Handbook

POME-to-Biogas

Project Development in Indonesia

Second Edition

USAID
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WINROCK INTERNATIONAL

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List of Acronyms

ASCE	American Society of Civil Engineers
BOD	Biological Oxygen Demand
BOO	Build Own Operate
BOT	Build Operate Transfer
CB	Circuit Breaker
CC	Close Command
CCBS	Climate Change and Biodiversity Standard
CDM	Clean Development Mechanism
CER	Certified Emission Reduction
CIRCLE	Capacity for Indonesian Reduction of Carbon in Land Use and Energy
COD	Chemical Oxygen Demand
CPO	Crude Palm Oil
CPT	Cone Penetration Test
CSTR	Continuously Stirred Tank Reactor
DAK	*Dana Alokasi Khusus* (Special Allocation Fund)
DNPI	*Dewan Nasional Perubahan Iklim*/ National Council of Climate Change
DO	Dissolved Oxygen
EEP-Indonesia	Energy and Environmental Partnership with Indonesia
EGSB	Expanded Granular Sludge Bed
EPC	Engineering, Procurement, and Construction
EPS	Expanded Polystyrene
ESIA	Environmental and Social Impact Assessment
EU ETS	European Union Emission Trading Scheme
FFB	Fresh Fruit Bunches
FIT	Feed-in-Tariff
FOG	Fat, Oil, and Grease
GHG	Greenhouse Gas
GLS	Geosynthetic Lining System
GWP	Global Warming Potential
ha	hectare
HDPE	High Density Polyethylene
HRT	Hydraulic Retention Time
ICED	Indonesia Clean Energy Development
IPCC	Intergovernmental Panel on Climate Change
ISCC	International Standard for Carbon Certification
ISO	International Standard Organization
ISPO	Indonesian Sustainable Palm Oil
IRR	Internal Rate of Return
IUKU	*Izin Usaha Ketenagalistrikan untuk Kepentingan Umum*
L-CORE	Least Cost for Renewable Energy
LPG	Liquid Petroleum Gas
MAC	Maximum Allowable Concentration
MCC	Millennium Challenge Corporation
MEMR	Ministry of Energy and Mineral Resources
MJ	Megajoule
MWe	Megawatt electricity
NGO	Non-governmental Organization
NPV	Net Present Value
PH	Phase
PKO	Palm Kernel Oil
PLC	Programmable Logic Controllers
PN	Pressure Nominal
POA	Program of Activity
POM	Palm Oil Mill
POME	Palm Oil Mill Effluent
PPA	Power Purchasing Agreement
PPE	Personal Protective Equipment
ppm	Parts per million
PROPER	*Program Penilaian Kinerja Perusahaan dalam Pengelolaan Lingkungan*
PT	*Perseroan Terbatas*
PT PLN	*PT Perusahaan Listrik Negara (Persero)* or State Electricity Company
PUP	*Penilaian Usaha Perkebunan*/ Plantation Unit Appraisal
RSPO	Roundtable on Sustainable Palm Oil
SCADA	Supervisory Control and Data Acquisition
SPC	Special Purpose Company
SPT	Soil Penetration Test
SPV	Special Purpose Vehicle
TSS	Total Suspended Solid
UASB	Upflow Anaerobic Sludge Blanket
UKL	*Upaya Pengelolaan Lingkungan Hidup*
UNFCCC	United Nations Framework Convention on Climate Change
UPL	*Upaya Pemantauan Lingkungan Hidup*
USAID	US Agency for International Development
VCS	Verified Carbon Standard
VER	Voluntary Emission Reduction
VFA	Volatile Fatty Acid
VSS	Volatile Suspended Solid
WWF	World Wide Fund for Nature

How to Use This Document

This handbook serves as an information bank on POME-to-energy technology and its benefits, as well as a how-to guide for those interested in conducting a feasibility study. The handbook consists of seven main parts:

Part 1, POME to Biogas Technology, provides basic information about palm oil mill effluent, biogas, biogas production technologies, and the process of anaerobic digestion.

Part 2, Commercial Biogas Plant Overview, covers the construction and operation of a plant, options for biogas utilization, and operational risks of the plant.

Part 3, Analyzing Your Mill's Potential, provides a step-by-step approach for assessing biogas production potential and electrical system requirements. Depending on location, capacity, operation, and wastewater quality, each mill may have a different biogas potential. Section III provides examples of analysis to complete for a feasibility study and the preparation work for biogas plant operation.

Part 4, Finance and Investment, covers the financial perspective, explaining different ways to fund a project.

Part 5, Palm Oil Sustainability Standards, discusses sustainability practices and standards associated with the palm oil industry, and also the environmental benefits of POME-to-energy technology.

Part 6: Greenhouse Gas Emissions from Palm Oil Production, discusses the emission along palm oil production supply chain, how to identify the sources and conduct GHG inventory.

Part 7: Calculating Greenhouse Gas Emissions from Palm Oil Production, explains how to calculate greenhouse gas emissions from plantation and palm oil, as well as potential reductions from a methane capture project and biogas plant installation.

An electronic version of this handbook can be downloaded at http://winrock-indo.org/4732.html.

Biogas from Palm Oil Production

Biogas is formed naturally when palm oil mill effluent (POME) decomposes in the absence of oxygen. Unharnessed, this gas is an unwanted, potentially hazardous contributor to global climate change. Biogas is typically composed of 50–75% methane (CH_4), 25–45% carbon dioxide (CO_2), and trace amounts of other gases. When POME collection is uncontrolled, CH_4 is released directly into the atmosphere. As a greenhouse gas (GHG), methane is 21 times more powerful than CO_2.

Biogas plant, on the other hand, takes advantage of this natural decomposition process to generate electricity. Organic liquid wastes generated during palm oil production represent a major untapped source of energy. So converting POME emissions to biogas for combustion can produce energy, as well as significantly reduce the climate change impacts of palm oil production.

Table 1 shows the typical power potential estimate for each mill's capacity.

Table 1. Projected potential power from POME

POM Capacity (FFB ton/hour)	POME Produced		Potential Power (MWe)
	m^3/hour	m^3/day	
30	21	400	1.1
45	31.5	600	1.6
60	42	800	2.1
90	63	1200	3.2
Indonesia's total potential			
34,280	23,996	479,920	1,280

Assumptions: each ton of FFB produces 0.7 m^3 of effluent,
mill operates 20 hours per day, COD concentration is 55,000 mg/l

POME-to-Energy Projects in Indonesia

Palm oil is one of Indonesia's leading agricultural commodities and has grown from 300,000 hectares of plantations producing 720,000 tons of crude palm oil in 1980 to 8.9 million hectares producing 23 million tons of CPO in 2011 (as shown in figure 1).

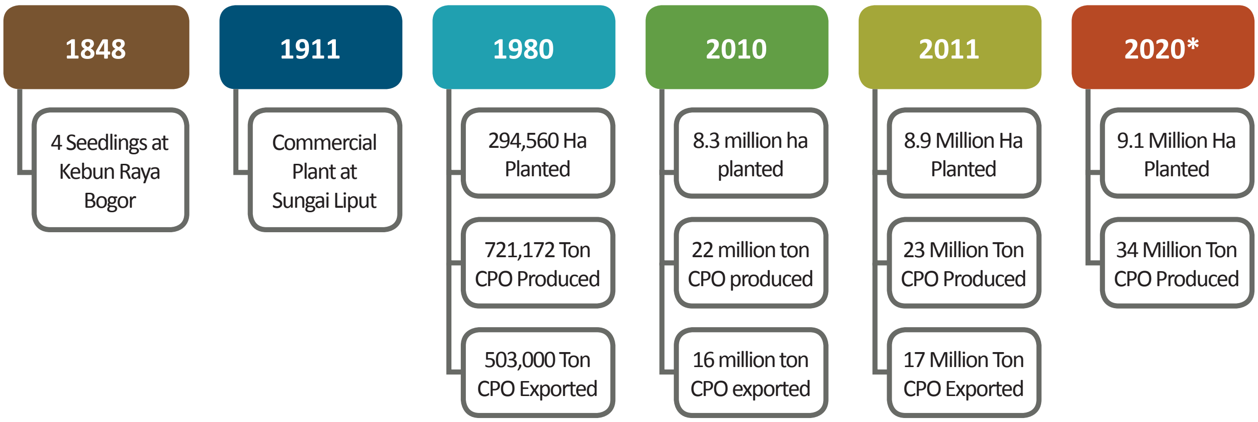


Figure 1. Development of the palm oil industry in Indonesia.

***Projected**

Source: Directorate General Plantation, Ministry of Agriculture, 2011

Indonesia is now the largest producer of palm oil in the world with approximately 608 palm oil mills (POMs) in 2011. The large and rapidly growing palm oil industry demands better agricultural, industrial and sustainability practices. Capturing and converting biogas to energy offers one way for palm oil mills to reduce their environmental impact and creating renewable energy at the same time.

The development of methane-capture installations like biogas plants were financially feasible through carbon credit incentive from Clean Development Mechanism (CDM). Early biogas-capture projects flared off POME-based methane. Despite of the falling price of carbon credit since the middle of 2011; the price has dropped from around 12 EUR to less than 0.5 EUR per ton of offset CO_2, CDM has significantly motivated palm oil companies to develop projects. By the end of 2012, there were 36 registered methane capture projects under the CDM, mostly for biogas flaring. Amongst the projects, 10 have successfully obtained CERs and received the economic benefits from carbon financing under the CDM (see **Table 2**).

Table 2. CDM-registered and profiting palm oil mills

Mill	Location	Regisration Date	Reduction (ton CO_{2eq}/year)
Milano Pinang Awam	North Sumatra	December 2008	33,390
Victorindo Alam Lestari	North Sumatra	January 2009	39,218
Tolan Tiga Indonesia (Perlabian)	North Sumatra	November 2009	31,757
Permata Hijau Sawit	North Sumatra	November 2009	38,424
Tolan Tiga Indonesia (Bukit Maradja)	North Sumatra	November 2009	10,094
Bakrie Pasaman	West Sumatra	November 2009	21,980
Sumbertama Nusapertiwi	Jambi	February 2010	15,743
Sisirau	Aceh	November 2009	16,470
Pinago Utama Sugihwaras	South Sumatra	November 2010	54,312
Musim Mas Pangkalan Lesung	Riau	October 2011	52,397

Source: CDM registry, accessed January 2014

In 2011, some palm oil companies started to look at the economic benefits of using the methane in biogas for electricity generation as captive power replacing diesel oil consumption. In 2013, Ministerial Regulation number 04/2012 about feed-in-tariffs for renewable energy from biomass and biogas increased interest in grid-connected power from POME-to-energy projects. Under the regulation, biogas project owners can sell power through Power Purchase Agreements (PPAs) or excess power through excess power agreement with *Perusahaan Listrik Negara (Persero)*. This government support makes the biogas project financially more viable and sound to be implemented.

PART 1: POME TO BIOGAS TECHNOLOGY

I. Palm Oil Mill Effluent (POME)

Processing fresh fruit bunches (FFBs) from palm trees for palm oil production generates several types of waste. Oil extraction, washing, and cleaning processes generate liquid waste we call palm oil mill effluent (POME). In the oild extraction process, three major operations generate the bulk of POME:

- Sterilizing fresh fruit bunches
- Clarifying extracted crude palm oil: pressing station, separation, clarification
- EFB pressing

For every ton of fresh fruit bunches processed, the mill discharges from 0.7–1 m^3 of POME. Fresh POME is hot (temperature 60–80°C), acidic (pH of 3.3–4.6), thick, brownish liquid with high solids, oil and grease, COD, and Biological Oxygen Demand (BOD) values.

I.1. Land Application

Since POME contains a considerable amount of nitrogen, phosphate, potassium, magnesium, and calcium, it can make a good fertilizer for palm oil plantations. Mill operators must pre-treat POME before they can apply it to fields, though. Applying untreated POME directly to land can kill vegetation on contact and water-log the soil. Environmental Ministerial Decree number 28/2003 sets discharge limits for land application of POME.

Table 1.1 shows the make-up and characteristics of POME compared with the maximum limits for discharge.

Table 1.1. Make-up of untreated POME and the regulatory discharge limits

Parameters	Unit	Untreated POME		Regulatory Discharge Limits	
		Range*	Average	Water Bodies**	Land Application
BOD	mg/l	8,200–35,000	21,280	100	5,000
COD	mg/l	15,103–65,100	34,740	350	
Total Suspended Solid	mg/l	1,330–50,700	31,170	250	
Ammonia (NH_3-N)	mg/l	12–126	41	50***	
Oil and Fat	mg/l	190–14,720	3,075	25	
pH		3.3–4.6	4	6–9	6–9
Max POME Produced	m^3/ton CPO			2.5	

** Source: Pedoman Pengelolaan Limbah Industri Sawit, Departemen Pertanian 2006, Permen LH Nomor 3 Tahun 2010*
*** Source: Environmental Ministerial Decree No. 51/1995, Appendix B.IV*
**** Total Nitrogen = Organic Nitrogen + Total Ammonia + NO_3 + NO_2*

I.2. Discharge into Water

Discharging POME directly into water is illegal given its adverse effects. Through Environmental Ministerial Decree number 51/1995, the Indonesian government regulates the levels of allowable contents in treated POME that mills may discharge into bodies of water.

The oil extraction process does not add chemicals, so POME is non-toxic, but it pollutes aquatic environments by depleting dissolved oxygen. To meet regulatory standards, mill operators must treat POME before discharging it into waterways. **Box 1** outlines the role of dissolved oxygen in aquatic ecosystems and explains how discharging untreated POME into bodies of water upsets the ecology.

Box 1. Dissolved oxygen and impacts of POME discharged into water

Discharging POME into bodies of water adversely affects the aquatic ecology by depleting dissolved oxygen.

Aquatic animals depend on dissolved oxygen (DO), the oxygen present in water, to live. The amount of dissolved oxygen in streams depends on the temperature, amount of sediment, amount of oxygen consumed by respiring and decaying organisms, and amount of oxygen produced by plants, and aeration. DO is measured in milligrams per liter (mg/l) or parts per million (ppm). For example, trout need DO levels of 8 mg/l, and most warm water fish need DO in excess of 2 mg/l.

Bacteria break down the organic materials in POME in the natural systems, which consume some amount of oxygen in the process. When the organic material level is too high, the oxygen may diminish to level that are lethal for aquatic organism. Biochemical oxygen demand (BOD) is a measure of the amount of oxygen that bacteria will consume while decomposing organic matter under aerobic conditions. BOD is determined by incubating a sealed sample of water for five days and measuring the loss of oxygen at certain temperature from the beginning to the end of the test.

Chemical oxygen demand (COD) covers both biologically available and inert organic matter, and it is a measure of the total quantity of oxygen required to oxidize all organic material into carbon dioxide and water. Hence, COD values are always greater than BOD values. COD measurements can be completed in a few hours, and are preferred over BOD measurements.

Both BOD and COD values indicate the amount of organic matter that exists in POME and can be accessible to produce biogas. The “Calculating Renewable Energy Potential” section discusses further how to calculate how much biogas can be obtained based on the measured COD value.

Source: Watershed Protection Plan Development Guidebook, Brown and Caldwell

I.3. POME Treatment

In Indonesia, almost all palm oil mills use open ponding systems to treat POME due to their low costs and operational simplicity. In this effluent management process, POME flows through a series of ponds and several treatment steps. The ponds may differ slightly from mill to mill, but generally the systems consist of four types of ponds: a fat pit, cooling pond, anaerobic pond, and aerobic pond. The fat pit collects remaining oil and grease in POME. Oil is the main product of the mill, so mill operators typically recover oil from the fat pit and combine it with the primary CPO product. The cooling pond decreases the temperature of POME, creating optimal conditions for the decomposition of organic material in the anaerobic and aerobic ponds. After treatment in these four ponds, the effluent is safe to discharge to waterways or use as a fertilizer.

Even though the ponding system is economical, it is land and time intensive, and it releases a large amount of methane gas into the atmosphere primarily from the organic decomposition that occurs in the anaerobic pond. The release of methane from the POME treatment system accounts for up to 70% of the total greenhouse gas emissions in CPO production.

II. What is Biogas?

Biogas is formed when microorganisms, especially bacteria, degrade organic material in the absence of oxygen. Biogas consists of 50% to 75% methane (CH_4), 25–45% carbon dioxide (CO_2) and small amounts of other gases. Table 1.2 details the composition of biogas.

Table 1.2. Composition of biogas

Elements	Formula	Concentration (Vol. %)
Methane	CH_4	50–75
Carbon dioxide	CO_2	25–45
Water vapor	H_2O	2–7
Oxygen	O_2	< 2
Nitrogen	N_2	< 2
Hydrogen	H_2S	< 2
Ammonia	NH_3	< 1
Hydrogen	H_2	< 1

Source: nachwaschende-rohstoffe.de

Biogas is about 20% lighter than air and has an ignition temperature between 650°C and 750°C. It is an odorless and colorless gas that burns with a clear blue flame similar to that of liquid petroleum gas (LPG). Biogas burns with 60% efficiency in a conventional biogas stove; it has a caloric value of 20 MJ/Nm^3. The volume of biogas is normally expressed in units of normal cubic meters (Nm^3), the volume of gas at 0°C and atmospheric pressure.

Methane, which makes up the bulk of biogas, can combust with oxygen. The energy release from combustion makes biogas a potential fuel. Biogas can serve any heating purpose, from cooking to fuel for an industrial burner. In gas engines, biogas converts its energy content into electricity and heat. Less commonly, compressed biogas can power motor vehicles through combustion.

The biogas production process exploits the natural ability of microorganisms to degrade organic wastes. The decomposition process produces biogas and a nutrient-rich residue suitable for use as a fertilizer. The organic wastes function as the substrate, the medium on which the organisms grow. **Figure 1.1** shows the anaerobic biological conversion process from various substrates.

Figure 1.1. Substrates and products in an anaerobic biological conversion process

Any biodegradable organic material can serve as a feedstock to produce biogas. Some materials, however, work better economically and technically. Costly inputs decrease the economic benefits of outputs. One of the main attractions of biogas technology is its ability to generate biogas from abundant, inexpensive organic wastes such as POME.

Biogas production using readily available biodegradable wastes has two key advantages. Economically, both the biogas and slurry are valuable. At the same time, project owners gain a safe way to process biodegradable waste that might otherwise end up in landfills or waterways, avoiding negative environmental impacts.

III. Anaerobic vs. Aerobic Digestion

Both anaerobic and aerobic digestion effectively degrade organic materials. An anaerobic process occurs in the absence of oxygen, while an aerobic process takes place in the presence of oxygen. POME-to-energy applications typically use the anaerobic process.

The main reason for choosing the anaerobic process is its high yield of biogas. Rather than converting materials to methane, an aerobic process produces large amounts of sludge along with fully treated wastewater. The anaerobic process, on the other hand, produces methane and pre-treated water rich in nutrients such as nitrogen and phosphorus. Palm oil plantation owners can use this pre-treated water for fertilization. **Figure 1.2** outlines the differences between anaerobic and aerobic systems.

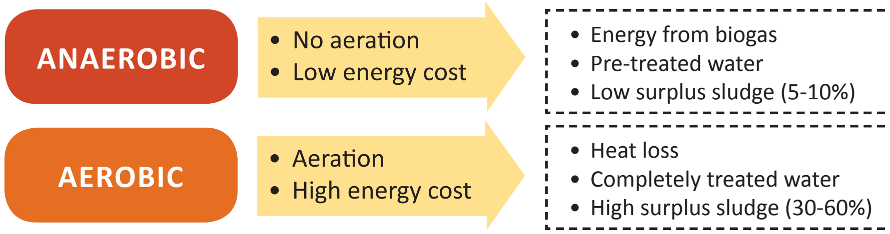


Figure 1.2. The differences between anaerobic and aerobic processes.

III.1. Anaerobic Digestion Process

Anaerobic digestion takes place over many stages. Several different groups of microorganisms must share the small amount of energy available.

The digestion process starts with bacterial hydrolysis, which breaks down insoluble long-chain polymers of fats, proteins, and carbohydrates into short-chain polymers. Next, acidogenic bacteria convert the fatty acids, amino acids, and sugars into CO_2, H_2, NH_3, and organic acids. The acetogenic bacteria then convert these organic acids into acetic acid. Finally, methanogenic bacteria convert these products into gases, mostly methane. **Figure 1.3** diagrams this process of digestion. The sections below explain each step of anaerobic digestion in greater detail.

III.1.1. Hydrolysis

In the hydrolysis phase, water reacts with long-chain organic polymers such as polysaccharides, fats, and proteins to form soluble shorter-chain polymers, such as sugars, long-chain fatty acids, and amino acids. Cellulose, amylase, lipase, or protease - enzymes produced by microorganisms - perform this process.

III.1.2. Acidogenesis

During the acidogenesis phase, anaerobic oxidizers use the sugars, long-chain fatty acids, and amino acids created during hydrolysis as substrates. A wide variety of different bacteria perform acidogenesis. Acidogenesis is often the fastest step in the conversion of complex organic matter during liquid-phase digestion. In a stable anaerobic digester, the main degradation pathway is via acetate, carbon dioxide, and hydrogen. The bacteria respond to increased hydrogen concentrations in the liquid by producing lactate, ethanol, propionate, butyrate, and volatile fatty acids (VFAs), which the methanogenic microorganisms use as substrates.

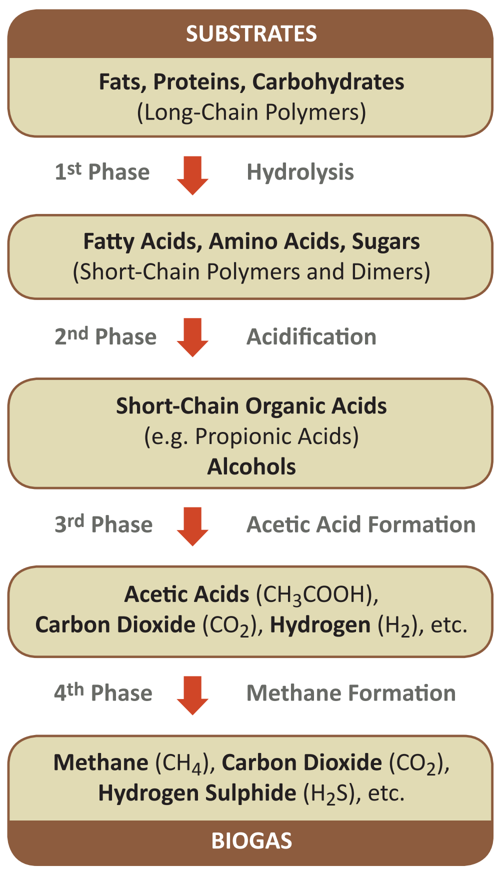


Figure 1.3. Anaerobic digestion process

Source: Adapted from nachwaschender-rohstoffe.de

III.1.3. Acetogenesis

In the acetogenesis stage, hydrogen-producing acetogenic bacteria convert fatty acids and ethanol/alcohol into acetate, carbon dioxide, and hydrogen. This intermediate conversion is crucial for the successful production of biogas, since methanogens cannot use these compounds directly. Acetogens grow slowly and depend on a low partial pressure of hydrogen for acetogenic degradation to yield energy. Acetogens are sensitive to environmental changes; they require long periods to adjust to new environmental conditions.

III.1.4. Methanogenesis

During the methanogenesis stage, methane forms by two main routes. In the primary route, the fermentation of acetic acid, the major product of the acid forming phase, produces methane and carbon dioxide. Acetoclastic (or acetophilic) bacteria use acetic acid. The overall reaction is:

$$CH_3COOH \rightarrow CH_4 + CO_2$$

Based on thermodynamics and experimental data, researchers have identified an additional reaction[1]:

$$CH_3COOH + 4H_2 \rightarrow 2CH_4 + 2H_2O$$

A secondary route uses hydrogen to reduce CO_2 to CH_4 by hydrogenophilic methanogens:

$$4H_2 + CO_2 \rightarrow CH_4 + 2H_2O$$

Only a limited number of compounds can act as substrates in methanogenesis. Acetate, H_2, CO_2, methanol, and formate are key substrates. Based on stoichiometric relations, experts estimate that about 70% of methane is produced from acetate, while the remaining 30% is produced from H_2 and CO_2.

[1] *Theory and Practice of Water and Wastewater Treatment, Droste, 1997*

III.2. Ideal Conditions for Anaerobic Digestion

To effectively convert organic materials into biogas, the active microorganisms require specific nutrients and environmental conditions. Nutrients and chemical synthesis required for anaerobic digestion include:

- Macronutrients such as C, H, O, N, S, P, K, Ca, Mg to provide food for bacteria
- Micronutrients such as Fe, Ni, Zn, Mn, Mo, and Co to keep bacteria healthy
- Vitamins are at times needed to fulfill specific catalytic needs in biosynthesis and if so would be required in small amounts.
- Enzymes (protein catalysts produced by living cells) to speed up cellular reactions of microorganisms
- Temperatures around 35°C for mesophilic and 55°C for thermophilic
- pH around 7.

Figure 1.4 depicts the growth of microorganism in the conducive conditions.

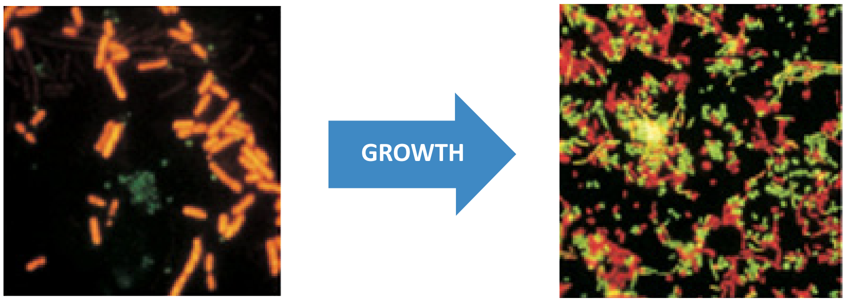


Figure 1.4. Growth of microorganisms in conducive conditions

Operators must monitor and maintain environmental conditions within the digester to support healthy numbers of microorganisms and optimal biogas production. The following sections explain the required conditions in temperature, pH and buffering systems, gas solubility, mixing, nutrients, and toxicity.

III.2.1. Temperature

Treating waste in anaerobic digesters requires two temperature ranges: the mesophilic range (25–40°C) and the thermophilic range (50–60°C). Biogas plants usually prefer the mesophilic range because the thermophilic range requires a stricter temperature-control system. Methane has been produced at lower temperatures, but for optimal production, digesters should maintain temperatures above 20°C. Rates of methane production approximately double for each 10°C increase in temperature in the mesophilic range.

Physical parameters such as viscosity and surface tension change with temperature. Thermophilic temperatures result in better mass transfer and a higher digestion rate than mesophilic conditions. A stable temperature achieves better results than fluctuating temperatures.

