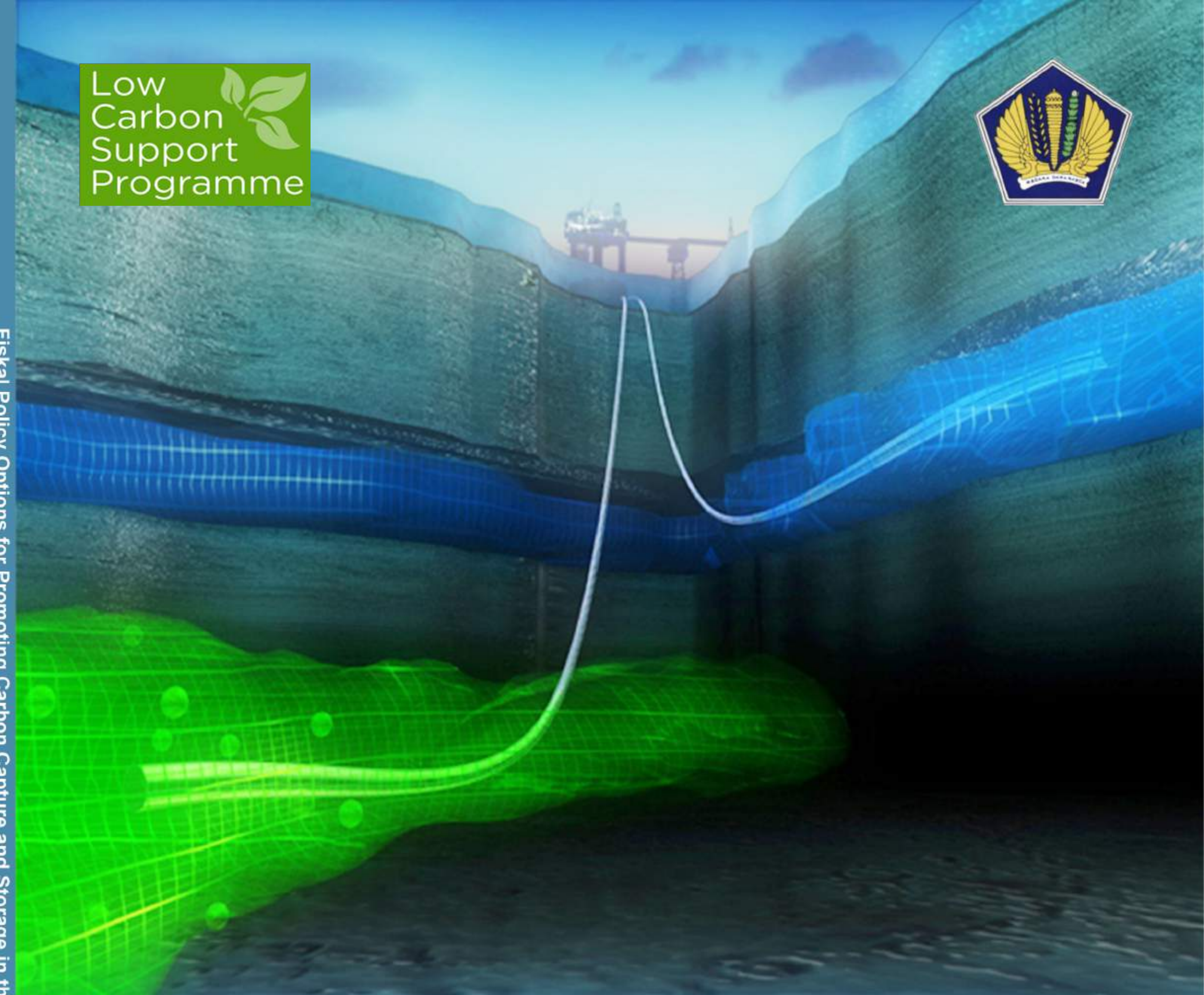

Fiscal Policy Options for Promoting Carbon Capture and Storage in the Oil and Gas Industries in Indonesia

Final Discussion Paper

March, 2015

Low Carbon Support Programme to Ministry of Finance, Indonesia

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Disclaimers

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LIST OF ABBREVIATIONS

ASME	American Society of Mechanical Engineers
API	American Petroleum Institute
BAPPENAS	Badan Perencanaan Pembangunan Nasional (National Development Planning Agency)
BAU	Business as Usual
BKF	Badan Kebijakan Fiskal (Fiscal Policy Agency)
CBM	Coal Bed Methane
CCS	Carbon Capture and Storage
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
CTF	Clean Technology Fund
DFID	UK Department for International Development
DNPI	Dewan Nasional Perubahan Iklim (National Council on Climate Change)
ECBM	Enhanced Coal Bed Methane
EE	Energy Efficiency
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
FE	Fossil Energy
GHG	Greenhouse Gas
GOI	Government of Indonesia
GWP	Global Warning Potential
HFC	Hydro-Fluoro Carbon
HSE	Health, Safety and Environment
IPA	Indonesian Petroleum Association
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
LCS	UK Low Carbon Support
LNG	Liquid Natural Gas
LPG	Liquid Petroleum Gas
MAG Welding	Metal Active Gas Welding
MIG Welding	Metal Inert Gas Welding
MOF	Ministry of Finance
Mt	Metric ton
MVA	Monitoring, Verification and Accounting
NAMA	Nationally Appropriate Mitigation Action
NOAA	U.S. National Oceanic and Atmospheric Administration
OPML	Oxford Policy Management Limited
PIP	Pusat Investasi Pemerintah (Government Investment Agency)
PKPPIM	Centre for Climate Change Financing and Multilateral Policy (MOF)
UNFCC	United Nations Framework Convention on Climate Change

CONTENTS

LIST OF TABLES

LIST OF FIGURES

EXECUTIVE SUMMARY

The GOI has committed to a unilateral objective to reduce Green House Gas (GHG) emissions to 26 percent by the year 2020 on its own efforts and to a proposed goal of 41 percent reduction by 2020 with international support. Of the 26% GHG emission reduction, 6% comes from the energy sector. GHG emissions contributed by the energy sector depend on the energy mix the trend of which has been targeted by the National Energy Policy under Government Regulation No. 79, Year 2014.

#	Energy Type	2010	YEAR 2025
			NEW N.E.P.*)
1	Liquid fuel oil	43.9%	25%
2	Natural Gas	21.0%	22%
3	Coal	30.7%	30%
4	New & Renewable Energy	4.4%	23%
	Total (MBOE)	113.1	3,200
	Energy Conservation		37.5%

The contribution of GHG emissions from the oil and gas sector is estimated to grow from 122 Mt CO2 in 2005 to 137 Mt CO2 in 2030, mainly on account of additional refining capacity to come on line. Other CO2 emission sources in the oil and gas sector are from upstream facilities, which includes gas flaring, associated production with natural gas, gas processing facilities, and various combustion equipment used in the upstream exploration and production activities.

The Carbon Capture and Storage (CCS) technology or carbon capture and sequestration has been identified as the most effective way to prevent CO2 emission into the atmosphere, especially in the oil and gas sector. The captured CO2 can be indefinitely stored into the oil and gas field acquivers some 1,000 meters down below ground level and can be utilized for Enhanced Oil Recovery (EOR) through miscible or immiscible processes.

There are three aspects of CCS undertaken:

- Capture — The separation of CO_2 from other gases produced at large industrial process facilities such as coal and natural gas power plants, oil and gas plants, steel mills and cement plants;

- Transport — Once separated, the CO_2 is compressed and transported via pipelines, trucks, ships or other methods to a suitable site for geological storage; and

- Storage — CO_2 is injected into deep underground rock formations, often at depths of one kilometer or more. There is a large proven usage of CO2 for EOR and ECBM but not in Indonesia.

The United Kingdom Department of International Development (UK DFID) has contracted Oxford Policy Management Ltd (OPML) which in turn appointed PT Pranata Energi Nusantara (PEN Consulting) to carry out a study on CCS Fiscal Policy under the supervision of the Centre for Climate Change Financing and Multilateral Policy (PKPPIM) of Indonesia Ministry of Finance (MOF) and the UK Low Carbon Support (LCS). The purpose and objectives of the study as contained in this discussion paper are:

(i) to assess the advantages (pros) and disadvantages (cons) of utilizing CCS technology in the oil and gas industry in Indonesia as a means to mitigate GHG emission from the energy industry;

(ii) to review existing fiscal regulations that have an impact on the implementation of CCS investments in the oil and gas industry; and

(iii) to propose appropriate new fiscal policy initiatives or reforms to the Ministry of Finance of the Republic of Indonesia to support the implementation of CCS to reduce GHG emissions from the oil industry over the medium term.

A "forced field analysis" was conducted to evaluate the "forces" supporting CCS application (the pros) and the forces opposing CCS (the cons) in Indonesia. Tabulated below is the result of the forced field analysis.

Forces Supporting CCS	Forces Against CCS
• Significantly reduce CO_2 emission by 80-90% compared to a plant without CCS; • International supports for financing CCS projects and obtaining carbon credits are available; • Availability of deep seas in Indonesia for CO2 ocean storage; • May have potential usage for future enhancement of Coal Bed Methane production; and • May have economic usage to supply industries using CO2.	• Increased costs of energy produced in a coal fired plant with CCS (by 21-91%); • Increased fuel needs and other system costs in a coal fired plant by 25-40%; • CCS technology is very expensive and largely unproven; • No large CO_2 utilization for EOR in Indonesia due to poor miscibility of CO_2 with Indonesian crude and incompatibility with relatively shallow reservoirs *); • No other significant CO_2 utilization market in Indonesia industry at this time; • Ocean storage of CO_2 may increase ocean acidification; • Need geological study to identify deep geological formations suitable for CO_2 storage *); • High seismic activities in Indonesia may not warrant safe CO_2 storage in deep geological formations due to leakage; • Indonesia has significant potential of renewable energy resources and energy efficiency improvement which could be developed faster and less expensive than CCS to address the urgency of GHG reduction; and • No regulation limiting and providing stimulus to mitigate CO2 emissions, and for promoting economic benefits of reducing GHG emissions.

Although the forces opposing CCS application in Indonesia at this time are much stronger than the forces in favor of CCS, it is recommended that further studies continue to be carried out, in the oil and gas industry, in the following areas:

(i) Assess sites for safe storage of CO2 in geological formations in the vicinity of large CO2 emitting facilities;

(ii) Conduct a feasibility study to reduce CO2 emissions in a selected refinery (to begin with) through improvement in the combustion efficiency (boiler, furnace, power plant) or installing carbon capture and storage, sequestration, and/or utilization facilities;

(iii) Conduct a "carbon audit" to identify potential GHG emitters/producers in the upstream and downstream oil and gas industry, and the corresponding order of magnitude for reducing GHG emissions through CCS, combustion efficiency improvement; and/or substituting fossil fuels with renewable energy; and

(iv) Advocate policies and regulations to promote GHG emission abatement through establishing appropriate GHG emission standards proportional with industry and population density in certain areas. Also introduce reward and penalty mechanisms for compliance or non-compliance with the established GHG emission standards, and provide stimulus for combustion efficiency improvements and the use of renewable energy to meet energy demand. There should also be established standards on plant efficiency using fossil fuels.

In advocating policies and regulations for mitigating carbon dioxide (CO2) emissions, questions arise as to whether CO2 emission is a pollutant or a resource. CO2 is a waste gas produced by any fuel combustion.

It is well known that the burning of fossil fuel, since the Industrial Revolution began in the 1800's, has risen the CO2 contaminant in the atmospehere from 275 ppm (0.0275%) to 375 ppm (0.0375%) and added to the observed rise in global temperature by 0.6 ^{0}C. Additionally, the tremendous CO2 emissions resulting from burning fossil fuels winds up in the oceans. The ocean has absorbed more than 48% of CO2 emissions caused by the burning of fossil fuels since the 1800's era; acidizing the ocean by an observed increase of 0.1 pH. In large and uncontrolled quantity, CO2 can be detrimental to mankind. It is a pollutant.

On the other hand, CO2 can be a valuable resource for plant life and human life. Large quantities of CO2 can be used for EOR and ECBM. Limited quantities of CO2 are used in the food and beverage industry, air conditioning, welding, fire extinguishers, and the chemical manufacturing indutry.

In view of increasing concern on the green-house gas emissions impact to climate change, Indonesia should establish a regulatory regime providing CO2 emission standards limiting levels for all stationary and mobile combustion and CO2 producing equipment which takes into consideration geographical sites and prevailing technology relevant to combustion efficiency. Beyond the standard CO2 limit or plant efficiency, appropriate penalties should be affected; however, below the standard CO2 emission or higher plant efficiency a reward should be due. This standard could be used to develop carbon trading at the national or international levels. It could also be used as reference to embark on carbon reduction initiatives and carbon economics.

LEMIGAS has conducted a detailed study of CCS potential throughout Indonesia's oil and gas producing provinces and has identified South Sumatera, East Kalimantan and Tarakan as having suitable oil and gas depleted reservoirs as potential storage of captured carbon in safe aquifer deeper than 1,000 meters. LEMIGAS recommends South Sumatera province be selected as the initial pilot site for CCS due to availability of large CO2 producing facilities in close proximity with CO2 storage capacity in oil and gas depleted reservoirs.

LEMIGAS further recommends a pilot CCS pilot project, using Merbau Gas Processing Plant as the source of captured CO2, a locally available pipeline to transport CO2 gas and several nearby fields as CO2 storage or CO2 EOR. If successful this pilot project could be expanded into a demonstration stage and full scale CCS and CO2 EOR projects.

Project economic calculations have been run for the pilot project, assuming 1 Mton CO2 captured from the Merbau GGS. The levelized cost for a natural gas processing facility capturing CO2 without EOR is US$ 28/t CO2 captured and storage. This levelized cost is composed of compressor plus dryer of $ 11/t CO2 captured, pipeline of $11.t CO2 captured and injection wells of $ 6/t CO2 captured. With EOR the levelized cost drops to $ 22/t CO2 since the storage cost will be borne by the operator. The credit price translates into an oil price of US$ 70/barrel at $ 0.32/t CO2/bbl). The capital cost for the carbon capture facilities and pipeline is estimated at USD 200 million, with annual operating cost of USD 12 million.

Source of funding for the pilot CCS from the Merbau GGS shall be from the Government and financial institutions which include assistance from bilateral and multilateral institutions related climate change projects, export credit agencies, and sovereign wealth-funds. For the use of CO2 EOR, the incremental capital and operating expenditures could be borne by the oil field operator under cost recovery scheme of the PSC.

The Indonesian Climate Change Trust Fund (ICCTF) was established in 2009 under Bappenas to facilitate access to financing from international sources for climate change-related adaptation and mitigation expenditures. The ICCTF also supports investments for communities exposed to severe pollution environments and plans to invest in revenue generating activities. ICCT and / or PKPPIM in MOF could be instrumental in the coordination of international financing for this important pilot project.

For the implementation of the MERBAU GGS CCS project, we recommend to assign the work to PT Perusahaan Gas Negara Tbk (PGN) to manage the construction and operation of the CO2 capture, processing it into saturated gas; and compressing and piping it to the storage site(s). PGN could seek a competent partner from donor country(s) to carry out the engineering, procurement and construction of the carbon capture and transportation through the pipe. PKPPIM could play a financing coordination role.

For the CO2 EOR implementation, we recommend to assign the field operator (in this case PT PERTAMINA Tbk), which in turn could appoint its appropriate business unit to carry out the field development work for the CO2 injection for EOR. The project could be handled under the existing PSC arrangement, sponsored under soft loan bilateral agreement with institutions, such as ADB, World Bank, and others with coordination of financing by PKPPIM. An appropriate incentives program could also be closely considered by way of PSC amendment for the pilot, demonstration and full scale EOR projects.

A review of capacity of the oil and gas industry to respond to the issue of climate change by conducting continuing initiatives in the control of green-house gas emissions was conducted. In general, GHG emissions in the oil and gas industry mainly result from combustion machinery used in production and refining activities, flaring of gas in the upstream and downstream activities, and associated CO2 with natural gas production. The review included:

- GHG issues in the upstream oil and gas Industry;

- GHG issues in the down-stream oil and gas Industry, with specific discussion on the Dumai refinery;

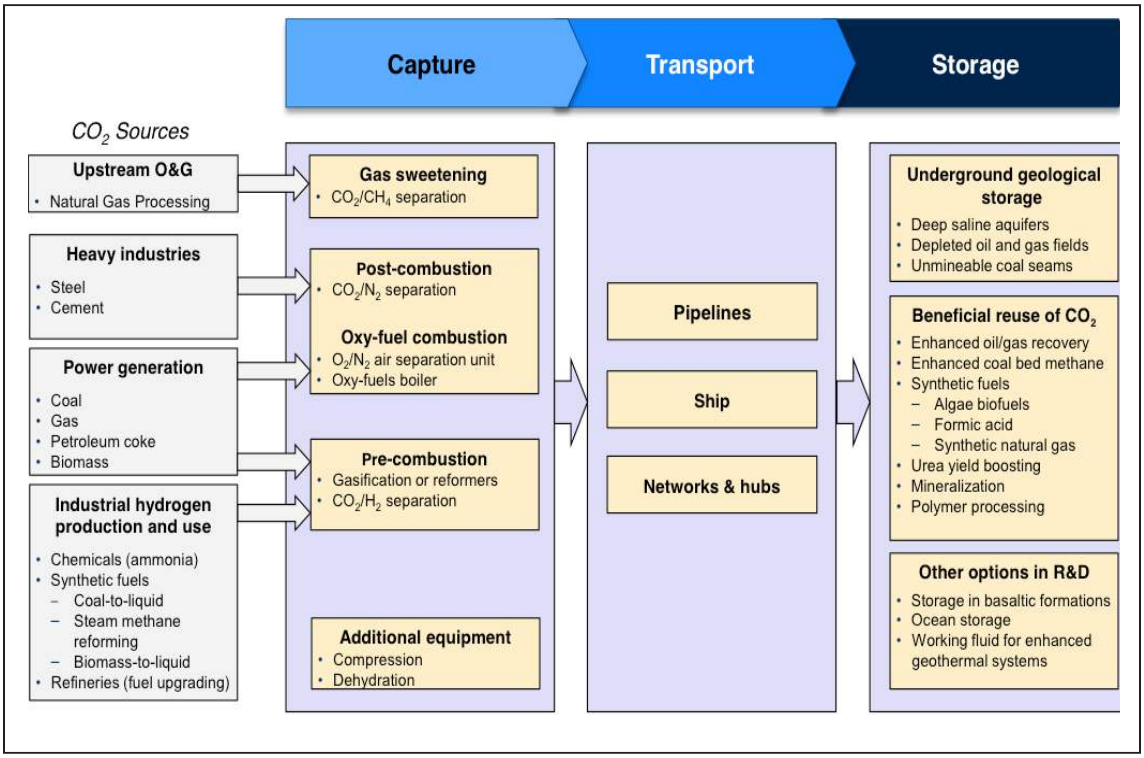
- CO_2 emission standards;

- Potential CCS projects In Indonesia's oil and gas industry; and

- Potential GHG emission prevention in Indonesia's oil and gas industry.

The study concludes that prevention of GHG emissions by developing technology to substitute the energy from fossile fuel to renewable energy, as well as to implement energy efficiency improvements in all equipment and in the refinery process activities are more economically sound and appropriate than allowing GHG emissions to increase and capturing and storing it for an indefinite time. However, continued experimentation and piloting of CCS options is also supported.

Figure 1.2: CCS Value Chain



Source: SBC Energy Institute, Carbon Capture and Storage, January 2013

1.2 Identification of Issues

The GOI is committed to creating a low-carbon development path. At the G20 meeting in September 2009, President of the Republic of Indonesia, HE Susilo Bambang Yudhoyono announced a unilateral objective to reduce GHG emissions by 26 percent by the year 2020 (compared to BAU) on its own effort and proposed a goal of 41 percent reduction by 2020 (compared to BAU) with international support. GOI also joined the G20 pledge to phase out subsidies for fossil fuels.

Government has provided major and growing amounts of subsidies for electricity, fuel and LPG over the past decade. In 2012 for example, the total subsidy provided was IDR 312.1 trillion (IDR 100.2 trillion for electricity, and 211.9 trillion for fuel and LPG).The budget provided for similar subsidy levels in 2013 (with this amount of subsidy needing to be further increased due to continuing high oil prices and the 2013 weakening of the IDR). While subsidies are mainly related to the use of oil there has also been provision of subsidies for LPG through the kerosene to LPG program; and furthermore domestic gas prices have been kept well below world prices through use of regulation.

In its effort to reduce oil subsidy, the Government of Indonesia announced that as of 18 November 2014 the subsidy for liquid fuel oils would be reduced by increasing prices of gasoline (RON88) and gas oil from Rp 6,500/liter and Rp 5,500/liter to Rp 8,500/liter and Rp 7,500/liter respectively thus effectively removing gasoline subsidies.

