Report on the Commissioned Feasibility Study on FY2016 Large-Scale JCM Project for Reducing GHG Emissions from Energy Consumption

(Project for refining BIO-CNG from waste at cassava and palm plants to use it as fuels for NGVs in the Kingdom of Thailand)

(English)

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The Japan Research Institute, Limited

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1. Summary

We studied the feasibility of this project to reduce greenhouse gas (GHG) emissions in the Kingdom of Thailand, a party to the Joint Crediting Mechanism (JCM), through introducing the biogas purification technology held by Osaka Gas Co., Ltd. (Osaka Gas).

A key material to be used in the project is biogas, which is produced through the fermentation of solid biomass or organic waste containing biomass at palm oil production plants and tapioca (made from cassava) plants in the Kingdom of Thailand. We examined the issue of increasing the concentration of CH_4 in the biogas by Osaka Gas's biogas purification technology and selling the purified gas mainly for NGVs.

Research activities to establish and study the project's operational structure included not only analyses on Thailand's policies related to this project (energy/gas/power policies and the outlook for subsidies for fuels) but also the selection of palm/cassava plants and local EPC businesses as potential project partners and the research of transport companies which own NGVs.

Our focus was put on plant sites with a good balance sheet and a high credit line, which are prerequisites for the first project partners. For the plants satisfying these standards, we looked into their biogas potential, the prices of CNG (natural gas being sold at fuel stations) in their vicinity, and the applicability of JCM. The survey found two plants which are considered to be promising candidates.

We also conducted field hearings and made summaries of conditions at the local sites, such as biogas yields and materials, in order to identify the necessary specifications for the technology to be introduced, to calculate the profitability, and to identify an MRV methodology applicable to the sites.

The findings obtained from these research activities let us conclude that under the current and expected environment of the Thailand market, this project with the selected two potential plant sites will be able to secure profitability through equipment support based on the JCM scheme.

Furthermore, it was confirmed that the project is likely to contribute to large-scale GHG emission reductions, as the introduction of CBG purification technology will make the release of biogas into the air avoidable, and the reduction of fossil fuel consumption possible; the carbon dioxide emission reduction is estimated at 190,000 tons and 76,000 tons per year at each of the potential sites, respectively.

Having already started pilot demonstration tests in April 2017, from this time forward, Osaka Gas will work on commercial operations through steps such as the verification of the Osaka Gas's purification technology through pilot tests, and in-depth discussions on how the technology should be introduced at the plant sites.

2. Overview of the project

2.1 Purpose

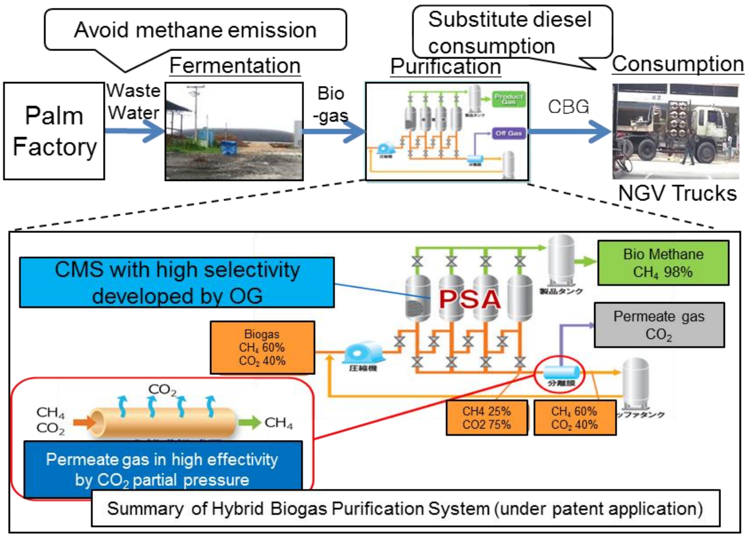
The project under study is designed to reduce GHG emissions as well as realizing the production and sale of compressed biogas (CBG) in the Kingdom of Thailand, a party to the JCM, through the introduction of the biogas purification technology developed by Osaka Gas.

In Thailand, the world's third-largest producer of palm oil and cassava, a huge amount of CH_4 is produced from waste resulting from the production of such products at plants, occupying a large slice of its overall GHG emissions.

The biogas, which is produced through the fermentation of waste, mainly consists of CH_4 and carbon dioxide. It can be used as a valuable resource through the purification technology developed by Osaka Gas, which enables an increase in the heating value of the gas (capable of raising the concentration of CH_4 up to 98%) without reducing it (recovery: 98%).

The purified biogas will be available as an alternative fuel to natural gas. In Thailand, the transport industry is a big consumer of natural gas. So, the feasibility study examined the expected profitability on sales of the gas as a fuel for vehicles.

Figure 1: Flow of gas purification in this project



Source: Osaka Gas

The above approach may enable the release of CH_4 into the atmosphere to be avoided. The use of CBG by natural gas vehicles (NGVs), especially NGV trucks, may also enable the reduction of carbon dioxide emissions from fossil fuels such as diesel and natural gas, which may in turn contribute to GHG emission reductions. So, the feasibility study was also carried out from the perspective of GHG emissions reductions, aimed at maximizing the reductions.

2.2 Outline of the applicable technology

The technology which shall be introduced in this project is the biogas purifying system developed by Osaka Gas Co., Ltd. This system is hybrid-type biogas purification equipment which combines Pressure Swing Adsorption (PSA) and a separation membrane.

In general, biogas purification technology can be divided into three categories: PSA, membrane separation, and a high-pressure water absorption method. Each method has strong points and weak points.

PSA is a method in which carbon dioxide is removed by adsorption to adsorbents; it is suitable for small- to-medium-scale systems. This method is able to purify biogas to high purity and has been implemented in more than 50 cases worldwide. On the other hand, the method has a relatively low recovery rate of methane. Membrane separation is a method which uses a polymer membrane as a separation membrane and separates carbon dioxide by the difference in speed between methane and carbon dioxide in passing through the membrane. The method is suitable for small-scale systems. As the system must be operated under high pressure, it involves high electricity costs and it has been implemented in about 10 cases, mainly in Europe. In the high-pressure water absorption method, carbon dioxide is removed by being absorbed into high-pressured water. The method is suitable for large-scale systems and has been implemented in more than 50 cases worldwide, including Asia. However, it involves high electricity costs because a large amount of circulating water is required.

Concerning the development of biogas purification technology for the Kingdom of Thailand, a medium-scale system which can deal with around 1,000 Nm^3/h of biogas was considered as a capacity which can treat waste water from a standard palm factory. Osaka Gas has developed hybrid-type biogas purification technology by combining the separation membrane method with the PSA method, which is the base method and in which the company has accumulated technology. This new technology aims to improve the recovery rate of methane, which is a weak point of PSA. The adsorbent installed in PSA equipment is a high-functional material and is an original Osaka Gas material.

The normal recovery rate of methane by PSA alone is about 85%. On the other hand, this system has specifications in which the methane concentration in purified gas is 98% and the recovery rate of methane is 98%.

This system consists of a compressor providing gas, PSA, and a gas separation membrane. Its special feature is that it re-concentrates offgas discharged from PSA with separation membrane up to a similar concentration as material biogas, and then recycles the gas to the PSA inlet. The system concentrates gas to a high concentration in PSA, while supplementing the recovery rate by offgas recycling. In addition, by using a separation membrane (which can efficiently concentrate gas under the condition of moderate methane concentration) for the recycling concentration, the system structure achieves high efficiency as a whole.

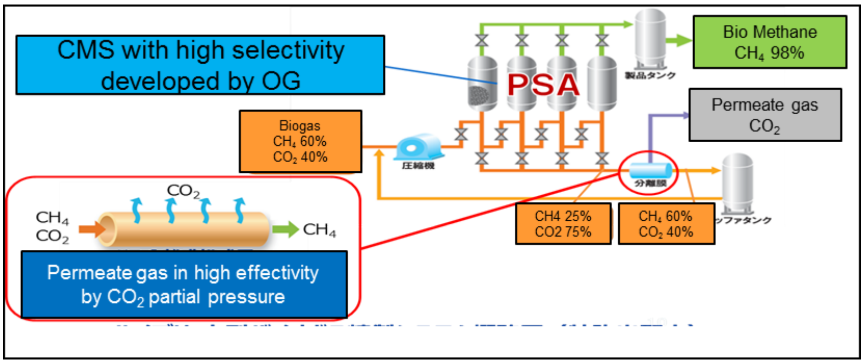
Raw-material gas is pressurized to about 0.7 MPaG by a compressor and is introduced into an adsorption tower. The adsorbing material in the tower removes carbon dioxide by selectively adsorbing carbon dioxide from the raw-material gas. The product gas (hereinafter referred to as "biomethane"), including high-purity methane while the carbon dioxide was being removed, is recovered from the upper part of the adsorption tower. After a certain amount of adsorption is conducted, the adsorption process is switched to another adsorption tower for the restoration of the adsorbing material in the adsorption tower. Thus a desorption process of reducing the pressure in the adsorption tower after the completion of adsorption is carried out. During this desorption process, methane left in air gaps in the adsorption tower is also discharged as offgas from the adsorption tower, together with desorbed carbon dioxide. This offgas is then introduced into a gas separation membrane and is divided into penetrating gas, including high-concentration carbon dioxide that passes through the membrane, and non-penetrating gas with higher methane concentration as a part of carbon dioxide has been removed. The penetrating gas is discharged from the system and the non-penetrating gas is recycled into the inlet port of PSA. Because almost no methane is discharged from the system as penetrating gas, while most methane introduced as raw-material gas can be recovered as biomethane, this system can achieve a high methane recovery rate.

Osaka Gas started laboratory experiments in 2013 and established the optimal system conditions during the following one and a half years. During the next one and a half years, field experiments were carried out using actual biogas generated by anaerobic fermentation from paper waste, trees and plants; the long-term operation was verified, and the control system was established.

At present, all bench-scale tests have been completed in Japan and pilot demonstration tests are being carried out with small-scale equipment (biogas flow rate: 250 Nm^3/h) in a palm factory in Thailand as a stage prior to commercialization. Liaison with local partner firms has already begun and construction is planned to start around July 2016. The operation will start in fiscal year 2017.

Besides biogas purification technology, the management of natural gas stations is also a field in which the CBG business of Osaka Gas has technical know-how and accomplishments. We have been operating 20 natural gas stations in Japan so far. In addition, we have also given technical support in the design and operation of "Kobe Biogas," in which biogas discharged from the Kobe City Higashinada Sewage Treatment Plant is purified and utilized as fuel for NGV. Since we have accumulated technical know-how and accomplishments in this field, it is our strong point that we are able to provide integrated services from CBG production to utilization for NGV to palm-cassava factories (hereinafter referred to as "biomass factories"), which use CBG for the first time.

Figure 2: Hybrid-type biogas purification system



Source: Osaka Gas Co., Ltd.

2.3 Policy of the project development

Osaka Gas has been engaged in self-funded pilot tests to demonstrate its hybrid-type biogas purification equipment since 2016, with a plan to promote its commercialization in 2017. In 2016, Osaka Gas endeavored to cultivate a potential business project through this project in parallel with the pilot tests, aimed at launching the CBG business at an early date.

2.4 Details of the conducted surveys

In order to achieve CBG business midterm plan, the following surveys were carried out this time.

- Basic information of and trends in target country

Survey of basic information and trends of policies of Thailand that is the target of introduction of the present technology was carried out. In particular, survey results were organized centering on energy supply and demand in Thailand, and current situation of GHG release and efforts toward reduction of GHG release. In addition, a survey on the target for renewable energy, in particular targets for production and utilization of energy from bio-gas in policies for efforts to reduce GHG release, was carried out and it was made sure that the CBG production from biomass plants in the present project meets Thailand's policy target.

Furthermore, for the purpose of achieving the above target for renewable energy, Thai Government has been considering FIT amendment and subsidies for CBG production and a survey on trends of such policy that might affect the business environment was carried out.

- Establishing business structure

Search for stake holders and discussions for examination of the project in order to achieve reduction of GHG discharge of accumulated amount of about 1,010 thousand tons by the end of 2021 fiscal year were carried out. More specifically, search for local EPC contractors that carry out plant design and construction, biomass plant owners that could function as bio-gas supply source and NGV truck owners that could become CBG consumer were carried out.

- Discussions with candidate EPC contractors

Two companies currently operating EPC business for bio-gas producing plants from biomass factories in Thailand were selected as candidates for EPC contractors for bio-gas producing plants in the present project. Both of them carry out EPC, operation and maintenance of power generation and heat supply plants using bio-gas generated from industrial liquid waste and have abundant knowledge in those field.

- Search for biomass plant owners

Search for biomass plants that could be targets for introduction of the present project was carried out. In carrying out the search, a long list of biomass plants was prepared for grasping locations and distribution of biomass plants all over Thailand through a close investigation of plants that were targets for advance survey and search for unidentified plants, and, at the same time, screening for satisfaction of requirements for business partners of the present project with respect to the scale of production (amount of FFB to be processed), bio-gas potential (existence/non-existence of use for power generation, etc.), location, interest in the project, etc. and search for candidates and negotiation for actual introduction were carried out.

- Search for truck owner

Search for truck owners that could become consumers of produced CBG was carried out. Although it can be expected that many biomass plants own trucks for transportation of products, but it is not clear whether or not demand that can cover the amount of produced CBG in the project ensured. Therefore, it was decided to carry out survey on transportation companies in the neighborhood of the biomass plants as candidate CBG users.

- Identification of technical specification

In this section, after selecting the site for physical introduction, technical specification for physical introduction was examined. To be more specific, based on the amount of generated bio-gas and methane concentration, existence/non-existence of impurities, etc. of the generated gas, the scale of purification, pressure, etc. that become necessary from technological point of view were examined.

- Estimate of business potential

In this section, costs and expenses of introduction of equipment necessary for CBG production were calculated and macro-economic trend (inflation rate, trends of utility unit price, etc.), raw material price, purification cost (initial cost, labor cost, electricity cost, etc.) were also calculated. Based on those parameters, business potential of the present project was estimated.

- Survey on possibility of spread and development

In order to survey possibility of spread of this business in Thailand in future, survey on trends of policies encouraging spread of the present technology, CBG production potential and needs for biomass plants in Thailand, as well as survey on competitiveness of the present project in comparison with other owners of CBG manufacturing technologies and small-size bio-gas power generating companies were carried out.

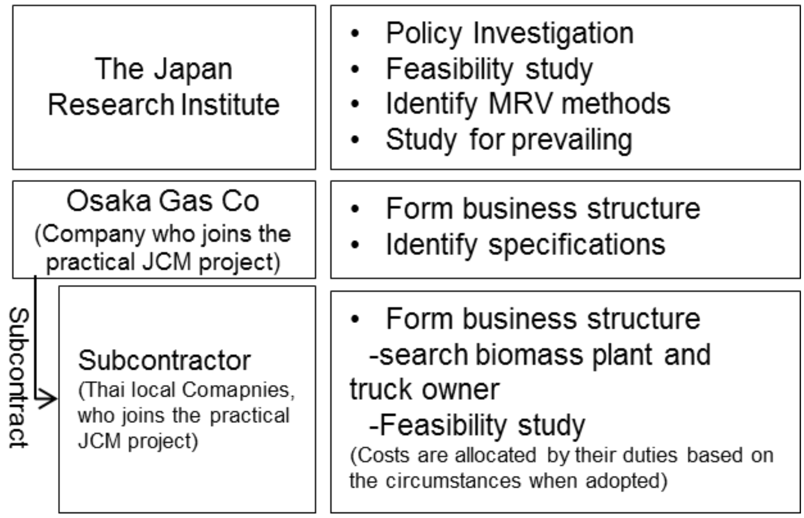
- Identification of MRV methodology

GHC discharge amount reduced through two activities, avoidance of methane release by bio-mass recovery from biomass plants and use of CBG for trucks for reduction of energy by automobile alternative fuels was identified. Referring to those methodologies, identification of MRV methodology was carried out. Project design (PDD) was prepared based on drawn-up methodologies and project (contents identified by field survey).

2.5 System for implementing surveys

This project will be carried out by a survey consortium composed of The Japan Research Institute, Limited as the contractor and Osaka Gas as co-contractor.

A part of surveys related to biomass plants, truck owners and estimate of business potential was outsourced to EPC contractors in Thailand for carrying out study for the project.



3. Kingdom of Thailand: Basic Information and Trends in Government Policy developments

3.1 Basic information on the Kingdom of Thailand

Figure 3: General information on the Kingdom of Thailand

Area	514,000 km^2 (about 1.4 times the size of Japan)
Population	68.3 million (2013)
Capital	Bangkok
Ethnic groups	Predominantly Thai. Among other ethnic groups are Chinese and Malays.
Language	Thai
Religion	Buddhism: 94%/Islam: 5%

Source: Ministry of Foreign Affairs website

The Kingdom of Thailand, while a land about 1.4 times the size of Japan, is inhabited by 68.3 million people, approximately half of Japan's population. On the cultural front, the Thai language is spoken as the country's official national language and Buddhists account for around 94% of the entire population.

Following the death in October 2016 of Rama IX (the Great; Bhumibol Adulyadej), the former head of state of Thailand, Rama X (Maha Vajiralongkorn) took office as new head of state. Bhumibol Adulyadej the Great remained in office as head of state for a long 70 years and 4 months, during which time he directly intervened in political crises to resolve them. This resulted in Thai citizens giving him their strong support and respect, and caused experts to worry that the death of Bhumibol Adulyadej the Great could potentially cause turmoil to the Thai economy. So far, however, the country has been steering clear of any noticeable turmoil, due partly to the Thai government's desire to minimize any effects on the nation's economic activities.

Meanwhile, after the current Prayuth administration came to power, the nation experienced terrorism repeatedly, meaning it is necessary to pay attention to the security situation in the country.

Figure 4: Political profile of the Kingdom of Thailand

Political system	Constitutional monarchy
Head of state	Rama X, Maha Vajiralongkorn (from December 1, 2016)
Parliament	National Council for Peace and Order (NCPO) (220 members)
Government	Prime Minister: Mr. Prayuth Chan-o-cha Minister of Foreign Affairs: Mr. Don Pramudwinai

Source: Ministry of Foreign Affairs website

The Thai economy grew 0.9%, a figure affected by the political turmoil caused by the accession to full power of the National Council for Peace and Order (NCPO) in May 2014. The NCPO consists chiefly of military officers. In the ensuing calm of 2015, the nation's economy grew 2.8%, with 2016 being expected to show growth of 3.0% to 4.0%.

Figure 5: State of the economy of the Kingdom of Thailand

Principal industries	Although it represents approximately 40% of all workforce, the agriculture industry accounts for a mere 12% of GDP. On the other hand, the manufacturing industry, while representing approximately 15% of all working citizens, accounts for approximately 34% of GDP and 90% of export value.
GDP	$395.2 billion (nominal, 2015, National Economic and Social Development Board, or NESDB)
Per-capita GDP	$5,878 (2015, NESDB）
Economic growth rate	2.8% (2015, NESDB)
Consumer price index	-0.9 (2015, NESDB）
Unemployment rate	0.8% (2014, NESDB)
Total trade value	(1) Exports: $212.1 billion (2015, NESDB) (2) Imports: $177.5 billion (2015, NESDB)
Principal trade items	(1) Exports: Computers, computer components, cars and car parts, machinery and tools, agricultural products and processed foods (2) Imports: Machinery and tools, crude oil and electronic components
Key trading partner countries and territories (2015)	(1) Exports: 1. U.S.A. 2. China 3. Japan (2) Imports: 1. China 2. Japan 3. U.S.A.
Currency	Baht
Foreign exchange rate	1 yen = THB3.17 (2016 average)

Source: Ministry of Foreign Affairs website

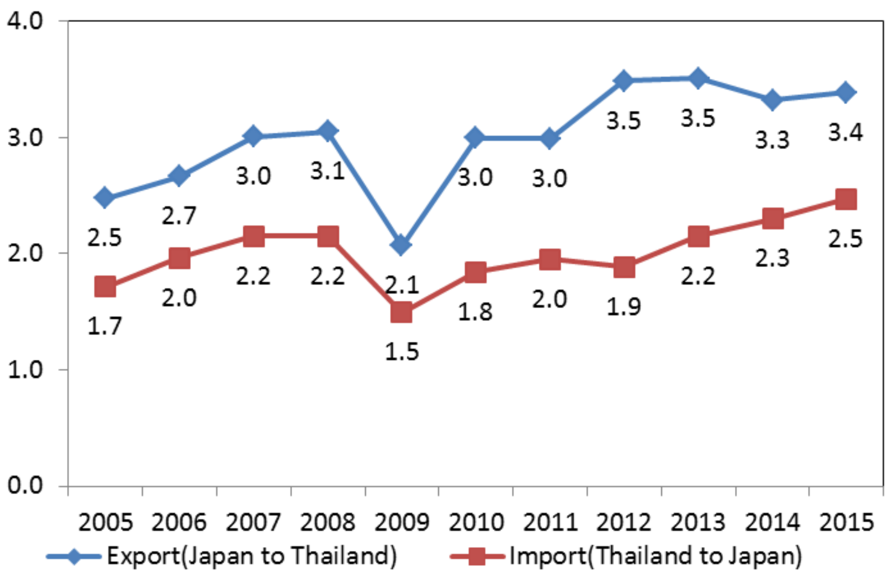
3.2 Japan-Thailand relationship

3.2.1 Thailand's relationship with Japan

Japan and Thailand, having been interacting with each other over the past 600 years or so, have traditionally maintained a friendly relationship. Recent years saw the two nations build close mutual relationships in a wide range of areas such as politics, economy and culture, based on the close relationship between the two nations' royal families.

The economic relationship between Japan and Thailand has also been good, as evidenced by the fact that an economic partnership treaty between them came into effect in 2007. Trade between Japan and Thailand has been steadily growing in value since 2005 with the exception of 2009 in the wake of the Lehman Brothers bankruptcy.

Figure 6: Value of imports and exports between Japan and Thailand



Source: Created by the Japan Research Institute, based on trade statistics from the Ministry of Finance

3.2.2 Signing of a bilateral JCM document

On November 19, 2015, Tamayo Marukawa, Minister of the Environment of Japan and General Surasak Karnjanarat, Minister of Natural Resources and Environment of the Kingdom of Thailand reached agreement on the proposed establishment of a bilateral joint crediting mechanism (JCM), signing the bilateral document on the operation of the mechanism, which made the Kingdom of Thailand the 16th signatory to a JCM.

Following the conclusion of the above-mentioned JCM, two methodologies were approved through two joint committee meetings.

Figure 7: Methodologies approved between Japan and Thailand

Sectorial scope	Methodology	Greenhouse gas (GHG) emissions reduction method
Energy demand	Energy Saving by Introduction of Multi-stage Oil-Free Air Compressor	Reduction in energy consumption through introduction of multi-stage oil-free compressors
Energy demand	Installation of a Solar PV System	Replacement of diesel fuel-based grid power or non-utility power generation through the introduction and operation of a solar photovoltaics (PV) system

Source: Prepared by the Japan Research Institute, based on the section “Approved Methodologies” on the Joint Crediting Mechanism (JCM) website

The JCM fund assistance program, aided since 2010 by the Ministry of the Environment, has already adopted 16 projects during the period from 2015 to 2016 (as of July 2016).

Figure 8: List of Thailand projects in the JCM fund assistance program aided by the Ministry of the Environment (from fiscal 2015 to 2016)

Fiscal year	Segment	Project operator	Project name
2015	Energy conservation	FamilyMart Co., Ltd.	Energy conservation for air-conditioners and refrigerated showcases at convenience stores
2015	Energy conservation	Toray Industries, Inc.	Energy-efficient loom introduction project for loom factories
2015	Energy conservation	Sony Semiconductor Manufacturing Corporation	Introduction of energy-efficient freezers and compressors for semiconductor plants
2015	Energy conservation	Pacific Consultants Co., Ltd.	Factory roof-based solar power generation system introduction project
2015	Energy conservation	Nippon Steel & Sumikin Engineering Co., Ltd.	Introduction of a gas cogeneration system for supplying energy on-site at motorcycle manufacturing plants
2015	Energy conservation	Sony Semiconductor Manufacturing Corporation	Introduction of energy-efficient air-conditioning systems and freezers for semiconductor plants
2016	Energy conservation	Asahi Glass Co., Ltd.	Introduction of highly efficient ion-exchange membrane-method electrolyzers for caustic soda manufacturing plants
2016	Energy conservation	Fast Retailing Co., Ltd.	Introduction of LED lighting at goods stores
2016	Energy conservation	Tepia Corporation Japan	Introduction of an energy-efficient cool water delivery system for milk factories
2016	Energy conservation	NTT DATA Institute of Management Consulting, Inc.	Introduction of a 12 MW waste heat-recovery power generation system for cement plants
2016	Energy conservation	DENSO Corporation	Introduction of cogeneration equipment for car parts plants
2016	Energy conservation	Kyowa Hakko Bio Co., Ltd.	Introduction of energy-efficient freezers and self-steam compression concentrators for amino-acid manufacturing plants
2016	Energy recycling	Sharp Corporation	Introduction of a 3.4 MW rooftop solar power generation system for air-conditioner parts manufacturing plants

2016	Energy recycling	Finetech Co., Ltd.	Supply of electricity to paint plants from 1.5 MW rooftop solar power generators and advanced EMS
2016	Energy conservation	Kanematsu Corporation	Introduction of energy-efficient cooling system for industrial refrigerators

Source: The new mechanism information platform “JCM Assistance Program: List of Projects Adopted”

3.3 Roles of government agencies and institutions involved in this program

We contacted the Thai government agencies below for interviews in order to gather information on the trend in local government policies relating to the program in question, as well as on regulation and subsidies associated with the program.

3.3.1 Ministry of Energy, Energy Policy & Planning Office (EPPO)

The Energy Policy & Planning Office (EPPO) is a government agency in charge of energy policy and planning under the umbrella of the Ministry of Energy, which oversees the country's energy sector, including electric power services. The EPPO promotes energy conservation efforts through encouraging the use of alternative energy sources, proposes measures to resolve oil shortages in the near- and long-term, and overseas and assesses governmental energy management plans.[1]

The EPPO is an agency authorized to determine national retail prices for energy sources (diesel, CNG and so on), so we contacted the agency for an interview about the outlook on future government subsidies for diesel and CNG retail prices. Thus, we learned that officials would deliberate on the proposed abolition of CNG price regulation in rural areas in order to help lower fiscal spending by the central government and PTT.

3.3.2 Department of Energy Development and Efficiency (DEDE)

The Department of Energy Development and Efficiency (DEDE) is an agency that, under the umbrella of the Ministry of Energy, arranges for the transfer of technologies related to the penetration of alternative energy sources with the aim of optimizing: 1) regulations on energy efficiency enhancement and energy conservation; 2) the procurement of energy resources; and 3) energy prices.[1]

In the interview, we asked about the likelihood of continuation of the CBG equipment subsidy provided in 2016. The DEDE provides the CBG equipment subsidy with the aim of achieving the CBG output volume target given in the Alternative Energy Development Plan. We learned that meanwhile the Thai government, being at the information-gathering stage on CBG manufacturing, will determine its future subsidy measures while monitoring the situation to see how the subsidy provided in 2016 had affected operators' production costs.

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[1] Japan Electric Power Information Center, Inc., *Electric Power Business in Foreign Countries*, Section 1 (second volume), 2014, pages 81–82

3.3.3 Department of Energy Business (DOEB)

The Department of Energy Business (DOEB), under the umbrella of the Ministry of Energy, is an agency that handles regulations on energy-related business. The DOEB has established regulations related to laws on biogas business activities.

Through the interview, we ascertained that, although regulation was in place with respect to safety in the biogas refinery business, there was no critical risk for launching the program in question, such as foreign capital regulation.

3.3.4 Thailand Greenhouse Gas Management Organization (TGO)

The Thailand Greenhouse Gas Management Organization (TGO), being a local agency to oversee initiatives to deal with climate change, is charged with performing clerical procedures within the Thai government in relation to JCM registration. The TGO informed us that effective biogas utilization business has been registered in CDM.

3.3.5 National Innovation Agency (NIA)

The National Innovation Agency (NIA) is a body that plays a role in the Kingdom of Thailand that is equivalent to the New Energy and Industrial Technology Development Organization (NEDO) in Japan, though it is smaller than the NEDO.

Unlike the NEDO, the NIA is not subject to any aid target restrictions, so the agency has been assisting EV and IoT projects as initiatives within its aid scope in recent years. The NIA is currently striving to support start-up companies.[2]

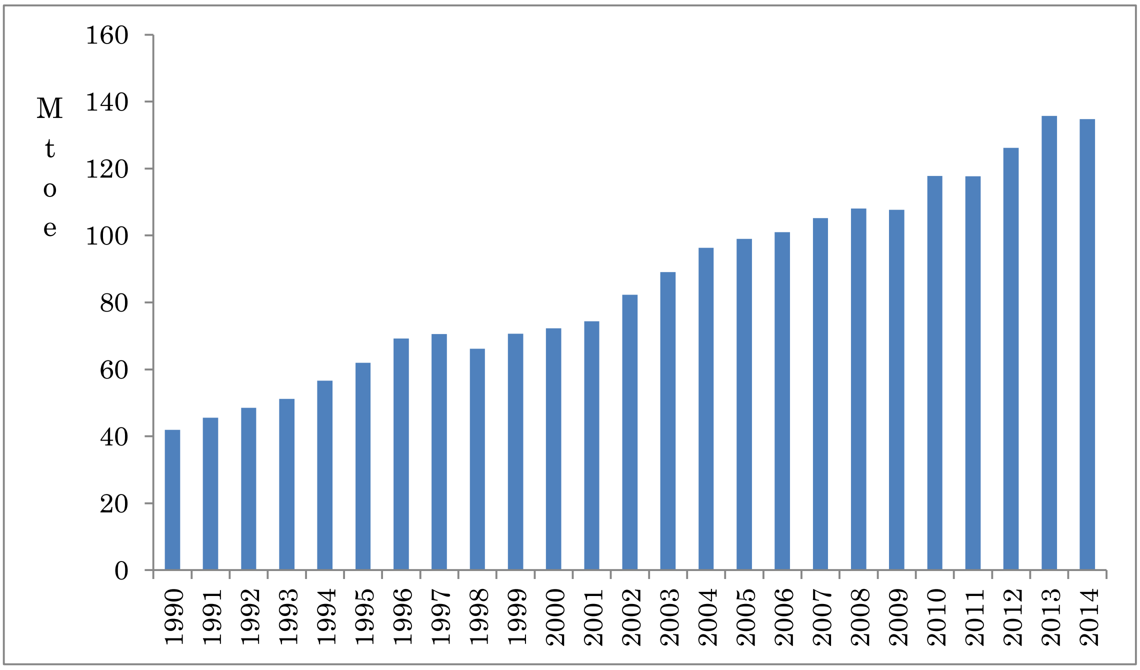
[2] From an on-site interview

3.4 Current and historical energy balance (output, import & export and consumption)

3.4.1 Historical demand for primary energy

In the Kingdom of Thailand, demand for primary energy has been growing relentlessly on the back of the nation's high economic growth rate.

Figure 9: Supply of primary energy in the Kingdom of Thailand



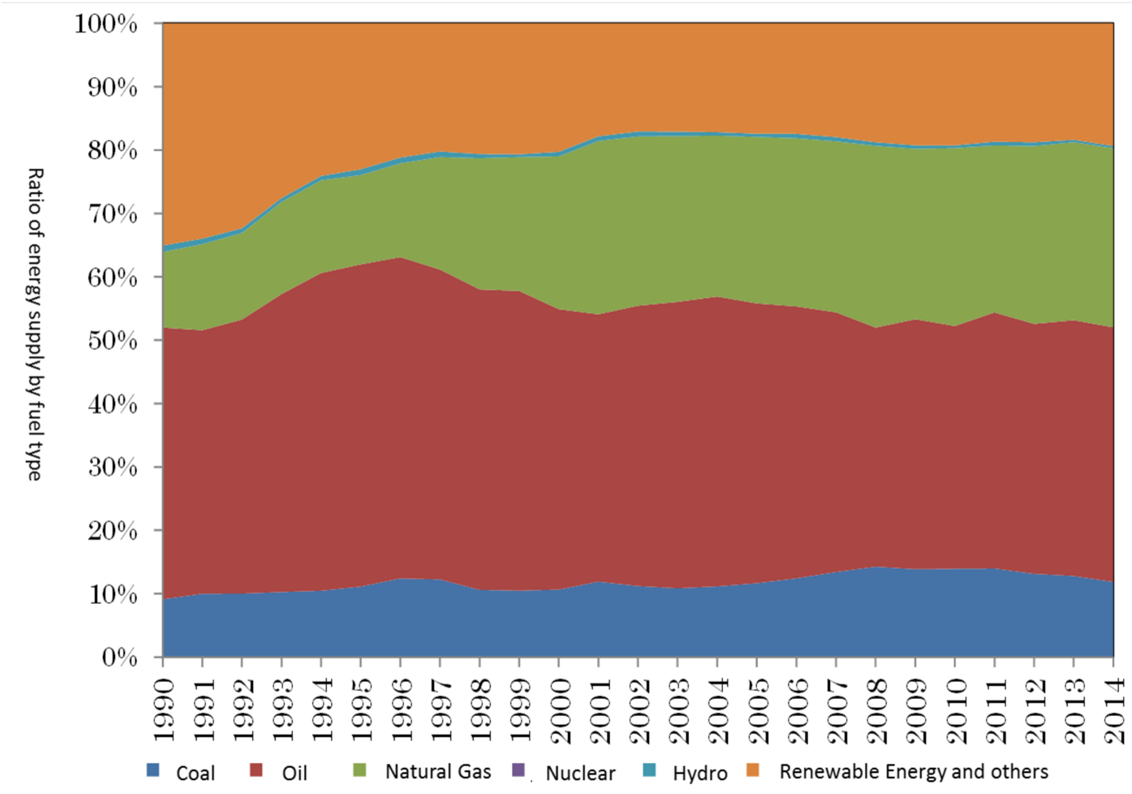
Source: OECD Library

3.4.2 Energy consumption developments by type of fuel

Oil is the type of energy source that is most widely used in Thailand, followed by natural gas. Gifted with fossil fuel resources, the Kingdom of Thailand has boasted a very high self-sufficiency rate for natural gas and coal, with its natural gas demand in particular being completely met all by domestic output. However, in order to address its rising energy demand, the country has been expanding imports of fossil fuel in recent years. Its natural-gas self-sufficiency rate, previously at 100%, has declined from the year 2000 and now stands at less than 80%. Thailand's coal self-sufficiency rate has also been falling markedly. Consequently, experts see the reduction of reliance on foreign energy as a challenge, as will be discussed later, meaning that the country's government policies are now focused on energy conservation and improvements in energy security.

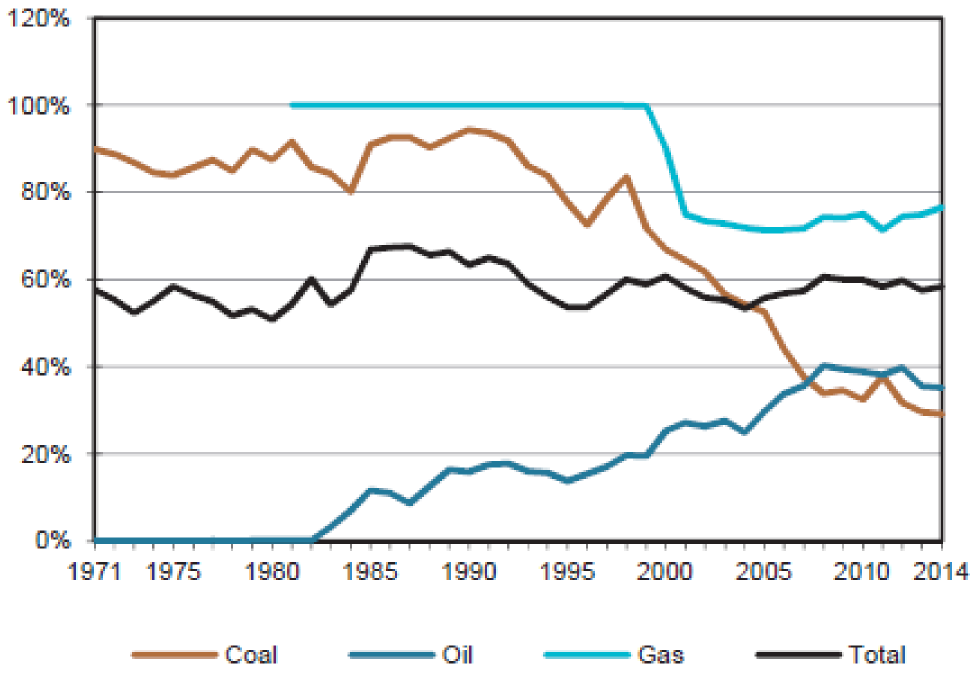
The following outlines how Thailand has been introducing renewable energy sources that are purely domestically produced and are thought to help enhance the nation's energy security. Accounting for a predominant portion of such renewable energy sources, biomass-derived energy sources under the long-term renewable energy plan discussed later are highly expected to play an important role.

Figure 10: Energy consumption volume breakdowns



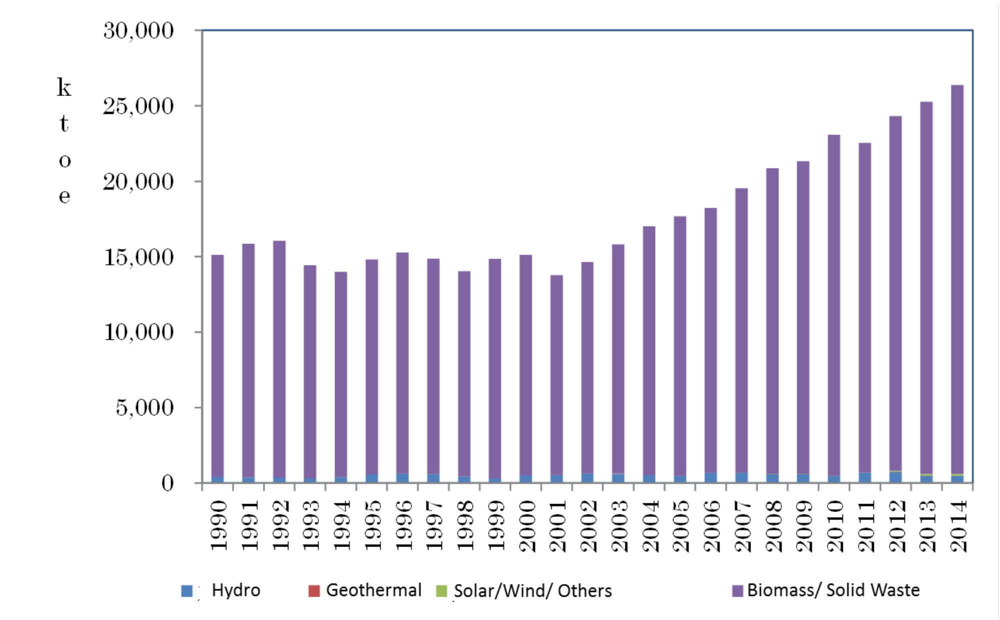
Source: OECD Library

Figure 11: Fossil fuel sufficiency rate



Source: IEA World Energy Balances 2016

Figure 12: Consumption volume of renewable energy-derived primary energy



Source: OECD Library

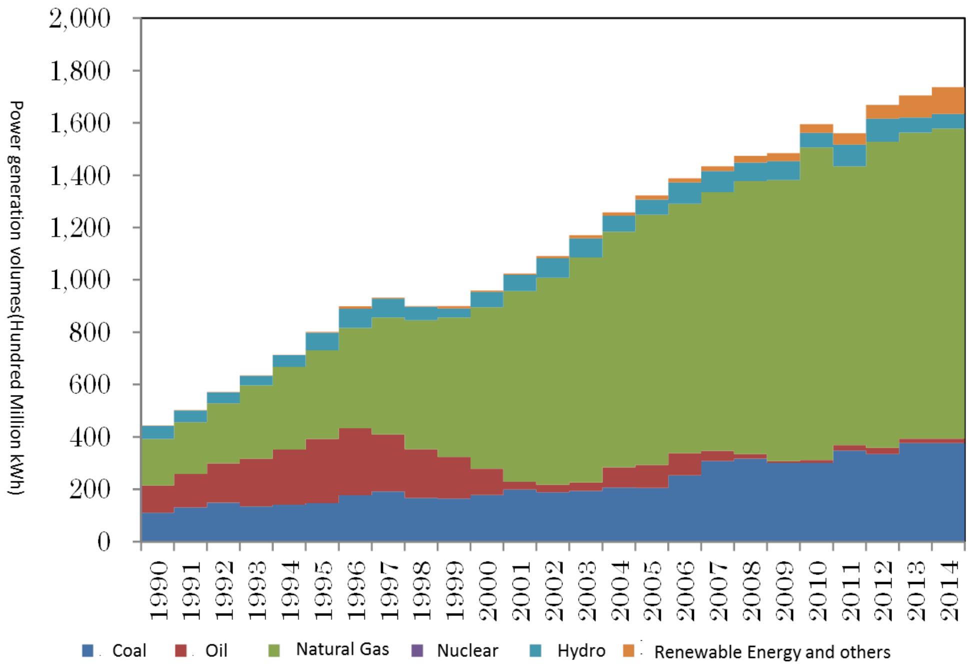
3.4.3 Energy consumption developments by segment

3.4.3.1 Electric power

Demand for electric power has been on the rise in just the same way as that for primary energy, making it necessary for Thailand to expand its power generation capacity in tandem with the growing demand. The data show that power plants using natural gas only began to grow in number in the early 1990s, resulting in a sharp increase in natural gas-fired power generation, coinciding with a marked decline in oil-fired power generation. The data also show that since around 2000 the country's consumption of non-hydraulic renewable energy began to grow significantly.

