Asia-Pacific
Economic Cooperation

Feasibility of Accelerating the Deployment of Carbon Capture, Utilization and Storage in Developing APEC Economies

Asia-Pacific Economic Cooperation's Energy Working Group

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Document prepared by:
Advanced Resources International, Inc.
4501 Fairfax Drive, Suite 910, Arlington, VA 22203 USA
Tel: (703) 528-8420 Fax: (703) 528.0439 Email: mgodec@adv-res.com
Website: www.adv-res.com

Pamela Tomski
En Tech Strategies
1130 16th Street NW, Suite 520, Washington, DC 20036 USA
Tel: (202) 390 8896 Email: ptomski@mac.com

Craig Hart
Development Technologies International
801 Riverside Drive, Suite 6G, New York NY 10032 USA
Tel: (212) 951-0903   Email: craighart@alum.mit.edu

Produced for:
Asia Pacific Economic Cooperation Secretariat
35 Heng Mui Keng Terrace
Singapore 119616
Tel: (65) 68919 600
Fax: (65) 68919 690
Email: info@apec.org Website: www.apec.org

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EXECUTIVE SUMMARY

Carbon dioxide (CO_2) capture, utilization, and storage (CCUS) represents one critical part of international efforts to achieve deep reductions in global CO_2 emissions, while continuing to allow for fossil fuel-based power generation, as well as addressing emissions from industrial processes emitting CO_2. Three main types of geological storage options are generally considered for such CCUS purposes: deep saline formations; depleted oil and gas fields, and unmineable coal seams. Many global experts believe that storage in depleted hydrocarbon fields can be achieved at much lower costs, especially through the application of CO_2-enhanced oil recovery (CO_2-EOR).

The objective of this study is to produce a feasibility assessment for accelerating CCUS-EOR in selected developing APEC economies. The study approach included a review of previous assessment efforts and the data and information needs for evaluating CCUS-EOR opportunities; identification and evaluation of barriers to exploitation of these opportunities; assessment of potential policies and programs that could help accelerate the development of large-scale CCUS-EOR demonstration projects; identification and description of existing elements of CCUS-EOR permitting frameworks that are likely to require particular attention by the relevant authorities in developing APEC economies; and development of recommendations for cost-effective capacity-building activities in the area of CCUS-EOR in these economies.

For purposes of this effort, the developing APEC economies considered were Brunei Darussalam, People's Republic of China, Indonesia, Malaysia, Mexico, Peru, Thailand, and Viet Nam.

This study has built upon previous work to develop a feasibility assessment of the CCUS-EOR potential in these developing APEC economies. This feasibility assessment includes both an estimate of the amount of incremental oil that could be recovered from oil basins in these economies and the amount of CO_2 that would be required, and that could ultimately be stored, to facilitate that recovery.

In total, the eight economies selected to be the focus of this study have the potential to produce 18 to 78 billion barrels (2.5 to 10.6 billion tonnes) of incremental oil from the application of CO_2-EOR, and could store from 5.8 to 24.2 billion tonnes of CO_2 as a result. These results are summarized in **Table ES-1**. All APEC economies considered in this study were included because they have some oil resource endowment that could be amenable to the application of CO_2-EOR. However, most of the CO_2-EOR potential in these eight APEC economies exists in just two – China and Mexico.

Table ES-1. Summary -- CO_2-EOR and Associated CO_2 Storage Potential in Selected APEC Economies

Economy	CO_2-EOR Potential				Potential CO_2 Storage Capacity	
	(Billion barrels)		(Billion tonnes)		(Billion tonnes)	
	Low	High	Low	High	Low	High
Brunei Darussalam	0.8	1.9	0.1	0.3	0.3	0.6
People's Republic of China	0.5	43.3	0.1	5.9	0.3	12.4
Indonesia	0.3	4.3	0.0	0.6	0.0	1.0
Malaysia-Thailand (Malay Basin)*	1.0	1.0	0.1	0.1	0.0	0.2
Mexico	14.1	23.9	1.9	3.3	4.6	8.9
Peru	1.1	2.6	0.1	0.4	0.3	0.8
Viet Nam	0.6	0.7	0.1	0.1	0.2	0.4
TOTAL	18.4	77.7	2.5	10.6	5.8	24.2

* Also includes resources from the Baram Delta/Brunei Sabah Basin reported for Brunei Darussalam

The range in estimates for CO_2-EOR and associated CO_2 storage potential is quite large even within each of the APEC economies. This range in estimates depends on the methods employed, assumptions made, and resources considered in the assessment. Regardless, the potential for CCUS with CO_2-EOR in each of these economies is considerable. Nonetheless, all of these APEC economies could benefit from more rigorous and consistent assessments of their potential for CO_2-EOR. To ensure this consistency, some economies would have to make greater information on the characteristics of their hydrocarbon resources accessible: something that has been a challenge to resource assessments to date, including the assessments presented in this report.

Moreover, the state of the commercial, policy, and regulatory environment varies considerably among the APEC economies. For example:

- Where resource endowments exist, APEC economies, for the most part, are pursuing policies and programs to encourage greater development of fossil fuels, for both internal use and for export, to take advantage of the economic benefits associated with such development.

- In some cases, these are being pursued in parallel with policies and programs to mitigate greenhouse gas emissions, though the state of development of these policies and programs varies widely. Moreover, in some APEC economies, such as China, mitigation policies and programs place high priority on CCS/CCUS; others, like Peru, place greater focus on deforestation, improved efficiency, and other mechanisms. In most cases, the focus is on their greatest sources of emissions.

- Most APEC economies are relatively new to considering the application of CO_2-EOR, though some have some experience, having at least pursued some pilot or engineering studies. However, some capacity development is likely to be necessary in all APEC economies.

- All APEC economies face challenges in effectively matching low-cost CO_2 sources with hydrocarbon prospects amenable to CO_2-EOR. A primary challenge is how costs and benefits will be distributed among the players. In economies where national oil companies and national power companies are the dominant players, governments are more able to dictate how costs and benefits are allocated. Where that is not the case, government policies, regulation, and incentives will likely be necessary.

- Achieving the potential for CCUS-EOR in each of the APEC economies will be challenging. Sources of CO_2 are often not well matched with CO_2-EOR prospects. Prospects exist in each; however, the number of prospects in these eight APEC economies varies. In some, like China, a significant number of large-scale integrated projects are already being pursued. In others, prospects are identified in this report for the first time. In addition, the state of assessment of these prospects varies widely.

Nonetheless, three case studies were identified for further assessment:

- CO_2 capture from natural gas processing for CO_2-EOR in an oil field in Indonesia,

- Natural gas-based power plant CO_2 capture for CO_2-EOR in the White Tiger Field in Viet Nam, and

- Power plant CO_2 capture for CO_2-EOR in an oil field in Mexico.

Under a reasonable set of assumptions, the results of these three case studies indicate that, given relatively low costs of CO_2 capture and transport, increased revenues resulting from oil production attributable to CO_2-EOR, and favorable regulatory regimes with regards to CO_2-EOR development, commercially viable CCUS-EOR projects are realizable. Specifically:

- The Indonesian case study assumes CO_2 captured from a gas processing facility. CO_2 from the Subang gas field was assumed to be the source; including the costs of separation, compression and transport, the delivered costs of CO_2 were assumed to amount to $18.50 per tonne. The economics of CO_2-EOR were determined based on the Handil oil field in the Mahakam Delta. This project was determined to have the potential to produce over 70 million barrels (9.5 million tonnes) of incremental oil due to CO_2-EOR. At an oil price of $90 per barrel, the CO_2-EOR project achieves a modest before-tax internal rate of return (IRR) of 11%. Given the marginal nature of this project, some project incentives may be necessary. This would be particularly important if the delivered CO_2 costs were to rise above these assumed values.

- The Viet Nam case study was based on the yet-to-be-approved White Tiger Clean Development Mechanism (CDM) project, which includes capture of CO_2 from a Combined Cycle Gas Turbine (CCGT) plant and injection into the White Tiger oil field. It is estimated that 698 million barrels (95 million tonnes) of incremental oil can be recovered, and 545 million tonnes of CO_2 would be injected (338 million tonnes of purchased CO_2, the balance being recycled CO_2) throughout the project life. The cost of the CO_2 delivered to the White Tiger field was estimated to be $32 per tonne. At an oil price of $90 per barrel, the CO_2-EOR project achieves a before-tax IRR of over 21%. Even at CO_2 costs of $50 per tonne, the project receives a before tax IRR of over 16%.

- In the Mexico case study, a proposed CCS demonstration project has been identified with the CO_2 source located at the natural gas combined cycle (NGCC) Power Plant located at Poza Rica. A number of prospective fields for EOR exist in this region, including the Poza Rica field in the Tampico-Misantla Basin, which was assumed for this assessment. Preliminary studies indicated that the capture facility could be viable at a CO_2 selling price ranging from $50 to $60 per tonne. Based on this assessment, a CO_2-EOR project in the Poza Rica field is estimated to produce over 270 million barrels (36 million tonnes) of incremental oil due to CO_2-EOR, and uses 220 million tonnes of CO_2. At an oil price of $90 per barrel, and a CO_2 cost of $60 per tonne, the project achieves an IRR of 24%.

To support the development of CCUS, regulatory regimes are needed to ensure public health and safety, and prevent environmental damage, particularly damage to underground sources of drinking water. Regulatory regimes are essential to:

- Provide a mechanism for stakeholder engagement that addresses local concerns and potential community impacts, and allows for stakeholder participation during project development and implementation,

- Establish a level playing field for project developers and operators,

- Provide transparency that can support market confidence, address financial assurance, and facilitate credit for CO_2 storage, and

- Address ownership, property rights, and liability considerations.

Over the past few years, there has been a considerable amount of activity worldwide on CCS regulatory framework development, mainly focusing on developed economies. More recent attention has shifted to developing economies, with APEC providing leadership in developing APEC economies (See C. Hart, P. Tomski, K. Coddington (2012) *Permitting Issues Related to Carbon Capture and Storage for Coal-Based Power Plant Projects in Developing APEC Economies: An Assessment of Essential Permitting Regimes for Nine APEC Economies*, Singapore: Asia-Pacific Economic Cooperation). This report further advances the regulatory analyses focusing specifically on emerging CCUS regulatory regimes in selected developing APEC economies.

None of the developing economies surveyed currently regulate any aspect of CCUS (e.g., CO_2 capture, transport, injection or storage). While none of these economies currently regulate CCUS, all possess laws that could apply to CCUS, be adapted, or provide a model for new regulation. This study presents key issues that should be addressed in a CCUS regulatory regime and provides an overview of the regulatory status for selected APEC developing economies in relation to CCUS.

A significant body of research already exists on the barriers and challenges to CCS and CCUS deployment, in APEC economies and globally, including work by APEC; the effort here avoids duplicating this. Like many emerging technologies, CCS and CCUS face barriers which discourage new projects from emerging and prevent existing projects from progressing. Funding for CCUS demonstration projects, while still considerable, is increasingly vulnerable and seems to be declining. Most CCUS projects still require strong government support to go forward. CCUS is also often not treated equivalently to other low-carbon technologies in policy settings and government support. In order to achieve emission reductions in the most efficient and effective way, governments should ensure that CCUS is not disadvantaged.

Barriers to CCUS deployment are amplified in developing APEC economies, and are complicated by additional issues related to energy security, price of electricity, and limited capacity to plan and implement complex, risky large-scale demonstration projects. Moreover, CCUS is generally seen as a greenhouse gas mitigation technology that should be led by developed economies.

Financial support from developed economy governments to CCS and CCUS demonstration projects in developing economies, including APEC economies, is contingent on making the results accessible, so that industry, governments, and the public develop a better understanding of the economic and environmental performance, and that knowledge can be developed, capacity building can be facilitated, and public engagement pursued. This involves a level of transparency that many APEC economies have traditionally avoided. Increased levels of transparency will likely be necessary to take the next steps for facilitating CCUS-EOR demonstration projects.

Therefore, going forward, capacity building for APEC economies needs to shift to from a focus just on source-sink matching and assessment of regulatory frameworks to emphasis on the deployment of real projects. Where they have not yet been conducted, capacity building needs to support the steps required for conducting pre-feasibility and feasibility studies, and assessing the applicability, limitations, and necessary modifications of regulatory frameworks as applied to actual proposed projects. In addition, these capacity building activities should also address what is required for implementing CCUS-EOR projects through planning, financing, construction, operation and monitoring.

Because of the need to accelerate deployment of CCUS-EOR demonstration projects, capacity building activities would be most valuable if they were conducted concurrently with the pursuit of these demonstration projects, not sequentially.

In conclusion, this report shows that substantial potential for incremental oil production from the deployment of CO_2-EOR in combination with CO_2 storage exists in the APEC economies assessed. Government support for pursuing greenhouse gas strategies exists; some consideration of opportunities for CO_2-EOR has taken place; regulatory frameworks that can be adapted to accommodate the unique requirements of CCS exist; and prospects for a CCUS-EOR demonstration project have been identified, a few of which appear to be potentially economically viable.

Thus, with the right incentives, government support, financing, and public commitment, CCUS-EOR can be a cost-effective mechanism for addressing concerns of global climate change in developing APEC economies.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1. INTRODUCTION AND PROJECT OBJECTIVES

1.1. INTRODUCTION

Carbon dioxide (CO_2) capture, utilization, and storage (CCUS) represents one critical part of international efforts to achieve deep reductions in global CO_2 emissions, while continuing to allow for the utilization of fossil fuels for power generation, as well as addressing emissions from industrial processes emitting CO_2.

Three main types of geological storage options are generally considered for such CCUS purposes: deep saline formations; depleted oil and gas fields, and unmineable coal seams. Recently, additional potential opportunities have been shown to exist in gas shales.[1] Of these options, storage in deep saline formations holds the greatest technical potential in terms of overall CO_2 volumes, if this potential can be both technically and economically realized. However, relative to previously exploited oil and gas fields that have benefited from extensive exploration, development, and previous geological investigation, much less is known about the geological characteristics and storage potential of deep saline formations. Moreover, the lower pressures that exist in depleted oil and gas reservoirs can facilitate greater storage capacity per unit of area, and can also allow for substantially higher rates of CO_2 injection per well.

Many experts believe that storage opportunities in depleted hydrocarbon fields can have much lower development costs than deep saline formations because of the generally greater availability of geological data from exploration and production operations, as well as the accessibility of existing oil field infrastructure.

Enhanced oil recovery (EOR) is a generic term for a wide variety of techniques to increase the amount of crude oil that can be extracted from an oil field. Gas injection (primarily CO_2) is presently the most-commonly used approach for EOR (called CO_2-EOR). With this process, CO_2 is injected into the oil-bearing stratum under high pressure. Oil displacement by CO_2 injection relies on the phase behavior of the mixtures of that gas and the crude, which are strongly dependent on reservoir temperature, pressure and crude oil composition. There are two main types of CO_2-EOR processes:

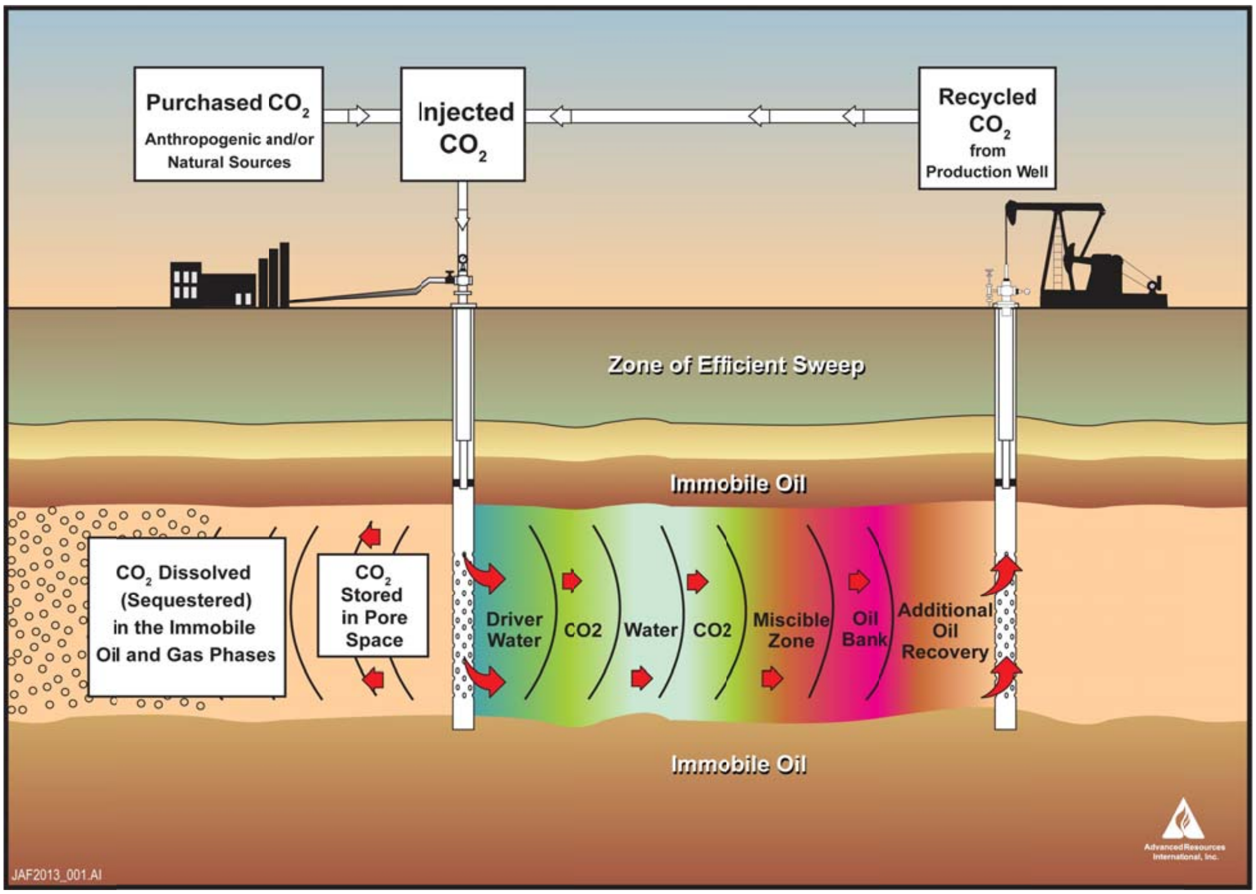
- Miscible CO_2-EOR is a multiple-contact process involving interactions between the injected CO_2 and the reservoir's oil. During this process, CO_2 vaporizes the lighter oil fractions into the injected CO_2 phase and CO_2 condenses into the reservoir's oil phase. The result is two reservoir fluids that become miscible (mixing in all parts), with favorable properties of low viscosity, enhanced mobility, and low interfacial tension. The primary objective of miscible CO_2-EOR is to remobilize and dramatically reduce the residual oil saturation in the reservoir's pore space after water flooding. **Figure 1-1** provides a one-dimensional schematic showing the dynamics of the miscible CO_2-EOR process.

[1] Godec, Michael; George Koperna, Robin Petrusak, Anne Oudinot, "Assessment of Factors Influencing CO_2 Storage Capacity and Injectivity in Eastern U.S. Gas Shales," *Energy Procedia*, Volume 37, 2013, Pages 6644-6655

- Immiscible CO_2-EOR occurs when insufficient reservoir pressure is available or the reservoir's oil composition is less favorable (heavier). The main mechanisms involved in immiscible CO_2 flooding are (1) oil phase swelling, as the oil becomes saturated with CO_2; (2) viscosity reduction of the swollen oil and CO_2 mixture; (3) extraction of lighter hydrocarbon into the CO_2 phase; and (4) fluid drive plus pressure. This combination of mechanisms enables a portion of the reservoir's remaining oil to be mobilized and produced.

Pursuing CCUS with CO_2-EOR offers significant potential to produce more oil from developed fields, while in the process allowing for large quantities of CO_2 to be permanently stored underground rather than emitted to the atmosphere.

Figure 1-1. Schematic Illustrating the Miscible CO_2-EOR Process

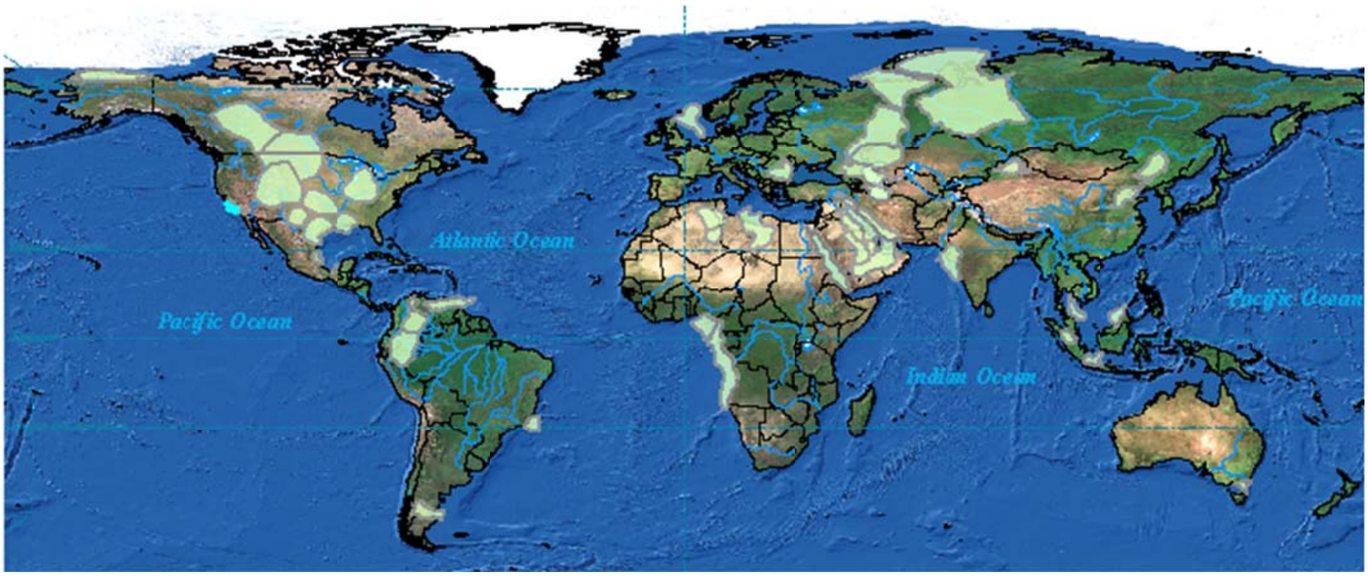


Previous studies have been conducted that assess the global potential for CO_2 storage through the application of CO_2-EOR technology. In a study conducted by Advanced Resources International and Melzer Consulting for the IEA Greenhouse Gas R&D Programme (IEA GHG),[2] a database was developed of the largest 54 oil basins of the world (that account for approximately 95% of the world's estimated ultimately

[2] IEA Greenhouse Gas R&D Programme, *CO_2 Storage in Depleted Oilfields: Global Application Criteria for Carbon Dioxide Enhanced Oil Recovery*, Report IEA/CON/08/155, Prepared by Advanced Resources International, Inc. and Melzer Consulting, August 31, 2009

recoverable (EUR) oil potential). These basins are shown in **Figure 1-2**. Defined technical criteria from this database were used to identify and characterize world oil basins with potential for CO_2-EOR. From this, a high-level, first-order assessment of the CO_2-EOR oil recovery and associated CO_2 storage capacity potential in these basins was developed using the United States experience, as analogue.[3] This methodology is outlined in brief in **Table 1-1**.

Figure 1-2. World Oil Basins Considered in the IEA GHG Assessment



Region Name	Basin Count
Asia Pacific	8
Central and South America	7
Europe	2
Former Soviet Union	6
Middle East and North Africa	11
North America/Non U.S.	3
United States	14
South Asia	1
Sub-Saharan Africa and Antarctica	2
Total	54

Source: IEA Greenhouse Gas R&D Programme, *CO_2 Storage in Depleted Oilfields: Global Application Criteria for Carbon Dioxide Enhanced Oil Recovery,* Report IEA/CON/08/155, Prepared by Advanced Resources International, Inc. and Melzer Consulting, August 31, 2009

[3] U.S. Department of Energy/National Energy Technology Laboratory, *Improving Domestic Energy Security and Lowering CO_2 Emissions with "Next Generation" CO_2-Enhanced Oil Recovery (CO_2-EOR),* report DOE/NETL-2011/1504 prepared by Advanced Resources International, June 20, 2011

The results of the application of this methodology in the above-referenced IEA GHG study are shown in **Table 1-2**. The largest oil basins of the world have reservoirs amenable to the application of miscible CO_2-EOR with the potential to produce nearly 470 billion barrels of additional oil, and store almost 140 billion tonnes of CO_2 with the application of "state-of-the-art" CO_2-EOR technology. A significant portion of this potential exists in APEC economies.

Based on the previous work on United States' basins, a set of cost/supply curves were also developed to estimate incremental oil production potential, as a function of oil price and cost of delivered CO_2, from the application of CO_2-EOR. It included the associated CO_2 requirements that required for achieving this economic production from CO_2-EOR, as a function of crude oil price and the cost of delivered CO_2.

Table 1-1. Overview of Methodology for Screening-Level Assessment of CO_2-EOR Potential and CO_2 Storage in the World's Oil Basins

Step	Basin-Level Average Data Used	Basis	Result
1. Select World Oil Basins favorable for CO_2-EOR operations	Volume of oil cumulatively produced and booked as reserves	Basins with significant existing development, and corresponding oil and gas production expertise, will likely have the most success with CO_2-EOR.	List of 54 (14 U.S., 40 in other regions) oil basins favorable for CO_2-EOR
2. Estimate the volume of original oil in place (OOIP) in world oil basins	API gravity; ultimately recoverable resource	Correlation between API gravity and oil recovery efficiency from large U.S oil reservoirs.	Volume of total OOIP in world oil basins
3. Characterize oil basins, and the potential fields within these basins, amenable to CO_2-EOR	Reservoir depth in basin, API gravity	Characterization based on results of assessment of U.S. reservoirs amenable to miscible CO_2-EOR	OOIP in basins and fields amendable to the application of miscible CO_2-EOR
4. Estimate CO_2-EOR flood performance/recovery efficiency	API gravity; reservoir depth	Regression analysis performed on large dataset of U.S. miscible CO_2-EOR reservoir candidates	CO_2-EOR recovery efficiency (% of OOIP)
5. Estimate the volume of oil technically recoverable with CO_2-EOR	OOIP; CO_2-EOR recovery efficiency	Regression analysis performed on large dataset of U.S. miscible CO_2-EOR reservoir candidates	Volume of Oil recoverable with CO_2-EOR
6. Estimate volume of CO_2 stored by CO_2-EOR operations	Technically recoverable oil from CO_2-EOR	Ratio between CO_2 stored and oil produced in ARI's database of U.S. reservoirs that are candidates for miscible CO_2-EOR	Volume of CO_2 used and ultimately stored during CO_2-EOR operations

Source: IEA Greenhouse Gas R&D Programme, *CO_2 Storage in Depleted Oilfields: Global Application Criteria for Carbon Dioxide Enhanced Oil Recovery,* Report IEA/CON/08/155, Prepared by Advanced Resources International, Inc. and Melzer Consulting, August 31, 2009

Table 1-2. Estimated Incremental Oil Recovery and CO_2 Storage Potential from the Application of "State-of-the-Art" CO_2-EOR in the World's Major Oil Basins

Region Name	CO_2 EOR Oil Recovery (MMBO)	Miscible Basin Count	CO_2 Oil Ratio (tonnes/Bbl)	CO_2 Stored (Gigatonnes)
Asia Pacific	18,376	6	0.27	5.0
Central and South America	31,697	6	0.32	10.1
Europe	16,312	2	0.29	4.7
Former Soviet Union	78,715	6	0.27	21.6
Middle East and North Africa	230,640	11	0.30	70.1
North America/Non-United States	18,080	3	0.33	5.9
United States	60,204	14	0.29	17.2
South Asia	-	0	N/A	-
Sub-Sahara Africa and Antarctica	14,505	2	0.30	4.4
Total	468,530	50	0.30	139.0

Source: IEA Greenhouse Gas R&D Programme, *CO_2 Storage in Depleted Oilfields: Global Application Criteria for Carbon Dioxide Enhanced Oil Recovery,* Report IEA/CON/08/155, Prepared by Advanced Resources International, Inc. and Melzer Consulting, August 31, 2009

This study also builds upon work by the Asian Development Bank (ADB) assessing the potential for CCS in Southeast Asia, focusing on four developing APEC economies: Indonesia, Philippines, Thailand and Viet Nam. The ADB study examined CO_2 sources, sinks (with emphasis on CCUS-EOR), financing, and legal/regulatory issues.

1.2. PROJECT OBJECTIVES

The objective of this study is to produce a feasibility assessment for accelerating CCUS-EOR in selected developing APEC economies. The study approach included a review of previous assessment efforts and the data and information needs for evaluating CCUS-EOR opportunities; identification and evaluation of barriers to exploit these opportunities; assessment of potential policies and programs to accelerate the development of large-scale CCUS-EOR demonstration projects; identification and description of existing elements of CCUS-EOR permitting frameworks that are likely to require particular attention by the relevant authorities in developing APEC economies, and development of recommendations for cost-effective capacity-building activities in the area of CCUS-EOR in these economies.

In addition, the study was also designed to facilitate knowledge sharing and the dissemination of the most up-to-date information from APEC, the Carbon Sequestration Leadership Forum (CSLF) (http://www.cslforum.org/), and other international fora concerning the identification of potential opportunities for use of CO_2 from fossil fuel power generation and from industrial processes that emit large volumes of CO_2 in developing APEC economies, in particular for enhanced oil or gas recovery.

For purposes of this effort, the developing APEC economies considered were Brunei Darussalam, People's Republic of China, Indonesia, Malaysia, Mexico, Peru, Thailand, and Viet Nam.

The focus of this study is to build upon previous feasibility assessments of the CCUS-EOR potential in these developing APEC economies. This feasibility assessment includes both an estimate of the amount of incremental oil that could be recovered from oil basins in these economies and the amount of CO_2 that would be required, and that could ultimately be stored, to facilitate that recovery. Assessments of EOR potential were performed for all of the APEC economies listed. Descriptions and assessments of existing elements of CCUS-EOR regulatory frameworks were based on previous assessments for APEC, with the exception of Brunei Darussalam. A new regulatory assessment for Peru was developed as part of this study.

The results from previous work were updated and tailored to enhance results for this study. This primarily involved expanding upon, enhancing, and updating this characterization, by adding consideration of new resources, and using more up-to-date information on areas considered previously. Where applicable and possible, the results from the previous efforts were disaggregated to develop economy-specific estimates for CO_2-EOR oil production and associated CO_2 storage capacity potential for the recommended developing APEC economies identified. For each, it was determined whether additional information was available to update and/or refine the assessments for these economics. Based on the data available, a high-level mapping and ranking was performed that related large-volume CO_2 sources with potentially attractive CO_2-EOR prospects.

The feasibility for CCUS-EOR in each of the selected developing APEC economies is discussed in the following sections.

2. FEASIBILITY FOR CCUS-EOR IN SELECTED DEVELOPING APEC ECONOMIES

2.1 BRUNEI DARUSSALAM

Overview. Brunei Darussalam is a substantial producer and exporter of crude oil and natural gas for Asia, and relies on hydrocarbon revenues for nearly two-thirds of its gross domestic product. Through its long-standing joint venture with Shell, Brunei Darussalam has produced oil for several decades, primarily from two large, mature fields—Southwest Ampa and Champion—in the offshore Baram Delta. Brunei Darussalam's oil production peaked in 1979 at over 260,000 barrels per day (about 12.8 million tonnes per year). Since then it has been deliberately cut back to extend the life of oil reserves and improve recovery rates, and is currently averaging about 158,000 barrels per day (7.8 million tonnes per year). Despite this decline, Brunei Darussalam is the largest net exporter of total oil liquids in the Asia-Pacific region. Brunei Shell Petroleum (BSP), an equal joint venture between the Brunei Darussalam Government and the Royal Dutch/Shell group of companies, is the largest producing company in Brunei Darussalam.

According to the BP Statistical Review,[4] Brunei Darussalam has 1.1 billion barrels of oil reserves (0.1 billion tonnes) and 10.2 trillion cubic feet (Tcf) (0.3 trillion cubic meters (Tcm)) of natural gas reserves as of 2012. In 2012, 1.2 billion cubic feet (Bcf) per day (12.6 billion cubic meters (Bcm) per year) of natural gas was produced.

Brunei Darussalam has an interest in hydrocarbon development in the South China Sea (SCS), although it has not made any formal claims to the hotly contested Spratly or Paracel Islands. The government prioritizes new exploration activity to counteract Brunei Darussalam 's older declining fields. Exploration has become easier since Malaysia and Brunei Darussalam formally resolved their offshore territorial dispute in March 2009. PetroleumBRUNEI successfully entered into a production sharing agreement (PSA) with Malaysia's PETRONAS. The two national oil companies began drilling in several offshore oil and gas fields off Brunei Darussalam in 2011.

In addressing climate change and its impacts, the Brunei Darussalam government has taken the position that there is a need to strike a balance between economic growth, social development and environmental protection.[5] Brunei Darussalam, because of its long coastline, could be particularly susceptible to sea level rise, potentially the result of climate change. The economy established the Brunei National Council on Climate Change in 2010 to look into policies and strategies relating to climate change. In addition, the National Energy Efficiency and Conservation Committee was established in January 2011 to examine energy issues related to energy issues.[6] Finally, Brunei

[4] http://www.bp.com/en/global/corporate/about-bp/statistical-review-of-world-energy-2013.html [Accessed September 14, 2013]
[5] http://borneoproject.org/updates/brunei-aims-to-combat-climate-change [Accessed September 14, 2013]
[6] Climate Change; Brunei Darussalam's Perspective, presentation at the 5th Meeting of the Southeast Asia Network of Climate Change Focal Points, 22 September 2011 (http://www.unep.org/climatechange/mitigation/sean-

Darussalam commissioned a greenhouse gas inventory as prerequisite to the preparation of its first National Communication for the United Nations Framework Convention on Climate Change (UNFCCC).

CO_2 Emissions. Brunei Darussalam emissions are relatively small compared to other Asian-Pacific economies, amounting to 9.3 million tonnes CO_2 in 2011. However, given its relatively small population (405,900) and high GDP ($16 billion United States[7]), it is one of highest CO_2 emitters per capita among Asian economies at 22.8 tonnes/person in 2011. Brunei Darussalam's per capita emissions are on par with other APEC economies including Australia, Japan, Republic of Korea, and Singapore. Brunei Darussalam's emissions are mostly generated by the transportation and building sectors, which are not amenable to CO_2 capture technologies.

About half of the economy's CO_2 emissions come from power plants, which could serve as a source of CO_2 for EOR. Additionally, BSP operates one small refinery, with a distillation capacity of 10,000 barrels per day, another potential target.

In the western Brunei Darussalam, Liang is currently experiencing a major development with the establishment of Sungai Liang Industrial Park (SPARK), a 271-hectare site that will serve as a world-class petrochemical hub. The first major investment at SPARK is the $450-million methanol plant developed by the Brunei Methanol Company, a joint venture between Petroleum Brunei, Mitsubishi Chemical Holdings Corporation, and Itochu Corporation. The plant design is for an output of 2,500 tonnes of methanol per day, and is expected to result in increased CO_2 emissions in Brunei Darussalam, unless a portion of those emissions can be captured.[8]

Previous Consideration/Application of CO_2-EOR and CCUS. The use of CO_2-EOR techniques is believed to have potential to increase recovery from the large Seria field, but the extent of this potential is yet to be extensively investigated. Brunei Shell Petroleum has conducted a single-well EOR trial in the field's North Flank, involving the injection of various alkali-surfactant-polymer mixtures. The results of this trial have not been published. No reported CO_2-EOR tests have been conducted.

Oil Resource Potential. The Baram Delta/Brunei-Sabah Basin, which underlies Brunei Darussalam and a part of Malaysia, is estimated to contain 22 billion barrels (three billion tonnes) of crude oil, of which about seven billion barrels (less than one billion tonnes) are currently defined as produced, proved or probable reserves (the ultimately recoverable resource (URR).

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cc/Portals/141/doc_resources/5th%20Regional%20Network%20Meeting/S3_Highlights_Brunei.pdf) [Accessed September 14, 2013]

[7] All monetary amounts reported in this report are in United States dollars unless otherwise noted.

[8] APEC Energy Demand and Supply Outlook – 5th Edition (http://publications.apec.org/publication-detail.php?pub_id=1389) [Accessed September 14, 2013]

In 2010, the U.S. Geological Survey (USGS) published its assessment of the remaining undiscovered oil and gas resources in Southeast Asia.[9] The Baram Delta/Brunei-Sabah Basin Province was one of the assessment units (AUs) this study considered. The USGS estimated that from 0.3 to 1.0 billion barrels (0.04 to 0.14 billion tonnes) remained to be discovered in the deltaic sands of this AU, with a mean estimate of 0.6 billion barrels (0.08 billion tonnes). In the turbidite sands of the AU, from 1.8 to 6.2 billion barrels (0.2 to 0.8 billion tonnes) were estimated to remain to be discovered, with a mean estimate of 3.6 billion barrels (0.5 billion tonnes).

All of the oil fields in Brunei Darussalam are contained within the Baram Delta/Brunei-Sabah Basin Province. The largest oil field is the Seria oil field. Discovered in 1929, the Seria field was the only producing field in the economy until the early 1960s. The field produced its billionth barrel in 1991, and is still producing about 28,000 barrels per day (1.4 million tonnes per year).[10] Another large onshore oil field in Brunei Darussalam is the Rasau field, west of the Belait River.

The most prolific offshore field is Champion, which is believed to hold about 40% of the economy's proved reserves, and produces 100,000 barrels per day (5 million tonnes per year). The oldest producing offshore field is South West Ampa, with 164 producing oil wells. Close to Ampa are the smaller Fairley and Gannet fields. Other fields include Magpie, Fairley-Baram, and Iron Duke.

Assessment of CO_2-EOR Potential. The IEA GHG report[11] concluded that in large, already discovered fields, the Baram Delta/Brunei-Sabah Basin had the technical potential for incrementally recovering 1.9 billion barrels (0.26 billion tonnes) of crude oil from the application of CO_2-EOR, with the potential for storing 600 million tonnes of CO_2 that would be purchased to facilitate this recovery. At 9.3 million tonnes CO_2 per year, this is over 60 years' worth of emissions for the entire economy.

In just the largest and oldest field, the Seria oil field, using the same methodology and assumptions from the IEA GHG study, nearly half of this potential could be realized.. This field has the potential to incrementally recover nearly 0.8 billion barrels (0.1 billion tonnes) of crude oil from the application of CO_2-EOR, and could store over 300 million tonnes of CO_2 that would be purchased to facilitate this recovery.

Best Prospects for a CCUS- CO_2-EOR Demonstration. Arguably the best prospect for a CCUS-EOR demonstration project in Brunei Darussalam would be to capture CO_2 from the SPARK methanol plant (or possibly other sources from the petrochemical complex) and transport the captured CO_2 approximately 25 kilometers via pipeline to the Seria oil field, which could have considerable potential for CO_2-EOR.