III.2.2. pH and Buffering System

Each of the microbial groups involved in anaerobic degradation has a specific pH region for optimal growth. For the acidogens, the optimal pH is around 6, whereas for acetogens and methanogens, the optimal is around 7. Numerous studies confirm that a pH range of 6.5–7.5 results in good performance and stability in anaerobic systems, although stable operation can occur outside this range.[2]

Anaerobic systems must have adequate buffering capacity to accommodate the production of volatile acids and carbon dioxide. To guard against the accumulation of excess volatile acids, system operators must prevent pH from becoming too acidic. Lime, sodium bicarbonate, and sodium hydroxide, three major chemical sources of alkalinity, can provide this buffer. Most POME applications, however, and especially covered lagoon technology, do not require chemical dosing to neutralize pH. Anaerobic effluent water contains buffer alkalinity from bicarbonate (HCO_3); recirculating the effluent water to the raw POME collecting tank maintains a neutral pH.

III.2.3. Gas Solubility

In an anaerobic process, gas is formed in the liquid phase and tends to escape to the air. This liquid-to-gas transfer is important for the anaerobic digestion process. Process design parameters such as the area of the liquid-gas interface, the stirring rate, and the temperature of the liquid (which influences the viscosity and surface tension) affect the liquid-to-gas phase. Typically, gases form at a much higher rate than that of the liquid-to-gas transfer, resulting in high concentration of gas in the liquid. Overconcentration of certain gases such as CO_2 and H_2S may cause a drop in pH, affecting the biological processes.[3]

III.2.4. Mixing

Mixing helps maintain pH and uniform environmental conditions. Without adequate mixing, unfavorable microenvironments can develop. Mixing distributes buffering agents throughout the digester and prevents localized build-up of high concentrations of intermediate metabolic products that can inhibit methane formation. Mixing is commonly performed using a mechanical stirrers, liquid mixing by the incoming POME through distribution pipes, or gas mixing using recirculated biogas.

III.2.5. Nutrients

Efficient biodegradation requires available nutrients including nitrogen, phosphorus and trace elements (micronutrients). Nutrients build cells that form microorganisms and produce biogas. General chemical elements that form microorganisms are carbon (50%), oxygen (20%), nitrogen (12%), hydrogen (8%), phosphorous (2%), sulphur (1%), and potassium (1 %). Generating biogas requires a carbon-to-nitrogen ratio of at least 25:1.[4]

[2] *Theory and Practice of Water and Wastewater Treatment, Droste, 1997.*
[3] *Liquid to Gas Mass Transfer in Anaerobic Processes, Pauss, 1990.*
[4] *The Microbiology of Anaerobic Digesters, Gerardi, 2003.*

POME, generally has sufficient nitrogen and phosphorus. Anaerobes have low growth yields, so their nutrient requirements are lower compared to those of aerobes. Operations must maintain the ratio of COD:nitrogen:phosphorus at specific levels, so workers must monitor the ratio and make adjustments as necessary during operations. Dosing pumps can add nutrients periodically. Operations should also maintain levels of micronutrients such as nickel and cobalt, which promote methanogenesis.[5]

III.2.6. Toxicity

Of all the microorganisms in anaerobic digestion, methanogens are commonly considered the most sensitive to toxicity. The toxicity of NH_3, H_2S and VFAs depends on pH. In un-adapted cultures, a free NH_3 level of 150 mg/l can inhibit methanogen growth. Methanogens can tolerate much higher concentrations, however, if the culture has adapted gradually. NH_3 is toxic at pH levels greater than 7. H_2S and VFAs are toxic at pH levels less than 7. Concentrations of up to 200 mg/l of H_2S do not inhibit growth, but the mixture may emit a strong smell from the hydrogen sulfide.[4]

Methanogenic bacteria are also sensitive to oxygen. In the mixed culture in an anaerobic digester, facultative anaerobic bacteria constitute some of the hydrolyzing and acidogenic bacteria that consume oxygen present in the digester.

Table 1.3 below summarizes the process parameters for commercial biogas production from liquid waste.

Table 1.3. Typical process parameters in commercial biogas produced from industrial liquid wastes.

Parameter	Units	Range	Remark
Temperature	°C	35–38	Mesophilic process
		55–57	Thermophilic process
Hydraulic Retention Time	day	20–50	Effluent dependent
COD Concentration	mg/l	< 80,000	POM dependent
Ratio POME:FFB	m^3/ton	0.7–1	POM dependent
Methane Concentration	%	50–75	Substrate dependent
pH Value		6.7–7.5	During fermentation

[4] *The Microbiology of Anaerobic Digesters, Gerardi, 2003.*
[5] *Theory and Practice of Water and Wastewater Treatment, Droste, 1997.*

Box 2: What is hydraulic retention time?

The hydraulic retention time (HRT) is the average length of time a soluble compound remains in the constructed bio-digester. Digester operators must manage the HRT to allow adequate substrate degradation without increasing the digester volume too much. Normally, commercial biogas units for POME require an HRT of 20–90 days. An HRT that is too low will result in an incomplete degradation process or in bacteria wash-out.

$$\text{HRT (days)} = \frac{\text{Volume of Digester } (m^3)}{\text{POME Flow rate } (m^3/day)}$$

The graph below shows a typical anaerobic process where the methanogenesis occurs on day 6-7, resulting in a high gas production rate.

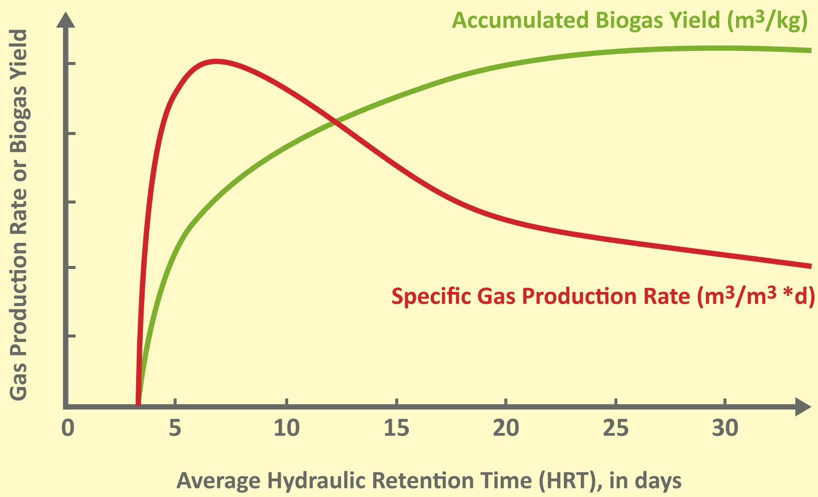


Figure 1.5. Biogas yield vs. average hydraulic retention time

Source: Biogas Handbook, Al Seadi, 2008

III.3. Anaerobic Digestion Technology

Biogas project operators can choose from among several different anaerobic digestion technologies for liquid wastes. All designs aim to ensure sufficient contact between the substrate and the microorganisms and prevent microorganisms from washing out of the system. Here are six common designs for anaerobic digestion technology:

1. Continuously Stirred Tank Reactor (CSTR)
CSTRs are typically concrete or metal cylinders with low height-to-diameter ratios. They can operate at mesophilic or thermophilic temperatures, with mechanical, hydraulic, or gas-injection mixing.

2. Covered Lagoon
Anaerobic lagoons are essentially covered ponds equipped with mixing mechanisms. This design normally handles a solids content of less than 2%, and operates in the mesophilic temperature range.

3. Anaerobic Filters
Anaerobic filters use 'carrier' materials, often made of plastic, to which the active microorganisms adhere to prevent washing out of the system. Anaerobic filters can produce very high-quality biogas, with a methane content of up to 85%.

4. Fluidized and Expanded Beds
In fluidized and expanded beds, microorganisms adhere small particles. The system creates a strong upflow that suspends the particles, bringing the microorganisms into contact with the substrate.

5. Upflow Anaerobic Sludge Blanket (UASB)
Upflow anaerobic sludge blanket reactors allow the microorganisms to grow in aggregations. Because of this, microorganisms remain in the reactor despite a strong inflow of substrate. The system pumps in new material with sufficient power to mix it, creating contact between the microorganisms and the substrate.

6. Expanded Granular Sludge Bed (EGSB)
Expanded granular sludge bed reactors are similar to UASB reactors, but with a faster rate of upward-flow velocity for the wastewater passing through the sludge bed. This design is appropriate for COD concentrations of less than 1 to 2 g COD/l or for wastewater with poorly biodegradable suspended particles.

Due to the high solids and oil content in palm-oil wastewater effluent, it is challenging to treat this kind of wastewater with anaerobic filters, fluidized bed, UASBs, or EGSBs. The high oil and solids content in the POME should be removed before entering the aforementioned systems, hence it would require more pre-treatment facilities. As consequence, the aforementioned systems would generate less biogas.

Palm-oil mills typically use either continuously-stirred tank reactors or covered lagoons for POME-to-biogas conversions. These two anaerobic digestion technologies can handle high solids and oil content. They are relatively simple to operate and maintain, and are less expensive compared to the others, making them suitable for agribusiness.

III.3.1. Covered Lagoon

Figure 1.6. Covered Lagoon

Source: PT Austindo Aufwind New Energy

Anaerobic lagoons, commonly called covered lagoons, are essentially impoundments with gas-tight covers to capture biogas. Anaerobic lagoons generally have poor bacteria-to-substrate contact, with a low processing rate. This method requires a hydraulic retention time of about 20–90 days and has a large footprint. The capital investment for covered lagoons is normally lower than tank system, however covered lagoons would lead to larger footprint. This design typically handles a solids content of less than 2%, and commonly operates in the mesophilic temperature range. Operators must remove fibrous solids prior to digestion.

III.3.2. Continuous Stirred Tank Reactor

Figure 1.7.
Continuous Stirred Tank Reactor (CSTR)

Source: Veolia Plant in Malaysia

Continuous stirred tank reactors (CSTRs), also known as contact reactors, are typically concrete or metal cylinders with a low height-to-diameter ratio. They involve a biomass concentration stage, which can consist of a thickener, clarifier, and dissolved-air flotation unit, among others. CSTRs can operate at mesophilic or thermophilic temperatures.

CSTRs can use mechanical, hydraulic, or gas-injection mixing. CSTRs can accommodate a wide range of solids. Prospective investors should weigh CSTRs' higher capital and operational costs against the stability of the system and reliability of energy production, which is higher than in covered lagoons. In addition, CSTRs accept multiple co-digestion feedstocks. This design typically handles a solids content of 3–10%.

Both technologies can work for POME-to-biogas processing, depending on the needs and conditions of the palm oil mill. **Table 1.4** below compares complete mix and covered lagoon systems.

Table 1.4. Continuously stirred tank reactor vs. covered lagoon systems

Technology	Waste Types	Residence Time (days)	Energy Yield	Capital Cost ($/kWe)	Operation Complexity
CSTR	Liquid & Solid	20–40	Good	High	Medium
Covered Lagoon	Thin liquid (< 3% DM)	20–90	Poor	Medium	Low

Source: Adapted from Electrigaz, 2007.

PART 2: COMMERCIAL BIOGAS PLANT OVERVIEW

Biogas plants open up a range of options for palm oil mills. Mill operators might choose to use biogas for:

- Fuel for the facility's burner, offsetting the use of shells and fibers
- Electricity for the facility, reducing fuel costs
- Electricity to sell to the grid, increasing revenues

The needs of the palm oil mill and the potential profit should guide the choice of applications for biogas. **Table 2.1** below outlines the most common uses.

Table 2.1. Biogas use options

Technology	Cost	Efficiency	Complexity	Reliability
Simple Combustion				
Burner	Low	High	Low	High
Boiler	Low	High	Low	High
Electrical/Other				
Generator	High	Medium	Medium	High
Turbine	High	Medium	High	Medium
Biogas Upgrading	Very high	High	High	Variable

Source: Feasibility Study - Anaerobic Digester and Gas Processing Facility in the Fraser Valley, British Columbia, Electrigaz, November 2007.

Since biogas is largely methane, it can replace natural gas for a range of applications, including heating through combustion, stationary engines, transportation fuel, and mixing into natural gas pipelines.

When building a commercial biogas plant, the mill owner must establish a clear end-use for the biogas. This section of the handbook applies generally to all options, but some sections relate to specific applications. For example, grid connections only apply to mills that plan to sell electricity to an external grid (such as PLN's). Similarly, for a project to use biogas in a burner, details about gas engines are not relevant. Read this section with those differences in mind.

I. Plant Components

Figure 2.1 depicts the main parts of a commercial POME-to-biogas facility. The section below explains each element.

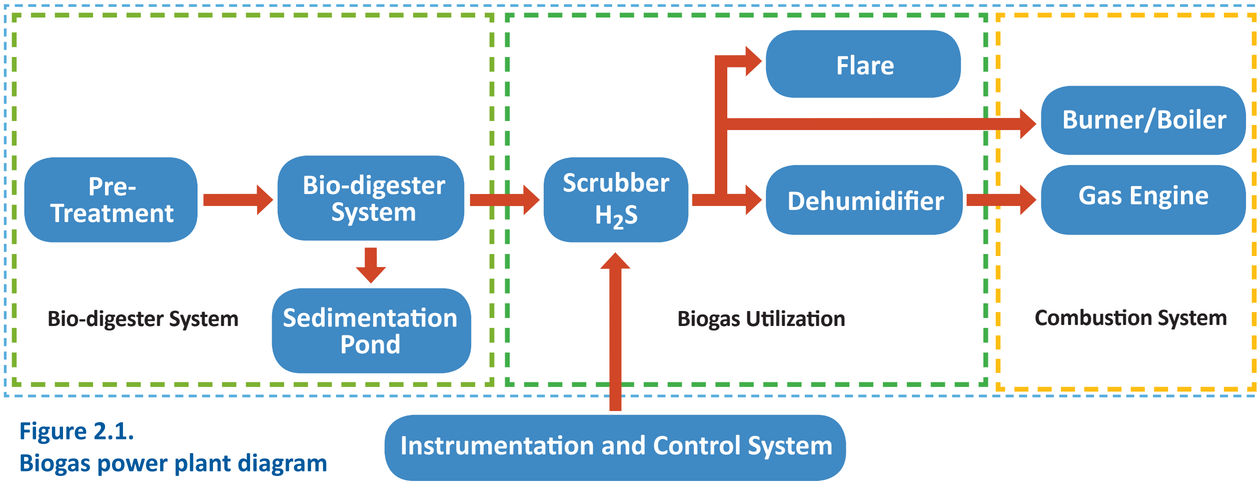
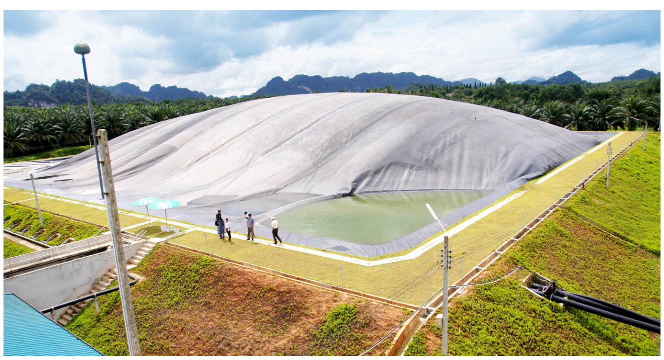


Figure 2.1.
Biogas power plant diagram

I.1. Bio-digester System

The bio-digester system consists of a pre-treatment process, the bio-digester itself, and a sedimentation pond. In the pre-treatment component, POME is conditioned to achieve the parameter values needed to enter the digester. There, a screening process removes bigger objects such as dirt or fibers. Mixing and pH neutralization achieves an optimal pH of 6.5–7.5. A cooling system (can be a cooling tower or heat exchanger) reduces the temperature of POME to about 40°–50°C. The temperature of the digester should be kept below 40°C for optimum mesophilic condition; therefore, the POME temperature is further cooled by recycling the digester effluent water.

Pre-treated liquids are pumped to the bio-digester, which may be either a covered lagoon or continuous stirred tank reactor (**Figure 2.2**). The digestion process produces biogas and a byproduct residue (slurry). The digester should be air and water tight. It can be constructed of various materials, and in various shapes and sizes. The size of the digester depends on the flow rate of the POME, COD load, and the HRT required for optimal digestion.



Source: Univanich - Krabi, Thailand

Source: Veolia Plant in Malaysia

Figure 2.2. Covered lagoon (left) and continuously stirred tank reactor (right)

The anaerobic effluent water from the digester flows to a sedimentation pond where the digested POME separates further from the sludge and solids. Plantations can use the liquid waste from the sedimentation as a fertilizer. A solids removal system extracts the sludge and solids accumulated in both the digester and sedimentation pond.

Biogas generated through an anaerobic process (see the Anaerobic Digestion Process section) collects under the cover of the digester in a covered lagoon or the roof of the tank in a tank system. A covered lagoon maintains a low pressure of 0–2 mbarg (depending on the design of the technology provider) while a tank system stores biogas at a higher pressure of 8-30 mbarg. Palm oil mills do not generally use separate biogas storage tanks due to their high costs. Tank systems have biogas storage capacities of between 30 minutes and 3 hours, while covered lagoons have capacities of 1–2 days. Biogas collected in the digester is then transferred and processed further in the gas treatment system or flared.

I.2. Hydrogen Sulfide (H_2S) Scrubber

Before biogas can generate power, hydrogen sulfide scrubber (**Figure 2.3**) must reduce the H_2S concentration to permissible levels by gas engine, typically below 200 ppm. This avoids corrosion, optimizes operation, and lengthens the lifetime of biogas engines. H_2S in biogas comes from the sulphate (SO_4^{2-}) and other sulphur components in wastewater. In the anaerobic digester, where there is no oxygen, the sulphate converts to H_2S. A biological, chemical, or water scrubber are used to reduce the H_2S content. A biological scrubber uses special sulphur-oxidizing bacteria to convert H_2S to SO_4, while a chemical scrubber uses a chemical such as NaOH to convert H_2S to SO_4. Water scrubbers, working based on the physical absorption of dissolved gases in liquid, use high-pressure water. POME applications usually use biological scrubbers due to their low operating costs.

Figure 2.3. H_2S Scrubber

Source: PT Austindo Aufwind New Energy

I.3. Biogas Dehumidifier

A gas dehumidifier (**Figure 2.4**), can be dryer, chiller, or cyclone; reduces moisture content in biogas to prepare it for use in a gas engine. The dehumidifier extracts water from the biogas. This helps optimize the combustion process in the engine, prevent condensation, and protect the engine from acid formation. Acid forms when water reacts with H_2S and oxygen. A high-quality, low-moisture biogas with a relative humidity below 80% promotes engine efficiency and reduces fuel gas consumption.

Figure 2.4. Biogas Dehumidifier

I.4. Gas Engine

A gas engine (**Figure 2.5**) is part of an internal combustion engine that runs on a gas fuel such as natural gas or biogas. After the production process reduces impurities in biogas to specified levels, the biogas feeds into a gas engine to generate electricity. Gas engines that run on biogas require a moisture content less than 80% and an H_2S concentration less than 200 ppm; these parameters depend on specification of the gas engines. Gas engines convert energy contained in the biogas into mechanical energy to drive the generator, which produces electricity. Typically, gas engines have an electrical efficiency between 36–42%.

Figure 2.5. Gas Engine

I.5. Burner and Boiler

Biogas generated with an anaerobic digestion process can fuel a boiler. An engineer installs a gas burner in the wall of the boiler (**Figure 2.6**). Feeding biogas into a boiler creates an alternative means to generate heat or electricity. Biogas can replace part of the biomass fuel, such as shell and fiber, which boilers in palm oil mills normally use.

Figure 2.6. Biogas Burner

I.6. Biogas Flare

Flares burn excess gas in industrial process plants. For safety reasons, biogas plants must have flares (**Figure 2.7**) installed to burn off excess biogas. Occasionally, biogas cannot enter the gas engine or other combustion equipment. This can happen while processing an abnormally large amount of fresh fruit bunches, resulting in excess biogas production. Excess production exceeds the maximum flow of biogas that can enter the gas engine. Similarly, when the gas engine is offline for maintenance, biogas has nowhere to go. Biogas installation, without gas engine or boiler, must use flare constantly to manage the gas. Operators should never release excess biogas directly into the atmosphere because it is extremely flammable in high concentrations. Direct release of biogas also releases greenhouse gases.

Figure 2.7. Biogas Flare

Source: Harapan Sawit Lestari

I.7. Instrumentation and Control System

Operators use an instrumentation and control system to monitor parameters such as temperature, pH, liquid and gas flows, and gas pressure. The control system also allows for manual and automatic shutdown of the system during unsafe conditions.

Figure 2.8 below depict an example process flow of a biogas power plant. In the figure, the dotted black line marks the battery limit where the contracted developer typically manages the scope of work. **Figure 2.2** shows the components in a biogas power plant, including the instruments and control systems: the level switch (LS), flow indicating totalizer (FIT), temperature indicator (TI), temperature transmitter (TT), pressure transmitter (PT), and pressure relief valve (PRV). **Table 2.2** below serves as the legend for the process flow diagram, detailing the material, type, and size of each component for a plant with a capacity of 2 MWe.

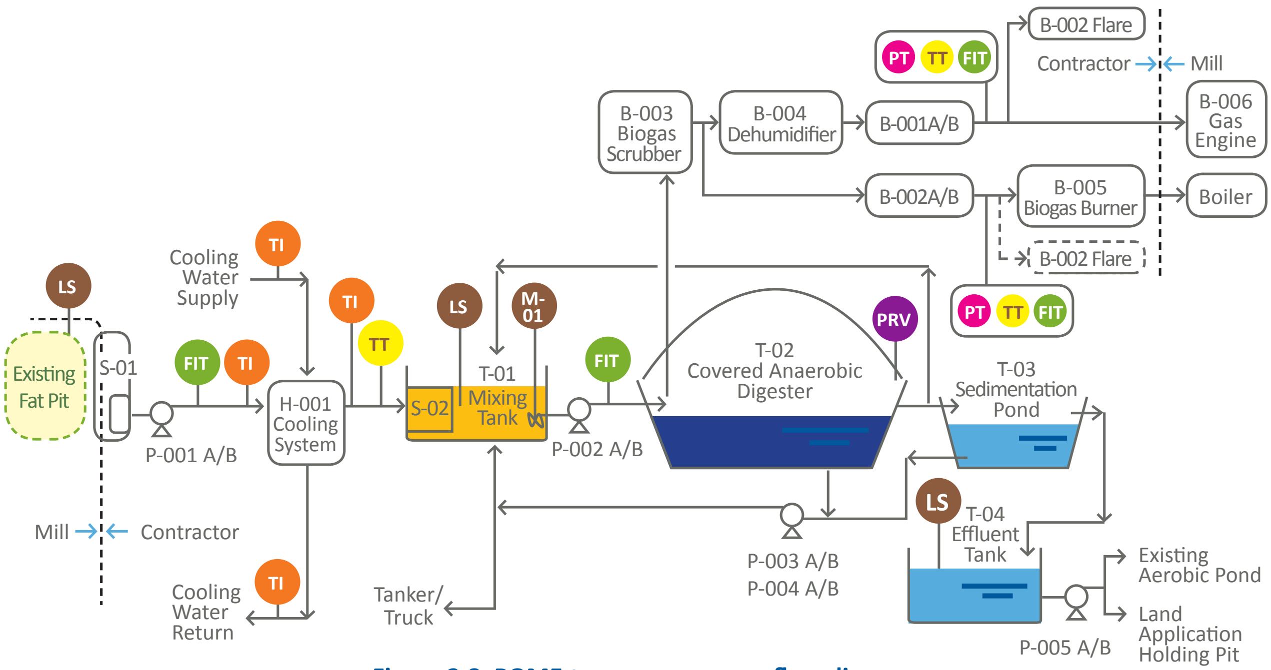


Figure 2.8. POME-to-energy process flow diagram

Table 2.2. Unit operations in the process flow diagram

Label	Unit	Material	Type	Remarks
T-01	Mixing tank	Concrete and Coating		Volume of 50 m^3
T-02	Anaerobic digester	Soil and HDPE Lining		Volume of 24,000 m^3
T-03	Sedimentation pond	Soil and HDPE Lining		Volume of 1,500 m^3
T-04	Effluent tank (optional)	Concrete		Volume of 50 m^3
M-01	Mixing tank mixer	Stainless steel	Top entry	0.5 kW
B-001A/B	Biogas Blowers to gas engine or flare	Cast Iron/Stainless Steel	Root	Capacity of 1,200 Nm^3/hour, pressure of 10-50 mbar
B-002A/B	Biogas blowers to burner or flare	Cast Iron/Stainless Steel	Root	Capacity of 1,200 Nm^3/hour, pressure of 200 mbar
B-002	Biogas Flare	Stainless steel	Open flame	Capacity of 1,200 Nm^3/hour
B-003	Scrubber	HDPE/FRP	Vertical Biological	Capacity of 1,200 Nm^3 /hour

Label	Unit	Material	Type	Remarks
B-004	Biogas Dehumidifier	Stainless steel		Capacity of 1,200 Nm^3/hr
B-006	Biogas engine			Capacity of 2 x 1 MW
S-01 and S-02	Coarse screen	Stainless steel		Screen size of 5 mm
H-001	Cooling system		Heat exchanger or cooling tower	Capacity of 50 m^3/hr
P-001A/B	Raw POME pumps	Cast iron/ Stainless steel	Dry centrifugal	Capacity of 50 m^3/hr
P-002A/B	Digester feed pumps	Cast iron/ Stainless steel	Dry centrifugal	Capacity of 210 m^3/hr
P-003A/B	Recirculation pumps	Cast iron/ Stainless steel	Dry centrifugal	Capacity of 80 m^3/h
P-004A/B	Sludge pump	Cast iron/ Stainless steel	Dry centrifugal	Capacity of 50 m^3/hr
P-005A/B	Anaerobic effluent pumps (optional)	Cast iron/ Stainless steel	Dry centrifugal	Capacity of 50 m^3/hr

II. Construction and Operations Management

The construction and operation of a biogas power plant requires project management and multi-disciplinary expertise from civil, process, mechanical, and electrical engineering. **Figure 2.9** shows a typical project organizational chart.

The project manager coordinates the work of engineers, suppliers, and contractors to ensure that the quality of the biogas plant, costs, and schedule of the project will be met.

Site preparation, soil analysis, and lagoon construction require expertise from civil engineering. A civil engineer will design a lagoon based on the characteristics of the site; for example, if the site is prone to landslides, the design will have a low angle of inclination. Otherwise the slope of the lagoon will require reinforcement to prevent landslides.

Process engineers ensure effective generation of methane in the lagoon. The process engineer determines the equipment and instruments to measure parameters such as temperature, flow rate, COD concentration, pH and other important parameters, and adjusts some parameters when necessary to ensure optimum generation of biogas.

Mechanical, electrical, and instrument engineers support the process engineer in providing, installing, and commissioning suitable mechanical equipment, electrical equipment, and instruments to ensure cost-effective construction and efficient performance.

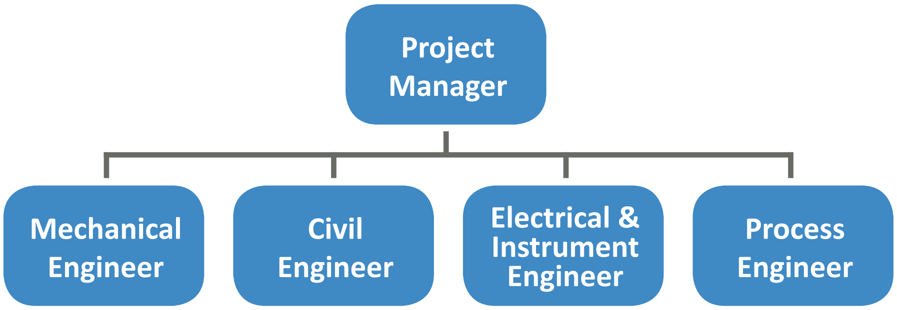


Figure 2.9. Typical organization chart for biogas power plant project

At the end of the installation, the operation team takes control of the biogas plant. The operation team consists of multi-disciplinary experts with backgrounds in process, mechanical, and electrical engineering and instrumentation. The team ensures optimal and reliable operation of the biogas plant. The operation team should use standard operation and maintenance manuals to properly maintain and operate the facility.

