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

CONTENTS

Annexes

SECTION A. General description of project activity

A.1. Title of the project activity:

Recovery and Utilization of Associated Gas at Pondok Tengah LPG Plant – PT. Yudistira Energy
Version 9.1
11/10/2012

A.2. Description of the project activity:

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 CO_2 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.

Contribution to sustainable development

Environmental sustainability:
This project will lead to environmental sustainability by providing a cleaner source of energy to the consumers and will displace other higher carbon intensive fossil fuels.

Economy sustainability:
The proposed project activity will benefit the local community by increased potential for employment. The increased availability of gas will help to secure a supply of reliable and quality energy resources to local industries.

Technological sustainability:
The project activity applies processing and basic engineering design from Mackenzie Hydrocarbons Australia, a proven technology provided by a company with over thirty years experience in oil and gas

projects. The utilization of a proven technology and transfer of knowledge and technical skill to the host country via employee training assists technological sustainability.

A.3. Project participants:

>>

Name of Party involved (*) (host) indicates a Host Party)	Private and/or public entity(ies) project participants (*) (as applicable)	Kindly indicate if the Party involved wishes to be considered as project participant (Yes/No)
Republic of Indonesia (host)	Private Entity: PT. Yudistira Energy	No
United Kingdom of Great Britain and Northern Ireland	Private Entity: Agrinergy Pte Ltd	No

Contact details as listed in Annex I.

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

A.4.1.1. Host Party(ies):

>>
Republic of Indonesia

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

>>
West Java Province, Bekasi District

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

>>
Babelan Sub District, Huripjaya Village

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

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

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.

Figure A.1: Location map of Pondok Tengah Gas Processing Plant

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

>>
Sectoral scope 10: Fugitive emission from fuels

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

>>
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, Demathaniser: 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

[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

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
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 m³)		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.

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

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 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 equipment related to the project emission measurement is located at Pertamina EP Gas Collecting Station, i.e. flowmeter to measure fuel usage for compressor.

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:

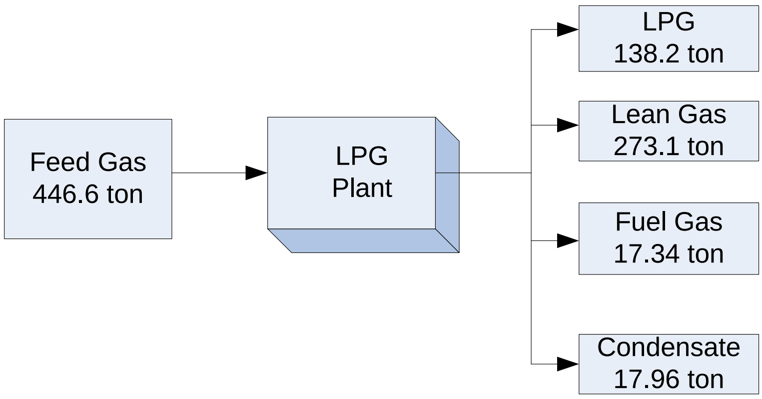


Figure A.2: Mass Flows and Balance of the System

Schematic Process Flow Diagram at LPG Plant Pondok Tengah

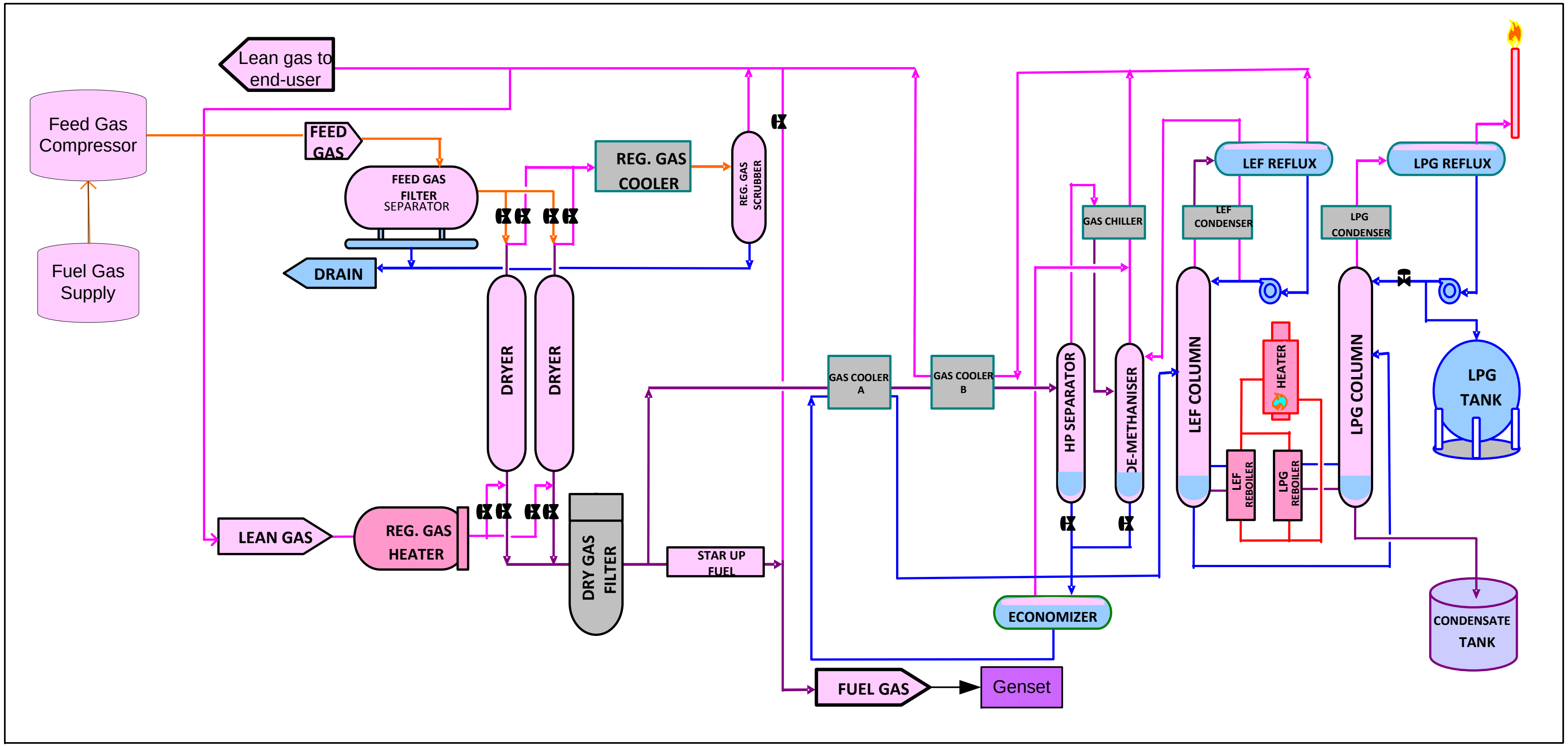


Figure A.3: Process Block Diagram at Pondok Tengah Gas Processing Plant

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

>>

The proposed project activity has applied a seven year renewable crediting period.

Years	Annual estimation of emission reductions in tonnes of CO_2 e
Jan 2013 – Dec 2013	327,570
Jan 2014 – Dec2014	336,746
Jan 2015 – Dec 2015	336,746
Jan 2016 – Dec 2016	336,746
Jan 2017 – Dec 2017	297,944
Jan 2018 – Dec 2018	231,792
Jan 2019 – Dec 2019	181,416
Total estimated reductions (tonnes of CO_2 e)	**2,048,960**
Total number of crediting years	7 years
Annual average over the crediting period of estimated reductions (tonnes of CO_2 e)	**292,708**

A.4.5. Public funding of the project activity:

>>

The project has not received any public funding or Official Development Assistance (ODA).

SECTION B. Application of a baseline and monitoring methodology

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

>>

Approved baseline methodology AM0009 – version 06.0.0: *"Recovery and utilization of gas from oil wells that would otherwise be flared or vented"*

This methodology also refers to the latest approved versions of the following tools:

- *Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion* version 02;
- *Tool for the demonstration and assessment of additionality* version 06.0.0;
- *Tool to calculate baseline, project and/or leakage emissions from electricity consumption* version 01

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

>>

Methodology AM0009 version 06.0.0 is applicable for the project activity for the following reasons:

Applicability	Project Activity
Under the project activity the recovered gas is: - Consumed on-site to meet energy demands; and/or - Transported to a gas pipeline without prior processing; and/orTransported to a processing plant where it is processed into hydrocarbon products (e.g. dry gas, LPG and condensate). The dry gas is either: (i) transported to a gas pipeline directly; or (ii) compressed to CNG first, then transported bytrailers/trucks/carriers and then decompressed again, before it finally enters the gas pipeline;	The recovered gas is transported to a processing plant where it is processed into LPG, lean gas and condensate. The dry gas is transported to a gas pipeline directly.
The project activity does not lead to changes in the process of oil-production, such as an increase in the quantity of quality of oil extracted, in the oil-wells within the project boundaries.	The project activity does not lead to changes in the process of oil production in the oil wells within the project boundaries.
The injection of any gases into the oil reservoir and its production system is allowed in the project activity only for the purpose of the gas-lift process.	The project activity does not involve the injection of any gases into the oil reservoir and its production system.
All recovered gas comes from oil wells that are in operation and are producing oil at the time of the recovery of the associated gas and/or gas-lift gas.	The project activity recovers gas from oil wells that are in operation and are producing oil at the time of the recovery of the associated gas.
The methodology is only applicable if the identified baseline scenario is : - The continuation of the current practice of either venting (scenario G1), flaring (scenario G2) of the associated gas and/or gas lift gas; and or on-site use of the partial amount of associated gas and/or gas-lift to meet on-site energy demands and rest of the	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 any other significant changes, as detailed in the Section B.4.

gas are either vented or flared (scenario G3); and - The continued operation of the existing oil and gas infrastructure without any other significant changes; and - In the case where gas-lift is used under the project activity: the gas –lift under the baseline uses the same source as under the project activity and the same quantity as under the project activity(scenario O1).	