[9] U.S. Geological Survey, *Assessment of Undiscovered Oil and Gas Resources of Southeast Asia, 2010*, Fact Sheet 2010-3-15, June 2010 (http://pubs.usgs.gov/fs/2010/3015/pdf/FS10-3015.pdf) [Accessed September 14, 2013]
[10] https://www.bsp.com.bn/main/aboutbsp/about_oil_gas.asp [Accessed September 14, 2013]
[11] IEA Greenhouse Gas R&D Programme, *CO_2 Storage in Depleted Oilfields: Global Application Criteria for Carbon Dioxide Enhanced Oil Recovery*, Report IEA/CON/08/155, Prepared by Advanced Resources International, Inc. and Melzer Consulting, August 31, 2009 (http://www.co2storage.org/Reports/2009-12.pdf)

Barriers and Challenges. Brunei Darussalam is an economy of limited natural resources, with the exception of oil and natural gas, upon which it is heavily reliant. The economy has a general lack of expertise, and has been slow to introduce, advanced or low carbon technology into its economy. There is also an overall lack of regulatory frameworks and legislation to facilitate the implementation of climate change mitigation policies and strategies. Perhaps more importantly, there is a general lack of awareness of climate change concerns among the population, which would require a commitment to public engagement and education.[12]

2.2 PEOPLE'S REPUBLIC OF CHINA

Overview. In 2011, the People's Republic of China emitted 8.7 billion tonnes of CO_2, more than any other economy in the world.[13] Most of China's electricity comes from coal-fired capacity, which is being added at a rapid rate. China is the largest producer and consumer of coal in the world, and accounts for almost half of the world's coal consumption. The Chinese government has made the expansion of natural gas-fired and renewable power plants, as well as electricity transmission, a priority. Though many of the newly constructed coal-fired power plants are highly efficient and employ modern controls on potential air pollutants, China's CO_2 emissions are likely to continue to increase. Therefore, any effort to control CO_2 emissions from China's coal-fired power generation sector could have substantial benefits for addressing global climate change.

China is also the world's second largest oil consumer behind the United States, and the largest global energy consumer. According to the BP Statistical Review,[14] China has 17.3 billion barrels of oil reserves (2.4 billion tonnes) and 109.3 Tcf (3.1 Tcm) of natural gas reserves as of 2012. In 2012, China produced nearly 4.2 billion barrels per day (nearly 208 million tonnes per year), its highest level ever. In addition, 3.9 Bcf per day (107 Bcm per year) of natural gas were produced, down somewhat from its peak just a few years earlier.

However, despite increasing oil and gas production, China's imports of crude oil are rising more rapidly, reflecting the economy's growing energy needs and its inability to develop its own resource base at a comparable rate. In 2012, China's crude oil consumption was 10.2 million barrels per day (484 million tonnes per year). Estimates are that 5.4 million barrels per day (271 million tonnes per year) are imported to satisfy demand. If this is the case, China's oil imports now exceed those of the United States.

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[12] Climate Change; Brunei Darussalam's Perspective, presentation at the 5th Meeting of the Southeast Asia Network of Climate Change Focal Points, 22 September 2011 (http://www.unep.org/climatechange/mitigation/sean-cc/Portals/141/doc_resources/5th%20Regional%20Network%20Meeting/S3_Highlights_Brunei.pdf) [Accessed September 14, 2013]

[13] http://www.eia.gov/cfapps/ipdbproject/iedindex3.cfm?tid=90&pid=44&aid=8&cid=r7,&syid=2007&eyid=2011&unit=MMTCD [Accessed September 14, 2013]

[14] http://www.bp.com/en/global/corporate/about-bp/statistical-review-of-world-energy-2013.html [Accessed September 14, 2013]

China's national oil companies (NOCs) wield a significant amount of influence in China's oil sector. Between 1994 and 1998, the Chinese government reorganized most state-owned oil and gas assets into two vertically integrated firms: the China National Petroleum Corporation (CNPC) and the China Petroleum and Chemical Corporation (Sinopec). CNPC is the leading upstream player in China and, along with its publicly-listed arm PetroChina, accounts for most of China's total oil and gas production. Sinopec controls the majority of downstream activities, such as refining and distribution, though it seeks to acquire more upstream assets gradually. Additional state-owned oil firms have emerged over the last several years. For example, the China National Offshore Oil Corporation (CNOOC), which is responsible for offshore oil exploration and production, has seen its role expand as a result of growing attention to offshore zones.

Whereas onshore oil production in China is mostly limited to the NOCs, international oil companies have been granted greater access to offshore oil prospects and unconventional gas fields, mainly through production sharing agreements and joint ventures. International oil companies involved in offshore efforts in China include Conoco Phillips, Shell, Chevron, BP, Husky, Anadarko, and Eni, among others. China's NOCs must hold the majority participating interest in a production-sharing contract (PSC) and can become the operator once development costs have recovered.[15]

Though large crude oil discoveries are reported in the China's western and offshore basins, additional actions are required to meet its growing oil demand. The government, cognizant of this reality, is pursuing several national technology research and demonstration projects to help increase production from its existing oil fields. With an emphasis on international and domestic research initiatives, the Chinese government is pursuing CO_2-EOR as a means to address both its domestic oil supply requirements and to possibly assist in reducing its CO_2 emissions. The government has established a specialized program to sponsor and further research into CO_2-EOR, and several academic research institutions have formed EOR research initiatives. Finally, the Chinese government has joined several public-private international consortiums that seek to demonstrate CCS-CO_2-EOR technologies within China.

In this environment, CO_2-EOR technology can potentially provide a win-win solution for China. By productively using, and permanently storing, CO_2 to produce incremental oil resources, this technology can help address both China's environmental and resource concerns. As such, CO_2-EOR represents a significant value-added opportunity, uniquely suited to China's situation.

Like most APEC economies, China government policy is trying to strike a balance between economic growth, social development and environmental protection. China recognizes its susceptibility to sea level rise, potentially the result of climate change, and its impact on densely populated coastal communities. Thus, the Chinese government attaches great importance to the issue of climate change. In 2011, the Fourth Session of the Eleventh National People's Congress approved the Outline of the 12th Five-Year Plan for National Economic and Social Development, which defines the

[15] http://www.eia.gov/countries/cab.cfm?fips=CH [Accessed September 14, 2013]

objectives, tasks and general framework for China's economic and social development during the 12th Five-Year Plan period. To fulfill the economy's objectives and tasks in addressing climate change during the 12th Five-Year Plan period and promote green and low-carbon development, the State Council has issued a number of important policy documents, including the Work Plan for Controlling Greenhouse Gas Emissions During the 12th Five-Year Plan Period and the Comprehensive Work Plan for Energy Conservation and Emission Reduction.

CO_2 Emissions. Most of China's CO_2 emissions are generated in the developed, northern part of the economy, within the proximity of the Bohaiwan, Songliao, and Ordos Basins.[16] Within these regions, anthropogenic CO_2 emissions far exceed the amount of CO_2 that would be required for CO_2-EOR operations. Over 30 years, industries currently in operation near the Bohaiwan, Songliao and Ordos basins will emit almost 17 billion tonnes of CO_2 (of which more than 70% is generated from power plants). Even if only 60% of these emissions could be captured and productively used, they would still be sufficient to meet CO_2 demand for the potential CO_2-EOR market in these basins, which are estimated to total 9.2 billion tonnes of CO_2 over 30 years.

Previous Consideration/Application of CO_2-EOR and CCUS. As in many areas of the world, production from China's most prolific oil fields is declining, and new discoveries are typically being found in remote or otherwise difficult areas. In response, Chinese petroleum companies and research institutions are seriously investigating the potential for EOR to augment production from the economy's rapidly maturing oil fields.

China is familiar with EOR, having pursued techniques to increase oil recovery efficiency, such as infill drilling and steam, polymer and even microbial injection for many years. Most Chinese experience with EOR techniques has been with polymer injection. The technique has been attempted in many Chinese oil fields, including the Daqing and Shengli fields.[17]

China's experience with CO_2-EOR, however, is less extensive. Although CO_2-EOR has been employed in various forms in Chinese oil fields since 1990, when the first pilot operation in the Daqing field began, the majority of CO_2 injection programs noted in the literature have involved the injection of flue gas streams which are, on average, 10-20% CO_2. This practice of using flue gas with low concentrations of CO_2 differs significantly from United States CO_2-EOR operations, where primarily pure streams of CO_2 are injected.

While published results are not generally available (especially in English), several pilot tests of CO_2-EOR have been performed in Chinese basins. Reportedly, pilots have been implemented in the Liaohe, Jilin, Dagang, Shengli, Zhongyuan, Daqing, Jiangsu, Changqing, Xuedong, Huebei, and Xinli oil fields.

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[16] Data on CO_2 emissions are from the IEA GHG Program and www.Carma.org. [Accessed September 14, 2013]

[17] Han, D., Zhi-Yang, C., Lou, Z., et al., "Recent Development of Enhanced Oil Recovery in China," *Journal of Petroleum Science and Engineering*, Vol. 22, Issues 1-3. pp.181-188, 1999

China continues to take a systematic approach to the deployment of CCS, focusing on research and development followed by the roll-out of pilot projects and demonstration projects. Research for CCS in China has been conducted since 2006 under the National Basic Research Program of China (973 Program), and since 2007 under the National High-tech Research and Development Program of China (863 Program), which includes a focused research area on CCS. China is also investing in CCS demonstrations abroad, including a September 2012 investment in one of the United States demonstrations, the Texas Clean Energy Project, that is nearing financial close.[18]

In August 2012, the ADB announced plans to work with the National Development and Reform Commission (NDRC) to develop a roadmap for CCS deployment in China. There has been significant international cooperation on CCS research in China, including engagement in the CSLF and the Global CCS Institute, as well as focused cooperative research efforts such as the EU-UK CCS Cooperative Action within China, or COACH program, the US-China Clean Energy Research Center (CERC), the China-EU Cooperation on Near Zero Emissions Coal (NZEC), and the Asia-Pacific Partnership on Clean Development and Climate.[19]

A memorandum of understanding (MoU) between China's Department of Climate Change, NDRC, and the Global CCS Institute has opened the door for greater cooperation and significant progress on CCS. Collaborative projects have already included a capacity building workshop for stakeholders on storing CO_2 with EOR, and public awareness activities.[20]

Many of the projects in China are discussed in the Annual Survey of the Global CCS Institute in 2012.[21] There are now 11 large-scale integrated projects (LSIPs) in China which are at various stages of development. Most involve major state-owned companies, as well as a wide array of international partners. These are summarized below:

- The Daqing Carbon Dioxide Capture and Storage Project in Heilongjiang Province is being developed by Datang Heilongjiang Power Generation with Alstom China. The project involves the proposed capture of CO_2 at one of two new-build 350-MWe cogeneration units, using bituminous coal as feedstock. One million tonnes per year of CO_2 would be captured at the plant over its project life. The CO_2 would be transported by pipeline for sequestration in a deep saline formation and used in EOR.

[18] Smith, Rebecca and Brian Spegele, "China Takes Big Role in Texas Power-Plant Project, *Wall Street Journal*, September 12, 2012 (http://online.wsj.com/article/SB10000872396390443696604577647951084423834.html)
[19] For more information on CCS in China, please see: *CCS in China: Towards an Environmental Health and Safety Regulatory Framework*, WRI Issue Brief (http://www.wri.org/publication/ccs-in-china), [Accessed September 14, 2013]; and *Guidelines for Carbon Dioxide Capture and Storage in China*, Tsinghua University Press, 2012.
[20] http://www.globalccsinstitute.com/institute/media-centre/media-releases/china-becoming-global-leader-ccs [Accessed September 14, 2013]
[21] Global CCS Institute, Global Status of CCS: 2012, 2012 (http://www.globalccsinstitute.com/get-involved/in-focus/2012/10/global-status-ccs-2012) [Accessed September 14, 2013]

- The Dongguan Taiyangzhou integrated gas combined cycle (IGCC) with CCS Project in Dongguan, China, is led by the Dongguan Taiyangzhou Power Corporation. The project will involve a newly built 800-MWe coal-based power plant, expected to capture up to 1 million tonnes per year of CO_2, with an expectation to capture 21 to 30 million tonnes over its lifetime. The CO_2 would be transported to and stored in depleted onshore oil and gas reservoirs. At present the proposed storage site is about 101 to 150 kilometers from the power plant.

- The Dongying Carbon Dioxide Capture and Storage Project in Shandong Province, is being proposed by China Datang Corporation and Alstom. The project is proposing to capture 1 million tonnes per year of CO_2 at a new power generation facility. They estimate that 21 to 30 million tonnes would be captured over the life of the project, to be transported by pipeline 50 kilometers and used for EOR.

- The Huaneng GreenGen IGCC Project in the Binhai New Area in Tianjin is being proposed by GreenGen Tianjin IGCC Co. (Huaneng). The first phase contains a 250-MW IGCC power plant and a pilot unit that will capture 100,000 tonnes per year of CO_2 for use in the food and beverage industry. The full-scale CCS plant is planned for Stage 3, and will include a 400 MW demonstration IGCC power plant that will capture up to 2 million tonnes per year for EOR, with expectations to capture 41 to 50 million tonnes of CO_2 over the life time of the project. Expected transportation to the storage facility is expected to be 151 to 200 kilometers. Secondary storage may be pursued in other depleted onshore oil and gas reservoirs. Approvals were granted by the NDRC, and the pilot IGCC facility is under construction and scheduled to be in operation by 2012. The second phase is expected to be completed by 2016, with CCS operations expected in 2020.

- The Jilin Oil Field EOR Project (Phase 2) at Songyuan in the Jilin Province will be performed by CNPC. A pilot is in operation and was the first commercial CO_2-EOR operation in China. After the successful injection of around 200,000 tonnes per year of CO_2 from a natural gas processing plant in the first phase, CNPC is planning to expand capacity to 800,000 to 1,000,000 tonnes per year by 2015. Estimated transport distance to the planned CO_2 storage facility is 151 to 200 kilometers, with the operation of the transport infrastructure planned to commence by 2015. CO_2 available for storage (capture operation start date) is planned for 2015. CO_2 Phase 1 commenced operation in 2009. The total investment for Phase 1 of the project was $11 million. The captured CO_2 from the planned Phase 2 will be used for EOR.

- The Lianyungang IGCC with CCS Project in Jiangsu Province is being pursued by Lianyungang Clean Energy Innovation Industrial Park Ltd. The project consists of a 1200-MW IGCC power plant and two 1300-MW ultra-supercritical pulverized-coal plants. Up to 1 million tonnes per year of CO_2 would be captured from the syngas and the flue gas, with an expectation of 21 to 30 million tonnes over the lifetime of the project. Captured CO_2 will be transported by pipeline 201 to 250 kilometers for injection into deep saline formations or for EOR. A pre-feasibility study has been completed and the feasibility study is nearing completion. The plant is expected to be operational by 2015 subject to government approvals.

- The Shanxi International Energy Group CCUS project in Taiyuan in Shanxi Province, led by Shanxi International Energy Group (SEIG) and Air Products, involves a new 350-MWe supercritical coal-fired power plant with oxyfuel combustion that will capture more than 2 million tonnes per year of CO_2, with total estimated capture over the life time of the project is 51 to 60 million tonnes. Air Products has been awarded a contract from SIEG to perform a feasibility study and detailed cost estimates this year, with the Final Investment Decision (FID) expected in 2014. Various transport and storage options are under investigation.

- The Shenhua Ningxia Coal to Liquids (CTL) Plant Project at the Ningdong Energy Chemical Industry Base in Ningxia Province is led by the Shenhua Group. It will involve a new CTL plant capturing around 2 million tonnes per year of CO_2; with an expected lifetime capture of 61 to 70 million tonnes. Estimated transport distance from the capture plant to the planned CO_2 storage facility is 200–250 kilometers, with various storage options being considered, including EOR. Pre-feasibility (concept) studies were completed in 2009.

- The Shenhua/Dow Chemical's Coal to Chemicals Plant Project at Yulin in Shaanxi Province, proposed by Dow Chemical, would involve capturing 2 to 3 million tonnes of CO_2 per year, to be transported by pipeline for storage in onshore oil or gas reservoirs. The project in very early stages of planning.

- The Shenhua Ordos CTL Project in Inner Mongolia is being proposed by the Shenhua Group, with a plan that, by 2020, around 1 million tonnes per year of CO_2 would be captured at the existing CTL plant, with a total lifetime capture capacity of 21 to 30 million tonnes. Transportation to the storage site is expected to be 200 to 250 kilometers. Operation at pilot scale started in 2010, with around 100,000 tonnes of CO_2 captured at the plant annually. The CTL plant will use Wuhai coal to produce olefins through an advanced gasification technology. Potential storage sites are being investigated for the second phase of the project.

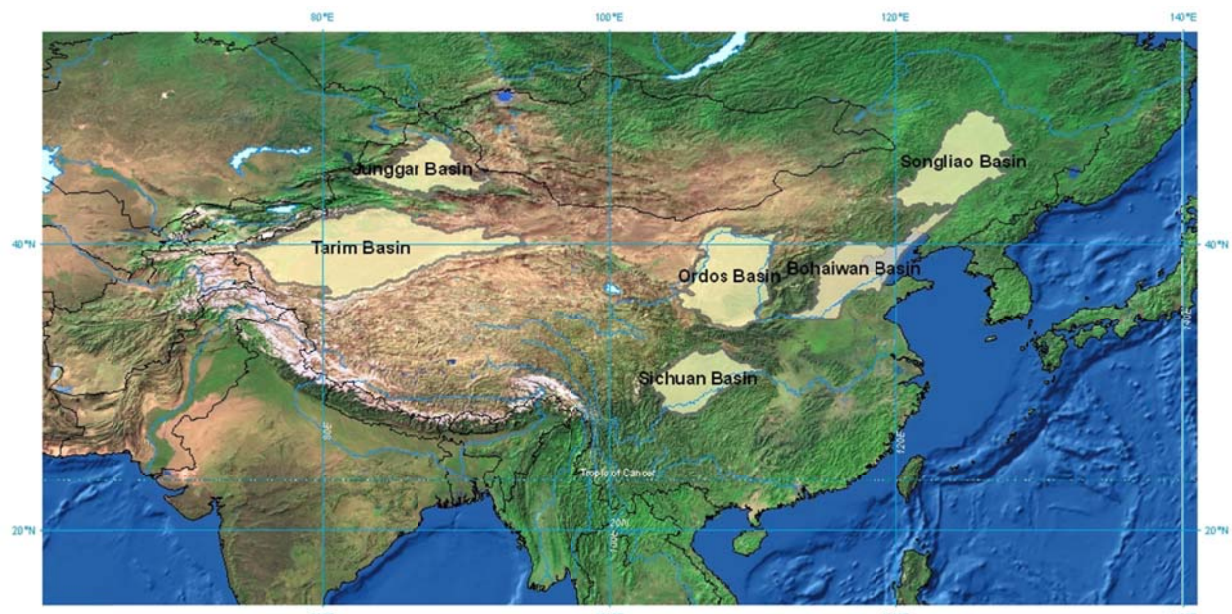
- The Sinopec Shengli Oil Field EOR Project Dongying in Shangdong Province involves a proposal to retrofit post-combustion CO_2 capture at an existing fluidized-bed boiler. Plans are to capture 1 million tonnes per year, with total capture volume for the lifetime of the project in the range of 21 to 30 million tonnes. Transport distance is about 51-100 kilometers by pipeline for use in EOR at an operating oil field. Pre-feasibility studies for the capture plant were expected to conclude in 2012, with a FID expected in 2013-2014. CO_2 available for storage (capture operation start date) is expected in 2017. A commercial agreement for the off-take of CO_2 for use in EOR has been reached.

The Global CCS Institute notes that significant recent progress has also been made with the successful demonstration of smaller-scale pilot projects. The growing number of proposals involving CO_2 utilization and EOR is being recognized, given the commercial challenges faced by projects and the importance of establishing a business case for CCS. However, cross-sectoral collaboration, they report, remains a challenge for CCS project developers, particularly for power generators that do not have access to a suitable CO_2 storage site.

Numerous other possible projects are also being discussed in China, but no formal plans have been announced.

Oil Resource Potential. The major oil basins in China include the Bohaiwan Basin, Songliao Basin, Junggar Basin, Tarim Basin, and the Ordos Basin (**Figure 2-1**). Together, these basins contain an estimated 460 billion barrels (63 billion tonnes) of crude oil, of which over 150 billion barrels (20 billion tonnes) are currently defined as produced, proved or probable reserves (the ultimately recoverable resource (URR)) **Table 2-1**). The Sichuan Basin is often noted as large hydrocarbon basin, though it is predominately gas and was not analyzed in this study.

Figure 2-1. Major Petroleum Basins of China



Source: Advanced Resources International, Inc.

Table 2-1. Petroleum Resources in China's Major Oil Basins[22]

Basin	Resource In Place (MMBO)	Ultimate Recoverable Resource (MMBO)	2004 Annual Oil Production (MMBO)
Bohaiwan	205,349	67,503	375
Songliao	96,798	50,158	373
Ordos	53,655	13,096	72
Sichuan	3,212	591	1
Tarim	58,838	6,557	59
Junggar	38,836	13,064	76
Total	456,688	150,970	956

The data in Table 2-1 are adapted from a presentation by Sinopec given in 2004, which represented the most comprehensive resource estimate found. While not directly comparable to other estimates, Sinopec's estimates seem reasonable when viewed in the context of other published data. The USGS estimates that the ultimately recoverable resource for the main Chinese oil basins is 69 billion barrels (9 billion tonnes), however, this does not include produced or proven reserves from the Tarim, Ordos, and Sichuan basins, nor 9 years of growth and additional discoveries and technological advancement since the assessment was performed in 2000.[23,24]

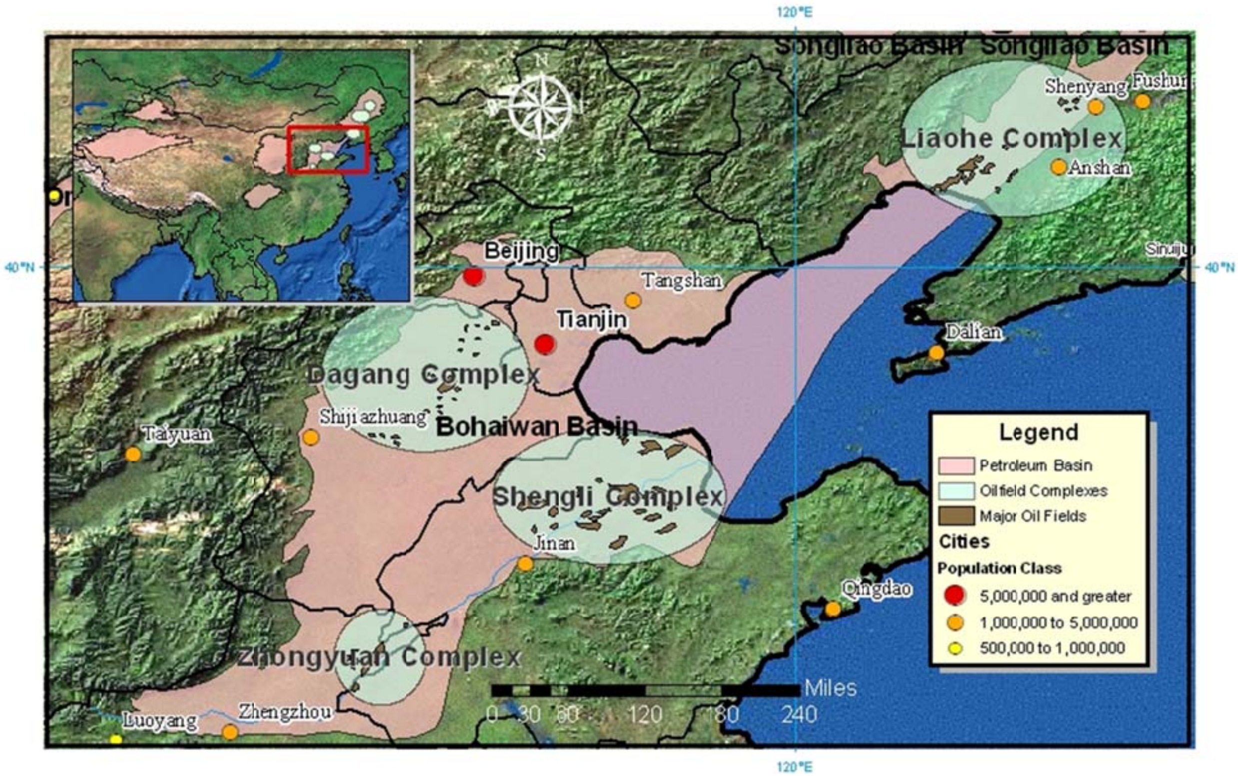
As shown in Table 2-1, the Bohaiwan and Songliao Basins represent the majority of China's oil reserves, as well as the bulk of China's oil production. The Tarim and Junggar Basins, on the other hand, are relatively undeveloped. And in the case of the Tarim Basin, the majority of its resource potential is estimated to exist in fields that have yet to be discovered.

The resource potential in each of the major hydrocarbon basins in China is described in more detail in the following.

Bohaiwan (Bohai) Basin. The Bohaiwan (Bohai) Basin (**Figure 2-2**) is the most intensively explored and developed basin in China. It accounts for about 40% of China's oil reserves and production. Because of its high level of development and favorable location in the East-Central region of China, near to the metropolitan hubs of Beijing and Tianjin, this basin has access to large volumes of CO_2 emissions that could be used for the future application of CO_2-EOR.

[22] Sinopec Corporation, Presentation given at the 4th Annual PPM Seminar, Hua Hin, Thailand, October 4-5, 2005
23 Statistical Review of World Energy, British Petroleum. Available at:
http://www.bp.com/productlanding.do?categoryId=6929&contentId=7044622 [Accessed September 14, 2013]
24 World Petroleum Assessment. United States Geological Survey. Digital Data Series DDS-60. 2000

Figure 2-2. Detail Map of the Bohaiwan Basin



Source: Advanced Resources International, Inc.

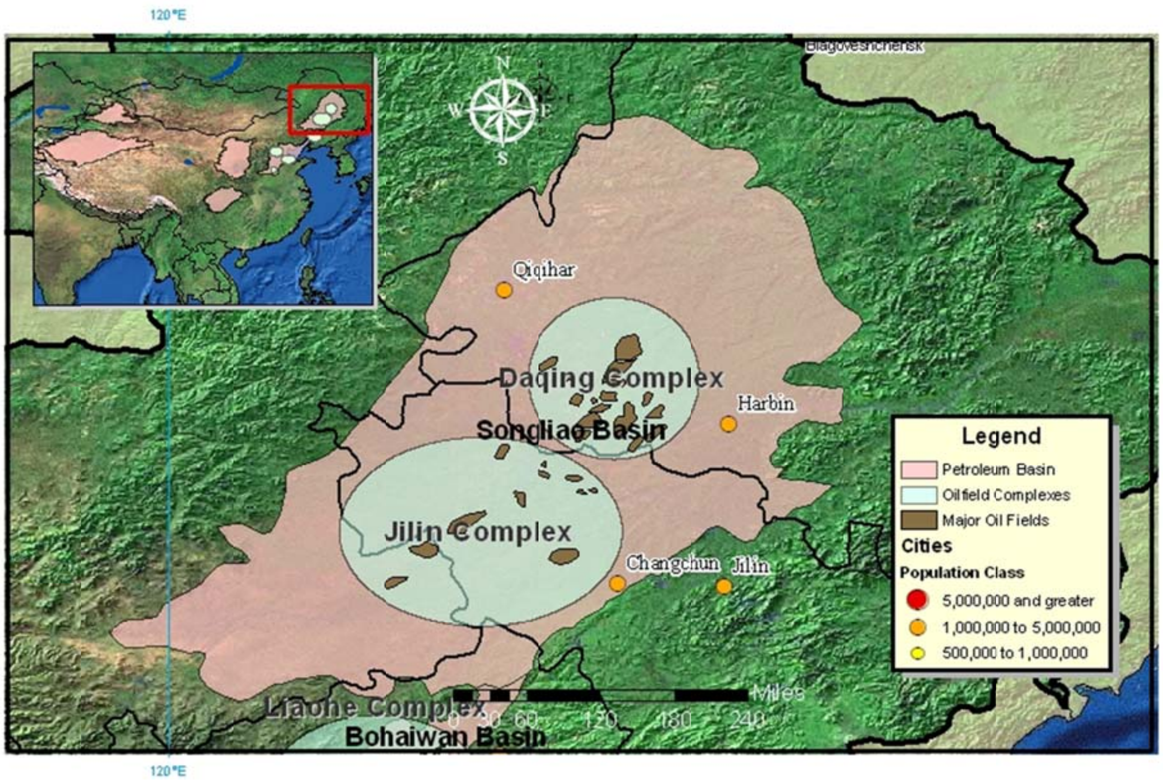
Relative to the other eastern Chinese basins, however, the Bohaiwan basin contains somewhat heavy oil, especially in its northern and offshore regions. Typically, heavy oil reservoirs do not respond as well to CO_2 flooding operations, though several successful CO_2-EOR pilots have been reported in the basin.

As China's oil reserves decline, investment is increasing in the offshore area of the Bohaiwan Basin. In late 2004, exploration teams claimed the Bohai Bay area could contain as much as 150 billion barrels (20.5 billion tonnes) of oil in place, of which 70 billion barrels (9.5 billion tonnes) had already been booked as reserves.[25]

Songliao Basin. In the Songliao Basin, the main oilfields are also experiencing declining production. The basin (**Figure 2-3**) is located in Northeast China and covers an area of approximately 260,000 square kilometers. According to the USGS, the basin is responsible for the highest volume of cumulative oil production in China. This is largely due to the contribution of the Daqing oilfield complex, one of the super-giant oil fields of the world, which has produced over 10 billion barrels (1.4 billon tonnes) since entering commercial production in 1960.

[25] http://peake.blogspot.com/2005/01/bohai-bay-update.html [Accessed September 14, 2013]

Figure 2-3. Detail Map of the Songliao Basin



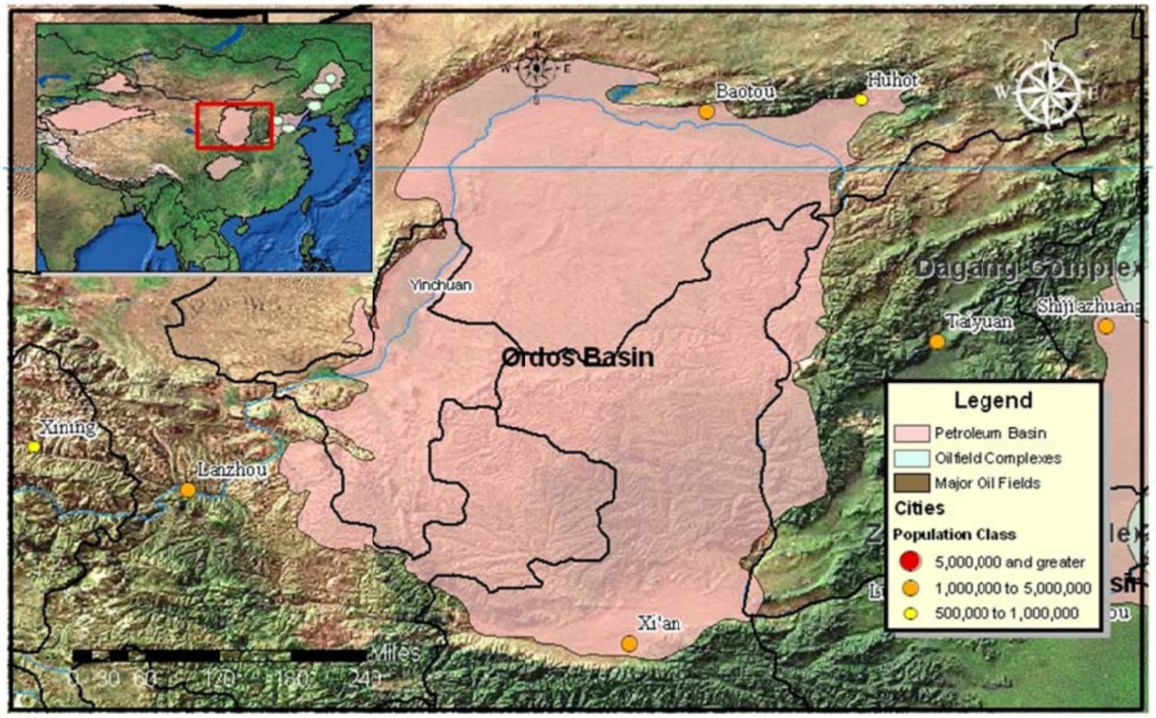
Source: Advanced Resources International, Inc.

Ordos (Erdos) Basin. While not as developed as the Bohaiwan or Songliao basins, the Ordos basin (**Figure 2-4**) is believed to contain large volumes of oil and gas, containing over 53 billion barrels (7 billion tonnes) of OOIP. However, a relatively small portion of this resource is believed to be commercially producible. Only 13 billion barrels of oil (2 billion tonnes) are considered reserves.

In recent years, significant attention has been given to adding additional reserves in this basin. In early 2009, the Chinese government announced that oil and gas production in the Ordos basin had been chosen for a national demonstration project, in which cutting-edge technology would be implemented and refined, then spread to other areas of the economy.[26] Within the last 5 years, PetroChina has begun making significant investments in bringing the oil and natural gas deposits of the Ordos to market. The Changqing field, operated by PetroChina, is China's third largest oilfield, after Daqing and Shengli.[27]

[26] "China To Focus On Oil & Gas Exploitation In Ordos Basin." *AsiaInfo Services*. 2009. *HighBeam Research.* 1 Jul. 2009
[27] "China: PetroChina to target oilfield production at 50 million tons of oil equivalent a year by 2015." TendersInfo. Al Bawaba (Middle East) Ltd. 2008. *HighBeam Research.* 1 Jul. 2009

Figure 2-4. Detail Map of the Ordos Basin



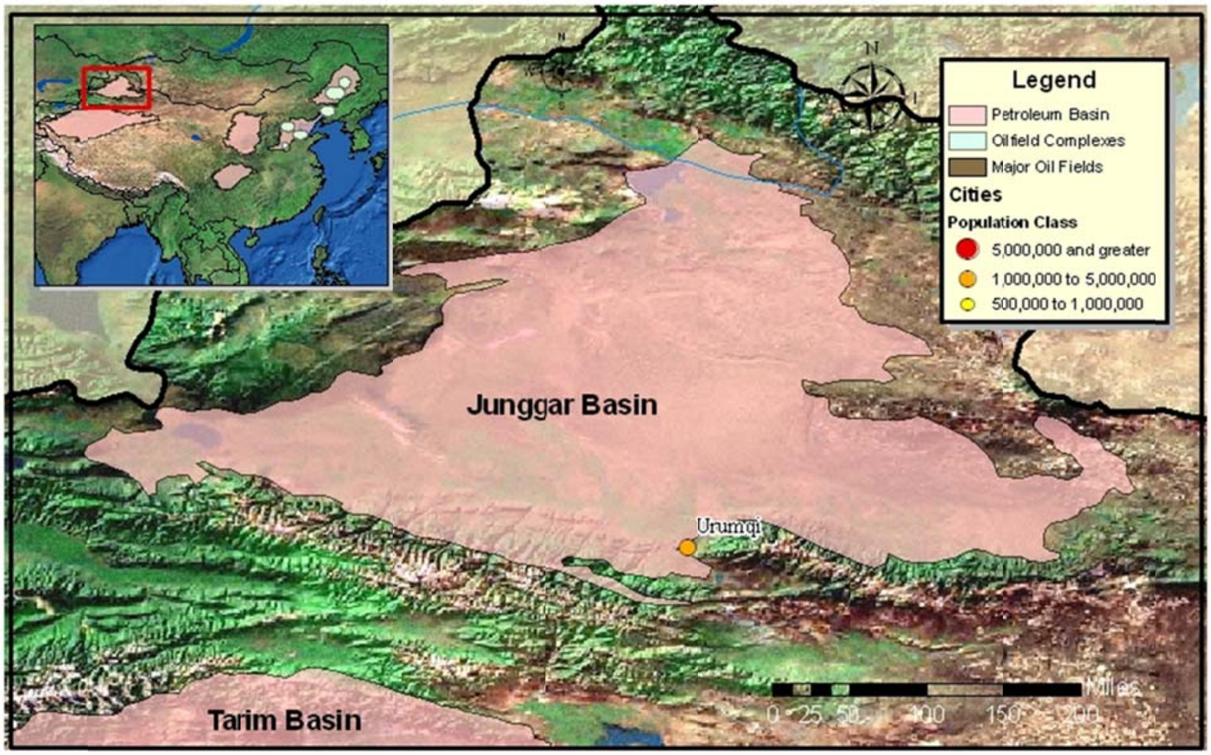
Source: Advanced Resources International, Inc.

Junggar Basin (Dzungarian) Basin. China's Junggar Basin (**Figure 2-5**), in the Northeast, is most widely known as a coal-producing basin. The East Junggar basin has recently become the economy's largest coalfield, with proven coal reserves of 390 billion tonnes. However, the Junggar Basin has reported oil reserves of at least 13 billion barrels (2 billion tonnes), as well as natural gas reserves of 2.1 Tcm (80 Tcf).

Assessment of CO_2-EOR Potential. The results of the application of the methodology in the IEA GHG report[28] results in an estimate of 226 billion barrels (31 billion tonnes) of OOIP amenable to CO_2-EOR, with 43 billion barrels (5.9 billion tonnes) estimated to be technically recoverable (**Table 2-2**). The Bohaiwan basin possesses the largest volume of technically recoverable resource from the application of CO_2-EOR − over 18 billion barrels − but this is primarily due to the large volume of OOIP in the basin. Its heavy oil and relatively shallow depth result in a low (18%) estimated recovery efficiency, the lowest of any basin. In the Songliao basin, an estimated 9 billion barrels of oil could be recovered using CO_2-EOR technology, though this only represents 19% of OOIP. Estimated CO_2-EOR recovery efficiency suffers in this basin due to its shallow average depth. Average recovery efficiency in the United States basins averages between 20 to 22% of OOIP.

[28] IEA Greenhouse Gas R&D Programme, *CO_2 Storage in Depleted Oilfields: Global Application Criteria for Carbon Dioxide Enhanced Oil Recovery*, Report IEA/CON/08/155, Prepared by Advanced Resources International, Inc. and Melzer Consulting, August 31, 2009 (http://www.co2storage.org/Reports/2009-12.pdf)

Figure 2-5. Detail Map of the Junggar Basin



Source: Advanced Resources International, Inc.

Table 2-2. CO_2-EOR Recovery Efficiency and Technically Recoverable Resource in Chinese Oil Basins

Basin Name	OOIP Favorable for Miscible CO2-EOR (MMBO)	API Gravity (Degrees)	Depth (Feet)	EOR Recovery Efficiency	EOR Oil Technically Recoverable (MMBO)
Bohaiwan Basin	101,614	28	5,654	18%	18,184
Songliao Basin	47,899	35	4,150	19%	9,288
Junggar Basin	19,217	32	6,890	20%	3,773
Tarim Basin	29,115	38	9,840	23%	6,610
Ordos Basin	26,550	35	3,936	19%	5,124
Sichuan Province	1,589	38	6,560	23%	362
Total	225,986			19%	43,340

Source: IEA Greenhouse Gas R&D Programme, *CO_2 Storage in Depleted Oilfields: Global Application Criteria for Carbon Dioxide Enhanced Oil Recovery*, Report IEA/CON/08/155, Prepared by Advanced Resources International, Inc. and Melzer Consulting, August 31, 2009

Table 2-3 shows that recovering the 43 billion barrels from China's large oil basins could require at least 12 billion tonnes of CO_2 that would eventually be stored in the depleted reservoirs.

