Project design document form

(Version 10.1)

Complete this form in accordance with the instructions attached at the end of this form.	
BASIC INFORMATION	
Title of the project activity	Recovery and Utilization of Associated Gas at Pondok Tengah LPG Plant – PT. Yudistira Energy
Scale of the project activity	☒ Large-scale ☐ Small-scale
Version number of the PDD	4
Completion date of the PDD	16-05-2019
Project participants	PT. Yudistira Energy Agrinergy Pte Ltd
Host Party	Republic of Indonesia
Applied methodologies and standardized baselines	AM0009: Recovery and utilization of gas from oil fields that would otherwise be flared or vented --- Version 7.0
Sectoral scopes linked to the applied methodologies	10
Estimated amount of annual average GHG emission reductions	143,428

SECTION A. Description of project activity

A.1. Purpose and general description of project activity

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The project activity involves the installation of a new associated gas recovery and utilization facility. The project activity is undertaken by PT. Yudistira Energy (Yudistira), an Indonesian private company specialising in the development of Oil & Gas projects. The project activity is located at the Pondok Tengah oil field in West Java, Indonesia.

The project activity encompasses the establishment and operation of a new LPG Plant to recover and utilise the associated gas which had been flared at Tambun and Pondok Tengah Gas Collection stations owned by Pertamina EP Station - Pertagas (Pertamina EP and Pertagas are subsidiaries of PT Pertamina, the state owned Oil & Gas Company), and also installation of new pipeline to connect Pondok Tengah- Pertamina EP Station with Yudistira's LPG Plant. The recovered gas is processed into LPG, Condensate and Lean Gas.

The greenhouse gas included in the project boundary is CO2 and emission sources in the baseline scenario are the combustion of non-associated gas or other fossil fuels by end-users. The project activity reduces emissions by recovering associated gas and utilizing the recovered gas. The utilization of the recovered gas displaces the use of other fossil fuel sources. In accordance with the methodology, the use of recovered gas has been assumed to displace the use of methane for simplification. The emission sources in the project activity are from the energy used for the recovery, transportation and compression of the recovered gas. In the absence of the project activity (the baseline scenario) and the scenario existing prior to the start of the implementation, the associated gas was flared. Flaring of associated gas is seen as the common practice in Indonesian oil production, although the practice has negative environmental impacts and wastes energy resources.

The proposed project activity has applied a seven-year renewable crediting period and this PDD is for the second crediting period. Expected annual average CER generation is 143,428 tCO2e.

A.2. Location of project activity

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The address of the project is Babelan Sub District, Huripjaya Village, West Java Province, Bekasi District, Indonesia

The project is located 200 meters away from the Pertamina EP Pondok Tengah oil and gas collecting station and 50 meters away from the lean gas distribution pipeline

The geographical coordinate set of the Pondok Tengah LPG plant is:
Latitude: 6.085806S
Longitude: 107.042564E

Figure 1: Location map of Pondok Tengah Gas Processing Plant

A.3. Technologies/measures

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The purpose of the proposed project activity is utilization of associated gas. The project activity involves the installation of a new pipeline to recover and transport the associated gas and the construction of a LPG Plant to utilize it. The pipeline and LPG Plant have been designed to process 17 MMSCFD of gas into LPG, condensate and lean gas. The LPG Plant Pondok Tengah applies a refrigeration and condensation process for LPG and condensate recovery. The final products of LPG, condensate and lean gas are produced through drying wet associated gas and then putting it through a distillation process to separate the dried gas hydrocarbon components.

The project activity uses processing and basic engineering design from Mackenzie Hydrocarbons Australia[1], a design specialist established since 1990 which holds licences for the Petroleum, Petrochemical and Power Industries. This entity has successfully executed similar projects worldwide.

[1] http://www.mackenziehydrocarbons.com.au/projects-and-experience

The project activity has obtained the approval certificate for Equipment and Facility Installation and Utilization (SKPP-SKPI) [2] from the Indonesian Directorate General of Oil and Gas, hence,the project activity is using safe and sound technology and is in compliance with the national standards.

The project activity is being implemented in accordance with the Indonesian Environmental Ministry Regulation No. 11 Year 2006, which requires the project activity to conduct an Environmental Impact Analysis (EIA). The project activity has obtained the approval from EIA Central Assessment Commission on 12/11/2008 and will be reporting its environmental monitoring activities during construction and operation period.

Prior to the implementation of the project activity, there was no equipment or system installed on-site to recover and utilize the associated gas and it was flared. The baseline scenario is the same as that existing scenario prior to the implementation of the project activity.

The LPG Plant consists of several systems which are:

1. Feed Gas Filtration: This process filters feed gas from liquid and dust particles.
2. Feed Gas Dehydration: This process dehydrates the filtered feed gas using molecular sieve beds and separates the dry gas from the wet gas. This dried feed gas has to be filtered again using dry gas filter.
3. Heat Exchanger: This process cools the dried feed gas from dry gas filter into liquid form.
4. High Pressure (HP) Separator, Demethaniser: The HP separator separates liquid formed in the heat exchanger. The dried gas is later cooled again through refrigeration package and Joule-Thompson valve. The liquid formed in this process is then processed further in the Demathaniser to release the light components.
5. LEF Column, Condenser, Reflux Drum and Reflux Pumps: LEF column separates the liquid from Demathaniser to obtain the light components (C_1 and C_2) by fractionation principle based on boiling points. The process yields lean gas (C_1 and C_2), and heavier components (LPG and Condensate). Lean gas will be pumped through the pipeline to the lean gas storage, while the heavier components (LPG and Condensate) will go to the LPG column for the next separation stage.
   LPG Column, Condenser, Reflux Drum, and Reflux Pumps: LPG column also work based on the differential boiling points to separate LPG and Condensate using a fractionation column. The result of this process is LPG (C_3 and C_4) and Condensate where each of these liquids are pumped to their respective storage tanks.

Table A.1: The technical detail of Tanks and Pressure Vessel

No	Description	Capacity	Design Press (Psig) or Pa	Design Temp (^oF) or K
1	Feed Gas Scrubber	17 MMSCFD (eq. 481,384 Sm^3)	(600) or 4,136,854	(135) or 330.22
2	Feed Gas Filter Separator	17 MMSCFD (eq. 481,384 Sm^3)	(600) or 4,136,854	(135) or 330.22
3	Dryer	17 MMSCFD (eq. 481,384 Sm^3)	(600) or 4,136,854	(650) or 616.33
4	Dry Gas Filter	17 MMSCFD (eq. 481,384 Sm^3)	(600) or 4,136,854	(135) or 330.22
5	Regeneration Gas Scrubber	2 MMSCFD (eq. 56,633 Sm^3)	(600) or 4,136,854	(135) or 330.22
6	HP Separator	17 MMSCFD (eq.481,384 Sm^3)	(600) or 4,136,854	(-20/135) or 244.11/330.22
7	De-Methanizer	14.2 MMSCFD (eq.402,097 Sm^3)	(600) or 4,136,854	(-50/135) or 227.44/330.22

[2] SKPI (Surat Kelayakan Penggunaan Instalasi) No 10760/18.01/DMT/2011, SKPP (Surat Kelayakan Penggunaan Peralatan) No 8348/18.01/DMT/2011 for Pressure Vessel and SKPP no 2834/18.01/DMT/2011 for Safety Valve

8	LEF-Column	5.86 MMSCFD (eq.165,936 Sm^3)	(500) or 3,447,378	(-20/650) or 244.11/616.33
9	LEF Reflux Drum	6.3 MMSCFD (eq.178,395 Sm^3)	(500) or 3,447,378	(-40/135) or 233/330.22
10	LPG Column	2.79 MMSCFD (eq.79,003 Sm^3)	(250) or 1,723,689	(-20/650) or 244.11/616/33
11	LPG Reflux Drum	3.6 MMSCFD (eq.101,940 Sm^3)	(250) or 1,723,689	(135) or 330.22
12	Condensate Blowdown Drum	0.23 MMSCFD (eq.6,512 Sm^3)	(200) or 1,378,951	(150) or 338.55
13	Fuel Gas Scrubber		(180) or 1,378,951	(160) or 344.11
14	Drain Pot		(20) or 137,895	(400) or 477.44
15	LPG Tank	1000 m^3		(210) or 371.88
16	Condensate Tank	1000 Bbl (eq 158.98 m^3)		AMB

Table A.2: The technical detail of Refrigeration Package

No	Description	Capacity	Input/Output
1	Refrigeration		
	Propane compressor	11.91 MMSCFD (eq.337.252 Sm^3)	4.43 MMBTU/hr (eq.4.673 MJ/hr)
	Oil Separator		
	Gas Chiller		3.1 MMBTU/hr (eq.3.270 MJ/hr)
	Economizer		
	Liquid Receiver		
	Propane Condenser		2.9 MMBTU/hr (eq.3.059 MJ/hr)
2	Hot Oil Heater		6 MMBTU/hr (eq.6.33 MJ/hr)
	Expansion Tank	2000 liter (eq.2 m^3)	
	Circulation Pump	150 GPM	
	Thermal Oil Heater		7.4 MMBTU/hr (eq.7.807 MJ/hr)
	Voidance Tank	2000 liter (eq.2 m^3)	
	Filling Pump	4 GPM	
	Gas Burner	11.9 MMBTU/hr (eq.12.554 MJ/hr)	

The average lifetime of the LPG plant is 16 years, in line with the Decree of Ministry of Finance Decree No 96 year of 2009[3] which defines the equipment lifetime for the Oil and Gas Industry as 16 years. The technical lifetime of equipment has been used for depreciating the assets as per the regulation.
The efficiency of the LPG plant is 99.5% which is calculated from the butane recovery rate. Butane recovery rate is an efficiency parameter of LPG Plant's performance since butane is the main component in LPG. It is described as the portion of butane succesfully recovered and processed into LPG product compared to the total butane being processed.