The proposed project activity meets the applicability conditions of the tools referred to as follows:

Applicability of the tools	**Project Activity**
Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion version 02 - This tool 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.	The project activity involves emissions from gas consumption. The emissions from lean gas combustion will be monitored as per the *Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion* version 02
Tool to calculate baseline, project and/or leakage emissions from electricity consumption version 01 - One out of the following three scenarios applies to the sources of electricity consumption: Electricity consumption from the grid, Electricity consumption from (an) off-grid fossil fuel fired captive power plant(s), Electricity consumption from the grid and (a) fossil fuel fired captive power plant(s) - 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 project activity does not involve electricity consumption.

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

>>

As per the approved methodology, the project boundary encompasses:

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

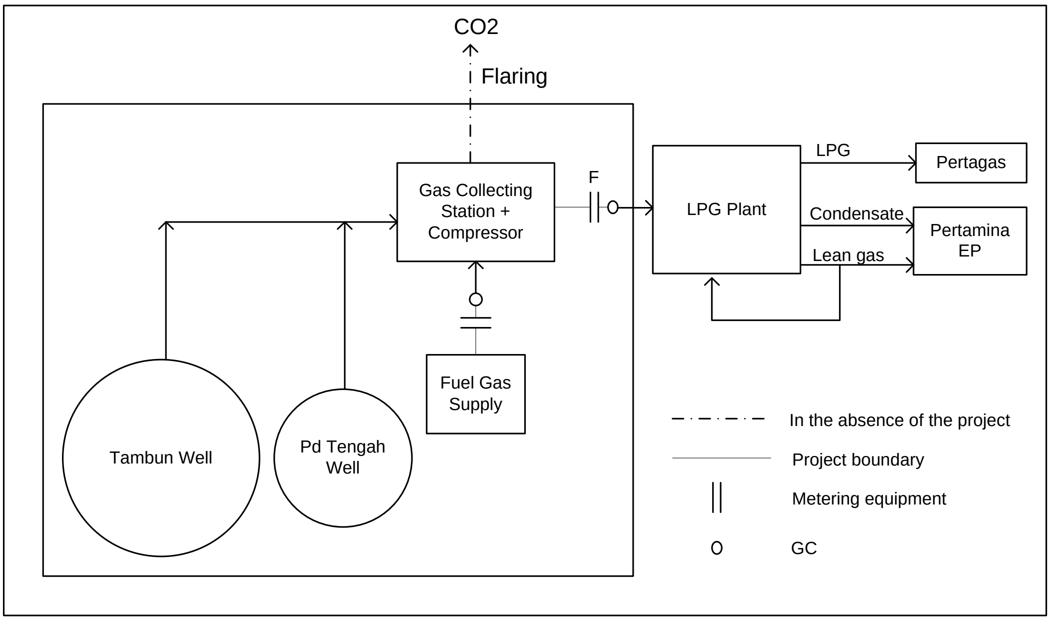


Figure B.1: Project Boundary

The greenhouse gases included in or excluded from the project boundary are shown in the table below:

Source		Gas	Included?	Justification / Explanation
Baseline	Combustion of fossil fuels at end-users that are produced from non-associated gas or other fossil sources	CO_2	Yes	Main source of emissions in the baseline
		CH_4	No	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 decompression, transportation of the recovered gas	CO_2	Yes	Main source of emissions in the project
		CH_4	No	Assumed negligible. Excluded for simplification.
		N_2O	No	Assumed negligible. Excluded for simplification.

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

>>

According to the approved methodology AM0009 - version 06.0.0, the baseline scenario is identified by applying the following procedure:

Step 1: Identify plausible 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 partial amount of associated gas and/or gas-lift gas to meet on-site energy and rest of the gas are either vented (G1) or flared (G2)	Not Plausible. 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	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.
G5	The proposed project activity 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.
G6	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 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

[4] Source: Permen Lingkungan Hidup 13 Tahun 2009
[5] http://fossil.energy.gov/programs/oilgas/eor

		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 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 G5	Flaring of the associated gas and/or gas-lift gas at the oil production site. The proposed project activity 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 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 G5 & 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 any other significant changes.
Combination 2	
G5	The proposed project activity 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.