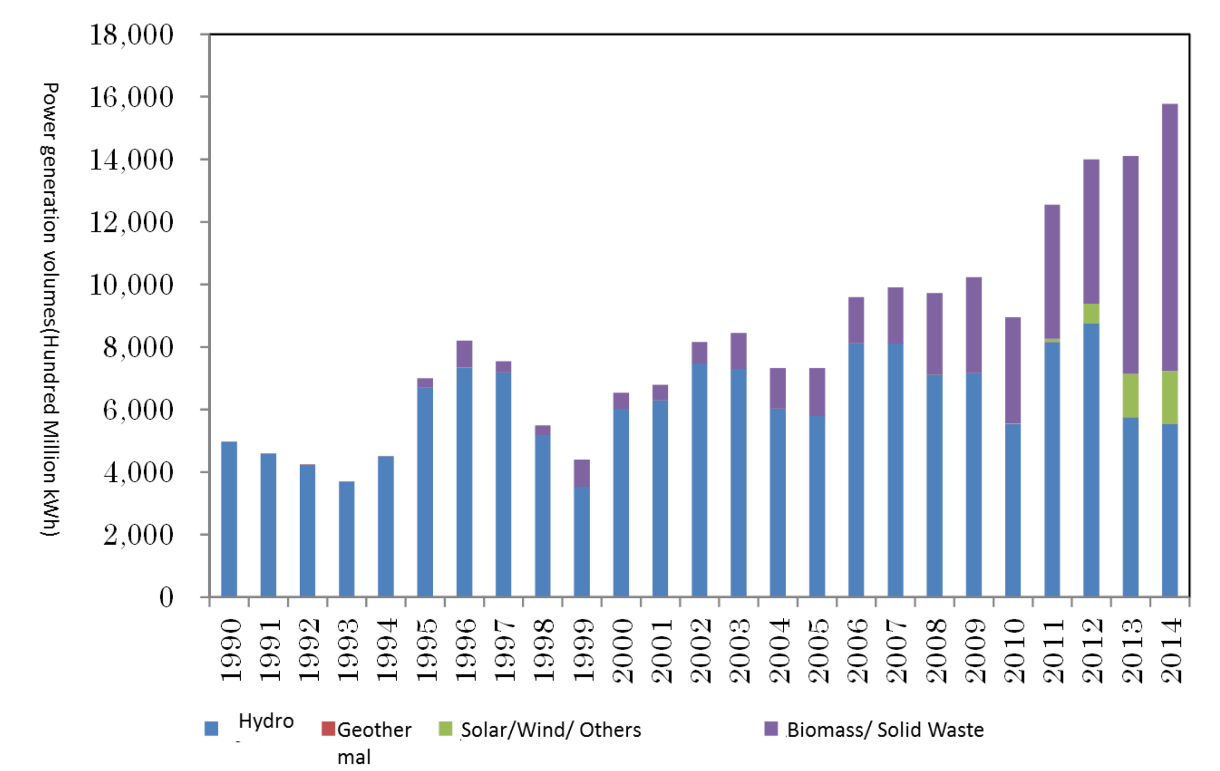
In the past, hydraulic power-derived energy accounted for a predominant portion of renewable energy in the electric power sector. In recent years, however, Thailand has been increasing employing non-hydraulic energy sources, with the result that in 2013 non-hydraulic renewable power sources overtook hydraulic sources in power generation volume. Biomass power generation has been driving the climbing consumption of non-hydraulic renewable energy, assuming a rising profile in the power generation sector, a phenomenon partly attributable to the growth of solar and wind power generation since around 2010.

Figure 13: Power generation volumes and breakdown



Source: OECD Library

Figure 14: Renewable energy power generation volumes



Source: OECD Library

3.4.3.2 Thermal energy sources

In Thailand, thermal use of renewable energy sources has been progressing, chiefly among industries such as the sugar, papermaking, rice polishing, wood processing and palm oil sectors. Such rising consumption of renewable energy by players in these sectors is attributable to the fact that they can utilize waste that is emitted through their operations. Thus, they use such waste as biomass or waste oil-derived biogas. The Thai government, while having set a target of raising the proportion of renewable energy to 36.67% of the total energy use in the nation's thermal power generation segment by 2036, has expressed the intent to strive to help increase the use of power cogeneration systems and solar power, in addition to the above-mentioned means, toward achieving the goal.

Figure 15: Thermal energy sources by industry

Industry	Thermal energy sources used in the industry
Sugar	Sugar cane lees 99.96%/other remnants 0.04%
Papermaking	Black liquid (waste liquid) 62.37%, coal 19.58%, firewood 6.23%
Rice polishing	Rice husks 99.24%
Wood processing	Firewood 95.04%, sawdust 4.91%
Palm oil	Coconut shells 84.27%, other remnants 8.96%

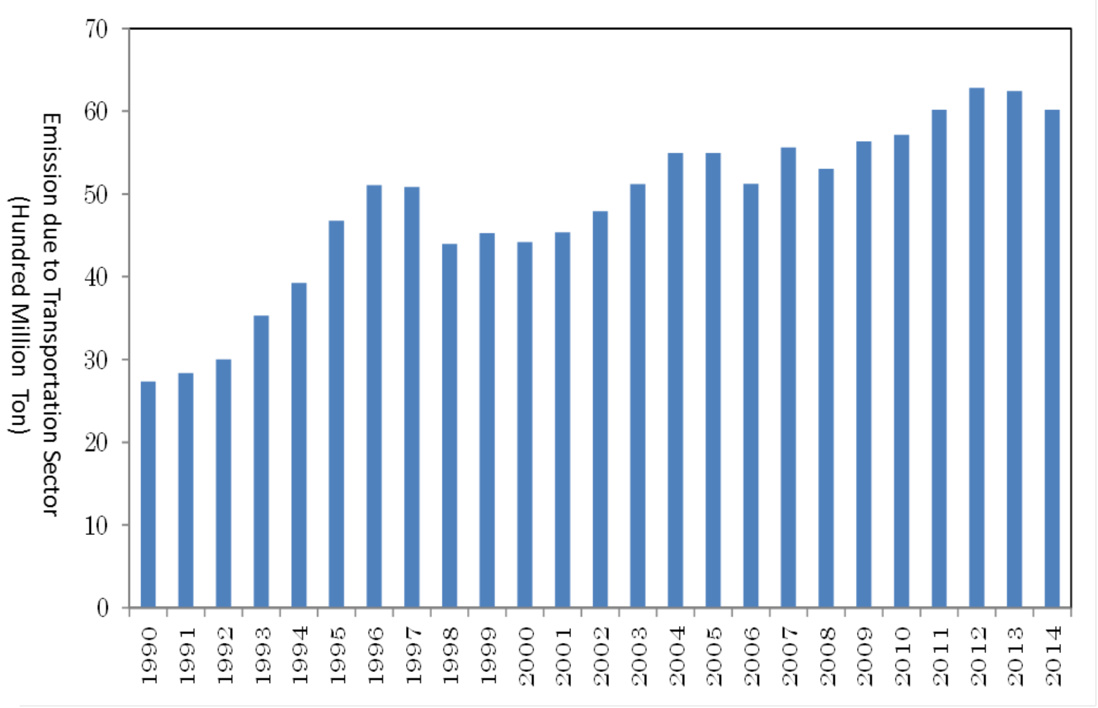
Source: Department of Alternative Energy Development and Efficiency of the Kingdom of Thailand, *Alternative Energy Development Plan 2015*

3.4.3.3 Fuels

In Thailand, transportation-generated carbon dioxide emissions have been growing year after year. Alongside industry, transportation accounts for an extremely high proportion of the nation's overall energy consumption. Therefore, experts think that raising the fuel self-sufficiency rate and low-carbon shift will have a significant effect on the overall situation, which is a challenge prioritized in the Thai government's energy policy. Shown below are the proportions of transportation-generated carbon dioxide emissions by type of fuel. In recent years, natural gas-generated carbon dioxide emissions have begun to increase instead of oil-generated emissions, a phenomenon caused by the rising number of consumers using compressed natural gas (CNG)-powered vehicles in response to surging gasoline prices. A look at natural gas consumption volumes by purpose of use shows that consumption for CNG-powered vehicles has been growing.

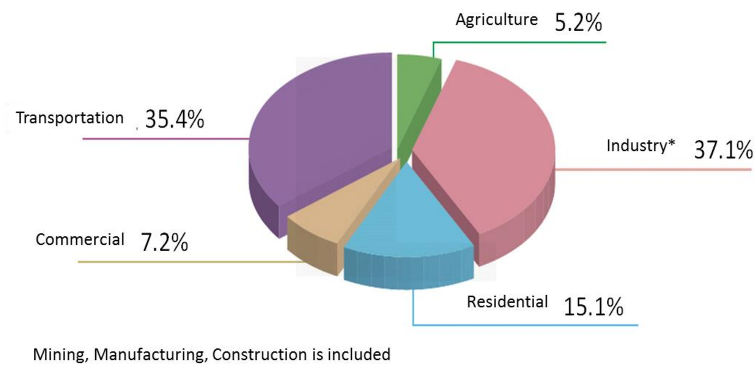
On the other hand, natural gas reserves in Thailand have been moving closer to depletion, as discussed earlier, while the nation's reliance on imports has been rising, meaning that there is a risk that the fuel for CNG-powered vehicles will become more expensive due to the tightening supply-demand balance. This appears to present a challenge for expanding the penetration of CNG-powered vehicles in the country from now on.

Figure 16: Transportation-generated carbon dioxide emissions



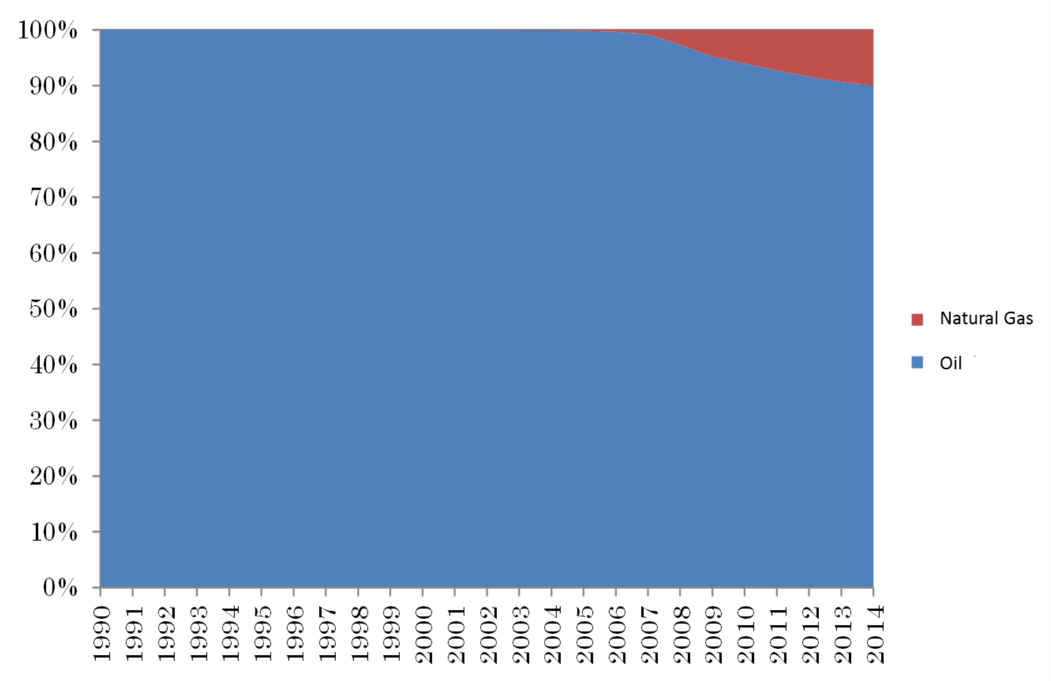
Source: OECD Library

Figure 17: Proportion of energy consumption by sector (the first quarter of 2014)



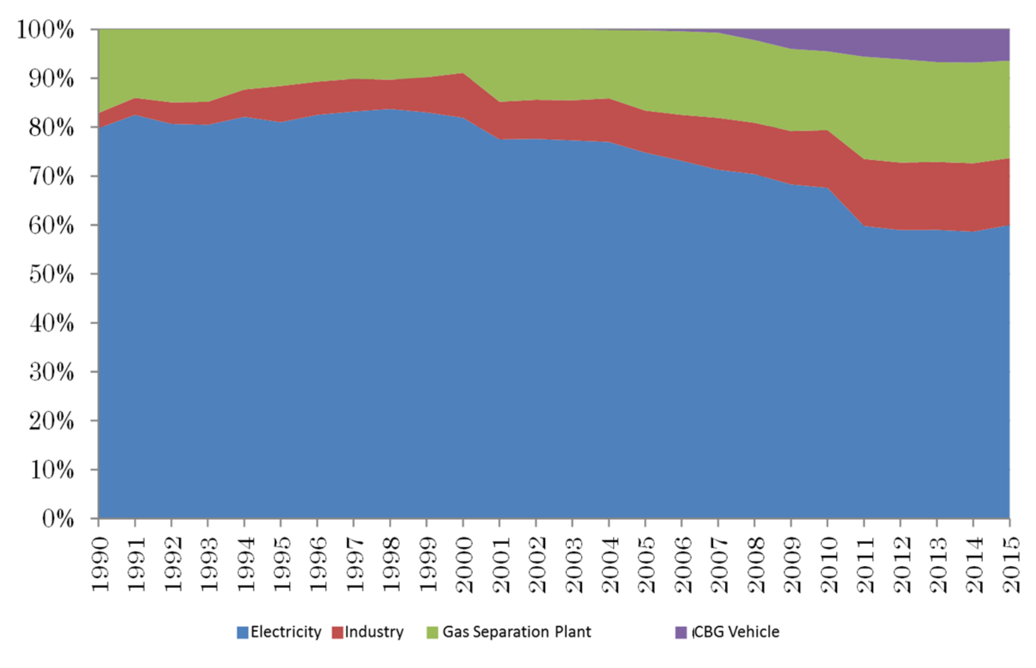
Source: Department of Alternative Energy Development and Efficiency of the Kingdom of Thailand, *Energy in Thailand Q1/2014*

Figure 18: Proportion of carbon dioxide emission by type of transportation fuel



Source: OECD Library

Figure 19: Proportion of natural gas consumption volume by purpose of use



Source: Statistical database of the Energy Policy & Planning Office (EPPO) of the Kingdom of Thailand

3.4.4 Summary of historical energy balance

As discussed earlier, until around 1990, the Kingdom of Thailand, being gifted with abundant coal and natural gas reserves, continued to enjoy a self-sufficiency rate of 100% in natural gas and above 90% in coal. The nation, however, became unable to retain such high self-sufficiency rates on the back of its economic growth. In particular, natural gas, a relatively-low-carbon type of fuel among the various types of fossil fuels, will likely be increasingly used for power generation and transportation in coming years, causing its balance of supply and demand to tighten.

For this reason, the Thai government is striving to pursue energy conservation policies and to expand renewable energy sources in an effort to raise its energy self-sufficiency rates and build a low-carbon society. Biomass will presumably continue to drive the nation's renewable energy-source expansion efforts because, being an agriculture-centric country, Thailand is endowed with a significant amount of biomass, with biomass-derived energy accounting for a predominant portion of its renewable energy sources.

Meanwhile, when looked at from a consumption perspective, transportation, alongside industry, represents a significant portion of Thailand's energy consumption. Due to surging gasoline prices, natural gas has been partially replacing gas as a transportation-segment fuel. Although the penetration of CNG-powered vehicles, using relatively-low-carbon fuel, is welcome for achieving a low-carbon-society, it is feared that such penetration could potentially become a factor for tightening the supply-demand balance for natural gas, as discussed earlier.

Against this background, experts are beginning to pay attention to the use of CBG, biomass-derived compressed methane gas, for CNG-powered vehicles. Using CBG, which taps abundant biomass resources as an alternative to natural gas, will likely help expand renewable energy sources and ease the supply-demand balance for natural gas, thus serving to resolve the nation's two major challenges simultaneously.

3.5 Energy goals and policies

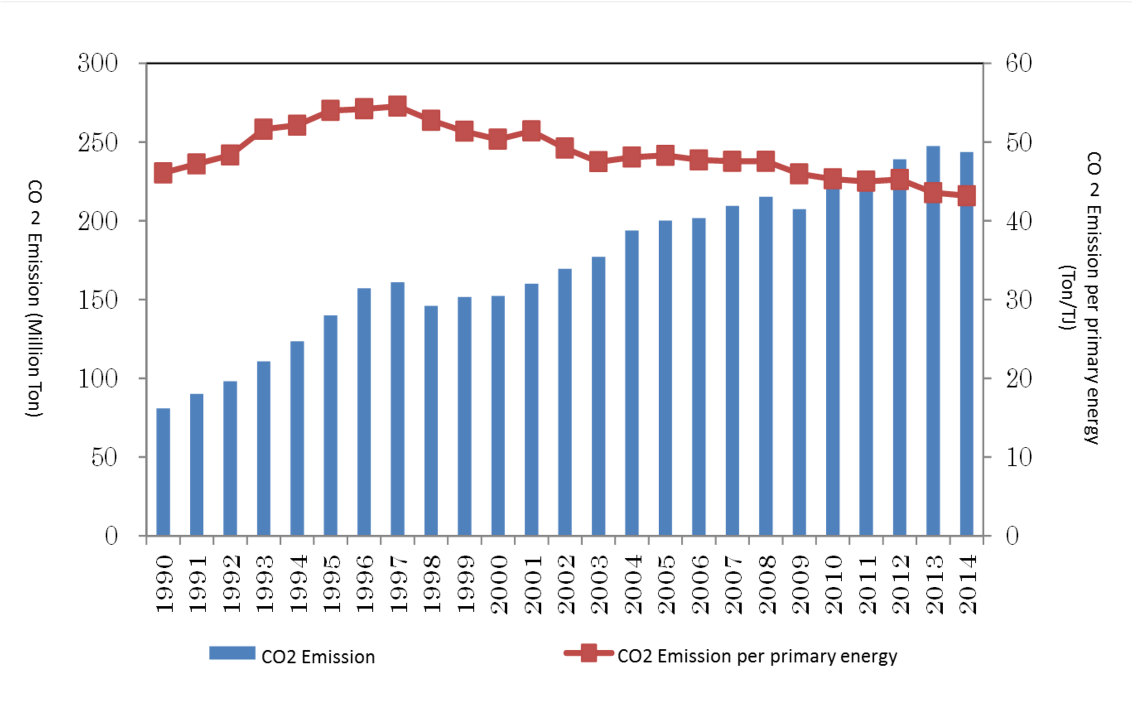
3.5.1 Alternative Energy Development Plan

3.5.1.1 Background

Although steadily lowering its carbon dioxide emissions per primary energy category, the Kingdom of Thailand is conversely experiencing growing total carbon dioxide emissions due to its continuously-rising energy consumption levels.

To put a brake on the continuously-climbing carbon dioxide emissions, the Thai government's energy measures are highly focused on carbon dioxide reduction. One of the key measures involved is the Alternative Energy Development Plan, which was put in place with the goal of raising the nation's renewable energy ratio to 30% by 2036.

Figure 20: Carbon dioxide emissions



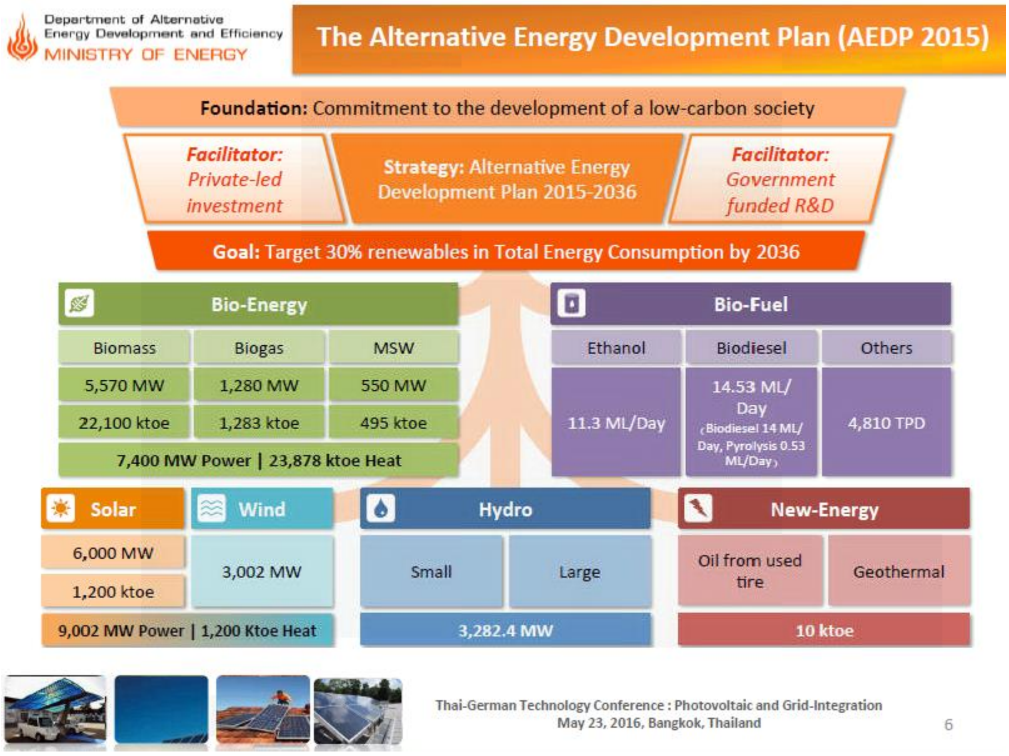
Source: OECD Library

3.5.1.2 Targets for renewable energy introduction

The Alternative Energy Development Plan (AEDP) is a long-term Thai government renewable energy development plan. The AEDP stipulates the country's targets concerning bio energy (electric power, thermal power and fuel), solar power, wind power, hydraulic power and new energy sources, as well as the orientation of measures to achieve the targets. In the AEDP, the Thai government states a target of raising the nation's renewable energy ratio to 30% by 2036.

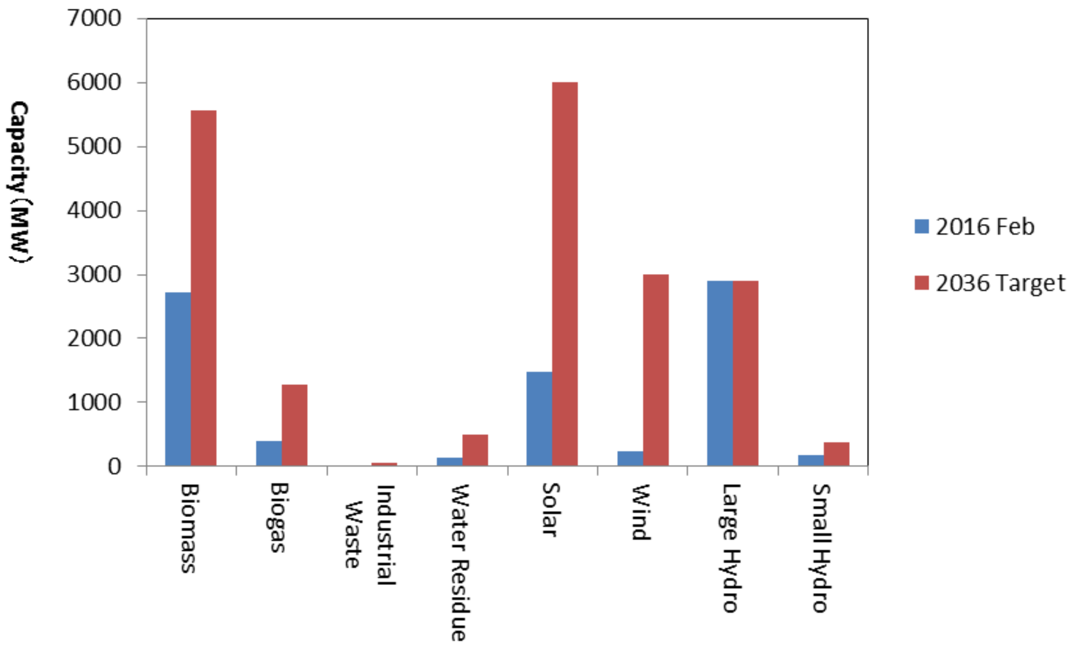
Shown below is the status of the introduction of renewable energy in Thailand, as well as the introduction target for 2036. In the power generation sector, the government plans to: 1) continue expanding biomass power generation, a renewable energy category that has so far been introduced in the highest volume among non-large-scale hydraulic power generation categories in the country; and 2) grow solar and wind power generation significantly. In the thermal energy sector, biogas and biomass, its current main components, will continue to account for the predominant shares, according to the plan, although there are expectations for solar heat. In the fuel sector, biodiesel will grow substantially, with the government intending to promote the penetration of CBG, which is hoped to serve as an alternative to CNG.

Figure 21: Alternative Energy Development Plan (AEDP)



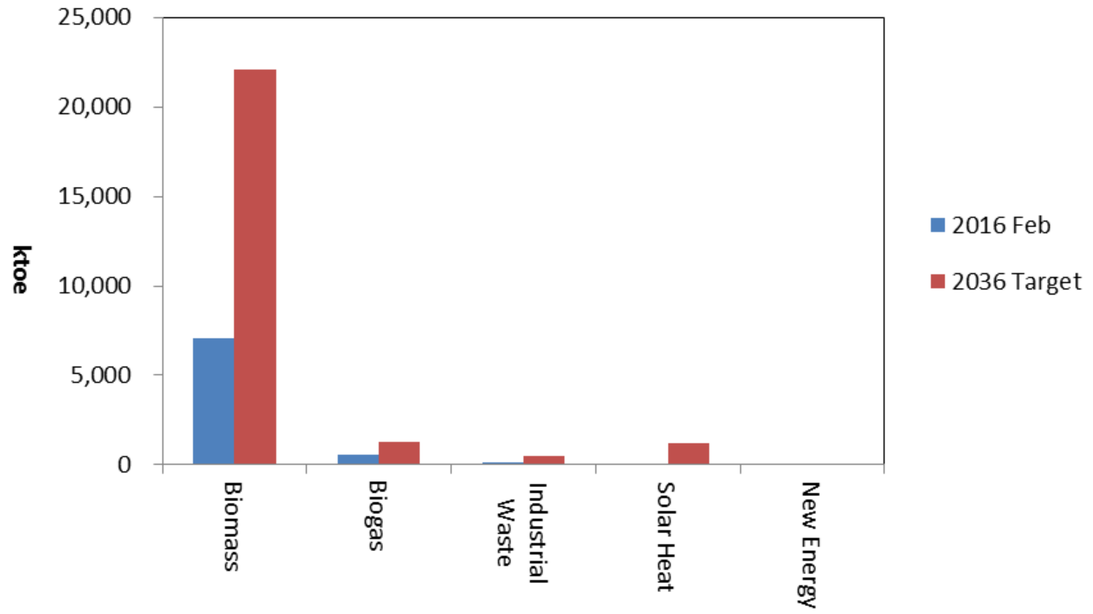
Source: Department of Alternative Energy Development and Efficiency of the Kingdom of Thailand, *Solar Power Policy: Status Update 2016*

Figure 22: Status of renewable energy introduction and targets (electric power)



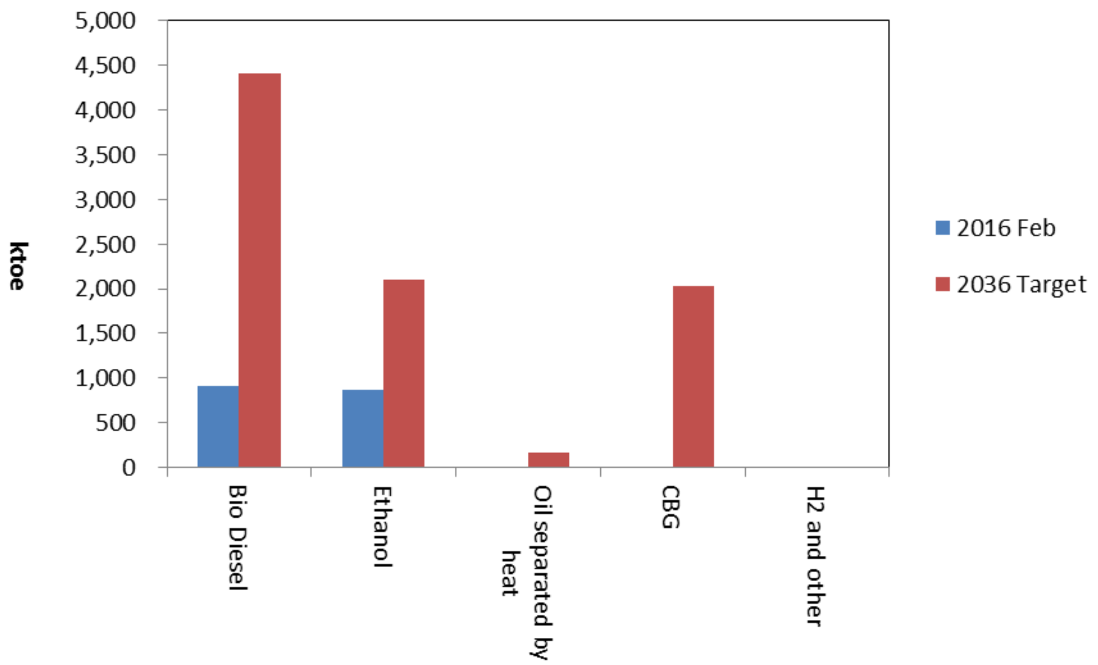
Source: Department of Alternative Energy Development and Efficiency of the Kingdom of Thailand, *Solar Power Policy: Status Update 2016*

Figure 23: Status of renewable energy introduction and targets (thermal power)



Source: Department of Alternative Energy Development and Efficiency of the Kingdom of Thailand, *Solar Power Policy: Status Update 2016*

Figure 24: Status of renewable energy introduction and targets (biofuel)



Source: Department of Alternative Energy Development and Efficiency of the Kingdom of Thailand, *Alternative Energy Development Plan 2015*

3.5.1.3 Measures to expand renewable energy sources

The Thai government has taken measures to support the introduction of renewable energy sources. These measures take the form of feed-in tariff-based purchases by the Energy Policy & Planning Office (EPPO), an ESCO Fund provided by the Department of Alternative Energy Development and Efficiency (DEDE), tax breaks by the Board of Investment of Thailand (BOI), subsidies by the EPPO and the DEDE and the provision of information by the DEDE.

In particular, the table below outlines, among the above-mentioned measures, a CBG-related assistance program including the feed-in tariff scheme, which is associated with biogas power generation, a power generation category that could potentially compete against CBG power generation since both of these two categories use biogas as fuel.

Figure 25: Renewable energy support measures in Thailand

Feed-in tariff scheme (EPPO)	The EPPO launched a scheme to purchase generated electricity at above market prices for a certain period of time, with the aim of encouraging users to start using renewable energy sources that are not cost-competitive. The technologies made applicable were biomass, biogas, waste, wind power, hydraulic power and solar power.
ESCO Fund (DEDE)	Investment in renewable energy businesses and projects. Leasing of relevant equipment, among other activities
Board of Investment (BOI)	Import duty deductions and corporate tax breaks for renewable energy sales and energy conservation businesses for a period of up to eight years
Subsidies (EPPO/DEDE)	Various types of subsidy for renewable energy business operations
Provision of information (DEDE)	Publication of information on the establishment of one-stop service centers and on trends in renewable energy development. Publication of a wind and solar power resources map

Source: Department of Alternative Energy Development and Efficiency of the Kingdom of Thailand, *Solar Power Policy: Status Update 2016*

3.5.2 Outline of feed-in tariff (FIT) scheme

3.5.2.1 Previous FIT schemes (until the end of 2015)

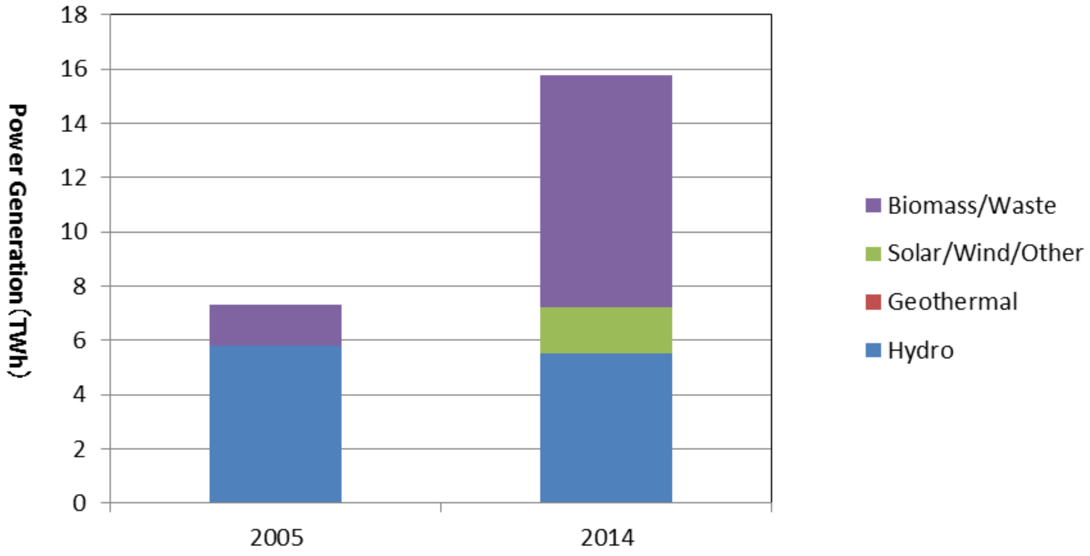
In 2007, the Kingdom of Thailand became the first ASEAN member state to launch a feed-in tariff scheme for renewable energy. Commonly referred to as “Adder,” this scheme started as a system for government-owned electric power companies to purchase, at a certain level of premium, electricity generated by private-sector companies using renewable energy. Shown below are the premium figures. The Adder scheme was launched in 2007 with the highest premium of 8.0 THB/kWh being set for solar power-generated electricity. This scheme was revised in 2009 by raising the premium for small-scale biomass power-generated electricity. Between 2005, prior to the launch of the feed-in tariff scheme, and 2014, after the launch, the amount of renewable energy use by power generators almost doubled on an equipment capacity basis and slightly more than doubled on a power generation amount basis. Particularly strong growth was posted by categories targeted by the feed-in tariff scheme such as biomass, biogas, waste, solar power and wind power, indicating the extent of the contribution made by the Adder scheme in the penetration of renewable energy sources in Thailand.

Figure 26: History of Adder premium price revisions (in THB/kWh)

<table>
<tr><th>Category</th><th>Scale</th><th>2007–08 Adder</th><th>2009 Adder</th><th>Replacement of diesel fuel</th><th>Power generation in any of specified areas in South Thailand</th><th>Purchase period</th><th>12/31/2015</th></tr>
<tr><td colspan="2">Solar power</td><td colspan="2">8.00</td><td rowspan="3">1.50</td><td rowspan="3">1.50</td><td rowspan="3">10 years</td><td rowspan="11">Discontinued. Migrated to a new feed-in tariff scheme</td></tr>
<tr><td rowspan="2">Wind power</td><td>Less than 50 kW</td><td rowspan="2">3.50</td><td>4.50</td></tr>
<tr><td>50 kW or above</td><td>3.50</td></tr>
<tr><td rowspan="2">Biomass</td><td>Less than 1 MW</td><td rowspan="2">0.30</td><td>0.50</td><td rowspan="8">1.00</td><td rowspan="8">1.00</td><td rowspan="8">7 years</td></tr>
<tr><td>1 MW or above</td><td>0.30</td></tr>
<tr><td rowspan="2">Biogas</td><td>Less than 1 MW</td><td rowspan="2">0.30</td><td>0.50</td></tr>
<tr><td>1 MW or above</td><td>0.30</td></tr>
<tr><td rowspan="2">Waste</td><td>Reclaimed land</td><td rowspan="2">2.50</td><td>2.50</td></tr>
<tr><td>Heat treatment</td><td>3.50</td></tr>
<tr><td rowspan="2">Low hydraulic power</td><td>50–20 kW</td><td>0.40</td><td>0.80</td></tr>
<tr><td>Less than 50 kW</td><td>0.80</td><td>1.50</td></tr>
</table>

Source: IEA website, Policies and Measures (Thailand)

Figure 27: Consumption amount of renewable energy before and after the launch of the feed-in tariff scheme



Source: OECD Library

3.5.2.2 New feed-in tariff scheme

In December 2014, the National Energy Policy Council (NEPC) approved a plan to launch a new feed-in tariff scheme as a replacement to the Adder scheme that had been in operation since 2007. It was then decided that this new feed-in tariff scheme would be applied as the first step to power generation projects of less than 10 MW ("Very Small Power Producer" or "VSPP") in consideration of Thailand's limited power grid capacity.

The new scheme differed from the previous one mainly in that: 1) the new one's purchase period was set at 20 years, with the exception of waste (reclaimed land gas) (25 years for solar power) in comparison to seven to 10 years under the previous scheme; and 2) the new scheme's unit price varied greatly according to the technology and operational scale.

The feed-in tariff (FIT) under the new scheme comprised a combination of the four factors shown in the table below. Also shown below are feed-in tariffs that will apply to renewable energy to be introduced in 2017 under the new feed-in tariff scheme.

The project selection method will be changed from one based on the order of application filing, used previously, to a tender system. Accordingly, the feed-in tariff will serve as upper limit price with the business operator applying for a project within that scope. The location and scale of projects will be determined by the Ministry of Energy jointly with the Electricity Generating Authority of Thailand, the Metropolitan Electricity Authority and the Provincial Electricity Authority, as discussed later. Currently, Thailand's power grid development is lagging behind the surging supply of renewable energy. However, migrating to the tender system is expected to enable experts to develop the power grid effectively, consequently allowing greater amounts of renewable energy to be connected to the power grids.

Figure 28: Components of the feed-in tariff

FIT (fixed)	Principal tariff fixed for the full purchase period
FIT (variable)	Tariff that is applied solely to categories requiring raw materials, such as biomass, biogas and waste; revised each year according to fluctuating raw material costs
FIT Premium 1	Premium tariff to be paid for the first eight years of the purchase period for biomass, biogas and waste
FIT Premium 2	Premium tariff to be paid for an operation in any of the specified South Thailand areas throughout the purchase period
FIT price	Sum of the tariffs for the above-mentioned four factors

Source: IEA website, Policies and Measures (Thailand)

Figure 29: Purchase price for renewable energy categories

(excluding solar power and in THB/kWh)

<table>
<tr><th>Category</th><th>Scale</th><th>FIT (fixed)</th><th>FIT (variable)</th><th>FIT (subtotal)</th><th>FIT Premium 1</th><th>FIT Premium 2</th><th>Purchase period</th></tr>
<tr><td rowspan="3">Waste (burning)</td><td>Less than 1 MW</td><td>3.13</td><td>3.21</td><td>6.34</td><td rowspan="3">0.70</td><td rowspan="11">0.50</td><td rowspan="3">20 years</td></tr>
<tr><td>1–3 MW</td><td>2.61</td><td>3.21</td><td>5.82</td></tr>
<tr><td>Above 3 MW</td><td>2.39</td><td>2.69</td><td>5.08</td></tr>
<tr><td colspan="2">Waste (reclaimed land)</td><td>5.60</td><td>-</td><td>5.60</td><td>-</td><td>10 years</td></tr>
<tr><td rowspan="3">Biomass</td><td>Less than 1 MW</td><td>3.13</td><td>2.21</td><td>5.34</td><td>0.50</td><td rowspan="7">20 years</td></tr>
<tr><td>1–3 MW</td><td>2.61</td><td>2.21</td><td>4.82</td><td>0.40</td></tr>
<tr><td>Above 3 MW</td><td>2.39</td><td>1.85</td><td>4.24</td><td>0.30</td></tr>
<tr><td colspan="2">Biogas (waste liquid)</td><td>3.76</td><td>-</td><td>3.76</td><td rowspan="2">0.50</td></tr>
<tr><td colspan="2">Biogas (crop)</td><td>2.79</td><td>2.55</td><td>5.34</td></tr>
<tr><td colspan="2">Hydraulic power</td><td>4.90</td><td>-</td><td>4.90</td><td>-</td></tr>
<tr><td colspan="2">Wind power</td><td>6.06</td><td>-</td><td>6.06</td><td>-</td></tr>
</table>

Source: Department of Alternative Energy Development and Efficiency of the Kingdom of Thailand, *AEDP 2015–2036 Presentation Material*

Figure 30: Purchase price for solar power generated (in THB/kWh)

Category	FIT (fixed)	FIT (variable)	FIT (subtotal)	FIT Premium 1	FIT Premium 2	Purchase period
Mega solar power (less than 90 MW)	5.66		5.66			
Home use (less than 10 kW)	6.85		6.85			
Commercial user (10–250 kW)	6.40	-	6.40	-	0.50	25 years
Commercial use (250–1,000 kW)	6.01		6.01			
Public or agricultural use (less than 5 MW)	5.66		5.66			

Source: Department of Alternative Energy Development and Efficiency of the Kingdom of Thailand, *AEDP 2015–2036 Presentation Material*

3.5.3 Outline and outlook of energy conservation and energy conservation subsidy schemes

Shown below are three principal subsidy schemes in Thailand for energy conservation and renewable energy. In 2016, the DEDE launched a subsidy program for CBG manufacturing equipment, but it is uncertain whether it will be continued.

- Energy conservation program (ENECON Program)
    - Under the 1992 Energy Conservation Program Act, energy conservation measures progressed and new and renewable energy sources were introduced. In 1995, the Energy Conservation Promotion Fund (ENECON Fund) was established as a financial aid scheme for promoting energy conservation and renewable energy introduction projects before being approved and executed as such.

- ESCO Fund (Energy Conservation Promotion Fund)
    - In 2008, the ESCO Fund was established as a joint investment program by private-sector bodies and investors under the Energy Conservation Promotion Fund (ENCON Fund). The fund's value, amounting to US$15.0 million at launch, will grow to US$100.0 million to US$200.0 million in the long term, according to the plan.