The project activity uses SCADA (Supervisory Control and Data Acquisition) for the monitoring and industry control process. For the monitoring purpose, some monitoring equipments have been installed in the site of project activity and gas collecting station. The monitoring equipments related to the baseline emission measurement are located at gas delivery point. They consist of Orifice MeterFlow Comp to measure the volume of feed gas and Gas Chromatography (GC) to measure Gross Calorific Value of feed gas. Barton Chart has been installed as well at the gas delivery point within the site of project activity to crosscheck the volume of feed gas measured by Orifice meterflow. The monitoring equipments related to the project emission measurement are located at Pertamina EP Gas Collecting Station. They

[3] http://faisalsmn.files.wordpress.com/2008/08/pmk-96-pmk-03-2009.pdf/ Source: Permen Lingkungan Hidup 13 Tahun 2009

consist of Flow Comp to measure fuel usage for compressor and Gas Chromatograph (GC) to measure Gross Calorific Value of fuel gas.

The greenhouse gas involved in the project activity as per methodology is CO_2. Emission sources of the project activity come from the consumption of fossil fuels for compression process. The compression process is carried out to increase the pressure of the recovered gas up to 450 Psig or 3,102,640.77 Pascal , as required pressure for a LPG Plant.

Mass flows and balances of the systems are described below:

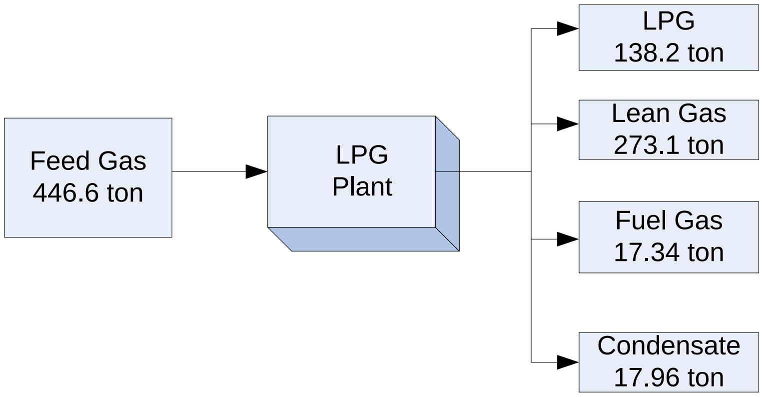

Figure 2: Mass Flows and Balance of the System

Schematic Process Flow Diagram at LPG Plant Pondok Tengah

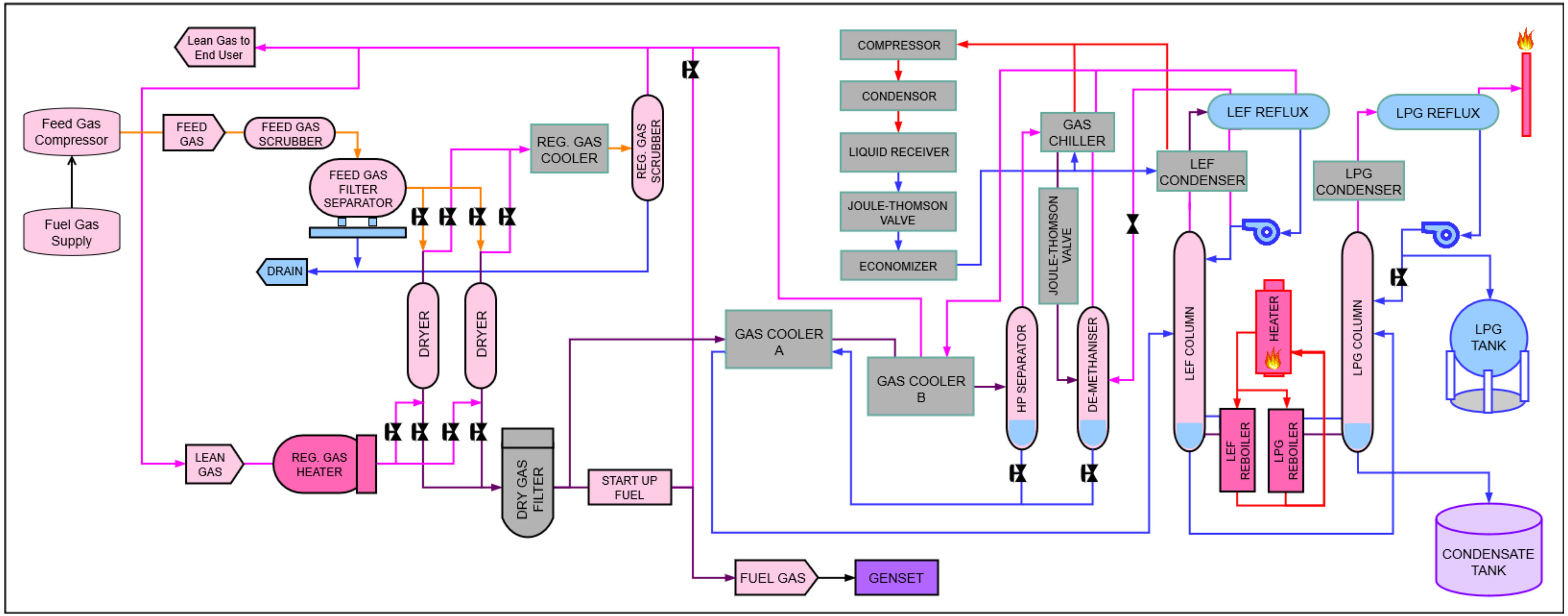

Figure 3: Process Block Diagram at Pondok Tengah Gas Processing Plant

A.4. Parties and project participants

Parties involved	Project participants	Indicate if the Party involved wishes to be considered as project participant (Yes/No)
Republic of Indonesia (host Party)	Private Entity: PT. Yudistira Energy	No
United Kingdom of Great Britain and Northern Ireland	Private Entity: Agrinergy Pte Ltd	No

A.5. Public funding of project activity

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The project activity receives no public funding from Parties included in Annex 1 to the Convention.

A.6. History of project activity

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This PDD is for the renewal of the crediting period. The project activity was registered as a CDM project activity on 17 Dec 2012. The project activity is not a project activity that has been deregistered.

The CDM project activity is not a CPA that has been excluded from a registered CDM PoA. No other CDM project activity or CPA under a registered CDM PoA exists in the same geographical location as the project activity.

A.7. Debundling

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Not applicable

SECTION B. Application of selected methodologies and standardized baselines

B.1. Reference to methodologies and standardized baselines

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AM0009: Recovery and utilization of gas from oil fields that would otherwise be flared or vented - Version 7.0.

Tools referenced in this methodology:
Tool for the demonstration and assessment of additionality Version 07.0.0
Combined tool to identify the baseline scenario and demonstrate additionality Version 07.0
Tool to calculate project or leakage CO2 emissions from fossil fuel combustion Version 03.0
Baseline, project and/or leakage emissions from electricity consumption and monitoring of electricity generation Version 03.0
Assessment of the validity of the original/current baseline and update of the baseline at the renewal of the crediting period Version 03.0.1

B.2. Applicability of methodologies and standardized baselines

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Applicability	Project Activity
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	Applicable. As outlined in Section B.4 prior to the implementation of the project activity the associated gas from Pondok Tengah & Tambun oil fields was flared. This gas is now recovered (including compression) and utilised in the LPG plant. As such the

mobile or stationary equipment	project activity involves the recovery and utilisation of associated gas that would have been flared.
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	Applicable. The recovered gas is transported to a processing plant where it is processed into LPG, lean gas and condensate.
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;	Applicable. The project activity recovers gas from oil wells that are in operation and are producing oil at the time of the recovery of the associated gas.
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.	Applicable. Associated gas is used in the feed gas compressor (pre-processing) and also in the compressor and generator within the LPG plant
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.	The identified baseline scenario of the project activity is the continuation of the current practice of flaring of the associated gas and the continued operation of the existing oil and gas infrastructure without processing of any recovered gas and without any other significant changes, as detailed in the Sections B.4. and B.5.

Applicability of tools referenced in the approved methodology:

Applicability of the tools	**Project Activity**
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: Scenario A: Electricity consumption from the grid. The electricity is purchased from the grid only, and either no captive power plant(s) is/are installed at the site of electricity consumption or, if any captive power plant exists on site, it is either not operating or it is not physically able to provide electricity to the electricity consumer; Scenario B: Electricity consumption from (an) off-grid fossil fuel fired captive power plant(s). One or more fossil fuel fired captive power plants are	The project activity does not involve electricity consumption hence the tool is not followed. (Electricity generation within the LPG plant is outside of the boundary and not considered for project emissions).

installed at the site of the electricity consumer and supply the consumer with electricity. The captive power plant(s) is/are not connected to the electricity grid; or Scenario C: Electricity consumption from the grid and (a) fossil fuel fired captive power plant(s). One or more fossil fuel fired captive power plants operate at the site of the electricity consumer. The captive power plant(s) can provide electricity to the electricity consumer. The captive power plant(s) is/are also connected to the electricity grid. Hence, the electricity consumer can be provided with electricity from the captive power plant(s) and the grid.	
Tool for the demonstration and assessment of additionality Version 07.0.0 The use of the "Tool for the demonstration and assessment of additionality" is not mandatory for project participants when proposing new methodologies. Project participants may propose alternative methods to demonstrate additionality for consideration by the Executive Board. They may also submit revisions to approved methodologies using the additionality tool.	Applicable. As referenced in the approved methodology the application of the tool is mandatory. As this PDD is for the renewal of the crediting period, the Section on Additionality has been copied from the registered PDD for the first crediting period.
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 tool is applicable to all proposed project activities.
Tool to calculate project or leakage CO2 emissions from fossil fuel combustion, Version 03.0 This tool provides procedures to calculate project and/or leakage CO_2 emissions from the combustion of fossil fuels. It can be used in cases where CO_2 emissions from fossil fuel combustion are calculated based on the quantity of fuel combusted and its properties. Methodologies using this tool should specify to which combustion process *j* this tool is being applied.	In line with the methodology, leakage is not considered as the recovered gas is not transported to processing plant where it is processed into hydrocarbon products and the dry gas compressed to CNG first the transported by trailers/trucks/carriers and then decompressed again before it finally enters the gas pipeline.
Assessment of the validity of the original/current baseline and update of the baseline at the renewal of the crediting period, Version 03.0.1 This tool provides a stepwise procedure to assess	Applicable due to renewal of crediting period. The use of the tool is outlined in Section B.4.

the continued validity of the baseline and to update the baseline at the renewal of a crediting period, as required by paragraph 49 (a) of the modalities and procedures of the clean development mechanism. The tool consists of two steps. The first step provides an approach to evaluate whether the current baseline is still valid for the next crediting period. The second step provides an approach to update the baseline in case that the current baseline is not valid anymore for the next crediting period.	

