# OFFSHORE THERMAL POWER WITH CCS: AN ALTERNATIVE TO $CO_2$ TRANSPORTATION

Björn Windén
Mingsheng Chen
Naoya Okamoto
Do Kyun Kim
Elizabeth McCaig

Southampton 2011

Titles in this series:

**Carbon Capture and Storage in Deep Ocean Space for the 21st Century: Guidelines for Implementation in China**
Elizabeth Livermont, YongJie Koh, Mahesa Bhawanin, Taurai Mlambo & BinBin Zhao
ISBN 978-0-854-32927-4

**Offshore Thermal Power with CCS: An Alternative to CO2 Transportation**
Björn Windén, Mingsheng Chen, Naoya Okamoto, Do Kyun Kim & Elizabeth McCaig
ISBN 978-0-854-32928-1

**The Key to Successful Carbon Capture and Storage: Engaging the Public**
Ning Cheng, Mirjam Fürth, Michael Charles Johnson & Zhi Yung Tay
ISBN 978-0-854-32929-8

**Offshore Renewable Energy Powered CO2 Injection: A Small Carbon Footprint Solution**
Aichun Feng, Taeyoung Kim, Xiaojun Li, Zeeshan Riaz & Justin Wee
ISBN 978-0-854-32930-4

University of Southampton
Highfield, Southampton
SO17 1BJ, England



First published 2011

**British Library Cataloguing in Publication Data**
A catalogue entry for this title is available from the British Library

**ISBN 978-0-854-32928-1**

Printed in Great Britain by Henry Ling Ltd, at the Dorset Press,
Dorchester, Dorset

## FOREWORD

The Lloyd's Register Educational Trust (The LRET) in collaboration with the University of Southampton instituted a research collegium in Advanced Ship and Maritime Systems Design in Southampton between 11 July and 2 September 2011.

The LRET is an independent charity that was established in 2004. Its principal purpose is to support advances in transportation, science, engineering and technology education, training and research worldwide for the benefit of all. It also funds work that enhances the safety of life and property at sea, on land and in the air. The LRET focuses on four categories:

- **Pre-university education:** through appropriate organisations (but not individual schools), promotes careers in science, engineering and technology to young people, their parents and teachers.
- **University education**: provides funding for undergraduate and post-graduate scholarships and awards at selected universities and colleges (does not fund students directly).
- **Vocational training and professional development:** supports professional institutions, educational and training establishments working with people of all ages.
- **Research:** funds existing or new centres of excellence at institutes and universities.

This year's collegium has focused on The LRET's research-led education agenda. Successful ship and maritime systems design depends on the collaborative application of a broad range of engineering competences as the drive for improved efficiency and environmental performance places greater demand on the design community. This aspect needs to be reflected in the education of naval architects, marine engineers and others who are the active contributors to the ship design processes.

The aim of the research collegium has been to provide an environment where young people in their formative post-graduate years can learn and work in a small, mixed discipline group drawn from the maritime community to develop their skills whilst completing a project in advanced maritime systems design. The project brief that initiates each project set challenging user requirements to encourage each team to develop an imaginative solution, using individual knowledge and experience, together with learning derived from teaching to form a common element of the early part of the programme.

The collegium format provided adequate time for the participants to enhance their knowledge through a structured programme of taught modules which focussed on the design process, advanced technologies, emerging technologies and novel marine solutions, regulatory and commercial issues, design challenges (such as environmental performance and climate change mitigation and adaptation) and engineering systems integration. Lecturers were drawn from academic research and industry communities to provide a mind-broadening opportunity for participants, whatever their original specialisation.

The subject of the 2011 collegium has been systems underpinning carbon capture and sequestration (CCS) in ocean space. The 19 scholars attending the 2011 collegium were teamed into four groups. The project brief included: (a) quantification of the environmental challenge; (b) understanding of the geo-political legal-social context; (c) possible techniques for sequestration; (d) one engineering system to achieve carbon storage in ocean space; (e) economics and logistics challenges. While all the groups addressed the items (a) to (c), each team focused on just one engineering system in dealing with items (d) and (e). This volume presents the findings of one of the four groups.

Mr. Michael Franklin (The LRET) and Professors Ajit Shenoi and Philip Wilson (University of Southampton)

Southampton 2 September 2011

## PREFACE

One of the most important issues facing our generation is that of climate change. As the world's demand for energy increases so do our carbon dioxide emissions. It is therefore vital that something be done to reduce the concentration of these emissions in the atmosphere. One such method is to capture the carbon dioxide and sequester it.

This book was written as an output of the 2011 LRET Collegium on Carbon Capture and Sequestration in Ocean space. We, the authors, came to participate in this collegium without any prior expertise or predefined opinions about the subject. A total of four books were written, of which this is one, each with an individual viewpoint on the subject matter. It has been an inspiring challenge for us to complete this book, ready for printing, in little over six weeks.

We would therefore like to stress that this publication should be seen as an example of what can be achieved by encouraging cooperation between institutions and by thinking outside of the box. Furthermore, based on the conclusions of this book we would strongly encourage further studies and detailed analysis of the subject.

One of the purposes of the collegium was to encourage interaction between different professions and cultures. Even though all five of the authors of this book are engineers from an offshore/naval architecture background, we appreciate the opportunity to broaden our horizons. We have done this both in terms of communicating with other groups who had more diverse backgrounds but also by researching subjects such as law, social studies and economics ourselves.

Finally, we hope that our contribution to the subject of CCS and the climate change debate will inspire others to pursue research in the same spirit that has been present in this collegium by considering large scale engineering problems in a more holistic way.

**ACKNOWLEDGEMENTS**

We would like to thank all of the people, who without help and input from, this book would not have been possible. First and foremost, we would like to thank Mr Michael Franklin of the LRET for allowing us to pursue this venture. Without the support of The LRET, and Michael in particular, this kind of event would have never come to pass. Equally we would like to thank the collegium secretary Ms Aparna Subaiah-Varma for providing us with all the background support in terms of accommodation, travel, meals and recreational trips. Without Aparna's dedicated arrangement of these things we wouldn't have enjoyed the pleasant time in Southampton that we can now look back at for years to come.

Secondly, we would like to thank our mentors at the University of Southampton, Professors Ajit Shenoi and Philip Wilson for constantly driving our projects forward with suggestions, constructive criticism and encouragement. We would also like to thank everyone who gave us inspiring presentations to fuel our thoughts. Even though we are equally thankful to all of those who came, we would like to especially thank Mr Simon Reeve and Mr Magnus Melin for giving us a very useful overview of CCS in the initial stages which has followed us throughout the process. We would also like to thank our supervisors, Professor Jeom Kee Paik, Professor Stephen Turnock, Professor Choo Yoo Sang, Professor Makoto Arai and Mrs Jackie Johnson, for giving us the opportunity to attend.

Last but not least we would like to thank our fellow scholars of the collegium for all of the discussions we have enjoyed, on and off topic.

**CONTENTS**

PREFACE ........ V

ACKNOWLEDGEMENTS ........ VI

INTRODUCTION ........ 1

1. THE CARBON CAPTURE & STORAGE SYSTEM ........ 3
   1.1 CCS Technology ........ 3
      1.1.1 Carbon Capture ........ 3
      1.1.2 Transport of $CO_2$ ........ 9
      1.1.3 $CO_2$ Storage ........ 12
      1.1.4 Interface between CCS systems ........ 17
   1.2 Other Considerations ........ 20
      1.2.1 Stakeholders ........ 20
      1.2.2 Public Perception ........ 21
      1.2.3 Government Policy ........ 23
      1.2.4 Legal Issues ........ 28
   1.3 Existing CCS projects ........ 29
   1.4 Potential Ideas for the Use of CCS ........ 33
      1.4.1 Proposed systems ........ 34
      1.4.2 System evaluation ........ 37

2. OFFSHORE THERMAL POWER WITH CCS ........ 40
   2.1 Initial Concept ........ 40
      2.1.1 Why build new thermal power plants? ........ 40
      2.1.2 How will it work? ........ 42
   2.2 Design Selection Process ........ 44
      2.2.1 Selection Flowcharts ........ 44
   2.3 Design Considerations ........ 46
      2.3.1 Location ........ 46
      2.3.2 Power Plant ........ 53
      2.3.3 Carbon Capture & Storage System ........ 73
      2.3.4 Risk relating to offshore structures, power plants & CCS ........ 79

3. APPLICATION OF THE CONCEPT ........ 86
   3.1 Selection of Location ........ 86
      3.1.1 Location candidates ........ 86
      3.1.2 Marine environment ........ 88
      3.1.3 Connections to grid ........ 88
      3.1.4 Licensing ........ 89
      3.1.5 Public perception ........ 90
      3.1.6 Choice of specific location ........ 90
   3.2 Power Generation & Carbon Capture System ........ 93
   3.3 Selection of platform ........ 96
   3.4 Methodology ........ 97
      3.4.1 Transportation cost of GTW versus conventional approaches ........ 98

3.5 Cost Analysis ........ 102
3.5.1 Capital costs ........ 103
3.5.2 Annual operating costs ........ 105
3.5.3 Fuel cost ........ 107
3.5.4 Transportation cost ........ 107
3.5.5 Cost of carbon capture and storage of $CO_2$ ........ 108
3.5.6 Levelised cost of energy; onshore power vs offshore power ........ 108

4. CONCLUSIONS ........ 111

5. FUTURE CONSIDERATIONS ........ 113

TABLES ........ 115

FIGURES ........ 117

REFERENCES ........ 120

APPENDIX A ........ 127

APPENDIX B ........ 131

## INTRODUCTION

According to the 3rd Assessment Report of the Intergovernmental Panel on Climate Change (IPCC 2001), between 1901 and 2001 the average global change in sea level was between 0.1 to 0.2m. This was caused by a change in the volume of water in the oceans resulting from either a reduction in density, an increase in the total mass of water or a combination of the two. The latter is a result of thermal expansion which happens when the ocean's temperature increases. The increase in mass is a result of glaciers and ice sheets on land melting and the water entering the ocean. Both of these are indicators of global warming. There are several possible causes of this increase in sea level. The first possible explanation is that, since the planet has geologic time-scales, the rise in sea levels could be a result of climate change in the distant past. Secondly, the earth could still be warming up after the end of the little ice age where temperatures were unusually cold. Finally, the increase in temperature could be attributed to human activity. Whilst scientists' opinions differ on the exact causes of global warming, it is generally accepted that even if humans are not solely responsible for climate change we are accelerating the process.

The mechanism by which increased global warming occurs is the greenhouse effect where the presence of greenhouse gases in the atmosphere result in an increase in temperature. The four main gases involved are water vapour, carbon dioxide, methane and ozone. Over the past two centuries there has been large increase in anthropogenic emissions of these greenhouse gases. The most important greenhouse gas in terms of human activity is carbon dioxide because it is emitted in the largest quantities. The pre-industrial concentration level of $CO_2$ was around 280 ppm; this increased to 379 ppm in 2005 (IPCC 2007).

In general, the main reason why $CO_2$ emissions are increasing is because of human development. The main sources of $CO_2$ emissions, comprising almost 75% of global $CO_2$ emissions, are power generation, transport and industry (Tanaka 2010). Of these sources, electricity generation is the largest. World energy consumption has been predicted to increase by 49% between 2007 and 2035 in a worst case scenario (IEA 2010) and the corresponding increase in world electricity generation is 87%. This scenario is a business-as-usual scenario based on current technological and demographic trends and that current laws and regulations are maintained throughout the projections. However, even if there is low economic growth there will still be a large increase in energy demand. This means that the focus must be on reducing the $CO_2$ emissions but not at the expense of world development. This is particularly important for developing and third world countries. Consequently, in the last 20 years climate change policy has developed and has been given increasing importance by the global community.

This started in 1992 in Rio de Janeiro where the United Nations Framework Convention on Climate Change was signed by 154 nations. Upon ratification this committed the governments of the signatories to voluntarily aim to reduce concentrations of greenhouse gases in the atmosphere. Greater obligation to do so was placed on the developed and industrialised countries which came to be known as Annex I or OECD countries. Following this, in 1996, the Kyoto Protocol outlined the obligation of the Annex I countries to reduce their greenhouse gas emissions. This was a first step towards stabilising the atmospheric content of greenhouse gases. Further Conferences of the Parties (COP) have met annually to deal with issues such as financing efforts in developing countries and negotiating political issues. In addition further COP's such as Copenhagen have aimed to introduce further binding emissions targets but have achieved little success. Despite this, many of the OECD countries as well as some of the now developed countries have implemented policies to further reduce their emissions as well as deal with other aspects of climate change.

There are several scenarios that have been created in order to both predict future levels of $CO_2$ in the atmosphere and calculate the $CO_2$ limits needed for a particular outcome. These can then be used to determine what needs to be done to limit increases in these levels. One such scenario is the 450 scenario

(Nakicenovic and Wien 2007). This is where $CO_2$ concentration in the atmosphere is limited to 450 parts per million so that the increase in global temperature will be no greater than 2 degrees Celsius. In order to achieve the 450 scenario a reduction in emissions to 44 to 46 Gigatonnes (Gt) $CO_2$ per year is required (Deutsche Bank 2009). If a business-as-usual trajectory based on 2007 climate change policies is used, the projected increase in $CO_2$ emissions is 59 Gt per year in 2020 from 47 Gt per year in 2007. This means that it will be necessary to reduce $CO_2$ emissions by 13 to 15 Gt per year. If all the legislation and proposed climate change policies existing in 2009 are enforced there will still be a 5 to 7 Gt per year difference and the 450 scenario will not be achieved. Furthermore, the 450 scenario assumes a slow-down in growth after 2014. If this does not happen, then there could be a further 7 Gt per year addition resulting in a potential 14 Gt per year of $CO_2$ emissions that need to be reduced.

There are several ways in which net $CO_2$ emissions can be reduced; reducing energy consumption, switching to low-carbon fuels, increasing the use of renewables and nuclear energy, planting trees and sequestering the $CO_2$ emissions. The first four methods are already being used to some extent but all have their limitations. Taking just the electricity generation sources of $CO_2$, it will not be possible to decrease net $CO_2$ emissions through improving energy efficiency. This is because there will still be a demand for more energy; improving energy efficiency will only decrease the amount of electricity required to meet this demand not eliminate it completely.

Switching to low-carbon fuels will help, however this will have a limited impact since there will still be some $CO_2$ emitted. Renewables and nuclear power are an attractive option as they are zero or low net carbon emitting sources. However, despite recent growth in capacity, not including hydroelectric generation, renewable energy sources such as wind and solar currently account for just 3.3% of world electricity generation (Ren 21 2011). Therefore, even with a rapid increase in the use of renewables it is unlikely that a major portion of electricity demand could ever be met. Nuclear power has its own issues relating to decommissioning, storage of nuclear waste and general unpopularity. Using a biological sink to remove $CO_2$ from the atmosphere is the most attractive of all the solutions as it is a natural solution. However, this solution requires a large amount of land putting it in direct conflict with human development. Global population is currently close to seven billion (UN 2011) and is projected to increase to 9.3 billion by the middle of the century. This means that there will be more competition for land and therefore less land will be available for re-forestation.

The last solution is to capture the carbon dioxide and sequester it. In this scenario, $CO_2$ would be removed at source and would therefore never enter the atmosphere. At present, carbon capture and sequestration (CCS) is not carried out on a commercial scale but there are indications that between 80% and 95% of the $CO_2$ emitted through power generation could be captured (IPCC 2005). This solution is considered by some to be an excuse to emit more $CO_2$. However, since there is currently no viable alternative to using fossil fuels for power generation, in the short term CCS is necessary. Furthermore, whilst in the distant future CCS may no longer be needed in the power industry, there are still the other sources of $CO_2$ to consider. It is possible that the CCS technology could be adapted for use in the transport sector and $CO_2$ is already being captured in the industrial sector if not stored. Ultimately, a combination of all the solutions will be used and CCS will have an important role to play.

The purpose of this study is to review the Carbon Capture and Sequestration system and then propose a way in which it could be used. Several ideas were evaluated and the offshore thermal power with CCS concept was chosen. This concept provides an alternative to transporting $CO_2$ between the point of capture and the storage site.

# 1. THE CARBON CAPTURE & STORAGE SYSTEM

Before a possible solution involving the use of carbon capture and storage can be developed, there needs to be an understanding of the various available options in the CCS chain. According to the International Energy Agency (IEA), electricity and heat account for approximately 41% of all emissions (IEA 2008). Therefore, this review will focus on the capture of $CO_2$ emissions from power plants and the subsequent transport and storage of these emissions.

## *1.1 CCS Technology*

Carbon capture and storage (CCS) technologies involve collecting carbon dioxide from main stationary sources, transporting it to a suitable storage location, and then storing it away from the atmosphere in geological formations or the ocean for a long period of time. Figure 1-1 shows an overview of the CCS system and the main options that can be used. These different options will be discussed in this chapter.

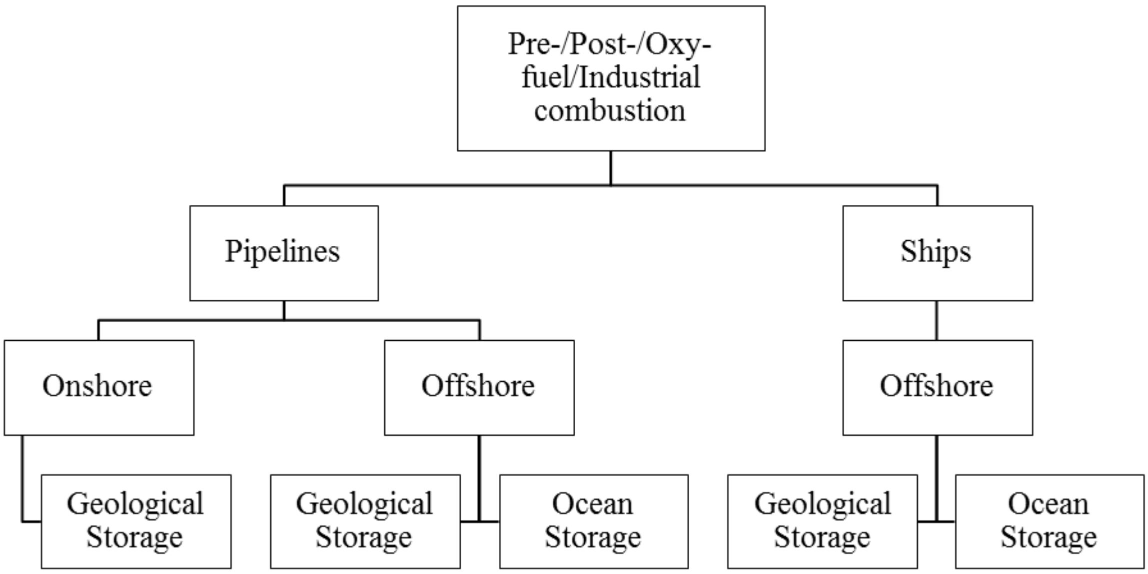


Figure 1-1: Carbon Capture & Storage flowchart

### *1.1.1 Carbon Capture*

Approximately 70-80% of the total cost of CCS is the capture of $CO_2$. Consequently, the manner in which the $CO_2$ is captured has large implications for the economic feasibility of CCS as a whole. Currently, three different techniques exist for capturing $CO_2$ from large power plants. The general features of these are as shown below (IPCC 2005).

- Pre-combustion
- Post-combustion
- Oxy-combustion

**Pre-combustion**

Pre-combustion technology is where $CO_2$ is removed from the fuel prior to combustion (IPCC 2005). This is done through a three stage process. The first stage is the removal of carbon monoxide and hydrogen from the primary fuel to produce syngas. Then the CO is converted to $CO_2$ by adding steam. Finally the $CO_2$ is separated out from the mixture of $CO_2$ and $H_2$. This process is shown in Figure 1-2.

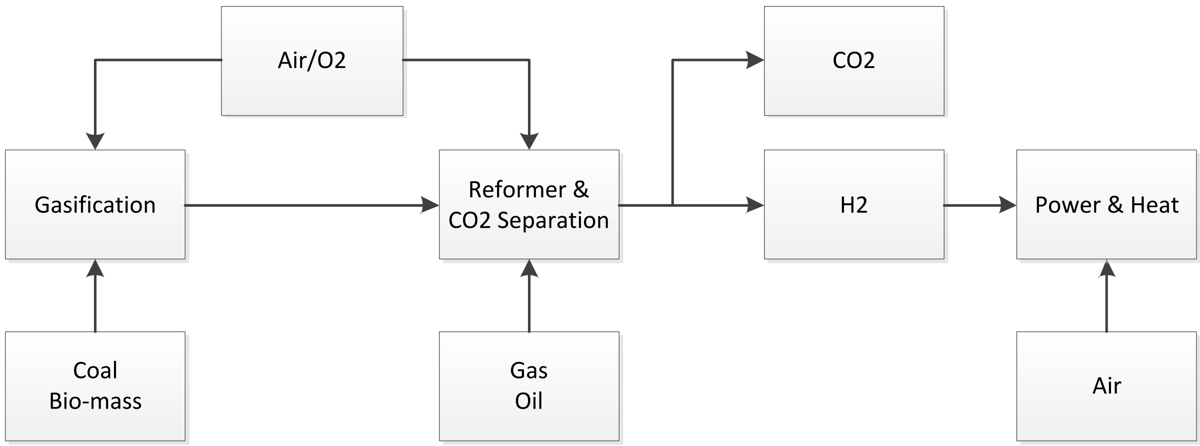


Figure 1-2: Pre-combustion process flowchart

Pre-combustion is seen as being suitable for capturing $CO_2$ when dealing with coal gasification in an Integrated coal Gasification Combined Cycle (IGCC) plant where it is considered a zero emission plant (ZEP) technology which removes greenhouse gases along with other pollutants ($SO_X$, $NO_X$ and particulates). However, pre-combustion carbon capture technology can also be applicable for gas fired combined cycle power plants. In addition, instead of using the hydrogen to produce electricity, it can also be used to produce ammonia. Sulphur can also be recovered from this process and sold as a by-product

As with all technology, there are advantages and disadvantages. These are listed below.

Advantages;

- Proven industrial scale technology in oil refineries, but needs 3x scale-up for power plants.
- 90-95% of CO2 emissions can be captured.
- Applicable to natural gas and to coal fired IGCC power plants.
- Lowest technology risk. May become the most efficient method.
- Can produce $H_2$ as transportable energy or liquid fuels from coal.

Disadvantages;

- Requires a chemical plant in front of the gas turbine/boiler.
- High investment cost of dedicated new-build plant.
- High $NO_X$ emissions – will require expensive scrubbers.
- Efficiency of $H_2$ combustion in turbines is lower than conventional turbines.
- May be less flexible under varying electricity generation market requirements.

There are several ways in which pre-combustion carbon capture can be done. Examples of currently available as well as developing pre-combustion technologies as given by Hester and Harrison (2010) are listed in Table 1-1.

TABLE 1-1
$CO_2$ AND $H_2$ SEPARATION TECHNOLOGIES FOR PRE-COMBUSTION

| Capture Separation technology | Currently developed technologies | Example technologies under development |
|---|---|---|
| Absorption | Physical solvents (e.g., Selexol, Fluor processes), chemical solvents | Novel solvents to improve performance; improve performance; improved design of processes and equipment |
| Adsorption | | Zeolite, activated carbon, carbonates, hydrotalcites and silicates |
| Membrane | | Metal membrane WGS reactors; ion transport membranes |
| Cryogenic | $CO_2$ liquefaction | Hybrid cryogenic + membrane processes |

The areas in which there are developed technologies available are absorption and cryogenic. In general processes that use chemical absorbents have a low initial cost and are advantageous for further $CO_2$ storage because a high $CO_2$ pressure stream is maintained after the recovery process. The disadvantage is the large amount of heat needed for the recycling process of absorbent (Park 2009). However, improvements are being researched to overcome this as well as developing adsorption and membrane methods.

**Post-combustion**

Post-combustion is where the $CO_2$ is separated from the flue gases produced by the combustion of the primary fuel. Post combustion systems normally use a liquid solvent to capture the $CO_2$ present in a flue gas stream, the main constituent of which is nitrogen. For a modern pulverized coal (PC) power plant, a post-combustion capture system would typically employ an organic solvent such as MEA (mono ethanol amine) (IPPC 2005).

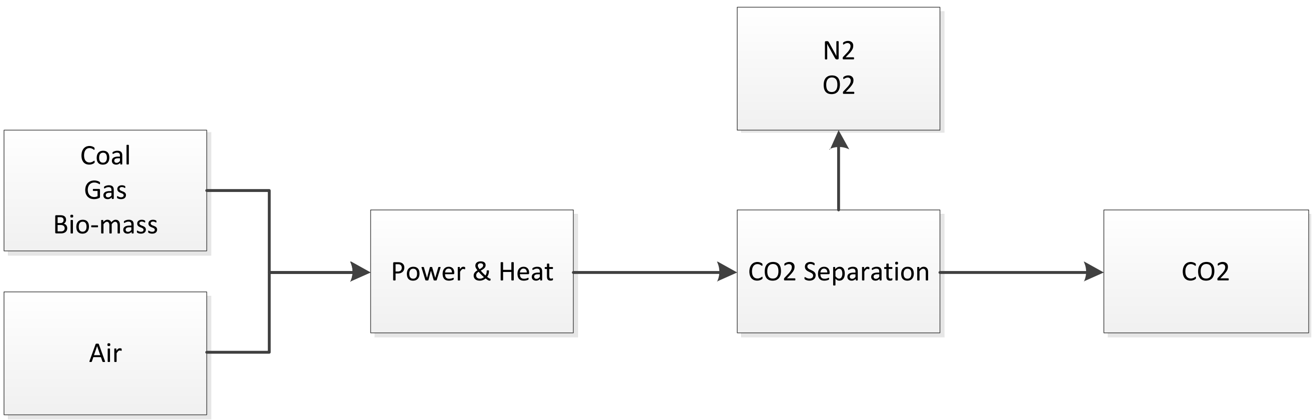


Figure 1-3: Post-combustion process flowchart

As with the pre-combustion method, there are advantages and disadvantages to post-combustion carbon capture. These are as follows;

Advantages

- Feasible to retrofit to current industrial plants and power stations.
- Existing technology - 60 years experiences with amine solvents.
- Currently in use to capture $CO_2$ for the soft drinks industry.

Disadvantages

- High running costs – absorber and degraded solvents require replacement.
- Limited large scale operating experience – existing systems need scaling up by around 10 times the capture capability.

Examples of currently available as well as developing post-combustion technologies as given by Hester and Harrison (2010) are listed in Table 1-2.

.

TABLE 1-2
$CO_2$ SEPARATION TECHNOLOGIES FOR POST-COMBUSTION CARBON CAPTURE

| Capture Separation technology | Currently developed technologies | Example technologies under development |
|---|---|---|
| Absorption | Chemical solvents(e.g., MEA, chilled ammonia) | Novel solvents to improve performance; improved design of processes and equipment |
| Adsorption | Zeolite and activated carbon molecular sieves | Carbonate sorbents; chemical looping |
| Membrane | Polymetric membranes | Immobilized liquid membranes; molten carbonate membranes |
| Cryogenic | $CO_2$ liquefaction | Hybrid cryogenic + membrane processes |

The same general types of separation processes used in pre-combustion are used in post-combustion however there is existing technology available in all areas as well research into new technology. The most developed separation process is the one using amine which is already being used other industries.

**Oxy-fuel**

Oxy-fuel combustion is where pure oxygen replaces air as the oxidizing agent (IPCC 2005). It achieves very high temperatures compared to normal air combustion. This leads to improved heat transfer characteristics meaning better efficiency and fuel economy. The combustion of hydrocarbons using pure oxygen theoretically results in a flue gas containing only water and $CO_2$. This process is shown in Figure 1-4.

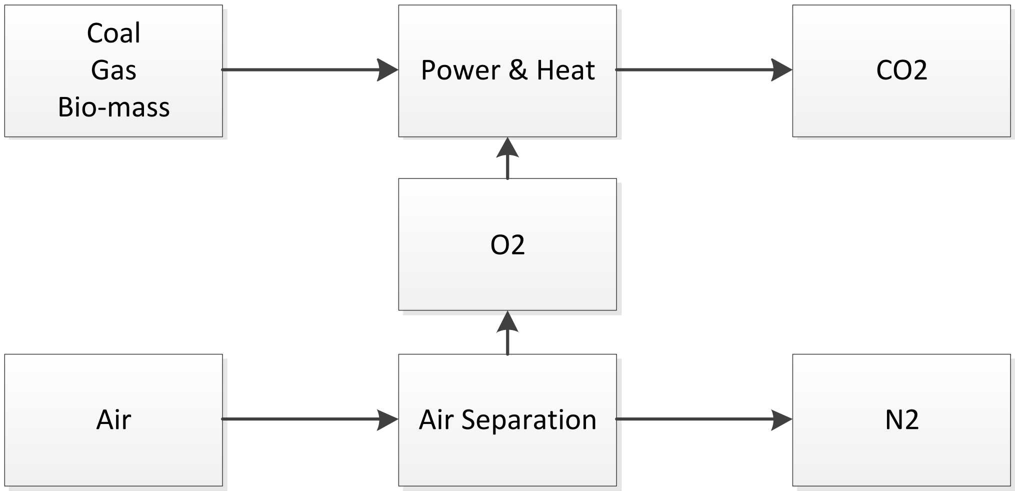


Figure 1-4: Oxy-fuel process flowchart

In general, the flue gas after the condensation of vapour can contain 80-98% $CO_2$ which makes the capture process straightforward. $CO_2$ recovery rate using the pure oxygen process could therefore reach up to 100%. Vattenfall (Sweden) and Cottbus (Germany) aim to commercialise research and development of Oxy-fuel by 2020.

One of the key pre-requisites of the oxy-fuel system is use of pure oxygen. This is because impurities in the supplied oxygen result in inert gases, SOx, NOx, hydrochloric acid and mercury being mixed with the $CO_2$ and water vapour in the flue gas. This can cause stability problems, both environmentally and economically, for an Oxy-fuel plant and has to be controlled.

The advantages and disadvantages of this process are as follows;

Advantages

- Potential for 100% $CO_2$ capture rate.
- Few other harmful emissions due to more complete combustion.
- May be possible to retro-fit the oxy-fuel burners onto modified existing coal power plants.

Disadvantages

- High energy penalty unless chemical looping combustion is used.
- Largely in the development stage at present.

Examples of currently available as well as developing Oxy-fuel technologies as given by Hester and Harrison (2010) are listed in Table 1-3.