Presidential Regulation No. 5 of 2006 sets out the National Energy Policy for the period 2005 – 2025 with the energy mix targets in year 2025. These targets increase the contribution of gas energy to a minimum level of 30% of the total energy mix by 2025 compared with recent levels of around 20% - 22%. The 2025 policy targets the use of increased gas for both economic and security purposes and seeks to pursue additional gas from nonconventional sources. In recent time demand for gas consumption has been outgrowing production supplied to the domestic market, making attainment of the 2025 target more challenging. Furthermore, some in the Government would like to see a higher than 30% target for gas given the fiscal and environmental costs of oil and the environmental costs of coal. In an effort to meet this target the government is exploring means for expanded usage of gas, including possible uses of fiscal instruments to support growth of the gas sector.

In October 2014, the Government of Indonesia promulgated Government Regulation No. 79, Year 2014, stipulating the new National Energy Policy for the period 2014-2050. The purpose of the National Energy Policy is to provide guidelines for the direction of national energy management to achieve national energy self-reliance and security to support sustainable national development.

The prevailing National Energy Policy 2014-2050 sets the following targets:

Targets for supply and utilization of primary and final energy

a.	Primary energy supply	2025	400 MTOE	2050	1,000 MTOE
b.	Energy utilization per capita	2025	1.4 TOE	2050	3.2 TOE
c.	Power generation supply cap.	2025	115 GW	2050	430 GW
d.	Electricity utilization per capita	2025	2,500 kWh	2050	7,000 kWh

For the supply and utilization, the energy mix targets are as follows;

a. A new paradigm that energy resources is the capital for national development
b. Energy elasticity of < 1% by 2025 in line with the economic growth
c. Energy intensity of 85% in 2015 and close to 100% in 2020
d. Household gas utilization ratio of 85% in 2015
e. Optimal utilization of primary energy mix:

i.	New and Renewable energy	2025	23%	2050	31%
ii.	Oil Fuel	2025	< 25%	2050	< 20%
iii.	Coal	2025	> 30%	2050	>25%
iv.	Gas	2015	> 22%	2050	>24%

The GHG emission contributed by the energy sector depends on the energy mix which trend has been targeted by the National Energy Policy as shown above.

At the inception of Dewan Nasional Perubahan Iklim (DNPI) or the National Council for Climate Change, McKinsey and Company conducted a study to develop a cost abatement curve to support strategy development for GHG emission reductions, which includes carbon sequestration undertakings as one of the potential options for reducing atmospheric emissions of CO2 from human activities. The study indicated that the total emissions from Indonesia's petroleum and gas sector are expected in the "business as usual case" to increase in the medium term from 122 MtCO2e in 2005 to 135 MtCO2e in 2020, mainly on account of additional refining capacity expected to come online. However, in the longer term, emission increases from refining are expected to be offset – as mature oil and gas fields are shut down and replaced with newer, more efficient ones – so that emissions stay relatively constant at 137 MtCO2e in 2030.

1.3 Purpose and Objective of the Study

The study on carbon capture storage fiscal policy was required to include the following:

(i) to assess the advantages and disadvantages of utilizing carbon capture and storage (CCS) technology in the oil and gas industry in Indonesia as a means to reduce green-house gas (GHG) emissions from the energy industry;

(ii) to review existing fiscal regulations that have an impact on the implementation of CCS investments in the oil and gas industry; and

(iii) to propose appropriate new fiscal policy initiatives or reforms to the Ministry of Finance of the Republic of Indonesia to support the implementation of CCS to reduce GHG emissions from the oil industry over the medium term.

1.4 Methodology of the Study

PEN Consulting worked closely with appointed counterparts of the Centre for Climate Change Financing and Multilateral Policy (PKPPIM) in the Fiscal Policy Agency (BKF) of the Ministry of Finance (MOF) and the UK Low Carbon Support (LCS) as a team under the leadership and direction of PKPPIM. PKPPIM provided policy direction and necessary information and data required by the team to effectively execute the study.

The team consulted with relevant offices of the Government of Indonesia (GOI) and key stakeholders. These included:

(i) PKPPIM;
(ii) Relevant units under Fiscal Policy Agency (BKF);
(iii) DG Taxation in MOF;
(iv) *Dewan Nasional PerubahanIklim (DNPI–National Council on Climate Change)*;
(v) Bappenas;
(vi) Ministry of Environment;
(vii) Ministry of Energy and Mineral Resources, in particular Directorate General Oil and Gas, SKK Migas, and LEMIGAS;
(viii) Institutions / organizations working in CCS;
(ix) Research institutions;
(x) Interested NGOs / civil society;
(xi) UKCCU and other development partners working on CCS in Indonesia (e.g. World Bank, Asian Development Bank);
(xii) oil and gas producers and refiners (PERTAMINA, Shell, Chevron; and BP); and
(xiii) *relevant industry associations such as IPA*.

The study started with gathering relevant information and data on sources of GHG emissions in the upstream, midstream and downstream oil and gas sector. We then proceeded with reviewing the state-of-the-art technology on carbon capture and storage as applied in the oil and gas sector; analyzing costs and benefits of carbon capture and storage activities, and commercial utilization of CO2 such as for Enhanced Oil Recovery (EOR) in the oil and gas fields and for other process industries. Based on CCS benefits that could be realized in the oil and gas sector, we developed proposals for workable policies and regulations that would attract investment and operational undertakings for CCS which may include but not be limited to fiscal and non-fiscal incentives, appropriate risk allocation, and effective permits and license applications.

Throughout the study, we applied analytical approaches which included but were not limited to:

- ***Systems Analysis***. In the process of studying the CCS system in the oil and gas industry, we focused on goals and purposes of the study, i.e. to reduce greenhouse gas (GHG) emissions and create CCS or alternative systems and policies that would achieve the GHG emission reductions in an efficient way;
- ***Economic and Technological Efficiency****.* We considered the economic efficiency for GHG emissions reductions in the oil and gas industry through CCS or other techniques at the lowest possible cost. We also considered Technological Efficiency, the least possible utilization of fuels, or use of cleaner fuels; and high efficiency combustion plants that would reduce GHG emission;
- ***Dynamic Efficiency.*** Through the dynamic efficiency approach, we analyzed the short-term and long-term benefits of CCS or its alternative systems and sought balance in term of the economics of the short run concerns (static efficiency) with concerns in the long run (focusing on encouraging research and development);
- ***Behavioral Economics***. We explored why Indonesia may make irrational (economic) decisions, e.g. of applying CCS to reduce carbon emissions, and why and how behavior does not always follow the predictions of economic models;
- **C*ompetitive Ways of Doing CCS versus market restrictions, price controls and SOE monopolies***
  - Accelerated use of new and renewable energy versus fossil fueled power / combustion plants was reviewed;
  - Low carbon stimulus and high carbon taxes versus market restrictions for low efficiency combustion technology was reviewed; and
  - Establishment of National/Bi-lateral Carbon markets was considered;
- ***Review of Alternatives to CCS.***
  - Improved engineering efficiency on technological processes that reduce CO2 emissions (supercritical boilers); and
  - Use less CO2 emitting energy (new/renewable energy instead of fossil fuel, gasification);
- ***Tangible Outcome.*** The study outcome produced actions or decision that contribute towards meeting one or more measurable policy objectives, in term of likely cost and benefit outcomes.
- ***Budget Optimization.*** There was review of carrying out CCS and alternative CO2 emission reduction policy implementation in stages commensurate with budget constraints;
- ***Improved Institutional Arrangements***. The study developed policy and a regulatory basis for the institutional arrangements and coordination among stakeholders; and

- ***Risk Analysis***. We identified risks that may be encountered and suggested relevant risk mitigation for decisions taken on CCS or its alternatives to reduce greenhouse gas emission in the oil and gas industry

During the course of the study several small public stakeholder discussions for interested stakeholders were held, both from within Government and from the private sector. Final public discussions focused on findings in the draft final report and the proposed strategy and recommendations set out there.

1.5 Framework for CCS and Reductions in Greenhouse Gas Emissions

Ranked in the top 10 in the developing world, energy related carbon dioxide (CO_2) emissions in Indonesia (excluding forestry and land use) are dominated by the industry, power, and transport sectors. The energy sector is the second largest source of CO_2 emissions in Indonesia. If Indonesia continues on a business as usual path, its emissions will nearly triple by 2025.

Indonesia has also recently issued its Green Paper on Economic and Fiscal Policy Options for Climate Change Mitigation (Ministry of Finance, November 2009). For the energy sector, it proposes to:

(i) Impose a carbon tax/levy on fossil fuel combustion coupled with access to international markets, facilitated by negotiation of a “no-lose” target, and

(ii) Introduce complementary measures to incentivize EE and deployment of low-emission technology, exemplified by a specific geothermal policy strategy.

The identified GHG reduction priorities are being translated into actions; i.e. investments, programs and policies. Beyond these specific actions, Indonesia has put forward three consistent development and climate change messages:

(i) Climate change cannot be addressed at the expense of the poor;

(ii) Climate investments must be consistent with development goals; and

(iii) Climate assistance must be on top of past development assistant commitments.

The priorities are:

Energy Efficiency (EE)

a. Many industrial plants in Indonesia rely on captive power units, and almost all industrial facilities maintain diesel-fired back-up and captive generation units. Efficiency gains of 30-40 percent can be realized by upgrading back-up and captive generation units to micro turbines, advanced cogeneration, and/or tri-generation (combined cooling, heat and power). Existing diesel generator sets could also be re-tuned for co-firing of a diesel-biogas blend. The feasibility of these projects depends largely on energy pricing and reliability of grid supplied power; introduction of net metering could facilitate rapid implementation and scale-up.

b. Potential supply-side Energy Efficiency opportunities which may be considered include: renovation of existing power plants, including technology upgrades for existing geothermal units; technical reductions through improved electricity transmission and distribution networks using advanced composite core conductors and "smart grid" technologies; and advanced energy storage technology to optimize utilization of intermittent renewable energy resources.

c. Energy Efficiency opportunities are attractive based on potential GHG reductions and the ability to implement projects faster than large centralized generation plants, but are challenging due to the continued weakness in the energy pricing regime, lack of in-country project experience, and limited commercial bank financing. However, rationalization of some energy prices has improved the prospects for Energy Efficiency, while the GOI has committed to the further removal and eventual elimination of subsidies in the sector with significant reforms having been implemented in late 2014.

Renewable Energy (RE)

Indonesia has a variety of RE sources with substantial potential. They include biomass, geothermal, hydropower, non-conventional gas, solar, and wind, which all remain relatively under-developed. The estimated power generation potential from each of these resources is summarized in Table 1.1.

Table 1.1: Estimated RE Potential in Indonesia

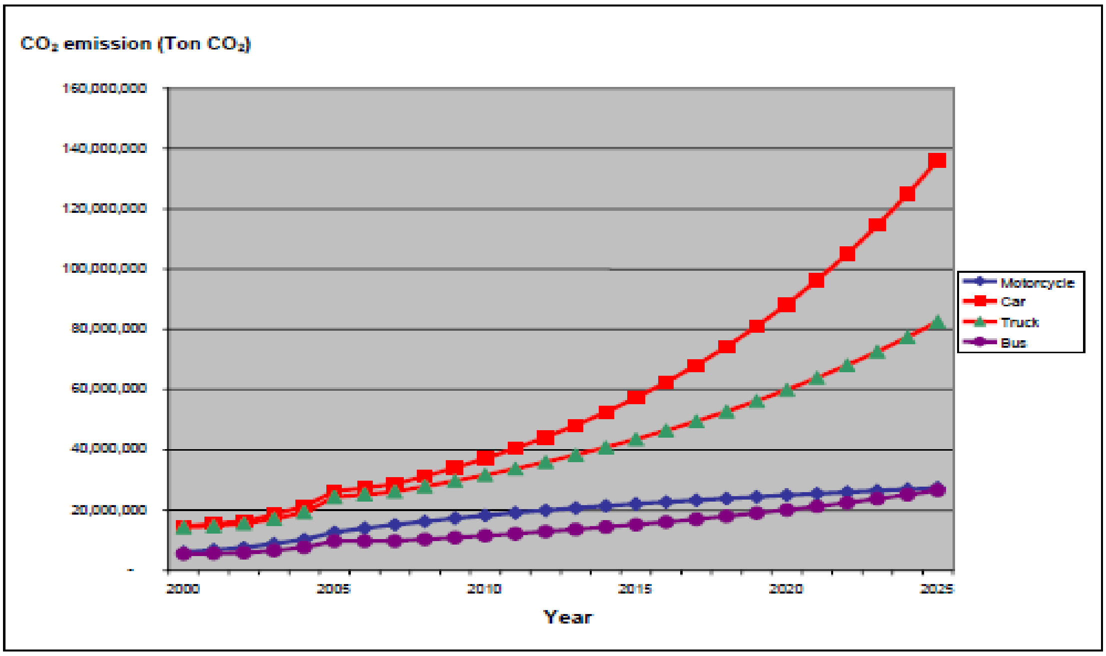
Resource	Potential capacity (MW, except as noted)[a]	Potential Generation Output (TWh/y)[b]	GHG Reductions ($MtCO_2e/y$)[c]
Biomass	49,810	343	274.4
Geothermal	27,150	217	169.6
Large hydro	75,000	328	262.4
Solar	4.8 $kWh/m^2/day$	N/A	N/A
Wind (Eastern Islands)	9,280	26	20.8

Source : (a) *RE Potential from Ministry of Mines and Energy; (b) Plant availability Load Factors: biomass -70%; Geothermal - 90%, hydro – 50%; wind – 30; (c) GHG Reduction assumes direct offsets vs coal at 0.8tCO_2e/MWh*

Transport

The transport sector in Indonesia is a significant GHG emitter due to its substantial consumption of fossil fuels. Road transportation consumes around 88 percent of primary energy consumption in the sector. Without significant actions to reduce the carbon intensity of the road transportation sector, GHG emissions are projected to double in less than 10 years. Emissions are roughly split between use of motor petrol (gasoline) and diesel and the future projections of GHG emissions are a matter of concern if current transport modal distribution and technology efficiency trends hold.

Figure 1.3: Projected growth in CO2 Emissions from Indonesia's Vehicle Fleet



Source: TNA

2. Carbon Capture and Storage Principles

Carbon capture and storage (CCS) is the separation and capture of carbon dioxide (CO_2) from the atmospheric emissions of industrial processes and the transport and safe, permanent storage of CO_2 in deep underground geologic formations.

Carbon dioxide capture and storage (CCS) as defined by UNFCCC, means the capture and transport of carbon dioxide from anthropogenic sources of emissions, and the injection of the captured carbon dioxide into an underground geological storage site for long-term isolation from the atmosphere";

A geological storage site means a paired geological formation, or a series of such formations, consisting of an injection formation of relatively high porosity and permeability into which carbon dioxide can be injected, coupled with an overlying cap rock formation of low porosity and permeability and sufficient thickness which can prevent the upward movement of carbon dioxide from the storage formation;

By preventing CO_2 from large-scale industrial and other facilities from entering the atmosphere, CCS is a potentially powerful tool for addressing climate change problems. Geologic storage is defined as the placement of CO_2 into a subsurface formation so that it will remain safely and permanently stored. Five types of underground formations for geologic carbon storage are being investigated, each with unique challenges and opportunities:

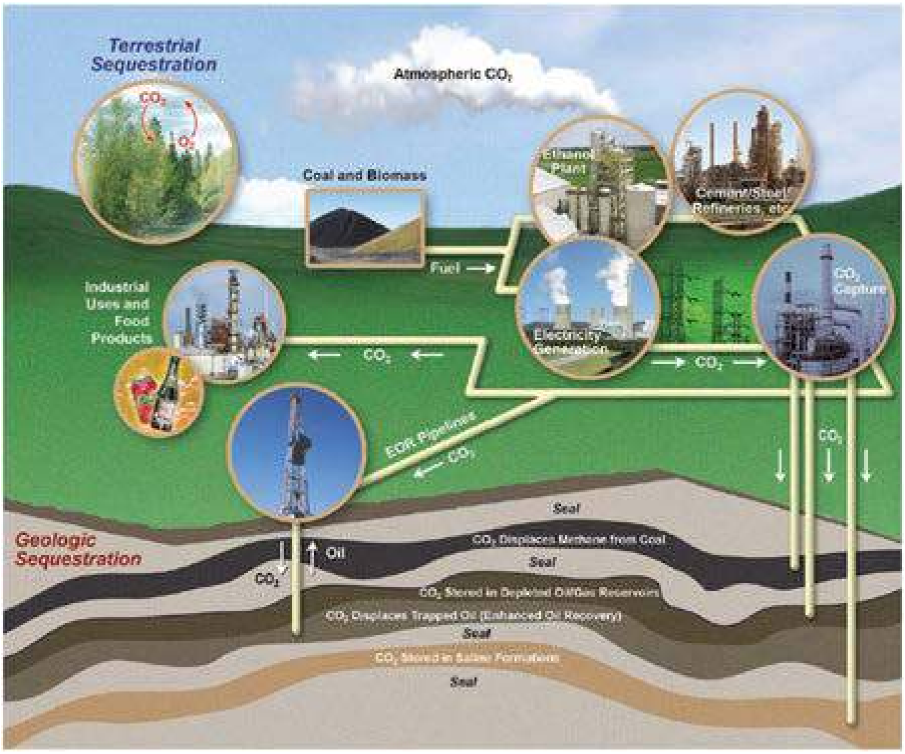
- saline formations;
- oil and gas reservoirs;
- un-mineable coal areas;
- organic-rich shales; and
- basalt formations.

The CO_2 for geologic storage comes from industrial and other facilities that emit large amounts of CO_2, particularly those that burn coal, oil, or natural gas. These facilities include power plants, petroleum refineries, oil and gas production facilities, iron and steel mills, cement plants, and various chemical plants. In CCS, CO_2 is not removed from the atmosphere. Rather, CO_2 that would otherwise have been emitted into the atmosphere is captured and disposed of underground. CCS enables industry to continue with less disruption, while minimizing industry's impact on climate change. Many studies show that CCS could make a significant contribution to reducing CO_2 emissions. The greatest emissions reductions are likely to be achieved when all options for reducing CO_2 emissions are utilized, including energy efficiency, fuel switching, renewable energy development; and CCS.

The CCS process includes monitoring, reporting and verification (MRV), and risk assessment at the storage site. MRV efforts may be focused on the development and deployment of technologies that can provide an accurate accounting of stored CO_2 and a high level of confidence that the CO_2 will remain permanently stored. Effective application of these MRV technologies will help to ensure the safety of storage projects, and provide the basis for establishing carbon credit trading markets for stored CO_2 should these markets develop. Risk assessment research focuses on identifying and quantifying potential risks to humans and the environment associated with carbon storage, and helping to identify appropriate measures to ensure that these risks remain low.

UNFCCC has decided to periodically review the modalities and procedures for carbon dioxide capture and storage in geological formations as clean development mechanism project activities and that the first review shall be carried out no later than five years after the adoption of its decision, on the basis of recommendations made by the Executive Board of the clean development mechanism and by the Subsidiary Body for Implementation, and drawing on technical advice provided by the Subsidiary Body for Scientific and Technological Advice, as needed.

Figure 2.1: Carbon Storage Diagram



Source: SBC Energy Institute, Carbon Capture and Storage, January 2013

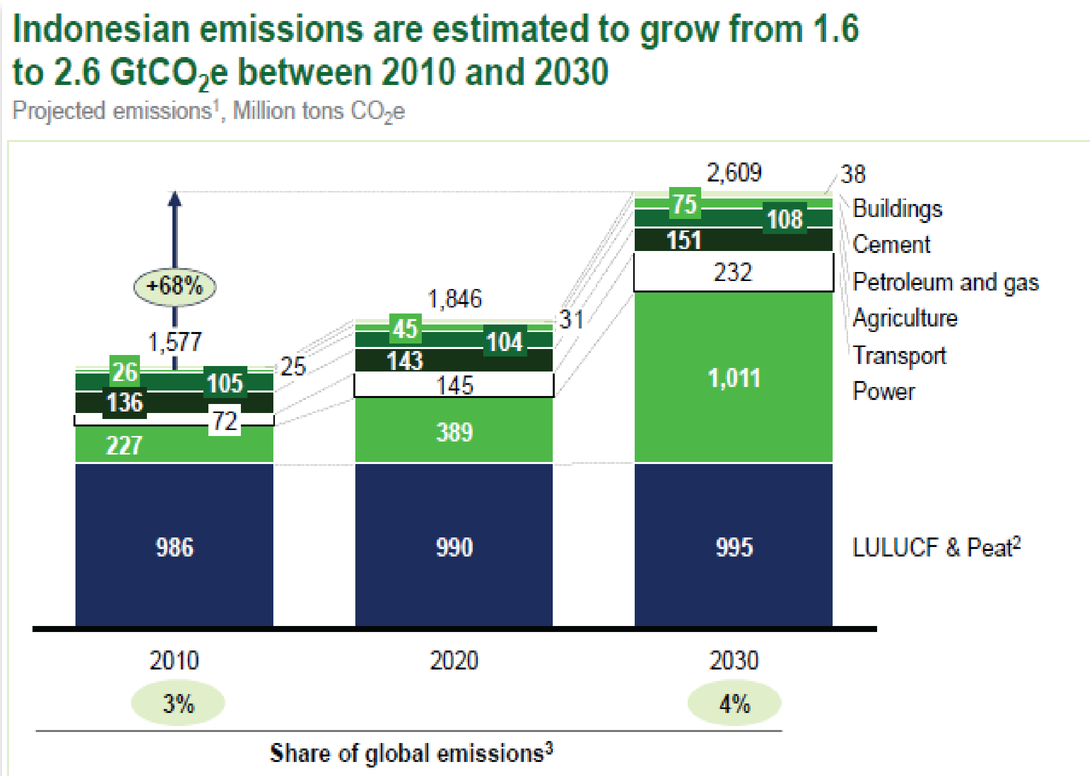
2.1 Generation of GHG

Indonesia's greenhouse gas emissions reached 1.6 billion tons of carbon dioxide in 2010, making it the world's sixth largest emitter of greenhouse gases based on the World Resources Institute report which was published in November 2014. It is projected that the total GHG emissions will rise to 2.6 billion tons of carbon dioxide by 2030. Indonesia's emissions account for approximately 3 to 4 percent of global GHG emissions.

