Project design document form
(Version 11.0)

Complete this form in accordance with the instructions attached at the end of this form.

BASIC INFORMATION	
Title of the project activity	Associated Gas Recovery and Utilization at Khamilah oil field area at Block-27 in Wilayat Ibri of the Sultanate of Oman
Scale of the project activity	☒ Large-scale ☐ Small-scale
Version number of the PDD	03.0
Completion date of the PDD	02/08/2020
Project participants	The Government of the Sultanate of Oman, represented by the Ministry of Oil & Gas
Host Party	The Sultanate of Oman
Applied methodologies and standardized baselines	AM0009 Recovery and utilization of gas from oil fields that would otherwise be flared or vented Version 07.0
Sectoral scopes	10
Estimated amount of annual average GHG emission reductions	432,416 tCO_2e

SECTION A. Description of project activity

A.1. Purpose and general description of project activity

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Associated Gas Recovery and Utilization at Khamilah oil field area at Block-27 in Wilayat Ibri of the Sultanate of Oman (hereafter referred as “the proposed project”) consists of the recovery and utilization of natural gas found in association with oil at Khamilah oil field at Block-27, Wilayat Ibri of Al- Dhahirah Governorate, the Sultanate of Oman. The proposed project 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 recovered associated gas by the project will be collected and processed at Khamilah station. 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 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 project boundary includes:

- The project oil reservoir and oil wells at at Khamilah oil field area at Block-27, where the associated gas is collected;
- The site where the associated gas was flared in the absence of the project activity;
- The gas recovery, pre-treatment, processing and transportation infrastructures, and compressors;
- The source of gas-lift gas.

The total estimated amount of associated gas to be recovered during crediting period is about 2.01 billion m^3 while average methane content is estimated at about 78%. The project activity is expected to reduce emissions by approximately 432,416 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.2. Location of project activity

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The project will collect associated gas from Khamilah oil field at Block-27, Wilayat Ibri of Al-Dhahirah Governorate, the Sultanate of Oman. The recovered gas will be collected and processed at Khamilah station. Al-Dhahirah Region is in the Northern Oman.

Approximate coordinates of Khamilah station are east longitude of 56°14'38" and north latitude of 22°43'01". Figure A.1 shows the location of the project.

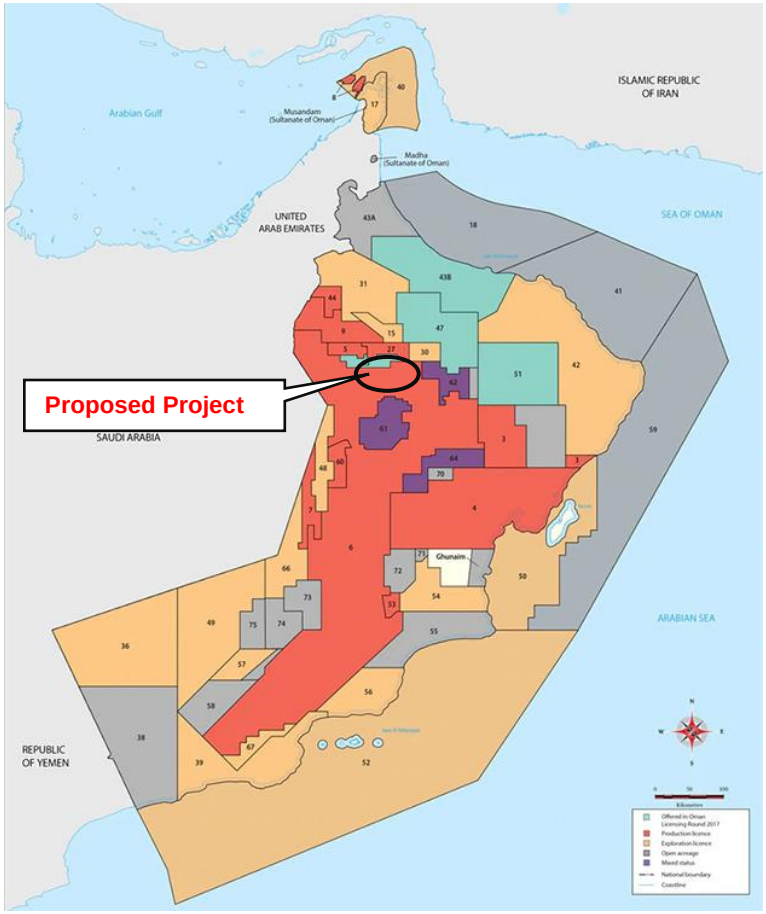

Figure A.1 Map of the project location

A.3. Technologies/measures

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The proposed project activity aims to recover associated gas flow that is currently flared in Khamilah oil field and will be processed the recovered gas at Khamilah station. 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. 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 recovered 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 8,106.8 mmscf over its lifetime. On average about 312.4 mmscf 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 7,482.7 mmscf after deduction of onsite gas consumption due to project activity and deduction of a gas shrinkage factor due to gas treatment at gas plant for the purpose of meeting the specifications of the national pipeline[1]. As per the project design and technical specifications, the pipeline transportation capacity is more than 1 million Nm^3 of gas per day.

[1] Expected average net gas volumes delivered to national pipeline = (expected gross gas volumes-projected quantity of gas used internally)*(100%- gas shrinkage factor). The calculation was performed on yearly basis, and year average data is calculated as the arithmetic mean over the 10 years of the project lifetime. Please refer to the ER spreadsheet for detail calculations. Relevant data source has been provided to DOE for validation.

The project activity mainly comprises the installation of compressor packages at Khamilah oil field, 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[2] the following equipment:

- Reduction of the flare by a series of new pipelines and re-routes.
- Addition of electrical motor driven reciprocating compressor 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.

The below figure provides an overview of the pipeline network.

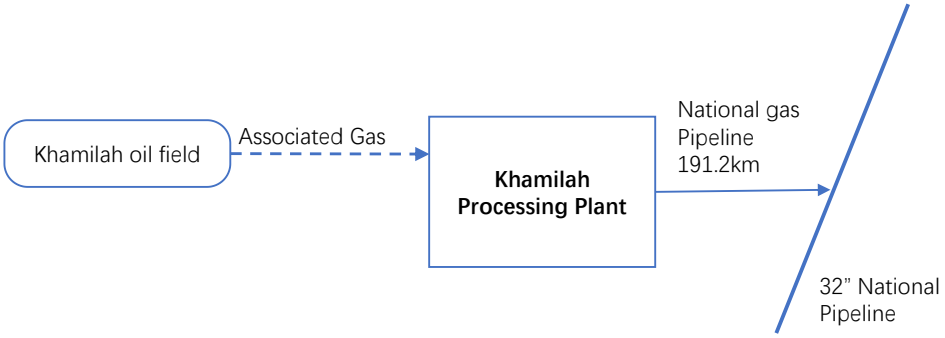

Figure A.2: Pipeline network of the Project

The Khamilah oil 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 100%. According to manufacturer specifications, compressors lifetime should be of 10 years for products properly maintained and used according to instructions. Detailed information regarding compressors is listed as follows:

Table A.1 Technical parameters of compressors from technical specifications

Parameter	Value
Capacity	5 * 8 MMSCFD
Manufacturer	Ariel
Type	JGK-4
Technology	Reciprocating compressors
Rated Power	5*1680 HP(1HP = 735 W) 5*1234.8kW=6.174MW

[2] 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".

Monitoring equipments and their location in the system:
Volume of the total recovered gas will be measured after pre-treatment (phase separation and compression) and after the part of the recovered gas used on-site by means of differential pressure flow meter 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 near the project by means of chromatography (gas composition analysis) through sampling at point F in methodology AM0009 version 07.0 Figure 2. Project electricity consumption will be measured through standard electricity meter located on power line providing electricity to compressor packages. Detailed information for monitoring has been specified in Section B.7.3.

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: The proposed project at Khamilah oil field has 5 compressors (K01~K05), Construction was started on 06/05/2019, and the project started commissioning on 05/01/2020.

A.4. Parties and project participants

Parties involved	Project participants	Indicate if the Party involved wishes to be considered as project participant (Yes/No)
The Sultanate of Oman (host Party)	The Government of the Sultanate of Oman, represented by the Ministry of Oil & Gas (public entity)	**No**

A.5. Public funding of project activity

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

A.6. History of project activity

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The project participant confirms:

(a) The proposed CDM project activity is neither registered as a CDM project activity nor included as a component project activity (CPA) in a registered CDM programme of activities (PoA);
(b) The proposed CDM project activity is not a project activity that has been deregistered.

The project participant declares:

(a) The proposed CDM project activity was not a CPA that has been excluded from a registered CDM PoA;
(b) A registered CDM project activity or a CPA under a registered CDM PoA whose crediting period has or has not expired (hereinafter referred to as former project) doesn't exist in the same geographical location as the proposed CDM project activity.

A.7. Debundling

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Not applicable.

SECTION B. Application of methodologies and standardized baselines

B.1. References to methodologies and standardized baselines

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The project activity uses the baseline and monitoring methodology AM0009/Version 07.0: "Recovery and utilization of gas from oil fields that would otherwise be flared or vented".

Any other methodological tools to which the selected methodology AM0009/Version 07.0 refer:

(a) "Baseline, project and/or leakage emissions from electricity consumption and monitoring of electricity generation (Version 03.0)";
(b) "Tool for the demonstration and assessment of additionality (Version 07.0.0)";
(c) "Combined tool to identify the baseline scenario and demonstrate additionality" (Version 7.0);

B.2. Applicability of methodologies and standardized baselines

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The baseline and monitoring methodology AM0009 Version 07.0 is applicable to the proposed project; because the project meets all the applicability criteria stated in the methodology:

Table B.1. Applicability of methodology AM0009 Version 07.0

No.	Applicability conditions of AM0009	The description of the project	Conclusion
1	The methodology is applicable to project activities that recover and utilize the associated gas and/or gas-lift gas from oil fields that would have been either vented or flared in the absence of the project activity. The recovery may include the pre-treatment (compression and phase separation) in mobile or stationary equipment.	In the absence of the project activity, part of the associated gas was used for the purpose of the gas-lift process and excess associated gas was flared on-site. The proposed project activity aims to recover and utilise associated gas from oil wells that would have been flared in the absence of the project activity. The recovery includes the pre-treatment (compression and phase separation) in or stationary equipment.	Applicable
2	The methodology is applicable under the following conditions: (a) Under the project activity the recovered gas is transported to a gas pipeline with or without prior processing. Prior processing may include transportation to a processing plant where the recovered gas is processed into hydrocarbon products (e.g. dry gas, liquefied petroleum gas (LPG)). The dry natural 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; and/or (b) 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; (c) Partial amount of the associated gas and/or gas-lift gas can be used on-site to meet on-site energy demands, i.e. to run auxiliary equipment prior to the implementation of the project activity and after the implementation of the project activity.	For the proposed project, the gas will be transported to a processing plant and processed into hydrocarbon products (dry gas and condensate) The dry gas will be transported to a gas pipeline directly. This situation belongs to category (a) and (a)-(i) of this requirement. The oil wells in Khamilah oil field is expected to be in operation and producing oil till 2044, therefore, all recovered gas comes from oil wells that are in operation and are producing oil when the associated gas is recovered, therefore, category (b) is applicable.	Applicable

		A small amount of recovered associated gas will be used annually in captive power plant on-site to supply electricity to the project activity after the implementation of the project activity. Therefore, category (c) is applicable.	
3	In addition, the applicability conditions included in the tools referred to above apply.	The project meets the applicability conditions of the applied tools as in Table B.2	Applicable
4	Finally, this methodology is only applicable if the application of the procedure to identify the baseline scenario and demonstrate additionality results in the venting and/or flaring of the associated gas and/or gas-lift gas at the oil production facility as the most plausible baseline scenario.	As identified and demonstrated in section B.4 and B.5, the most plausible baseline scenario is the flaring of the associated gas at the oil production facility.	Applicable
Conclusion: Methodology AM0009 (Version 07.0) is applicable to the project activity.			