- Revolving Fund
    - The Thai government has been implementing various financial subsidy programs simultaneously with the Adder scheme. Among such programs is the Revolving Fund scheme targeting the energy sector. Through government-financial sector cooperation, this scheme aims to stimulate private-sector investment designed to improve energy efficiency and encourage the use of renewable energy.

- CBG Equipment Subsidy
    - The CBG Equipment Subsidy program was established in 2016 by the DEDE as a subsidy program for CBG manufacturing equipment. This program will likely continue to encourage the use of CBG equipment by providing subsidies in the future toward achieving the targets set out in the AEDP 2015. However, it is uncertain how the subsidy program will be implemented, because the government agency is still seeking to identify what form and ratio of subsidy is effective.[3]

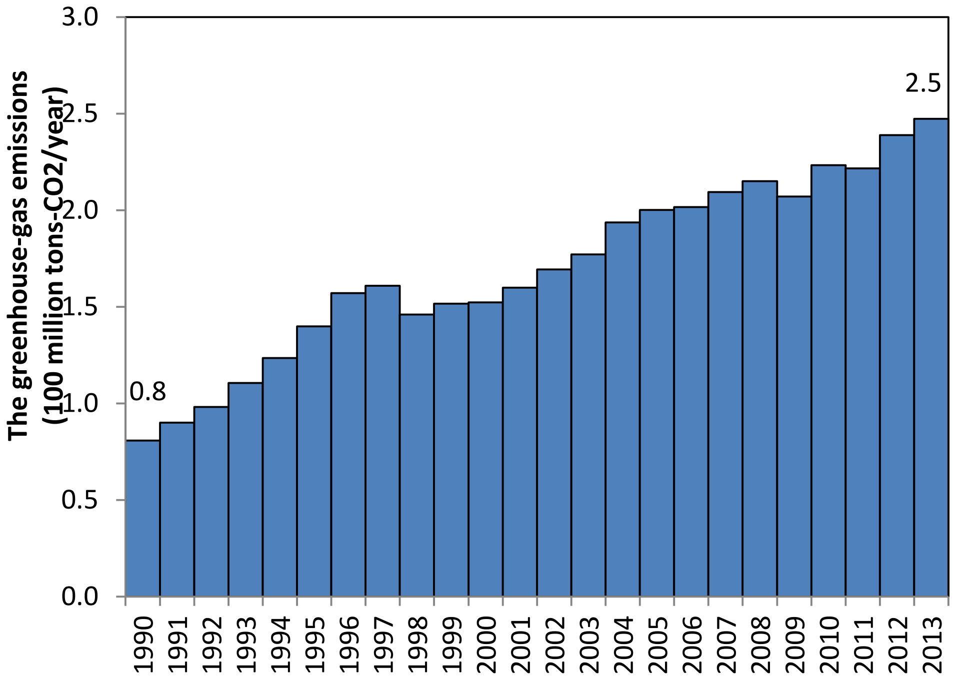
[3] From on-site interviews with DEDE personnel

3.6 GHG emission trends

3.6.1 GHG emission volumes

Carbon dioxide emissions in Thailand, having been rising year after year, stood at 250 million t-CO_2/year in 2013, an increase of 30% compared to 1990.

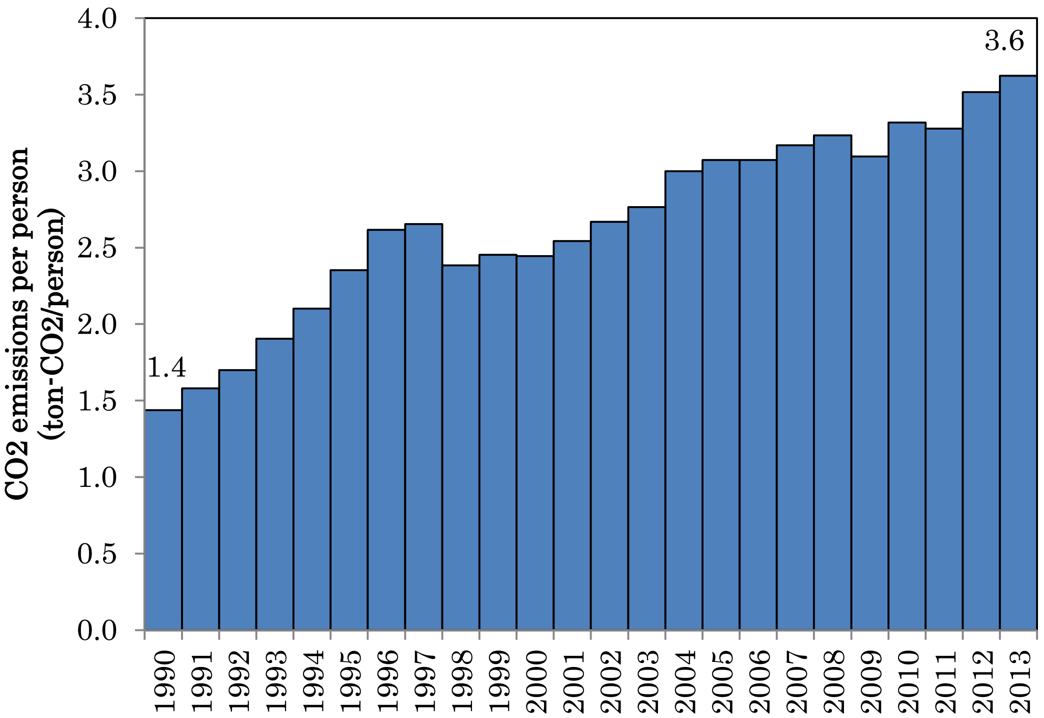
Figure 31: Carbon dioxide emissions in Thailand



Prepared by the Japan Research Institute, based on the database for the report “CO_2 Emissions from Fuel Combustion 2015” by the International Energy Agency (IEA)

The chart below shows Thailand's historical per-capita carbon dioxide emissions, which have been on the rise, in just the same way as total emissions, on the back of the nation's improving standards of living as evidenced by the steady growth from 1990 to 2013.

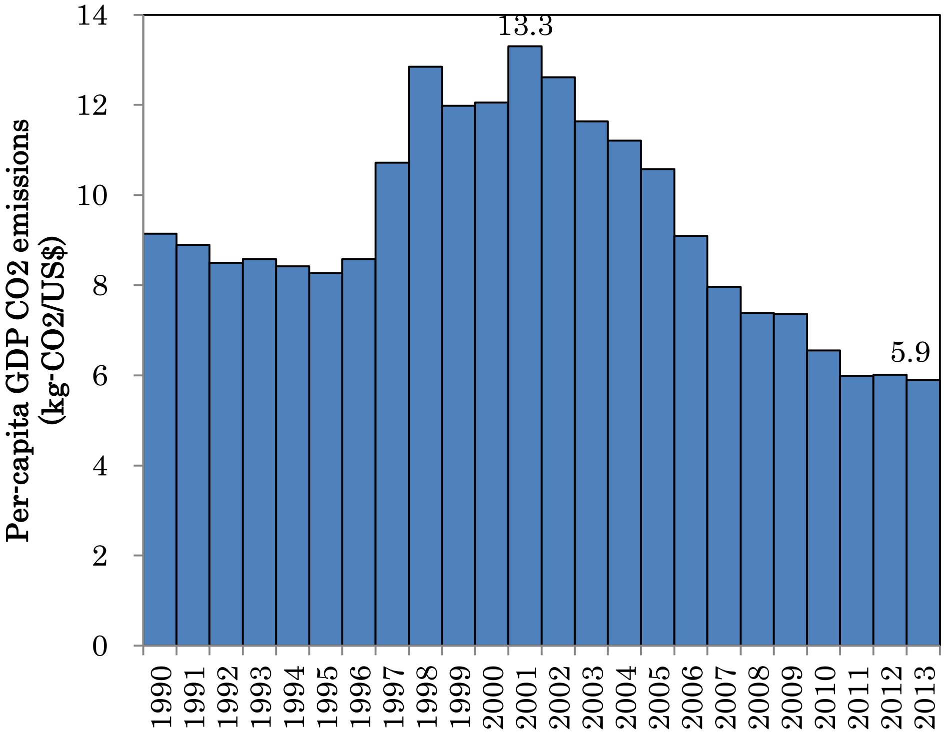
Figure 32: Per-capita carbon dioxide emissions



Source: The greenhouse-gas data was prepared by the Japan Research Institute, based on the database for the report "CO_2 Emissions from Fuel Combustion 2015" by the International Energy Agency (IEA). The population data was prepared by the Institute, based on the World Economic Outlook Database by the International Monetary Fund.

Meanwhile, per-capita GDP carbon dioxide emissions peaked in 2001 at 13.3 (kg-CO_2/US dollar) before declining.

Figure 33: Per-capita GDP carbon dioxide emissions



Source: The greenhouse gas data was prepared by the Japan Research Institute, based on the database for the report "CO_2 Emissions from Fuel Combustion 2015" by the International Energy Agency (IEA). The nominal GDP data was prepared by the Institute, based on the World Economic Outlook Database by the International Monetary Fund.

3.6.2 Intended Nationally Determined Contributions (INDCs)

The Thai government submitted to the UNFCCC a draft of the document "Intended Nationally Determined Contributions" (INDCs) on October 1, 2015. The nation's greenhouse gas (GHG) emissions reduction target is set at a 20% cut against BAU in 2030 compared to 2005, on a voluntary basis, and at a 25% cut on an international aid utilization basis. The targeted gas categories were CO_2, CH_4, N_2O, HFCs, PFCs and SF_6.

The Thai government, being aware of the importance of market-based mechanisms as a means of mitigating climate change, has been pushing forward with international mechanism schemes such as the Joint Crediting Mechanisms (JCM) initiative entered into with Japan, as well as the nation's independent domestic mechanism schemes.

The INDCs initiative is consistent with the following Thailand's national economic and social development plans and its climate change master plan.

- National Economic and Social Development Plants
- Climate Change Master Plan B.E. 2558-2593 (2015-2050)
- Power Development Plan B.E. 2558-2579 (2015-2036)
- Thailand Smart Grid Development Master Plan B.E. 2558-2579 (2015-2036)
- Alternative Energy Development Plan B.E. 2558-2579 (2013-2030)
- Environmentally Sustainable Transport System Plan B.E. 2556-2573 (2013-2030)
- National Industrial Development Master Plan B.E. 2555-2574 (2012-2031)
- Waste Management Roadmap

3.6.3 National Master Plan on Climate Change 2013–2050

The "National Master Plan on Climate Change 2013–2050" has been put in place by Thailand with the aim of addressing climate change and achieving low-carbon-based growth while adhering to the nation's sustainable state development plan. This master plan is intended to deal with long-term challenges, and the centerpiece of its strategy is to address challenges related to climate change adaptation and mitigation measures, as well as relevant cross-sectional challenges. The master plan gives priority to establishing policy measures based on near, medium and long term target roadmaps formulated.

Figure 34: List of strategy segments

Adaptation measures segment	Mitigation measures segment	Cross-sectional challenges
Water-source management Agriculture and food preservation Tourism Public sanitation Natural resources management Residential and human security	Power generation Transportation Construction Industry Waste management Agriculture Forest Urban area management	Database, R&D and technological development Establishment of policy measures Awareness-raising and capacity building Improvements in international cooperation

Source: Ministry of Natural Resources and Environment of the Kingdom of Thailand, presentation material *Thailand's Climate Change Policies* (http://www-gio.nies.go.jp/wgia/wg12/pdf/0_3_ONEP_N.pdf) and the Ministry of the Environment of Japan, *Thailand's Climate Change Policy* (December 24, 2015)

Figure 35: Near-term, medium-term and long-term targets

	Adaptation measures	Mitigation measures
Near-term targets (2016)	Create a comprehensive risk map for climate change as a map that factors in key socioeconomic and environmental perspectives. Expand the nation's mangrove forests by 5,000 rai or more a year in an effort to grow its biodiversity preservation zones. Bolster the plan to preserve coastal areas. Develop an index for the entire economy's ability to adapt to climate change.	Develop domestic NAMA and MRV systems. Integrate the nation's economic and law systems in order to stimulate low-carbon-based development initiatives. Enhance climate change database systems such as the GHG inventory system, the mitigation registry system and the proactive emission volume trading system. Devise a national climate change strategy and an action plan for both adaptation and mitigation.

Mid-term targets (2020)	Create effective forecasting and early warning systems for the agriculture sector. Establish natural disaster management for fragile areas across the country. Set up a protection system for farm crops affected by climate change. Establish a national adaptation fund mechanism for recovery from climate change effects. Expand biodiversity protection areas.	Expand the nation's forests by 40% in size. Reduce GHG emission by about 7% to 20% by 2020 (NAMA). Raise the proportion of renewable energy among all energy consumption categories to 25%. Grow per-capita forest area to 10 m^2. Achieve greater energy efficiency by introducing smart grid technology.
Long-term targets (2030)	Expand irrigation areas. Manage water sources in areas where irrigation has yet to be developed. Cultivate skills to deal with natural disasters in areas with high natural disaster risks. Increase the number of agricultural workers enrolled in crop protection schemes. Reduce the volume of crops prone to climate change impacts.	Expand public transportation traffic volumes. Improve the energy coefficient to a level 25% or more above the BAU value. Reduce land transportation-generated emissions. Reduce the outdoor burning of farming waste. Strengthen the management of agricultural production processes and increase the proportion of organic farming. Expand the low-carbon development plans of the central and municipal governments.

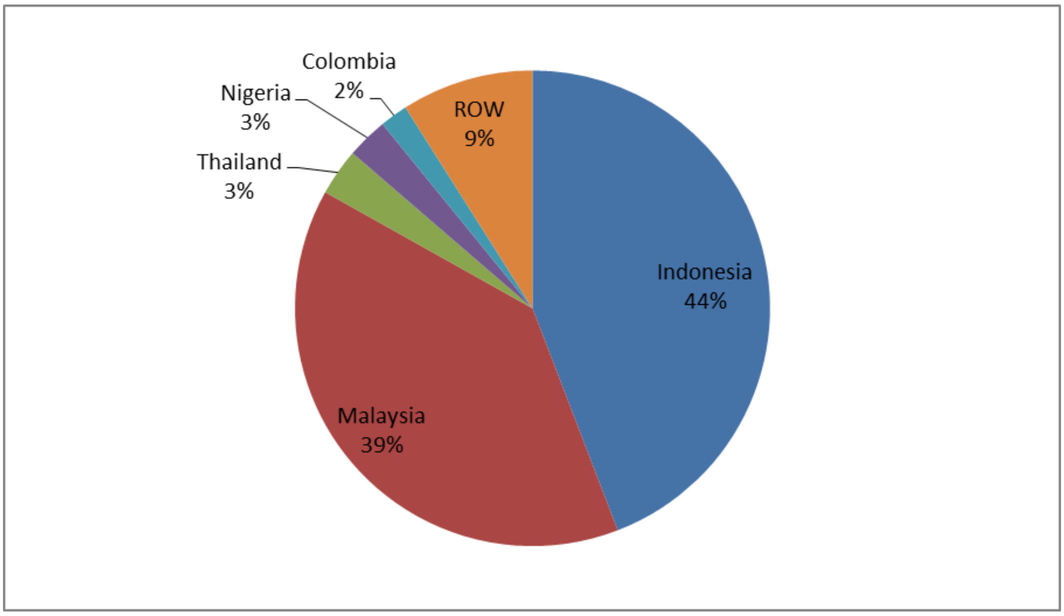
Source: Ministry of Natural Resources and Environment of the Kingdom of Thailand, presentation material *Thailand's Climate Change Policies* (http://www-gio.nies.go.jp/wgia/wg12/pdf/0_3_ONEP_N.pdf) and the Ministry of the Environment of Japan, *Thailand's Climate Change Policy* (December 24, 2015)

4. Environment of the project

4.1 Trends in the palm/cassava industries

Annual worldwide production of palm oil was around 60 million tons in 2013. With a share of about 3.6%, Thailand is the third-largest palm-oil producing country in the world after Indonesia and Malaysia.

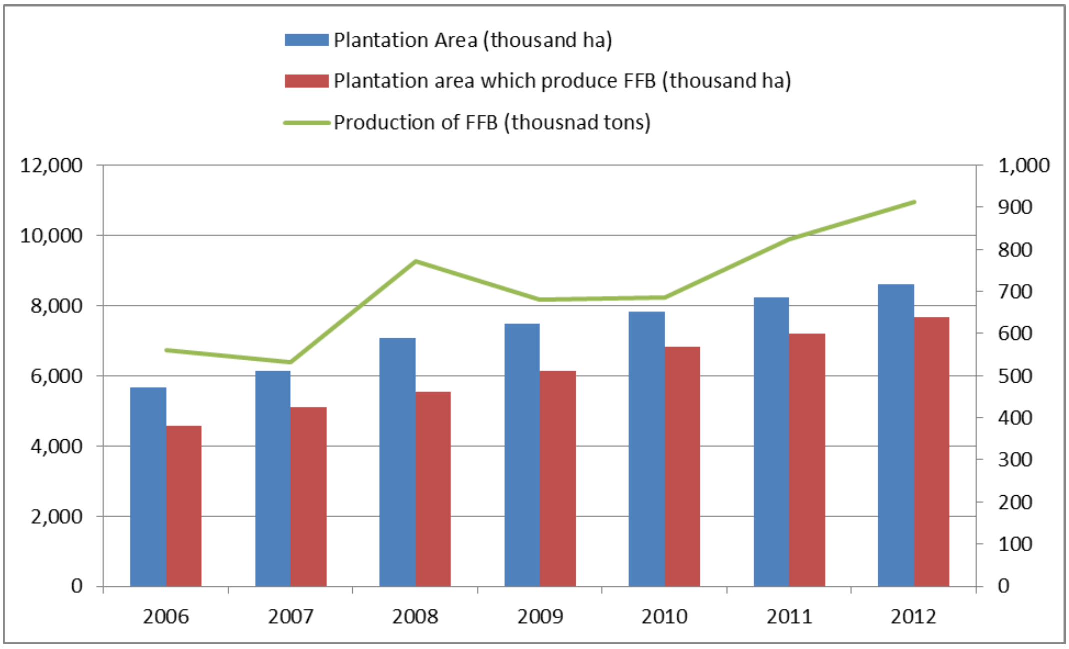
Figure 36: Share of each country in palm production



About 97% of produced palm oil is consumed domestically in Thailand, and out of domestic consumption; about 50% is consumed as food products and about 40% as biodiesel fuel.

In addition, the production of palm in Thailand has been increasing in line with the growth of demand worldwide, and while it was about 7 million tons in 2006, it reached about 11 million tons in 2012.

Figure 37: Progress of palm production in Thailand



Source: Prepared by the Japan Research Institute, Limited, based on various materials

Cassava production worldwide was about 270 million tons in 2014, and Thailand was the second-largest cassava-producing country after Nigeria. The peak of the share in production volume was 16% in 1989 and it has remained at around 11% in recent years. Processed products from cassava include chips (and pellets obtained by crushing chips), starch (and processed starch obtained from starch) and ethanol. Thailand's worldwide production shares in 2015 were 55% for starch, 40% for chips and 5% for ethanol; starch production constituted more than half of the total.

4.2 Trends in the energy sector

4.2.1 Structure of the electric power sector in Thailand

In the past, the state-owned power company EGAT monopolized power generation, power transmission and the retail sector. However, regulations have been eased, chiefly in the power-generation sector, is developing and market participation by independent power producers (IPPs) is now permitted.

In addition, as stated above, renewable energy production is being promoted in Thailand, and private investment in power generation by renewable energy is being promoted through Feed-in Tariffs.

4.2.1.1 Power transmission/distribution system

Power transmission/distribution equipment has been developed centering on the state-owned power company EGAT. In recent years, however, partly because the power distribution system is developing more widespread use of renewable energy, the growth of the transmission/distribution system cannot keep up with the increasing demand for transmission and distribution of electricity on the part of electricity producers. In certain cases, requests for connection to the power transmission and distribution system have been refused.

In Thailand, partly because of introduction of the FIT system, biogas power generation using biogas generated in palm/cassava plants is developing. In the southern provinces in particular, however, certain site owners and EPC contractors reported cases in which the sale of electric power was not permitted because of insufficient capacity in power transmission and distribution systems.

Since biogas power generation is a competing technology for the present project (i.e., a competing technology for acquiring biomass as a raw material), it is considered that such restrictions in connection with the power transmission and distribution system could be a positive factor for the project.

4.2.2 Structure of the natural gas sector

As stated above, natural gas is consumed in the traffic sector in Thailand in addition to the industrial, commercial and domestic sectors.

The number of NGVs in Thailand is 420,000 and the number of CNG filling stations is 488; the number of NGVs is larger than that in Japan (43,000). Thailand is the world's tenth-largest user of NGVs (on a number of vehicles basis).

The transportation and distribution of gas in Thailand has been monopolized by the state-owned company PTT, and although participation of private companies in retail sector is permitted, it is basically monopolized by PTT.

Infrastructure has been expanding in line with the increase in demand, and the transportation of gas by pipeline from offshore gas fields is being developed. In addition, PTT has been active in gas imports through a cross-border pipeline between Thailand/Myanmar and Map Ta Phut LNG receiving base.

On the other hand, the domestic gas infrastructure is still under development, and while gas pipelines have been developed in Bangkok and its surrounding areas, there are no gas pipelines in the central and northern provinces.

In these provinces, gas is transported by truck from the nearest gas processing facility, known as the "mother station" (MS) to stations known as the daughter station (DS) in districts where there are no gas pipelines.

4.2.3 Development and outlook for fuel subsidies

In Thailand, it is permitted to sell CNG in rural areas at prices higher than in Bangkok and its surrounding areas. However, transportation costs from MS to DS cannot be totally passed on sales prices and the costs for sales are borne by the state-owned gas supplier PTT.

As explained below, in order to correct this imbalance, increases in the regulated CNG prices in rural areas are considered, and it is expected that CNG prices in rural areas will go up in the future.

In the present project, since CBG purified from biogas is to be sold as a substitute for CNG, the price of CNG in the area surrounding the site is quite important in determining the sales price of CBG. As stated above, rises in CNG prices are being observed in Thailand because of the discontinuation of subsidies on a long-term basis, and it is expected that this will benefit the project.

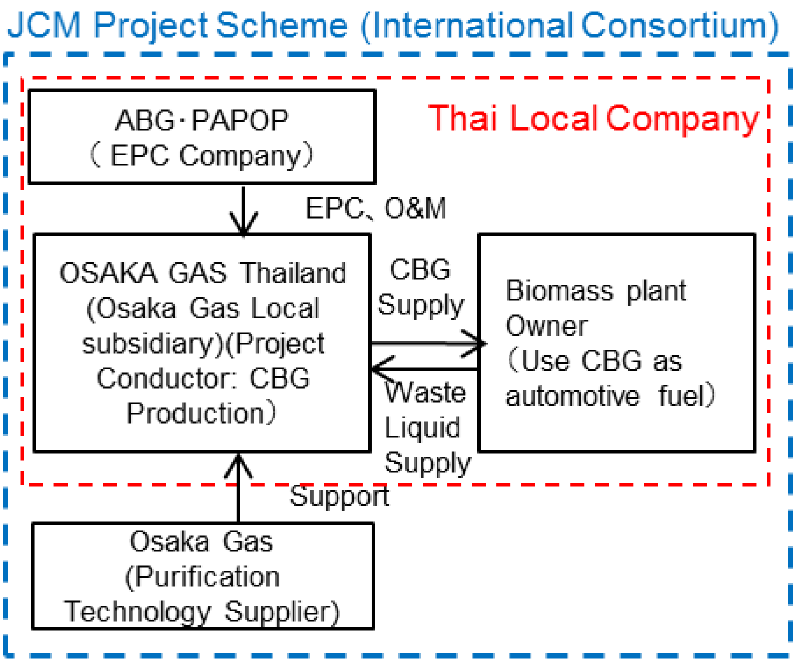
5. Establishing a business structure

5.1 Assumed business structure

Osaka Gas established OSAKA GAS (THAILAND) CO., LTD. (OGT) in October 2013. The firm operates an energy service business in the industrial market in Thailand. In addition, in September 2015, in a joint investment with PTT, Osaka Gas established OGP Energy Solutions Co., LTD. This firm provides fuel conversion energy services for industrial customers. As a part of the expansion of the operating base of Osaka Gas in Thailand, the present project is intended to introduce the biogas purification technology developed by Osaka Gas that provides high methane recovery rate to palm/cassava plants in order to produce CBG and use it as fuel for NGV trucks.

In the present project, OGT acts as a manufacturer and purchases biomass feedstock as raw materials from palm/cassava plants and produces CBG. The target CBG consumers are palm/cassava plants and transportation companies, and an international consortium including EPC contractors will be established.

Figure 38: Assumed business structure



Source: Osaka Gas

Since the continuity of material supply (along with biogas potential and CBG consumption potential as a matter of course) is an important factor in establishing the business structure, the credit status of palm/cassava plants is also included in the criteria for selecting candidate sites.

5.2 Conditions for establishing a business structure

5.2.1 Palm/cassava plants

Based on information from various sources, we have prepared a long list of 60 plants with biogas potential.

After that, since continuity of material supply is an important factor for maintaining the operation, in order to assess credit status as a guide to estimate each plant's reliability as a going concern, the evaluation of credit status was outsourced to two firms with which OGT has business relationships to make a short list of candidate sites based on the long list. In addition, palm/cassava plants that had previously expressed written interest in the present project were filtered by credit status. As a result, 12 candidates have been selected. The breakdown of candidates is 5 cassava plants, 3 palm plants, 3 ethanol plants and one food plant (These plants are collectively referred to as "biomass plants, etc.").

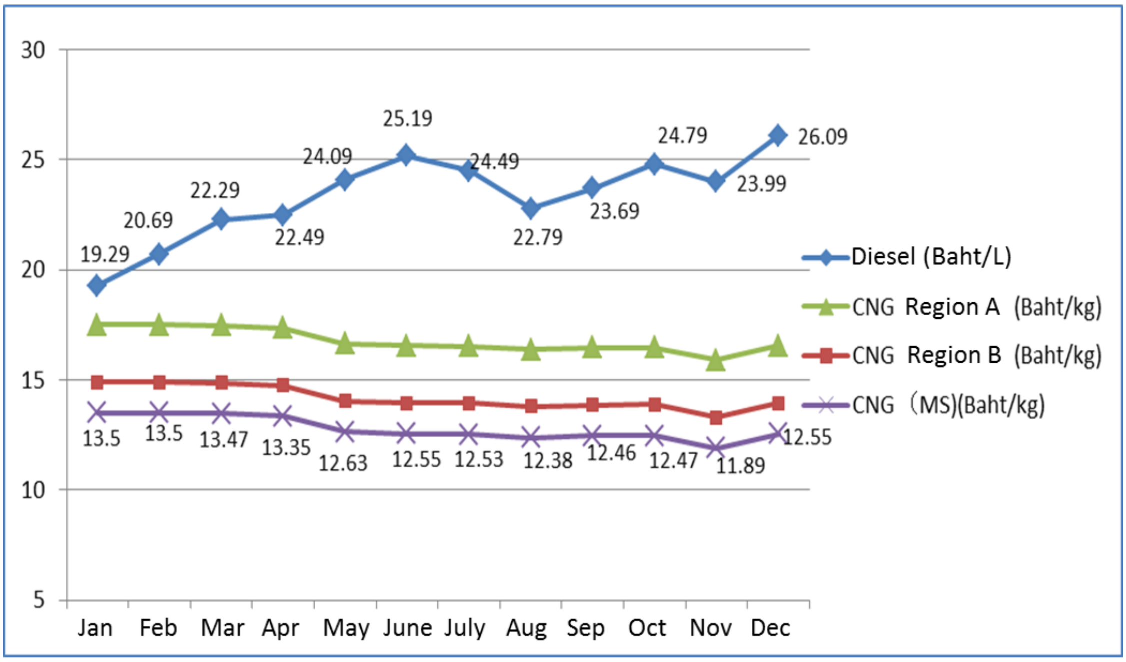
5.2.2 CBG consumption potential

The vehicles owned by the biomass plants, etc. and trucks for transporting products to the plants were taken as candidate users of CBG. It is ideal if the biomass plants, etc. and their affiliated companies own the trucks for transporting products, but since it is assumed that the transportation will be outsourced to third parties, transportation companies are also included as candidate CBG users. Based on information published by the Thai Truck Center and through telephone interviews, eight transportation companies owning 50 or more trucks each were selected as candidate CBG users.

5.2.3 CNG prices in areas neighboring the plants

In Thailand, the CNG price was changed on July 2017 from the government-controlled price to a natural gas-linked price. In addition, the system whereby sales prices were determined by adding transportation expenses and the former upper limit for the transportation expenses of 1.84 THB/kg for DS more than 50 km away from the MS s was discontinued. CNG prices were set as retail prices calculated by adding a transportation expense of 1.4 THB/kg or 4.0 THB/kg to the price in the MS. The larger the distance from the MS is, the higher the CNG price is and it can be noticed that CNG prices are stable compared to diesel fuel prices.

Figure 39: Development of CNG prices in areas neighboring plants (2016)



Source: Prepared by Osaka Gas

5.3 Details and outcomes of the initiative

5.3.1 Selection of biomass plants, etc.

Biomass plants, etc. were selected in accordance with the following procedures:

- Unannounced visits were made to candidates, and the candidates were asked for their cooperation as FS candidates for the JCM business.
- After obtaining consent for cooperation, field surveys for biogas potential were carried out, along with site surveys for installing facilities and surveys of CBG consumption potential.
- FS was carried out based on the collected data.

At first, visits to the 12 selected candidates were requested; 7 biomass plants, etc. consented to cooperate in FS and field surveys were carried out.

Next, in carrying out FS, GHG reduction effects of the biogas materials were examined based on information obtained from the field surveys. As a result, changes to the use of biogas already being used effectively were excluded from the targets, along with cassava pulp used as cattle feed. Two plants of Company A (an existing one and a planned new plant) in which EFB and waste water are used for raw materials were selected as candidates for FS. Company B, where flare gas can be used, was also selected.

5.3.2 Selection of users (business operators owning CNG vehicles)

Of two companies selected as biomass plants, etc. for FS candidates, Company A does not have any transportation trucks and outsources its transportation jobs. In addition, Company B cannot consume the whole amount of manufactured CBG by its own consumption, because it outsources a large part of its transportation jobs and owns only a small number of vehicles. Therefore, the transportation companies to which both companies outsource their transportation, and other transportation companies listed up by an advance survey, were examined as candidates for customers.

Through hearings at Company B, it was found that Company X, to which Company B outsources a major part of its transportation jobs, was a transportation company listed as a candidate by the advance survey, and a promising candidate that owns a large number of NGV trucks. Under the circumstances, an unannounced visit to Company X was made and cooperation for FS was asked for. Company X expressed an interest in CBG if it has a price advantage over diesel fuel, and agreed to cooperation in FS. Company X was thus selected as a candidate user.

Unannounced visits to other transportation companies will be carried out, and we plan to continue setting up the business structure.

5.3.3 Selection of EPC contractors

The facilities necessary for the present project are fermenters, purification equipment and fuel stations. Osaka Gas has the technology for purification equipment, but has no expertise in fermenters. Accordingly, two engineering companies were selected, with expertise in fermenters and a proven track record in EPC for biogas power generation business. Both of them are supportive of the CBG business and have a large number of customers, and it was judged that they could be candidate EPC contractors.

For the purification equipment, the EPC contractors for the facilities for the pilot verification experiment currently being carried out by Osaka Gas were selected. For the station facilities, it is decided to select for each candidate site from among three companies with a proven track record in EPC for NGV stations in Thailand.

6. Examination of business potential

6.1 Examination of business potential of Company A

6.1.1 Overview of Company A

Company A is one of the biggest palm companies in Thailand with a proven track record of over 40 years. Annual turnover in 2014 was about 17 billion yen.

At present, Company A has three plants in Thailand. In addition, it plans to establish a new plant in 2017 and after the completion of the new plant it will have four palm oil mills. Of those four plants, two plants (Plant A and Plant B) were selected as candidate sites, taking the conditions of location and biogas potential into consideration.

6.1.2 Equipment specifications for Plant A

In Company A, 5% of EFB is used as fertilizer and the rest is disposed on its own plantation, and Company A has been looking for means for the effective use of EFB. Therefore, it has been decided to check whether or not it can be used as raw material for CBG. Based on the result of estimate, it was determined to consider a capacity of 2,000 m^3/h.

Since Company A does not have vehicles as potential consumers of CBG, it was decided to assume companies operating transportation businesses in the neighboring areas as targets of CBG consumption potential. Unannounced visits to candidates were not made while this report was being prepared, but the advance survey revealed that one of the candidates owns several tens of NGVs and it is expected that it could be a promising partner if an attractive CBG price can be offered.

Based on the above-mentioned field survey and subsequent examinations, equipment specifications for Plant A were determined.

Figure 40: Equipment specifications for Plant A

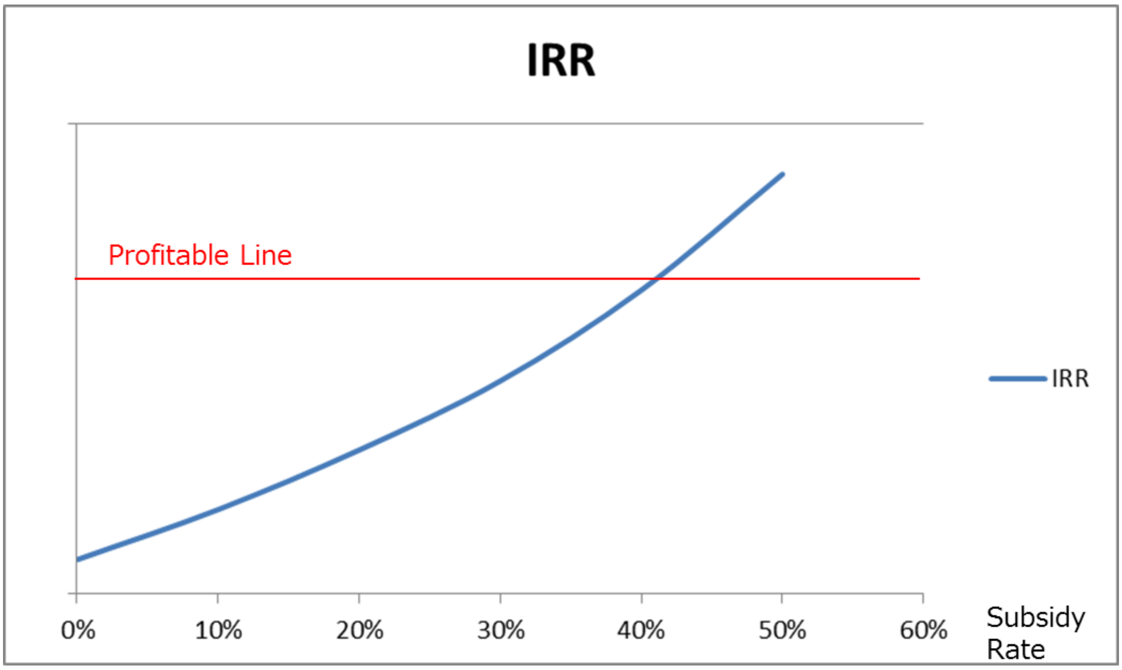
	Fermenter	Purification equipment	Equipment for station
Equipment capacity	Rated 48,000 Nm^3/d-BG	Raw material: 2,000 Nm^3/h-BG Product: 1,025 kg/h-CBG	Storage 12 ton/d, 2 dispensers-2 nozzles

6.1.3 Evaluation of business potential of Plant A (JCM subsidy rate vs IRR) and sensitivity analysis

The result of the estimate of the ten-year IRR based on the above-described examination is shown in Fig. 58 below. Purchase prices of biogas and selling prices of CBG are determined through negotiations with biomass plants, etc. and transportation companies, but it is considered that the conditions estimated in the present FS show a high possibility of realization. In this case, the project can be realized with a subsidy rate of 40% or higher.

In addition, since EFB biogasification requires a larger investment for facilities than a normal fermenter, it is required to make the scale of the business large to pursue economies of scale for realization of the project. Fortunately, since there is a sufficient amount of EFB as raw material for both Plant A and Plant B, the problem to be solved is the acquisition of customers for CBG. Studies on customers for CBG, including sales to DS, will be carried out in the future.

Figure 41: IRR analysis



6.1.4 Equipment specifications for Plant B

The problem to be solved by Company A in Plant B is that while it is obliged to establish a covered lagoon in order to follow the water quality standards, it has no potential to use biogas, since it cannot sell electricity.

Since 12,000 Nm^3/d of biogas can be generated from POME according to the estimate, it has been decided to consider purification equipment with a capacity of 500 m^3/h. A situation similar to Plant A above is assumed with respect to CBG consumption potential. Based on the above-described survey, the Plant B facility was decided on.

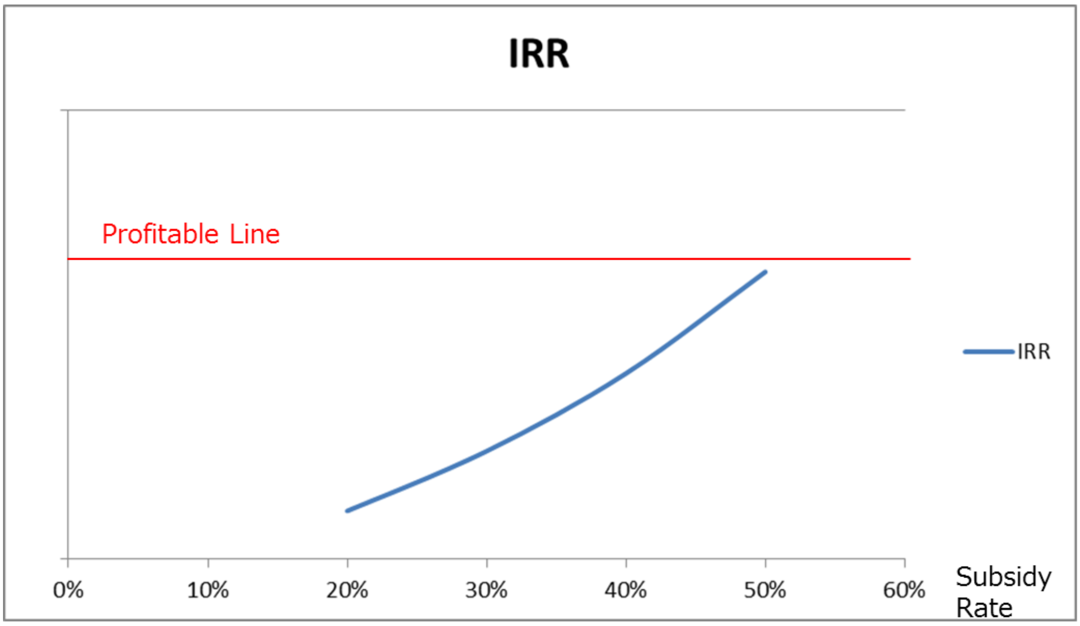
Figure 42: Equipment specifications for Plant B

	Fermenter	Purification equipment	Equipment for station
Equipment capacity	Rated 15,000 Nm^3/d-BG	Raw material: 500 Nm^3/h-BG Product: 292 kg/h-CBG	Storage 7 ton/d 1 dispenser-2 nozzles

6.1.5 Evaluation of business potential of Plant B (JCM subsidy rate vs IRR) and sensitivity analysis

The result of the estimate of the ten-year IRR based on the above-described study is shown in Fig. 61 below. Purchase prices of biogas and selling prices of CBG are determined through negotiations with biomass plants, etc. and transportation companies, but it is considered that the conditions estimated in the present FS show a high possibility of realization. In this case, the project can be realized with a subsidy rate of 50% or higher.

Figure 43: IRR analysis



6.2 Examination of business potential of Company B

6.2.1 Equipment specifications

Company B has been a processed starch manufacturer for over 20 years, and its annual turnover is 11 billion yen. It operates a manufacturing plant using cassava as raw material.

Company B processes industrial liquid water with an upflow anaerobic sludge blanket reactor (UASB) and a covered lagoon (CL) for water quality management. Biogas generated in the UASB cannot be diffused into the atmosphere because of odor problems and it is totally flared. Biogas from CL is used as fuel for power-generating equipment and boiler equipment.

In addition, since the UASB line has only flaring equipment in its latter stage, wastewater is preferentially supplied to the CL side and the remaining wastewater is sent to UASB.

From the amount of actually flared gas in 2015, it was decided to consider a capacity of 750 m^3/h as a level to constantly carry out stable operations.

Since the candidate site for the purifying equipment was located adjacent to the existing fermenter at the back side of the plant, it was judged inconvenient for access by trucks for fueling. Therefore, the examination was carried out assuming that the station is located near the entrance to the plant. Because of this, it is planned to construct a pipeline for biogas transportation of about 500 m.

Although Company B has a certain number of its own trucks as potential consumers of CBG, it is not expected that there will be enough consumption to cover the whole amount of CBG to be produced. On the other hand, the majority of product transportation is outsourced to a transportation company. As stated above, this transportation company is a major NGV truck-owning firm, and on an unannounced visit it was ascertained that it can be a promising purchaser if an attractive CBG price can be offered.

Base on the result of the above-described field survey, the equipment specifications for Company B were determined.