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

>>

Step 3: Evaluate the economic attractiveness of alternatives

As recommended in AM0009 version 06.0.0, 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 06.0.0*

Alternative 1

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

P4: Continuation of the operation of the existing oil and gas infrastructure without any other significant changes.

Alternative 2

G5: The proposed project activity 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[6], 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

[6] http://www.bi.go.id/seki/tabel/TABEL1_26.xls

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 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%

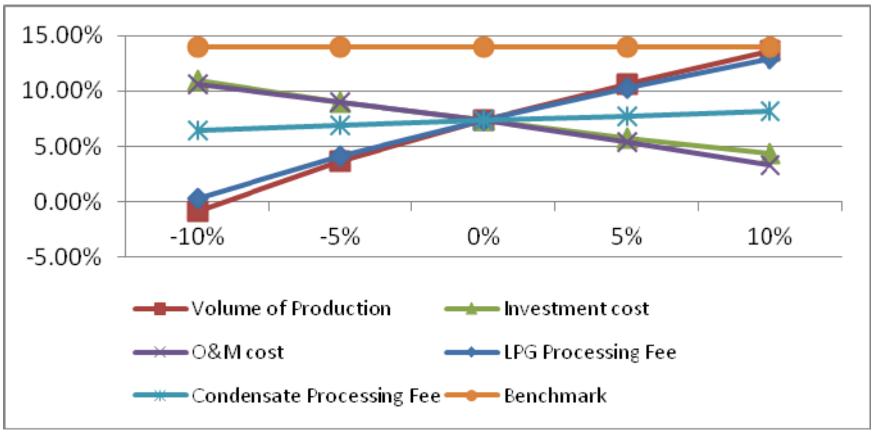


Figure B.2: Sensitivity Analysis

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 agremeent 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 following the guidance for the common practice analysis in the latest approved version of the *Tool for the demonstration and assessment of additionality*.

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[7]. 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[8]. 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 & Beringin, Sumatera Selatan	PT. Titis Sampurna	Feed Gas	30 MMSCFD (849,502.74 m^3/day)	2003	CO_2 Removal Dehydration Plant
			LPG	182 ton/day		
			Condensate	550 bbl/day (87.443 m^3/day)		
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	Kwala	PT.	Feed Gas	Gebang:	2001	Dehydration

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

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

Gebang & Palu Tabuhan Timur	Gebang & East Paluh Tabuhan , North Sumatera	Maruta Bumi Prima		5,180MMBTUD (142824.54 m^3/day) PTT :3,035 MMBTUD (83681.95 m^3/day)		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).[9] 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[10] 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[11]. 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) based on Presidential Regulation No.104 year 2007[12]. Since the government regulates the LPG price, this price limitation has an implication that LPG is priced below its economic price in the market[13]. 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.

---

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

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

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

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

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

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 services	Copy of correspondence and validation quotation from DOE

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

>>

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

$$ER_y = BE_y - PE_y - LE_y \qquad \textbf{(7)}$$

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

$$BE_y = V_{F,y} .NCV_{RG,F,y} .EF_{CO2Methane} \qquad \textbf{(1)}$$

Where:

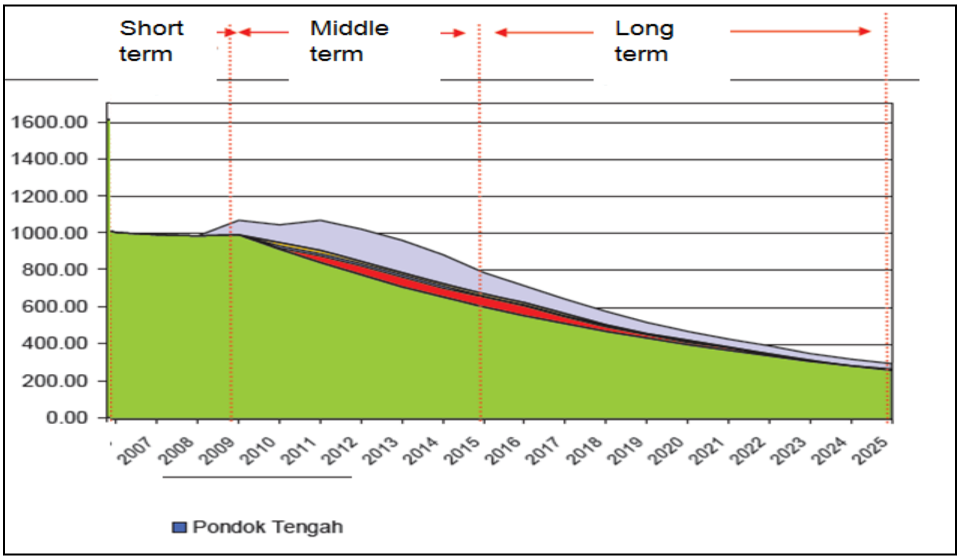
BE_y	= Baseline emissions in year *y*, (tCO_2e)
$V_{F,y}$	= Volume of total recovered gas measured at point F in Figure B.1in year *y*, (Nm³)
$NCV_{RG,F,y}$	= Average net calorific value of recovered gas at point F in Figure B.1 in year y, (TJ/Nm^3)
$EF_{CO2Methane}$	= CO_2 emission factor for methane (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 B.1. This gas would be flared in the absence of the project activity. There is a level of uncertainty with regards to the amount of associated gas since it is directly linked to the oil production. Such uncertainty would ultimately be taken into account since the emission reductions are calculated based on actual data of the associated gas recovered. With this in mind and considering that there will be necessary monitoring in place, an over estimate of the emissions reductions based upon the predicted data, would not present a problem.