Table 2-3. CO_2 Storage Potential from CO_2-EOR in Chinese Oil Basins

Basin Name	EOR Oil Technically Recoverable (MMBO)	API Gravity (Degrees)	Depth (Feet)	CO_2/ Oil Ratio (cf/Bbl)	CO_2 Stored	
					Tcf	Gigatonnes
Bohaiwan Basin	18,184	28	5,654	5,611	102	5.4
Songliao Basin	9,288	35	4,150	4,947	46	2.4
Junggar Basin	3,773	32	6,890	5,629	21	1.1
Tarim Basin	6,610	38	9,840	5,865	39	2.1
Ordos Basin	5,124	35	3,936	4,907	25	1.3
Sichuan Province	362	38	6,560	5,764	2	0.1
Total	43,340				235	12.4

Source: IEA Greenhouse Gas R&D Programme, *CO_2 Storage in Depleted Oilfields: Global Application Criteria for Carbon Dioxide Enhanced Oil Recovery*, Report IEA/CON/08/155, Prepared by Advanced Resources International, Inc. and Melzer Consulting, August 31, 2009

Several studies have also reported on the CO_2-EOR potential in China.[29] In most cases, these studies were conducted at a very aggregate level, or were focused on activities other than CO_2-EOR, therefore not fully capturing the CO_2-EOR potential contained in Chinese basins. Where estimates of incremental oil production capacity were given, they are presented here, though none of these studies reported estimates of the national potential for CO_2-EOR in China.

- Near Zero Emissions from Coal (NZEC) and Cooperative Action within CCS China-EU project (COACH) Consortia. As part of a series of evaluations, researchers from the EOR Research Center in the China University of Petroleum estimated the CO_2 storage potential in several Chinese oil and gas basins using guidelines developed by the CSLF, and based on oilfield reservoir data to which they had access. One such study found that 458 million tonnes of CO_2 could be stored in the large oilfields of the Daqing oilfield complex and 48 million tonnes could be stored in the Jilin oilfield complex. Additionally, the study found that 20 million tonnes of CO_2 could be stored in the Jiang Su oilfield, of which 16 million tonnes could be stored through CO_2-EOR.[30,31]

- Battelle. A study performed researchers at Battelle and Pacific Northwest National Labs entitled "A Preliminary Cost Curve Assessment of Carbon Dioxide Capture and Storage Potential in China" found that approximately 4.8 billion

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[29] Meng, KC, R.H. Williams, and M.A. Celia, "Opportunities for low-cost CO_2 storage demonstration projects in China," *Energy Policy*, 35, 2368-2378, (2007)

[30] Li, Mingyuan, Regional Assessment of Carbon Dioxide Storage Potential. EOR Research Center, China University of Petroleum Beijing, May 2008.

[31] The methodology behind these estimates relays on a number of simplifying assumptions and does not necessarily represent the likely CO_2 storage capacity available for CO_2-EOR operations in these basins. However, the results are useful in to provide a relative estimates of areas with higher storage potential.

tonnes of CO_2 (of which 4.6 billion tonnes are onshore) could be stored in depleted oil fields in China, helping to produce 7 billion barrels of oil.[32] A more recent study indicates that 200 million barrels (28 million tonnes) per year could be produced annually at a net profit using CO_2-EOR.[33]

- Chinese Office of Global Environmental Affairs. In a presentation given to the UNFCCC in 2006, the deputy director general of the Chinese Office of Global Environmental Affairs (part of the Ministry of Science and Technology (MOST)), reported that 7.2 billion tonnes of CO_2 could be stored in 46 Chinese oil and gas reservoirs. These numbers were introduced as very initial estimations, and further detail on estimation techniques or whether they applied specifically to EOR was not provided.[34]

- PetroChina. In a public presentation given by a representative of PetroChina Corporation, it was estimated that CO_2-EOR technology could be applied in oil fields in China with approximately 7.3 billion barrels of reserves, allowing for an additional 1.1 billion barrels to be incrementally produced. Assuming that an average CO_2-EOR operation purchases approximately 0.5 tonnes of CO_2 per barrel of oil produced, 550 million tonnes of CO_2 could be injected and possibly stored in these oilfields.[35]

- China's Ministry of Petroleum Industry (MOPI). In a study commissioned in 1998 by MOPI, the authors estimated that approximately 500 million barrels of oil could be incrementally produced from depleted oil fields with stranded oil volumes of 3.8 billion barrels. Assuming a 0.5 tonnes CO_2 injected per barrel of oil produced, 250 million tonnes of CO_2 would be demanded by these projects.[36]

Each of the three promising basins for CO_2-EOR operations are within close proximity to large volumes of CO_2 emissions. Within a 10-mile (16 kilometer) radius of the Bohaiwan, Songliao, and Ordos basins, anthropogenic CO_2 emissions exceed the volume of CO_2 that would be demanded by CO_2-EOR operations, **Table 2-4**.Through CO_2-EOR operations, these three basins could produce almost 33 billion barrels of incremental oil, thereby productively using, and storing, 9.2 billion tonnes of CO_2. If the fields were managed to maximize CO_2 storage, instead of CO_2-EOR operation profit, they could potentially store even much larger volumes of CO_2.

[32] Dahowski, RT, X Li, CL Davidson, N Wei, JJ Dooley, and RH Gentile, "A Preliminary Cost Curve Assessment of Carbon Dioxide Capture and Storage Potential in China, " *Energy Procedia*, 1 (2009) 2849-2856
[33] Dahowski, Robert; Casie Davidson, Xiaochun Li, and Ning Wei, "CCUS Deployment Potential and Costs in China," presentation at the 12th Annual Carbon Capture Utilization & Sequestration Conference, Pittsburgh, PA, May 15, 2013
[34] Xuedu, Lu. "Experiences and Opportunities of CCS in China" Presentation given to UNFCCC, May 20, 2009. Bonn, Germany. Accessed at: http://unfccc.int/files/meetings/sb24/in-session/application/pdf/experience_and_opportunity_in_china_by_lu_xuedu.pdf [Accessed September 14, 2013]
[35] PetroChina Company Limted. "CCS Activities and Developments in China." Presentation given September 10, 2007.
[36] Liu, D.S, Yun, G. C., Ou Yang, L.H., 1998. Waste CO_2 capture and utilization for enhanced oil recovery (EOR) and underground storage-a case study in Jilin Oil Field, China. Greenhouse gas mitigation: technologies for activities implemented jointly. Elsevier, Oxford, UK (pp. 273-279).

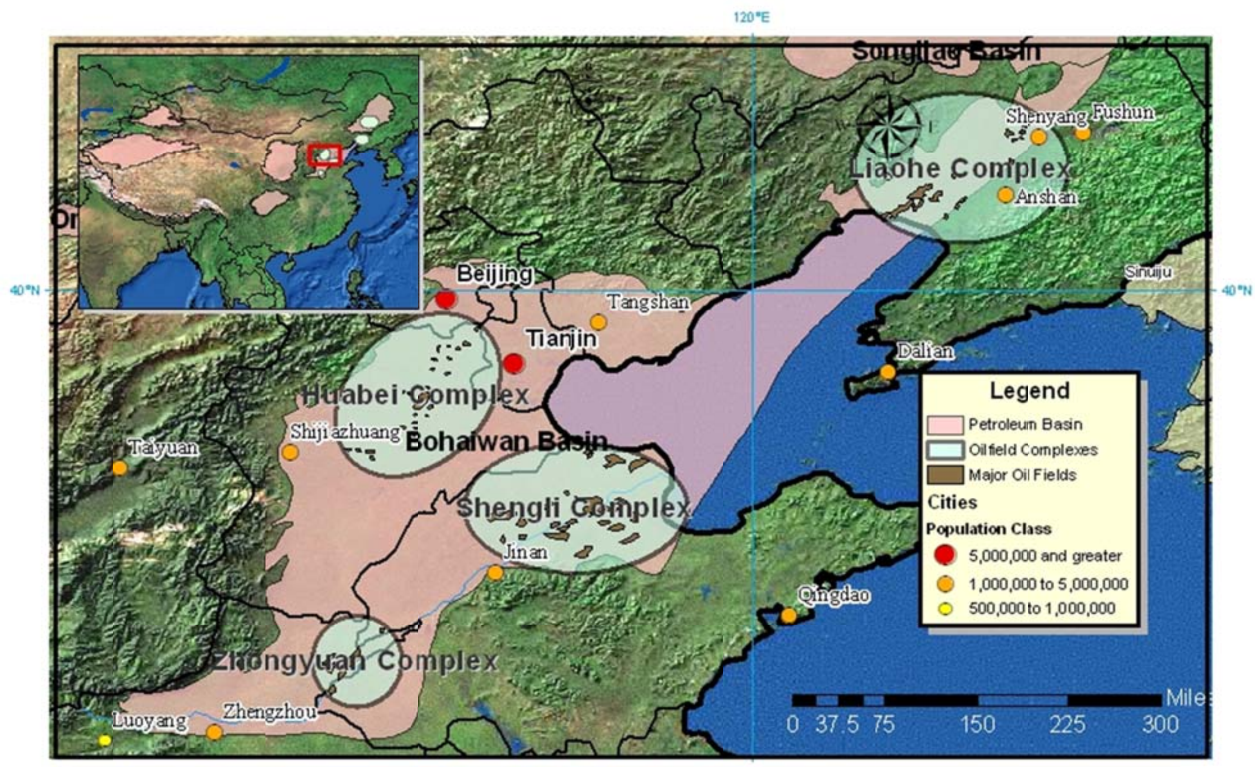
Table 2-4. Availability of Anthropogenic CO_2 for EOR Operations

Basin	EOR Recoverable Oil (MMBO)	CO_2 Demand (Million Tons)	Anthropogenic CO_2 Emissions Within 10 Mile Radius (Million Tons)
Bohaiwan Basin	18,184	5,398	10,255
Songliao Basin	9,288	2,431	2,525
Ordos Basin	5,124	1,330	4,207
Total	32,596	9,160	16,986

Source: IEA Greenhouse Gas R&D Programme, *CO_2 Storage in Depleted Oilfields: Global Application Criteria for Carbon Dioxide Enhanced Oil Recovery*, Report IEA/CON/08/155, Prepared by Advanced Resources International, Inc. and Melzer Consulting, August 31, 2009.

Figure 2-6 shows the relative location of CO_2 sources in the Bohaiwan basin that could provide captured CO_2 to the EOR market. The data presented in Table 2-4, above, were compiled by summing the emissions of all sources that appear inside, or within 10 miles of, the basin outlines as shown in this figure.

Figure 2-6. Location of CO_2 Sources and Major Oil Fields within the Bohaiwan Basin, China



Source: IEA Greenhouse Gas R&D Programme, *CO_2 Storage in Depleted Oilfields: Global Application Criteria for Carbon Dioxide Enhanced Oil Recovery*, Report IEA/CON/08/155, Prepared by Advanced Resources International, Inc. and Melzer Consulting, August 31, 2009

To aid in selecting potential areas for a CCS demonstration/CO_2-EOR pilot project, a CO_2 availability analysis was performed on the largest oil field complexes within the Bohaiwan and Songliao basins. While data constraints prevented performing a CO_2-EOR feasibility analysis on this scale, the largest CO_2 emitting power plants within close proximity to these oilfield complexes were identified.

The three main oilfield complexes in the Bohaiwan basin are the Huabei, Shengli and Liaohe Complexes. CO_2 injection pilots have been performed in each of these oilfield complexes, and there are substantial sources of CO_2 emissions that could be captured within close proximity to each of these oilfield complexes.

Within the Songliao basin, there are two major oilfield complexes, the Daqing and Jilin, both of which have been the subject of CO_2-EOR pilots. Substantial sources of CO_2 emissions that could be captured are also within close proximity to these oilfield complexes.

The oil basins with the largest volume of technically recoverable resource through CO_2-EOR technology, the Bohaiwan, Songliao and Ordos basins, possess significant and sufficient supplies of anthropogenic CO_2 to provide for CO_2-EOR operations. The Bohaiwan basin, with the largest amount of CO_2-EOR technically recoverable resource, could provide over 10 billion tonnes of captured CO_2 emissions over a 30-year timeframe, almost double the 5 billion tonnes that CO_2-EOR operations in the basin could productively use and store.

Additionally, all of the major oil field complexes in the Bohaiwan and Songliao basins contain several large volume power plant CO_2 sources that could be potential sites for integrated CCS retrofit and EOR pilot projects. Within the Bohaiwan basin, the Shengli and Huabei complexes exhibit favorable characteristics such as several, reasonably efficient power plants and proximity to developed metropolitan areas.

Within the Songliao basin, both the Jilin and Daqing oilfield complexes exhibit favorable characteristics. However, due to the long history of extensive water flooding and infill drilling in the Daqing complex, residual oil saturation may be lower than optimal for effective CO_2 flooding. Therefore, the Jilin oilfield complex may present the most favorable setting for a pilot project in the Songliao basin.

Best Prospects for a CCUS-EOR Demonstration. With a reported 11 large scale integrated projects at various stages of development in China, there are a number of prospects for a CCUS-EOR demonstration. Moreover, other possible projects are being discussed, but with no formal plans announced. Most involve CO_2 utilization for EOR or enhanced coalbed methane (ECBM), and involve major state-owned power, oil, or coal companies, as well as a wide array of international partners. Finally, most have some level of international involvement and support, implying that the results of these projects will be eventually be published.

Barriers and Challenges. Like most other APEC economies, China is challenged by the need to balance economic growth, social development and environmental protection objectives. In all likelihood, carbon-intensive coal and other fossil fuels will continue to dominate Chinese needs in meeting future energy requirements. CCUS offers China the opportunity to meet climate change objectives while still providing the economy's energy needs, along with energy efficiency, renewable energy, nuclear energy, more efficient coal technologies and fuel switching from coal to gas.

China is taken a very aggressive approach to the pursuit of CCUS-CO_2-EOR opportunities within the economy. Preliminary work on CCS in China has focused on CCS in the power sector. However, capture in the power sector is technically challenging, energy-intensive and expensive. Capture can be implemented at lower cost at large point sources of concentrated CO_2, such as in ammonia and methanol plants, coal-to-liquids facilitie,s and hydrogen production processes. China has a large industrial base in these sectors, resulting in a significant CO_2 emission reduction potential through CCUS.

A recent study by the IEA[37] concluded that, like most economies evaluating deployment of CCS technologies, China must consider many complex issues, including significant investment needs for demonstration projects, regional development priorities, coal-sector employment, the coal-development chain, political concerns, centralization of power generation, security of supply, and long-term trade and commodities markets. Another set of issues relates to the technical sophistication and human resource capacity required to build execute such projects, as well as the competitive advantages of various related technologies and limitations in understanding storage potential.

The key findings and conclusions of the IEA assessment are as follows:

- The pace of China's economic growth and the resulting increase of emissions over the next ten years, together with China's commitment to addressing the problem of global climate change, are likely to bring CCS technologies into focus with crucial actions for deployment necessary between 2020 and 2030. The pace of CCS development and deployment in China will have a significant impact on the overall global potential of CCS to play its role in mitigating CO_2 emissions.

- China has several technology demonstration projects with aspects of CCS, in operation, under construction, or planned, and the national government continues to support technical development and research into feasibility of CCS on a larger scale. However, at top levels of China's policy-making process, co-ordination among agencies, regulatory bodies and steering groups will be essential to further develop this area and determine the most efficient path for CCS technology development.

[37] Best, Dennis and Ellina Levina, Facing China's Coal Future: Prospects and Challenges for Carbon Capture and Storage, OECD/IEA, 2012

- In addition to energy security and the desire to develop technology, China's actions on CCS are driven by global climate policy considerations and the Chinese government's national climate policy and sustainable development objectives. Given limited economic incentives for CCS projects in China, as in most parts of the world, additional international mechanisms are likely to be required for early deployment of CCS.

- China's move towards CCUS is underpinned by early experiences in EOR and enhanced coalbed methane (ECBM) projects. However, safety, storage permanence and long-term monitoring will be critical, and doubts remain whether all such utilization projects can meet the inherent objectives of CCS as a climate change mitigation tool.

- Clarification on cost estimates and comparative capture routes relevant to China's case, along with advanced coal technology and cleaner pathways, such as efficiency improvements, retrofits and plant upgrades, will help to clarify strategic priorities towards CCS research, development and demonstration.

- Survey results point to the key focus and challenge of further demonstrating economic feasibility and clarifying industrial and support policies to address cost concerns if CCS pilot projects and further demonstration will be deployed.

- China is already engaged in an ambitious effort on CCS research, development and demonstration. It has the right conditions and political will to enhance these efforts provided that international support and global climate policy also expand.

2.3 INDONESIA

Overview. Indonesia is the fourth most-populous economy in the world with a population of 240 million, is the world's largest archipelago state, and is currently the world's third fastest growing economy. Fossil fuels dominate Indonesia's energy supply. Indonesia is also among the world's largest emitters of GHGs, with land use change and deforestation the largest contributors to emissions. Energy-related emissions are dominated by industry, power, and transport sectors.[38]

Indonesia has abundant primary energy resources that are utilized to meet domestic demand and export requirements in the form of oil, liquefied natural gas (LNG), and coal. Coal is Indonesia's largest fossil fuel resource, with proven reserves of 5,300 million tonnes of lignite and sub-bituminous coal located predominantly in Sumatera and Kalimantan. The Indonesian Government plans to rapidly expand the domestic use of coal for electricity generation. In the foreseeable future power generation and industrial use will continue to dominate coal utilization.

[38] http://www.globalccsinstitute.com/location/indonesia [Accessed September 14, 2013]

According to the BP Statistical Review,[39] Indonesia had 3.7 billion barrels (0.5 billion tonnes) of proven oil reserves as of January 2012. Total oil production has continued to decline, from a high of nearly 1.6 million barrels per day (81 million tonnes per year) in 1991 to under 0.92 million barrels per day (45 million tonnes per year) in 2012. In addition, Indonesia had 103 Tcf (3.9 Tcm) of proven natural gas reserves as of January 2012. Total natural gas production is in slow to decline, from a high of 7.9 Bcf per day (82 Bcm per year) in 2010 to 6.9 Bcf per day (71 Bcm per year) in 2012.

Several international oil companies dominate Indonesia's upstream oil sector – in particular, Chevron, Total, ConocoPhillips, Exxon, and BP. Other NOCs such as the China National Offshore Oil Corporation (CNOOC) and South Korea's KNOC also have significant upstream stakes. Chevron is the largest single oil producer, followed by PT Pertamina, Indonesia's state-owned integrated energy supply company.

The oil and gas industry, including refining, contributed approximately 7% to GDP in 2010, according to data from Indonesia's National Bureau of Statistics. Indonesia was a member of OPEC from 1962 to 2009. However, the combination of growing domestic oil consumption, the natural maturing of Indonesia's oil fields, and limited investment into reserve replacement caused Indonesia to become a net importer of both crude oil and refined products by 2004. Indonesia suspended its OPEC membership in January 2009, to concentrate on meeting demand at home.

Indonesia also has substantial renewable energy resources. Historically, while the focus has been on export revenue, there has been a rapid re-orientation by the Indonesian Government towards meeting its domestic energy needs since early this decade.

Moreover, Indonesia has begun to mobilize institutionally to take advantage of the increased prominence of the climate change issue to develop, promote and implement domestic climate change policy and position itself to be a leader among developing economies on this issue. In 2009, President Susilo Bambang Yudhoyono announced that Indonesia would reduce GHG emissions by 26% by 2020, and make a further reduction of up to 41% with international support.[40] The Government also joined the G20 pledge to phase out subsidies for fossil fuels. Indonesia is developing a strategic, multi-year policy and investment program for low-carbon growth.

There are many types of CO_2 storage that are available in Indonesia. First, a saline aquifer is believed to exist in the Natuna region. However, its capacity and distribution still remain in question. Coal seams are scattered among the islands; Indonesia has abundant coal seam reserves, particularly low-rank coal deposits that are distributed across eleven onshore coal basins. To utilize this type of storage the adsorbed

[39] http://www.bp.com/en/global/corporate/about-bp/statistical-review-of-world-energy-2013.html [Accessed September 14, 2013]
[40] Satriastanti, Fidelis E., "Yudhoyono Signs Decree to Reduce Greenhouse Gas Emissions," Jakarta Globe, September 26, 2011 (http://www.thejakartaglobe.com/archive/yudhoyono-signs-decree-to-reduce-greenhouse-gas-emissions/) [Accessed September 14, 2013]

methane has to be produced. However, many of the coal seams in Indonesia are still presently in a non-producing phase.

Interest in CCS in Indonesia crosses a number of government areas. The Ministry of Energy and Mineral Resources and the Environmental Ministry have actively contributed to the most recent study and findings about CCS. LEMIGAS, who used to be involved in subsurface technology, is well aware of the need of comprehensive research into CCS, and have issued short-term R&D plans on CCS that not only focus on technical aspects but also non-technical aspects such as regulatory development. Moreover, the private sector, including multinational oil companies, is beginning to look at the potential of CCS in Indonesia by engaging with LEMIGAS to conduct CCS research projects.

In 2009, an overview of the current status of CCS in Indonesia was developed and published by an Indonesia CCS Study Working Group, representing collaboration between Indonesian R&D centre for oil and gas technology (LEMIGAS), Kementrian Lingkungan Hidap (KLH), PT PLN (Persero), World Energy Council (WEC), PT Shell Indonesia, and the British Embassy in Jakarta. The report found that there is significant potential for CCS in Indonesia, but also a number of barriers to overcome.[41]

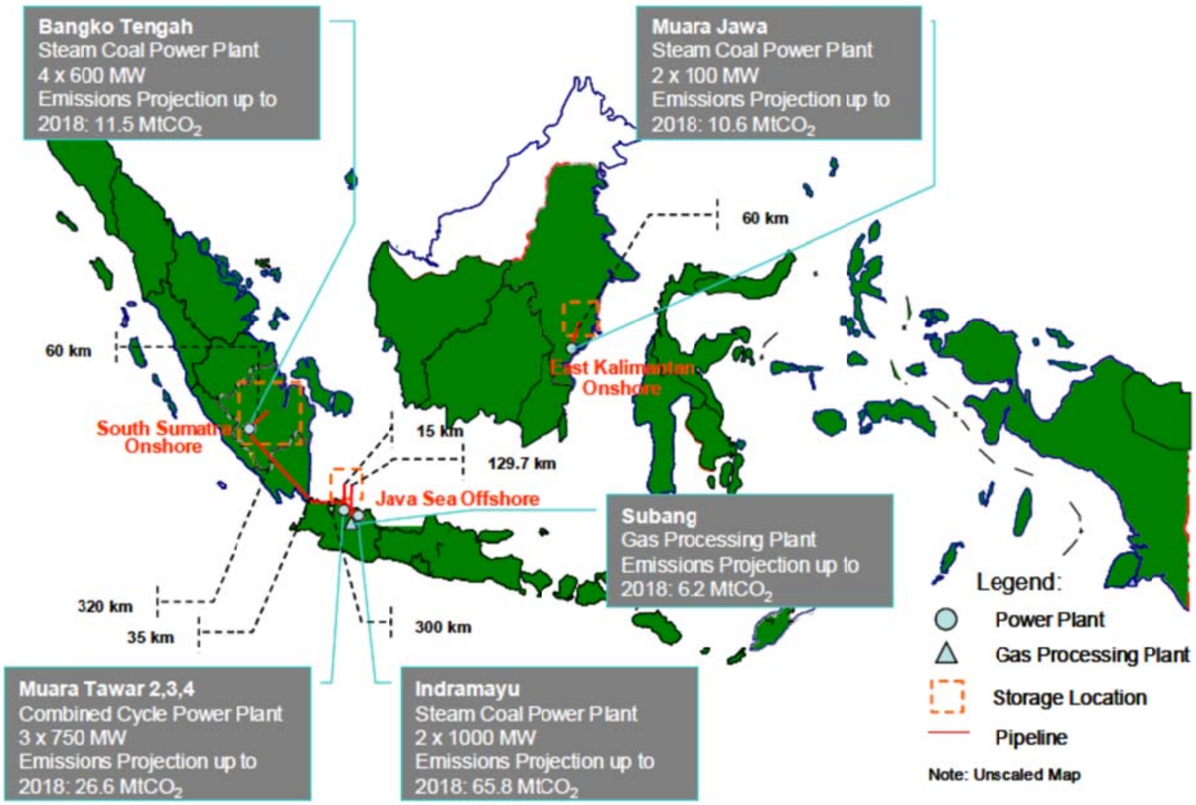
CO_2 Emissions. Based on 2012 data from the BP Statistical Review,[42] Indonesia's CO_2 emissions were 495 million tonnes, ranking it 14th in the world.

There are multiple industry sources of CO_2 emissions in Indonesia, such as power plants, oil and gas processing plants, steel and ammonia plants and cement factories. Indonesia has many small, scattered coal plants, making the economics of CO_2 capture challenging. This dispersion of CO_2 point sources reduces the potential benefits that can be gained through a pipeline network and the clustering of CO_2 sources.

Most industrial CO_2 sources are located in Jawa and Sumatera, and to a lesser extent in Kalimantan and Sulawesi Island, consisting of power plants, oil and gas processing plants, steel and ammonia plants and cement factories (**Figure 2-7**). Total industry-generated CO_2 emissions in these areas, including from oil and gas processing, are estimated to be about 17.5 million tonnes annually (lower case estimate). It has been projected that the total CO_2 emissions from 8 interconnected power systems will be 1,938 million tonnes CO_2 accumulated from 2008 to 2018.[43]

[41] Indonesia CCS Study Working Group, Understanding Carbon Capture and Storage Potential in Indonesia, August 14, 2009
[42] http://www.bp.com/en/global/corporate/about-bp/statistical-review-of-world-energy-2013.html [Accessed September 14, 2013]
[43] Best, Dennis, Rida Mulyana, Brett Jacobs, Utomo P. Iskandar, and Brendan Beck, "Status of CCS Development in Indonesia, *Energy Procedia* 4 (2011) 6152–6156

Figure 2-7. Major CO_2 Emissions Sources and Emissions Projects in Indonesia



Source: Indonesia CCS Study Working Group, Understanding Carbon Capture and Storage Potential in Indonesia, August 14, 2009

One gas sweetening plant at Subang field located in West Jawa is a particularly interesting source of CO_2 emissions. The field produces 200 million cubic feet (5.7 million cubic meters) per day of gas with a CO_2 content of 23%. The cost of compressing the extracted CO_2 has been estimated to be \$10.70/tonne of CO_2, which is relatively low compared with the power plant examples.

The growth of electricity demand in Indonesia is expected to remain strong in the next few decades to supply electricity particularly to remote areas. Responding to this demand growth, PLN (the state owned electricity enterprise) issued a Ten-Year Electricity Development Plan to build several power plants that would be dominated by coal. Hence, in the future, coal-fuelled power generation will continue to be the main contributor of CO_2 emissions in Indonesia.

Some natural gas reserves in Indonesia, as elsewhere in South-East Asia, have a high proportion of CO_2. This is particularly the case for the giant Natuna gas field which has approximately 70% CO_2. One option is to make use of the captured CO_2 for enhanced gas recovery (EGR) of the Natuna gas reserves or to be injected into saline aquifers beneath the gas reservoirs.

Previous Consideration/Application of CO_2-EOR and CCUS. Interest in CCS in Indonesia has been growing over recent years with several studies conducted from 2003 to 2005 by LEMIGAS assessing the potential of CO_2-EOR in conjunction with CO_2 storage in East Kalimantan and South Sumatera. LEMIGAS is also collaborating with a number of international partners to look at related issues.

A long oil exploration and production history in Indonesia has left a legacy of many depleted oil and gas fields that could be used for potential CO_2 storage. This type of storage may be preferable due to well-characterized reservoirs and existing infrastructure. However, concerns have been expressed that these abandoned oil and gas fields possess a higher leakage potential through existing well penetrations that must be mitigated properly. Also, the long distances involved in reaching offshore sinks could prove prohibitively expensive. Key areas would include South Sumatera, East Kalimantan, and Natuna for CO_2 storage. These regions are suitable due to geological stability and low population density.

An integrated reservoir study was performed on the Handil oil field in the Mahakam Delta to evaluate possible ways to revive production from the mature oil field, discovered in 1974. Among the options considered was lean-gas injection and gravity assisted immiscible recovery,[44] although not CO_2-EOR.

Oil Resource Potential. Indonesia is a significant and well-established player in the international oil and gas industry, though production has failed to keep up with demand in recent years. Indonesia was ranked 20th among the world's oil producers in 2011, accounting for approximately one percent of the global daily production.[45]

According to the BP Statistical Review,[46] Indonesia had 3.7 billion barrels (0.5 billion tonnes) of proven oil reserves as of January 2012. Total oil production has continued to decline, from a high of nearly 1.6 million bbl/d (81 million tonnes per year) in 1991 to under 0.92 million bbl/d (45 million tonnes per year) in 2011. This fell short of the government's production goal for that year.

Aging infrastructure and fields suggest the economy will struggle to meet production targets in the short term. Indonesia's two largest producing and oldest oil fields are Duri and Minas, located on the eastern coast of Sumatera in the South Sumatera Basin. Chevron operates both fields with a 100% working interest. Production at both fields is declining, even with EOR techniques to bolster production. Chevron uses steam injection EOR for 80% of the Duri field, one of the largest steam-flood projects in the world. This field is too shallow, and its oil too viscous, to be a reasonable candidate for CO_2-EOR.

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[44] Herwin, Henricus, Emmanuel Cassou, and Hotma Yusuf, "Reviving the Mature Handil Field: From Integrated Reservoir Study to Field Application," SPE Paper No. 11082 prepared for the 2007 Asia Pacific Oil and Gas Conference and Exhibition, Jakarta, October 30-November 1

[45] http://www.eia.gov/countries/cab.cfm?fips=ID [Accessed September 14, 2013]

[46] http://www.bp.com/en/global/corporate/about-bp/statistical-review-of-world-energy-2013.html [Accessed September 14, 2013]

The most important recent discovery with the potential to counteract some of Indonesia's production decline is the Cepu Block of East and Central Java, which contains three significant fields: Banyu Urip, Jambaran, and Cendana. Moreover, in August 2011, ExxonMobil announced a new oil discovery at an exploration well in the block. ExxonMobil operates the Cepu production-sharing contract (PSC) with 45% interest in a joint venture with PT Pertamina's Exploration and Development (E&P) unit (45% working interest) and four local government companies. The partners estimate that Cepu contains 600 million barrels (82 million tonnes) of recoverable liquids and will have a peak production of 165,000 barrels per day.

Besides the Sumatera Basin, the country of Indonesia produces significant quantities of oil from the East Java Basin. This is produced under a joint operating agreement between PT Pertamina and PetroChina. This venture produced approximately 43,000 barrels per day at the end of 2011, and both companies announced plans to raise production by up to 10,000 barrels per day in the next few years.

BPMigas and the Indonesian government introduced policies aimed at increasing investment in the economy's upstream sector, in particular by creating investment incentives and improving the flexibility of the PSC bidding process.

Despite declining production, the future potential for oil production in Indonesia is considerable. A large number of hydrocarbon basins underlie Indonesia (**Figure 2-8**). Some of these have been quite prolific and are estimated to still contain large volumes of hydrocarbon resources that remain to be discovered. However, many of the basins are relatively small in size and mostly located in deep water, such that they are not targets for CO_2-EOR and associated CO_2 storage any time in the foreseeable future.

Hydrocarbon resources that remain to be discovered in the major basins of Indonesia, as estimated by the USGS,[47] are shown in **Table 2-5**.

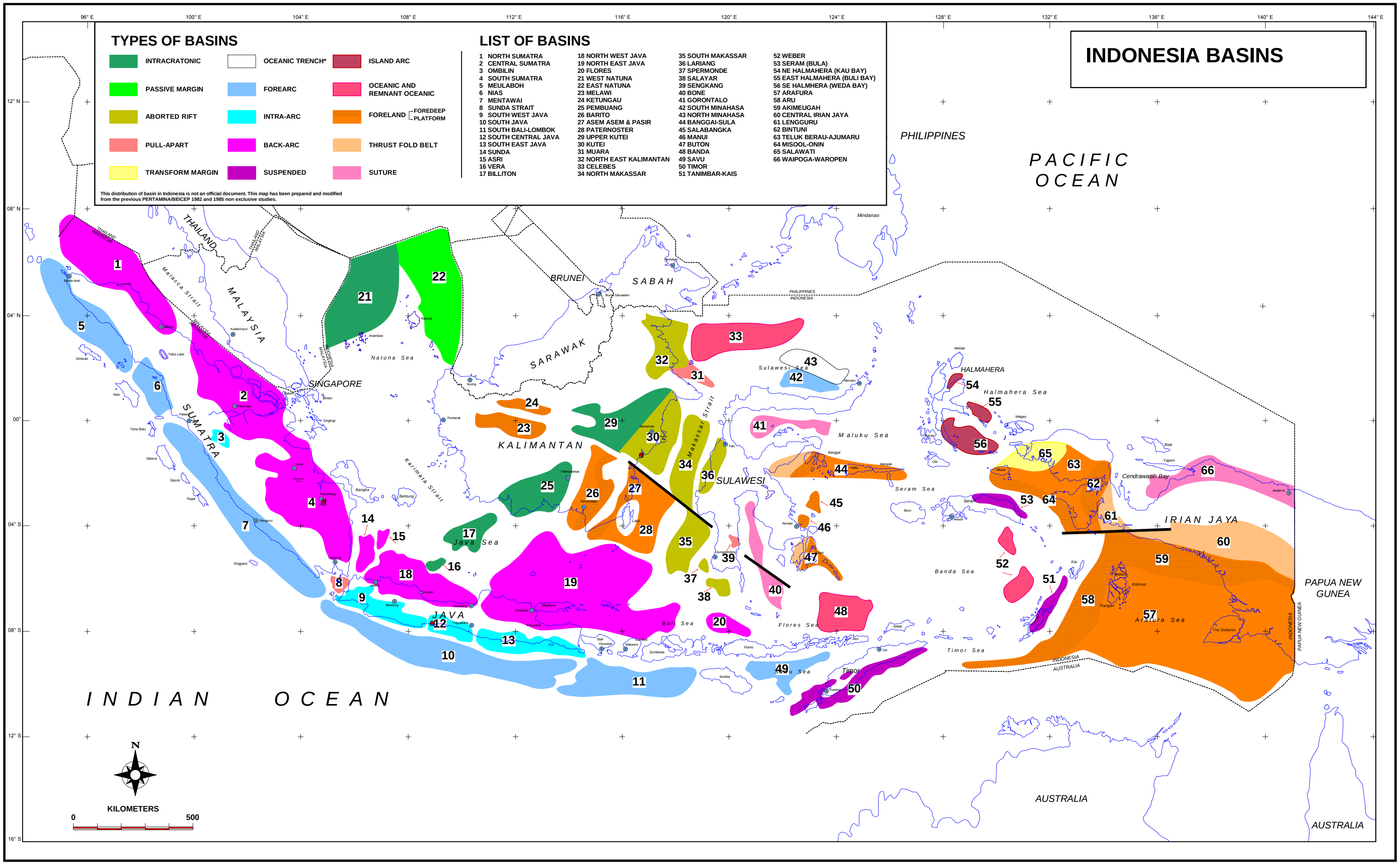
In total, these major basins within and near the Indonesian archipelago contain 12 billion barrels of oil (1.6 billion tonnes) that remains to be discovered, with additional potential in the significant number of other basins where no such estimates have yet been made.

Assessment of EOR Potential. The 2009 Indonesia CCS Study Working Group study[48] estimated that from 38 to 152 million tonnes (**Figure 2-9**) could be stored in the depleted oil reservoirs in East Kalimantan region, with the potential to recover 265 to 531 million barrels (36 to 72 million tonnes). In South Sumatera region, they estimated that 18 to 36 million tonnes could possibly to be stored in the depleted oil and gas reservoirs, with potential oil recoveries of 84 to 167 million barrels (11 to 23 million tonnes).

[47] *USGS, Assessment of Undiscovered Oil and Gas Resources of Southeast Asia*, 2010, USGS Fact Sheet 2010-2015, June 2010; and USGS, *Assessment of Undiscovered Oil and Gas Resources of Papua New Guinea, Eastern Indonesia, and East Timor*, 2011, USGS Fact Sheet 2012-3029, March 2012

[48] Indonesia CCS Study Working Group, Understanding Carbon Capture and Storage Potential in Indonesia, August 14, 2009

Figure 2-8. Hydrocarbon Basins of Indonesia



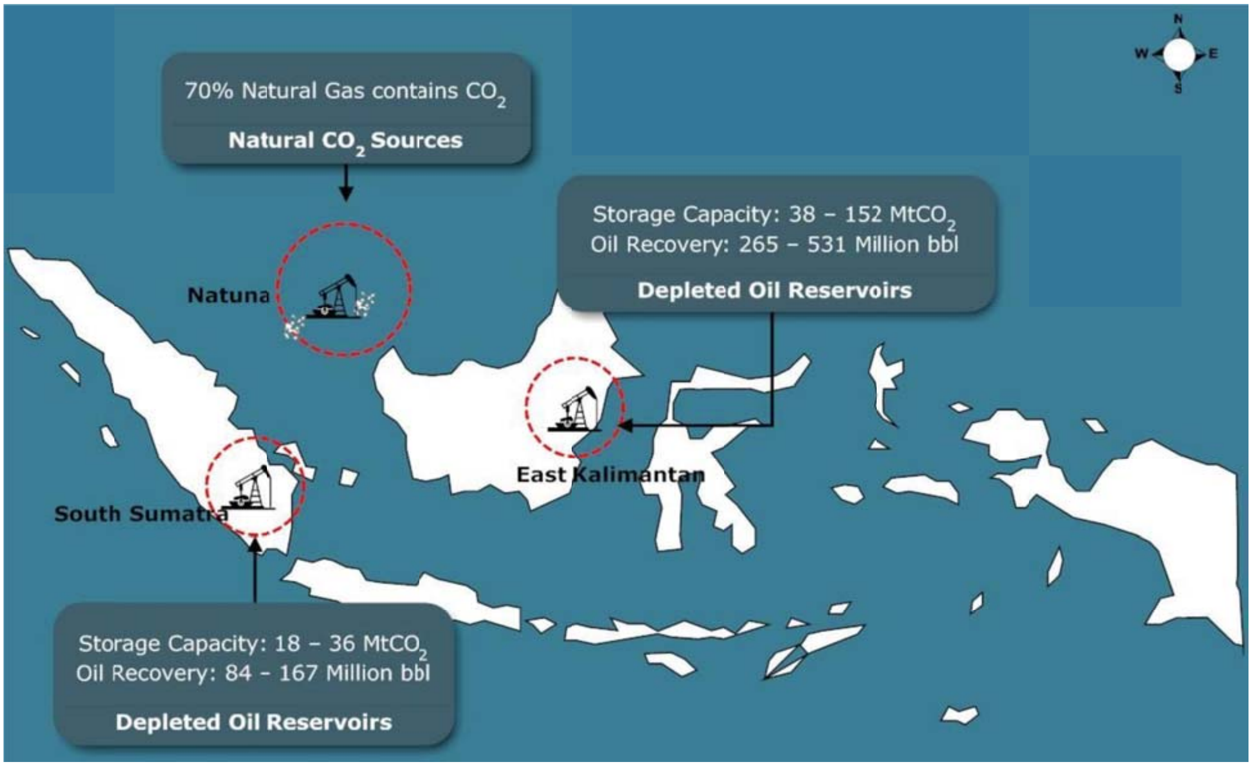
Source: Indonesian Petroleum Association (http://www.ipa.or.id/home.php?page_id=7&page_category_id=3) [Accessed September 14, 2013]

Table 2-5. Hydrocarbon Resources that Remain to be Discovered in the Major Oil Basins of Indonesia

Basin	Mean Undiscovered Oil Resources (Million Barrels)
Tarakan Basin (Neogene TPS)	707
Greater Sarawak Basin Province (Sarawak Basin TPS)	643
Barito Basin (Eocene-Miocene Composite TPS)	146
Central Sumatera Basin (Brown Shale-Sihapas TPS)	148
East Java Basin (Eocene-Miocene Composite TPS)	2,036
Kutei Basin TPS	3,215
North Sumatera Basin (Bampo-Cenozoic TPC)	453
Northeast Java Basin (Eocene-Miocene Composite TPS)	726
South Sumatera Basin (Lahat/Talang Akar-Cenozoic TPS)	353
Irian Jaya Fold Belt	325
Arafura Platform	534
Bintuni Basin	184
Sulawati Basin	349
Seram Thrust Structures	831
Timor Thrust Structures	1,275
	11,925

Sources: USGS, Assessment of Undiscovered Oil and Gas Resources of Southeast Asia, 2010, USGS Fact Sheet 2010-3015, June 2010; and USGS, Assessment of Undiscovered Oil and Gas Resources of Papua New Guinea, Eastern Indonesia, and East Timor, 2011, USGS Fact Sheet 2012-3029, March 2012

Figure 2-9. Potential Areas for CCS in Indonesia



Source: Indonesia CCS Study Working Group, Understanding Carbon Capture and Storage Potential in Indonesia, August 14, 2009

The IEA GHG report[49] assessed the potential for CO_2-EOR in two basins in Indonesia. However, both of these basins −the Northwest Java Basin, and the Central Sumatera Basin) − were determined to not be amenable to CO_2-EOR because they were on average too shallow.