Total emissions here refers to emissions from eight sectors including LULUCF, peat, agriculture, power, petroleum and refining, transportation, cement and buildings, which together account for the majority of Indonesia's emissions

LULUCF-related emissions are by far the largest contributors to Indonesia's current and expected future emissions) under the new projection of emissions through 2030. Power emissions only exceed the LULUCF sector in 2030. LULUCF also represents the largest opportunities to abate emissions. High growth rates in power and transport-related emissions mean that, although opportunities in these sectors become progressively more important in the years ahead, strategic choices on the development pathway must begin today.

Figure 2.2: Indonesia CO2 Emission Projection 2010 -2030



Source: Updating Indonesia's Greenhouse Gas Abatement Cost Curve, September 2014

2.1.1. GHG from Oil/Petroleum and Gas Sectors

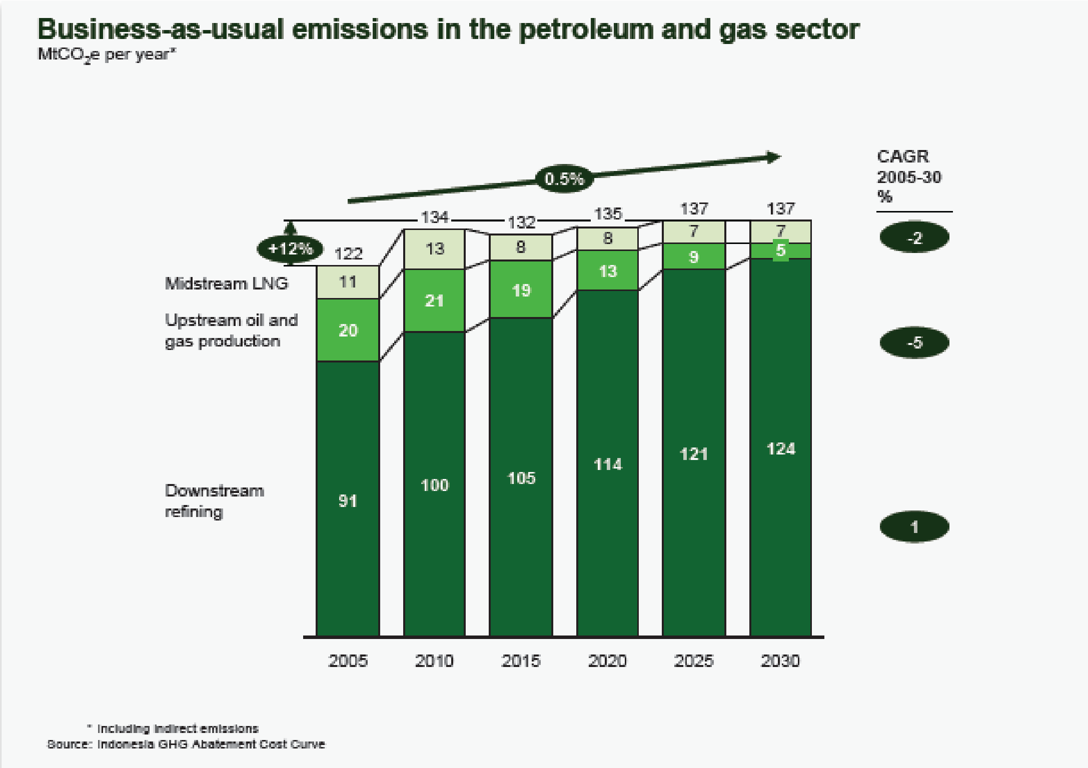
The sectoral emissions from the Oil/Petroleum and Gas Sectors are estimated to increase 12 percent from 122 $MtCO_2e$ in 2005 to 137 $MtCO_2e$ in 2030 (*DNPI:Indonesia's Greenhouse Gas Abatement Cost Curve, August 2010*) [5)].

For petroleum, the scope of this analysis includes production (including gas flaring) and refining activities. Excluded are emissions related to exploration and development of petroleum reserves, shipping, and petrochemicals. This analysis also excludes emissions related to the final consumption of petroleum products by the end user.

For natural gas, the scope of this analysis includes production and liquefaction of natural gas into liquefied natural gas (LNG).

Under these definitions, total emissions from Indonesia's petroleum and gas sector are expected to increase in the medium term from 122 $MtCO_2e$ in 2005 to 135 Mt CO_2e in 2020, mainly on account of additional refining capacity expected to come online. However, in the longer term, emission increases from refining are expected to be offset – as mature oil and gas fields are shut down and replaced with newer, more efficient ones – so that emissions stay relatively constant at 137 $MtCO_2e$ in 2030.

Figure 2.3: CO2 Emission in the Oil & Gas Sector, Business as Usual



Source: Indonesia's Greenhouse Gas Abatement Cost Curve, August 2010

2.1.1.1. Upstream

Indonesia's oil production has been in decline for decades, which crude oil production almost halving since the mid -1900s (currently is about 800,000 barrels/day), though next year oil production may increase slightly due to start-up of production from the Banyu Urip field in Central-East Java, which has been long overdue. But the increasing trend will not be sustainable unless sizeable oil discoveries are made. Given such a declining trend, the country's proven reserves of 4.0 billion barrels are likely to be sucked dry by the early 2020s.

Despite declining oil production, flaring and in some cases even venting of associated gases continues to remain a problem in Indonesia. Current estimates suggest that 25–30 percent of all flaring activities in Southeast Asia are occurring in and around Indonesia, which is significant given that Indonesia only accounts for around 12 percent of all oil production in the region. However, flaring emissions in Southeast Asia have been reducing at a fairly strong pace; current estimates from the U.S. National Oceanic and Atmospheric Administration (NOAA) show reductions of around 5 percent per year from 2000 to 2004 while in 2011, the most recent year with data available, gas flaring in Indonesia was estimated to be 2.23 billion cubic meters (bcm) per year.

2.1.1.2. Midstream

Natural gas liquefaction is currently estimated at 44 bcm per year, with the majority of it being exported. Most of the emissions associated with LNG are the result of gas compression and methane leakage during the processing and transporting of the gas.

Current estimates suggest a decline in the volume of LNG being produced over the next 20 years and almost halved by 2030, as it is expected that increasingly larger shares will be diverted for domestic consumption where the need for liquefaction would be reduced.

2.1.1.3. Downstream

Refining capacity in Indonesia has remained constant for the past few years at around 1 million barrels per day, consisting of Dumai refinery 170,000 barrels, Plaju Refinery 133,700 barrels, Cilacap Refinery 348,000 barrels, Balikpapan Refinery 60,000 barrels, Balongan Refinery 125,000 barrels, and Kasim Refinery 10,000 barrels. All refining capacity in Indonesia is owned and operated by state-owned PERTAMINA, which has announced plans to add an additional 500,000 barrels per day refining capacity in the next 5–10 years, increasing total refining capacity up to 1.5 million barrels of oil per day. This planned capacity addition is included in the current emission analysis.

2.1.2. Emission Sources in Oil and Gas Sectors

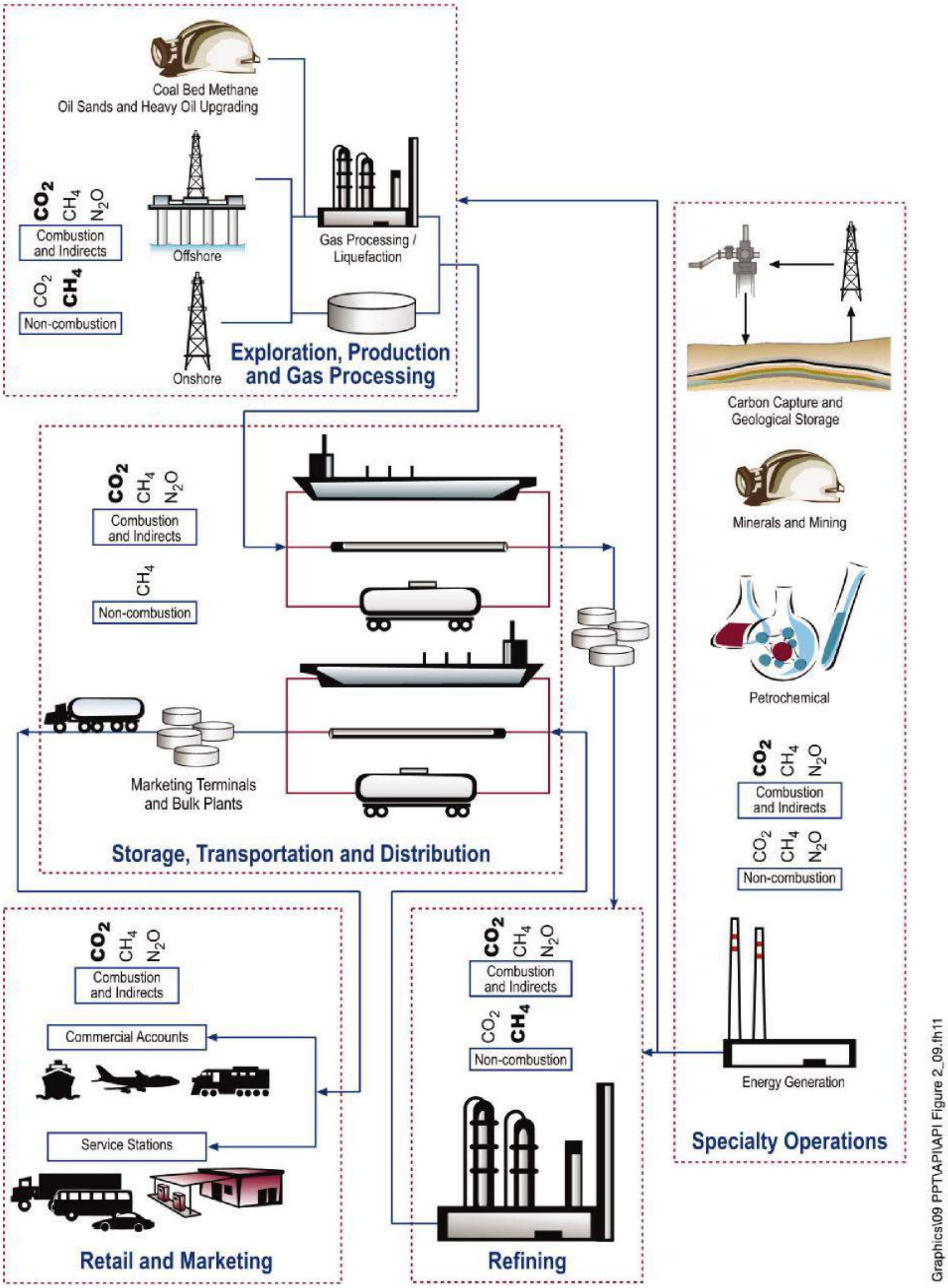
The GHG emissions from the oil and natural gas industries includes all direct activities related to producing, refining, transporting, and marketing crude oil and associated natural gas, and refined products. For the purposes of this report, only CO2 emission from production and gas processing, and refining sectors will be evaluated. Figure 2.4 shows a graphical overview of the industry. The key industry segments include:

- Exploration, production, and gas processing;
- Transportation and distribution;
- Refining; and
- Retail and marketing.

These segments are the direct activities within the oil and natural gas industry that have the potential to emit GHG. Integrated petroleum companies may also have operations associated with energy generation (electricity, heat/steam generation, or cooling), mining and minerals, petrochemical manufacturing, and/or carbon capture and geological storage.

Emissions of GHG in the oil and natural gas industry typically occur from one of the following general source classes: i) combustion sources, including both stationary devices and mobile equipment; ii) process emissions and vented sources; iii) fugitive sources; and iv) indirect sources. Some pieces of equipment, such as compressors, may emit under multiple classes − fugitive emissions when pressurized, vented emissions when depressurized for maintenance; and combustion emissions from the driver engines during normal operations. A detailed list of the types of potential emission sources associated with each of the general source classes is discussed further in Chapter 4.

Figure 2.4: Oil and Natural Gas Industry Schematic of GHG Emissions



Source: Compendium of GHG of Emissions Methodologies for the Oil and Natural Gas Industry, August 2009

2.1.2.1. Combustion

Combustion of carbon-containing fuels in stationary equipment such as engines, burners, heaters, boilers, flares, and incinerators results in the formation of CO_2 due to the oxidation of carbon. Emissions resulting from the combustion of fuel in transportation equipment (i.e., vessels, barges, ships, railcars, and trucks) that are included in the inventory are also categorized as combustion sources. Very small quantities of N_2O may be formed during fuel combustion by the reaction of nitrogen and oxygen. Methane may also be released in exhaust gases as a result of incomplete fuel combustion.

2.1.2.2. Process Emissions and Vented Sources

Vented sources occur as releases resulting from normal operations, maintenance and turnaround activities, and emergency and other non-routine events. These include sources such as crude oil, condensate, oil, and gas product storage tanks; blanket fuel gas from produced water or chemical storage tanks; loading/ballasting/transit sources, and loading racks; as well as equipment such as chemical injection pumps and pneumatic devices that release GHGs (CH_4 and potentially CO_2) as part of their operation.

Process vents, a subcategory of vented sources, are defined as those sources that produce emissions as a result of some form of chemical transformation or processing step. Examples of these sources include dehydration, gas sweetening, hydrogen plants (often referred to as steam reformers), naphtha reformers, catalytic cracking units, delayed cokers, coke calciners, and others. These sources are generally specific to the particular industry segment.

Depressurizing equipment for maintenance or turnaround activities may result in vented emissions. Similarly, GHG emissions may result from equipment startup activities or from purging equipment prior to re-pressurization. Examples of other maintenance or turnaround activities classified as venting sources are well work overs, compressor turnaround, pipeline pigging operations, and heater/boiler tube decoking.

Other releases included as vented emission sources are non-routine releases from emergency or pressure relieving equipment such as emergency shutdowns (ESD) or emergency safety blow downs (ESB), pressure relief valves (PRV), and breakout/surge tanks.

2.1.2.3. Fugitive Sources

Fugitive emissions are unintentional releases from piping components and equipment leaks at sealed surfaces, as well as from underground pipeline leaks. Fugitive emissions are usually low volume leaks of process fluid (gas or liquid) from sealed surfaces, such as packing and gaskets, resulting from the wear of mechanical joints, seals, and rotating surfaces over time. Specific fugitive emission source types include various components and fittings such as valves, flanges, pump seals, compressor seals, PRVs, or sampling connections. Fugitive emissions also include non-point evaporative sources such as from wastewater treatment, pits, and impoundments.

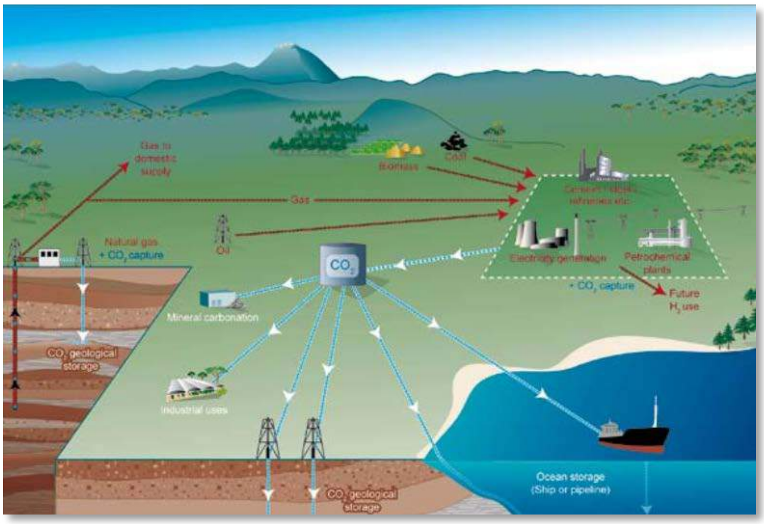
2.1.2.4. Indirect Sources

Indirect emissions are emissions that are a consequence of activities of the reporting company but which results from sources owned or controlled by another party (IPIECA, 2003). This category includes emissions from the combustion of hydrocarbon fuels to generate electricity, heat, steam, or cooling, where this energy is imported or purchased.

2.2 Carbon Capture and Transportation

Carbon Capture and Storage (CCS) (or carbon capture and sequestration), is the process of capturing waste carbon dioxide (CO2) from large point sources, such as fossil fuel power plants, transporting it to a storage site, and depositing it where it will not enter the atmosphere, normally an underground geological formation, or to be used in EOR. The aim is to prevent the release of large quantities of CO2 into the atmosphere (from fossil fuel use in power generation and other industries). It is a potential means of mitigating the contribution of fossil fuel emissions to global warming and ocean acidification. Although CO2 has been injected into geological formations for several decades for various purposes, including enhanced oil recovery (EOR), the long term storage of CO2 is a relatively new concept.

Figure 2.5: Schematic Diagram of Possible CCS System



Source: IPCC Special Report, 2005
(http://www.ipcc.ch/pdf/specialreports/srccs/srccs_wholereport.pdf)

2.2.1 Capture

Capturing CO_2 is typically most effective at key point sources, such as large fossil fuel or biomass energy facilities, industries with major CO_2emissions, natural gas processing, synthetic fuel plants and fossil fuel-based hydrogen production plants. Extraction (recovery) from the air is possible, but is not very practical. The CO_2 concentration drops rapidly moving away from the point source. The lower concentration increases the amount of mass flow that must be processed (per ton of carbon dioxide extracted).

There are three different types of technologies for scrubbing; i.e. post- combustion, pre-combustion, and oxyfuel combustion:

2.2.1.1 **In *post-combustion capture*** the CO_2 is removed after combustion of the fossil fuel. This is the scheme that would be applied to a fossil-fuel burning power plant. Here, carbon dioxide is captured from flue gases at power stations or other large point sources. The technology is well understood and is currently used in other industrial applications, although not at the same scale as might be required in a commercial scale power station.

2.2.1.2 **The technology for *pre-combustion*** is widely applied in fertilizer, chemicals, gaseous fuels (H_2, CH_4), and power production. In these cases, the fossil fuel is partially oxidized, for instance in a gasifier. The resulting syngas (CO and H_2) is shifted into CO_2 and H_2. The resulting CO_2 can be captured from a relatively pure exhaust stream. The H2 can now be used as fuel, the carbon dioxide is removed before combustion takes place. There are several advantages and disadvantages when compared to conventional post-combustion carbon dioxide capture. The CO_2 is removed after combustion of fossil fuels, but before the flue gas is expanded to atmospheric pressure. This scheme is applied to new fossil fuel burning power plants, or to existing plants where re-powering is an option. The capture before expansion, i.e. from pressurized gas, is standard in almost all industrial CO_2 capture processes, in the same scale as will be required for utility power plants.

2.2.1.3 **In *oxy-fuel combustion*** the fuel is burned in oxygen instead of air. To limit the resulting flame temperatures to levels common during conventional combustion, cooled flue gas is re-circulated and injected into the combustion chamber. The flue gas consists of mainly carbon dioxide and water vapor, the latter of which is condensed through cooling. The result is an almost pure carbon dioxide stream that can be transported to the sequestration site and stored. Power plant processes based on oxy-fuel combustion are sometimes referred to as “zero emission” cycles, because the CO_2 stored is not a fraction removed from the flue gas stream (as in the cases of pre- and post-combustion capture) but the flue gas stream itself.

2.2.2 Transport

After capture, the CO_2 has to be transported to suitable storage sites. This can be done by transporting through a pipeline, which is generally the cheapest form of transport.

Transport of CO_2 in pipelines is a known and mature technology, with significant experience from more than 6 000 km of CO2 pipes in the United States. There is also experience, albeit limited, with transport of CO2 using offshore pipelines in the Snøhvit project in Norway. Guidance for the design and operation of CO2 pipelines that supplements existing technical standards for pipeline transport of fluids (e.g. ISO 13623 and ASME B31.4) was released in 2010 (DNV, 2010).