At current, the associated gas production forecast in the PDD is based on the survey by Pertamina in 2008 and is directly related to the oil production, i.e. a gas to oil ratio (GOR) of the oil produced. The initial GOR of Pondok Tengah Oil Field was estimated at approximately 3,855 scf/bbl and the gas deliverability would be declining[14] in accordance to the declining curve analysis as shown by the projected production profile below.

[14] Source: Program to Increse Oil and Gas Production, Indonesian Ministry of Energy and Mineral Resources, June 2007. (http://www.scribd.com/doc/92150474/29-Program-Peningkatan-Produksi-Minyak-Dan-Gas-Bumi) – page 54.



The same declining profile is expected for Tambun oil field, as explained by M. Bunyamin, Pertamina Enhanced Oil Recovery General Manager, that the decline rate of oil production from Tambun wells was approximately 20% in 2004 – 2008, before applying EOR technology, and with EOR technology the decline rate of oil production is expected to be 12%.[15]

The forecast of quantity and composition of associated gas from Pondok Tengah and Tambun oil field based on the study and agreement are presented in Annex 3.

As such, while forecast are used in the PDD, the quantity and composition of the recovered gas are monitored ex-post and baseline and project emissions are actual emissions that are monitored as described in Section B.7.

Project emissions

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

- 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 the Figure B.1. In this project activity, the source of these emissions for the project activity comes from fuel gas combustion of compressor.
- 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 the Figure B.1. 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.

$$PE_y = PE_{FC,j,y} \tag{2}$$

Where:

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

[15] Warta Pertamina, Edition No. 01/ Year XLIV/January 2009

$PE_{FC,j,y}$	= 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 2 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) up to point F in Figure B.1. 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:

$$PE_{FC,j,y} = \sum_i FC_{i,j,y} x COEF_{i,y} \qquad \textbf{(3)}$$

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:

$$COEF_{i,y} = NCV_{i,y} x EF_{CO2,i,y} \qquad \textbf{(4)}$$

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
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.
Since the project does not involve compression of dry gas to CNG, no leakage emission is considered

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

Data / Parameter:	$EF_{CO2Methane}$
Data unit:	tCO_2/TJ
Description:	CO_2 emission factor for methane
Source of data used:	Calculated in line with procedures and data presented in ISO 6976: <table><tr><th>Unit</th><th>Value</th><th>Source</th></tr><tr><td>Carbon Content of Methane</td><td>12,011 kg/kmol</td><td>ISO 6976: Table 1</td></tr><tr><td>CO2 Emission Factor for Methane</td><td>44.01 kg/kmol</td><td>ISO 6976: Table 1</td></tr><tr><td>NCV of Methane (at 250C)</td><td>802.60 kJ/mol</td><td>ISO 6976: Table 3</td></tr></table>
Value applied:	$54.834tCO_2/TJ$
Justification of the choice of data or description of measurement methods and procedures actually applied :	As per AM0009 version 06.0.0 , the CO_2 emission factor for methane is included in the parameters that are not monitored.
Any 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:

Based on the feed gas projection, the volume of recovered gas expected is shown as below[16]:

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

Period y	Projected Volume of Recovered Gas (Nm^3)		Projected Total Volume of Recovered Gas($V_{F,y}$) (Nm3)
	Tambun	**Pd Tengah**	**Point F**
Jan 2013 – Dec 2013	98,117,566	42,050,386	140,167,952
Jan 2014 – Dec2014	140,167,952	-	140,167,952
Jan 2015 – Dec 2015	140,167,952	-	140,167,952
Jan 2016 – Dec 2016	140,167,952	-	140,167,952
Jan 2017 – Dec 2017	128,954,516	-	128,954,516

[16] Source: Projection data from PERTAGAS and Feasibility Study based on HYSIS software simulation by technical team

Jan 2018 – Dec 2018	102,789,832	-	102,789,832
Jan 2019 – Dec 2019	84,100,771	-	84,100,771

Table B.6.3-2: Expected Net Calorific Value (NCV) of the recovered gas[17]