For purposes of this study, however, this restriction was not imposed, since despite the fact that, on average, these basins may be considered too shallow, many of the fields within the basin are deeper than average, and could be amenable to CO_2-EOR. Removing this constraint in large, already discovered fields in the Northwest Java Basin, it was estimated that there was the potential for incrementally recovering 850 million barrels (110 million tonnes) of crude oil from the application of CO_2-EOR, with the potential for storing 200 million tonnes of CO_2 that would be purchased to facilitate this recovery. In the Central Sumatera Basin, nearly 3.4 billion barrels (0.46 billion tonnes) could be recovered from the application of CO_2-EOR, with an estimated storage potential of over 800 million tonnes of CO_2.

[49] IEA Greenhouse Gas R&D Programme, *CO_2 Storage in Depleted Oilfields: Global Application Criteria for Carbon Dioxide Enhanced Oil Recovery*, Report IEA/CON/08/155, Prepared by Advanced Resources International, Inc. and Melzer Consulting, August 31, 2009 (http://www.co2storage.org/Reports/2009-12.pdf)

Like most basins, a large portion of this potential exists in just a few giant fields. For example, applying the same methodology on a field-specific basis as that used in the IEA GHG report for the largest oil basins, just five of the largest oil fields in Indonesia have the potential to recover 1.9 billion barrels (260 million tonnes) of oil from the application of CO_2-EOR, and could potentially store over 700 million tonnes of CO_2, as shown in **Table 2-6**.

Table 2-6. CO_2-EOR and CO_2 Storage Potential for Selected Fields in Indonesia

Field Name	Estimated Ultimate Conventional Recovery (MMBbls)	Depth (feet)	EOR Recovery (%)	EOR Potential (MMBbls)	Purchased CO_2 Requirements (MM tonnes)
Ardjuna B	600	2,800	19%	309	114
Attaka	1,000	7,500	23%	532	197
Handil	800	6,500	19%	485	179
Kuang	600	5,249	17%	377	139
West Seno Complex	320	8,000	19%	201	74
	3,320			1,903	704

Source: Advanced Resources International, Inc.

Best Prospects for a CCUS- CO_2-EOR Demonstration. In Indonesia, a number of prospective projects have been identified for the potential application of CCUS-EOR. Just three fields in South Sumatera that are currently undergoing EOR were identified by an Asian Development Bank (ADB) study to have the potential for storing 28 million tonnes of CO_2.[50] Without naming the facilities due to confidentiality concerns, they recommended consideration of a CCUS pilot that matched an existing gas processing facility with onshore oil fields in the South Sumatera basin. With this approach, an existing gas processing facility such as the one at Natuna could be matched with one or more fields in the South Sumatera basin or East Kalimantan.

The 2009 Indonesia CCS Study Working Group study identified several prospective "source-sink" matches for a CCS pilot for preliminary costing estimates:[51]

- Capture of CO_2 at a 1000-MW supercritical coal-fired power plant in Indramayu-West Java and transport to an onshore storage location in South Sumatera.
- Capture of CO_2 at a natural gas combined cycle power plant (NGCC) in Muara Tawar-West Java and transport to offshore storage, North of Java.

[50] Asian Development Bank, Prospects for Carbon Capture and Storage in Southeast Asia: Executive Summary, November 2012

[51] Indonesia CCS Study Working Group, Understanding Carbon Capture and Storage Potential in Indonesia, August 14, 2009

- Capture of CO_2 at a lignite-fired power plant in Bangko Tengah-South Sumatera and transport to onshore storage.
- Capture of CO_2 at a coal-fired power plant in Muara Jawa-East Kalimantan and transport to an onshore storage location on Kalimantan.
- Capture of CO_2 from a gas processing plant at the Subang gas field in West Java, with storage offshore.

For any of these to be considered in this study, they would need to be modified to include the use of CO_2 for CO_2-EOR, rather than merely storage without enhanced recovery.

Barriers and Challenges. The 2009 Indonesia CCS Study Working Group study concluded that successful deployment of CCS in Indonesia requires a sound policy framework to minimize risks related to policy and commercial aspects. Partnerships between governments, international organizations and private sector were determined to be essential. Most of the non-technical challenges of deploying CCS were determined to evolve around the regulatory and policy aspects. Parallel to establishing the regulatory regime, a key enabling policy identified was the need for international financing, which was determined to be pivotal since CCS generates no revenue stream other than the CO_2 price (if it is recognized to generate CO_2 credits, which currently is not yet the case) - which in the short-term may not be sufficient to deploy a CCS project.

2.4 MALAYSIA

Overview. Malaysia is a significant oil and natural gas producer and is strategically located amid important routes for the seaborne energy trade. Malaysia's oil reserves are the fifth highest in the Asia-Pacific region, after China, Indonesia, Viet Nam, and India. Malaysia was the world's second largest exporter of LNG − after Qatar − in 2012.

According to the BP Statistical Review,[52] oil production in Malaysia in 2012 was 657,000 barrels per day (30 million tonnes per year), and appears to be stabilizing. Natural gas production is also relatively stable, at nearly 3.2 Bcf per day (65 Bcm per year) in 2012. Nearly all of Malaysia's oil production comes from offshore fields.

Energy policy in Malaysia is set and overseen by the Economic Planning Unit (EPU) and the Implementation and Coordination Unit (ICU), which report directly to the Prime Minister. Malaysia's national oil and gas company, Petroliam Nasional Berhad (Petronas), holds exclusive ownership rights to all oil and gas exploration and production projects in Malaysia, and is responsible for all licensing procedures. The company holds stakes in the majority of oil and gas blocks in Malaysia, and is the single largest contributor of Malaysian government revenues. Since its incorporation in 1974, Petronas has grown to be an integrated international oil and gas company with business interests in over 30 economies. Under legislation enacted in 1985, a 15% minimum

[52] http://www.bp.com/en/global/corporate/about-bp/statistical-review-of-world-energy-2013.html [Accessed September 14, 2013]

equity for Petronas is specified in production sharing contracts. ExxonMobil, Shell, and Murphy Oil are the largest foreign oil companies by production volume.

The Malaysian government is focused on efforts to enhance output from existing oil and natural gas fields, as well as to advance exploration in deep water areas. New tax and investment incentives introduced in 2010 aim to promote oil and natural gas exploration and development. Their goal is to increase production capacity by 5% per year up to 2020 to meet domestic demand growth and to sustain crude oil and LNG exports. Malaysia also aims to become a regional oil storage and trading hub, taking advantage of its strategic location in the center of the Asia-Pacific region astride key shipping lanes.

When compared with other developing economies in Asia, the carbon intensity of Malaysia's economy is relatively high. Nonetheless, Malaysia is committed to addressing CO_2 emissions and has tasked its Ministry of Natural Resources and Environment with the responsibility of developing an emissions reduction plan. The commitment was to voluntary reduce the economy's carbon intensity by 40% compared to 2005 levels, conditional on receiving technology transfer and finance from Annex 1 countries. The Government of Malaysia is exploring many different mitigation and energy efficiency options, including CCS and deployment of renewable energy.[53]

Malaysia's primary energy use − and therefore emissions − is dominated by fossil fuels. While this use mainly consists of hydrocarbons, the use of coal is on the increase. Over 90% of electricity generation is through fossil fuels. The major non-energy source of CO_2 emissions is the cement industry.

In 2010, the Ministry of Energy, Green Technology and Water (KeTTHA) partnered with the Global CCS Institute and the Clinton Climate Initiative to produce a CCS Scoping Study to assess the specific potential for CCS in Malaysia. Key findings of the study included:

- There is an opportunity to reduce significant volumes of CO_2 emitted by Malaysian point sources using CCS technologies,
- CCS can reduce emissions directly from the power, oil and gas, and industrial sectors, and
- The cost of electricity produced using CCS on fossil fuel plants is competitive with other low-emission sources of power such as solar and wind.

KeTTHA is now planning for CCS implementation in Malaysia, starting with the establishment of a multi-stakeholder steering committee to consider the recommendations of the study.

[53] http://www.globalccsinstitute.com/location/malaysia [Accessed September 14, 2013]

CO_2 Emissions. Based on 2012 data from the BP Statistical Review,[54], Malaysia's CO_2 emissions were nearly 220 million tonnes. Emissions from the consumption of fossil fuels represented most of this. Power sector contributes about 30% to 40% of CO_2 emissions of Malaysia, mostly from the combustion of coal. The major non-energy source of CO_2 emissions is the cement industry.

The largest concentration of CO_2 emissions is in the Malay basin (76% of the total). High CO_2 gas fields in Malaysia represent an opportunity, since CO_2 contents in the natural gas production streams can range from 28% to 87%.

Previous Consideration/Application of CO_2-EOR and CCUS. Recognizing the potential for EOR to increase oil production, PETRONAS initiated a comprehensive screening study in 2000.[55] The study found that miscible CO_2 flooding opportunities were limited due to depleted reservoir pressures.

Several immiscible gas injection projects were identified (Dulang field, Baronia field), and pilot projects were initiated, with the injected gas consisting of natural gas with high CO_2 concentrations. Miscible CO_2 injection potential was identified at the West Lutong field and the Tapis field (either miscible or near-miscible).

All of these pilots were in offshore fields. This creates a number of additional challenges relative to onshore CO_2-EOR projects. The results of this investigation prompted PETRONAS to require operators to investigate EOR opportunities as part of production sharing contracts (PSCs) for Malaysia's fields.

Most notably, ExxonMobil's EOR project at the Tapis field, which lies 118 miles off Terengganu in 210 feet of water, is due to start in 2013.[56] Tapis is one of seven mature fields in offshore Malaysia that ExxonMobil and Petronas have agreed to develop as part of a 25-year production-sharing contract that was finalized in June 2010. Under the agreement, which includes provisions for the deployment of EOR and further drilling to boost output, work is being carried out on all seven fields - Seligi, Guntong, Tapis, Semangkok, Irong Barat, Tebu, and Palas − with an estimated gross investment of more than $1 billion.

In 2011, Shell and Petronas agreed to invest $12 billion over 30 years in two EOR projects offshore Sarawak and Sabah (Baram Delta and North Sabah) covering nine fields. The projects are expected to boost reserves by 750 million barrels and use the world's first offshore, chemical injection process for resource recovery.

[54] http://www.bp.com/en/global/corporate/about-bp/statistical-review-of-world-energy-2013.html [Accessed September 14, 2013]
[55] Samsudin Y, Darman N, Husain D, Hamdan K. "Enhanced oil recovery in Malaysia: making it a reality. Part II," SPE Paper No. 95931 presented at the SPE International Improved Oil Recovery Conference in Asia Pacific. Kuala Lumpur, Malaysia, December 5-6, 2005
[56] "Malaysian Tapis oil field EOR project set to start up end 2012: Exxon Mobil," *Platts* (Singapore), July 10, 2013

In 2010, Malaysia provided tax incentives for upstream investment in EOR and marginal field development projects. The income tax rate for marginal fields dropped from 38% to 25%, and the government waived export duties on total oil production from these smaller fields. Malaysia also provided income tax allowances of up to 100% of capital expenditure for EOR projects.[57]

Oil Resource Potential. According to the BP Statistical Review,[58] Malaysia held proven oil reserves of 3.7 billion barrels (0.5 billion tonnes) as of January 2012. Nearly all of Malaysia's oil comes from offshore fields. The continental shelf is divided into three producing basins: the Malay basin offshore peninsular Malaysia in the west and the Sarawak and Sabah basins in the east. Most of the economy's oil reserves are located in the Malay basin and tend to be of high quality. Total oil production in 2012 was estimated to be 657,000 barrels per day (30 million tonnes per year).

Malaysia consumes the majority of its oil production and domestic consumption has been rising as production has been falling. The government is focused on opening up new investment opportunities by enhancing output from existing fields and developing new fields in deep water areas offshore Sarawak and Sabah.[59]

Malaysia's continental shelf is made up of six major sedimentary basins, in three main regions:

- Peninsular Malaysia: Malay Basin in the offshore east covers more than 12,000 square kilometers; and Penyu Basin in the south covers an area of 5,000 square kilometers.
- Sarawak: Sarawak Basin with seven geological provinces.
- Sabah: Sabah Basin, Northeast Sabah Basin and Southeast Sabah Basin, containing prolific deep water discoveries.[60]

Hydrocarbon resources that remain to be discovered in the major basins of Malaysia, as estimated by the USGS,[61] are shown in **Table 2-7**.

57 http://www.eia.gov/countries/cab.cfm?fips=MY [Accessed September 14, 2013]
58 http://www.bp.com/en/global/corporate/about-bp/statistical-review-of-world-energy-2013.html [Accessed September 14, 2013]
59 http://www.eia.gov/countries/cab.cfm?fips=MY [Accessed September 14, 2013]
60 The Baram Delta/Brunei-Sabah Basin mostly underlies Brunei Darussalam, but also underlies a part of Malaysia
61 USGS, Assessment of Undiscovered Oil and Gas Resources of Southeast Asia, 2010, USGS Fact Sheet 2010-2015, June 2010

Table 2-7. Hydrocarbon Resources that Remain to be Discovered in the Major Oil Basins of Malaysia

Basin	Mean Undiscovered Oil Resources (Million Barrels)
Greater Sarawak Basin	
Central Luconia AU	0
Balingian AU	643
East Natuna Carbonate AU	0
Malay Basin Province (Oligocene-Miocene Composite TPS)	
Main Malay-Tho Chu AU	450
Khmer Trough AU	214
Penyu-West Natuna Basin Province (Oligocene-Miocene Composite TPS)	
Gabus-Udang-Urang Sandstones	74
Baram Delta/Brunei-Sabah Basin Province (Brunei-Sabah TPS)	
Brunei-Sabah Deltaics AU	635
Brunei-Sabah Turbidites AU	3,643
	5,659

Source: USGS, Assessment of Undiscovered Oil and Gas Resources of Southeast Asia, 2010, USGS Fact Sheet 2010-3015, June 2010

In total, these major basins within and near Malaysia contain nearly 6 billion barrels of oil (0.8 billion tonnes) that remains to be discovered.

Assessment of EOR Potential in IEA GHG Report. One study estimated that the implementation of CO_2-EOR in Malaysia could add approximately 166,000 barrels (23,000 tonnes) per day of oil production by 2020, assuming policy measures are put in place to encourage its deployment.[62]

The IEA GHG report[63] concluded that in large, already discovered fields, the Baram Delta/Brunei-Sabah Basin, which underlies Brunei Darussalam and a part of Malaysia, had the potential for incrementally recovering 1.9 billion barrels (0.26 billion tonnes) of crude oil from the application of CO_2-EOR in large fields, with the potential for storing 600 million tonnes of CO_2 that would be purchased to facilitate this recovery. In addition, the Malay Basin was estimated to have the potential for 1.0 billion barrels (0.14 billion tonnes), and could store 200 million tonnes of CO_2 associated with CO_2-EOR operations.

[62] http://etp.pemandu.gov.my/Oil,_Gas_and_Energy-@-Oil,_Gas_and_Energy.aspx [Accessed September 14, 2013; and http://etp.pemandu.gov.my/upload/etp_handbook_chapter_6_oil_gas_and_energy.pdf [Accessed September 14, 2013]

[63] IEA Greenhouse Gas R&D Programme, *CO_2 Storage in Depleted Oilfields: Global Application Criteria for Carbon Dioxide Enhanced Oil Recovery*, Report IEA/CON/08/155, Prepared by Advanced Resources International, Inc. and Melzer Consulting, August 31, 2009 (http://www.co2storage.org/Reports/2009-12.pdf)

Best Prospects for a CCUS- CO_2-EOR Demonstration. The IEA identified one example of an application for CO_2-EOR − use the CO_2 recovered in association with natural gas from the South West Luconia gas fields to increase recovery from Sarawak North East fields.

Petronas was one the early implementers of Mitsubishi Heavy Industries/ Kepco's solvent (KS-1) for flue gas CO_2 recovery from the Kedah fertilizer plant. The technology has been operational since 1999 and has allowed recovery of about 200 tonnes per day of CO_2, which is used for urea production.[64] This CO_2 could also potentially be used for CO_2-EOR.

In addition, an application for CDM project registration has been made for the Bintulu LNG project involving the capture of CO_2 and H_2S from an offshore field (off the Sarawak coast) and its storage in deep saline formations.[65] This project does not include use of CO_2 for CO_2-EOR or any other purpose, and therefore, was not considered in this study.

Barriers and Challenges. The barriers and challenges in Malaysia are similar to those described for Indonesia. Successful deployment of CCS will require a sound policy framework to minimize risks related to policy and commercial aspects. Partnerships between governments, international organizations and private sector were determined to be essential; international financing will be critical to success. In addition, almost all of the CO_2-EOR prospects in Malaysia are located offshore – creating substantial economic and logistical challenges relative to onshore prospects. Like most other Asia-Pacific economies, non-technical challenges of deploying CCS and CO_2-EOR were determined to evolve around the regulatory and policy aspects.

On the other hand, much of Malaysia's natural gas production contains high concentrations of CO_2. Finding creative, cost-effective ways to profit from this CO_2 for use in CO_2-EOR can result in vast improvement in the long-term commercial viability of natural gas production in Malaysia, along with increasing the productive life of the economy's crude oil resources.

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[64] IEA. *CO_2 capture and storage, a key carbon abatement option*, 2008 (http://www.iea.org/publications/freepublications/publication/CCS_2008.pdf) [Accessed September 14, 2013]

[65] ———. 2006. The Capture of the CO_2 from the Liquefied Natural Gas (LNG) Complex and Its Geological Storage in the Aquifer Located in Malaysia. Reference NM0168. Clean Development Mechanism, UNFCCC, Bonn, Germany https://cdm.unfccc.int/methodologies/PAmethodologies/pnm/byref/NM0168 [Accessed September 14, 2013]

2.5 MEXICO

Overview. Mexico is one of the ten largest oil producers in the world, the third-largest in the Western Hemisphere, and an important partner in the United States energy trade. According to the BP Statistical Review,[66] oil production in Mexico in 2012 was 2.9 million barrels per day (144 million tonnes per year). Oil production has been relatively stable since 2009, after declining for a number of years. Natural gas production has remained fairly steady for the last few years at roughly 5.6 Bcf per day (59 Bcm per year).

The amount of oil produced in Mexico has declined through most of the last decade due to natural production declines from Cantarell and other large offshore fields, though the rate of their decline has abated more recently. The responsibility for reversing production rests with Petróleos Mexicanos (PEMEX), the state-owned oil company, which is in charge of oil and gas exploration, refining and distribution in the economy. There are six refineries in Mexico. Due to constitutional limits on foreign involvement in the exploration, production, and ownership of the nation's hydrocarbon resources, all responsibility for hydrocarbon resource development falls on PEMEX. Nonetheless, recently enacted and potential reforms could liberalize the sector and promote greater foreign investment. However, constitutional reforms are under consideration.[67]

The Comisión Federal de Electricidad (CFE) provides electricity to Mexico that is generated in different power plants across the economy. These plants are mainly combined cycle (44%) and conventional oil-fired (21%). Approximately 14% of the total electricity is generated in coal-fired plants. The rest of the electricity in Mexico is generated by hydro, nuclear, wind and geothermal plants.

The oil sector generated 16% of the economy's export earnings in 2011, according to Mexico's central bank, but has been declining. More significantly, earnings from the oil industry (including taxes and direct payments from PEMEX) accounted for 34% of total government revenues in 2011.[68]

Mexico's total energy consumption is dominated by hydrocarbons – both crude oil and natural gas -- accounting for nearly 90% of Mexico's energy usage.

Mexico has been among the most active economies in international climate change discussions and is actively investigating CCS as part of its energy and climate change strategies. On April 19, 2012 the Mexican Senate unanimously passed the General Climate Change Law, which seeks to reduce greenhouse gas emissions 30% by 2020

[66] http://www.bp.com/en/global/corporate/about-bp/statistical-review-of-world-energy-2013.html [Accessed September 14, 2013]
[67] Snow, Nick, "Mexico reforms seen as key to North American energy alliance," Oil and Gas Journal (online), July 24, 2013, (http://www.ogj.com/articles/2013/07/mexico-reforms-seen-as-key-to-north-american-energy-alliance.html) [Accessed September 14, 2013]
[68] http://www.eia.gov/countries/analysisbriefs/Mexico/Mexico.pdf [Accessed September 14, 2013]

and 50% by 2050, relative to 2000 levels. The law also creates mandatory emissions reporting for the largest sources of GHG emissions.[69]

A permanent Inter-ministerial Commission on Climate Change was established comprising the Departments of Foreign Relations, Social Development, Environment and Natural Resources, Energy, Economy, Agriculture, and Communications and Transport.

Mexico's Special Program on Climate Change 2009-12 recognized the importance of CCS through Mitigation Goal 2.1.10 - "strengthen national capacity for the eventual uptake of capture and geological storage of CO_2 generated by the energy industry". In recognition of this importance, the Mexican Government established a CCS Working Group in early 2011. The Ministry of Energy (SENER) chairs the Working Group, which consists of organizations in government and industry. SENER and the CFE are engaged in a number of capacity development and knowledge sharing initiatives with international organizations, such as APEC and the Global CCS Institute.

Mexico also held an IEA-SENER Joint Workshop *on CCS in Mexico: Policy Strategy Options for CCS* in March 2012, which addressed regulation amongst other issues, and plans to undertake further capacity building initiatives with various international CCS organizations over the coming months.[70]

CO_2 Emissions. Based on 2012 data from the BP Statistical Review,[71], Mexico's CO_2 emissions were nearly 500 million tonnes, ranking it 13th in the world. The main sources of Mexico's carbon emissions come from fossil fuel-based energy production and consumption, including significant fugitive emissions (leakage, venting, flaring) in oil and gas production and transportation.[72]

[69] http://www.globalccsinstitute.com/location/mexico [Accessed September 14, 2013]
[70] http://co2.energia.gob.mx/res/Wrokshop%20Agenda%20SENER-AIE%207-8%20March.pdf [Accessed September 14, 2013]
[71] http://www.bp.com/en/global/corporate/about-bp/statistical-review-of-world-energy-2013.html [Accessed September 14, 2013]
[72] http://www.globalccsinstitute.com/location/mexico [Accessed September 14, 2013]

Previous Consideration/Application of CO_2-EOR and CCUS. The large Cantarell field, once the largest producer in Mexico, has been undergoing nitrogen (N_2) flooding for EOR for a number of years, and is the world's largest N_2-EOR project.

In addition, a number of studies have also evaluated the potential for the use of CO_2 for EOR in Mexico, as summarized below:[73]

Sources of CO_2

- Assessment of natural sources of CO_2 – 1985
- Study of the use of CO_2 from Oxiacaque plant – 1980

Technical and Economic Studies

- CO_2 injection in Southern Region fields; feasibility analysis – 1990
- Technical and economic analysis of EOR process in national fields – 1989-1991
- Technical and economic analysis of EOR process in Filo Morado field – 1991
- Technical and economic analysis of EOR process in Cactus, Jiliapa, Sitio Grande – 1993-1994
- Technical and economic analysis of EOR process in Ek Balam Field – 1996

Modeling and Simulation

- Field characterization of Carmito field – 2002
- Integrated study of Artesa field – 2003-2004

Project Data Base

- Yearly report of the secondary and enhanced oil recovery projects in Mexico – 2006
- Yearly report of the secondary and enhanced oil recovery projects in Mexico – 2007

[73] "Enhanced Oil Recovery by CO_2 Injection" presentation by Ph. D. Andr Andrés E. Moctezuma Berthier, Project Leader, Oil Recovery Department, Instituto Mexicano Del Petroleo, at the Carbon Sequestration Leadership Forum meeting -- 4th Capacity Building in Emerging Economies Workshop, Mexico City, Mexico, July 8-9, 2008 (http://www.cslforum.org/publications/documents/4_BerthierEORMexico2008.pdf) [Accessed September 14, 2013]

Oil Characterization in the Presence of CO_2/N_2; Recovery by N_2/CO_2 Injection

- Effects of CO_2 in PVT properties, well Cuichapa – 1981
- Experimental studies of oil recovery by CO_2 injection in Artesa field – 2001
- Additional recovery by CO_2 injection in NFR – 2006-2009
- Experimental studies of gas injection in the field KU – 2007-2008
- Experimental studies of gas injection in the field Cantarell – 1998-2008
- EOR studies in the fields of Northeastern Marine Region – 2008-2010

Different feasibility studies have been undertaken since 2009 for the assessment of a CCS-EOR demonstrative project. These studies focused on CO_2 capture and evaluated the use of CO_2 for EOR purposes in oil and gas reservoirs near CFE power plants.

Given that the State owns both the national electric and oil and gas companies, the Ministry of Energy may become a positive feature for a CCS demonstration project in Mexico. Another important characteristic that would act in favor of a CCUS-EOR project in Mexico is that the State owns the rights of the economy's subsurface, which will assist liability aspects for site selection and closure.

Oil Resource Potential. According to the BP Statistical Review,[74] Mexico has proven oil reserves amounting to 11.4 billion barrels (1.6 billion tonnes) as of the end of 2012. Most reserves consist of heavy crude oil varieties, with the largest concentration occurring offshore in the southern part of the economy, especially in the Campeche Basin. There are also sizable reserves in Mexico's onshore basins in the northern parts of the economy.

Mexico produced, on average, 2.9 million barrels per day in 2012, or 144 million tonnes over the year. After declining for a number of years, Mexico's oil production has been relatively stable since 2009, and the minor decreases that have occurred mark an improvement from the more drastic declines that were occurring earlier.

Mexico is a large but declining net crude exporter, and is a net importer of refined petroleum products. Its most important trading partner is the United States, which is the destination for most of its crude oil exports and the source of most of its refined product imports.

Most of Mexico's oil production occurs in the Bay of Campeche of the Gulf of Mexico, near the states of Veracruz, Tabasco, and Campeche. Three-quarters of Mexico's crude oil is produced offshore in the Bay of Campeche. Over half of Mexico's oil production comes from these two offshore fields in the northeastern region of the Bay of

[74] http://www.bp.com/en/global/corporate/about-bp/statistical-review-of-world-energy-2013.html [Accessed September 14, 2013]

Campeche. The two main production centers in the area include Cantarell and Ku-Maloob-Zaap (KMZ).

Cantarell was once one of the largest oil fields in the world, but its output has been declining dramatically for almost a decade. Production at Cantarell began in 1979, but stagnated due to falling reservoir pressure. In 1997, PEMEX developed a plan to reverse the field's decline by injecting N_2 into the reservoir to maintain pressure, which was successful for a few years, but production is now again declining. Meanwhile, KMZ, which is adjacent to Cantarell, has emerged as Mexico's most prolific field. Production doubled between 2006 and 2009, as PEMEX employed a N_2 re-injection program similar to that used at Cantarell.

Hydrocarbon resources that remain to be discovered in the major basins of Mexico (along with neighboring Guatemala and Belize) assessed by the USGS[75] are shown in **Table 2-8**. In total, these basins within and near Mexico contain an estimated 19.3 billion barrels of oil (2.6 billion tonnes) that remain to be discovered.

Assessment of EOR Potential in IEA GHG Report. As part of the North American Carbon Atlas Partnership, Mexico completed its National Carbon Storage Atlas.[76] A basin assessment for CO_2 storage in saline aquifers was undertaken as part of this project. The theoretical CO_2 storage resource estimate for saline formations in 111 assessed sectors in Mexico is 100 billion tonnes, distributed in different regions. Work is progressing to continue this assessment at a regional and local level. No specific estimate was developed on the CO_2 storage potential in oil reservoirs in association with the application of CO_2-EOR.

The IEA GHG report[77] assessed the CO_2-EOR recovery and CO_2 storage potential in large, already discovered fields in two large basins that are wholly or partly in Mexico – the Villahermosa Uplift and the Tampico-Misantla Basin. The Villahermosa Uplift was estimated to contain 12.3 billion barrels (1.7 billion tonnes) of oil recovery potential from CO_2-EOR, with 4.1 billion tonnes of CO_2 that could be stored in its pursuit. The Tampico-Misantla Basin was estimated to have 1.8 billion barrels (250 million tonnes) of CO_2-EOR recovery potential, and could store as much as 500 million tonnes of CO_2.

[75] USGS, *Assessment of Undiscovered Conventional Oil and Gas Resources of Mexico, Guatemala, and Belize,* 2012, USGS Fact Sheet 2012-3069, July 2012

[76] http://www.netl.doe.gov/technologies/carbon_seq/refshelf/NACSA2012.pdf [Accessed September 14, 2013]

[77] IEA Greenhouse Gas R&D Programme, *CO_2 Storage in Depleted Oilfields: Global Application Criteria for Carbon Dioxide Enhanced Oil Recovery*, Report IEA/CON/08/155, Prepared by Advanced Resources International, Inc. and Melzer Consulting, August 31, 2009 (http://www.co2storage.org/Reports/2009-12.pdf)

Table 2-8. Hydrocarbon Resources that Remain to be Discovered in the Major Oil Basins of Mexico

Basin	Mean Undiscovered Oil Resources (Million Barrels)
Burgos Basin, Mesozoic-Cenozoic Composite TPS	
Upper Jurassic-Cretaceous Reservoirs AU	59
Frio-Vicksburg Sandstones AU	40
Eocene-Miocene Sandstones AU	6,065
Tampico-Misantla Basin, Mesozoic-Cenozoic Composite TPS	
Golden Lane El Abra Reservoirs AU	9
Golden Lane Tamabra Reservoirs AU	75
Tampico Mesozoic-Cenozoic Reservoirs AU	5,365
Veracruz Basin, Mesozoic-Cenozoic Composite TPS	
Cretaceous-Cenozoic Reservoirs AU	95
Tuxla Uplift, Mesozoic-Cenozoic Composite TPS	
Cretaceous-Cenozoic Reservoirs AU	25
Saline-Comalcalco Basin, Mesozoic-Cenozoic Composite TPS	
Salt Basin Reservoirs AU	1,137
Villahermosa Uplift, Mesozoic-Cenozoic Composite TPS	
Reforma Trend Reservoirs AU	1,427
Macuspana Basin, Mesozoic-Cenozoic Composite TPS	
Mesozoic-Cenozoic Reservoirs AU	22
Campeche-Sigsbee Salt Basin, Mesozoic-Cenozoic Composite TPS	
Salt Structures AU	2,865
Yucatan Platform, Mesozoic-Cenozoic Composite TPS	
Platform Reservoirs AU	758
Southeast Yucatan Margin Reservoirs AU	440
Sierra Madre de Chiapas Foldbelt-Peten Basin, Mesozoic Composite TPS	
Chiapas-Peten Basin Reservoirs AU	933
	19,315

Source: USGS, Assessment of Undiscovered Conventional Oil and Gas Resources of Mexico, Guatemala, and Belize, 2012, USGS Fact Sheet 2012-3069, July 2012

Applying the basin-specific methodology of the IEA GHG to a greater number of selected fields in Mexico with CO_2-EOR potential shows that as much as 23.9 billion barrels (3.3 billion tonnes) of oil recovery potential could be realized from CO_2-EOR, with the potential for storing as much as 8.5 billion tonnes of CO_2 (**Table 2-9**).

Best Prospects for a CCUS- CO_2-EOR Demonstration. PEMEX is currently undertaking two pilot projects using captured CO_2 for EOR. CFE, PEMEX and the Mario Molina Centre (an environmental non-governmental organization (NGO) based in Mexico) have collaborated on a scoping study for a demonstration facility to capture CO_2 from a power plant and utilize it for CO_2-EOR at a nearby oil field. The World Bank is currently pursuing a feasibility study for this project.

Table 2-9. CO_2-EOR and CO_2 Storage Potential for Selected Fields in Mexico

Field Name	Estimated Ultimate Conventional Recovery (MMBbl)	Depth (feet)	EOR Recovery (%)	EOR Potential (MMBbls)	Purchased CO_2 Requirements (MM tonnes)
Abkatun-Pol-Chuc	5,417	10,197	18%	3,168	1,172
Cantarell (includes Akal, Nohoch, Chac, Kutz, and Sihil)	16,338	3,281	14%	7,892	2,920
Ixtoc	800	10,100	17%	467	173
Ku-Maloob-Zaap	4,212	9,482	17%	2,419	895
Cactus	1,700	13,500	19%	1,077	398
Jujo	500	19,462	22%	360	133
Rio Nuevo	500	14,000	19%	320	119
Agave	876	12,041	18%	536	198
Giraldas	435	13,944	19%	278	103
Paredon	500	18,586	21%	354	131
Samaria (Bermudez Complex)	7,000	14,200	19%	4,505	1,667
Sitio Grande	765	15,000	20%	501	186
Arenque	1,000	3,700	15%	489	181
Cerro Azul (Amatlan, Naranjos)	1,250	2,100	14%	582	215
Iris	1,500	14,800	20%	979	362
Poza Rica	2,000	7,100	16%	1,078	399
	42,794			**23,928**	**8,853**

Source: Advanced Resources International, Inc.

Barriers and Challenges. Although Mexico is a member of the Organisation for Economic Co-operation and Development (OECD) and contributes to nearly 1.5% of global greenhouse emissions, it has no specific international obligation to reduce GHG emissions. In the past, the environmental performance of industry in Mexico has advanced at a slower rate than many other comparably developed economies. Lack of obligation to reduce GHG emissions discourages state-owned companies from investing more aggressively in greenhouse gas mitigation technologies. CCS is planned to be included in the National Climatic Action Strategy. However, to be deployed, it will likely require major technological and economic adjustments be made to industrial production in the energy sector, which is the federal government's main source of revenue. As a result, polices, actions, strategies, objectives, and targets established to encourage deployment of CCS must be backed by a sufficient budget and a complementary fiscal policy.

2.6 PERU

Overview. Peru is the seventh-largest crude oil reserve holder in Central and South America, with 1.2 billion barrels (200 million tonnes) of proved reserves, based on 2012 data from the BP Statistical Review.[78] Much of Peru's proved oil reserves are onshore, and the majority of these onshore reserves are in the Amazon region.

According to the BP Statistical Review, oil production in Peru in 2012 was 107,000 per day (4.8 million tonnes per year). Oil production has been relatively stable since 2009, after declining for a number of years. Natural gas production is increasing reaching 1.2 Bcf per day (13 Bcm per year) in 2012. Most of the gas production comes from the giant Camisea gas field. Natural gas production in Peru has grown rapidly since the Camisea field went on-stream in 2004.

Peru imports crude oil and refined products to satisfy both domestic demand and export commitments. The economy imports most of its crude oil from Ecuador, with smaller amounts from other economies in South America and West Africa.

The National Agency of Hydrocarbons (Perupetro) oversees all exploration and production activities. The Ministry of Energy and Mines (MEM) also participates in developing planning and policies for the sector. According to Perupetro, 75% of Peru's crude oil output in 2011 was produced by three companies: Argentina's Pluspetrol, Brazil's Petrobras, and Peru's Savia (formerly Petrotech). Not to be confused with Perupetro, Petroperu is a state-owned company founded in 1969, which is engaged in the production, transport, refining, and distribution of petroleum. Petroperu owns Peru's pipelines and other transportation systems, four of its refineries, and fuel stations.[79]

Relatively speaking, Peru’s contribution to global greenhouse gas emissions is small. Nonetheless, the economy is highly vulnerable to the impacts of global climate change. Historically, Peru’s main climate strategy was adaptation and how to finance this adaptation; emissions mitigation was not a priority. However, since 2008, policymakers have realized that adaptation will not be enough, and that strong global mitigation goals and efforts are needed, including from Peru.

In this regard, Peru outlined voluntary targets to reduce net deforestation to zero by 2021 and increase renewable energy to at least 33% of the total energy use by 2020. Deforestation in the Peruvian Amazon accounts for about 47% of Peru’s emissions, with

[78] http://www.bp.com/en/global/corporate/about-bp/statistical-review-of-world-energy-2013.html [Accessed September 14, 2013]
[79] http://www.eia.gov/countries/cab.cfm?fips=PE [Accessed September 14, 2013]

agriculture accounting for 19%, and energy consumption accounting for 21% of their emissions.[80]

Climate change related issues in Peru, specifically Clean Development Mechanism (CDM) efforts, are managed by two institutions, the Ministry of Environment (MINAM), as the National Environmental Authority, and the Fondo Nacional del Ambiente – Peru (FONAM), or the National Environment Fund (in English), as the promoter of environmental investments.

Peru has carried out a series of actions for the implementation, promotion and development of projects that qualify under the CDM, under the coordination of FONAM (www.fonamperu.org). As a consequence of focused government policies[81] along with the work of FONAM, Peru is currently recognized as one of the most attractive economies for CDM investments. As a result, Peru's CDM project portfolio has grown to over 200 CDM projects (proposed or registered). Of these, most are energy efficiency and renewable energy projects in the energy sector, followed by the forestry sector (focus on afforestation and reforestation, as well as deforestation). No projects are yet being pursued relative to CCS, though FONAM is interested in facilitating such a project.[82]

CO_2 Emissions. Based on 2012 data from the BP Statistical Review,[83] Peru's direct CO_2 emissions were nearly 50 million tonnes. However, unlike most developed economies, where most emissions come from burning fossil fuels (mainly oil and coal), in Peru most of the CO_2 emissions come from Land-Use Change and Forestry (LULUCF). This is principally because of deforestation of the Peruvian Amazon, which represents almost half of the economy's total CO_2 emissions. Following deforestation are emission from power generation and industrial processes, primarily associated with the burning of the manufacture of cement.