The CO_2 can be transported to oil production fields where it is then injected into older fields to extract oil. The injection of CO_2 to produce oil is generally called Enhanced Oil Recovery (EOR) with the technology already in use today.

Ships and tank-trucks could also be utilized to transport where pipelines are not feasible. These methods can be used to transport CO_2 for other applications.

2.3 CO2 Storage

Various options have been conceived for permanent storage of CO_2. These options include gaseous storage in various deep geological formations (including saline formations and exhausted gas fields), and solid storage by reaction of CO_2 with metal oxides to produce stable carbonates. Those possible storages are:

- Geological Storage;
- Ocean Storage; and
- Mineral Storage.

2.3.1 Geological Storage

Geological storage of CO_2 involves the injection of CO_2 into appropriate geological formations that are typically located between one and three kilo-meters under the ground; it also involves the subsequent monitoring of injected CO_2. Suitable geologic formations include saline equifers, depleted oil and gas fields, oil fields with the potential for CO2 flooding for EOR; and coal seams that cannot be mined with potential for enhanced coal-bed methane (ECBM) recovery. Figure 2.6 illustrates the geological storage approach.

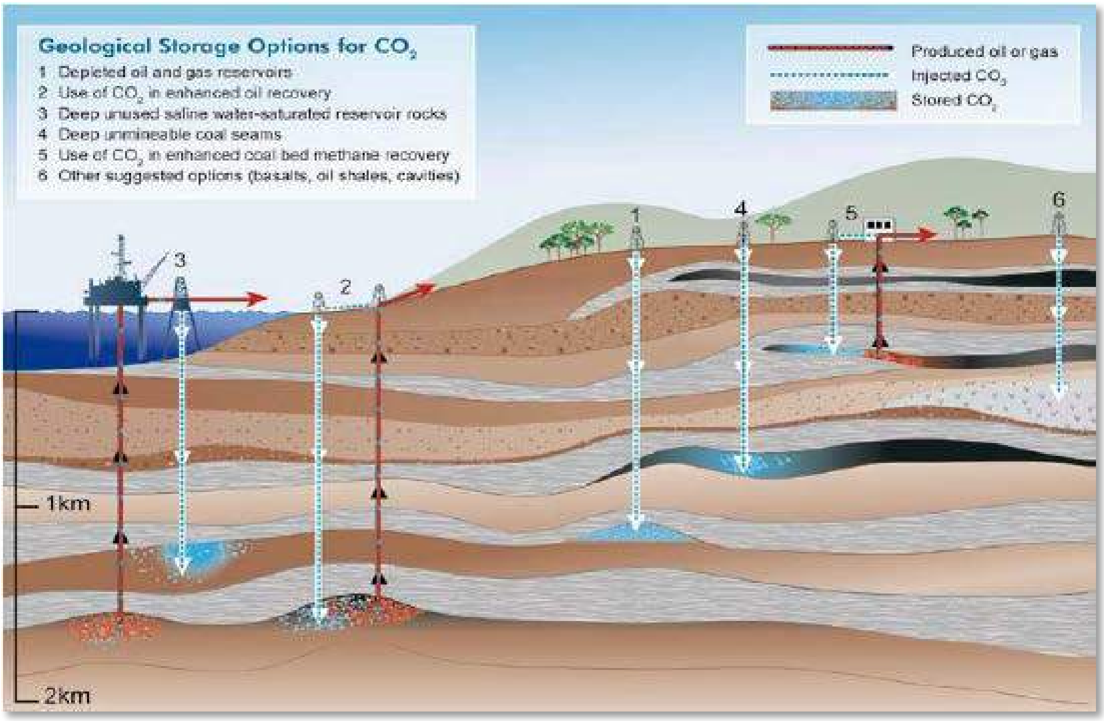
2.3.2 Ocean Storage

Ocean storage is putting CO_2 in the natural sink of the oceans. It is not currently recommended due to the acidification impact to the sea water in the event of leakage that could endanger fish and other ocean life.

2.3.3 Mineral Storage

In the case of mineral carbonation storage, captured CO_2 is reacted with metal-oxide bearing materials, thus forming the corresponding carbonates and a sold byproduct, silica for example. Natural silicate minerals can be used in artificial processes that mimic natural weathering phenomena, but also alkaline industrial waste can be considered. The products of mineral carbonation are naturally occurring stable solids that would provide storage capacity on a geological time scale. Moreover, magnesium and calcium silicates deposits are sufficient to fix the CO2 that could be produced from the combustion of all fossil fuel resources. The fix ton of CO2 requires about 1.6 to 3.7 tonnes of rock. The resulting carbonated solids must be stored at an environmentally suitable location.

Figure 2.6: Geological Storage Options for CO2



Source: IPCC Special Report, 2005 (http://www.ipcc.ch/pdf/special-reports/srccs/srccs_wholereport.pdf)

2.4 The Use of CO2

Carbon dioxide (CO2) use and re-use efforts focus on the conversion of CO2 to useable products and fuels that will reduce CO2 emissions in areas where geologic or other storage may not be an optimal solution. These include:

2.4.1 **Enhanced Oil/Gas Recovery** – Injecting CO2 into depleting oil or gas bearing fields to maximize the amount of CO2 that could be stored as well as to maximize hydrocarbon production. Carbon dioxide is used in enhanced oil recovery where it is injected into or adjacent to producing oil wells, usually under supercritical conditions, when it becomes miscible with the oil. This approach can increase oil recovery, by reducing residual oil saturation, by 7% to 23% in addition to primary extraction. It acts as both a pressurizing agent and, when dissolved into the underground crude oil, significantly reduces its viscosity, and changing surface chemistry enabling the oil to flow more rapidly through the reservoir to the removal well. In mature oil fields, extensive pipe networks are used to carry the carbon dioxide to the injection points. This approach can increase original oil recovery by reducing residual oil saturation, thereby resulting in additional recovery to primary extraction.

2.4.2 **Coal Bed Methane (CBM) recovery** - In enhanced coal bed methane recovery, carbon dioxide would be pumped into the coal seam to displace methane, as opposed to current methods which primarily use water to make the coal seam release its trapped methane.

2.4.3 **CO2 as Feedstock** - CO2 can be used as a feedstock to produce chemicals (including fuels and polymers) and to find applications for the end products.

2.4.4 Non-Geologic Storage of CO2 – It is possible to use CO2 from an effluent stream to immobilize the CO2 permanently by producing stable solid materials that are either useful products with economic value or a low cost produced material. This approach could be viewed as an effective carbon storage method.

2.4.5 Indirect Storage – There can be promotion of indirect carbon storage by removing CO2 in the air (such as enhanced photosynthesis) or by enhancing carbon intakes in terrestrial vegetation and soils.

2.4.6 Beneficial Use of Produced Water – For produced water from CO2 storage in saline formations, novel methods can be developed to use CO2 to react with metallic ions to form less soluble carbonates that can be removed; and to then find useful applications for the desalinated water.

2.4.7 Breakthrough Concepts – Develop novel applications of CO2 that would limit its emissions into the air and novel approaches to using microbes that consume CO2 and other materials to produce useful products or fuels.

2.4.8 Fossil Energy's Carbon Utilization Projects

Processes or concepts that undertake this CO2 reduction must take into account the life cycle of the processes to ensure that additional CO2 is not produced beyond what is already being removed from or going into the atmosphere. Several other challenges exist in using/reusing CO2. One involves determining how best to tap energy sources, since turning CO2 into fuels and chemicals would require energy input. In photosynthesis, solar energy is the obvious energy source. However, for solar applications as well as other approaches such as chemical processes or the use of microbes, consideration has to be given as to how best to tap solar or other energy sources. Another challenge is to find new reaction paths, including new catalysts and enzymes. This is important for many approaches in using CO2 to make new products, such as polymers. For some of these reactions, especially those involved in biological systems, the rate of reactions need to be improved.

2.4.9 Inert gas

Inert gas is one of the most commonly used compressed gases for pneumatic (pressurized gas) systems in portable pressure tools. Carbon dioxide also finds use as an atmosphere for welding, although in the welding arc, it reacts to oxidize most metals. Use in the automotive industry is common despite significant evidence that welds made in carbon dioxide are more brittle than those made in more inert atmospheres, and that such weld joints deteriorate over time because of the formation of carbonic acid. It is used as a welding gas primarily because it is much less expensive than more inert gases such as argon or helium. When used for MIG welding, CO_2 use is sometimes referred to as MAG welding, for Metal Active Gas, as CO_2 can react at these high temperatures. It tends to produce a hotter puddle than truly inert atmospheres, improving the flow characteristics; although, this may be due to atmospheric reactions occurring at the puddle site. This is usually the opposite of the desired effect when welding, as it tends to embrittle the site, but may not be a problem for general mild steel welding, where ultimate ductility is not a major concern.

It is used in many consumer products that require pressurized gas because it is inexpensive and nonflammable, and because it undergoes a phase transition from gas to liquid at room temperature at an attainable pressure of approximately 60 bar (870 psi, 59 atm), allowing far more carbon dioxide to fit in a given container than otherwise would occur. Life jackets often contain canisters of pressured carbon dioxide for quick inflation. Aluminum capsules of CO_2 are also sold as supplies of compressed gas for air-guns, paintball markers, inflating bicycle tires, and for making carbonated water. Rapid vaporization of liquid carbon dioxide is used for blasting in coal mines. High concentrations of carbon dioxide can also be used to kill pests.

2.4.10 Fire Extinguishers

Carbon dioxide extinguishes flames, and some fire extinguishers, especially those designed for electrical fires, contains liquid carbon dioxide under pressure. Carbon dioxide extinguishers work well on small flammable liquid and electrical fires, but not on ordinary combustible fires, because although it excludes oxygen, it does not cool the burning substances significantly and when the carbon dioxide disperses they are free to catch fire upon exposure to atmospheric oxygen. Carbon dioxide has also been widely used as an extinguishing agent in fixed fire protection systems for local application of specific hazards and total flooding of a protected space. International Maritime Organization standards also recognize carbon dioxide systems for fire protection of ship holds and engine rooms. Carbon dioxide based fire protection systems have been linked to several deaths, because it can cause suffocation in sufficiently high concentrations. A review of CO_2 systems identified 51 incidents between 1975 and the date of the report, causing 72 deaths and 145 injuries (*US EPA: Carbon Dioxide as a Fire Suppressant: Examining the Risk, February 2000*).

2.4.11 Bio Transformation Into Fuel

Researchers have genetically modified a strain of the cyanobacterium Synechococcus elongatus to produce fuel components, such as: isobutyraldehyde and isobutanol from CO2 using photosynthesis, the process by which green plants and some other organisms use sunlight to synthesize foods from carbon dioxide and water.

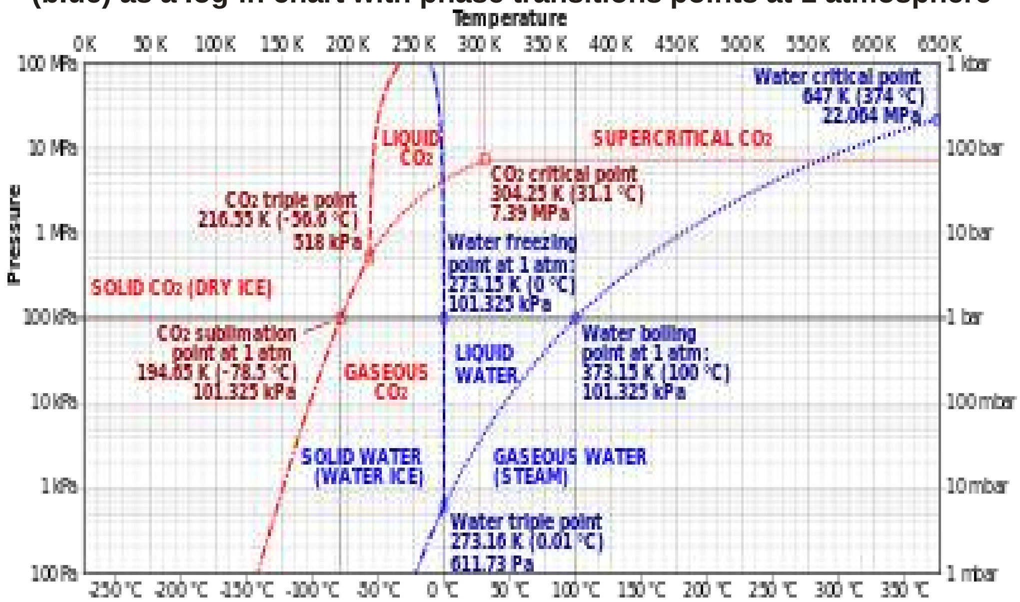
2.4.12 Refrigerant

Liquid and solid carbon dioxide are important refrigerants, especially in the food industry, where they are employed during the transportation and storage of ice cream and other frozen foods. Solid carbon dioxide is called "dry ice" and is used for small shipments where refrigeration equipment is not practical. Solid carbon dioxide is always below −78.5 °C at regular atmospheric pressure, regardless of the air temperature.

Liquid carbon dioxide (industry nomenclature R744 or R-744) was used as a refrigerant prior to the discovery of R-12 and may enjoy a renaissance due to the fact that R134a along with all HFC refrigerants contributes to climate change. Its physical properties are highly favorable for cooling, refrigeration, and heating purposes, having a high volumetric cooling capacity. Due to its operation at pressures of up to 130 bar. (1880 psi), CO_2 systems require highly resistant components that have already been developed for mass production in many sectors. In automobile air conditioning, in more than 90% of all driving conditions for latitudes higher than 50°, R744 operates more efficiently than systems using R134a. Its environmental advantages (GWP of 1, non-ozone depleting, non-toxic, non-flammable) could make it the future working fluid to replace current HFCs in cars, supermarkets, hot water heat pumps, among others. Coca-Cola has fielded CO_2-based beverage coolers and the U.S. Army is interested in CO_2 refrigeration and heating technology.

The global automobile industry is expected in the future to decide on the next-generation refrigerant in car air conditioning with CO_2 being one seriously discussed option.

Figure 2.7: Comparison of phase diagrams of carbon dioxide (red) and water (blue) as a log-in chart with phase transitions points at 1 atmosphere



Source : Wikipedia the Free Encyclopedia, Carbon Dioxide.

2.5 Green House Gas Emissions Reductions

2.5.1 GHG Emission Reductions in the Oil and Gas Industry

Reduction of GHG emission in the oil and gas sector can be achieved among other things by improving efficiency of oil and gas fuel utilization, carbon sequestration, conservation of energy, reduction or elimination of gas flaring in the upstream production and refinery operations. Raw natural gas produced from gas fields may contain contaminants, which include carbon dioxide (CO_2), ranging from less than 10% to as high as 70%, such as raw natural gas from Natuna Gas Field, In the natural gas processing plants, the raw natural gas is purified from contaminants to meet the quality standards for pipeline transportation. Specification for CO_2 typically limits the content to 2 or 3%. Large quantities of CO2 content can be re-injected back into gas wells; small quantities of CO2 can be dispersed in water or the air.

Commercial undertakings for potential application of CCS and utilization of CO_2 in Indonesia's upstream and downstream oil industries should be further reviewed and identified. For example a study by PT Caltex Pacific Indonesia on the potential use of CO_2 for EOR, as part of the study for alternative EOR methodology for the Minas and Duri fields in the 1970's indicated that CO_2 is not compatible for EOR application in Indonesia due to the specific characteristics of oil and reservoirs and miscible pressure conditions of shallow reservoirs.

LEMIGAS Studies, based on geology and reservoir evaluation, indicates that there are CCS and CO_2 EOR potential in depleted oil fields, with sources of CO_2 emission from various industries in the vicinity, in South Sumatera. Most reservoirs, however, are small and spread over a large area. Before a full scale CCS or CO_2 EOR projects could be undertaken, the suitability of CO_2 to be stored and/or used for EOR in South Sumatera oil field reservoirs should be tested in the laboratory. If the laboratory tests shows favorable results, a pilot project should be developed.

Shell Canada is championing the Quest Carbon Capture and Storage Project in Alberta, Canada. The Athabasca Oil Sands project produces 255,000 barrel of heavy oil or bitumen per day, which is transported to the Shell's Up-grader near Edmonton, Alberta. By 2015, Quest will capture and store deep underground more than 1 Million-ton a year of CO_2 produced in bitumen processing, reducing direct CO_2 emission by 35%. The storage is an onshore saline aquifer at a depth of two kilometer (the Cambrian Basal Sands), located 65 km of the CO_2 source.

Total cost of the Quest project is US$ 1.35 billion. The Canadian and Alberta governments are to invest C$ 865 Million. The project was also awarded C$ 120 million from the Clean Energy Fund (a fund established by the Canadian Government to demonstrate CCS technology). The Alberta Government has offered to provide $ 745 million to the project.

Peter Voster, former Chief Executive Officer of the Royal Dutch Shell Plc explained: "If you want to achieve climate change goals, CCS has to be part of the solution". He added: "Lower CO_2 energy sources will grow, but even by 2050 at least 65 per cent of our (*world)* energy will still come from fossil fuels; so CCS will be important to manage climate impacts". Indonesia has set a target of energy mix whereby 69% of the energy will come from fossil fuel by 2050.

Latest technology development indicates that CO_2 could be used to enhance recovery of Coal Bed Methane (CBM) gas. The Ministry of Energy and Mineral Resources estimates Indonesia's CBM resources at 453 TSCF, consisting of 250 TSCF in South and Central Sumatera and 210 TSCF in East Kalimantan. The development of CBM has not been progressing well to date.

2.5.2 Alternatives for Reducing/Minimizing Carbon Emission

Up to several years ago, the global atmospheric CO_2 levels had nearly surpassed an average of 390 ppm, about a 40% increase over pre-industrial levels of 280 ppm. This represents both the highest total and fastest acceleration of atmospheric CO_2 levels in the past several hundred years. The parallel warming of the climate system, evidenced by rising average global temperatures and global average sea levels and increased aberrations in weather patterns, is consistent with the modeled effects of increasing atmospheric CO_2 levels resulting from anthropogenic greenhouse gas emissions. Under the Cancun Agreements, signatory nations agreed on the need to reduce greenhouse gas emissions to a level that would hold average global temperature increase below 2oC in comparison to pre-industrial levels. This would be achievable, with medium to high probability, by stabilizing atmospheric CO2 concentrations between 350 and 400 ppm, according to the latest climate models.

2.5.3 Reducing / Minimizing Carbon Emissions

Though developed countries are largely responsible for historical anthropogenic CO2 emissions, all nations are vulnerable to climate change impacts. To successfully limit and significantly reduce future emissions, developed countries must take the lead, but developing countries must also take robust action to shift to a low carbon economy and reduce emissions, with support from developed countries to address key barriers currently preventing them from doing so.

In facing the challenge of climatic change, many world leaders have acknowledged the scientific findings that no single solution exists for mitigating climate change; therefore, a portfolio of CO2 reduction technologies and methods that meet the need of each locality will be needed to successfully confront rising CO2emissions.

Each nation has different emission profiles, and while CO2 accounts for over 75% of anthropogenic greenhouse gas emissions, it derives from multiple sectors, each of which must undertake methods to reduce emissions. Of all sectors, the energy supply and industrial sectors are the greatest contributors to CO2 emissions.

In addition to efficiency improvements and enhancing clean energy use, one key option for limiting future CO2 emissions from fossil fuel energy supply is CCS. CCS is a suite of technologies integrated to capture and transport CO2 from major point sources (e.g. fossil fuel power plants; steel, cement, and fertilizer plants; and other industrial facilities) to a storage site where the CO2 is injected down wells and then trapped in porous geological formations deep below the surface.

At present, the individual technology components utilized in a CCS project are mature relative to many emerging clean energy technologies. CO2 separation and capture is already widely applied on a commercial scale for use in the food and beverage industry, as well as in other industrial uses; CO2 transport by pipeline is a mature industry in some regions; and technologies for storage site selection, injection, and monitoring are well developed across the industry. However, power plant-scale integration of all technologies comprising a CCS project is still at the developmental stage.

International organizations have repeatedly cited CCS as a potential major tool to achieve CO2 emission reductions. In many projections, CCS deployment plays a large role in limiting CO2emissions from developed as well as developing countries.

2.6 The Pros and Cons of Carbon Capture and Storage

Based on the foregoing discussion on methods to mitigate CO_2 emission, whether by avoiding CO_2 release to the atmosphere, such as in the CCS case, or minimizing CO_2 emission in industrial processes through improved combustion efficiency or utilization of renewable energy, a “forced field analysis” is conducted to evaluate the “forces” supporting CCS application (the pros) and the forces opposing CCS (the cons) in Indonesia. Table 2.1 shows results of the force field analysis, which shows that there are more forces opposing than supporting CCS application in Indonesia at this time.

There is no doubt that CCS is the most effective technology known to-date for the abatement of CO2 emission from static fossil fueled combustion facilities such as coal fired and other fossil fuel applications, however, CCS faces the following challenges: (i) high cost of CO2 capturing and transporting facilities; (ii) relatively high power consumption; and (iii) finding suitable and safe storage, including injecting CO2 in geological formations for Enhanced Oil Recovery.