Period y	Net Calorific Value (TJ/Nm^3)		Weighted Average Net Calorific Value ($NCV_{RG,F,y}$) (TJ/Nm^3)
	Tambun	**Pd Tengah**	**Point F**
Jan 2013 – Dec 2013	0.000047	0.000043	0.000046
Jan 2014 – Dec2014	0.000047	-	0.000047
Jan 2015 – Decp 2015	0.000047	-	0.000047
Jan 2016 – Decp 2016	0.000047	-	0.000047
Jan 2017 – Dec 2017	0.000046	-	0.000046
Jan 2018 – Dec 2018	0.000046	-	0.000046
Jan 2019 – Dec 2019	0.000046	-	0.000046

$EF_{CO2Methane}$ = 54.834 tCO_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

Year	Baseline Emissions (tCO_2/year)
Jan 2013 – Dec 2013	355,662
Jan 2014 – Dec2014	364,838
Jan 2015 – Dec 2015	364,838
Jan 2016 – Dec 2016	364,838
Jan 2017 – Dec 2017	326,036
Jan 2018 – Dec 2018	259,884
Jan 2019 – Dec 2019	209,508

Project Emission

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

Project emissions from the consumption of fossil fuels[18]

[17] Source: Feasibility Study - based on HYSIS software simulation by technical team and tender document

[18] Source: Fuel gas consumption is estimated based on the consumption of compressor and the amount is based on the technical specification of the compressor.

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

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

Where:

y	$FC_{i,j}$ (m^3/year)
Jan 2013 – Dec 2013	10,622,896
Jan 2014 – Dec2014	10,622,896
Jan 2015 – Dec 2015	10,622,896
Jan 2016 – Dec 2016	10,622,896
Jan 2017 – Dec 2017	10,622,896
Jan 2018 – Dec 2018	10,622,896
Jan 2019 – Dec 2019	10,622,896

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

Where:

$NCV_{i,y}$ = 0.0454 GJ/m^3 [19]

$EF_{CO2,i,y}$ = 0.0583 tCO_2/GJ [20]

Year	$NCV_{i,y}$ in GJ/m³	$COEF_{i,y}$ in tCO_2/m^3	$PE_{FC,j,y}$ in tCO_2/year
Jan 2013 – Dec 2013	0.0454	0.0026	28,092
Jan 2014 – Dec2014	0.0454	0.0026	28,092
Jan 2015 – Dec 2015	0.0454	0.0026	28,092
Jan 2016 – Dec 2016	0.0454	0.0026	28,092
Jan 2017 – Dec 2017	0.0454	0.0026	28,092
Jan 2018 – Dec 2018	0.0454	0.0026	28,092
Jan 2019 – Dec 2019	0.0454	0.0026	28,092

Total estimation of project activity emissions

PE_y in tCO_2/year 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 2013 – Dec 2013	28,092	28,092
Jan 2014 – Dec2014	28,092	28,092

[19] Source: 2006 IPCC Volume 2. Table 1.2: Default Net Calorific Values (NCVs) - natural gas – upper limits of the 95% confidence intervals

[20] Source: 2006 IPCC Volume 2. Table 1.4: Default CO2 emission factors for combustion - natural gas– upper limits of the 95% confidence intervals

Jan 2015 – Dec 2015	28,092	28,092
Jan 2016 – Dec 2016	28,092	28,092
Jan 2017 – Dec 2017	28,092	28,092
Jan 2018 – Dec 2018	28,092	28,092
Jan 2019 – Dec 2019	28,092	28,092

Leakage

No leakage emission is considered.

Emission reductions

$ER_y = BE_y - PE_y - LE_y$

Year	Baseline Emissions (tCO_2/year)	Project Emissions (tCO_2/year)	Emission Reductions (tCO_2/year)
Jan 2013 – Dec 2013	355,662	28,092	327,570
Jan 2014 – Dec2014	364,838	28,092	336,746
Jan 2015 – Dec 2015	364,838	28,092	336,746
Jan 2016 – Dec 2016	364,838	28,092	336,746
Jan 2017 – Dec 2017	326,036	28,092	297,944
Jan 2018 – Dec 2018	259,884	28,092	231,792
Jan 2019 – Dec 2019	209,508	28,092	181,416

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

>>

A summary of the ex-ante estimation of emission reductions for all 10 years of the crediting period is presented in the table below:

Year	Estimation of project activity emissions (tonnes of CO_2e)	Estimation of baseline emissions (tonnes of CO_2e)	Estimation of leakage (tonnes of CO_2e)	Estimation of overall emission reductions (tonnes of CO_2e)
Jan 2013 – Dec 2013	28,092	355,662	0	327,570
Jan 2014 – Dec2014	28,092	364,838	0	336,746
Jan 2015 – Dec 2015	28,092	364,838	0	336,746
Jan 2016 – Dec 2016	28,092	364,838	0	336,746
Jan 2017 – Dec 2017	28,092	326,036	0	297,944
Jan 2018 – Dec 2018	28,092	259,884	0	231,792
Jan 2019 – Dec 2019	28,092	209,508	0	181,416
Total (tonnes of CO_2e)	**196,644**	**2,245,604**	**0**	**2,048,960**