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

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As per the approved methodology, the project boundary encompasses:

a) *The project oil field and oil wells where the associated gas and/or gas-lift gas is collected;*
b) *The site where the associated gas and/or gas-lift gas would have been flared or vented in the absence of the project activity;*
c) *The gas recovery, pre-treatment, transportation infrastructure, including where applicable, compressors;*
d) *The source of gas-lift gas.*

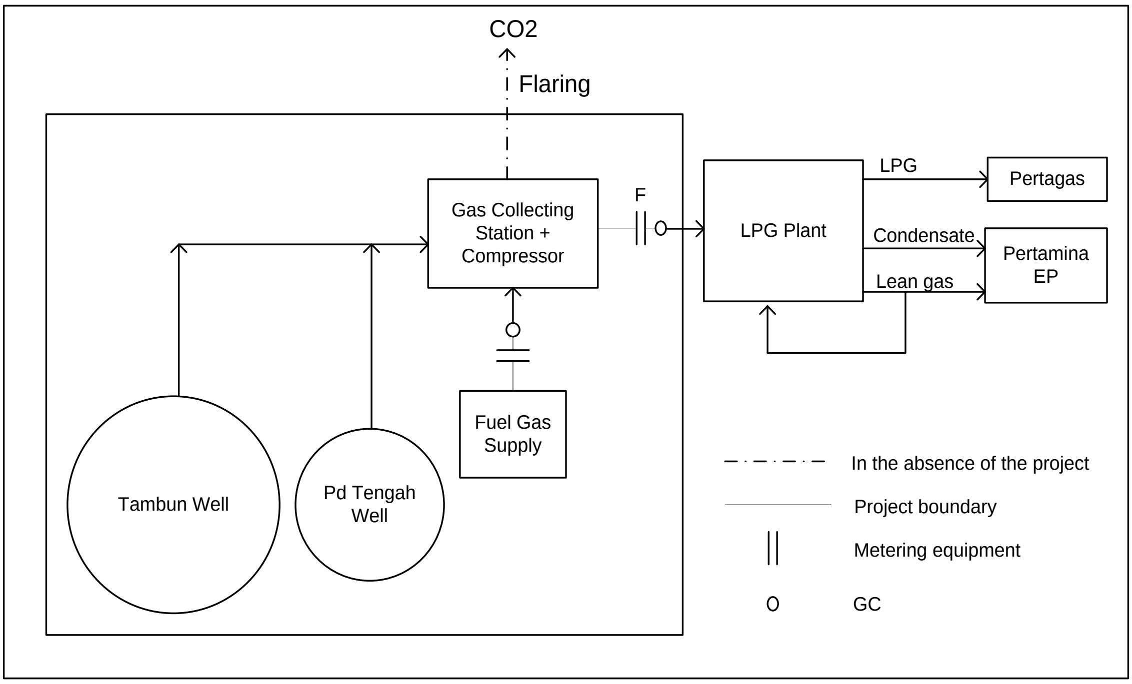

Figure 4: Project Boundary

The greenhouse gases included or excluded from the project boundary are shown below.

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	Minor source, neglecting this source is conservative

		N_2O	No	Minor source, neglecting this source is conservative
Project Activity	Energy use for the recovery, pre-treatment, transportation, and if applicable, compression of the recovered gas	CO_2	Yes	Main source of emissions in the baseline
		CH_4	No	Assumed negligible
		N_2O	No	Assumed negligible

B.4. Establishment and description of baseline scenario

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According to the approved methodology AM0009 - version 07.0, the baseline scenario is identified by following the latest approved version of the “Combined tool to identify the baseline scenario and demonstrate additionality” (Version 07.0) with additional guidance. Moreover, as this PDD is for the renewal of crediting period, the tool “Assessment of the validity of the original/current baseline and update of the baseline at the renewal of the crediting period” (Version 03.0.1) is applied.

Below we first follow the Combined tool to identify the baseline scenario and demonstrate additionality.

Step 1: Identification of alternative scenarios

The project activity involves three components. Plausible alternative scenarios should include alternatives for the following components:

a. Plausible alternative baseline scenarios for the associated gas from the project oil wells
b. Plausible alternative baseline scenarios for oil and gas infrastructure
c. Plausible alternative baseline scenarios for the use of gas-lift

Table B.4-a: Plausible alternative baseline scenarios for the associated gas from the project oil wells

G1	Release of the associated gas and/or gas-lift gas into the atmosphere at the oil production site (venting).	Not plausible. Venting of the associated gas is prohibited by Indonesian Law[4] since it is life threatening due to likelihood of explosion and negative environmental health issues. Alternative (G1) is therefore not a plausible baseline scenario and will not be considered further.
G2	Flaring of the associated gas and/or gas-lift gas at the oil production site.	Plausible. Prior to the implementation of the project activity the associated gas from Pondok Tengah & Tambun oil fields was flared. Alternative (G2) is a plausible baseline scenario and will be considered further.
G3	On-site use of the associated gas and/or gas-lift gas for power generation.	Not Plausible. On site power generation from the associated gas, without processing, would not have been feasible due to its high moisture content. Moreover, the captive consumption of the plant would only require less than 5% of the associated gas being processed in Pondok Tengah Plant. Alternative (G3) is not a plausible baseline scenario and will not be considered further.
G4	On-site use of the associated gas and/or gas-lift gas for liquefied natural gas (LNG) production.	Not plausible. Transportation links and/or geographical distance between production site and end-user location is a major consideration to decide the plausible alternative to transport the gas. Technically there are some ways to transport the gas, as follows :

[4] Source: Permen Lingkungan Hidup 13 Tahun 2009

		• Through Pipeline or • By Compressing the Gas (CNG technology); to optimize transportation capacity (max. distance of 200 km) for economical feasibility or • By Liquefying the Gas (LNG Technology); as liquid form creates even more optimization for transportation capacity, however the LNG further must be converted back into Gas at end-user location (through Re- Gasification Process) In the project activity case, the pipeline system to end-user location (in this case Muara Tawar) is already present. Considering these situations, it is most ideal and economical to deliver the produced Lean Gas to end-user through the existing pipeline system. Alternative (G4) is not a plausible baseline scenario and will not be considered further.
G5	Injection of the associated gas and/or gas-lift gas into an oil or gas reservoir.	Not Plausible. Injection of the associated gas into the oil reservoir would not have been required due to sufficient pressure. Furthermore gas injection is considered costly due to its unpredictable effectiveness[5]. Alternative (G5) is not a plausible baseline scenario and will not be considered further.
G6	Recovery, transportation, processing of the associated gas and/or gas-lift gas and distribution of products thereof to end-users without being registered as a CDM project activity.	Plausible. This scenario represents the project activity without CDM revenues. However as shown in Step3 below this scenario would not be financially attractive. Alternative (G6) is a plausible baseline scenario and will be considered further.
G7	Recovery, transportation and compression of the associated gas and/or gas-lift gas into a gas pipeline without prior processing, without being registered as a CDM project activity.	Not plausible. Without prior processing, the composition of associated gas is lower in methane number and is not a preference to be compressed directly to pipeline since the industries require high methane content in gas composition. Moreover, the heavy components from the associated gas could cause condensation and clogging in the pipeline if the associated gas is to be transported into pipeline over long period, compared to only the processed gas being transported. Alternative (G7) is not a plausible baseline scenario and will not be considered further.
G8	Consumed on-site to meet energy demands without being registered as a CDM project activity	Not Plausible. On site power generation from the associated gas, without processing, would not have been feasible due to its high moisture content. Alternative (G8) is not a plausible baseline scenario and will not be considered further.
G9	Recovery, transportation and utilization of the associated gas and/or gas-lift gas as feedstock for manufacturing of useful products.	Not plausible. Recovery, transportation and utilization of the associated gas and/or gas-lift gas as feedstock for manufacturing of useful products would not have been feasible without prior processing, due to the composition of gas. The composition of associated gas

[5] http://fossil.energy.gov/programs/oilgas/eor

		is lower in methane number and hence is not preferred since the industries require higher methane number in gas composition. Alternative (G8) is not a plausible baseline scenario and will not be considered further

Table B.4-b: Plausible alternative baseline scenarios for oil and gas infrastructure