Construction of an industrial-scale biogas plant usually requires 12–15 months. **Figure 2.10** provides a typical time schedule for facility construction.

Biogas Project Schedule

ID	Task Name	Duration
1	**Preparation**	**75 days**
2	Signing contract	1 days
3	Soil and geotechnical survey	7 days
4	General drawing	14 days
5	Detail drawing	50 days
6	Site preparation	20 days
7	**New Digester Construction**	**174 days**
8	Civil work	100 days
9	Pipes installation	30 days
10	Geotextile installation	14 days
11	Lining installation	20 days
12	Water filling	25 days
13	Cover installation	15 days
14	**Gas Handling System**	**66 days**
15	Cleaning the area	7 days
16	Cut and fill	14 days
17	Pump house	30 days
18	Pipe installation	45 days
19	Pumps installation	20 days
20	Scrubber and blower installation	35 days
21	Chiller/dehumidifier installation	10 days
22	**Power Generator**	**90 days**
23	Power house building	90 days
24	Engine installation	40 days
25	Electrical installation	40 days
26	**Miscellaneous**	**27 days**
27	Fencing biogas area	20 days
28	Road and pathway around biogas area	20 days
29	Cleaning whole area	7 days
30	**Start-Up and Comissioning**	**75 days**

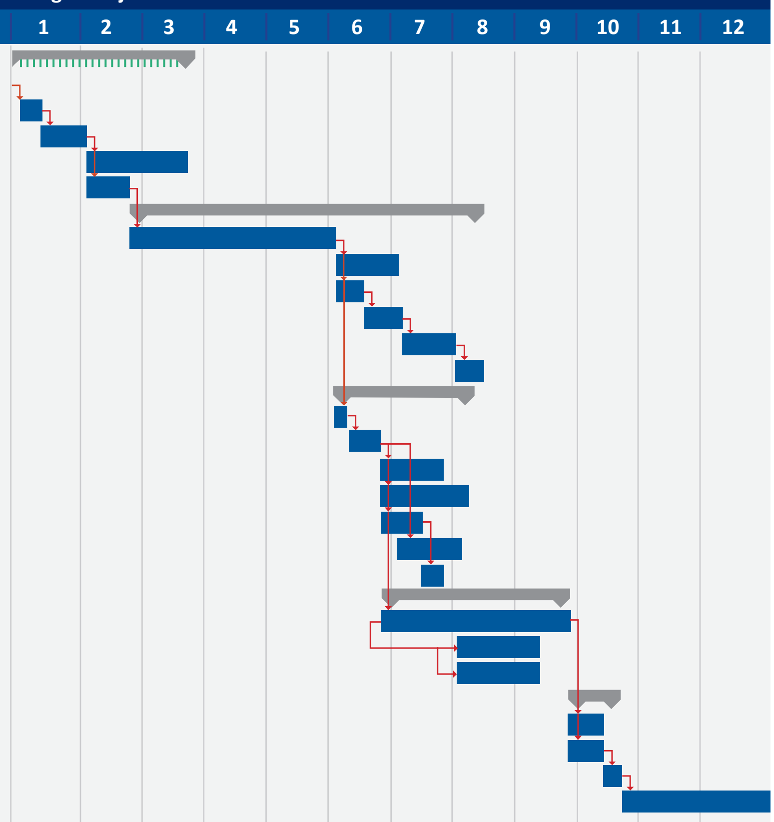


Figure 2.10. Schedule for biogas plant construction

II.1. Lagoon Construction

Palm oil mills commonly use two types of digesters to produce biogas from POME: the covered lagoon and the continuous stirred tank reactor (CSTR). Most mills use covered lagoons due to their simple design and lower price, so this section will only cover the construction of a covered lagoon.

Prior to construction, a civil engineer conducts a soil test and boring to assess soil conditions. The soil investigation report describes the soil type, group, depth to bedrock, and depth to seasonal wetness, as well as the depth, color, and texture of the different soil layers. The soil boring report remains valid as long as the land is not modified; cutting soil away or adding fill soil changes the profile.

Using the soil test (**Figure 2.11**), engineers assess the stability of the soil slope and select the most appropriate foundation design for the gas treatment system and gas engine. The soil test indicates the ground water level where the digester is located, and points to possible organic soils that may produce gases at the bottom of the lagoon.

The standard penetration test (SPT), a common in-situ method, determines the geotechnical engineering properties of sub-surface soils. The SPT is a simple and inexpensive way to estimate the relative density of soils and the shear strength parameters.

To conduct an SPT, the engineer uses a slide hammer with a standard weight (63.5 kg or 140 lb) and falling distance (76 cm or 30 inch) to drive a standard thick-walled sample tube (size of 450 mm) into the ground at the bottom of a borehole. The engineer drives the sample tube 150 mm into the ground and then records the number of blows required for the tube to penetrate each 150 mm (6 in) of soil, recording up to a depth of 450 mm (18 in). The total number of blows required for the second and third 6-inch penetrations is the SPT blowcount value, commonly known as the standard penetration resistance or N-value.

The N-value indicates the relative density of the sub-surface soil. Civil engineers use the N-value to estimate the approximate shear strength of the soils. **Table 2.3** below shows the correlation between the N-value, soil packing, and relative density. Depending on the soil type, the slope of the lagoon can range from 1:1.5 to 1:2 (vertical:horizontal).

Figure 2.11. Soil Test

Table 2.3. Correlation between N-value, soil packing, and relative soil density

SPT N (Blows/0.3 m - 1 ft)	Soil packing	Relative Density (%)
< 4	Very loose	< 20
4–10	Loose	20–40
10–30	Compact	40–60
30–50	Dense	60–80
> 50	Very Dense	> 80

Source: Meyerhoff, 1956.

For more detailed results, engineers conduct a Cone Penetration Test (CPT), also known as a bore hole test. A bore hole test results in a more accurate assessment, a continuous soil profile, and groundwater monitoring results.

Figure 2.12 below depicts a typical lagoon cross-section. The anchor trench secures the liner and the cover of the lagoon. The freeboard in the lagoon copes with heavy rain and additional water from other activities such as equipment cleaning.

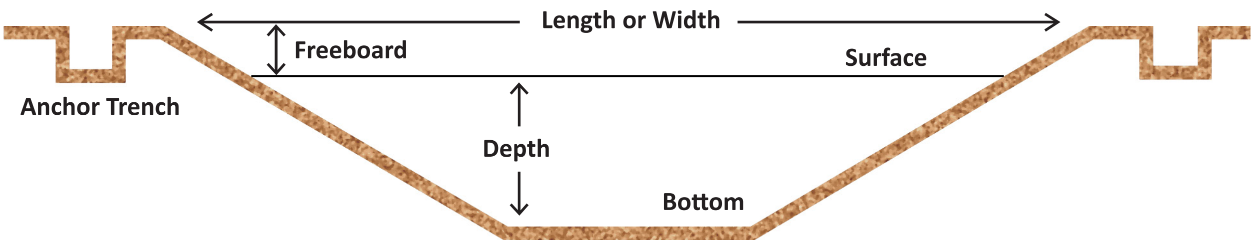


Figure 2.12. Lagoon cross-section

As noted, in normal situations, the slope of the lagoon has a vertical-to-horizontal distance ratio of 1:2. If the soil is sensitive to landslides, the lagoon may need a slope ratio of 1:3; otherwise, engineers should reinforce the slope. Engineering standards such as those developed by the American Society of Civil Engineers (ASCE) provide more detailed information on lagoon design.

The following sections describe the key steps in lagoon construction.

II.2. Earthwork

Preferably, engineers will conduct the earthwork for the digester during the dry season. Earthwork takes about 3–6 months.

Figure 2.13. Backhoes and bulldozers are some of the equipment used during lagoon construction.

Figure 2.14. Compacted soil ready for lining.

II.3. Water and Gas Release System

When soil testing shows that the level of ground water is higher than the bottom of the pond, and when the soil at the bottom of the pond is organic, engineers must install water and gas release system since organic soil producing gas. This release systems channel away any water or gas trapped under the liner.

Trenches on the bottom of the pond channel the water under the liner to a sump (**Figure 2.15**), where a submersible pump removes the water from the pond. The trench is usually 50 cm wide and filled with gravel.

Figure 2.15. Water Trench construction (left), Sump for water collection (right)

Trapped gas may cause the bottom lining to rise, reducing the digester's effective volume. To create a release system, engineers usually use a geo-composite where air can travel through openings and eventually escape.

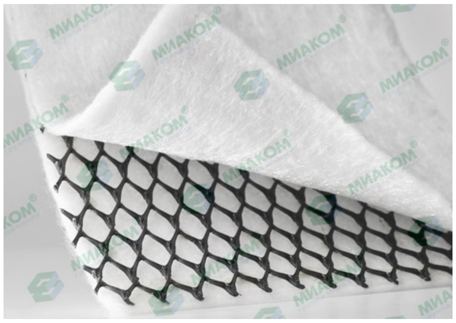


Figure 2.16. Sample of geo-composite

Figure 2.17. Geo-composite installation

Figure 2.18. Liner installation

II.4. Liner Installation

Lining the lagoon is optional, but highly recommended (**Figure 2.18**). Some pond designers do not install bottom liners when the underlying soil is highly impermeable. The suitable liner to use is high-density polyethylene (HDPE), commonly called geo-membrane. HDPE is the most chemical resistant type of polyethylene, and offers great ultraviolet protection and ageing resistance from the intense stresses of weather. Usually, the thickness of HDPE liner used is 1–1.5 mm.

II.5. Pipe Installation

Biogas digesters require specific types of pipes that can withstand the digester environment, for all pipes including inlet, outlet, feeding, recirculation, sludge, and gas-collector pipes.

Figure 2.19. Piping installation

POME and biogas are both corrosive, so builders must use anti-corrosive pipes in biogas installations. Within the digester itself, builders use HDPE pipes with a pressure specification of 6–10 bar. According to the International Organization for Standardization (ISO)'s standard number 4427 for high-density polyethylene (HDPE) materials, the minimum strength for pipes ranges from 32 to 100 bar, while the maximum hydrostatic design stress ranges from 50 to 80 bar (**see Table 2.4**).

Table 2.4. Minimum Required Strength (MRS) and Hydrostatic Design Stress (HDS) for pipe materials

Pipe Material	MRS at 50 years and 20 ºC (bar)	Max. allowable hydrostatic design stress (bar)
PE 100	100	80
PE 80	80	63
PE 63	63	50
PE 40	40	32
PE 32	32	25

Engineers use color codes to identify different types of pipes, each with a different pressure grade.

- Brown : sludge
- Blue : compressed air
- Green: potable water
- Yellow or black on yellow : gas

Pressure nominal (PN) grade is the pressure at which the pipe can hold at 20°C. **Table 2.5** beside shows the pressure grades, maximum pressures, and color codes for different types of pipes.

Table 2.5. Color codes and pressure grades on HDPE pipes

Type of pipe	Color Code	Pressure Grade	Maximum pressure (bar)
Gas	Yellow	PN 4	4 bar
	Yellow	PN 6	6 bar
Potable water	Green	PN 10	10 bar
	Green	PN 16	16 bar

II.6. Baffle installation

Baffles function as barriers that prevent the suspended solids in POME from coming out of the lagoon outlet. Usually these baffles are constructed from a geo-membrane that is attached to the floaters at the top and ballast at the bottom.

In a properly installed baffle, no part of the baffle attaches to the cover. That way, when biogas production raises the cover, the cover does not drag the baffle upwards. When a cover pulls a baffle upwards, the cover often tears under the weight of the baffle.

Figure 2.20. Torn cover due to baffle attachment

II.7. Floaters

Engineers attach floaters below the cover. In addition to buoying the cover, the floater provides a way for gas to enter the pipe during periods of low gas production, when the cover is closed.

To make floaters, engineers usually use expanded polystyrene (EPS) covered by geo-membrane. The covered EPS must be water and gas resistant.

Figure 2.21. Floater made of EPS covered by a geo-membrane

II.8 Lagoon Cover

The lagoon cover holds the biogas within the digester. Therefore, the installed cover must be gas-proof and able to endure the gas pressure so it is not easily broken. Normally, the area below the cover may store biogas for one to two days when the mill is not in operation. The cover material is HDPE geo-membrane with a minimum thickness of 1.5 mm.

III. Electrical Systems

In general, palm oil mills and biogas power plants in Indonesia generate electricity at low voltage 380 V AC, 50 Hz, three-phase systems. The power capacity varies depending on electricity demand and mill capacity.

Some palm oil mills use diesel engines, steam generators, and biogas power plants to fulfill mill and non-mill the electrical loads. **Figure 2.22** is a single-line diagram showing the electricity flows and electrical loads in an integrated supply system at a palm oil mill. This typical system consists of two diesel generators, one steam turbine, and a biogas power plant.

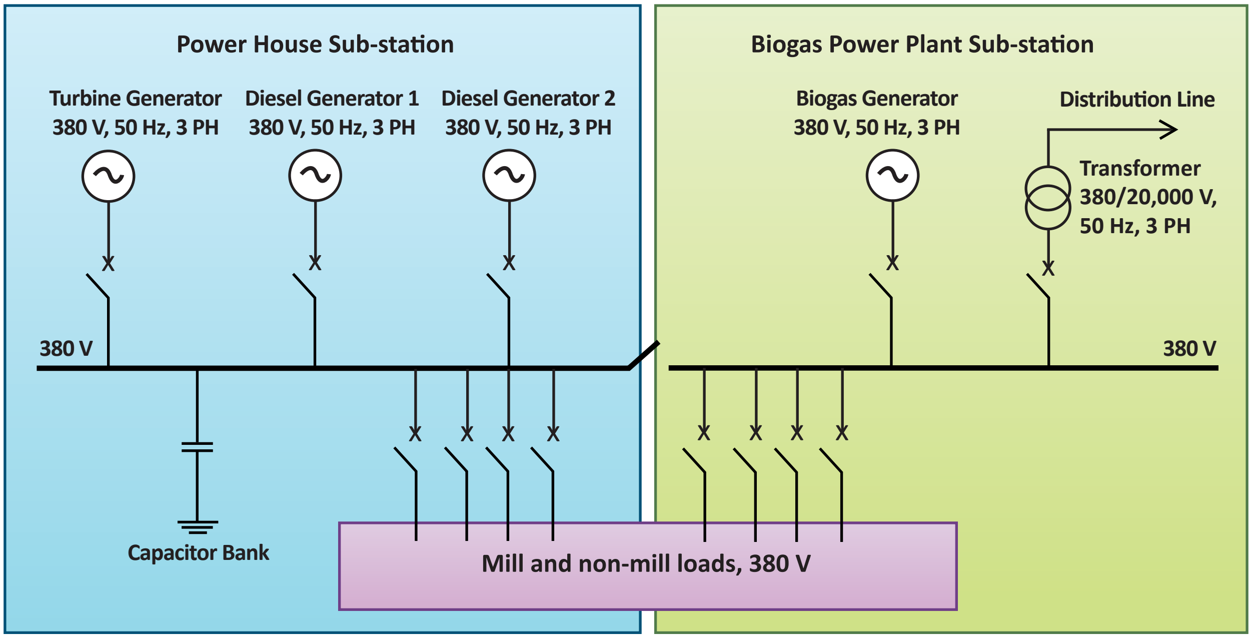


Figure 2.22. Electricity flow in a palm oil mill with a biogas power plant

III.1. Synchronization

Traditional power generation systems in palm oil mills - steam turbine generators and diesel generator sets - work in parallel. Biogas power plants in palm oil mills can either integrate with existing power sources or function as stand-alone power generation systems.

When mill operators build biogas power plants to distribute electricity to consumers outside the mill (e.g. PLN), the biogas power plant does not need to work in parallel with the existing power plant. The biogas plant only needs to work with the electrical system that supplies consumers.

When a mill installs a biogas power plant to work together with the existing power plant, on the other hand, engineers must synchronize voltage magnitudes, voltage frequencies, and the phase angle difference between the voltages for the two different power plants. Synchronization ensures that both plants can supply electricity to the same loads, for example to mill operations or offices and housing in the mill area.

Synchronization aligns electrical characteristics to allow a circuit breaker between two energized parts of the power system to close. In this case, the output of the biogas power plant generator (380 V) must have the same voltage as the buses on a network. If the electrician synchronizes voltages incorrectly, a power system disturbance will result, damaging equipment.

To synchronize properly, an electrician must closely monitor and align three different aspects of the voltage across the circuit breaker:

- The magnitudes of the instantaneous voltage from the incoming generator and the busbar must be equal.
- The voltage frequency from the incoming generator must be the same as the busbar frequency.
- The voltage phase angle difference between the incoming generator and the busbar must be the same.

When the differences among these variables are within allowable limits, the circuit breaker may be closed manually or automatically. The normal limits specified for synchronization are:

a) 4 volts for the maximum voltage differential;
b) 0.1 Hz for the maximum slip frequency; and
c) +/- 10 degrees for the phase angle.

These limits are the maximum settings of a synch-check relay.

Operators can choose between two synchronization methods, manual synchronization and auto synchronization. Manual synchronization requires precision and skill to match synchronizing variables; operators generally use this method in old palm oil mills. Automatic synchronization uses an automatic synchronizer tool, making it a more practical method.

III.1.1. Manual Synchronization

To perform manual synchronization, the operator adjusts generator speed so that its frequency is slightly higher than the bus frequency. This allows the generator to pick up electrical load immediately. Next, the operator uses a multifunction synch-check relay or a supervisory relay that compares synchronization variables is used (labeled as device 25 in **Figure 2.23**). The operator uses a synchronizing panel to monitor the parameters and determine when to close the breaker.

Manual synchronization with a supervisory relay requires the operator to manually control voltage and frequency. Because achieving the exact frequency is difficult, the supervisory relay sets up a range of allowable frequencies around the set value before the operator closes the circuit breaker to parallel the generator.

The operator puts the relay's output contacts in series with the control switch. The circuit breaker only closes when 1) the operator manually attempts to close the circuit breaker, and 2) the supervisory relay contacts are closed after all system parameters are satisfied.
A diagram of manual synchronization using supervisory control is shown in **Figure 2.23**.

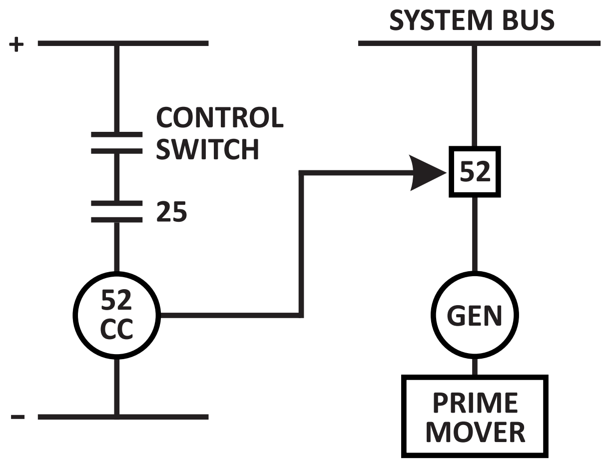


Figure 2.23. Manual synchronization with supervisory control

Source: Introduction to Synchronizing, Basler Electric Company.

III.1.2. Automatic synchronization

Some loads require immediate attention from standby emergency generator sets and require automatic synchronizing (**Figure 2.24**). Automatic synchronizers (ANSI/IEE Device 25A) monitor frequency, voltage, and phase angle, provide correction signals for voltage and frequency matching, and provide the signal to parallel the generators. This is known as "close command" (CC). To allow the generators to parallel as quickly as possible, each generator needs a dedicated synchronizer.

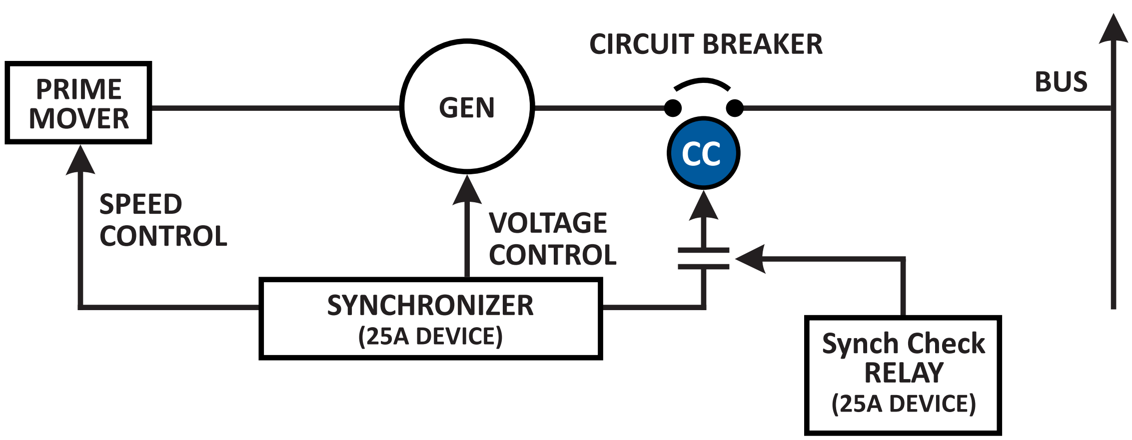


Figure 2.24. Automatic synchronization

Source: Introduction to Synchronizing, Basler Electric Company

IV. Operating Conditions

Safe, efficient biogas production requires operators to maintain appropriate temperature, pressure, material level, flow, effluent pH, and other variables. Engineers monitor operating conditions using these process variables, working to keep each variable in a specified range. The following section summarizes the role of each key process variable in biogas production.

IV.1. Temperature

Temperature control is critical to maintaining product quality and ensuring safe and reliable biogas plant operation. Operators commonly use resistance temperature devices (RTDs), thermocouples, thermistors, and, to a lesser degree, infrared (IR) to monitor temperature. In a biogas system, operators must measure two critical temperatures: (1) the temperature of wastewater before and after the digester; and (2) the temperature of gas before and after the dehumidifier.

IV.2. Pressure

Controlling pressure ensures safety and influences key process operations such as heat transfer, fluid flow, and vapor-to-liquid equilibrium. Operators should measure gas pressure at these critical points: (1) before and after blowers; (2) in the digester and before the flare system; and (3) before gas engine and/ or burner.

IV.3. Material level (Volume)

Monitoring the level of material level in a tank or vessel aids filling and inventory control and maintains safe operations for personnel and equipment. Operators often measure material level as a percentage of level height or volume, but engineers may record level in units of feet or inches, or even pounds, when accounting for tank geometry and material density. Level measurement technologies fall into one of two groups, contact and non-contact. Both contact and non-contact level technologies can have continuous or point sensors. In the biogas system, operators usually measure the level of liquid in a mixing tank.

IV.4. Flow Rate

Flow describes the motion characteristics of constrained fluids (liquids or gases). Biogas production can include both high- and low-viscosity fluid streams. When selecting a flow instrument for optimum performance, the engineer must consider the viscosity of the fluid under process conditions. Key measurements of flow in biogas systems include: (1) the flow rate of wastewater at the inlet, measured by a flow meter and totalizer; and (2) the flow rate of gas measured by a gas flow meter and totalizer.

Engineers categorize flow meters by the variable they measure, either the velocity or mass of the fluid flow. Typical instruments include magnetic flow meters for volumetric measurements and coriolis flow meters for mass measurements. Common flow meter types applied in biogas system are magnetic flow meter to measure POME flow rate and thermal mass to measure the biogas flow rate.

Additional variables commonly controlled in biogas systems include:

- pH of inlet and outlet effluent
- COD levels (optional)
- Gas composition measured using a portable or online gas analyzer.
  CO_2, CH_4 and O_2 are measured continuously, H_2S is measured periodically.
  If biogas is fed to the gas engine, it is better to use an online gas analyzer.
- Humidity of gas before the gas engine
- Valve positions
- Equipment status (on/off, auto/manual);
- Gas engine status (frequency, voltage, kW produced, temperature of oil, etc.)
- Electrical consumption of biogas plant components

V. Instrumentation and Control

Biogas power plants use a range of instruments and control equipment to monitor process conditions and control electrical systems.

To maintain safe operations, achieve optimum production rate, and ensure quality products and business viability, plant operators must maintain certain variables at specific levels. For example: an effective mesophilic process in anaerobic digestion requires temperature in the range of 35°C to 38°C, and pH in the range of 6.5 to 7.5. Engineers have designed control mechanisms to correct any deviations from the desired temperature and pH range. Such control mechanisms include on-off control and the proportional integral derivative (PID) controller. Operators use instruments with automatic alarms to monitor critical conditions and potentially hazardous changes.

Installing a gas engine in a biogas power plant system requires biogas with specific pressure, flow rate, methane content, moisture content, and hydrogen sulfide (H_2S) content. To maintain process variables at the desired values, the gas engine uses automatic control loops. When conditions deviate too much from the established value ranges, operators may face health hazards. Dangerous deviations trigger a trip system on the gas engine to avoid problems.

To make sure operators use the required sequence, especially during start-up and shutdown, the process control design of a biogas power plant system includes an interlock system.

Operators use online measurement devices for some of the process parameters and monitor others periodically as required. **Figure 2.25** shows a schematic diagram for an online gas installation.