Figure 44: Equipment specifications for Company B

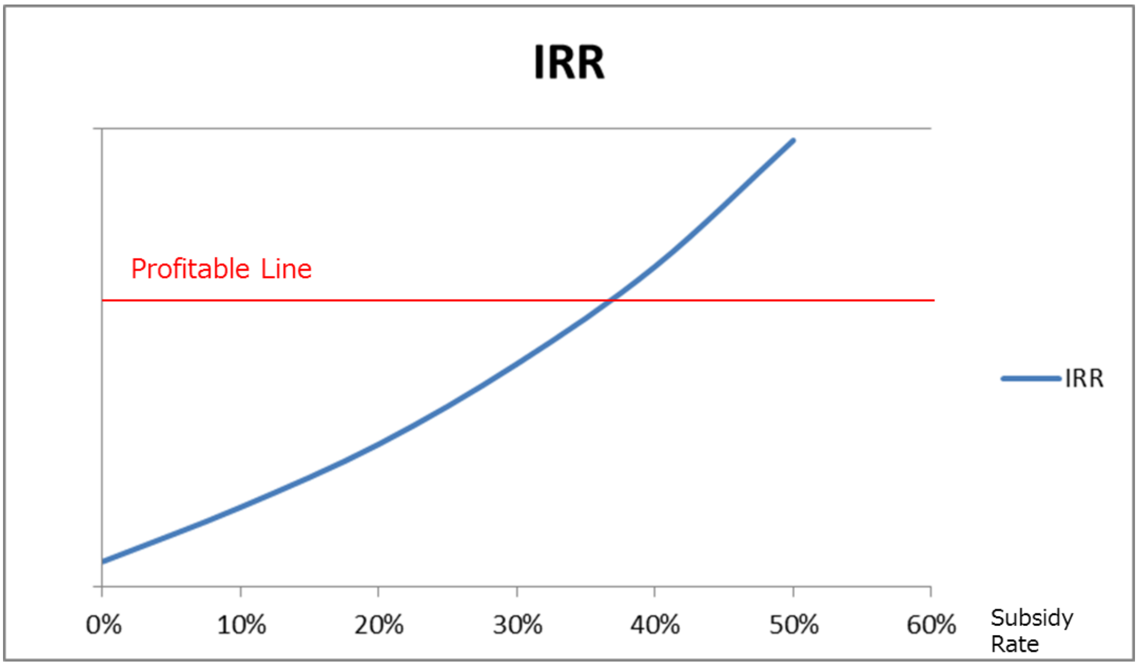
	Fermenter	Purification equipment	Equipment for station
Equipment capacity	Rated 40,000 Nm^3/d-BG	Raw material: 750 Nm^3/h-BG Product: 404 kg/h-CBG	Storage 7 ton/d 1 dispenser-2 nozzles

6.2.2 Evaluation of business potential of and sensitivity analysis for Plant B (JCM subsidy rate vs IRR)

The result of the estimate of the ten-year IRR based on the above-described examination is shown in Fig. 54 below. Purchase prices of biogas and selling prices of CBG are determined through negotiations with biomass plants, etc. and transportation companies, but it is considered that the conditions estimated in the present FS show a high possibility of realization. In this case, the project can be realized with a subsidy rate of 40% or higher.

In addition, if more surplus gas from Company B can be procured and corresponding CBG demand can be expected, a scale-up will be possible and the business potential can be improved. In the future, a study to improve the business potential should be carried out by continuing this study further.

Figure 45: IRR analysis



6.3 Study for commercialization at the verification site

6.3.1 Overview of cooperating firms for pilot verification

Company C, selected by Osaka Gas as a site for carrying out pilot verification test, is a palm oil company with a 15-year history of operations and a turnover of about 1 billion yen in 2014. Company C does not have any palm plantations and purchases all of its FFB from outside suppliers. The plant has a plan to expand in 2017, but since no increase in the volume of sales of electric power have been agreed to by the electricity producer, the increased biogas has to be flared.

Since around 2014, Osaka Gas has been looking for a pilot verification site for purification equipment in Thailand. Since it is difficult to increase the number of power generators in the future, and Company C already owns NGV trucks and it considers CBG a promising renewable energy for the future, Company C is supportive of the proposal by Osaka Gas. Against this background, as we could reach an agreement for conditions for a verification test with Company C, Company C was selected as a pilot verification site.

6.3.2 Overview of the pilot verification

In the pilot verification, Osaka Gas will be provided with biogas as raw material and utilities and will produce CBG and supply it to Company C. Company C will use CBG as fuel for its own NGV trucks. During the test period, Osaka Gas will check on system performance, durability of separation membranes, durability of compressors, and responses to change in methane concentrations in products, etc., and will collect data for commercialization.

The equipment size of 250 m^3/h was selected as a minimum necessary capacity for the test. At present, the pilot equipment is under construction and is expected to be completed by the end of March 2017. If everything goes well, it is planned to carry out a verification test from April 2017, for one year.

6.3.3 Equipment specifications for Company C

The equipment specifications were determined for carrying out CBG business in Company C after completion of the verification test.

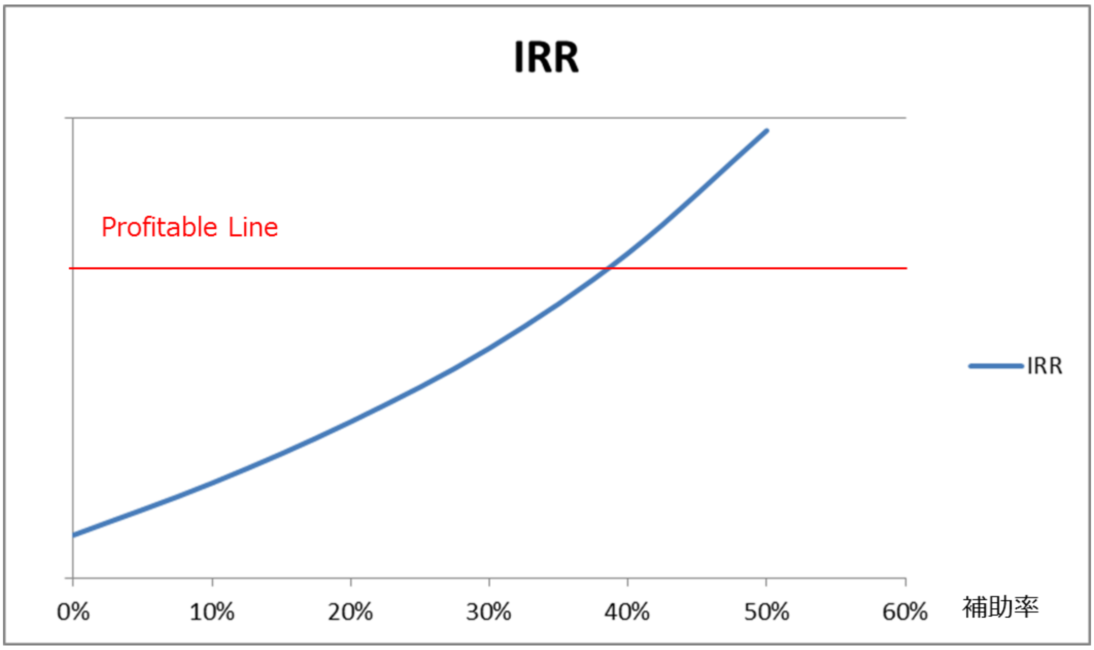
Figure 46: Equipment specifications for Company C

	Fermenter	Purification equipment	Equipment for station
Equipment capacity	Company C's existing equipment	Raw material: 250 Nm^3/h-BG Product: 146 kg/h-CBG	Company C's existing equipment

6.3.4 Evaluation of business potential of Company C (JCM subsidy rate vs IRR) and sensitivity analysis

The result of the estimate of ten-year IRR based on the above-described study is shown in Fig. 65 below. Purchase prices of biogas and selling prices of CBG are determined through negotiations with biomass plants, etc. and transportation companies, but it is considered that the conditions estimated in the present FS show a high possibility of realization. In this case, the project can be realized with a subsidy rate of 40% or higher.

Figure 47: IRR analysis



7. Analysis of possibility of spread and expansion

7.1 Basic approach to analysis

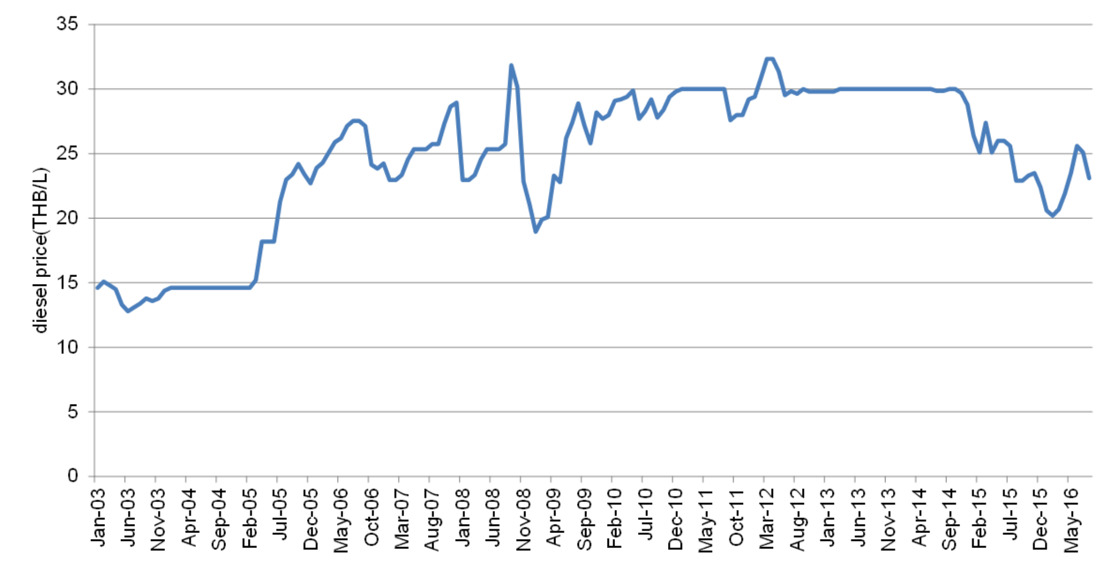
In the preceding chapter, the business potential of CBG business was estimated and it was showed that the business has a high possibility of sufficient business potential in Thailand. In this chapter, price trends for automobile fuels such as diesel fuel, CNG, etc. are laid out, and the competitiveness of CBG against such fuels is analyzed. At the same time, possible competing technologies in which biomass is used as a material in the same way as CBG (such as biogas power generation) and organic use of agricultural residue are surveyed, and it is examined whether or not there is sufficient incentive to carry out CBG as a business. The possibility of spread and expansion of the CBG business in Thailand is also analyzed. In addition, analysis of competitors is carried out.

7.2 Trends of alternative fuels

7.2.1 Prospects for diesel fuel prices

Developments in retail prices for diesel fuel in Thailand are shown below. The retail price of diesel fuel has been on a descending trend in recent years and has remained within a range not exceeding 30 THB/L. This is because of the price cap of 30 THB/L in effect since January 2011.

Figure 48: Developments in retail prices of diesel fuel in Thailand

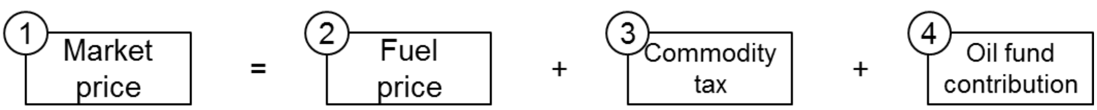


Source: Prepared by the Japan Research Institute, Limited, based on statistics by Thailand's Ministry of Energy, Energy Policy & Planning Office (EPPO)

The retail price of diesel fuel in Thailand consists of three elements: fuel price, commodity tax and contributions for the petroleum fund. Each element is determined according to the following method:

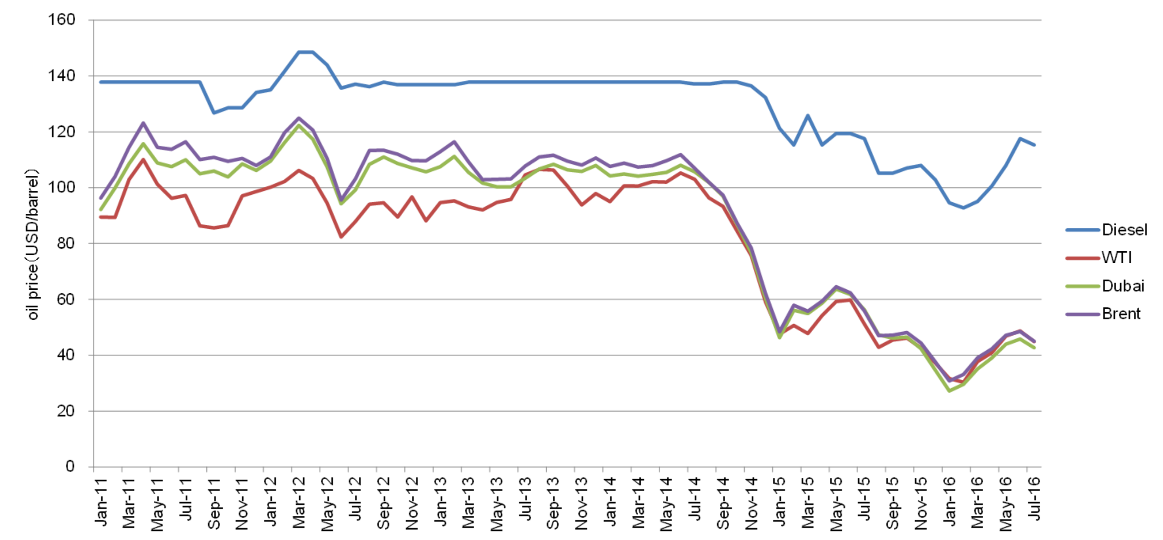
- Fuel price: Determined by PTT, based on international fuel prices.
- Commodity tax: Determined by Thailand's Ministry of Finance.
- Contributions for the petroleum fund: The fund was established for the purpose of compensation during fuel price hikes. It is also used in investment for renewable energy. It adjusts fluctuations due to fuel prices and commodity tax and minimizes price volatility.

Figure 49: Constituent elements of retail prices of diesel fuel in Thailand



The following table shows developments in the retail price of diesel fuel in Thailand and major international crude oil prices (WTI, Dubai and Brent). While international crude oil price decreased by 70% at the maximum compared to the price as of January 2011, the decrease in diesel fuel price in Thailand was only 30%. In addition, generally speaking, it can be observed that fluctuations in diesel fuel prices in Thailand are smaller than those of international crude oil prices.

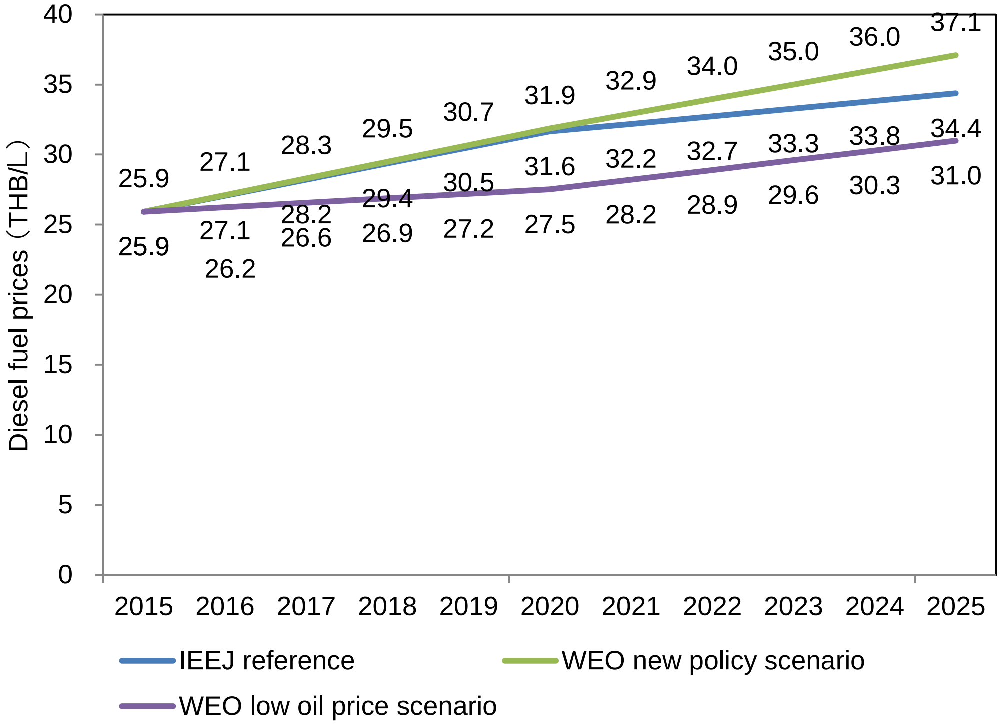
Figure 50: Comparison between developments in diesel fuel prices in Thailand and international crude oil prices



Source: Prepared by the Japan Research Institute, Limited, based on statistics by Thailand's Ministry of Energy, Energy Policy & Planning Office (EPPO) and IMF (International Monetary Fund), Primary Commodity Prices

On the other hand, contributions for the petroleum fund is now under study toward discontinuation in the future, because of anxieties about government financial difficulties because of increases in investments for purposes other than fuel prices[4]. In addition, the price cap will reportedly be discontinued for similar reasons. Accordingly, it is surmised that future diesel prices in Thailand will change in accordance with the fluctuations of international crude oil prices. The following table shows the prospects for movement of diesel fuel prices in Thailand. Each result was estimated so that it moves in line with the crude oil price published by each survey institution. In any case, it is expected to exceed the price cap of 30 THB/L in 2025.

Figure 51: Prospects for future diesel fuel prices in Thailand



* Future price is estimated. The fuel price was calculated by adding transportation cost of 9.5 THB/L (actual amount as of August 2016) to international fuel prices. With respect to commodity tax and contributions for the petroleum fund also, the estimate was made using 5.65 THB/L and 0.14 THB/L (actual amount as of August 2016) respectively.

Source: Estimated by The Japan Research Institute, Limited, taking into consideration reports from each research agency (Refer to the information below).

4 From hearings with EPPO-related persons

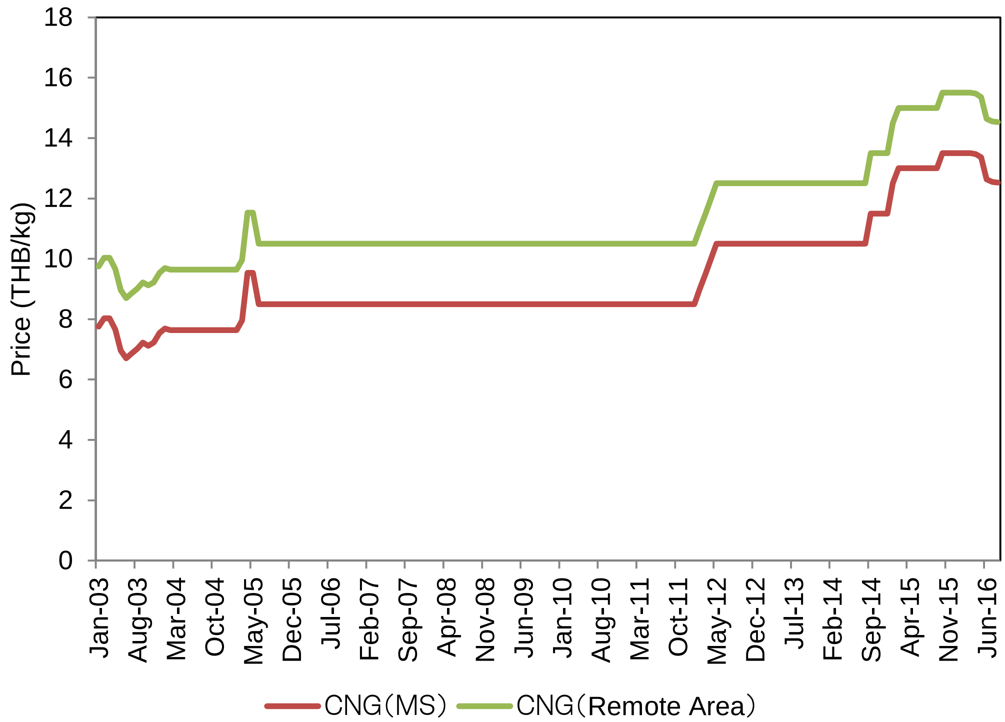
Figure 52: Elements in each survey result

Case	Research agency	Name of the report	Overview of the case
IEEJ reference	The Institute of Energy Economics Japan	Asia/World Energy Outlook 2015	Case in which the price moves in accordance with the past tendency and energy/ environment policy, etc.
WEO new policy scenario	International Energy Agency	World Energy Outlook 2015	Case in which the price moves in accordance with the past tendency and energy/environment policy, etc.
WEO low oil price scenario			Case based on the prospect that the low crude oil price tendency will continue

7.2.2 Prospects for CNG prices

The following graph shows developments in CNG prices in Thailand. The price did not fluctuate until around 2015 because trading was carried out at the government-controlled price[5].

Figure 53: Developments in CNG prices in Thailand



Source: Prepared by the Japan Research Institute, Limited, based on statistics from Thailand's Ministry of Energy, Energy Policy & Planning Office (EPPO)

The current CNG price consists of manufacturing cost, tax when transported and operational costs. However, a price cap of 15.84 THB/L is applicable to retail prices.

Accordingly, there is a high possibility that the CNG price will be linked to the market trend, and it is expected that CNG prices will increase in accordance with the increase in international crude oil prices.

5 From hearings with EPPO-related persons

7.3 Trends of competitive technologies

7.3.1 Competition in the broad sense

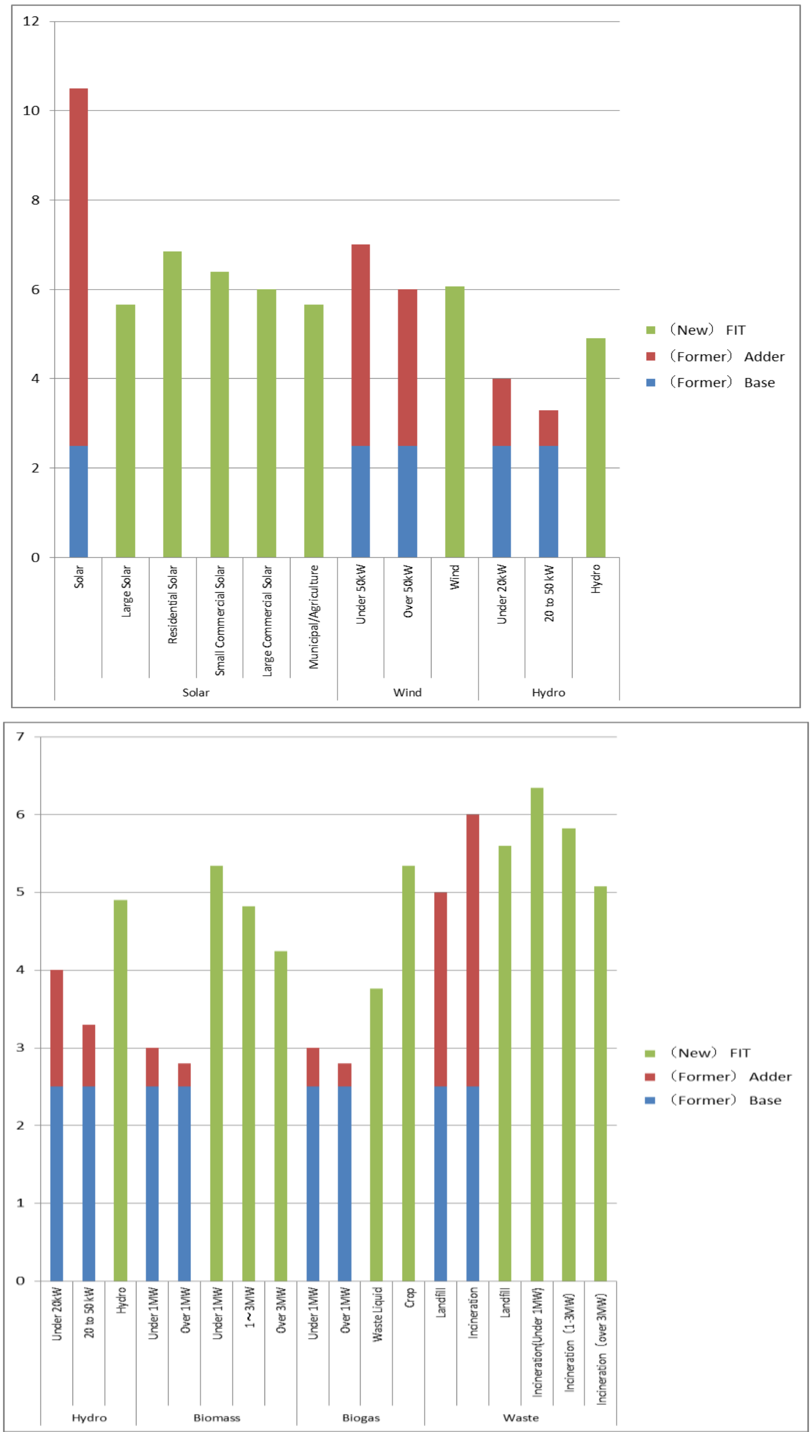
7.3.1.1 Biogas power generation

As shown in below, the feed-in tariff system in Thailand was changed in 2016 to a comparatively beneficial system for biomass and waste. Figure 54 gives the comparison between the purchase price under the former system, calculated using a base unit price of 2.5 THB/kWh (Source: IEA, price on the higher side of 2.0 to 2.5 THB/kWh) and an Adder, and the purchase price under the new system. The blue and red bars show the purchase price (blue: base; red: Adder) under the former system, and the green bars are for the new system. In addition, for the variable portion (FIT (variable)), which is reviewed every year, in the purchase price under the new system the value applied to the purchase price of renewable energy power supply which will become operable in 2017 was used.

It is observed that, while purchase prices for solar power have decreased greatly and wind power slightly, the purchase prices for hydraulic and waste has increased slightly and biomass and biogas increase greatly. Therefore, the business potential of biogas power generation has a higher possibility of improvement than in the past. (However, as described in below, the above amount is the upper limit and there remains a possibility that it will decrease to a level lower than the purchase price under the former system, depending on bidding by each company).

On the other hand, as stated above, the development of transmission and distribution systems is lagging behind the spread of renewable energy at present, and, in areas where the transmission and distribution system is poor, connection of renewable energy to the transmission and distribution system is restricted. Although it is considered that, in line with the shift to the bidding system, the systematic introduction of renewable energy and development of transmission and distribution system will be carried out, farm operators in areas out of the range of the plant cannot use biomass for power generation in the future either, and studies effective usage methods are being considered.

Figure 54: Comparison of purchase prices between the old and new systems (THB/kWh)



Source: IEA, and Thailand's Department of Alternative Energy Development and Efficiency

7.3.1.2 Organic use of agricultural residue

Generally, chemical fertilizer prices have a strong correlation with crude oil prices. In fact, in 2008, when the crude oil price hiked in Thailand, chemical fertilizer prices also hiked. As stated above, Thailand's import dependence for fossil fuel has been increasing and the risk of hikes in the crude oil price exists in the future, too. In order to hedge against such risks, and in line with the rise in public health awareness, interest in the use of agricultural residues as fertilizer has been increasing.

However, if excreta, POME, etc. are used as fertilizer only after fermentation, it will not directly compete with the CBG business and biogas power generation business and it is liable to be positioned as an incidental business.

7.3.2 Competition in the narrow sense

7.3.2.1 Competitors for CBG manufacturing technology

There is no business manufacturing CBG on an ongoing basis in Thailand. Other than small-scale experiments at universities, etc., there is a case in which UAC Global Public Company Limited (hereafter, UAC) carried out CBG verification operations. UAC constructed a facility that has been capable of annually producing about 1,100 t (corresponding to 2,200 thousand tons of diesel fuel) of CBG from 2003, using pig excreta s and Napier grass as materials. It has also been conducting verification of a model to sell to PTT's DS. In this operation, daily production of three tons was planned, but, in fact, CBG of only about one-third of the target could be produced because of technical problems. As stated above, the CBG manufacturing operation is still at the level of verification, both commercially and technologically.

One of reasons why CBG has not been successful as a business in Thailand could be, as seen in the case of UAC, that reliable technology has not yet become widespread.

In addition, it can be pointed out that in the past, stable and long-term turnover could not be expected from biogas power generation, for which the purchase price and the period were fixed. However, the transmission and distribution system is poor in the southern provinces of Thailand in particular, and it is foreseen that in the future there will still be a certain number of districts in which the connection of biogas power generation to the transmission and distribution system is impossible. As analyzed in 6, it is considered that, while CBG will become a business that allows investment to be recouped in the future, occasions in which CBG becomes a candidate for effective utilization of waste from farms will increase. On the other hand, the number of local companies abandoning CBG technology as a business that does not recoup investments is very small, as already stated. Accordingly, acquiring sufficient knowhow through verification, it is considered possible to achieve the position of leading company in Thailand's dawn for CBG, while holding competitors at bay.

8. MRV methodology, specifications of PDD

8.1 Draft MRV methodology

In the present project, raw materials, wastes from biomass plants (waste liquid and processing residue) are digested anaerobically by the covered lagoon system, and biogas is recovered and purified to improve purity. The gas obtained is used as automobile fuel. Reductions of GHG emission are realized through the following two activities:

- Avoidance of methane emissions through recovery of biogas using wastes for biomass plants (waste liquid and processing residue) as raw materials
- Reduction of consumption of fossil fuel energy through use of bio-CNG.

MRV methodology has been established taking into consideration a CDM methodology that fits the two in the present project. The following three CDM methodologies have been taken into consideration:

AMS-III.H: Methane recovery in wastewater treatment (Version 18.0) (CDM methodology for avoidance of methane emission from waste liquid)
AMS-III.E: Avoidance of methane production from decay of biomass through controlled combustion, gasification or mechanical/thermal treatment (Version 17.0) (CDM methodology for avoidance of methane emission from processing residues)
AMS-III.AQ.: Introduction of Bio-CNG in transportation applications (Version 2.0) (Transportation equipment-related CDM methodology)

CDM methodology for avoidance of methane emission from waste liquid is applicable to projects for recovering methane from organic waste water. At present, waste water from the biomass plant is anaerobically treated by the covered lagoon system at the project site and the acquired energy is used, but a part of it is flared as surplus gas. Flaring is carried out as a voluntary and additional activity as a countermeasure against odor problems. Therefore, the reference is set assuming that surplus gas is released into the atmosphere.

CDM methodology for the avoidance of methane emission from processing residues is applicable to projects for mixing the processing residues from the plant into waste liquid and recovering methane. In the project site, in the current situation, processing residues from the biomass plants are disposed by piling them up in plantations. Accordingly, the reference is set assuming that methane is released into the atmosphere from landfill facilities.

Figure 55: Disposed processing residue

Source: Plantation of Company A

Transportation equipment-related CDM methodology is applicable to projects in which bio-CNG (biogenic compressed natural gas) is produced by purification of biogenic biogas and increasing the pressure of the gas; the acquired bio-CNG is used for transportation equipment as fuel. Biogenic biogas is obtained by anaerobic treatment of biomass from plantations dedicated for biomass, waste water processing, fertilizer treatment and biomass residue. The present project is for purification of biogas using wastes from biomass plants (waste liquid and processing residues) as raw material, and increasing the pressure of the gas; it uses the obtained CBG as fuel for transportation equipment.

In the present project, eligibility criteria and reference scenarios were set based on these three CDM methodologies, and in accordance with the JCM approach. Eligibility criteria were set based on the preconditions of the technology to be introduced into the project and the wastes to be used as raw material. As technological specifications, it was decided to use a hybrid-type CO_2 removal system in which a gas separation membrane and Pressure Swing Adsorption (PSA) are combined. PSA is a technology owned by Osaka Gas for purifying biogas and indispensable for CBG production. The recovery rate of methane purified by PSA alone is around 85%, but the present system has specifications that makes it possible to take out purified gas of methane concentrations of 98% with a methane recovery rate of 98%. The present system consists of a compressor for supplying gas, PSA and a gas separation membrane and has features whereby off-gas discharged from PSA is recondensed by the separation membrane to a concentration similar to that of material biogas, and recycled to the entrance of PSA. The present system is configured as highly efficient as a whole, because it enhances the recovery rate by recycling off-gas while condensing to a high concentration in PSA, and it uses a separation membrane that can condense with high efficiency in the medium methane concentration level. Normally, off-gas is released into the atmosphere but in the present system, it is recycled, contributing to higher efficiency. Therefore this technology was also set as a criterion for eligibility. In addition, in order to ensure safety while using transportation equipment, it is also planned to make purified bio-CNG satisfy international and Thai quality standards for use as NGV fuel.

In the reference scenario, the two following sources of release are assumed:

- Methane release into the atmosphere from wastes (waste liquid and processing residue) from biomass plants
- CO_2 emission through use of fossil fuel by NGV

BaU is set so that wastes (waste liquid and processing residue) from biomass plants are anaerobically treated and unused methane is released into the atmosphere. The reference is set to a similar state; however, in order to ensure the realization of pure reduction, in calculating the amount of methane released into the atmosphere the amount used as bio-CNG is taken as the amount of methane from liquid waste, and the amount of methane disposed of as landfill is calculated using the FOD model (2006 IPCC guidelines) and is used for the amount of methane from processing residue. Accordingly, it is set so that the reference emission amount is smaller than BaU emission amount.

The draft MRV methodology was prepared using JCM Proposed Methodology Form ver. 01.0, concluded between the governments of Thailand and Japan and shown in the following sections below. It was prepared using the spreadsheet JCM_TH_F_PMS_ver01.0 and is attached as Appendix 1.

JCM Proposed Methodology Form

Cover sheet of the Proposed Methodology Form

Form for submitting the proposed methodology

Host Country	Kingdom of Thailand
Name of the methodology proponents submitting this form	Osaka Gas Co., Ltd.
Sectoral scope(s) to which the Proposed Methodology applies	7. Transport 13. Waste Handling and Disposal
Title of the proposed methodology, and version number	Refining Bio-CNG from organic waste at Biomass Plant for using as fuels of NGV in Thailand, ver1.0.
List of documents to be attached to this form (please check):	☐The attached draft JCM-PDD: ☐Additional information
Date of completion	17/02/2017

History of the proposed methodology

Version	Date	Contents revised
1.0	17/02/2017	First edition

A. Title of the methodology

Refining Bio-CNG from organic waste at Biomass Plant for using as fuels of NGV in Thailand, ver1.0.

B. Terms and definitions

Terms	Definitions
Organic waste	Liquefied and solid waste that contains degradable organic matter. This may include, for example, waste water and processing residue from Biomass plant.
Bio-gas	Gases generated from anaerobic digesters.
Bio-CNG	Biogenic Compressed Natural Gas purified from Bio-gas.

C. Summary of the methodology

Items	Summary
GHG emission reduction measures	• The project is to capture CH_4 from anaerobic digestion system with organic waste (e.g. waste water and processing residues) at Biomass Plant and purify to Bio-CNG (Compressed Natural Gas), which are used for NGV (Natural Gas Vehicle) in Thailand. It is to achieve GHG emission reduction through the following 2 activities. 1) Avoiding CH_4 emissions by recovering biogas

	using organic waste at Biomass Plant. 2) Reducing consumption of fossil fuel by using Bio-CNG for vehicle.
Calculation of reference emissions	● Reference emissions are GHG emissions from releasing CH4 to the atmosphere from organic waste (e.g. waste water and processing residues) at Biomass plant, and consuming fossil fuel for vehicles. ● Reference emissions are calculated with volume of Bio-gas putting into upgrading system and consumption of Bio-CNG (for estimating consumption of fossil fuel) by vehicles.
Calculation of project emissions	● Project emissions are calculated with project activity and CO2 emission factor (default value). ● Project activities are the following; ➢ Upgrading process: Electricity consumption by bio-gas upgrading system.
Monitoring parameters	● (In case of waste water and processing residues) Amount of processing residue putting into anaerobic digestion system [t/p] ● (In case of waste water and processing residues) Electricity consumption by anaerobic digestion system during the period p [MWh/p] ● Electricity consumption by Bio-gas upgrading system during the period p [MWh/p] ● Electricity consumption by refueling station during the period p [MWh/p] ● Bio-CNG consumption by transport application (j) during the period p [t/p]

D. Eligibility criteria

This methodology is applicable to projects that satisfy all of the following criteria.

Criterion 1	The project is to capture CH_4 from anaerobic digestion system with organic waste (e.g. waste water and processing residues) at Biomass Plant and purify to Bio-CNG (Compressed Natural Gas), which are used for NGV (Natural Gas Vehicle) in Thailand.
Criterion 2	Organic waste from Biomass Plant is not used for Energy or Materials. (e.g. Waste water is discharged into river, captured CH_4 is released into atmosphere, and process residue is landfilled or left in the field.)
Criterion 3	The technology of purifying to Bio-CNG is Hybrid type CO_2 removal system combining Pressure Swing Adsorption and Gas Separation Membrane.
Criterion 4	The off-gas discharged from PSA is recycled.
Criterion 5	Plant to apply the international or national qualification standard of Bio-CNG for using NCV is prepared.

E. Emission Sources and GHG types

Reference emissions	
Emission sources	GHG types
Methane emissions from decay of organic waste	CH_4
Fossil fuel consumption by Natural Gas Vehicle	CO_2
Project emissions	
Emission sources	GHG types

Electricity consumption by anaerobic digestion system	CO_2
Electricity consumption by upgrading system for Bio-CNG	CO_2
Electricity consumption by refueling station for Bio-CNG	CO_2

F. Establishment and calculation of reference emissions

F.1. Establishment of reference emissions

Reference emissions consist of two types of emission sources:

1) Methane emissions from decay of organic waste
2) Fossil fuel consumption by Natural Gas Vehicle

1) Calculation of reference emissions from decay of organic waste

- In case of using waste water for raw material

Waste water from a Biomass Plant is typically discharged into river and anaerobically digested which leads to methane emissions to the atmosphere. The reference emissions from decay of waste water are calculated using volume of CH_4 consisted of Bio-CNG.

- In case of using waste water and processing residues for raw material

Waste water from a Biomass Plant is typically discharged into river, and organic waste from a Biomass Plant is typically landfilled at SWDSs and anaerobically digested which leads to methane emissions to the atmosphere. The reference emissions from decay of organic waste are calculated using volume of CH_4 consisted of Bio-CNG and the FOD model adopted in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories.

2) Fossil fuel consumption by Natural Gas Vehicle

Bio-CNG replaces the fossil fuel which is used for NGV. The reference emissions from fossil fuel consumption are calculated by multiplying the amount of Bio-BNG supplied to NGV, NCV of Bio-CNG and CO_2 emission factor of the reference fossil fuel.

This methodology ensures a net emission reduction by following reasons:
The avoidance of CH_4 from decay of organic waste is calculated with Bio-CNG consumption by transport application and set the default DOC value conservatively in line with 2006 IPCC Guidelines for National Greenhouse Gas Inventories. Default DOC value of 8%, which is the lower value of the range 8-20% for food waste, is applied and FOD model adopted in the 2006 IPCC Guidelines. Food waste, which has the lowest DOC value among organic waste types, is assumed to represent the organic waste from Biomass Plant. The reference emissions are underestimated by using conservatively-set Bio-CNG consumption, since reference emissions are lower than the BaU emissions.