TABLE 1-3
SEPARATION TECHNOLOGIES FOR OXY-FUEL CARBON CAPTURE

| Capture Separation technology | Currently developed technologies | Example technologies under development |
|---|---|---|
| Absorption | - | - |
| Adsorption | Zeolite and activated carbon molecular sieves | Perovskites and chemical lopping technology |
| Membrane | Polymeric membranes | Ion transport membranes; carbon molecular sieves |
| Cryogenic | Distillation | Improvements in distillation processes |

As can be seen above, it is not possible to use the absorption method with oxy-fuel combustion. The other areas have some developed technology but these are mostly still under development.

**Comparison of capture methods**

Advantages and disadvantages of the above mentioned concepts are listed in Table 1-4 and the risks associated with each capture system (Hester and Harrison 2010) can be seen in Table 1-5.

TABLE 1-4
ADVANTAGES AND DISADVANTAGES OF DIFFERENT CARBON CAPTURE SYSTEMS

| Capture type | Advantages | Disadvantages |
|---|---|---|
| Pre-combustion | Lower energy requirements for CO2 capture and compression | Temperature and efficiency issues associated with hydrogen-rich gas turbine fuel |
| Post-combustion | Fully developed technology, commercially deployed at the required scale in other industrial sectors<br>Opportunity for retrofit to existing plant | High parasitic power requirement for solvent regeneration<br>High capital and operating costs for current absorption systems |
| Oxy-fuel combustion | Mature air separation technologies available | Significant plant impact makes retrofit less attractive |

TABLE 1-5
RISKS ASSOCIATED WITH EACH CARBON CAPTURE SYSTEM

| Capture type | Risk level | Considerations |
|---|---|---|
| Post-combustion | Low | Some viable technology options are already commercially deployed and requirements for these are well understood. Further developments may provide opportunities for easier retrofit at reduced costs, or for the use of new technologies |
| Oxy-fuel combustion | Medium | Oxy-fuel combustion has reached the demonstration scale but is not yet commercially deployed, and requirements are therefore not yet fully understood |
| Pre-combustion | Medium or high | Higher base cost of IGCC relative to conventional pulverized coal plant and increased capture readiness means that the choice of IGCC over PC is currently a major pre-investment |

It is also important to consider the relative energy penalties and costs associated with each system. The energy penalty of the capture process for plants capturing 90% $CO_2$ ranges from 24-40% for a new supercritical PC plants, 11-22% for Natural Gas Combined Cycle (NGCC) plants, and 14-25% for coal-based IGCC systems (IPCC 2005). This is on the basis that each plant is using the best existing technology. Based on this, the electricity production costs for fossil fuel plants with $CO_2$ capture ranges from 0.04-0.09 US$/kWh. It should be noted that this figure is also dependent on the efficiency of the power plant as well as the size, age and cost of the plant (IPCC 2005).

Both pre-combustion and oxy-fuel combustion are in the research stage whilst post-combustion is used in commercial projects. As a result of this, implementation of these involves a lot of uncertainty and would depend on many technical assumptions and estimations. This would complicate any technical or economic analysis and make their outcomes uncertain. Furthermore, if oxy-fuel combustion is used the fuel costs would increase because of the high cost of producing pure oxygen. In this respect, pre-combustion is currently more attractive than oxy-fuel combustion.

Post-combustion with chemical absorption (scrubbing) using amine solvents is therefore the most attractive solution for a novel CCS concept at the moment because of its availability and experience gained from many previous applications. However, the high efficiency of amine scrubbing is costly since the energy consumption is very high. Furthermore, the cost of installation and maintenance are also high. Nevertheless, the high rate of $CO_2$ absorption compared to that currently achieved by other techniques can offset these issues.

The two other techniques cannot, however, be discarded. The usage of these should be encouraged since they can potentially achieve much higher efficiencies and provide a more sustainable solution than post-combustion.

### *1.1.2 Transport of $CO_2$*

The most important sources of $CO_2$ are located long distances (> 300 km) from potential storage sites (IPCC 2005). This means that, under current prerequisites, some form of transport will be involved in a CCS system. At the moment three different mature technologies exist for transporting a substance like $CO_2$ over such distances:

- Pipeline transport
- Shipping
- Transport by road or rail

Each of these options will have positive and negative aspects depending entirely on the intended route. It is, therefore, important to consider the geographic possibilities as well as geo-political and national prospects before choosing a mode of transport. Most locations will involve a route crossing both land and water. This means that a pipeline, a combination of pipelines and ships or a combination of road/rail and ships is necessary. The road/rail alternative is generally seen as being too uneconomical because of the large number of vehicles that would be needed for large scale $CO_2$ transport (IPCC 2005). A pipeline must therefore be used for land based transport although exceptions may be considered for small sources in densely populated areas where a pipeline is not possible.

The next consideration is whether or not to continue that pipeline to the offshore site or transport the $CO_2$ by ship. The decision is dependent on the distance and nature of the offshore route. This is illustrated in Figure 1-5. This figure shows a projected cost of different methods of transporting $CO_2$

and is based on a transport volume of six $MTCO_2$ per year. It can be seen that offshore pipelines are the most economically viable solution up to a distance of around 1000 km.

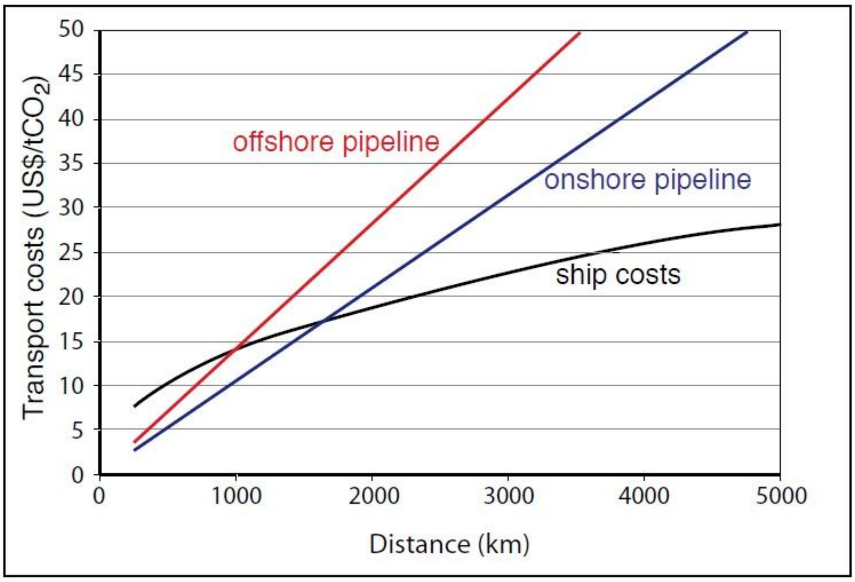


Figure 1-5: Cost estimate for CO2 transport options (IPCC 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change, Figure TS.6 Cambridge University Press)

The highly prospective areas for geological storage are currently located relatively close to shore, as illustrated in Figure 1-6.

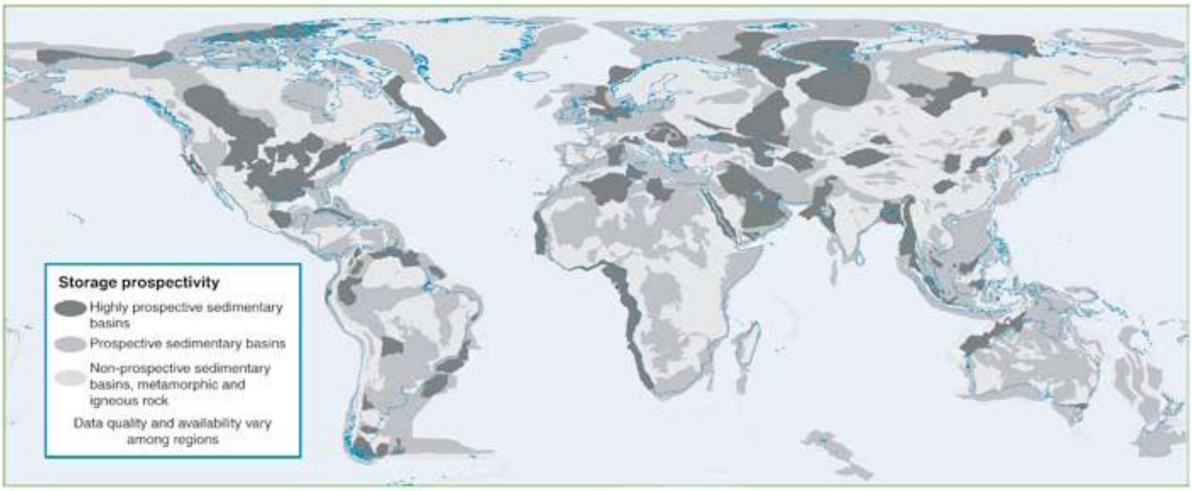


Figure 1-6: Prospective areas for $CO_2$ storage (IPCC 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change, Figure TS.2b Cambridge University Press)

A more local overview of two example areas of interest is given in Figure 1-7. This shows a 300 km "radius from shore" boundary for reference in the Gulf of Mexico and two reference circles of 300 km and 200 km in the North Sea.

It is shown here that transportation in the Gulf of Mexico and the North Sea would be very likely to be less than 1000 km. An exception to this is if $CO_2$ were to be transported from land locations along the southern shores of the North Sea to locations in the Norwegian Sea which also has a high prospect for storage capacity.

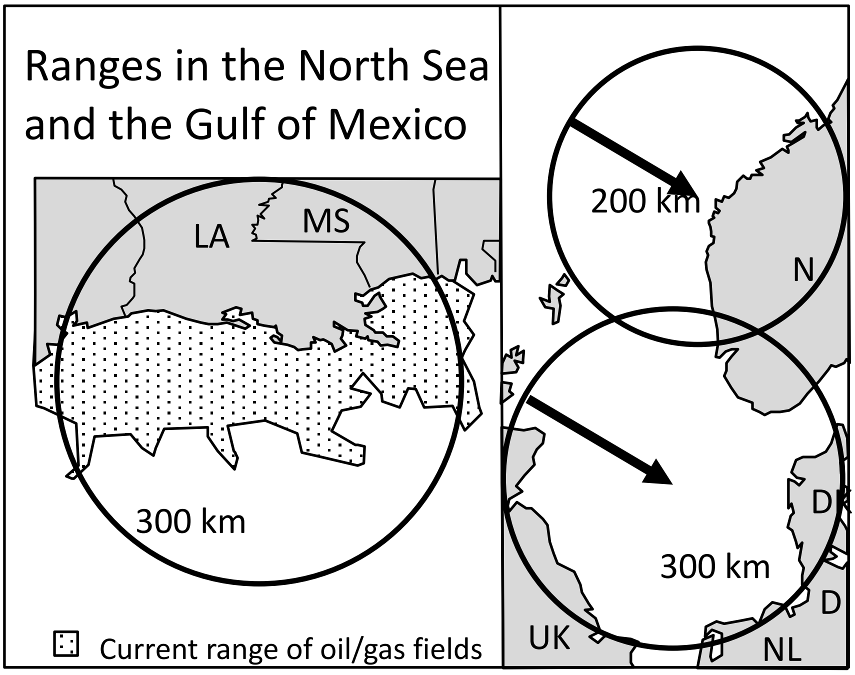


Figure 1-7: Extent of current gas/oil fields in the Gulf of Mexico and the North Sea.

Even this example only covers these two areas, it is important to ensure that the reasoning conducted here will also have merit in future applications. Large capture volumes could be possible from a future introduction of CCS technology in China and there is a prospect for storing $CO_2$ under the South China Sea (as shown in Figure 1-6.) The question is if the same conclusions apply there as in the North Sea and the Gulf of Mexico. The most interesting areas for storage in this region lie off the coast of Malaysia even though the entire South China Sea has potential. The size of the region and the uncertainty of where it is possible to store leads $CO_2$ to the conclusion that transportation could exceed 1000 km.

The question of whether to use pipelines or ships is also a question of flexibility. A pipeline system cannot currently be moved between different locations whereas a ship can be deployed anywhere within its operating range. However, when the locations of the deposit sites are relatively certain, a pipeline system can be designed to be more versatile. Pipeline construction has shown a decreasing trend in construction costs as well as construction time and, if the trend continues, is likely to surpass ships as the most cost effective alternative; even in Asia where distances are greater (Zhao 2000). Despite this, the break-even point between transporting gas with pipeline versus transporting it with LNG tankers still shows a falling trend due to falling costs for tanker transport (Cornot-Gandolphe, Appert et al. 2003). With increased tanker size, a reduction of transportation costs for LNG carriers of 10% is predicted with the next generation of larger carriers. There is however an issue with port capacity if further reduction is to be achieved (Cornot-Gandolphe, Appert et al. 2003). This may lead to a situation where pipelines becomes a more viable option even for longer distances if nothing is done to increase port capacity (or if a larger capacity is not possible to achieve.)

Further considerations to make when choosing between pipelines and ships are:

- If a pipeline is laid between two countries, will they agree and are there any third parties involved? An example is the Nord Stream pipeline between Russia and Germany being delayed because of protests from Swedish and Finnish stakeholders (Johnson 2009).

- Development and maintenance costs of pipelines will depend on the development level and remoteness of the proposed location.

- The proximity of current or possible mooring locations for ships will determine the length of the onshore pipeline whereas a full-distance pipeline could give a shorter total distance.

There are two possibilities for transporting $CO_2$ using pipelines. Either new pipelines are laid out to the chosen injection site or the existing infrastructure is utilised. Each of these concepts will be discussed briefly.

The purpose built pipeline for $CO_2$ transport has been utilised since the early 1970's for Enhanced Oil Recovery (EOR) in the United States where the $CO_2$ comes from natural sources or as waste from different industries (Parfomak and Folger 2007). Such onshore pipelines operate at high pressure and ambient temperature to keep the $CO_2$ in a liquid phase. Purpose built pipelines can be built exactly to the requirements of the companies that will be using them giving benefits in operational costs.

An example of using an existing pipeline for $CO_2$ transportation is the Longannet project in Scotland. An existing natural gas pipeline is proposed as a means of transporting captured $CO_2$ from a coal-fired power station to an injection site in the North Sea. The project is a joint venture between Scottish Power who run the Longannet power station, the National Grid who operate the current natural gas pipeline and Shell who manage the gas field that is proposed for injection(Bolger 2009). The pipeline has been made available because of declining production of natural gas in the North Sea. As this project involves several stakeholders, there will be problems with agreement on areas of responsibility. This is why such pipeline projects may be hard to realize quickly and efficiently.

Ultimately, the option that provides the lowest lifetime cost for the intended route has to be chosen independently. In the case of the North Sea and the Gulf of Mexico, the short distances and long experience of pipeline-laying suggests that pipelines are the most viable option.

### *1.1.3 $CO_2$ Storage*

Once the $CO_2$ has been captured and transported, it needs to be stored indefinitely. There are two main storage options; geological storage (both onshore and offshore) and ocean storage. This section will give a review of the existing technologies for storage with an emphasis on geological storage.

**Geological storage**

Storage of $CO_2$ into geological formations can be carried out in a number of geological settings in sedimentary basins. Depleted oil and gas fields, deep coal seams and deep saline formations are all possible storage formations (IPCC 2005). In general, storing $CO_2$ in geological formations is expected to take place at depths below 800m where the ambient pressures and temperatures will usually keep the $CO_2$ in a liquid or supercritical state (IPCC 2005). Once $CO_2$ is injected into the storage formation, it remains trapped underground due to the combination of physical and geochemical trapping mechanisms (IPCC 2005). These mechanisms are described below;

- Physical trapping, which is provided by a layer of shale and clay rock above the storage formation, known as "cap rock", blocks the upward migration of $CO_2$.

- Geochemical trapping due to $CO_2$ reacting with in-situ fluids and host rock.

Figure 1-8 shows the different geological storage formations and the typical depths at which they can take place.

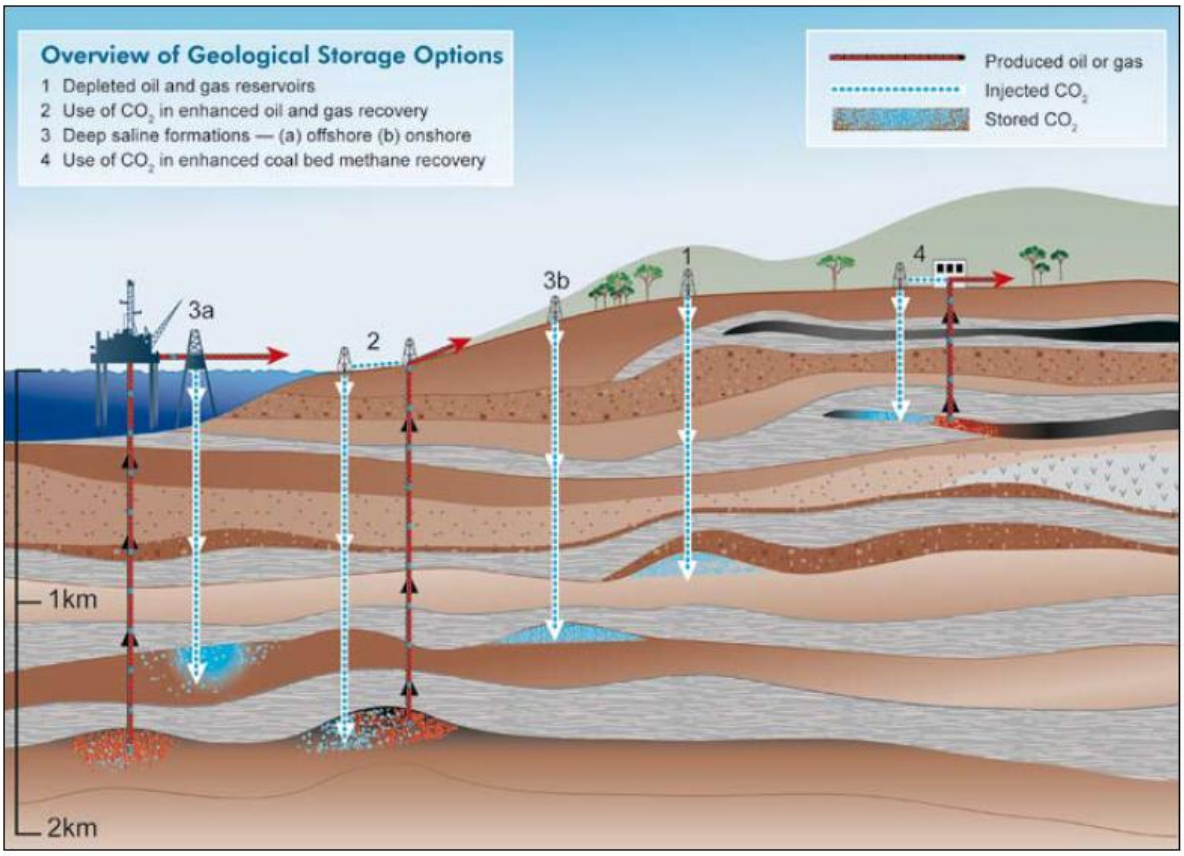


Figure 1-8: Methods for storing CO2 in geological formations (IPCC 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change, Figure TS.7 Cambridge University Press)

Table 1-6 shows a number of existing projects that include the geological storage of $CO_2$ and the type of formation used. Depleted oil and gas reservoirs are suitable candidates for storing $CO_2$ and are especially attractive when combined with Enhanced Oil/ Gas Recovery (EOR/EGR). As can be seen a number of CCS projects involve storing $CO_2$ by using EOR or EGR. EOR/EGR is used for increasing the amount of crude oil / natural gas that can be extracted from an oil/gas field by injecting $CO_2$ into the field. This has the advantage of reducing the cost of the $CO_2$ storage.

TABLE 1-6
A SELECTION OF EXISTING PROJECTS INVOLVING GEOLOGICAL STORAGE

| Project name | Country | Start-up | Storage reservoir type |
|---|---|---|---|
| Sleipner | Norway | 1996 | Saline formation |
| Fenn Big Valley | Canada | 1998 | ECBM |
| Weyburn | Canada | 2000 | EOR |
| Qinshui Basin | China | 2003 | ECBM |
| Recopol | Poland | 2003 | ECBM |
| Frio | U.S.A | 2004 | Saline formation |
| K12B | Netherlands | 2004 | EGR |
| In-Salah | Algeria | 2004 | Gas field |
| Yubari | Japan | 2004 | ECBM |
| Snøhvit | Norway | 2006 | Saline formation |
| Gorgon | Australia | 2009 | Saline formation |
| Zama | Canada | 2006 | EOR |

The first engineered injection of $CO_2$ into underground geological formations was carried out in Texas, USA, in the early 1970s, for the purpose of EOR and has been taking place there and at many other locations ever since (IPCC 2005). In addition, industrially produced $CO_2$ was first used for EOR in the USA since 1986 (Steeneveldt, Berger et al. 2006). The first commercial CCS project was the Weyburn project which was started in Canada in 2000 (Steeneveldt, Berger et al. 2006). Over the 25 years lifetime of Weyburn project, about 5 million tonnes of carbon (MtC) are expected to be stored (Moberg, Stewart et al. 2002). However, most EOR operations obtain their $CO_2$ from natural formations such as gas processing and separation from natural gas, and do not reduce the carbon emissions, although the Weyburn project would result in a net reduction in carbon emissions (Anderson and Newell 2004).

A major consideration is the level of risk associated with a particular solution. Existing technologies and knowledge suggest that storage of $CO_2$ in depleted oil and gas fields, where their ability to store pressurized fluids for millions of years have already been demonstrated, results in the least potential environmental risk (Anderson and Newell 2004). In addition, knowledge obtained from the oil and gas exploration and production industry has resulted in a relatively good understanding of the depleted oil and gas fields. However, environmental risks do exist for the storage of $CO_2$ in depleted oil and gas fields. This includes the potential leakage of $CO_2$ via the natural pathways or fractures which were caused by injecting $CO_2$ into geological formations with possibility of the groundwater being polluted (Anderson and Newell 2004). Although, experience gained from EOR operations have demonstrated that leakage risks can be reduced through high quality construction, maintenance, operation, and control of storage facilities, it is also possible that $CO_2$ could leak from surface installations and wells (Adams, W.Ormerod et al. 1994). Therefore, monitoring technology is of paramount importance for the overall risk management strategy for geological storage projects (IPCC 2005). Monitoring methods which have been developed in other areas, need to be tested and assessed to meet the needs for monitoring geological storage of $CO_2$. Furthermore, the reservoir-monitoring project is being undertaken at the Weyburn EOR project to give increased understanding regarding the long-term storage capacity and integrity of these locations (Brown, Jazrawi et al. 2001).

Another option for storing $CO_2$ is in deep saline formations which are sedimentary rocks saturated with formations water or brines which contain high concentrations of dissolved salts (IPCC 2005). Deep saline formations may represent a better option for storing $CO_2$ in the longer term and are generally nearer to the large point sources of emissions, compared to the depleted oil and gas fields (Anderson and Newell 2004). Therefore, the costs for transporting $CO_2$ to the storage sites may be reduced. In addition, the potential capacity for storing $CO_2$ is much higher than that of depleted oil and gas reservoirs. There is some uncertainty about the environmental effect of storing $CO_2$ in these formations however negative effects can be reduced by selecting suitable storage locations. These are where there is an impermeable cap that prohibits the release of injected $CO_2$ but also has high permeability and porosity below the cap that allows large quantities of $CO_2$ to be distributed uniformly (Herzog, Drake et al. 1997; Anderson and Newell 2004). Although the potential leakage into groundwater drinking supplies theoretically could occur, the risks are generally small (Anderson and Newell 2004). Once $CO_2$ injected into deep saline formations, it will likely displace the formation water which is originally contained within the saline formations, and would finally be dissolved in the pore fluids (Anderson and Newell 2004). In addition, even longer storage times could be achieved due to the chemical reactions between absorbed $CO_2$ and the surrounding rock which lead to the formations of highly stable carbonates (Johnson 2000).

The Sleipner project, operated by Statoil in the North Sea about 250 km off the coast of Norway, is the first commercial scale project of storing $CO_2$ in a saline formation. More than seven $MtCO_2$ had been injected at a rate of approximately 2700 t per day by early 2005 and a total of 20 $MtCO_2$ is expected to be stored over the lifetime of this project (IPCC 2005). In addition, according to the studies and simulations which covered hundreds to thousands of years, the injected $CO_2$ will eventually dissolve in the pore water, which will become heavier and sink, therefore minimizing the potential for long-term leakage (Lindeberg and Bergmo 2003).

However, knowledge and technologies need to be further developed in order to meet the needs for investigating how long $CO_2$ can remain trapped in the deep saline formations and the uncertainty towards the environmental effects of this storage method.

Deep coal beds may also be considered as potential geological formations for storage of $CO_2$. Similar to EOR/EGR, it has the potential to have an economic benefit by storing $CO_2$ in the deep coal beds by using the Enhanced Coal Bed Methane (ECBM) method (Anderson and Newell 2004). By using the ECBM technique, methane which is absorbed into the coal surface, could be recovered by injecting $CO_2$ into the coal beds. Moreover, the storage capacity for deep coal beds is quite considerable. The storage capacity of un-minable coal seams has three to 15 $GtCO_2$ for the lower estimate and 200 $GtCO_2$ for the upper estimate (IPCC 2005). For example, it was estimated that opportunities for coal-bed methane in the United States could provide 5–10 Gt of storage capacity (Chargin, Anthony et al. 1997; Herzog, Drake et al. 1997; Stevens, H. et al. 1998). However, although a few demonstration projects of storing $CO_2$ in the deep coal beds have been deployed, this concept is still in the demonstration phase (IPCC 2005).

**Ocean storage**

An alternative to geological storage of $CO_2$ is to directly inject $CO_2$ into the deep oceans at depths greater than 1,000m where the injected $CO_2$ would be isolated from the atmosphere for hundreds of years (IPCC 2005). This concept is still in the research phase, no demonstration or pilot scale projects have been undertaken. However, there have been small scale field experiments and over 25 years of theoretical, laboratory and modelling studies on the intentional ocean storage of $CO_2$ exists (IPCC 2005).

Despite this, the oceans are still considered to be the largest potential location for storing $CO_2$ and they already take up $CO_2$ at a rate of seven $GtCO_2$ per year (IPCC 2005). This is due to the increased $CO_2$ concentrations in the atmosphere creating an imbalance between the atmosphere and the ocean. In addition, over the past 200 years, the oceans have already absorbed 500 $GtCO_2$ from the atmosphere out of 1300 $GtCO_2$ total anthropogenic emissions (IPCC 2005). It has been estimated that approximately 90% of present-day emissions will finally end up into the oceans but the effects on marine organisms and ecosystems are still uncertain (Chargin, Anthony et al. 1997). Figure 1-9 shows the different methods of ocean storage which take place at varying depths within ocean space.

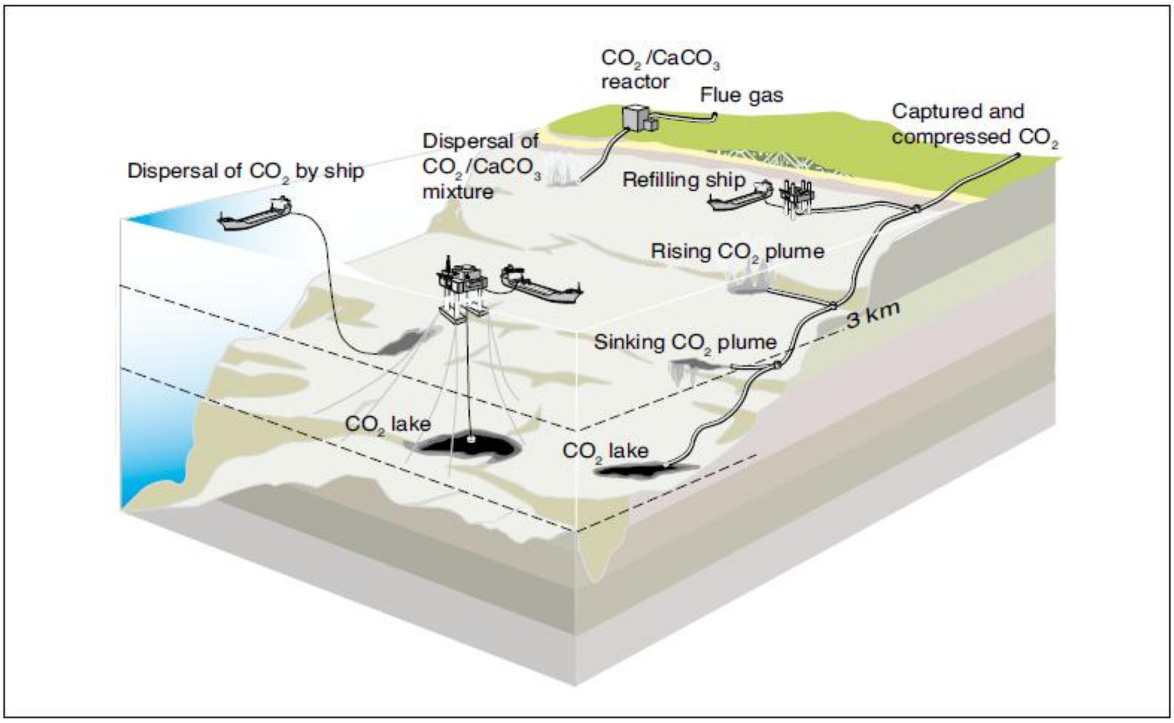


Figure 1-9: Methods of ocean storage (IPCC 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change, Figure TS.9 Cambridge University Press)

Although there is no practical physical limit to the amount of anthropogenic $CO_2$ that could be stored in the ocean, it is estimated that the storage capacity of the ocean is approximately 1,000 to 10,000 Gt if applying what is deemed an "acceptable" increase in average ocean water acidity (Chargin, Anthony et al. 1997; IPCC 2005). It is indicated by the analysis of ocean observations and modes that the injected $CO_2$ will be isolated from the atmosphere for at least several centuries and even longer for deeper injection (IPCC 2005).

One potential way for ocean storage to take place is to directly inject captured $CO_2$ into the deep ocean at depths greater than 1,000 m where most of the injected $CO_2$ would be isolated from the atmosphere (IPCC 2005). This can be achieved by transporting $CO_2$ either by pipelines or by ships to an ocean site for release in the ocean or on the sea floor.