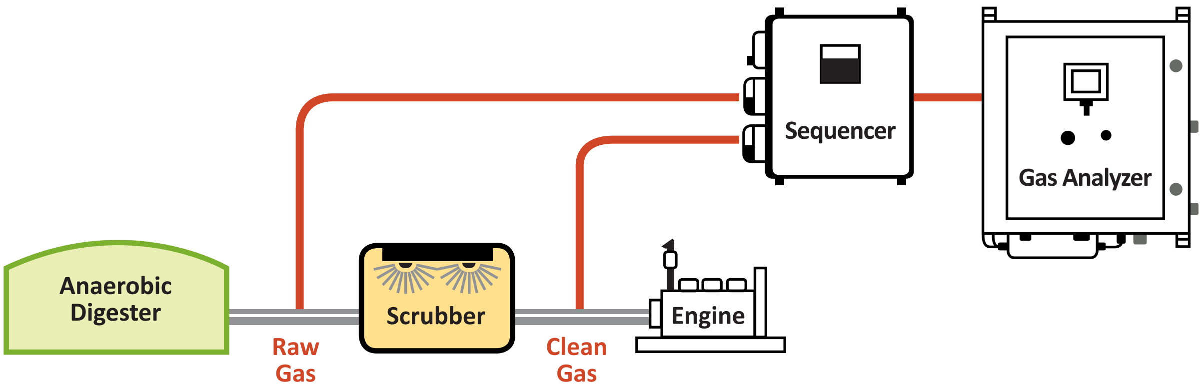
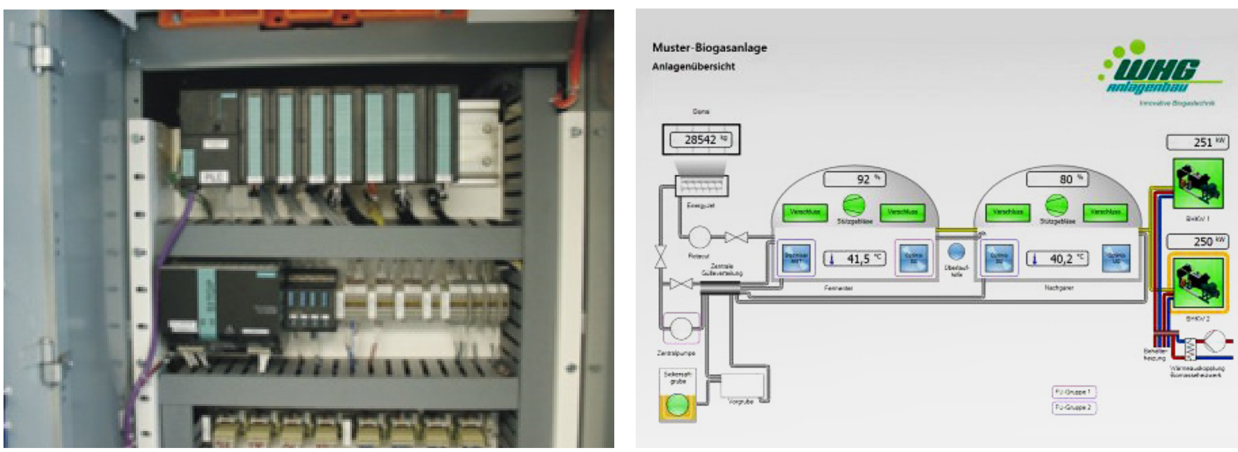


Figure 2.25. Schematic diagram of an online gas analyzer and installation

Operators use online measurement devices for some of the process parameters and monitor others periodically as required.

Some biogas power plants also use PC-based supervisory control and data acquisition (SCADA) systems to acquire, store, and analyze process and electrical data. This system uses a controller, normally a programmable logic controller (PLC) with an embedded PID controller logarithm, to adjust parameters (**Figure 2.26**).



www.biogas-center.com

Figure 2.26. PLC (left) and Scada display (right)

The mill manager can connect the computer system used for on-site process control with a remote computer, such as a computer at the company's headquarters, through integrated services for digital networks (ISDNs) or digital subscriber line (DSL) routers. This set-up enables managers to control the plant remotely.

Figure 2.27 provides a schematic diagram of a data acquisition system. The data communication interfaces use the RS-232 and RS-485 digital standards. **Figure 2.28** shows a schematic of an electrical control system. **Figure 2.29** provides a diagram of a biogas power plant integrated with existing biomass and diesel power plants. For more detailed information about instrumentation and control, refer to specialized references such as *Chemical Engineer's Handbook*, Perry et al (1997) and *Process Control Instrumentation Technology*, Johnson (1997).

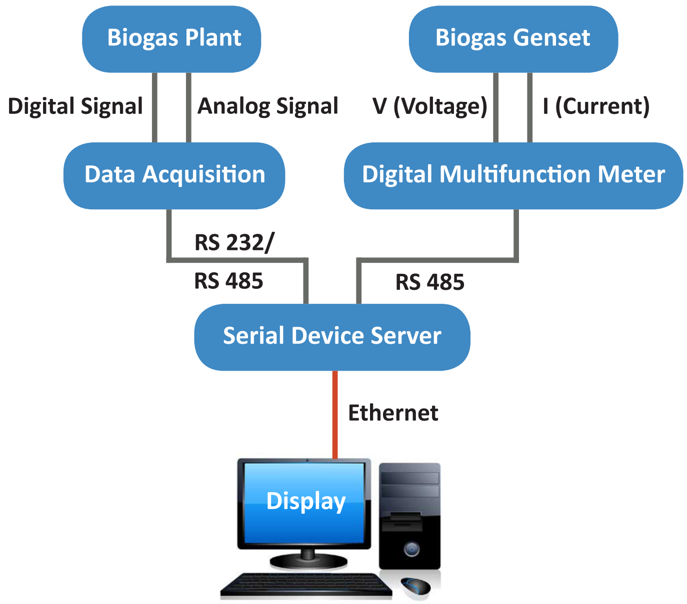


Figure 2.27. Data acquisition

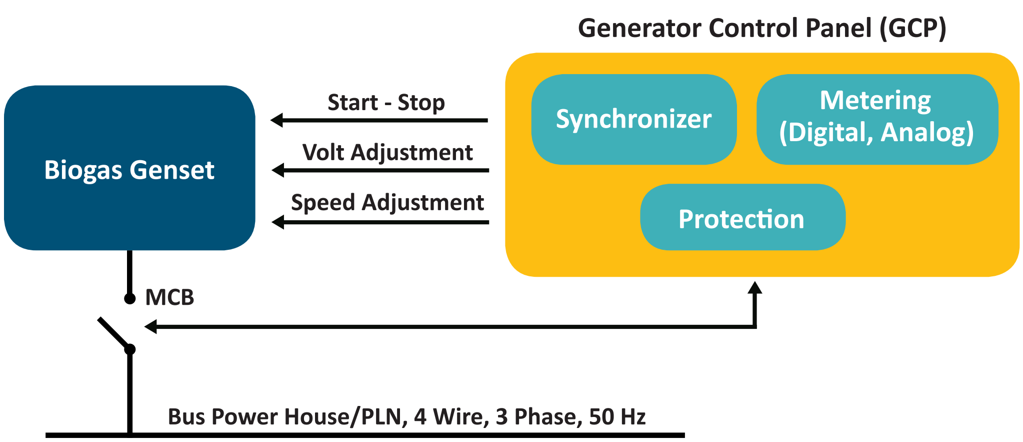


Figure 2.28. Electrical control system

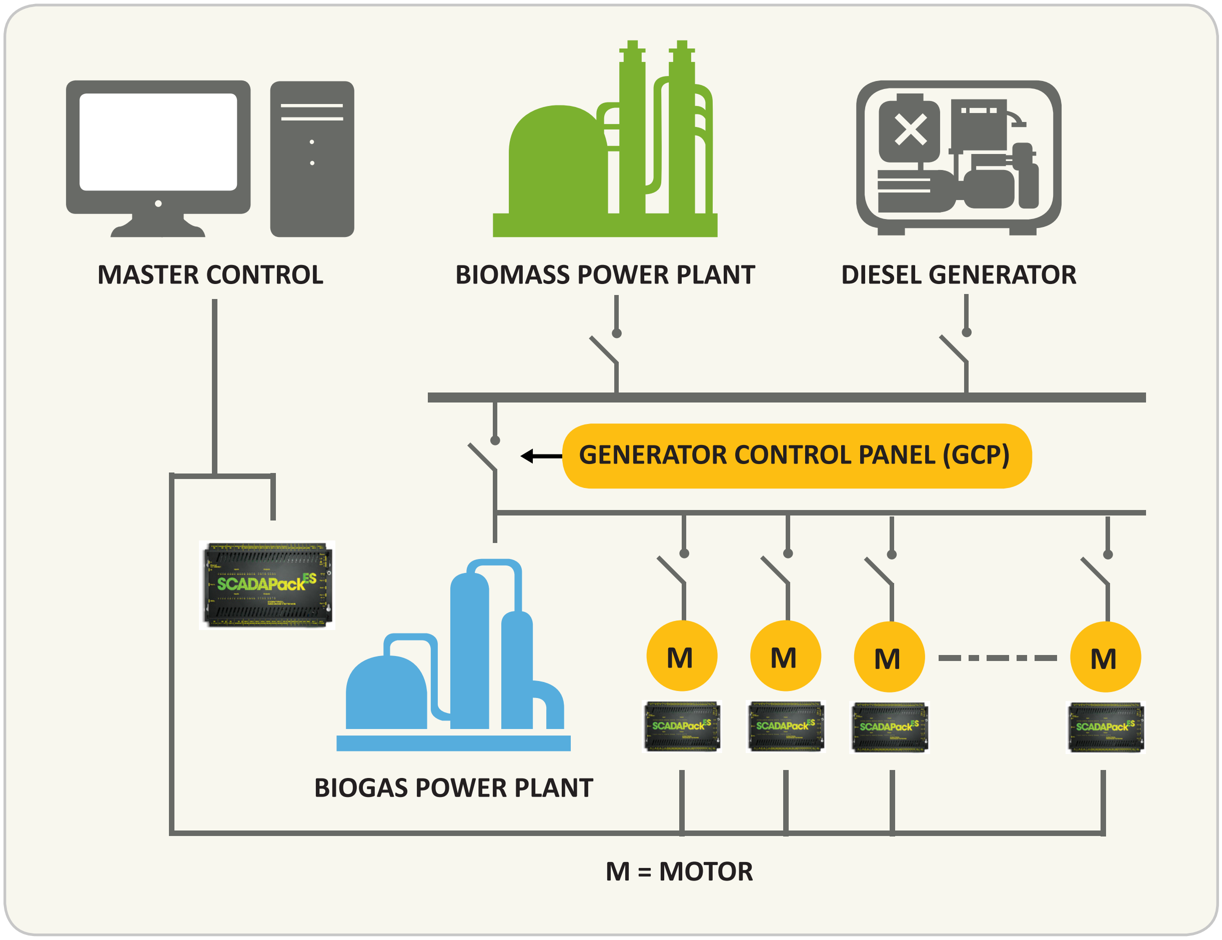


Figure 2.29. Integrating biogas and existing power plants in a mill

VI. Safety and Operational Risks

Safety is essential during the construction and operation of a biogas plant. Proper safety precautions minimize problems, prevent accidents, and reduce costly delays and disruptions. Using safety procedures during construction and operation helps teams meet targets for construction time, quality, performance, cost, and operations.

Like other industrial installations, biogas plants pose potential risks for humans, wildlife, and the environment. If not properly managed, biogas plants can create unsafe working environments that threaten health and life. Preventive actions such as safety training will raise awareness about dangers, encourage safe behavior, and help minimize risks.

VI.1. Health and Safety Risk

Biogas plants produce high amounts of combustible and toxic gases. Biogas is 50–75% methane, which is a flammable gas, and poses a fire hazard when in the presence of oxygen and an ignition source. The fire and explosion risks are particularly high near the digester and gas reservoirs. Explosions can cause serious injuries, severe ecological damage, and property damage. Plants must use good process design, material selection, and control systems to minimize the risk of fire and explosions.

Table 2.6 below illustrates the flammability of biogas.

Table 2.6. Flammability of biogas

	Unit	Biogas
Density	kg/m³	1.2
Ignition Temperature	°C	700
Explosive Range	%Vol	6–12
Theoretical air requirement to form flammable mixtures	m³ air/m³ biogas	5.7

Source: German Agricultural Occupational Health and Safety Agency, 2008

International standard IEC 60079-10-1 provides a methodology for safety zone classification based on the duration and frequency of an explosive atmosphere for both gases and vapors **Table 2.7** outlines these classifications.

Table 2.7. Zone classification for an explosive atmosphere

Zone	Definition	Exposure Duration in Industrial Practice
0	Explosive gas atmosphere present continuously, for long periods, or frequently	> 1000 hours/year
1	Explosive gas atmosphere likely to occur in normal operation occasionally	10–1000 hours/year
2	Explosive gas atmosphere unlikely in normal operation (within design parameters), but if so, only for a short period	< 10 hours/year

Figure 2.30. Gas Leak

Source: www.metallurgist.com

Carbon dioxide makes up 25–45% of the biogas mixture. In concentrations between 1–5%, carbon dioxide can cause dizziness, and in concentrations higher than 9% it causes suffocation. Hydrogen sulfide is an extremely hazardous component of biogas. Thirty minutes of exposure to hydrogen sulfide at a concentration of only 300 ppm will render a person unconscious. Exposure to H_2S at a 1,000 ppm concentration in air rapidly paralyzes the respiratory system, causing cardiac arrest and death within minutes. **Table 2.8** below lists the toxic effects of H_2S at different concentrations.

Table 2.8. Symptoms of hydrogen sulfide poisoning

Concentration (ppm)	Symptoms/Effects
0.01–1.5	Odor (rotten egg smell) noticeable
2–5	Nausea, tearing, headaches, or loss of sleep. Airway problems in some asthma patients.
20	Fatigue, loss of appetite, headache, irritability, poor memory, dizziness.
50–100	Slight conjunctivitis and respiratory tract irritation after 1 hour. May cause digestive upset and loss of appetite.
100	Coughing, eye irritation, loss of smell after 2–15 minutes (olfactory fatigue). Altered breathing, drowsiness after 15–30 minutes. Throat irritation after 1 hour. Gradual increase in severity of symptoms over several hours. Death may occur after 48 hours.
100–150	Loss of smell (olfactory fatigue or paralysis).
200–300	Marked conjunctivitis and respiratory tract irritation after 1 hour. Pulmonary edema may occur from prolonged exposure.
500–700	Staggering, collapse in 5 minutes. Serious damage to the eyes in 30 minutes. Death after 30–60 minutes.
700–1000	Rapid unconsciousness, immediate collapse within 1 to 2 breaths, breathing stops, death within minutes.
1000–2000	Nearly instant death

Source: US Occupational Safety and Health Administration

VI.2. Safe Working Procedures

Safe working procedures provide guidelines for workers to ensure safe operations and conduct in high-risk situations. All workers who operate and maintain biogas plants should wear personal protective equipment (PPE) (**Figure 2.31**):

- Safety shoes with a non-skid profile
- Industrial clothing
- A personal H_2S gas detector with pre-set maximum allowable concentration (MAC) alarm set points (**Figure 2.32**)
- Special protective clothing and mask for handling chemicals.

Biogas plant managers must train workers in the use of personal protective equipment, including how, where, and when to use it. Workers should know the hazards that PPE protects them against, along with the limits of that protection. Plant managers should check equipment regularly for damage. To maintain effectiveness and minimize the chance of contamination, users must maintain, clean, and store PPE properly. Workers should wear respirators and dust masks as conditions require.

Figure 2.31. Personal protective equipment

Top row, left to right: high-visibility vest, head protection, hearing protection, eye protection.
Bottom row, left to right: foot protection, hand protection

Figure 2.32. Personal H_2S gas detector

Source: www.coleparmer.com

The following safety procedures protect against the health and safety risks of biogas:

- If the safety relief valve at the anaerobic digester is activated, immediately reduce the biogas production by stopping the wastewater intake into the digester.
  Activation of the safety relief valve could signal a danger of suffocation, poisoning, or gas explosion near the biogas sources.
- In case of a biogas cloud, all workers must immediately cease activities and evacuate the area. Use escape routes perpendicular to the wind direction.
  Gas clouds move in the direction of the wind. Calm conditions pose the greatest danger, because the biogas accumulates into a large cloud and stays near the emission point. During strong wind conditions, biogas will mix relatively quickly with air, bringing concentration levels below the explosion limit.
- Do not attempt to extinguish possible gas fires.
- After the situation is under control, determine the cause of the gas emission and take corrective action to prevent future emissions.

Figure 2.33 below shows some of the safety equipment in a biogas power plant.

Figure 2.33. Electric padlock for safety protection (left), Fixed guard for protection from rotating machinery (right)

Source (left): www.ebay.co.uk

Figure 2.34 shows some of the typical signs that are used in a biogas power plant compound.

Figure 2.34. Safety signs in biogas power plants

VI.3. Operational Risks

Alongside the risks of the biogas itself, the plant and its construction can pose operational hazards. Engineers must design biogas plants to minimize damage in the case of natural disasters such as landslides, flooding, and earthquakes. The plant must operate reliably, avoiding equipment damage and unnecessary down time. Builders must use high-quality materials for the lagoon cover or tank to minimize leakage of biogas into the atmosphere.

Mill operators often overlook the stability of the supply of fresh fruit bunches. In designing the digester, engineers must consider the volume of POME produced each day, which is highly dependent on the amount of FFB processed. Palm trees have high- and low- production seasons throughout the year. Plant design must take these trends into account to avoid long periods of under- or over-capacity of FFBs during operation.

Table 2.9 below summarizes the risks involved in the construction and operation of biogas plants, which include environmental, health, safety, economic and legal risks.

Table 2.9. Risks in construction and operation of biogas plants

Risk	Identified Issues	Mitigation
POME Supply	Availability, COD content, flow rate	Long term FFB process scheduling; secure supply from own plantation or supplier.
Technology	Reliability and cost	Follow best practices, engineering standards, and employ proven and cost effective technologies.
Environmental & Civil	Landslide, flooding Earthquake, lightning	Technically safe site and secure environment; use proper engineering standards, proper materials, and proper construction procedures; implement flood management and lightning protection systems.
Legal	Permits for business, environment, and construction.	Ensure all permits are complete and no legal issues exist that may hinder project execution.
Logistics & Construction	Access, human resources, project delay	Plan access; use skilled labor; plan timely material delivery and handling; ensure proper resource scheduling and project management.
Cost Overrun	Over budget	Accurate feasibility study, optimum engineering design and project management.
Operation & Maintenance	Unexpected down time	Implement best practices for operations and maintenance; well-trained manpower.
Covered lagoon, methane capture	Cover leak Under or over capacity	Cover material is very well tested; proper engineering design; anticipate low and high input.
Tank, methane capture	Tank or roof leak Under or over capacity	Proper engineering design; maintain correct process parameters to avoid acid formation.
Wet biogas	Create issues for gas engine	Cyclone or chiller to be installed to dry biogas.
Pollution	Air polluting emissions Leakages to ground and surface water	Follow engineering standards; pollution monitoring; comply with regulations.
Fire and explosions	Cause health and safety issues for workers and disrupt operations	Follow standard of materials and monitoring procedure; area zoning based on the probability of occurrence; access control with fencing; periodic inspection; use access/work permits to control personnel; provide firefighting equipment and training.
Mechanical and rotating equipment	Safety issues for workers	Follow design and operation standard and install protection systems.
Electrical equipment	Electrical problems	Follow operation and maintenance standard, use work permit and electric padlock for safety protection
Noise	Health issues for workers	Provide noise protection equipment

PART 3: ANALYZING YOUR MILL'S POTENTIAL

If you are considering installing a biogas plant in a palm oil mill, you will want to conduct a feasibility study to evaluate your mill's potential. **Figure 3.1** below outlines the steps you will need to take.

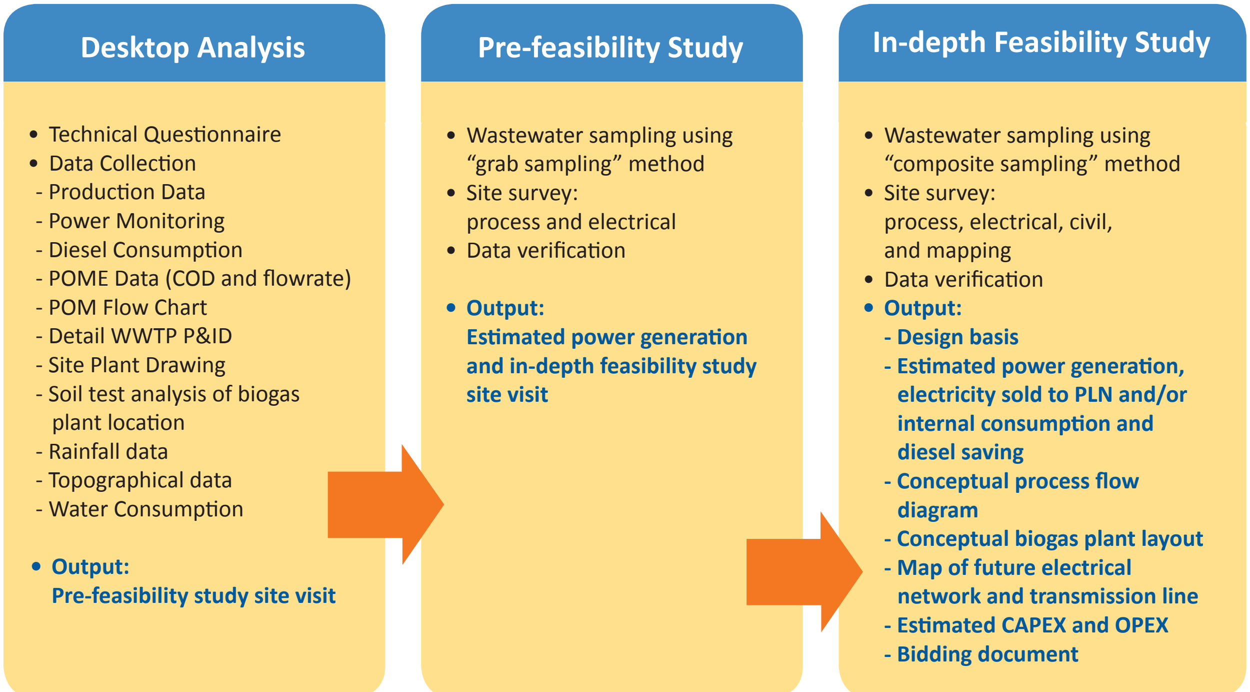


Figure 3.1. Feasibility study process for POME-to-energy installations

If an in-depth feasibility study concludes that a mill is appropriate for a POME-to-energy operation, the implementation stage begins. Implementation consists of the following steps:

- *Meet permit requirements.* Permits will include environmental management and monitoring (*Upaya Pengelolaan Lingkungan Hidup* [UKL]/*Upaya Pemantauan Lingkungan Hidup* [UPL]), local government (survey, principle, location, building), Ministry of Energy and Mineral Resources (*Izin Usaha Ketenagalistrikan untuk Kepentingan Umum* [IUKU]), and Power Purchase Agreement (PPA)
- *Financial closure*
- *Land preparation*
- *Choose a contracting model*. Options include contracting with one firm for all engineering, procurement, and construction; hiring separate contractors for civil, mechanical, and electrical portions of the project.
- Construction and commissioning
- Commercial operations

In a complete feasibility study, the mill's energy generation potential, the electrical supply and demand characteristics, and a civil works assessment together determine the technical viability of a project. A civil engineer normally conducts the civil works assessment through a soil test analysis to determine a suitable location and appropriate digester design. (See **Part 2** of this handbook.) The following sections focus on the energy potential and electrical assessments of biogas projects.

I. Energy Potential Assessment

Estimating the amount of energy that a POME-to-energy project could produce helps inform design and cost decisions. To conduct an energy potential assessment, you will need to determine the mill's production parameters and the composition of the palm oil mill effluent.

I.1. POME Sampling Methodology

The composition of the mill's palm-oil effluent provides key information for the power potential calculation, so it requires careful, thorough investigation. POME analysis determines the quality and content of effluent and identifies potential issues with safety or regulatory compliance. The engineer should analyze a representative sample of POME from the facility; relying on common engineering assumptions only leads to inaccurate potential energy estimates. Obtaining valid results in a laboratory testing requires proper, representative sampling.

I.1.1. Sampling Methods

Engineers generally perform wastewater sampling (**Figure 3.2**) using one of two methods: grab sampling or composite sampling.

Grab sampling. In grab sampling, the tester collects all of the sample material at one time. A grab sample reflects performance only at the point in time when the sample was collected, and then only if the sample is properly collected. This method provides a relatively quick initial assessment of the POME characteristics, and is sufficient for a pre-feasibility study.

Figure 3.2. Wastewater sampling

Composite sampling. Composite sampling requires collecting discrete samples at regular intervals over a period of time, usually 24 hours. The tester collects the POME in a common container. Composite sampling allows the analyst to model the average performance of a biogas plant during the collection period.

In flow-proportional sampling, sample volumes reflect the size of the overall POME flow. Flow-proportional collection provides better information since palm oil mills operate discontinuously (using a batch system). Wastewater characteristics and production rates are not uniform from season to season. Flow-proportional sampling takes into consideration fluctuations in the flow rate. Testers can choose one of two methods to conduct flow-proportional sampling:

- Vary the sample collection frequency based on flow volume
  Example: Collect a fixed volume every 1 m^3.
- Vary the volume of each individual grab based on flow volume
  Example: Collect a sample every hour, linking the volume of each sample to the flow rate recorded at that hour. If the tester collected 500 ml when the flow rate was 5m^3/hour and the flow rate at the next sampling time was 4 m^3/hour, the tester would collect a 400 ml sample.

The second method, varying the volume, requires an auto-sampler that records the instantaneous flow rate and adjusts the sample volume accordingly. The first method easily lends itself to manual sampling. Usually, testers collect samples at a fixed volume of 500 ml every 5–10 m^3 of effluent (depending on POM capacity) over a period of 3–4 days. Testers then mix the samples together so that the wastewater analysis represents average effluent characteristics.

I.1.2. Choosing Sampling Points

The biogas plant's design requirements determine the sampling points. The inlet to the biogas plant and the streams where raw POME flows out should make up the sampling points. Because wastewater treatment plant designs vary, the sampling point locations may be different for each facility. In general, testers take samples where POM effluents have high organic content (e.g. condensate sterilizer and sludge centrifuge), and at outlet points of the wastewater treatment units, before the effluent enters the anaerobic pond (e.g. fat pit, de-oiling pond, and cooling pond). **Figure 3.3** depicts sampling points.

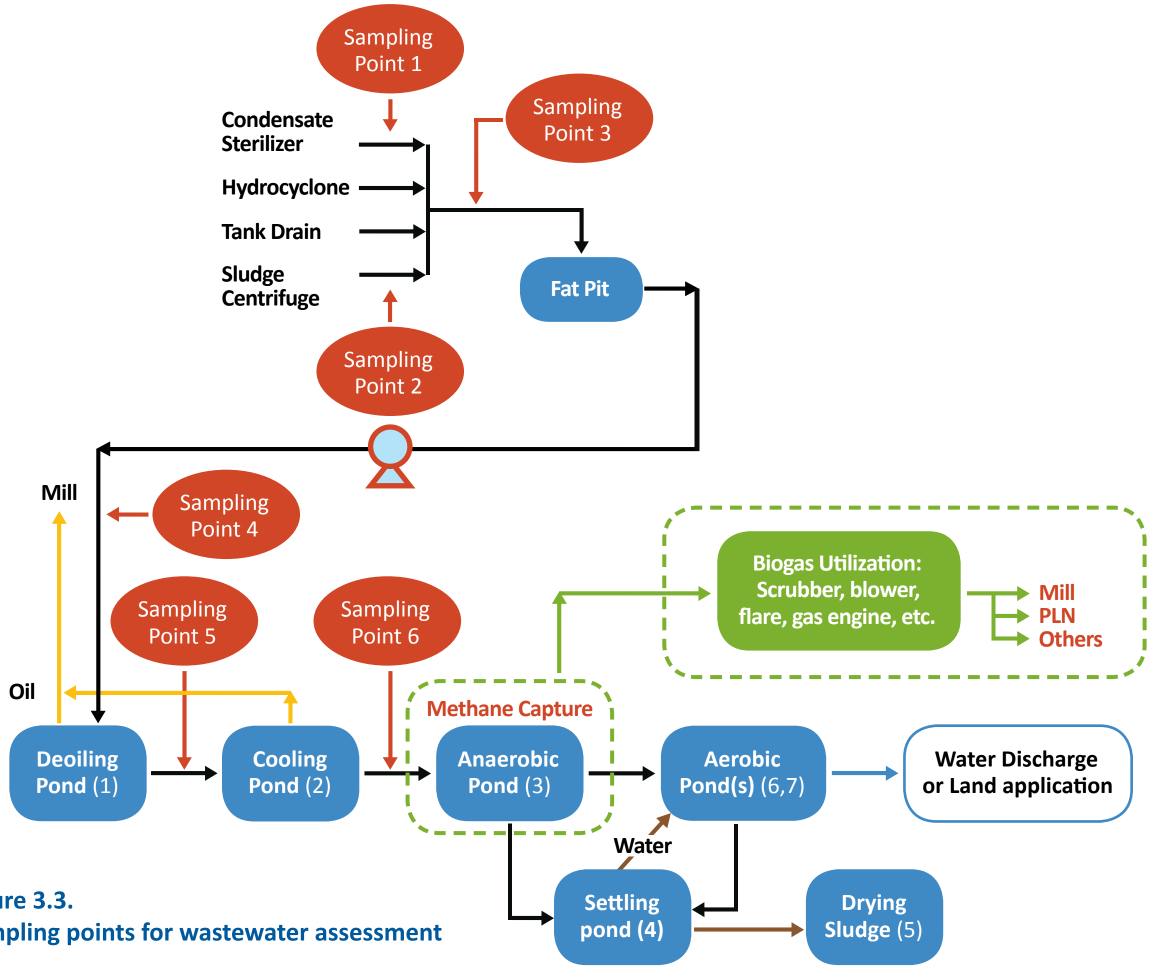


Figure 3.3.
Sampling points for wastewater assessment

Palm-oil mill laboratory staff should test samples collected by grab or composite methods in the on-site laboratory using calibrated instruments. For confirmation, staff may choose to send samples to a reliable external laboratory for testing. When taking samples for an external laboratory, testers must store them in refrigerator or cooling box at 4˚C and/or lower the pH to pH of 2 by adding sulphuric acid to minimize degradation of organic content.