F.2. Calculation of reference emissions

$$RE_p = RE_{CH4,p} + RE_{trans,p}$$

(EQ1)

RE_p	: Reference emissions during the period p [tCO_2e/p]
$RE_{CH4,p}$	: Reference emissions from decay of organic waste during the period p [tCO_2e/p]
$RE_{trans,fuel,p}$	: Reference emissions from fossil fuel consumption by transport applications during the period p [tCO_2e/p]

$$RE_{CH4,p} = RE_{CH4,ww,p} + RE_{CH4,residue,p}$$

(EQ2)

$RE_{CH4,p}$	: Reference emissions from CH_4 into atmosphere during the period p [tCO_2e/p]
$RE_{CH4,ww,p}$	: Reference emissions from CH_4 of waste water into atmosphere during the period p [tCO_2e/p]
$RE_{CH4,residue,p}$	: Reference emissions from CH_4 of processing residue into atmosphere during the period p [tCO_2e/p]

- In case of using waste water for raw material

$$RE_{CH4,ww,p} = FC_{Bio-CNG,j,p} \times R_{CH4,Bio-CNG} \times GWP_{CH4}$$

(EQ2-1)

$RE_{CH4,ww,p}$	: Reference emissions from CH_4 of waste water into atmosphere during the period p [tCO_2e/p]
$FC_{Bio-CNG,j,p}$	: Bio-CNG consumption by transport application (j) during the period p [t/p]
$R_{CH4,Bio-CNG}$	: Rate of CH_4 content of Bio-CNG by volume [-]
GWP_{CH4}	: Global Warming Potential for CH_4:25

➢ In case of using waste water and processing residues for raw material

$$RE_{CH4,ww,p} = \left[FC_{Bio-CNG,j,p} \times R_{CH4,Bio-CNG} - \left(W_{residue,p} \times R_{CH4,residue}\right)\right] \times GWP_{CH4}$$

(EQ2-2)

$RE_{CH4,ww,p}$	: Reference emissions from decay of waste water during the period p [tCO_2e/p
$FC_{Bio-CNG,j,p}$	: Bio-CNG consumption by transport application (j) during the period p [t/p]
$R_{CH4,Bio-CNG}$	: Rate of CH_4 content of Bio-CNG by volume [-]
$W_{residue,p}$	: Weight of processing residue putting into anaerobic digestion system during the period p [t/p]
$R_{CH4,residue}$	: Rate of CH_4 gasification from processing residue [-]
GWP_{CH4}	: Global Warming Potential for CH_4:25

$$RE_{CH4,residue,p} = \sum_{m=p\_start}^{p\_end} \left\{ (1-f) \times GWP_{CH4} \times (1-OX) \times \frac{16}{12} \times F \times DOC_f \times MCF \right.$$
$$\left. \times \sum_{x=1}^{m-13} W_{residue,p} \times DOC \times e^{-\frac{k}{12}(m-13-x)} \times \left(1 - e^{-\frac{k}{12}}\right) \right\}$$

(EQ2-3)

$RE_{CH4,residue,p}$	: Reference emissions from decay of processing residue during the period p [tCO_2e/p]
f	: Fraction of methane captured at the SWDS and flared, combusted or used in another manner that prevents the emissions of methane to the atmosphere
GWP_{CH4}	: Global Warming Potential for CH_4:25
OX	: Oxidation factor (reflecting the amount of methane from SWDS that is oxidized in the soil or other material covering the waste)
16/12	: Molecular weight ratio of methane and carbon
F	: Fraction of methane in the SWDS gas [volume

fraction]

DOC_f	: Fraction of degradable organic carbon (DOC) that decomposes under specific conditions occurring in the SWDS [weight fraction]
MCF	: Methane Correction Factor
$W_{residue,p}$	: Weight of processing residue putting into anaerobic digestion system [t/p]
DOC	: Fraction of degradable organic carbon (by weight) [weight fraction]
k	: Decay rate [1/year]
x	: Months in the time period in which waste is disposed at the SWDS, extending from the first month in the time period (x=1) to month m (x=m)
m	: The Nth month from the first disposal at the SWDS, extending from the first month of the period p (m=p_start) to the last month of the period p (m=p_end)
p_start	: The Nth month from the first disposal, which is the first month of the period p. If that month is smaller than 14 and p_end is larger than 13, p_start is set at 14 because CH_4 generation can be accounted only after 13 months have passed since the first disposal at the SWDS.
p_end	: The Nth month from the first disposal, which is the last month of the period p. If p_end is smaller than 14, CH4 generation cannot be accounted.

$$RE_{trans,p} = FC_{Bio-CNG,j,p} \times NCV_{CNG} \times EF_{CNG}$$

(EQ3)

$RE_{trans,p}$	: Reference emissions from fossil fuel consumption by transport applications during the period p [tCO_2e/p]
$FC_{Bio-CNG,j,p}$	: Bio-CNG consumption by transport application (j) during the period p [t/p]
NCV_{CNG}	: Net calorific value of CNG [GJ/t]
EF_{CNG}	: CO_2 emission factor of CNG [tCO_2e/GJ]

G. Calculation of project emissions

$$PE_p = PE_{ww\_elec,p} + PE_{upgrading\_elec,p} + PE_{refueling\_elec,p}$$

(EQ4)

PE_p	: Project emissions during the period p [tCO_2e/p]
$PE_{ww\_elec,p}$	: Project emissions from electricity consumption by wastewater treatment during the period [tCO_2e/p]
$PE_{upgrading\_elec,p}$	: Project emissions from electricity consumption by Bio-gas upgrading system during the period [tCO_2e/p]
$PE_{refueling\_elec,p}$	: Project emissions from electricity consumption by refueling station during the period [tCO_2e/p]

$$PE_{ww\_elec,p} = EC_{ww,p} \times \left[\left(W_{residue,p} \times R_{CH4,residue}\right) \div FC_{Bio-CNG,j,p}\right] \times EF_{grid}$$

(EQ5)

$PE_{ww\_elec,p}$	: Project emissions from electricity consumption by wastewater treatment during the period [tCO_2e/p]
$EC_{ww,p}$	: Electricity consumption by anaerobic digestion system during the period p [MWh/p]
$FC_{Bio-CNG,j,p}$	: Bio-CNG consumption by transport application (j) during the period p [t/p]
$W_{residue,p}$	: Weight of processing residue putting into anaerobic

digestion system [t/p]

$R_{CH4,residue}$: Rate of CH_4 gasification from processing residue [-]

EF_{grid} : CO_2 emission factor of grid electricity [tCO_2e/MWh]

$$PE_{upgrading\_elec,p} = EC_{upgrading,p} \times EF_{grid}$$

(EQ6)

$PE_{upgrading\_elec,p}$: Project emissions from electricity consumption by upgrading system during the period [tCO_2e/p]

$EC_{upgrading,p}$: Electricity consumption by upgrading system during the period p [MWh]

EF_{grid} : CO_2 emission factor of grid electricity [tCO_2e/MWh]

$$PE_{refueling\_elec,p} = EC_{refueling,p} \times EF_{grid}$$

(EQ7)

$PE_{refueling\_elec,p}$: Project emissions from electricity consumption by refueling station during the period [tCO_2e/p]

$EC_{refueling,p}$: Electricity consumption by refueling station during the period p [MWh]

EF_{grid} : CO_2 emission factor of grid electricity [tCO_2e/MWh]

H. Calculation of emissions reductions

$$ER_p = RE_p - PE_p$$

(EQ7)

ER_p : Emission reductions during the period p [tCO_2e/p]

RE_p : Reference emissions during the period p [tCO_2e/p]

PE_p : Project emissions during the period p [tCO_2e/p]

I. Data and parameters fixed *ex ante*

The source of each data and parameter fixed *ex ante* is listed as below.

<table>
<tr><th>Parameter</th><th>Description of data</th><th>Source</th></tr>
<tr><td>$R_{CH4,residue}$</td><td>Rate of CH_4 gasification from processing residue [-]</td><td>Default value in the methodology</td></tr>
<tr><td>f</td><td>Fraction of methane captured at the SWDS and flared, combusted or used in another manner that prevents the emissions of methane to the atmosphere
f=0</td><td>Default value in the methodology</td></tr>
<tr><td>OX</td><td>Oxidation factor (reflecting the amount of methane from SWDS that is oxidized in the soil or other material covering the waste)
Value of either 0.1 or 0 is applied to OX depending on the type of SWDS.
<table>
<tr><th>Type of SWDS</th><th>Values</th></tr>
<tr><td>Managed[1], unmanaged and uncategorised SWDS</td><td>0</td></tr>
<tr><td>Managed covered with CH_4 oxidising material[2]</td><td>0.1</td></tr>
</table>
[1] Managed but not covered with aerated material
[2] Examples: soil, compost</td><td>IPCC default values provided table 3.2 of Vol.3 of 2006 IPCC Guidelines for National Greenhouse Gas Inventories.</td></tr>
<tr><td>F</td><td>Fraction of methane in the SWDS gas</td><td>IPCC default values</td></tr>
</table>

<table>
<tr><td></td><td>[volume fraction]
F=0.5</td><td>provided in “FRACTION OF CH4 IN GENERATED LANDFILL GAS (F)” of Ch.3 Vol.5 of 2006 IPCC Guidelines for National GHG Inventories.</td></tr>
<tr><td>DOC_f</td><td>Fraction of degradable organic carbon (DOC) that decomposes under specific conditions occurring in the SWDS [weight fraction]
DOC_f=0.5</td><td>IPCC default values provided table 2.4 and 2.5 of Vol.5 of 2006 IPCC Guidelines for National Greenhouse Gas Inventories.</td></tr>
<tr><td>MCF</td><td>Methane correction factor

<table><tr><th>Type of SWDS</th><th>Value</th></tr><tr><td>Anaerobic managed SWDS</td><td>1.0</td></tr><tr><td>Semi-aerobic managed SWDS</td><td>0.5</td></tr><tr><td>Unmanaged SWDS-deep</td><td>0.8</td></tr><tr><td>Unmanaged-shallow SWDS or stockpiles that are considered SWDS</td><td>0.4</td></tr></table>In Thailand, Type of SWDSs is Anaerobic managed SWDS.</td><td>IPCC default values provided table 3.1 of Vol.5 of 2006 IPCC Guidelines for National Greenhouse Gas Inventories.</td></tr>
<tr><td>DOC</td><td>Fraction of degradable organic carbon (by weight) [weight fraction]
DOC =0.08

Lower value of the range 8-20% for food</td><td>IPCC default values provided table 2.4 and 2.5 of Vol.5 of 2006 IPCC Guidelines for National Greenhouse Gas</td></tr>
</table>

	waste set in IPCC 2006 Guidelines for National Greenhouse Gas Inventories is applied.	Inventories.
k	Decay rate [1/year] k=0.4	IPCC default values provided table 3.3 of Vol.5 of 2006 IPCC Guidelines for National Greenhouse Gas Inventories.
NCV_{CNG}	Net calorific value of CNG [GJ/t]	IPCC default values provided in table 3.2.1 of Ch.1 Vol.2 of 2006 IPCC Guidelines for National GHG Inventories.
EF_{CNG}	CO_2 emission factor of CNG [tCO_2e/GJ]	IPCC default values provided in table 1.4 of Ch.1 Vol.2 of 2006 IPCC Guidelines for National GHG Inventories.
EF_{grid}	CO_2 emission factor of grid electricity [tCO_2e/MWh]	Updates on Grid Electricity Emission Factors, National Committee on Clean Development Mechanism, Thailand unless otherwise instructed by the Joint Committee.
GWP_{CH4}	Global Warming Potential for CH4 GWP_{CH4}=25	2006 IPCC Guidelines for National Greenhouse Gas Inventories

8.2 PDD and estimated emission reductions in candidate sites

With respect to two sites as candidates for the project with satisfactory credit status and high potential for bio-CBG manufacture and consumption, preparation of PDD (Project Design Document) and estimates of the expected CO_2 emission reductions were carried out.

8.2.1 Site A (Company A)

It was ascertained that in Plant A of Company A, biogas can be purified through anaerobic treatment of 95% of EFB emitted from the plant mixed in waste water. As a result, it has been decided to consider a capacity of 2,000 Nm^3/h for the purifying equipment as a level that makes it possible to carry out stable operations. If a machine with the capacity of 2,000 Nm^3/h is selected, an annual production of bio-CNG for about 8,118 t/year can be expected.

For roughly estimating CO_2 emission reductions, without taking into consideration methane avoidance in EFB landfill, the amount of methane avoidance from atmospheric release for the amount of used biogas is used as the reference emission. The reference emission was estimated as avoided methane 172,507t-CO_2/y for avoided methane and 22,953 t-CO_2/y for the use of fossil fuel by vehicles, the project emission by power consumption of equipment 3,253 t-CO_2/y, and, as the difference between them, CO_2 emission reduction 192,207 t-CO_2/y.

Figure 56: Equipment specification for Plant A

	Fermenter equipment	Purifying equipment	Equipment for station
Equipment capacity	Rated 48,000 Nm^{qwetg}/d-BG	Raw material: 2,000 Nm^3/h-BG Product: 1,025 kg/h-CBG	Storage 12 ton/d 2 dispensers-2 nozzles

Figure 57: Monitored items and values in estimating CO_2 emission reduction for Plant A

Monitored item	Value	Ground
Bio-CNG amount [t/y]	8,118	Estimated by Osaka Gas
CNG unit calorific value [GJ/t]	50.4	IPCC2006 TABLE 1.2
CNG emission factor [t-CO2/GJ]	0.0561	IPCC2006 TABLE 3.2.1
Electricity emission factor (*)[t-CO2/MWh]	0.5477	Thailand Greenhouse Gas Management Organization "The Study of emission factor for an electricity system in Thailand 2009_Table 10 Calculated Combined Margin Emission Factor"

*: The value of BM (built margin) of "General project" is used. JCM's approach for maintaining conservative estimates is ensured by comparing values of OM (operating margin) 0.6147 and CM (combined margin) 0.5812 and using the smallest BM (build margin) of 0.5477.

Figure 58: Estimated result of CO_2 emission reduction for Plant A

CO_2 emission reduction [t-CO2/y]	Reference emission [t-CO2/y]	Project emission [t-CO2/y]
192,207	195,460	3,253

JCM Project Design Document Form

A. Project description

A.1. Title of the JCM project

Refining Bio-CNG from organic waste at Biomass Plant for using as fuels of NGV in Thailand.

A.2. General description of project and applied technologies and/or measures

The proposed JCM project aims to achieve GHG emission reduction by capturing CH_4 from anaerobic digestion system with organic waste (e.g. waste water and processing residues) at Biomass Plant and purify to Bio-CNG (Compressed Natural Gas), which are used for NGV (Natural Gas Vehicle) in Thailand. It is to achieve GHG emission reduction through the following 2 activities. 1) Avoiding CH_4 emissions by recovering biogas using organic waste at Biomass Plant. 2) Reducing consumption of fossil fuel by using Bio-CNG for vehicle. The key technology of purifying to Bio-CNG is Hybrid type CO_2 removal system combining Pressure Swing Adsorption and Gas Separation Membrane.

A.3. Location of project, including coordinates

Country	Kingdom of Thailand
Region/State/Province etc.:	TBD
City/Town/Community etc:	TBD
Latitude, longitude	TBD

A.4. Name of project participants

The Kingdom of Thailand	Participant A
Japan	Osaka Gas Co., Ltd.

A.5. Duration

Starting date of project operation	2018
Expected operational lifetime of project	10 years

A.6. Contribution from Japan

The state-of-the-art technology of purifying to Bio-CNG which has been developed by the Japanese project participant is introduced in the proposed project. The Japanese project participant transfers the technology through training to the Thailand project participants. The Japanese side provides financial support to the project.

B. Application of an approved methodology(ies)

B.1. Selection of methodology(ies)

Selected approved methodology No.	Proposed methodology：Refining Bio-CNG from organic waste at Biomass Plant for using as fuels of NGV in Thailand.
Version number	Ver. 01.0
Selected approved methodology No.	N/A
Version number	N/A
Selected approved methodology No.	N/A
Version number	N/A

B.2. Explanation of how the project meets eligibility criteria of the approved methodology

Eligibility criteria	Descriptions specified in the methodology	Project information
Criterion 1	The project is to capture CH_4 from anaerobic digestion system with organic waste (e.g. waste water and processing residues) at Biomass Plant and purify to Bio-CNG (Compressed Natural Gas), which are used for NGV (Natural Gas Vehicle) in Thailand.	The project participant plan to capture CH_4 from anaerobic digestion system with organic waste at Biomass Plant and purify to Bio-CNG (Compressed Natural Gas), which are used for NGV (Natural Gas Vehicle) in Thailand.
Criterion 2	Organic waste from Biomass Plant is not used for Energy or Materials. (e.g. Waste water is discharged into river, captured CH_4 is released into atmosphere, and process residue is landfilled or left in the field.)	Organic waste from Biomass Plant is not used for Energy or Materials.
Criterion 3	The technology of purifying to Bio-CNG is Hybrid type CO_2 removal system combining Pressure Swing	The project participant plan to apply the technology of purifying to Bio-CNG which is Hybrid type CO2 removal system combining

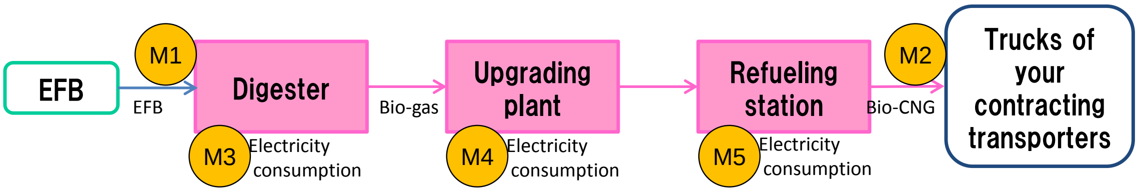
	Adsorption and Gas Separation Membrane.	Pressure Swing Adsorption and Gas Separation Membrane.
Criterion 4	The off-gas discharged from PSA is recycled.	The project participant plan to reuse the off-gas discharged from PSA.
Criterion 5	Plant to apply the international or national qualification standard of Bio-CNG for using NCV is prepared.	The project participant plan to apply the international qualification standard of Bio-CNG for using NCV

C. Calculation of emission reductions

C.1. All emission sources and their associated greenhouse gases relevant to the JCM project

Reference emissions	
Emission sources	**GHG type**
Methane emissions from decay of organic waste	CH_4
Fossil fuel consumption by Natural Gas Vehicle	CO_2
Project emissions	
Emission sources	**GHG type**
Electricity consumption by anaerobic digestion system	CO_2
Electricity consumption by upgrading system for Bio-CNG	CO_2
Electricity consumption by refueling station for Bio-CNG	CO_2

C.2. Figure of all emission sources and monitoring points relevant to the JCM project



M1: Weight of processing residue putting into anaerobic digestion system

M2: Bio-CNG consumption by transport applications

M3: Electricity consumption by anaerobic digestion system

M4: Electricity consumption by upgrading system

M5: Electricity consumption by refueling station

C.3. Estimated emissions reductions in each year

Year	Estimated Reference emissions (tCO_{2e})	Estimated Project Emissions (tCO_{2e})	Estimated Emission Reductions (tCO_{2e})
2018	172,507	3,253	169,254
2019	172,507	3,253	169,254
2020	172,507	3,253	169,254
Total (tCO_{2e})	517,521	9,759	507,762

D. Environmental impact assessment	
Legal requirement of environmental impact assessment for the proposed project	To be confirmed later

E. Local stakeholder consultation

E.1. Solicitation of comments from local stakeholders

Project participants plan to implement the local stakeholder consultation at the start of the demonstration project.

E.2. Summary of comments received and their consideration

Stakeholders	Comments received	Consideration of comments received
TBD	TBD	TBD

F. References

Reference lists to support descriptions in the PDD, if any.

Annex

Revision history of PDD		
Version	Date	Contents revised
01.0	17/02/2017	First Edition

8.2.2 Site B (Company B)

For Company B, based on the amount of actually flared gas in 2015, it was decided to consider a capacity of the purifying equipment of 750 Nm^3/h as a level that makes constantly stable operations possible. If a machine for 750 Nm^3/h is selected, about 3,200 t/year of annual production of bio-CNG can be expected.

For estimating CO_2 emission reductions, the amount of methane avoidance from atmospheric release for the amount of used biogas is used as the reference emission. The reference emission was estimated as avoided methane 68,000 t-CO_2/y for avoided methane and 9,047 t-CO_2/y for the use of fossil fuel by vehicles, the project emission by power consumption of equipment 954 t-CO_2/y, and, as the difference between them, CO2 emission reduction 76,093 t-CO_2/y.

Figure 59: Equipment specification for Company B

	Fermenter equipment	Purifying equipment	Equipment for station
Equipment capacity	Rated 40,000 Nm^3/d-BG	Raw material: 750 Nm^3/h-BG Product: 404 kg/h-CBG	Storage 7 ton/d 1 dispenser – 2 nozzles

Figure 60: Monitored items and values in estimating CO_2 emission reduction for Company B

Monitored item	Value	Ground
Bio-CNG amount [t/y]	3,200	Estimate by Osaka Gas
CNG unit calorific value [GJ/t]	50.4	IPCC2006 TABLE 1.2
CNG emission factor [t-CO2/GJ]	0.0561	IPCC2006 TABLE 3.2.1
Electricity emission factor (*)[t-CO2/MWh]	0.5477	Thailand Greenhouse Gas Management Organization "The Study of emission factor for an electricity system in Thailand 2009_Table 10 Calculated Combined Margin Emission Factor"

*: The value of BM (built margin) of "General project" is used. JCM's approach for maintaining conservative estimates is ensured by comparing values of OM (operating margin) 0.6147 and CM (combined margin) 0.5812 and using the smallest BM (build margin) of 0.5477.

Figure 61: Estimated result of CO_2 emission reduction for Company B

CO_2 emission reduction [t-CO2/y]	Reference emission [t-CO2/y]	Project emission [t-CO2/y]
76,093	77,047	954

JCM Project Design Document Form

A. Project description

A.1. Title of the JCM project

Refining Bio-CNG from organic waste at Biomass Plant for using as fuels of NGV in Thailand.

A.2. General description of project and applied technologies and/or measures

The proposed JCM project aims to achieve GHG emission reduction by capturing CH_4 from anaerobic digestion system with organic waste (e.g. waste water and processing residues) at Biomass Plant and purify to Bio-CNG (Compressed Natural Gas), which are used for NGV (Natural Gas Vehicle) in Thailand.

It is to achieve GHG emission reduction through the following 2 activities.

1) Avoiding CH_4 emissions by recovering biogas using organic waste at Biomass Plant.

2) Reducing consumption of fossil fuel by using Bio-CNG for vehicle.

The key technology of purifying to Bio-CNG is Hybrid type CO_2 removal system combining Pressure Swing Adsorption and Gas Separation Membrane.

A.3. Location of project, including coordinates

Country	Kingdom of Thailand
Region/State/Province etc.:	TBD
City/Town/Community etc:	TBD
Latitude, longitude	TBD

A.4. Name of project participants

The Kingdom of Thailand	Participant B
Japan	Osaka Gas Co., Ltd.

A.5. Duration

Starting date of project operation	2018
Expected operational lifetime of project	10 years

A.6. Contribution from Japan

The state-of-the-art technology of purifying to Bio-CNG which has been developed by the Japanese project participant is introduced in the proposed project. The Japanese project participant transfers the technology through training to the Thailand project participants. The Japanese side provides financial support to the project.

B. Application of an approved methodology(ies)

B.1. Selection of methodology(ies)

Selected approved methodology No.	Proposed methodology：Refining Bio-CNG from organic waste at Biomass Plant for using as fuels of NGV in Thailand.
Version number	Ver. 01.0
Selected approved methodology No.	N/A
Version number	N/A
Selected approved methodology No.	N/A
Version number	N/A

B.2. Explanation of how the project meets eligibility criteria of the approved methodology

Eligibility criteria	Descriptions specified in the methodology	Project information
Criterion 1	The project is to capture CH_4 from anaerobic digestion system with organic waste (e.g. waste water and processing residues) at Biomass Plant and purify to Bio-CNG (Compressed Natural Gas), which are used for NGV (Natural Gas Vehicle) in Thailand.	The project participant plan to capture CH_4 from anaerobic digestion system with organic waste at Biomass Plant and purify to Bio-CNG (Compressed Natural Gas), which are used for NGV (Natural Gas Vehicle) in Thailand.
Criterion 2	Organic waste from Biomass Plant is not used for Energy or Materials. (e.g. Waste water is discharged into river, captured CH_4 is released into atmosphere, and process residue is landfilled or left in the field.)	Organic waste from Biomass Plant is not used for Energy or Materials.
Criterion 3	The technology of purifying to Bio-CNG is Hybrid type CO_2 removal system combining Pressure Swing	The project participant plan to apply the technology of purifying to Bio-CNG which is Hybrid type CO2 removal system combining

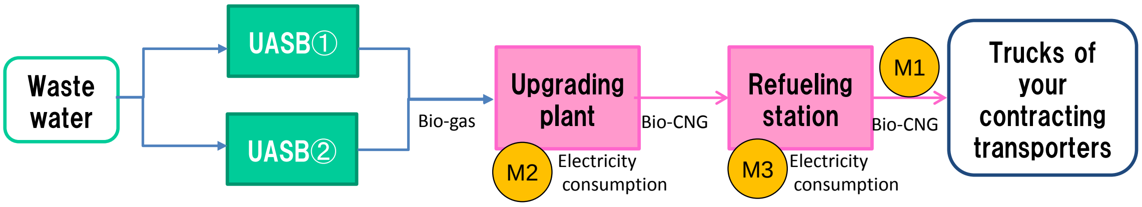
	Adsorption and Gas Separation Membrane.	Pressure Swing Adsorption and Gas Separation Membrane.
Criterion 4	The off-gas discharged from PSA is recycled.	The project participant plan to reuse the off-gas discharged from PSA.
Criterion 5	Plant to apply the international or national qualification standard of Bio-CNG for using NCV is prepared.	The project participant plan to apply the international qualification standard of Bio-CNG for using NCV

C. Calculation of emission reductions

C.1. All emission sources and their associated greenhouse gases relevant to the JCM project

Reference emissions	
Emission sources	**GHG type**
Methane emissions from decay of organic waste	CH_4
Fossil fuel consumption by Natural Gas Vehicle	CO_2
Project emissions	
Emission sources	**GHG type**
Electricity consumption by anaerobic digestion system	CO_2
Electricity consumption by upgrading system for Bio-CNG	CO_2
Electricity consumption by refueling station for Bio-CNG	CO_2

C.2. Figure of all emission sources and monitoring points relevant to the JCM project



M1: Bio-CNG consumption by transport applications

M2: Electricity consumption by upgrading system

M3: Electricity consumption by refueling station

C.3. Estimated emissions reductions in each year

Year	Estimated Reference emissions (tCO_{2e})	Estimated Project Emissions (tCO_{2e})	Estimated Emission Reductions (tCO_{2e})
2018	77,047	954	76,093
2019	77,047	954	76,093
2020	77,047	954	76,093
Total (tCO_{2e})	231,141	2,862	228,279

D. Environmental impact assessment

Legal requirement of environmental impact assessment for the proposed project	To be confirmed later

E. Local stakeholder consultation

E.1. Solicitation of comments from local stakeholders

Project participants plan to implement the local stakeholder consultation at the start of the demonstration project.

E.2. Summary of comments received and their consideration

Stakeholders	Comments received	Consideration of comments received
TBD	TBD	TBD

F. References

Reference lists to support descriptions in the PDD, if any.

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以上

Appendix 1

Joint Crediting Mechanism Proposed Methodology Spreadsheet Form (input sheet) [Attachment to Proposed Methodology Form]

JCM_TH_F_PMS_ver01.0

Joint Crediting Mechanism Proposed Methodology Spreadsheet Form (input sheet) [Attachment to Proposed Methodology Form]

Table 1: Parameters to be monitored *ex post*

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Monitoring point No.	Parameters	Description of data	Estimated Values	Units	Monitoring option	Source of data	Measurement methods and procedures	Monitoring frequency	Other comments
1	$FC_{Bio\text{-}CNG,j,p}$	Bio-CNG consumption by transport application (j) during the period p		t/p	Option C	monitored data	Measured by gas flow meter certified in line with international/national standards.	Continuously	N/A
2	$R_{CH4,Bio\text{-}CNG}$	Bio-CNG consumption by transport application (j) during the period p		t/p	Option C	monitored data	Measured by gas flow meter certified in line with international/national standards.	Continuously	N/A
3	$W_{residue,p}$	Weight of processing residue putting into anaerobic digestion system during the period p		t	Option C	monitored data	Measured in wet basis by mesurement equipments certified in line with international/national standards.	Continuously and aggregated monthly	Input on "PMS(input)(2)" sheet
-	p_start	The Nth month from the first disposal, which is the first month of the period *p*	13	-	Option C	monitored data	Count the number of the month (Nth month) from the first disposal, which is the first month of the period *p* . If that month is smaller than 14 and *p_end* is larger than 13, *p_start* is set at 14.	-	N/A
-	p_end	The Nth month from the first disposal, which is the last month of the period *p*	0	-	Option C	monitored data	Count the number of the month (Nth month) from the first disposal, which is the last month of the period *p* .	-	N/A
4	$EC_{ww,p}$	Electricity consumption by anaerobic digestion system during the period p	0	MWh/p	Option C	monitored data	Measured by electricity meter certified in line with international/national standards.	Continuously	N/A
5	$EC_{upgrading,p}$	Electricity consumption by upgrading system during the period p	0	MWh/p	Option C	monitored data	Measured by electricity meter certified in line with international/national standards.	Continuously	N/A
6	$EC_{refueling,p}$	Electricity consumption by refueling station during the period p	0	MWh/p	Option C	monitored data	Measured by electricity meter certified in line with international/national standards.	Continuously	N/A

Table 2: Project-specific parameters to be fixed *ex ante*

(a)	(b)	(c)	(d)	(e)	(f)
Parameters	Description of data	Estimated Values	Units	Source of data	Other comments
$R_{CH4,Bio\text{-}CNG}$	Rate of CH4 content of Bio-CNG by volume	0.85	-	The specifications of system for quotation or the factory acceptance test data by manufacturer.	N/A
GWP_{CH4}	Global Warming Potential for CH4	25	-	2006 IPCC Guidelines for National Greenhouse Gas Inventories	N/A
$R_{CH4,residue}$	Rate of CH4 gasification from processing residue		-	The specifications of system for quotation or the factory acceptance test data by manufacturer.	N/A
MCF	Methane correction factor	1.0	-	Select from the default values	N/A
OX	Oxidation factor	0.1	-	Select from the default values	N/A
NCV_{CNG}	Net calorific value of CNG	50.40	GJ/t	IPCC default values provided in table 3.2.1 of Ch.1 Vol.2 of 2006 IPCC Guidelines for National GHG Inventories.	N/A
EF_{CNG}	CO2 emission factor of CNG	0.0561	tCO_2/GJ	IPCC default values provided in table 1.4 of Ch.1 Vol.2 of 2006 IPCC Guidelines for National GHG Inventories.	N/A
EF_{elec}	CO_2 emissions factor of the electricity consumed	0.5477	tCO_2/MWh	Thailand Greenhouse Gas Management Organization [The Study of emission factor for an electricity system in Thailand 2009_Table 10 Calculated Combined Margin Emission Factor]	N/A

Table3: *Ex-ante* estimation of CO_2 emission reductions

CO_2 emission reductions	Units
#DIV/0!	tCO_2/p

[Monitoring option]

Option A	Based on public data which is measured by entities other than the project participants (Data used: publicly recognized data such as statistical data and specifications)
Option B	Based on the amount of transaction which is measured directly using measuring equipments (Data used: commercial evidence such as invoices)
Option C	Based on the actual measurement using measuring equipments (Data used: measured values)

JCM Proposed Methodology Spreadsheet Form (input sheet)

[Attachment to Proposed Methodology Form]

Table 1: Parameters to be monitored *ex post*

(a)	Monitoring point No.	-
(b)	Parameters	$W_{residue,p}$
(c)	Description of data	Weight of processing residue putting into anaerobic digestion system during the period p
(e)	Units	t
(f)	Monitoring option	Option C
(g)	Source of data	monitored data
(h)	Measurement methods and procedures	Measured in wet basis by mesurement equipments certified in line with international/national standards.
(i)	Monitoring frequency	Continuously and aggregated monthly
(j)	Other comments	Input on "PMS(input) (2)" sheet
(d)	Estimated Values	
	Month 1	
	Month 2	
	Month 3	
	Month 4	
	Month 5	
	Month 6	
	Month 7	
	Month 8	
	Month 9	
	Month 10	
	Month 11	
	Month 12	
	Month 13	
	Month 14	
	Month 15	
	Month 16	
	Month 17	
	Month 18	
	Month 19	
	Month 20	
	Month 21	
	Month 22	
	Month 23	
	Month 24	
	Month 25	
	Month 26	
	Month 27	
	Month 28	
	Month 29	
	Month 30	
	Month 31	
	Month 32	
	Month 33	
	Month 34	
	Month 35	
	Month 36	
	Month 37	
	Month 38	
	Month 39	
	Month 40	
	Month 41	
	Month 42	
	Month 43	
	Month 44	
	Month 45	
	Month 46	
	Month 47	
	Month 48	
	Month 49	
	Month 50	
	Month 51	
	Month 52	
	Month 53	
	Month 54	
	Month 55	
	Month 56	
	Month 57	
	Month 58	
	Month 59	
	Month 60	

Joint Crediting Mechanism Proposed Methodology Spreadsheet Form (Calculation Process Sheet)

[Attachment to Proposed Methodology Form]

1. Calculations for emission reductions	Fuel type	Value	Units	Parameter
Emission reductions during the period *p*	N.A.	#DIV/0!	tCO_2/p	ER_p
2. Selected default values, etc.				
Methane correction factor	N.A.	1.0		MCF
3. Calculations for reference emissions				
Reference emissions during the period *p*	N.A.	0.0	tCO_2/p	RE_p
EQ1_Reference emissions during the period p	N.A.	0.0	tCO_2/p	$RE_{CH4,p}$
Reference emissions from decay of organic waste during the period p	N.A.	0.0	tCO_2/p	$RE_{CH4,ww,p}$
Reference emissions from fossil fuel consumption by transport applications during the period p	Natural Gas	0.0	tCO_2/p	$RE_{trans,fuel,p}$
EQ2_Reference emissions from decay of organic waste during the period p	N.A.	0.0	tCO_2/p	$RE_{CH4,p}$
Reference emissions from CH4 of waste water into atmosphere during the period p	N.A.	0.0	tCO_2/p	$RE_{CH4,ww,p}$
Reference emissions from CH4 of processing residue into atmosphere during the period p	N.A.	0.0	tCO_2/p	$RE_{CH4,residue,p}$
EQ2-1_Reference emissions from CH4 of waste water into atmosphere during the period p	N.A.	0.0	tCO_2/p	$RE_{CH4,ww,p}$
Bio-CNG consumption by transport application (j) during the period p	N.A.	0.0	t/p	$FC_{Bio\text{-}CNG,j,p}$
Rate of CH4 content of Bio-CNG by volume	N.A.	0.85	-	$R_{CH4,Bio\text{-}CNG}$
Global Warming Potential for CH4	N.A.	25	-	GWP_{CH4}
EQ2-2_Reference emissions from CH4 of waste water into atmosphere during the period p	N.A.	0.0	tCO_2/p	$RE_{CH4,ww,p}$
Bio-CNG consumption by transport application (j) during the period p	N.A.	0.0	t/p	$FC_{Bio\text{-}CNG,j,p}$
Rate of CH4 content of Bio-CNG by volume	N.A.	0.85	-	$R_{CH4,Bio\text{-}CNG}$
Weight of processing residue putting into anaerobic digestion system during the period p	N.A.	0.0	t/p	$W_{residue,p}$
Rate of CH4 gasification from processing residue	N.A.	0.0	-	$R_{CH4,residue}$
Global Warming Potential for CH4	N.A.	25.0	-	GWP_{CH4}
EQ2-3_Reference emissions from decay of processing residue during the period p	N.A.	0.0	tCO_2/p	$RE_{CH4,residue,p}$
EQ3_Reference emissions from fossil fuel consumption by transport applications during the period p	Natural Gas	0.0	tCO_2/p	$RE_{trans,fuel,p}$
Bio-CNG consumption by transport application (j) during the period p	N.A.	0.0	t/p	$FC_{Bio\text{-}CNG,j,p}$
Net calorific value of CNG	CNG	50.4	GJ/t	NCV_{CNG}
CO2 emission factor of CNG	CNG	0.1	tCO_2/GJ	EF_{CNG}
4. Calculations of the project emissions				
Project emissions during the period *p*	N.A.	#DIV/0!	tCO_2/p	PE_p
EQ4_Reference emissions during the period p	N.A.	#DIV/0!	tCO_2/p	PE_p
Project emissions from electricity consumption by wastewater treatment during the period	electricity	#DIV/0!	tCO_2/p	$PE_{ww\_elec,p}$
Project emissions from electricity consumption by Bio-gas upgrading system during the period	electricity	0.0	tCO_2/p	$PE_{upgrading\_elec,p}$
Project emissions from electricity consumption by refueling station during the period	electricity	0.0	tCO_2/p	$PE_{refueling\_elec,p}$
EQ5_Project emissions from electricity consumption by wastewater treatment during the period	N.A.	#DIV/0!	tCO_2/p	$PE_{ww\_elec,p}$
Electricity consumption by anaerobic digestion system during the period p	electricity	0.0	tCO_2/p	$EC_{ww,p}$
Weight of processing residue putting into anaerobic digestion system	N.A.	0.0	t/p	$W_{residue,p}$
Rate of CH4 gasification from processing residue	N.A.	0.0	-	$R_{CH4,residue}$
Bio-CNG consumption by transport application (j) during the period p	N.A.	0.0	t/p	$FC_{Bio\text{-}CNG,j,p}$
CO2 emission factor of grid electricity	electricity	0.5477	tCO_2/MWh	EF_{elec}
EQ6_Project emissions from electricity consumption by Bio-gas upgrading system during the period	N.A.	0.0	tCO_2/p	$PE_{upgrading\_elec,p}$
Electricity consumption by upgrading system during the period p	electricity	0.0	tCO_2/p	$EC_{upgrading,p}$
CO2 emission factor of grid electricity	electricity	0.5477	tCO_2/MWh	EF_{elec}
EQ7_Project emissions from electricity consumption by refueling station during the period	N.A.	0.0	tCO_2/p	$PE_{refueling\_elec,p}$
Electricity consumption by refueling station during the period p	electricity	0.0	tCO_2/p	$EC_{refueling,p}$
CO2 emission factor of grid electricity	electricity	0.0000	tCO_2/MWh	EF_{elec}

[List of Default Values]

Fraction of methane captured at the SWDS and flared, combusted or used in another manner that prevents the emissions of methane to the atmosphere	0	f
Global Warming Potential of methane	25	GWP_{CH4}
Oxidation factor		
Managed, unmanaged and uncategorised SWDS	0	OX
Managed covered with CH_4 oxidising material	0.1	OX
Fraction of methane in the SWDS gas	0.5	F
Fraction of degradable organic carbon that decomposes under specific conditions occurring in the SWDS	0.5	DOC_f
Methane correction factor		
Anaerobic managed SWDS	1.0	MCF
Semi-aerobic managed SWDS	0.5	MCF
Unmanaged SWDS-deep	0.8	MCF
Unmanaged-shallow SWDS or stockpiles that are considered SWDS	0.4	MCF
Fraction of degradable organic carbon (by weight)	8%	DOC
Decay rate (1/year)	0.4	k
Net calorific value of the biogas (GJ/t)	50.4	NCV_{BG}

JCM Proposed Methodology Spreadsheet Form (Calculation Process Sheet) **[Attachment to Proposed Methodology Form]**

	m	$\Sigma W_{residue,p} \times DOC \times e^{-k(m-13-x)/12} \times (1-e^{-k/12})$
	The N^{th} month from the first disposal at the SWDS, extending from the first month of the period p ($m=p\_start$) to the last month of the period p ($m=p\_end$)	Decayed degradable organic carbon in month m
Month 1	0	0.00
Month 2	0	0.00
Month 3	0	0.00
Month 4	0	0.00
Month 5	0	0.00
Month 6	0	0.00
Month 7	0	0.00
Month 8	0	0.00
Month 9	0	0.00
Month 10	0	0.00
Month 11	0	0.00
Month 12	0	0.00
Month 13	0	0.00
Month 14	0	0.00
Month 15	0	0.00
Month 16	0	0.00
Month 17	0	0.00
Month 18	0	0.00
Month 19	0	0.00
Month 20	0	0.00
Month 21	0	0.00
Month 22	0	0.00
Month 23	0	0.00
Month 24	0	0.00
Month 25	0	0.00
Month 26	0	0.00
Month 27	0	0.00
Month 28	0	0.00
Month 29	0	0.00
Month 30	0	0.00
Month 31	0	0.00
Month 32	0	0.00
Month 33	0	0.00
Month 34	0	0.00
Month 35	0	0.00
Month 36	0	0.00
Month 37	0	0.00
Month 38	0	0.00
Month 39	0	0.00
Month 40	0	0.00
Month 41	0	0.00
Month 42	0	0.00
Month 43	0	0.00
Month 44	0	0.00
Month 45	0	0.00
Month 46	0	0.00
Month 47	0	0.00
Month 48	0	0.00
Month 49	0	0.00
Month 50	0	0.00
Month 51	0	0.00
Month 52	0	0.00
Month 53	0	0.00
Month 54	0	0.00
Month 55	0	0.00
Month 56	0	0.00
Month 57	0	0.00
Month 58	0	0.00
Month 59	0	0.00
Month 60	0	0.00

$e^{-k(m-13-x)/12} \times (1-e^{-k/12})$

Month m

Month x	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
Month 1														0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Month 2															0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Month 3																0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Month 4																	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Month 5																		0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Month 6																			0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01
Month 7																				0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01
Month 8																					0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01
Month 9																						0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01
Month 10																							0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01
Month 11																								0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01
Month 12																									0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Month 13																										0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Month 14																											0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Month 15																												0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Month 16																													0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Month 17																														0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Month 18																															0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Month 19																																0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Month 20																																	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Month 21																																		0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02
Month 22																																			0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02
Month 23																																				0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02
Month 24																																					0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02
Month 25																																						0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02
Month 26																																							0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02
Month 27																																								0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Month 28																																									0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Month 29																																										0.03	0.03	0.03	0.03	0.03	0.03	0.03
Month 30																																											0.03	0.03	0.03	0.03	0.03	0.03
Month 31																																												0.03	0.03	0.03	0.03	0.03
Month 32																																													0.03	0.03	0.03	0.03
Month 33																																														0.03	0.03	0.03
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Reference Material
Referenced CDM methodology

① AMS-III.H: Methane recovery in wastewater treatment (Version 18.0)

② AMS-III.E: Avoidance of methane production from decay of biomass through controlled combustion, gasification or mechanical/ thermal treatment (Version 17.0)

③ AMS-III.AQ.: Introduction of Bio-CNG in transportation applications (Version 2.0)

Small-scale Methodology

AMS-III.H: Methane recovery in wastewater treatment

Version 18.0

Sectoral scope(s): 13

1. Introduction

The following table describes the key elements of the methodology:

Table 1. Methodology key elements

Typical project(s)	Recovery of biogas resulting from anaerobic decay of organic matter in wastewaters through introduction of an anaerobic treatment system for wastewater and/or sludge treatment with biogas recovery
Type of GHG emissions mitigation action	GHG destruction. Destruction of methane emissions

2. Scope, applicability, and entry into force

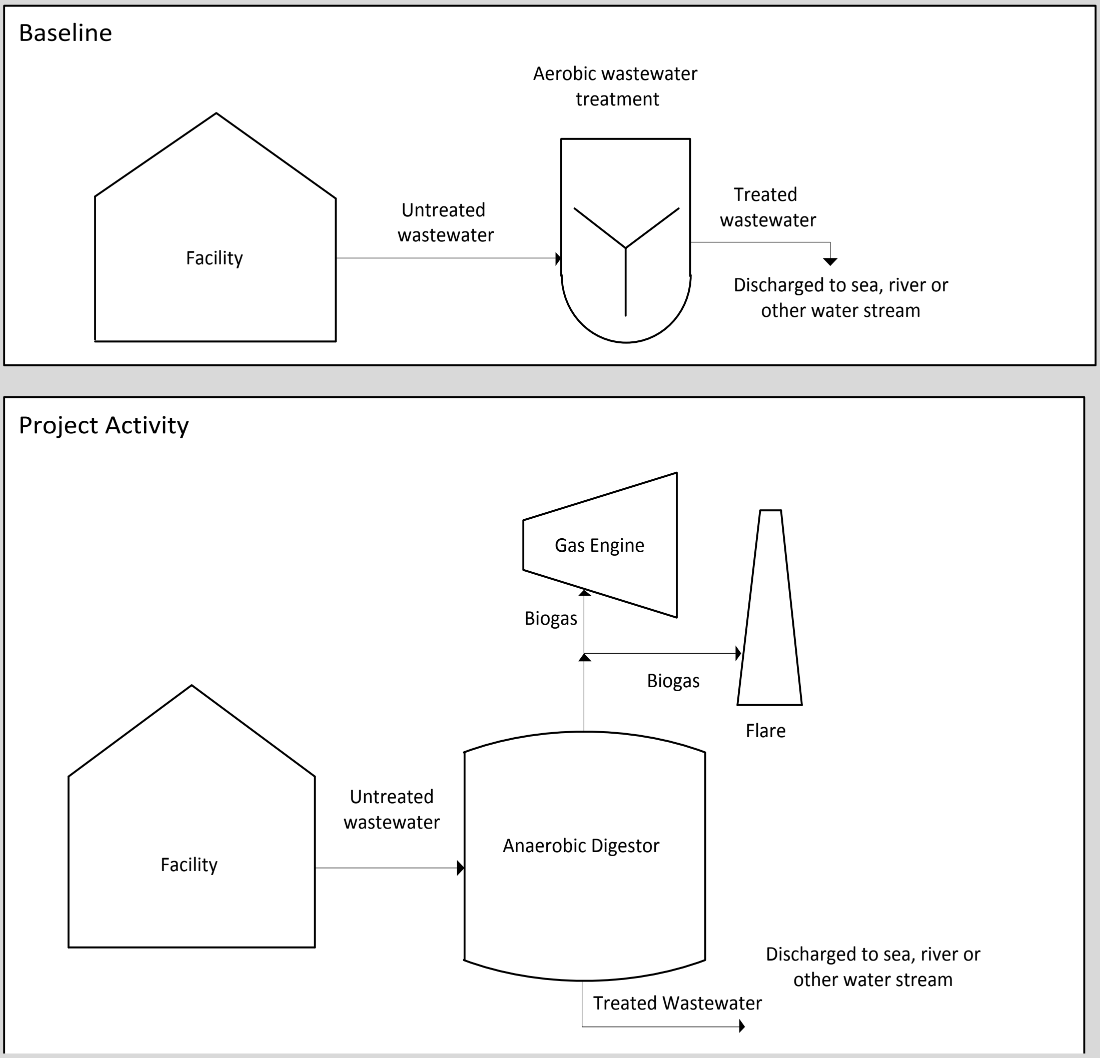
2.1. Scope

This methodology comprises measures that recover biogas from biogenic organic matter in wastewater by means of one, or a combination, of the following options:

Substitution of aerobic wastewater or sludge treatment systems with anaerobic systems with biogas recovery and combustion;

Figure 62. Non-binding best practice example 1: Application of paragraph 2 (a)

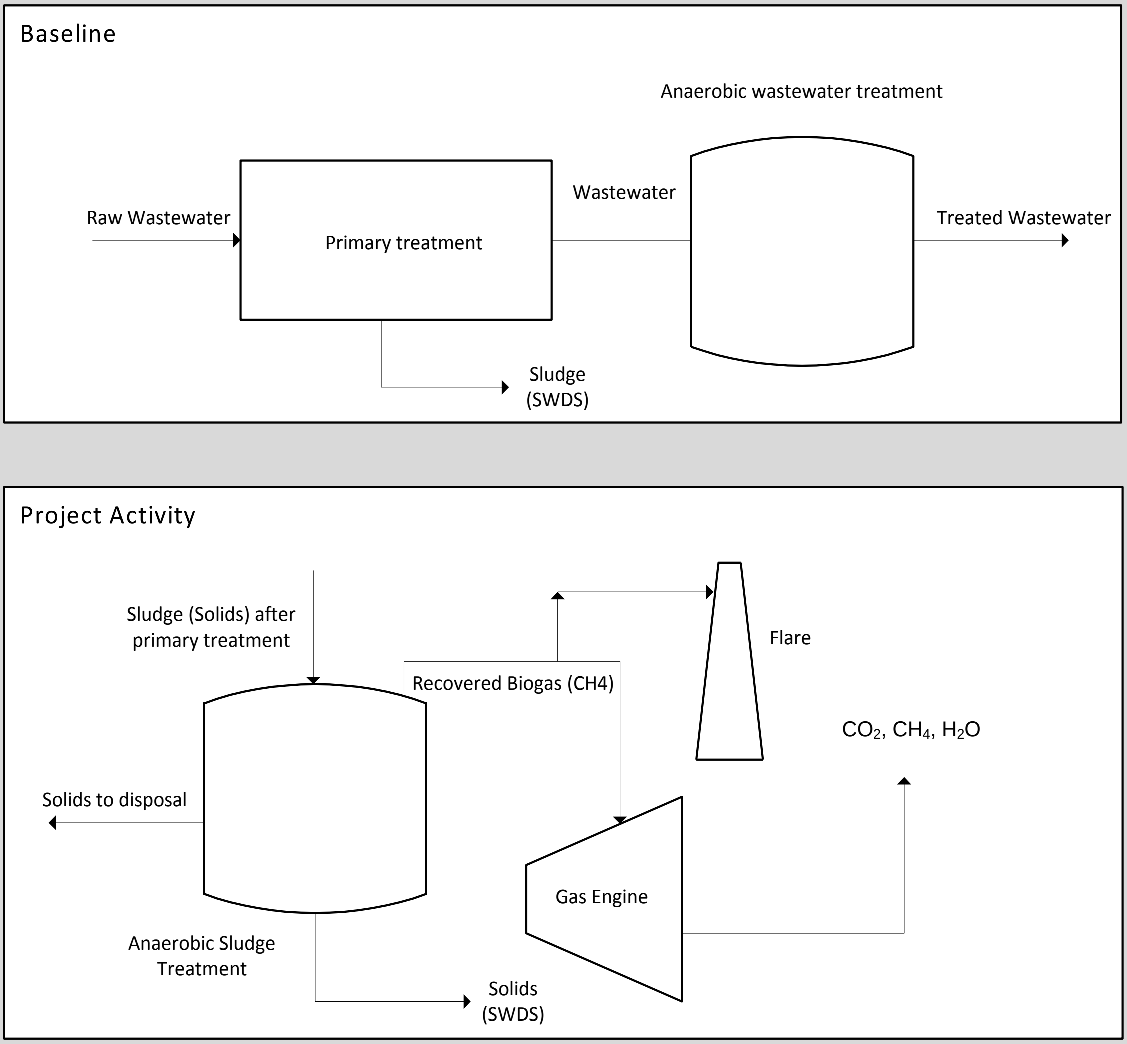
In absence of the project activity, the wastewater is treated aerobically. The project activity aims to recover biogas using anaerobic digester and utilize it for electricity generation using a gas engine.