Various technologies have been proposed in the literature to ensure that injected $CO_2$ reaches these depths (Adams, W.Ormerod et al. 1994; Herzog, Drake et al. 1997). It is thought that the most near-term option is to inject $CO_2$ at depths of 1,000 to 1,500 m via a pipeline or towed pipelines which would create a rising stream of $CO_2$ that would be taken up into the surrounding waters (Anderson and Newell 2004). Another option is a carefully controlled shallow release of dense seawater where the absorbed $CO_2$ would sink to the deeper ocean (Anderson and Newell 2004). In addition, $CO_2$ can be injected by a ship or platform on the sea floor to form a stable and isolated "lake". Such $CO_2$ lakes need to be deeper than 3 km because at this depth $CO_2$ becomes denser than sea water (IPCC 2005).

The environmental effects of ocean storage are more uncertain than for geological storage (Anderson and Newell 2004). The increased acidity of the ocean, due to the huge amount of dissolved $CO_2$, is the primary issue that needs to be considered in order to assess the environmental impact of ocean storage concepts. The direct injection of $CO_2$ into the deep ocean should only slightly increase average acidity since it should mix with the deep ocean (Chargin, Anthony et al. 1997), where little marine life lives (Adams, W.Ormerod et al. 1994). However, directly injecting $CO_2$ into the oceans will also introduce more rapid and localised effects which may cause immediate mortality of marine organisms. This can be avoided via a deeply towed pipeline since the injected $CO_2$ should sufficiently disperse (Anderson and Newell 2004).

In general, geological storage is the best near-term solution for $CO_2$ storage; especially in depleted oil and gas reserves (Anderson and Newell 2004). When not considering transportation, it is estimated that the cost of geological storage is approximately \$5/t$CO_2$ to \$30/t$CO_2$ stored (Herzog, Drake et al. 1997). Whilst the costs of geological storage are roughly comparable with that of ocean storage, the mechanisms and technologies for storing $CO_2$ into geological formations are much better understood that that of ocean storage (Anderson and Newell 2004). Due to the technological immaturity and environmental uncertainty, ocean storage of $CO_2$ is still in the research phase.

In addition, the injection of $CO_2$ into deep geological formations involves many of the same technologies that have been developed in the oil and gas industry such as well drilling technology, injection technology, computer simulation of storage reservoir dynamics and monitoring methods (IPCC 2005). These technologies need to be adapted for the application of CCS projects. Furthermore, other underground injection practices, such as natural gas storage, the deep injection of liquid wastes and acid gas disposal etc. also provide more experience for $CO_2$ storage in geological formations (IPCC 2005). In addition, the environmental risks and uncertainties of geological storage seem to be much lower than ocean storage (Anderson and Newell 2004).

### *1.1.4 Interface between CCS systems*

It is important to consider the interface between the different aspects of CCS as the various systems will not be acting in isolation. How the emissions are transferred to the carbon capture mechanism; how the $CO_2$ is then transferred to the transportation system; and finally how the $CO_2$ is transferred between the transportation system and the storage site. All of these factors will determine how the different technologies are applied as well as guide the decision making process.

**Interface between plant and carbon capture**

Different carbon capture systems have their own requirements although there are common features. The common requirements are listed below;

- What is the energy efficiency of the plant? Since the process requires an input of energy, a proportion of the energy produced by the plant that is diverted to the process will be greater in plants with low energy efficiency.

- Are there any site constraints? Retro-fit of existing plants to include carbon capture processes will require additional space.

- What is the remaining plant life? If the plant will come to the end of its life before the carbon capture technology then this will result in a financial loss.

- Will any modifications have to be made to an existing plant? Some processes will require the extraction of steam from the low-pressure part of the steam-cycle which will then not be available for producing power.
- Are there any environmental considerations? When chemicals are used as part of the process, this can result in an environmental hazard which needs to be controlled.

- What is done with the solid and liquid wastes? Environmental and legislative issues need to be considered when disposing of the by-products of carbon capture.

Each carbon capture system also has additional requirements. The important considerations for post-combustion are as follows;

- What is the concentration of the $CO_2$ in the flue gas? Flue gases are usually at atmospheric pressure which means that the pressure of $CO_2$ could be as low as 3-15 KPa (IPCC 2005). This will affect which separation process is used as typically membranes are used where there is a high partial $CO_2$ pressure difference and solvents where it is low.

- What is the cooling requirement of the process? When solvents are used, the temperature of the flue gas and solvent will have to be reduced so that carbon capture can take place.

- Are any additional processes required? For example, coal fired power stations will produce flue gases with a lot of impurities. These impurities need to be removed before carbon capture can take place.

The important additional considerations for the oxy-fuel process are;

- In what phase state does the oxygen need to be transported? Oxygen needs to be supplied as a gas but it may be more cost effective to pump it as a liquid and then convert it to a gas just before delivery to the combustion chamber.

- How is the heat supplied? Some oxy-fuel systems require in-direct heating and others direct heating.

- What is the combustion temperature? When pure oxygen is used the combustion temperature of the fuel can be as much as 3500 degrees Celsius which is far too high for conventional power plant materials.

The additional considerations for the pre-combustion process are;

- What is the phase state of the supplied fuel? The fuel needs to be used in a gaseous form and therefore needs to be converted if it is supplied in a liquid or solid form.

- Do impurities need to be removed? Before reaction with the steam to produce $CO_2$ and more $H_2$, the syngas needs to be cleaned.

- What is required to use $H_2$ as a fuel? Integrated Gasification Combined Cycles (IGCC) can be used although these are not yet fully commercial. Fuel cells are also currently being developed.

**Interface between carbon capture and transportation**

As with carbon capture, various considerations have to be taken into account when transferring the $CO_2$ from the carbon capture system to the transportation system. These include;

- What temperature and pressure is the $CO_2$ after the carbon capture? At this point the $CO_2$ is likely to be at atmospheric pressure and in a gaseous form which may not be suitable for transport.

- What temperature and pressure does the $CO_2$ need to be in order to be transported? Different transport options as well as variations within the same transport option may have different requirements.

- What equipment is needed to get the $CO_2$ to the appropriate temperature and pressure? In order to get the $CO_2$ to the correct phase state for transport, it will be necessary to compress the $CO_2$.

- Are there any additional processes required? Many pipelines have tolerances on the amount of impurities allowed. This means that if the impurities were not removed prior to carbon capture, then the $CO_2$ needs to be cleaned.

- What type of transportation is being used? Whilst both pipelines and ships will likely require the $CO_2$ to be in liquid form, the way this needs to be achieved will be different. Pipelines use high pressure to achieve the liquid state whereas in ships this is not feasible. Instead, the temperature of the $CO_2$ is reduced to allow relatively low pressures.

- Are there any requirements for specialised infrastructure? It may be necessary to use a combination of transport methods. One example is using a pipeline to transport the $CO_2$ to a port and to load on a ship. This would require additional compression/decompression processes at the port.

**Interface between transportation and storage**

The final interface involves the question of how to get the $CO_2$ from the transportation system and into the storage system. Considerations include;

- How was the $CO_2$ transported? If the $CO_2$ was transported by ship then just before it enters the storage system, it is at the surface of the water. If it was transported by pipeline then it will be at the seabed or if on land, just below the ground surface. This means that with ships, there will need to be some form of connection point such as a platform or buoy. If the storage is on land then the pipeline will have to connect directly to the wellhead.

- Is there existing infrastructure? This may limit the design of the transportation system however capital costs will also be reduced.

- Is enhanced oil recovery going to be used? If EOR is to be used then two pipelines are usually required although it might be possible to use the same riser. It might also be possible to use just one pipeline.

## *1.2 Other Considerations*

### *1.2.1 Stakeholders*

In addition to the technological considerations of CCS, it is also important to consider the different groups of people who will have an interest in any CCS project. The CCS stakeholders can be typically divided into four groups; government, industry, academia and others (banks and Non-Governmental Organisations (NGO) etc.). Stakeholders from different groups will either support or protest against a CCS project depending on their motivations and concerns. It is therefore vital to identify these motivations and concerns co that they can be satisfied.

Governments normally hold a positive attitude towards CCS and consider it a means to mitigate climate change. However, they are also concerned about the reliability of technology and high costs. In addition, the global image of a government may benefit from deploying CCS projects. Stakeholders from industry, especially energy firms, tend to believe that CCS is necessary to reduce $CO_2$ emissions and are willing to support CCS because of regulations, laws, tax, company image and potential profits. The motivations for stakeholders from academia can be concerns about climate change and the large potential for research. By contrast, stakeholders from banks or NGOs might be less supportive about CCS than other stakeholders since they are more concerned about the risks, costs and the energy penalty. This group also includes the general public.

In order to assess the perception and attitudes of the different stakeholders towards CCS, many surveys have been carried out in different countries. In general, stakeholders' perceptions towards CCS vary depending on when and where the survey took place. Two surveys conducted in China and the EU respectively will be reviewed to investigate the stakeholders' perception and attitudes towards CCS and how they influence the deployment of CCS projects.

Reiner and Liang (2009) conducted a survey in order to assess the potential challenges and opportunities for CCS projects in China and also compared the new findings with previous surveys. 131 Chinese stakeholders from 68 key institutions were selected from 27 provinces and regions by using 31 face-to-face interviews and an online survey. The survey offered insights into a wide range of subjects relevant to CCS projects in terms of perception towards climate change, preference of technologies, scale of demonstration projects and relevant costs. It was found that more respondents considered climate change as a serious problem in 2009 than they did in 2006 and that these respondents were also more likely to consider CCS as necessary. In addition, it was found that CCS was not a new concept for the Chinese stakeholders surveyed and was widely regarded as an important technology to mitigate climate change. However, a few respondents were concerned about the reliability of CCS technologies and the availability of storage sites. In addition, their final decision regarding CCS may be significantly influenced by their concern about the reliability of the technology and the high cost of this technology. It was also found that the government has an important role in the development of CCS projects. This is particularly important in China as many of the energy companies are state owned.

Shackley, Reiner et al. (2008) investigated the acceptability of CCS in EU with an assessment of the key determining factors. The stakeholders included representatives from NGOs, the energy sector, politicians etc. They also investigated the social acceptability of CCS and the impacts of its implementation. Their findings were that there no major barriers to the deployment of $CO_2$ capture and geological storage (CCS) from scientific, technical and legal perspectives. However it was found that an appropriate level of economic incentives and suitable regulatory measures would be necessary before CCS can be implemented.

From the survey, it was found that most of the respondents moderately supported CCS and believed that it had a role to play in their own country's plans to mitigate emissions of $CO_2$. Moreover, their belief in the role of CCS had an increased tendency when moving from the national, to the EU, and to the global scale. In addition, the respondents tended to consider the risks of CCS moderate or non-existent. It was also found that stakeholders from different institutions or organisations had different perceptions and attitudes towards CCS since they had different interests and concerns. NGO respondents seemed to be seriously concerned about the role of CCS and to have a more negative perception of the potential risks than other stakeholders. On the other hand stakeholders from the energy sector were found to be the most optimistic regarding the role of CCS with a relatively low perception of the risks. Government officials and academics had a similar responses to that of stakeholders from the energy sectors, whilst elected politicians who were not part of government at the time were typically somewhere in between the pinions of the energy and NGO respondents.

On the whole, the stakeholders in developed countries such as the U.S., Canada and the EU, where many pilot projects have been carried out, are more aware of CCS as they are the leading countries for deploying CCS projects. However, as the largest net emitter of $CO_2$, China is now considering CCS projects. This is because many of the stakeholders in China believe that the global image of the government can benefit from developing a commercial demonstration CCS project and that such a project could also create advantages for Chinese power companies investing in CCS technologies (Reiner and Liang 2009).

Whilst the views of all the stakeholders are important, the two most important stakeholders are governments and the public. Since CCS technology is immature and has high costs associated with it, the main sources of support for CCS projects are governments. The general public on the other hand, can play very important role in halting a CCS project and there is still a large proportion of the general public who lack knowledge or are misinformed about CCS or climate change (Malone, Bradbury et al. 2009). The influence of these two groups will be discussed further in the next sections.

### *1.2.2 Public Perception*

When envisioning an engineering system to achieve $CO_2$ sequestration, it is very important to take into account with whom the final decision lies as to whether or not it will be realised. Even though decisions are perceived to be made by international lawmakers, governments, local politicians or CEOs; one must look at the true reasons why some projects are realised and some are not.

Public opinion is arguably the most important and most influential factor since it is public opinion that forms both the base of a government's power and the financial success of a company. National governments will not adopt policies that are opposed by the electorate and local decision makers will not approve projects that they know that their constituents are against. The motivation of course is re-election; that the opportunity to apply all of their ideological principles in government should not be given up just to address a particular issue. An example comes from the Dutch town of Barendrecht where a proposal to store $CO_2$ more than 1500 m below ground met with large public concerns and the project was postponed indefinitely (Voosen 2010). A similar example comes from Germany where the energy giant Vattenfall halted plans to inject its $CO_2$ into underground aquifers because of fierce local resistance (Chazan 2009). In this case the plant had already installed capture technology and currently vents the separated $CO_2$ into the atmosphere as well as selling it to other industries.

An example where the public concern has been utilized for seemingly purely political purposes is the blocking of proposed research into storing $CO_2$ underground in the German province of Schleswig-Holstein. The issue was raised by politicians in a local election campaign, drawing upon the general scepticism about such storage. They subsequently won this election and blocked the initial feasibility study (AGS 2010). Apart from the concrete examples of the Netherlands and Germany, surveys of public opinion have shown a high level of scepticism when it comes to $CO_2$ capture and storage in countries such as the US, UK and Japan (Reiner, Curry et al. 2006) and China (Reiner and Liang 2009).

Scepticism of development usually comes from two different observations; either that something has been proven to be a hazard or a disadvantage or that something is unknown. Studies have shown very little knowledge of what $CO_2$ sequestration actually means (Malone, Bradbury et al. 2009). Further surveys demonstrated that only 4-5% of the public in the US had heard of CCS from 2003-2006 due to lack of media attention although this rose to 17% in 2009 (Okeefe and Herzog 2010). The lack of knowledge alone is not always enough to produce a negative attitude against a proposal as people tend to be curious and find out for themselves if they think it is going to affect them. In the case of Barendrecht, the proposer was Shell who, as with most companies in the oil and gas industry, provoked an inherent scepticism amongst the public which may have overshadowed reality. Shell themselves have confessed that they should have spent more time informing the public before choosing a site and that they will conduct public hearings and consultations for future projects(Chestney and Wynn 2011). The importance of the lack of knowledge is even more evident when considering that, in the Barendrecht case, Shell encountered little protest when the original plant was constructed even though gas extraction has a record of being prone to accidents (Voosen 2010). It is not surprising that most of the resistance has been against storage proposals on land since people seem to be most interested about things that are going on in their “back yard”. This is further illustrated by the general public in the Netherlands being moderately supportive of CCS (Shackley, Reiner et al. 2009).

These examples all relate to onshore storage however $CO_2$ storage offshore has also met with public resistance. An example is an international initiative to store $CO_2$ close to the coast of Hawaii where the project seemed very promising in terms of feasibility. The initiative included a public outreach programme but before this could be started an article appeared in a local newspaper revealing the plans and who were behind it. This stirred emotions mostly because it was an international initiative and people did not want foreigners dumping what they saw as waste near Hawaii (de Figueiredo, Reiner et al. 2002).

Early outreach to the public is important to achieve acceptance which is necessary for a project to be realized. This applies not only at a national level but, more importantly, to a local level. It is also important that this information comes from a trusted source; this poses a problem since the oil and gas companies do not generally enjoy a good reputation amongst local communities.

To summarise, if CCS is to be adopted in a certain country it is important to:

- Educate the public through increased media exposure about what CCS actually means, what its aims are and what risks it poses. General scepticism can be utilised for purely political purposes as was the case in Germany but also feed the worries of local communities.

- Reach out to the local community which will be affected and gain support and understanding.

- Make sure all communication comes from sources that the public sees as reliable. This may be a popular government in one community and possibly a popular company in another community.

### *1.2.3 Government Policy*

As discussed earlier, the support of the government is vital to the success of a CCS project. This support can be given directly in the form of incentives and subsidies or it can be given indirectly through carbon taxing. It is therefore important to know which parts of the world provide a suitable regulatory regime and the level of investment available.

In order to determine the global trends in climate change policy, investment information provided by the Deutsche Bank Group (2009) was analysed to provide a breakdown of various aspects of the climate change policies that were in place in 2009. The climate change policies have been divided into different categories and then grouped by the region they apply to. Figure 1-10 shows the breakdown of policy types by region and Figure 1-11 shows the breakdown of regions by policy type. In both cases the y-axis is the percentage of the total number of policies for a given region for each policy type.

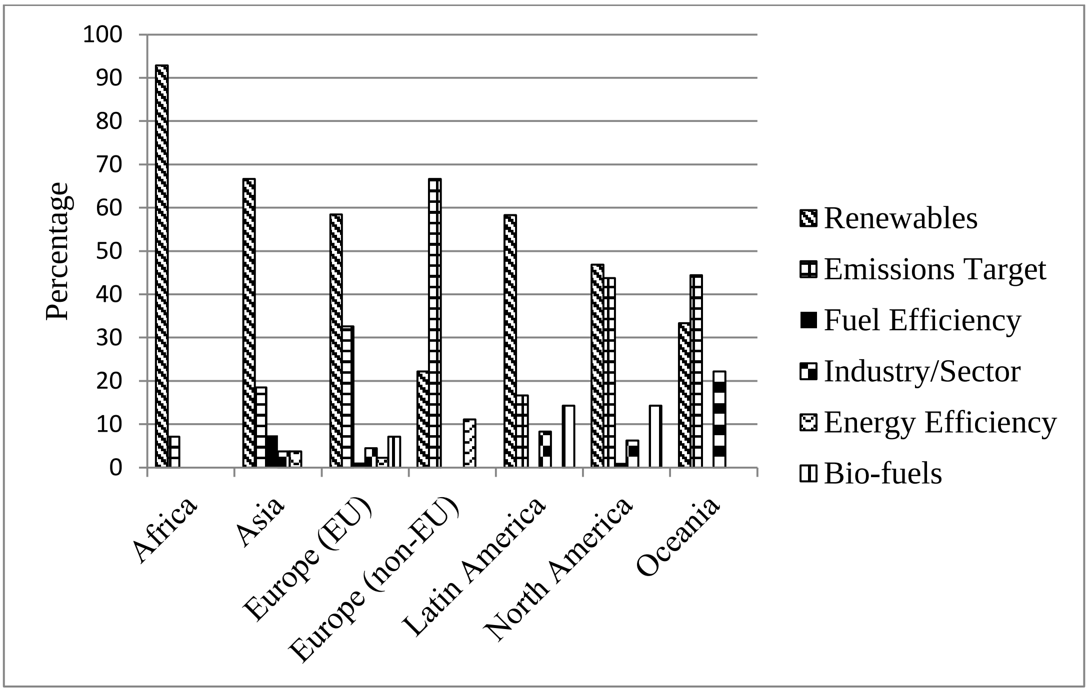


Figure 1-10: Breakdown of regional climate change policy by type

The two most important policy types in any part of the world relate to the use of renewable energy to indirectly reduce emissions and by setting emission targets such as the Kyoto Agreement to directly reduce or control emissions. It can also be seen that there is a significant philosophical difference between developed and developing regions in the types of policy they pursue. Whilst the more developed regions have policies for both renewables and emissions targets, the less developed countries are focussing on increasing the use of renewable energy.

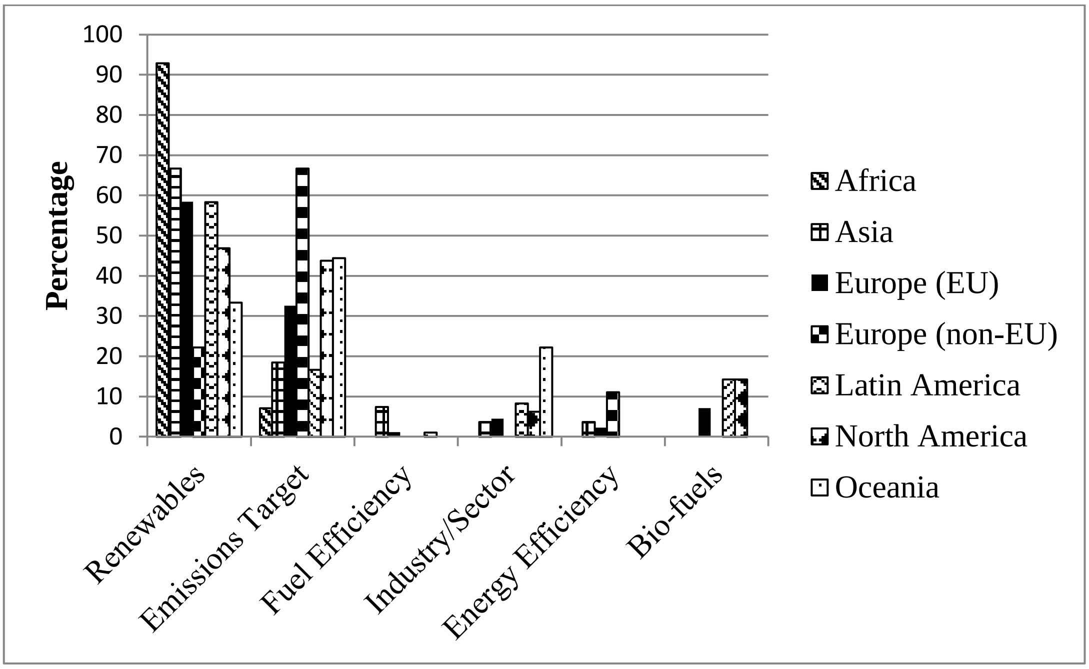


Figure 1-11: Breakdown of climate change policy type by region

Many of the climate change policies in existence are either voluntary or aspirational i.e. the government would like to pursue these policies. This means that many of the policies may never be implemented. It is therefore important to know what proportions of these policies are mandatory; whether this is through international treaty or national legislation. Figure 1-12 shows the split between aspirational or "soft" policies and mandatory or "hard" policies. In general the more developed regions have a greater proportion of hard policies and in the least developed region (Africa) over 90% of the policies are aspirational. Latin America also shows a large proportion of hard policies however this may be due to there being a number of policies relating to bio-fuels which is an important economic concern in this region.

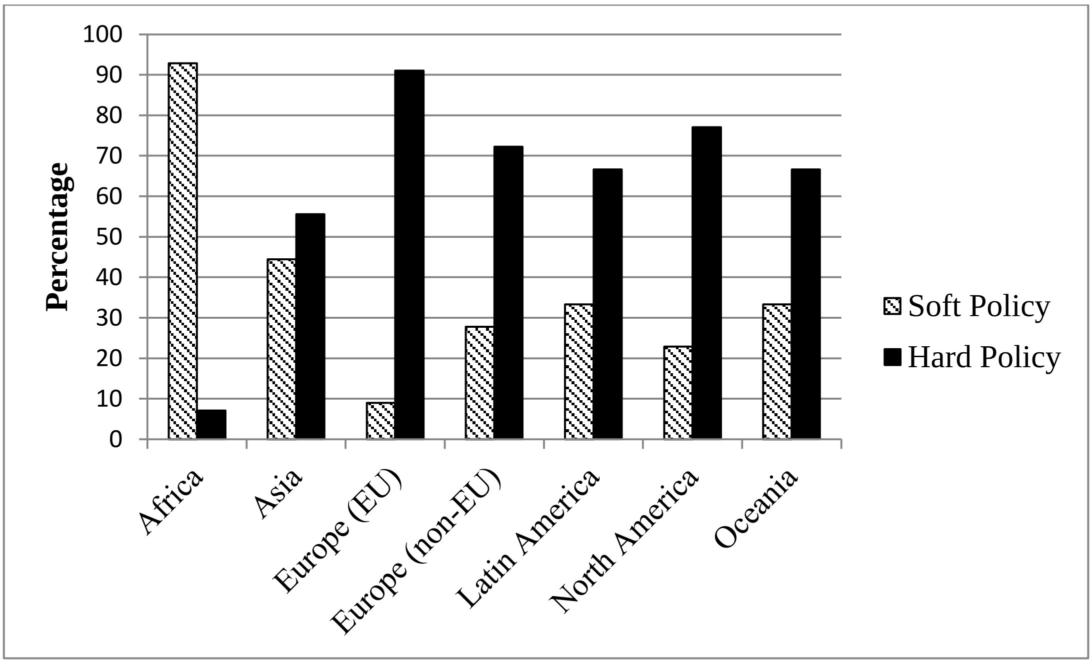


Figure 1-12: Percentage of climate change policies that are mandatory in 2009

A further breakdown of mandatory policies by policy type and region is shown in Figure 1-13 which shows that renewables policies are still the most implemented followed closely by emissions targets. It can also be seen that Europe (EU), North America and Oceania place a similar emphasis on these two policy types whereas Asia has legislated far more renewables policies than emissions targets. The main reason for this may be that the majority of the developed regions must comply with the Kyoto Agreement and that more constraint is placed on these regions with regards to how they implement their climate change policy. They may also have much greater pressure placed on them to act as a result of global expectation.

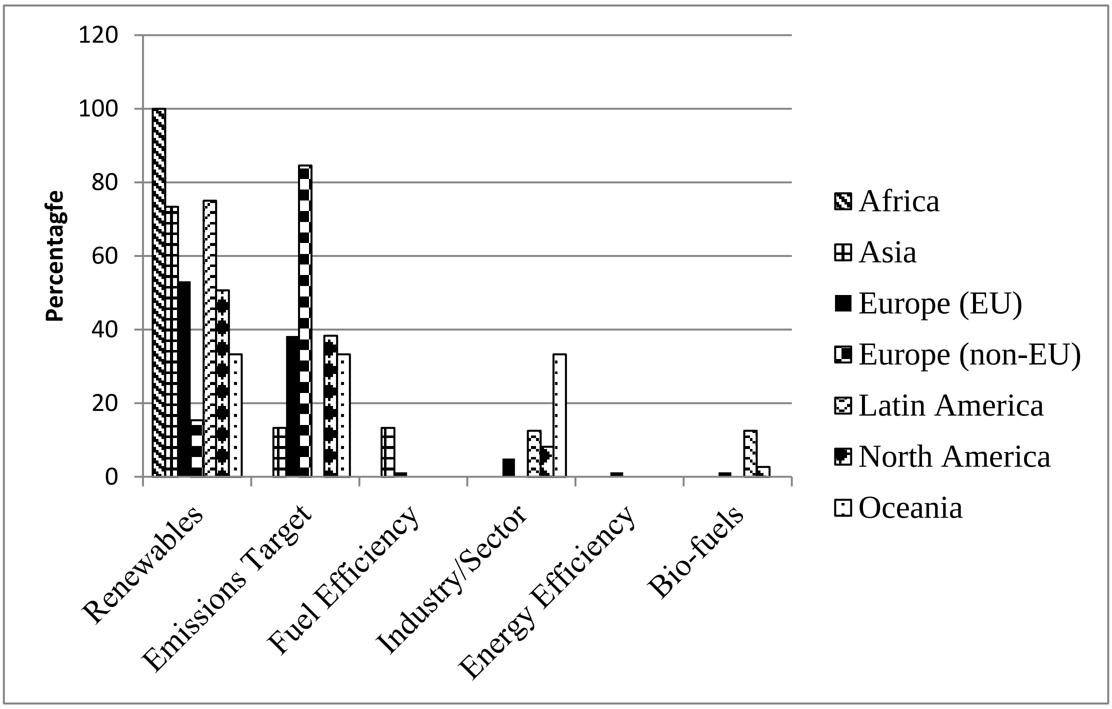


Figure 1-13: Breakdown of mandatory climate change policy type by region

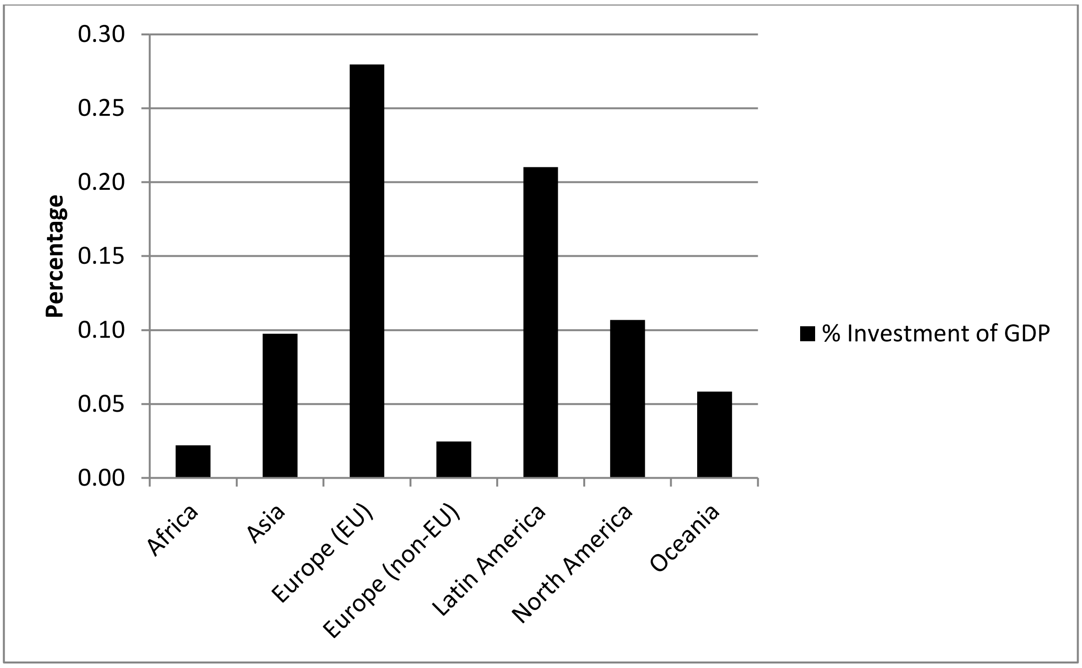


Figure 1-14: Percentage investment of GDP in 2008 by region

The effects of these constraints and expectations can be seen in Figure 1-14 where the percentage of GDP that was invested in 2008 in clean energy is shown for each region. The biggest investor was the EU which is the greatest promoter of emission target led solutions. Latin America also invested heavily; again, this may be due to the number of bio-fuels projects implemented in this region as a result of a desire to develop this industry. Oceania also has relatively high investment in clean energy when the fact that only two countries are included in this region is taken into account.