I.1.3. Analyzing Samples

Identifying POME characteristics is a crucial step to assessing potential energy generation from biogas. A proper analysis covers the following characteristics:

- pH
- Temperature
- COD
- Sulfate
- TSS (total suspended solids) and VSS (volatile suspended solids)
- FOG (fat, oil, and grease).

Figure 3.4. Hach spectrometer for COD, sulfate, and TSS concentration measurement (left)
Portable pH meter and thermometer for measurement immediately after sampling (right)

Testers measure temperature and pH on the spot using portable temperature and pH meters. (See **Figure 3.4**. right). Mill staff conduct other analyses in the on-site laboratory, using a spectrophotometer to measure COD, sulfate, and TSS concentrations. A spectrophotometer (**Figure 3.4**. left) cannot measure FOG, so an external laboratory must assess FOG. Calorimeter or portable spectrophotometer is advised to measure the COD on site due to its simplicity, portability, and reliable test results.

I.2. Calculating Renewable Energy Potential

Calculating the potential energy generated from biogas uses several key parameters.
Table 3.1 lists the input parameters the mill must measure.

Table 3.1. Calculating POME renewable energy potential

Parameter	Unit	Explanation
Operating hours	hours/day	The average number of hours the mill is in operation in a day
Operating days	days/year	The average number of days the mill is in operation in a year
Annual FFB	ton FFB/year	The amount of FFBs processed in a year
Ratio POME to FFB	m^3/ton FFB	The ratio of POME volume produced per FFB processed. POME:FFB = (m^3 POME) / (ton FFB)
Typical COD	mg/l	The COD of the wastewater analyzed by spectrophotometer

This calculation rests on several assumptions about operating parameters. **Table 3.2** below lists the assumptions.

Table 3.2. Assumptions in calculating potential power

Parameter	Symbol	Value	Unit	Explanation
CH_4 to COD ratio	CH_4 /COD	0.35	Nm^3 CH_4 /kg COD removed	Theoritical volume of methane produced per kg of COD removed from the waste water.
COD Removal Efficiency	COD_{eff}	80-95	%	The percentage of COD that will be converted to methane.
Methane Energy Value	$CH_{4,ev}$	35.7	MJ/m^3	The energy content of methane.
Average electrical efficiency	Gen_{eff}	38-42	%	Efficiency of gas engine in converting energy value of methane to electrical energy.

Based on the mill's wastewater characteristics, and on the assumptions listed above, analysts can calculate potential power. The following section shows the calculation step by step:

$$(1)\ \textit{Daily throughput (tons FFB/day)} = \frac{\textit{Annual FFB}}{\textit{Operating days}}$$

$$(2)\ \textit{Daily wastewater flow } (m^3/day) = \textit{Daily throughput} \times \textit{Ratio POME to FFB}$$

$$(3)\ \textit{COD loading (kg COD/day)} = \textit{Typical COD} \times \textit{Daily wastewater flow} \times \frac{kg}{1{,}000{,}000\ mg} \times \frac{1000\ L}{m^3}$$

$$(4)\ CH_4 \textit{ production } (Nm^3\ CH_4/day) = \textit{COD loading} \times COD_{eff} \times CH_4/COD$$

$$(5)\ \textit{Generated power capacity (MWe)} = \frac{CH_4 \textit{ production} \times CH_{4,ev} \times Gen_{eff}}{24 \times 60 \times 60}$$

Generated power capacity, the result of the calculation, corresponds to the potential power produced by the gas engine. For mills that plan to sell all of the electricity to the grid, the analyst calculates anticipated income by multiplying the generated capacity by 24 hours (changing MWe to MWh per day) and multiplying the result by the feed-in tariff. In reality, mills will earn less than the calculated amount due to electricity losses in the distribution line and down-time for maintenance. To account for this, use an availability factor. Multiply the availability factor - which can range from 90% to 98% - by the potential amount of electricity generated by the gas engines.

Box 3: Sample Calculation, POME-to-Energy Potential

A palm oil mill with a capacity of 60 tons of FFB per hour operates for 5,000 hours and 300 days per year. Based on the flow meter reading, it is calculated that the volume of POME (m^3) to tons of FFB ratio is 0.8. The typical COD concentration of the wastewater is 62,000 mg/l measured after the cooling pond. The calculation assumes 90% COD conversion to methane and 38% gas engine efficiency. Following the step-by-step calculation provided above, we can project the potential generated capacity as follows:

Daily wastewater flow: $$60\ \frac{\text{ton FFB}}{\text{hour}} \times \frac{\text{5000 hours}}{\text{300 days}} \times 0.8\ \frac{m^3\ \text{POME}}{\text{ton FFB}} = 800\ \frac{m^3\ \text{POME}}{\text{day}}$$

COD loading: $$62{,}000\ \frac{\text{mg COD}}{\text{L}} \times 800\ \frac{m^3\ \text{POME}}{\text{day}} \times \frac{\text{kg}}{\text{1,000,000 mg}} \times \frac{\text{1000 L}}{m^3} = 49{,}600\ \text{kg COD/day}$$

CH_4 production: $$49{,}600\ \frac{\text{kg COD}}{\text{day}} \times 90\% \times 0.35\ \frac{Nm^3CH_4}{\text{kg COD}} = 15{,}624\ Nm^3\ CH_4/\text{day}$$

Generated power capacity: $$15{,}624\ \frac{Nm^3CH_4}{\text{day}} \times 35.7\ \frac{\text{MJ}}{Nm^3\ CH_4} \times 38\% \times \frac{\text{day}}{24\times60\times60\ \text{second}} = 2.45\ \text{MWe}$$

II. Electrical Supply and Demand Assessment

An electrical engineer conducts an electrical assessment to understand the mill's existing electricity supply and demand, and identify the peak load for the proposed biogas plant. Analysts prefer to review of three years' historical data for electricity supply and demand to accurately see the trends in energy balance within the mill.

Integrating the operations of a palm oil mill and a biogas power plant is a synergy between maximizing the energy potential from POME and utilizing the electricity in the mill or for outside use. Best practices in electrical power system dictate that the total electricity supply capacity be slightly more than the total electrical demand. The excess capacity allows for peak demand, losses in transmission and distribution, and internal electricity use (called parasitic load or auxiliaries). If one of power plant in the unit fails, the electricity system would operates with support of excess electricity capacity supply. **Figure 3.5** shows a typical electricity supply and demand curve. This figure depicts the relationship between total plant capacity for electricity supply, peak load, the load curve, and the average load.

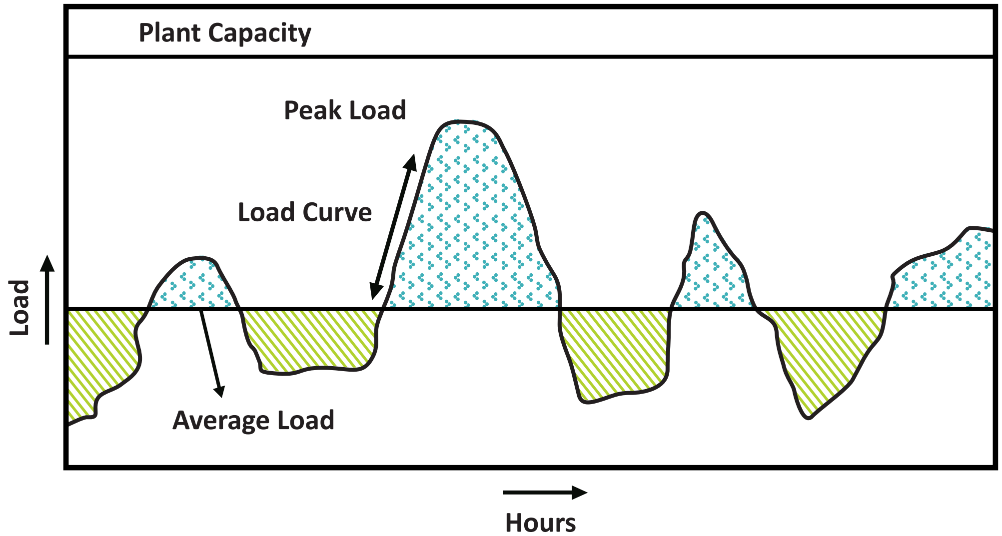


Figure 3.5. Electricity supply capacity and variation of electrical load

In a palm oil mill, the electricity generated from the biogas power plant needs to be synchronized with the existing electricity sources within the palm oil mill to meet the total electricity demand in the electricity network. The existing electricity sources in the palm oil mill normally include a biomass power plant and diesel generators. If the mill is connected to the PLN grid, it can sell the excess power to PLN. Alternatively, when the mill requires more electricity, it can buy electricity from PLN. The diagram below shows the electricity sources and loads in a palm oil mill with methane capture.

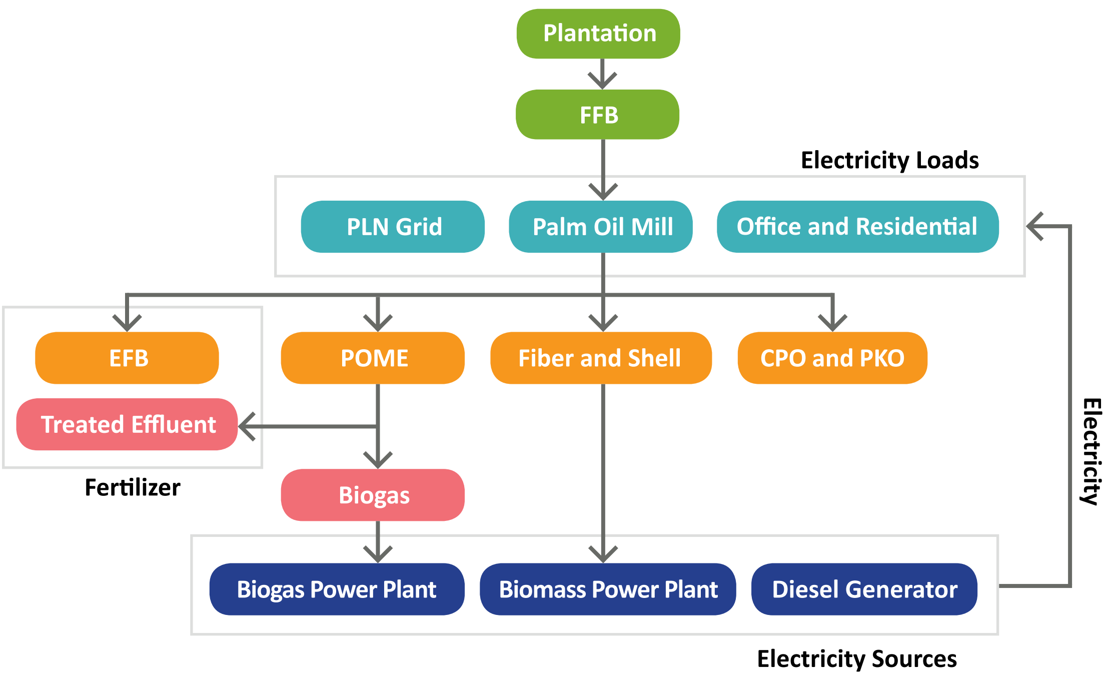


Figure 3.6. Electricity sources and loads in a palm oil mill

The main assessment of the electrical system covers both current electricity sources and loads and those anticipated after biogas power plant installation. Using the historical data on power measurement, Electrical engineers can assess the energy balance.

Prior to the installation of a biogas power plant, biomass power plants and diesel engines meet the electricity demand of the palm oil mill. To meet the electricity demand from the mill and non-mill draws, some mills have more than one biomass power plant or install diesel engines. **Figure 3.7** shows the electricity balance in a palm oil mill with a processing capacity of 60 tons of FFB per hour prior to the installation of a biogas power plant.

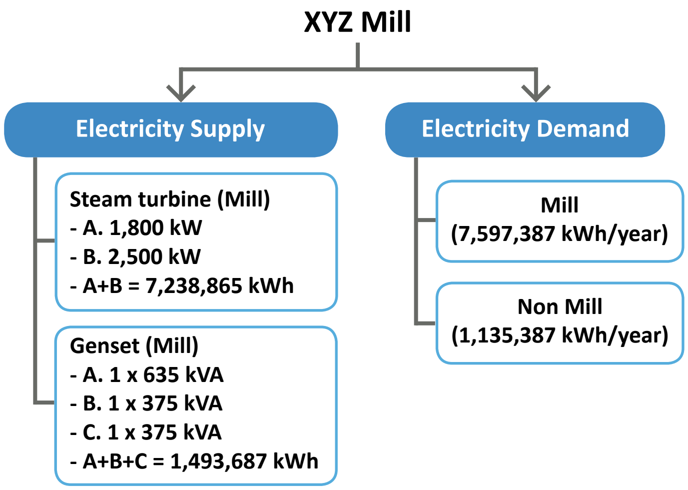


Figure 3.7.
Palm oil mill electricity balance before biogas installation

II.1. Electricity Supply

A typical mill uses a biomass power plant to supply electricity and process steam for the mill. The biomass power plant typically uses a boiler (**Figure 3.8**) to burn shells and fiber, the waste products from palm-oil processing, and a steam turbine (**Figure 3.9**) to convert heat into electricity. High-efficiency turbines use superheated steam with high pressure and temperature, taking advantage of the higher enthalpy.

In additional to biomass power plants, diesel engines provide electricity supply in many palm oil mills particularly serve as back-up power when biomass power plants are not in operation .

Figure 3.8. Boiler unit in a palm oil mill

Figure 3.9. Steam turbine in a palm oil mill

Figure 3.10. Diesel generators in a palm oil mill

In typical industrial practice, the total electricity supply is slightly higher than the total resistive load or real power required for uses such as lighting and heating. The excess electricity supply accounts for losses in the transmission and distribution network and reactive power from inductive loads (eg motors, fans, mixers and transformers) and capacitive loads (e.g. long extension cords). High voltage reduces losses in the transmission and distribution network. To reduce losses from reactive power that is mostly from inductive loads, an electrical engineer should install a capacitor bank in parallel or series with inductive loads.

Diesel generators often generate electricity for the start-up of the mills (**Figure 3.10**), as a back-up supply for times when the mill is not in operation, and to cover electricity demands beyond the capacity of the turbines. If the area around the mill and plantation is off the electrical grid, diesel generators often supply electricity to remote operation units such as offices and houses.

II.2. Electricity Demand

Typical electrical demand in a palm oil mill comes from process plants for crude palm oil or palm-kernel oil, offices, housing, and lighting.
Similar to other power generation, a biogas power plant also has the following loads: (1) parasitic loads (in-house power consumption and auxiliaries for the biogas plant itself); (2) mill and non-mill loads; and (3) outside loads (main electrical grid, villages).

II.2.1. Parasitic Load

A parasitic load is the load from internal electrical equipment. In the biogas power plant, the parasitic loads may come from raw POME pumps, digester feed pumps, the cooling system, mixing tank pumps, recirculation pumps, biogas blowers, the biogas flare, the anaerobic effluent pump, compressors, portable pumps, indoor and outdoor lighting, and panel instruments.

II.2.2. Mill and non-mill loads

In general, the mill load is the electrical load directly related to producing crude palm oil. The load on the mill includes lighting in the factory, threshing station, boiler station, oil dispatch station, street lighting, and fuel pump station; the sterilizer and loading ramp station, workshops, the water treatment station, the clarification station, the pressing station, the depericarper, and the kernel recovery station.
Other loads include the management office, employee housing, sports facilities, street lighting, mosques, and water pumps. These are commonly referred to as non-mill loads.

II.2.3. Outside loads

POME to Energy project that sell the produced electricity to PLN shall comply to 'Guidance of connection to PLN Distribution System for Renewable Energy Power Plant', a guidance issued for renewable energy power plant with capacity below 10 MW and connected to 20 kV line.
The guideline requires project developer to conduct grid study which includes load flow analysis, short circuit analysis, stability of network, and relay coordination.

PART 4: FINANCE AND INVESTMENT

Available financing and anticipated return on investment may determine the feasibility of a biogas project. Given the many possible uses of biogas and the different needs of palm-oil mills, prospective investors should carefully weigh costs and benefits. **Table 4.1** below outlines the benefits of five major uses of biogas:

Table 4.1. Biogas use scenarios and their benefits

	Utilization scenario	Benefit
1	Biogas to grid-connected electricity	Electricity selling
2	Biogas to electricity (own use)	Displacement of diesel oil
3	Biogas to boiler (thermal energy)	Displacement of shell or other solid waste
4	Biogas for cooking	Selling of biogas Displacement of kerosene or woods
5	Biogas for transportation	Displacement of gasoline or diesel oil

Scenarios 1, 2 and 3 —biogas to grid-connected electricity, biogas to electricity for internal use, and biogas to boilers for heating— have proven successful in many projects around the world. These three uses are technically feasible and financially attractive. Developers have not yet implemented scenarios 4 and 5 —biogas for cooking and transportation— on industrial scales. Biogas for cooking and transportation are technically viable options, but supporters still face challenges bringing the relevant technologies to market and making them profitable. This section of the handbook discusses the financial viability of biogas projects that produce electricity for the grid, electricity for internal use, and energy for boilers.

I. Project Cost Structure

The costs of biogas projects consist of engineering, procurement, and construction (EPC) costs and other, non-EPC costs. The project location and the mix of technologies selected will influence the project cost structure.

I.1. EPC Costs

The EPC costs are all costs related to engineering, procurement, and construction activities. The digester and biogas conversion systems are generally the two most expensive elements. The cost of the biogas conversion system depends on the utilization scenario, especially whether the biogas is injected into a boiler for thermal energy production or into biogas engines for electricity production. Biogas-to-electricity systems require the project owner to purchase and install a new biogas engine, while biogas-to-thermal systems need only some modifications to the existing boiler. Biogas engines require greater investment compared to boiler injection. **Table 4.2** provides further detail on the components of the EPC costs.

Table 4.2. Engineering, procurement, and construction costs

A. BIO-DIGESTER & BIOGAS MANAGEMENT SYSTEM			Remark
Item	Components		
	Covered Lagoon	Tank Reactor	
Bio-digester System	a. Civil works: earthworks,cut & fill land, bio-digester construction b. Geo-membrane c. HDPE membrane d. Hydraulic works e. Piping system f. Equipment, e.g. pumps, valves, cooling tower	a. Cooling, hydrolysis & acidification ponds b. Civil & foundation works c. Pumping system & pump-house d. Fabrication & installation of anaerobic digester tank e. Digester continuous mixing system f. Feed tank & piping system	About 25% of total EPC costs
Biogas Management System	a. Civil works: earthworks, foundation, concrete works b. Hydraulic works c. Equipment (chiller, scrubber, blower, flaring system)	a. Civil & foundation works b. Equipment (scrubber, blower, flaring system)	About 16% of total EPC costs
Electrical & Instrumentation System	a. Electrical works & system b. Motor control center (MCC) panel, control panel c. Instrumentation d. Integration of SCADA system		About 10% of total EPC costs
Logistics			20-25% of total EPC costs
Shipping & Insurance			
Installation, Commissioning & Start-up (including biomass seeding)			
B. BIOGAS CONVERSION			
Biogas to energy conversion	Biogas to electricity	Biogas to thermal energy	
	a. Biogas engines & installation b. Shipping & insurance c. Equipment & instrumentation system	a. Boiler modification	20-30% of total EPC costs for biogas to electricity
C. OTHERS			
Grid installation	If biogas-to-electricity scenario is adopted: a. Grid within mill b. Grid connection to PLN's grid		USD 28,000 – 42,000 per km
Project Contingency	Established to address risks and unforeseen events (e.g., price escalation, exchange rate, design growth, change in scope, and inaccurate estimates). This is not a budget allowance, so the balance should be reviewed and adjusted along the project duration.		5-10% of total EPC costs

In general, tank systems cost more than covered lagoons. The investment costs for tank systems range from USD2.5–3.5 million per MWe, while the covered lagoon costs range from USD1.5–3 million per MWe. **Table 4.3** below compares EPC costs for covered lagoons and tank reactors for 1.2 MWe of power generation from biogas.

Table 4.3. Sample pricing for covered lagoon and tank reactor technology

Applied Technology	Digester Cost (USD)	Gas Engine (1x1.2 MWe) *	Total Investment Cost	Investment Cost (USD/MWe)
Covered lagoon	2,692,920	641,755	3,334,675	2,778,896
Tank reactor	3,021,368	641,755	3,663,123	3,052,602

* including insurance, control system, installation, VAT 10%

I.2. Non-EPC costs

Non-EPC costs include development costs, working capital, and financing costs, as detailed in **Table 4.4**.

Table 4.4. Components of non-EPC costs

Cost	Component
Pre-development costs	a. Project management cost b. Engineering and design c. Land procurement (if any) d. Legal and permitting e. Environmental assessment reports (UPL & UKL)
Working capital	This covers labor, operation and maintenance costs during the first operating periods (usually 3, 6 or 12 months)
Financing cost	This covers costs related to loans such as up-front fee, commitment fee, etc.

II. Operation and Maintenance Costs

Operation and maintenance costs for a biogas plant include labor, digester maintenance, and system maintenance. Using biogas with gas engines incurs an overhaul cost for the gas engines for every 48,000–60,000 operating hours, depending on the provider. **Table 4.5** below lists the typical components of operation and maintenance costs.

Table 4.5. Operation and maintenance costs

Cost Types	Examples
Components	
a. Labor	
- Biogas plant manager	
- Supervisor	
- Maintenance staff	
- Operators	
- Laboratory technician	
b. Lab analysis	Monthly sampling of COD, TSS, VFA, etc.
c. Insurance of biogas plant	
d. Insurance of staff	
e. Consumables	Office material, etc.
f. Instrument calibration	Annual calibration or based on acceptable standard
Maintenance	
a. Maintenance management fee	
b. Bio-digester & spare parts	Maintenance of cooling system, pumps, cover, electrical system, etc.
c. Biogas handling system & spare parts	Maintenance of scrubbers, blowers, filters, electrical system, etc.
Gas Engine Maintenance	
a. Spare parts	Every 2,000 operating hours
b. Spark plugs	
c. Maintenance	
d. Service contract	If under service agreement with engine provider

The annual operation and maintenance costs range from 5–9% of the EPC costs. During operation, the project owner may engage a service contract with the technology provider or gas engine provider for the first few years (three years minimum). Service contracts ensure efficient operation, reduce operational risks, and prepare the mill's personnel to run the biogas plant when the service contract ends.

III. Revenue Streams

POME-to-energy projects can generate several different revenue streams. Using biogas for grid-connected electricity generates revenue from electricity sales to PLN. Using biogas to produce electricity for captive power may offset fossil fuel costs or enable the sale of biomass that would otherwise serve as fuel. Selling carbon credits on compliance or voluntary markets may also generate revenue.

Table 4.6. Price estimates for different revenue streams

Revenue Stream	Unit *	Value	Scheme
Solid waste replacement	USD/tons of shells	30–50	Market based price
Electricity sales	USD/kWh	0.08–0.15	Excess power or PPA
Carbon credits	USD/tCO_{2eq}	0.48 **	Market based price

Notes: * Exchange rate: 11,500IDR/USD; 1.3USD/Euro
** Based on green CER price at EU market in January 2014

Ministerial Regulation number 27/2014 regulates the new feed-in tariff for renewable energy from biomass and biogas. The feed-in tariff is 1,050IDR/kWh for medium-voltage interconnections and 1,400IDR/kWh for low-voltage interconnections. A multiplication factor (F) applies to the tariff based on the location of the project, **Table 4.7** lists feed-in tariffs and multiplication factors for different regions.

Table 4.7. Feed-in tariffs for renewable energy from biomass and biogas

Regions	Multiplication Factor (F)	Feed-in-tariff (Rp/kWh) Medium voltage	Feed-in-tariff (Rp/kWh) Low voltage
Java	1.00	1,050.0	1,400.0
Sumatera	1.15	1,207.5	1,610.0
Sulawesi	1.25	1,312.5	1,750.0
Kalimantan	1.30	1,365.0	1,820.0
Bali Island, Bangka Belitung Island, Lombok Island	1.50	1,575.0	2,100.0
Riau Islands, Papua Island and other Islands	1.60	1,680.0	2,240.0

IV. Evaluating Financial Feasibility

Prospective investors can evaluate a project's financial viability in several different ways. The following sections explain how to calculate the payback period, net present value, and internal rate of return for projects.

IV.1. Payback Period

Payback period is the simplest way to evaluate a project; it looks at how many years it will take to earn back the amount of money invested in the project. The payback period can be calculated by dividing the cost of the project by the annual cash flow generated by the project.

$$\textit{Payback Period} = \frac{\textit{Cost of the Project}}{\textit{Annual Cash Inflow}}$$

Alternatively, analysts could add annual cash flows until the total equals the cost of the project; the year in which the sum equal the total cost of the project is the payback year.

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Project Cost	(1,500,000)						
Annual Cash Flow		100,000	300,000	500,000	500,000	600,000	600,000
	(1,500,000)	(1,400,000)	(1,100,000)	(600,000)	(100,000)	500,000	1,100,000

Payback period in Year 5

Figure 4.1. Alternative method: finding the payback year

The shorter the payback period, the better the project viability. Payback periods do not account for the time-value of money, so they should not serve as a sole evaluation method.