In addition, the project meets the applicability conditions of the applied tools as follows:

Table B.2. Applicability of the applied tools

Tool	Criteria	Applicability	Conclusion
Baseline, project and/or leakage emissions from electricity consumption and monitoring of electricity generation (Version 03.0)	If emissions are calculated for electricity consumption, the tool is only applicable if one out of the following three scenarios applies to the sources of electricity consumption: (a) Scenario A: Electricity consumption from the grid. (b) Scenario B: Electricity consumption from (an) off-grid fossil fuel fired captive power plant(s). (c) Scenario C: Electricity consumption from the grid and (a) fossil fuel fired captive power plant(s).	For the project, emissions are calculated for electricity consumption, and the sources of electricity consumption belongs to (b) Scenario B: Electricity consumption from (an) off-grid fossil fuel fired captive power plant(s).	Applicable
	This tool can be referred to in methodologies to provide procedures to monitor amount of electricity generated in the project scenario, only if one out of the following three project scenarios applies to the recipient of the electricity generated: (a) Scenario A: Electricity consumption from the grid; (b) Scenario B: Electricity consumption from (an) off-grid fossil fuel fired captive power plant(s); (c) Scenario C: Electricity consumption from the grid and (a) fossil fuel fired captive power plant(s).	The project includes a captive gas power plant on-site to supply electricity to the project activity. Electricity will be supplied to on-site electricity consuming facilities. Therefore, scenario B of the tool is eligible and applied.	Applicable
	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 tool only accounts for CO_2 emissions.	There are no captive renewable power generation technologies installed to provide electricity in the project activity, in the baseline scenario or to sources of leakage.	Applicable
Tool for the demonstration and assessment	Once the additionally tool is included in an approved methodology, its application by project participants using	--	Applicable

of additionality (Version 07.0)	this methodology is mandatory.		
Combined tool to identify the baseline scenario and demonstrate additionality (Version 07.0)	The tool is applicable to all types of proposed project activities. However, in some cases, methodologies referring to this tool may require adjustments or additional explanations as per the guidance in the respective methodologies. This could include, inter alia, a listing of relevant alternative scenarios that should be considered in Step 1, any relevant types of barriers other than those presented in this tool and guidance on how common practice should be established.	The applied methodology does not require any adjustments or additional explanations.	Applicable
Conclusion: The applied tools are applicable to the project activity.			

B.3. Project boundary, sources and greenhouse gases (GHGs)

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The project boundary encompasses, •

- The project oil reservoir and oil wells at at Khamilah oil field area at Block-27, where the associated gas is collected;
- The site where the associated gas was flared in the absence of the project activity;
- The gas recovery, pre-treatment, processing and transportation infrastructures, and 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.3 below.

Table B.3. Emission sources included in or excluded from the project boundary

Source		GHG	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 if applicable, compression/decompression, transportation of the recovered gas	CO_2	Yes	Main source of emissions in the project
		CH_4	No	Excluded for simplification. This emission source is assumed negligible
		N_2O	No	Excluded for simplification. This emission source is assumed negligible

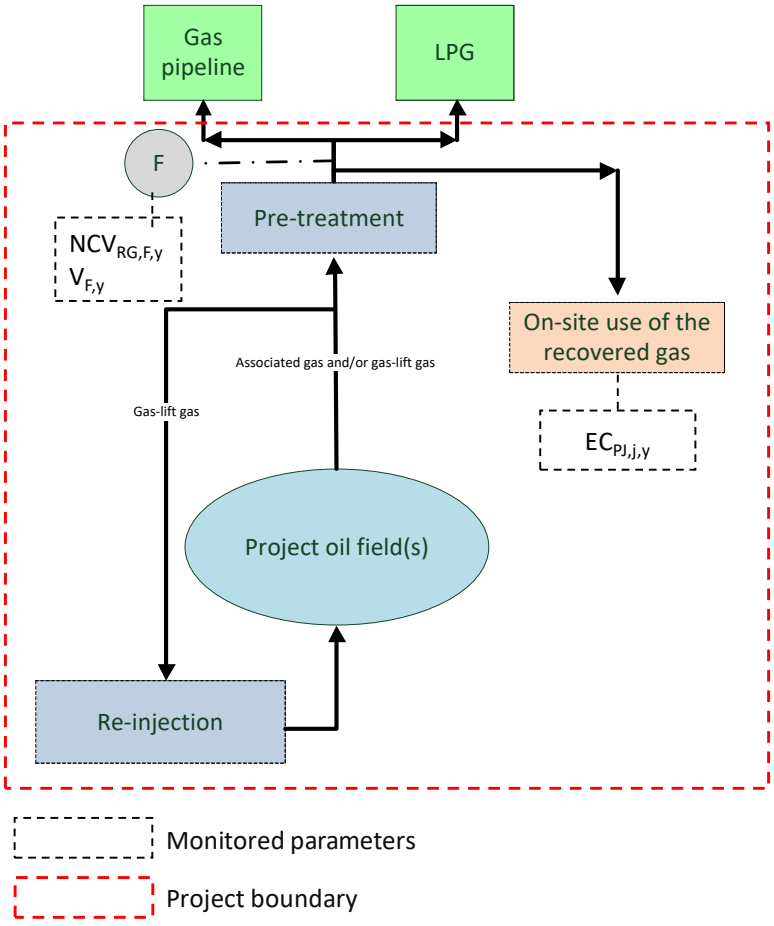

Figure B.1. Flow diagram of the project boundary

B.4. Establishment and description of baseline scenario

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According to AM0009 version 07.0, the project participant shall apply the following steps in "Combined tool to identify the baseline scenario and demonstrate additionality" (Version 07.0) to identify the baseline scenario:

Step 1 of the "Combined tool to identify the baseline scenario and demonstrate additionality": Identification of alternative scenarios

Step 3 of the "Combined tool to identify the baseline scenario and demonstrate additionality": Investment analysis

Step 1 is analysed in section B.4 as follow, and Step 3 is analysed in section B.5.

Step 1: Identification of alternative scenarios

Step 1a: Define alternative scenarios to the proposed CDM project activity

Identify all alternative scenarios that provide the same output (service or product) as the proposed CDM project activity and discussed as below table:

Plausible alternative baseline scenarios

S1	*The proposed project activity undertaken 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 and maximum net calorific value of the recovered gas as per specifications of national gas line where the gas will be sold; according to the investment analysis in section B.5, if the project is not undertaken as CDM project, the equity IRR after taxes is only 7.37% and lower than the benchmark IRR of 11.66% (after-tax) of oil industry in Oman, which means the alternative is financially unattractive. Therefore S1 is excluded from further consideration. Full details on economic attractiveness have been discussed in section B.5.
S2	*Where applicable, no investment is undertaken by the project participants, i.e., the same output as that produced by the proposed CDM project activity can also be provided by others than the project proponent (i.e., the PP is not the only output provider). For example:* *(i) In the case of a Greenfield power project, an alternative scenario may be that the project participants would not invest in the Greenfield power plant but that power would be generated in existing and/or new power plants in the electricity grid;* *(ii) In the case of a transportation project, an alternative scenario may be that the project participants would not invest in alternative modes (e.g. rail or pipelines), but these alternatives would be implemented by third parties.*	Not Plausible If no investment is taken by the PP, in this particular scenario, no third party will invest in the similar kind activities with the same output as the oil wells are owned and managed by the project owner only.
S3	*Where applicable, the continuation of the current situation, not requiring any investment or expenses to maintain the current situation, such as, inter alia:* *(i) The continued venting of methane from a landfill;* *(ii) The continued release of N_2O from adipic or nitric acid production.* *As per the applicable methodology para 19 (b), venting and/or flaring of the associated gas and/or gas-lift gas at the oil production facility.*	Plausible Prior to the project, part of the associated gas was used for the purpose of the gas-lift process and excess associated gas was flared on-site. There is no local or national regulation in Oman that restricts from flaring the gas. A World Bank Report shows gas flaring volumes in Oman was between 2.4~2.6 billion cubic meters from 2014 to 2018. 3 It's common situation that the associated gas is flared in Oman. In this scenario, 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, the injection of gas into the oil reservoir and its production process for the purpose of

[3] https://www.worldbank.org/en/programs/gasflaringreduction#7

		the gas-lift process is common production. Gas used as gas-lift gas originates from the wells where it is re-injected, while volumes of gas required for gas-lift process are calculated by field operator for efficient oil production. S3 is the scenario existing prior to the start of the implementation of the project activity and it is the baseline scenario of the project activity.
S4	*Where applicable, the continuation of the current situation, requiring an investment or expenses to maintain the current situation, such as, inter alia:* *(i) The continued use of an existing boiler involving expenses for operation and maintenance;* *(ii) The continued use of a specific fuel mix for power generation in an existing power plant;* *(iii) The continued use of existing transportation infrastructure for transporting a product.*	Not Plausible No investment is required for the current situation as the gas is being flared.
S5	*Other plausible and credible alternative scenarios to the project activity scenario, including the common practices in the relevant sector, which deliver the same output considering examples of scenarios identified in the underlying methodology where relevant;* *As per the applicable methodology para 19 (c), All other plausible and credible alternatives to the project activity. Such alternatives may include, for example, recovery and use of the associated gas and/or gas-lift gas:* *(i) In chemical industry;* *(ii) To produce heat and/or electricity;* *(iii) To use on-site.*	(i) In chemical industry; Not Plausible. A factory which utilizes gas as chemical feedstock for chemical manufacturing industry of a useful product tends to require large investments and a stable gas supply. However, 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 Scenario is not considered a plausible alternative (ii) To produce heat and/or electricity; Not plausible. It is not common practice in the oil and gas sector to produce heat and/or electricity with associated gas in Oman, the detailed common practice analysis is provided in Section B.5. The electricity used for the oil wells in Oman are from non-associated gas and other fossil sources in power generation. There is no need for heat at the project site. The gas has been flared in the baseline situation. This Scenario is not considered a plausible alternative (iii) To use on-site. Not plausible. On-site use of the associated gas is not a common practice

		in the oil and gas sector in Oman, as flaring of the associated gas is legally allowed. This Scenario is not considered a plausible alternative
S6	*Where applicable, the "proposed project activity undertaken without being registered as a CDM project activity" to be implemented at a later point in time (e.g. due to existing regulations, end-of-life of existing equipment, financing aspects)*	Not Plausible The proposed project activity undertaken without being registered as CDM project activity is not being implemented under any existing regulation. As in the host country, as per Ministerial Decision 5/86 of 17 May 1986, all the selected alternatives i.e. S1 &S3 are in compliance with Oman laws or other regulation. Further there is also no legislation that mandates the Project Participants to recover the associated gas. Further descriptions has been displayed in step 1b blow. Due to end-of life of existing equipment as it is greenfield project and no equipments exist.