Introduction of anaerobic sludge treatment system with biogas recovery and combustion to a wastewater treatment plant without sludge treatment;

Figure 63. Non-binding best practice example 2: Application of paragraph 2 (b)

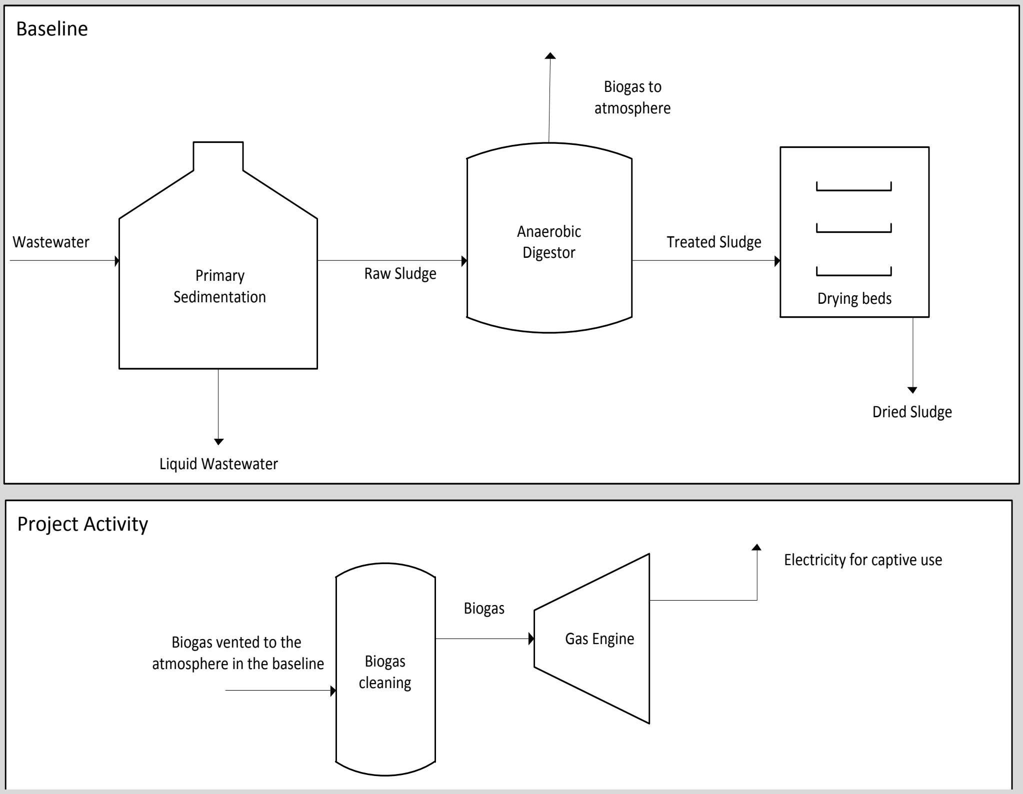
In absence of the project activity, wastewater is treated (aerobically or anaerobically) without sludge treatment (e.g. the sludge is disposed anaerobically in a solid waste disposal site without methane recovery). The project activity aims to treat the sludge in anaerobic digester to recover biogas and to flare it or utilize it to generate electricity using gas engines.



Introduction of biogas recovery and combustion to a sludge treatment system;

Figure 64. Non-binding best practice example 3: Application of paragraph 2 (c)

In absence of the project activity, the biogas generated in the anaerobic digester is vented. The project activity aims to capture and use the biogas for electricity generation using a gas engine. The project involves the installation of gas cleaning facility, gas engines and eventually an enclosed flaring system to burn the excess biogas. The electricity will be used for captive use, replacing electricity from the grid.



I
ntroduction of biogas recovery and combustion to an anaerobic wastewater treatment system such as anaerobic reactor, lagoon, septic tank or an on-site industrial plant;[6]

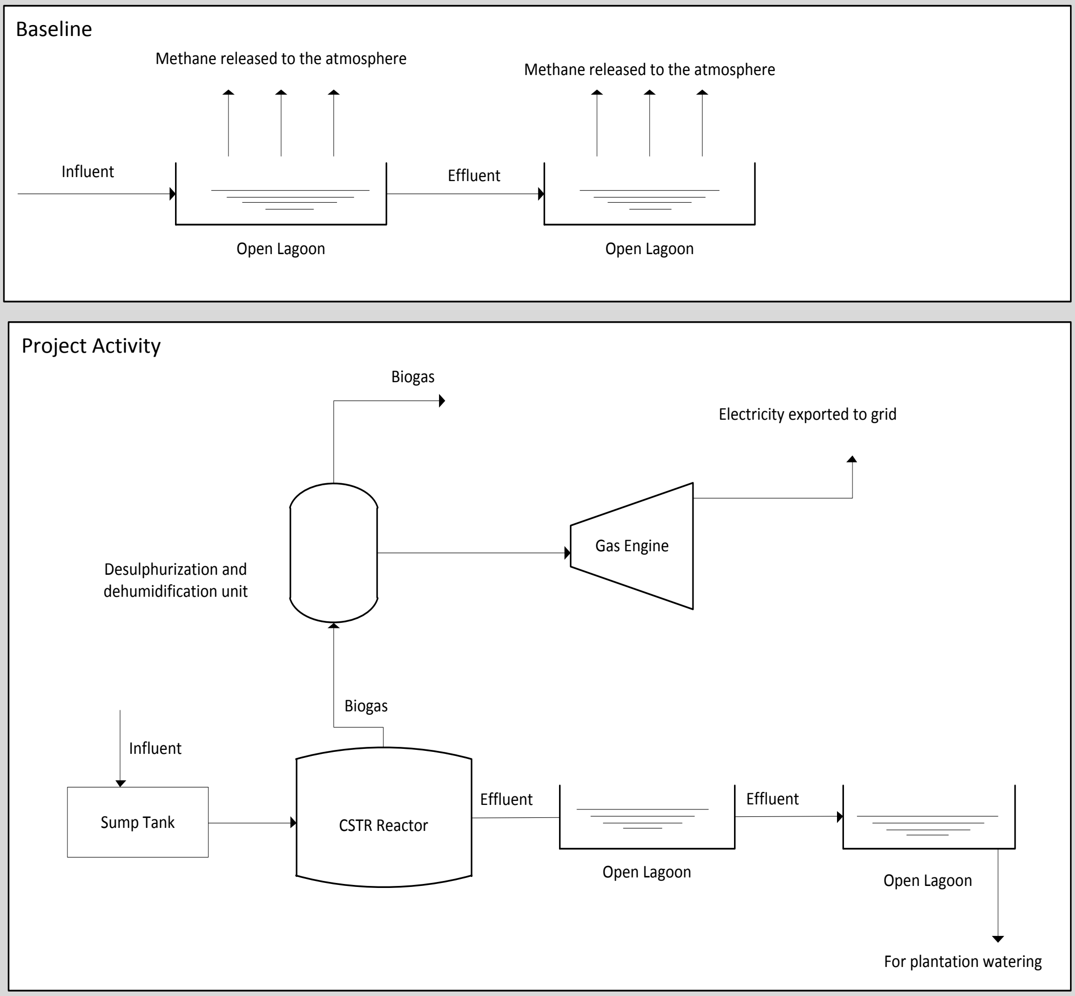
Introduction of anaerobic wastewater treatment with biogas recovery and combustion, with or without anaerobic sludge treatment, to an untreated wastewater stream;

[6] Other technologies in Table 6.3 of Chapter 6: Wastewater Treatment and Discharge of 2006 IPCC Guidelines for National Greenhouse Gas Inventories are included.

Introduction of a sequential stage of wastewater treatment with biogas recovery and combustion, with or without sludge treatment, to an anaerobic wastewater treatment system without biogas recovery (e.g. introduction of treatment in an anaerobic reactor with biogas recovery as a sequential treatment step for the wastewater that is presently being treated in an anaerobic lagoon without methane recovery).

Figure 65. Non-binding best practice example 4: Application of paragraph 2 (f)

In absence of the project activity, the wastewater would have been treated in anaerobic open lagoons. The project activity involves the installation of a new stage in the wastewater system (for example CSTR reactor in the figure below); the wastewater is treated sequentially in a sump tank, then treated in the biogas reactor with methane recovery and it's utilization for electricity generation, without sludge separation, and finally treated by the existing series of anaerobic open lagoons.



2.2. Applicability

In cases where baseline system is anaerobic lagoon the methodology is applicable if:

The lagoons are ponds with a depth greater than two meters, without aeration. The value for depth is obtained from engineering design documents, or through direct measurement, or by dividing the surface area by the total volume. If the lagoon filling level varies seasonally, the average of the highest and lowest levels may be taken;

Ambient temperature above 15°C, at least during part of the year, on a monthly average basis;

The minimum interval between two consecutive sludge removal events shall be 30 days.

The recovered biogas from the above measures may also be utilised for the following applications instead of combustion/flaring:

Thermal or mechanical,[7] electrical energy generation directly;

Thermal or mechanical, electrical energy generation after bottling of upgraded biogas, in this case additional guidance provided in the appendix shall be followed; or

Thermal or mechanical, electrical energy generation after upgrading and distribution, in this case additional guidance provided in the appendix shall be followed:

Upgrading and injection of biogas into a natural gas distribution grid with no significant transmission constraints;

Upgrading and transportation of biogas via a dedicated piped network to a group of end users; or

Upgrading and transportation of biogas (e.g. by trucks) to distribution points for end users;

Hydrogen production;

Use as fuel in transportation applications after upgrading.

If the recovered biogas is used for project activities covered under paragraph 4(a), that component of the project activity can use a corresponding methodology under Type I.

For project activities covered under paragraph 4(b), if bottles with upgraded biogas are sold outside the project boundary, the end-use of the biogas shall be ensured via a contract between the bottled biogas vendor and the end-user. No emission reductions may be claimed from the displacement of fuels from the end use of bottled biogas in such situations. If, however, the end use of the bottled biogas is included in the project boundary and is monitored during the crediting period CO_2 emissions avoided by the displacement of fossil fuel can be claimed under the corresponding Type I methodology, e.g. “AMS-I.C.: Thermal energy production with or without electricity”.

For project activities covered under paragraph 4(c)(i), emission reductions from the displacement of the use of natural gas are eligible under this methodology, provided the geographical extent of the natural gas distribution grid is within the host country boundaries.

[7] For example combusted in a prime mover such as an engine coupled to a machine such as grinding machine.

For project activities covered under paragraph 4(c)(ii), emission reductions for the displacement of the use of fuels can be claimed following the provision in the corresponding Type I methodology, e.g. AMS-I.C.

In particular, for the case of paragraph 4(b) and (c)(iii), the physical leakage during storage and transportation of upgraded biogas, as well as the emissions from fossil fuel consumed by vehicles for transporting biogas shall be considered. Relevant procedures in paragraph 18 of the appendix of “AMS-III.H.: Methane recovery in wastewater treatment” shall be followed in this regard.

For project activities covered under paragraph 4(b) and (c), this methodology is applicable if the upgraded methane content of the biogas is in accordance with relevant national regulations (where these exist) or, in the absence of national regulations, a minimum of 96 per cent (by volume).

If the recovered is utilized for the production of hydrogen (project activities covered under paragraph 3(d)), that component of the project activity shall use the corresponding methodology “AMS-III.O.: Hydrogen production using methane extracted from biogas”.

If the recovered biogas is used for project activities covered under paragraph 4(e), that component of the project activity shall use corresponding methodology “AMS-III.AQ.: Introduction of Bio-CNG in transportation applications”.

New facilities (Greenfield projects) and project activities involving a change of equipment resulting in a capacity addition of the wastewater or sludge treatment system compared to the designed capacity of the baseline treatment system are only eligible to apply this methodology if they comply with the relevant requirements in the “General guidelines for SSC CDM methodologies”. In addition the requirements for demonstrating the remaining lifetime of the equipment replaced, as described in the general guidelines shall be followed.

Box 1. Non-binding best practice example 5: Application of “General guidelines to SSC CDM methodologies” as per paragraph 13

New facilities (Greenfield projects) and project activities involving capacity addition should follow step-wise approach (step 1 to step 4) in accordance with the “General guidelines to SSC CDM methodologies”.

In regard to the application of Step 1 under paragraph 19 of “General guidelines to SSC CDM methodologies”, EB 61 Annex 21 (i.e. Identify the various alternatives available to the project proponent that deliver comparable levels of service), practices carried out in the industry or similar industry should also be considered.

For a project activity involving capacity addition, e.g. because the industrial process increases its production capacity, the continuation of the current practice can be an available alternative if it is demonstrated that it is able to attend the increasing quantity of wastewater from the production facility and/or the difference of the quality of the inflowing wastewater. For example, if the existing practice is the use of anaerobic lagoons, it needs to be demonstrated that there is enough land area available in the neighboring terrains, adequate to be used for increasing the size or to build new lagoons such as to attend the increased capacity for wastewater treatment plant using the same technology.

The location of the wastewater treatment plant as well as the source generating the wastewater shall be uniquely defined and described in the PDD.

Measures are limited to those that result in aggregate emissions reductions of less than or equal to 60 kt CO_2 equivalent annually from all Type III components of the project activity.

2.3. Entry into force

The date of entry into force is the date of the publication of the EB 86 meeting report on 16 October 2015.

3. Normative references

Project participants shall apply the "General guidelines for SSC CDM methodologies and information on additionality (attachment A to Appendix B) provided at <http://cdm.unfccc.int/methodologies/SSCmethodologies/approved.html> mutatis mutandis.

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

"AMS-I.C.: Thermal energy production with or without electricity";

"AMS-III.H.: Methane recovery in wastewater treatment";

"AMS-III.O.: Hydrogen production using methane extracted from biogas";

"AMS-III.AQ.: Introduction of Bio-CNG in transportation applications";

"AM0053: Biogenic methane injection to a natural gas distribution grid";

"Project emissions from flaring";

"Tool to calculate baseline, project and/or leakage emissions from electricity consumption";

"Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion";

"Emissions from solid waste disposal sites".

4. Definitions

The definitions contained in the Glossary of CDM terms shall apply.

5. Baseline methodology

5.1. Project boundary

The project boundary is the physical, geographical site where the wastewater and sludge treatment takes place, in the baseline and project situations. It covers all facilities affected by the project activity including sites where processing, transportation and application or disposal of waste products as well as biogas takes place.

Implementation of the project activity at a wastewater and/or sludge treatment system will affect certain sections of the treatment systems while others may remain unaffected. The treatment systems not affected by the project activity, i.e. sections operating in the project scenario under the same operational conditions as in the baseline scenario (e.g. wastewater inflow and COD content, temperature, retention time, etc.), shall be described in the PDD, but emissions from those sections do not have to be accounted for in the baseline and project emission calculations (since the same emissions would occur in both baseline and project scenarios).[8] The assessment and identification of the systems affected by the project activity will be undertaken ex ante, and the PDD shall justify the exclusion of sections or components of the system. The treatment systems (lagoons, reactors, digesters, etc.) that will be covered and/or equipped with biogas recovery by the project activity, but continue to operate with the same quality of feed inflow, volume (retention time), and temperature (heating) as in the baseline scenario, may be considered as not affected i.e. the methane generation potential[9] remains unaltered.

5.2. Additionality

The following project activities are deemed additional if it is demonstrated that:

The existing treatment system is an anaerobic lagoon and waste water discharged meets the host country legislation; and

There is no regulation in the host country, applicable to the project site that requires the management of biogas from domestic, industrial and agricultural sites.

This additionality condition does not apply to Greenfield project activities.

Furthermore, for project activities applying this methodology in combination with a Type I methodology, that has an energy component whose installed capacity is less than 5 MW, this procedure for additionality demonstration also applies to that component.

The above simplified additionality demonstration is valid for three years from the date of entry into force of Version 17.0 of AMS-III.H. on the date of the publication of the EB 81 meeting report on 28 November 2014; the CDM Executive Board may reassess the validity of the simplified additionality demonstration and extend or update it if needed. Any update does not affect the projects that request registration as a CDM project activity or a programme of activities by 28 November 2017 (i.e. three years from the date of entry into force) and apply the simplified additionality demonstration contained in Version 17.0 of AMS-III.H.

5.3. Baseline

Wastewater and sludge treatment systems equipped with a biogas recovery facility in the baseline shall be excluded from the baseline emission calculations.

Baseline emissions for the systems affected by the project activity may consist of:

Emissions on account of electricity or fossil fuel used ($BE_{power,y}$);

Methane emissions from baseline wastewater treatment systems ($BE_{ww,treatment,y}$);

8 As per EB 22, annex 2 “Guidance regarding methodological issues” section E.

9 The covering of lagoons and the installation of biogas recovery equipment may result in changes in the operational conditions (such as temperature, COD removal, etc.) of an anaerobic treatment system. These changes are considered small and hence not accounted for under this methodology.

Methane emissions from baseline sludge treatment systems ($BE_{s,treatment,y}$);

Methane emissions on account of inefficiencies in the baseline wastewater treatment systems and presence of degradable organic carbon in the treated wastewater discharged into river/lake/sea ($BE_{ww,discharge,y}$);

Methane emissions from the decay of the final sludge generated by the baseline treatment systems ($BE_{s,final,y}$).

$$BE_y = \{BE_{power,y} + BE_{ww,treatment,y} + BE_{s,treatment,y} + BE_{ww,discharge,y} + BE_{s,final,y}\} \quad \text{Equation (1)}$$

Where:

BE_y	=	Baseline emissions in year *y* (t CO_2e)
$BE_{power,y}$	=	Baseline emissions from electricity or fuel consumption in year *y* (t CO_2e)
$BE_{ww,treatment,y}$	=	Baseline emissions of the wastewater treatment systems affected by the project activity in year *y* (t CO_2e)
$BE_{s,treatment,y}$	=	Baseline emissions of the sludge treatment systems affected by the project activity in year *y* (t CO_2e)
$BE_{ww,discharge,y}$	=	Baseline methane emissions from degradable organic carbon in treated wastewater discharged into sea/river/lake in year y (t CO_2e). The value of this term is zero for the case 1(b)
$BE_{s,final,y}$	=	Baseline methane emissions from anaerobic decay of the final sludge produced in year *y* (t CO_2e). If the sludge is controlled combusted, disposed in a landfill with biogas recovery, or used for soil application in the baseline scenario, this term shall be neglected

Baseline emissions from electricity and fossil fuel consumption ($BE_{power,y}$) are determined as per the procedures described in the “Tool to calculate baseline, project and/or leakage emissions from electricity consumption” and “Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion”, respectively. The energy consumption shall include all equipment/devices in the baseline wastewater and sludge treatment facility. If recovered biogas in the baseline is used to power auxiliary equipment it should be taken into account accordingly, using zero as its emission factor.

Methane emissions from the baseline wastewater treatment systems affected by the project ($BE_{ww,treatment,y}$) are determined using the COD removal efficiency of the baseline plant:

$$BE_{ww,treatment,y} = \sum_i \left(Q_{ww,i,y} \times COD_{inflow,i,y} \times \eta_{COD,BL,i} \times MCF_{ww,treatment,BL,i}\right) \times B_{o,ww} \times UF_{BL} \times GWP_{CH4}$$ Equation (2)

Where:

$Q_{ww,i,y}$	=	Volume of wastewater treated in baseline wastewater treatment system i in year y (m^3). For ex ante estimation, forecasted wastewater generation volume or the designed capacity of the wastewater treatment facility can be used. However, the ex post emissions reduction calculation shall be based on the actual monitored volume of treated wastewater
$COD_{inflow,i,y}$	=	Chemical oxygen demand of the wastewater inflow to the baseline treatment system *i* in year *y* (t/m^3). Average value may be used through sampling with the confidence/precision level 90/10
$\eta_{COD,BL,i}$	=	COD removal efficiency of the baseline treatment system *i*, determined as per the paragraphs 38, 39 or 40 below
$MCF_{ww,treatment,BL,i}$	=	Methane correction factor for baseline wastewater treatment systems *i* (MCF values as per Table 2 below)
i	=	Index for baseline wastewater treatment system
$B_{o,ww}$	=	Methane producing capacity of the wastewater (IPCC value of 0.25 kg CH_4/kg COD)[10]
UF_{BL}	=	Model correction factor to account for model uncertainties (0.89)[11]
GWP_{CH4}	=	Global Warming Potential for methane

If the baseline treatment system is different from the treatment system in the project scenario, the monitored values of the COD inflow during crediting period will be used to calculate the baseline emissions ex post.

The Methane Correction Factor (*MCF*) shall be determined based on the following table:

Table 2. IPCC default values[12] for Methane Correction Factor (*MCF*)

[10] Project activities may use the default value of 0.6 kg CH_4/kg BOD, if the parameter $BOD_{5,20}$ is used to determine the organic content of the wastewater. In this case, baseline and project emissions calculations shall use BOD instead of COD in the equations, and the monitoring of the project activity shall be based in direct measurements of $BOD_{5,20}$, i.e. the estimation of BOD values based on COD measurements is not allowed.

[11] Reference: FCCC/SBSTA/2003/10/Add.2, page 25.

Type of wastewater treatment and discharge pathway or system	*MCF* value
Discharge of wastewater to sea, river or lake	0.1
Land application	0.1
Aerobic treatment, well managed	0.0
Aerobic treatment, poorly managed or overloaded	0.3
Anaerobic digester for sludge without methane recovery	0.8
Anaerobic reactor without methane recovery	0.8
Anaerobic shallow lagoon (depth less than 2 metres)	0.2
Anaerobic deep lagoon (depth more than 2 metres)	0.8
Septic system	0.5
Land application [13]	0.1

Methane emissions from the baseline sludge treatment systems affected by the project activity are determined using the methane generation potential of the sludge treatment systems:

$$BE_{treatment,s,y} = \sum_{j} S_{j,BL,y} \times MCF_{s,treatment,BL,j} \times DOC_s \times UF_{BL} \times DOC_F \times F \times 16/12 \times GWP_{CH4} \quad \text{Equation (3)}$$

Where:

$S_{j,BL,y}$	=	Amount of dry matter in the sludge that would have been treated by the sludge treatment system *j* in the baseline scenario (t). For ex ante estimation, forecasted sludge generation volume or the designed capacity of the sludge treatment facility can be used. However, the ex post emissions reduction calculation shall be based on the actual monitored volume of treated sludge
j	=	Index for baseline sludge treatment system
DOC_s	=	Degradable organic content of the untreated sludge generated in the year *y* (fraction, dry basis). Default values of 0.5 for domestic sludge and 0.257 for industrial sludge[14] shall be used

[12] Default values from chapter 6 of volume 5. Waste in 2006 IPCC Guidelines for National Greenhouse Gas Inventories.

[13] Please refer SSC_664, "Clarification on methane correction factors for treated water used for irrigation under AMS-III.H ver. 16".

$MCF_{s,treatment,BL,j}$	=	Methane correction factor for the baseline sludge treatment system *j* (*MCF* values as per Table 2 above)
UF_{BL}	=	Model correction factor to account for model uncertainties (0.89)
DOC_F	=	Fraction of DOC dissimilated to biogas (IPCC default value of 0.5)
F	=	Fraction of CH_4 in biogas (IPCC default of 0.5)

If the sludge is composted, the following equation shall be applied:

$$BE_{s,treatment,y} = \sum_j S_{j,BL,y} \times EF_{composting} \times GWP_{CH4}$$ Equation (4)

Where:

$EF_{composting}$	=	Emission factor for composting organic waste (t CH_4/t waste treated). Emission factors can be based on facility/site-specific measurements, country specific values or IPCC default values (Table 4.1, chapter 4, Volume 5, 2006 IPCC Guidelines for National Greenhouse Gas Inventories). IPCC default value is 0.01 t CH_4/ t sludge treated on a dry weight basis

If the baseline wastewater treatment system is different from the treatment system in the project scenario, the sludge generation rate (amount of sludge generated per unit of COD removed) in the baseline may differ significantly from that of the project scenario. For example, it is known that the amount of sludge generated in aerobic wastewater systems is larger than in anaerobic systems, for the same COD removal efficiency. Therefore, for these cases, the monitored values of the amount of sludge generated during the crediting period will be used to estimate the amount of sludge generated in the baseline, as follows:

$$S_{j,BL,y} = S_{l,PJ,y} \times \frac{SGR_{BL}}{SGR_{PJ}}$$ Equation (5)

Where:

$S_{l,PJ,y}$	=	Amount of dry matter in the sludge treated by the sludge treatment system *i* in year *y* in the project scenario (t)
SGR_{BL}	=	Sludge generation ratio of the wastewater treatment plant in the baseline scenario (tonne of dry matter in sludge/t COD removed). This ratio will be determined as per paragraphs 38, 39 or 40 below

[14] The IPCC default values of 0.05 for domestic sludge (wet basis, considering a default dry matter content of 10 per cent) or 0.09 for industrial sludge (wet basis, assuming dry matter content of 35 per cent), were corrected for dry basis.

SGR_{PJ}	=	Sludge generation ratio of the wastewater treatment plant in the project scenario (tonne of dry matter in sludge/t COD removed). Calculated using the monitored values of COD removal (i.e. $COD_{inflow,i}$ minus $COD_{outflow,i}$) and sludge generation in the project scenario

Methane emissions from degradable organic carbon in treated wastewater discharged in e.g. a river, sea or lake in the baseline situation are determined as follows:

$$BE_{ww,discharge,y} = Q_{ww,y} \times GWP_{CH4} \times B_{o,ww} \times UF_{BL} \times COD_{ww,discharge,BL,y} \times MCF_{ww,BL,discharge} \quad \text{Equation (6)}$$

Where:

$Q_{ww,y}$	=	Volume of treated wastewater discharged in year y (m^3)
UF_{BL}	=	Model correction factor to account for model uncertainties (0.89)
$COD_{ww,discharge,BL,y}$	=	Chemical oxygen demand of the treated wastewater discharged into sea, river or lake in the baseline situation in the year y (t/m^3). If the baseline scenario is the discharge of untreated wastewater, the COD of untreated wastewater shall be used
$MCF_{ww,BL,discharge}$	=	Methane correction factor based on discharge pathway in the baseline situation (e.g. into sea, river or lake) of the wastewater (fraction) (MCF values as per Table 2 above)

To determine $COD_{ww,discharge,BL,y}$: if the baseline treatment system(s) is different from the treatment system(s) in the project scenario, the monitored values of the COD inflow during crediting period will be used to calculate the baseline emissions ex post. The outflow COD of the baseline systems will be estimated using the removal efficiency of the baseline treatment systems, estimated as per paragraphs 38, 39 or 40 below.

Methane emissions from anaerobic decay of the final sludge produced are determined as follows:

$$BE_{s,final,y} = S_{final,BL,y} \times DOC_s \times UF_{BL} \times MCF_{s,BL,final} \times DOC_F \times F \times 16/12 \times GWP_{CH4} \quad \text{Equation (7)}$$

Where:

$S_{final,BL,y}$	=	Amount of dry matter in the final sludge generated by the baseline wastewater treatment systems in the year *y* (t). If the baseline wastewater treatment system is different from the project system, it will be estimated using the monitored amount of dry matter in the final sludge generated by the project activity ($S_{final,PJ,y}$) corrected for the sludge generation ratios of the project and baseline systems as per equation (5) above
$MCF_{s,BL,final}$	=	Methane correction factor of the disposal site that receives the final sludge in the baseline situation, estimated as per the procedures described in the methodological tool "Emissions from solid waste disposal sites"
UF_{BL}	=	Model correction factor to account for model uncertainties (0.89)

In determining baseline emissions using equation (1), historical records of at least one year prior to the project implementation shall be used. This shall include for example the COD removal efficiency of the wastewater treatment systems, the amount of dry matter in sludge, power and electricity consumption per m^3 of wastewater treated the amount of final sludge generated per tonne of COD removed, and all other parameters required for determination of baseline emissions.

For wastewater treatment plant that has been operating for at least three years and if one year of historical data is not available, the following procedures shall be followed:

All the available data in determining the required parameters (COD removal efficiency, specific energy consumption and specific sludge production) shall be used to determine the baseline emissions in year *y*;

An ex ante measurement campaign shall be implemented to determine the required parameters (COD removal efficiency, specific energy consumption and specific sludge production). The measurement campaign shall be implemented in the baseline wastewater systems for at least 10 days. The measurements should be undertaken during a period that is representative for the typical operation conditions of the systems and ambient conditions of the site (temperature, etc). Average values from the measurement campaign shall be used and the result shall be multiplied by 0.89 to account for the uncertainty range (30 per cent to 50 per cent). The parameters from the measurement campaign are used to calculate the baseline emission in year *y*;

The baseline emissions in year *y* is taken as the minimum between the result of (a) and (b).

Box 2. Non-binding best practice example 6: Ex-ante measurement campaign for existing facilities as per paragraph 39 (a) and (b)

The project activity involves the installation of a UASB digester in a palm oil industry to recover and utilize biogas. In the pre-project scenario, the wastewater was being treated in an existing anaerobic open lagoon system.

Partial historical COD data for the treatment system is available; therefore, an ex-ante measurement campaign has been carried out to determine the required parameters (CODinflow,y, CODoutflow,y, ηCOD,BL and Qww,y) to calculate the baseline emissions in year y. The average value of the baseline emissions obtained through measurement campaign was lower than the historical value, therefore, the minimum value was taken up for ex-ante calculation (see paragraph of 39 (c)).

The average baseline emissions value measured is thereafter multiplied by 0.89 to account for the uncertainty in accordance with the methodology paragraph 39 (b). During the 10-days COD-measurement campaign, the inflow and the outflow COD content of the open lagoon was measured. The efficiency was estimated as the quotient between the removal capacity and the inflow.

Table 1: Average value of the 10 days COD -measurement campaign may be demonstrated as follows:

	COD content before open lagoon	COD content after open lagoon	COD content before released to the river	Water temp. before covered lagoon	Air Tempe-rature	Amount of wastewater per ton of product
Unit	(mg/L)	(mg/L)	(mg/L)	(^oC)	(^oC)	(m^3/t)
Average 10 days	9558	3239	117	27.7	26.3	26.26

External data obtained from other wastewater treatment plants or registered PDDs are not allowed.

In the case of Greenfield and capacity addition projects, or existing plant without three year operating history, the following procedures shall be used to determine the baseline emissions:

For existing plant without three year operating history, procedures in paragraph 39 shall be followed;

For Greenfield and capacity addition projects, one of the following procedures shall be used:

Value obtained from a measurement campaign in a comparable existing wastewater treatment plant i.e. having similar environmental and technological circumstances for example treating similar type of wastewater. Average values from the measurement campaign shall be used and the result shall be multiplied by 0.89 to account for the uncertainty range (30 per cent to 50 per cent) associated with this approach. The treatment plant and wastewater source can be considered as similar as the baseline plant, whereby the measurement campaign can be implemented when following conditions can be fulfilled:

The two sources of wastewater (wastewater treated in the selected plant and from the project activity) are of the same type, e.g. either domestic or industrial wastewater;

The selected plant and the baseline plants employ the same treatment technology (e.g. anaerobic lagoons or activated sludge), and the hydraulic retention times in their biological and physical treatment systems do not vary by more than 20 per cent; and

For project activity treating industrial wastewater, both industries have the same raw material and final products, and apply the same industrial technology. Alternatively, different industrial wastewaters may be considered as similar if the following requirements are fulfilled:

The ratio COD/BOD (related to the proportion of biodegradable organic matter) does not differ by more than 20 per cent; and

The ratio total COD/soluble COD (related to the proportion of suspended organic matter, and therefore to the sludge generation capacity) does not differ by more than 20 per cent.

Value provided by the manufacturer/designer of a Greenfield wastewater treatment plant using the same technology, demonstrated to be conservative, e.g. average values from the top 20 per cent plants with lowest emission rate per tonne COD removed among the plants installed in the last five years designed for the same country/region to treat the same type of wastewaters as the project activity.

Box 3. Non-binding best practice example 7: Ex-ante measurement campaign for greenfield projects as per paragraph 40 (b) (i)

> This is a greenfield project which aims to build and operate a biogas plant that will process Palm Oil Mill Effluent (POME) from a new palm oil mill. The recovered biogas will be used to generate electricity in two units of 609 kWe biogas engines for the mill's own consumption.
> The project activity only claims emission reductions from baseline emissions of the wastewater treatment system affected by the project activity. Other values such as electricity consumption, sludge generation etc. are not included in the baseline calculation and no emission reductions are claimed for the potential emissions that could be reduced.
> Since this is a greenfield project, the estimation of COD values shall be based on paragraph 40 (b) of the methodology
>
> The estimated COD values for the conventional open lagoon wastewater treatment system are obtained from a measurement campaign for a similar registered CDM project with all the baseline data clearly depicted in the PDD. The average values from the measurement campaign are multiplied by 0.89 to account for the uncertainty. The treatment plant and wastewater source is considered as similar as the baseline plant based on the following facts:
>
> a) POME is the type of wastewater treated in the selected CDM project and from the proposed project activity. So both of the plants are treating same type of wastewater.
> b) The selected CDM project and the baseline plants employ the same treatment technology, which is comprised of a cooling/ acidification pond, anaerobic lagoons, aerobic lagoons. The hydraulic retention time for the selected plant in the CDM project is about 90 days, and the baseline plant of the proposed project activity is 106 days. The difference is no more than 20%.
> c) The baseline plant of the selected CDM project and the proposed project activity are treating POME. Both of the mills process raw FFBs and produce crude palm oil.

5.4. Project emissions

Project emissions consists of:

CO_2 emissions from electricity and fuel used by the project facilities ($PE_{power,y}$);

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

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

Methane emissions on account of inefficiency of the project activity wastewater treatment systems and presence of degradable organic carbon in treated wastewater ($PE_{ww,discharge,y}$);

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

Methane fugitive emissions due to inefficiencies in capture systems ($PE_{fugitive,y}$);

Methane emissions due to incomplete flaring ($PE_{flaring,y}$);

Methane emissions from biomass stored under anaerobic conditions which would not have occurred in the baseline situation ($PE_{biomass,y}$).[15]

$$PE_y = \begin{Bmatrix} PE_{power,y} + PE_{ww,treatment,y} + PE_{s,treatment,y} + PE_{ww,discharge,y} + PE_{s,final,y} + \\ PE_{fugitive,y} + PE_{biomass,y} + PE_{flaring,y} \end{Bmatrix} \quad \text{Equation (8)}$$

Where:

PE_y	Project activity emissions in the year y (t CO2e)
$PE_{power,y}$	Emissions from electricity or fuel consumption in the year *y* (t CO_2e). These emissions shall be calculated as per paragraph 28, for the situation of the project scenario, using energy consumption data of all equipment/devices used in the project activity wastewater and sludge treatment systems and systems for biogas recovery and flaring/gainful use
$PE_{ww,treatment,y}$	Methane emissions from wastewater treatment systems affected by the project activity, and not equipped with biogas recovery, in year *y* (t CO_2e). These emissions shall be calculated as per equation (2) in paragraph 29 using an uncertainty factor of 1.12 and data applicable to the project situation ($MCF_{ww,treatment,PJ,k}$ and $\eta_{,PJ,k,y}$) and with the following changed definition of parameters: $MCF_{ww,treatment,PJ,k}$: Methane correction factor for project wastewater treatment system *k* (*MCF* values as per Table 2 above) $\eta_{,PJ,k,y}$: Chemical oxygen demand removal efficiency of the project wastewater treatment system *k* in year *y* (t/m^3), measured based on inflow COD and outflow COD in system *k*
$PE_{s,treatment,y}$	Methane emissions from sludge treatment systems affected by the project activity, and not equipped with biogas recovery, in year *y* (t CO_2e). These emissions shall be calculated as per equations (3) and (4) in paragraphs 32 and 33, using an uncertainty factor of 1.12 and data applicable to the project situation ($S_{l,PJ,y}$, $MCF_{s,treatment,l}$) and with the following changed definition of parameters: $S_{l,PJ,y}$: Amount of dry matter in the sludge treated by the sludge treatment system *l* in the project scenario in year *y* (t) $MCF_{s,treatment,l}$: Methane correction factor for the project sludge treatment system l (*MCF* values as per Table 2 above)

[15] For instance in the baseline situation Palm Kernel Shells (PKS) are used as fuel in a boiler. In the project situation PKS is replaced by biogas captured at a wastewater treatment system. The PKS will no longer be used as fuel in the boiler, but sold on the market. Before it is sold it is likely it will be stored for a period of time (few months or longer) on site which might lead to methane emissions from anaerobic decay.