IV.2. Net Present Value

The net present value (NPV) represents the value today of the sum of future net project cash flows. To calculate net present value, add up the discounted net cash flow from each year and compare the result with the total project costs. A financially feasible project will have a positive NPV, indicating that the present value of net cash flows generated throughout the project's lifetime exceeds the project's costs.

$$NPV = PV - C_0$$

$$\text{atau} \quad NPV = -C_0 + \frac{C_1}{(1+r)^1} + \frac{C_2}{(1+r)^2} + \frac{C_3}{(1+r)^3} + \dots \dots$$

$$NPV = -C_0 + \sum_{t=1}^{T} \frac{C_t}{(1+r)^t}$$

Where:
NPV = Net Present Value
PV = Present value
C = Cash flow for the year
r = Discount rate
t = Year
C_0 = Initial investment

It is very important to select an appropriate discount rate (r). You can apply an internal group company discount rate, the interest rate from a lender, a weighted average cost of capital (WACC), or a commonly used sector standard. Project developers should remember that biogas projects fall under the sector category of energy and infrastructure, which is different from the palm oil sector.

IV.3. Internal Rate of Return

The internal rate of return (IRR) compares the value of a known interest rate with the economic returns expected from the project. The internal rate of return is an indicator of the efficiency, quality, or yield of an investment. The IRR is the interest rate that will bring the net present value of expected cash flows (positive and negative) to zero. Calculating the IRR without a computer or financial calculator requires trial and error. The simple formula is as follows:

$$IRR = \frac{\text{Cash flow}}{\text{Present Value (PV)}}$$

Analysts consider an investment acceptable if its internal rate of return is greater than an established minimum acceptable rate of return or cost of capital. The higher a project's internal rate of return, the more desirable it is.

The internal rate of return for a desirable POME-to-energy project may vary from 11% to 23%. Financing structures, investment costs, project locations, and biogas-use scenarios all influence what makes a desirable IRR. The two most viable scenarios with attractive financial returns are: (1) selling electricity to the grid; and (2) replacing diesel generators. Further study will show whether biogas use for cook stoves or transportation on an industrial scale has a desirable IRR.

Projects in Kalimantan and Sulawesi enjoy higher electricity tariffs than those in Sumatera, which could increase revenue for the former. The project investment costs in Kalimantan and Sulawesi might be higher, though, due to transportation costs and procurement activities.

Box 4: Factors influencing financial returns

Several key factors influence financial returns on biogas projects:

- Investment, operation, and maintenance costs
- Exchange rates. Mill operators must buy most biogas plant components from overseas USD, so a less favorable exchange rate would negatively impact profitability.
- Utilization scenario. Favorable scenarios for financial return include selling electricity to the grid or replacing diesel generators. Injecting biogas into boilers brings less attractive financial returns (the IRR could be lower than 10%).
- Feedstock. The quality of effluent supplied to the bio-digester (eg volume of wastewater, COD levels) will drive the productivity of the biogas plant, affecting power generation. A change in the mill's production system or effluent supply could disrupt the bacteria and their ability to digest POME, so should be managed to ensure smooth operation.

V. Business Models

For biogas projects, there are two common business models: build, own, operate (BOO) or build, own, transfer (BOT). The model selected can influence how a project is financed and may impact profitability for the different parties involved.

V.1.1. Build, Own, Operate

Under the build, own, operate (BOO) model, the owner of the palm-oil mill builds the biogas plant extension and operates it as part of regular mill operations. The model may involve external parties such as investors, EPC contractors, or project operators, but the overall responsibility and ownership belong to the mill. **Figure 4.2** provides a graphical representation of the BOO model.

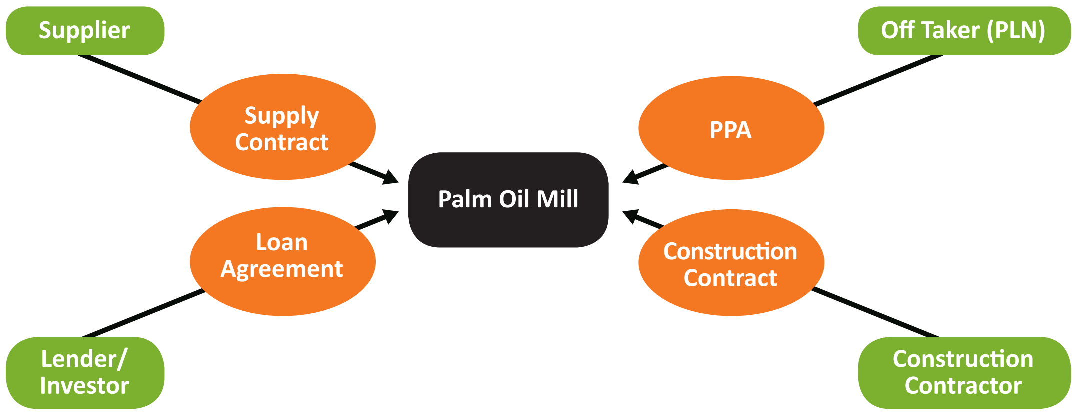


Figure 4.2. Build, own, operate (BOO) business model

The advantage of using the BOO business model is that the owner has full control over the project. If the mill employees lack the experience necessary to operate the plant, however, hazards, delays, or cost overruns could result.

In one variation of the BOO model, the mill engages a business cooperation with a third-party developer and establishes a special project vehicle (SPV) to run the biogas project. In this arrangement, the mill acts as a minor shareholder, while the third party acts a major shareholder and manages the overall project.

V.2. Build, Operate, Transfer

The build, operate, transfer (BOT) model uses financing to fund the project. In BOT-based projects, a third party receives a concession to build and operate a biogas project that a mill would otherwise build. In this scheme, the third party develops and operates the biogas project during an agreed-upon concession period, generally 10 to 15 years. At the end of the agreement period, the third party transfers the operation and ownership to the mill. **Figure 4.3** depicts the BOT model.

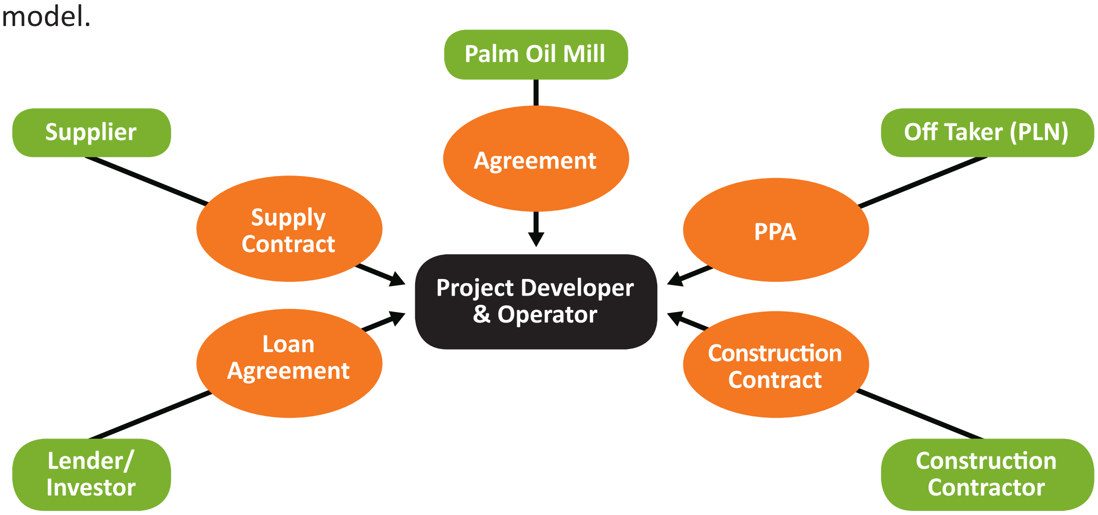


Figure 4.3. Build, operate, transfer (BOT) business model

Table 4.8 lists some of the key advantages and disadvantages of the BOT model.

Table 4.8. Advantages and disadvantages of build, operate, transfer (BOT)

Advantages	Disadvantages
• Offers the possibility of realizing a project that would otherwise not be built • The efficiency and competency of the project developer and its economic interest in the project will produce cost efficiencies to the mill when the agreement period ends.	• Complicated structure that requires detailed planning, time, and money throughout the concession period. The project developer must have commitment and interest to maintain the project.

VI. Financing the Project

VI.1. Internal Financing

Typically, the company's or group's own equity - usually, retained earnings for investment - is the first source project funding. Internal financing is generally less expensive than external financing since it does not involve transaction costs or incur taxes. **Table 4.9** lays out some of the key advantages and disadvantages to internal financing.

Table 4.9. Advantages and disadvantages of internal financing

Advantages	Disadvantages
• Funding is immediately available • No interest payments incurred • No control procedures regarding credit worthiness • Full control, no influence from third parties	• Limited amount of funding, largely subjected to company's financial capability • Probability of incurred opportunity costs

VI.2. External Financing

External financing funds a project through a combination of equity and external sources. External financing typically costs more than internal financing since it usually involves transaction costs and interest payments. The following are common types of external financing:

- External investor. A financially and technically feasible project attracts an investor to participate as a minority or majority shareholder in the project.
- Loan. A bank provides a term loan under a corporate or project financing scheme. Corporate financing is easier to obtain since the group company guarantees it, whereas project financing is solely based on the project itself as collateral.
- Bond issuance. The company may issue bonds to finance the project development.
- Lease. Many vendors provide leasing options for their equipment or even the whole project.
- Grant/aid funding. Biogas projects that provide power to local communities may qualify for assistance from governments or other donors. In this project scheme, the local government typically manages the ownership and operation of the project.

PLN's recent establishment of an electricity feed-in tariff makes biogas projects more appealing to the financial sector. Some investors and third-party developers are actively seeking biogas projects with good potential for power generation.

Project financing for biogas projects is not yet common practice in Indonesia. No commercial banks in the country has disbursed such financing. Most existing biogas projects received their funding through equity or corporate financing, where the bank analyzes credit worthiness based on the balance sheet of the group or holding company. In project financing, the project itself is the collateral for the loan. The lender conducts due diligence on the project, including power purchase agreements, legal permits and status, and the project's technical aspects to ensure the project's success. Therefore, obtaining project financing may take longer than corporate financing.

On the other hand, POME-to-energy projects' potential for emission reductions and energy provision is drawing attention from key stakeholders, including the Government of Indonesia and international donor agencies. The Ministry of Energy and Mineral Resources (MEMR) has launched a bio-energy program under the Special Allocation Fund *(Dana Alokasi Khusus – DAK)* that awards grants to local governments to develop POME-to-energy projects. Three projects on Sumatera Island are developed under this program.

Several donor-funded programs, including CIRCLE, Indonesia Clean Energy Development (ICED), Energy and Environmental Partnership with Indonesia (EEP-Indonesia), and Least Cost for Renewable Energy (L-CORE) provide technical assistance or grant funding for feasibility studies of POME-to-energy projects. Other programs, such as the Millennium Challenge Corporation (MCC), administer grants or soft loans for green projects that could have positive social and environment impacts in Indonesia, such as POME-to-energy projects.

VII. Carbon Financing

Renewable energy projects in developing countries like Indonesia can generate funds by selling certified carbon credits. Access to the international carbon market was initially designed under the Kyoto Protocol flexible mechanism that linked the Clean Development Mechanism (CDM) for "Non-Annex" (developing) countries to cap-and-trade mechanisms in "Annex I" (industrialized) countries such as the European Union Emissions Trading Scheme (EU ETS), or the Australian and New Zealand mechanisms.

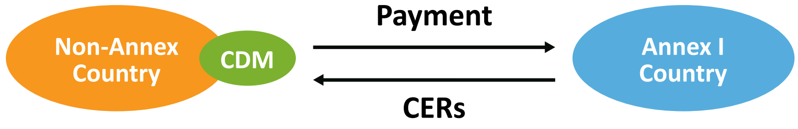


Figure 4.4. Relationship between Non-Annex and Annex I countries under the CDM scheme

Alongside the Kyoto flexible mechanism, voluntary markets have emerged where groups, businesses, and governments have collectively committed billions of dollars to buy emissions reductions. According to the World Bank, the total value of voluntary carbon markets increased dramatically from USD $11 billion in 2005 to USD $176 billion by 2011.

Table 4.10 below outline the steps required to obtain carbon credits to sell on the market.

Table 4.10. Steps to obtain carbon credits

Step	Description
1. Project Development	This step consists of several activities including selecting the validation methodology, conducting the baseline assessment and calculation, estimating the project emissions reductions, creating a monitoring plan, and project documentation.
2. Validation	A validation process is carried out prior to the registration process. Some voluntary registration bodies allow small-scale projects to be validated upon registration and along with the verification.
3. Registration	Projects under a UN offset mechanism or voluntary registration body must be registered.
4. Monitoring & Verification	The monitoring stage must be implemented based on the monitoring plan and verified by an independent verifier.
5. Carbon Credits Issuance	Carbon credits are issued for the verified project

Currently, carbon markets can be categorized into two types, which are outlined below.

VII.1. Compliance Market

In the compliance market, credits are generated by projects that operate under one of the United Nations Framework Convention on Climate Change (UNFCCC) mechanisms. The market consists of industrialized countries (Annex I), which have made commitments under the Kyoto Protocol to reduce their greenhouse gas emissions. The countries monitor and regulate carbon-intensive industries, and impose an annual emissions cap; industry stakeholders may purchase carbon credits on the open compliance market to offset emissions they produce that exceed their emissions allocation. Non-Annex countries are not subject to emissions reduction commitments, but they are allowed to generate carbon credits through emissions-reducing projects, and they may sell those credits on the open market.

The methodologies applied to determine the authenticity and size of the offsets generated by projects in this market are standard methodologies developed by Executive Board of the UNFCCC. Projects are registered by the UNFCCC and the products are called Carbon Emission Reductions (CERs). The main market for CERs is the EU ETS.

The Kyoto Protocol's first commitment period ended in 2012, and the second commitment period has yet to come into force; as a result, the price of CERs has been declining from €20 per ton of CO_{2eq} in 2008 to €0.40 per ton in 2013. Presently, there is no international agreement replacing the Kyoto Protocol in force that would apply to EU member states to ensure the demand for CERs and drive the price. The EU ETS accepts CERs from projects that have been registered prior to December 2012, including projects under the Program of Activities (PoA).

A PoA is a voluntary coordination of individual CDM project activities (CPAs) by private or public entities. A biogas or methane capture project in 2014 can be included in a PoA that has been registered in 2012, without necessarily being registered in 2012 as an individual project. Biogas projects in Indonesia have an opportunity to access the carbon market through inclusion in the registered biogas project PoAs listed in **Table 4.11**.

Table 4.11. Projects Registered under Program of Activities (PoAs) in Indonesia

No	Project Number	Project Title	Managing Entity
1	PoA 9096	BWC Sustainable Biogas Recovery Programme of Activities in Indonesia	PT Blue World Carbon Indonesia
2	PoA 7864	Recovery and Avoidance of Methane from Industrial Wastewater Treatment Projects	PT Knowledge Integration Services
3	PoA 6209	Indonesia Biogas Projects	PT GP Carbon Solutions Services Indonesia
4	PoA 6749	South East Asia Biogas Programme	PT Biogas Program International

Source: cdm.unfccc.int, accessed on January 2014.

The countries that have implemented a cap-and-trade program regulate the eligibility of international carbon credits used for compliance. **Table 4.12** summarized the carbon reduction regulations in several key trading programs:

Table 4.12. Carbon reduction regulation in several countries.

Country	Description
Australia	Use of international credits (Kyoto-units) for compliance is limited to 50%. Potential restrictions on CERs if they arise from: - Nuclear projects - The destruction of trifluoromethane - The destruction of nitrous oxide from adipic acid plants - Large scale hydro-electric projects not consistent with criteria adopted by the EU World Commission on Dams guidelines
California Cap-and-Trade (USA)	The usage for total offsets is limited to: - 2% of a firm's total compliance obligation in the first compliance period - 4% of a firm's total compliance obligation in the second and third compliance periods Offset protocols under California carbon program are for ozone depleting substance (ODS), livestock, urban forests, and US forest projects. These protocols do not allow offsets outside of the US, Canada, or Mexico.

Country	Description
New Zealand	The Government is considering restricting international emissions units from surrender in the New Zealand Emissions Trading Scheme for the following: - ERUs generated from HFC-23 and N_2O industrial gas destruction projects (effective in December 2011) - CERs and ERUs generated from large scale hydropower projects greater than 20 MWe that do not meet the World Commission on Dams guidelines
Korea	Under the Korea Enforcement Decree of Allocation and Trading of Greenhouse Gas Emissions Allowance Act (13 November 2012) CERs and ERUs are excluded from use until 2020. The later phase allows a relevant limit of 50%, however the absolute number of international offsets submitted for compliance cannot exceed the number of domestic offsets submitted for each compliance year.
European Union	EU-ETS establishes restrictions for credits: - from projects registered after December 2012 from non-Least Developed Countries; - from industrial gas projects.

VII.2. Voluntary Market

In the voluntary market, carbon credits are generated by projects that are accredited based on independent international standards. The credits are known as Verified Emissions Reductions (VERs). The voluntary market generally applies to companies, individuals, and other entities and activities not subject to mandatory limitations that wish to offset greenhouse gas emissions of their own accord.

Box 5: Hilton Worldwide Carbon Offset Program

The Hilton chain of hotel has launched the ‘Hilton Worldwide Carbon Offset Program in Southeast Asia’ as part of its sustainability efforts. It aims to reduce the impact of meetings and events held at participating hotels in Southeast Asia. Hilton will offset the carbon emissions by participating properties in Indonesia, Malaysia, Singapore, Thailand and Vietnam. Hilton buys carbon credits from the following projects:

Borneo Rainforest Rehabilitation Project; Sabah, Malaysia
Musi Hydro Project; Bengkulu, Sumatera, Indonesia
Mungcharoen Biomass Project; Thailand
Song Ong Small Hydro Project; Ninh Thuan Province, Vietnam

Source: http://www.hiltonmiceasia.com/carbon

The voluntary market typically allows projects developed under any new methodologies approved by the Voluntary Carbon Standard Board or individual new methodologies. There are several applied standards that may be adopted by project developers, including the Verified Carbon Standard (VCS), the Gold Standard, the Climate Change and Biodiversity Standards (CCBS), and ISO 14064.

Buyers in the voluntary market are mostly private sector organizations motivated by corporate social responsibility and industry leadership that desire to positively impact the climate resilience of their supply chain. The market volume has grown significantly from USD88 million in 2006 to USD101 million in 2012. While the price of CERs has fallen sharply in the past three years, VERs prices have remained quite stable, with an average of USD6.2/tCO_{2eq} in 2011 and USD5.9/tCO_{2eq} in 2012. Forest Trends and Bloomberg New Energy Finance in their 2013 report projects that the voluntary market could reach USD1.6 to 2.3 billion by 2020 if the market actors can significantly communicate the importance of carbon offsetting and carbon market infrastructure to the related stakeholders. **Figure 4.5** shows the amount of CO_{2eq} traded annually on the voluntary market.

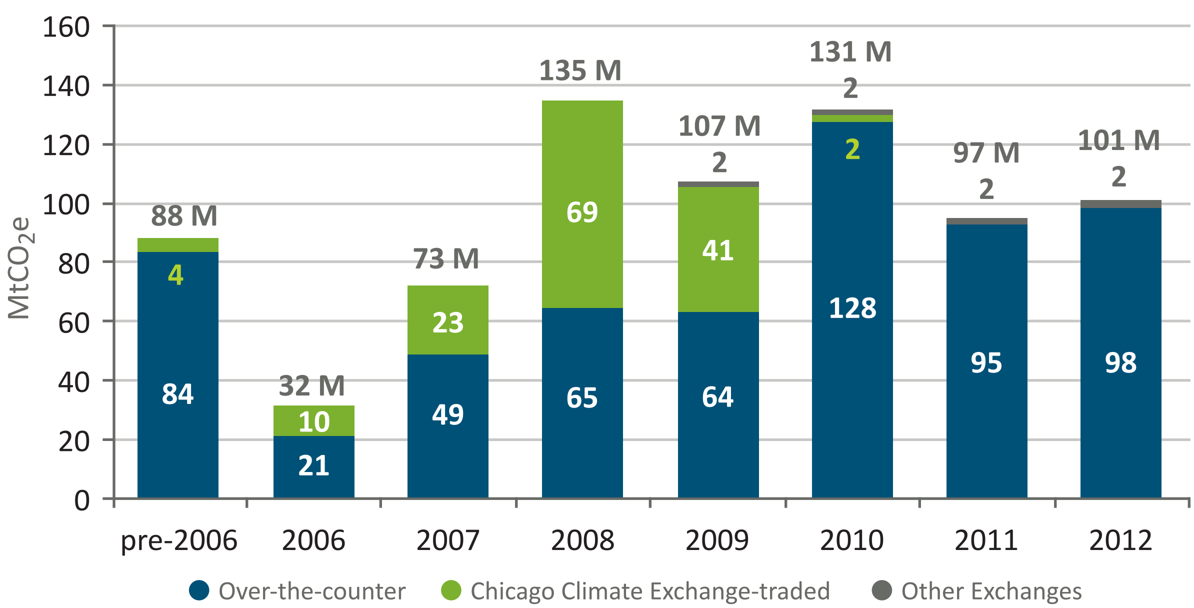


Figure 4.5. Voluntary emissions reductions (VERs) market over time

Source: Forest Trends' Ecosystem Marketplace, State of the Voluntary Carbon Markets 2013

VII.3. Domestic Market

Several countries such as China and Japan have developed domestic offset schemes to stimulate further emissions reductions and abatement investments in the non-traded sector. The projects are carried out in the investor country and do not involve other countries nor are they interlinked with other carbon market schemes.

In Indonesia, the National Council of Climate Change (*Dewan Nasional Perubahan Iklim* – DNPI), as the Designated National Authority of Indonesia, proposed the Nusantara Carbon Scheme *(Skema Karbon Nusantara)* for a domestic carbon market. The scheme aims to promote the deployment of emissions reductions projects and create sustainable development in Indonesia. However, the DNPI had not announced the launch schedule, which industries must comply, or the methodology to be applied for this domestic scheme.

PART 5: PALM OIL SUSTAINABILITY STANDARDS

Palm oil is the most commonly used vegetable oil, found in food products, detergents, cosmetics, and biofuels. Palm oil production has grown significantly over the past several decades; the industry is rapidly expanding today.

Global production of palm oil has doubled over the last decade. In 2000, palm oil was the most produced and traded vegetable oil (FAO, 2002), accounting for 40% of all vegetable oils traded internationally. By 2006, the percentage had risen to 65%. Worldwide demand for palm oil is expected to double again by 2020. Palm oil producers are developing new plantations and expanding existing ones in Indonesia, Malaysia, and other Asian countries, as well as in Africa and Latin America. **Table 5.1** below shows the expansion of the palm oil industry in Indonesia.

Table 5.1. Development of Indonesia's palm oil industry since 1980

	1980	2000	2010	2020 (Target)
Palm oil plantation area (ha)	294,560	4.16 million	8.38 million	9.14 million
Annual CPO production (ton)	721,172	7 million	21.9 million	34.3 million

Source: Ditjen Perkebunan, 2011

The rapid expansion of the palm oil industry has raised concerns about sustainability. As palm oil producers expand the scale of their plantations, they often convert land with high conservation value.

A responsible approach to economic development must account for environmental, social, and economic impacts, considered the three pillars of sustainability. Ideally, sustainable solutions protect the environment while strengthening communities and fostering long-term prosperity. The diagram below shows the three pillars and how they overlap.

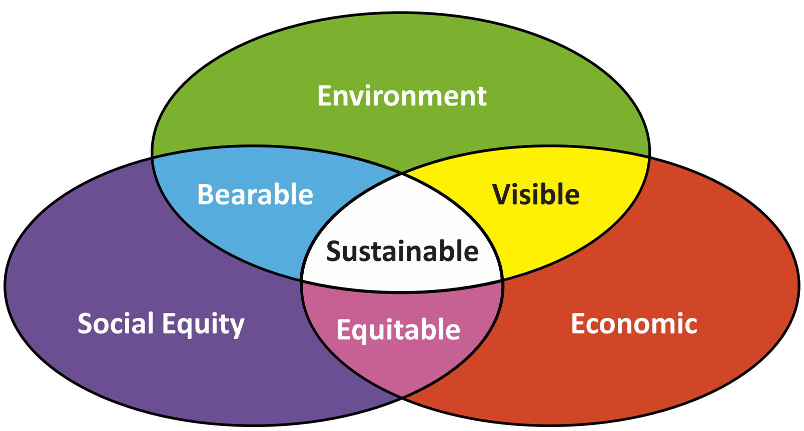


Figure 5.1. The three pillars of sustainability: environmental, social, and economic

Source: The World Conservation Union, 2006

Environmentally sustainable projects protect the quality of air, water, and land, reduce greenhouse gas emissions and waste, and promote biodiversity. The social pillar of sustainability encompasses diversity, human rights, community empowerment, corporate social responsibility, livelihoods for indigenous communities, and labor rights. Economic factors in sustainability include innovation, growth, improving margins, and providing returns for shareholders.

Box 6: How biogas and other methane-capture installations improve sustainability

POME is the second largest single source of greenhouse gas emissions in the palm oil industry, after the emissions from land-use change. Degradation of organic content in POME releases methane gas into the atmosphere. POME has an average methane yield of 0.39 m^3/kg of volatile solids. This methane yield is higher than other common feedstock sources such as dairy manure (0.38 m^3/kg) and municipal solid wastes (0.35 m^3/kg). Capturing the methane released from POME translates directly into GHG emissions reductions, which is a goal in the environmental sustainability pillar.

Methane capture processes are operated essentially as a wastewater treatment plant. It ensures proper liquid waste treatment and disposal, and avoids ground or surface water contamination. Because the organic degradation process is more efficient and controlled, the same treatment results can be achieved using a smaller lagoon footprint than the regular WWTP. The use of a smaller area results in reduction of land use change.

Sources: Lam and Lee et al. 2011, Amonet al. 2007, Chynoweth et al. 1993, Forster-Carneiroet al. 2007; Kabouriset al. 2009, Mølleret al. 2004.

I. Sustainability Standards

There are many different sustainability standards for the biomass and biofuels market. Each set of standards has different principles and criteria, but all standards stem from the three pillars of sustainability. Since 2005, when sustainability began to gain traction, these standards have proliferated. **Figure 5.2** shows a variety of biomass sustainability standards currently available.