Outcome of step 1a: S1 and **S3** are **plausible**.

Step 1b: Consistency with mandatory applicable laws and regulations

All the realistic and credible alternative scenarios (**Scenario (a)** and **Scenario (b)**) outlined above are permitted by law or other industrial agreements and standards in Oman. 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[4], 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-27 (existing scenario prior to the proposed project activity) does not violate the emissions standards as prescribed by the Ministerial Decision 5/86 of May 17 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 environmental permit issued on September 3rd, 2018 by Ministry of Environment and Climate Affairs according to Law on Conservation of Environment and Prevention of Pollution promulgated by Royal Decree.

Outcome of step 1b: Scenario (a) and **Scenario (b)** are **plausible**.

Conclusion of step 1: Scenario (a) and **Scenario (b)** are **plausible** and both discussed further in section B.5.

[4] http://documents.worldbank.org/curated/en/590561468765565919/pdf/295540Regulati1aring0no10301public1.pdf

As detailed in section B.5, the outcome of the investment analysis shows that Scenario (a) above (i.e. The project activity not implemented as a CDM project) is not considered economically attractive by the project participants and the operator. Therefore, the most plausible baseline scenario for the proposed project is identified as Scenario (b), Venting and/or flaring of the associated gas and/or gas-lift gas at the oil production facility.

B.5. Demonstration of additionality

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Step 3: Investment analysis

According to AM0009 (version 07.0), the economic attractiveness is assessed for those alternative scenarios that are feasible in technical terms in Step 1.

If this option is used, apply the following:

(a) Apply an investment comparison analysis, as per Step 3 of the "Combined tool to identify the baseline scenario and demonstrate additionality", if more than one alternative is remaining after Step 2 and if the remaining alternatives include scenario (a) and (c);

(b) Apply a benchmark analysis, as per Step 2(b) of the "Tool for the demonstration and assessment of additionality", if two alternatives are remaining after Step 2 and if the remaining alternatives are scenarios (b) and either (a) or (c).

If venting or flaring of the associated gas in a host party is not prohibited by law, but instead is subject to taxes or fines, the impact of these taxes and fines should be taken into account.

Venting or flaring of associated gas in Oman is not subject to taxes or fines, as demonstrated in Step 1b, therefore, no taxes or fines need to be taken into account.

Revenues and avoided cost from using the recovered gas to meet the energy demand on-site shall be included in the investment analysis, where applicable.

Part of the gas is consumed onsite to provide electricity to the project activity. On average about 312.4 mmscf 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 operated by on-site operator and the gas is delivered free of charge to the power plant. The captive gas power plant only supplies electricity for the project, and the electricity supplied for the project activity isn't required before the start of the project activity, therefore, there are no revenues or avoided cost from using the recovered gas to meet the energy demand on-site. The volume of on-site used associated gas for electricity has been excluded in the calculation of baseline emission reductions.

This methodology is only applicable if the application of the procedure to identify the baseline scenario and demonstrate additionality results in the venting and/or flaring of the associated gas and/or gas-lift gas at the oil production facility as the most plausible baseline scenario.

As the proposed project applied a benchmark analysis, as per Step 2(b) of the "Tool for the demonstration and assessment of additionality" (Version 7.0). The economic attractiveness is assessed by determining an expected Internal Rate of Return (IRR) of each alternative scenario.

Sub-step 3a: Determine appropriate analysis method

Determine whether to apply simple cost analysis, investment comparison analysis or benchmark analysis (Sub-step 2b). If the CDM project activity and the alternatives identified in Step 1 generate no financial or economic benefits other than CDM related income, then apply the simple cost analysis (Option I). Otherwise, use the investment comparison analysis (Option II) or the benchmark analysis (Option III).

The project activity and the alternatives identified will generate financial and economic benefits other than CDM related income, the project participant choose Option III benchmark analysis.

Sub-step 3b: Option III. Apply benchmark analysis

Identify the financial/economic indicator, such as IRR, most suitable for the project type and decision context.

When applying Option II or Option III, the financial/economic analysis shall be based on parameters that are standard in the market, considering the specific characteristics of the project type, but not linked to the subjective profitability expectation or risk profile of a particular project developer. Only in the particular case where the project activity can be implemented by the project participant, the specific financial/economic situation of the company undertaking the project activity can be considered.

Investment analysis tool is taken into account according to the "Tool for the demonstration and assessment of additionality" (Version 7.0). At the time of investment decision dated on 05/03/2019, the most available investment analysis tool is version 9.0, which entry into force on 29/11/2018. According to Investment analysis (version 9.0), the project belongs to Sectoral Scope 10 "Fugitive Emissions from fuels" and therefore falls under project category Group 2, and the default value for benchmark equity Internal Rate of Return after tax (IRR) for the Sultanate of Oman is 10.79%. Thus, 10.79% was considered as benchmark for equity IRR at the time of investment decision.

However, at the time of validation, Investment analysis (version 10.0) was available which was valid since 28/11/2019. In the version 10.0 tool, the benchmark equity Internal Rate of Return after tax for the Sultanate of Oman is the 11.66%. Since version 10.0 is the most available investment analysis, 11.66% was adopted for the PDD.

As displayed in below IRR calculation, the equity IRR of the project is 7.37%, which is blow 10.79% (version 9.0) and blow 11.66% (version 10.0).

Sub-step 3c: Calculation and comparison of financial indicators (only applicable to Options II and III):

The project participant and the operator estimated the financial indicators such as capital costs, gas price, liquid price, annual operational expenditures, expected recovered gas volume, expected liquid gain volume, net calorific value of the recovered gas income, tax rate, etc. according to 2019 Oman State Budget, Taxation law in Oman, on-site operator reports, and the project participant and the operator's surveys, Oil and Gas Regulation in Oman, and Oman financial regulations, etc. The financial indicator of investment analysis shows that the equity IRR of the project of 7.37% is lower than the benchmark IRR of 11.66% (after-tax) and the project is financially unviable.

On 05 March 2019, the project participant and the operator held a board meeting. In the meeting, the board discussed and confirmed the financial indicators for the equity IRR analysis, and concluded that without carbon revenue the project is not financially attractive, as the equity IRR after taxes is 7.37%, lower than the benchmark in Oman. Therefore, the project participant decided to construct the project under CDM support.

Below is the basic data for the calculation of equity IRR.

Table B.4. Basic data for Equity IRR calculation

Parameter	Data	Unit	Source
Capital expenditures (100% equity)	51,595,802	US$	Memo of Associated Gas Recovery and Utilization at Khamilah oil field area at Block-27 in Wilayat Ibri of the Sultanate of Oman provided by the project participant and the operator, dated on 05/03/2019. The capital expenditures in

			the Memo were calculated as per *Oil and Gas Regulation in Oman* by process engineer in charge of the project and the amount was approved internally in the *Project Authorization Request.* The capital expenditures in the Memo is the most available reference for investment at the time of investment decision.
Annual Operational expenditures	591,553	US$	Memo dated of Associated Gas Recovery and Utilization at Khamilah oil field area at Block-27 in Wilayat Ibri of the Sultanate of Oman provided by the project participant and the operator, dated on 05/03/2019. The annual operational expenditures in the Memo were calculated as per *Oil and Gas Regulation in Oman* by process engineer in charge of the project. The annual operational expenditures in the Memo is the most available reference for OM cost at the time of investment decision.
Projected quantity of gas recovered over the project lifetime	81,068	mmscf	Memo dated on Associated Gas Recovery and Utilization at Khamilah oil field area at Block-27 in Wilayat Ibri of the Sultanate of Oman provided by the project participant and the operator, dated on 05/03/2019. Calculated by the reservoir management team and served as the basis of investment decision. The recovered gas volume was derived based on projected oil production volumes and Gas/Oil Ratio (GOR). The oil production was sourced from the operational production plan approved by Oman government. Detailed documents have been provided to DOE.
Projected fuel gas consumption for on-site electricity generation over the project lifetime	3,124	mmscf	The operator estimated according to compressor capacity, gas turbine efficiency, etc. Detailed calculation has been displayed in the ER spreadsheet.
Projected quantity of gas sold over the project lifetime	74,827	mmscf	The operator estimated according to the oil production, and the consumption of the captive power plant at the time of investment consideration. Detailed documents have been provided to DOE.
Projected quantity of liquid sold over the project lifetime	2,061,471	Brl	Liquid volumes were estimated by the operator through complex modelling using HYSYS software based on gas composition at the time of investment decision. Detailed documents have been provided to DOE.
Agreed price for the delivery of recovered gas	1.03 estimated for 2020 (incremental +1.5% per year)	US$/mmbtu	Communications with government at the time of investment decision.

Net calorific value of the recovered gas	42.441	MJ/m^3	Lab analyzes data.
Expected price for liquid gains	58	US$/Brl	Official oil price for budget purpose at investment decision, as per Oman State General 2019 Budget published on January 2019.
Income tax rate for Operator	55	%	Oman Tax Law , Royal Decree, No. 2009/28, effected since 24/05/2009, amended by Royal Decree in Sep 2017. This the most valid data for income tax at the time of investment decision.
Project lift time	10	years	Technical manual of the compressors

Table B.5. Comparison of the financial indicator and the financial benchmark

Equity IRR after taxes	7.37%
Financial benchmark	11.66%

It is concluded that the project activity has a less favourable indicator than the benchmark, therefore the project activity without implemented as a CDM project (alternative baseline Scenario (a) is not considered financially attractive.

Suitability of key input values:

- CAPEX

Capital expenditures for the project are taken from the Memo on Associated Gas Recovery and Utilization at Khamilah oil field area at Block-27 in Wilayat lbri of the Sultanate of Oman provided by the project participant and the operator. The capital expenditures in the Memo were calculated as per *Oil and Gas Regulation in Oman* by process engineer in charge of the project and the amount was approved internally in the *Project Authorization Request.*

According to the financial statement provided by the operator, the capital expenditures includes screw compressors, reciprocating compression, motors, air cooled exchanger, scrubbers and discharge scrubbers, pipelines, suction bottles, storage, transportation, meters, construction, electrical facilities, etc. the capital expenditures estimated in the PDD are in line with the actual costs as per the financial statement. The detailed actual expense has been provided to DOE for validation.

Furthermore, the compressor invoice and electrical facilities has been provided to DOE for crosscheck. The cost values are consistent with the estimation of the operator and PP.

- OPEX

The annual operational expenditures were sourced from Memo of Associated Gas Recovery and Utilization at Khamilah oil field area at Block-27 in Wilayat lbri of the Sultanate of Oman provided by the project participant and the operator, dated on 05/03/2019.

The annual operational expenditures in the Memo were calculated as per *Oil and Gas Regulation in Oman* by process engineer in charge of the project. Annual operational expenditures correspond to around 1.1% of CAPEX. Table below provides the breakdown, which is the most available at the time of investment decision.

Table B.6. Annual operational expenditures

O&M Items	Labour	Maintenance	Materials	Support & others	Total
Expenditures	320,000	82,553	114,000	75,000	591,553

The prices and labour has been rising in recent years in Oman due to the positive inflation rate[5]. The annual Operational expenditures was cross-checked with the actual O&M costs happened for the proposed in Jan 2020, and can be concluded the estimation in the PDD is consistent with the actual O&M costs.