Although the forces opposing CCS application in Indonesia at this time are much stronger than the forces in favor of CCS, it is recommended that further studies continue to be carried out, in the oil and gas industry, in the following areas:

(i) Assess sites for safe storage of CO2 in geological formations in the vicinity of large CO2 emitter facilities. Studies on geological CO2 storage and EOR by CO2 injection in depleted oil fields in South Sumatera underway by LEMIGAS for PERTAMINA should proceed until a pilot project can be defined and executed. This pilot project would provide lessons learned to improve the economic, technological and dynamic efficiency of a CCS project, identify what regulatory framework and incentive mechanism should be developed, and analyze the cost – benefit data to develop a full scale CCS project or seek out workable alternatives;

(ii) Conduct a feasibility study to reduce CO2 emissions in a selected refinery (to begin with) through improvements in the combustion efficiency (boiler, furnace, power plant) or installing carbon capture and storage, sequestration, and/or utilization facilities. Review the regulatory framework as well as fiscal and non-fiscal stimulus that may be required to economically and significantly reduce carbon emissions in refineries;

(iii) Conduct "carbon audits" to identify potential GHG emitters/producers in the upstream and downstream oil and gas industry, and the corresponding order of magnitude for reducing GHG emission through CCS, combustion efficiency improvement, and/or substituting fossil fuels with renewable energy. These include flared gas, associated GHG produced with and separated from natural gas production, and GHG emitted from production support facilities (power plants, steam plants, heat exchanges, and furnaces); and

(iv) Advocate policies and regulations to promote GHG emissions abatement through establishing appropriate GHG emission standards proportional with industry and population density in certain areas, develop reward and penalty mechanisms for compliance or non-compliance with the established GHG emission standards, and stimulus for combustion efficiency improvement and the use of renewable energy to meet energy demand. There should also be established standards on plant efficiencies for plants using fossil fuels.

The International Energy Agency (IEA) stated in its July 2009 report on "Carbon Capture and Storage: Full Scale Demonstration Progress Update" that "the only technology available to mitigate GHG emissions from large-scale fossil fuel usage is CCS. CCS is therefore an essential part of the portfolio of technologies that is needed to achieve deep global emission reductions".

On the other hand, those opposing CCS, such as Greenpeace, state that "Capturing CO2 from existing fossil fuel facilities requires the use of expensive equipment and large quantities of energy, thus reducing overall efficiency of the facility...........spending money on CCS is diverting urgent funding away from renewable energy and efficiency improvement solutions, which could be readily available for large-scale deployment in the short-term for the climate crisis." [33)].

Table 2.1: Forced Field Analysis of CCS undertaking in Indonesia

Forces Supporting CCS →	← **Forces Against CCS**
• Significantly reduce CO_2 emission by 80-90% compared to a plant without CCS; • International support for financing CCS projects and obtaining carbon credit are available; • Availability of deep seas in Indonesia for CO2 ocean storage; • May have potential usage for future enhancement of Coal Bed Methane production; and • May have economic usage to supply industries using CO2.	• Increased cost of energy produced in a coal fired plant with CCS by 21-91%; • Increase fuel needs and other system costs in a coal fired plant by 25-40%; • CCS technology is very expensive and largely unproven; • No large CO_2 utilization for EOR in Indonesia due to poor miscibility of CO_2 with Indonesian crude and incompatibility with relatively shallow reservoirs *); • No other significant CO_2 utilization market in Indonesia industry at this time; • Ocean storage of CO_2 may increase ocean acidification; • Need geological study to identify deep geological formation suitable for CO_2 storage *); • High seismic activities in Indonesia may not warrant safe CO_2 storage in deep geological formations due to leakage; • Indonesia has significant potential of renewable energy resources and energy efficiency improvement which could be developed faster and less expensively than CCS to address the urgency of GHG reduction; and • No regulation limiting and providing stimulus to mitigate CO2 emission, and promoting economic benefits of reducing GHG emissions

*) LEMIGAS has conducted studies on EOR using CO2 injection and CO2 storage in PERTAMINA's depleted small oil fields in South Sumatera, .A pilot project may be in order to determine the feasibility of a full scale CO2 EOR .(Refer Study on: "Worksheet *Screening CO2 EOR Sequestration Potential in Indonesia* " by Usman Pasarai, et.al, Lemigas Scientific Contribution, Vol. 33 No.1, May 2010).

Furthermore, Indonesia is facing a potential electricity and energy crisis between the years 2015 – 2018, and could not afford reductions in existing overall efficiency of power plants, let alone the required investment for large CCS facilities. Although a full scale CCS project may not be imminent, it is believed that a pilot CCS should still be undertaken as a learning curve prior to considering a large-scale CCS program, particularly if financial support could be made available.

3. CCS Regulatory Framework, Economics and Funding

3.1 CO2 as a Resource or a Pollutant

The fossil fuel industry points out that carbon dioxide is essential for both plant life and human life. Is it wrong, then, to label carbon dioxide as a pollutant? The definition of pollution in Webster's *dictionary is "to make physically impure or unclean: befoul, dirty." By that definition, carbon dioxide is not pollution. However,* Webster's *also has the definition: "to contaminate (an environment) especially with man-made waste." Carbon dioxide is a waste gas produced by fossil fuel combustion, so thus can be classified as man-made waste. One can also make the case that carbon dioxide is contaminating the environment, since increased CO2 from burning fossil fuels has already harmed sea life. Carbon dioxide, when dissolved in sea water, is deadly to shell-building microorganisms that form an important part of the food chain in some cold ocean regions. The extra CO2 lowers the pH and make the water too acidic for these organisms to build their shells. As has been reported in Acidifying the Oceans, the observed increase in acidity of 0.1 pH units during the past century due to fossil fuel burning, and expected continued acidification in the coming decades, could cause a massive die off of marine life and collapse of the food chain in these ocean areas. Based on these arguments, the fossil fuel industry's slogan, "Carbon dioxide: they call it pollution, we call it life!" could just as truthfully be phrased, "Carbon dioxide. We call it pollution, and we call it death." One need only look at our sister planet, Venus, to see that too much "life" can be a bad thing. There, an atmosphere of 96% carbon dioxide has created a hellish greenhouse effect. The temperatures of 860 F at the surface are hot enough to melt lead. There's not too much life there!*

The fossil fuel industry point out that the burning of fossil fuels has brought dramatic increases in wealth and prosperity to the world. This is a good point, and we should not seriously damage the basis of the world economy through reckless efforts to cut CO2 emissions. We can credit a good portion of the marvels of modern civilization to the availability of cheap fossil fuels to power our technological revolution. However, we shouldn't get all misty-eyed about the wondrous things we've accomplished by using this ready source of energy left for us by the fossilized plants of Earth's past. Any technology can bring about terrible suffering if used unwisely. Consider that fossil fuels have also made possible the horrors of modern warfare. The tanks of Hitler's blitzkrieg and the aircraft that have dropped the bombs that have killed millions of innocent people this past century were all powered by fossil fuels. Air pollution from fossil fuel burning has killed millions as well. We need to be honest about both the importance of fossil fuels, and the dangers they pose if used unwisely. The threat of climate change due to burning fossil fuels needs to be addressed truthfully, so that we can make wise decisions about the future of our energy technology. The untruthful new ad campaign by the fossil fuel industry is harmful to this end.

It is well known that CO2 in the atmosphere has risen from about 275 ppm (.0275%) to 375 ppm (.0375%) since the Industrial Revolution began in the 1800s. This extra CO2, added to the atmosphere by the burning of fossil fuels, has contributed to the observed rise in global temperatures of 0.6 degrees C via the greenhouse effect. What is less well known, and is discussed in detail in a March 2006 article in Scientific American called "The Dangers of Ocean Acidification", is that a tremendous amount of the CO2 emitted by fossil fuel burning winds up in the oceans. The oceans have absorbed 48% of all the CO2 emitted since 1800, according to a study published by Sabine *et al.* in 2004 in *Science*. Without the action of the oceans to absorb so much of our waste gases we've pumped into the atmosphere, Earth would be a seriously toasty planet right now.

3.2 Overview of CCS International Regulations and Best Practices

The Model Framework (as summarized in Table 3.1) proposes principles for addressing twenty-nine key issues associated with regulating CCS, based on the work of early-movers such as Australia, Europe and the United States, to assist with national and regional CCS regulatory framework development. For each issue, an explanation is provided as well as examples of how the issue has been addressed in existing legislation. For CO_2 storage issues, base, or “starting point”, model legislative text is also provided, which countries and regions can draw on in developing CCS regulatory frameworks. Issues addressed include:

Table 3.1: Model Framework of International CCS Regulations

1. Classifying CO_2	11. Engaging the public in decision making	21. Corrective measures and remediation measures
2. Property rights	12. CO_2 capture	22. Liability during the project period
3. Competition with other users and preferential rights issue	13. CO_2 transportation	23. Authorisation for storage site closure
4. Transboundary movement of CO_2	14. Scope of framework and prohibitions	24. Liability during the post-closure period
5. International laws for the protection of the marine environment	15. Definitions and terminology applicable to CO_2 storage regulations	25. Financial contributions to post-closure stewardship
6. Providing incentives for CCS as part of climate change mitigation strategies	16. Authorisation of storage site exploration activities	26. Sharing knowledge and experience through the demonstration phase
7. Protecting human health	17. Regulating site selection and characterisation activities	27. CCS ready
8. Composition of the CO_2 stream	18. Authorisation of storage activities	28. Using CCS for biomass-based sources
9. The role of environmental impact assessment	19. Project inspections	29. Understanding enhanced hydrocarbon recovery with CCS
10. Third-party access to storage site and transportation infrastructure	20. Monitoring, reporting and verification requirements	

Source: International Energy Agency, CCS Model Regulatory Framework, 2010

3.3 Regulations on GHG emissions in Indonesia’s Oil and Gas Industry

Law No. 22 Year 2001 governs Indonesia’s oil and gas industry activities. Government Regulations (GR) No. 55 Year 2009, replacing GR No. 35 Year 2004, and GR No. 30 Year 2009, replacing GR No. 36 Year 2004, regulate the upstream and downstream oil and gas activities respectively. These GRs state that operators of upstream and downstream oil and gas activities are obliged to follow and comply with stipulations in prevailing safety, health and environmental regulations. Consequently, the legal basis of Green House Gas emission abatement in the oil and gas industry rests under the environmental law and regulations.

Table 3.2: Legal Basis of Developing a GHG Inventory in Indonesia

1. Law Number 6/1994 concerning Ratification of the United Nations Framework Convention on Climate Change means Indonesia is obligated to periodically develop its National Communication, financed by developed country parties to the Convention; a GHG Inventory is part of the National Communication.
2. Law Number 31/2009 concerning Meteorology, Climatology and Geophysics calls for a need to develop a GHG Inventory for climate change policy development.
3. Law Number 32/2009 concerning Environmental Protection and Management stipulates that the Government at national, provincial and city level must develop GHG Inventories.
4. A Draft Presidential Decree concerning National GHG Inventory (on-going process) provides for:
   a. A legal basis for all relevant ministries/sectors to conduct GHG inventories
   b. Also regulates: (i) the role of each line ministry and local government; (ii) GHG inventory relating to NAMA's implementation in a MRV manner; and (iii) the use of national GHG inventory reports

Source: Ministry of Environmental Affairs/UNDP: "Indonesia's Second National Communication", the 9th Workshop on GHG Inventories in Asia, Phnom Penh, Cambodia, July 2011.

Based on Government Regulation No. 41/1999 on Air Pollution Control, the Minister of Environmental Affairs (MEA) has issued Regulation No. 13/2009 on Standard Quality of Emissions of Stationary Sources in the Oil and Gas Activities/Business, which stipulates the maximum allowable emission of particulates, carbon monoxide, nitrogen oxide, and sulfur oxide; but no standard limitations for carbon dioxide.

Considering Law Number 32/2009 concerning Environmental Protection and Management and MEA Regulation No, 13/2009, the Minister of Environmental Affairs issued MEA Regulation No. 12/2012, which provides a guideline for calculating the emission load of oil and gas activities, including CO2 emissions.

Presidential Regulation No. 71/2011 has been promulgated to prepare an inventory of National Green House Gases. The objectives of Presidential Regulation No. 71/2011 are: (i) to make available periodical information on the level, status and trend of emission changes and GHG capture, including carbon storage at the national, provincial and regional levels; and (ii) to record information on achievement of GHG emissions reductions from the national mitigation on climate change. The report on national GHG emissions inventory is used to formulate policy and evaluate the implementation of activities of national climate change mitigation, including a plan of national action of GHG emission reductions. The regulation stipulates the process and procedure for the GHG inventories and the obligation of the Minister of Environmental Affairs and other relevant ministers, governors, regents and city mayors, and other relevant institutions. The Minister of Environmental Affairs is responsible to coordinate all reports and submit an annual report to Coordinating Minister of Welfare.

The GHG inventory should be conducted at the carbon emission sources and their absorption, which include: (a) agriculture, forestry, peat and other land usages; (b) supply and utilization of energy: (i) energy generation, (ii) industry, (iii) transportation, (iv) household, (v) commercial, (vi) agriculture, construction, and mining; (vii) process industries and product utilizations; and (viii) waste management.

It appears, however, that implementation of this Presidential Regulation has lacked follow-up. Each relevant minister, governor, regent/city mayor, should issue corresponding regulations for the consistent realization of the national GHG inventory. Having this GHG inventory data, appropriate standard limits for GHG emission for each province and major city could be established and become the basis for the needs of CCS.

Furthermore, a government regulation on environmental economic instruments has been undergoing drafting since 2013. The economic instrument covers: (i) development and economic activity plan; (ii) environmental funding; and (iii) incentives and / or disincentives.

The development and economic activity plan includes preparation of an annual National and Regional Natural Resources and Environmental Balance, which is used as the basis for calculating the Gross Domestic Product and the Green Gross Domestic Product. To ensure sustainability of environmental services, the regulation stipulates the compensation / fee for the environmental services and the internalization of environmental costs.

On environmental funding, the regulation provides broad statements of the purposes and sources of funding covering: (i) environmental recovery fund; (ii) environmental abatement and recovery fund; and (iii) conservation support / mandatory fund.

Environmental incentives and disincentives are given in the following forms:

a. Development of environmentally friendly labeling;

b. Procurement of environmentally friendly goods and services;

c. Performance reward system in environmental protection and management;

d. Development of environmentally friendly financial institutions and investment market;

e. Development of trading system in waste and/or emissions disposal licenses;

f. Development of financial system in environmental services;

g. Development of environmental insurance;

h. Application of environmental taxes, retribution and subsidy; and

i. Application recovery fund for recycle process.

The regulation provides general stipulations on the types of incentives and disincentives but no implementation details, including for carbon emissions abatement.

In view of the urgency for the GHG emission abatement to minimize the impact on Climate Change, it is recommended to consider issuance of Presidential Regulation to provide a strong legal basis specifically for GHG emission abatement and corresponding appropriate mitigation actions at national level based on the spirit or results of Presidential Regulation No. 71/2011 on national and regional GHG Inventories. This Presidential Regulation should become the basis for a joint Minister of Finance and Minister of Environmental Regulation for Indonesia's National Appropriate Mitigation Actions on GHG emission as it involves environmental as well as financial issues covering fiscal incentives and penalties, carbon tax and carbon economics, without necessarily waiting for the issuance of the Government Regulation on environmental economic instruments. The aforementioned Presidential Regulation and Joint MEA-MOF Regulation should address GHG issues as tabulated in the Model Framework on Paragraph 3.2 with due consideration on the Indonesian context.

In particular an appropriate regulatory framework for Indonesia should at least address (but not be limited to), the following issues:

a. GHG emission abatement targets for 2020 and beyond;

b. Guideline for each ministry or institution in charge of GHG emissions mitigation to prepare a five to ten year rolling plan (Refer Presidential Regulation No. 61 Year 2011 on National Action Plan on Reduction of Greenhouse Gas Emission);

c. Standards for GHG or CO2 emission limits for each stationary and mobile equipment with due consideration to population density, geographical conditions, and economy (Reference: Presidential Regulation No. 71 of 2011 on GHG Inventories; Ministry of Environment Regulations No. 13/2009 on Standard Emission for Non-Moving Sources in the Oil and Gas Business and/or Activities, No. 12/2012 on Guideline for the Calculation of Emission Load in the Oil and Gas Industry Activities, and No. 15/2013 on Measurement, Reporting and Verification on Climate Change Actions);

d. Penalty and reward mechanisms for non-compliance or compliance with the GHG rules. This could be in the form of: (i) carbon tax or carbon disincentive or penalty for inefficient plants or plants with efficiency below the set standard; (ii) carbon credit or carbon incentive for plant efficiency above the standard; and (iii) fiscal and non-fiscal incentives for installing carbon capture facilities;

e. Stipulations on necessity to conduct periodical energy and GHG audits (Refer Minister Energy and Mineral Resources Regulation No. 14/2012 on Energy Management which elaborates Energy Audits. This could be expanded into GHG emission audits);

f. Synchronization with prevailing Ministerial Regulations, such as Minister of Energy and Mineral Resources Regulation No. 14/2012 and Minister of Environment Regulation No. 15/2013; and

g. National or bilateral carbon trading systems and regulations as a substitute for the Kyoto Protocol on CDM.

Carbon taxes or penalties for negative externalities and carbon credits or incentives are fiscal instrument that should not be directly associated with the tax law. They represent Government policy responses specifically established for the promotion and abatement of GHG emission at national level. The sources of funds could include, but not necessarily be limited to, the State Income and Expenditure Budget (APBN), carbon penalties or money collected from GHG emitters who emit beyond established standards, and non-binding foreign grants or government to government / multilateral soft loans. Carbon incentives can be granted to entities that are complying with or exceeding GHG emission standards. The carbon incentives can be nationally and / or internationally traded or used to compensate for carbon penalties, within the entity or its subsidiaries.

For Indonesia, we recommend the Government establish standards for Green House Gas emissions for new coal and fuel oil fired stationary GHG sources used in selected industries. These could be power plants, boilers, furnaces, and gas sweetening plants. Gas and renewable energy industry sources are considered as low GHG emitters. The standards of GHG emissions should be determined with due consideration to Indonesia's regional population densities, geographical conditions, available technology, and economy.

The U.S. Environmental Protection Agency (EPA) proposes a standard GHG emission limit of 1,100 pounds of CO2 per MWh of electricity generated by new coal fired power plants. This standard has been considered onerous by industries, as it would not be achievable without the application of CCS technology to capture 40% of the CO2 produced. (*Congressional Research Service: "EPA Standards for GHG Emissions from Power Plants: Many Questions, Some Answers", 15 November 2013)*.

The GHG emission standard could also be expressed in term of plant efficiency. The average coal fired steam power plant efficiency is 30% to 32%. Higher efficiency coal fired power plants such as those using super-critical boilers could reach 38% to 40% efficiency. Small coal fired power plants of 7 to 20 MW have efficiency of 20% to 22% and produce relatively high GHG emissions and therefore should no longer be used. They should be substituted with gas fired or renewable energy power plants.

3.4 Regulations on Carbon Capture, Transportation, Storage and Utilization in Indonesia's Oil and Gas Industry

The report of the LEMIGAS study on "Determining the Potential for Carbon Capture and Storage in South East Asia, Indonesia Country Report", which focuses on geology and reservoir evaluation of depleted oil and gas fields in South Sumatera; and ADB – Global CCS Institute Study on "Prospects for Carbon Capture and Storage in SE Asia" show that there are potential CCS projects and EOR projects using CO2 injection in South Sumatera province. The province offers: (i) numerous high CO2 emitting industries, such as fossil fuel fired power plants, coal mining activities, natural gas processing plants, and an oil refinery; (ii) depleted oil and gas fields; (iii) oil field surface facilities; and (iv). infrastructure.

The selection of South Sumatera province also takes into consideration the geological stability, characteristic of wells, low population density, and an established surface infrastructure. Additionally, South Sumatera offers abundant un-mineable coal seams which could produce coal bed methane gas (CBM). By injecting CO2 into CBM wells, the CBM production could be enhanced and the CO2 would be absorbed to replace the methane gas.