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

B.7.1 Data and parameters monitored:

>>

Baseline Emissions

Data / Parameter:	$V_{F,y}$
Data unit:	Nm³
Description:	Volume of total recovered gas measured at point F in Figure B1 in year y
Source of data to be used:	On site measurement at point F as described in Figure B1 using Flow Meter
Value of data applied for the purpose of calculating expected emission reductions in section B.5	Period y: Value Jan 2013 – Dec 2013: 140,167,952 Jan 2014 – Dec2014: 140,167,952 Jan 2015 – Dec 2015: 140,167,952 Jan 2016 – Dec 2016: 140,167,952 Jan 2017 – Dec 2017: 128,954,516 Jan 2018 – Dec 2018: 102,789,832 Jan 2019 – Dec 2019: 84,100,771
Description of measurement methods and procedures to be applied:	For the purpose of monitoring plan, the total feed gas input will be measured continuously at point F of Figure B1 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 or by accredited third party laboratory. Operator is responsible to collect the data and the data result will be reviewed and validated by the Supervisor.
QA/QC procedures to be applied:	Calibration will be taken annually. Accuracy of the meter is +/- 1%. In case of emergency when main metering can not be used, Barton Chart as backup meter is used and used as crosscheck.
Any comment:	---

Data / Parameter:	$NCV_{RG,F,y}$
Data unit:	TJ/Nm^3
Description:	Net calorific value of recovered gas at point F in Figure B1 during the period *y*
Source of data to be used:	On site sampling of recovered gas at point F in Figure B1 for laboratory analysis.(Chemical analysis of gas samples taken at point F in Figure B.1)
Value of data applied for the purpose of calculating expected emission reductions in section B.5	Period *y*: Value 1: 0.000047 2: 0.000047 3: 0.000047 4: 0.000047

	<table><tr><td>5</td><td>0.000046</td></tr><tr><td>6</td><td>0.000046</td></tr><tr><td>7</td><td>0.000045</td></tr></table>
Description of measurement methods and procedures to be applied:	Measurements should be undertaken in line with national or international fuel standards. Gas samples should regularly be taken at point F in Figure B.1 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 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. Sampling and compositional analysis and calculation of net calorific value at least monthly
QA/QC procedures to be applied:	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 comment:	The qualifier .net. is synonymous with .lower. and .inferior.and the term .calorific value. is synonymous with .heating value.

Project Emissions

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 to be used:	On site measurement will be in MMSCF unit and will be converted to m^3.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	<table><tr><td>Period *y*</td><td>Value</td></tr><tr><td>1</td><td>10,622,896</td></tr><tr><td>2</td><td>10,622,896</td></tr><tr><td>3</td><td>10,622,896</td></tr><tr><td>4</td><td>10,622,896</td></tr><tr><td>5</td><td>10,622,896</td></tr><tr><td>6</td><td>10,622,896</td></tr><tr><td>7</td><td>10,622,896</td></tr></table>
Description of measurement methods and procedures to be applied:	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.
QA/QC procedures to be applied:	Accuracy of the meter is +/- 1%.

Any comment:	The consistency of metered fuel consumption quantitis will be crosschecked by the running hour of compressor in the period of monitoring.

Data / Parameter:	$NCV_{i,y}$
Data unit:	GJ/m³
Description:	Net calorific value of gas fuel in year *y* for combustion of compressor
Source of data to be used:	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 of data applied for the purpose of calculating expected emission reductions in section B.5	0.0454
Description of measurement methods and procedures to be applied:	Any future revision of the IPCC Guidelines should be taken into account
QA/QC procedures to be applied:	-
Any comment:	---

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 to be used:	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 of data applied for the purpose of calculating expected emission reductions in section B.5	0.0583
Description of measurement methods and procedures to be applied:	Any future revision of the IPCC Guidelines should be taken into account
QA/QC procedures to be applied:	-
Any comment:	Since there is no CO_2 emission factor provided, IPCC Guidelines value should be used.

B.7.2. Description of the 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.

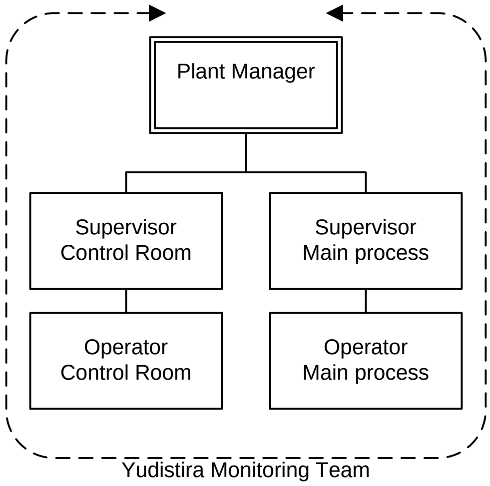


Figure 6: Organization Structure for Monitoring Plan

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.