-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 as shown in the below figure:

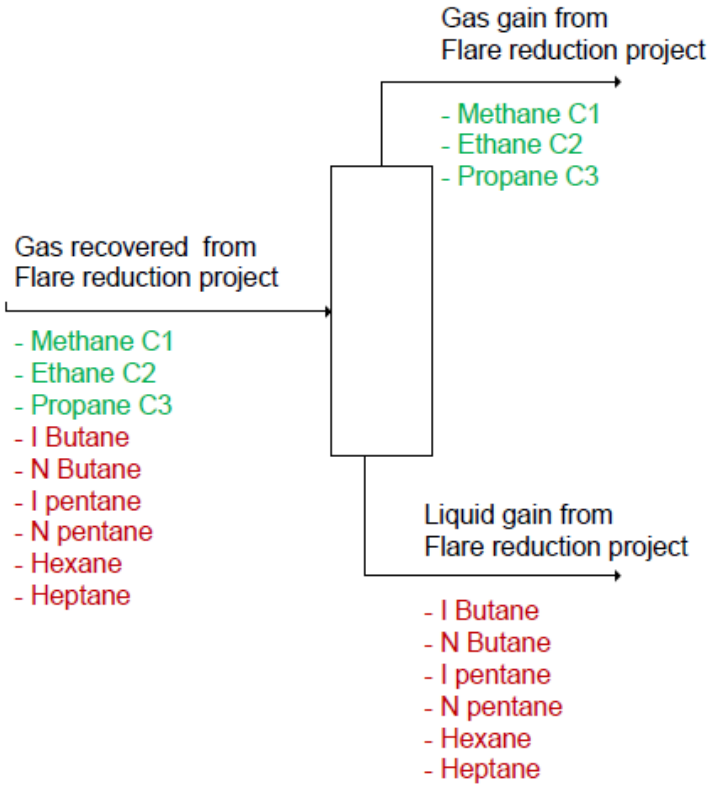

Figure B.2. Gas and liquid gains composition

Source: operator of the project, 'liquid gain from flare reduction project' statement.

***-Recovered gas*:**

Volumes of the recovered gas detailed in ER spreadsheet were calculated by the reservoir management team and served as the basis of investment decision. The recovered gas volume was derived based on projected oil production volumes and Gas/Oil Ratio (GOR) at Khamilah oil field area Block-27. The oil production was sourced from the operational production plan approved by Oman government. The projected gross gains for the proposed CDM project were calculated through multiplying the expected oil production by the Gas/Oil Ratio (GOR). The detailed estimation and calculation have been provided to DOE. Projected values used in IRR calculations are deemed conservative.

In accordance with recommendation of the monitoring methodology, the quantity of recovered gas will be monitored ex-post. A gas shrinkage factor during processing at gas plant of 4% was estimated by operator through computerized model using HYSYS software, therefore, the 4% gas shrinkage factor values have been used for projected quantity of gas sold in IRR calculations.

Expected annual gross gas volumes to be recovered as part of the project activity are on average 8,106.8mmscf over its lifetime. On average about 312.4 mmscf of the recovered gas will be used annually in captive power plant on-site to supply electricity to the project activity based on the calculation from the facility rated power, compressor capacity, estimated recovered gas volume,

[5] https://www.theglobaleconomy.com/Oman/inflation/

gas turbine efficiency, etc. The captive gas power plant is 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 7,482.7 mmscf after deduction of onsite gas consumption due to project activity and deduction of a gas shrinkage factor due to gas treatment at gas plant for the purpose of meeting the specifications of the National pipeline[6]

Moreover, the values have been cross-checked with actual data after the project was commissioned since 05/01/2020.

***-Recovered liquids*:** The recovered gas is treated at processing plant 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. A separate report prepared by operator of the project named 'liquid gain statement from flare reduction project' dated on 05/03/2019, which is available at the investment decision, detailing the liquid gains estimation process and original HYSYS files have been provided to DOE. Liquid volumes were estimated through liquid gains factor named NGL(Natural Gas Liquids, 27.55 brls per mmscf recovered) by the operator based on gas composition, the liquid gain is calculated as:

Yearly Projected quantity of liquid sold (brls)
= Projected quantity of gas sold (mmscf) *27.55
= (projected quantity of gas recovered - projected quantity of gas used internally) *(1- shrinkage factor) *27.55

Moreover, considering that NGL volumes are a direct function of gas volumes and that actual recovered gas volumes during Jan – May 2020 have been cross-checked as being on the conservative side from an additionality point of view compared with projected data, projected NGL volumes are deemed to reflect actual NGL volumes in an equally conservative manner.

-Agreed price for the delivery of recovered gas

The operator has been in discussion with the relevant authority with regards to the price for the recovered gas. The gas price was sourced from Memo of Associated Gas Recovery and Utilization at Khamilah oil field area at Block-27 in Wilayat Ibri of the Sultanate of Oman provided by the project participant and the operator, dated on 05/03/2019.

At the time of investment decision, the price of 1.03 US$/mmbtu (incremental +1.5% per year) was estimated for the gas as per the discuss outcome with the government.

The agreed price for the delivery of recovered gas at the delivery point is set later as per GSPA (Gas Sales and Purchase Agreement). Taking into account the operation of the escalation provisions in Article 5.1.1, As at January 2020, Gas Price is US$1.0300 per MMBTU (Gross Heating Value) at the Delivery Point and escalated at one decimal point five percent (1.5%) per annum (compounded).

-Agreed price for the delivery of liquid

The liquid price was estimated as per official oil price for budget purpose at investment decision, i.e. Oman State General 2019 Budget published in January 2019. The oil price dropped sharply in recently, it's highly unlikely to be increased.

[6] Expected average net gas volumes delivered to national pipeline = (expected gross gas volumes- projected quantity of gas used internally)*(100%- gas shrinkage factor). The calculation was performed on yearly basis, and year average data is calculated as the arithmetic mean over the 10 years of the project lifetime. Please refer to the ER spreadsheet for detail calculations. Relevant data source has been provided to DOE for validation.

Sub-step 3d: Sensitivity analysis (only applicable to Options II and III)

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 Investment analysis (version 10.0) paragraph 27 and 28. Variables listed in Table below have been considered in the sensitivity analysis:

Table B.7. Sensitivity analysis: impact of variations in assumptions on the IRR

Parameter \ Percentage Variation	-10%	-5%	0%	5%	10%
Capital expenditures	8.31%	7.82%	7.37%	6.97%	6.61%
Annual Operational expenditures	7.51%	7.44%	7.37%	7.31%	7.24%
Gas volumes / price	6.72%	7.05%	7.37%	7.71%	8.05%
Liquid gains / price	6.52%	6.94%	7.37%	7.82%	8.27%

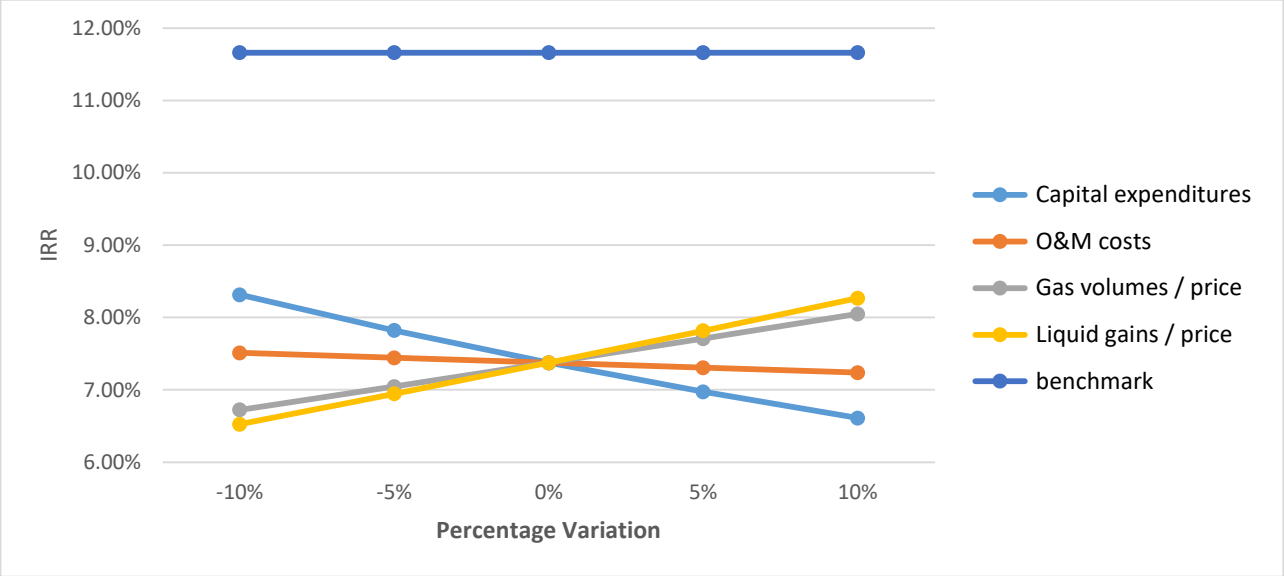

Figure B.3. Results of the sensitivity analysis

Even with a variation of -10% to +10% for Investment costs, O&M costs, gas volumes / price, and liquid gains / price, the project is still not financially attractive.

Table B.8. Critical analysis: Variation at which IRR equates the benchmark

Critical assumption	Variation at which IRR equates the benchmark	Remarks
Capital expenditures	-33.80%	This is almost impossible to happen, as the capital expenditures have already paid in the construction year (2019) as a lump sum. According to the financial statement provided by the operator, the actual capital expenditures estimated in the PDD are in line with the actual costs. Furthermore, the compressor invoice and electrical facilities has been provided to DOE for crosscheck. Therefore, it's impossible that for the capital expenditures to decrease 33.80%.
Annual Operational expenditures	/	This is impossible to happen. Even when O&M costs decreases by more than -100%, the IRR still could not reach the benchmark.

Gas volumes / price	58.50%	The escalation of 58.50% in the gas volumes or gas price is highly unlikely since the recovered gas volume was derived based on projected oil production volumes and Gas/Oil Ratio (GOR) at Block-27 and has been crosschecked with the actual gas volume data during Jan – May 2020. The gas price has been agreed as per GSPA (Gas Sales and Purchase Agreement) and is impossible to increase 58.5%.
Liquid gains / price	44.20%	The escalation of 44.20% in the liquid gains or liquid price is highly unlikely since the liquid volumes were estimated by the operator through complex modelling using HYSYS software based on gas composition. The Liquid price is the Official oil price for budget purpose at investment decision as per Oman State General 2019 Budget published in January 2019. The estimated liquid gains have been crosschecked with the actual liquid volume data during Jan – May 2020. The oil price has been dropped hugely, at the time when the validation is in finalization, the Brent oil price is around 40US$/rl , which is far below the estimation of 58 US$/Brl in the PDD. The economy of the whole world was affected by covid-19, according to the forecast of World Bank and Bloomberg, the oil price will not rise greatly in recently years[7]. Therefore, it's unlikely for the liquid price to increase by 44.20%.

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 11.66% benchmark.

According to AM0009 version 07.0, step 1 and step 3 are selected for the identification of the baseline scenario. The outcome of the investment analysis shows that Scenario (a) above (i.e. The project activity not implemented as a CDM project) is not considered economically attractive by the project participants. Therefore, the baseline scenario for the proposed project is identified as Scenario (b), Venting and/or flaring of the associated gas and/or gas-lift gas at the oil production facility.