Figure 3.1: Block Diagram of CCS and CO2 EOR Activities

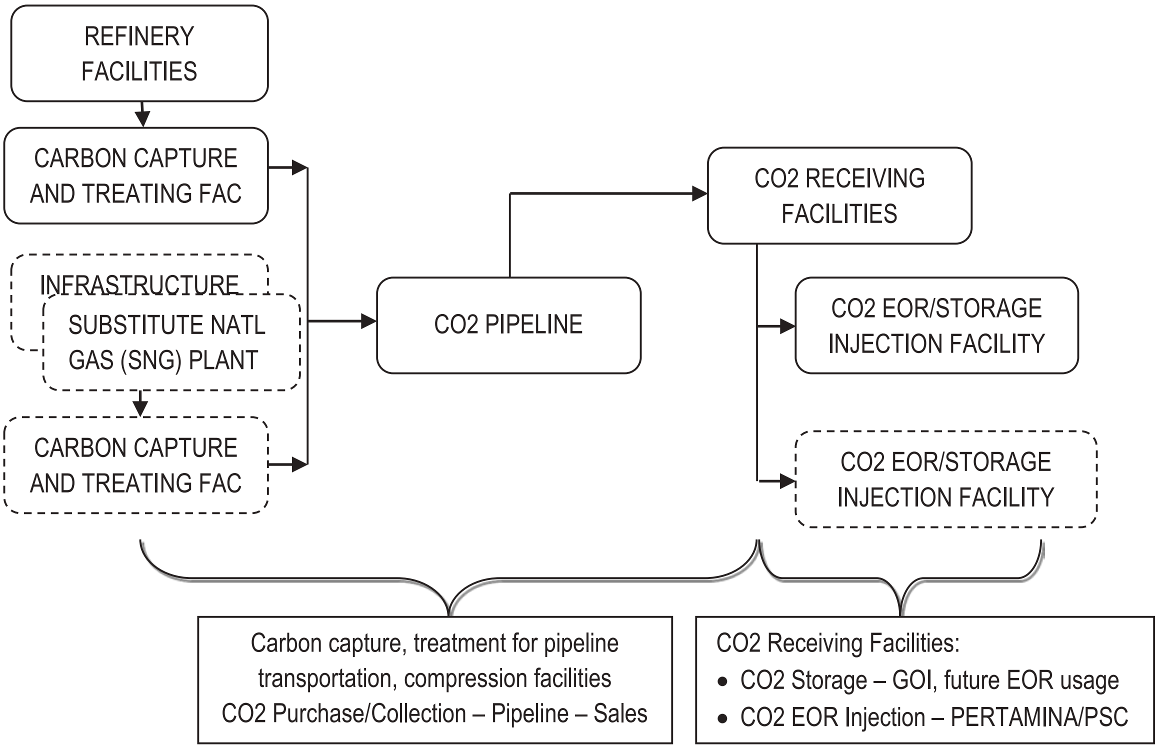


Figure 3.1 shows a simplified block diagram of CCS and CO2 EOR activities, for example, in South Sumatera where CO2 is captured from various facilities, such as fossil fuel fired power plants, refineries, natural gas processing plants, and future low rank coal gasification (substitute natural gas – SNG) plants, and injected into depleted oil field reservoirs for storage or EOR application.

3.4.1 CO2 Capture and Natural Gas Processing Plants

Depending on the level of CO_2 in natural gas, different processes for natural gas sweetening (i.e., H2S and CO_2 removal) are available:

- chemical solvents;
- physical solvents; and
- membranes.

Natural gas sweetening using various alkanolamines (MEA, DEA, MDEA, etc.), or a mixture of them, is the most commonly used method. When the CO_2 concentration in natural gas is high, membrane systems may be more economical. Industrial application of membranes for recovery of CO_2 from natural gas started in the early 1980s for small units, with many design parameters unknown. It is now a well-established and competitive technology with advantages compared to other technologies, including amine treatment in certain cases. These advantages include lower capital costs, ease of skid-mounted installation, lower energy consumption, ability to be applied in remote areas, especially offshore; and flexibility.

The CBM exploitation in Indonesia is in the early stages of development and the CBM prospects for CO2 storage are still uncertain.

Although LEMIGAS has conducted comprehensive studies on CCS and the CO2 EOR project potential in South Sumatera, including recommending a PERTAMINA depleted oil field, Merbau, as the selected pilot area for CCS and CO2 EOR, more technical, financial, policy and regulatory issues have yet to be addressed before the pilot project can be well defined and planned. These issues include but are not necessarily limited to:

a. The oil and gas fields in South Sumatera consist of small, discontinuous layers of reservoirs, which diminish the economies of scale for an effective and economic full scale EOR project. Most marginal fields in South Sumatera have been returned to the Government (MIGAS);

b. Beside PERTAMINA, different entities operate the South Sumatera oil and gas fields, under different contract terms and conditions. Certain fields have been abandoned or inoperative for quite some time;

c. The integrity of the surface and sub-surface facilities should be re-evaluated for developing the pilot and full scale CCS and CO2 EOR;

d. Before a field pilot can be determined, a laboratory CO2 EOR injectivity test, using cores, crude oil and simulated reservoir conditions should be conducted. The results of this laboratory experimentation will be instrumental for appropriate design and specification of the pilot project; and

e. Merbau is a very small field and the pilot CO2 EOR at Merbau may not provide representative data for region-wide CO2 EOR application. There are other larger fields that could be chosen in South Sumatra. The selection should consider, among other things, which would be the best candidate for CO2 EOR, who currently operates the field and under what contract, what is the status of the contract; and who will bear the cost.

- CO_2 storage capacity after ultimate oil recovery and EOR stages is approximately 92 MMton; and

- More detailed data is needed to calculate the amount of CO_2 consumption of each field and to determine the CO_2 injection strategy.

Further the LEMIGAS study focuses on CO_2 sequestration and EOR in oil/gas fields within a radius of 100 km from Pendopo, north of Palembang. A commercial low rank coal gasification plant to produce substitute natural gas (SNG) will be built at Pendopo. Significant associated CO_2 production from this plant should be well managed by appropriate utilization for EOR and sequestration in surrounding oil/gas fields. Highlights and conclusions of the study include:

- Multi sources of CO_2 have been identified within a 100 km radius of Pendopo (see Table 3.1);

Table 3.3: Multi –sources of CO_2 in South Sumatera

CO_2 Source	Method	CO_2 (tons/year)
Power Plants (Multiple Sources)	Fuel Combustion & Data Survey 2012	1,786,062
Petroleum Refinery (Single Source)	Data Survey 2012	619,527
Gas Gathering Station (Single Source)	Data Survey 2012	132,754
Cement Plant (Single Station)	Data Survey 2012	500,760
Fertilizer Plant (Single Station)	Data Survey 2012	2,506, 862
Low Rank Coal – Substitute Nat. Gas	Data Survey 2012	4,500,000

Source: Utomo P.Iskandar, LEMIGAS: The First In-depth Assessment of Carbon Capture Utilization and Sequestration for CO_2 Management of South Sumatera SNG Plant

- The injection profile is defined as the cumulative gross CO_2 volume injected divided by the volume of incremental oil produced as a direct result of the injected CO_2. The number is 10.74 Msf/stb;

- Out of 93 oil fields, 20 have oil gravity between 27^0 - 48^0 API. The fields are located in three zones: North, South East; and West;

- The A1 field has the highest rank in the sink scoring, indicating that this field has highest suitability for CO_2 EOR application and CO_2 storage. The second and third ranks are F and E oil fields;

- West Cluster is selected for early pipelines development due to proximity to the source, having the most suitable field for CO_2 EOR and sequestration, a willing partner to implement CO_2 EOR, and less extensive infrastructure development in the early stages; and

- The largest CO_2 storage potential is the southeast cluster, 27 $MtCO_2$.Total storage capacity for the whole cluster is 72 $MtCO_2$ or equal to 13 years of storage capacity with 4.5 $MtCO_2$/year filling rate.

Table 3.4 Top 20 Oil Field Ranking Relative to Proximity and Stream Phase for all Clusters

Cluster On Stream Phase	Field's Rank	Field Name	Pendopo (km)	OOIP (MSTB)	Total CO2 Storage (ton)	Add'l Oil Rec. (MSTB)	Cum. Inj. Per Phase Mton/yr	Period Inj.	
								yr	i-year
North 1	9	D5	48.3	237,946	3,130,974	11,897	1,68	10	1
	5	D3	49.0	366,000	4,253,415	18,300		10	
North 2	20	E8	62.9	43,210	713,691	2,161	3.02	10	3
	2	F	69.7	273,300	865,347	32,796		10	
	11	H1	96.9	160,357	2,312,435	19,243		10	
North 3	17	E1	70.2	92,550	1,239,534	11,106	0.83	10	4
	8	D2	71.2	77,260	429,544	3,863		10	
West 1	18	B	11.1	119,004	1,961,680	14,280	3.65	10	1
	1	A1	13.8	902,405	18,441,682	45,120		10	
	4	D6	63.7	124,301	4,968,752	14,916		10	
West 2	13	F9	80.7	25,910	729,936	3,109	0.17	10	2
So, West 1	15	D4	16.1	16,551	680,683	1,986	0.11	10	1
So. West 2	19	D	14.7	157,331	4,551,889	18,880	3.20	10	2
	3	E	20.0	321,064	1,276,226	38,528		10	
So, West 3	14	E10	36.6	96,000	1,600,541	11,520	0.64	10	3
So. West 4	12	H5	63.3	164,094	3,126,618	18,491	1.03	10	5

Source: Utomo P.Iskandar, LEMIGAS: The First In-depth Assessment of Carbon Capture Utilization and Sequestration for CO2 Management of South Sumatera SNG Plant

Before embarking on a full scale CO2 EOR, it would be advisable to undertake a pilot CO2 EOR. A study conducted by LEMIGAS under a joint sponsorship of Ministry of Energy and Mineral Resources, BAPPENAS, and the Asian Development Bank on "Determining the Potential for Carbon Capture and Storage in Southeast Asia (Indonesia Country Report)", dated September 2012, provides a proposal for a CO2 EOR pilot project in South Sumatra.

- The proposed CO2 sequestration and EOR pilot project takes Merbau Gas Gathering Station (GGS), as the source of CO2, and fields, identified as H1, F21, I2 and I1, which are located 70 – 100 km from Merbau GGS. Merbau GGS can supply 0.15 megatons of CO2 per year, which is enough for a commercial EOR operation and more than enough for a pilot CO2 storage project with an injection rate of 50-100 tCO2/day; and

- For the pilot, CO2 transport could be by truck or boat as constructing a pipeline may not be justified for the low capacity of CO2.

3.4.4 Enabling Regulations for CCS and CO2 EOR

To enable Carbon Sequestration and utilization of CO2 for EOR activities as described in the foregoing paragraphs the following GOI policies and regulations should be contemplated:

1. Carbon Emission Standards;

2. Carbon Capture and Processing into Pipeline Gas;
3. Carbon Transportation Through Pipeline and Trucking;
4. Carbon Sequestration; and
5. CO2 Enhanced Oil Recovery.

A Regulation on Carbon Emission Standards (CES) is discussed and proposed in Section 3.3. Since carbon emission sources are spread over the jurisdiction of many Ministries, the appropriate regulation should be in the form of a Presidential Regulation, with reference to Law No. 32 Year 2009 on Environmental Protection and Management; Presidential Regulation No. 61 Year 2011 on National Action Plan on Climate Change; and Presidential Regulation No. 71 of 2011 on GHG inventories. This Regulation should affect new facilities; however, existing facilities which are not in compliance with the CES could be given incentives for making the emissions attain compliance within certain agreed time-frames.

Carbon capture and processing into a carbon gas pipeline, trucking or other gas transportation means should be regulated under the Ministry of Energy & Mineral Resources with due consideration of a CES Standards Regulation to be developed. CO2 gas processing and pipeline transportation should be regulated under a Ministry of Energy and Mineral Resources regulation, similar to the regulation on gas transportation through pipelines.

No ownership currently applies to CO2 emitted to the air. But, if the Government decides to capture emitted CO2 and store it, the Government should be able to claim ownership of the CO2. The capture, processing and transporting of CO2 to the oil and gas fields for storage and/or CO2 EOR could be tendered to third parties. The costs of carbon capture facilities should not be borne by emitters, including any cost to operate the carbon capture and related facilities as well as the power requirements, if they have met the CO2 standard limit. If they have not met the limit they should be separately penalized.

Typical production sharing contracts cover only primary production and compliance with prevailing environmental regulations, but there is no standard limitation for CO2 emissions. Some oil and gas fields produce associated gas and natural gas which may contains CO2 in excess of 20% by weight. Before piping the natural gas to be used for fuel, the CO2 contents are reduce to 3% to meet the gas quality requirement and the CO2 captured in the natural gas plant is released to the air or mixed with effluent water.

For carbon storage in the oil and gas fields, the Government could consider amending the production sharing contracts with the respective operators to allow injections of CO2 gas for storage in their oil and gas fields. The amended production sharing contract should include cost recovery, liability, and other terms and conditions relevant to the carbon storage operations.

For the use of CO2 for EOR, the Government could consider amending the production sharing contract with the operator of the respective field to include among other things but not limited to: cost of CO2 at the ownership transfer, CO2 specifications, EOR splits, and other incentive programs. We do not recommend the EOR split be based on incremental oil over a baseline, but rather a primary split for the projected primary oil production and an EOR split for production exceeding the primary oil production. This is to avoid argumentation in determining the base line in the future. For example, in the Duri Field EOR by steam flood, 10% of the production after steam-flooding is considered as primary production and leads to a production split of 88:12, and 90% of the production results from the steam flood and a production split of 85:15 is applied.

3.5 CCS Cost and Benefit Analysis

The study conducted by LEMIGAS under a joint sponsorship of the Ministry of Energy and Mineral Resources, BAPPENAS, and the Asian Development Bank on “Determining the Potential for Carbon Capture and Storage in Southeast Asia (Indonesia Country Report)”, dated September 2012, provides a proposal for the CO2 EOR pilot project in South Sumatra with preliminary economic analysis for the MERBAU GGS CO2 emitters to store in a nearby oil field.

Key assumptions for the preliminary analysis are outlined below:

- Oil price =$ 90/barrel;
- Lifting cost = $ 10/barrel;
- CO2 cost = $ 9/barrel;
- FTP = 10% non-sharable;
- GOI share = 0.7321;
- PSC Contractor share = 0.2679;
- Domestic Market obligation = 25%;
- Domestic Market Obligation Share = 25%;
- Taxes = 44%; and
- CO2 trading revenue as part of PSC contractor’s share.

Results of the economic analysis are presented in Table 3.5.

Table 3.5: Preliminary Project Economics – Merbau GGS CCS Pilot Project

NO	PARAMETER	UNIT	BASE CASE (PSC)		
			PESSIMISTIC	MODERATE	OPTOMISTIC
1	**CAPITAL EXPENDITURE**				
a	Capital	MUS$	11,825	32,223	133,959
b	Non-Capital	MUS$	3,563	9,754	40,551
c	Total Expenditure	MUS$	15,388	41,977	174,510
2	**LIFTINGS**				
a	Incremental Oil	Mbbl	5,000	5,000	5,000
b	Oil Price	US$/Bbl	90	90	90
3	**GROSS REVENUE**	MUS$	450,000	450,000	450,000
a	First Tranche Petroleum	MUS$	45,000	45,000	45,000
b	Investment Credit	MUS$	0	0	0
4	**GROSS REVENUE AFTER FTP**	MUS$	405,000	405,000	405,000
5	**COST RECOVERY**				
a	Operating Cost				
	- Lifting Cost	MUS$	50,000	50,000	50,000
	- CO2 Price (US$/ton x Ton	MUS$	34,551	34,551	34,551
	CO2 Inj.	MUS$	11,825	32,223	133,959
b	Depreciation	MUS$	3,563	9,754	40,551
c	Non-Capital	MUS$	99,939	125,528	259,061
c	Total Cost Recovery	%	22.2	28.1	57.6

NO	PARAMETER	UNIT	BASE CASE (PSC)		
			PESSIMISTIC	MODERATE	OPTOMISTIC
e	CR/GR				
6	**EQUITY TO BE SPLIT**	MUS$	305,061	278,472	135,939
7	**INDONESIA SHARE**				
a	GOI Share	MUS$	233,348	203,881	106,848
b	GOI Share from FTP	MUS$	45,000	45,000	45,000
c	Domestic Requirement	MUS$	15,321	13,986	7,330
d	Government Tax Entitlement	MUS$	29,212	26,666	13,975
e	Total Indonesia Share	MUS$	312,882	289,533	179,353
f	GOI/GR	%	69.5	64.3	38.5
8	**CONTRACTOR SHARE**				
a	Contractor Equity Share	MUS$	81,713	74,591	39,091
b	Contractor Equity Share from	MUS$	0	0	0
b	FTP	MUS$	20,428	18,648	9,773
c	Gross Domestic Requirement	MUS$	5,107	4,662	2,443
d	Domestic Requirement	MUS$	66,392	60,605	31,761
e	Adjustment	MUS$	29,212	26,666	13,975
f	Taxable Share	MUS$	17,179	33,939	17,786
g	Government Tax Entitlement	%	8.3	7.5	4.0
	Net Contractor Share				
	Cont./GR				
9	**FISCAL CONDITION**		FTP 10%, No Shere Investm. Credit 0% GOI: Cont 85:15 DMO 25% DMO Fee 25% Tax 44%	FTP 10%, No Shere Investm. Credit 0% GOI: Cont 85:15 DMO 25% DMO Fee 25% Tax 44%	FTP 10%, No Shere Investm. Credit 0% GOI: Cont 85:15 DMO 25% DMO Fee 25% Tax 44%
10	**REFERENCES**		Snovit CO2 Storage Project Cost Sleipner CO2 operating cost	California Reservoir CO2 Storage Project Cost East Texas Reserv. CO2 Storage Proj. Cost Sleipner CO2 operating cost	California Reservoir CO2 Storage Project Cost Sleipner CO2 operating cost
Pessimistic = Low Capital Investment; Moderate = Mid Capital Investment; Optimistic = High Capital Investment					

Source: LEMIGAS – "Determining the Potential for Carbon Capture and Storage in Southeast Asia – Indonesia Country Report", September 2012

The economic analysis indicates:

- Higher crude oil prices will increase the contractors and GOI revenues, while the rise of the secondary recovery split and investment credits will only increase the contractors revenues. In the case of low crude oil prices, the contractor who provides the financing will incur most of the losses;

- An acceptable ratio of Net Contractor Share and GOI Share to Gross Revenue should be decided to establish the feasible CCS project deployment in Indonesia;

- There is a need to have an incentive package for enhanced oil recovery operations, which is in the form of valuing domestic market oil at prevailing export prices for say the first five years of production and an investment credit on capital costs associated with production facilities. Such incentives are applicable for incremental oil production, that is, all production above an agreed base line, which is assumed to be primary production; and

- It is necessary that policy and regulations be framed to link CCS projects to possible sources of external funding.

The study recommends three stages for commercial development of CCS. Following a successful Pilot Project, a Demonstration Project should be in order, before a full scale Commercial Project could be undertaken.

PILOT PROJECT

Stage 1: 50 – 100 ton/day of CO_2 injected into many wells continuously over several months. This would provide knowledge of reservoir performance to support financing and designing of a Demonstration Project.

DEMONSTRATION PROJECT

Stage 2: Large quantities of CO_2 injected into many wells continuously over many years with 500 – 2,700 ton/day or more of CO_2 injected into many wells for 10 + years. This would confirm long-term successful CO_2 storage to support financing and construction of at least one full scale commercial operation.

COMMERCIAL PROJECT

Stage 3: Very large quantities of CO_2 captured from one or more sources and injected into one or more locations over a very long-term period - 2,700 – 30,000 ton/day of CO_2 captured and injected over 20 + years. Capture and store sufficient quantities of CO_2 to reduce substantially CO_2 emissions.

3.6 CCS Project Funding and Financing Best Practices

The study conducted by LEMIGAS provides an overview of CCS costs, which consist of:

a. Capital Cost (CAPEX), which includes equipment and system to separate, compress, transport, inject and monitor CO_2 in long-term storage sites over a defined period of time. These costs also include owner's costs related to land purchase, facilitation of legal issues, application of permits, and other development costs; and

b. Operating and maintenance costs (OPEX) refer to costs which are incurred during production, transportation, injection, monitoring. They also include fuel costs, operating labor, consumables and maintenance charges. The operating cost may be further broken down into three components: Fixed Operating and Maintenance

(FOM) costs, Variable Operating and Maintenance (VOM) costs, and Fuel Costs (FC).

The source of CO_2 is assumed to be the onshore gas processing plant (MERBAU GGS) with a full scale CCS project at nominal size for the gas processing case of 1 Mt/year CO_2. This capacity matches the recommended size for a demonstration unit. The per-unit cost for pilot and demonstration stages will be higher due to the limited economies of scale.

Table 3.6 shows the capital and operating costs for the gas processing case:

Table 3.6: CO_2 Assumptions of Costs for Gas Processing Plant

Carbon Capture Plant Capital Costs	$ MM	167
Pipeline		
Length of pipeline, volume	km, inch	150, 10
Pipeline construction cost	$/inch.km	51.300
Injection wells in saline aquifer	Number	2
Off-shore storage construction cost	$ MM/well	7
Storage maintenance cost	$ MM/y-well	1
Operating Costs		
CO_2 compression power	$ MM/year	5
Fixed OPEX	$ MM/year	1
Variable OPEX	$ MM/year	-
Pipeline Maintenance	$ MM/year	3
CO_2 storage operating cost	$ MM/year	3
Total annual cost	$ MM/year	12

For the EOR cost, the following assumptions were used for the base case:

- Gravity/basis differentials, production, tax, royalties etc. $ 15/bbl
- Depreciation $ 7.50/bbl/well/lease
- O& M $ 12 / bbl
- Required pre-tax margin 40%
- 1 barrel of incremental EOR oil requires: 0.32 t CO_2/bbl

The study assumes that the maximum price that an oil producer will be willing to pay for CO_2 for EOR is given by the following equation:

Maximum willingness to pay for CO_2 for EOR [$/t net CO_2 injected] =

[Poil – {Poil*PROFITPT) + EOR cost}]/Inject Product

Where:

- o Poil = market price of oil ($/bbl);
- o PROFITPT = Threshold pre-tax profit required by the oil producers (%);
- o EOR cost = EOR Cost ($/bbl) given by the sum of (a) Gravity/basis differentials, production, tax, royalties; (b) depreciation and operation; and (c) maintenance cost of well lease; and
- o Inject Product = CO_2 injection productivity given by the CO_2 required per barrel of production (t CO_2/bbl).