Since CCS has not been carried out on a commercial scale and is still in the development phase, one of the only ways that it can be demonstrated is with large scale investment. Whilst some of this investment may come from industry, there is an expectation that governments will need to provide large subsidies. Since the EU is already investing a lot of money, this would be a logical location to develop CCS technology and techniques. It should be noted that whilst the proportion of China's GDP that was invested was relatively small, in real terms this is a substantial amount of money. In addition, Japan has stated its intention to invest in CCS technology although this is currently a government aspiration and not a legislated requirement.

The other method by which companies could be encouraged to invest in CCS is through carbon taxation. Providing the cost of implementing CCS is less the tax they would otherwise pay on their $CO_2$ emissions, CCS should be commercially viable. It is therefore also important to know which countries have already introduced a carbon tax as this could influence where CCS takes place. Table 1-7 shows a breakdown of the different carbon tax regimes currently in existence. It should be noted that individual states within the USA and Canada have their own carbon taxes but there is no carbon tax on a national level.

It is concluded that the EU, China and Australia provide the most suitable locations for the development of CCS technology based on a combination of regulation, level of investment, political will and carbon taxation. Funding from private investors and investment banks will also be more readily available as they will feel that the level of investment risk is lower where the regulatory framework is more supportive of the technology they will be investing in.

TABLE 1-7
CARBON TAX BY COUNTRY

| Country | Year | Description | Amount |
|---|---|---|---|
| South Africa | 2010 | Applies to automotive industry; tax will apply at time of sale, and will be related to the amount of CO2 emitted by the vehicle. | 75 South African Rand will be added to the price for every gram of CO2 per kilometer the vehicle emits over 120 g/km. |
| India | 2010 | All coal imports and mined (50% of India's power generation is from coal) | 50 rupees per metric tonne ($1.07/t) coal |
| Australia | 2012 | 500 largest polluters | A$23/t CO2 |
| Denmark | 1992 | Rate varies depending on use of energy efficient measures and what energy is used for. Applies to all industries | 100DKK/t (1164 DKK/t for electricity) CO2 |
| Ireland | | Kerosene, marked gas oil, liquid petroleum gas, fuel oil, and natural gas. Electricity generation is exempt. Also applies to domestic use | €15/t CO2 |
| Netherlands | 1992 | Tax on all fossil fuels unless being used as a raw material | Environmental tax is 5.16 NLG/t, Regulatory tax is 27 NLG/t CO2 |
| Sweden | 1991 | Transport, space heating, and non-combined heat and power generation | SEK 930/t CO2 |
| UK | 2001 | All electricity except new renewables (nuclear is taxed even though no CO2 is produced) Domestic use and transport exempted | Electricity: 0.470p per kWh<br>Mains Gas: 0.164p per kWh<br>LPG: 1.050p per kg<br>Any other "taxable commodity" : 1.281p per kg |
| Norway | 1991 | All fossil fuels. Also applies to production of oil and gas offshore | High rate of US$51/t, average tax of US$21/t CO2 |
| Switzerland | 2008 | All fossil fuels unless used for energy or petrol/diesel. Companies can exempt themselves if they take part in a cap-and-trade scheme | CHF 12/t CO2 to CHF36/t |
| Costa Rica | 1997 | All fossil fuels | 3.50% |

### *1.2.4 Legal Issues*

Liabilities for different stages in a CCS project are shown in Table 1-8. The critical liability issue associated with the short term aspects of CCS projects is operational liability. This refers to the environmental, human and safety risks associated with capture, transport, and storage of $CO_2$.

TABLE 1-8
LIABILITY TIMEFRAMES AND ISSUES

| Timeframe | Liability |
|---|---|
| Short term<br>Project and any contractual time period covering post-injection | Operational liability |
| Long term<br>50-100 up to thousands of years | Environmental liability<br>In-situ liability<br>Trans-border liability |

In the long term, there are three types of liability issues; environmental, in-situ, and trans-border liability. Environmental liability is associated with any $CO_2$ leakage from storage sites that may affect the global climate by contributing to $CO_2$ concentrations in the atmosphere. In-situ liability is associated with leakage or migration that could result in public health, environmental, or ecosystem damage. Trans-border liability refers to any liability issues that may affect more than one country. This is important in instances of migration of $CO_2$ across national borders and/or damage to the global climate caused by $CO_2$ leakage in one individual country. These issues will have to be addressed by intergovernmental agreements and international treaties.

A big issue associated with $CO_2$ storage is that a legal framework is absent in most countries and regions. Because the storage of $CO_2$ in oceans and geological formations is not a particularly well pursued venture, organisations and governments do not have enough motivation and/or experience to draw up such a framework. Any company or organisation that wishes to pursue CCS will thus be met by large legal uncertainties. Such legal uncertainties are likely to act as a deterrent from further development. This leads to a vicious circle where no experience is gathered and therefore no experience can be used. This means that no precedents can be established leading to enduring legal uncertainty. It is clear that it is necessary for either governments or industry to take the initiative of establishing the required experience without relying on a legal framework. So far, this initiative has been largely absent.

Many countries like the United States and Canada have regulations for $CO_2$ storage written into various regulations concerning groundwater protection, regulations for the oil and gas industry and the dumping of pollutants in marine environments. Most countries have observed the London convention and its 1996 protocol (UN 1996) on marine dumping. However this is contradictory when it is used to assess the legality of depositing $CO_2$ in ocean space because it lacks specific clauses relating to carbon dioxide. One of the main reasons for the uncertainty is due to unspecific regulations when dealing with the classification of $CO_2$ as most conventions regulating marine dumping specifically prohibit the dumping of "waste". If $CO_2$ is classified as waste from an industrial process it would then be illegal to deposit it in ocean space. So far there has not been a specific addition to these conventions clarifying how $CO_2$ should be classified.

Most substances that are specifically classified as prohibited for dumping are substances where the world has seen large scale spills and/or dumping. This is because they have been in circulation for much longer (before the developments of said conventions) and because the handling of them is associated with large profits. This again points to the lack of experience with handling and storing $CO_2$ offshore being a major obstacle to specific legislation being developed. This could be overcome by strong initiative from either government or international organisations to create pilot projects with the purpose of gathering experience. Such initiatives have been relatively rare.

Exceptions can be found in the EU and Australia. Australia has taken a progressive approach to CSS because of their large per capita emissions. The Australian government has realised the need for a regulatory framework to make CCS an attractive option for companies and passed a bill in 2005 outlining the legal context of $CO_2$ storage (MCMPR 2005). The European parliament passed a bill in 2009 outlining a legal framework for $CO_2$ capture and geological storage (Official Journal of the European Union 2009). These frameworks make the EU and Australia more attractive for pilot projects which may be used to gather more experience when working towards a goal of global consensus on the legal aspects of CCS.

### *1.3 Existing CCS projects*

Currently CCS is not ready to be used on a wide-spread commercial scale. As previously mentioned, demonstration projects are required to test the different methods and their viability. As of the year 2010, there are 77 Large-Scale Integrated Projects (LSIP) for CCS (Global CCS Institute 2010). The locations of these projects are shown in Figure 1-15. It can be seen that the majority of these projects are in North America, Europe, China and Australia. However there are currently no projects being carried out by some of the largest emitters of $CO_2$ including Japan, India and Russia.


Figure 1-15: Large scale integrated project by industry sector and location

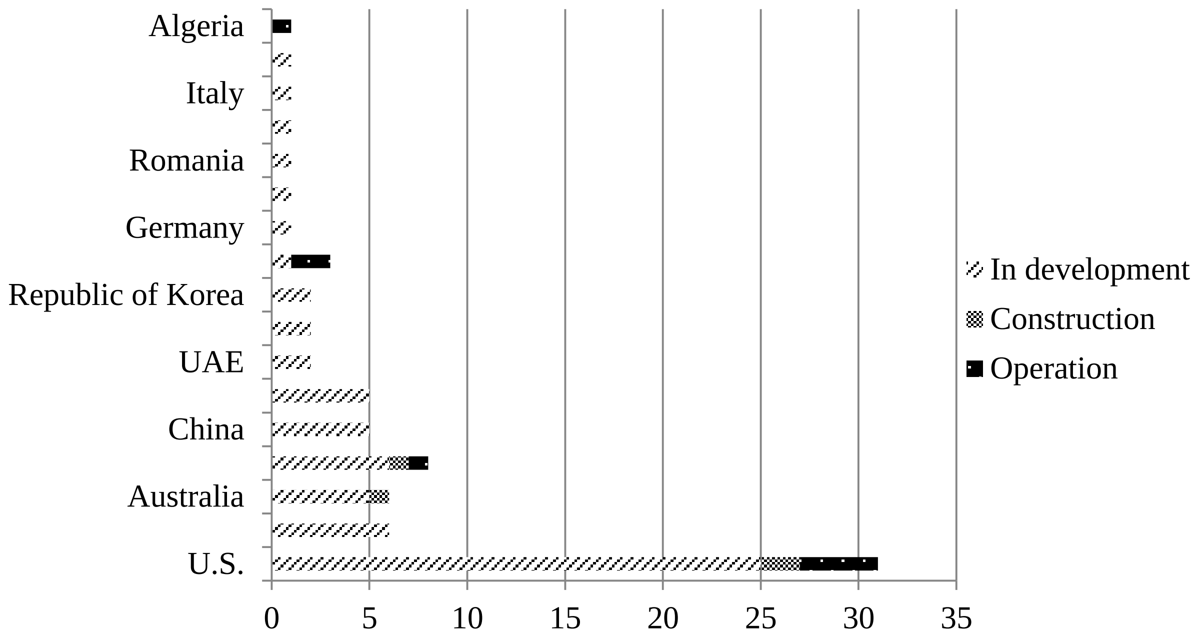


Figure 1-16: Status of large-scale integrated projects by location

Figure 1-16 shows a break-down of the status of these projects. Of the 77 projects, only 8 are running on a commercial basis (four in the U.S., two in Europe, one in Canada and one in Africa). The other 69 projects are still being planned.

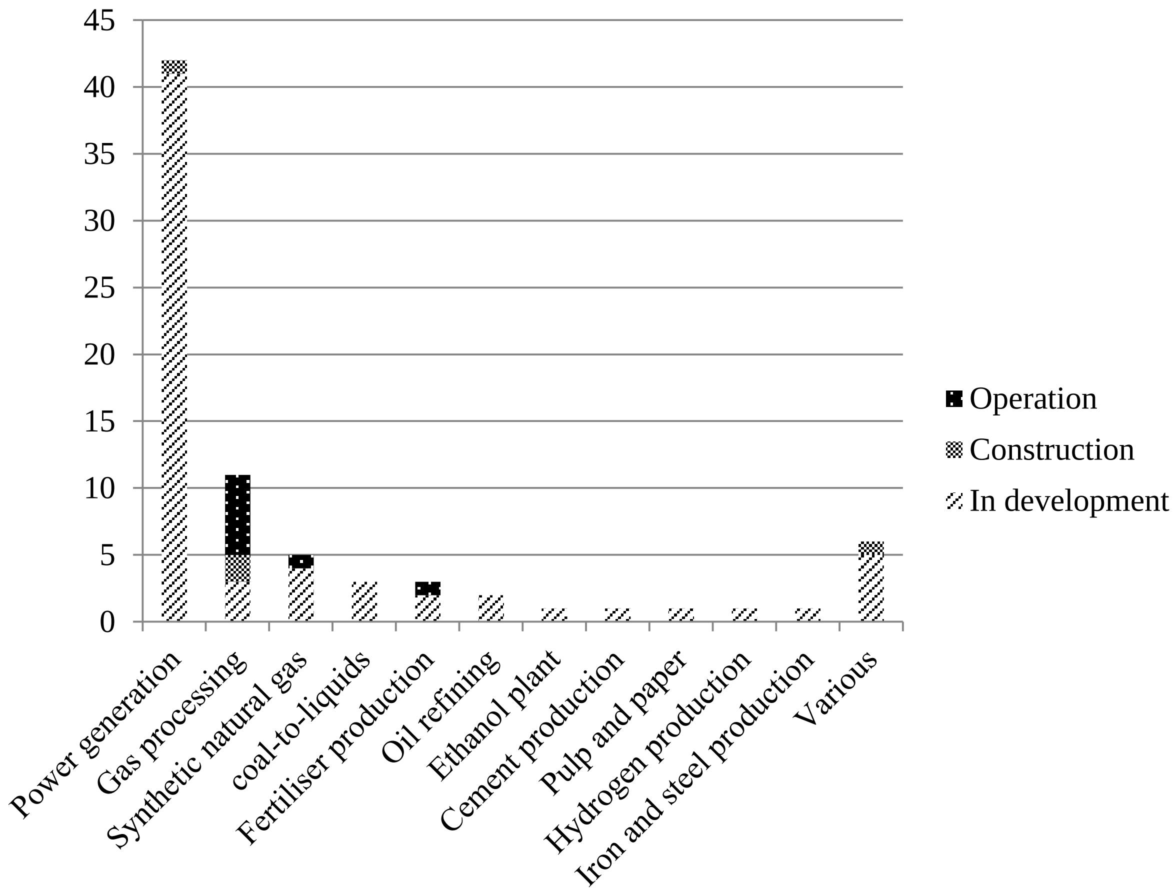


Figure 1-17: Large-scale integrated projects by sector

42 LSIPs are in the power generation sector and most of these are planned for coal-fired plants. This is shown in Figure 1-17. Despite being major contributors to global $CO_2$ emissions, there are few LSIPs in sectors such as cement, iron and steel, and paper and pulp products industries. "Various" refers to projects that capture $CO_2$ from a hub or network of projects and therefore covers a range of industries.

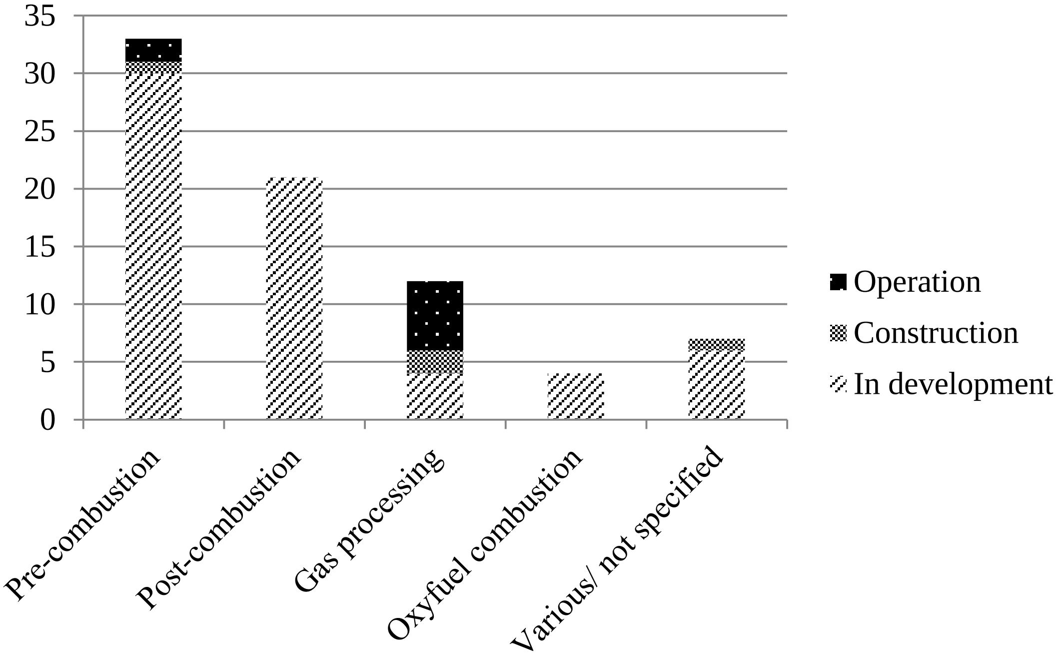


Figure 1-18: Large-scale integrated projects by carbon capture type

As Figure 1-18 shows, most LSIPs using pre-combustion and post-combustion are in the power generation industries. The pre-combustion capture system is being developed mainly for new facilities whilst the post-combustion capture system is mostly used for existing facilities. The capture system used for gas processing is at the most mature stage of technology implementation and is utilised by most of the LSIPs in operation. All the oxy-fuel combustion projects are planned in the power generation sector.

Almost all of the LSIPs being considered or planned use pipelines for the $CO_2$ transportation. Figure 1-19 shows these projects in terms of their pipeline length. This type of transportation technology is proven by EOR in North America. Most of the projects are within 100km of the storage site making the cost of the transportation a small part of the overall cost. However, many of the projects being considered are offshore and in the future the option of transporting $CO_2$ by ship may be considered.

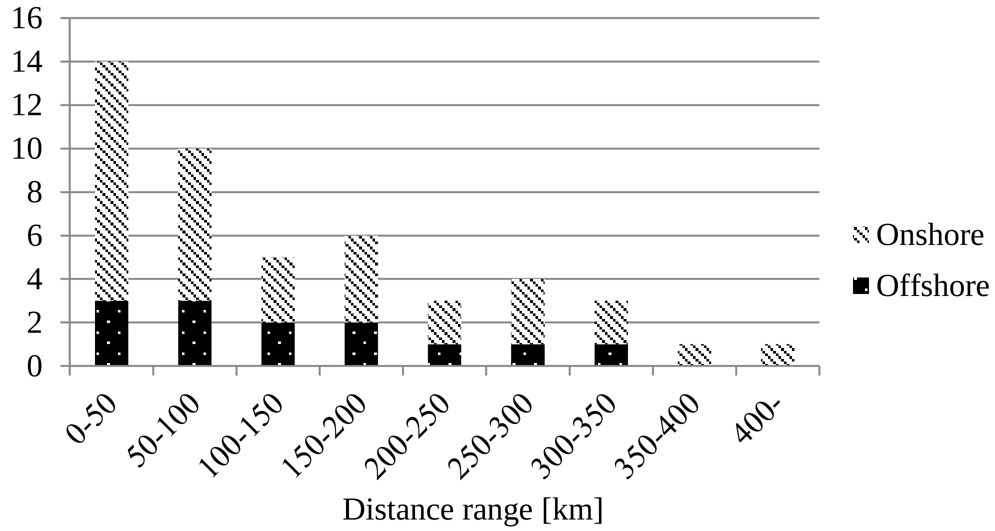


Figure 1-19: Large-scale integrated projects by pipeline length

Figure 1-20 shows that 32 projects are being considered or planned using geological storage with EOR. Other geological storage options are being utilised for other projects in addition to EOR, but at present ocean storage such as dissolution and lake type has not been considered or planned for LSIPs.

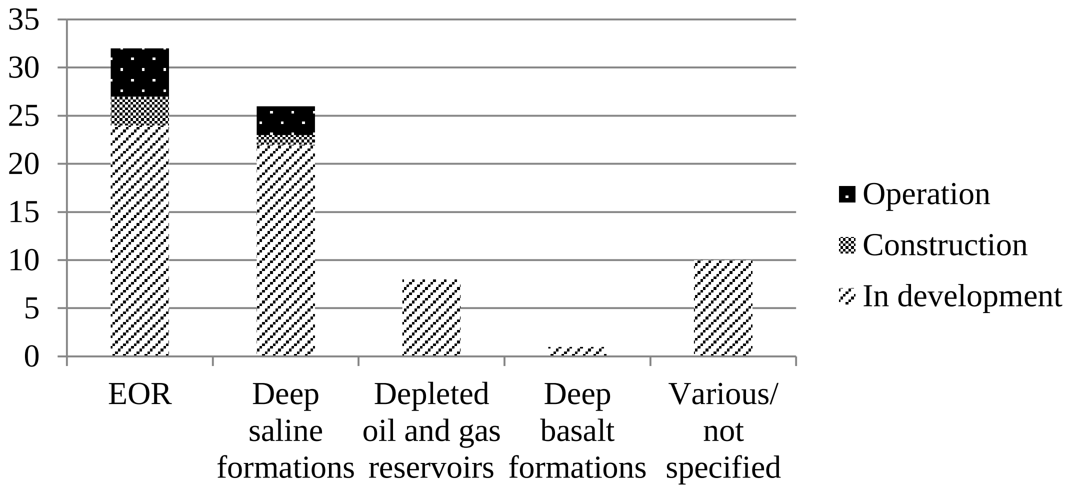


Figure 1-20: Large-scale integrated projects by $CO_2$ storage type

Table 1-9 shows the main projects that are currently in operation. It can be seen that around one million tonnes of $CO_2$ per annum are being captured and stored with costs ranging from \$6/t$CO_2$ to \$20/t$CO_2$. The distances the $CO_2$ is being transported range from minimal to 330km and all of the projects are capturing $CO_2$ from gas processing or removing the $CO_2$ prior to combustion.

In general, there are very few projects that demonstrate CCS on a large-scale and they use a limited range of the different types of CCS technology being proposed. This means that there are opportunities to apply CCS technology and systems in new ways.

TABLE 1-9
MAIN COMMERCIAL SCALE PROJECTS

| | In Salah $CO_2$ Injection | Sleipner $CO_2$ Injection | Snøhvit $CO_2$ Injection | Weyburn Operations |
|---|---|---|---|---|
| Location | Ouargla Wilaya, Algeria | North Sea, Norway | Barents Sea, Norway | Saskatchewan, Canada |
| Capture | Natural Gas Processing Plant | Offshore Platform Natural Gas Processing | LNG Plant Natural Gas Processing | Coal Gasification Plant Pre-Combustion |
| Transportation | 14 km pipeline | Minimal | 160 km pipeline | 330 km pipeline |
| Storage | Geological (Deep Saline Formations) | Geological (Offshore Deep Saline Formations) | Geological (Offshore Deep Saline Formations) | Beneficial Reuse (Enhanced Oil Recovery) |
| Injection depth [m] | 1,850 | 1,000 | 2,500 | 1,450 |
| Capacity | 14-17Mt | 20Mt | unknown | 17Mt (20-25 years) |
| Incremental Cost | $100M ($6/t$CO_2$) | Cap: $106M Op: $7/t$CO_2$ | unknown | Cap: $127M ($10.19/t$CO_2$) Op: $23.6M ($9.85/t$CO_2$) |
| Amount of $CO_2$ captured | 1.2 million tonnes per annum ( >60% of total project emissions ) | 1 million tonnes per annum | 0.7 million tonnes per annum | 1 million tonnes per annum |

## 1.4 *Potential Ideas for the Use of CCS*

It has been shown that the context in which a CCS system will exist and operate consists of many factors. It will therefore be difficult to propose a complete system that fits well within that context and that fulfils the expectations of all the stakeholders. Any novel proposal for a CCS system must therefore be preceded by a judgement of which of these factors should receive more attention. This should be based on the identified major obstacles, available investor potential and the available knowledge base.

For the purposes of this study, a number of novel suggestions for CCS systems addressing different issues were proposed. These were evaluated against their potential for success based on a scoring system. 13 factors were selected and weighted based on the individual opinion and knowledge of each author (in no particular order). This is shown in Table 1-10. A weighting of 1-10 was applied (where 1 means very unimportant and 10 means very important) and the average was calculated for each factor. The final weighting factors were taken as the percentage contribution of each factor to the total weight (sum of the averages.)

TABLE 1-10
WEIGHTING USED TO EVALUATE IMPORTANCE OF DIFFERENT FACTORS

| Author | Costs | Public attitude | CO2 storage capacity | Technology maturity | Innovative solution | Legality | Carbon footprint/Energy Penalty | Existing projects | National interests | Responsible body | Transport complexity | Environmental impact | Safety |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A1 | 8 | 3 | 2 | 6 | 8 | 6 | 7 | 5 | 6 | 6 | 6 | 9 | 10 |
| A2 | 7 | 9 | 9 | 9 | 5 | 7 | 7 | 5 | 8 | 9 | 7 | 10 | 10 |
| A3 | 6 | 7 | 5 | 3 | 8 | 5 | 10 | 2 | 6 | 4 | 4 | 9 | 9 |
| A4 | 7 | 10 | 9 | 3 | 8 | 1 | 5 | 4 | 7 | 1 | 8 | 8 | 9 |
| A5 | 9 | 7 | 6 | 6 | 2 | 10 | 5 | 3 | 7 | 8 | 4 | 8 | 8 |
| Avg. | 7.4 | 7.2 | 6.2 | 5.4 | 6.2 | 5.8 | 6.8 | 3.8 | 6.8 | 5.6 | 5.8 | 8.8 | 9.2 |
| % | 9 | 8 | 7 | 6 | 7 | 7 | 8 | 4 | 8 | 7 | 7 | 10 | 11 |

The weighting was applied to a systematic scoring matrix where different ideas were scored based on these factors. The score of an individual system given for each of the factors was based on a scoring system where 1 means very negative and 10 very positive in terms of the potential success of that system. The weighting factor was then applied to give a weighted score. As an example, a particular system is given a score of eight for "public attitude" and eight for "existing projects"; since "public attitude" has been weighted as being more important, the weighted score (8x8=64) is higher than for "existing projects" (8x4=32.) A total weighted score is calculated for each system as the sum of all the factors which will then reflect how well the given proposal fits within the context of CCS as described earlier.

### *1.4.1 Proposed systems*

A total of nine novel solutions were evaluated; these include both suggestions for engineering systems but also the further research of existing concepts. In addition, conventional systems for capture, transport and storage were also scored in the same way. This was done both to compare them to the novel solutions and also because a system that addresses only one of these areas will still have to rely on the best currently available conventional systems to address the other two parts of the CCS chain.

The nine novel concepts were; in no particular order:

**Offshore geological storage with gas cap**

A concept was proposed where a gas is inserted into the chosen geological formation before the injection of the $CO_2$. The gas should be of less density than $CO_2$ at the prescribed depth so as to always rest in a higher position (lesser depth) than the $CO_2$. This gas would act as an inner cap against the existing cap rock preventing the $CO_2$ from ever reaching it. Future leakages would initially be of the lighter harmless gas. If monitoring systems were set up for detecting it, the harmless gas would serve as an early warning system allowing for action to be taken before any actual $CO_2$ escapes the reservoir. This would work well since the time scales of leakage would be likely to be very long unless a seismic event or similar triggers a sudden breach of the cap rock. The disadvantages of this method is that it may be very costly to produce a gas with the correct buoyancy capabilities, it would not necessarily protect against leakages towards the sides of the reservoirs and it is not clear how the two phase flow would behave over very long time scales.

**Adaptation of artificial trees**

This is based on the Artificial Tree concept (Lackner 2009) where a scrubber using sodium hydroxide is used to capture $CO_2$ from the atmosphere. Since post-combustion relies on the use of scrubbers, it should be therefore possible to use sodium hydroxide instead of the more established amine. It is claimed that with full technological maturity that cost of carbon capture will be US$30/t$CO_2$ although the current cost is US$600/t$CO_2$ (Blackstock 2011). The most negative aspect is that the current system can only capture one tonne of $CO_2$ per day and the energy consumption of the system is estimated to be 50 KJ/mol$CO_2$.

**GM Trees**

It has recently been shown that the world's forests play a larger role than previously been thought in absorbing $CO_2$ from the atmosphere with a capacity to absorb up to 1/3 of the total emissions (Pan, Birdsey et al. 2011). The reforestation of large parts of the world seems unlikely when looking at the predictions of human development in the coming century. The genetic modification of existing trees and vegetation to absorb more $CO_2$ as well as being able to grow in new areas such as the oceans is a radical idea to offset the lack of reforestation. This concept has been considered before and many negative aspects have been found (Lang 2005). The most negative aspects of the idea are that it is relatively unstable (i.e. a fire could release all the absorbed $CO_2$ instantly), the environmental impact and general public perception.

**Ocean storage membrane**

Ocean storage of $CO_2$ is associated with many uncertainties and questions about the rate of dissolution and the effects of deep currents. It would therefore be preferable to introduce technical systems that provide more control. If a relatively closed trench/depression is chosen for storage, this could potentially be covered by an impermeable membrane to avoid escape. This idea would work best for smaller deposits since the technical challenges of constructing and securely installing the membrane would be smaller. Problems with this idea include leakage at the intersection with the sea bed, shifting of sediments causing changes in the shape of the sea bed, damage to the membrane due to currents as well as the long term structural integrity of the system.

**Transporting of flue gas to central location**

The largest part of the cost for a complete CCS system is the capture of the $CO_2$. The reason why CCS has been discussed mainly in connection to power plants and not for smaller sources such as vehicles and smaller industries is the scale of those sources. It is impractical to pursue a capture system for many small point sources which is why the desire is to assimilate them into one (power plants) by, for example, promoting the use of electric cars. This means that more investment can be centralised into the development of one large unit instead of a production process of many smaller units.

The same logic can be thought to apply for the power plants themselves. If all power plants were using the same centralised location for carbon capture, the investment would be simplified and a national or international effort could be combined to reduce the emissions of an entire region. This concept would include laying pipelines capable of carrying uncompressed flue gas which has a very large volume. The positive side of this is that the remaining heat in the flue gas could be used to provide heating for towns passed by the pipeline. Pipelines from a whole region would converge at a suitable location for capture, preferably at a storage site or at a site with good transport links. The disadvantages of this concept are the scale of the pipelines needed to transport the flue gas compared to just transporting the $CO_2$, the uncertainty if economics of scale applies in this case and cooperation between different power companies/governments.

**Offshore pipeline hub**

To mitigate the lack of flexibility in transporting $CO_2$ with pipelines, one concept is proposed where a large pipeline is used to connect two hubs, one onshore and one offshore. The onshore hub would be located close to major point sources of $CO_2$ for easy connection (this can be combined with the centralised capturing concept) and the offshore hub would be located as close to as many high-capacity storage sites as possible. Due to the smaller distances new pipelines would have to be laid and there is a possibility to lay flexible pipelines from the hub and onwards. This concept offers the low cost of pipelines compared to ships but with an increased level of flexibility. Negative aspects include cooperation between different operators both onshore and offshore, the size of the central pipeline and problems with different levels of $CO_2$ purity from sources using different capture systems.

**Offshore EOR/EGR**

The potential negative costs associated with storage of $CO_2$ when using it as a way to enhance the recovery of oil and gas makes this concept very attractive. For offshore applications this is currently considered to be impractical due to economic reasons. However, more research into how EOR/EGR can be safely and practically applied offshore could potentially highlight the concept as the future preferred way of offshore storage of $CO_2$.