Prior consideration of the CDM

CDM was a decisive factor in the decision to proceed with the project. As per para 33 of "CDM project standard for project activities" Version 2.0, EB 101, paragraph 31, "*If the start date of a proposed CDM project activity, is prior to the date of publication of the PDD for global stakeholder consultation, the project participants shall demonstrate that the CDM benefits were considered necessary in the decision to undertake the project as a CDM project activity*".

As per para 33 of "CDM project standard for project activities" Version 2.0, EB 101, paragraph 32, "*For a proposed CDM project activity with a start date on or after 2 August 2008, project participants shall inform the host Party's designated national authority (DNA) and the UNFCCC secretariat, in writing of the commencement of the project activity and their intention to seek the CDM status for the project activity, or, through a DOE, publish the PDD for global stakeholder consultation, within 180 days of the start date in accordance with the "CDM project cycle procedure for project activities."*

[7] https://www.worldbank.org/en/region/mena/brief/coping-with-a-dual-shock-coronavirus-covid-19-and-oil-prices

The proposed project started on 06/05/2019, and the PDD publication date of the global stakeholder consultation is 30/11/2019. Therefore the project participants shall demonstrate that the CDM benefits were considered necessary in the decision to undertake the project as a CDM project activity.

The operator estimated the financial indicators such as capital costs, gas price, liquid price, annual operational expenditures, expected recovered gas volume, expected liquid gain volume, net calorific value of the recovered gas income, tax rate, etc. according to 2019 Oman State Budget, Taxation law in Oman, on-site operator reports, and the operator's surveys, Oil and Gas Regulation in Oman, and Oman financial regulations, etc. The financial indicator of investment analysis shows that the equity IRR of the project 7.37% is lower than the benchmark IRR of 11.66% (after-tax) and the project financially unviable.

On 05/03/2019, the project participant and the operator held a board meeting. In the meeting, the board discussed and confirmed the financial indicators for the equity IRR analysis, and concluded that without carbon revenue the project is not financially attractive, as the equity IRR after taxes is 7.37%, lower than the benchmark in Oman. Therefore, the project participant decided to construct the project under CDM support.

Following the Memo decision on 05/03/2019, and project participant signed Carbon Asset Development Agreement was signed with Carbon Resource Management S.A. on 28/03/2019 for to develop the proposed project as CDM project. Subsequently, Carbon Resource Management S.A. began to communicate with the project participant of the project details and did some carbon training for the project participant.

On 06/05/2019 the project owner signed *Purchase Agreement of Gas Compressor, Motor, and Process Air Cooler* of the proposed project. This is defined as the project start date.

On 02/06/2019, the construction of the project started as per the notification letter issued from the construction company to the operator.

On July 2019, Carbon Resource Management S.A. performed site visit for information exchange, carbon communications and CDM training for the project participant and the operator.

Project participant sent the commencement of the project activity and their intention to seek the CDM status for the project activity to both Oman DNA (Ministry of Environment & Climate Affairs) and the UNFCCC on 29/09/2019. This was done within 180 days of the start date of this project activity, which meets the requirement of prior consideration of CDM.

Continuing and real actions taken to secure the CDM status

The project participants has taken continuing and real actions to secure the CDM status for the project activity in parallel with its implementation, the implementation timeline and the related actions taken to secure the CDM status are listed in the following table.

Table B.9. Implementation timeline

Date	Implementation timeline	Real actions to secure the CDM status for the project activity
05/03/2019	Memo on Associated Gas Recovery and Utilization at Khamilah oil field area at Block-27 in Wilayat Ibri of the Sultanate of Oman (investment decision)	On the Memo the project participants and the operator mentioned that the project is not financially attractive without the carbon revenue, and they will secure to carbon revenue to overcome the financial barrier and register the project as CDM project at UNFCCC.
28/03/2019	Carbon Asset Development Agreement (CADA)	CADA has been signed between signed between the project participant and Carbon Resource Management S.A. This agreement reflects the terms on which the Parties have agreed

		to cooperate in developing the Project as a CDM project. Subsequently, Carbon Resource Management S.A. began to communicate with the project participant and the operator of the project details and did some carbon training for the operator.
06/05/2019	Purchase agreement of gas compressor, motor and process air cooler for the project.	Starting date of the project.
02/06/2019	The notification letter issued from the construction company to the operator	Construction started
Jul 2019	Carbon Resource Management S.A. performed site visit for information exchange, carbon communications and CDM training for the operator.	Continuing and real actions to secure the CDM status
29/09/2019	Inform the host Party's DNA and the UNFCCC secretariat	PP sent the notification to both the host party DNA and the UNFCCC about the commencement and their intention to seek the CDM status for the project activity.
30/11/2019	PDD for publication of the global stakeholder consultation	PDD for publication of the global stakeholder consultation on UNFCCC's website.
05/01/2020	Completion of the project	Commissioning date of the project.

Conclusion

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

Sub-step1: *calculate applicable capacity or output range as +/-50% of the total design capacity or output of the proposed project activity.*

The average annual gross gas recovery volume 23.16mmscfd, therefore the applicable output range is between 11.58 mmscfd and 34.74 mmscfd.

Sub-step2: *identify similar projects (both CDM and non-CDM) which fulfil all of the following conditions.*

(a) The projects are located in the applicable geographical area;
(b) The projects apply the same measure as the proposed project activity;
(c) The projects use the same energy source/fuel and feedstock as the proposed project activity, if a technology switch measure is implemented by the proposed project activity;
(d) The plants in which the projects are implemented produce goods or services with comparable quality, properties and applications areas (e.g. clinker) as the proposed project plant;
(e) The capacity or output of the projects is within the applicable capacity or output range calculated in Step 1;
(f) The projects started commercial operation before the project design document (CDM-PDD) is published for global stakeholder consultation or before the start date of proposed project activity, whichever is earlier for the proposed project activity.

In order to identify all plants delivering the same output as the proposed project, all the oil and gas concessions in the Sultanate of Oman was listed and discussed, based on concession boundaries

from officially publicly available source Oman society for Petroleum Services[8]. The table below summarizes the findings. Original source of information is displayed in Table Appendix-6 of Annex 3. The information and data were also confirmed with Ministry of Oil & Gas.

Table B.10. Blocks checklist in Oman for common practice

Block No.	Key information	Conclusion
3	Oil production began in August 2010. There are no facilities for the recovery of associated gas (AG).	No recovery of AG, excluded.
4		
5	Associated gas is recovered since 2017. The average AG production is 35 mmscfd	Block 5 doesn't fall into applicable capacity or output range between 11.58 mmscfd and 34.74 mmscfd. As its production is close to 34.74 mmscfd, Block 5 is further discussed and in Sub-step3.
6	Associated gas recovery production is around 600 mmscfd. there are initiatives of gas reduction projects.	Associated gas production is around 600 mmscfd, not in range between 11.58 mmscfd and 34.74 mmscfd. Excluded.
7	According to public data source, for Block 7, there is little gas associated with oil which is heavy and viscous and will not flow readily and continuously. No facilities installed for recovery of associated gas.	No recovery of AG, excluded.
8	Offshore oil field.	Offshore is different oil extraction technology with the onshore of the proposed project, excluded.
9	Registered CDM project (PA 6817)	CDM project, excluded.
15	Still in exploration phase.	Currently no oil producing, excluded.
17	Still in exploration phase.	Currently no oil producing, excluded.
27	The proposed project	
30	Still in exploration phase.	Currently no oil producing, excluded.
31	Still in exploration phase.	Currently no oil producing, excluded.
36	Still in exploration phase.	Currently no oil producing, excluded.
39	Still in exploration phase.	Currently no oil producing, excluded.
40	Offshore oil field.	Offshore is different oil extraction technology with the onshore of the proposed project, excluded.
42	Still in exploration phase.	Currently no oil producing, excluded.
44	Block 44 is primarily a natural gas and condensate field.	Gas field, not oil field, excluded.
48	Still in exploration phase.	Currently no oil producing, excluded.
49	Still in exploration phase.	Currently no oil producing, excluded.
50	Offshore oil field.	Offshore is different oil extraction technology with the onshore of the proposed project, excluded.
52	Still in exploration phase.	Currently no oil producing, excluded.
53	There are no facilities for the recovery of associated gas.	No recovery of AG, excluded.
54	Still in exploration phase.	Currently no oil producing, excluded.
56	Still in exploration phase.	Currently no oil producing, excluded.
57	Still in exploration phase.	Currently no oil producing, excluded.
60	Block 60 is a tight gas field, it's unconventional gas project.	Gas field, not oil field, excluded.
61	Block 61 is unconventional gas project.	Gas field, not oil field, excluded.
62	Block 62 is gas field.	Gas field, not oil field, excluded.
66	Still in exploration phase.	Currently no oil producing, excluded.

[8] https://opaloman.org/wp-content/uploads/2019/02/Concession_map-16.01.2019.pdf

67	Still in exploration phase.	Currently no oil producing, excluded.

Sub-step3: *within the projects identified in Step 2, identify those that are neither registered CDM project activities, project activities submitted for registration, nor project activities undergoing validation. Note their number N_{all}.*

From above analysis, only Block 5 delivers an output close to applicable output range defined in sub-step 1 (but actually not within the applicable output range) and has started commercial operation before the start date of the proposed CDM project is. Therefore $N_{all} = 1$.

Sub-step4: *within similar projects identified in Step 3, identify those that apply technologies that are different to the technology applied in the proposed project activity. Note their number N_{diff}*

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"*[9]*, and that "IFC plans to monitor the Operator's progress towards the reduction/elimination of gas flaring*".

Block 5 applies a technology different than the technology applied in the proposed project activity. $N_{diff} = 1$

Sub-step4: *calculate factor $F=1-N_{diff}/N_{all}$ representing the share of similar projects (penetration rate of the measure/technology) using a measure/technology similar to the measure/technology used in the proposed project activity 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 the factor F is greater than 0.2 and N_{all}-N_{diff} is greater than 3.*

F = 1- (1/1)
F= 1-1 = 0
$N_{all} – N_{diff}$ = 1-1 = 0

The factor F is 0 and N_{all} minus N_{diff} is 0.

The proposed project is not a 'common practice' within the sector in the applicable geographical area. The requirements of the common practice analysis are fulfilled and the project is additional.

B.6. Estimation of emission reductions

B.6.1. Explanation of methodological choices

>>
In accordance with AM0009 Version 07.0, baseline is calculated as below:

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

Baseline emissions are calculated as follows:

9 https://ifcextapps.ifc.org/ifcext/pressroom/ifcpressroom.nsf/1f70cd9a07d692d685256ee1001cdd37/391f8b6de1ab507b85256fb8007c7d08

$$BE_y = V_{F,y} \times NCV_{RG,F,y} \times EF_{CO2,Methane} \quad (1)$$

Where

BE_y = Baseline emissions in year *y*, (t CO_2e)

$V_{F,y}$ = Volume of total recovered gas measured at point F in methodology AM0009 version 07.0 Figure 2 in year y (Nm^3)

$NCV_{RG,F,y}$ = Average net calorific value of recovered gas at point F in methodology AM0009 version 07.0 Figure 2 in year y (TJ/Nm^3)

$EF_{CO2,Methane}$ = CO_2 emission factor for methane (t CO_2/TJ)

Project emissions

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

(a) 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 point F in methodology AM0009 version 07.0 Figure 2;

(b) CO_2 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 AM0009 version 07.0 Figure 2.