The study assumes 40% as the threshold pre-tax profit. EOR costs were taken to be US$ 35/barrel. Furthermore, the study team used a reference assumption of 0.32 t CO_2/barrel for oil production from EOR.

The levelized cost for a natural gas processing facility capturing CO_2 without EOR is US$ 28/t CO_2 captured and storage. This levelized cost is composed of compressor plus dryer of $ 11/t CO_2 captured, pipeline of $11/t CO_2 captured and injection wells of $ 6/t CO_2 captured. With EOR the levelized cost drops to $ 22/t CO_2 since the storage cost will be borne by the operator. The credit price translates into an oil price of US$ 70/barrel at $ 0.32/t CO_2/bbl.

Source of funding for the pilot CCS from the Merbau GGS shall be from the Government and financial institutions which include assistance from bilateral and multilateral institutions related climate change projects, export credit agencies, and sovereign wealth-funds. PKPPIM could be provided a role in generating and coordinating the domestic and international financing. For the use of CO_2 EOR, the incremental capital and operating expenditures could be borne by the oil field operator under a cost recovery scheme of the PSC.

The Indonesian Climate Change Trust Fund (ICCTF) was established in 2009 to facilitate access to financing from international sources for climate change-related adaptation and mitigation expenditures. The ICCTF also supports investments for communities exposed to severe pollution environments and plans to invest in revenues generating activities. It and / or PKPPIM in the Ministry of Finance could be provided a role in securing and coordinating financing.

For the implementation of the MERBAU GGS CCS project, we recommend to assign the work to PT Perusahaan Gas Negara Tbk (PGN) to manage the construction and operations of the CO_2 capture, processing into saturated gas, compressing and piping to the storage site(s). PGN could seek a competent partner from donor country(ies) to carry out the engineering, procurement and construction of the carbon capture and transportation through the pipe.

For the CO_2 EOR implementation, we recommend to assign the field operator (in this case PT PERTAMINA Tbk) which in turn could appoint its appropriate business unit to carry out the field development work for the CO_2 injection for EOR. The project could be handled under the existing PSC arrangement, sponsored under soft loan bilateral / multilateral agreements with institutions, such as ADB, World Bank, and others. An appropriate incentives program could be considered for introduction into the PSC amendment for the pilot, demonstration and full scale EOR projects.

A suitable simple type of incentive could be in the form of an investment credit such as that applicable in the second generation of Production Sharing Agreements (after 1977). The investment credit may be a certain percentage of capital investment costs directly required for developing the project, including the wells, wellhead and subsurface equipment, injection and oil production facilities.

Another possible type of additional incentive could be based on incremental oil production, that is, all oil production above an agreed base line, which is assumed to be primary oil production. This incentive would value the crude oil price for the domestic market at world oil prices for say 5 (five) years. This would address the experience whereby negotiations to reach an agreement on the base line production have been time consuming and costly, resulting in delays of project start up.

It is noted that looking at the EOR methods which have been commercially successful, it can be said that steam injection has a high chance of success, miscible displacement may be successful under special conditions and carbon dioxide (miscible) flooding is still somewhat of a question mark, although it has potential. All EOR methods are low margin operations under best circumstances.

4. Review of Indonesia's Oil and Gas Industry and CCS

The oil and gas industries respond to the issues of climate change by conducting continuing reviews and pursuing initiatives in the control of greenhouse gas (GHG) emissions. Efforts include preparing inventories of sources of emissions, and the periodic calculation and reporting of GHG emission loads. Meanwhile, broader climate change mitigation initiatives include the development of new and renewable energies, energy conservation, Clean Development Mechanism (CDM) projects, clean production technologies, and product development to reduce impacts on climate change.

In general, GHG emissions from the oil and gas industry mainly result from engines used in production activities, flaring in upstream activities and oil refinery activities.

4.1 GHG issues in the Up-stream Oil and Gas Industry

4.1.1 Gas Flaring

The GHG issues in the up-stream oil and gas industry in Indonesia are primarily in gas flaring and in some cases venting of associated gases. Gas flaring still continues to remain a problem. Direct reduction of GHG emissions in upstream business activities can be achieved by reducing flared gas, whereby the associated gases that were formerly flared or otherwise disposed of into the atmosphere are now utilized to generate electricity or are commercialized in various ways.

Current estimates suggest that 25–30 percent of all flaring activities in Southeast Asia are occurring in and around Indonesia, which is significant given that Indonesia only accounts for around 12 percent of all oil production in the region. However, flaring emissions in Southeast Asia have been reducing at a fairly strong pace; current estimates from the U.S. National Oceanic and Atmospheric Administration (NOAA) show reductions of around 5 percent per year from 2000 to 2004. In 2011, the most recent year with data available, gas flaring in Indonesia was estimated to be around 2.3 billion cubic meters (bcm) per year [5)].

Reduced flaring through the implementation of a zero-flaring program could offer 2 $MtCO_2e$ of abatement at a relatively high cost of 28 USD per ton CO_2e. The relatively small abatement is a result of significant anticipated reductions in flaring emissions in the business-as-usual scenario (currently at 5 percent per annum). In the near future, carbon capture and storage could offer a significant abatement opportunity for the petroleum and gas sector. However, the deployment of this technology is still limited and cost structures are largely unknown but are likely to be high.

4.1.2 CO2 Gas Associated with Natural Gas and Oil Production

Handling of large amounts of CO2 gas from new wells that are associated with natural gas or oil and gas production will become a problem in the future. Contents of CO2 gas vary from field to field. In South Sumatra the average associated CO2 gas production content ranges from 3% to 10%. Relatively small amounts of associated gas produced is either flared or vented into the atmosphere. In Riau, CO2 content of associated gas production averages 24%. Natural gas processing plants treat the associated gas into pipeline gas for fuel with reduced CO2 content to about 3% using the amine process. At Natuna Alpha D gas field, the CO2 content was estimated at 70%. The plan calls for a gas process in the treating plant that will separate CO2 from the natural gas and then re-inject it back to the reservoir.

4.1.3 Carbon Sequestration and CO2 Potential for EOR

The upstream oil industry in Indonesia offers large CO2 storage capacity and CO2 usage for enhanced oil recovery (EOR) in depleted reservoirs. LEMIGAS, has conducted geological and reservoir studies of the CO2 potential for Enhanced Oil Recovery and Carbon Capture Storage potential in Indonesia. The study reveals that South Sumatera Basin offers potential depleted oil and gas reservoirs for CCS and CO2 EOR undertakings with existing and near future CO2 sources and gas pipeline infrastructure.

The use of carbon dioxide (CO2) for enhanced oil recovery (EOR) in the maturing oil reservoirs of Indonesia offers a unique opportunity to extend the use of existing oil and gas infrastructure while providing solutions to increasing fossil fuel demand, climate change and commitments to reduce greenhouse gas (GHG) emissions. Implementation of such projects requires alignment of commercial interests along a complete CO2 value chain and creation of incentives that may go beyond national boundaries.

To address these issues there needs to be dialogue between the oil industry sector with the three key government bodies (finance, energy and environment). The key facilitating parameters are market oil price, CO2 delivered price and the nature of government incentives. It is the type and magnitude of the incentives that will draw the parties together to realize as much of the potential incremental oil prize as possible. No other commercial solution has the potential to reduce CO2 emissions as much as CO2 for EOR.

In order to encourage its use Government needs to consider offering fiscal incentives under the framework of Production Sharing Contracts to encourage CO2 capture and storage for EOR. The incentive mechanisms could take many forms. From the CO2 experience in the United States during the past 30 years, the incentive has been in the form of federal government tax credits and specific State allowances that have created the prerequisite incentives to initiate tertiary oil production using CO2. The application of investment tax credits of 15% to 25% has helped reduce the pain for the large investments and purchased CO2 required before incremental oil production is realized.

In Indonesia, the incentive could be in the form of an investment credit and/or incremental oil production, which would be that production over an agreed base-line or decline curve. While these curves have been difficult to establish for new oil fields, they are readily understood and are already provided to the government on existing oil fields. Moreover, based on the Indonesian experiences in the 1970 and 1980’s, the negotiation to reach an agreement on the base line production can be time consuming and costly resulting in delays of project start-ups. The disagreement covers a wide range of issues, starting from the methodology, tools, and determination of reservoir parameters, recoverable reserves and economic limits.

In summary, there are likely to be challenges ahead to apply CO2 for enhanced oil recovery in Indonesia. The challenges seem clear; to face additional costs of production, incentives must be considered to offset the increasing cost. Moreover, the Indonesian oil industry’s competitive position has been declining for years due principally to commercial/business factors and that there is no reason to believe the negative, historic trend will change without a meaningful improvement in the return of investors. This coupled with specific actions of the Government of Indonesia and the long lead time required for enhanced oil recovery ventures should be one of the central points of improvement efforts to CO2 capture and storage for

EOR. Equally important are programs for improvement of the investment climate for the oil industry, which has been deteriorating for years.

Note that Indonesia's PSC terms have mainly been designed for primary oil production with the objective of maximizing revenue for the Government. The present Indonesia's PSC terms include capping the annual recovery of the contractor's cost not exceeding 85% of the gross revenue and the obligation for the contractor to supply the product for domestic market at 10% of the market oil price. Capping cost recovery creates disincentives for enhanced oil recovery projects in view of large initial capital investments required. Therefore an incentive will be required for improving the economics of tertiary recovery projects which involve more complex processes, requiring high capital and having higher risk. For Indonesia, the need to maximize the recovery of oil in place by application of improved recovery techniques is critical to complement the exploration efforts.

As natural resource extraction and production projects can cost many billions of dollars and take up to a decade to produce returns, Indonesia remains dependent on foreign investments in order to promote growth in the related sectors and to be able to integrate into the global economy. Uncertainty or disincentives created by the changing of laws necessary to increase governments' stakes in the natural resources sector may be problematic for long-term foreign investment. Governments should be wary of being perceived as unpredictable or unreliable. Few companies are willing to commit to long-term investments in countries offering an unpredictable business climate in which fiscal policies constantly change. As Indonesian natural resources development is expected to grow in the coming decades, political stability and consistent records of good governance, both nationally and in the natural resource sector should not be forgotten in the quest to secure long-term viable economic development.

Therefore, economic incentives need to be considered to attract risk capital for promoting pilot testing and application of enhanced oil recovery techniques.

4.2 GHG Issues in the Down-stream Oil and Gas Industry

GHG reductions in the down-stream oil and gas industry mainly relate to the development of new and renewable energies, energy conservation, clean Development Mechanism projects, clean production technologies, and product development to reduce the impacts of climate change.

The oil and gas sector has more direct opportunities to reduce emissions by as much as 30 percent by 2030 through a focused effort across three abatement areas: improved maintenance and process control, energy efficiency programs; and reduced flaring.

Improved maintenance and process control across the production and refining subsectors could result in a little over 7 $MtCO_2e$ of abatement and is net-profit-positive (-103 USD per tCO_2e), which implies significant savings over the life of the abatement measures. Specific programs within these areas include conservation programs, energy-awareness programs, and measures to reduce fouling build-up in pipes, optimize well and separator pressures; and to optimize the spinning reserves of rotating equipment.

Implementation of energy-efficiency programs could provide an additional 27 $MtCO_2e$ of abatement at negative cost (for energy programs) or modest cost (for implementing cogeneration units). While the levers identified within this category require high capital investments, significant operational savings can be captured through efficiency via reduced energy requirements.

Efficiency is reached through the installation of equipment to improve efficiency and reduce emissions. In oil refineries, fuel efficiency and reduced flaring are strived for. In marketing activities, reduction of GHG emissions is done through the re-engineering of refinery facilities and distribution pipelines, as well as changes in the distribution patterns towards more efficient operations and reduced GHG emissions. In Pertamina, total GHG reductions in 2012 amounted to 512,337 ton of CO_2e.

4.2.1 Low GHG Emission Products

Efforts by PERTAMINA to indirectly reduce GHG emissions also include the development of products with lower emissions of GHG compared with conventional products. Among their flagship products with lower GHG emission levels are the 3kg LPG Kerosene conversion package that is cleaner-burning than kerosene, the Musicool Refrigerant, Gas Fuel Product, Envogas and Vigas that are more efficient and cleaner than oil fuel for motor vehicles, and also Biofuel products.

4.2.2 Blue Sky Project

The Blue Sky Project will enable the Cilacap Refinery Unit to produce more of the High Octane Mogas component (HOMC) needed for the production of fuel with 92 Octanes, and also reduce the benzene content to the level required by EURO IV emission standards. This project will also reduce imports of HOMC used for domestic fuel needs. The Cilacap Blue Sky Project received budgetary approval in 2011, followed by the processes for engineering design integration and initial EPC (Engineering, Procurement and construction) tender in 2012. EPC works are scheduled to commence by the end of 2013. The Cilacap Blue Sky Project is the second of such projects following a similar undertaking at the Balongan Refinery Unit VI in 2005.

4.2.3 PERTAMINA Dumai Refinery - Potential CCS Project

PERTAMINA Refinery Unit II Dumai consists of 2 (two) refineries namely: Dumai Refinery with capacity of 130.000 barrels per day (see Figure 4.1) and Sei Pakning Refinery with capacity of 50.000 barrels per day.

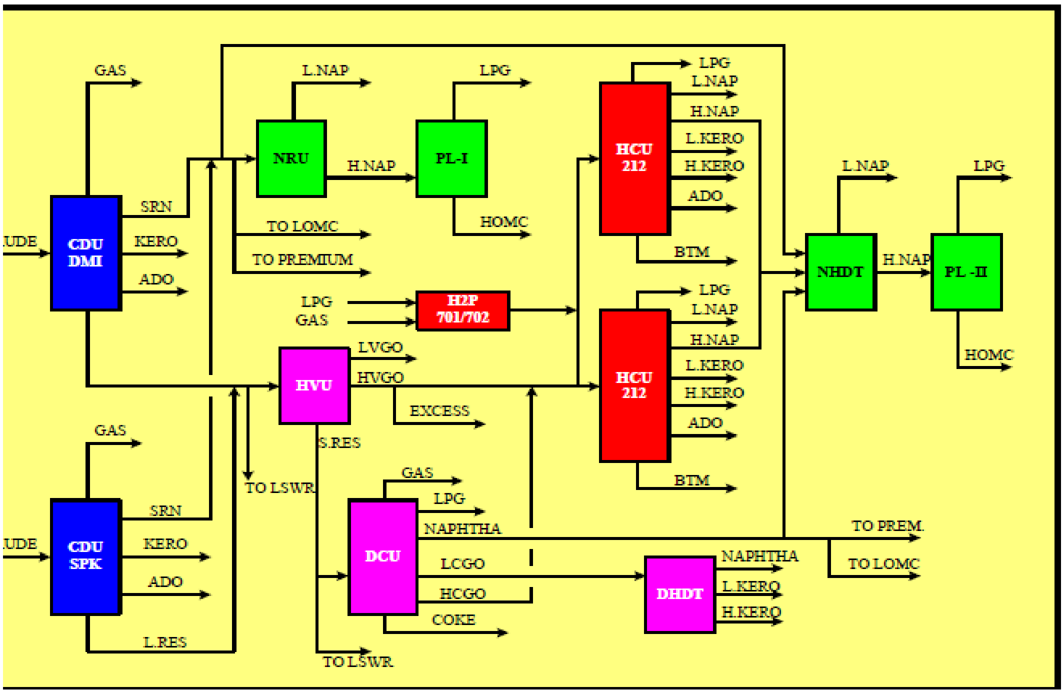
Refinery Unit II Dumai was built in 1969, has 14 processing units and two supporting units. UP II Dumai refinery consists of the old refinery (Existing Plant) and the new refinery (New Plant). Existing Plant consists of three process units, namely Topping Unit / Crude Distilling Unit (CDU), Naphtha Rerun Unit (NRU), and Hydrobon Platforming unit (platforming I).

New Plant (Hydrocracker Complex) involved an extension of the Existing Plant and was built in 1981. Its operation was inaugurated by President Soeharto, February 16, 1984. New Plant consists of 11 processing units, namely High Vacuum Unit (HVU), Delayed Coking Unit (DCU), Hydrocracking Unit (HCU), Naphtha Hydrotreating Unit (NHDTU), CCR Platforming unit, Distillate Hydrotreating Unit (DHDTU), Amine & LPG Recovery Unit, Hydrogent Plant, Nitrogen Plant, and Sour Water System Plant. The two supporting units are Shipment and Tank Installation, and Utilities Unit.

Meanwhile Sei Pakning Refinery is located on the waterfront of Pakning River with an area of 40 hectares. The oil refinery was built in November 1968 by the Contractor REFICAN Ltd.

(Refining Associates Canada Limited). It completed and started production in December 1969. At the start of operations production capacity was 25,000 barrels per day. In September 1975 the entire operation of Refinery Sei Pakning was switched from REFICAN to PERTAMINA. Thereafter, this refinery began a gradual improvement so that production capacity could be further improved as well. In late 1977 the production capacity increased to 35,000 barrels per day and in April 1980 rose up to 40,000 barrels per day. Then from 1982 production capacity achieved its design capacity of 50,000 barrels per day. Sei Pakning Refinery operations consist of: Crude Distillation Unit (CDU), Tank Installation and Shipment), Utilities units, and laboratories.

Figure 4.1: Block Flow Diagram Pertamina Refinery Unit II – Dumai



4.2.3.1 Potential Sources of GHG emitters in Refineries

Table 4-1 provides a checklist of potential GHG emission sources for refineries. Greenhouse gas emissions from refining occurs primarily from combustion of fuels to provide the energy needed for the refining processes. Carbon dioxide emissions from boilers, process heaters, turbines, flares, and incinerators are the primary GHG emissions. Nitrous oxide emissions also result from these sources, but in quantities much smaller than those of CO_2. When these combustion sources are fired with natural gas or refinery fuel gas, there may also be trace quantities of unburned CH_4 emissions.

The natural gas system, and potentially the refinery fuel gas system, are the only process streams within the refinery with potentially significant CH_4 concentrations. Fugitive CH_4 emissions may result from the piping and components associated with these systems and the combustion equipment fired by these fuels. Results from an API study on fugitive emissions from refinery fuel gas systems indicate that these emissions appear to be negligible.

Table 4.1: Potential Greenhouse Gas Emission Sources in Refining

REFINING	CO_2	N_2O	CH_4
COMBUSTION SOURCES – Stationary Devices			
Boilers/steam generators	X	X	X
Heaters	X	X	X
Fire pumps	X	X	X
Internal combustion (IC) engine generators	X	X	X
Pumps	X	X	X
Reciprocating compressor drivers	X	X	X
Turbine electric generators	X	X	X
Turbine/centrifugal compressor drivers	X	X	X
Flares	X	X	X
Catalyst and thermal oxidizers	X		
Incinerators	X	X	X
Coke calcining kilns	X	X	X
COMBUSTION SOURCES – Mobile Sources			
Company vehicles	X	X	X
INDIRECT SOURCES			
Electricity imports	X	X	X
Process heat/steam imports	X	X	X
VENTED SOURCES – Process Vents			
Sulfur recovery units	X		
Catalytic cracking	X		
Catalytic reforming	X		
Catalyst regeneration	X		
Steam methane reforming (hydrogen plants)	X		
Delayed coking	X		
Flexi-coking	X		
Asphalt production			X
Thermal cracking	X		
VENTED SOURCES – Other Venting			
Storage tanks			
Loading racks			
Pneumatic devices			
VENTED SOURCES – Maintenance/Turnarounds			
Compressor starts			
Equipment/process blowdowns			
Heater/boiler tube decoking	**X**		
VENTED SOURCES – Non-routine Activities			
Emergency shutdown (ESD)			
Pressure relief valves (PRVs)			
Fire suppression			
FUGITIVE SOURCES			
Fuel gas system leaks			**X**
Other process equipment leaks			
Sludge/solids handling			
Wastewater collection and treating	**X**		**X**
Air conditioning/refrigeration			

Note: X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.
Source : API Compendium of Greenhouse Gas Emissions Methodologies for Oil & Gas Industry, August 2009

A number of specialized process vents also may contribute to GHG emissions. Some potential process vents include the fluid catalytic cracker (FCC) regenerator/CO boiler vent, cokers, hydrogen plant vents, and other catalyst regeneration. The FCC vent is primarily a source of CO_2 emissions, although there could be some unburned CH_4 if supplemental fuel is fired in a CO boiler. The hydrogen plant vent is primarily a source of CO_2 emissions, as are other catalyst regeneration vents.