Previous Consideration/Application of EOR and CCUS. No previous national or basin-wide assessments of the CCUS-EOR potential in Peru, to our knowledge, have been performed. However, some fields are under waterflooding, and additional studies of production enhancements in some fields have been performed, but no published studies assessing the potential for CO_2-EOR were found. For example, the potential of microbial enhanced oil recovery (MEOR) has been assessed in seven wells in the Talara basin in Northwest Peru, however.[84]

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[80] http://switchboard.nrdc.org/blogs/jschmidt/developing_countries_outlined.html [Accessed September 14, 2013]
[81] http://www.reuters.com/article/2012/04/26/us-peru-climate-idUSBRE83P1H820120426 [Accessed September 14, 2013]; and http://cdkn.org/project/planning-for-climate-change-plancc-phase-i/ [Accessed September 14, 2013]
[82] Personal communication, Executive Director, FONAM, January 2012
[83] http://www.bp.com/en/global/corporate/about-bp/statistical-review-of-world-energy-2013.html [Accessed September 14, 2013]
[84] Maure, A., A.A. Saldaña and A.R. Juarez, "Biotechnology Applications to EOR in Talara Offshore Oil Fields, Northwest Peru," SPE Paper No. 94934 presented at the SPE Latin American and Caribbean Petroleum Engineering Conference, Rio de Janeiro, Brazil, 20-23 June 2005

Recent activity associated with leases owned by UniPetro ABC in the Talara Basin requires special mention. UniPetro ABC, an oil company owned by the National Engineering University (UNI - Peru)[85] signed a contract in June 1993 for exploration and exploitation of hydrocarbons in the 1,500 hectare Block IX (Lote IX) in the Talara basin in Northwest Peru. In September 1993, oil operations began based on the objectives of producing oil and gas in an environmental sustainable manner, and a research center for oil and gas development was established. Block IX is currently producing less than 300 barrels per day (15,000 tonnes per year), and its operating contract originally scheduled to end in 2013 has been extended to June 2015. The block has cumulatively produced about 10 million barrels (1.4 million tonnes).

Negotiations between UniPetro ABC and MEM for a 20-year extension of the operating agreement for Block IX have been underway for some time. A novel consideration under discussion involves requirements to investigate ways to enhance production from the lease and extend its life; this includes consideration of enhanced oil recovery techniques, including CO_2-EOR. Enhancing production is a priority in order to maintain the capacity to use Block IX operations to serve as a source of training and education for students entering the petroleum industry in Peru.

In the coming years, seven concessions of oil blocks revert to the State. In these, MEM is looking to promote standards to promote the continuity of these concessions. Among these conditions will be a requirement for an investment plan, which would include plans for investments to enhance production and extend the productive lives of the concessions.[86]

However, the lack of large, concentrated volumes of CO_2 that could be used to facilitate CO_2-EOR remains a major constraint to the application of CO_2-EOR in Peru.

Oil Resource Potential. Compared to other economies in Latin America, Peru is a small oil producing economy. As described above, Peru has 1.2 billion barrels (200 million tonnes) of proved reserves, based on 2012 data from the BP Statistical Review.[87] Crude oil production in Peru has been declining since the mid-1990s, but the economy's total liquid fuels production has been bolstered by increased output of natural gas liquids (NGL). Peru has production from the Talara, Tumbes, Marañon, and Ucayali basins and previous production from a field in the Titicaca Basin.

Assessment of EOR Potential in IEA GHG Report. The IEA GHG report[88] assessed the CO_2-EOR recovery and CO_2 storage potential in large, already discovered fields in one large basin in Peru – the Putumayo-Oriente-Marañon Basin – which also underlies Columbia and Ecuador. The Putumayo-Oriente-Marañon Basin was estimated to

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85 http://www.ingenieriadepetroleo.com/2009/08/unipetro-abc.html [Accessed September 14, 2013]

86 http://revistaoronegro.com/portal/noticias/mem-impulsara-proceso-de-concesiones-petroleras/ [Accessed September 14, 2013]

87 http://www.bp.com/en/global/corporate/about-bp/statistical-review-of-world-energy-2013.html [Accessed September 14, 2013]

88 IEA Greenhouse Gas R&D Programme, *CO_2 Storage in Depleted Oilfields: Global Application Criteria for Carbon Dioxide Enhanced Oil Recovery*, Report IEA/CON/08/155, Prepared by Advanced Resources International, Inc. and Melzer Consulting, August 31, 2009

contain 2.6 billion barrels (350 million tonnes) of oil recovery potential from CO_2-EOR in existing fields, with 0.8 billion tonnes of CO_2 that could be stored.

For this effort, this same methodology was applied to two other large basins in Peru – the Marañon and Talara Basins. The Marañon Basin was estimated to contain 590 million barrels (80 million tonnes) of oil recovery potential from CO_2-EOR in large fields, with 200 million tonnes of CO_2 that could be stored. The Talara Basin was estimated to contain 470 million barrels (64 million tonnes) of oil recovery potential from CO_2-EOR in large fields, with 130 million tonnes of CO_2 that could be stored.

Best Prospects for a CCUS-EOR Demonstration. As stated above, the lack of large, concentrated volumes of CO_2 that could be used to facilitate CO_2-EOR remains a major constraint to a potential CCUS-EOR in Peru. Natural gas production in Peru has tended to be relatively low in CO_2 content, minimizing the need for processing to remove CO_2, which would provide a low-cost source of CO_2 for CO_2-EOR. Cement plants are located a long distance from fields with CO_2-EOR potential, making commercial viability problematic. The large Camisea gas field has CO_2 content of only about 57 ppm,[89] which is probably too low to support the economic viability of CO_2 separation for use in CO_2-EOR.

One option that could be considered is associated with current plans for upgrading the refinery in the Talara Basin in northwest Peru. About $2.73 billion will be invested in the modernization of the Talara oil refinery, involving expansion of capacity and the addition of desulphurization facilities. Petroperu plans to launch the modernization in the third quarter of 2013.[90]

Alternatively, several cement plants exist in the economy that could conceptually provide CO_2, if captured, for CO_2-EOR applications, though in most cases the CO_2 would need to be transported some distance. For example, Cementos Pacasmayo reported that it obtained the approval of the environmental impact study in May 2013 for the construction of the new cement plant in Piura, which is only about 100 to 120 kilometers from the Talara Basin.[91] The larger Cementos Pacasmayo plant near the town of Pacasmayo is over 300 kilometers from the Talara Basin.

Barriers and Challenges. As described above, in Peru most of the CO_2 emissions come from Land-Use Change and Forestry (LULUCF), because of deforestation of the Peruvian Amazon. Emissions reductions from power generation and industrial processes are secondary. Moreover, the lack of large, concentrated volumes of CO_2 that could be used to facilitate CO_2-EOR remains a major constraint to the application of CO_2-EOR and economically viable CCS in Peru.

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[89] http://www.gasandoil.com/news/ms_america/e4d8ba0f189486a59c9d3e4895b69b89 [Accessed September 14, 2013]

[90] http://www.andina.com.pe/english/noticia-peru-to-invest-273bn-in-talara-refinery-upgrade-468213.aspx [Accessed September 14, 2013]

[91] http://www.microsofttranslator.com/BV.aspx?ref=IE8Activity&a=http%3A%2F%2Fwww.sec.gov%2FArchives%2Fedgar%2Fdata%2F1221029%2F000115752313000553%2Fa50556560.htm [Accessed September 14, 2013]

2.7 THAILAND

Overview. Oil production and reserves in Thailand are limited, with imports providing a significant portion of the economy's oil consumption. Thailand holds large reserves of natural gas, and natural gas production has increased substantially over the last few years, but it still remains dependent on imports of natural gas to meet growing domestic demand for the fuel. Thailand's primary energy consumption is mostly from fossil fuels, accounting for over 80% of the economy's total energy consumption.[92]

According to the BP Statistical Review,[93] oil production in Thailand in 2012 was 440,000 barrels per day (16 million tonnes per year), and has been consistently increasing. Natural gas production is also increasing, and amounted to 4.0 Bcf per day (41 Bcm per year) in 2012.

Oil represents about 40% of total energy consumption, though this is down from nearly half in 2000. In recent years, natural gas has replaced some oil demand and is the next largest fuel, growing to nearly a third of total consumption. Solid biomass and waste have played a strong role as an energy source in Thailand and comprise roughly 16% energy consumption. Most biomass feedstock , (rice husk, bagasse, wood waste, and oil palm residue) is used in residential and manufacturing sectors. Thailand's Alternative Energy Development Plan calls for renewable energy to increase its share to 25% of total energy consumption by 2022 to reduce dependence on fossil fuels.[94]

Thailand is a developing economy in Southeast Asia, which has shifted from an agricultural to an industry-driven economy. Since 1960, there has been rapid economic growth in Thailand, with significant expansion of the industry sector. The national economy is predicted to continue to grow at a slower rate up to 2030. The National Institute of Development Administration projected that Thailand’s GDP would increase by 3 to 5% per year from 2010 to 2030.[95]

The development of renewable energy and the promotion of energy conservation and efficiency have been identified as the primary means to mitigate greenhouse gas emissions in Thailand. Progress in renewable energy and energy efficiency has been made. Recently, the 15-Year Renewable Energy Development Plan and the 20-Year Energy Conservation Plan introduced several measures and incentive mechanisms to advance the development of energy efficiency and renewable energy in Thailand.

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92 http://www.eia.gov/countries/cab.cfm?fips=TH [Accessed September 14, 2013]
93 http://www.bp.com/en/global/corporate/about-bp/statistical-review-of-world-energy-2013.html [Accessed September 14, 2013]
94 http://eeas.europa.eu/delegations/thailand/documents/thailande_eu_coop/energy_efficiency/thailand_re_pol_and_challenges_en.pdf [Accessed September 14, 2013]
95 Chotichanathawewong, Qwanruedee and Natapol Thongplew, Development Trajectory, Emission Profile, and Policy Actions: Thailand, ADBI Working Paper Series No. 352, April 2012 (http://www.adbi.org/files/2012.04.12.wp352.dev.trajectories.emission.thailand.pdf) [Accessed September 14, 2013]

The Department of Mineral Fuels in the Ministry of Energy has established a CCS Task Force that examined the potential for CCS in Thailand. The potential in Thailand was assessed as part of an ADB assessment of the potential for CCS in Southeast Asia. [96] In this assessment, 22 sources, amounting to 70 million tonnes of CO_2 emissions, were identified as suitable for carbon capture, with the most promising associated with natural gas processing. Four oil and gas fields in Thailand were determined to be best suited for CO_2 storage, with the potential for storing as much as 516 million tonnes. In total, estimated theoretical CO_2 storage capacity in Thailand was estimated to be 10.3 billion tonnes, with most of this capacity located in saline aquifers.

CO_2 Emissions. In 2012, the BP Statistical Review[97] estimates that CO_2 emissions in Thailand amounted to over 330 million tonnes, ranking it 20th in the world. Over 60% of the emissions are associated with the production of energy, with another 23% associated with the agricultural sector. ADB estimated that 120 million tonnes of CO_2 emission come from existing industrial and energy production point sources. [98]

Previous Consideration/Application of CO_2-EOR and CCUS. One potential study of the geological storage potential in Thailand was developed in cooperation with Tetra Tech.[99] This study identified a number of fields in Thailand as good candidates for CO_2 storage. These included Sirikit (E, K) in the Pitsanulok Basin, Namphong in Khorat Basin, Uthong in the SuphanBuri Basin, Erawan - H in the Pattani Basin, Benchamas in the Pattani Basin, Bualaung in the Western Basin, and Bongkot (3, 6, 9) in the North Malay Basin. The study focused on currently producing petroleum fields, which were subjected to a site selection screening process based on work by Oldenburg.[100] Based on this, it was determined that the CO_2 storage capacity in depleted oil and gas reservoirs amounted to about 70 million tonnes. High-level technical-financial assessments of two potential CCS projects in Thailand were performed, with the objective to inform policy makers, regulatory agencies and other key stakeholders of the potential, obstacles and key success factors for implementing CCS in Thailand.

One case (onshore) assessment involved the capture of one million tonnes of CO_2 per year from a coal-fired power plant and CO_2 transport to an onshore oil field for use in EOR. The other case (offshore) assessed a natural gas cleaning operation at the Southern gas field with geological storage of the captured CO_2 in a depleted gas reservoir.

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[96] Asian Development Bank, Prospects for Carbon Capture and Storage in Southeast Asia: Executive Summary, November 2012

[97] http://www.bp.com/en/global/corporate/about-bp/statistical-review-of-world-energy-2013.html [Accessed September 14, 2013]

[98] Asian Development Bank, Prospects for Carbon Capture and Storage in Southeast Asia: Executive Summary, November 2012

[99] Witsarut T., Trin I., Siree N., Anuchit L., "Carbon Capture and Storage, CCS, Study in Thailand: Result and Way Forward," presentation, September 12, 2012 http://www.ccop.or.th/eppm/projects/42/docs/Thailand_CCS_Presentation.pdf [Accessed September 14, 2013]

[100] Oldenburg, C.M., Health, Safety, and Environmental Screening and Ranking Framework for Geologic CO_2 Storage Site Selection, Lawrence Berkeley National Laboratory LBNL Report No. LBNL-58873 Rev. 1.0, 2005

Oil Resource Potential. According to the BP Statistical Review,[101] Thailand held proven oil reserves of over 400 million barrels (about 100 million tonnes) in January 2013, an increase of 11 million barrels from the prior year. In 2012, Thailand produced an estimated 440,000 barrels per day (16.2 million tonnes per year) of oil. Supply of oil does not meet demand in Thailand, making it the second largest net oil importer in Southeast Asia.

About 80% of the economy's crude oil production comes from offshore fields in the Gulf of Thailand. Chevron is the largest oil producer in Thailand, accounting for nearly 70% of the economy's crude oil and condensate production in 2011.

The largest oil field in Thailand is Chevron's Benjamas field located in the north Pattani Trough. The field's production peaked in 2006 and declined to less than 30,000 barrels per day in 2010. Chevron is developing satellite fields to sustain production around Benjamas. PTTEP's Sirikit field is another significant crude oil producer supplying 22,000 barrels per day of oil in 2010.

Thailand's oil resource exists in several major sedimentary basins. The Malay Basin is a major oil-producing basin offshore peninsular Malaysia, but yields mostly gas in Thailand. The Thai portion of the Malay Basin includes the Bongkot Gas Field, Thailand's largest, as well as recent major gas discoveries in the Arthit area that have added substantially to Thailand's gas reserve base. The Pattani Basin is an important producer of both oil and gas, with nearly all of the oil production in the northern part of the basin and most of the gas production in the southern part. The Chumpon Basin has one oil field, Nang Nuan. Other basins have been tested, but no commercial production from them has yet been realized.[102]

Hydrocarbon resources that remain to be discovered in the major basins of Thailand assessed by the USGS[103] are shown in **Table 2-10**.

In total, these major basins within and near Thailand contain 1.6 billion barrels of oil (0.2 billion tonnes) that remain to be discovered.

Assessment of EOR Potential in IEA GHG Report. The IEA GHG report[104] concluded that in large, already discovered fields, the Malay Basin was estimated to have the potential for 1.0 billion barrels (0.14 billion tonnes), and could store 200 million tonnes of CO_2 associated with CO_2-EOR operations.

[101] http://www.bp.com/en/global/corporate/about-bp/statistical-review-of-world-energy-2013.html [Accessed September 14, 2013]
[102] http://www.gregcroft.com/thailand.ivnu [Accessed September 14, 2013]
[103] USGS, *Assessment of Undiscovered Oil and Gas Resources of Southeast Asia*, 2010, USGS Fact Sheet 2010-2015, June 2010
[104] IEA Greenhouse Gas R&D Programme, *CO_2 Storage in Depleted Oilfields: Global Application Criteria for Carbon Dioxide Enhanced Oil Recovery*, Report IEA/CON/08/155, Prepared by Advanced Resources International, Inc. and Melzer Consulting, August 31, 2009 (http://www.co2storage.org/Reports/2009-12.pdf)

Table 2-10. Hydrocarbon Resources that Remain to be Discovered in the Major Oil Basins of Thailand

Basin	Mean Undiscovered Oil Resources (Million Barrels)
Khorat Plateau Province (Mesozoic TPS)	
Permian Carbonates AU	0
Khorat Group Sandstones AU	0
Thai Basin Province (Eocene-Miocene Composite TPS)	
Pattani Trough AU	634
Offshore Western Cenozoic Rifts AU	578
Thai Cenozoic Basins Province (Eocene-Miocene Composite TPS)	
Onshore Cenozoic Rifts AU	391
	1,603

Source: USGS, Assessment of Undiscovered Oil and Gas Resources of Southeast Asia, 2010, USGS Fact Sheet 2010-3015, June 2010

Best Prospects for a CCUS- CO_2-EOR Demonstration. In Thailand, as described above, 22 sources, amounting to 70 million tonnes of CO_2 emissions, were identified as suitable for carbon capture, with four oil and gas fields determined to be best suited for CO_2 storage.[105] Of these, without naming the facilities due to confidentiality concerns, the most promising prospect identified in Thailand corresponded to a near-shore gas processing facility or coal-fired power plant with onshore oil and gas fields.

In the study of the geological storage potential in Thailand referenced above,[106] one case study (onshore) assessed the capture of CO_2 from a coal-fired power plant with storage of the CO_2 to an onshore oil field for use in EOR. The other case assessed a natural gas cleaning operation offshore at the Southern gas field with geological storage of the captured CO_2 in a depleted offshore gas reservoir. For this to be considered in this study, it would need to be modified to include the use of CO_2 for CO_2-EOR, rather than merely storage without enhanced recovery.

Barriers and Challenges. The barriers and challenges in Thailand are similar to those characterized for other APEC economies. CCUS is not one of the primary energy and environment policies identified for greenhouse gas emissions mitigation in the economy. Renewable energy, energy efficiency, and reforestation have all been identified as cheaper and easier options for Thailand. Moreover, no main government or public organization has been assigned responsibility for CCUS policy or the CCUS value chain

[105] Asian Development Bank, Prospects for Carbon Capture and Storage in Southeast Asia: Executive Summary, November 2012

[106] Witsarut T., Trin I., Siree N., Anuchit L., "Carbon Capture and Storage, CCS, Study in Thailand: Result and Way Forward," presentation, September 12, 2012 http://www.ccop.or.th/eppm/projects/42/docs/Thailand_CCS_Presentation.pdf [Accessed September 14, 2013]

in Thailand. Nonetheless, a roadmap has been developed for overcoming these challenges. [107]

2.8 VIET NAM

Overview. Over the last 20 years, Viet Nam emerged as an important oil and gas producer in Southeast Asia, increasing exploration activities, allowing greater foreign company investment and cooperation, and introducing market reforms. These measures have helped to increase oil and gas production, but the economy's rapid economic growth, industrialization, and export market expansion have also spurred energy consumption.

According to the BP Statistical Review,[108] oil production in Viet Nam in 2012 was 348,000 barrels per day (17 million tonnes per year), an increase over 2011. Natural gas production is also increasing, and amounted to 0.9 Bcf per day (9 Bcm per year) in 2012, also up from 2011. Future gas production in Viet Nam is likely to be higher in CO_2 content, necessitating the need for CO_2 removal from the produced gas, but also providing the opportunity for low-cost CO_2 capture.

In 2012, Viet Nam consumed 361,000 barrels per day of oil, slightly surpassing production, reflecting the economic growth and industrial developments common within Southeast Asia.

PetroVietnam is the economy's state-owned oil and gas company and serves as the primary operator and regulator of the industry. Oil and natural gas production is either undertaken by PetroVietnam's upstream subsidiary, PetroVietnam Exploration and Production (PVEP), or through PetroVietnam's joint venture with other companies. ExxonMobil, Chevron, and Zarubezhneft have formed partnerships with PetroVietnam. Foreign oil companies must receive approval from the Oil and Gas Department of the Prime Minister, and must negotiate upstream licenses with PVEP.

Nearly 25% of Viet Nam 's energy consumption comes from oil, with hydropower (10%), coal (20%), and natural gas (11%) also contributing. As the economy continues industrializing and installing greater power capacity, Viet Nam is seeking to develop all its natural resources. The U.S. Energy Information Agency (EIA) estimates that about a third of Viet Nam 's energy consumption is from traditional biomass and waste.[109] About 70% of its population lives in rural areas, and agriculture accounts for a sizeable portion of the economy's GDP. Viet Nam is currently promoting greater use of biofuels to replace some of the fossil fuel consumption.

[107] See, Witsarut T., Trin I., Siree N., Anuchit L., "Carbon Capture and Storage, CCS, Study in Thailand: Result and Way Forward," presentation, September 12, 2012; slide 21 http://www.ccop.or.th/eppm/projects/42/docs/Thailand_CCS_Presentation.pdf [Accessed September 14, 2013]
[108] http://www.bp.com/en/global/corporate/about-bp/statistical-review-of-world-energy-2013.html [Accessed September 14, 2013]
[109] http://www.eia.gov/countries/cab.cfm?fips=VM [Accessed September 14, 2013]

The Ministry of Natural Resources and Environment (MONRE) estimates that Viet Nam's energy sector will produce 224 million tonnes of CO_2 annually by 2020, while other key industrial sectors will discharge about 10 million tonnes.[110]

Viet Nam signed the Framework Convention on Climate Change and several national programs have been established to cope with climate change and promote deployment of CCS technologies.[111]

The potential for CCS in Viet Nam was assessed as part of an ADB study of the potential for CCS in Southeast Asia.[112] In this assessment, five sources, amounting to 53 million tonnes of CO_2 emissions, were identified as suitable for carbon capture, with potential future natural gas combined cycle and subcritical coal-fired power plants ranked as the most promising. Potential was also identified for new natural gas processing plants associated with high CO_2 content gas fields that are expected to be developed. In Viet Nam, the largest single storage prospect identified was a large oil and gas field, believed to be suitable for CO_2-EOR, and with the potential to store 357 million tonnes. In total, estimated theoretical CO_2 storage capacity in Viet Nam was estimated to be 12.2 billion tonnes, with most of this capacity located in saline aquifers.

CO_2 Emissions. According to the BP Statistical Review,[113] about 130 million tonnes of CO_2 were emitted in Viet Nam in 2012, with the agricultural sector being the leading contributor, followed by the energy sector. CO_2 emissions are also generated by various industries, the two largest being cement and steel production. In 2010, 55% than half of Viet Nam's electricity was generated from thermal power plants, with 18.5% fired by coal and 36.6% by burning oil and gas. [114]

Previous Consideration/Application of CO_2-EOR and CCUS. A CO_2 capture facility at the Phu My fertilizer plant was initiated in January 2009 with the intention to apply post-combustion "KM-CDR Process" CO_2 recovery technology of Mitsubishi Heavy Industries, Ltd. (MHI) of Japan. The plan for this estimated $27 million plant is to recover 240 tonnes of CO_2 per day from exhaust gas of Phu My fertilizer plant to increase urea production capacity. It is anticipated that this will result in a decrease in CO_2 emissions of 40,000 tonnes per year.[115]

Work to date by ADB concludes that many attractive CO_2 sources exist in Viet Nam, both today and in the future. Suitable sinks are available both onshore and offshore,

[110] http://www.eco-business.com/news/co2-emissions-in-vietnam-at-alarming-rate/ [Accessed September 14, 2013]
[111] Nguyen Anh Dung, "Role of CCS in Vietnam," presentation at the APEC/ADB Joint Workshop on Carbon Capture and Storage in Viet Nam, Hanoi, 12-14 December, 2011
[112] Asian Development Bank, Prospects for Carbon Capture and Storage in Southeast Asia: Executive Summary, November 2012
[113] http://www.bp.com/en/global/corporate/about-bp/statistical-review-of-world-energy-2013.html [Accessed September 14, 2013]
[114] http://www.eco-business.com/news/co2-emissions-in-vietnam-at-alarming-rate/ [Accessed September 14, 2013]
[115] Nguyen Anh Dung, "Role of CCS in Vietnam," presentation at the APEC/ADB Joint Workshop on Carbon Capture and Storage in Viet Nam, Hanoi, 12-14 December, 2011

with perhaps the best prospects located in South Viet Nam. Good sources include gas and coal fired power plants and gas processing facilities. In fact, gas processing opportunities are particularly attractive, as they may allow for the acceleration of the development of high CO_2-content fields, allowing for the separation of the CO_2 from high CO_2 content gas for use in EOR, resulting in increases in Viet Nam's reserves of both oil and natural gas.

Oil Resource Potential. According to the BP Statistical Review,[116] Vietnam now ranks third in terms of proven oil reserves for the Asia-Pacific region, with 4.4 billion barrels (0.6 billion tonnes) of proven oil reserves. Reserves are increasing as a result of Vietnam's efforts to intensify exploration and development of its offshore fields. Ongoing exploration activities could increase this figure in the future, as Vietnam's waters remain relatively underexplored.

Vietnam's oil production increased steadily until 2004, when it peaked above 400,000 barrels per day (20.7 million tonnes per year). Since 2004, oil production slowly declined, but now appears to be rising again, with production reaching an estimated 348,000 barrels per day (17.0 million tonnes per year) in 2012. Most forecast that the economy's oil production will continue to rise, based on several smaller fields anticipated to come online by 2015. These fields should offset declining production from mature basins, but Viet Nam must accelerate exploration efforts to maintain current production levels in the longer term.

The Russian Federation energy companies are expanding their presence in Vietnam as the two economies seek to form strategic partnerships and expand their overseas equity and production. The largest oil-producing company in Viet Nam is Vietsovpetro (VSP), a long-standing joint venture between PetroVietnam and Zarubezhneft of the Russia Federation, which continues to operate the Bach Ho, Rong, and Rong South-East oilfields.

Viet Nam 's oil production has decreased over the last seven years primarily as a result of declining output at the Bach Ho (White Tiger) field, the economy's largest field, which accounts for about half of the economy's crude oil production. After reaching peak output of 263,000 barrels per day in 2003, the field's production dropped to an average 92,000 barrels per day in early 2011.

Several new projects have come online in recent years, offsetting declines at Bach Ho and other mature oil fields. One of the most active areas for ongoing exploration and production activities in Viet Nam is the offshore Cuu Long Basin. Two key developments in Cuu Long Basin's Block 15-1 are the Su Tu Den (Black Lion) and Su Tu Vang (Golden Lion) fields that produced a combined 100,000 barrels per day of oil in 2011. Su Tu Vang is currently Viet Nam 's second largest oilfield, producing around

[116] http://www.bp.com/en/global/corporate/about-bp/statistical-review-of-world-energy-2013.html [Accessed September 14, 2013]

70,000 barrels per day. There are also extensive exploration and development activities ongoing in the Nam Con Son and Malay basins.[117]

Viet Nam remains relatively underexplored, and there is potential for exploration companies to uncover several new natural gas finds. Nearly all of Viet Nam 's natural gas production originates from three offshore basins: the Cuu Long, Nam Con Son, and Malay Basins. Currently, the largest gas development project in Viet Nam is located in the northern section of the shared basin with Malaysia and includes exploration and development of several fields and construction of a gas pipeline. The Song Hong basin could enhance gas development in northern Viet Nam. However, much of the gas contains high levels of CO_2 and hydrogen sulfide.

Hydrocarbon resources that remain to be discovered in the major basins of Viet Nam assessed by the USGS[118] are shown in **Table 2-11**. In total, these major basins within and near Viet Nam contain 2.8 billion barrels of oil (0.4 billion tonnes) that remain to be discovered.

Table 2-11 Hydrocarbon Resources that Remain to be Discovered in the Major Oil Basins of Viet Nam

Basin	Mean Undiscovered Oil Resources (Million Barrels)
Song Hong Basin Province (Eocene-Miocene Composite TPS)	
Paleogene-Neogene Reservoirs AU	204
Phu Khanh Basin Province (Paleogene TPS)	
Paleogene-Neogene Reservoirs AU	223
Cuu Long Basin Province (Eocene-Oligocene Composite TPS)	
Syn-Rift Reservoirs AU	1,735
Nam Con Son Basin Province (Eocene-Miocene Composite TPS)	
Oligocene-Miocene Reservoirs AU	685
	2,847

Source: USGS, Assessment of Undiscovered Oil and Gas Resources of Southeast Asia, 2010, USGS Fact Sheet 2010-3015, June 2010

[117] http://www.eia.gov/countries/cab.cfm?fips=VM [Accessed September 14, 2013]
[118] USGS, *Assessment of Undiscovered Oil and Gas Resources of Southeast Asia*, 2010, USGS Fact Sheet 2010-2015, June 2010

Assessment of EOR Potential in IEA GHG Report. None of the major basins in Viet Nam were assessed in the IEA GHG report. Applying the same methodology as used in the IEA GHG report for the White Tiger field would indicate incremental oil recovery potential on the order of 600 million barrels (80 million tonnes) of oil (about 20% of OOIP), with total CO_2 storage of about 220 million tonnes.

However, earlier work by Advanced Resources International to assess the potential for miscible CO_2-EOR at the Bach Ho (White Tiger) field determined that CO_2-EOR is technically feasible. Laboratory measurements verified the reservoir oil and CO_2 is miscible at pressures at least consistent with the deeper half of the field's main reservoir. Incremental oil recovery factors of on the order of 21% (of OOIP) were predicted assuming a gravity-stable CO_2-EOR flood, or 689 million barrels. The project was determined to have the potential to store in excess of 350 million tonnes of CO_2.[119]

Best Prospects for a CCUS- CO_2-EOR Demonstration. In the ADB assessment of the potential for CCS in Southeast Asia, [120] one storage hub area was identified consisting of eight oil and gas fields in the Cuu Long Basin. Of these, two EOR prospects were identified in the Cuu Long Basin – Bach Ho and Rang Dong.[121]

The proposed pilot recommended in the ADB report for Viet Nam was intended to match an existing natural gas combined cycle (NGCC) power plant with offshore oil fields in the Cuu Long basin in South Viet Nam, unless a new gas processing facility to process high CO_2-content natural gas comes on line.[122]

A final prospective project, similar to the one above, the so-called White Tiger CDM project[123], was the first CDM proposal based on CCS (application for registration in September 2005 under UNFCC-NM0167). This was the first commercial CCS project proposed in Asia. The project includes capture of CO_2 from a Combined Cycle Gas Turbine (CCGT) plant and injecting into the White Tiger oil field. This is a joint project between Mitsubishi Heavy Industry and Marubeni, with Vietsovpetro as local partner. The plan was for the annual capture of up to 4.6 million tonnes of CO_2 per year, with injection planned via an oil well at 4,000 meters into the active reservoir, connected by a 144 kilometer pipeline. This project has not yet been registered by the CDM Executive Board.

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[119] Reeves, Scott, "Feasibility Study on CO_2-EOR of White Tiger Field in Viet Nam (CO_2 Capture from Phu-My Power Plant)," presentation at the Third Annual DOE Conference on Carbon Capture and Sequestration, Alexandria, VA, May 3-6, 2004

[120] Asian Development Bank, Prospects for Carbon Capture and Storage in Southeast Asia: Executive Summary, November 2012

[121] Macdonald, Doug, "CO_2 Capture Opportunities and Challenges in Viet Nam," presentation at the APEC/ADB Joint Workshop on Carbon Capture and Storage in Viet Nam, Hanoi, 12-14 December, 2011

[122] Asian Development Bank, Prospects for Carbon Capture and Storage in Southeast Asia: Executive Summary, November 2012

[123] The White Tiger Oilfield Carbon Capture and Storage (CCS) Project in Viet Nam. Reference NM0167. Clean Development Mechanism, UNFCCC, Bonn, Germany. 2005. https://cdm.unfccc.int/methodologies/PAmethodologies/pnm/byref/NM0167 [Accessed September 14, 2013]

Barriers and Challenges. Like Thailand, CCUS is not one of the primary energy and environment policies identified for greenhouse gas emissions mitigation in the Viet Nam. The high cost of electricity as a proportion of family income hinders incentives to mitigate emissions. Like Malaysia, future natural gas production will be higher in CO_2 content, though current Natural Gas Production does not reject or process CO_2. And while gas processing is likely to be the best CO_2 source for CCUS and CO_2-EOR, deployment would require major financial support; probably including a combination of internal tax and other development incentives, external capital subsidy for CCS costs, feed-in tariff and/or base load prioritization, revenue from production for CO_2-EOR, and/or CO_2 emission reduction credits. There is a need for a policy framework for GHG emission reductions, a legal framework for widespread CCUS, and sources of financing.[124]

2.9 SUMMARY

In total, the eight economies that are the focus of this study have the potential to produce 18 to 78 billion barrels (2.5 to 10.6 billion tonnes) of incremental oil from the application of CO_2-EOR, and could store from 5.8 to 24.2 billion tonnes of CO_2 as a result. However, the vast majority of this potential exists in two economies – China and Mexico.

These results are summarized in **Table 2-12**.

Table 2-12. Summary -- CO_2-EOR and Associated CO_2 Storage Potential in Selected APEC Economies

Economy	CO_2-EOR Potential				Potential CO_2 Storage Capacity	
	(Billion barrels)		(Billion tonnes)		(Billion tonnes)	
	Low	High	Low	High	Low	High
Brunei Darussalam	0.8	1.9	0.1	0.3	0.3	0.6
People's Republic of China	0.5	43.3	0.1	5.9	0.3	12.4
Indonesia	0.3	4.3	0.0	0.6	0.0	1.0
Malaysia-Thailand (Malay Basin)*	1.0	1.0	0.1	0.1	0.0	0.2
Mexico	14.1	23.9	1.9	3.3	4.6	8.9
Peru	1.1	2.6	0.1	0.4	0.3	0.8
Viet Nam	0.6	0.7	0.1	0.1	0.2	0.4
TOTAL	18.4	77.7	2.5	10.6	5.8	24.2

* Also includes resources from the Baram Delta/Brunei Sabah Basin reported for Brunei Darussalam

[124] Macdonald, Doug, "CO_2 Capture Opportunities and Challenges in Viet Nam," presentation at the APEC/ADB Joint Workshop on Carbon Capture and Storage in Viet Nam, Hanoi, 12-14 December, 2011

Also important to note in Table 2-12 is that in many economies, the range in estimates for CO_2-EOR and associated CO_2 storage potential is quite high, depending on the methods employed, assumptions made, and resources considered in the assessment. Regardless, however, the potential for CCUS with CO_2-EOR in each of these economies is considerable.

All APEC economies considered in this study were included because they have some oil resource endowment that could be amenable to the application of CO_2-EOR. However, as illustrated above Table 2-12, most of the CO_2-EOR potential in these eight APEC economies exist in just two – China and Mexico.

Moreover, the range in estimates for CO_2-EOR and associated CO_2 storage potential is quite large even within each of the APEC economies. This range in estimates depends on the methods employed, assumptions made, and resources considered in the assessment. Nonetheless, all of these APEC economies could benefit from more rigorous and consistent assessments of their potential for CO_2-EOR. However, to ensure this consistency, some economies need to make greater information on the characteristics accessible; something that has been a challenge to resource assessments to date, including the assessments presented in this report.

Moreover, the state of the commercial, policy, and regulatory environment varies considerably among the APEC economies. For example:

- Where resource endowments exist, APEC economies, for the most part, are pursuing policies and programs to encourage greater development of fossil fuels, for both internal use and for export, to take advantage of the economic benefits associated with such development.

- In some cases, these are being pursued in parallel with policies and programs to mitigate greenhouse gas emissions; thought the state of development of these policies and programs varies widely. Moreover, in some APEC economies, such as China, mitigation policies and programs place high priority on CCS/CCUS; in others, like Peru, greater focus is on deforestation, improved efficiency, and other mechanisms. In most cases, the focus is on where their greatest sources of emissions exist.

- Most APEC economies are relatively new to considering the application of CO_2-EOR, though some have experience, having at least pursued some pilots or engineering studies. However, some capacity development is likely to be necessary in all APEC economies.

- All APEC economies face challenges in effectively matching low-cost CO_2 sources with hydrocarbon prospects amenable to CO_2-EOR. A primary challenge is how costs and benefits will be distributed among the players. In economies where national oil companies and national power companies are the dominant players, governments are more able to dictate how costs and benefits are allocated. Where that is not the case, government policies, regulation, and incentives will be necessary.

- Achieving the potential for CCUS-EOR in each of the APEC economies will be challenging. Sources of CO_2 are often not well matched with CO_2-EOR prospects. Prospects exist in each. However, the number of prospects in these eight APEC economies varies. In some, like China, a significant number of large scale integrated projects are already being pursued. In others, prospects are identified in this report for the first time. In addition, the state of assessment of these prospects varies widely. These prospects for CCUS-EOR projects were identified, and are examined in more detail in the next chapter.

3. CASE-STUDY ASSESSMENTS OF REPRESENTATIVE CCUS-EOR PROSPECTS

Based on the assessments of the feasibility for CCUS-EOR in the developing APEC economies included in this assessment, we identify “best prospects” in each APEC economy in order. For selected prospects identified, we sought to:

- Characterize potential costs of developing an integrated prospect, accounting for capture, transport and storage
- Describe data and information needs appropriate for specifically conducting detailed assessments.
- Develop detailed specifications of the elements necessary for conducting such first-order case study assessments of integrated CCUS-EOR opportunities in selected economies, matching CO_2 sources with potential attractive CO_2-EOR prospects.
- Attempt to perform first-order case study assessments of the 2 or 3 “best prospects” integrated CCUS-EOR opportunities.
- Determine how policy frameworks may assist in ensuring commercial viability.

In this regard, commercially viable prospects were assumed to require the following:

- A commercially viable method to obtain value for utilization and ultimate storage of CO_2 −through EOR application, emission reduction credits, carbon taxes, etc.
- A source of CO_2 that can provide volumes sufficient to assure that this value can be realized.
- A policy framework, including a regulatory framework, which assures that this value can be realized.

The best CCUS-EOR prospects identified in the selected APEC economies are summarized as follows:

- In Brunei Darussalam, a demonstration project that would capture CO_2 from the SPARK methanol plant (and/or possibly other sources from the petrochemical complex) and transport the captured CO_2 approximately 25 kilometres to the Seria oil field, which could have considerable potential for CO_2-EOR.
- In the People’s Republic of China, any of the large-scale integrated projects at various stages of development that are considering CO_2-EOR as a CO_2 storage option.

- In Indonesia, either the prospect identified in the ADB study that matched the capture of CO_2 from an existing gas processing facility (such as the one at Natuna) with onshore oil fields in the South Sumatera basin; or one of the prospects identified in the 2009 Indonesia CCS Study Working Group study, such as the one involving the capture of CO_2 from a gas processing plant at the Subang gas field in West Java, with storage in an offshore oil field.

- In Malaysia, one of the following: the IEA-identified example to use the CO_2 recovered in association with natural gas from the South West Luconia gas fields for CO_2-EOR in the Sarawak North East fields; the expansion of the existing PETRONAS flue gas CO_2 recovery project from the Kedah fertilizer plant, for use for CO_2-EOR; or the proposed CDM project involving the capture of CO_2 and H_2S from the Bintulu LNG project, used for CO_2-EOR rather than its plan for storage in deep saline formations.

- In Thailand, either the onshore case study identified involving the capture of CO_2 from a coal-fired power plant with transport of the CO_2 to an onshore oil field for use in CO_2-EOR; or the case involving an offshore natural gas processing operation at the Southern gas field with geological storage of the CO_2 in a depleted offshore gas reservoir, but otherwise applied for CO_2-EOR.

- In Viet Nam, either the ADB proposed pilot matching an existing natural gas combined cycle (NGCC) power plant with offshore oil fields in the Cuu Long basin in South Viet Nam; or the White Tiger project, which includes capture of CO_2 from a Combined Cycle Gas Turbine (CCGT) plant for injection into the White Tiger oil field.

- In Mexico, one of the two PEMEX pilot projects using captured CO_2 for CO_2-EOR; most likely the one involving the CO_2 source located at the CFE-Tuxpan Power Plant complex pressurized and transported to CO_2-EOR prospects in the Paleaocanal de Chicontepec area.