Project emissions are calculated as follows:

$$PE_y = PE_{CO2,fossil\ fuels,y} + PE_{CO2,elec,y} \quad (2)$$

Where

PE_y = Project emissions in year y, (t CO_2e)

$PE_{CO2,fossi\ fuels,y}$ = 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 point F in methodology AM0009 version 07.0 Figure 2 in year y (t CO_2e)

$PE_{CO2,elec,y}$ = CO_2 emissions due to the use of electricity for recovery, pre-treatment, transportation and, if applicable, compression of the recovered gas up to the point F in methodology AM0009 version 07.0 Figure 2 in year y, (t CO_2e)

(i) 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 AM0009 version 07.0 Figure 2. All applicable emission sources should be documented transparently in the CDM-PDD and in monitoring reports.

For the proposed project, 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 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 for the recovery, pre-treatment, transportation, compression is considered in below (ii) Project emissions from consumption of electricity. Therefore, $PE_{CO2,\ fossilfuels,\ y} = 0$.

(ii) 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 *"Baseline, project and/or leakage emissions from electricity consumption and monitoring of electricity generation (Version 03.0)*" where $PE_{CO2,elec,y}$ corresponds to $PE_{EC,y}$ in the tool and the electricity consumption sources *j* in the tool corresponds to all sources of electricity consumption (e.g. a compressor, etc.) up to point F in methodology AM0009 version 07.0 Figure 2. All applicable sources of electricity consumption should be documented transparently in the CDM-PDD and in monitoring reports.

For the proposed project, a small amount of recovered gas is used for captive power generation, which is used for the recovery, pre-treatment, transportation, compression. Accordingly, the project includes a captive gas power plant on-site to supply electricity to the project activity. Electricity will be supplied to on-site electricity consuming facilities.

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:

$$PE_{CO2,elec,y} = PE_{EC,y} \quad (3)$$

$$PE_{EC,y} = \sum_{j} EC_{PJ,j,y} \times EF_{EF,j,y} \times \left(1 + TDL_{j,y}\right) \quad (4)$$

Where

$PE_{CO2,elec,y}$	=	CO_2 emissions due to the use of electricity for recovery, pre-treatment, transportation and, if applicable, compression of the recovered gas up to the point F in methodology AM0009 version 07.0 Figure 2 in year y, (t CO_2e)
$PE_{EC,y}$	=	Project emissions from electricity consumption in year y (t CO_2 / yr)
$EC_{PJ,j,y}$	=	Quantity of electricity consumed by the project electricity consumption source j in year y (MWh/yr)
$EF_{EF,j,y}$	=	Emission factor for electricity generation for source j in year y (t CO_2/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 the emission factor for electricity generation ($EF_{EL,j/k/l,y}$)

Scenario B "*Baseline, project and/or leakage emissions from electricity consumption and monitoring of electricity generation (Version 03.0)*" of the tool 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 1.3tCO_2/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.

Determination of the 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 reciprocating compression units which 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 by the expected operating hours. Expected operating hours are calculated as daily gross gas gains divided by total installed compression capacity, and then multiplied by 24 hours and 350 days, considering annual downtime for maintenance. The actual quantity of all the electricity consumed by the project electricity will be monitored through the electricity meter installed at the project site.

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:

$$ER_y = BE_y - PE_y - LE_y \quad (5)$$

Where

ER_y = Emission reductions in year y, (tCO_2e)

BE_y = Baseline emissions in year y, (tCO_2e)

PE_y = Project emissions in year y ($t\ CO_2e$)

LE_y = Leakage emissions in year y ($t\ CO_2e$)

B.6.2. Data and parameters fixed ex ante

Data/Parameter	$EF_{CO2,Methane}$
Data unit	t CO_2/TJ
Description	CO_2 emission factor for methane
Source of data	Calculated in line with procedures and data presented in ISO 6976: **Table 3. Carbon content, CO_2 emission factor and NCV of methane** Unit / Value / Source: Carbon Content of Methane — 12,011 kg/kmol — ISO 6976: Table 1 CO_2 Emission Factor for Methane — 44.01 kg/kmol — ISO 6976: Table 1 NCV of Methane (at 250C) — 802.60 kJ/mol — ISO 6976: Table 3
Value(s) applied	54.834 t CO_2/TJ
Choice of data or measurement methods and procedures	---

Purpose of data	Calculate Baseline emissions
Additional comment	---

Data/Parameter	$TDL_{j,y}$
Data unit	---
Description	Average technical transmission and distribution losses for providing electricity to source j in year y
Source of data	Methodological tool: Baseline, project and/or leakage emissions from electricity consumption and monitoring of electricity generation (Version 03.0)
Value(s) applied	0
Choice of data or measurement methods and procedures	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. In case of scenario B, assume $TDL_{j,y}$ = 0 as a simplification.
Purpose of data	Calculate Project emissions
Additional comment	---

Data/Parameter	$EF_{EF,j,y}$
Data unit	t CO_2/MWh
Description	Emission factor for electricity generation for source j in year y
Source of data	Methodological tool: Baseline, project and/or leakage emissions from electricity consumption and monitoring of electricity generation (Version 03.0)
Value(s) applied	1.3
Choice of data or measurement methods and procedures	Scenario B, Option B2 (a) is applied.
Purpose of data	Calculate Project emissions
Additional 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 have been provided by the project entity. $EF_{CO2,\ Methane}$ uses the default value 54.834 tCO_2/TJ according to methodology AM0009 (version 07.0). Applying formula (1) presented in Section B.6.1, we obtain the values for the baseline emissions during crediting period provided in Table below:

Table B.10. Baseline emissions calculation

Year	$V_{F,y}$	$NCV_{RG,F,y}$	$EF_{CO2,Methane}$	BE_y
	(Nm^3)	(TJ/Nm^3)	(tCO_2/TJ)	(tCO_2e)
05/08/2020-31/12/2020	134,712,580	0.000042441	54.834	313,503
01/01/2021-31/12/2021	330,904,727	0.000042441	54.834	770,080
01/01/2022-31/12/2022	320,977,586	0.000042441	54.834	746,978
01/01/2023-31/12/2023	320,977,586	0.000042441	54.834	746,978
01/01/2024-31/12/2024	248,178,546	0.000042441	54.834	577,560
01/01/2025-31/12/2025	198,542,836	0.000042441	54.834	462,048

01/01/2026-31/12/2026	165,452,364	0.000042441	54.834	385,040
01/01/2027-31/12/2027	132,361,891	0.000042441	54.834	308,032
01/01/2028-31/12/2028	82,726,182	0.000042441	54.834	192,520
01/01/2029-31/12/2029	76,108,087	0.000042441	54.834	177,118
01/01/2030-04/08/2030	0	0.000042441	54.834	0
Total	2,010,942,385			4,679,859

Note: The project started operation since 05/01/2020, and the designed project lifetime is 10 years from the commissioning of the project activity. Therefore, the volume of recovered gas ($V_{F,y}$) is zero for period 01/01/2030-04/08/2030.

Project emissions

Project emissions are calculated as follows:

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

Where:

PE_y	=	Project emissions in year 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 point F in year y (tCO_2e)
$PE_{CO2,elec,y}$	=	CO_2 emissions due to the use of electricity for recovery, pre-treatment, transportation and if applicable, compression of the recovered gas up to the point F in year y (tCO_2e)

According to PDD 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:

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

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

Average technical transmission and distribution losses for providing electricity to source j in year y ($TDL_{j,y}$) is set at 0% as the project consumes electricity from an off-grid captive power plant, and $EF_{EL,j,y}$ is set at $1.3tCO_2/MWh$ as it is a project electricity consumption source, which is the conservative default value set in the tool.

Applying formula above, we obtain the values for the project emissions during crediting period provided in Table below:

Table B.11. Project emissions calculation

Year	$PE_{CO2,\ fossilfuels,\ y}$	$EC_{PJ,j,y}$	$EF_{EL,j,y}$	$TDL_{j,y}$	$PE_{EC,y}$	PE_y
	(tCO_2/yr)	(MWh/yr)	(tCO_2/MWh)	/	(tCO_2/yr)	(tCO_2/yr)
05/08/2020-31/12/2020	0	18,329	1.3	0	23,828	23,828
01/01/2021-31/12/2021	0	45,024	1.3	0	58,531	58,531
01/01/2022-31/12/2022	0	43,673	1.3	0	56,775	56,775
01/01/2023-31/12/2023	0	43,673	1.3	0	56,775	56,775
01/01/2024-31/12/2024	0	33,768	1.3	0	43,898	43,898
01/01/2025-31/12/2025	0	27,014	1.3	0	35,118	35,118
01/01/2026-31/12/2026	0	22,512	1.3	0	29,265	29,265
01/01/2027-31/12/2027	0	18,009	1.3	0	23,412	23,412
01/01/2028-31/12/2028	0	11,256	1.3	0	14,633	14,633
01/01/2029-31/12/2029	0	10,355	1.3	0	13,462	13,462
01/01/2030-04/08/2030	0	0	1.3	0	0	0
Total		273,614				355,698

Note: The project started operation since 05/01/2020, and the designed project lifetime is 10 years from the commissioning of the project activity. Therefore, the electricity consumed on-site ($EC_{PJ,j,y}$) is zero for period 01/01/2030-04/08/2030.

Leakage

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

B.6.4. Summary of ex ante estimates of emission reductions

Year	Baseline emissions (t CO_2e)	Project emissions (t CO_2e)	Leakage (t CO_2e)	Emission reductions (t CO_2e)
05/08/2020-31/12/2020	313,503	23,828	0	289,675
01/01/2021-31/12/2021	770,080	58,531	0	711,550
01/01/2022-31/12/2022	746,978	56,775	0	690,203
01/01/2023-31/12/2023	746,978	56,775	0	690,203
01/01/2024-31/12/2024	577,560	43,898	0	533,662
01/01/2025-31/12/2025	462,048	35,118	0	426,930
01/01/2026-31/12/2026	385,040	29,265	0	355,775
01/01/2027-31/12/2027	308,032	23,412	0	284,620
01/01/2028-31/12/2028	192,520	14,633	0	177,887
01/01/2029-31/12/2029	177,118	13,462	0	163,656
01/01/2030-04/08/2030	0	0	0	0
Total	4,679,859	355,698	0	4,324,161
Total number of crediting years	10			
Annual average over the crediting period	467,986	35,570	0	432,416

B.7. Monitoring plan

B.7.1. Data and parameters to be monitored

Data/Parameter	$V_{F,y}$
Data unit	Nm^3
Description	Volume of the total recovered gas measured at point F in methodology AM0009 version 07.0 Figure 2 in year y
Source of data	Flow meter installed by project entity
Value(s) applied	

05/08/2020-31/12/2020	134,712,580
01/01/2021-31/12/2021	330,904,727
01/01/2022-31/12/2022	320,977,586
01/01/2023-31/12/2023	320,977,586
01/01/2024-31/12/2024	248,178,546
01/01/2025-31/12/2025	198,542,836
01/01/2026-31/12/2026	165,452,364
01/01/2027-31/12/2027	132,361,891
01/01/2028-31/12/2028	82,726,182
01/01/2029-31/12/2029	76,108,087
01/01/2030-04/08/2030	0

Measurement methods and procedures	Data will be measured continuously using calibrated flow meter. Measurements will be taken at the point where recovered gas exits the pre-treatment plant and after the point where the recovered gas is directed for on-site use. Lead operator of the project is responsible for monitoring. The recorded gas volume is automatically converted to the volume at normal temperature and pressure using the temperature and pressure at the time to measurement. Accuracy is 0.04%.
Monitoring frequency	Continuously measured and monthly recorded
QA/QC procedures	Volume of gas will be metered through a flow meter installed. Calibration frequency is annual. The total recovered gas volume is crosschecked with commercial data.
Purpose of data	Baseline emissions calculation
Additional comment	-

