager of the entity operating the project. The monitoring officer will be selected from among the senior technical or managerial staff.

Tasks and responsibilities:
The monitoring officer will be responsible for carrying out the following tasks:

- **Supervise and verify metering and recording:**
  The monitoring officer will coordinate with the lead operators at each location to ensure and verify adequate metering and recording of volumes of gas recovered at each location. The monitoring officer will also coordinate with the lab at Safah gas plant to ensure proper measurement of net calorific values of recovered gas.
- **Collect data:**
  The monitoring officer will collect volumes of recovered associated gas and net calorific values.
- **Monitoring report**
  The monitoring officer will coordinate with CDM consultant to prepare periodic monitoring reports including calculation of emission reductions on the basis of measured results. The monitoring officer will be provided with a calculation template in electronic form by the project's CDM advisors