- In Peru, a possible project involving the capture of CO_2 from an existing, upgraded refinery and/or cement manufacturing facility for use for CO_2-EOR in an oil field in the Talara Basin.

3.1 REVIEW OF IDENTIFIED PROSPECTS

In total, as many as 27 prospects for a CCUS-EOR demonstration project were identified in the eight APEC economies considered in this study. In most of the cases where CCS demonstration project prospects have been identified and/or recommended, some level of analysis was performed regarding the costs of CO_2 capture and transport from the source of CO_2 to the storage target. However, in all of these cases, either the storage target was not a CO_2-EOR application, or the deployment of CO_2-EOR in an oil field was specified, but a specific field was not identified, and the potential for oil recovery and CO_2 storage was not evaluated, nor was the economic viability of the CO_2-EOR project determined.

Thus, each of these recommendations needs to be evaluated in the context of their ability to facilitate a CCUS-EOR demonstration project, with particular attention to the prospects for deploying CO_2-EOR.

In the following discussion, these prospects are reviewed, with the objective of narrowing down the CCUS-EOR demonstration project prospects to several worthy of further assessment.

Brunei Darussalam. The best prospect identified for a CCUS-EOR demonstration project in Brunei Darussalam is in the western part of the economy, in Liang, associated with the establishment of SPARK, a 271-hectare site designed to be a world class petrochemical hub. The first major investment at SPARK is the $450-million methanol plant with designed output of 2,500 tonnes of methanol per day. With the capture of CO_2 from the SPARK methanol plant (or possibly other sources from the petrochemical complex) and the transport of the captured CO_2 approximately 25 kilometers to the Seria oil field which could have considerable potential for CO_2-EOR, this could be a viable demonstration project prospect.

However, this option has not been thoroughly studied to date, and adequate data to assess the viability of this effort in a case study is not, to our knowledge, publicly available. Therefore, this project was determined not a viable case-study candidate for consideration in this report.

People's Republic of China. China has 11 large-scale integrated projects (LISP) in various stages of development, with others under consideration. Most are at least considering the utilization of CO_2 for EOR or ECBM. They all involve major state-owned power, oil, or coal companies, as well as large international partners. Finally, most have some level of international involvement and support, implying that the results of these projects will eventually be published.

Since there are already many CCUS-EOR demonstrations already underway in China, it was determined that, for purposes of this report, identifying and analyzing potential CCUS-EOR demonstration projects in other APEC economies provided better diversity of assessed opportunities in developing APEC economies.

Indonesia. A number of prospective projects were identified for the potential application of CCUS-EOR:

- Without naming the facilities due to confidentiality concerns, ADB recommended consideration of a CCUS pilot that matched an existing gas processing facility with onshore oil fields in the South Sumatera basin. With this approach, an existing gas processing facility such as the one at Natuna could be matched with one or more onshore oil fields in the South Sumatera basin or East Kalimantan (Kutei basin). [125]

[125] Asian Development Bank, Prospects for Carbon Capture and Storage in Southeast Asia: Executive Summary, November 2012

- The 2009 Indonesia CCS Study Working Group study identified several prospective "source-sink" matches for a CCS pilot for preliminary costing estimates:[126]

  1. Capture of CO_2 at a 1000-MW supercritical coal-fired power plant in Indramayu-West Java and transport to an onshore storage location in South Sumatera.
  2. Capture of CO_2 at a natural gas combined cycle power plant (NGCC) in Muara Tawar-West Java and transport to offshore storage, North of Java.
  3. Capture of CO_2 at a lignite-fired power plant in Bangko Tengah-South Sumatera and transport to onshore storage.
  4. Capture of CO_2 at a coal-fired power plant in Muara Jawa-East Kalimantan and transport to an onshore storage location on Kalimantan.
  5. Capture of CO_2 from a gas processing plant at the Subang gas field in West Java, with storage offshore.

The ADB study clearly indicated that CCS associated with natural gas processing facilities in Indonesia offer the best option for broader CCS deployment associated with CO_2-EOR. The study provided some characterization of the average annual costs to support this conclusion. Although these costs included the revenue offsets associated with oil production from CO_2-EOR, the bases for these determinations were not provided in the publicly available materials. Nonetheless, by defining a CO_2-EOR prospect in the South Sumatera basin or East Kalimantan with sufficient data for high-level evaluation, the basis for a case study assessment of this prospect could exist.

None of the CCS Working Group Study prospects specifically involved the use of CO_2 for CO_2-EOR.[127] Nonetheless, these could be adapted to assess their viability for a CCUS-EOR demonstration, provided sufficient data exist to perform an assessment of CO_2-EOR project viability. This study also concluded that "…capturing of CO_2 from existing gas sweetening plants provides the most cost effective source of CO_2 for storage."

The one "source-sink match" involving gas sweetening at the Subang field located in West Jawa was assumed to produce 200 million standard cubic feet per day (MMscfd) of gas with CO_2 content of 23%. This corresponds to about 46 MMscfd of CO_2, which is equivalent to about 0.9 million tonnes of CO_2 per year. The cost of compressing the CO_2 extracted as a result of gas processing was determined to be $10.70 per tonne CO_2, which is relatively low compared with the power plant examples assessed in the study. The study assumed that the CO_2 would be transported about 30 km, at a cost ranging from $5.60 to $7.80 per tonne CO_2, depending on the need for compression.

[126] Indonesia CCS Study Working Group, Understanding Carbon Capture and Storage Potential in Indonesia, August 14, 2009
[127] Indonesia CCS Study Working Group, Understanding Carbon Capture and Storage Potential in Indonesia, August 14, 2009

The initial assessment of the CCS Working Group study determined that the prospects for CO_2 storage in Indonesia's geological formations are best in the South Sumatra basins, Kutai Basins (East Kalimantan) and Natuna basins due to good reservoir characterisation, geologically stable, existing infrastructures, and low population density.

Based on this assessment, a case study involving a gas processing facility in one of these basins (similar to that proposed in the ADB study) could be viable candidate for case study assessment.

Malaysia. The IEA identified one example of an application for CO_2-EOR in which the CO_2 recovered in association with natural gas from the South West Luconia gas fields is used to increase recovery from Sarawak North East fields. However, insufficient data are available from the IEA work to appropriately evaluate this option.

The project involving flue gas CO_2 recovery from the Kedah fertilizer plant is operational, so the CO_2 capture economics are well established.[128] The application for CDM made for the Bintulu LNG project involving the capture of CO_2 and H_2S from an offshore field (off the Sarawak coast), with storage in a deep saline formation 120 kilometers away, cannot provide the basis for assessing the viability of CO_2 capture for this facility.[129] Moreover, the CDM application itself also did not provide much information on the costs associated with separating CO_2 from the natural gas processed at Bintulu plant, estimated to be on the order of three million tonnes of CO_2 per year.

However, the use of CO_2 for CO_2-EOR was not considered for either of these prospects. Detailed evaluation would require oil field data not readily available for storage with potential CO_2-EOR prospects associated with the Kedah facility. The closest prospective CO_2-EOR fields for this facility would be in the North Sumatra, Thai, Penyu-West Natuna, and Malay basins. The best prospect for CO_2-EOR would likely be the Tapis field in the offshore Malay Basin. CO_2-EOR prospects for the CO_2 produced from the Bintulu facility would most likely be offshore oil fields in the Greater Sarawak Basin or the Baram Delta/Brunei-Sabah Basin, which are likely to be considerably smaller than the Tapis field.

However, and perhaps most importantly, reservoir properties for are generally not published. This makes evaluation of specific CO_2-EOR prospects problematic. Therefore, primarily for this reason, prospects for a CCUS-EOR demonstration project in Malaysia were excluded as not being viable case-study candidates for consideration.

[128] IEA. *CO_2 capture and storage, a key carbon abatement option*, 2008 (http://www.iea.org/publications/freepublications/publication/CCS_2008.pdf) [Accessed September 14, 2013]

[129] ———. 2006. The Capture of the CO_2 from the Liquefied Natural Gas (LNG) Complex and Its Geological Storage in the Aquifer Located in Malaysia. Reference NM0168. Clean Development Mechanism, UNFCCC, Bonn, Germany https://cdm.unfccc.int/methodologies/PAmethodologies/pnm/byref/NM0168 [Accessed September 14, 2013]

Thailand. In Thailand, the ADB study identified 22 sources, amounting to 70 million tonnes of CO_2 emissions that were suitable for carbon capture, with four oil and gas fields determined to be best suited for CO_2 storage.[130] Of these, without naming the facilities due to confidentiality concerns, the most promising prospect identified in Thailand corresponded to a near shore gas processing facility or coal-fired power plant matched with onshore oil and gas fields. However, no data were publicly made available for assessing these prospects as a case study.

In another study of the geological storage potential in Thailand,[131] one case study (onshore) assessed the capture of CO_2 from a coal-fired power plant with storage of the CO_2 to an onshore oil field for use in EOR. However, the field was not identified, and data associated with the prospective field was not provided.

Like Malaysia, reservoir properties for oil fields in Thailand are generally not published. This makes evaluation of specific CO_2-EOR prospects problematic. Therefore, primarily for this reason, prospects for a CCUS-EOR demonstration project in Thailand were also excluded as not being viable case-study candidates for consideration.

Viet Nam. In the ADB assessment of the potential for CCS in Southeast Asia, [132] one storage hub area was identified consisting of eight oil and gas fields in the Cuu Long Basin. Of these, two CO_2-EOR prospects were identified in the Cuu Long Basin – Bach Ho (White Tiger) and Rang Dong.[133] The proposed pilot recommended in the ADB report for Viet Nam was intended to match an existing natural gas combined cycle (NGCC) power plant with offshore oil fields in the Cuu Long basin in South Viet Nam.[134] The White Tiger CDM project,[135] involved the capture of CO_2 from a Combined Cycle Gas Turbine (CCGT) plant and injecting into the Bach Ho (White Tiger) oil field.

Both of these prospects are viable candidates for a case study. The issues and costs associated with CO_2 capture from a CCGT and NGCC facilities are fairly well established, and since Advanced Resources International performed the original CO_2-EOR assessment for this proposal, access to the data for an updated assessment of the potential CO_2-EOR can be performed.

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[130] Asian Development Bank, Prospects for Carbon Capture and Storage in Southeast Asia: Executive Summary, November 2012

[131] Witsarut T., Trin I., Siree N., Anuchit L., "Carbon Capture and Storage, CCS, Study in Thailand: Result and Way Forward," presentation, September 12, 2012 http://www.ccop.or.th/eppm/projects/42/docs/Thailand_CCS_Presentation.pdf [Accessed September 14, 2013]

[132] Asian Development Bank, Prospects for Carbon Capture and Storage in Southeast Asia: Executive Summary, November 2012

[133] Macdonald, Doug, "CO_2 Capture Opportunities and Challenges in Viet Nam," presentation at the APEC/ADB Joint Workshop on Carbon Capture and Storage in Viet Nam, Hanoi, 12-14 December, 2011

[134] Asian Development Bank, Prospects for Carbon Capture and Storage in Southeast Asia: Executive Summary, November 2012

[135] The White Tiger Oilfield Carbon Capture and Storage (CCS) Project in Viet Nam, Reference NM0167, Clean Development Mechanism, UNFCCC, Bonn, Germany, 2005 https://cdm.unfccc.int/methodologies/PAmethodologies/pnm/byref/NM0167 [Accessed September 14, 2013]

Mexico. As described above, two pilot projects for using captured CO_2 for EOR are being considered in Mexico. Both involve the capture of CO_2 from a major coal-fired power plant to utilize for CO_2-EOR at a nearby oil field. One proposed CCS demonstration project was identified with the CO_2 source located at the CFE-Tuxpan Power Plant complex in the Gulf of Mexico region. CFE has decided to switch the fuel capacities in the six units progressively into units that will be able to use pulverized coal and oil petcoke fuels. The first unit that will be refitted will be acting as the CO_2 source where the capture system will be installed.

The CO_2 that will be captured at the Tuxpan plant will be subsequently pressurized and transported along a 150-kilometer pipeline to the Paleaocanal de Chicontepec area, where fields for EOR are located. CO_2 injection pilot tests are already being carried out in a few of the PEMEX oil fields. It is estimated that significant amounts of CO_2 would be necessary for future EOR processes in the region.[136]

Sufficient data appear to be available related to this project to perform a high-level case study assessment of this prospect in Mexico.

Peru. As stated above, the lack of large, concentrated volumes of CO_2 that could be used to facilitate CO_2-EOR remains a major constraint to a potential CCUS-EOR in Peru. The recommendations for consideration of natural gas processing, refining, and/or cement manufacturing sources are not based on any pre-existing assessments, nor have any of these been matched with prospective fields amenable to CO_2-EOR.

Consequently, potential prospects in Peru were excluded as not being viable case-study candidates for consideration.

Conclusion. Based on the assessments for each APEC economy summarized above, three case studies were identified for further assessment:

1. CO_2 capture from natural gas processing for CO_2-EOR in an oil field in Indonesia
2. Natural gas power plant CO_2 capture for CO_2-EOR in the White Tiger Field in Viet Nam
3. Pulverized carbon and oil pet-coke power plant CO_2 capture for CO_2-EOR in an oil field in Mexico

Each of these case studies is described in the following sections. For these case study assessments, we draw upon the resource recovery, cost, and economic models used by Advanced Resources International for the U.S. Department of Energy/National Energy Technology Laboratory (DOE/NETL).[137] These include Advanced Resources'

[136] http://www.globalccsinstitute.com/insights/authors/rodolfo-lacy/2011/02/24/co2-capture-and-geologic-storage-demonstrative-project [Accessed September 14, 2013]
[137] U.S. Department of Energy/National Energy Technology Laboratory, *Improving Domestic Energy Security and Lowering CO_2 Emissions with "Next Generation" CO_2-Enhanced Oil Recovery (CO_2-EOR),* report DOE/NETL-2011/1504 prepared by Advanced Resources International, June 20, 2011

modified streamline reservoir simulator (CO_2-PROPHET) and CO_2-EOR cost and economic models, that have been extensively peer reviewed by representatives from a number of CO_2-EOR-focused companies in the United States (e.g., Kinder Morgan, Hess, Denbury, Whiting, BlueSource, Trinity CO_2, Apache, and Legado).

The “near-term” characterization of CO_2-EOR opportunities and CO_2 demand provided in this report assumes industry uses “state-of-the-art” CO_2-EOR technology, without consideration of optimizing CO_2 storage in oil fields, the use of “next-generation” CO_2-EOR technology, or the pursuit of CO_2-EOR in more challenging settings.

3.2 CASE STUDY #1 – CO_2 CAPTURE FROM NATURAL GAS PROCESSING FOR CO_2-EOR IN AN OIL FIELD IN INDONESIA

This case study is developed assuming CO_2-EOR deployment in a depleted oil field in the South Sumatra, Kutai (East Kalimantan) and/or Natuna basins due to good reservoir characterization, geologically stable, existing infrastructures, and low population density. The case study assumes CO_2 captured from a gas processing facility.

The 2009 Indonesia CCS Study Working Group study[138] identified one prospective “source-sink” match for a CCS pilot for preliminary costing estimates that involved the capture of CO_2 from a gas processing plant at the Subang gas field in West Java. The field produces 200 million cubic feet (5.7 million cubic meters) per day of gas with a CO_2 content of 23%. The cost of compressing the extracted CO_2 was estimated to be $10.70 per tonne. These costs are based on the following assumptions:

- CO_2 inlet pressure − 0.2 MPa
- CO_2 delivery pressure − 15.0 MPa
- Compressor rating − 8.8 MW
- Capital cost of compressor − $13.6 million
- Operating cost $5.93 million per year
- Capital factor − 11%
- Annual charge $7.4 million per year

Transport costs were estimated based on an assumed 50-kilometer pipeline from the natural gas processing plant. Estimates of costs were based on the outlet pressure of the plant, and were assumed at an outlet pressure of 13.0 Mpa to be $7.80 per tonne CO_2, decreasing to $5.60 per tonne CO_2 at a lower outlet pressure of 11.3 Mpa.

138 Indonesia CCS Study Working Group, Understanding Carbon Capture and Storage Potential in Indonesia, August 14, 2009

Thus, including separation, compression, and transport, the delivered costs of CO_2 would be $16.30 to $18.50 per tonne to the offshore oil field. About 6 million cubic feet per day (625,000 tonnes per year) would be generated from the Subang plant.

If greater amounts of CO_2 are required for CO_2-EOR, the Indonesia CCS Study Working Group study identified a number of other potential additional sources of CO_2:

- Refinery (flue gas) from the Cilacap and/or Balongan facilities.
- CO_2 from H_2S separation units at the Cilacap and/or Balongan facilities.
- CO_2 from gas processing at the Langit Biru, North Cylamaya, and/or Tugu Barat facilities.

The economics of CO_2-EOR in this case study draws on the results of a series of integrated reservoir studies performed on the Handil oil field in the Mahakam Delta to evaluate possible ways to revive production from the mature oil field, discovered in 1974. Among the options considered was lean-gas injection, gravity assisted immiscible recovery.[139,140] In addition, they take advantage of the results of several pilot studies of various EOR approaches.[141,142]

For purposes of performing the assessment of CO_2-EOR potential, reservoir properties for the Handil field were assumed, as shown in **Table 3-1**. The economic assessment was performed assuming an oil price paid to the operator, at the wellhead, of $90 per barrel, and a delivered CO_2 cost, delivered to the field at sufficient pressure to achieve miscibility when injected into the oil reservoir, of $18.50 per tonne. Also assumed it that this offshore project is developed assuming a CO_2-EOR injection pattern spaced at 80 acres (0.32 square kilometers) per pattern. The project assumes that 25 existing production wells could be used for the CO_2-EOR project, with 26 new production wells and 38 new CO_2 injection wells drilled. This assessment assumes the project is developed over 10 years, and produces for 25 years.

[139] Herwin, Henricus, Emmanuel Cassou, and Hotma Yusuf, "Reviving the Mature Handil Field: From Integrated Reservoir Study to Field Application," SPE Paper No. 11082 prepared for the 2007 Asia Pacific Oil and Gas Conference and Exhibition, Jakarta, October 30-November 1

[140] Hadiaman, Farid, Julfree Sianturi, Emmanuel Cassou, and Win Zaw Naing, "Case History: Lesson Learnt from Enhanced Oil Recovery Screening Method in Handil Field," SPE Paper No. 144914-MS presented at SPE Asia Pacific Oil and Gas Conference and Exhibition, Jakarta, Indonesia, 20-22 September 2011

[141] Gunawan, Sugianto and Didier Caie, "Handil Field: Three Years of Lean-Gas Injection Into Waterflooded Reservoirs" (SPE Paper No. 71279), *SPE Reservoir Evaluation & Engineering Journal*, Volume 4, Number 2, Pages 107-113, April 2001

[142] Duiveman, M.W., H. Herwin, and P. Grivot, "Integrated Management of Water, Lean Gas and Air Injection: The Successful Ingredients to IOR Projects on the Mature Handil Field," SPE Paper No. 93858 presented at the SPE Asia Pacific Oil and Gas Conference and Exhibition, Jakarta, Indonesia, 5-7 April 2005

Table 3-1. Assumed Reservoir Properties for the Handil Field Used in the Case Study Assessment of CO_2-EOR Potential

Reservoir Property	Value
Perm (md)	1,100
Porosity (%)	25
Dykstra Parsons	0.75
Oil Gravity	31
Oil Viscosity (cp)	0.8
Pattern Size	80
Reservoir Temperature (deg F)	140 (59 ^oC)
Residual Saturation	0.24
Gas Oil Ratio	75
Net Pay (feet)	200 (60 m)
Area (acres)	3,000 (12 km^2)
Depth (feet)	6,500 (1,980 m)
OOIP (MMB)	1,200
P/S Recovery (MMB)	300
Dip, degrees	8
No of producers	383
No of injectors	unknown
Oil formation vol. factor (B_o)	1.25
Connate Water Sat (%)	22
Current reservoir pressure (psia)	2,000

Based on this assessment, the project produces over 70 million barrels (9.5 million tonnes) of incremental oil due to CO_2-EOR (about 6% of originally oil in place), and uses 48 million tonnes (913 Bcf) of CO_2. At an oil price of $90 per barrel, and a CO_2 cost of $18.50 per tonne, the project achieves a modest before-tax internal rate of return (IRR) of 11%. These results of this analysis are illustrated in **Figure 3.1**.

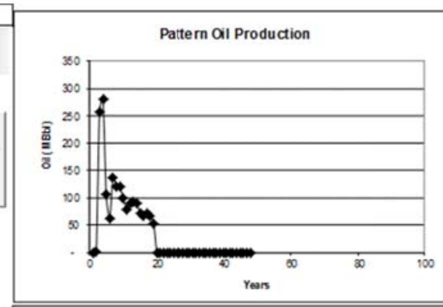
Given the marginal nature of this project, some project incentives may be necessary. This would be particularly important if the delivered CO_2 costs rise above these assumed values.

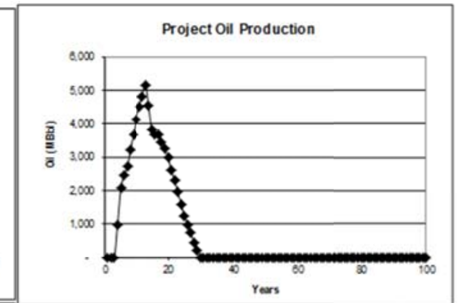
Figure 3-1. Economic Assessment of CO_2-EOR Potential for the Handil Field Case Study Assessment

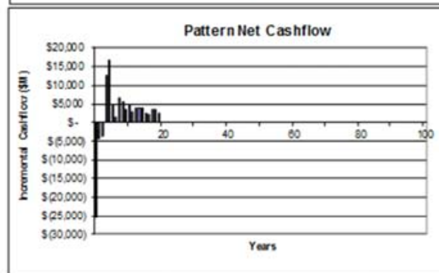
AIndonesia	3.0	2	
Basin	**FED-OFF**		
Field	**Indonesia**		
Formation	**Offshore**		
Technology Case	**Next Generation**	Print All Cashflow Summaries	
Depth (ft)	6,500		
Total OOIP (MMBls)	1,200.0		
Cumulative Recovery (MMbls)	-		
Primary EUR (MMbls)	-	WATER DEPTH	
Miscibility	Miscible	0	
API Gravity	31.0		
Patterns	38.0		
Existing Injectors Used	0.0		
Convertible Producers Used	0.0		
New Injectors Drilled	38.0		
Existing Producers Used	25.0		
New Producers Drilled	26.3		
Spacing (Acres)	80		
Pattern Detail			
Cum Oil (Mbbl)	1,876		
Cum H2O (Mbw)	17,423	9.29	Bw/Bbl
Gross CO2 (MMcf)	39,073	20.83	Mcf/Bbl
Purchased CO2 (MMcf)	24,764	13.20	Mcf/Bbl
Recycled CO2 (MMcf)	14,309	7.63	Mcf/Bbl
	-	Tech Oil	
Field Detail	-	Tech CO2	
Cum Oil (MMbbl)	71.29		
% OOIP Recovered	5.9%		
Cum H2O (MMbw)	662		
Gross CO2 (MMcf)	1,484,763		
Purchased CO2 (MMcf)	913,678		
Recycled CO2 (MMcf)	571,085		
Payback Period (per pattern)	5	years	
Project Length	27	years	

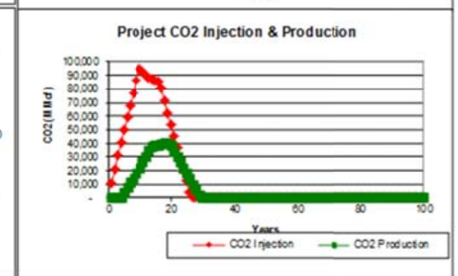
Pattern Detail				$/BBl
Total Net Revenue ($M)	$	133,614		
Total Capital Investment ($M)	$	(29,532)	$	15.74
Total CO2 Cost ($M)	$	(31,423)	$	16.75
Total O&M Costs ($M)	$	(21,900)	$	11.67
	$	(82,855)	$	44.17

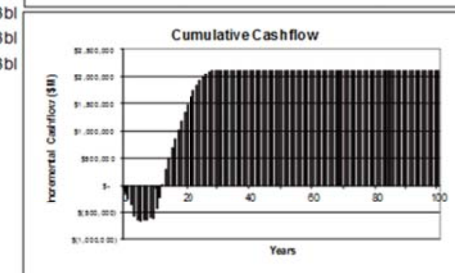
Pattern IRR (BTx)	14.5%
Project IRR (BTx)	11.4%

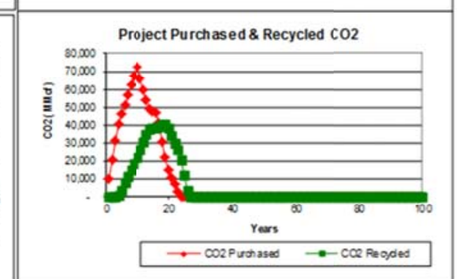


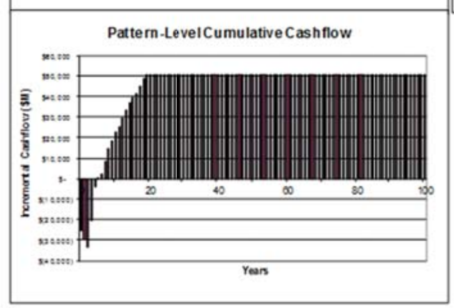












Assumptions:

Economic Case:		
Oil Price	$	90.00
CO2 Purchase Cost	$	0.98
CO2 Recycle Cost	$	0.50
Recycling Plant Cost	2 at Breakthru, 1/2 at Exceedan	
Well O&M	All Wells	
Minimum IRR	**20.0%**	
Next Gen Tech Case	**0**	

3.3 CASE STUDY #2 – POWER PLANT CO_2 CAPTURE FOR CO_2-EOR IN THE WHITE TIGER FIELD IN VIETNAM

This case study is based on the yet to be approved White Tiger CDM project,[143] the first CDM proposal based on CCS (application submitted in September, 2005). This was the first commercial CCS project proposed in Asia. The project includes capture of CO_2 from a Combined Cycle Gas Turbine (CCGT) plant and injecting into the White Tiger oil field in Vietnam. This is a joint project between Mitsubishi Heavy Industry (MHI) and Marubeni, with Vietsovpetro as local partner. The plan was for the annual capture of up to 4.6 million tonnes of CO_2 per year, with injection planned into an oil well at 4,000 meters into the active offshore reservoir, connected by a 144-kilometer pipeline.

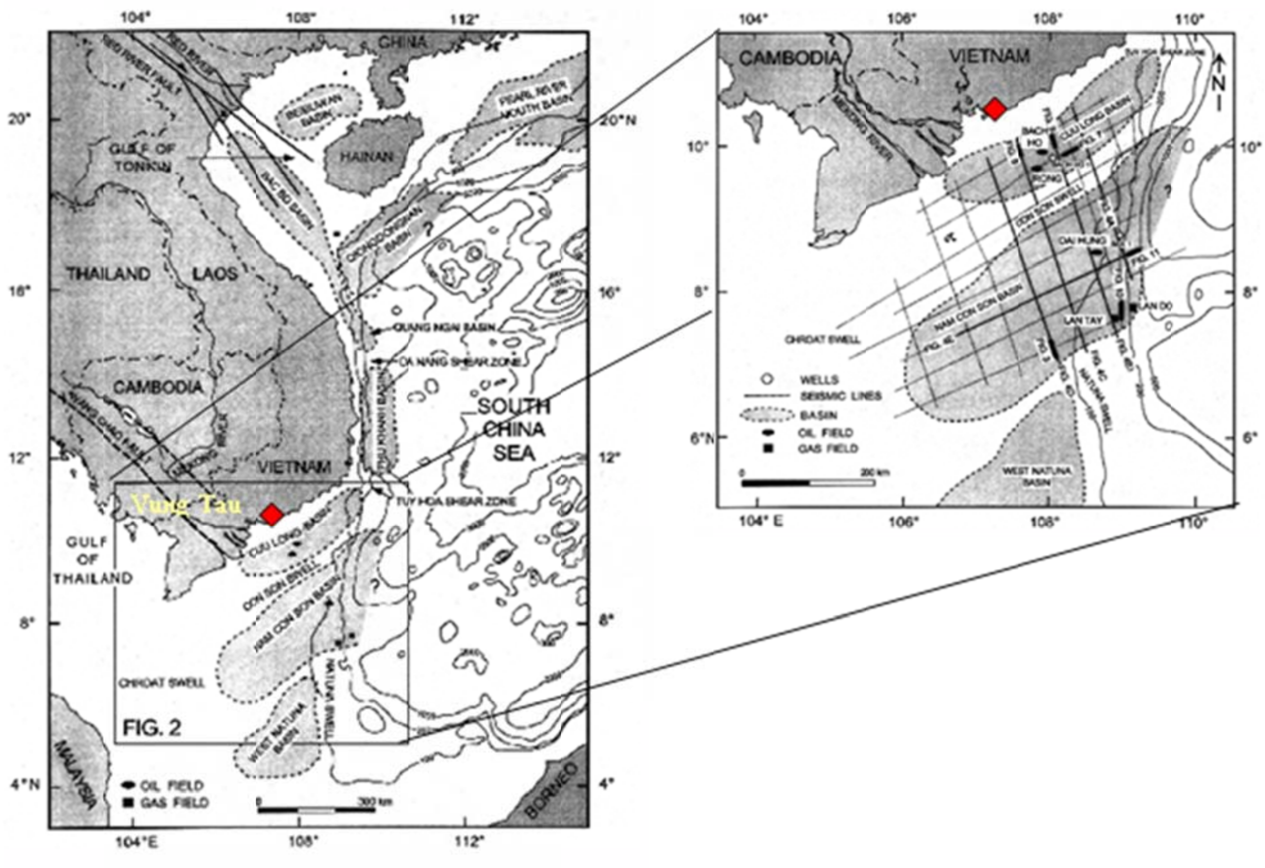
The project proposal is based on MHI technology to extract CO_2 from power plant flue gases. In 2002, MHI finished constructing a 1,000-MW gas turbine power plant at the Phu-My industrial complex, approximately 35 kilometers north and west of Vung Tau. It is estimated that the plant emits over 9,000 tons per day of CO_2. The Japanese Ministry of Economy, Trade and Industry (METI) awarded MHI a grant to evaluate the technical and economic feasibility of CO_2 capture from the plant (as well as an additional 21,000 tons/day from future power plants at Phu-My), its transportation offshore, to be used for CO_2-EOR,

To perform the "subsurface" component of the study, as well as the overall project economics, MHI contracted with Advanced Resources International.

The target field for the application of CO_2-EOR was the Bach Ho (White Tiger) field, located approximately 120 kilometers southeast of the coastal city of Vung Tau, in the Cuu Long basin off the southern coast of Vietnam (**Figure 3-2**).

[143] The White Tiger Oilfield Carbon Capture and Storage (CCS) Project in Viet Nam. Reference NM0167. Clean Development Mechanism, UNFCCC, Bonn, Germany. 2005
https://cdm.unfccc.int/methodologies/PAmethodologies/pnm/byref/NM0167 [Accessed September 14, 2013]

Figure 3-2. Location of the Cuu Long Basin and Bach Ho (White Tiger) Field, Offshore Southern Viet Nam



The field is operated by Vietsovpetro (VSP), a 50/50 joint venture between the Vietnam Oil and Gas Corporation (PetroVietnam, or PV) and the Russian Foreign Economic Association (ZarubezhNeft). The primary reservoir in the field, the Basement reservoir, has estimated original oil in place (OOIP) of 3.3 billion barrels (440 million tonnes, with estimated waterflood recovery to be approximately 42% of OOIP. Due to the important natural resource the White Tiger field represents for VSP, PV and Viet Nam, various EOR processes were considered for the field, and CO_2 miscible-displacement EOR was specifically identified as a potential means to improve oil recovery due to suitable reservoir depth and oil properties. However, lack of a suitable CO_2 supply was an obstacle to such an approach.

To assess the potential for CO_2-EOR at the White Tiger field, ARI's assessment was based on the following:

- Laboratory studies (specifically slim-tube experiments) to determine minimum miscibility pressure (MMP) between the reservoir oil and CO_2.
- Reservoir simulation to determine the best operating strategy and estimate incremental oil recoveries.

- Public literature review to compare the oil recovery predictions to other, analogous miscible CO_2-EOR projects.
- Cost estimation and economic modeling to forecast financial performance.

At the time of the initial assessment by ARI in 2003, the major conclusions of the report were as follows:

- Miscible CO_2-EOR at the White Tiger field is technically feasible; laboratory measurements have verified that the reservoir oil and CO_2 are miscible at pressures above 4,080 psia. At the time, the lower half of the reservoir was determined to be above the MMP, but the upper half was determined to be below the MMP.
- Incremental oil recovery factors of approximately 21% (of OOIP) were predicted with gravity-stable, bottom-up CO_2-EOR. This was estimated to yield an additional 698 million barrels (92 million tonnes) of oil from the Basement reservoir.
- This level of incremental oil recovery had been reported for other gravity-stable floods, and is therefore not an unrealistic oil recovery projection.
- Based on cost estimates for CO_2 capture, compression, pipeline, offshore recycling, subsea flow lines, new platforms and new wells, and a phased development schedule (assuming 9,000 tonnes/day in Phase 1, 30,000 tonnes/day in Phase 2), a total net present value of $523 million is achieved for the project (for both phases).

It is not the intent of this case study assessment to duplicate this previous analysis, but to update it based on more recent characterizations of CO_2-EOR project costs, along with the costs of developing and producing offshore oil fields. In addition, oil price projections today are substantially different than those existing in 2003. However, the reservoir simulation still remains essentially valid.

The incremental oil and associated natural gas and water recovery profiles are originally developed presented in **Figures 3-3** and **3-4**, and summarized in **Table 3-2**. It is estimated that 698 million barrels of incremental oil can be recovered, about 21% of OOIP, and 688 Bcf of incremental associated gas. This level of recovery is consistent with the high recovery efficiency associated with gravity stable floods. The financial cost to achieve this recovery, on the other hand, can be high. Approximately 545 million tonnes of CO_2 would be injected (338 million tonnes of purchased CO_2, the balance being recycled CO_2) throughout project life. Note that it was assumed that all produced CO_2 would be separated and re-injected during both Phases. A plot of injection volumes, of both new and recycled CO_2, is presented in **Figure 3-5**.

Figure 3-3. Field-Level Incremental Oil Recovery for the White Tiger Oil Field CO_2-EOR Project

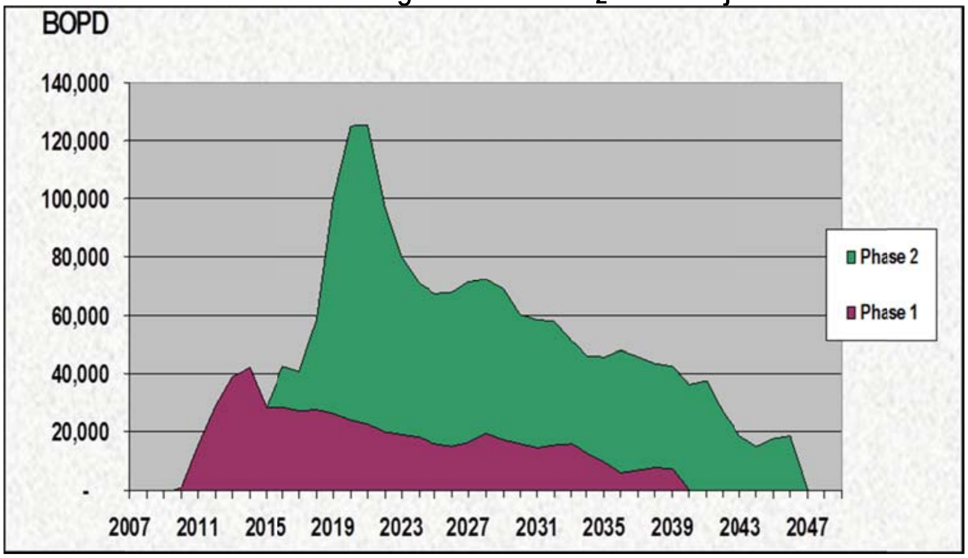


Figure 3-4. Field-Level Incremental Associated Gas Recovery for the White Tiger Oil Field CO_2-EOR Project

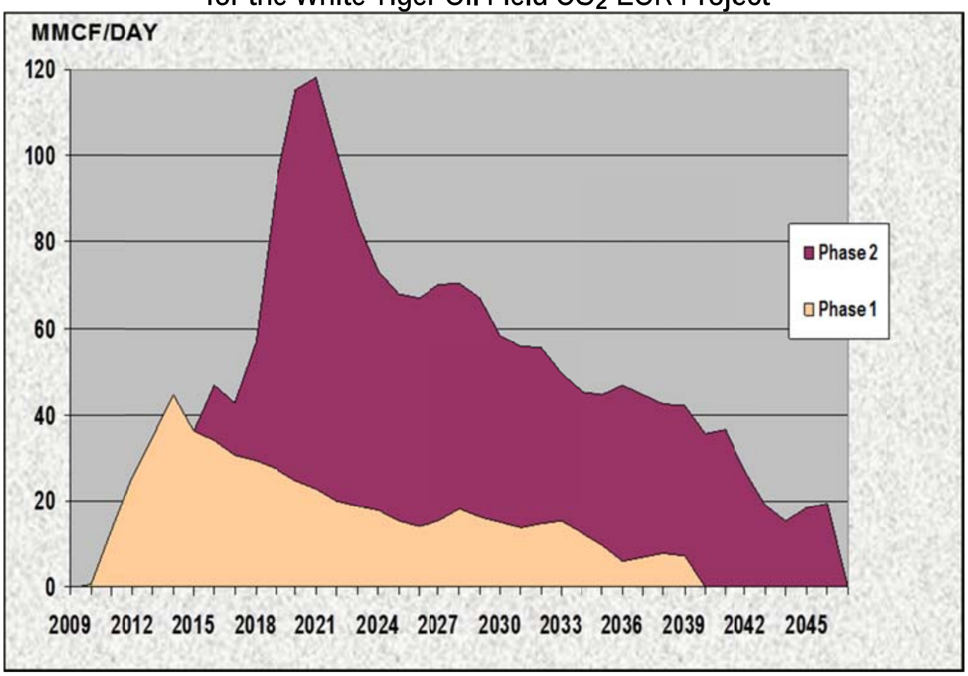


Figure 3-5. Total CO_2 Injection Volumes for the White Tiger Oil Field CO_2-EOR Project

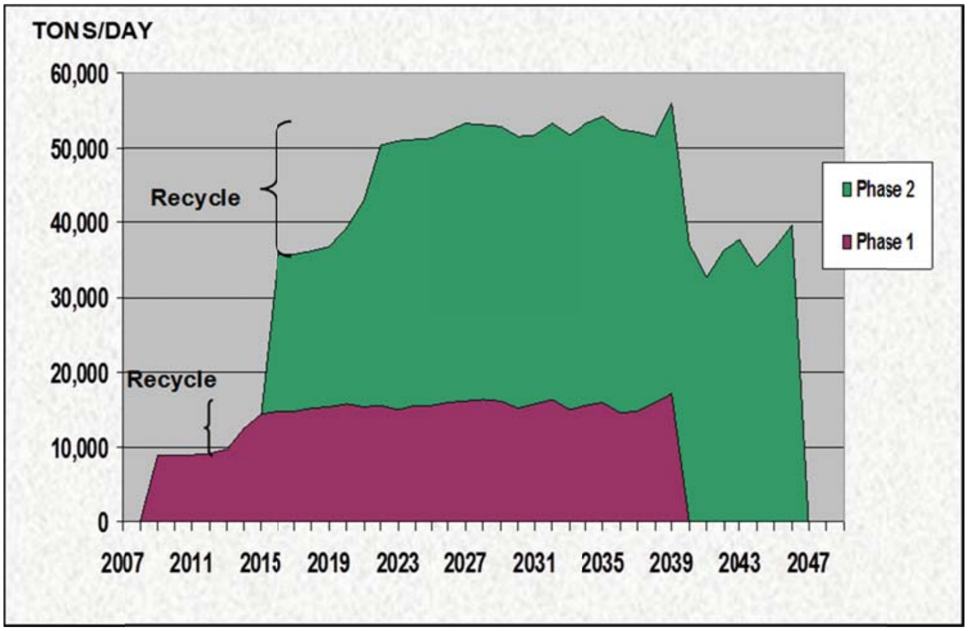


Table 3-2. Summary of Incremental Oil, Gas and Water Recovery for the White Tiger Oil Field CO_2-EOR Project

	Oil	Hydrocarbon Gas	Water
	(MMbbls)	(Bcf)	(MMbbls)
Phase 1	205	207	320
Phase 2	493	481	1,206
Total	698	688	1,526

In ARI's original assessment, due to the capital-intensive nature of the project, it was assumed that a separate CO_2 Company would be formed to capture the CO_2 at Phy-My and deliver it to the White Tiger Field. The assumption was that this company would be responsible for the capture plant and pipeline capital and operating expenses and that VSP would be responsible for the recycle facilities, new wells, and workovers. This approach spreads risk and reduces the capital requirements for VSP. The cost of the CO_2 to VSP, delivered at the field, was estimated to be $32.00 per tonne.