Data/Parameter	$NCV_{RG,F,y}$
Data unit	TJ/Nm^3
Description	Average net calorific value of recovered gas at point F in methodology AM0009 version 07.0 Figure 2 in year y
Source of data	On site measurement
Value(s) applied	0.000042441 TJ/Nm^3 (estimated in the PDD, will be further monitored during each monitoring period)
Measurement methods and procedures	Gas composition measurements will be undertaken in line with national or international fuel standards under the responsibility of the on-site lab near the project. Samples will be taken at least monthly and the molar composition of the gas sample will be determined through chemical analysis. Gas samples will be taken at point F in Figure 2. Based on the molar composition, the Net Calorific Value on a volumetric basis will be determined for each sample in line with ISO 6976 or an equivalent standard for a combustion reference temperature of 25^0C and the same metering 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.7.3 for details.
Monitoring frequency	Sampling and compositional analysis and calculation of net calorific value at least monthly
QA/QC procedures	Sampling in accordance with ISO 10715 or equivalent standard. 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 ISO 17025 or equivalent standard. In case third party laboratories are used, these should as a minimum have ISO 17025 accreditation or justify that they can comply with similar quality standards. Calibration frequency is at minimum annual using standard gas.
Purpose of data	Baseline emissions calculation
Additional comment	--

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	Electricity meter installed at point F in methodology AM0009 version 07.0 Figure 2 in year y

Value(s) applied	05/08/2020-31/12/2020: 18,329 01/01/2021-31/12/2021: 45,024 01/01/2022-31/12/2022: 43,673 01/01/2023-31/12/2023: 43,673 01/01/2024-31/12/2024: 33,768 01/01/2025-31/12/2025: 27,014 01/01/2026-31/12/2026: 22,512 01/01/2027-31/12/2027: 18,009 01/01/2028-31/12/2028: 11,256 01/01/2029-31/12/2029: 10,355 01/01/2030-04/08/2030: 0
Measurement methods and procedures	Continuous measurement with national standard metering equipment Accuracy is 0.5s. Lead operator of the project is responsible for monitoring.
Monitoring frequency	Continuously measured and at least monthly recorded
QA/QC procedures	Electricity meter will be subject to regular maintenance and testing in accordance with the stipulation of the meter supplier or national requirements The calibration of meters, including the frequency of calibration, will be done in accordance with national standards or requirements. The consumed electricity is crosschecked with relevant records.
Purpose of data	Project emissions calculation
Additional comment	-

B.7.2. Sampling plan

Not applicable. None of the data and parameters monitored in section B.7.1 above are to be determined by a sampling approach.

B.7.3. Other elements of 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.

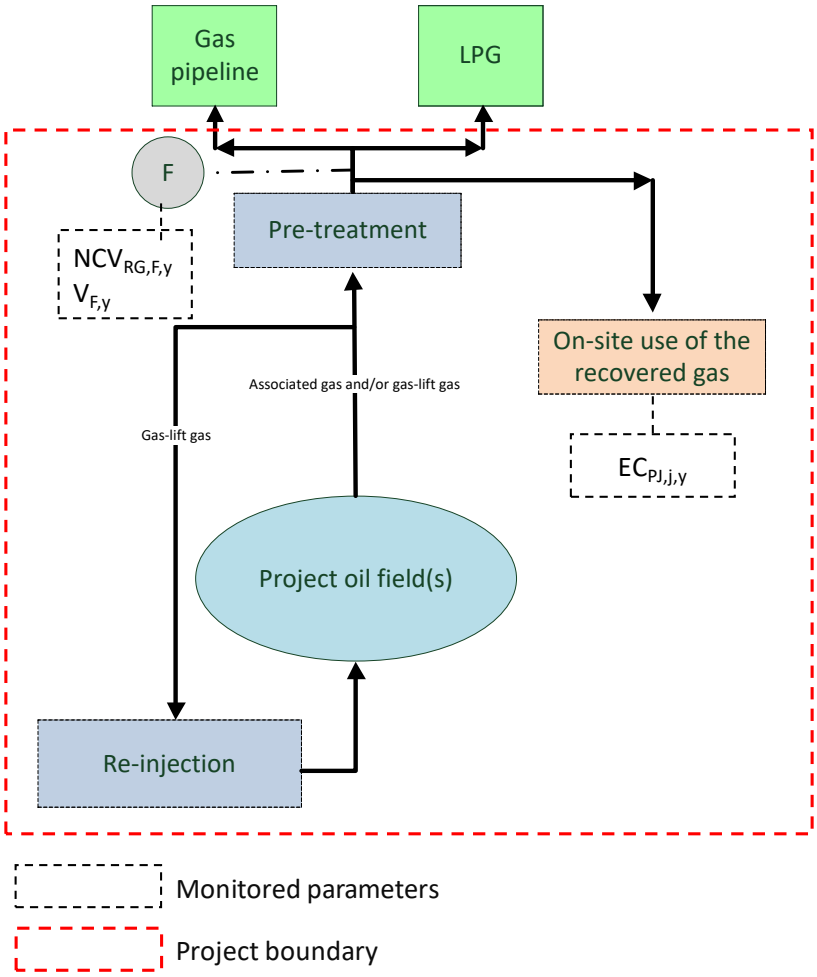

Figure B.4. General monitoring plan

Operational procedures:

Monitoring of volume of recovered gas ($V_{F,y}$)

Gas flow meter will measure the volume of recovered gas after pre-treatment and after part of the recovered gas is used on-site.

Monitoring Net calorific value of recovered gas ($NCV_{RG,F,y}$)

The net calorific value (volume based) of the recovered gas in TJ/ Nm^3 will be calculated according to the following method:

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

X_i = Molar fraction of the individual component i in the recovered gas sample provided by the Lab using chromatography gas analyzer at least monthly.

NCV_i = Net Calorific Value (volume based) of the individual component i as per ISO: 6976 standard for a combustion reference temperature of 25°C and the same metering reference condition used for parameter $V_{F,y}$, as indicated in below table:

Table B.12. Values of NCV_i

	Net calorific value (MJ/m^3) of component (25°C combustion reference temperature and 0°C metering reference temperature)
hydrogen	10.788
nitrogen	0
C6 group	173.41
methane	35.808

CO_2	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*

Molar fraction of recovered gas will be measured at least monthly by on-site lab near the project.

Monitoring of electricity consumption ($EC_{PJ,i,y}$)

Electricity meter will measure electricity consumed by equipment at the project site.

Emergencies:

In case of emergencies[10], 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 Figure B.5. 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 Figure B.5. Measurements of the associated gas volumes recovered and project electricity consumption will fall under the responsibility of the lead operator. Measurement of NCV of the recovered gas will be performed by on-site lab near the project.

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 Appendix 5.

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

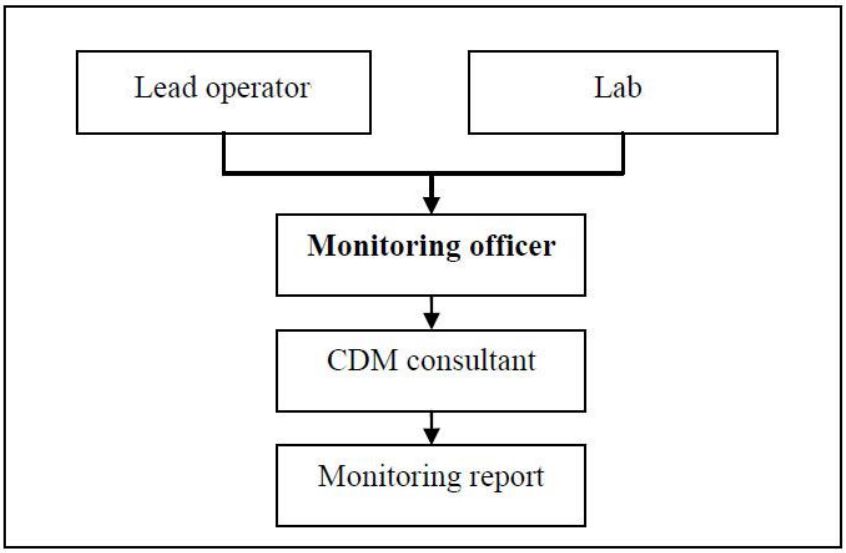

Figure B.5. Responsibilities for measurements and reporting emission reductions

Data management:

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.

SECTION C. Start date, crediting period type and duration

C.1. Start date of project activity

>>
06/05/2019 (Purchase agreement of gas compressor, motor and process air cooler)

C.2. Expected operational lifetime of project activity

>>
10 years 0 month

C.3. Crediting period of project activity

C.3.1. Type of crediting period

>>
Fixed crediting period

C.3.2. Start date of crediting period

>>
05/08/2020 (or the registration date, whichever is earlier)

C.3.3. Duration of crediting period

>>
10 years 0 month

SECTION D. Environmental impacts

D.1. Analysis of environmental 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 for the Exploration & Production of Oil & Gas was issued on September 3rd, 2018 by Ministry of Environment and Climate Affairs according to Law on Conservation of Environment and Prevention of Pollution promulgated by Royal Decree No.13287.

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 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. Environmental impact assessment

>>

It is concluded that the proposed project will have no significant environmental impacts either during construction phase or post project implementation.

SECTION E. Local stakeholder consultation

E.1. Modalities for local stakeholder consultation

>>

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 the 27th and 28th of April 2019. 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 far away. Only one small tribe leaves nearby. All men from the tribe are employed on project site at the 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 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

NO.	Impacts of the project			Results	Number of total interviewees	Percentage
1	Environment	Construction of associated gas utilization project	Benefit local environment	20	20	100%
			No benefit	0	20	0%
			Not sure	0	20	0%
		Current practice of gas flaring	Benefit local environment	0	20	0%
		Global warming	Reduce	20	20	100%
			No benefit	0	20	0%
			Not sure	0	20	0%
		Any negative impact	No effect	0	20	0%
			Not sure	0	20	0%
			Yes	0	20	0%
			No	20	20	100%
2	Local economy		Benefit local economy	20	20	100%
			No benefit	0	20	0%
			Not sure	0	20	0%
3	General opinion	Regarding the project construction	Fully support	20	20	100%
			Not support	0	20	0%
			Not sure	0	20	0%

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. Consideration of comments received

>>

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

SECTION F. Approval and authorization

>>

The DNA of Oman, Ministry of Environment and Climate Affairs, issued Letter of Approval (LoA) on 07/06/2020, to approve the Government of the Sultanate of Oman, represented by the Ministry of Oil & Gas to be the project participant.

Appendix 1. Contact information of project participants

Organization name	The Government of the Sultanate of Oman, represented by the Ministry of Oil & Gas
Country	OMAN
Address	MINISTRY OF OIL & GAS, P O BOX 551, MUSCAT, OMAN.
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Appendix 2. Affirmation regarding public funding

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

Appendix 3. Applicability of methodologies and standardized baselines

The detailed information on selected methodology is provided in section B.2.