$PE_{ww,discharge,y}$	Methane emissions from degradable organic carbon in treated wastewater in year *y* (tCO_2e). These emissions shall be calculated as per equation (6) in paragraph 35, using an uncertainty factor of 1.12 and data applicable to the project conditions ($COD_{ww,discharge,PJ,y}$, $MCF_{ww,PJ,discharge}$) and with the following changed definition of parameters: $COD_{ww,discharge,PJ,y}$ — Chemical oxygen demand of the treated wastewater discharged into the sea, river or lake in the project scenario in year *y* (t/m^3) $MCF_{ww,PJ,discharge}$ — Methane correction factor based on the discharge pathway of the wastewater in the project scenario (e.g. into sea, river or lake) (*MCF* values as per Table 2)
$PE_{s,final,y}$	Methane emissions from anaerobic decay of the final sludge produced in year *y* ($t\ CO_2e$). These emissions shall be calculated as per equation (7) in paragraph 37, using an uncertainty factor of 1.12 and data applicable to the project conditions ($MCF_{s,PJ,final}$, $S_{final,PJ,y}$). If the sludge is controlled combusted, disposed in a landfill with biogas recovery, or used for soil application in aerobic conditions in the project activity, this term shall be neglected, and the sludge treatment and/or use and/or final disposal shall be monitored during the crediting period with the following revised definition of the parameters: $MCF_{s,PJ,final}$ — Methane correction factor of the disposal site that receives the final sludge in the project situation, estimated as per the procedures described in the methodological tool "Emissions from solid waste disposal sites" $S_{final,PJ,y}$ — Amount of dry matter in final sludge generated by the project wastewater treatment systems in the year *y* (t)
$PE_{fugitive,y}$	Methane emissions from biogas release in capture systems in year *y*, calculated as per paragraph 42 ($t\ CO_2e$)
$PE_{flaring,y}$	Methane emissions due to incomplete flaring in year *y* ($t\ CO_2e$). For ex ante estimation, baseline emission calculation for wastewater and/or sludge treatment (i.e. equation (2) and/or equation (3)) can be used but without the consideration of GWP for CH_4. However, the ex post emission reduction shall be calculated as per methodological tool "Project emissions from flaring"
$PE_{biomass,y}$	Methane emissions from biomass stored under anaerobic conditions. If storage of biomass under anaerobic conditions takes place in the project and does not occur in the baseline , methane emissions due to anaerobic decay of this biomass shall be considered and be determined as per the procedure in the methodological tool "Emissions from solid waste disposal sites" ($t\ CO_2e$)

Project activity emissions from methane release in capture systems are determined as follows:

Based on the methane emission potential of wastewater and/or sludge:

$$PE_{fugitive,y} = PE_{fugitive,ww,y} + PE_{fugitive,s,y}$$ Equation (9)

Where:

$PE_{fugitive,ww,y}$	=	Fugitive emissions through capture inefficiencies in the anaerobic wastewater treatment systems in the year y (t CO2e)
$PE_{fugitive,s,y}$	=	Fugitive emissions through capture inefficiencies in the anaerobic sludge treatment systems in the year *y* (t CO_2e)

$$PE_{fugitive,ww,y} = (1 - CFE_{ww}) \times MEP_{ww,treatment,y} \times GWP_{CH4}$$ Equation (10)

Where:

CFE_{ww}	=	Capture efficiency of the biogas recovery equipment in the wastewater treatment systems (a default value of 0.9 shall be used)
$MEP_{ww,treatment,y}$	=	Methane emission potential of wastewater treatment systems equipped with biogas recovery system in year *y* (t)

$$MEP_{ww,treatment,y} = Q_{ww,y} \times B_{o,ww} \times UF_{PJ} \times \sum_k COD_{removed,PJ,k,y} \times MCF_{ww,treatment,PJ,k}$$ Equation (11)

Where:

$COD_{removed,PJ,k,y}$	=	The chemical oxygen demand removed[16] by the treatment system *k* of the project activity equipped with biogas recovery in the year *y* (t/m^3)
$MCF_{ww,treatment,PJ,k}$	=	Methane correction factor for the project wastewater treatment system *k* equipped with biogas recovery equipment (*MCF* values as per Table 2 above)
UF_{PJ}	=	Model correction factor to account for model uncertainties (1.12)

$$PE_{fugitive,s,y} = (1 - CFE_s) \times MEP_{s,treatment,y} \times GWP_{CH4}$$ Equation (12)

[16] Difference between the inflow COD and the outflow COD.

Where:

CFE_s	=	Capture efficiency of the biogas recovery equipment in the sludge treatment systems (a default value of 0.9 shall be used)
$MEP_{s,treatment,y}$	=	Methane emission potential of the sludge treatment systems equipped with a biogas recovery system in year *y* (t)

$$MEP_{s,treatment,y} = \sum_{l}\left(S_{l,PJ,y} \times MCF_{s,treatment,PJ,l}\right) \times DOC_s \times UF_{PJ} \times DOC_F \times F \times 16/12$$ Equation (13)

Where:

$S_{l,PJ,y}$	=	Amount of sludge treated in the project sludge treatment system l equipped with a biogas recovery system (on a dry basis) in year *y* (t)
$MCF_{s,treatment,PJ,l}$	=	Methane correction factor for the sludge treatment system equipped with biogas recovery equipment (MCF values as per Table 2 above)
UF_{PJ}	=	Model correction factor to account for model uncertainties (1.12)

Optionally a default value of 0.05 m³ biogas leaked/m³ biogas produced may be used as an alternative to calculations per equation (9) to (13).

5.5. Leakage

If the technology is using equipment transferred from another activity, leakage effects at the site of the other activity are to be considered and estimated (LE_y).

5.6. Emission reduction

For all scenarios in paragraph 2, emission reductions shall be estimated ex ante in the PDD using the equations provided in the baseline, project and leakage emissions sections above. Emission reductions shall be estimated ex ante as follows:

$$ER_{y,ex\ ante} = BE_{y,ex\ ante} - \left(PE_{y,ex\ ante} + LE_{y,ex\ ante}\right)$$ Equation (14)

Where:

$ER_{y,ex\ ante}$	=	Ex ante emission reduction in year *y* (t CO_2e)
$LE_{y,ex\ ante}$	=	Ex ante leakage emissions in year *y* (t CO_2e)
$PE_{y,ex\ ante}$	=	Ex ante project emissions in year *y* calculated as paragraph 41 (t CO_2e)

$BE_{y,ex\ ante}$	=	Ex ante baseline emissions in year *y* calculated as per paragraph 27 (t CO_2e)

Ex post emission reductions shall be determined for case 2(a) and 2(e) as per paragraph 48. For cases 2(b), 2(c), 2(d) and 2(f), ex post emission reductions shall be based on the lowest value of the following, as per paragraph 46:

The amount of biogas recovered and fuelled or flared (MD_y) during the crediting period, that is monitored ex post;

Ex post calculated baseline, project and leakage emissions based on actual monitored data for the project activity.

For cases 2(b), 2(c), 2(d) and 2(f): it is possible that the project activity involves wastewater and sludge treatment systems with higher methane conversion factors (*MCF*) or with higher efficiency than the treatment systems used in the baseline situation. Therefore the emission reductions achieved by the project activity is limited to the ex post calculated baseline emissions minus project emissions using the actual monitored data for the project activity. The emission reductions achieved in any year are the lowest value of the following:

$$ER_{y,ex\ post} = min\left(\left(BE_{y,ex\ post} - PE_{y,ex\ post} - LE_{y,ex\ post}\right), \left(MD_y - PE_{power,y} - PE_{biomass,y} - LE_{y,ex\ post}\right)\right) \quad \text{Equation (15)}$$

Where:

$ER_{y,ex\ post}$	=	Emission reductions achieved by the project activity based on monitored values for year *y* (t CO_2e)
$BE_{y,ex\ post}$	=	Baseline emissions calculated as per paragraph 27 using ex post monitored values
$PE_{y,ex\ post}$	=	Project emissions calculated as per paragraph 41 using ex post monitored values
MD_y	=	Methane captured and destroyed/gainfully used by the project activity in the year *y* (t CO_2e)

In the case of flaring/combustion MD_y will be measured using the conditions of the flaring process:

$$MD_y = BG_{burnt,y} \times w_{CH4,y} \times D_{CH4} \times FE \times GWP_{CH4} \quad \text{Equation (16)}$$

Where:

$BG_{burnt,y}$	=	Biogas[17] flared/combusted in year *y* (m^3)
$w_{CH4,y}$	=	Methane content[13] of the biogas in the year *y* (volume fraction)

[17] Biogas volume and methane content measurements shall be on the same basis (wet or dry).

D_{CH4}	=	Density of methane at the temperature and pressure of the biogas in the year *y* (t/m^3)
FE	=	Flare efficiency in year *y* (fraction). If the biogas is combusted for gainful purposes, e.g. fed to an engine, an efficiency of 100 per cent may be applied

For the cases 2 (a) and (e) the emission reduction achieved by the project activity (ex post) will be the difference between the baseline emissions and the sum of the project emissions and leakage.

$$ER_y = BE_{y,ex\ post} - \left(PE_{y,ex\ post} + LE_{y,ex\ post}\right) \quad \text{Equation (17)}$$

The historical records of electricity and fuel consumption, the COD content of untreated and treated wastewater, and the quantity of sludge produced by the replaced units will be used for the baseline calculation.

In case (a), if the volumetric flow and the characteristic properties (e.g. COD) of the inflow and outflow of the wastewater are equivalent in the project and the baseline scenarios (i.e. the project and baseline systems have the same efficiency for COD removal for wastewater treatment), then the higher energy consumption and sludge generation in the baseline scenario are the only significant differences contributing to emissions reductions in the project case. In this case, the emission reductions can be calculated as the difference between the historical energy consumption of the replaced unit and the recorded energy consumption of the new system, plus the difference in emissions from sludge treatment and/or disposal. Project emissions from fugitive emissions and incomplete flaring ($PE_{fugitive,y}$, $PE_{flaring,y}$) shall also be considered in the calculation of the emission reductions, however the emissions from the wastewater outflow and sludge ($PE_{ww,discharge,y}$, $PE_{s,final,y}$) may be disregarded, if they are equivalent in the baseline and project scenarios.

6. Monitoring methodology

Relevant parameters shall be monitored as indicated in the tables below. The applicable requirements specified in the “General guidelines for SSC CDM Methodologies” (e.g. calibration requirements, sampling requirements) are also an integral part of the monitoring guidelines specified below and therefore shall be referred by the project participants.

6.1. Parameters for monitoring during the crediting period

Data / Parameter table 1.

Data / Parameter:	**$Q_{ww,i,y}$**
Data unit:	m^3/month
Description:	The flow of wastewater
Measurement procedures (if any):	Measurements are undertaken using flow meters
Monitoring frequency:	Monitored continuously (at least hourly measurements are undertaken, if less, confidence/precision level of 90/10 shall be attained)
Any comment:	-

Data / Parameter table 2.

Data / Parameter:	**$COD_{ww,untreated,y}$, $COD_{ww,treated,y}$, $COD_{ww,discharge,PJ,y}$**
Data unit:	t COD/m^3
Description:	The chemical oxygen demand of the wastewater before and after the treatment system affected by the project activity
Measurement procedures (if any):	Measure the COD according to national or international standards. COD is measured through representative sampling
Monitoring frequency:	Samples and measurements shall ensure a 90/10 confidence/precision level
Any comment:	-
Data / Parameter:	-

Data / Parameter table 3.

Data / Parameter:	**$S_{l,PJ,y}$, $S_{final,PJ,y}$**
Data unit:	t
Description:	Amount of dry matter in the sludge
Measurement procedures (if any):	Measure the total quantity of sludge on a wet basis. The volume (m^3) and density or direct weighing may be used to determine the sludge amount (wet basis). Representative samples are taken to determine the moisture content to calculate the total sludge amount on dry basis. If the methane emissions from anaerobic decay of the final sludge are to be neglected because the sludge is controlled combusted, disposed of in a landfill with methane recovery, or used for soil application, then the end-use of the final sludge will be monitored during the crediting period. If the baseline emissions include the anaerobic decay of final sludge generated by the baseline treatment systems in a landfill without methane recovery, the baseline disposal site shall be clearly defined, and verified by the DOE
Monitoring frequency:	Monitoring of 100 per cent of the sludge amount through continuous or batch measurements and moisture content through representative sampling to ensure the 90/10 confidence/precision level
Any comment:	-

Data / Parameter table 4.

Data / Parameter:	**$BG_{burnt,y}$**
Data unit:	m^3
Description:	Biogas volume in year *y*
Measurement procedures (if any):	In all cases, the amount of biogas recovered, fuelled, flared or otherwise utilized (e.g. injected into a natural gas distribution grid or distributed via a dedicated piped network) shall be monitored ex post, using continuous flow meters. If the biogas streams flared and fuelled (or utilized) are monitored separately, the two fractions can be added together to determine the total biogas recovered, without the need to monitor the recovered biogas before the separation. The methane content measurement shall be carried out close to a location in the system where a biogas flow measurement takes place
Monitoring frequency:	Monitored continuously (at least hourly measurements are undertaken, if less, confidence/precision level of 90/10 shall be attained)
Any comment:	-

Data / Parameter table 5.

Data / Parameter:	$\mathbf{w_{CH4,y}}$
Data unit:	%
Description:	Methane content in biogas in the year *y*
Measurement procedures (if any):	The fraction of methane in the gas should be measured with a continuous analyser or, alternatively, with periodical measurements at a 90/10 confidence/precision level. It shall be measured using equipment that can directly measure methane content in the biogas - the estimation of methane content of biogas based on measurement of other constituents of biogas such as CO_2 is not permitted. The methane content measurement shall be carried out close to a location in the system where a biogas flow measurement takes place
Monitoring frequency:	-
Any comment:	-

Data / Parameter table 6.

Data / Parameter:	***T***
Data unit:	^{o}C
Description:	Temperature of the biogas
Measurement procedures (if any):	The temperature of the gas is required to determine the density of the methane combusted. If the biogas flow meter employed measures flow, pressure and temperature and displays or outputs the normalised flow of biogas, then there is no need for separate monitoring of pressure and temperature of the biogas
Monitoring frequency:	Shall be measured at the same time when methane content in biogas ($w_{CH4,y}$) is measured
Any comment:	-

Data / Parameter table 7.

Data / Parameter:	***P***
Data unit:	Pa
Description:	Pressure of the biogas
Measurement procedures (if any):	The pressure of the gas is required to determine the density of the methane combusted. If the biogas flow meter employed measures flow, pressure and temperature and displays or outputs the normalised flow of biogas, then there is no need for separate monitoring of pressure and temperature of the biogas
Monitoring frequency:	Shall be measured at the same time when methane content in biogas ($w_{CH4,y}$) is measured
Any comment:	-

Data / Parameter table 8.

Data / Parameter:	**-**
Data unit:	%
Description:	The flare efficiency
Measurement procedures (if any):	As per the methodological tool “Project emissions from flaring”. Regular maintenance shall be carried out to ensure optimal operation of flares
Monitoring frequency:	-
Any comment:	-

Data / Parameter table 9.

Data / Parameter:	**-**
Data unit:	-
Description:	Parameters related to emissions from electricity and/or fuel consumption in year *y*
Measurement procedures (if any):	As per the procedure in the “Tool to calculate baseline, project and/or leakage emissions from electricity consumption” and/or “Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion”. Alternatively it shall be assumed that all relevant electrical equipment operate at full rated capacity, plus 10 per cent to account for distribution losses, for 8760 hours per annum
Monitoring frequency:	-
Any comment:	-

Data / Parameter table 10.

Data / Parameter:	**-**
Data unit:	t CO_2e
Description:	Parameters related to methane emissions from biomass stored under anaerobic conditions which does not occur in the baseline situation
Measurement procedures (if any):	As per the latest version of the methodological tool “Emissions from solid waste disposal sites”
Monitoring frequency:	-
Any comment:	-

7. Project activity under a programme of activities

The following conditions apply for use of this methodology in a project activity under a programme of activities:

In case the project activity involves the replacement of equipment, and the leakage effect of the use of the replaced equipment in another activity is neglected, because the replaced equipment is scrapped, an independent monitoring of scrapping of replaced equipment needs to be implemented. The monitoring should include a check if the number of project activity equipment distributed by the project and the number of scrapped equipment correspond with each other. For this purpose scrapped equipment should be stored until such correspondence has been checked. The scrapping of replaced equipment should be documented and independently verified.

Appendix. Provisions for upgradation and distribution of biogas

Project boundary

In case of project activities covered under paragraph 4(b) and 4 (c),[1] if the project activity involves bottling of biogas the project boundary includes the upgrade and compression installations, the dedicated piped network/natural gas distribution grid for distribution of biogas from the wastewater treatment plant to the end user sites and all the facilities and devices connected directly to it.

Baseline

In case of project activities covered under paragraph 4(c)(i) the baseline emissions for upgraded biogas injection ($BE_{injection,y}$) are determined as follows:

$$BE_{injection,y} = E_{ug,y} \times CEF_{NG} \quad \text{Equation (1)}$$

Where:

$BE_{injection,y}$	=	Baseline emissions for injection of upgraded biogas into a natural gas distribution grid in year *y* (t CO_2e)
$E_{ug,y}$	=	Energy delivered from the upgraded biogas in the project activity to the natural gas distribution grid in year *y* (TJ)
CEF_{NG}	=	Carbon emission factor of natural gas (t CO_2e/TJ); (Accurate and reliable local or national data may be used where available, otherwise appropriate IPCC default values shall be used)

The energy delivered from the upgraded biogas in the project activity to the natural gas distribution grid in year *y* ($E_{ug,y}$) is calculated as follows:

$$E_{ug,y} = Q_{ug,y} \times NCV_{ug,y} \quad \text{Equation (2)}$$

[1] These are references to the section “Scope, applicability, and entry into force” in the methodology including upgrading of biogas before distribution to the quality of natural gas for use as fuel or for bottling or for injection into a natural gas distribution system. The eligible biogas upgrading technologies covered in this appendix include: (1) Pressure Swing Adsorption; (2) Absorption with/without water circulation; (3) Absorption with water, with or without water recirculation (with or without recovery of methane emissions from discharge). For those technologies, please refer to annex 1 of the approved methodology “AM0053: Biogenic methane injection to a natural gas distribution grid”/Version 04.0 regarding the description of these technologies project proponent may submit a request for revision to include more technology options.

Where:

$Q_{ug,y}$	=	Quantity of upgraded biogas displacing the use of natural gas in the natural gas distribution grid in year *y* (kg or m^3)
$NCV_{ug,y}$	=	Net calorific value of the upgraded biogas in year *y* (TJ/kg or TJ/m^3)

The quantity of upgraded biogas displacing the use of natural gas in the natural gas distribution grid in year *y* is calculated as follows:

$$Q_{ug,y} = \min(Q_{ug,in,y}, Q_{cap,CH4,y})$$ Equation (3)

Where:

$Q_{ug,in,y}$	=	Quantity of upgraded biogas injected into the natural gas distribution grid in year *y* (kg or m^3)
$Q_{cap,CH4,y}$	=	Quantity of methane captured at the wastewater treatment source facility(ies) in year *y* (kg or m^3)

The quantity of methane captured at the waste water treatment source facility(ies) is calculated as follows:

$$Q_{cap,CH4,y} = w_{CH4,ww} \times Q_{cap,biogas,y}$$ Equation (4)

Where:

$w_{CH4,ww}$	=	Methane fraction of biogas as monitored at the outlet of the wastewater treatment source facility(ies) (kg or m^3 CH_4/kg or m^3 of biogas)
$Q_{cap,biogas,y}$	=	Monitored amount of biogas captured at the source facility(ies) in year *y* (kg or m^3)

Project activity emission

In case of project activities covered under paragraph 4(b) and 4(c) the following project emissions related to the upgrading and compression of the biogas ($PE_{process,y}$) shall be included:

CO_2 emissions from electricity and fuel used by the upgrading facilities (t CO_2e);

Methane emissions from the discharge of the upgrading equipment (t CO_2e);

Fugitive methane emissions from leaks in compression equipment (t CO_2e);

Emissions on account of vent gases from upgrading equipment (t CO_2e).

$$PE_{process,y} = PE_{power,upgrade,y} + PE_{ww,upgrade,y} + PE_{CH4,equip,y} + PE_{ventgas,y}$$ Equation (5)

Where:

$PE_{process,y}$	=	Project emissions related to the upgrading and compression of the biogas in year *y* (t CO_2e)
$PE_{power,upgrade,y}$	=	CO_2 emissions from electricity and fuel used by the upgrading facilities (t CO_2e), as per paragraph 19 of AMS-III.H.
$PE_{ww,upgrade,y}$	=	Emissions from methane contained in any waste water discharge of upgrading installation in year *y* (t CO_2e)
$PE_{CH4,equip,y}$	=	Emissions from compressor leaks in year *y* (t CO_2e)
$PE_{ventgas,y}$	=	Emissions from venting gases retained in upgrading equipment in year *y* (t CO_2e)

Project activity emissions from methane contained in waste water discharge of upgrading installation are determined as follows:

$$PE_{ww,upgrade,y} = Q_{ww,upgrade,y} \times \left[CH_4\right]_{ww,upgrade,y} \times GWP_{CH4}$$ Equation (6)

Where:

$Q_{ww,upgrade,y}$	=	Volume of wastewater discharge from upgrading installation in year *y*
$\left[CH_4\right]_{ww,upgrade,y}$	=	Dissolved methane contained in the wastewater discharge in year *y*

Project activity emissions from compressor leaks are determined as follows:

$$PE_{CH4,equip,y} = GWP_{CH4} \times \left(\frac{1}{1000}\right) \times \sum_{equipment} w_{CH4,stream,y} \times EF_{equipment} \times T_{equipment,y}$$ Equation (7)

Where:

$w_{CH4,stream,y}$	=	Average methane weight fraction of the gas (kg-CH_4/kg) in year *y*
$T_{equipment,y}$	=	Operation time of the equipment in hours in year *y* (in absence of detailed information, it can be assumed that the equipment is used continuously, as a conservative approach)
$EF_{equipment}$	=	Leakage rate for fugitive emissions from the compression technology as per specification from the compressor manufacturer in kg/hour/compressor. If no default value from the technology provider is available, the approach below shall be used

Fugitive methane emissions occurring during the recovery and processing of gas may in some projects be small, but should be estimated as a conservative approach. Emission factors may be taken from the 1995 Protocol for Equipment Leak Emission Estimates, published by EPA.[2]

Emissions should be determined for all relevant activities and all equipment used for the upgrading of biogas (such as valves, pump seals, connectors, flanges, open-ended lines, etc.).

The following data needs to be obtained:

The number of each type of component in a unit (valve, connector, etc.);

The methane concentration of the stream;

The time period each component is in service.

The EPA approach is based on average emission factors for Total Organic Compounds (TOC) in a stream and has been revised to estimate methane emissions. Methane emissions are calculated for each single piece of equipment by multiplying the methane concentration with the appropriate emission factor from the table below.

Table. Methane emission factors for equipment[3]

Equipment type	Emission factor (kg/hour/source) for methane
Valves	4.5E-0.3
Pump seals	2.4E-0.3
Others[4]	8.8E-0.3
Connectors	2.0E-0.4
Flangs	3.9E-0.4
Open ended lines	2.0E-0.3

Project activity emissions from venting gases retained in upgrading equipment do not have to be considered if vent gases ($PE_{vent\ gas,y}$) are channeled to storage bags. In case vent gases are flared, emissions due to the incomplete or inefficient combustion of the gases will be calculated using the methodological tool “Project emissions from flaring”, as follows:

$$PE_{ventgas,y} = \sum_{h=1}^{8760} TM_{RG,h} \times (1-\eta_{flare,h}) \times \frac{GWP_{CH4}}{1000} \qquad \text{Equation (8)}$$

[2] Please refer to the document US EPA-453/R-95-017 at: <http://www.epa.gov/ttn/chief/efdocs/equiplks.pdf>, accessed on 23/10/2007.

[3] Please refer to the document US EPA-453/R-95-017 Table 2.4, page 2-15, accessed on 23/10/2007.

[4] The emission factor for “other” equipment type was derived from compressors, diaphragms, drains, dump arms, hatches, instruments, meters, pressure relief valves, polished rods, relief valves and vents. This “other” equipment type should be applied for any equipment type other than connectors, flanges, open-ended lines, pumps or valves.

Where:

$TM_{RG,h}$	=	Mass flow rate of methane in the residual gas in hour *h* (kg/h)
$\eta_{flare,h}$	=	Flare efficiency in hour *h*

In case vent gases are not flared the methodological tool “Project emissions from flaring” will be used, without considering measurements and calculations for the flare efficiency, which will be assumed to be zero. In this case, emissions due to the vent gases will be:

$$PE_{y,ventgas} = \sum_{h=1}^{8760} TM_{RG,h} * \frac{GWP_{CH4}}{1000} \quad \text{Equation (9)}$$

Alternatively, in case vent gases are directly vented to the atmosphere, it may also be calculated by conservatively calculating the mass of the gases vented based on the volume, pressure and temperature of gas retained in upgrading equipment. This mass should be multiplied with the frequency with which it is vented and assuming that the vented gas is pure methane.

In order to account for emissions that occur when the upgrade facility is shut down due to maintenance, repair work or emergencies one of the alternatives proposed above should be used to calculate and include emissions from flaring or venting.

In case of project activities covered under paragraph 4(c)(ii) emissions due to physical leakage of upgraded biogas from the dedicated piped network ($PE_{leakage,pipeline,y}$) shall be determined as follows:

$$PE_{leakage,pipeline,y} = Q_{methane,pipeline,y} \times LR_{pipeline} \times GWP_{CH4} \quad \text{Equation (10)}$$

Where:

$PE_{leakage,pipeline,y}$	=	Emissions due to physical leakage from the dedicated piped network in year *y* (t CO_2e)
$Q_{methane,pipeline,y}$	=	Total quantity of methane transported in the dedicated piped network in year *y* (m^3)
$LR_{pipeline}$	=	Physical leakage rate from the dedicated piped network (if no project-specific values can be identified a conservative default value of 0.0125 Gg per 10^6 m^3 of utility sales shall be applied[5])

[5] 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, chapter 4, Table 4.2.5 provides default values for fugitive emissions from gas operations in developing countries. The default values provided for fugitive emissions for the distribution of natural gas to end users range from 1.1 E-3 to 2.5 E-3 Gg per 10^6 m^3 of utility sales. The uncertainty in this value is -20 per cent to 500 per cent. A conservative value of 2.5 E-3 * 500% = 0.0125 Gg per 10^6 m^3 of utility sales shall be taken.

Leakage emissions

In case of project activities covered under paragraph 4(b) and the users of the bottles filled with upgraded biogas are not included in the project boundary then the following leakage emissions shall be included and calculated as follows:

Emissions due to physical leakage of biogas from the bottles during storage, transport etc. until final end use (t CO_2e);

Emissions due to fossil fuel use for transportation of bottles; biogas filled bottles to the end users and the return of empty bottles to the filling site (t CO_2e).

$$LE_{bottling,y} = LE_{leakage,bb,y} + LE_{trans,y} \qquad \text{Equation (11)}$$

Where:

$LE_{bottling,y}$	=	Leakage emissions project activities involving bottling of biogas in year *y* (t CO_2e)
$LE_{leakage,bb,y}$	=	Emissions due to physical leakage from biogas bottles in year *y* (t CO_2e)
$LE_{trans,y}$	=	Emissions due to fossil fuel use for transportation of bottles; biogas filled bottles to the end users and the return of empty bottles to the filling site in year *y* (t CO_2e)

Leakage emissions due to physical leakage from biogas bottles are determined as follows:

$$LE_{leakage,bb,y} = Q_{methane,bb,y} \times LR_{bb} \times GWP_{CH4} \qquad \text{Equation (12)}$$

Where:

$Q_{methane,bb,y}$	=	Total quantity of methane bottled in year *y* (m^3)
LR_{bb}	=	Physical leakage rate from biogas bottles (if no project-specific values can be identified a default value of 1.25 per cent shall be applied)[6]

Leakage emissions due to fossil fuel use for transportation of bottles (biogas filled bottles to the end users and the return of empty bottles to the filling site) are determined as below. If some of the locations of the end-users are unknown a conservative approach assuming transport emissions of 250 km, shall be used.

[6] Victor (1989) Leaking Methane from Natural Gas Vehicles: Implication for Transportation Policy in the Greenhouse Era, in Climatic Change 20: 113-141, 1992 and American Gas Association (1986), 'Lost and Unaccounted for Gas', Planning and Analysis issues, issue brief 1986-28, p. 3.

$$PE_{trans,y} = \left(\frac{Q_{bb,y}}{CT_{bb,y}} \right) \times DAF_{bb} \times EF_{CO2}$$ Equation (13)

Where:

$Q_{bb,y}$	=	Total freight volume of upgraded biogas in bottles transported in year *y* (m^3)
$CT_{bb,y}$	=	Average truck freight volume capacity for the transportation of bottles with upgraded biogas (m^3/truck)
DAF_{bb}	=	Aggregated average distance for bottle transportation; biogas filled bottles to the end users and the return of empty bottles to the filling site (km/truck)
EF_{CO2}	=	CO_2 emission factor from fuel use due to transportation (t CO_2/km)

Monitoring methodology

The project proponents shall maintain a biogas (or methane) balance based on:

Continuous measurement of the amount of biogas captured at the wastewater treatment system;

Continuous measurement of the amount of biogas used for various purposes in the project activity: e.g. heat, electricity, flare, hydrogen production, injection into natural gas distribution grid, etc. The difference is considered as loss due to physical leakage and deducted from the emission reductions.

In case of project activities covered under paragraph 4(c) the quantity of biogas, temperature, pressure and concentration of methane in the biogas injected into the natural gas grid/distributed via the dedicated piped network shall be measured continuously using certified equipment. The net calorific value (NCV) shall be measured directly from the gas stream using an online Heating Value Meter or calculated based on the measured methane content using the NCV of methane. This measurement must be in mass or volume basis and the project participants shall ensure that units of the measurements of the amount of biogas injected and of the net calorific value are consistent. The methane content of the injected or transported biogas shall always be in accordance with national regulations or, in absence of national regulations, 96 per cent (by volume) or higher. Biogas injected or transported with inferior methane content shall be excluded from the emission reduction calculations.

In case of project activities covered under paragraph 4(b) and 4(c), the following parameters shall be monitored and recorded:

The volume of discharge into the desorption pond from the upgrading installation ($Q_{ww,upgrade,y}$), monitored continuously;

The methane content ($[CH_4]_{ww,upgrade,y}$) of the discharge water from the upgrade facility, samples are taken at least every six months during normal operation of the facility;

The annual operation time of the compressor and each piece of equipment in the biogas upgrading and compression installations in hours ($T_{equipment,y}$). In case this information is not available it shall be assumed that the upgrading installation and compressor is used continuously;

The quantity, pressure and composition of the bottled biogas, biogas injected into a natural grid or transported via a dedicated piped network; monitored continuously using flow meters and regularly calibrated methane monitors. The pressure of the biogas shall be regulated and monitored using a regularly calibrated pressure gauge. The methane content of the biogas shall always be in accordance with national regulations or, in absence of national regulations, 96 per cent (by volume) or higher in order to ensure that biogas could readily be used as a fuel, inferior methane content shall be excluded from the emission reduction calculations;

In case vent gases are calculated using the methodological tool “Project emissions from flaring”, the monitoring criteria contained in this tool shall be used. In case this tool is not used and the alternative approach in paragraph 13 of this appendix is used, then temperature and pressure of gas retained in upgrading equipment shall be measured continuously and their values before the venting process are used, together with the volume capacity of the installation, to estimate the amount of methane released during the venting process;

During the periods when the biogas upgrading facility is closed due to scheduled maintenance or repair of equipment or during exigencies, project participants should ensure that the captured biogas is flared at the site of its capture using an (emergency) flare. Appropriate monitoring procedures should be established to monitor this emergency flare;

In case of project activities covered under paragraph 4(b) the number and volume of biogas bottles produced and transported, the average truck capacity ($CT_{bb,y}$) and the average aggregated distance for transporting the bottled biogas (DAF_{bb}).

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Document information

Version	*Date*	*Description*
18.0	16 October 2015	EB 86, Annex 16 Revision to include non-binding best practice examples.
17.0	28 November 2014	EB 81, Annex 34 Revision to standardize the requirements on additionality in the methodology in line with other waste sector methodology such as AMS-III.D. It includes provisions for automatic additionality.
16.0	26 November 2010	EB 58, Annex 22 To include additional guidelines pertaining to transport of biogas (e.g. by trucks) and biogas application for transportation; To clarify the conditions under which the measurement campaign can be used for baseline emissions determination.
15.0	30 July 2010	EB 55 Annex 34 To clarify the criteria to be satisfied for the baseline lagoon treatments systems under the methodology; To include the monitoring table with the required frequency of

Version	*Date*	*Description*
		measurements and options for collection and recording of data.
14.0	26 March 2010	EB 53, Annex 17 To include additional clarification on the monitoring requirements of biogas.
13.0	17 July 2009	EB 48, Annex 21 To include additional eligible technologies for upgrading biogas for bottling or feeding to natural gas distribution grid. Include an option to use the calculated net calorific value (NCV) of biogas based on methane content measurement instead of directly monitoring NCV using a NCV meter.
12.0	28 May 2009	EB 47, Annex 26 To include additional guidance on use of methane generation potential based on Biochemical Oxygen Demand ($BOD_{5,20}$).
11.0	25 March 2009	EB 46, Annex 22 To clarify the methods for determination of baseline for Greenfield projects; To specify minimum requirements concerning sludge removal interval in the baseline anaerobic lagoon; Further guidance on measuring equipment for biogas pressure, temperature and flow rate.
10.0	26 September 2008	EB 42, Annex 17 Additional guidance on baseline determination and project emission calculations; Restructured, provisions related to methane correction factor and related uncertainties were revised.
09.0	14 March 2008	EB 38, Annex 10 Expand applicability to include pipeline transport of the recovered and upgraded biogas; Additional guidance on sequential treatment of wastewater in anaerobic lagoons.
08.0	30 November 2007	EB 36, Annex 24 Expand applicability to bottling of recovered biogas; Additional guidance on emissions from dissolved methane in the treated wastewater; Guidance on use of IPCC default factors for the degradable organic content of sludge.
07.0	19 October 2007	EB 35, Annex 29 Expand the applicability to allow recovered biogas to be used for hydrogen production.
06.0	27 July 2007	EB 33, Annex 35 Additional leakage guidance to allow for application under a programme of activities (PoA).
05.0	04 May 2007	EB 31, Annex 27 To exclude scope 15 from the methodology

Version	*Date*	*Description*
04.0	15 December 2006	EB 28, Annex 26 Broaden the applicability to include sequential stage of anaerobic wastewater treatment; Additional guidance based on 2006 IPCC Guidelines for National Greenhouse Gas Inventories on the following: (a) Methane correction factor (*MCF*) determined by wastewater discharge pathways or type of treatment; (b) Default values for sludge treatment, particularly for degradable organic carbon (DOC) and methane correction factor (*MCF*).
03.0	21 July 2006	EB 25, Annex 28 Clarify the inclusion of methane emission factor in the equation for baseline calculations.
02.0	10 May 2006	EB 24, paragraph 64 of the report The Board at its twenty-fourth meeting noted that Type III project activities might be able to achieve significant emission reductions, without exceeding the direct emissions limits i.e. 15 kilo tonnes CO_2e applicable at the time. As an interim solution, the Board agreed to include the following text in all Type III categories: “This category is applicable for project activities resulting in annual emission reductions lower than 25,000 tonnes CO_2e. If the emission reduction of a project activity exceeds the reference value of 25,000 tonnes CO_2e in any year of the crediting period, the annual emission reduction for that particular year is capped at 25,000 tonnes CO_2e.”
01.0	24 February 2006	EB 23, Annex 23 Initial adoption.

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Business Function: Methodology
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AMS-III.E

Small-scale Methodology

Avoidance of methane production from decay of biomass through controlled combustion, gasification or mechanical/thermal treatment

Version 17.0

Sectoral scope(s): 13

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1. Introduction

The following table describes the key elements of the methodology:

Table 3. Methodology key elements

Typical projects	Decay of the wastes that would have been let to decay or are already deposited in a waste disposal site is prevented through controlled combustion; or gasification to produce syngas/producer gas; or mechanical/thermal treatment to produce refuse-derived fuel (RDF) or stabilized biomass (SB).
Type of GHG emissions mitigation action	Greenhouse gas (GHG) emission avoidance. Avoidance of methane emissions due to prevention of anaerobic decay of biomass in waste. Use of biomass in waste as energy source.

2. Scope, applicability, and entry into force

2.1. Scope

2. This project category comprises measures that avoid the production of methane from biomass or other organic matter that:

(a) Would have otherwise been left to decay under clearly anaerobic conditions throughout the crediting period in a solid waste disposal site without methane recovery, or

(b) Is already deposited in a waste disposal site without methane recovery.

3. Due to the project activity, decay of the wastes of type referred to in paragraph 1(a) and/or 1(b) above is prevented through one of the following measures:

(a) Controlled combustion;

(b) Gasification to produce syngas/producer gas;

(a) Mechanical/thermal treatment to produce refuse-derived fuel (RDF) or stabilized biomass (SB).[1] An example of a mechanical/thermal treatment process is the pelletization of wood particles.[2]

4. The produced RDF/SB shall be used for combustion either on site or off-site.

5. In the case of stockpiles of wastes baseline emission calculations as described in the methodological tool "Emissions from solid waste disposal sites" shall be adjusted. Stockpiles can be characterised as waste disposal sites that consist of wastes of a homogenous nature with similar origin (e.g. rice husk, empty fruit bunches of oil palm, sawmill waste, etc.). Paragraph 22 provides specific instructions for the calculation of baseline emissions where the baseline is stockpiling of the waste.

6. Measures are limited to those that result in emission reductions of less than or equal to 60 kt CO_2 equivalent annually.

7. Where in the baseline usually there is a reduction in the amount of waste through regular open burning or removal for other applications, the use of the methodological tool "Emissions from solid waste disposal sites" shall be adjusted to take account of this burning or removal in order to estimate correctly the baseline emission.

2.2. Applicability

8. The project activity does not recover or combust methane unlike AMS-III.G. Nevertheless, the location and characteristics of the disposal site in the baseline condition shall be known, in such a way as to allow the estimation of its methane emissions.

9. If the project activity involves combustion, gasification or mechanical/thermal treatment of partially decayed waste mined (i.e. removed) from a solid waste disposal site in addition to freshly generated waste the project participants shall demonstrate that there is adequate capacity of the combustion, gasification or mechanical/thermal treatment facility to treat the newly generated wastes in addition to the partially decayed wastes removed from the disposal site. Alternately justifications for combusting, gasifying or mechanically/thermally treating the partially decayed wastes instead of the newly generated wastes shall be provided.

10. If the combustion facility, the produced syngas, producer gas or RDF/SB is used for heat and electricity generation within the project boundary, that component of the project activity may use a corresponding methodology under Type I project activities.

11. In case of RDF/SB production, project proponents shall provide evidence that no GHG emissions occur, other than biogenic CO_2, due to chemical reactions during the thermal

[1] The thermal treatment process (dehydration) shall occur under controlled conditions (up to 300 Celsius) and shall generate a stabilized biomass that would be used as fuel or raw material in other industrial processes. Stabilized biomass (SB) is defined as biomass adequately treated to prevent further degradation in the environment. Examples of SB are: pellets, briquettes and torrefied wood chips.

[2] Pelletization is defined as the compression of wood particles into modules of solid fuel. The process includes thermal and mechanical pre-treatment of the raw material (e.g. saw dust). Pellets have moisture content of maximal 12 per cent.

treatment process for example limiting the temperature of thermal treatment to prevent the occurrence of pyrolysis and/or the stack gas analysis.[3]

12. In case of gasification, the process shall ensure that all the syngas produced, which may contain non-CO_2 GHG, will be combusted and not released unburned to the atmosphere. Measures to avoid physical leakage of the syngas between the gasification and combustion sites shall also be adopted.

13. In case of RDF/SB processing, the produced RDF/SB should not be stored in such a manner as resulting in high moisture and low aeration favouring anaerobic decay. Project participants shall provide documentation showing that further handling and storage of the produced RDF/SB does not result in anaerobic conditions and do not lead to further absorption of moisture.

14. In case of RDF/SB processing, local regulations do not constrain the establishment of RDF/SB production plants/thermal treatment plants nor the use of RDF/SB as fuel or raw material.

15. During the mechanical/thermal treatment to produce RDF/SB no chemical or other additives shall be used.

16. In case residual waste from controlled combustion, gasification or mechanical/thermal is stored under anaerobic conditions and/or delivered to a landfill emissions from the residual waste shall to be taken into account using the first order decay model (FOD) described in AMS-III.G.

2.3. Entry into force

17. The date of entry into force is the date of the publication of the EB 81 meeting report on 28 November 2014.

3. Normative references

18. Project participants must take into account the “General guidelines for SSC clean development mechanism methodologies”, “Guidelines on the demonstration of additionality of small-scale project activities” at <http://cdm.unfccc.int/Reference/Guidclarif/index.html#meth> mutatis mutandis.

19. This methodology also refers to the latest approved versions of the following approved methodologies and tool:

    (a) “AMS-III.G.: Landfill methane recovery”;

    (b) “AMS-III.H.: Methane recovery in wastewater treatment”;

    (c) “Emissions from solid waste disposal sites;

    (d) “Project and leakage emissions from transportation of freight”.

[3] See also footnote 1.