	Alternatives	**Plausibility/Eligibility**
P1	Construction of a processing plant for the purpose of processing the recovered gas, in the same way as in the project activity, without being registered as a CDM project activity.	Plausible. This is a plausible alternative baseline scenario for the proposed project. However as shown in Step 3 below this scenario is not financially attractive without being registered as a CDM project. Alternative (P1) is a plausible baseline scenario and will be considered further.
P2	Construction of a processing plant of a lower capacity than under the project activity, which processes only non-associated gas and no recovered gas.	Not plausible. The project activity has been designed for the capacity of 17 MMSCFD (eq 481384.89 m^3). All of the feed gas comes from oil wells, which is associated gas, so there is no non-associated gas. Since the non-associated gas is not available on site, this scenario is not applicable. Alternative (P2) is not a plausible baseline scenario and will not be considered further
P3	Supplying recovered gas to an existing gas processing plant and constructing the necessary infrastructure, without being registered as a CDM project activity.	Not Plausible. The only existing gas processing plant at the region is owned by a different entity and that plant is not able to deal with increased associated gas, as it has been designed to fulfil its own gas allocation only. Therefore, supplying recovered gas to an existing gas processing plant and constructing the necessary infrastructure is not an applicable scenario. Alternative (P3) is not a plausible baseline scenario and will not be considered further
P4	Continuation of the operation of the existing oil and gas infrastructure without processing of any recovered associated gas and/or gas-lift gas and without any other significant changes.	Plausible. In the absence of the project activity, the operation of the existing oil and gas infrastructure would have continued without processing of any recovered associated gas and/or gas lift and there would have been no other significant changes. Alternative (P4) is a plausible baseline scenario and will be considered further.
P5	Supplying recovered gas to a gas pipeline without prior processing and without being registered as a CDM project activity.	Not plausible. Without prior processing, the composition of associated gas is lower in methane number and is not a preference to be compressed directly to pipeline since the industries require high methane content in gas composition. Moreover, the heavy components from the associated gas could cause condensation and clogging in the pipeline if the associated gas is to be transported into pipeline over long period, compared to only the processed gas is transported. Alternative (P5) is not a plausible baseline scenario and will not be considered further

c. Plausible alternative baseline scenarios for the use of gas-lift

The gas-lift is not used under the project activity; therefore the alternative baseline scenarios for the use of gas-lift are not applicable.

Identified plausible alternative scenarios for each component are summarized below:

For the associated gas	G2 G6	Flaring of the associated gas and/or gas-lift gas at the oil production site. Recovery, transportation, processing of the associated gas and/or gas-lift gas and distribution of products thereof to end-users without being registered as a CDM project activity.
For Oil and gas infrastructure	P1 P4	Construction of a processing plant for the purpose of processing the recovered gas, in the same way as in the project activity, without being registered as a CDM project activity. Continuation of the operation of the existing oil and gas infrastructure without processing of any recovered associated gas and/or gas-lift gas and without any other significant changes.
For the use of gas-lift		Not applicable to the project since no gas-lift system is used under the project activity.

Out of the 4 combinations, the combination of G2 &P1 and G6 & P4 are considered as not realistic and impossible because the scenarios contradict each other, thus there are only two identified realistic combinations as described in the table below:

Table B.4-1: Realistic combinations of the three components

Combination 1	
G2	Flaring of the associated gas and/or gas-lift gas at the oil production site.
P4	Continuation of the operation of the existing oil and gas infrastructure without processing of any recovered associated gas and/or gas-lift gas and without any other significant changes.
Combination 2	
G6	Recovery, transportation, processing of the associated gas and/or gas-lift gas and distribution of products thereof to end-users without being registered as a CDM project activity.
P1	Construction of a processing plant for the purpose of processing the recovered gas, in the same way as in the project activity, without being registered as a CDM project activity.

These combinations are considered as possible and realistic alternative scenarios to the proposed project activity and will proceed to the Step 2 for legal evaluation.

Step 2: Evaluate legal aspects

All the realistic and credible alternative scenarios outlined above are in compliance with existing legislation and regulations taking into account the enforcement in the region and EB decisions on national and/or sectoral policies and regulations.

Step 3 and Step 4 for the identification of the baseline scenario and additionality are carried out in Section B.5.

Assessment of the validity of the original/current baseline and update of the baseline at the renewal of the crediting period Version 03.0.1

As this PDD is for the renewal of the crediting period, the above tool is followed to confirm the original baseline remains valid. Para 283 of the CDM project standard for project activities Ver02.0 states “To demonstrate the validity of the original baseline or its update, the project participants are not required to re-assess the baseline scenario. Instead, the project participants shall assess the GHG emission reductions or net anthropogenic GHG removals that would have resulted from that scenario”.

As outlined below, Alternative 1 is the baseline scenario (Flaring of the associated gas and/or gas lift and continued operation of the existing oil and gas infrastructure without processing of any recovered associated gas and/or gas-lift gas without any other significant changes.

Step 1: Assess the validity of the current baseline for the next crediting period
Step 1.1: Assess compliance of the current baseline with relevant mandatory national and/or sectoral policies

There remains no legislation in Indonesia which prohibits the flaring of associated gas and/or gas lift and Indonesia remains the 15th largest country for gas flaring according to world bank Global Gas Flaring Reduction Partnership (GGFR) data[6]. As such, the current baseline complies with relevant mandatory national and sectoral policies.

Step 1.2: Assess the impact of circumstances
There have been no changes to the availability of new fuels or raw materials, not electricity or fuel prices which will impact baseline emissions. As such there is no impact of circumstances that requires an update of the baseline.

Step 1.3: Assess whether the continuation of use of current baseline equipment(s) or an investment is the most likely scenario for the crediting period for which renewal is requested.
The previous flaring equipment was rudimentary and could have continued to be used. Therefore, there is no requirement to update the baseline for this reason.

Step 1.4: Assessment of the validity of the data and parameters
In line with Step 1.4 it is assessed that the CO2 emission factor for methane was determined at the first crediting period and fixed ex-ante. In line with the guidance and methodology revision, this value should be updated.

Step 2: Update the current baseline and the data and parameter

Steps 1.1, 1.2 and 1.3 above show that baseline emissions do not need to be updated. However, Step 1.4 shows that that the CO2 emission factor should be updated.

Step 2.2: Update the data and parameters
The value $EF_{CO2/Methane}$ is outlined in AM009 Version 07.0 at **54.8/34** tCO_2/TJ. This value is outlined in Section B.6.2 of this PDD.

B.5. Demonstration of additionality

>>
This section is copied from the registered PDD for the first crediting period in line with para 280 of the CDM project standard for project activities Ver02.0.

Step 3: Evaluate the economic attractiveness of alternatives
As recommended in AM0009 version 4, the identification of the first likely alternative scenario to the project activity has been demonstrated in section B.4. The economic attractiveness is assessed for combinations (1) and (2) by determining an expected Internal Rate of Return (IRR) for each alternative scenario based on the latest approved version of the *Tool for demonstration and assessment of additionality version 05.2.1.*

Alternative 1
G2: Flaring of the associated gas and/or gas-lift gas at the oil production site, and

[6] http://www.worldbank.org/en/programs/gasflaringreduction#7

P4: Continuation of the operation of the existing oil and gas infrastructure without processing of any recovered associated gas and/or gas-lift gas and without any other significant changes.

Alternative 2
G6: Recovery, transportation, processing of the associated gas and/or gas-lift gas and distribution of products thereof to end-users without being registered as a CDM project activity, and
P1: Construction of a processing plant for the purpose of processing the recovered gas, in the same way as in the project activity, without being registered as a CDM project activity.

Economic attractiveness evaluation for Alternative 1
Flaring of the associated gas in Indonesia is permitted and this alternative will not require any investment, thus this alternative will not create additional cost or additional revenue. In this case, the required return of this alternative refers to the return of benchmark. As also stated in point 19 of the guidance for the investment analysis of the *Guidelines on the assessment of investment analysis version 05:*
''The benchmark approach is suited to circumstances where the baseline does not require investment or is outside the direct control of the project developer, i.e. cases where the choice of the developer is to invest or not to invest''.

The benchmark has been based on the average local investment lending rate charged by commercial banks in Indonesia[7], 13.95%, and the IRR of the project will be compared to this. As stated in point 12 of the guidance for the investment analysis of the *Tool for the demonstration and assessment of additionality:*
''Local commercial lending rates or Weighted Average Costs of Capital (WACC) are appropriate benchmarks for a project IRR''.

An average 1 year local investment lending rate before the investment decision for the project activity has been used for the benchmark. The chosen benchmark is the average investment lending rate from September 2008 – August 2009, which is quoted at 13.95% relating to the time of investment decision of the project activity as shown in the Minutes of Board Meeting dated 15th September 2009 All financial information used for the benchmark determination is publicly available. The calculation of benchmark has been detailed in the spreadsheet that has been submitted with the PDD.

Economic attractiveness evaluation for alternative 2
This alternative is the project activity without CDM revenue, and its economic attractiveness is assessed by the IRR calculation. The majority of the financing of the project is through debt and Yudistira has a liability to service debt, which also needs to be considered while calculating the returns associated with the project. Thus a project IRR as the financial indicator was considered more appropriate for the project activity. The project IRR is determined using the main relevant parameters as follows:

Parameter	**Value**	**Source**
The projected quantity of gas recovered which is consumed on-site and is processed into products (LPG, Condensate and lean gas)	The projected quantity of gas recovered is shown in the table below	Projection data from PERTAGAS and Feasibility Study based on HYSIS software simulation by technical team
On-site fuel gas own consumption	0.744 MMSCFD	Feasibility Study based on HYSIS software simulation by technical team, (09/09/2009)
Annual projected volume of associated gas	140,168,408 Nm^3/year declining to 61,487,208 Nm^3/year	Projection data from PERTAGAS and Feasibility Study based on HYSIS software simulation by technical