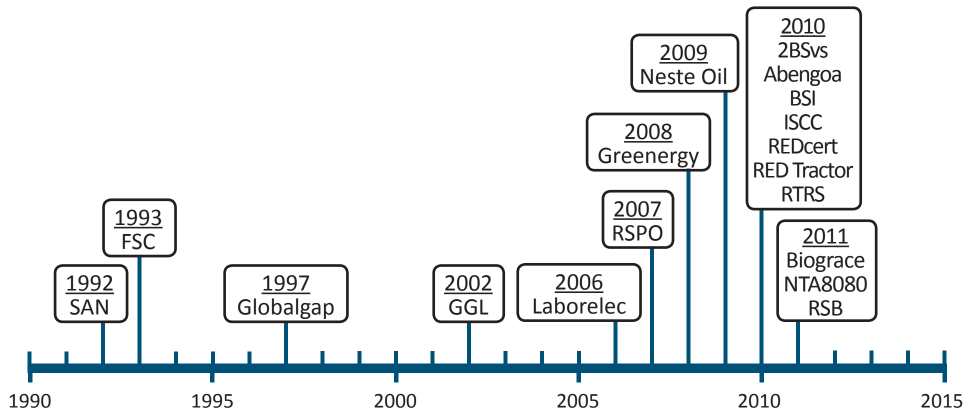


Figure 5.2. Biomass sustainability standards

Source: Partners for Innovation, 2011

Biomass producers who adhere to a specific standard earn independent seals of approval marking their products as sustainable. Standards provide specific guidelines for all participants in the biomass chain about how to comply with regulations and ensure sustainable production. The main elements of a certification system are:

- Sustainability standard: a set of principles and criteria that govern the three pillars of sustainability.
- Chain of custody: the method connecting the entire supply chain from feedstock production, through intermediate products, to the final product.
- Management rules: rules that govern audits, levels of transparency and accessibility, stakeholder engagement, and complaints.

A palm oil company usually starts the process of earning a sustainability stamp based on its needs. The following section outlines similarities and differences among the main standards used in the industry. Independent auditors approved by certification bodies normally conduct the sustainability audits. The flow chart in **Figure 5.3** below shows the common process for obtaining a sustainability certification for a product.

Figure 5.3. Obtaining a sustainability stamp on a product

II. International Standards

In Indonesia, the palm oil industry commonly uses two sets of sustainability standards: Roundtable on Sustainable Palm Oil (RSPO) and International Standard for Carbon Certification (ISCC). Both of these international standards are voluntary, each with different potential markets and incentives. The standards share similar principles and criteria with slightly different emphases. RSPO, for example, focuses on transparency and economic viability. Unlike ISCC, RSPO is specifically for palm oil commodities, so it also focuses on re-plantings.

A breakdown of principles and criteria shows how these two standards apply the three sustainability pillars. **Table 5.2** outlines the main principles and criteria in RSPO and ISCC. The table places similar principles on the same row to show overlap.

Table 5.2. RSPO and ISCC principles and sample criteria

Principles	Examples of Criteria
Commitment to transparency (RSPO)	• Provision of information to stakeholders on environmental, social, and legal issues for effective participation in decision making. • Management documents that do not have commercial confidentiality are publicly available.
Commitment to long-term economic and financial viability (RSPO)	• Business management plan that aims to achieve long-term economic and financial viability.

Biomass should not be generated from land with high biodiversity value or high carbon stock. (ISCC)
 	
Environmental responsibility and conservation of natural resources and biodiversity. (RSPO)
	• Biomass shall not be produced on:
	  • Land with high biodiversity value.
	  • Areas that serve the purpose of natural protection
	  • Grassland of high bio-diversity
	  • Peat land
	• The status of rare, threatened or endangered species and high conservation value habitats shall be identified and their conservation taken into account.
	• Waste is reduced, recycled, reused, and disposed of properly
	• Efficient use of energy/renewable energy
	• Avoid use of fire for waste disposal and for preparing land
	• Plans to reduce pollution and emissions, including greenhouse gases, must be developed, implemented and monitored.

Biomass shall be produced in an environmentally-responsible way, including protection of soil, water, and air, and application of Good Agricultural Practices. (ISCC) Use of appropriate best practices by growers and millers. (RSPO)	• Soil management plan • Minimize erosion • Maintaining quality and availability of ground water • The use of Integrated Pest Management • Appropriate use of agrochemicals • Responsible water usage and abstraction • Proper disposal of surplus application mix • Facilities to deal with spillage • Documented product inventory • Proper and safe facility for storage of products • Adequate provision of waste disposal
Safe working conditions through training and education, use of protective clothing, and proper and timely assistance in the event of accidents. (ISCC)	• Well-implemented occupational health and safety plan • Training for workers, smallholders, and contractors • Availability of first aid kits • Proper protective clothing • Appropriate warning signs • Clean dining areas and running water • Procedures and facilities to handle accidents • Habitable living quarters

Principles	Examples of Criteria
Biomass production shall not violate human rights, labor rights, or land rights. It shall promote responsible labor conditions and workers' health, safety, and welfare and shall be based on responsible community relations. (ISCC) Responsible consideration of employees and individuals and communities affected by growers and millers. (RSPO)	• Social impact assessment • Transparent communication between mill and growers, communities, government, and other related parties • System for complaints and grievances • Documented compensation for impacted communities • Legal, minimum standard wages • Freedom to form workers' union • No child labor • Protection from sexual harassment • No discrimination • Fair and transparent deal with smallholders • Contribution to local sustainable development
Biomass production shall take place in compliance with all applicable regional and national laws, and shall follow relevant international treaties. (ISCC) Compliance with applicable laws and regulations. (RSPO)	• Legitimate land rights • Compliance with regional and national laws, and international treaties • Free, prior, and informed consent from local communities on land use
Responsible development of new plantings. (RSPO)	• A comprehensive and participatory independent social and environmental impact assessment • Soil surveys and topographic information for site planning • Avoid planting on steep surfaces • Appropriate land compensation for local people • Avoid use of fire for land clearing
Good management practices shall be implemented. (ISCC) Commitment to continuous improvement in key areas of activities. (RSPO)	• Regular monitoring and review of main activities • Effective data recording system

For full lists of the standards' principles and criteria, refer to the organizations' websites: www.rspo.org, and www.iscc-system.org.

III. Indonesian Sustainable Palm Oil (ISPO)

The Indonesian Sustainable Palm Oil (ISPO) is a mandatory initiative by the Indonesian Agricultural Ministry established through the Ministerial Decree number 19/2011 to integrate sustainability standards into palm oil production. The Indonesian government created these standards to fulfill its trading partners' growing demands for sustainable palm oil and to increase producers' commitment to sustainable practices. The European Union, for example, has targeted buying only sustainable palm oil by 2015.

ISPO's principles and criteria are based on 141 national regulations related to the palm oil industry. Some of these regulations have been in effect since 1960. ISPO's creators compiled regulations to ensure that all palm oil companies in Indonesia comply with national law. ISPO has 7 principles, 40 criteria, and 126 indicators. The seven categories of principles are:

1. Legal Permits (Agrarian Law and Forestry Law)
2. Plantation management and guidance for cultivating and processing palm oil (Law of Cultivation System)
3. Moratorium on location permits for plantations (Presidential Instruction)
4. Environmental management and monitoring (Environment Law)
5. Responsibility toward employees (Labor Law)
6. Social responsibility and increased economic role in the surrounding community (Cooperation Law, Plantation Law, Investment Law)
7. Commitment to long term economic empowerment (Plantation Law)

Slightly different schemes govern nucleus plantations, smallholders in plasma programs, and independent farmers. All seven principles apply for nucleus plantations and palm oil mills; for smallholders in plasma programs, the principle on economic development (number 6 above) does not apply. For independent smallholders, only four principles apply:

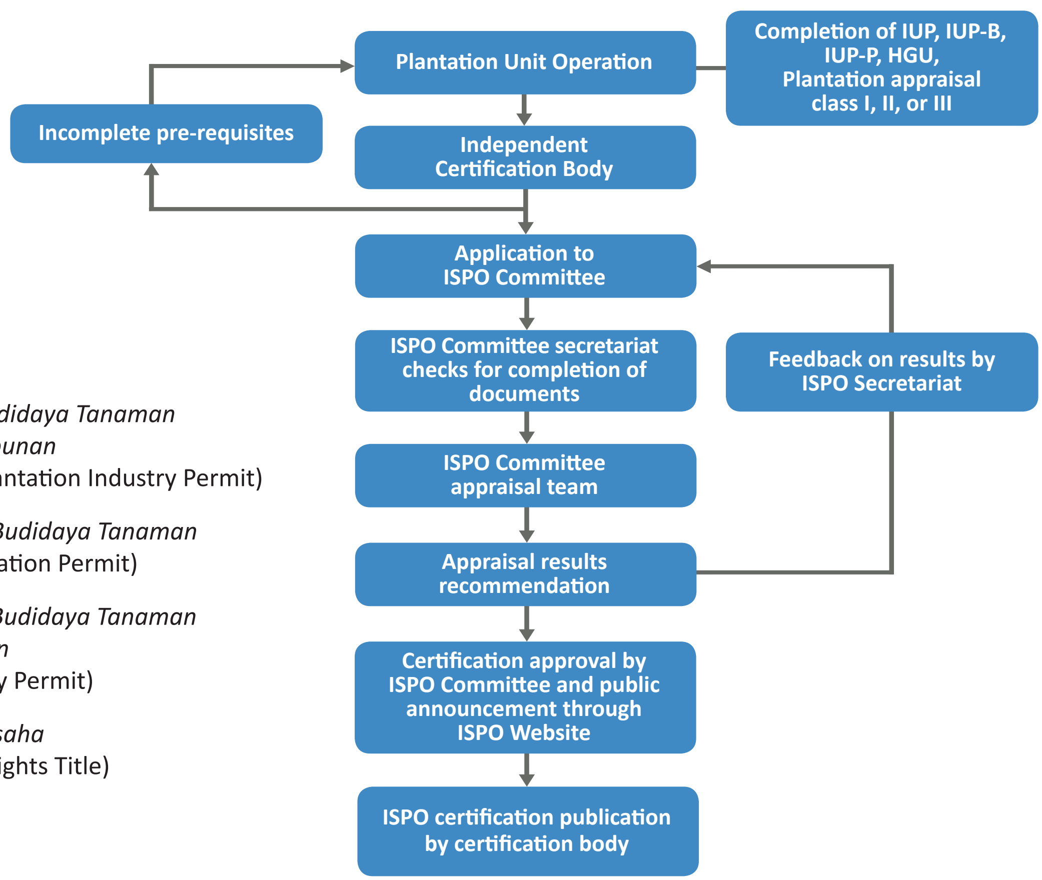
- Legal permits
- Plantation management and guidance for cultivating and processing palm oil
- Environmental management and monitoring
- Commitment to long term economic empowerment

ISPO aims to certify all palm oil mills and plantations by December 2014. The organization will certify holding companies with multiple mills as the holding group for operations that implement the same management system. The ISPO certification is valid for five years with regular yearly monitoring.

As a prerequisite of the ISPO certification audit process, palm oil plantations must obtain the Plantation Units Appraisal (*Penilaian Usaha Perkebunan*/PUP), as regulated in Agricultural Ministry Regulation number 7/2009. Appraisers score plantations as class "I" through "V," with class I being the best. For a plantation under development and not yet operational, appraisers give a class grade of A through E, with class A being the best. Only operations in class I, II, III, A, B, or C can move forward with an ISPO audit. Those in class IV, V, D, or E receive up to three warnings and 4 to 6 months to meet the standards.

Companies ready for the ISPO audit work together with an independent certification body that will submit an application to the Ministry of Agriculture and produce the audit report. As of the end of 2013, seven independent bodies conduct ISPO audits:

1. Mutu Agung Lestari
2. TUV Rheinland
3. PT Sucofindo (Persero)
4. TUV Nord
5. SAI Global
6. Mutu Hijau
7. SGS Indonesia



Note:
IUP : *Izin Usaha Budidaya Tanaman dan Industri Perkebunan* (Cultivation and Plantation Industry Permit)

IUP-B : *Izin Usaha Budidaya Tanaman Perkebunan* (Cultivation Permit)

IUP-P : *Izin Usaha Budidaya Tanaman Industri Perkebunan* (Plantation Industry Permit)

HGU : *Hak Guna Usaha* (Land Cultivation Rights Title)

Figure 5.4. Steps for ISPO certification

ISPO is still in the early stages of implementation, with ongoing modifications and updates to principles and criteria. **Table 5.3** below compares ISPO, RSPO, and ISCC.

Table 5.3. Comparing ISPO, RSPO, and ISCC standards

Criteria	RSPO	ISCC	ISPO
Scheme Initiator	Multi-stakeholder initiative from NGOs, companies, financial institutions, etc.	BLE (*Bundesanstalt für Landwirtschaft und Ernährung*/Federal Office of Agriculture and Food) Germany and European Union government	Indonesian Ministry of Agriculture
Implementation	Voluntary certification	Mandatory certification for biomass and biofuel products in European Union	Mandatory for palm oil unit operations in Indonesia
Starting Date	Signed on November 1, 2005 and implemented November 2007	Starting from January 1, 2011, all biofuel company in EU must be certified	Mandatory beginning December 31, 2014
Product Scope	Palm oil and its product derivatives	All commodities that produce vegetable oil for biofuels. It will be expanded to food, feed, and biochemical	Palm oil and its product derivatives
Audited Operations	Palm oil plantations, palm oil mills, palm oil refineries	Plantations, first gathering, vegetable oil mills, refineries, traders, used cooking oil industry	Palm oil plantations, palm oil mills, palm oil refineries
Implemented Standard	Sustainability principles and criteria, and supply chain	Sustainability principles and criteria, traceability and mass balance, and GHG calculation	Sustainability principles and criteria
Prerequisite	RSPO membership	Certification process to be registered to ISCC	Plantation appraisal and class grade I, II, III.
Greenhouse Gas Calculation	GHG calculation implemented (in progress)	GHG calculation implemented	GHG calculation implemented (in progress)
High Conservation Value (HCV) areas	HCV identification needed	Not specifically using HCV, but there are “Go” and “No Go” areas. “No Go” areas include high carbon stock areas and high biodiversity areas after January 2008.	Not specifically using HCV, but maintenance of protected areas required.
Risk assessment	No risk assessment	Risk assessment needed: regular, medium, and high risk	No risk assessment
Independent Auditor	Conducted by RSPO accredited certification bodies (Accreditation Services International [ASI] as accreditation body)	Conducted by ISCC accredited certification bodies (BLE as accreditation body)	Conducted by ISPO accredited certification bodies (ISPO committee as accreditation body)
Public Consultation	Public consultation and announcement	No public consultation and announcement	No public consultation, public announcement
Audit Result	Major and minor indicators	Major and minor musts. Full compliance on major musts and 60% compliance on minor musts.	Full compliance on all criteria. Three to six months are given for re-audit.
Certification validity	5 years	1 year and can be extended	Valid for 5 years with yearly surveillance
Price	CPO price may be higher	Premium price on CPO	No guarantee yet on higher CPO price

PART 6: GREENHOUSE GAS EMISSIONS FROM PALM OIL PRODUCTION

Greenhouse gases (GHGs) are gases that trap heat in the atmosphere. Some occur naturally, while others result from human activities such as industrial processes. The primary greenhouse gases in the Earth's atmosphere are water vapor, carbon dioxide, methane, nitrous oxide, and ozone.

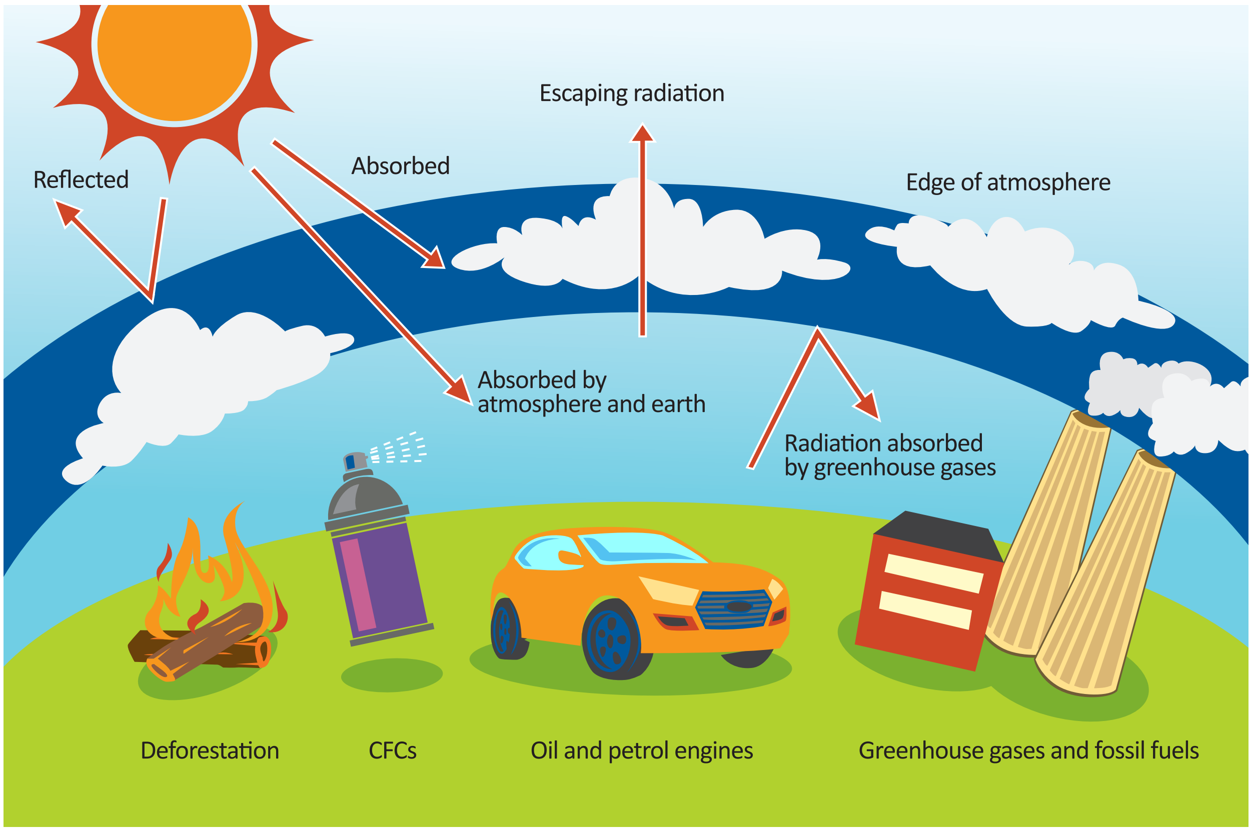


Figure 6.1. Global warming process and causes

Source: www.geogonline.org.uk

Greenhouse gases differ in how much they contribute to global climate change. The Global Warming Potential (GWP) index estimates the potential future impacts of different gases on the climate system based on the gases' heat trapping properties. The GWP index covers a specific time horizon, accounts for the effect of clouds, and incorporates predicted environmental scenarios. GWPs compare the heat trapped by a given mass of a GHG to the amount of heat trapped by the same mass of carbon dioxide. Therefore, the GWP of carbon dioxide is always 1. **Table 6.1** presents a GWP index.

Table 6.1. Global Warming Potential (GWP) index for common greenhouse gases

Compound	Chemical Formula	Global Warming Potential (GWP) in a given time horizon 20 years	100 years	100 years	500 years
Carbon Dioxide	CO_2	1	1	1	1
Methane	CH_4	72	21	25	7.6
Nitrous Oxide	N_2O	289	310	298	153

Sources: IPCC Third and Fourth Assessment Reports (2001 and 2007)

We based **Table 6.1** above on the 2007 report by the Intergovernmental Panel on Climate Change, on organization under the United Nations that draws a consensus from experts all over the world on climate change issues. Most calculations on climate change, however, use data from the previous report published in 2001 using a 100-year time horizon. Based on that 2001 data, the 100-year GWP for methane is 21, which means that if the same amount of CO_2 and CH_4 were introduced to the atmosphere, the methane would trap 21 times more heat than the carbon dioxide over the next 100 years.

$$\textbf{1 ton of } \mathbf{CH_4} \textbf{ = 21 ton } \mathbf{CO_{2\text{-equivalent}}} \ (\mathbf{CO_{2eq}})$$

All human activities –from producing and using products, traveling, or clearing land for agriculture– emit some amount of GHG. Just like in any other industry, GHG emissions occur throughout the palm oil production chain. GHG emissions result from material inputs, energy consumption, and degradation processes in all parts of the chain. A GHG inventory for the entire production chain must include all of these emissions sources.

Material inputs for palm oil production may include fertilizer, pesticides, chemicals used in the plant, and process water. A boiler using solid palm oil by-products including fibers and shells typically powers mill production. Producers consider fibers and shells by-products, so they qualify as a zero-emission source of energy. As a result, emissions from power generation that uses these two feedstocks are relatively low. Mills also generate energy from fossil fuels used for transportation and diesel engines. Land-use change from plantation development is the single largest source of GHG emissions in the palm oil industry. The largest source of emissions from palm oil mills is POME treated in open lagoons, where the effluent releases methane to the atmosphere.

Figure 6.2 below shows the typical emissions from the palm oil industry.

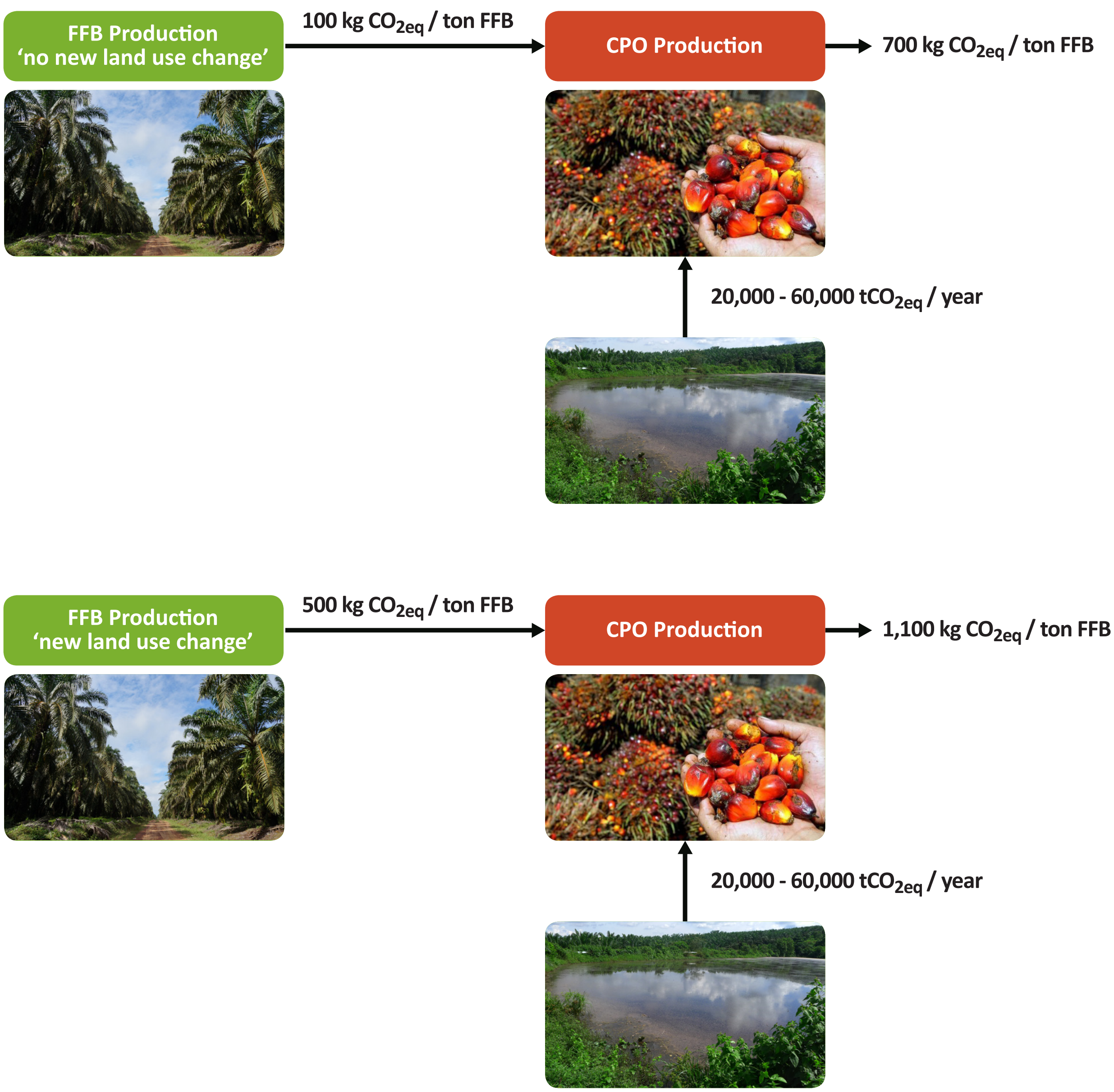


Figure 6.2. Emissions from FFB and CPO production

Table 6.2 below presents emissions figures from a plantation and mill in greater detail.

Table 6.2. GHG emissions values from a sample plantation and mill

Plantation				Mill			
Emissions Source	Unit	Value	%	Emissions Source	Unit	Value	%
Chemical fertilizer	tCO_{2eq}/year	4,571	87.81	Electricity	tCO_{2eq}/year	933	3
Fossil fuel	tCO_{2eq}/year	537	10.31	Inputs	tCO_{2eq}/year	48	0.2
Electricity	tCO_{2eq}/year	98	1.88	Wastewater	tCO_{2eq}/year	28,408	90
				Transportation	tCO_{2eq}/year	2,158	6.8
Total	tCO_{2eq}/year	5,206	100	Total	tCO_{2eq}/year	31,547	100
FFB yield	Ton/year	57,980		CPO yield	Ton/year	55,702	
Total GHG emissions	$kgCO_{2eq}$/ ton FFB	89.79		Total GHG emissions	$kgCO_{2eq}$/ ton CPO	566	

The amount of emissions released from plantations and mills varies depending on the sustainability practices, supply chain steps, and production processes used. As shown in **Figure 6.2**, a fixed-size plantation emits significantly less GHG than a plantation where farmers clear new land for palm-oil production. The biggest emissions source in the mill is wastewater treatment in open lagoons, where methane and other GHGs escape into the atmosphere. Methane-capture projects like POME-to-biogas reduce a mill's largest source of emissions and convert methane into a useful energy source. Using previously planted land and implementing a methane capture project could significantly reduce emissions from the palm oil production process.

Current sustainability standards favor methane-capture installation at palm oil mills. The standards use slightly different criteria and procedures for GHG calculations, but they use the same basic concept. **Table 6.3** below compares ISPO, RSPO, and ISCC standards with as they relate to GHG accounting.

Table 6.3. Comparison between ISPO, RSPO, and ISCC in GHG accounting

	ISPO	RSPO	ISCC
Policy Driver	Support government of Indonesia's target in emissions reductions of 26% by own effort or 41% with foreign assistance	No particular policy driver	EU Directive 2003/30/EG: The Directive strives for using a share of 5.75% of biofuels as a portion of total fuel used The materials supplied for biofuels shall comply to a minimum GHG saving threshold
GHG Inventory Considerations	- Land use change - Use of fertilizer and pesticides - POME - Diesel for transport and electricity - Process to produce CPO from FFB in the mill	- Emissions arising from operations during oil palm growing and FFB processing - Emissions arising from changes in carbon stocks during the development of new plantations and operations	- Biomass producers - Conversion units (conversion of solid biomass into liquid biomass or processing of liquid biomass) - Transport

PART 7: CALCULATING GREENHOUSE GAS EMISSIONS FROM PALM OIL PRODUCTION

Before performing a GHG calculation, it is important to understand some basic emissions reduction terms and concepts. An emission reduction is the amount of GHG that does not enter the atmosphere as a result of an implementation.