Based on this assessment, at an oil price of $90 per barrel, and a CO_2 cost of $32.00 per tonne, the project achieves a before-tax IRR of over 21%. These results of this analysis are illustrated in **Figure 3-6**.

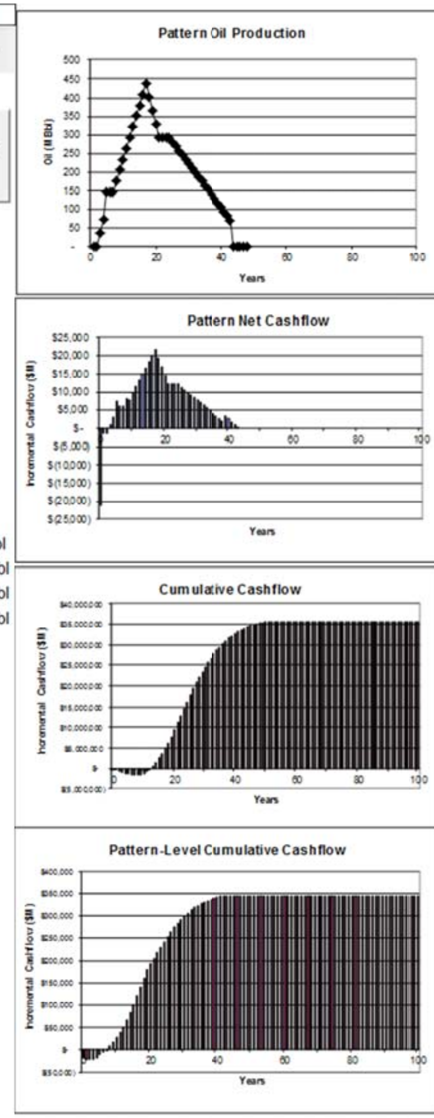
If the delivered CO_2 costs rise above this, the project appears economic. Even at CO_2 costs of $50 per tonne, the project receives a before tax IRR of over 16%.

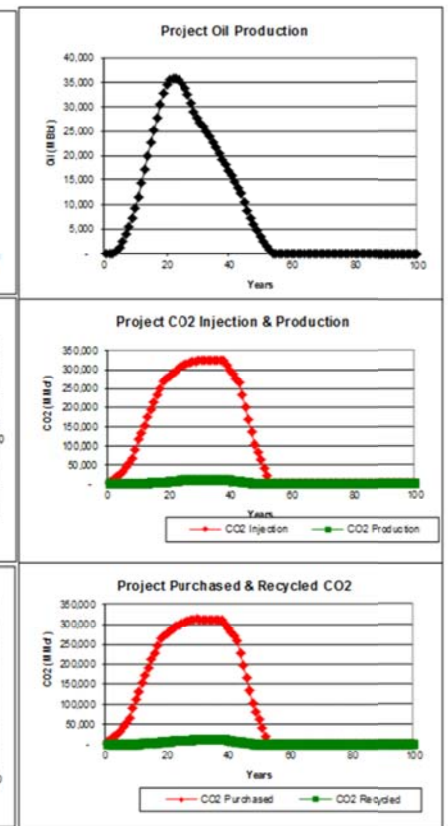
Figure 3-6. Economic Assessment of CO_2-EOR Potential for the White Tiger Field Case Study Assessment

WhiteTiger	3.0		1
Basin	**FED-OFF**		
Field	**Viet Nam**		
Formation	**Offshore**		
Technology Case	**Next Generation**	Print All Cashflow Summaries	
Depth (ft)	9,500		
Total OOIP (MMBls)	3,300.0		
Cumulative Recovery (MMbls)	-		
Primary EUR (MMbls)	-	WATER DEPTH	
Miscibility	Miscible	0	
API Gravity	-		
Patterns	100.0		
Existing Injectors Used	47.0		
Convertible Producers Used	0.0		
New Injectors Drilled	53.0		
Existing Producers Used	61.0		
New Producers Drilled	60.0		
Spacing (Acres)	40		
Pattern Detail			
Cum Oil (Mbbl)	9,205		
Cum H2O (Mbw)	16,535	1.80	Bw/Bbl
Gross CO2 (MMcf)	108,548	11.79	Mcf/Bbl
Purchased CO2 (MMcf)	105,502	11.46	Mcf/Bbl
Recycled CO2 (MMcf)	3,046	0.33	Mcf/Bbl
	-	Tech Oil	
Field Detail	-	Tech CO2	
Cum Oil (MMbbl)	920.53		
% OOIP Recovered	27.9%		
Cum H2O (MMbw)	1,653		
Gross CO2 (MMcf)	10,854,790		
Purchased CO2 (MMcf)	10,550,221		
Recycled CO2 (MMcf)	304,569		
Payback Period (per pattern)	8	years	
Project Length	45	years	

Pattern Detail			$/BBl
Total Net Revenue ($M)	$	588,182	
Total Capital Investment ($M)	$	(21,392)	$ 2.32
Total CO2 Cost ($M)	$	(179,822)	$ 19.53
Total O&M Costs ($M)	$	(42,793)	$ 4.65
	$	(244,006)	$ 26.51

Pattern IRR (BTx)	21.2%
Project IRR (BTx)	18.8%



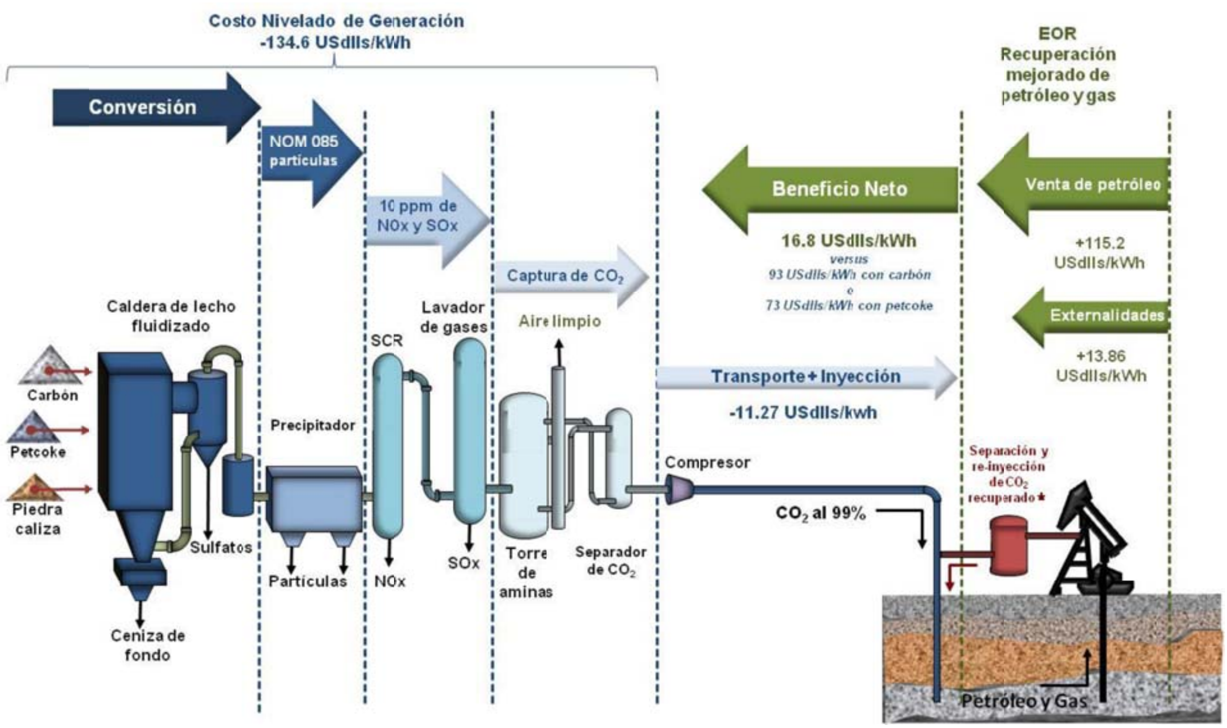


Assumptions:	
Economic Case:	
Oil Price	$ 90.00
CO2 Purchase Cost	$ 1.69
CO2 Recycle Cost	$ 0.50
Recycling Plant Cost	2 at Breakthru, 1/2 at Exceedan
Well O&M	All Wells
Minimum IRR	**20.0%**
Next Gen Tech Case	**0**

3.3 CASE STUDY #3 – POWER PLANT CO_2 CAPTURE FOR CO_2-EOR IN AN OIL FIELD IN MEXICO

As described above, a proposed CCS demonstration project has been identified with the CO_2 source located at the CFE-Tuxpan Power Plant complex in the Gulf of Mexico region. The Tuxpan plant is comprised of six 350-MW units and is equipped to use fuel oil as primary fuel, but the plan is for it to switch the fuel capacities in the six units progressively into units that will be able to use pulverized carbon and oil pet-coke fuels. The first unit that will be refitted will be acting as the CO_2 source where the capture system will be installed (**Figure 3-7**).

Figure 3-7. General Operating Diagram of the CFE-Tuxpan Power Plant Complex



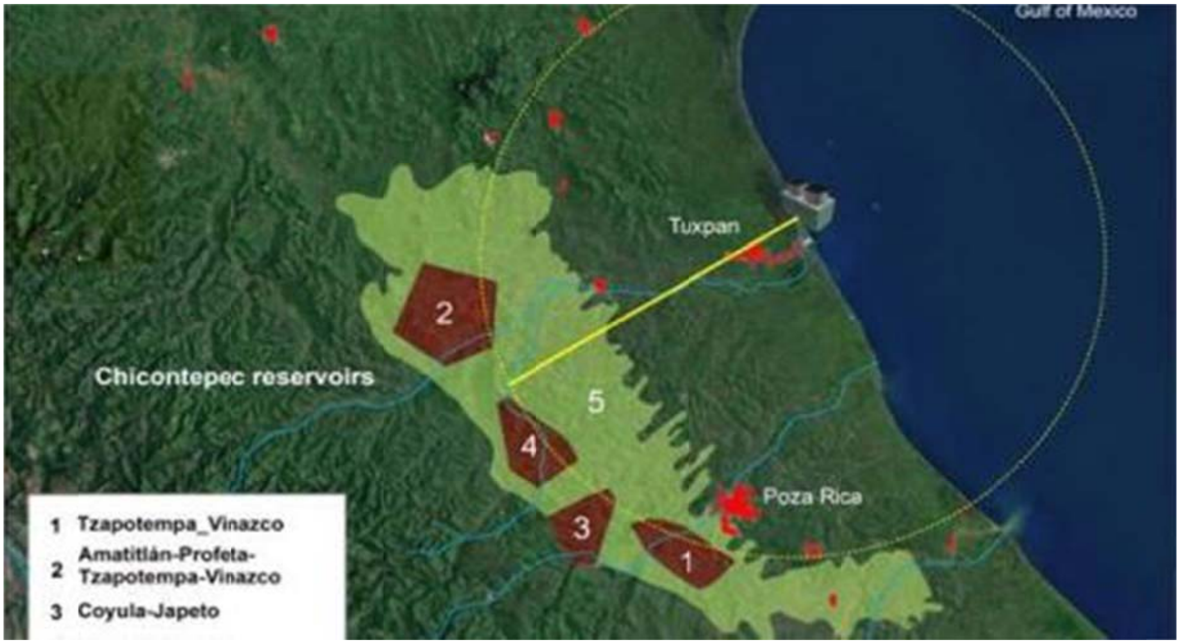
Source: MEXICAN CCS+EOR DEMONSTRATION PROJECT: Environmental Impact and Risk Analysis Monitoring, presented by Rodolfo Lacy, Mario Molina Center, at the IIE-UNAM Workshop on CO_2 Geological Storage and EOR, March 2012[144]

The plan is for the CO_2 to be pressurized and transported along a 150-km pipeline to the Paleaocanal de Chicontepec, where fields identified to have potential for CO_2-EOR are located (in particular, the Humapa oil field). **Figure 3-8** illustrates the plant's location and the possible oil reservoirs where CO_2 could be injected for EOR activity. CO_2 injection pilot tests are already being carried out in a few of the PEMEX oil fields. It is estimated that significant amounts of CO_2 would be necessary for future EOR

144 http://eventos.iingen.unam.mx/CCSworkshops/ponenciasMEXICO2012/LACYPresentacionMONITORINGPOZARICA.pdf [Accessed September 14, 2013]

processes in the region. CFE power plants could lie among the anthropogenic sources; this also would help reducing GHG emissions.[145]

Figure 3-8. Location of the CFE Plant at Tuxpan, Veracruz, and Possible PEMEX Oil Fields for EOR



Source: MEXICAN CCS+EOR DEMONSTRATION PROJECT: Environmental Impact and Risk Analysis Monitoring, presented by Rodolfo Lacy, Mario Molina Center, at the IIE-UNAM Workshop on CO_2 Geological Storage and EOR, March 2012

In 2009, the Mario Molina Center evaluated different alternatives for power generation plant with pet-coke and carbon, combined with EOR in Mexico, **Figure 3-9**. Based on this initial assessment, the initial proposal was to run the demonstration project in the CFE Tuxpan power plant that would be refitted to use coal and pet-coke. However, due to CFE strategic decisions, it was decided to have the CCS project in the NGCC Power Plant located at Poza Rica. A number of fields prospective for EOR exist in this region, including Tajin Iris, Panuco (Ebano Panuco), Coapechaca, and Poza Rica fields, in the Tampico-Misantla Basin.

145 http://www.globalccsinstitute.com/insights/authors/rodolfo-lacy/2011/02/24/co2-capture-and-geologic-storage-demonstrative-project [Accessed September 14, 2013]

Figure 3-9. Costs of CCS + EOR* Operations in Mexico

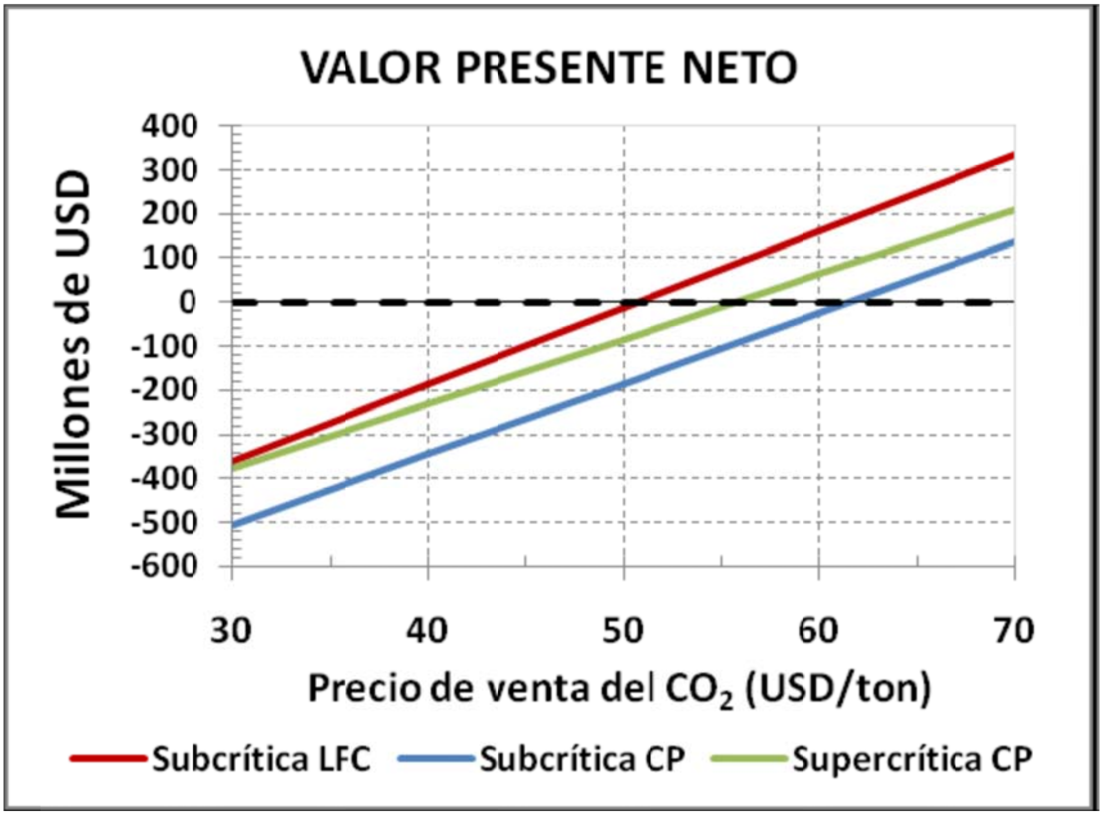
(USD/MWh)

	OPCIONES TECNOLÓGICAS				
	IGCC 150 MW	IGCC 300 MW	PCSC 300 MW	LECHO FLUIDIZADO 300 MW	NGCC 250MW
Costo nivelado de generación	177.40	155.81	159.51	134.60	110.06
Costo nivelado de transporte/compresión	22.92	10.54	10.32	11.03	6.06
Costo nivelado de inyección/almacenamiento	0.60	0.31	0.24	0.24	0.32
COSTO NIVELADO TOTAL	**200.92**	**166.66**	**170.07**	**145.87**	**116.44**
Recuperación mejorada de petróleo (**EOR**, por sus siglas en inglés)	97.50	97.50	101.10	115.20	50.40
COSTO NIVELADO TOTAL CON EOR*	**103.42**	**69.16**	**68.97**	**30.67**	**66.04**
Valor monetario de CO_2 capturado**	11.73	11.73	12.17	13.86	6.07
COSTO TOTAL NIVELADO CON EOR Y EXTERNALIDADES AMBIENTALES	**91.7**	**57.4**	**56.8**	**16.8**	**59.9**

Source: MEXICAN CCS+EOR DEMONSTRATION PROJECT: Environmental Impact and Risk Analysis Monitoring, presented by Rodolfo Lacy, Mario Molina Center, at the IIE-UNAM Workshop on CO_2 Geological Storage and EOR, March 2012

A decision was made to pursue the design and construction of a Pilot Plant for capturing CO_2 emissions for a plant added to a CFE facility in Poza Rica, Veracruz, in the Gulf of Mexico region. The initial plan is for the pilot plant to capture up to 8 tonnes of CO_2 per day. A sensibility analysis was performed to evaluate the sale price of CO_2 that could be realized, based on the investment in capture system as well as its operation, which would be economically viable. These preliminary studies indicated that the capture facility could be viable at a CO_2 selling price ranging from \$50 to \$60 per tonne (**Figure 3-10**).

Figure 3-10. Estimated Value of CO_2 for Viable Capture Facility Operations



Source: MEXICAN CCS+EOR DEMONSTRATION PROJECT: Environmental Impact and Risk Analysis Monitoring, presented by Rodolfo Lacy, Mario Molina Center, at the IIE-UNAM Workshop on CO_2 Geological Storage and EOR, March 2012

For purposes of performing the assessment of CO_2-EOR potential, reservoir properties for the Poza Rica field were assumed, as shown in **Table 3-2**. The economic assessment was performed assuming an oil price paid to the operator, at the wellhead, of $90 per barrel, and a delivered CO_2 cost, delivered to the field at sufficient pressure to achieve miscibility when injected into the oil reservoir, of $60 per tonne. Also assumed it that this offshore project is developed assuming a CO_2-EOR injection pattern spaced at 80 acres (0.32 square kilometers) per pattern. The project assumes that 29 existing production wells could be used for the CO_2-EOR project, with 86 new production wells and 94 new CO_2 injection wells drilled. This assessment assumes the project is developed over 10 years, and produces for over 40 years.

Table 3-2. Assumed Reservoir Properties for the Poza Rica Field Used in the Case Study Assessment of CO_2-EOR Potential

	Mexico (Poza Rica)
Reservoir Property	Value
Perm (md)	100
Porosity (%)	8
Dykstra Parsons	0.75
Oil Gravity	35
Oil Viscosity (cp)	1.0
Pattern Size	320
Reservoir Temperature (deg F)	150 (66 ^{o}C)
Residual Saturation	0.24
Gas Oil Ratio	180
Net Pay (feet)	200 (60 m)
Area (acres)	30,000 (121 km^2)
Depth (feet)	7,100 (2,164 m)
OOIP (MMB)	4,800
P/S Recovery (MMB)	1,200
Dip, degrees	0
No of producers	unknown
No of injectors	unknown
Oil formation vol. factor (B_o)	1.1
Connate Water Sat (%)	19
Current reservoir pressure (psia)	unknown

Based on this assessment, the project produces over 270 million barrels (36 million tonnes) of incremental oil due to CO_2-EOR and uses 220 million tonnes (almost 1,700 Bcf) of CO_2. At an oil price of $90 per barrel, and a CO_2 cost of $60 per tonne, the project achieves an IRR of 24%. These results of this analysis are illustrated in **Figure 3-11**.

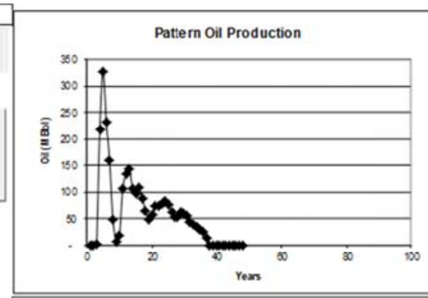
Figure 3-11. Economic Assessment of CO_2-EOR Potential for the Poza Rica Field Case Study Assessment

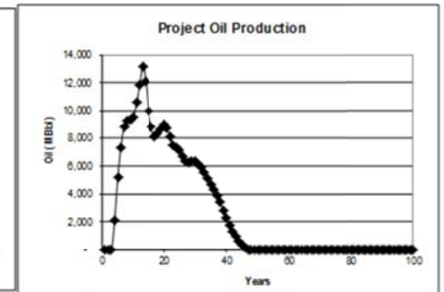
PozaRica	3.0	1	
Basin	TX 8		
Field	Poza Rica		
Formation	0		
Technology Case	Next Generation		
Depth (ft)	7,100		
Total OOIP (MMBls)	4,800.0		
Cumulative Recovery (MMbls)	-		
Primary EUR (MMbls)	-		
Miscibility	Miscible		
API Gravity	35.0		
Patterns	94		
Existing Injectors Used	0		
Convertible Producers Used	0		
New Injectors Drilled	94		
Existing Producers Used	29		
New Producers Drilled	86		
Spacing (Acres)	320		
Pattern Detail			
Cum Oil (Mbbl)	2,898		
Cum H2O (Mbw)	21,122	7.29	Bw/Bbl
Gross CO2 (MMcf)	44,372	15.31	McfBbl
Purchased CO2 (MMcf)	19,430	6.71	McfBbl
Recycled CO2 (MMcf)	24,942	8.61	McfBbl
	-	Tech Oil	
Field Detail	-	Tech CO2	
Cum Oil (MMbbl)	272.38		
% OOIP Recovered	5.7%		
Cum H2O (MMbw)	1,985		
Gross CO2 (MMcf)	4,170,996		
Purchased CO2 (MMcf)	1,683,289		
Recycled CO2 (MMcf)	2,487,707		
Payback Period (per pattern)	5	years	
Project Length	44	years	

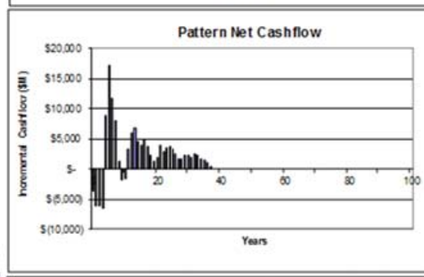
Print All Cashflow Summaries

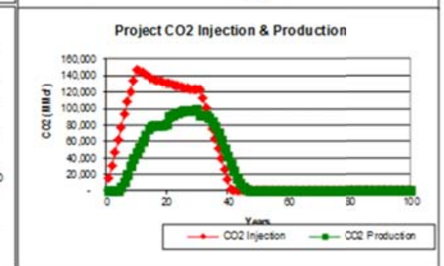
Pattern Detail			$/BBl
Total Net Revenue ($M)	$	191,725	
Total Capital Investment ($M)	$	(5,789)	$ 2.00
Total CO2 Cost ($M)	$	(69,077)	$ 23.84
Total O&M Costs ($M)	$	(16,001)	$ 5.52
	$	(90,867)	$ 31.36

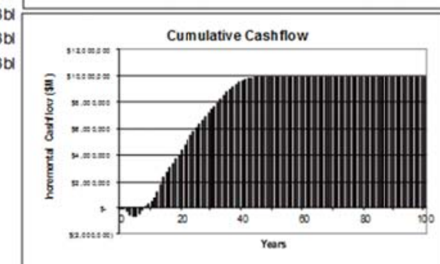
Pattern IRR (BTx)	25.5%
Project IRR (BTx)	24.2%

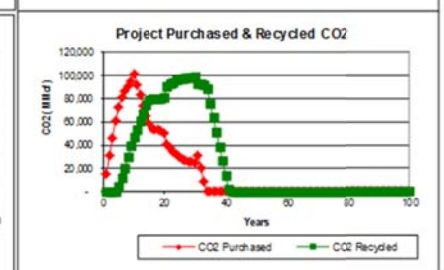


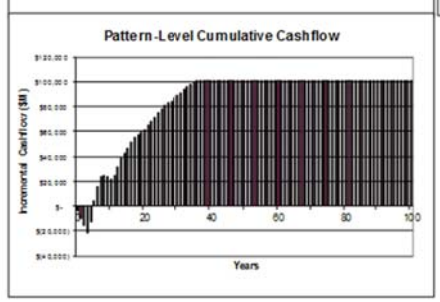












Assumptions:

Economic Case:		
Oil Price	$	90.00
CO2 Purchase Cost	$	3.17
CO2 Recycle Cost	$	0.30
Recycling Plant Cost	2 at Breakthru, 1/2 at Exceedan	
Well O&M	Injection Wells Only	
Minimum IRR	20.0%	
Next Gen Tech Case	0	

3.4 INTERPRETATION OF CASE STUDY RESULTS

The case study assessments presented are a high-level, first phase analyses based on average reservoir properties generally obtained or derived from publicly available data (except for the White Tiger example). In order to obtain a better understanding of the potential of these CO_2-EOR prospects, further efforts are required to acquire additional data and develop a better understanding of the each of the identified “best” prospects’ characteristics. This includes, to the extent practical, affordable, and achievable, the acquisition and assessment of better data on the exact location and layout of the prospect (including platform, roads, pipelines, existing facilities, etc.); ranges of key properties, such as depth, reservoir thickness, permeability, etc.; and, to the extent available, the geographic distribution of properties within each field/reservoir (for purposes of identifying a good site for CO_2-EOR pilot and/or project). For these “best prospects,” more detailed characterizations of CO_2-EOR /storage potential would then be developed based the better information.

In this more detailed assessment, the initial step will involve developing a detailed plan for conducting such a feasibility study, along with an estimate of the cost associated with such an assessment. This will involve a fairly rigorous characterization of what may be required to reduce uncertainty, and acquire more detailed, site-specific data at the location of a specific CO_2-EOR development. Additional data acquisition and development for this level of feasibility assessment could require the acquisition of more reliable data from well records, geophysical logs, seismic information, core reports and injection records and tests. Another key aspect is developing an understanding of the relative condition of surface and subsurface facilities and equipment (wellbore conditions, surface facilities, gathering and distribution systems, etc.)

Nonetheless, the results of these three case studies indicate that under a reasonable set of assumptions, relatively low costs of CO_2 capture and transport, the increased revenues resulting from oil production attributable to CO_2-EOR, and favorable regulatory regimes with regards to CO_2-EOR development, commercially viable CCUS-EOR projects can be realizable.

4. ASSESSMENT OF POLICY/REGULATORY FRAMEWORK FOR SELECTED APEC ECONOMIES

For this assessment, we build upon the previous efforts sponsored by APEC and others to review current activities regarding policy, legal, regulatory, and permitting aspects of CCS-EOR implementation in national administrations and international bodies.

4.1 NEED FOR CCUS REGULATORY REGIMES

CCS and CCUS regulatory regimes are needed for two primary reasons: (1) ensure public health and safety; and (2) prevent environmental damage, particularly damage to underground sources of drinking water. They are also needed to:

- Provide a mechanism for stakeholder engagement that addresses local concerns, potential community impacts, and allows for stakeholder participation during project development and implementation;
- Establish a level playing field for project developers and operators;
- Provide transparency that can support market confidence address financial assurance, and facilitate credit for CO_2 storage; and
- Address ownership, property rights, and liability considerations.

Over the past few years, there has been a considerable amount of activity worldwide on CCS regulatory framework development. (See, *The Carbon Capture and Storage Legal and Regulatory Review* published by the International Energy Agency for regular updates on CCS regulatory frameworks worldwide.) Specific CCUS regulatory regimes have been slower to develop, largely because utilization opportunities have been considered relatively limited in terms of CO_2 volumes and are mainly associated with CO_2-EOR operations, which are predominately located in the United States within the Permian Basin of West Texas. Like most emerging CCS regulatory regimes, CCUS regulations often fit within existing regulations (depending on the CO_2 use), and oil and gas regulations that include CO_2-EOR are most advanced.

Many CO_2-EOR sites are ideal for CO_2 storage because they have proven injectivity with known traps that have held hydrocarbons in place over geologic time. They are also located in areas with oil and gas infrastructure (e.g. pipelines, injection wells), a skilled workforce, and a general public that is accepting of local operations. Despite these advantages, the primary purpose of CO_2-EOR has been to maximize oil recovery; not reduce atmospheric CO_2 emissions. Therefore, additional consideration under a CCUS regulatory regime must be given to monitoring, verification and accounting (MVA) − also recognized as monitoring, reporting and verification (MRV) − to ensure that injected CO_2 remains safely confined in the subsurface for atmospheric emissions reductions and any related carbon credits.

All large CO_2-EOR projects are designed as closed loop systems to ensure the efficient use of CO_2 (the most expensive operational cost of an EOR project). Facilities are accustomed to measuring and monitoring CO_2 on a mass balance basis, which includes examining reservoir conditions (e.g. temperature, pressures,) during injection, production and CO_2 recycling. Over the life of an EOR project, essentially all of the injected CO_2 is stored in the reservoir. Any CO_2 losses to the EOR system are considered *de minimus* and may either occur at the surface processing systems or down hole within the target formation. Current data on CO_2 storage is generally not published as it involves proprietary contractual information on CO_2 purchase volumes. However, in the United States, the U.S. Environmental Protection Agency (U.S. EPA) is beginning to track CO_2 storage with CO_2-EOR as part of its Greenhouse Gas Reporting Rule (see discussion below).

Traditionally, when following regulatory policies for well abandonment and plugging, CO_2-EOR operators have not been required to monitor CO_2 during a post-closure period. When accounting for concurrent volumes of CO_2 stored, operators will need to go beyond business as usual for EOR operations and include additional operational and/or post-closure monitoring. This approach could build on existing regulatory structures already in place. The extent of a required MVA program to account for EOR with concurrent CO_2 storage (and any incremental storage after CO_2-EOR operations have ceased) may vary by jurisdiction, local geology, and reservoir conditions.

In the United States CO_2-EOR operations have to date been regulated as oil and gas operations under the existing Underground Injection Control (UIC) program, promulgated by the United States EPA under the Safe Drinking Water Act.146. The UIC program (administered by most states under primacy agreements with the EPA) has six categories of injection wells and associated regulations with the primary purpose to protect underground sources of drinking water. UIC Class II rules were designed for injections associated with oil and gas production, including CO_2-EOR (over 150,000 EOR wells have been permitted under this class). UIC Class VI rules (finalized in 2010) cover geologic CO_2 storage, and the EPA is in the process of publishing guidance documents for MVA implementation. There currently are no Class VI wells in operation, but two are in the permitting stage and North Dakota is seeking primacy for permitting Class VI wells.

As a complement to the UIC program, EPA's Greenhouse Gas Reporting Rule (FR V. 75 No. 230, December 1, 2010 at 75065) subparts RR and UU provides a framework for quantifying total CO_2 volumes. Under Subpart RR, geologic storage facilities (except for research and development projects that obtain an exemption) are required to report basic information on CO_2 received for injection (e.g. source and concentration, mass received, volumetric flow); develop and implement an EPA-approved site-specific MRV plan (Box), and annually report the amount of CO_2 stored using monitoring activities and a mass balance approach. Subpart UU is a less involved reporting requirement and governs all other facilities that inject CO_2 underground, including CO_2-EOR. Under

[146] http://water.epa.gov/type/groundwater/uic/regulations.cfm [Accessed September 14, 2013]

subpart UU, operators are only required to report basic information on CO_2 received for injection, which has been routinely measured as standard industry practice.

To date, no facilities have reported under Subpart RR. While EOR operators are only obligated to report under Subpart UU, should they seek credit for CO_2 storage, they may be required to comply with subpart RR or another regulatory path. It is likely that such a path would require MVA beyond business-as-usual in order to assure safe, long-term containment, address stakeholder concerns, and account for CO_2 storage.

It is important to point out that the UIC Class VI and Class II permits and subpart RR and UU have separate monitoring objectives. The UIC program focuses on demonstrating that underground sources of drinking water are not endangered as a result of CO_2 injection into the subsurface. The GHG Reporting program enables reporters to quantify the amount of CO_2 that is geologically stored. While complementary, in practice, these programs require further integration, coordination and inputs from field pilots and early commercial projects.

A number of CO_2-EOR projects with MVA research and testing should be considered when undertaking CCUS regulatory framework development (**Table 4-1**). A variety of technologies and methods have been field tested to optimize commercial MVA applications, evaluate protocols, demonstrate safe storage and assess economic feasibility. These various projects are also important to better understand how the risk profile for EOR sites differs from saline reservoir storage, and what type of MVA program is needed to address those risks. For example, CO_2-EOR sites generally have much more extensive geologic data and site characterization than saline reservoirs. CO_2-EOR operations also have primary and secondary production data with

Accounting for CCUS

The United States has the world's most active CO2-EOR industry, which has been dominated over the past 40 years by the Permian Basin in West Texas. EOR is also being deployed in the Rocky Mountain and Southwest regions, as well as the states of Wyoming and Michigan. These jurisdictions offer the leading CCUS regulatory frameworks.

As noted, the United States does not have a single comprehensive set of CCS / CCUS rules that would deem or certify a certain volume of CO_2 stored, and at the Federal level, two complementary programs (UIC and Greenhouse Gas Reporting Rule) must be coordinated and integrated. Under Subpart RR of the Greenhouse Gas Reporting Rule, geologic storage facilities (UIC Class VI) are required to: report basic information on CO_2 received for injection; develop and implement an EPA-approved site-specific MRV plan, and annually report the amount of CO_2 stored using monitoring activities and a mass balance approach. Specifically, MRV plans must:

- Delineate the maximum monitoring area (MMA) and active monitoring areas (AMA);
- Identify potential surface leakage pathways (including abandoned wells) and assess the likelihood, magnitude and timing of surface leakage of CO_2 through these pathways;
- Detail a strategy for surface leakage detection and surface baseline monitoring;
- Specify well identification number(s)
- List all units, operations, processes, and activities.

Facilities that conduct CO_2-EOR are not required to submit the above elements of an EPA-approved site-specific MRV plan unless the operator "opts-in" to Subpart RR reporting requirements. The primary reason for doing so would be to account for volumes of CO_2 stored; however, current incentives are insufficient for CO_2-EOR operators to overcome the additional cost and risk associated with implementation.

associated reservoir models, and build on existing regulatory structures. Therefore, the types of MVA requirements for CCUS with CO_2-EOR may vary on a more site-specific basis and across jurisdictions. **Table 4-1** summarizes selected CO_2-EOR field test projects that include an MVA component.

Table 4-1. Selected CO_2-EOR Field Test Projects that Include MVA

Project Name	Location	Operator	MVA Lead
Weyburn	Saskatchewan, Canada	Cenovus, Apache	Petroleum Technology Research Center
Hastings	Alvin, Texas	Denburry	Texas Bureau of Economic Geology; Denbury
West Pearl-Queen	New Mexico	Strata Production	Los Alamos National Lab; Sandia National Lab, NETL
Zama Acid Gas EOR, CO2 Storage and Monitoring Project	Alberta, Canada	Apache Canada	Energy & Environmental Research Center, PCOR
Cranfield	Adams County, Mississippi	Denbury	Texas BEG, SECARB
Bell Creek	Montana	Denbury	Energy & Environmental Research Center, PCOR
SACROC CO2 Injection Project	Snyder, Texas	Kinder Morgan	Texas BEG, SWP
Louden	Fayette, Illinois	Petco	Illinois State Geological Survey, MGSC
Aneth	Paradox Basin, Utah	Resolute Natural Resources Co.	SWP, Navajo Nation Oil & Gas Co

CCUS Model Regulations, Standards and Best Practices

Model CCS / CCUS regulations, standards and best practices often guide regulatory framework development and play an important role in gaining public and regulator confidence in the technology. The following highlights some key efforts that include a focus on CCUS with CO_2-EOR and offer guidance for those involved in CCUS including project developers, regulators, policymakers, financiers and the public

Model Regulations

In 2002, the Interstate Oil and Gas Compact Commission (IOGCC) of the United States established a Geological CO_2 Sequestration Task Force with diverse participation from IOGCC member states and several Canadian provinces, state and provincial oil and gas agencies, industry, state geological surveys, the federal government, and the U.S. Department of Energy's Regional Carbon Sequestration Partnership Program. Drawing from broad state regulatory experience and project expertise, the task force addressed the various technical, policy and regulatory issues associated with EOR and long-term CO_2 storage. In September 2007, the IOGCC issued its final report, "Storage of Carbon Dioxide in Geologic Structures, a Legal and Regulatory Guide for States and Provinces," which included a Model Statute for Geologic Storage of Carbon Dioxide. The model provides a summary of legal areas that need to be addressed to account for concurrent long-term CO_2 storage with EOR.