[7] http://www.bi.go.id/SDDS/series/inr/index_inr.htm

		team, (09/09/2009)
The agreed price for the delivery of processed gas (processing fee) as the revenue of the project activity	• LPG = USD 175 / ton • Condensate = USD 17/bbl	Contract agreement with PERTAGAS (04/11/2009)
Investment cost for gas infrastructure (CAPEX)	18,650,946 USD	Feasibility Study Report (09/09/2009)
Operational expenditure (OPEX)	USD 0.43 / MSCF	Feasibility Study Report (09/09/2009)
Fuel Gas Price	4 USD/MMBTU	Feasibility study report (09/09/2009) and Contract agreement with PERTAGAS(04/11/2009)
Equipment Lifetime	16 years	The equipment lifetime as per Decree of Ministry of Finance Decree No 96 year of 2009
Depreciation rate (double declining method)	13% on plant and equipment 10% on construction	Decree of Ministry of Finance Decree No 96 year of 2009
Inflation rate	7.25%	Average inflation rate recorded by Bank of Indonesia from November 2006 to November 2009
Income tax	25%	Feasibility Study Report (09/09/2009) and Indonesian Income Tax Law no. 36 Year 2008

The projected quantity of gas recovered which is consumed on-site and processed into products (LPG, Condensate and lean gas):

Year	1	2	3	4	5	6	7	8	9
Tambun (MMSCFD)	9	10.5	15	15	15	13.8	11	9	6.58
Tambun (Nm^3) / day	254,850	297,325	424,751	424,751	424,751	390,771	311,484	254,850	186,324
Pd Tengah (MMSCFD)	6.00	4.50	-	-	-	-	-	-	-
Pd Tengah (Nm^3) / day	169,900	127,425	-	-	-	-	-	-	-

Based on the technical lifetime of the project, a 16 year lifetime period must be applied to calculate the project IRR. However the calculation results in a negative IRR and due to conservativeness, as per the version 5 of "*Guidelines on the assessment of investment analysis*" a 10 year period of assessment has been chosen to present the project IRR calculation. Since a shorter period than lifetime is chosen, the residual value of the project activity assets for the remaining years has been included as cash inflow. A negative IRR over the lifetime of the project activity also emphasizes the importance of CER revenues in the project activity. The calculation of the project IRR has been detailed in the excel spreadsheet that is provided to validator during site visit.

The project IRR for the project activity without taking into account the CER revenue is 7.16% which is lower than the benchmark (13.95%) and this highlights that the project activity is not financially attractive.

According to the methodology, the alternative scenario that is economically the most attractive course of action is considered as the baseline scenario. Hence alternative 1, wherein the activities of gas flaring and the operation of the existing oil and gas infrastructure are continued without any significant changes (G2 & P4), is considered as the baseline scenario.

Sensitivity analysis
To show whether the conclusion regarding the economic attractiveness above is robust and provides a valid argument in favour of additionality, a sensitivity analysis has been conducted in accordance with EB 62, Annex 5 point 20 of the Guideline on the assessment of investment analysis version 05. Variables which constitute more than 20% of either total project cost or total project revenues, including the initial investment cost, or have a material impact on the analysis, have been identified below and been subjected to reasonable variation range of ±10%:

1. Volume of Production
2. Operation & Maintenance Cost
3. Investment Cost
4. LPG Processing Fee
5. Condensate Processing Fee

The impacts were analyzed in the range of ± 10% and the corresponding impacts have been highlighted in the table and graph below:

Table B.5-1: Sensitivity Analysis

Yudistira	-10%	-5%	0%	5%	10%
Volume of Production	-1.21%	3.39%	7.16%	10.47%	13.48%
Investment cost	10.73%	8.87%	7.16%	5.58%	4.13%
O&M cost	10.45%	8.88%	7.16%	5.24%	3.03%
LPG Processing Fee	0.06%	3.88%	7.16%	10.09%	12.77%
Condensate Processing Fee	6.29%	6.73%	7.16%	7.58%	8.00%

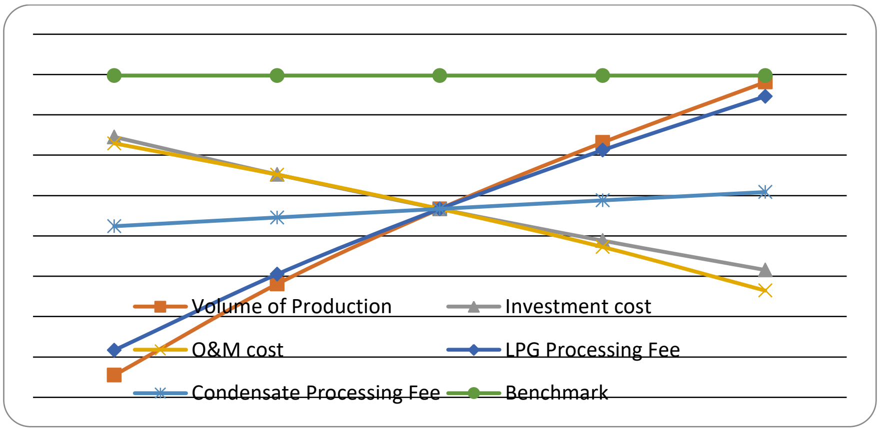

Figure B.2: Sensitivity Analysis

The results show that in the absence of CDM revenues, the variations between +10% and -10% of production volume, investment cost, operation and maintenance cost, and processing fee consistently support the conclusion that the project activity is unable to pass the benchmark and is not the most financially attractive alternative. Moreover processing fee is already fixed based on the Build Operate Own (BOO) Agreement between Project Owner and Pertagas, hence scenario of change in processing fee is unlikely to occur. The increase in volume production is not likely to occur due to the depleting associated gas amount and it is limited by the gas amount signed in the contract agreement with Pertagas.

In accordance with the methodology, if the IRR of the project activity is lower than the hurdle rate of the project participants and if the most plausible baseline scenario is not the project activity without being registered as a CDM project activity; the analysis should proceed to the step 4 of Common Practice Analysis.

Step 4: Common practice analysis
The project proponent is required to establish that the project activity is not a common practice in the relevant country and sector, by applying the Guidelines on common practice (version 1.0)

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

The capacity of the proposed project activity is 17 MMSCFD. Hence, the applicable output range identified as +/- 50% of the design output or capacity of the proposed project activity is 8.5 – 25.5 MMSCFD.

Step 2: In the applicable geographical area, identify all plants that deliver the same output or capacity, within the applicable output range calculated in Step 1, as the proposed project activity and have started commercial operation before the start date of the project. Note their number N_{all}.

In 2001, the Indonesian government allowed the private business entities to participate in the development of oil and gas projects and divided the business activities into upstream and downstream[8]. Every downstream business entity, whose activity is gas recovery and processing, is required to obtain a business license from the government to operate.

The common practice analysis has focused on the geographical area as the country of Indonesia. The analysis includes the operational project activities which recover and utilize the associated gas from onshore oilfields and are under the same regulatory framework as mentioned above. A more specific analysis based on other activities similar to the proposed project activity is carried out based on PERTAGAS' database[9]. The projects are considered similar to the project activity with respects to partnership with PERTAGAS. There are five other LPG Plants utilizing associated gas that are now operational under the partnership with PERTAGAS and are considered as LPG plants of PERTAGAS, these are listed in the table below:

Table B.5-3: The detailed information of LPG plants in Indonesia

LPG Plant	Location	Developer	Capacity		Commissioning Year	Additional Facility
Tugu Barat	West Java	PT. Sumber Daya Kelola	Feed Gas	10 MMSCFD (283167.58 m^3/day)	2008	Dehydration PlantCO_2 Removal
			LPG	15 ton/day		
			Condensate	140 bbl/day (22.2582 m^3/day)		
			Lean Gas	3.6 MMSCFD (101940.33 m^3/day)		
Cilamaya Utara	North Cilamaya, West Java	PT. Yudistira Haka Perkasa	Feed Gas	15 MMSCFD (424,751.37 m^3/day)	2003	CO_2 removal Dehydration Plant
			LPG	47.2 ton/day		
			Condensate	121 liters/day (0.121 m^3/day)		
Limau Timur	Air Serdang	PT. Titis Sampurna	Feed Gas	30 MMSCFD (849,502.74	2003	CO_2 Removal

[8] Government Law in Oil and Gas No. 22 Year 2001: http://www.pwc.com/en_ID/id/energy-utilities-mining/assets/law22-2001.pdf

[9] The list of LPG Plants published on the Pertagas' websiteaccessed on 10 April 2010 has been submitted to the DOE as attachment

	& Beringin, Sumatera Selatan			m^3/day)		
			LPG	182 ton/day		
			Condensate	550 bbl/day (87.443 m^3/day)		Dehydration Plant
Cemara	West Java	PT. Wahana Insan Nugraha	Feed Gas	15 MMSCFD (424,751.37 m^3/day)	2002	Dehydration Plant
			LPG	95 ton/day		
			Condensate	250 bbl/day (39.7468 m^3/day)		
			Lean Gas	13.15 MMSCFD (372,365.37 m^3/day)		
Kwala Gebang & Palu Tabuhan Timur	Kwala Gebang & East Paluh Tabuhan, North Sumatera	PT. Maruta Bumi Prima	Feed Gas	Gebang: 5,180MMBTUD (142824.54 m^3/day) PTT :3,035 MMBTUD (83681.95 m^3/day)	2001	Dehydration Plant
			LPG	Gebang:18 ton/day PTT :11.6 ton/day		
			Condensate	Gebang:145 bbl/day (23.0531 m^3/day) PTT :81 bbl/day (12.8779 m^3/day)		
			Lean Gas	Gebang:4.7 MMSCFD (133,088.76 m^3/day) *PTT :2.8* MMSCFD (79,286.92 m^3/day)		

Out of 5 plants above, Tugu Barat and Limau Timur have been excluded. Tugu Barat has been published on UNFCCC website for global stakeholder consultation as part of the validation process. Limau Timur has a capacity of 30 MMSCFD, beyond the applicable output range of 8.5 - 25.5 MMSCFD as explained above. Thus, the identified N_{all} are 3, namely Cilamaya Utara, Cemara, and Kwala Gebang Palu Tabuhan Timur.