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

>>

13/08/2012

Santy Dermawi, PT Agrinergy Indonesia, santy.dermawi@agrinergy.com. Not a project participant.

SECTION C. Duration of the project activity / crediting period

C.1. Duration of the project activity:

C.1.1. Starting date of the project activity:

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

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

>>
10 years – 00 months

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

C.2.1. Renewable crediting period:

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

>>
01/01/2013 or the date of registration whichever is later.

C.2.1.2. Length of the first crediting period:

>>
07years - 00months

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

>>
Not applicable

C.2.2.2. Length:

>>
Not applicable

SECTION D. Environmental impacts

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

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

>>
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 proposed project activity is an environmental 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.

[21] http://www.menlh.go.id/popup.php?cat=201&id=2531

SECTION E. Stakeholders' comments

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

>>
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 the 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. Report on how due account was taken of any comments received:

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

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Organization:	PT. Yudistira Energy
Street/P.O.Box:	Jl. Kapten Tendean Kav. 28
Building:	BPH MIGAS Building 1st Floor
City:	Jakarta
State/Region:	DKI Jakarta
Postcode/ZIP:	12710
Country:	Indonesia
Telephone:	+62 21 520 2633
FAX:	+62 21 525 5703
E-Mail:	
URL:	www.yudistiraenergy.com
Represented by:	
Title:	Director
Salutation:	Mr.
Last name:	Ruwiyadi
Middle name:	
First name:	Iwan
Department:	
Mobile:	
Direct FAX:	
Direct tel:	
Personal e-mail:	yudistira@agrinergy.com

Organization:	Agrinergy Pte. Ltd
Street/P.O.Box:	10 Hoe Chiang Road
Building:	#08-04 Keppel Towers
City:	Singapore
State/Region:	
Postcode/ZIP:	089315
Country:	Singapore
Telephone:	+65 6592 0400
FAX:	+65 6592 0401
E-Mail:	
URL:	www.agrinergy.com
Represented by:	
Title:	Director
Salutation:	Mr.
Last name:	Atkinson
Middle name:	
First name:	Ben
Department:	
Mobile:	
Direct FAX:	
Direct tel:	
Personal e-mail:	moc@agrinergy.com

Annex 2

INFORMATION REGARDING PUBLIC FUNDING

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

Annex 3

BASELINE INFORMATION

While forecast are used in the PDD, the quantity and composition of the recovered gas are monitored ex-post and baseline and project emissions are actual emissions that are monitored as described in Section B.7. The amount of feed gas as estimated in the agreement in June 2009 with Pertamina are as follows:

Year	Tambun Field (MMSCFD)	Pondok Tengah Field (MMSCFD)	Tambun Field (Nm^3/day)	Pondok Tengah Field (Nm^3/day)
2012	9.00	6.00	254,850	169,900
2013	7.00	4.50	198,216	127,425
2014	10.00	-	283,166	-
2015	7.00	-	198,216	-
2016	12.50	-	353,958	-
2017	10.00	-	283,166	-
2018	8.00	-	226,533	-
2019	7.00	-	198,216	-

This volume of feed gas is not guaranteed by Pertamina, gas supply will be on a reasonable endeavours basis, depending on the gas source availability. The Feasibility Study Report estimates the gas availability as below:

Year	Tambun Field (MMSCFD)	Pondok Tengah Field (MMSCFD)	Tambun Field (Nm^3/day)	Pondok Tengah Field (Nm^3/day)
2012	9.00	6.00	254,850	169,900
2013	10.50	4.50	297,325	127,425
2014	15.00	-	424,751	-
2015	15.00	-	424,751	-
2016	15.00	-	424,751	-
2017	13.80	-	390,771	-
2018	11.00	-	311,484	-
2019	9.00	-	254,850	-

Taking the above data into consideration, and the design capacity of the project activity, the emissions reductions for the project activity are calculated based on maximum gas availability with 15 MMSCFD as the ceiling.

Detail of the associated gas composition:

Component	Tambun Field (%mol)	Pondok Tengah Field (%mol)
N2	0.17	0.10
CO2	2.53	8.03
C1H4	66.75	65.55
C2H6	11.96	10.97

C3H8	11.71	9.8
n-C4H10	2.93	2.22
i-C4H10	2.33	1.67
n-C5H12	0.54	0.47
i-C5H12	0.7	0.57
C6H14+	0.38	0.68

Annex 4

Refer to section B.7.1 and B.7.2.

- - - - -