Standards

In June 2010, two Canadian organizations, the CSA Group (a standards firm) and the International Performance Assessment Centre for Geologic Storage of Carbon Dioxide (IPAC-CO_2) (an environmental NGO) launched a bilateral effort between Canada and the United States with over 30 industry experts, regulators, researchers and NGOs to develop a CCS standard (CSA Z741). This standard is primary applicable to saline reservoirs but it does not preclude its application to storage via CO_2-EOR. CSA Z741 provides recommendations for the development of management documents, community engagement, risk assessment, and risk communication. It also covers the project lifecycle including site screening, selection, characterization, operations, closure and post-injection; however, the standard does not specify post-closure requirements.

CSA Z741 provides the foundation for the development of an international CCS standard through the International Organization for Standardization (ISO). To undertake this work, ISO has established Technical Committee (TC) 265 and has engaged 26 economies and NGOs under five working groups: capture, transportation, storage, quantification and verification and cross-cutting issues. Release of the ISO CCS standards is expected in 2014.

While standards are not mandatory and do not have the force of law, regulators often refer to ISO standards as an example of good practice and in many cases, regulatory authorities will adopt them in part or in full.

Best Practices

Best practice manuals have been made available to support CCS / CCUS regulatory framework development and provide project developers with guidance. The following documents are primarily applicable to saline reservoir storage but also include information relevant to CCUS with CO_2-EOR.

- "Best Practices for Monitoring, Verification and Accounting of CO_2 Stored in Deep Geologic Formations – 2012 Update." Second Edition DOE/NETL-2012/1568, U.S. Department of Energy, National Energy Technology Laboratory (www.netl.doe.gov/technologies/carbon_seq/refshelf/MVA_document.pdf) [Accessed September 14, 2013]
- "GEO-SEQ Best Practices Manual: Geologic Carbon Dioxide Sequestration: Site Evaluation to Implementation" (2004) (www.escholarship.org/uc/item/27k6d70j.pdf) [Accessed September 14, 2013]
- "CCS Guidelines: Guidelines for Carbon Dioxide Capture, Transport, and Storage" (2008) (www.wri.org/publication/ccs-guidelines) [Accessed September 14, 2013]

4.2 FIVE KEY CHARACTERISTICS OF CCUS POLICY

CCS and CCUS regulation will share many similar elements but differ in certain key characteristics. (For a treatment of essential elements of a CCS regime in developing APEC economies, see C. Hart, P. Tomski, K. Coddington (2012) *Permitting Issues Related to Carbon Capture and Storage for Coal-Based Power Plant Projects in Developing APEC Economies: An Assessment of Essential Permitting Regimes for Nine APEC Economies,* Singapore: Asia-Pacific Economic Cooperation.) A primary reason for differentiating CCS and CCUS from a regulatory point of view is related to the type of application that utilizes CO_2. For each application, use of CO_2 can be expected to be subject to its own set of regulations. For certain applications, especially EOR, the usage regime could potentially complement or support a regulatory regime for CO_2 capture, transport and storage.

Five characteristics should be reflected in a CCUS-specific regulatory regime:

- Integration into pre-existing regulation governing use application;
- Safety and environmental integrity;
- Public outreach and consultation;
- Clear lead regulator and coordination among subsidiary regulatory agencies; and
- Efficient use of resources and protection of property rights.

4.2.1 Integration into Pre-Existing Regulation Governing Use Applications

CCUS regulation should be comprehensive, which has several aspects. Most importantly, regulation should cover all critical aspects of CCS and address threshold issues that must be resolved for any project to be considered. All laws that could potentially be relevant to CCS should also be included in the review process and amended appropriately.

Because CCUS emphasizes the use of CO_2 for an application that is already subject to regulation, the CCUS regulatory regime must be integrated with the pre-existing regulatory regime. The nature and extent of that integration will be determined by the comprehensiveness of the regulatory regime governing the application with respect to capture, transport, use and storage. For example, in the case of EOR, pre-existing oil and gas regulatory regimes in APEC oil producing economies generally provide guidance for the transport, use and injection of fluids in the subsurface. In this case, the integration of a CCUS regime can be closely integrated with, or even embedded in, oil and gas regulation. In contrast, regulation of CO_2 use in the food and beverage industry will not address the issues relating to transport and subsurface storage (presumably for excess CO_2) at the volumes required of a commercial-scale CCUS operation. Thus, to an extent, integration of CCUS regulation to pre-existing regulatory regimes will be sector specific. The table below presents a high-level representation of regulation for selected CCUS applications.

As suggested by **Table 4-2**, only EOR offers a regulatory framework that covers the full breadth of the four stages of CCUS. However, we note that a full CCUS regulatory regime would require much greater specificity than is currently provided by even the most detailed EOR regulatory regimes.

Table 4-2. Major Applications for CO_2 and Corresponding Regulatory Regimes

Application	Capture	Transport	Use	Storage
EOR	•	•	•	•
Food and Beverage	•		•	
Chemicals		•		
Metals and Manufacturing			•	

List of possible uses: http://www.co2gasplants.com/applications-co2.html

As suggested by the table, only CO_2-EOR offers a regulatory framework that covers the full breadth of the four stages of CCUS.

Moreover, CO_2-EOR as part of a CCUS strategy can provide a highly synergistic regulatory regime that can be highly efficient from both the viewpoint of regulators and industry. **Table 4-3** illustrates the synergies in CCUS-EOR in the United States.

4.2.2 Safety and Environmental Integrity

For both CCS and CCUS operations, safety and environmental integrity should be a priority of regulation. The foundation of CCUS regulation needs to be fact-based, scientific assessments, which helps ensure that decision-making concerning environmental safety is grounded on several technical factors. Site characterization and selection are critical steps in order to ensure environmental safety of a storage operation. As part of this step, multiple potential sites should be identified and pre-screened against agreed-upon criteria before proceeding to more in-depth and costly characterization. Consideration of multiple sites also reduces the risk that stakeholders/ project developers will become locked-in to a single site, which may prove to be unsound for technical, economic or public acceptance reasons.

Table 4-3: Comparison of Key Considerations for Storage in Saline Aquifers vs. the Application of CO_2-EOR

Type	Storage Only-Saline	EOR with Incremental Storage
Land	Greenfield	Brownfield-already impacted by oil industry operations
CO_2 Management	CO_2 injection only	CO_2 injection, production, recycle
Pressure Build-up Risk	Potential for large areas of pressure increase; large area of impact; pressure management may be needed	Pressure management if goal of EOR; lower areal footprint
CO_2 Trapping	Inferred trapping mechanisms	Demonstrated trapping
Solubility of CO_2 in Formation Fluid	CO_2 weakly soluble formation brine	High solubility of CO_2 in oil
Subsurface Information density	Few wells; sparse information	Many wells; subsurface well known
Mechanical Integrity/Risk of Well Failure	Few wells, carefully drilled, cased and cemented.	Many existing ells, some in unacceptable condition. Expensive to remedy: identify, and re-enter to plug/repair
Pore space access	Variable by state; evolving	Existing legal framework
Revenue to offset CO_2 capture cost	No	Yes
MVA	MVA must be based on comprehensive geologic assessment.	Existing reservoir production and surveillance knowledge contributes to development of MVA; integrity of existing wells in the field a principal leakage concern.
Public Acceptance	Unknown	Likely to be good. Public familiar/comfortable with oil production.

To ensure safety and environmental integrity objectives are met, all agencies that regulate aspects of CO_2 storage should be included in the development of regulation, have full access to information concerning CCUS research and demonstration projects, and coordinates their various regulatory roles. Cooperation among agencies in sharing information and participation in decisions concerning issues relevant to their jurisdiction is critical to the safe operation of a project and ultimately the success of the technology itself. A broad group of agencies have potential roles in regulating or facilitating CCUS including: regulators concerned with environment, health and safety; water; oil and gas; power generation, and science and technology, to name a few.

4.2.3 Public Outreach and Consultation

Public support for CCUS is essential for its successful adoption and diffusion, and is one of the threshold issues for individual project implementation. Gaining public support requires information sharing about the project as well as public engagement and consultation. The consultation process should be initiated early in a project's planning and involve an open dialogue with stakeholders broadly drawn from government, industry, expert organizations, civil society groups, such as NGOs, and most importantly, the local community in the project area.

The World Resources Institute (an environmental NGO based in the United States) and DOE/NETL have both developed guidance for community engagement for CO_2 storage projects.[147] Both emphasize on-going communication with the local communities and the public that begins at the early project development stage and continues throughout the entire life of the project. A public engagement program following these guidelines involves two-way interaction, and invites the public to provide input into project design and operation. By involving the public in a deliberative process, well-designed public engagement can contribute to improving the project and securing community support.

Most jurisdictions require environmental impact assessments (EIAs) to be conducted for projects that could potentially cause significant environmental impacts. Regulations governing the preparation of EIAs typically require public participation during the approval process (e.g., one or more public hearings concerning the project). The EIA process can be critical to assuring the social acceptance and environmental integrity of CCUS projects; however, a meaningful and effective public consultation process will involve more extensive public outreach than required for compliance with existing environmental and zoning laws.

The specific CO_2 use in a CCUS application will influence the appropriate extent of public consultation. CCUS projects that involve low volumes of CO_2 and no storage (e.g., beverage applications) would not require public consultation beyond anything required under an EIA. On the other hand, an EOR project designed to store large volumes of CO_2 should engage in substantial public consultation, taking into account the degree of public acceptance and understanding of similar practices in the area.

4.2.4 Identification of Lead Regulator and Coordination Among Subsidiary Regulatory Agencies

Streamlining regulation and improving coordination among regulatory agencies – without compromising safety or environmental integrity – is a critical aspect of best practices in any regulatory regime and can promote greater certainty for project developers, improve financing opportunities, and ultimately facilitate successful commercial deployment. Streamlining regulation has several aspects: competing jurisdiction, conflicting rules, and appropriate level of regulation.

The potential for different government agencies to exercise overlapping or competing jurisdiction has been recognized in the context of CCS and could also be an issue for a CCUS project that involves substantial storage, such as for EOR applications.

Several leading OECD jurisdictions have addressed the issue of competing jurisdiction in their own legislation governing CCS, which could apply to CCUS projects involving permanent storage. The Commonwealth of Australia issues licenses for offshore CCS activities through the Commonwealth Minister or in the National Offshore Petroleum Titles Administrator (NOPTA) and the National Offshore Petroleum Safety and

[147] World Resources Institute (2010), *CCS and Community Engagement: Guidelines for Community Engagement in Carbon Dioxide Capture, Transport, and Storage Projects*. Washington, D.C.: World Resources Institute; National Energy Technology Laboratory (2009) Public Outreach and Education for Carbon Storage Projects. Washington, D.C.: U.S. Department of Energy.

Environmental Management Authority (NOPSEMA). A number of jurisdictions follow a similar model where greenhouse gas storage regulatory responsibility is delegated to the same body that regulates oil and gas where such activities are likely to occur together. In addition to the Australian Commonwealth, this is the case in the Australian states of Victoria, Western Australia, South Australia, and the Canadian provinces of British Columbia and Alberta.

4.2.5 Efficient Use of Resources and Protection of Property Rights

CCUS regulation should ensure that natural resources are efficiently used and that property rights in those resources are protected. For CCUS projects involving EOR, this means the extraction of oil and gas is coordinated with CO_2 storage and preserves other resource opportunities (e.g., minerals, geothermal). One approach to accomplish this is to consider CO_2 storage rights together with mineral extraction rights under the same law, by the same regulator, or institutional arrangements for coordination among agencies.

The Australian Offshore Petroleum and Greenhouse Gas Storage Act provides an example of some of these practices. It contains procedures to facilitate petroleum exploitation and greenhouse gas storage in the same area and checks to ensure that new petroleum or storage titles do not adversely impact existing titleholders. It sets out detailed criteria to determine whether resources are adversely affected. If a proposed new petroleum exploration or exploitation or greenhouse gas storage operation significantly adversely impacts existing activities, the responsible Commonwealth Minister can deny a permit for the new activity, order suspension of activity or take other mitigation measures.[148]

4.3 OVERVIEW OF 10 APEC ECONOMIES FOR CCUS

This section provides a general overview of selected legal and regulatory issues associated with the capture, transport, use and storage phases of a CCUS project. (For additional information about permitting regimes that would be relevant to a CCUS project in the context of coal-fired power plant capture and storage, see C. Hart, P. Tomski, K. Coddington (2012) *Permitting Issues Related to Carbon Capture and Storage for Coal-Based Power Plant Projects in Developing APEC Economies: An Assessment of Essential Permitting Regimes for Nine APEC Economies,* Singapore: Asia-Pacific Economic Cooperation.)

4.3.1 Capture

At the capture stage, it must be determined under the law whether CO_2 is classified as a waste, pollutant, contaminant, hazardous or some other designation that could trigger reporting, special handling or treatment requirements, and/ or a more stringent liability regime. The composition of the CO_2 stream, which would otherwise be regulated at the point of emission, could be regulated at the point of capture as it is relevant to all

[148] Sections 25-29, 316, Commonwealth of Australia Offshore Petroleum and Greenhouse Gas Storage Act 2006

phases of capture, transport and storage. Similarly, health and safety requirements concerning equipment and the handling of gases under pressure (following compression) also would apply to all phases. Environmental laws applicable to the environmental impact of operating a power plant that will capture its CO_2, such as increase in fly ash or water usage, could trigger expanded environmental assessment requirements and would involve other environmental laws pertaining to discharge or disposal of substances onto land or water.

Regulations concerning capture could also include requirements for reporting greenhouse gas emissions and/or obligations to reduce emissions, requirements to build capture ready power plants or apply best available technology in order to reduce greenhouse gas emissions. If a facility is subject to an emissions cap, the release of CO_2 at a facility or any point during transport or storage could trigger liability under greenhouse gas regulations.

The capture portion of a CCUS project would require permits for the plant and could involve local planning authorizations. The expansion or retrofit of a plant to include a CCUS component could trigger regulatory requirements concerning the modification of a facility, which could result in imposition of more stringent environmental or other performance requirements.

4.3.2 Transport

The most cost-effective and safest way to transport CO_2 in significant volumes is by pipeline. CO_2 can also be transported by road (tanker truck), rail, or ship. Laws applicable to CO_2 transportation include those relating to handling gases under pressure, pipeline or vessel construction that considers pressure and possible corrosivity, health and safety, environmental laws, and general permitting and siting requirements. Oil and gas regulations also typically address these issues and can apply to a CCUS project that involves oil and gas operations or could provide a source for guidance. Regulation governing the composition of CO_2 is important in the transportation phase as water mixed with CO_2 forms carbonic acid that corrodes steel and other substances that could pose hazardous if released in the environment.

Regulatory issues concerning pipelines focus on pipeline construction and safety, and access and pricing. For pipeline transportation, construction and safety issues are essential. When pipeline infrastructure serves multiple users, access and pricing regulation becomes important.

Existing regulation concerning the safe operation of the selected mode of transportation should be reviewed for application to CO_2, and where necessary, supplementary regulation should be adopted if such issues are not adequately covered by existing law to ensure the safe transport of CO_2.

If laws imposing an emissions cap or CO_2 tax apply to the CO_2 being transported, the release of CO_2 during transportation could also trigger liability under greenhouse gas regulations.

4.3.3 Use

The use of CO_2 as part of a CCUS project will involve the regulatory regime for that particular use. For example, EOR, food and beverage, and chemicals applications will all involve regulations specific to that activity. CO_2-EOR regimes typically regulate the impacts on groundwater and environmental impacts. Food and beverage regulations are concerned with health and safety of food products. For CO_2 usage, this would require a certain purity of CO_2. Chemicals productions regulations are concerned with industrial safety (e.g., gases under pressure), as well as risk of a substance contained in a final product, which in the case of CO_2, would not pose a concern).

As we have discussed above, the use regime may in some cases complement the CCUS regulatory regime, as is the case in CO_2-EOR applications. For EOR, pre-existing oil and gas regulatory regimes provide guidance for the transport, use and injection of fluids in the subsurface.

4.3.4 Storage

The storage aspects of CCUS projects involve a broad range of issues that would be addressed under existing laws or require the adoption of additional regulation. Regulations should specify the obligations of the project developer at each stage of the project from exploration through injection to closure and post-closure.

Jurisdictions promoting adoption of CO_2 storage generally develop regulations and permitting regimes for site exploration and characterization, requirements concerning the demonstration of integrity of geologic containment structures, injection permission and operating requirements, well closure, corrective and remedial measures requirements, and monitoring, reporting and verification requirements. Standards for well construction, operation and closure requirements should be identified or established. Operating procedures would include environmental and worker health and safety requirements. Regulations should clearly identify obligations of the developer after an injection well has been closed, including responsibility for monitoring and remediation, provision of financial assurance, and any continuing liability. As part of the regulatory scheme, a mechanism for securing subsurface property rights could be helpful to facilitating projects, especially if existing laws on subsurface rights to pore space are not clear.

As suggested by the range of issues, various existing laws would apply to or inform requirements for the storage aspects of CCUS. These include environmental laws, health and safety laws, oil and gas laws, mining laws, permitting and zoning laws, tort laws, and property laws.

4.3.5 Liability for Stored CO_2

Legal responsibility for CCUS is a concern for industry and government stakeholders in each of the four study economies. In the context of a CCUS project, ordinary operating liability should be distinguished from long-term liability. Liability associated with daily operations, such as injection, has generally not been a significant barrier to projects. In contrast, liability associated with the long-term storage of CO_2 or for an extended period of time after injection operations have permanently ceased have been a concern to project developers.[149] Long-term responsibility for CO_2 injection involves the following types of potential liabilities:

- Long-term monitoring, remediation, and financial responsibility for storage sites
- Liability for leakage of CO_2 to atmosphere
- Liability for damage to property (induced seismicity, commingled resources)
- Liability for CO_2 migration (multiple users of reservoirs, boundary disputes, including transnational and international waters)
- Liability under environmental statutes (groundwater contamination, flora, fauna)

With respect to long-term liability, although there is no universally accepted solution, several jurisdictions that have pro-actively addressed this issue provide for a government authority to take title to, and release operators from liability for, CO_2 reservoirs after these operations have permanently ceased injection, the wells are properly closed and meet all regulatory requirements and a period of active monitoring or the storage site has been completed. The monitoring period is designed to ensure that the underground CO_2 plume has stabilized or is behaving in a predictable manner and the risks associated with the operation have diminished to a level deemed acceptable by the regulatory authority. Operators would generally remain liable for leakage caused by their own negligence or intentional misconduct.[150] This has been the approach followed by Canada's province of Alberta, the European Union, and several United States' states that have elected to accept liability for CO_2 injection for storage.

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[149] See C. Hart, "Putting It All Together: The Real World of Fully Integrated CCS Projects." Discussion Paper 2011-06, Cambridge, Mass.: Belfer Center for Science and International Affairs, June 2011.

[150] See, e.g., Interstate Oil and Gas Compact Commission Task Force on Carbon Capture and Geologic Storage, Storage of Carbon Dioxide in Geologic Structures: A Legal and Regulatory Guide for States and Provinces (September 25, 2007) *available at* http://www.southwestcarbonpartnership.org/_resources/pdf/2008-co2-storage-legal-and-regulatory-guide-for-states-full-report.pdf. [Accessed September 14, 2013]

4.4 STATUS OF CCUS REGULATION IN SELECTED DEVELOPING APEC ECONOMIES

None of the developing economies surveyed in this study currently regulate any aspect of CCUS (e.g., CO_2 capture, transport, injection or storage).[151] While none of these study economies currently regulate CCUS, all possess laws that could apply to CCUS, be adapted, or provide a model for new regulation. The **Table 4-4** indicates the status of law and regulation for eight key CCUS issues in each economy included in this study except for Brunei Darussalam. For additional information about the development of law in the ten economies surveyed here, see C. Hart, P. Tomski, K. Coddington (2012) *Permitting Issues Related to Carbon Capture and Storage for Coal-Based Power Plant Projects in Developing APEC Economies: An Assessment of Essential Permitting Regimes for Nine APEC Economies,* Singapore: Asia-Pacific Economic Cooperation.

4.5 CCUS AND CARBON CREDITS

There are a number of carbon market systems in various stages of development, implementation or operation throughout the world; however, only a few include carbon credits for CCS/CCUS.

4.5.1 CCS / CCUS in the CDM

In 2011, CCS was formally included in the Clean Development Mechanism (CDM) under the United Nations Framework Convention on Climate Change (UNFCCC), providing a pathway for developing economies to secure a funding mechanism for CCS and develop regulatory frameworks that are consistent with international regulatory best practices. CCS projects that use approved methodologies and receive CDM Executive Board approval are able to generate Certified Emission Reduction (CER) units.

The UNFCCC decision that included CCS in the CDM was silent on the issue of whether CCUS would qualify. We believe it would be provided it can meet CDM methodologies for CCS and pass the additionality test required of all CDM projects. A CDM project activity is “additional” (i.e., meets the “additionality” test) if anthropogenic emissions of greenhouse gases by sources are reduced below those that would have occurred in the absence of the registered CDM project activity. It is this latter issue relating to additionality that is likely to be determinative to whether specific CCS or CCUS projects qualify for CDM treatment.

[151] The only possible exception to this is the Republic of Korea, where the Ministry of Land, Transport and Maritime Affairs has issued a ministerial order to allow offshore (subsea) CO_2 storage subject to the development of standards and other requirements.

Table 4.4 Eight Key Issues in Selected APEC Economies

	China	Indonesia	Malaysia	Mexico
Classification of CO_2	Not specified. Environmental laws contain definitions that could be used to classify CO_2 as pollutant or waste.	Not classified. Environmental Law contains definitions of "hazardous and toxic waste" that could categorize CO_2 as waste	Not classified. Environmental Quality Act contains definitions for "pollution" and "pollutants" that could potentially apply to CO_2.	Not classified. General Law of Ecological Equilibrium and Environmental Protection (LGEEPA) defines "waste" broadly that could potentially apply to CO_2.
Jurisdiction over Pipelines and Reservoirs	State Council, National Development and Reform Commission, Ministry of Environmental Protection, Ministry of Land Resources	State Oil Company, with oversight from Ministry of Environment and DG Migas.	State, delegated to Petronas.	Secretariat of Energy (SENER), Secretariat of Environment and Natural Resources (SEMARNAT)
Pore Space Ownership	State	State	Federal government, delegated to Petronas for oil-bearing reservoirs. Individual states generally have authority over onshore surface.	State
Regulatory regime related to storage and transportation	Law on the Protection of the Oil and Natural Gas Pipelines could be adapted for CO_2 or serve as a model.	Oil and gas and environmental laws	Petronas Production Management Unit and Ministry of Natural Resources and Environment (MNRE)'s Department of Environment would likely have jurisdiction.	General Law for Prevention and Integral Waste Management provides for injection of substances in underground geologic formations. If applied to CO_2, transport, storage or reuse would require license from SEMARNAT ad use of best practices and technology.
Long-term Management & Liabilities	Civil Law and environmental laws require compensation and remediation for damage to land.	Various polluter pays statutes	Civil law and environmental laws impose liability for damage and require remediation.	Civil Code, LGEEPA and other environmental laws provide for general civil liability for causing damage to the environment.
Financial Assurance for Long-term Stewardship	Law on the Prevention and Control of Atmospheric Pollution provides a system of collecting fees for discharge of pollutants, which could serve as possible model.	Oil and gas regulation and production sharing contracts require operators to reserve funds for decommissioning. Environmental law requires guarantee funds to protect the environment.	National Environment Fund could serve as model for liability fund. Fund defrays costs of monitoring and remediation, partly funded by fees collected from industry.	If CO_2 were treated as a "pollutant" under General Law for Prevention and Integral Waste Management, storage operators required to provide guarantees and remain liable for the site a minimum of 20 years after site closure for dangerous substances.
Third Party Access Rights to Pipelines	Not specified.	Production sharing contracts contain provisions. DG Migas resolves disputes.	Petronas Carigali owns all upstream oil and gas pipelines.	PEMEX owns, operates and regulates all oil and gas pipelines. SEMARNAT and the Ministry of Transportation and Communications regulate pipelines that transport dangerous and toxic substances.
Regulatory Compliance & Enforcement Scheme	Mineral Resources Law and various environmental protection laws	Ministry of Energy and Mineral Resources' DG Migas and Ministry of Environment	Petronas is responsible for planning, investment and regulation of all up-stream oil and gas activities. MNRE's Department of Environment regulate environmental compliance.	SEMARNAT and SENER. For oil and gas operations, PEMEX would have operational and certain regulatory responsibility.
Public Participation	Law of the People's Republic of China on the Environmental Impact Assessment calls for public participation in "appropriate ways." It requires projects that could have an adverse environmental impact to seek the opinion of the public.	Environmental Impact Assessment, pro-community provisions in production sharing contracts, customary law	MNRE issues guidelines for conducting EIAs. While not strictly requiring public hearings, guidelines describe the purpose of scoping the Environmental Impact Assessment to include understanding public opinion.	LGEEPA provide certain rights to the public to participate in the EIA review process. The Federal Transparency Law requires federal agencies to provide public access to information.

	Peru	Thailand	Viet Nam
Classification of CO_2	Not classified.	Not classified. National Environmental Protection and Promotion Act, contains definitions of “pollutant” and “waste” which could potentially apply, as well as Hazardous Substances Act.	Not classified. Law on Environmental Protection and Law on Water Resources, define “Waste” and “Pollution of Water Resources” that could potentially apply to CO_2.
Jurisdiction over Pipelines and Reservoirs	The Ministry of Energy and Mines regulates upstream and downstream oil and gas pipelines in Peru. OSINGERMIN has jurisdiction over rates for pipeline transport.	State Oil Company, with oversight from Ministry of Energy’s Department of Mineral Fuels and Mineral of Natural Resources and Environment.	State Oil Company, with oversight from Ministry of Natural Resources and Environment and Ministry of Industry and Trade.
Pore Space Ownership	State	State	State
Regulatory regime related to storage and transportation	Organic Law for Hydrocarbons and the Organic Law for Environmental Protection contain provisions relevant to carbon dioxide storage and transportation.	Oil and gas and environmental laws	Oil and gas and environmental laws
Long-term Management & Liabilities	Civil Code, Organic Law for Environmental Protection and Organic Law for Hydrocarbons provide for general civil liability for causing damage to the environment.	Various polluter pays statutes	Various polluter pays statutes
Financial Assurance for Long-term Stewardship	Oil and gas contracts could specify long-term stewardship obligations.	Environment Fund could serve as model for financial assurance mechanism.	Well decommissioning requirements and Oil and Gas Prospecting and Exploration Fund could provide a model for financial assurance mechanism.
Third Party Access Rights to Pipelines	PetroPeru owns Peru’s pipelines. OSINGERMIN has jurisdiction over rates for pipeline transport.	Energy Regulatory Commission regulates downstream gas pipelines. Oil and gas concession agreements contain provisions	Ministry of Industry and Trade regulates pipelines.
Regulatory Compliance & Enforcement Scheme	Organic Law for Hydrocarbons and the Organic Law for Environmental Protection.	Department of Mineral Fuels and Various Environmental Protection Laws	Ministry of Industry and Trade and Ministry of Natural Resources and Environment
Public Participation	Peru’s Constitution ensures rights to information and participation, and environmental laws require holding local hearings as part of the EIA process that include civil society and the local government, and reporting proceedings as part of the final EIA.	Constitutional protections and Environmental Impact Assessment	Public “right to know” laws and Environmental Impact Assessment

CDM modalities require that the host economy where a CCS project is located possess laws and regulations that govern:

- Licensing criteria for site selection, characterization and development;
- Rights to store CO_2 in subsurface formations and obtain site access;
- Redress for adversely affected parties cause by the project;
- Remedial measures to stop and control any CO_2 seepage and restore storage site integrity; and
- Liability mechanisms for environmental and other damages.

Before submitting a validation report to the CDM Executive Board for approval of the project, the Designed Operational Entity (DOE) must assess the fulfillment of the participation requirements of the host Party together with the completion of site characterization and selection; safety and risk assessment (unique to CCS projects), and environmental and socio-economic impact assessments. The DOE must also verify that liability and financial provisions have been put into place, and that monitoring provisions have been established. Finally, the national authority of the host party must confirm in writing to the operational entity:

1. The right to store CO_2 and the access to the storage site have been conferred;
2. Financial provision has been given and allocation of liability and transfer accepted (the decision implicitly considers transfer is not possible earlier than 20 years after the end of the crediting period); and
3. Whether or not the host party also accepts the obligation to address a net reversal of storage.

The CCS modalities and procedures clarify the concept of 'project boundary', which was one of the pending issues on the eligibility of CCS within the CDM. The project boundary of a CCS project activity is broad and includes the capture installation; any treatment facility; transport equipment; reception facility at the injection site; the storage site and all "vertical and lateral limits of the carbon dioxide geological storage site that are expected when the carbon dioxide plume stabilizes over the long term during the closure phase and the post-closure phase" (paragraph 12 and 13 of the Decision).

In 2005 (prior to the adoption of CCS into CDM), the White Tiger Oil Field Carbon Capture and Storage Project in Viet Nam submitted a project design document to the CDM Executive Board for consideration (as described in Section 3). The project was expected to reduce CO_2 emissions by approximately 7.7 million tonnes per year over a period of eight years. Although the project did not receive registration, it represents the only CO_2-EOR project submitted under the CDM and remains the most advanced CCUS proposal.

Despite inclusion of CCS in the CDM, a crucial question concerns the value and use of credits produced by CCS under the CDM. Carbon credits from the CDM have been trading at historical lows, with Certified Emission Reductions (CERs) below €1 per tonne CO_2-equivalent in 2013. Without a more robust price on carbon, project activity will not be economic.

Current low prices are largely the result of supply and demand relationships with the European Union Emissions Trading Scheme (EU ETS), the world's largest market for carbon emissions credits, accounting for approximately 85% of all emissions trading. The EU ETS is also the single most important market for CDM projects, thus it sets the price for CERs.

The low price of CDM CERs is strongly influenced by the fact that regulated emitters under the EU ETS and EU Member States under the Effort Sharing Decision are both reaching the limit of the use of CERs under current policy. Without a change in policy (e.g., an increase in the EU remissions reduction target or an increase in CER limits, demand for CERs will continue to diminish and is expected to disappear entirely within the EU ETS by 2015. Thus, without a change in market fundamentals that deliver a robust price on carbon, CDM offsets would not likely enhance the economics of a CCUS project.

4.5.2. Voluntary Carbon Markets and CCUS

In the absence of government-mandated emissions reduction targets, some companies have embarked on a pre-compliance and risk management strategy that anticipates future carbon regulation. In this case, companies voluntarily reduce their emissions profile and may seek to purchase carbon credits as a way to achieve that goal. While there are a number of voluntary carbon market standards/registries, the American Carbon Registry (ACR) is the only one that has developed a CCUS methodology (authored by Blue Strategies), which is also aligned with CARB offset protocol requirements under California's cap-and-trade program (AB32).

The objective of the CCUS methodology under ACR is to monetize carbon credits from commercial CCUS project, which specifies anthropogenic CO_2 that is transported via pipeline and stored specifically during EOR operations. The methodology uses the accounting framework detailed in *the Greenhouse Gas Accounting Framework for Carbon Capture and Storage Projects*, a multi-stakeholder process led by the Center for Climate and Energy Solutions (C2ES), for which both ACR and Blue Strategies served as workgroup participants. Projects using this methodology must comply with all requirements of the ACR Standard, submit a GHG Project Plan for certification by ACR, and secure independent validation and verification by an ACR-approved third-party Validation/Verification Body.

Blue Strategies contracted with ACR to initiate the methodology approval process, which included a public comment period and scientific peer review process. The methodology is currently available through ACR for use by project proponents.

5. KEY ISSUES AND BARRIERS FOR CCUS-EOR

In this section of the report, the objective was to evaluate and combine the elements that are likely to be critical to developing APEC economies for accelerating the deployment of CCUS-EOR projects. In the previous section, elements of CCUS-EOR permitting frameworks were identified that are likely to require particular attention by relevant authorities in the developing APEC economies. In the following, an overview of the issues and barriers affecting CCS deployment are identified. After that, recommendations are presented on how best to address these issues within APEC economies. This includes recommendations for cost-effective capacity-building activities as well as other follow-on activities to promote CCUS-EOR deployment in APEC economies.

5.1 Issues and Barriers

A significant body of research already exists on the barriers and challenges to CCS, CCUS deployment, in APEC economies and globally, including work by APEC, so the effort here will seek to avoid duplicating this.[152]

In general, this research concludes that:

- Deployment of CCS must accelerate to achieve the necessary level of greenhouse gas emissions reduction necessary to impact global warming trends.

- CCS offers the opportunity to balance economic growth and emissions reductions in developing economies that have existing hydrocarbon resource endowments, like the APEC economies which are the focus of this report.

- The costs of CCS given current technology make commercial deployment challenging. Issues to address to create a pathway to make CCS commercially viable include addressing technical issues of integration and scale-up, legal and regulatory requirements to reduce investor risk, policies to create market drivers and mitigate economic impacts, including increases in electricity prices, and financing mechanisms to facilitate investment in the technology.

- The revenues from additional oil production from CO_2-EOR, pursued in combination with CCS, can help to offset these high costs. This can be even

[152] See, for example, Asian Development Bank, *Carbon Dioxide Capture and Storage Demonstration in Developing Countries: Analysis of Key Policy Issues and Barriers*, ADB TA 7278-REG, Final Report, April 2011; Asian Development Bank and the Global CCS Institute, *Prospects for Carbon Capture and Storage in Southeast Asia: Executive Summary of a Regional Analysis*, November 2012; Best, Dennis and Ellina Levina, International Energy Agency, *Facing China's Coal Future: Prospects and Challenges for Carbon Capture and Storage*, 2012; Kulichenko, Natalia and Eleanor Ereira, World Bank Group, *Carbon Capture and Storage in Development Countries: a Perspective on Barriers to Deployment* , Energy and Mining Sector Board Discussion Paper No. 25, June 2011; Asian Pacific Economic Cooperation, *Increasing the Knowledge and Awareness of Carbon Capture and Storage: Capacity-Building in the APEC Region (Phase V)*, September 2012 (APEC#212-RE-01.9); Asian Pacific Economic Cooperation, *Permitting Issues Related to Carbon Capture and Storage for Coal-Based Power Plant Projects in Developing APEC Economies*, September 2012 (APEC#212-RE-01.7); Maver, Marko, "Barriers to Carbon Capture and Storage," *EHS Journal*, July 22, 2012

further enhanced by pairing prospects amenable to CO_2-EOR with low-cost sources of CO_2, such as natural gas processing facilities.

- Commercial scale CCS, with or without CO_2-EOR, requires an enabling regulatory environment which currently does not exist, but is evolving, in most APEC economies. However, such a necessary regulatory environment can evolve from existing regulations, which can be even more effectively facilitated by combining CCS with CO_2-EOR. These regulatory frameworks are essential for addressing legitimate environmental concerns, as well to facilitate access to concessional and climate finance, reduce investor risk and create market drivers to leverage all available sources of domestic and international support.

- Moreover, in developing APEC economies and other developing economies, broader CCS deployment is contingent upon the availability and accessibility of a mix of sources of finance from public funds and/or carbon market mechanisms, as well as concessional financing sources that can be deployed.

- Effective public communication and engagement processes are essential to support CCS deployment.

- Accelerated deployment of demonstration CCS projects in the near term is essential.

Like many emerging technologies, CCS faces barriers which discourage new projects from emerging and prevent existing projects from progressing. Funding for CCS demonstration projects, while still considerable, is increasingly vulnerable and seems to be declining. Most CCS projects still require strong government support to go forward. CCS is also often not treated equivalently to other low-carbon technologies in policy settings and government support. In order to achieve emission reductions in the most efficient and effective way, governments should ensure that CCS is not disadvantaged.

5.2 Addressing these Issues within APEC Economies

Storage site selection and characterization is a lengthy and costly process. This, in itself, is limiting new projects from entering into an initial project stage. Most projects currently being pursued exist in just a few economies (USA, Canada, China, Australia, North Sea), of which only China is part of the APEC economy group that is the focus of this study.

Barriers to CCS deployment are amplified in developing APEC economies, and are complicated by additional issues related to energy security, price of electricity, and limited capacity to plan and implement complex, risky large-scale demonstration projects. Moreover, CCS is generally seen as a greenhouse gas mitigation technology that should be led by developed economies.

Financial support from developed economy governments to CCS and CCUS demonstration projects in developing economies, including APEC economies, is contingent on making the results accessible, so that industry, governments, and the public can develop a better understanding of the economic and environmental performance, knowledge can be developed, capacity building can be facilitated, and public engagement pursued. This involves a level of transparency that many APEC economies have traditionally avoided. To take the next steps for facilitate CCUS-EOR demonstration projects to be pursued will likely require increased levels of transparency to move forward.

5.3 Recommendations for Cost-Effective Capacity Building

While specific needs may vary by APEC economy, the CSLF's Capacity Building Program has identified four basic tasks that most economies will require to implement CCUS:[153]

- Identifying, characterizing and matching CO_2 sources to potential reservoirs
- Analyzing and formulating policy and legal/regulatory frameworks
- Conducting pre‑feasibility, feasibility and regulatory studies to evaluate and support decisions about proposed projects
- Implementing projects through planning, financing, construction, operation and monitoring.

Under support from APEC, ADB, World Bank, Global CCS Institute, and other international fora, much of the work under the first two items in the CSLF list are already underway in most APEC economies, with this report contributing somewhat. Moreover, substantial progress has been made in some APEC economies on the third item in the CSLF list, though certainly not in all. Finally, work remains to be done in all CSLF economies on the fourth item in the list with the possible exception of China, which is at least initiating development of a number of large scale integrated demonstration projects.

Therefore, going forward, capacity building for APEC economies needs to shift from a focus just on source-sink matching and assessment of regulatory frameworks to emphasis on the deployment of real projects. Where they have not yet been conducted, capacity building needs to support the steps required for conducting pre-feasibility and feasibility studies, and assessing the applicability, limitations, and necessary modifications of regulatory frameworks as applied to actual proposed projects. In addition, these capacity building activities should also address what would be required for implementation of CCUS-EOR projects through planning, financing, construction, operation and monitoring.

[153] http://www.cslforum.org/publications/documents/cslf_infocus_whatiscapacity_building.pdf [Accessed September 14, 2013]

Because of the potential need to accelerate deployment of CCUS-EOR demonstration projects, capacity building activities would be most valuable if they were conducted concurrently with the pursuit of these demonstration projects, not sequentially.

In conclusion, this report shows that substantial potential exists for incremental oil production from the deployment of CO_2-EOR in combination with CO_2 storage in these developing APEC economies. In the APEC economies assessed, government support for pursuing greenhouse gas strategies gas exists, some consideration of opportunities for CO_2-EOR has taken place, regulatory frameworks can be adapted to accommodate the unique requirements of CCS, and as many as 27 prospects for CCUS-EOR demonstration projects have been identified, a few of which were examined in some detail and shown via a simplified analysis to be potentially economically viable. Thus, with the right incentives, government support, financing, and public commitment, CCUS-EOR can be a cost-effective mechanism for addressing concerns of global climate change in developing APEC economies.

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Prepared By:
Advanced Resources International, Inc.
4501 Fairfax Drive, Suite 910, Arlington, VA 22203 USA
Tel: (703) 528-8420 Fax: (703) 528.0439
Email: vkuuskraa@adv-res.com Website: www.adv-res.com

Produced for
Asia-Pacific Economic Cooperation Secretariat
35 Heng Mui Keng Terrace Singapore 119616
Tel: (65) 6891-960 Fax: (65) 6891-9690
Email: info@apec.org Website: www.apec.org

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