Emission Reduction = Baseline Emission – Project Emission – Leakage

Baseline emissions are those resulting from business-as-usual activities, while project emissions result from implementing project activities. Leakage refers to emissions outside the project boundary that are due to the project activity. Calculations consider emissions from leakage negligible because they are typically small.

Five main steps determine the amount of emissions. **Figure 7.1** below gives a summary of those steps.

1. Boundary establishment	• Project based? • Overall supply chain? • Specific business Unit?
2. Methodology	• CDM methodology or Voluntary Carbon Standard? • ISCC, RSPO, ISPO? • ISO 14065?
3. Emission Sources Inventory	• What activities to be included? • Emission sources?
4. Data Gathering	• On-site data gathering • Literature data for default value and emission factors • Tier to be applied
5. GHG Calculation	• Amount of activity x Emission factor x Global Warming Potential (GWP)

Figure 7.1. Basic steps to calculate emissions

Establishing boundaries helps define which activities the calculation should include. Boundaries determine, for example, whether the calculation focuses on a single project, the complete supply chain, or a particular business unit in the supply chain. With a clear boundary, the calculation shows which activities contribute directly to GHG emissions.

Analysts commonly calculate potential emissions reductions for methane-recovery projects using the CDM AMS.III-H Version 17 ‘Methane recovery in wastewater treatment’ methodology. The AMS.I-D Version 18 ‘Grid connected renewable energy generation’ methodology is best for calculating emissions reductions for electricity generation. Other methodologies work, but applying consistent assumptions is essential when mixing methodologies.

After calculating potential emissions reductions, identify emissions sources. **Figure 7.2** shows the main emissions sources in the three main parts of palm oil production: plantation, transportation, and palm oil mill.

Plantation
- Land use change
- Chemical fertilizer and pesticides
- Fossil fuel consumption

Transportation
- Fossil fuel consumption

Palm Oil Mill
- Inputs
- Fossil fuel consumption
- Chemical inputs
- Palm oil waste

Figure 7.2. Emission sources in palm oil mill

Then, gather operational data. Key data include the amount of inputs used, wastewater production, electricity consumption, and other factors related to production processes. Collect data from the literature to determine heating values and emission factors. Emission factors are well-researched data that show how much GHG is emitted from a unit of activity or product. For example, the emissions factor for nitrogen-based fertilizer is 5.88 kg CO_{2eq}/kg of fertilizer used; the emissions factor for $P_2O_5^-$ based fertilizer is 1.01 kg CO_{2eq}/kg of fertilizer (Biograce, 2011). **Table 7.1** below lists some of the site-specific and literature-based data.

Table 7.1. Site-specific and literature-based data for GHG calculations

Site-Specific Data	Literature-based Data
- Amount of main product and by-products - Amount of chemicals used - Amount of $P_2O_5^-$, K_2O^-, CaO^- and N^- fertilizer - Diesel and electricity consumption - Thermal energy consumption - Process energy source and consumption - Amount and use of by-products and wastes, e.g. POME or EFB	- Heating values of main product and by-product - Emission factors of diesel, chemical, electricity, etc - Emission factor of N_2O

Once the analyst has gathered all the data, the GHG calculation is a relatively straight forward task. The basic calculation is:

Emissions = Amount of material x Emission factor x Global Warming Potential

For example, if a plantation uses 920,000 kg of N fertilizer/year and 260,000 kg P_2O_5 fertilizer/year, the resulting emissions would be calculated as follows:

$$Emissions = \left(920{,}000\ \frac{kg\ N}{year} \times 5.88\ \frac{kg\ CO_{2eq}}{kg\ N} \times 1\right) + \left(260{,}000\ \frac{kg\ P_2O_5}{year} \times 1.01\ \frac{kg\ CO_{2\ eq}}{kg\ P_2O_5} \times 1\right)$$

$$= 5{,}672{,}200\ \frac{kg\ CO_{2eq}}{year}$$

The global warming potential of 1 is used because the emissions factor already uses carbon dioxide equivalents in the units.

Assuming the plantation is producing 110,000,000 kg FFB/year, the emission per ton of FFB emissions from these two fertilizers alone would be:

$$5{,}672{,}200\ \frac{kg\ CO_{2eq}}{year} \div 110{,}000{,}000\ \frac{kg\ FFB}{year} = 0.052\ \frac{kg\ CO_{2\ eq}}{kg\ FFB} \text{ or } 52\ \frac{kg\ CO_{2\ eq}}{ton\ FFB}$$

To obtain the total emissions to produce 1 ton of FFB, other inputs have to be included in the calculation, such as pesticides, land use change, etc.

Appendix

Appendix 1: Power Purchasing Agreements and Excess Power

For mills with a methane-capture facility that intend to sell their generated electricity to PLN, there are two schemes under which this can be done: a Power Purchasing Agreement (PPA) and an excess power agreement. A PPA is a multi-year agreement with relatively stringent application and price negotiation processes. Excess power, meanwhile, has a more straight-forward application process, with the electricity price already determined in Indonesia's current feed-in tariff for biomass- and biogas-based electricity. Table A.1 below provides a comparison between the two schemes.

Table A.1. Comparison between PPA and Excess Power arrangements for electricity purchase by PLN.

Item	PPA	Excess Power
Administration requirement (UU No.30/2009; PP No. 14/2012)	- Company identity - Company profile - Tax registration - Business license of power provider (IUPTL)	- Company identity - Company profile - Tax registration - Business license of power provider (IUPTL)
Technical requirement	- Power plant location - Single line diagram - Type and capacity of power plant - Construction schedule - Operation schedule	- Power plant location - Single line diagram - Type and capacity of power plant - Construction schedule - Operation schedule
Environmental requirements	Environment/Social Impact Assessment (ESIA): - AMDAL - UPL/UKL (Power plants with capacity below 10MW are not mandated to conduct full ESIA; UPL and UKL are sufficient.)	Environment/Social Impact Assessment (ESIA): - UPL/UKL
Business entity	Independent Power Producer	Any business entity which owns and operates a power plant with excess power
Agreement type	Multi-year agreement. 10–20 year contract, depending on the power plant type and negotiation.	Annual agreement. The agreement is renewable every year
Power tariff	- Feed-in tariff (Peraturan Menteri ESDM No. 27/2014) - Possible for price negotiation with approval from Minister of Energy and Mineral Resources	Feed-in tariff (Peraturan Menteri ESDM No. 27/2014)
Power tariff approval	Central PLN, Directorate General of Electricity	Regional PLN
Time to obtain the agreement	More than six months	Potentially less than three months

For excess power procurement, the company directly applies to PLN Regional and once PLN confirms that they are able to absorb the excess electricity, a business-to-business agreement (excess power agreement) is carried out. For Independent Power Producer (IPP) that wants to obtain PPA with PLN, there are three type of process, direct appointment, direct selection, and open tender. The differences between the three are explained in **Table A.2** below.

Table A.2. Three types of IPP Process

	Conditions	Project Type	Tariff
Direct Appointment	Renewable energies, mine-mouth coal fired power plant, local energy, excess power, expansion project, energy crisis conditions.	Coal-fired power plant, renewable energy (mini/micro hydro, geothermal, biomass, wind, solar).	Based on negotiation and/or applicable regulation issued by MEMR
Direct Selection	Energy diversification to non-fuel oil, more than one (1) direct appointment proposal in a system.	Non-fuel oil generators	Lowest price proposal submitted by the participants
Open Tender	IPP projects that are not eligible for direct appointment or direct selection, or PLN requires an open tender.	All kinds of power plants	Lowest price proposal submitted by the bidders

Figure A.1. below shows the general steps to obtain a PPA contract with PLN.

Pre - Qualification

Criteria:
- Financial Strength: Assets, Net Profit
- Technical Strength: Experience in IPP development, EPC and O & M

Request for Proposal

Contains:
- Information for Bidders
- Project Description
- Model Power Purchase Agreement
- Instruction to Bidders
- Proposal Requirements
- Evaluation Procedure

Letter of Intent

Contains:
- Agreed Major Terms & Conditions
- Agreed Electricity Tariff and Basic Formula

PPA Signing

Requirements: Performance Security Stage I, PLN's corporate approval MEMR tariff approval, SPC (Special Purpose Company)

Contains:
- Term of Agreement: Coal (25 years), Hydro (30 years), Geothermal (30 years), Gas (20 years)
- Project Scheme: BOO or BOT
- Tariff and Payment
- Force Majeure: natural and political
- Government Guarantee (if applicable)
- Termination
- Other Rights and Obligations of the Parties
- Sponsor's Agreement

Financial Closure/ Financing Date

Requirements (among other things)
- Copies of: EPC Contract, policies of insurance required by the PPA; fuel supply plan; Financing Agreements; Foreign Investment Approval
- The Legal Opinion Issued for PLN
- The Legal Opinion Issued for SELLER
- A copy of document(s) providing legal right to use and control over the site
- Performance Security Stage II

Commercial Operation Date

Requirement:
- Net Dependable Capacity test procedures completed

End of Contract

Transfer Procedure to PLN (if applicable)

Figure A.1. IPP project business scheme

The IPP procurement division of PLN has published a user handbook that can be accessed for more information at http://www.pln.co.id/dataweb/ipp/bookletipp.pdf.

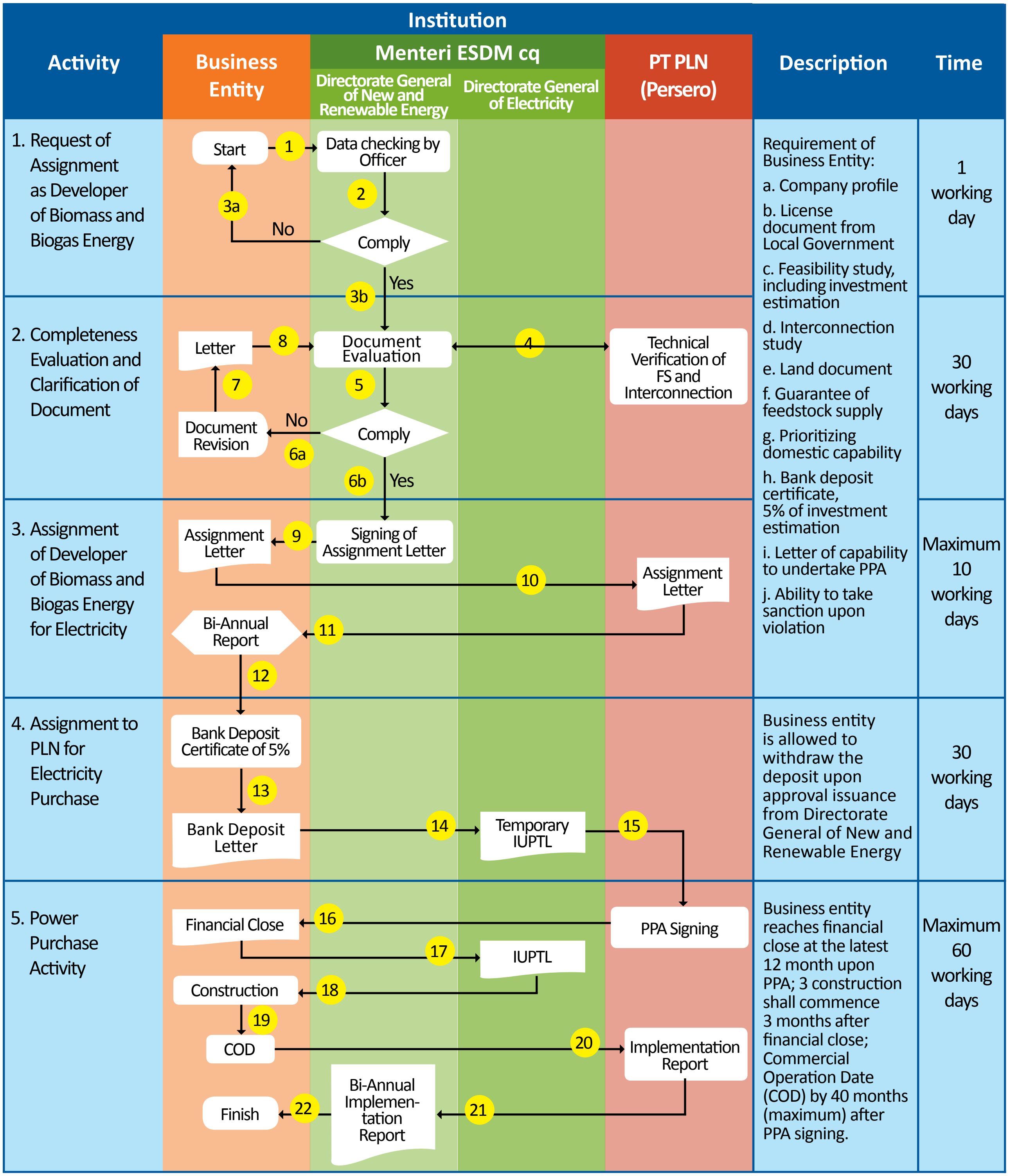


Figure A.2. Standard Operating Procedure of IPP Establishment for Biogas Power Plant

Source: Regulation of Minister of Energy and Mineral Resources No.27/2014

Appendix 2: GHG Calculation

Emissions reductions can be calculated based on baseline emissions, which are the GHG emissions during normal operation, and the project emissions, which are the GHG emissions when methane capture has been installed and the electricity has been sold to the grid. The emissions reduction is obtained through the formula below:

Emission Reductions (ER) = Baseline Emissions (BE) – Project Emissions (PE)

The estimation of potential emissions reductions for the methane recovery project is calculated with the CDM AMS.III-H Version 17 'Methane recovery in wastewater treatment' methodology. The estimation of emissions reductions for the electricity generation is calculated with the AMS.I-D Version 18 'Grid connected renewable energy generation' methodology.

Baseline Emissions

The baseline emissions are calculated ex-ante using available data of COD levels, COD inflow and outflow volume, and COD removal efficiency. The data is collected using one the following methods:

a. Historical data of minimum one year prior to project implementation.
b. Sample analysis conducted by the feasibility team, internal lab and/ or independent accredited laboratories.

The estimated baseline emissions (BE_y) are determined as follow:

$$BE_y = \{ BE_{power,y} + BE_{ww,treatment,y} + BE_{s,treatment,y} + BE_{ww,discharge,y} + BE_{s,final,y} \}$$

Where :

BE_y	=	Baseline emissions in year y (tCO_{2eq}).
$BE_{power,y}$	=	Baseline emissions from electricity or fuel consumption in year y (tCO_{2eq}).
$BE_{ww,treatment,y}$	=	Baseline emissions of the wastewater treatment systems affected by the project activity in year y (tCO_{2eq}).
$BE_{s,treatment,y}$	=	Methane emissions from baseline sludge treatment systems in year y (tCO_{2eq}).
$BE_{ww,discharge,y}$	=	Baseline methane emissions from degradable organic carbon in treated wastewater discharged to open water in year y (tCO_2eq).
$BE_{s,final,y}$	=	Baseline methane emissions from anaerobic decay of the final sludge produced in year y (tCO_{2eq}). If the sludge is control- combusted, disposed in a landfill with biogas recovery, or used for soil application in the baseline scenario, this term is neglected.

Each component of the formula is explained as follows:

- $BE_{power,y}$ is the energy consumption of all equipment/ devices in the baseline wastewater and sludge treatment facility. The energy consumption includes effluent pumping system where effluent flow cannot be facilitated by gravity. Due to conservativeness, the baseline emissions for power consumption can be assumed to be zero.
- $BE_{ww,treatment,y}$ is determined using the following formula:

$$BE_{ww,treatment,y} = \sum_i (Q_{ww,i,y} * COD_{inflow,i,y} * \eta_{COD,BL,i} * MCF_{ww,treatment,BL,i}) * B_{o,ww} * UF_{BL} * GWP_{CH_4}$$

Where:

i	=	Index for baseline wastewater treatment system.
$Q_{ww,i,y}$	=	Volume of wastewater treated in the wastewater treatment system.
$COD_{inflow,i,y}$	=	Chemical oxygen demand of the wastewater inflow to the treatment system.
$\eta_{COD,BL,i}$	=	COD removal efficiency of the treatment system.
$MCF_{ww,treatment,BL,i}$	=	Methane correction factor for wastewater treatment systems as per Table III.H.1 of AMS.III.H.
$B_{o,ww}$	=	Methane producing capacity of the wastewater (0.25 kg CH_4/kg COD as per IPCC value).
UF_{BL}	=	Model correction factor to account for model uncertainties (0.89 as per IPCC default values).
GWP_{CH_4}	=	Global Warming Potential for methane (21 as per IPCC value).

- $BE_{treatment,s,y}$ is determined using the following formula:

$$BE_{treatment,s,y} = \sum_i S_{j,BL,y} * MCF_{s,treatment,BL,j} * DOC_S * UF_{BL} * F * \frac{16}{12} * GWP_{CH_4}$$

Where:

j	=	Index for baseline sludge treatment system.
$S_{j,BL,y}$	=	Amount of dry matter in the sludge that would have been treated by the sludge treatment system.
$MCF_{s,treatment,BL,j}$	=	Methane correction factor for the baseline sludge treatment system as per Table III.H.1 of AMS.III.H.
DOC_S	=	Degradable organic content of the untreated sludge generated (The default value of 0.257 for industrial sludge is applied as per IPCC value).
UF_{BL}	=	Model correction factor to account for model uncertainties (0.89 as per IPCC default values).
DO_{CF}	=	Fraction of DOC dissimilated to biogas (0.5 as per IPCC value).
F	=	Fraction of CH_4 in biogas (0.5 as per IPCC value).

- *$BE_{ww,discharge,y}$ is determined to be 0 (zero) since there is no wastewater discharged to river, sea or lake.*
- *$BE_{s,final,y}$ is determined to be 0 (zero) since the final sludge is used for land applications in the plantation.*

Project Emissions

The project emissions are determined using the following formula:

$$PE_y = \{ PE_{power,y} + PE_{ww,treatment,y} + PE_{s,treatment,y} + PE_{ww,discharge,y} + PE_{s,final,y} + PE_{fugitive,y} + PE_{biomass,y} + PE_{flaring,y} \}$$

Where:

$PE_{power,y}$ = CO_2 emissions from electricity and fuel used by the project facilities.

$PE_{ww,treatment,y}$ = Methane emissions from wastewater treatment systems affected by the project activity, and not equipped with biogas recovery in the project scenario.

$PE_{s,treatment,y}$ = Methane emissions from sludge treatment systems affected by the project activity, and not equipped with biogas recovery in the project situation.

$PE_{ww,discharge,y}$ = Methane emissions resulting from inefficiency of the project activity wastewater treatment systems and presence of degradable organic carbon in treated wastewater.

$PE_{s,final,y}$ = Methane emissions from the decay of the final sludge generated by the project activity treatment systems.

$PE_{fugitive,y}$ = Methane fugitive emissions due to inefficiencies in capture system.

$PE_{flaring,y}$ = Methane emissions due to incomplete flaring.

$PE_{biomass,y}$ = Methane emissions from biomass stored under anaerobic conditions which would not have occurred in the baseline situation.

The estimate project emissions usually are within range of 10% to 20% of baseline emissions.

The application and complete methodology can be found in the following links:

1. Methodology for identifying baseline and greenhouse gases emissions calculation of POME methane capture.
   AMS-III.H.: Methane recovery in wastewater treatment Version 17.0; Download link:
   http://cdm.unfccc.int/methodologies/DB/0VAXUEJCAFN54BBE98CARMZU2TPMPJ
2. Methodology for identifying baseline and greenhouse gases emissions calculation for electricity generation that supplies to household users located in off grid areas.
   AMS-I.A.: Electricity generation by the user Version 16.0; Download link:
   http://cdm.unfccc.int/methodologies/DB/8FKZFJ7SG551TS2C4MPK78G12LSTW3
3. Methodology for identifying baseline and greenhouse gases emissions calculation for electricity generation that supplies to national grid or identified consumer facility via national or regional grid.
   AMS-I.D.: Grid connected renewable electricity generation Version 18.0; Download link:
   http://cdm.unfccc.int/methodologies/DB/W3TINZ7KKWCK7L8WTXFQQOFQQH4SBK
4. Methodology for identifying baseline and greenhouse gases emissions calculation for electricity generation that displaces grid electricity consumption and/or captive fossil fuel electricity generation at the user end, or supplies electricity to a mini grid system where in the baseline all generators are exclusively fuel oil and/or diesel fuel.
   AMS-I.F.: Renewable electricity generation for captive use and mini grid Version 3.0; Download link:
   http://cdm.unfccc.int/methodologies/DB/9KJWQ1G0WEG6LKHX21MLPS8BQR7242

Appendix 3: Law and Regulations

Table A.3. Law and Regulations Related to POME-to-Energy Project

Regulation Number	Topic	Relevance to Biogas Project
Ministry of Environment Regulation No. 17/2001	Private energy production	Institutes requirements for business licenses for electricity production companies; exempts producers of renewables under 10 MW for own-use from full environmental impact review process.
Presidential Regulation No. 5/2006	Energy policy	Targets energy balance in energy mix, and sets goal of at least 5% new renewable energy by 2020.
Law No.30/2007	Energy	Prioritizes locally available energy sources and renewable energy generation, and provided for incentives to support the economic viability of new renewables. Obliges government to provide funding for electricity development for low income, underdeveloped, isolated, and rural areas.
Law No. 30/2009	Electricity	Prioritizes the use of locally available energy resources for electricity generation. Allows independent power producers (IPPs) to generate and sell electricity to end users in the Indonesian market, breaking PLN monopoly.
Energy and Mineral Resource Minister Regulation No. 31/2009	PLN purchase of renewable energy	Obligates PLN to purchase renewable energy at fixed rates from < 10 MW size plants or excess power; 656 IDR/kWh (medium voltage) or 1,004 IDR/kWh (low voltage) plus an applied location factor.
Government Regulation No. 52/2011	Tax facility for new and renewable energy project	- 30% deduction of net income (for 6 years) - Accelerated depreciation and amortization - 10% income tax for dividend paid to foreign tax subject, or lower rate based on the applied tax treaty - Loss compensation for more than 5 years, but less than 10 years
Government Regulation No. 94/2010	Tax Holiday	- Tax exemption for 5 to 10 years since the commercial production - Tax deduction of 50% for 2 years withholding tax (it is regulated in Ministry of Finance Regulation No. 130/ PMK.011/2011
Government Regulation No. 31/2007	Added Value Tax	Exemption for added value tax
Law No. 17/2006	Custom exemption	Custom exemption for imported goods, further defined in Finance Minister Regulation No. 76/PMK/011/2012
MOF Regulation No. 21/PMK.011/2010	Tax incentives for renewable energy	Import duty exemptions (for own use electricity)

Regulation Number	Topic	Relevance to Biogas Project
MOF Regulation No. 154/PMK.011/2008 Jo No. 128/PMK.011/2009	Tax incentives for renewable energy	Import duty exemptions (for grid connected electricity)
Presidential Regulation No. 61/2011	Greenhouse Gas Emissions Reduction	Commits GOI to reducing greenhouse gases emissions by 26% with own effort and by 41% with international support by 2020; includes activities in agriculture, forestry and peat land, energy and transportation, industry, waste management and other supporting activities.
Energy Minister Regulation No. 4/2012	PLN purchase of renewable energy	Replaces Energy Minister Regulation No. 31/2009 about PLN renewable/excess power purchase prices for < 10 MW plants; the new feed-in tariff for renewable energy from biogas and biomass ranging from 975–1,722.5IDR/kWh depending on technology and voltage (plus an applied location factor).
Environment Minister Regulation No. 51/1995	Wastewater discharge standard	Regulates parameters of discharged wastewater from industries. Palm oil industry is regulated on attachment IV A and B.
Environment Minister Regulation No. 29/2003	POME discharge for land application	Regulates parameters for POME that is discharged for land application purposes. BOD is less than 5000 ppm, with pH at 6-9, and applied to land that is not peatland, land that does not have permeability higher than 15 cm/hour or less than 1.5 cm/hour, and land with ground water level more than 2 m. Monitoring well has to be constructed.
Agriculture Minister Regulation No. 19/2011	Indonesian Sustainable Palm Oil	Obligates all palm oil mills and plantations to adhere to all regulations related to the palm oil industry. Audits are needed to obtain the mandatory ISPO certification by 31 December 2013.
Energy and Mineral Resource Minister Regulation No. 27/2014	PLN purchase of renewable energy	Replaces Energy and Mineral Resources Regulation No. 4/2012 about PLN renewable/excess power feed-in tariff for biogas and biomass power plant below 10 MW. The new feed in tariff ranging from 1,050–2,240IDR/kWh depending on voltage and region.

Appendix 4: Challenges and Potential Solutions

POME-to-energy projects offers economic and environment benefit to palm oil companies in particular and Indonesia in general. In order to promote and accelerate the project development, some challenges and potential solutions have been identified as described below.

Table A.4. Challenges and Potential Solutions of POME-to-Energy Project

Challenges	Potential Solutions
Lack of information on technology for methane capture	Capacity building for stakeholders such as companies, government, NGOs (non-governmental organization), and financial institutions; knowledge sharing by companies with methane capture facilities; establishment of a training center; apply international standard; government to establish national guideline and standard, and safety standard on biogas power plant.
Companies' lack of human resources to be allocated for the project	Standard technical training for the partner mills prior to feasibility study to prepare them for requirements and steps (i.e. why flow meters need to be installed, why POME characteristics shall be measured, why they need to provide production data, and energy supply and demand, etc.).
Lack of incentives	Agriculture Ministry to push for methane capture compliance through ISPO (Indonesian Sustainable Palm Oil); feed-in-tariff specific to POME-to-energy projects; voluntary sustainability certification to set GHG emission standard that requires methane-capture installation; additional points in PROPER (*Program Penilaian Peringkat Kinerja Perusahaan dalam Pengelolaan Lingkungan*/Public Disclosure Program for Environmental Compliance) for mills that have methane capture and track GHG emissions.
Limited successful cases in Indonesia	Government initiation of a pilot plant that can be used as a training center; Reference to projects in neighboring countries such as Thailand and Malaysia.
Companies' perception of difficulty in working with PLN	Easier access for companies to apply for PPA or excess power agreement; Willingness from PLN to invest in new electricity grids near mill locations; Standardized PPA for biogas projects.
Lack of interest for investment or loan	Focus on balance sheet financing-since biogas projects are considered small on an investment project scale, they are not attractive for financial institutions to support under project financing scheme; Bundling 2-3 projects to increase the attractiveness of the investment; Ensure thorough financial feasibility studies; Capacity building for financial institutions in assessing the risk and nature of these projects; Pursue options for soft loans.

Appendix 5: The Winrock-USAID CIRCLE Project

To realize mills' potential to reduce emissions and generate electricity, the Capacity for Indonesian Reduction of Carbon in Land Use and Energy (CIRCLE) project provides technical assistance to interested palm oil mills (POMs) in Indonesia to create renewable energy from POME. Winrock International implements the USAID-funded CIRCLE project in partnership with World Wide Fund for Nature (WWF) Indonesia. CIRCLE assists Indonesian POMs with sustainability assistance, pre-feasibility studies, in-depth feasibility studies, technical assistance, and capacity building.

CIRCLE shares technical expertise through training sessions and publications like this handbook. Winrock International aims to provide the palm oil sector and its stakeholders in Indonesia with the information they need about methane capture technology to reduce emissions of greenhouse gases and increase energy production.

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