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

According to the Guidelines on common practice version 01.0, different technologies are defined as technologies that deliver the same output and differ by at least one of the following: energy source / fuel; feed stock; size of installation (power capacity); investment climate in the date of the investment decision, (inter alia: access to technology; subsidies or other financial flows; promotional policies; legal regulations); and other features (inter alia: unit cost of output are considered different if they differ by at least 20%).

The three projects, i.e., Cilamaya Utara, Cemara, Kwala Gebang and Palu Tabuhan are considered to have different technology from the proposed project activity, in terms of the investment climate, which is explained in detail below.

Cilamaya Utara LPG plant is owned by PT. Yudistira Haka Perkasa, a sister company of PT. Yudistira Energy. The agreement for Cilamaya Utara with Pertamina has included certain benefits which are not applicable to the proposed project activity. In the agreement, Cilamaya Utara has the right to maintain a minimum revenue/day and it has different provision in the event of delay of gas supply, which rendered Cilamaya Utara LPG Plant financially less risky than the proposed project activity. Cilamaya Utara's revenue per day was maintained while the project activity would not enjoy this benefit unless the feed gas supply from Pertagas stopped for 90 consecutive days. So Cilamaya Utara has a benefit in terms of a reduced financial risk and Cilamaya faced different investment climate during its investment decision based on its legal agreement with Pertamina. Thus, Cilamaya Utara has different technology from the proposed project activity.

The essential distinction between the Cemara LPG Plant owned by PT Wahana Insan Nugraha and the project activity is in terms of access to financing. Cemara LPG Plant obtained support from Pertamina Dana Ventura (PDV). [10] PDV itself is a Pertamina subsidiary, which has been established to finance Pertamina's business partners. The nature of this venture capital company is to give management and technical support, besides capital financing support. PDV gave working capital loans of USD 6,000,000 to PT Wahana Insan Nugraha with 120 month loan repayment term in September 2003.

The proposed project activity does not have access to such financing due to the changes in the Pertamina's objectives. According to the Law of the Republic of Indonesia No. 22 Year 2001, Goverment of Indonesia indicated its plan to transform Pertamina, as the state-owned company, into limited liability company (Persero) and this plan was executed by the Government Regulation No. 31 Year 2003. Initially the objectives of Pertamina[11] was to develop the oil and gas industry for the public interest supply and the welfare of country, as well as to establish national sustainability. The transformation of Pertamina into limited liability company (Persero) has changed its objectives into profit gaining based on good corporate governance. In this respect, Cemara LPG Plant has a benefit in gaining the financial flows compared to the proposed project activity. Thus, Cemara has a different technology from the proposed project activity.

Kwala Gebang - Palu Tabuhan Timur were built and commissioned in a different investment climate in 2001, before Pertamina was changed to Pertamina (Persero). Also in 2001 the price of steel, as the major component in gas processing plant construction, was below 148 USD/ ton[12]. The project activity's construction started in July 2010, when the steel price had increased up to 156% compared with those in 2001. Furthermore, LPG price in 2001 was 253 USD/tonne, while the price in 2009 was 485 USD/tonne, which is translated into an increase of 91%. By comparing associated steel as cost and LPG price as revenue, we can say that increase in cost is much higher than the increase in revenue. Moreover in the project activity, the revenue is given fixed (since the processing fee is fixed), despite of the increase of market gas price. Hence, Kwala Gebang - Palu Tabuhan has a benefit in terms of investment climate. Thus, Kwala Gebang - Palu Tabuhan has a different technology from the proposed project activity.

The project activity itself was proposed to support Public Service Obligation (PSO) program given by the Indonesian Government to Pertagas. This program, which aimed to convert kerosene consumption into LPG, was started in 2007. In order to encourage LPG usage for the low income people, as the major users of kerosene, the government introduced subsidized LPG (LPG 3 kg)

[10] http://pdv.co.id/index.php?page=detail&ncid=0&aid=860

[11] Law of the Republic of Indonesia No. 8 year 1971

[12] Attachment in http://www.steelonthenet.com/kb/steel-billet-prices-1998-2009.html

based on Presidential Regulation No.104 year 2007[13]. Since the government regulates the LPG price, this price limitation has an implication that LPG is priced below its economic price in the market[14]. This condition has affected the entities entering LPG business in Indonesia, since 2007, including the proposed project activity. So the proposed project activity is also facing obstacle related with the policy and legal regulation.

Based on the above reasons, it is concluded that all other projects has applied different technology from the proposed project activity and the proposed project acitivity has to face policy and legal regulation obstacle. Thus N_{diff} = 3, namely Cilamaya Utara, Cemara and Kwala Gebang - Palu Tabuhan Timur.

Step 4: Calculate factor $F=1-N_{diff}/N_{all}$ representing the share of plants using technology similar to the technology used in the proposed project activity in all plants that deliver the same output or capacity as the proposed project activity.

- F=1-3/3= 0,
- $N_{all}-N_{diff} = 3 – 3 = 0$

The proposed project activity is deemed to be 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. Since F=0 and $N_{all}-N_{diff}$ = 0 therefore the proposed project activity is not a common practice in the chosen geographical area of host country Indonesia.

CDM consideration

As shown above, when the project activity is successfully approved and registered as a CDM project, the income from CERs sales will improve the financial attractiveness of the project activity. In this project activity, the CDM benefit was a decisive factor to proceed with the project and it provides a significant return allowing the project to be feasible.

Steps with regards to CDM registration have been taken by PT Yudistira, including contacts with CDM consultant, and prior notification to the UNFCCC secretariat and Host Party DNA about the intention to obtain CDM status. All of those real and continuing actions are demonstrated in the timeline of the project as shown below.

Table B.5-6: Chronology of the events for the project

Date	Description	Source of evidence/remarks
09/09/2009	Feasibility Study Report	Copy of Feasibility Study Report
15/09/2009	Board Meeting decision for CDM	Copy of minutes of meeting
12/10/2009	CDM contract agreement with Agrinergy	Copy of contract agreement
04/11/2009	Yudistira signed agreement contract with PERTAGAS	Copy of Agreement contract between Yudistira and PERTAGAS
09/11/2009	Purchase order of Propane Refrigeration Package (Start date)	Copy of purchase order agreement
20/11/2009	Prior Consideration	Copy of correspondences to UNFCCC and Indonesian DNA
20/04/2010	Publication in the newspaper notice as invitation of CDM stakeholder meeting	Copy of publication in the newspaper
29/04/2010	CDM Stakeholder consultation	Copy of Minutes of meeting and photographs
18/06/2010	Contacts with DOE for validation	Copy of correspondence and

[13] http://www.esdm.go.id/regulasi/perpres/doc_download/443-peraturan-presiden-ri-no104-tahun-2007.html

[14] Business Competition Supervisory Commission Report-KPPU in Indonesia: http://www.kppu.go.id/docs/Positioning_Paper/LPG.pdf

	services	validation quotation from DOE

B.6. Estimation of emission reductions

B.6.1. Explanation of methodological choices

>>
In line with the methodology, the emission reductions are calculated as explained below.

$$ER_y = BE_y - PE_y - LE_y \quad \textbf{(1)}$$

Where:

ER_y	Emissions reductions in year y (t CO_2e)
BE_y	Emissions in the baseline scenario in year y (tCO_2e)
PE_y	Emissions in the project scenario in year y (tCO_2e)
LE_y	Leakage in year y (t CO_2e)

Baseline emissions

$$BE_y = V_{F,y}.NCV_{RG,F,y}.EF_{CO2Methane} \quad \textbf{(2)}$$

Where:

BE_y	= Baseline emissions during the period *y*, (tCO_2e)
$V_{F,y}$	= Volume of total recovered gas measured at point F in Figure 4 in year *y*, (Nm^3)
$NCV_{RG,F,y}$	= Net calorific value of recovered gas measured at point F in Figure 4 in year y, (TJ/Nm^3)
$EF_{CO2Methane}$	= CO_2 emission factor for methane (tCO_2/TJ)

Projection of Associated Gas Production and adjustment of Baseline Emissions

As mentioned above, baseline emissions are based on the volume of total recovered gas measured at point F in Figure 4. This gas would be flared in the absence of the project activity. There is a level of uncertainty with regard to the amount of associated gas as it is directly linked to the oil production. Such uncertainty would be taken into account since the emissions reductions are calculated based on actual data of the associated gas recovered.

For the purposes of this PDD and the renewal of crediting period the annual associated gas volume recovered is assumed to be flat at the level of year 7 of the previous crediting period.

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 Figure 4. In this project activity, the source of these emissions for the project activity comes from fuel gas combustion of compressor.
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 Figure 4. In this project activity, these emissions do not occur as there is no electricity used for the recovery, pre-treatment, transportation and compression of the recovered gas.

$$PE_y = PE_{FC,j,y} \quad \textbf{(3)}$$

Where:

PE_y	= Project emissions in the period *y,* (tCO_2e)
$PE_{FC,j,y}$	= CO_2 emissions due to consumption of fossil fuels for the recovery, pre-treatment, transportation, and, if applicable, compression of the recovered gas during the period *y,* (tCO_2e)

Project emissions from the consumption of fossil fuels

Project emissions $PE_{CO2,fossilfuel,y}$ 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 (3) of the *Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion* where process *j* corresponds to a source of fuel combustion (e.g. a compressor, etc) up to point F in Figure 4. The CO_2 emissions from fossil fuel combustion in process are calculated based on the quantity of fuels combusted and the CO_2 emission coefficient of those fuels, as follows:

$$PE_{FC,j,y} = \sum_i FC_{i,j,y} x COEF_{i,y} \quad \textbf{(4)}$$

Where:

$PE_{FC,j,y}$ = The CO_2 emissions from fossil fuel combustion in process j during the year *y* (tCO_2/yr)

$FC_{i,j,y}$ = The quantity of fuel type *i* combusted in process *j* during the year *y* (mass or volume unit/yr);

$COEF_{i,y}$ = The CO_2 emission coefficient of fuel type *i* in year *y* (tCO_2/mass or volume unit)

i = The fuel types combusted in process *j* during the year *y*

The CO_2 emission coefficient of fuel, $COEF_{i,y}$, calculated using option B regarding data availability, and calculated as follows:

Option B : The CO_2 emission coefficient $COEF_{i,y}$ is calculated based on net calorific value and CO_2 emission factor of the fuel type *i*, as follows:

$$COEF_{i,y} = NCV_{i,y} x EF_{CO2,i,y} \quad \textbf{(5)}$$

Where:

$COEF_{i,y}$ = The CO_2 emission coefficient of fuel type i in year *y* (tCO_2/mass or volume unit)

$NCV_{i,y}$ = The weighted average net calorific value of the fuel type *i* in year *y* (GJ/mass or volume unit)

$EF_{CO2,i,y}$ = The weighted average CO_2 emission factor of fuel type *i* in year *y* (tCO_2/GJ)

i = fuel types combusted in process *j* during the year *y*

Leakage

In line with the methodology, leakage is not considered as the recovered gas is not transported to processing plant where it is processed into hydrocarbon products and the dry gas compressed to CNG first the transported by trailers/trucks/carriers and then decompressed again before it finally enters the gas pipeline.