Appendix 4. Further background information on ex ante calculation of emission reductions

The calculation for emission reductions following AM0009 (Version 07.0) has been listed as follow:

Baseline emissions:

Table Appendix-1. Baseline emissions base data calculation

	2020 (full year)	2021	2022	2023	2024	2025	2026	2027	2028	2029
Daily Gross gas gains (mmscf per day)	34.73	34.73	33.68	33.68	26.04	20.84	17.36	13.89	8.68	7.99
Projected quantity of gas recovered (mmscf) on a 350 days per year basis	12,154	12,154	11,789	11,789	9,116	7,292	6,077	4,862	3,039	2,795
Yearly gas gains at methodology Figure 2 Point F (Nm^3)	330,904,727	330,904,727	320,977,586	320,977,586	248,178,546	198,542,836	165,452,364	132,361,891	82,726,182	76,108,087

The recovered gas volume was derived based on projected oil production volumes and Gas/Oil Ratio (GOR) at the project site.

Table Appendix-2. Conversions

1SCF （Ft3） =	0.02831682	m^3
1 mmscf =	1000000	scf
1MJ=	947.817	Btu
$1sm^3$=	35.3147	SCF

Table Appendix-3. Mole fraction and NCV of gas component

	NCV (MJ/m^3)	NCV (Btu/scf)	%mol
hydrogen	10.788	290	0
nitrogen	0	0	2.99
C6 group	173.41	4654	0.36
methane	35.808	961	78.13

co2	0	0	2.72
ethane	63.74	1711	7.25
propane	91.15	2446	4.68
i-butane	118.15	3171	0.93
n-butane	118.56	3182	1.75
i-pentane	145.66	3909	0.56
n-pentane	145.96	3917	0.55
C7+	200.82	5390	0.08
total	42.441	1139.07	

Source: ISO 6976

Project emissions:

Table Appendix-4. System rated power and compression capacity

# compressors	Rated Power (KW) per compressor	total rated power (KMW)	compression capacity per compressor (mmscfd)	total compression capacity (mmscfd)
5	1234.8	6174	8	40

Source: Compressor technical manual

Table Appendix-5. Project emissions base data calculation

	2020 (full year)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Estimation of annual operating hours (h)	7,292	7,292	7,074	7,074	5,469	4,375	3,646	2,917	1,823	1,677
$EC_{PJ,j,y}$ (MWh)	45,024	45,024	43,673	43,673	33,768	27,014	22,512	18,009	11,256	10,355
Daily expected fuel gas consumption for on-site electricity generation (MMSCFD)	1.338	1.338	1.298	1.298	1.003	0.803	0.669	0.535	0.334	0.308
Annual expected fuel gas consumption for on-site electricity generation (MMSCFD)	468.30	468.30	454.25	454.25	351.22	280.98	234.15	187.32	117.07	107.71

Annual gains at Point F (after deduction of internal consumption) (Nm^3)	330,904,727	330,904,727	320,977,586	320,977,586	248,178,546	198,542,836	165,452,364	132,361,891	82,726,182	76,108,087
Projected quantity of gas sold (mmscf)	11,218	11,218	10,882	10,882	8,414	6,731	5,609	4,487	2,805	2,580

Note:

Estimation of annual operating hours = daily gross gas gains (as per Table Appendix-1) /total compression capacity (40 mmscfd in Table Appendix-4) *24*350

$EC_{PJ,j,y}$ = installed total rated power capacity (in Table Appendix-4) in MW * operating hours

Energy needed = Rated Power per compressor / η off-grid gas turbine system = 1234.8 KW / 28.80% = 4287.5 KW per comp

Total fuel gas needed/comp = Energy needed / NCV of fuel gas /1000000 * 24
= 4287.5 KW per comp / 0.3338 KWh/CF /1000000 * 24
= 12843.37 CF/h /1000000 * 24
=0.3082 MMSCFD

Expected fuel gas consumption = Daily Gross gas gains / compression capacity per compressor * total fuel gas needed per compressor

Projected quantity of gas used internally per year = Expected fuel gas consumption * 350 days per year basis

Gas shrinkage factor = 4%**.**

Yearly projected quantity of gas sold (mmscf) = (projected quantity of gas recovered - projected quantity of gas used internally)*(100%- shrinkage factor)

Note:
The projected gross gains for the proposed CDM project were calculated through multiplying the expected oil production by the Gas/Oil Ratio (GOR).
In accordance with recommendation of the monitoring methodology, the quantity of recovered gas will be monitored ex-post.
η off-grid gas turbine system was sourced from turbine specifications, and corrected for ambient temperature as per US EPA guidance
Internally consumption factor was calculated as per displayed in the ER sheet
A gas shrinkage factor during processing at gas plant of 4% was estimated by operator through computerized model using HYSYS software.
Liquid volumes were estimated by the operator through complex modelling using HYSYS software based on gas composition.
The detailed estimation and reference have been provided to DOE for validation.

Table Appendix-6. Information for common practice

Block No.	Key information	Information source

3	Production began in August 2010. There are no facilities for the recovery of associated gas.	https://www.tethysoil.com/en/operations/oman-blocks-34
4		https://www.tethysoil.com/en/operations/oman-blocks-34
5	Associated gas is recovered since 2017. The average gas production is 35 mmscfd	https://www.daleelpetroleum.com/operational-excellence/production
6	Associated gas recovery production is around 600 mmscfd. there are initiatives of gas reduction projects.	https://www.energyvoice.com/oilandgas/middle-east/213477/omani-bid-round-falls-foul-of-shift-away-from-wildcat-ep/
7	According to public data source, for Block 7, there is little gas associated with oil which is heavy and viscous and will not flow readily and continuously. No facilities installed for recovery of associated gas.	https://www.onepetro.org/conference-paper/SPE-148925-MS
8	Offshore oil field.	https://www.ogj.com/drilling-production/production-operations/article/17295607/dno-to-relinquish-block-8-offshore-oman
9	Registered CDM project (PA 6817)	
15	Still in exploration phase.	https://www.globenewswire.com/news-release/2013/06/24/555840/0/en/Long-term-production-test-commences-on-Block-15.html
17	Still in exploration phase.	https://www.dfc.gov/sites/default/files/2019-08/9000042675.pdf https://www.omanobserver.om/petrotel-gets-450m-in-funding-support-for-musandam-blocks/
27	The proposed project	https://cdm.unfccc.int/Projects/DB/BVQI1343120764.64/view
30	Still in exploration phase.	https://www.omanobserver.om/oxy-oman-operator-block-30-72-86-per-cent-stake/ https://www.oxy.com/News/Documents/Occidental-Fast-Facts_Oman.pdf
31	Still in exploration phase.	https://www.arapetroleum.com/ara-petroleum-oman-b31/
36	Still in exploration phase.	https://www.omanobserver.om/canadas-apex-sets-sights-block-36-prospects/
39	Still in exploration phase.	https://theenergyyear.com/interviews/offshore-expertise-in-oman/
40	Offshore oil field.	https://www.omanobserver.om/petrotel-gets-450m-in-funding-support-for-musandam-blocks/
42	Still in exploration phase.	http://www.oilandgasinnovation.co.uk/international/brazil/2-uncategorised/1346-shell-signs-block-42-agreement-in-oman
44	Block 44 is primarily a natural gas and condensate field.	https://www.linkedin.com/company/ara-petroleum-oman-block-44/about/
48	Still in exploration phase.	https://www.ogj.com/exploration-development/article/17290291/oman-oil-unit-to-explore-omani-block-48
49	Still in exploration phase.	https://www.omanobserver.om/swedish-oil-firm-set-to-drill-well-in-oman-block-49/

50	Offshore oil field.	https://www.offshore-mag.com/drilling-completion/article/14074143/appraisal-drilling-under-way-at-yumna-offshore-oman
52	Still in exploration phase.	https://www.omanobserver.om/oman-block-52-exploration-to-start-by-early-2020/
53	The field's average gross daily production is in excess of 100,000 bopd.There are no facilities for the recovery of associated gas.	https://www.energy-pedia.com/news/oman/tethys-oils-acquistion-of-an-interest-in-oman-block-53-pre-empted-by-partner-175745
54	Still in exploration phase.	https://oxfordbusinessgroup.com/overview/pipeline-efficiency-watchword-new-low-price-environment
56	Still in exploration phase.	
57	Still in exploration phase.	https://www.omanobserver.om/petroleb-makes-oman-foray-block-57/
60	Block 60 is a tight gas field, it's unconventional gas project.	https://www.oilandgasnewsworldwide.com/Article/39595/Oman%E2%80%99s_first_tight_gas_project_to_come_on_stream
61	Block 61 is unconventional gas project.	https://www.omanobserver.om/petronas-acquires-10pc-stake-in-block-61/
62	Block 62 is gas field.	https://www.oxy.com/News/Documents/Occidental-Fast-Facts_Oman.pdf
66	Still in exploration phase.	https://www.omanobserver.om/mol-advance-block-66-exploration/
67	Still in exploration phase.	https://www.omanobserver.om/oman-based-ep-firm-inks-pact-sarawaks-petros/

Appendix 5. Further background information on monitoring plan

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 to ensure and verify adequate metering and recording of volumes of gas recovered. The monitoring officer will also coordinate with the designated Lab 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.

Appendix 6. Summary report of comments received from local stakeholders

No comments received from local stakeholders.

Appendix 7. Summary of post-registration changes

The CDM project activity is not yet registered up to the date of this PDD version.

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Document information

Version	*Date*	*Description*
11.0	31 May 2019	Revision to: • Ensure consistency with version 02.0 of the "CDM project standard for project activities" (CDM-EB93-A04-STAN); • Make editorial improvements.
10.1	28 June 2017	Revision to make editorial improvement.
10.0	7 June 2017	Revision to: • Improve consistency with the "CDM project standard for project activities" and with the PoA-DD and CPA-DD forms; • Make editorial improvement.

Version	*Date*	*Description*
09.0	24 May 2017	Revision to: • Ensure consistency with the “CDM project standard for project activities” (CDM-EB93-A04-STAN) (version 01.0); • Incorporate the “Project design document form for small-scale CDM project activities” (CDM-SSC-PDD-FORM); • Make editorial improvement.
08.0	22 July 2016	EB 90, Annex 1 Revision to include provisions related to automatically additional project activities.
07.0	15 April 2016	Revision to ensure consistency with the “Standard: Applicability of sectoral scopes” (CDM-EB88-A04-STAN) (version 01.0).
06.0	9 March 2015	Revision to: • Include provisions related to statement on erroneous inclusion of a CPA; • Include provisions related to delayed submission of a monitoring plan; • Provisions related to local stakeholder consultation; • Provisions related to the Host Party; • Make editorial improvement.
05.0	25 June 2014	Revision to: • Include the Attachment: Instructions for filling out the project design document form for CDM project activities (these instructions supersede the "Guidelines for completing the project design document form" (Version 01.0)); • Include provisions related to standardized baselines; • Add contact information on a responsible person(s)/ entity(ies) for the application of the methodology (ies) to the project activity in B.7.4 and Appendix 1; • Change the reference number from F-CDM-PDD to CDM-PDD-FORM; • Make editorial improvement.
04.1	11 April 2012	Editorial revision to change version 02 line in history box from Annex 06 to Annex 06b.
04.0	13 March 2012	Revision required to ensure consistency with the “Guidelines for completing the project design document form for CDM project activities” (EB 66, Annex 8).
03.0	26 July 2006	EB 25, Annex 15
02.0	14 June 2004	EB 14, Annex 06b
01.0	03 August 2002	EB 05, Paragraph 12 Initial adoption.

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