**Offshore power plants**

The transport of $CO_2$ in any form is associated with many problems. While there are currently available systems for capture and storage (e.g. the Sleipner project), no large scale examples of offshore $CO_2$ transport exist. Transport of $CO_2$ is associated with many geo-political and technical issues. It is also the part of the three stage process of capture, transport and storage that is possible to avoid. This can be done by positioning the storage site under a point source or vice versa. The location of prospective storage sites is governed by the local geology and it is therefore most likely that the point source would be positioned according to that geology rather than the other way round. This can be done relatively easily onshore by ensuring new power stations are constructed above suitable storage sites. Offshore this would mean a shift of the power generation to an offshore platform. This has advantages in that it not only reduces the need for $CO_2$ transport but also the transport of the feed gas in the case of a gas fired power plant. The negative aspects of this concept are the associated costs with offshore operations, that it only applies to new power plants and that it lends itself best to gas fired power plants which are not as abundant as coal fired plants.

**Sharing with existing pipelines**

The laying of new pipelines would be the largest part of the transport cost for a new CCS system, so it is therefore preferable to use existing infrastructure. However many point sources are located within in busy oil and gas producing regions. This means that much of the infrastructure is likely to be used. A solution to this problem may be the sharing of existing pipelines between the produced hydrocarbon (oil/gas) being transported ashore and the $CO_2$ being transported offshore. This concept is associated with many problems among other things the characteristics of the multiphase flow in such a pipeline and the separation of the two phases. However, if it could be made to work there is potential for large savings.

### *1.4.2 System evaluation*

The weighted scores for each system are shown in Table 1-11. The different alternatives have been categorised as dealing with capture, transport, storage or a combined approach.

TABLE 1-11
TABULATED SCORES FOR EACH OPTION

| | | Cost effectiveness | Public attitude | CO2 storage capacity | Technology maturity | Innovative solution | Legality | Energy Penalty | Existing projects | National interests | Responsible body | Transport complexity | Environmental impact | Safety | Total score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capture | Pre-combustion | 44 | 59 | 66 | 44 | 29 | 41 | 56 | 27 | 48 | 40 | | 21 | 65 | **45** |
| | Post-combustion | 44 | 59 | 58 | 57 | 22 | 41 | 56 | 36 | 64 | 46 | | 41 | 65 | **49** |
| | Oxy-fuel | 17 | 59 | 73 | 19 | 51 | 41 | 24 | 9 | 16 | 40 | | 21 | 65 | **36** |
| | Adaptation of artificial trees | 17 | 59 | 7 | 19 | 58 | 61 | 32 | 18 | 40 | 13 | | 72 | 22 | **35** |
| Transport | Offshore power plants | 70 | 42 | 73 | 51 | 58 | 48 | 72 | 31 | 56 | 40 | 68 | 62 | 76 | **57** |
| | Transporting flue gas to central location | 44 | 51 | 44 | 38 | 66 | 20 | 40 | 13 | 32 | 26 | 41 | 83 | 76 | **44** |
| | Combination of pipelines and ships | 52 | 59 | 36 | 51 | 29 | 55 | 48 | 36 | 72 | 33 | 41 | 62 | 76 | **50** |
| | Sharing with existing pipelines | 70 | 68 | 51 | 32 | 58 | 48 | 64 | 22 | 72 | 53 | 41 | 72 | 87 | **57** |
| | Offshore pipelines | 61 | 68 | 66 | 64 | 15 | 55 | 64 | 36 | 72 | 40 | 55 | 83 | 87 | **59** |
| | Offshore pipeline hub | 78 | 68 | 66 | 51 | 15 | 48 | 64 | 36 | 56 | 40 | 48 | 83 | 87 | **57** |
| | Ships | 44 | 59 | 36 | 51 | 15 | 61 | 40 | 36 | 32 | 33 | 48 | 62 | 76 | **46** |
| Storage | Ocean Storage Membrane | 61 | 34 | 22 | 6 | 66 | 27 | 40 | 0 | 24 | 33 | | 41 | 76 | **36** |
| | Offshore geological with gas cap | 44 | 68 | 66 | 19 | 51 | 41 | 48 | 13 | 32 | 40 | | 72 | 76 | **47** |
| | Offshore EOR/EGR | 78 | 68 | 51 | 57 | 22 | 34 | 48 | 45 | 72 | 40 | | 62 | 76 | **54** |
| | Offshore geological | 61 | 68 | 73 | 57 | 15 | 34 | 48 | 40 | 64 | 40 | | 62 | 76 | **53** |
| | Ocean Storage | 70 | 25 | 22 | 25 | 58 | 14 | 72 | 13 | 40 | 33 | | 31 | 76 | **40** |
| combined | GM trees | 70 | 17 | 36 | 44 | 58 | 14 | 80 | 22 | 24 | 13 | 61 | 10 | 108 | **43** |

The highest scoring novel concepts are the offshore power plants, the offshore pipeline hub and the shared pipeline concept whilst the highest scoring existing techniques are post-combustion for capture, pipelines for transport and offshore geological for storage.

The offshore pipeline hub was not regarded as a strong enough concept on its own and was therefore seen as being interesting in combination with the shared pipeline concept. This would mean a scenario where all oil and gas produced in a certain region is transported via a central hub on to a central pipeline carrying it ashore. The $CO_2$ would be carried in the same pipeline going the other way thus connecting the point sources on land to a variety of different oil/gas fields, depleted and active, for storage and EOR/EGR.

The key question for the shared pipeline concept is then whether or not, under the existing conditions in the pipeline, the $CO_2$ and crude oil/gas will travel in an opposite directions. This study is done for North Sea crude oil only to get an initial idea of the viability of the concept.

The direction of the flow is determined by two factors.

- How much force is exerted on the $CO_2$ from the moving oil and the pressure gradient?
- What is the relative buoyancy (i.e. will the $CO_2$ have negative buoyancy in crude oil?) ($\rho_{CO2} > \rho_{crude}$?)

The aim of a combined pipeline would be to raise oil from a certain depth and deposit $CO_2$ at that same depth. The concept is thus not possible without negative buoyancy, hence this is considered first. The density of $CO_2$ at different temperatures and pressures (Jacobs 2005), is compared to the properties of North Sea crude oil as (Schmidt, Quiñones-Cisneros et al. 2005). Three similar isotherms are shown in Figure 1-21. A pressure range between 6.5 and 12 MPa is chosen to represent the range working of pressures for existing pipelines.

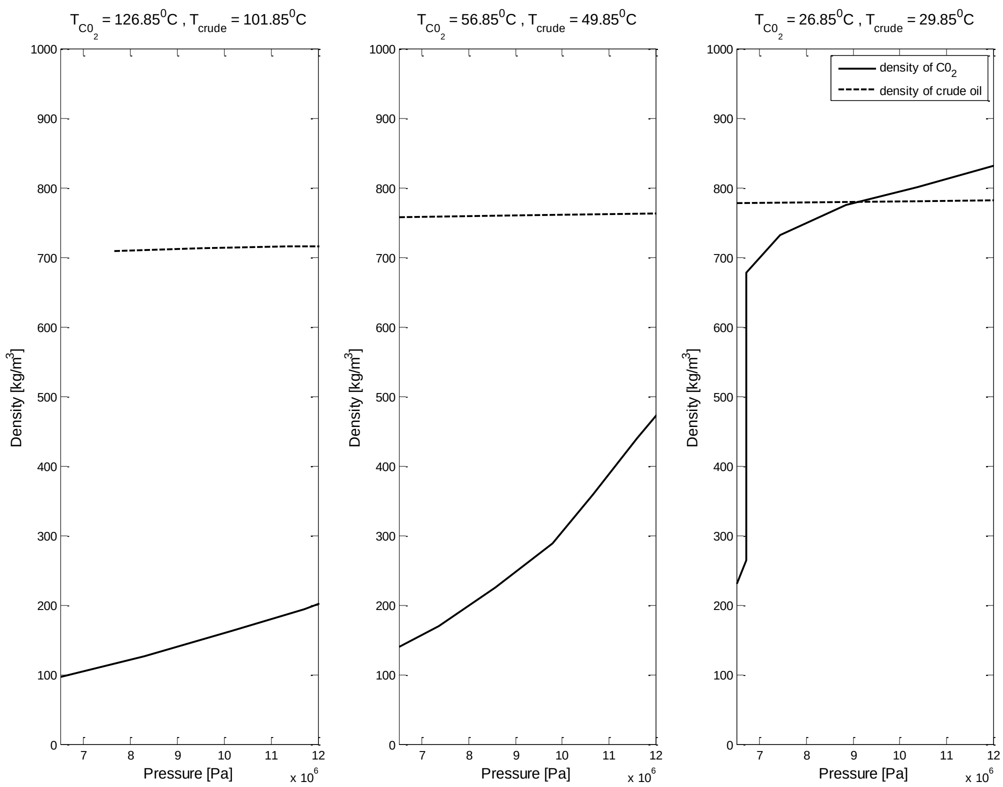


Figure 1-21: Comparison of CO2 and North Sea crude oil densities at different temperatures and within the working pressure range of most pipelines

It is apparent that negative buoyancy can only be achieved for high pressure pipelines and for relatively low temperatures. At $T \approx 30^0C$ and p=12 MPa the difference in density is about 55 kg/m$^3$ which would exert a sinking force of 540 N/m$^3$ on the $CO_2$. If this can be shown to be more than the effects of viscosity and the adverse pressure gradient, the concept may have merit.

A major obstacle to the concept is that it would only work for a continuous drop/rise of the pipe. Any point where the pipe changes vertical direction would mean that the sinking force would act in the same direction as the pressure gradient thus stopping the counter directional flow. This major technical obstacle would divert attention from focusing on the suitability of this system for CCS. It is therefore decided that this study will focus on offshore thermal power plants with CCS as an alternative to $CO_2$ transportation.

# 2. OFFSHORE THERMAL POWER WITH CCS

## *2.1 Initial Concept*

The concept of an offshore thermal power plant with the inclusion of CCS involves integrating power generation equipment, gas processing equipment, a carbon capture system and electricity transmission systems onto one or more offshore platforms. The idea is to build an onshore power plant with CCS and move it offshore. Therefore, one of the main considerations when deciding whether to build an offshore power plant is if there are plans to build new onshore power plants.

### *2.1.1 Why build new thermal power plants?*

The decision to build new thermal power stations is mainly driven by whether there is a demand for more electricity and how that electricity can be produced. The three main options are nuclear power, renewables or fossil fuelled power stations (coal, gas and oil). However as discussed before, each of these has its own issues. Nuclear power is unpopular and there are concerns regarding de-commissioning, renewables are currently expensive and also lack the capacity to satisfy the global demand for electricity. Finally fossil fuels are finite and emit greenhouse gases.

According to the International Energy Agency (IEA), electricity generation is predicted to increase by 87% between 2007 and 2035 (IEA 2010). Table 2-1 shows the proportions of electricity generated by each of the fuel sources in 2007 as well as the projected percentage contributions for 2035. It can be seen that, instead of being replaced by renewables or nuclear power, fossil fuels will still play an important role in generating electricity in 2035.

TABLE 2-1
PERCENTAGE CONTRIBUTIONS OF EACH FUEL SOURCE TOWARDS ELECTRICITY GENERATION

| Fuel Source | 2007 | 2035 |
|---|---|---|
| Oil | 5 | 2 |
| Coal | 42 | 43 |
| Natural Gas | 21 | 20 |
| Renewables | 18 | 23 |
| Nuclear | 13 | 13 |

TABLE 2-2
PROJECTED INCREASE IN DEMAND FOR ELECTRICITY BY FUEL SOURCE

| Fuel Source | 2007 Trillion kilowatt hours | 2007% | 2035 Trillion kilowatt hours | 2035% |
|---|---|---|---|---|
| Oil | 0.9 | 5 | 0.8 | 2 |
| Coal | 7.9 | 42 | 15 | 43 |
| Natural Gas | 3.9 | 21 | 6.8 | 19 |
| Renewables | 3.5 | 19 | 8 | 23 |
| Nuclear | 2.6 | 14 | 4.5 | 13 |

Table 2-2 shows that there is an increase in the demand for nuclear power and renewables however the biggest increase in fuel source is that of coal even though the proportion that is coal remains roughly the same. There is also an increase in the need for natural gas and the use of oil in electricity generation is predicted to fall. This suggests that there will be an increase in the demand for fossil fuelled power stations.

Furthermore, many of the power stations in developed countries were built in the 1960s, 70s and 80s. This means that they are coming to the end of their lives and will need replacing in the near future. Europe, for example, will require at least 712 GW of new/replacement energy capacity between 2008 and 2030 (IEA 2009) and the OECD countries combined will need at least 1639 GW. The non-OECD countries require 3160 GW with China needing 1325 GW of capacity addition. This does not take into account recent issues with nuclear power where Germany, for example, has decided to replace their nuclear power stations with new fossil fuelled power facilities as result of a loss in confidence in nuclear power.

With the assumption that CCS will be used with new power stations, the next question is that given new fossil fuelled power stations will be built, why take them offshore? Conventional power plant CCS projects consist of separating $CO_2$ from flue gases, compressing it and transporting it via pipelines or ships to the storage sites, and storing it into geological formations or in the oceans. The combination of offshore thermal power with CCS positions the source of $CO_2$ closer to the final storage location, which eliminates the needs for transporting $CO_2$ via pipelines or ships. This therefore reduces total costs and risks. The resulting CCS system only consists of the capture of $CO_2$ and the subsequent storage of the captured $CO_2$.

In addition, natural gas is the preferred fuel for this concept as the limitation of deck area, storage capacity and costs make coal unfeasible. There has been a decline in the use of oil in power stations suggesting that they will be phased out. The cost of gas may be significantly reduced if the power station is offshore since it could be supplied from existing offshore natural gas fields. If the power plant is equipped with gas processing facilities, this gas can then be directly supplied through risers from a subsea wellhead when the power plant is close to a gas field.

The final question is; has this concept been implemented before? Offshore thermal power plants can be considered as an evolution version of the floating power plant (power barge) which is a barge with a power plant on the deck. The concept of the floating power plant was first developed during World War II and evolved into power ships. A power barge itself has no propulsion and needs to be transported to the final location by other ships. In addition, power barges can only operate in sheltered waters.

The power ship is a specially designed self-propelled marine vessel equipped with a power plant. It can serve as a movable power generation resource that is ready to go wherever electricity is demanded and be plugged into an electricity grid. The concept of a power ship is more flexible than that of a power barge because a power ship is capable of sailing and operating in higher sea states and travelling longer distances.

The concept of an open ocean power plant, also known as an offshore floating power plant, was initially considered as a way to deal with stranded offshore natural gas. Recently, Independent Power Producers (IPPs) have shown an interest in offshore power plants to reduce the need for lengthy applications for permission to start land based power plants (WALLER MARINE). Other similar concepts such as Gas to Wire (GTW) and Floating Power Generation Plant (FPGP) can also be found in the literature.

The GTW concept is an application of the offshore thermal power plant. Instead of transporting liquefied natural gas by pipeline or LNG ships, the GTW concept integrates offshore gas production equipment and power plant equipment together on one offshore platform and transmits the generated electricity to onshore national grids by subsea cables (HVDC is generally preferred for long distance). It is estimated that the final energy efficiency is approximately 43% by applying the GTW concept (HITACHI). This concept is also considered a good solution for the commercialisation of marginal gas fields and remote stranded gas fields, with a reduced environmental impact (HITACHI). However, due to the limitation of deck area, payload, system integration and technology immaturity, the maximum proposed capacity of an offshore thermal power plant is approximately 500MW (WALLER MARINE ; Hetland, Kårstad et al. 2008), which is small when compared with conventional onshore gas power plants.

The concept of an offshore thermal power plant is not limited to floating structures. Since the key point of this concept is to build a power plant offshore to facilitate $CO_2$ storage in ocean space, all existing offshore platform designs can be considered as potential platforms to be equipped with power plants. This includes fixed and floating platforms. However, the offshore floating power plant is investigated here due to its mobility and workability in remote areas. In addition, the offshore floating platform itself has the following advantages;

- Fully constructed in shipyards under controlled conditions.
- Short construction period depending on equipment availability.
- Mobility; large electricity capacity that can be quickly moved as needed.
- Capital costs may be comparable or lower with land power plants.
- Gas directly supplied from wellhead or Floating Production & Storage Offshore (FPSO).

The concept of combining an offshore power plant with a carbon capture system is not new. The SEVAN GTW concept, developed by Sevan Marine and Siemens is a cylindrical platform equipped with eight combined cycle gas turbines and an amine based carbon capture system (Hetland, Kårstad et al. 2008). It is estimated that a capacity of 540 MW without CCS can be achieved with 54% efficiency and a capacity of 450 MW with CCS can be achieved with 45% efficiency. The produced $CO_2$ from power generation would be captured with a 90% capture rate, compressed and directly injected into a sub-seabed reservoir (Hetland, Kvamsdal et al. 2009).

Although the concept of an offshore thermal power plant is still in the conceptual design stage, many companies such as Waller Marine and Sevan Marine are developing this concept (WALLER MARINE ; Hetland, Kårstad et al. 2008). Moreover, as the technology develops, this concept may become more and more attractive.

### *2.1.2 How will it work?*

The offshore thermal power plant with CCS is an offshore floating platform equipped with a power plant, gas processing plant and carbon capture system. The electricity produced by the power plant is transmitted ashore using subsea cables. Figure 2-1 shows a schematic of the proposed concept.

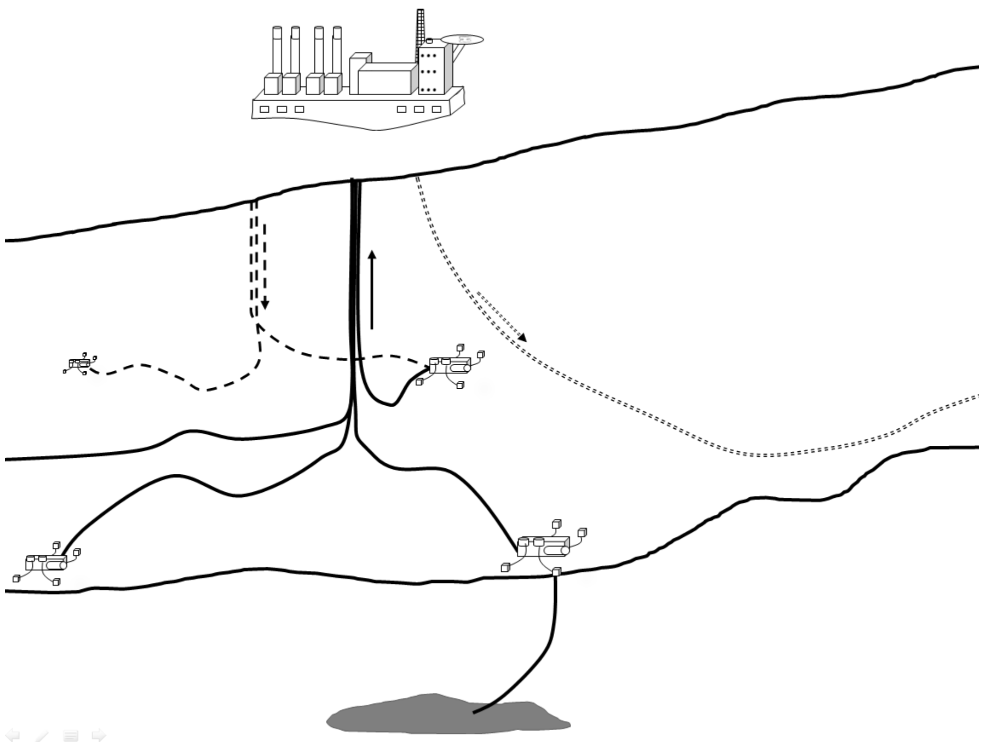

Figure 2-1: Schematic of offshore thermal power with CCS

This shows one scenario where the power plant directly obtains gas from the wellheads. In this case, a gas processing plant is needed to process the gas in order for it to be used for power generation. The solid lines represent the risers that pump natural gas from the wells to the platform. The dashed lines represent the captured $CO_2$ that is compressed and injected for storage. The dotted line represents the subsea power cable which transmits electricity to onshore national grids.

Figure 2-2 shows a second scenario where the offshore thermal power plant operates in conjunction with an FPSO. Gas can be directly supplied from the FPSO and therefore the gas processing equipment is unnecessary.

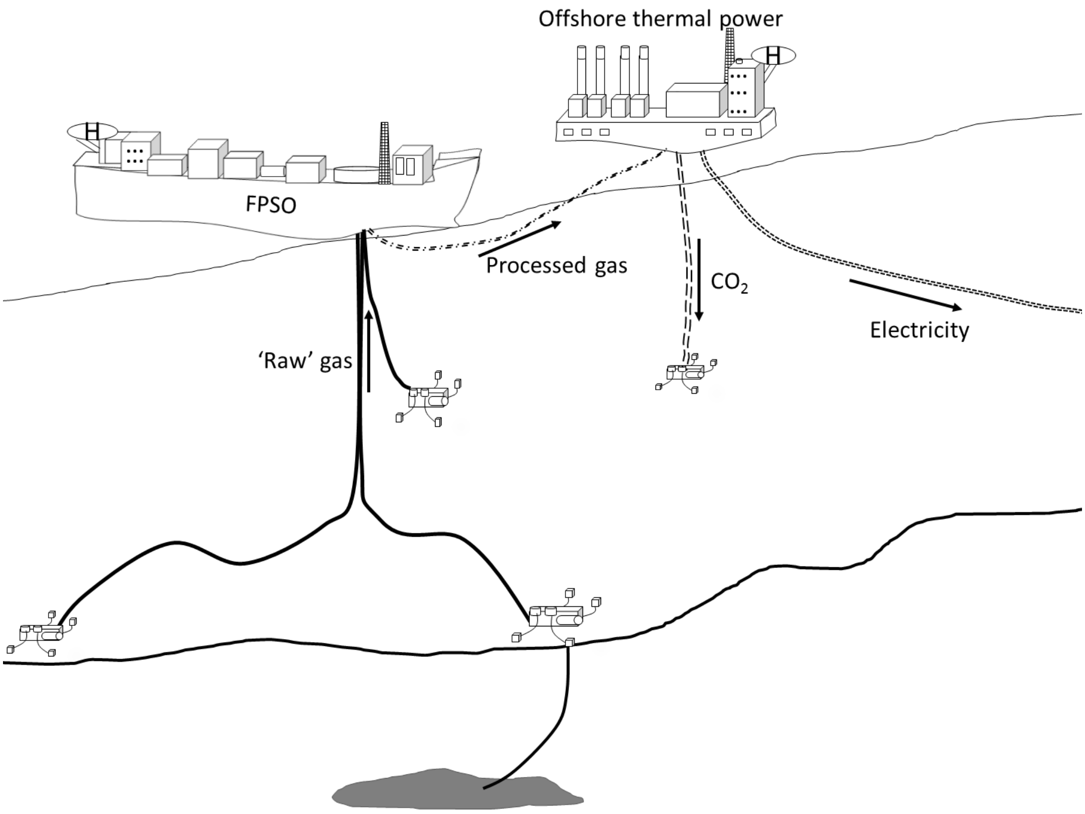


Figure 2-2: Schematic of offshore thermal power with FPSO

This concept includes the storage of $CO_2$ into offshore geological formations or the ocean. Since geological storage of $CO_2$ is more understood than ocean storage (Anderson and Newell 2004), offshore geological storage will be mainly investigated here. However, ocean storage of $CO_2$ may be considered in the future depending on the technology maturity. The $CO_2$ will be captured using a post-combustion system as this is the most mature technology available. In the future, it may be possible to use pre-combustion and generate the electricity using hydrogen.

Technology and processes developed from the offshore oil and gas industry can be directly applied to the offshore thermal power plan. This includes hydrodynamic analysis, structural analysis, fatigue analysis, and mooring analysis etc. In addition, different types of offshore floating platforms can be chosen as the base of the offshore thermal power plant depending on the specific situation.

The offshore thermal power plant has to be capable of operating and surviving in the offshore location for a long time. Therefore, the environmental load effects need to be investigated in the design stage based upon a given site. Sea states including wave heights, currents and wind need to be taken into account and station keeping systems may be needed to keep the floater in place. In addition, both intact and damaged stability needs to be assessed in order to ensure maximum operability of the floating power plant. Structural analysis also needs to be carried out based on the given environmental loads, including fatigue analysis under the cyclic wave loadings.

Since the offshore power plant is an integration of different systems including the power plant, carbon capture and gas processing, it is of paramount importance to consider the system integration in the design stage. Furthermore, safety and risk for the whole operational life needs to be assessed.

Design codes and regulations which may be useful to the design and analysis of floating platforms are listed as follows:

- API RP2SK
- ABS MODU Regulations
- International Gas Code (IGC)

## *2.2 Design Selection Process*

The engineering design process is an iterative decision making process where a system is devised to meet the required objectives. It involves several stages including concept design, a feasibility study, preliminary design, detailed design and production design. The purpose of this study is to describe the process by which the concept design and its feasibility can be carried out.

In order to create a pathway for the design of a floating power plant concept, the key components were identified as well all the various factors affecting the decision making process. These components and factors were then prioritised. The entry points into the system were also identified and combined with the key components to create three flowcharts.

### *2.2.1 Selection Flowcharts*

The following flowcharts all contain the same key stages however, the order in which they are considered and the associated feedback loops differ depending on the motivation for constructing a floating power plant. The purpose of these feedback loops is to match supply and demand as well as apply operational constraints. For example the power plant, carbon capture system, transformers and processing plant determine the size of the floating structure. However the location also plays a role in selecting the floating structure. There are also a variety of factors associated with each stage in the flowchart which will be discussed in Chapter 3.

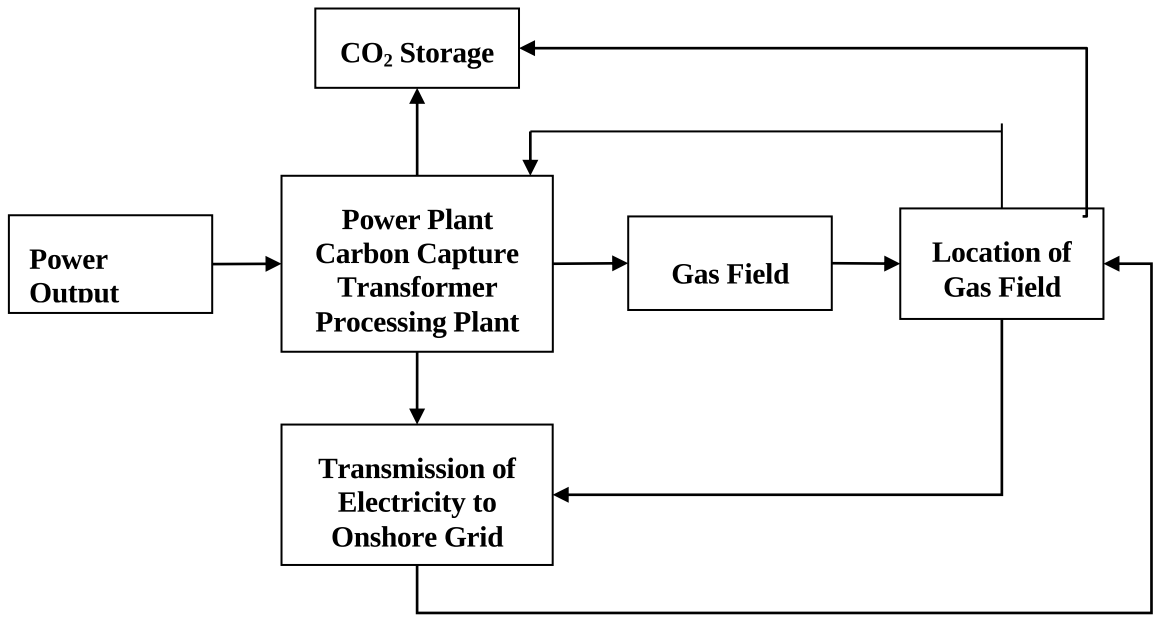


Figure 2-3: Design selection flowchart for power output option

If the motivation is to produce electricity, for example if a 500MW power station is needed then the flowchart shown in Figure 2-3 should be used. As this figure shows, the power output of the plant determines the power plant configuration. This then determines where the location will be so that the gas supply can be matched to the power output requirement. From this the $CO_2$ storage option can be selected. The electricity transmission system design is based on a combination of the power output and the location. All of these factors influence the size of the platform. The important thing to remember is that if there is not sufficient storage capacity for the $CO_2$ captured, then the power plant may not necessarily be relocated if the current location is optimal for electricity generation and transmission.

The second motivation is to exploit gas fields that cannot be used as they are too far offshore or in too deep waters. Here the gas field location is fixed and the power plant configuration, transmission system and $CO_2$ storage option are adjusted accordingly as shown below in Figure 2-4.