4. Definitions

20. The definitions contained in the Glossary of CDM terms shall apply.

5. Baseline methodology

5.1. Project boundary

21. The project boundary are the physical, geographical sites:

(a) Where the solid waste would have been disposed or is already deposited and the avoided methane emission occurs in absence of the proposed project activity;

(b) Where the treatment of biomass through controlled combustion, gasification or mechanical/thermal treatment takes place;

(c) Where the final residues of the combustion process will be deposited (this parcel is only relevant to controlled combustion activities);

(d) And in the itineraries between them, where the transportation of wastes and combustion residues and/or residues of gasification and mechanical/thermal treatment process occurs.

5.2. Project emissions

22. Project emissions consist of:

(a) CO_2 emissions related to the gasification and combustion of the non-biomass carbon content of the waste (plastics, rubber and fossil derived carbon) or RDF/SB and auxiliary fossil fuels used in the combustion, gasification or mechanical/thermal treatment facility;

(b) Incremental CO_2 emissions due to:

(i) Incremental distances between the collection points to the project site as compared to the baseline disposal site;

(ii) Transportation of combustion residues and final waste from controlled burning to disposal site;

(iii) Transportation of RDF/SB from the mechanical/thermal treatment facility to the storage site within the project boundary;

(iv) Transportation of RDF/SB to the sites of the end users (if some of the sites are unknown a conservative approach assuming transport emissions for a specific distance, for example a default of 250 km, shall be used);

(c) CO_2 emissions related to the fossil fuel and/or electricity consumed by the project activity facilities, including the equipment for air pollution control required by regulations. In case the project activity consumes grid-based electricity, the grid emission factor (t CO_2e/MWh) should be used, or it should be assumed that diesel generators would have provided a similar amount of electricity, calculated as described in category I.D.

$$PE_y = PE_{y,comb} + PE_{y,transp} + PE_{y,power}$$ Equation (18)

Where:

PE_y	=	Project activity direct emissions in the year *y* (t CO_2e)
$PE_{y,comb}$	=	Emissions through combustion and gasification of non-biomass carbon of waste and RDF/SB in the year *y* (t CO_2e)
$PE_{y,transp}$	=	Emissions through incremental transportation in the year *y* (t CO_2e)
$PE_{y,power}$	=	Emissions through electricity or diesel consumption in the year *y* (t CO_2e)

23. The expected annual quantity (tonnes) and composition of the waste combusted, gasified or mechanically/thermally treated by the project activity during the crediting period shall be described in the project design document, including the biomass and non-biomass carbon content of the combusted or gasified waste and RDF/SB ($Q_{biomass}$ and $Q_{non\text{-}biomass}$).

24. The expected consumption of auxiliary fuel for the incineration, gasification, mechanical/thermal treatment process (Q_{fuel}) should also be reported in the project design document. CO_2 emissions from the combustion of the non-biomass (i.e. fossil) carbon content of the wastes and RDF/SB and from the auxiliary fossil fuel consumed will be estimated assuming the complete oxidation of carbon to CO_2 in the combustion.

$$PE_{y,comb} = Q_{y,non-biomass} \times 44/12 + Q_{y,fuel} \times EF_{y,fuel}$$ Equation (19)

Where:

$Q_{y,non-biomass}$	=	Non-biomass carbon of the waste and RDF/SB combusted/gasified in the year *y* (tonnes of carbon)
$Q_{y,fuel}$	=	Quantity of auxiliary fossil fuel used in the year *y* (tonnes)
$EF_{y,fuel}$	=	CO_2 emission factor for the combustion of the auxiliary fossil fuel (tonnes CO_2 per tonne fuel, according to latest IPCC Guidelines)

25. Project emissions from trucks for incremental collection activities will be estimated following the methodological tool "Project and leakage emissions from transportation of freight".

26. Project proponents shall monitor the RDF fate and consumption through e.g. purchase by/delivery to final users.

27. If the project activity includes wastewater release, which are treated anaerobically or released untreated, methane emission shall be considered as project emissions and estimated using the provisions of AMS-III.H.

5.3. Baseline scenario and baseline emissions

28. The baseline scenario is the situation where, in the absence of the project activity, organic waste matter is left to decay within the project boundary and methane is emitted to the atmosphere. The yearly baseline emissions are the amount of methane that would have been emitted from the decay of the cumulative quantity of the waste diverted or removed from the disposal site, to date, by the project activity, calculated as the methane generation potential using the "Tool to determine methane emissions avoided from disposal of waste at a solid waste disposal site".

29. In the case of stockpiles of waste the baseline emission calculations as described in the methodological tool "Emissions from solid waste disposal sites" shall be adjusted. It is recognised that biomass waste disposal practices and the final fate of the disposed waste in stockpiles is highly region and waste specific, therefore the quantity of waste taken as input for the calculations and MCF and *k* values shall be chosen conservatively.

30. For projects utilising MSW, when calculating $BE_{CH4,SWDS,y}$, a MCF of 0.8 may be used[4] to account for the existence of a suppressed demand situation as described in the "Guidelines on the consideration of suppressed demand in CDM methodologies" when all of the following conditions apply:

    (a) It can be demonstrated that waste is being dumped in an uncontrolled manner in human settlement areas under the current practice due to a lack of organized waste collection and disposal system;

    (b) It can be demonstrated that only the municipal solid waste is being treated under the project activity and wastes from other sources such as agricultural or agro-industrial wastes are not being treated under the project activity;

    (c) It can be demonstrated that entire portion of the waste treated under the project activity would comply with the above two conditions.

31. In determining the amount of waste prevented from disposal in the solid waste disposal site (SWDS) ($W_{j,x}$) as input in equation 1 in the tool, the percentage of the biomass that is combusted in the project activity and which would have been dumped in a stockpile in the baseline situation and also would have remained in the stockpile for a sufficient period of time to decay shall be determined. A quantitative analysis shall be carried out using the following options (in the order of priorities):

    (a) Project specific waste disposal data from at least three years prior to the implementation of the project activity;

    (b) A control group;

[4] Deep landfill (>5m) is most likely the technology for disposing MSW in the scenario of constrained availability of area/space within or close to urban areas and where waste scavenging does not occur. And it is also the least cost alternative for providing comparable level of service to the project technology for treating the waste i.e. composting in this case. MCF value is chosen from the definition provided in 2006 IPCC Guideline applicable to unmanaged deep landfills that do not have controlled placement of waste (i.e. waste directed to specific deposition areas, a degree of control of scavenging and a degree of control of fires) and do not include any cover material, mechanical compacting and levelling of the waste.

(c) Official data sources.

32. The following factors shall be taken into account in this analysis:

(a) Parts of the biomass may be taken from the stockpile for various reasons. Examples are that the biomass: (a) may be used as a fuel; (b) incinerated to use the ashes as fertilizer; (c) directly applied to land as fertilizer (mulching); (d) composted; (e) or used as a raw material (e.g. panel board production). The various uses shall be analysed and quantified to show what percentage of biomass would have remained in the stockpile;

(b) There may be restrictions for leaving the biomass in a stockpile indefinitely. Examples are restrictions concerning land surface used for stockpiling or height of the stockpile.

33. These two factors shall be quantified and $W_{j,x}$, shall be adjusted accordingly, as the model in the tool assumes that the waste would have remained at the disposal site for sufficient time to fully decay.

34. Due to the high uncertainty in the estimation of methane emissions from stockpiles, conservative assumptions shall be made for the MCF and *k* values given in the tool. As piles have a large surface area to volume ratio anaerobic conditions are not ensured like in the case of SWDS. In addition the homogenous nature of the waste in stockpiles result in a different decay rate compared to normal SWDS that contain mixed wastes. For the purpose of this methodology, project participants shall use an MCF value of 0.36[5] This is the MCF value for an unmanaged shallow SWDS multiplied by 0.89 discount factor, corresponding to 30 per cent uncertainty, as specified in CMP decision 21/CP.7. The *k* value for the relevant waste type must be the lower value from the range provided for the Boreal and Temperate Climate Zone as listed in Table 3.3 in Chapter 3, volume 5 of 2006 IPCC Guidelines for National Greenhouse Gas Inventories.

35. In the case of project activities combusting, gasifying or mechanically/thermally treating only freshly generated wastes, the baseline emissions at any year *y* during the crediting period is calculated using the amount and composition of wastes combusted, gasified or mechanically/thermally treated since the beginning of the project activity (year “x=1”) up to the year *y*, using the first order decay model as referred to in the “Tool to determine methane emissions avoided from disposal of waste at a solid waste disposal site”. Baseline emissions shall exclude methane emissions that would have to be removed to comply with national or local safety requirement or legal regulations.

$$BE_y = BE_{CH4,SWDS,y} \quad \text{Equation (20)}$$

Where:

BE_y	=	Baseline emissions at year *y* during crediting period (t CO_2e)

[5] Project proponents are encouraged to submit procedures to accurately assess the values for *k* and MCF in the case of stockpiles as a revision to this methodology for EB approval.

$BE_{CH4,SWDS,y}$	=	Yearly Methane Generation Potential of the wastes diverted to be disposed in the landfill from the beginning of the project (x=1) up to the year *y*, calculated according to the "Tool to determine methane emissions avoided from disposal of waste at a solid waste disposal site" (t CO_2e)

36. In the case of project activities that combust, gasify or mechanically/thermally treat wastes that have partially decayed in a disposal site, the calculation of the yearly methane generation potential of the wastes combusted, gasified or mechanically/thermally treated from the project beginning (x=1) up to the year *y* will consider the age of the wastes at the start of the project. One of the following options may be used:

(a) Estimate the mean age of the wastes contained in the disposal site in the beginning of the project activity ("ā"). It may be estimated as the weighted average age considering the yearly amount of wastes deposited in the SWDS since its beginning of operation up to the year prior to the start of the project:

Equation (21)

$$\bar{a} = \frac{1 \cdot A_1 + 2 \cdot A_2 + 3 \cdot A_3 + ... + a \cdot A_a}{A_1 + A_2 + A_3 + ... + A_a} = \frac{\sum_{a=1}^{a\max} A_a \cdot a}{\sum_{a=1}^{a\max} A_a}$$

Where:

$\bar{a}$	=	Weighted mean age of the wastes present in the SWDS prior to the project start
a	=	Years before project start, starting in the first year of waste disposal (*a*=1) up to the maximal age of the wastes contained in the SWDS at the project start (*a*=amax)
A_a	=	Total amount of waste deposited in the SWDS in each year *a*. It shall be obtained from recorded data of waste disposals, or estimated according to the level of the activity that generated the wastes (for example, considering the amount of wood processed by a sawmill in each year *a*, and estimating the amount of wastes generated and disposed in the SWDS in that year). If the yearly amount of waste deposited in the SWDS cannot be estimated, then an arithmetic mean age may be used (ā = 0.5 x amax). By using this option, the baseline emissions at any year *y* during the crediting period are calculated using the same equation as provided in the last paragraph, nevertheless, the exponential term for the First Order Decay Model "exp [-k_j.(y-x)]" will be corrected for the mean age, and will be substituted by "exp[-k_j.(y-x+ā)]"

(b) Calculate the yearly methane generation potential of the SWDS as described in the methodological tool "Emissions from solid waste disposal sites", considering the total amount and composition of wastes deposited since its start of operation.

The methane generation potential of the wastes removed to be combusted, gasified or mechanically/thermally treated up to the year *y* in the crediting period will be estimated as proportional to the mass fraction of these wastes, relative to the initial amount:

Equation (22)

$$BE_y = \frac{\sum_{x=1}^{y} A_x}{A} BE_{CH4,SWDS,y}$$

Where:

A_x	=	Amount of wastes removed to be combusted, gasified or mechanically/thermally treated in the year *x* (tonnes)
A	=	Total amount of wastes present in the SWDS at the beginning of the project activity (tonnes)
$BE_{CH4,SWDS,y}$	=	Yearly methane generation potential of the SWDS at the year *y*, considering all the wastes deposited in it since its beginning of operation, and without considering any removal of wastes by the project activity

(c) Estimate the quantity and the age distribution of the wastes removed each year *x* during the crediting period,[6] and calculate the methane generation potential of these wastes in the year *y*. For example, in the year x=2 of the project activity, the amount A_2 was removed to be combusted, gasified or mechanically/thermally treated, and this amount can be divided into $A_{2,n}$ parts, each part belonging to the age *n*. In the year *y* the methane generation potential of the portions removed from the SWDS may be estimated as:

[6] Age distribution is the discrete partitioning of the waste by age (i.e. the number of years since it was generated and deposited at the site). The estimation of the age of the portions of waste being removed from the disposal site and combusted, gasified or mechanically/thermally treated each year may be done by topographical modelling of the wastes present in the relevant sections of the disposal site. This approach should include segregation of the wastes into even-age layers or volumetric blocks based on historical or constructive data (design of the disposal site). This information on quantity, composition, and age may be based on (a) historical records of the yearly mass and composition of waste deposited in the section of the disposal site where waste is being removed for combustion, gasification or mechanical/thermal treatment; or (b) historical production data for cases in which the waste at the site is dominated by relatively homogeneous industrial waste materials (e.g. waste by-products from sawmills or finished wood product manufacturing). Option (b) that uses historical industrial production data should apply the following steps. Step1: Estimate the total mass of waste at the disposal site in the section where it is to be removed based on the section's volume and the average density of the waste. Step 2: Apportion the mass of waste in this section into waste types and ages using historical records on the output of products produced in a given year from the industrial facility and factors for the average mass of waste by-products produced per unit of each product.

$$BE_y = \sum_{n=nmin}^{nmax} BE_{CH4,SWDS,yn}$$ Equation (23)

Where:

$BE_{CH4,SWDS,yn}$	=	Yearly methane generation potential of the wastes removed since the beginning of the project activity “x=1” up to the year *y* during the crediting period, segregated according to its age “n” at the time of removal (t CO_2e). It is calculated using the tool referred to in AMS-III.G., substituting the exponential term for the First Order Decay Model “exp [-k_j.(y-x)]” by “exp[-k_j.(y-x+n)]”

5.4. Leakage

37. In case of RDF/SB production, project proponents shall demonstrate that the produced RDF/SB is not subject to anaerobic conditions before its combustion end-use resulting in methane emissions. If the produced RDF/SB is not used in captive facilities but sold to consumers outside the project boundary as a fuel, a default 5 per cent of the baseline emissions shall be deducted as leakage to account for these potential methane emissions, unless project proponents can prove otherwise (e.g. by demonstrating that potential risks of methane emissions from RDF/SB are avoided through measures such as appropriate packaging, by showing that monitored moisture content of the RDF/SB is under 12 per cent or by the use of standards that ensure that characteristics of the RDF/SB during the entire lifecycle of the product is not conducive for methane production).

6. Monitoring

38. The emission reduction achieved by the project activity will be measured as the difference between the baseline emission and the sum of the project emission and leakage.

$$ER_y = BE_y - \left(PE_y + Leakage_y\right)$$ Equation (24)

Where:

ER_y	=	Emission reduction in the year *y* (t CO_2e)

39. The amount of waste combusted, gasified or mechanically/thermally treated by the project activity in each year (Q_y) shall be measured and recorded, as well as its composition through representative sampling, to provide information for estimating the baseline emissions. The quantity of auxiliary fuel used ($Q_{,fuel}$) and the non-biomass carbon content of the waste or RDF/SB combusted ($Q_{,non\text{-}biomass}$) shall be measured, the latter by sampling. The total quantity of combustion and gasification residues and residues from mechanical/thermal treatment ($Q_{y,ash}$) and the average truck capacity (CT_y) shall be measured. The electricity consumption and/or generation shall be measured.

The distance for transporting the waste in the baseline and the project scenario and the distance for transporting the produced RDF/SB (km/truck) shall also be recorded.[7]

40. In the case of project activities processing newly generated biomass wastes, the project participants shall demonstrate annually, through the assessment of common practices at proximate waste disposal sites, what percentage of the amount of waste combusted, gasified or mechanically/thermally treated in the project activity facilities would have been disposed in a solid waste disposal site without methane recovery in the absence of the project activity and would decay anaerobically in the disposal site throughout the crediting period.

7. Project activity under a programme of activities

41. The methodology is applicable to a programme of activities. No additional leakage estimations are necessary other than that indicated under the leakage section above.

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Document information*

Version	*Date*	*Description*
17.0	28 November 2014	EB 81, Annex 33 Revision to: • introduces supressed demand scenario based on the approach provided under the methodology such as “ACM0014: Treatment of wastewater” and AMS-III.F. • takes into the account the past clarifications issued by the SSC WG, and • streamlines the uncertainty factor used with uncertainty factors/procedures in other methodologies.
16.0	17 July 2009	EB 48, Annex 19 To include additional guidelines for monitoring of project activities involving production and sale of refuse derived fuel (RDF) from biomass solid waste.
15.1	14 December 2007	EB 36, Annex 25 Minor editorial corrections.
15.0	14 December 2007	EB 36, Annex 25 To clarify the applicable MCF (methane correction factor) and *k* (decay rate of the waste) values to use for biomass stockpiles in the

[7] In cases where the RDF/SB is sold in the open market, the project emissions due to auxiliary fuel consumption and transportation of final residues of combustion ($Q_{y,ash}$) may be neglected. The sold RDF/SB is not eligible for a Type I (renewable energy) project component under the same project activity since it is not in the project boundary. The sale invoices of RDF/SB shall be maintained at the project site.

Version	*Date*	*Description*
		baseline emissions calculation.
14.0	02 November 2007	EB 35, Annex 32 To broaden the applicability of the approved methodology by including thermal/mechanical treatment of biomass waste to produce refuse-derived fuel (RDF) or stabilized biomass (SB) such as pellets or briquettes.
13.0	27 July 2007	EB 33, Annex 33 Revision of the approved small-scale methodology AMS-III.E to allow for its application under a programme of activities (PoA).
12.0	04 May 2007	EB 31, Annex 26 To exclude AMS-III.E from scope 15, and to clarify that that DOE functions (validation, verification etc.) of project activities applying earlier versions can only be performed by DOEs accredited to all of the sectoral scopes to which the earlier versions of these methodologies respectively belong to.
11.0	23 February 2007	EB 29, Annex 8 Changes include: (a) Applicability of the methodology is expanded to include partially degraded waste with three options being provided to calculate methane emissions avoided i.e. (i) Based on the weighted average age of the waste; or (ii) Based on the yearly methane generation potential of the disposal site and the relative amount of waste removed from it for combustion; or (iii) Based on the profile of the disposal site and historic waste disposal data. (b) To clarify that the methodology is applicable only in cases where it can be demonstrated that organic matter combusted by the project activity would have remained disposed under clearly anaerobic conditions throughout the crediting period in the absence of the project activity.
10.0	23 December 2006	EB 28, Meeting report, Para. 42 To remove the direct emissions limits i.e. 15ktCO_2e/y as well as the interim applicability condition i.e. 25ktCO_2e/y.
09.0	12 May 2006	EB 24, Meeting report, Para. 64 Introduced the interim applicability condition i.e. 25ktCO_2e/y limit for all Type III categories.
08.0	03 March 2006	EB 23, Annex 28 To include detailed guidance on the direct project emissions.

Decision Class: Regulatory
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Keywords: avoidance of methane emission, solid waste, simplified methodologies, type (iii) projects

* This document, together with the 'General Guidance' and all other approved SSC methodologies, was part of a single document entitled: Appendix B of the Simplified Modalities and Procedures for Small-Scale CDM project activities until version 07.

History of the document: Appendix B of the Simplified Modalities and Procedures for Small-Scale CDM project activities

Appendix B of the Simplified Modalities and Procedures for Small-Scale CDM project activities contained both the General Guidance and Approved Methodologies until version 07. After version 07 the document was divided into separate documents: 'General Guidance' and separate approved small-scale methodologies (AMS).

Version	*Date*	*Description*
07.0	25 November 2005	EB 22, Para. 59 References to "non-renewable biomass" in Appendix B deleted.
06.0	20 September 2005	EB 21, Annex 22 Guidance on consideration of non-renewable biomass in Type I methodologies, thermal equivalence of Type II GWhe limits included.
05.0	25 February 2005	EB 18, Annex 6 Guidance on 'capacity addition' and 'cofiring' in Type I methodologies and monitoring of methane in AMS-III.D included.
04.0	22 October 2004	EB 16, Annex 2 AMS-II.F was adopted; leakage due to equipment transfer was included in all Type I and Type II methodologies.
03.0	30 June 2004	EB 14, Annex 2 New methodology AMS-III.E was adopted.
02.0	28 November 2003	EB 12, Annex 2 Definition of build margin included in AMS-I.D, minor revisions to AMS-I.A, AMS-III.D, AMS-II.E.
01.0	21 January 2003	EB 7, Annex 6 Initial adoption. The Board at its seventh meeting noted the adoption by the Conference of the Parties (COP), by its decision 21/CP.8, of simplified modalities and procedures for small-scale CDM project activities (SSC M&P).

Decision Class: Regulatory
Document Type: Standard
Business Function: Methodology

AMS-III.AQ

Small-scale Methodology

Introduction of Bio-CNG in transportation applications

Version 02.0

Sectoral scope(s): 07

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1. Introduction

1. The following table describes the key elements of the methodology:

Table 4. Methodology key elements

Typical project(s)	Production of Biogenic Compressed Natural gas (Bio-CNG) from biomass and use in transportation applications. The Bio-CNG is derived from various sources such as biomass from dedicated plantations; waste water treatment; manure management; biomass residues etc.
Type of GHG emissions mitigation action	Renewable energy. Displacement of more-GHG-intensive fossil fuel used in vehicles

2. Scope, applicability, and entry into force

2.1. Scope

This methodology comprises activities for production of Biogenic Compressed Natural Gas (Bio-CNG) from biomass including biomass residues and cultivated biomass to be used in transportation applications. Biomass cultivated for production of the Bio-CNG should be sourced from dedicated plantations.

The project activity involves installation and operation of Bio-CNG plant that includes:

Anaerobic digester(s) to produce and recover biogas;

Biogas treatment system that includes processing, purification and compression of the biogas to obtain up-graded biogas such that methane content, its quality and the physical and chemical properties are equivalent to the CNG;

Filling stations, storage and transportation.

This methodology covers the use of Bio-CNG in various types of transportation applications such as Compressed Natural Gas (CNG) vehicles, modified vehicles. Examples include buses, trucks, three-wheeler, cars, jeeps, etc.

If the part of the recovered biogas is injected into a natural gas distribution grid, emission reduction for that component of the project activity can be claimed following the provisions in annex 1 of “AMS-III.H: Methane recovery in wastewater treatment”.

2.2. Applicability

This methodology is applicable if the methane content of the upgraded biogas is in accordance with relevant national regulations and in their absence a minimum of 96 per cent (by volume).

If the project activity utilizes biomass sourced from dedicated plantations, the applicability conditions prescribed in the methodological tool “project emissions from cultivation of biomass” shall apply.

The retailers, final users (where applicable) and the producer of the Bio-CNG are bound by a contract that states that the final consumers and retailers shall not claim emission reductions resulting from its consumption. Only the producer of the Bio-CNG can claim emission reductions under this methodology.

The export of Bio-CNG produced under this methodology is not allowed.

The digested residue waste leaving the reactor shall be handled aerobically and submitted to soil application, the proper procedures and conditions not resulting in the methane emissions shall be ensured; otherwise the emissions shall be taken into account as per relevant procedures of “AMS-III.AO: Methane recovery through controlled anaerobic digestion”.

Measures are limited to those that result in emission reduction of less than or equal to 60 kt CO_2 equivalent annually. Where applicable the sum of the emission reductions from all Type III components of a project activity should comply with 60 kt CO_2 equivalent annually.

2.3. Entry into force

The date of entry into force is the date of the publication of the EB 79 meeting report on 1 June 2014.

3. Normative references

Project participants shall take into account the “General guidelines for SSC CDM methodologies”, “Guidelines on the demonstration of additionality of small-scale project activities” provided at: <http://cdm.unfccc.int/methodologies/SSCmethodologies/approved.html> mutatis mutandis.

This methodology also refers to the latest approved versions of the following approved methodologies, guidelines[31] and tools:

"General guidance on leakage in biomass project activities";

"AMS-III.H: Methane recovery in wastewater treatment";

"AMS-III.AK: Biodiesel production and use for transport applications";

"AMS-III.AO: Methane recovery through controlled anaerobic digestion";

"Tool to calculate baseline, project and/or leakage emissions from electricity consumption";

"Project emissions from cultivation of biomass";

"Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion"

"Upstream leakage emissions associated with fossil fuel use".

4. Definitions

The definitions contained in the Glossary of CDM terms shall apply.

5. Baseline methodology

5.1. Project boundary

The spatial extent of the project boundary encompasses:

The Bio-CNG plant;

Where applicable, transportation of biomass from the point of their origin to Bio-CNG plant;

Where applicable, transportation Bio-CNG from biogas plant to filling stations where it is used by final consumers;

The land at which the cultivation of biomass used for the production of Bio-CNG and/or the area/region from where the waste organic matters for the production of Bio-CNG is sourced;

In cases where project participants carry out modification of gasoline vehicles to enable the use of Bio-CNG, the vehicles shall be included in the boundary.

5.2. Baseline emissions

Baseline emissions are calculated by using one of the two available approaches. Under approach 1 baseline emissions are calculated based on the amount of Bio-CNG produced and distributed, and it is applicable to project activities those are:

Use of Bio-CNG in modified diesel vehicles;[32] and/or

[31] Please refer to: <https://cdm.unfccc.int/Reference/index.html>.

Use of Bio-CNG in modified gasoline vehicles when such vehicles are not included in the boundary.

Under approach 2 baseline emissions are calculated based on the quantity of Bio-CNG filled into converted gasoline vehicles and it is applicable to the project activities that are the production and use of Bio-CNG in modified gasoline vehicles when such vehicles are included in the boundary and are monitored. Approach 2 is not applicable to the modified diesel vehicles.

5.2.1. Approach 1:

It is conservatively assumed that all Bio-CNG produced will displace CNG from fossil origin and the baseline emissions are calculated as follows:

$$BE_y = FS_{Bio-CNG,y} \times NCV_{Bio-CNG} \times EF_{Co2,CNG} \tag{Equation (25)}$$

Where:

BE_y	=	Total baseline emission in year *y* (t CO_2e)
$FS_{Bio-CNG,y}$	=	Amount of Bio-CNG distributed/sold directly to retailers, filling stations by the project activity in year *y* (tonnes)
$EF_{Co2,CNG}$	=	CO_2 emission factor of CNG (tCO_2e/GJ), determined using reliable local or national data. IPCC default values (lower value of 95 per cent confidence interval (CI)) shall be used only when country or project specific data are not available or demonstrably difficult to obtain. Values shall be updated if national values or IPCC values changes
$NCV_{Bio-CNG}$	=	Net calorific value of Bio-CNG (GJ/tonne). If it is demonstrated that the methane content of the Bio-CNG is minimum 96 per cent by volume then NCV of CNG shall be used. For NCV of CNG, reliable local or national data shall the used. IPCC default values shall be used only when country or project specific data are not available or demonstrably difficult to obtain. Values shall be updated if national values or IPCC values change

Under the condition of:

$$FS_{Bio-CNG,y} \leq FP_{Bio-CNG,y} \tag{Equation (26)}$$

Where:

$FP_{Bio-CNG,y}$	=	Quantity of the Bio-CNG produced by the project activity in the year *y* (tonnes)

[32] In contrast to the conversion of gasoline (Otto cycle) vehicles to use natural gas or CNG as a fuel, the technologies for conversion of diesel engines will result in a variable efficiency drop (or variable specific fuel consumption) depending on the operational conditions (load and speed). Therefore, the efficiency drop varies according to the transportation service provided by the vehicles during their use. Approach 1 assumes that the diesel vehicles have been converted to run on natural gas, which is then considered being the baseline fuel.

5.2.2. Approach 2:

In cases where the project activity also undertakes the conversion of gasoline vehicles including those vehicles in the project boundary, the baseline emission calculations are calculated as per equations 3 and 4 below.

$$FC_{gasoline,k,y} = FC_{Bio-CNG,k,y} \times \frac{NCV_{Bio-CNG}}{NCV_i} \times n \times f_{FO,gasoline}$$ Equation (27)

Where:

$FC_{gasoline,k,y}$	=	Amount of gasoline of fossil origin which would have been consumed in the baseline by vehicle *k* in the year *y* (tonnes)
$FC_{Bio-CNG,k,y}$	=	Bio-CNG consumed by the project vehicle *k* in the year *y* (tonnes)
$NCV_{Bio-CNG}$	=	Net calorific value of Bio-CNG (GJ/tonne). The net calorific value of the Bio-CNG shall be determined based on direct measurement of a representative sample
NCV_i	=	Net calorific value of gasoline (GJ/tonne) that was used by project vehicle *k*. In case the gasoline is blended with biofuels the NCV of the blended gasoline shall be used. For *NCVi* reliable local or national data shall be used. IPCC default values (lower value of 95 per cent CI) shall be used only when country or project specific data are not available or demonstrably difficult to obtain. Values shall be updated if national values or IPCC values changes
n	=	Discount factor to account for the possible drop in the fuel efficiency of the retrofitted Bio-CNG vehicles. A default value of 0.95 shall be used for converted vehicles that previously used gasoline
$f_{FO,gasoline}$	=	Fraction of gasoline of fossil fuel origin. 1.0 if pure gasoline has been displaced. In cases where national regulations require mandatory blending of the fuels with biofuels then the fraction of gasoline (on mass basis) in the blend should be applied

Total baseline emissions for approach 2 are calculated on an annual basis as below:

$$BE_y = \sum_k FC_{gasoline,k,y} \times NCV_{gasoline} \times EF_{CO2,gasoline}$$ Equation (28)

Where:

BE_y	=	Total baseline emission in year *y* (t CO_2e)
$NCV_{gasoline}$	=	Net calorific value of gasoline (GJ/tonne), determined using reliable local or national data. IPCC default values (lower value of 95 per cent CI) shall be used only when country or project specific data are not available or demonstrably difficult to obtain. Values shall be updated if national values or IPCC values change
$EF_{CO2,gasoline}$	=	CO_2 emission factor of gasoline (t CO_2e/GJ)

Under the condition of:

$$\sum FC_{Bio-CNG,k,y} \leq FP_{Bio-CNG,y} \qquad \text{Equation (29)}$$

Where:

$FC_{Bio-CNG,k,y}$	=	Total consumed Bio-CNG by all project vehicles in year *y* (tonnes)

In the cases where project proponents apply both approach 1 and 2, project proponents shall describe in the PDD how the double counting of emission reductions has been avoided.

5.3. Project emissions

The project emissions should be calculated as follows:

$$PE_y = PE_{elec,y} + PE_{fuel,y} + PE_{transport,y} + PE_{cultivation,y} + PE_{CH4,y} \qquad \text{Equation (30)}$$

Where:

PE_y	=	Project emissions in year *y* (t CO_2e)
$PE_{elec,y}$	=	Project emissions due to electricity consumption in year *y* (t CO_2)
$PE_{fuel,y}$	=	Project emissions due to fossil fuels consumption in year *y* (t CO_2)
$PE_{transport,y}$	=	Project emissions from transportation of the biomass from the places of their origin to the biogas production site and where applicable, transportation Bio-CNG from biogas plant to filling stations where it is used by final consumers in year *y* (t CO_2)
$PE_{cultivation,y}$	=	Project emissions from biomass cultivation in a dedicated plantation in year *y* (t CO_2e)
$PE_{CH4,y}$	=	Project emissions due to the physical leakage of methane from the systems affected by the project activity for production, processing, purification, compression; storage and filling of the Bio-CNG in year *y* (t CO_2e)

5.3.1. Calculation of $PE_{elec,y}$

The emissions include electricity consumption (including auxiliary use) $PE_{elec,y}$ associated with the operation of Bio-CNG plant, calculated as per the parameter $PE_{EC,y}$ in the "Tool to calculate baseline, project and/or leakage emissions from electricity consumption".

5.3.2. Calculation of $PE_{fuel,y}$

The emissions include fossil fuel consumption (including auxiliary use) $PE_{fuel,y}$ associated with the operation of Bio-CNG plant, calculated as per the parameter $PE_{FC,j,y}$ in the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion", where each combustion processes *j* in the tool should correspond to one of the fossil fuel consumption sources of the plant.

In cases where it is demonstrated that the energy requirements of the biogas production and treatment system and Bio-CNG plant are met only by renewable energy source the values of $PE_{elec,y}$ and $PE_{fuel,y}$ are considered as zero.

5.3.3. Calculation of $PE_{transport,y}$

Project emissions from transportation of the biomass and/or waste organic matters from the places of their origin to the biogas production site and where applicable, transportation Bio-CNG from biogas plant to filling stations where it is used by final consumers have to be accounted following the procedures in “AMS-III.AK: Biodiesel production and use for transport applications” if the transportation distance is more than 200 km, otherwise they can be neglected.

5.3.4. Calculation of $PE_{cultivation,y}$

If the project activity utilizes biomass sourced from dedicated plantations, project emissions from biomass cultivation shall be calculated as per the methodological tool “Project emissions from cultivation of biomass”.

5.3.5. Calculation of $PE_{CH4,y}$

Project emissions associated with the physical leakage of methane from the systems affected by the project activity are calculated as follows:

$$PE_{CH4,y} = PE_{AD,y} + PE_{Bio-CNG,y} \quad \text{Equation (31)}$$

Where:

$PE_{AD,y}$	=	CH_4 leakage emissions from the anaerobic digesters in year *y* (t CO_2e)
$PE_{Bio-CNG,y}$	=	Project emissions of CH_4 from biogas and Bio-CNG processing, upgrading, purification, compression, storage and transportation (leaks and dissolved in wastewater) in year *y* (t CO_2e)

5.3.6. Methane emissions from physical leakage emissions from the anaerobic digesters ($PE_{AD,y}$)

Methane emissions due to physical leakages from the digester and recovery system ($PE_{AD,y}$) shall be estimated using a default factor of 0.05 m³ biogas leaked/m³ biogas produced. For ex ante estimation the expected biogas production of the digester may be used, for ex post calculations the effectively recovered biogas amount shall be used for the calculation.

5.3.7. Methane emissions from physical leakage due to the biogas treatment system ($PE_{Bio-CNG,y}$)

The following project emission sources shall be determined as per the relevant procedures in annex 1 of “AMS-III.H: Methane recovery in wastewater treatment”:

Methane emissions from the discharge of the upgrading equipment are determined;

Fugitive methane emissions from leaks in compression equipment;

Methane emissions due to the vent gases from upgrade equipment;

Methane emissions related to physical leakage from filling operations shall be computed as per the procedures for calculating emissions from compressor leaks as per paragraph 32 b) above;

Where applicable methane emissions associated with the physical leakage of the upgraded biogas from the dedicated pipelines;

Where applicable methane emissions due to physical leakage from Bio-CNG/biogas filled bottles (e.g. mobile cascades) which are used for the storage and transportation of Bio-CNG/biogas.

The digested residue waste leaving the reactor shall be treated aerobically, and disposed in land properly, such as to avoid methane emissions. If disposed under anaerobic conditions (e.g. landfill) the methane emissions shall be estimated and discounted as project emissions following the relevant provisions in “AMS-III.AO: Methane recovery through controlled anaerobic digestion”.

5.4. Leakage

Leakage emissions $LE_{BIOMASS,y}$ due to competing use of biomass shall be accounted for as per the approved “General guidance on leakage in biomass project.

The substitution of Bio-CNG for CNG from fossil origin reduces indirect (“upstream”) emissions associated with the production of fossil CNG and is treated as negative leakage $LE_{PROCESS,y,CNG}$ that can be calculated as per the latest approved version of the tool “Upstream leakage emissions associated with fossil fuel use”.

The substitution of Bio-CNG for gasoline reduces indirect (“upstream”) emissions associated with the production of gasoline and is treated as negative leakage $LE_{PROCESS,y,GAS}$ (leakage emissions related to production and refining of the gasoline) that can be calculated using the latest approved version of the tool “Upstream leakage emissions associated with fossil fuel use”.

Negative leakage emissions related to the avoided production of fossil fuel (CNG, gasoline) (t CO_2/yr) shall be calculated as per the equation below:

$$LE_{PROCESS,y,FF} = LE_{PROCESS,y,CNG} + LE_{PROCESS,y,GAS}$$ Equation (32)

Where:

$LE_{PROCESS,y,FF}$	=	Leakage related to the avoided production of fossil fuel (t CO_2/yr)

5.5. Emission reductions

The emission reductions achieved by the project activity shall be calculated as the difference between the baseline emissions and the sum of the project emissions and leakage.

$$ER_y = BE_y - PE_y - LE_{BIOMASS,y} + LE_{PROCESS,y,FF}$$ Equation (33)

Where:

ER_y	=	Emission reductions in the year *y* (t CO_2e)

6. Monitoring methodology

Relevant parameters shall be monitored as indicated in the Tables below.

Parameters for determining project emissions from biomass cultivation shall be monitored as per relevant provisions of "AMS-III.T: Plant oil production and use for transport applications".

Parameters for calculating methane emissions from physical leakage of methane from the systems affected by the project activity for production, processing, purification, compression; storage and filling of the Bio-CNG shall be monitored as per the procedures prescribed in AMS-III.H.

Parameters for establishing methane emissions from residue waste disposed under anaerobic conditions shall be monitored as per relevant procedures of AMS-III.AO.

The applicable requirements specified in the "General guidelines for SSC CDM methodologies" (e.g. calibration requirements, sampling requirements) are also an integral part of the monitoring guidelines.

Evidence shall be provided to demonstrate that the modification of gasoline vehicles has been implemented.

In the case of approach 2, the filling stations must be equipped with the following devices/systems:[33]

Automatic Number Plate Recognition (ANPR); or Electronic Vehicle Identification (EVI);

Automatic locking and unlocking function of dispenser directly controlled by equipped device/system responsible for project vehicle identification to ensure that all the Bio-CNG that is produced is only consumed in the project vehicles;

System for logging of the data on quantity of Bio-CNG filled into identified project vehicles;

Natural gas analyzer capable of analysing ethane and propane to ensure that the gas delivered to the vehicle by the dispenser does not contain ethane or/and propane.

6.1. Parameters to be monitored

Data / Parameter table 11.

Data / Parameter:	$FC_{Bio\text{-}CNG,k,y}$
Data unit:	t
Description:	Bio-CNG consumed by the project vehicle *k* in the year *y*
Measurement procedures (if any):	Measurements of the amount of Bio-CNG filled into vehicles of the end users are undertaken using calibrated meters at the filling station site. Measurements results shall be cross-checked with production and sales data
Monitoring frequency:	Continuously

[33] The PPs are encouraged to propose a revision of the methodology for allowing/including other alternative procedures.

Any comment:	-

Data / Parameter table 12.

Data / Parameter:	**$FS_{Bio\text{-}CNG,y}$**
Data unit:	t
Description:	Amount of Bio-CNG distributed/sold directly to retailers, filling stations by the project activity in year *y*
Measurement procedures (if any):	Measurements of the amount of Bio-CNG distributed/sold to retailers/filling stations are undertaken using calibrated meters at the delivery section of Bio-CNG production site. Measurements results shall be cross checked with records for sold amount (e.g. invoices/receipts) and with the amount of biogas produced
Monitoring frequency:	Continuously or in batches
Any comment:	-

Data / Parameter table 13.

Data / Parameter:	**$FP_{Bio\text{-}CNG,y}$**
Data unit:	t
Description:	Quantity of the Bio-CNG produced by the project activity in the year *y*
Measurement procedures (if any):	Measurements are undertaken using calibrated meters at the outlet of the biogas upgrading section of the Bio-CNG production site
Monitoring frequency:	Continuously
Any comment:	-

Data / Parameter table 14.

Data / Parameter:	**$NCV_{Bio\text{-}CNG}$**
Data unit:	GJ/t
Description:	Net calorific value of Bio-CNG
Measurement procedures (if any):	Measured according to relevant national/international standards through sampling. Analysis has to be carried out by accredited laboratory
Monitoring frequency:	Monthly or as prescribed by the applied national/international standard
Any comment:	-

Data / Parameter table 15.

Data / Parameter:	**NCV_i**
Data unit:	GJ/t
Description:	Net calorific value of gasoline/blended gasoline that was used by project vehicle *k*
Measurement procedures (if any):	Measured according to relevant national/international standards. Analysis has to be carried out by accredited laboratory
Monitoring frequency:	At the validation, and annually during the crediting period
Any comment:	-

Data / Parameter table 16.

Data / Parameter:	**$w_{CH4,y}$**
Data unit:	%
Description:	Methane content in the Bio-CNG

Measurement procedures (if any):	The fraction of methane in the gas should be measured with a continuous analyzer or, alternatively, with periodical measurements at a 90/10 sampling confidence/precision level. It shall be measured using equipment that can directly measure methane content in the biogas - the estimation of methane content of biogas based on measurement of other constituents of biogas such as CO_2 is not permitted. The methane content measurement shall be carried out at the location where $FP_{Bio\text{-}CNG,y}$ is measured
Monitoring frequency:	Continuous/periodic
Any comment:	-

Data / Parameter table 17.

Data / Parameter:	$\mathbf{f_{FO,gasoline}}$
Data unit:	%
Description:	Fraction of gasoline from fossil fuel origin in the displaced gasoline
Measurement procedures (if any):	As per the following options (in preferential order): (i) Data from the supplier of the gasoline; (ii) If it accrues to national regulations requiring mandatory blending of biofuels, the regulatory blend fraction may be used; (iii) If measured, it shall be according to relevant national/international standards through sampling
Monitoring frequency:	Continuously or in batches
Any comment:	-

6.2. Project activity under a programme of activities

The methodology is applicable to a programme of activities.

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Document information

Version	*Date*	*Description*
02.0	1 June 2014	EB 79, Annex 17 Revision to: (a) Expand the applicability of the methodology to: (i) Use of Bio-CNG in modified diesel vehicles; (ii) Injection of biogas into natural gas grid; (b) Include a reference to the methodological tool "Project emissions from cultivation of biomass".
01.0	26 November 2010	EB 58, Annex 18 Initial adoption.

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