B.6.2. Data and parameters fixed ex ante

(Copy this table for each piece of data or parameter.)

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 25^0C) / 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	As per AM0009 Version 07.0
Purpose of data	Baseline emissions
Additional comment	-

B.6.3. Ex ante calculation of emission reductions

>> As per methodology AM0009, the emission reductions by the project activity is calculated as follows

Table B.6.3-1: Expected volume of recovered gas

Period	Projected volume of recovered gas (Nm3)
Jan 2020 - Dec 2020	61,487,008
Jan 2021 - Dec 2021	61,487,008
Jan 2022 - Dec 2022	61,487,008
Jan 2023 - Dec 2023	61,487,008
Jan 2024 - Dec 2024	61,487,008
Jan 2025 - Dec 2025	61,487,008
Jan 2026 - Dec 2026	61,487,008

Table B.6.2-2 Expected Net Calorific Value (NCV) of the recovered gas

Period	Net Calorific Value (TJ/Nm3)
Jan 2020 - Dec 2020	0.000045
Jan 2021 - Dec 2021	0.000045
Jan 2022 - Dec 2022	0.000045
Jan 2023 - Dec 2023	0.000045
Jan 2024 - Dec 2024	0.000045
Jan 2025 - Dec 2025	0.000045
Jan 2026 - Dec 2026	0.000045

$EF_{CO2,Methane}$ = 54.834 t CO_2/TJ

Baseline Emissions

$BE_y = V_{F,y}.NCV_{RG,F,y}.EF_{CO2Methane}$

Based on the calculation above, baseline emissions for each specific year are summarized below

Table B.6.3-3 Annual Baseline Emissions

Period	Baseline Emissions (tCO_2/year)
Jan 2020 - Dec 2020	153,174
Jan 2021 - Dec 2021	153,174
Jan 2022 - Dec 2022	153,174
Jan 2023 - Dec 2023	153,174
Jan 2024 - Dec 2024	153,174
Jan 2025 - Dec 2025	153,174
Jan 2026 - Dec 2026	153,174

Project Emissions

$PE_y = PE_{FC,j,y}$

Project emissions from the consumption of fossil fuels

$PE_{FC,j,y}$ for each specific year is calculated as follows:

$PE_{FC,j,y} = \sum_i FC_{i,j,y} x COEF_{i,y}$

Where:

y	$FC_{i,j}$ (m^3/year
Jan 2020 - Dec 2020	3,685,271
Jan 2021 - Dec 2021	3,685,271
Jan 2022 - Dec 2022	3,685,271
Jan 2023 - Dec 2023	3,685,271
Jan 2024 - Dec 2024	3,685,271
Jan 2025 - Dec 2025	3,685,271
Jan 2026 - Dec 2026	3,685,271

$COEF_{i,y} = NCV_{i,y} x EF_{CO2,i,y}$

Where:

$NCV_{i,y}$ = 0.0454 GJ/m^3

$EF_{CO2,i,y}$ = 0.054834 tCO_2/Gj

Year	$NCV_{i,y}$ in GJ/m^3	$COEF_{i,y}$ in tCO_2/m^3	$PE_{FC,j,y}$ in tCO_2/yr
Jan 2020 - Dec 2020	0.0454	0.0026	9,746
Jan 2021 - Dec 2021	0.0454	0.0026	9,746
Jan 2022 - Dec 2022	0.0454	0.0026	9,746
Jan 2023 - Dec 2023	0.0454	0.0026	9,746
Jan 2024 - Dec 2024	0.0454	0.0026	9,746
Jan 2025 - Dec 2025	0.0454	0.0026	9,746
Jan 2026 - Dec 2026	0.0454	0.0026	9,746

Total estimation of project activity emissions

PE_y in tCO_2 for each specific year are summarized as table below

Year	$PE_{FC,j,y}$ in tCO_2/year	PE_y in tCO_2/year
Jan 2020 - Dec 2020	9,746	9,746
Jan 2021 - Dec 2021	9,746	9,746
Jan 2022 - Dec 2022	9,746	9,746
Jan 2023 - Dec 2023	9,746	9,746
Jan 2024 - Dec 2024	9,746	9,746
Jan 2025 - Dec 2025	9,746	9,746
Jan 2026 - Dec 2026	9,746	9,746

Leakage
No leakage emissions considered

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)
Jan 2020 - Dec 2020	153,174	9,746	0	143,428
Jan 2021 - Dec 2021	153,174	9,746	0	143,428
Jan 2022 - Dec 2022	153,174	9,746	0	143,428
Jan 2023 - Dec 2023	153,174	9,746	0	143,428
Jan 2024 - Dec 2024	153,174	9,746	0	143,428
Jan 2025 - Dec 2025	153,174	9,746	0	143,428
Jan 2026 - Dec 2026	153,174	9,746	0	143,428
Total	**1,072,216**	**77,965**	**0**	**1,147,426**
Total number of crediting years	7			
Annual average over the crediting period	153,174	9,746	0	143,428

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 Figure 4 in year *y*
Source of data	Flow Meter.
Value(s) applied	

Period y	Value
Jan 2020 - Dec 2020	61,487,008
Jan 2021 - Dec 2021	61,487,008
Jan 2022 - Dec 2022	61,487,008
Jan 2023 - Dec 2023	61,487,008

	<table><tr><td>Jan 2024 - Dec 2024</td><td>61,487,008</td></tr><tr><td>Jan 2025 - Dec 2025</td><td>61,487,008</td></tr><tr><td>Jan 2026 - Dec 2026</td><td>61,487,008</td></tr></table>
Measurement methods and procedures	Measured at point F of Figure 4 using calibrated Flow Meter in MMSCF and the unit will be converted to Nm^3. Volume would be converted to Nm^3 at normal temperature and pressure using the temperature and pressure at the time of measurement. Calibration will be taken annually and will be done by Metrology Department under Ministry of Trade. Operator is responsible to collect the data and the data result will be reviewed and validated by the Supervisor
Monitoring frequency	Continuously
QA/QC procedure	Calibration will be taken annually and/or when measuring equipment shows deviation from its tolerated fair value. Deviation from tolerated fair value can be identified by energy mass balance between feed gas as input and sum up of LPG, lean gas, condensate, and fuel gas. Accuracy of the meter is +/- 1%. In case of emergency when main metering cannot be used, Barton Chart as backup meter is used.
Purpose of data	Calculation of baseline emissions
Additional comment	

Data / Parameter:	$NCV_{RG,F,y}$
Data unit	Tj/Nm^3
Description	Net calorific value of recovered gas at point F of Figure 4 during the period 7.
Source of data	On site sampling of recovered gas at point F in Figure 4 for laboratory analysis (Chemical analysis of gas sampled taken at point F of figure 4)
Value(s) applied	<table><tr><th>Period y</th><th>Value</th></tr><tr><td>Jan 2020 - Dec 2020</td><td>0.000045</td></tr><tr><td>Jan 2021 - Dec 2021</td><td>0.000045</td></tr><tr><td>Jan 2022 - Dec 2022</td><td>0.000045</td></tr><tr><td>Jan 2023 - Dec 2023</td><td>0.000045</td></tr><tr><td>Jan 2024 - Dec 2024</td><td>0.000045</td></tr><tr><td>Jan 2025 - Dec 2025</td><td>0.000045</td></tr><tr><td>Jan 2026 - Dec 2026</td><td>0.000045</td></tr></table>
Measurement methods and procedures	Measurements should be undertaken in line with national or international fuel standards. Gas samples should regularly be taken at point F in Figure 4 and the molar composition of each gas sample should be determined through chemical analysis following the procedures for QA/QC. Based on the molar composition, the Net Calorific Value on a volumetric basis should be determined for each sample in line with ISO 6976 or an equivalent standard for a combustion reference temperature of 250C and the same metering reference condition used for parameter VF,y. The average NCV during the period y is defined as the arithmetic average of NCVs for the samples taken during the same period.