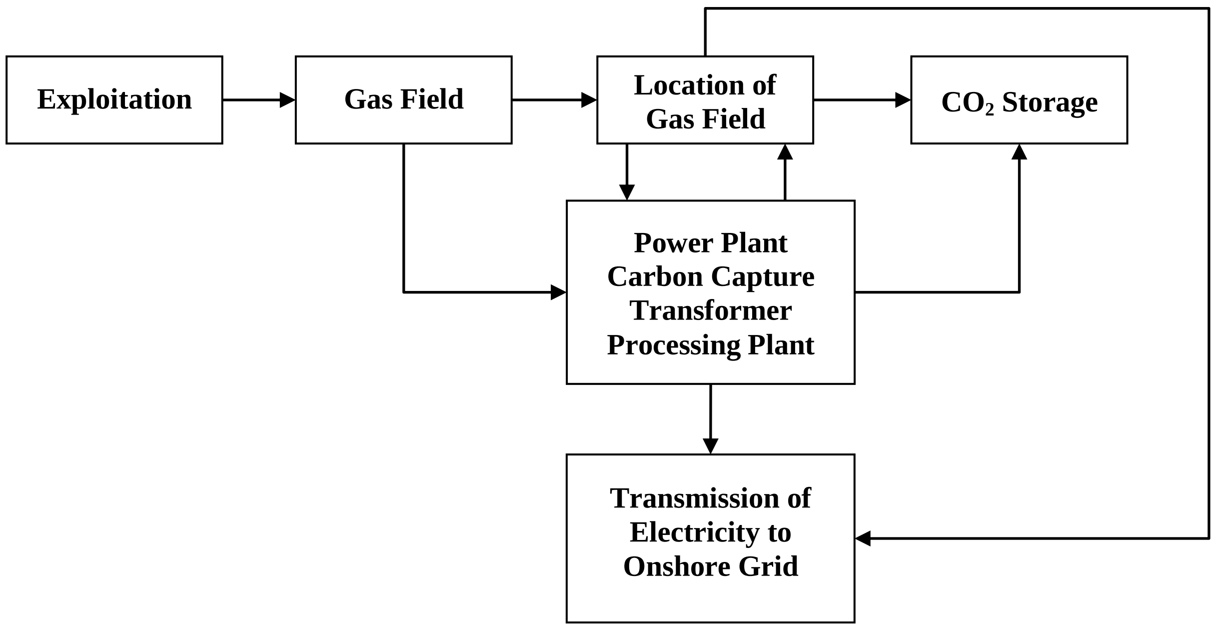


Figure 2-4: Design selection flowchart for exploitation of gas field option

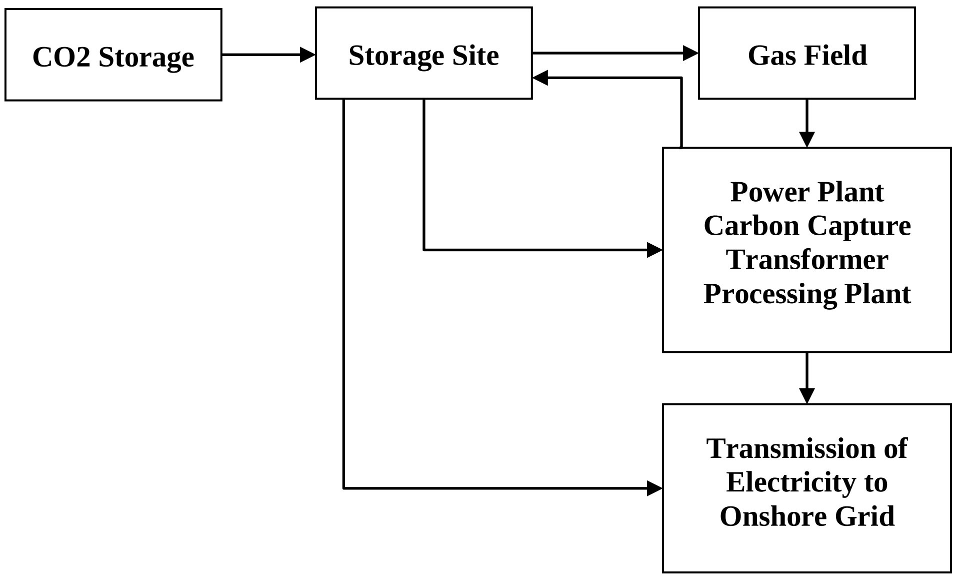


Figure 2-5: Design selection flowchart for $CO_2$ storage option

The final motivation is to select a site to store $CO_2$. This then fixes the location and an appropriate power output for the power plant is chosen based on the gas supply in the region as shown in Figure 2-5. This can also be dependent on how much $CO_2$ can be stored in the storage site since if $CO_2$ sequestration is the primary motivation then it follows that the maximum amount of $CO_2$ needs to be extracted from the flue gas. This means that the capacity of the carbon capture system becomes a main driver.

## *2.3 Design Considerations*

### *2.3.1 Location*

One of the most important factors affecting the design of an offshore facility is its location. This is because many of the design considerations depend on the location. As Figure 2-6 shows, the factors can be split into five categories; gas field characteristics, existing infrastructure, $CO_2$ storage, government and environment. For each category, there are further sub-sections which will be discussed later.

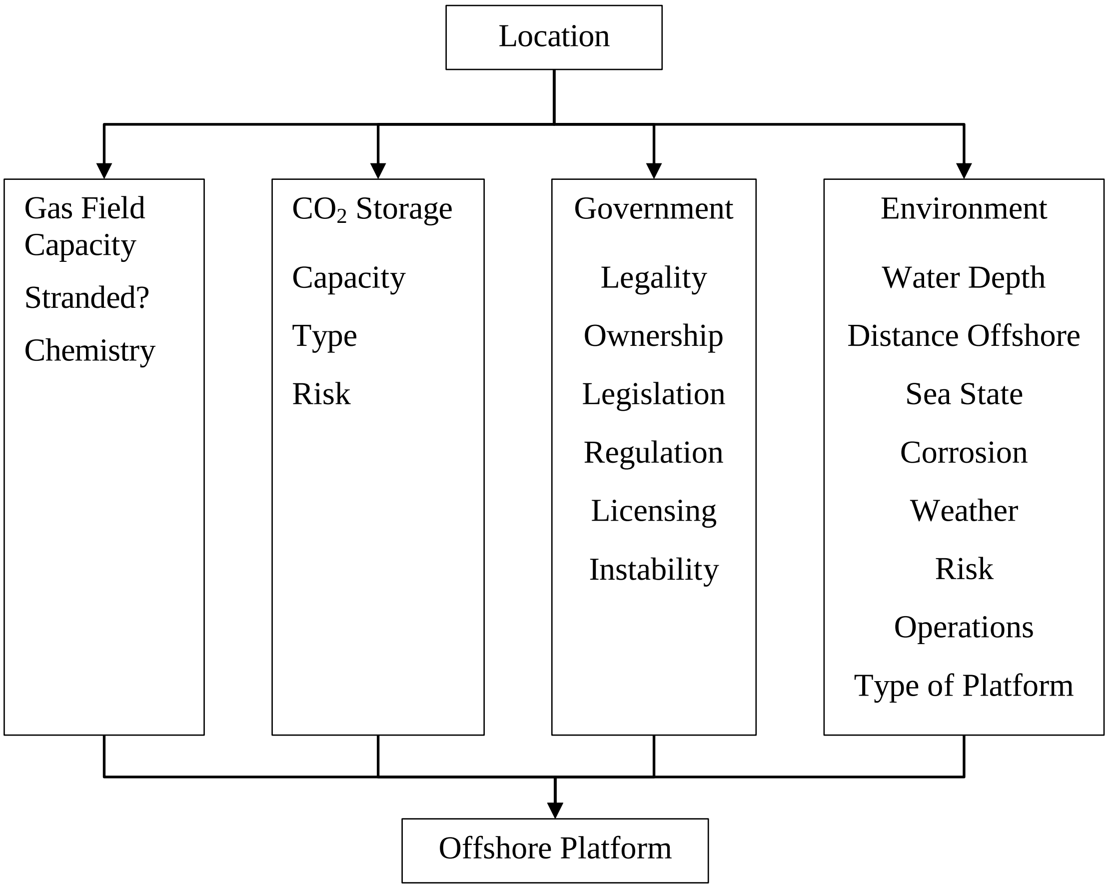


Figure 2-6: Factors affecting design of offshore power plants

**Gas field**

The main considerations for siting an offshore power plant are the location and capacity of the offshore gas reserves. Currently, the world's gas reserves comprise around 6289.147 trillion cubic feet (IEA 2010), however these figures are only estimates as some of the data used is unreliable (Seljom and Rosenberg 2011). This is because some countries consider the data to be commercially sensitive and others have not revised their estimates in years despite new discoveries in their territory. Furthermore, the offshore gas reserves have only been partially surveyed making it difficult to estimate their capacity. Figure 2-7 shows a map of the main global offshore reserves.


Figure 2-7: Location of global offshore gas reserves

The largest gas reserves are off the coast of Western Australia, the pre-salt basin off Brazil, Venezuela and the eastern Mediterranean. In addition, the Persian Gulf is the location of the South Pars/North Dome gas-condensate fields which contain around 19% of the world's recoverable gas reserves (Scaroni 2006).

Some of the gas fields are currently considered stranded. This is where a discovered gas field is considered unusable for either physical or economic reasons. When the gas field is stranded due to economic reasons; this may be because the reserve is too remote from the natural gas markets. This then makes the use of pipelines too expensive. Another reason is that the gas market in a particular region is saturated. The gas then needs to be transported to another region which may prohibitively expensive. Physical reasons preventing the exploitation of a gas field may include a gas field being too deep for drilling or one that is underneath an obstruction.

In 2005, almost 60% of the world's gas reserves were considered stranded (NEXANT ChemSystems 2005) however in the future, these stranded gas fields may be exploited as technology improves and the currently exploitable gas fields become depleted.

Some of the gas reserves are found within oil fields and this gas is usually known as associated gas. In the past, this gas was flared (vented and combusted) however now this gas is either circulated back into the oil fields or used to produce electricity.

**Government**

Issues relating to government can be divided into two categories when considering an offshore installation; whether it is possible to choose that particular location in the first place and what happens once the location has been determined.

The main factors for the former category mostly relate to the issue of ownership and potential regional or political instability. Whilst in some cases, the matter of ownership is fairly straightforward due to the location such as Western Australia or as a result of international treaty e.g. the North Sea, there are areas where offshore territory is under dispute. One such location is the eastern Mediterranean where Israel has discovered gas reserves that may contain more than 24 trillion cubic feet of natural gas (Wainer and

Derhally 2010). The issue is that some of this gas may be in Lebanese waters as the sea boundary between Israeli and Lebanese waters is unclear. This is exacerbated by the fact that there is no written or unwritten agreement between these countries regarding their sea border. In addition Cyprus may also have a claim to some of the gas.

Another area where there may be issues is the Caspian Sea. There are five countries that have coastline on the Caspian Sea (see Figure 2-8) and they have differing ideas on how to divide the territory. Some of the countries think that a median line should be used with areas assigned based on the length of coastline they have. Iran, on the other hand, thinks that each country should receive one fifth of the Caspian Sea. As a result of these differing views, whilst bi-lateral and tri-lateral treaties have been signed, no unified treaty is in existence and the current treaties are being disputed by the non-signatories.

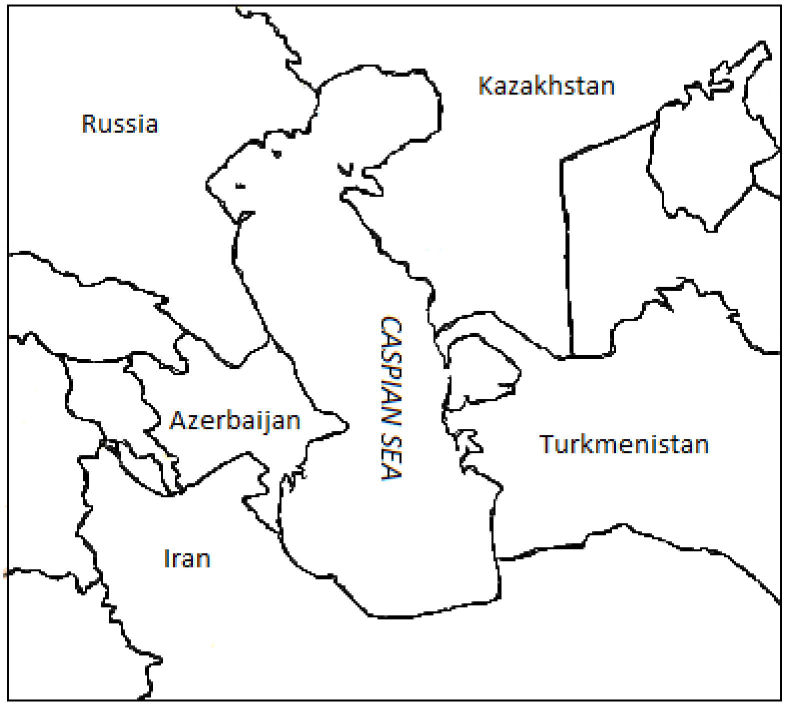

Figure 2-8: Map of Caspian Sea and surrounding countries

Once the decision has been made to locate the offshore facility in a particular location, a license has to be obtained from the country to whom the gas reserve belongs. In most countries, the procedure by which their territory is divided up is part of their legislative framework. The most common method by which sectors are divided into quadrants is to use one degree latitude by one degree longitude although this can vary depending on the size of the sector. Germany, for example, uses 10 minutes latitude by 20 minutes longitude. In most cases, many of the regulatory provisions such as abandonment of offshore installations are included in the conditions attached to the license and in the EU, for example, there are strict rules that member states have to follow when issuing licenses (DECC 2011). These include the factors that have to be considered when issuing a license as well the level of public consultation required. There are also rules covering the relinquishment of licenses and transferral to third parties.

In addition to regulations covering licensing, there is legislation that relates to a wide range of activities from construction to operations to decommissioning. This means that there are a wide range of organisations involved in regulating offshore activities. Taking the United Kingdom as an example, Figure 2-9 shows the different parties involved in regulating the offshore industry.

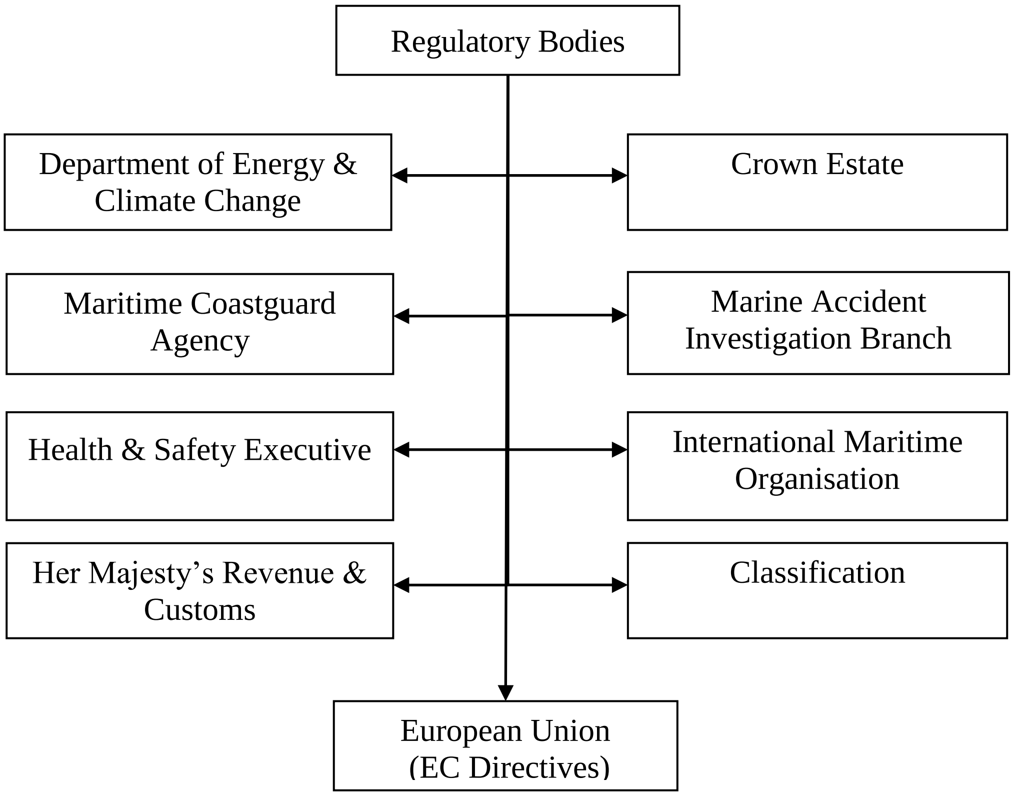


Figure 2-9: Regulatory framework for offshore activities in the UK

As can be seen, there are a variety of organisations involved with some overlap between them. One example of this is with the issue of health and safety. Normally with offshore platforms, the Health & Safety Executive (HSE) is the main legislative body with the Health & Safety at Work Act (HSE 2002). However if the installation in question can be classed as a ship, which would be the case if mobile floating units or support vessels are being used, then the Maritime Coastguard Agency and the International Maritime Organisation will also have applicable regulations.

Another key area is the environmental impact of the offshore facility. Again taking the UK as an example, there are numerous legal requirements to be complied with as Table 2-3 shows.

TABLE 2-3
UK ENVIRONMENTAL LEGISLATION FOR OFFSHORE FACILITIES

| Legislation | Name |
|---|---|
| Coast Protection Act | CPA |
| The Energy Act – Offshore Environmental Protection Order | OEPO |
| The Offshore Installations (Emergency Pollution Control) Regulations | EPC |
| Greenhouse Gases Emissions Trading Scheme | EU ETS |
| Food and Environmental Protection Act | FEPA |
| Offshore Petroleum Activities (Conservation of Habitats) | Habitats |
| Offshore Chemicals Regulations | OCR |
| The REACH Enforcement Regulations | REACH |
| Offshore Combustion Installations (Prevention & Control of Pollution) Regulations | PPC |
| The Environmental Protection (Controls on Ozone Depleting Substances) Regulations | ODS |
| The Fluorinated Greenhouse Gases Regulations | F-Gas |

**Marine environment**

The marine environment is defined as the environment in which offshore structures will operate. This includes both natural phenomena and more man-made influences such as piracy and risks of collision. However the main concern of designers of offshore platforms (unless operating in an area prone to other risks) should be the natural phenomena occurring at that location. All offshore structures will have to endure harsh conditions at different periods in their lifetime; for some locations these will be enduring phenomena while for others, they will be less frequent. Therefore, the local conditions where an offshore structure will be placed are vital inputs to the design of the platform. The main considerations regarding the conditions at the surface and in the water column below are given in Table 2-4 which is provided by HSE (2001). Both Table 2-4 and Table 2-5 contain public sector information published by the Health and Safety Executive and licensed under the Open Government Licence v1.0.

Seismic conditions at the local site can have an effect on the mooring of platforms; however this is mostly a problem for TLPs which rely on a constant tension in their tendons for stability. Other moored structures can withstand movements of their anchors as long as the mooring lines are intact.

TABLE 2-4
CONSIDERATION PARAMETERS FOR OFFSHORE INSTALLATIONS

| Parameter | Required information | Influential parameters |
|---|---|---|
| Wind | Extreme wind speed and direction; vertical profile; gust speeds and wind spectra; persistence | Averaging time; height above sea level |
| Wave and swell | Extreme wave crest elevation; extreme wave height, direction, and range of associated periods; cumulative frequency distribution of individual wave height joint probability of significant wave height and period; persistence of sea state; wave spectra and directional spreading | Water depth; current; length of measurement period |
| Water depth and sea level variations | Depth below mean sea level; extreme still-water-level variations | Long-term changes in water depth; tide and storm surge |
| Current | Extreme current speed and direction; variation through the water column; fatigue design; current speed | Tidal and other currents; averaging time |
| Temperature | Extreme air temperature (maximum and minimum); extreme sea temperatures (maximum and minimum) | Depth below sea surface |
| Rain and squall | Intensity in cm/hour for given return periods | Averaging time |
| Snow and ice | Maximum thickness of snow; maximum thickness of ice; densities of snow and ice | Geographical area; season; part of the structure |
| Marine growth | Type of growth; permitted thickness; terminal thickness profile | Water depth; growth rate |

Since most floating platforms have a relatively small draught (with the exception of the Spar), the most severe loads are confined to the surface in the form of wind and waves. Since the wind is the cause of the waves, these two loads often go hand in hand. The maximum likely significant wave height for different regions of the world is shown in Table 2-5. A wide variety of wave heights are shown for these regions, many of which have similar wave depths and distances to land. This means that the platform designer cannot rely solely on data regarding water depth for deciding on the dimensions of components.

TABLE 2-5
MAXIMUM SIGNIFICANT WAVE HEIGHTS FOR DIFFERENT REGIONS OF THE WORLD

| | 100 Year Significant Wave Height (metres) | Wave Period (Seconds) |
|---|---|---|
| West Shetland | 18 | 20 |
| Northern North Sea | 15 | 17 |
| Gulf of Mexico | 13 | 16 |
| Philippines | 11 | 15 |
| Brazil | 7 | 14 |
| West Africa | 4 | 17 |

Following advances in design and technology, the impact of environmental conditions on the design is decreasing however it is still influential in terms of cost. As an example; TLPs can be deployed in West Africa where the climate is relatively mild and West of Shetland where the climate is very harsh but the amount of steel used, and thus the cost, will be different.

Recorded wave heights for different regions of the world are given (Hogben, Dacunha et al. 1985) for larger areas which allows for a general comparison of different regions of the world in terms of maximum significant wave height.

Table 2-6 shows significant wave heights for waters in the vicinity of countries possessing findings of oil and gas. This represents a more general overview than Table 2-5 but gives good indications as to where the most severe conditions will be encountered.

*Currents*

There are two main causes of currents being generated; global and local factors. Global factors include wind, geotropic factors and differences in temperature and salinity. Local factors include marine sediment movements, waves, tides, winds and typhoons. Constant water particle velocities induced by these factors constitutes a large part of the loads the structure is being subjected to.

*Tides*

If the structure is located close to shore or in an inland sea, the effects of tide should be considered. Usually, external loads and the height of the deck are determined by assuming the maximum height of the approaching waves and the maximum water depth. Changes in water depth due to tides will affect the design of moorings, anchors and risers.

TABLE 2-6
SEA STATES AND MAXIMUM SIGNIFICANT WAVE HEIGHTS FOR DIFFERENT AREAS

| Country | Area | Max $H_{13}$ (m) | Max Sea state |
|---|---|---|---|
| Canada | Grand Banks | 10 - 11 | 8 |
| USA | Gulf of Mexico | 6 - 7 | 7 |
| Venezuela | Caribbean Sea | 6 - 7 | 7 |
| Trinidad & Tobago | Caribbean Sea | 6 - 7 | 7 |
| Brazil | South Atlantic Ocean | 6 - 7 | 7 |
| Morocco | North Atlantic Ocean | 6 - 7 | 7 |
| Ghana | Gulf of Guinea | 4 - 5 | 6 |
| Nigeria | Gulf of Guinea | 4 - 5 | 6 |
| JDZ | Gulf of Guinea | 4 - 5 | 6 |
| Congo | South Atlantic Ocean | 5 - 6 | 7 |
| Angola | South Atlantic Ocean | 5 - 6 | 7 |
| Australia | Indian Ocean | 7 - 8 | 7 |
| Indonesia | Banda Sea | n/a | n/a |
| Malaysia | South China Sea | 6 - 7 | 7 |
| Vietnam | South China Sea | 6 - 7 | 7 |
| China | South China Sea | 8 - 9 | 7 |
| Thailand | South China Sea | 6 - 7 | 7 |
| India | Bay of Bengal | 6 - 7 | 7 |
| Israel | Mediterranean | 7 - 8 | 7 |
| Egypt | Mediterranean | 7 - 8 | 7 |
| Libya | Mediterranean | 7 - 8 | 7 |
| Denmark | Baltic Sea | 5 - 6 | 6 |
| UK | North Sea | 9 - 10 | 8 |
| Netherlands | North Sea | 9 - 10 | 8 |
| Ireland | North Atlantic Ocean | 9 - 10 | 8 |
| Norway | Norwegian Sea | 9 - 10 | 8 |

*Marine organisms*

Over the course of time, offshore floating structures will develop growth of marine organisms such as barnacles. As a result of this, the projection area and volume of each structural member that is subjected to waves and current will be increased. Furthermore, structures covered in barnacles are hard to maintain because of impaired access. For these reasons, growth of organisms on the hull should be considered at the design stage.

*Corrosion*

Since the marine environment involves salt water, all types of offshore structures will experience issues due to corrosion. Corrosion affects both the maintenance of on-board components and the design of the hull in terms of steel type and thickness but also in terms of level of painting required. This means that corrosion will add substantially to both the operational and the capital costs. Furthermore corrosion related failures accounts for 25% of the failures experienced by the oil and gas industry (Kermani and Harrop 1996).

### *2.3.2 Power Plant*

**Floating Platforms**

There are three main categories of offshore platforms; fixed, articulated and floating (Paik and Thayamballi 2007). These are shown in Table 2-7. In addition, new concepts have been developed such as the Sevan Marine cylindrical hull concept. In general, the development of new offshore structures is driven by an increased demand for oil and gas production.

TABLE 2-7
TYPES OF OFFSHORE STRUCTURES

| Classification | Type | Representative structure |
|---|---|---|
| Fixed | Fixed pile | Jacket structure |
| | Gravity | Concrete gravity platform |
| | Jack-up platform | Jack-up platform |
| Articulated | Tower | Guyed tower |
| | Spar | Spar buoyancy |
| | Tension | Tension leg platform |
| Floating | Semi-submersible | Semi-submersible |
| | Barge/ship | Drilling ship |
| | Floating oil production system | FPSO |

Of the oil and gas fields that have been developed in the past 30 years, approximately 70-80% were in shallow or deep water. In the 21st century, this has changed and exploitation is now conducted not only in deep water but also ultra-deep water. This means that more and more floating and articulated platforms are being used as the water depth increases beyond the capabilities of the fixed platforms.

There are four main types of non-fixed offshore structures that are suitable for production and can therefore be considered for use as an offshore power plant;

- TLP (Tension Leg Platforms)
- Semi-submersible
- Spar
- Ship shaped vessel (FPSO, FLNG)

Each type of platform requires different considerations regarding, for example, acquisition, wells, drilling and export. These will vary depending on the specifics but a general overview is given in Table 2-8 which is adapted from (Inglis 1996).

TABLE 2-8
DESIGN CONSIDERATIONS OF DIFFERENT OFFSHORE FLOATING STRUCTURES

| Concept | | |
|---|---|---|
| Ship-shaped | Platform acquisition | New-build or tanker conversion |
| | Well options | Remote wells, normally completed subsea |
| | Drilling | Drilling/work-over requires specialist vessel |
| | Export options | Integral oil storage & off-loading |
| | Risers | Flexible risers |
| | Loading | Insensitive to topside load |
| | Development | Short development schedule |
| Semi-submersible | Platform acquisition | New-build or conversion |
| | Well options | 1) Remote subsea wells with work-over by specialist vessel |
| | | 2)Wells below with integral drilling/work-over facilities |
| | Export options | No oil storage; pipeline, FSU or direct tanker loading |
| | Risers | Flexible risers – large number possible |
| | Loading | Sensitive to topside load |
| | Development | Short to medium development schedule |
| Spar | Platform acquisition | Custom designed for site specific application |
| | Well options | Remote wells completed subsea by specialist vessel |
| | Drilling | Single drilling centre, surface completed wells, integral work-over. |
| | Export options | No oil storage, pipeline or direct tanker loading |
| | | Integral oil storage, export via offshore loading unit |
| | Risers | Tensioned risers, flexible or steel catenary risers |
| | Development | Medium development schedule |

| | | |
|---|---|---|
| TLP | Platform acquisition | Custom designed for site specific application |
| | Well options | Single drilling centre |
| | | Surface completed wells |
| | Drilling | Integral drilling/work-over facilities |
| | Export options | No oil storage; pipeline, FSU or direct tanker loading |
| | Risers | Flexibles or steel catenaries for import/export, Tensioned rigid riser for production |
| | Loading | Sensitive to topside load |
| | Development | Relatively long development schedule |

*Ship-shaped offshore structures*

Ship-shaped offshore structures include drill ships, FSUs (Floating Storage Units), and FPSOs (Floating Production Storage and Offloading Units). Only FPSOs will be discussed since they possess the most features that are suitable for offshore power generation. The hull of an FPSO is used for storage whereas the topside facilities handle processing of the incoming crude oil or gas. In the case of gas being processed, this vessel is known as a Floating Liquified Natural Gas (FLNG) facility. Depending on their storage capacity, floating production units can be classified as small (< 1 Mbbl), medium (1-2 Mbbl), big (1.5-2.0 Mbbl) or ultra-big (> 2 Mbbl). FPSOs also possess the capability of offloading to shuttle tankers or other forms of transportation. Due to the major oil companies' increasing interest in exploiting resources in deeper waters, FPSOs are becoming the most popular offshore floating unit (Paik and Thayamballi 2007).

The advantages of FPSOs include the following;

- Can be used in deep-water sea.
- The initial investment is small.
- The short period between the return on investment.
- The development phase, depending on the type of production system can be changed.
- The production system can be reused in the development of new fields.

There are two alternatives for the acquisition of a new FPSO; new-build or tanker conversion. Both of these options have advantages (Parker 1999) which are shown in Table 2-9.

TABLE 2-9
COMPARISON BETWEEN NEW-BUILD AND TANKER CONVERSION OPTIONS FOR FPSOS

| Advantage of new build | Advantage of tanker conversion |
|---|---|
| Design and fatigue lives for a field can be achieved easier. | Capital costs can be reduced. |
| Technical, commercial, and environmental risks can be more easily contained. | Design and construction schedule can be faster and less extensive. |
| A system can be more easily designed to survive harsh environments. | Construction facility availability is increased. |
| Resale and residual values can be maximized. Reusability opportunities can be improved. | Overall project supervision requirements can be less. |

In general, a new-build will have more appropriate design features which will be better suited to the task. The tanker conversion is cheaper and can be obtained faster.

*Semi-submersible*

A semi-submersible is a floating structure that achieves its buoyancy using submersed pontoons. Some semi-submersibles have ring shape pontoons but the most common configuration is two parallel pontoons supporting 4-8 columns which in turn support the deck. The deck structures and/or the deck box are located on the platform supported by the columns and will hold facilities for the crude oil and gas production. The water plane area is relatively small so the natural frequency of the Heave, Pitch, and Roll motions is increased. This, combined with the fact that the buoyant elements are submerged gives the structure good sea-keeping capabilities compared to ship-type floating structures (Paik and T hayamballi 2007).

Relative to the FPSO, semi submersibles lack large scale loading capacity because of the small under-deck volume. For this reason, it is widely used as a drilling platform relying on other units for storage. Positioning control of a semi-submersible is usually achieved using a mooring system consisting of a chain/wire. A number of rigs have been fitted with thrusters which reduces the applied load. Thrusters can also be used as a propulsion device when moving the platform. They are also used in deep water where the use of fixed moorings is not possible (Paik and Thayamballi 2007).

*Spar*

A Spar is a type of floating platform used in deep waters. Spar platforms consist of a single vertical large diameter cylinder supporting a deck. Spars are becoming more popular and a large number have been installed in recent years. The first spar platform in the Gulf of Mexico was installed in September 1996. The world's deepest operating platform is the Perdido in the Gulf of Mexico, floating above 2,438 meters of water (Paik and Thayamballi 2007).

Typically, the shape of a Spar platform is a long cylinder wrapped on the outside by a helical spiral to reduce the vibration induced by the trailing vortex. The principle of the basic design concept of a Spar is the great draught compared to other types of offshore platforms. As a result of this, the heave motions are less severe which means that rigid risers can be used. This allows for deployment in deeper waters. Internally, the rigid riser is guided by the platform itself which is the reason why a riser tensioner is not needed. The Spar also has the advantage of being easy to manufacture and to move.

*Tension Leg Platform*

In the design of an offshore platform, one of the most important requirements is that it should maintain its functionality in terms of oil production or/and drilling in harsh weather (good operability.) Generally, the operability of an offshore platform is affected by Heave, Roll, and Pitch motions. The concept of the Tension Leg Platform (TLP) is to reduce these motions when the platform is subjected to heavy waves (Paik and Thayamballi, 2007). This means it can operate drilling continuously. Tendons are attached to the platform and are designed to avoid resonance. This makes the natural frequency of the platform lower than the period of the ocean waves. However, the natural frequencies of Surge, Sway, and Yaw motions are typically longer than the period of the ocean waves.