The largest emission sources are associated with energy use. As shown by the breakdown by sources given in Table 4.2:

Table 4.2: The largest emission sources from refineries

Source	Percent of refinery CO2 emissions
Oil and gas fuel firing of furnaces and boilers	65%
Regeneration of cat cracker catalyst	16%
Flares	<3%
Methane steam reforming to make hydrogen	2%
Incineration and effluent processes	1%
Power (55%) imported	13%

Source: The reduction of greenhouse gas emissions from the oil refining and petrochemical industry, AEA Technology, June 1999

a) Data Collection

The original plan was, the data would be collected through site visit to the refinery. But, due to time constraint to get the entry permission to the refinery, site visit to collect data directly from PERTAMINA RU II Dumai and Sei Pakning could not be performed. As a substitute, for this case study purposes, data provided by Dewan Nasional Perubahan Iklim (National Council on Climate Change) provided in chapter II along with other available data were taken as a basis to estimate GHG emissions from the PERTAMINA Refinery Unit II.

b) Data Evaluation

Refining capacity in Indonesia has remained constant for the past few years at around 1 million barrels per day. All refining capacity in Indonesia is owned and operated by state-owned PERTAMINA, which has announced plans to add an additional 500,000 barrels per day refining capacity in the next 5–10 years, increasing total refining capacity up to 1.5 million barrels of oil per day. This planned capacity addition is included in the current emission analysis.

The emission from PERTAMINA RU II Dumai and Sei Pakning were derived from available data from ‘Indonesia’s Green House Abatement Cost Curve’ prepared by Dewan Nasional Perubahan Iklim (National Council on Climate Change), by determining emissions value/barrel. Then the emissions value from the refinery is estimated from the average emission/barrel calculated from the data and capacity factor (180.000 barrels per day vs 1.050.000 total barrels per day), as contained in Table 4.3.

Table 4-3: Estimated Refinery Unit II Dumai Emissions, BAU

Year	Average Emissions MtCO2e/yr	RU II Refinery Emissions MtCO2e/yr	Emission Increment (%)
2005	91	15,6	
2010	100	17,1	9,9
2015	105	18,0	5,0
2020	114	19,5	8,6
2025	121	20,7	6,1
2030	124	21,3	2,5
		Anunal Average Increment (2005 ~ 2030)	**1,3**

4.2.3.2 Analysis of opportunity for energy / combustion efficiency improvement

A baseline scenario was developed which has projected current industries emissions until 2030. Estimated data for Dumai refinery shows a rise in emissions from 15.6 Mt CO_2e/yr in 2005 to 21.3 Mt CO_2e/yr in 2030. To examine the impact of energy efficiency improvements and CO_2 capture/storage on oil and gas industry emissions two scenarios can be evaluated as variants on the baseline. These scenarios are summarised as follows :

1) "Energy efficiency" – focusing on reductions which can be achieved through reducing energy use, with consequent cost savings. This scenario assumes that the products meet requirements and environmental standards (e.g. particulate emissions, etc); and

2) "Maximum CO2 reduction" – in which CO2 capture/storage is added on top of the "Energy efficiency" scenario.

4.2.3.3 Technology/Approach Selection

4.2.3.3.1 Energy Efficiency

Options for reducing greenhouse gas emissions from refineries include:

- Refinery process optimisation;
- Refinery use of non-carbon-based energy sources;
- Reducing the carbon content of fuel;
- Optimising the efficiency of heat and power production and use; and
- Reducing the amount of waste flared.

The largest source of emissions in refineries comes from fuel combustion in furnaces, boilers, etc. (> 65% total emissions). By optimising combustion efiiciency, the fuel consumption in furnaces can be reduced significantly as well as the CO_2 emissions.

For old refineries like Refinery Unit II Dumai, the way to optimise combustion conditions can be performed by monitoring at most furnaces about every three days. Stack gases are analysed for oxygen, CO and CO_2. The excess air rate and combustion efficiency are then calculated for each furnace.

The most important observation is the high excess air rates. The combustion problems were generally similar to many of the other furnaces on site. It appeared that the basic problem was ‘instability’ of the fuel gas system. The pressure of fuel gas fluctuated to such an extent that it was difficult to manage the air flow rate consistently – at low air rates, there was a risk that flames would be forced out of gaps between plates at the base of the furnace. A high air rate was therefore maintained to ensure that there was a good upward air flow from the bottom of each furnace under all conditions. Solutions identified included measures to reduce fluctuations in the fuel gas system, and continuous monitoring of combustion conditions, and frequent monitoring of combustion conditions, and frequent monitoring of the pressure and composition of fuel gas.

The potential savings across the refinery for proper combustion control were estimated to be an increase in efficiency of about two percentage points. Potential savings come from fuel consumption reduction and avoidance of CO_2 emissions.

It is suggested that energy saving of 20-30% could be achieved by a reorganization of the heat exchanger network. Other potential saving were identified in distillation units, without any investment required.

Improved maintenance and process control across the production and refining subsectors could result in a little over 1.2 $MtCO_2e$ of abatement and is net-profit-positive (-103 USD per tCO_2e), which implies significant savings over the life of the abatement measures. Specific programs within these levers include conservation programs, energy-awareness programs, and measures to reduce fouling build-up in pipes, optimize well and separator pressures, and optimize the spinning reserves of rotating equipment.

Implementation of energy-efficiency programs could provide an additional 4.6 $MtCO_2e$ of abatement at negative cost (for energy efficiency programs) or modest cost (for implementing cogeneration units). While the levers identified within this category require high capital investments, significant operational savings can be captured through reduced energy requirements.

The flares in the old refinery were frequently seen to be burning large quantities of material, often with a pulsing flame which suggested that the flare lines were not draining properly (and therefore condensing liquids were not being completely recovered for processing); or that a compressor system was connected to the flare. An optimisation of extracting the condensing liquid will reduce potential emissions and the flare will routinely burn only a pilot flame.

Reduced flaring through the implementation of a zero-flaring program could offer 0.34 $MtCO_2e$ of abatement at a relatively higher cost of 28 USD per tCO_2e. The relatively small abatement is a result of significant anticipated reductions in flaring emissions in the business-as-usual scenario (currently at 5 percent per annum).

The opportunity to reduce emissions through a focused effort across three abatement areas: improved maintenance and process control, energy efficiency programs, and reduced flaring could achieve gains as high as 30 percent by 2030.

4.2.3.3.2 CO2 capture and storage (CCS)

CO2 capture using an absorption-based technique appears to be a viable option for refinery exhaust streams for on site power generation, from process furnaces and boilers, and from catalyst regeneration. High concentrations of CO2 are found in the off-gases from the steam reforming process; for such relatively small, high concentration emission sources, cryogenic separation is a promising option.

The concept of CCS still has to be proven to a certain extent. The individual steps have all been applied in commercial activities, often for a long time and partly in combination with each other. However, perpetual storage of CO_2 is new and has not been demonstrated in practice before.

There is some uncertainty as to if and how it can be guaranteed that CO_2 injected in deep geological gas fields and aquifers will actually stay there for thousands of years. This can only be estimated using model simulations, and mitigation of risks by the application of a stringent set of storage site selection criteria and storage reservoir closure and abandonment criteria. The probability is more predictable and the criteria can be more easily met for geologically intensively explored, intrinsically gas-tight natural gas fields than for aquifers.

This lack of solid proof of the viability, reliability and safety of the concept has resulted in public concern and hesitation by environmental NGOs to rely on such a technology. Beside this the potential of CCS is probably not sufficiently great to reach an economy-wide reduction of 80-95% in industrial CO_2 emissions as required in the period up to 2050. The latter is due to:

- the limited capacity of sufficiently safe deep geological storage reservoirs; and
- competition with the power sector to acquire storage capacity.

4.2.3.3.3 Direct use at the production location

Most of the potential commercial use of CO_2 occurs at the location where it is generated.

- About a third of the carbon dioxide produced as a by-product of the hydrogen generation required for the ammonia production process is used to produce ureum (a fertilizer) from ammonia;
- Carbon dioxide produced during the brewing of beer is used to carbonise the beer;
- Carbon dioxide produced in combined power and heat generation units of glass houses and soft drink plants is used to respectively feed the plants and carbonize the drinks. The CO2 in carbonated drinks is the same as the CO2 that is spewed from tailpipes and power plants and causes global warming. In fact, the CO2 that makes the bubbles in soda drink comes from those same power plants. Instead of being released into the atmosphere as a global-warming gas, the CO2 is captured from power plant exhausts, purified and sold to the nation's bottlers and soft drink fountain suppliers. When you pop the tab, however, the CO2 escapes into the atmosphere anyway. In the first application generating carbon dioxide is so important that these units are said to be fired up in summer for the purpose of the carbon dioxide alone.

In the future, carbon capture and storage could offer a significant abatement opportunity for the petroleum and gas sector. However, given the limited deployment of this technology and high cost structures, this project may not be warranted by conventional economic returns. We can use this case as a possible example of commitment of Indonesia to reduce GHG emission up to 41% with foreign help.

4.3 CO2 Emission Standards

Based on Government Regulation No. 41/1999 on Air Pollution Control, the Minister of Environmental Affairs (MEA) issued Ministerial Regulation No. 13/2009 on Standard Quality of Emission of Stationary Sources in the Oil and Gas Activities/Business, which stipulates the maximum allowable emission of particulates, carbon mono-oxide, nitrogen oxide, and sulfur oxide; but no standard limitations are set for carbon dioxide. The following terms have been used extensively to determine the amount of greenhouse gas emissions by using CO2 as a reference to describe how much the global warming potential is due to the emission of each GHG, and could be used to determine the CO2 emission standards thresholds later, as well as the comparison of emission standards from other developing countries and/or develop countries.

Emissions standards are requirements that set specific limits to the amount of pollutants that can be released into the environment. Many emissions standards focus on regulating pollutants released by automobiles (motor cars) and other powered vehicles but they can also regulate emissions from industry, power plants, small equipment such as lawn mowers and diesel generators. Frequently policy alternatives to emissions standards are technology standards.

An emissions performance standard is a limit that sets thresholds above which a different type of emission control technology might be needed. While emission performance standards have been used to dictate limits for conventional pollutants such as oxides of nitrogen and oxides of sulfur (NOx and SOx), this regulatory technique may also be used to regulate greenhouse gases, particularly carbon dioxide (CO_2). In the US, this is given in pounds of carbon dioxide per megawatt-hour (lbs. CO_2/MWhr), and kilograms CO_2/MWhr elsewhere.

Carbon dioxide equivalent (CDE) and **Equivalent carbon dioxide (CO_2e)** are two related but distinct measures for describing how much global warming a given type and amount of greenhouse gas may cause, using the functionally equivalent amount or concentration of carbon dioxide (CO_2) as the reference. Carbon dioxide equivalency is a quantity that describes, for a given mixture and amount of greenhouse gas, the amount of CO2 that would have the same global warming potential (GWP), when measured over a specified timescale (generally 100 years). Carbon dioxide equivalency thus reflects the time-integrated radiative forcing of a quantity of *emissions* or rate of greenhouse gas emission—a *flow* into the atmosphere - rather than the instantaneous value of the radiative forcing of the *stock* (concentration) of greenhouse gases *in the atmosphere* described by CO2e.

5. Conclusions and Recommendations

This study comes to the following conclusions:

1. The total emissions from Indonesia's petroleum and gas sector are expected in the "business as usual case" to increase in the medium term from 122 Mt CO2e in 2005 to 135 Mt CO2e in 2020, mainly on account of additional refining capacity expected to come online. However, in the longer term, emission increases from refining are expected to be offset – as mature oil and gas fields are shut down and replaced with newer, more efficient ones – so that emissions stay relatively constant at 137 Mt CO2e in 2030.
2. At the G20 meeting in September 2009, President of the Republic of Indonesia, HE Susilo Bambang Yudhoyono anounced a unilateral objective to reduce GHG emissions 26 percent by the year 2020 (compared to BAU) on its own effort and proposed a goal of 41 percent reduction by 2020 (compared to BAU) with international support. GOI also joined the G20 pledge to phase out subsidies for fossil fuels. Energy contribution to total CO2 emission is estimated recently at 6% but is expected to grow rapidly over time.
3. The pros and cons analysis of CCS indicates that the use of CCS can significantly reduce CO_2 emissions, by 80-90% compared to a plant without CCS, however, potential reductions are offset by: (i) increases in costs of energy produced in a coal fired plant with CCS by 21-91%; (ii) increased fuel needs and other system costs in a coal fired plant by 25-40%; and (iii) CCS technology is very expensive and largely unproven.
4. Indonesia has no regulations on standard limitations of carbon emission by economic activity.
5. Sources of carbon emission in the oil and gas industries are: (i) CO2 produced in association with oil and natural gas from wells; (ii) natural gas processing plants which separate CO2 from natural gas apart from 2-3% retained, before sending the gas to the pipeline; with separated CO2 being released to the air; (iii) flared gas from production gathering stations or refineries; (iv) oil refineries from fuel combustion in power plants, furnaces, and boilers; and (v) combustion facilities in power plants used in the upstream producing facilities.
6. The upstream oil and gas fields offer large depleted reservoirs for storage of CO2 provided these are deeper than 1,000 meters and are not subject to seismic activities. A study by LEMIGAS identified that oil and gas reservoirs in South Sumatra, East Kalimantan and Tarakan are suitable for CO2 storage.
7. CO2 has proven to be a good fluid for Enhanced Oil Recovery (EOR) in the United States of America, in miscible or immiscible conditions, and could be used to enhance Coal Bed Methane (ECMB) production. LEMIGAS has conducted a study indicating that South Sumatera province offers good potential for pilot CO2 EOR which could be expanded into Demonstration and Full-scale stages if the pilot shows favorable results. The development of CMB in Indonesia is still in progress.
8. The LEMIGAS study reports on a CCS pilot using MERBAU GGS as the source of CO2, using a pipeline to nearby fields for storage into the reservoir aquiver. This pilot project could be expanded into EOR applications during demonstration and full-scale stages.
9. A review of the Dumai Refinery indicates that a better approach for reducing CO2 emissions is by conducting continuous improvement in combustion efficiency. Capturing

CO2 for storage would not be an economic solution due to remoteness of suitable storage sites. Industrial usage of captured CO2 could be in order if economically justified.

10. Although CCS projects in Indonesia may not yet be warranted on their sole economic merits, on the basis of Indonesia commitment to reduce the Green House Gas emission to 41% by the year 2020 with international support, it is worthwhile for Indonesia to consider CCS projects in the oil and gas industry and / or also the energy industry, due to: (i) growing energy demand, particularly for coal fired power plants; (ii) availability of depleted oil and gas fields which could offer good CO2 storage spaces; and (iii) the need to address the increasing trend of world-wide GHG emissions.

11. LEMIGAS Studies [6,7)] indicate that depleted oil and gas fields in South Sumatera, East Kalimantan and Tarakan are suitable for CO2 storage and probably CO2 EOR. The study identifies pilot opportunities through the source-sink match between capture technology at the CO2 source and storage sites and / or EOR for commercial operations. The study recommended two scales of commercial projects: those less than 2,700 t/day based on commercial EOR projects and those greater than 2,700 t/day storage in depleted gas reservoirs, saline aquifers and some larger EOR projects.

12. LEMIGAS recommend a pilot project, consisting of CO2 capture from Merbau GGS at 1 Mt/year CO2, with transport of CO2 through pipelines or trucking, and storage or use of CO2 as EOR in nearby fields. Total CAPEX for the capture facility is estimated at US$ 167 million for the pipeline and injection wells (2); with surface storage estimated at USD 33 million; and OPEX at USD 12 million/year. LEMIGAS recommends the pilot to be operated and evaluated for 7 years before a commercial demonstration and full scale CCS project can be undertaken.

13. Although the full scale CCS project may not be economically viable, implementation of the pilot CCS may be warranted bearing in mind behavioral economics considerations: (i) to confirm the feasibility of storing CO2 in South Sumatera reservoirs; (ii) to gain valuable experience and expertise in operating a CCS project involving CO2 capture, transportation, injection, measurement, and verification of storage and understanding EOR processes; (iii) to learn the lesson of various challenges, risks, cost and funding resources; (iv) to obtain information for the development of an appropriate regulatory framework, fiscal policies, and communication needs for wider CCS implementation; (v) to address Indonesia's commitment to reduce GHG emissions by 26% on its own and by 41% with international support by 2020; and (vi) in anticipation of GHGs increasing to critical level as Indonesia will continue to use significant fossil fuel in the future as targeted by the new National Energy Policy.

14. The pilot CCS will add a financial burden to CO2 emitters (the industries) and oil and gas field operators, although there may be economic benefits from EOR incremental oil. There should be a regulatory framework developed to implement CCS projects at the national level which could attract international participation by business players/investors and international funding institutions: (i) a Presidential regulation to establish standard limits for CO2 emissions, with appropriate penalties for non-compliance and rewards for those in compliance with the policy; (ii) Presidential regulation for Indonesia to initiate an energy efficiency drive and CCS project in industries as a national drive to reduce GHG emission by 50% in 2050, starting with implementing the CCS pilot project in South Sumatera Province followed by commercial demonstration and a full scale CCS project;

(iii) Minister of Finance regulations to provide fiscal and non-fiscal incentives to reduce the financial burden to industry to minimize GHG emissions in compliance with the established standard GHG emission limits; and (iv) a Minister of Energy and Mineral Resources regulation to provide stimulus for the oil and gas industry to instigate CO2 storage and CO2 EOR in their respective oil and gas fields.

We recommend following actions to be implemented:

1. The GOI should issue a Presidential Regulation based on the Environmental Law No. 32, Year 2009 on Environmental Protection and Management; Presidential Regulation No. 61 Year 2011 concerning National Action Plan on Climate Change; and Presidential Regulation No. 71 of 2011 on GHG Inventories to establish a set of limits for CO2 emission for stationary plants and mobile equipment. The limits should be based on: (i) currently available technology; (ii) economic propositions; (iii) self-reliance; and (iv) sustainable development.
2. Effective GHG emission reductions through preventative actions should be given immediate priority over the CCS. This includes providing economic stimulus and supportive regulations for activities of energy services companies, acceleration of renewable energy power generation projects, usage of energy efficient equipment, and energy conservation and efficiency initiatives,
3. Although the CCS pilot project with its ultimate development into a full scale CCS project may not be economically viable in Indonesia, in term of its economic and technology efficiencies, Indonesia may consider the possibly enhanced long-term benefits of having successful pilot and full-scale CCS projects, taking the opportunity of bilateral and multilateral financial support for climate change funding from other countries or institutions. PKPPIM of MOF could play a leading role in coordinating this finance. Indonesia is forecast to double its energy demand by 2050, with more than 65% still coming from fossil fuels, including 30% from coal, which would generate significant CO2 emissions. Additionally, Indonesia plans to produce natural gas with CO2 content over 70% from the Natuna D-Alpha field, and to increase production of oil from the current 800,000 bopd to more than 1 million BOPD, and to increases refinery capacity by 50% by 2025 – all of these would benefit from effective carbon sequestration to reduce the green-house gas impacts. Results of proposed pilot CCS should provide excellent lessons learned to develop future CCS projects.
4. Regulations for the CCS and CO2 EOR projects should be developed by the Minister of Energy and Mineral Resources, in coordination with Minister of Industry; and the Minister of Environment and Forestry and other relevant technical ministries to cover the activities of Capturing CO2 from the plant and processing CO2 into saturated pipeline gas and pumping the CO2 gas into the storage or EOR fields. An amendment of existing PSC contracts should be carried out between PERTAMINA or oil and gas field operators to cover receiving CO2, compressing and distributing to CO2 injection wells for storage or for EOR, including the possibilities of regulations, incentives; international financial support; and the formation of trust funds.
5. For the implementation of the MERBAU GGS CCS project, we recommend to assign the work to PT Perusahaan Gas Negara Tbk (PGN) to manage the construction and operation of the CO2 capture, processing it into saturated gas; and compressing and piping it to the storage site(s). PGN could seek a competent partner from donor

country(ies) to carry out the engineering, procurement and construction of the carbon capture and transportation through the pipe.

6. For the CO2 EOR implementation, we recommend to assign the field operator (in this case PT PERTAMINA Tbk), which in turn could appoint its appropriate business unit to carry out the field development work for the CO2 injection for EOR. The project could be handled under the existing PSC arrangements, sponsored under soft loan bilateral agreement with institutions, such as ADB, World Bank, and others. PKPPIM of MOF could play an important role in coordinating and managing this financing. An appropriate incentives program could be introduced in the PSC amendment for the pilot, demonstration and full scale EOR projects.
7. Trading systems for CO2 emissions credits should be developed to encourage the available investment capital, expertise and training to less developed regions, thereby accelerating implementation of energy efficiency measure at both the local and global scale.
8. The Government should continuously promote GHG emissions reductions through public communications and education.

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