	Sampling and compositional analysis and calculation of net calorific value at least monthly.
Monitoring frequency	Continuously
QA/QC procedure	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 ISO17025 or equivalent standard. In case third party laboratories are used, these should as a minimum have ISO17025 accreditation or justify that they can comply with similar quality standards Any
Purpose of data	Calculation of baseline emissions
Additional comment	

Data / Parameter:	$FC_{i,j,y}$
Data unit	m^3/year
Description	Quantity of gas fuel combusted in process *j* during the year *y*
Source of data	On site measurement will be in MMSCF unit and will be converted to m^3
Value(s) applied	see table below
Measurement methods and procedures	Quantity of fuel gas combusted will be continuously measured using Flow Meter and will be monthly aggregated. The gas fuel is used for Compressor. Operator is responsible to collect the data and the data result will be reviewed and validated by the Supervisor. Accuracy of the meter is +/- 1%
Monitoring frequency	Continuously monitored
QA/QC procedure	Accuracy of the meter is+/- 1%
Purpose of data	Calculation of project emissions
Additional comment	

Period y	Value
Jan 2020 - Dec 2020	3,685,271
Jan 2021 - Dec 2021	3,685,271
Jan 2022 - Dec 2022	3,685,271
Jan 2023 - Dec 2023	3,685,271
Jan 2024 - Dec 2024	3,685,271
Jan 2025 - Dec 2025	3,685,271
Jan 2026 - Dec 2026	3,685,271

Data / Parameter:	$NCV_{i,y}$
Data unit	GJ/m^3
Description	Net calorific value of gas fuel in year y for combustion of compressor
Source of data	IPCC default values at the upper limit of the uncertainty of a 95% confidence interval as provided in Table 1.2 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories.
Value(s) applied	0.0454
Measurement methods and procedures	Any future revision of the IPCC Guidelines should be taken into account
Monitoring frequency	-
QA/QC procedure	-
Purpose of data	-

Data / Parameter:	$EF_{CO2,i,y}$
Data unit	tCO_2/GJ
Description	Weighted average CO_2 emission factor of lean gas fuel in year y for combustion
Source of data	IPCC default values at the upper limit of the uncertainty at a 95% confidence interval as provided in table 1.4 of Chapter1 of Vol. 2(Energy) of the 2006 IPCC Guidelines on National GHG Inventories
Value(s) applied	0.0583
Measurement methods and procedures	Any future revision of the IPCC Guidelines should be taken into account
Monitoring frequency	-
QA/QC procedure	-
Purpose of data	-
Additional comment	-

B.7.2. Sampling plan

>>
Not applicable

B.7.3. Other elements of monitoring plan

>>
All the data and parameters that need to be monitored, as listed in B.7.1, will be monitored under a monitoring plan to ensure that the emission reductions are going to be properly monitored and transparently recorded. Data collection will be prepared by the Operator and will be checked by the Supervisor and approved by the Plant Manager. The management structure for the monitoring will be established as described in Figure 6.

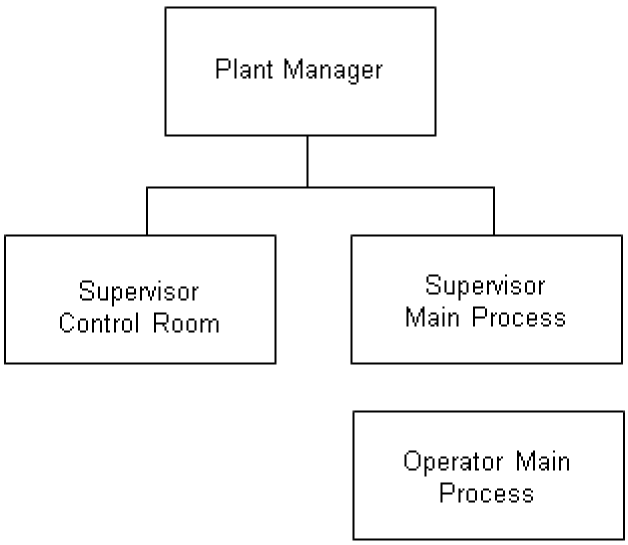

Figure 6: Organization Structure for Monitoring Plan

Calibration of Instruments
Standard method of instruments calibration in Yudistira will be conducted in accordance to National Standard and ISO 9001:2000 article 7.6: Control Monitoring and Measuring Equipment. Calibration will be done by accredited laboratory or Directorate of Metrology under Ministry of Trade. Calibration period is set based on equipment usage duration, calendar schedule or combination of both. In special cases, calibration will take place when measuring equipments show deviation from

its fair value. Calibration schedule for metering system, including Feed Gas Flow meter Package and Fuel Gas Flow meter Package will be held once per year.

Staff and Operator Training

The purpose of staff and operator training is to make sure all the personnel involved understand and know how to carry out the proper procedures for monitoring. The training for Operators will take 2 months and will be conducted by PT Yudistira Haka Perkasa as appointed operator for the project activity.

Data Collection and Storage

The data collection will be conducted and recorded in the frequencies and periods as explained in section B.7.1. The project Operator will collect the data, and the collected data will be checked by the Production Supervisor and approved by the Plant Manager. Data collection in the form of paper will be archived electronically. Regular data back-up will be conducted to guarantee the completeness of the electronic data. As per the methodology, all data collected as part of monitoring should be archived electronically and be kept at least for 2 years after the end of the last crediting period.

Projection and adjustment of project and baseline emissions on the basis of oil production

The project as well as baseline emissions depend on the quantity of associated gas and gas-lift gas recovered, which is linked to the oil production. Oil production may be projected with the help of a reservoir simulator, reflecting the rock and fluid properties in the oil reservoir. As projections of the oil production, the methane content of the gas and other parameters involve a considerable degree of uncertainty, the quantity and composition of the recovered gas are monitored ex post and the baseline and project emissions are adjusted respectively during monitoring.

SECTION C. Start date, crediting period type and duration

C.1. Start date of project activity

>>

09/11/2009, purchase order of the propane refrigeration package

C.2. Expected operational lifetime of project activity

>>

16 years – 00 months

C.3. Crediting period of project activity

C.3.1. Type of crediting period

>>

Renewable crediting period

C.3.2. Start date of crediting period

>>

01 January 2020

C.3.3. Duration of crediting period

>>

07years – 00 months

SECTION D. Environmental impacts

D.1. Analysis of environmental impacts

>>

The Environmental Impact Analysis (EIA) (AMDAL – Analisa Mengenai Dampak Lingkungan) has been done for the project activity together with PERTAGAS in compliance with the latest regulation of the Indonesian Environmental Ministry, Regulation No. 11 in 2006[21]. This documentation has been approved by the EIA Central Assessment Commission on 12/11/2008. No other licenses are required to carry out the project activity regarding its environmental impact. The EIA remains valid unless there is a substantial change in the project. There is no such change and hence the existing EIA remains valid. Environment Permit is a permit given to the person/project owner who have AMDAL/EIA or UKL-UPL to protect and manage the environmental as a requirement to obtain Business and/or Activity Permit.

D.2. Environmental impact assessment

>>

The environmental impacts due to the project activity are not considered significant.

Before the implementation of the project activity, the associated gas was flared and caused air pollution. The project activity is an environmentally friendly project which enables improvement of the environment of local area by a reduction in gas flaring. It does not require any displacement of the local population and nor will it cause any adverse social impacts on the local population.

SECTION E. Local stakeholder consultation

E.1. Modalities for local stakeholder consultation

>>

The stakeholder consultation meeting was held on 29/04/2010 at Babelan Village, Bekasi, with the objective of allowing the local stakeholders to understand the project activity and to facilitate the receipt of comments by local stakeholders in an open and transparent manner. This event had been publicly announced in the newspaper "Bisnis Indonesia" on 21/04/2010. Project Owner also directly invited local villagers via Chief of Village and officials by sending them invitation letters dated 21/04/2010. The event was attended by 102 people, including:

- Local community and local authorities, viz. Babelan Head of District and Head of Village;
- Representatives of PT Pertagas as project feed gas supplier;
- Representatives of PT Yudistira Energy as project owner;
- Representatives of PT Agrinergy Indonesia as project consultant for the Clean Development Mechanism

This event was opened by welcoming speeches from Mr. Pudjianto as Project Manager – PT Yudistira Energy, and H. Hasan Basri as Head of Babelan District. Followed by a presentation by Mr. Faizal Al Fariz from PT Yudistira Energy, explaining the company profile, the description of the project and its environmental effects and a presentation by PT Agrinergy Indonesia about the Clean Development Mechanism (CDM). After the presentations, there was question and answer session for the audience related to the project activity.

The minutes of the meeting, photographs and signature of the attendees has been provided to the validator during the validation process.

E.2. Summary of comments received

>>

A question and answer session was held and the project owner replied to the questions of the local people. The overall comments received were either questions or supporting statements from the stakeholders regarding the project activity. Details of question and answer session can be found in the minutes of meeting. The signed minutes of the question and answer session in Bahasa Indonesia, photographs and signature of attendees will be provided to the validation team

E.3. Consideration of comments received

>>
There were no objections or negative comments received from the local stakeholders which required the project owner to take specific action.

SECTION F. Approval and authorization

>>
Letters of approval have been obtained from Parties and will be made available to the DOE for validation. Each project participant listed in the PDD has received a letter of authorisation from their respective Party, this will be provided.

Appendix 1. Contact information pf project participants

Organization name	PT. Yudistira Energy
Country	Indonesia
Address	Grand Slipi Tower Level 48 & Penthouse, JL. Letjend S. Parman, Kav 22 - 24, Slipi, Jakarta 11480
Telephone	+62 21 29022575
Fax	+62 21 29022576
E-mail	pudjianto@yudistiraenergy.com
Website	www.yudistiraenergy.com
Contact person	Pudjianto Marto Sudarmo

Organization name	Agrinergy Pte. Ltd
Country	Singapore
Address	Temasek Boulevard, #12-07 Suntec Tower One
Telephone	
Fax	
E-mail	moc@agrinergy.com
Website	www.agrinergy.com
Contact person	Mr. Ben Atkinson

Appendix 2. Affirmation regarding public funding

The project has not received any public funding from Annex 1 parties.

Appendix 3. Applicability of methodologies and standardized baselines

Please refer to Section B.1 of the PDD.

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

Left intentionally blank.

Appendix 5. Further background information on monitoring plan

Please refer to section B.7 of the PDD

Appendix 6. Summary report of comments received from local stakeholders

Please refer to Section E.2 of the PDD

Appendix 7. Summary of post-registration changes

NA