TLPs usually consist of 3-6 tendons with a ring shaped pontoon for buoyancy. TLPs are very sensitive to changes in payload since it increases the compression force acting on the tendon. This will decrease the tensioning force which means that the TLP cannot maintain its original shape. For this reason, TLPs are not suitable for on-board storage and would need to rely on separate storage units. The permanent mooring of the tenders means that TLPs cannot be moved from location to location. TLPs are generally considered to be suitable for water depths between 300 and 1500 meters (Paik and Thayamballi, 2007).

*Location of existing offshore platforms*

Figure 2-10 to Figure 2-13 shows the location of existing offshore platforms. It can be seen that FPSOs and semi-submersibles are widely used in oil fields worldwide whilst Spar and TLP platforms are mainly used in the Gulf of Mexico. Figure 2-10 to Figure 2-23 are based on information sourced from Offshore Magazine (2011)

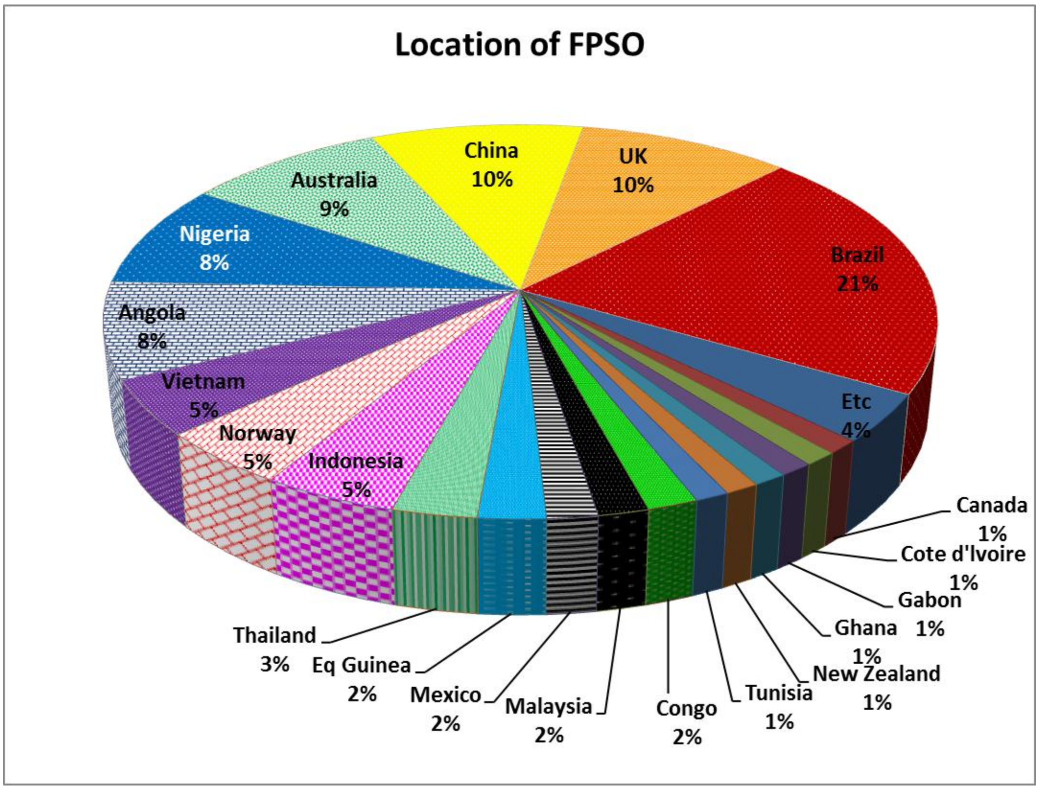


Figure 2-10: Relationship between location and platform type (FPSO)

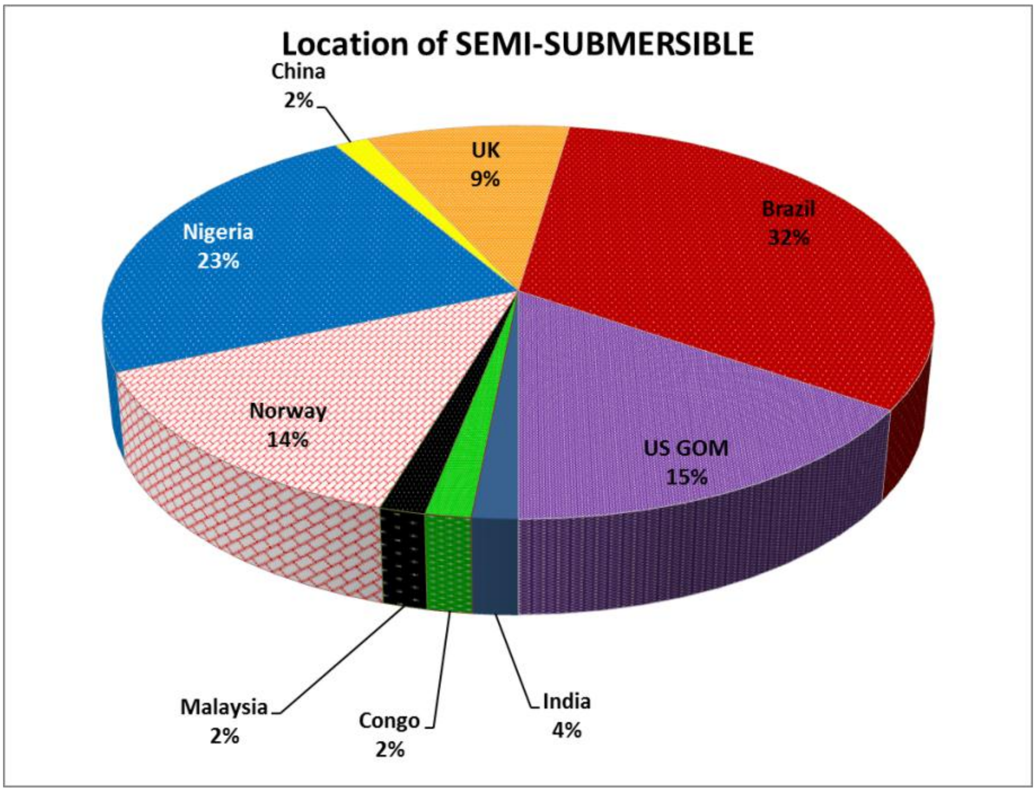


Figure 2-11: Relationship between location and platform type (semi-submersible)

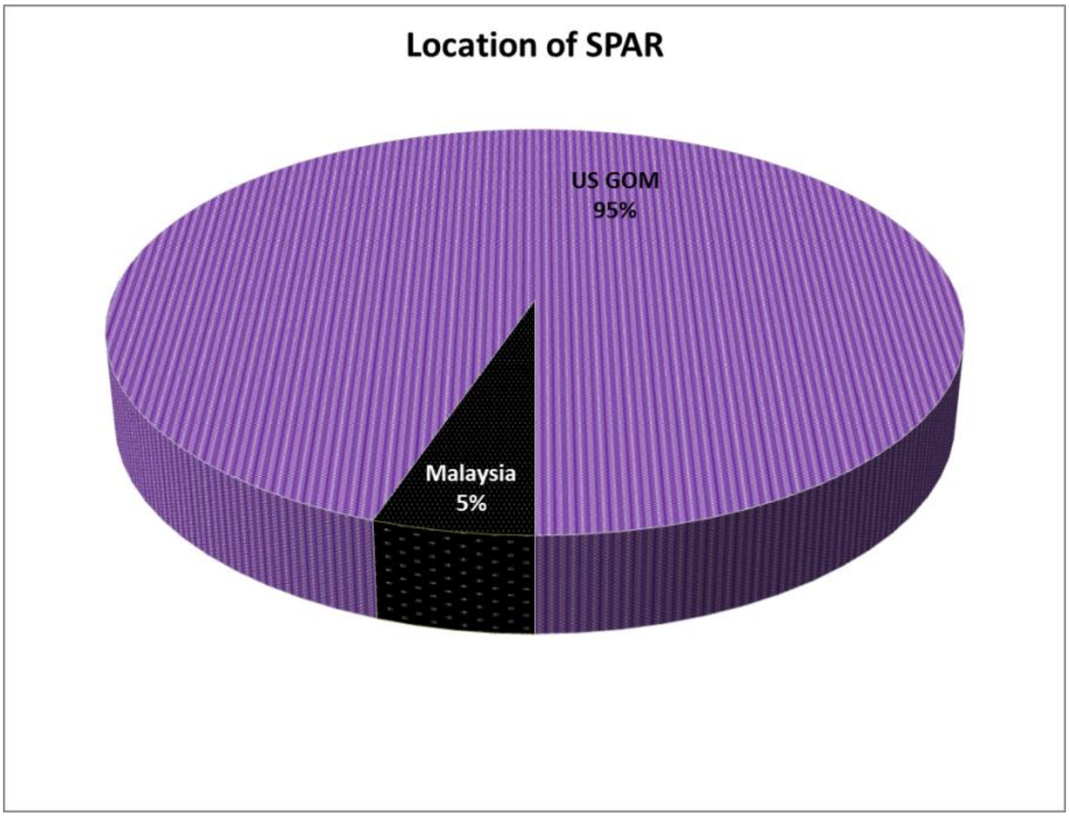


Figure 2-12: Relationship between location and platform type (spar)

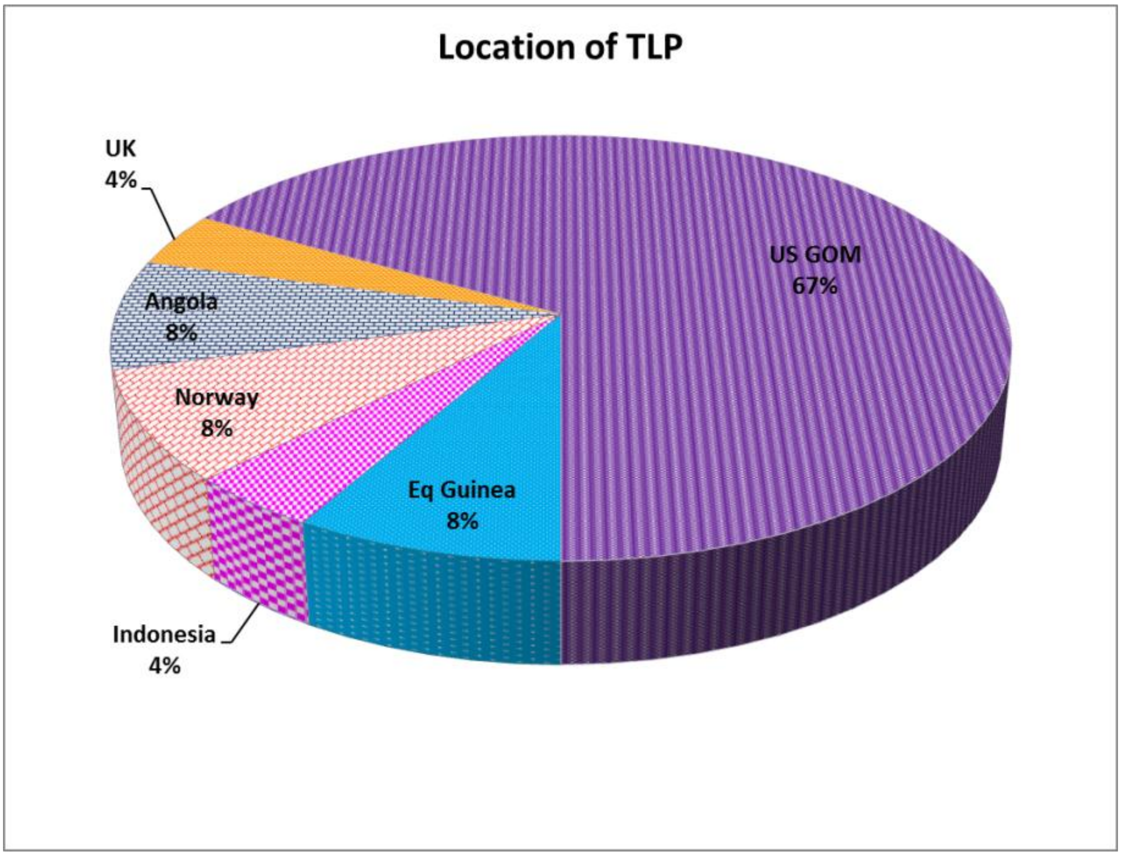


Figure 2-13: Relationship between location and platform type (TLP)

These different regions all involve different types of environments and water depths. To assess suitable platforms for different desired locations of an offshore power plant, the relationship between general location and water depth data is presented in Figure 2-14. The depth of the oilfields in Brazil, the Gulf of Mexico, Angola, and Nigeria are much greater than in other parts of the world. This is why almost 95% of spar platforms are located in the Gulf of Mexico. However, as discussed previously, water depth alone cannot be used as an indicator of the type of environment a platform will encounter.

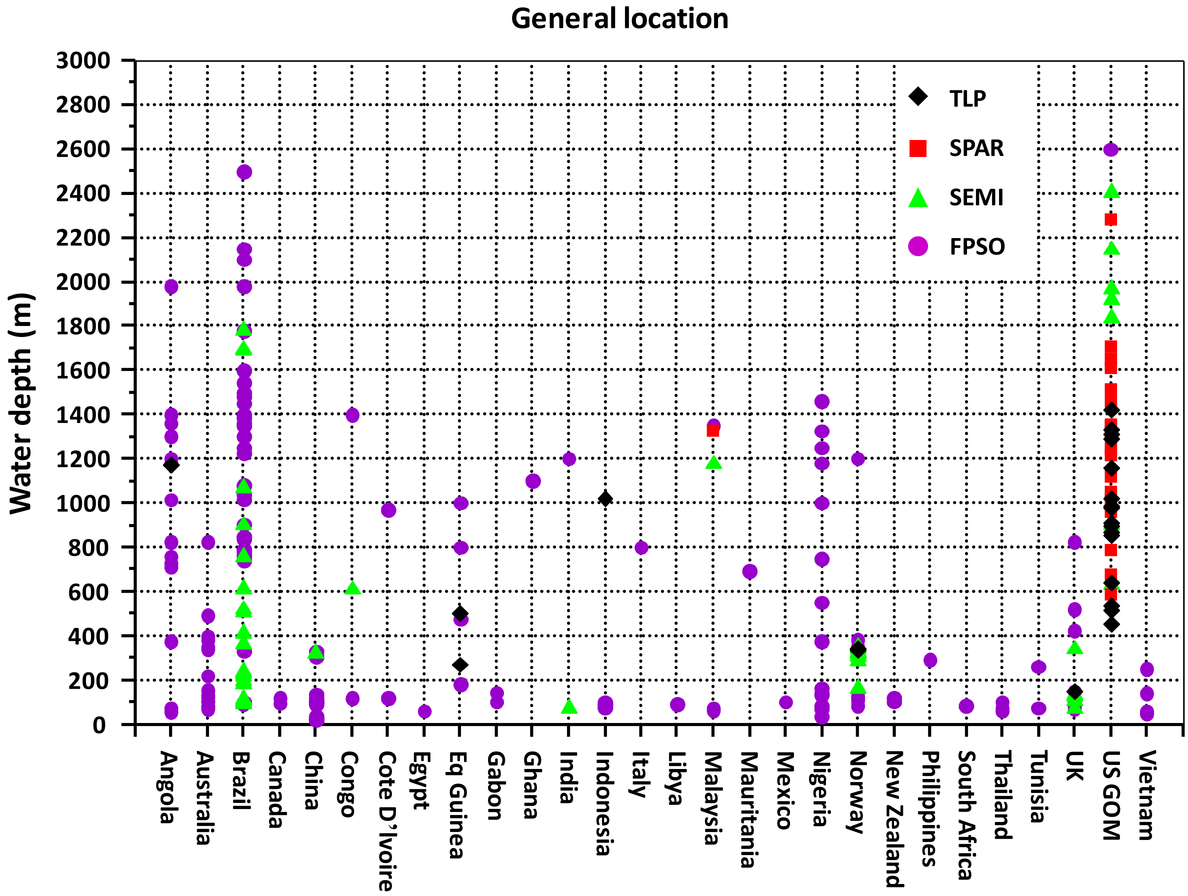


Figure 2-14: Relationship between general location of oilfield and water depth

To get a clearer picture of the current usage of the different types of platforms, each one is presented in a diagram where water depth and associated reserves are shown. This is shown for each of the four concepts in Figure 2-15 to Figure 2-18. This data is useful as an indicator of the production capacity and hence size of a platform as a larger field will require larger production volumes.

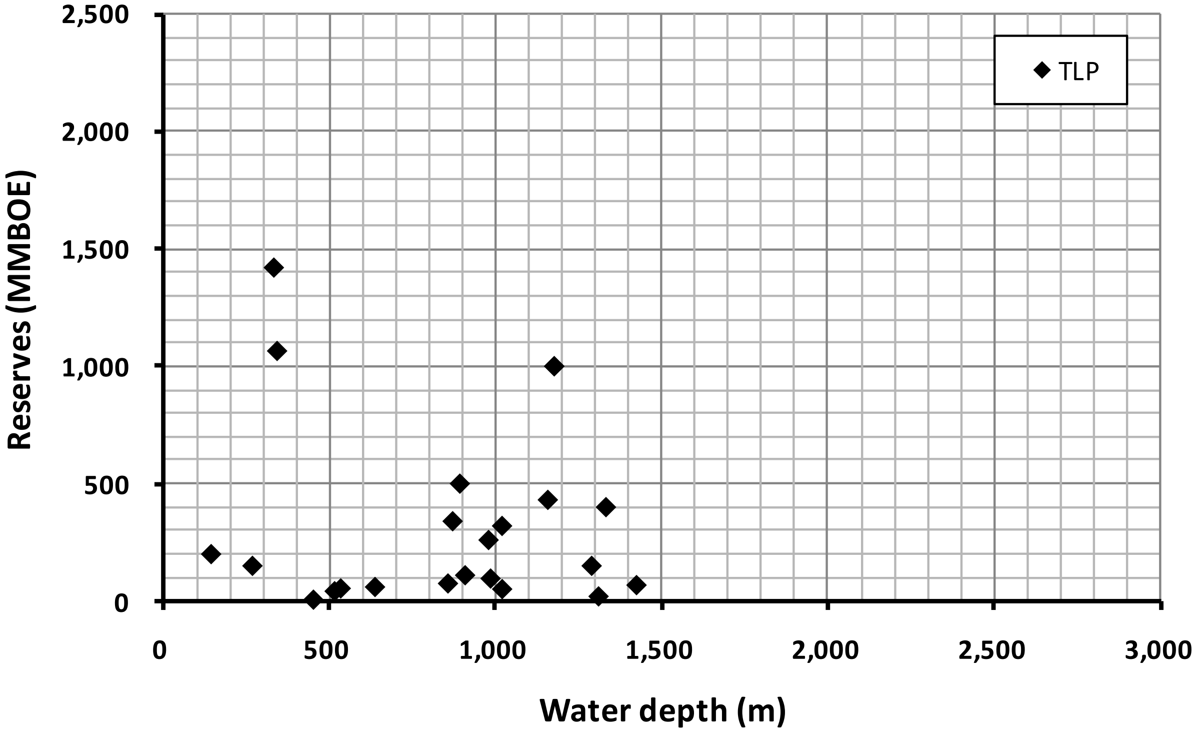

Figure 2-15: Relationship between water depth and reserves for TLPs

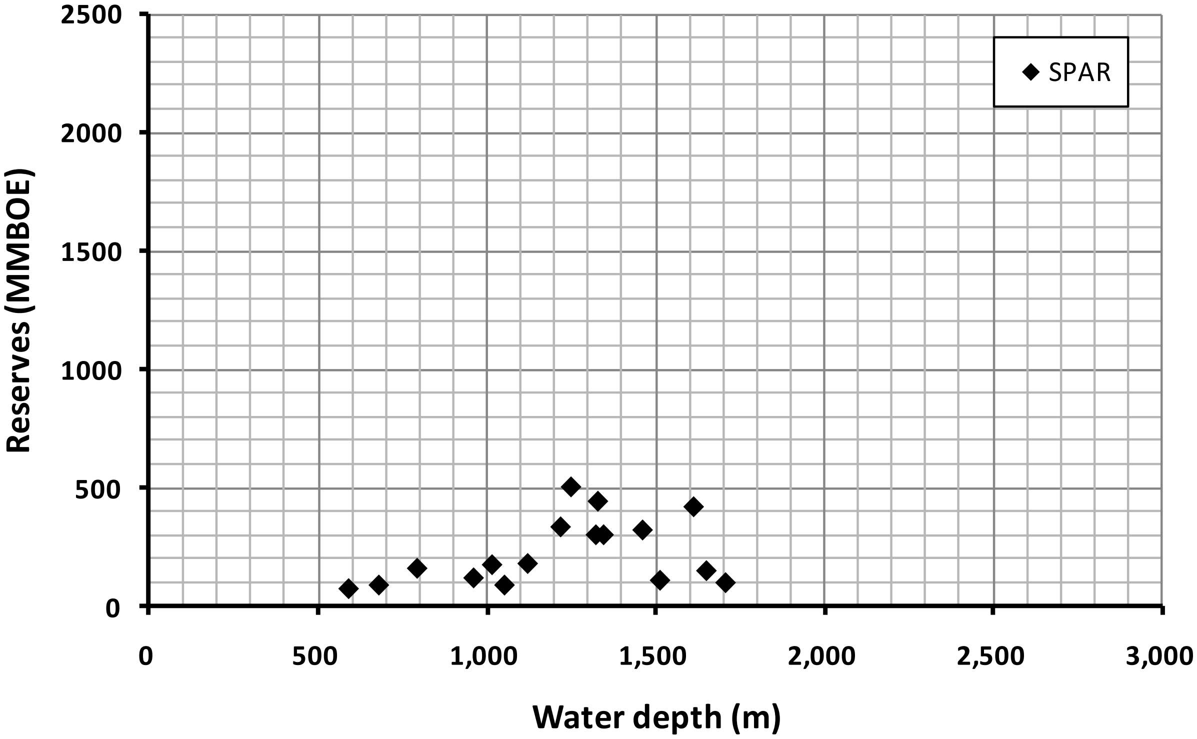

Figure 2-16: Relationship between water depth and reserves for spars

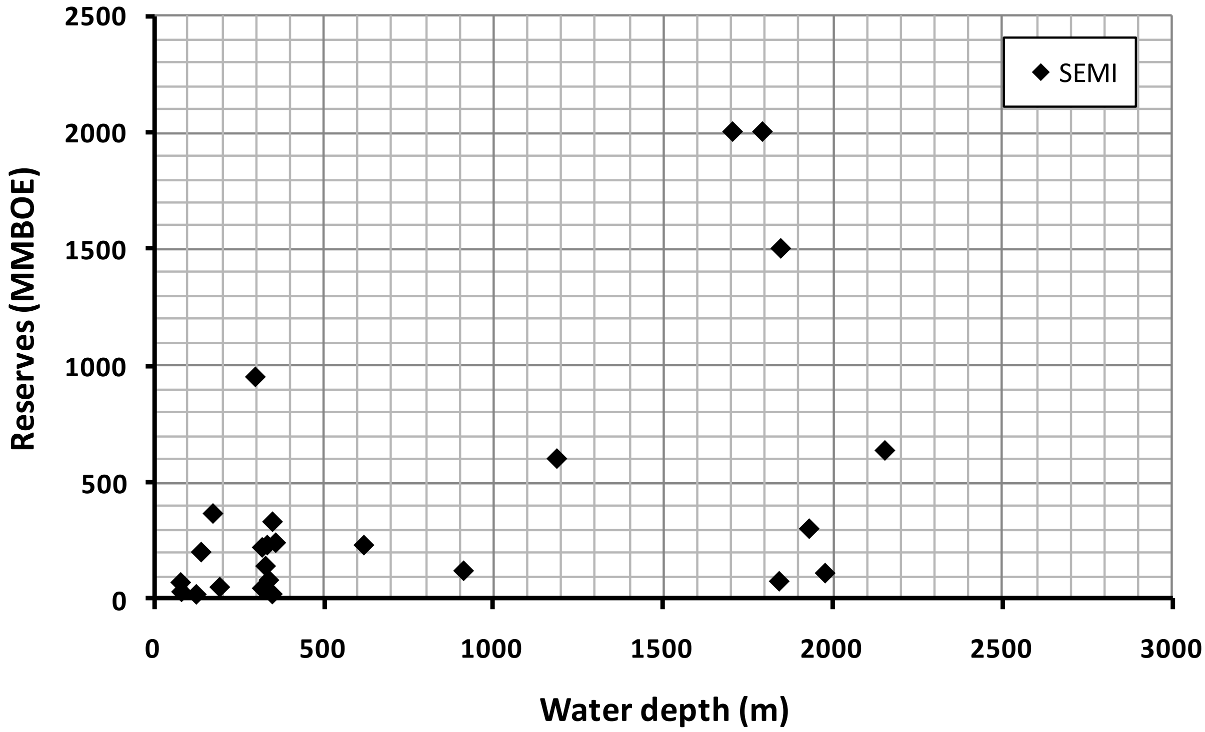


Figure 2-17: Relationship between water depth and reserves for semi-submersibles

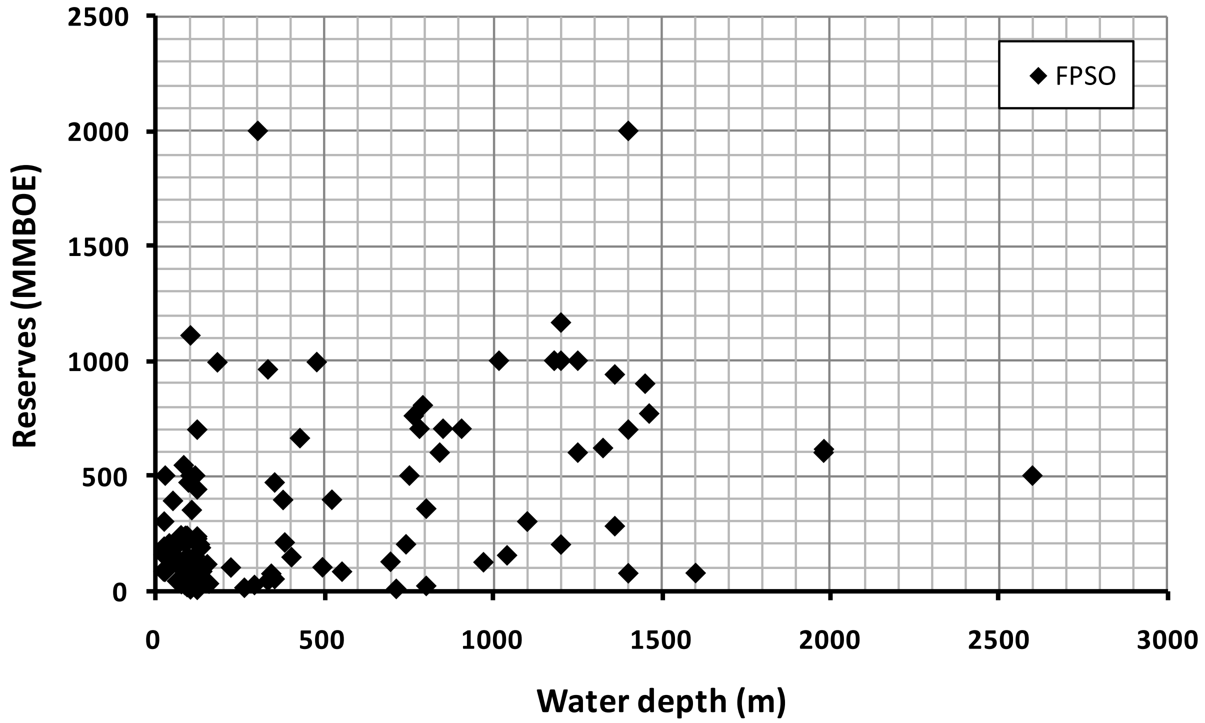


Figure 2-18: Relationship between water depth and reserves for FPSOs

It can be seen that TLPs tend to operate in depths less that 1500m and in reserves of less than 1500 million barrels. Spars tend to operate in depths up to 1700m, but they are being used in reserves that are less than 500 million barrels. The semi-submersibles and FPSOs show less of a general trend but they have both been used in reserves of 2000 million barrels and at depths greater than 2000m. The greatest depth reached by an FPSO is over 2500m.

It is also important to show the current trends of reachable water depth. This is shown for each different type of platform in Figure 2-19 to Figure 2-22 where the achieved water depth is plotted against the year of deployment.

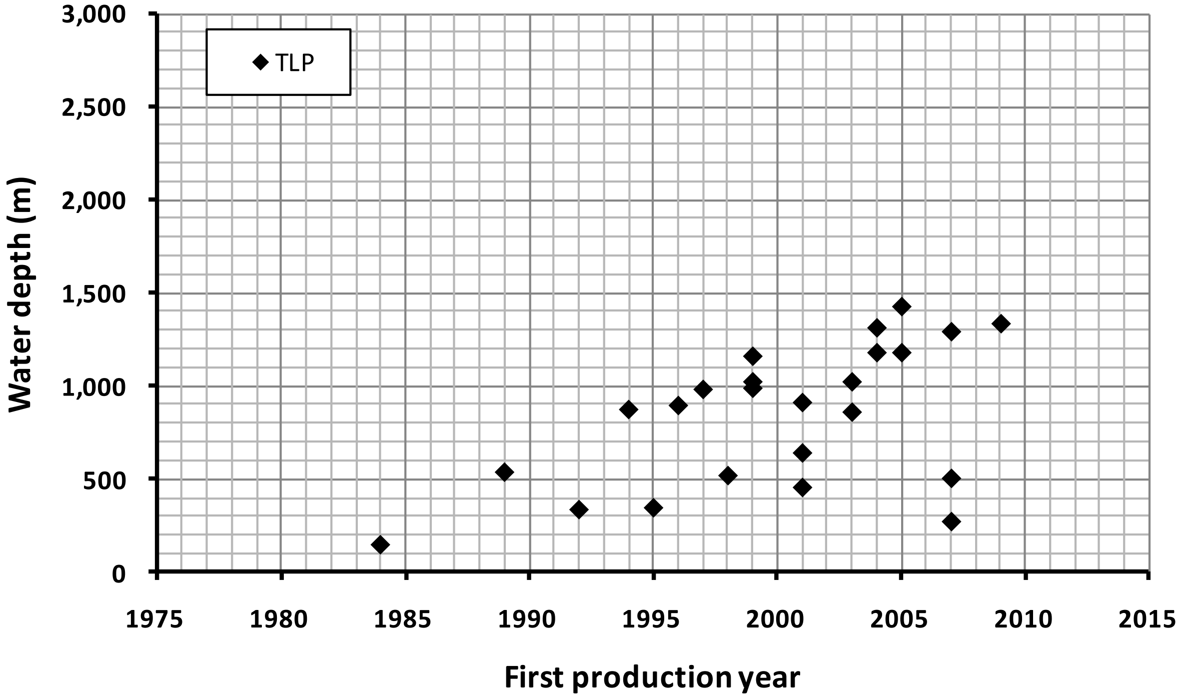

Figure 2-19: Relationship between first production year and water depth for TLPs

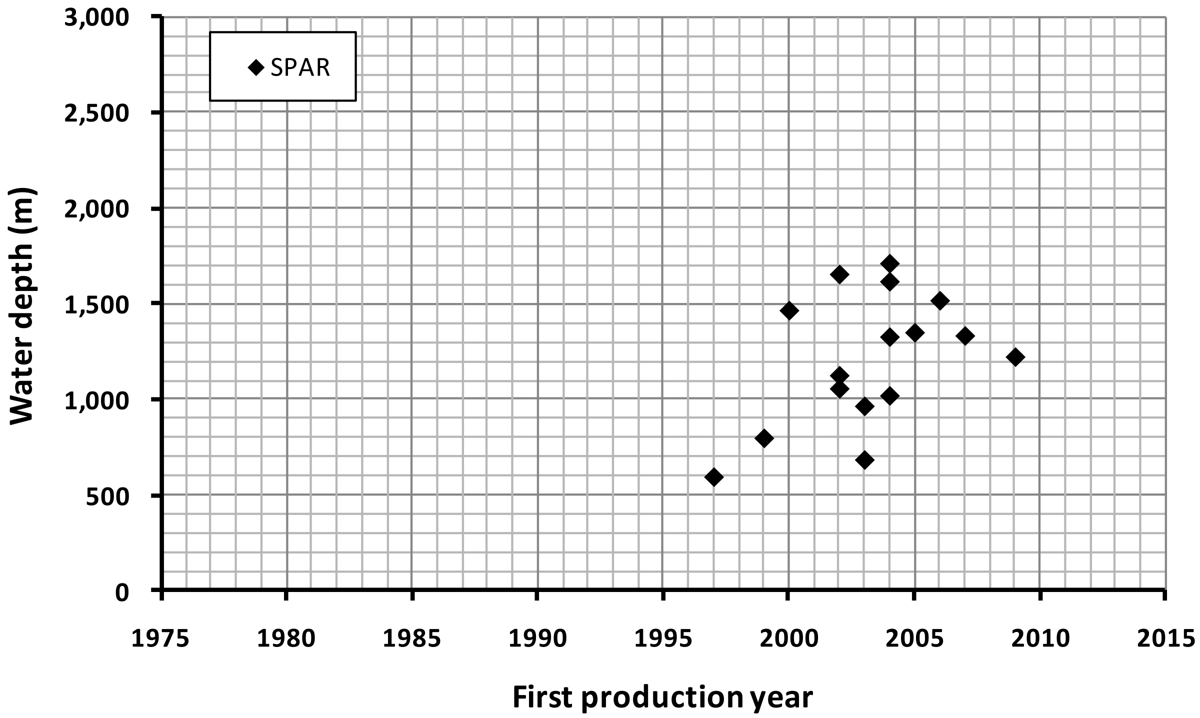

Figure 2-20: Relationship between first production year and water depth for spars

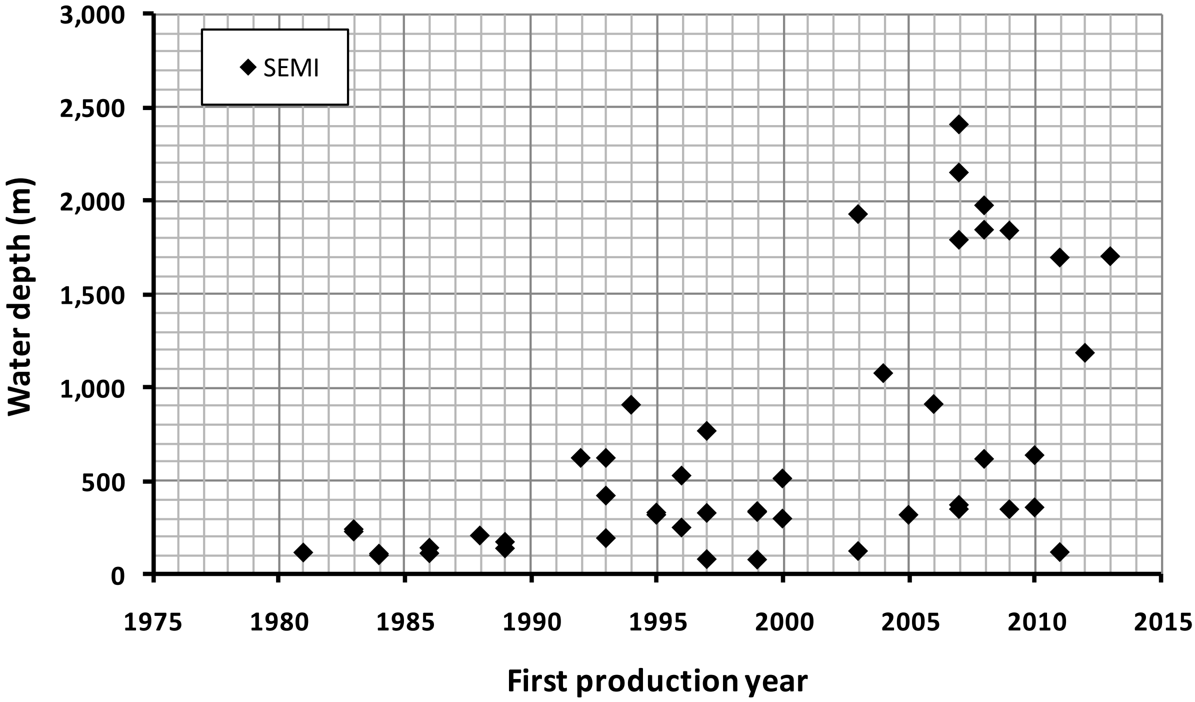


Figure 2-21: Relationship between first production year and water depth for semi-submersibles

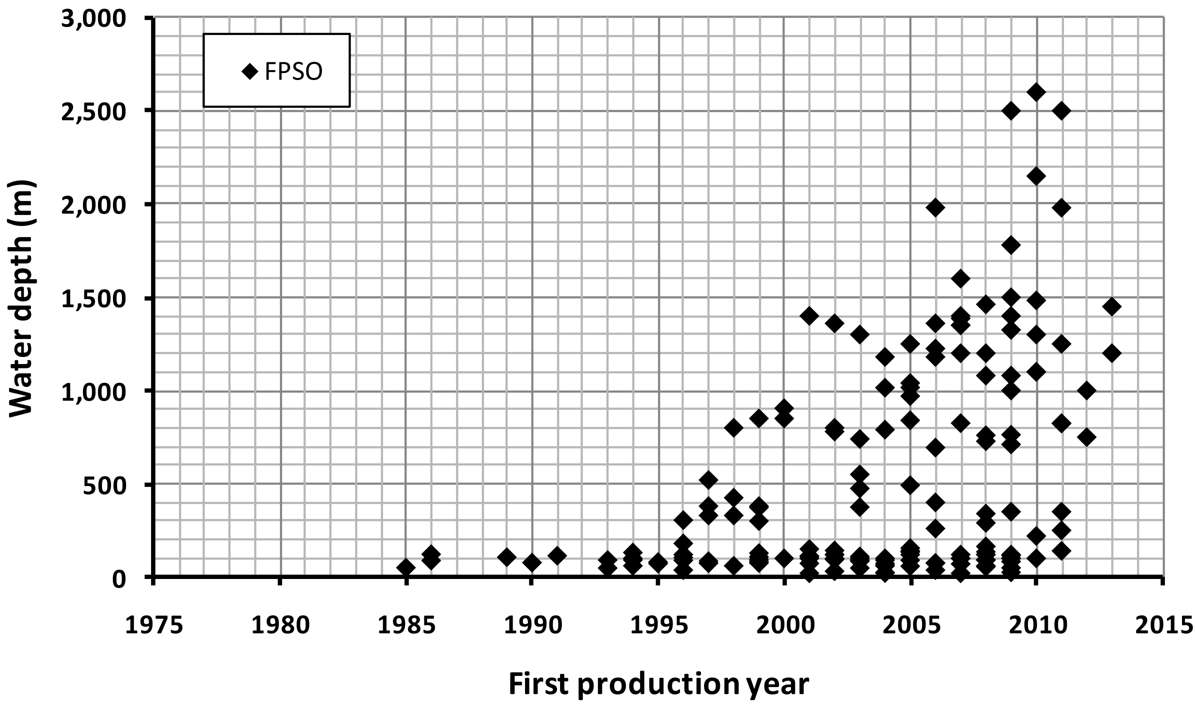


Figure 2-22: Relationship between first production year and water depth for FPSOs

The achieved water depth has greatly increased over the past 30 years, especially using FPSOs and Semi-submersibles. This study shows that it is likely that even deeper findings could be exploited in the near future. It also shows that the steepest trend is for FPSOs and semi submersibles with Spars and TLPs remaining stagnant since 2005. These trends must also be compared to the achieved deck area in each individual case since this is of great significance to the success of any offshore processing/power generating facility. A chart of achieved deck area at a certain water depth for existing structures is shown in Figure 2-23. It is concluded that the FPSO is the most versatile of the units since it is capable of achieving all ranges of deck areas over a very large range of water depths.

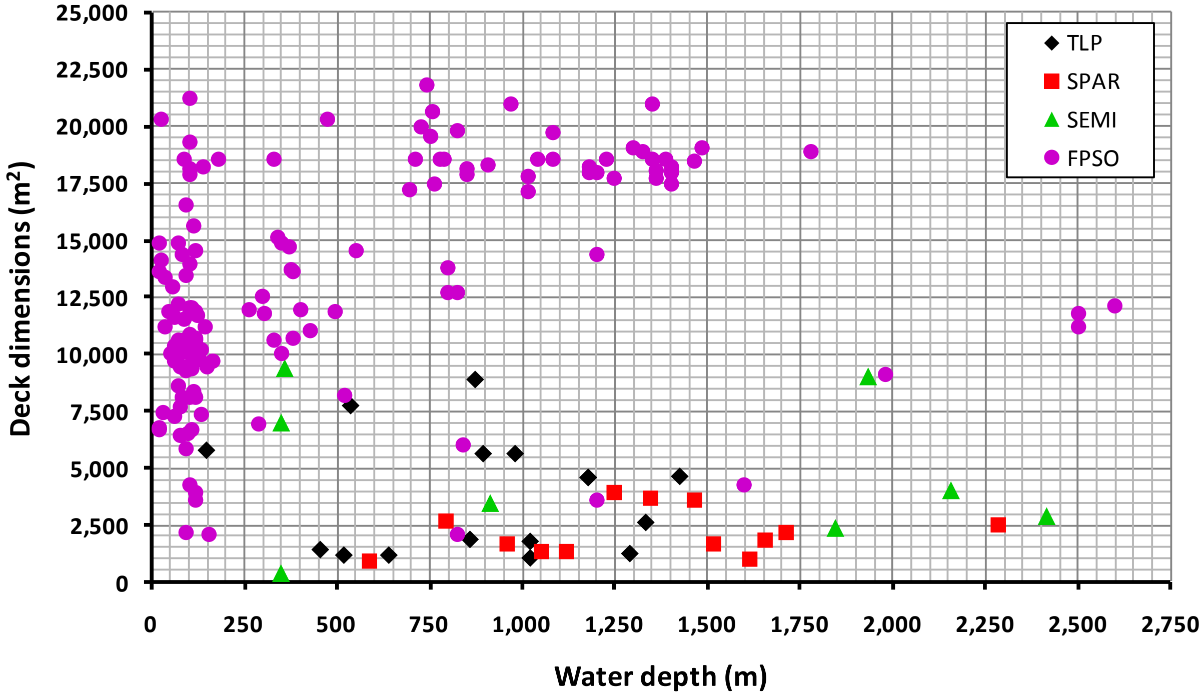


Figure 2-23: Relationship between deck area and water depth for different types of offshore structure

**Subsea Electrical Cables**

When placing power sources offshore, the feasibility will depend on if the generated electricity can be safely and economically transferred to the onshore grid. The energy generated offshore is growing in magnitude because of the introduction of larger wind farms and larger individual plants. There is therefore already a motivation in place to develop high capacity offshore cables. Furthermore there are already a number of long and medium distance offshore cables in operation using different technologies. The decision of which type of cable should be used should be based on material costs, installation cost, operational costs and energy losses during transmission. With almost any type of cable a large advantage is that it is retrievable and therefore moveable which will mean large cost savings when changing the location of the platform.

The material costs for any cable depend both on its design and the choice of conductor. For most cables either copper or aluminium is used. Copper is the most attractive for longer distances because of its superior conducting capacity. Aluminium cables, whilst being cheaper than copper per tonne of material) would have to be made thicker to carry the same current thus greatly increasing the material costs (Worzyk 2009). The large amount of proposed offshore power generating projects has a high risk of creating a shortage of copper, both due to international trade politics and global supply (Falconer 2009). The availability and prize of mined copper makes recycling a more attractive option. There are therefore issues with where large quantities of copper is positioned, both in terms of the future recyclability but also which country's market that copper will benefit. A Direct Current (DC) cable generally requires less copper (smaller diameter) to carry the same current as an Alternating Current (AC) cable and is thus preferable in this sense.

The operational costs will depend greatly on the individual case. Over long distances, a High Voltage DC (HVDC) cable is preferable over High voltage AC cable (HVAC) since it gives fewer losses in the actual transfer. However, DC cables require transforming the electricity from AC to DC at the offshore site which is costly and involves losses of about 2-3% per transformer (Erlich and Brakelmann 2007). For this reason, AC seems to be preferable for transmission over shorter distances like from near-shore wind-farms. The break-even distance, considering both material and operational costs seems to be about 50-100 km (Lazaridis 2005; Negra, Todorovich et al. 2006; van Eeckhout 2008). This however depends on the specific technologies involved but there seems to be more potential in further developing the HVDC option to become even more cost effective and it is likely that this will be used to carry electricity generated by future offshore installations. Many new developments in HVDC technology have been made in the last decade and experience is growing, for example the HVDC Light technology was used for the first time in 1999 with a 200 km link. By 2009 almost 2000 km of HVDC Light cables had been implemented worldwide (Johannesson, Gustafsson et al. 2009).

A further consideration that has to be made when choosing the type of cable to use is connectivity to existing and planned offshore grids. If an offshore power plant can connect directly to an existing international cable costs could be reduced. The vision for the future seems to be high capacity HVDC cables connecting nations; an example is the proposed European Supergrid which would most likely be a HVDC solution (van Hertem and Ghandhari 2010). Connecting a HVAC system to such a grid would require additional installations at the connection points which will most likely not be situated close to the power plant itself. Such a scenario would be more costly since it would require additional offshore infrastructure in a different location than the power plant and thus adding more complexity to the system.

*Carbon footprint of HVDC cables*

Since the aim is to create a system with a low carbon footprint, one must consider the energy penalty associated with the material of choice. Aluminium production generates around 5.7-7.8 kg $CO_2$/kg Al in Europe (Koch and Harnisch 2002) depending on how the electricity grid is utilised (from which sources) but can be considerably higher (up to 20 kg $CO_2$/kg Al) in less developed countries and older plants (Das and Chandra Kandpal 1998). No data exists for the specific $CO_2$ emissions associated with copper production however, the total energy consumption for producing 1 kg of copper is 60 MJ (Cornelissen 1997). About 60% the consumed energy is due to the smelting and refining process which is usually powered by burning of fuel oil which would produce 21.1 tonnes of $CO_2$ per TJ (Alvarado, Maldonado et al. 1999). This would give a figure of 1.26 kg $CO_2$/kg Cu for the refining process. Assuming that this is the “dirtiest” part of the process the maximum emissions for the whole process would be less than 2.11 kg $CO_2$/kg Cu. This is a conservative estimate since the remaining processes should be much cleaner than the burning of fuel oil.

These figures apply for copper and aluminium extracted by mining and smelting. Recycling of the same materials must also be considered as a source. The energy required to recycle one tonne of aluminium has been estimated at 55000 kWh which can be compared to the same figure for recycling copper (1560 kWh) (Bravard and Portal 1971). The increased need for recycling cables has a high likelihood of lowering these figures; however the ratio between them is likely to remain the same. In any case, the carbon footprint of using copper as a material seems considerably less than the one of using aluminium.

As an example, a 1250 $mm^2$ copper cable capable of carrying 500 MW at 400 kV over 160 km (reference cable taken from (Giorgi, Rendina et al. 2002) would require about 1800 tonnes of copper corresponding to emissions of less than 3800 tonnes of $CO_2$. According to the UK Sustainable Development Commission (UK SDC 2006) a typical gas power plant emits 356g of $CO_2$ per kWh. For a 500 MW plant, this would mean that laying a 160 km HVDC copper cable would incur $CO_2$ emissions corresponding to 0.24% of the annual emissions of that plant. For comparison, using the figure of 1560 kWh per tonne of recycled copper, supplying the conductor for the same cable using recycled copper would require 0.00014% of the plants yearly capacity.

*Costs of offshore HVDC cables*

An example of costs for subsea HVDC cables (Thomas 2009) is presented in Table 2-10 showing the relation between total cost and capacity of different size of cable.

TABLE 2-10
EXAMPLES OF OFFSHORE HVDC CABLES, ESTIMATED COST AND CAPACITY

| Cable Properties | Units | 33 kV | | 132 kV | | |
|---|---|---|---|---|---|---|
| Cross-sectional area | mm² | 95 | 240 | 800 | 300 | 400 |
| Approximate cable weight | Kg/m | 15 | 22 | 44 | 58 | 62 |
| DC Resistance at 20°C | Ohms/km | 0.193 | 0.0754 | 0.022 | 0.06 | 0.047 |
| Reactance at 50Hz | Ohms/km | 0.131 | 0.111 | 0.092 | 0.14 | 0.13 |
| Capacitance | µF/km | 0.206 | 0.277 | 0.38 | 0.15 | 0.17 |
| Subsea current rating | Amps | 325 | 535 | 822 | 570 | 635 |
| Typical cost | $/m | $101 | $150 | $378 | $380 | $410 |

The 132 kV cables would probably be more suitable for transmission over longer distances even though new technology may reduce the need for higher voltage. The cost of the cable in the example presented by (Thomas 2009) is 43% of the total installation and material costs for the 33 kV cable and 33% of the total cost for the 132kV cable. This would give a total cost of between 2 and 4 million US Dollars per mile of 132 kV cable depending on the desired capacity.

Total cost estimates can be created using Table 2-11 if it is assumed that cable will represent about 40% of the total cost, this is based on the figure for the Estlink 2 subsea cable scheduled for 2014 (Ryynänen 2010). This table also shows the Power rating (based on the current rating and voltage) and a cost/capacity index for comparison with existing projects.

TABLE 2-11
COST COMPARISON FIGURES BASED ON TABLE 3.4

| | | 33 kV | | 132 kV | | |
|---|---|---|---|---|---|---|
| Cross-sectional area | mm² | 95 | 240 | 800 | 300 | 400 |
| Power rating | MW | 11 | 18 | 109 | 75 | 84 |
| Est. Total cost | MM$/km | 0.391 | 0.581 | 1.909 | 1.919 | 2.071 |
| Cost/capacity index | MM$/kWkm | 0.037 | 0.033 | 0.018 | 0.026 | 0.025 |

A list of existing long-range HVDC cables with the calculated cost/capacity index calculated in the same way is shown in Table 2-12.

TABLE 2-12
SELECTION OF EXISTING HVDC OFFSHORE CABLES

| Cable | Length (km) | Total Cost (M$) | MM$/km | DC Voltage (kV) | Power Rating (MW) | M$/MMWkm |
|---|---|---|---|---|---|---|
| Nord-Ned | 580 | 856 | 1.5 | 450 | 700 | 0.0021 |
| Brit-Ned | 260 | 856 | 3.3 | 450 | 1000 | 0.0033 |
| Estlink 2 | 171 | 456 | 2.7 | 450 | 650 | 0.0041 |
| Baltic Cable | 250 | 280 | 1.1 | 450 | 600 | 0.0019 |

Based on these figures it seems reasonable that the total cost for connecting offshore power plants to the land grid will be in the range of *0.002-0.004 MM$/MWkm*. For the example 500 MW power plant 160 km offshore the cable cost would be 160-320 million dollars.

*Possible alternatives*

High Temperature Superconductor (HTS) cables are a proposed novel concept which may reduce the energy losses in the transmission by more than 80% (Elsherif, Taylor et al. 2011). HTS cables can also operate at a lower voltage and still retain their near-zero resistance which means that the need for offshore transforming stations could be reduced. Depending on future developments of the involved technology, HTS cables may thus be the most cost effective option for offshore generated power (Elsherif et al. 2011).

*Transformers*

The generators in any power plant will produce AC. For transmission in HVDC cables, the current has to be converted to DC using rectifiers (transformers.) Since the insulation distance in the transformers has to increase in size with increased voltage, many smaller converters would be desirable in a size restricted environment. However, the losses associated with conversion and the high costs of installing and operating the transformers offshore ultimately mean that the economical optimum is achieved with fewer converters (Koldby and Hyttinen 2009). The size of the transforming unit would depend on the specific company involved but it has been shown that the coils can be optimised to take up approximately 0.08 $m^3$ and 600 kg per MW (based on figures for a 3 MW and a 100 MW unit) (Nian 2009). Since the coils only constitute the core components of a converter; a fully operational transforming station would require more space in terms of auxiliary systems, cooling and separation of different components. The total size of the converter station is therefore much larger. Furthermore, the size of the transformer will depend on the frequency of the generated AC input where a higher frequency makes for a smaller transformer (Morren, de Haan et al. 2002).

As a reference, the National Grid gives the total size of a 1000 MW offshore AC/DC converter station as 80 x 40 x 35 m (112 $m^3$/MW) and 2000 tonnes (2000 kg/MW). The capitals costs are given as approximately 120.000$ per MW (National Grid 2009). Since the size estimate is for a standalone unit that requires various secondary facilities, a similar installation in a larger structure would be likely to be smaller.

**External Connections**

Similar to an FPSO, a floating power station would be supplied with gas from one or more wells located nearby. Depending on the local conditions and experience of the operating company, the downstream structure could be either a surface platform or a subsea installation. If using geological storage, $CO_2$ injection would take place either in connection to an active gas well using EGR or in a separate location.

The plant would either be moored in a fixed position or to a turret allowing it to swivel. The swivel option would be preferable in environments with changes in current, wave and wind directions at high loads. An added complexity in a floating CCS plant compared to a normal FPSO is the routing of injection pipes. It would be preferable if these could exit the hull in the same location as the incoming gas risers but in case this is not possible, a fixed mooring system may have to be considered to avoid excessive bending. Furthermore the exit point of the transmission cable must also be considered in correlation with the various risers to avoid entangling. High voltage DC swivel connections are not yet available for larger power outputs ( > 50 MW) but the technology is being developed and DC systems capable of carrying 260 MW are due to be available in 2011/2012 (Poldervaart 2010).

In case the gas is processed on a separate platform, flexible connections will have to be deployed to facilitate relative motions.

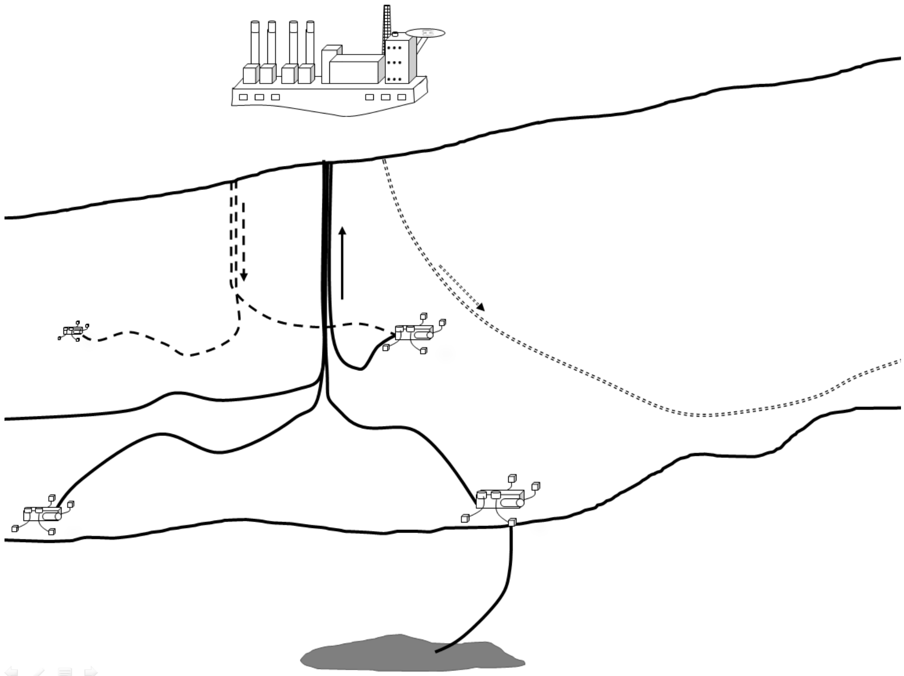

Figure 2-24: An Offshore Power Plant served by local subsea installations and a more distant source

**Prime Movers**

There are four main types of prime mover that could be used for generating electricity using natural gas in one form or another. These are diesel engines, gas turbines, steam turbines and fuel cells.

There are two types of diesel engine that could be used; slow speed and medium speed. Slow speed diesel engines are primarily used to power ships and have power outputs up to around 85 MW (MAN Diesel 2009). Medium speed engines have power outputs up to 20 MW and would therefore have limited applicability for large scale power generation. Diesel engines also have a fairly high efficiency and can generally convert at least 50% of the fuel energy into mechanical energy. Furthermore, they are high maintenance and very few versions are designed to run on natural gas.

Single cycle gas turbines are capable of producing high power outputs; a typical large turbine can produce between 100 to 400 MW of power (Soares 1998). They also have a good power-to-weight ratio and there are marine applications in existence. However, their efficiency is low compared to a diesel engine; around 25% (MAN Diesel 2009) and they are a lot more expensive per kW.

Around 80% of all electricity generation in the world is driven by steam turbines. They are low maintenance, can produce high power outputs and are very robust. They also have a long history of being used for marine applications. Their disadvantages are that they are extremely heavy as boilers and condensers are required and they have a low thermal efficiency (typically around 30% (MAN Diesel 2009).

Fuel cells have no moving parts do not use combustion so it is possible for them to achieve efficiencies of almost 100% although typical efficiencies are around 60% (DOE 2006). They are low maintenance and have a modular construction as well being a lot cleaner than traditional systems. However there are very few versions available, they are extremely expensive and they have almost never been used offshore. Furthermore, existing fuel cells are still small-scale and have not yet been proven at a large-scale power generation level yet.

Based on the respective advantages and disadvantages of the power generation systems mentioned above, the two most likely choices are gas turbines or steam turbines as they are capable of producing the required power without needing too many multiple systems as well as being well proven in marine applications. However they are inefficient which means that a lot of gas would be wasted. One way round this is to use a combined cycle gas turbine plant. This combines the two systems where a gas turbine is used to combust the fuel producing hot gases as a by-product in addition to the electricity. These hot gases are then sent to a heat recovery boiler which produces steam that can then be used to power a steam turbine which will produce more electricity. This then increases the overall efficiency to around 55 -59%. Some manufacturers also claim that they are close to reaching over 60% efficiency (Robb 2010). Figure 2-25 shows a typical arrangement of the gas turbine and steam plant.

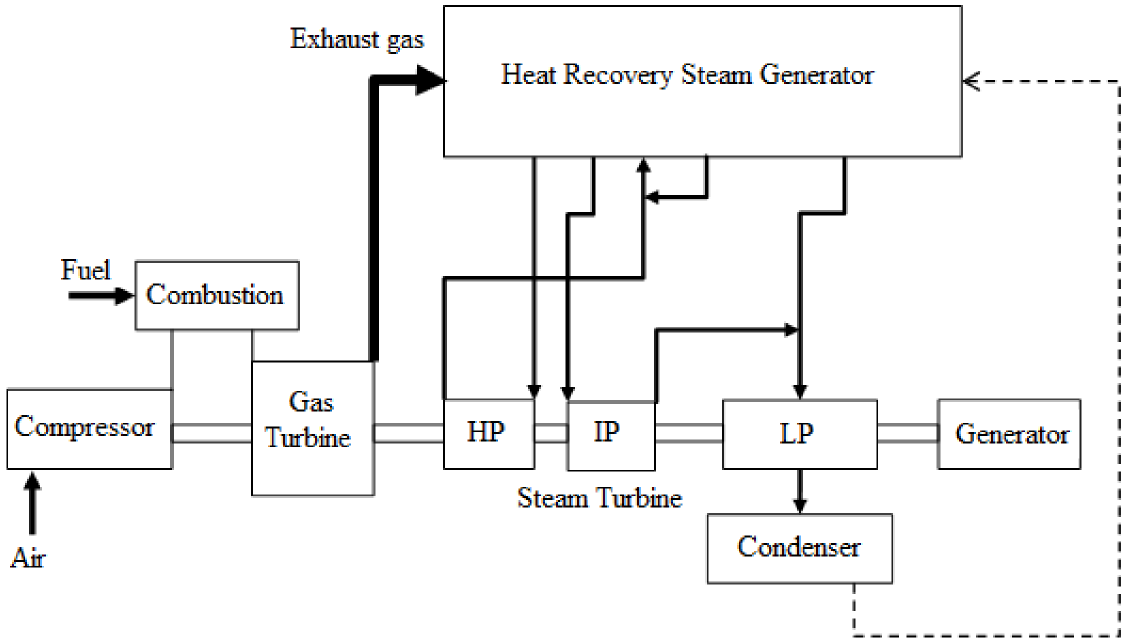


Figure 2-25: Combined cycle gas turbine

There are two types of combined cycle plants; single shaft and multi-shaft (Soares 1998). A single shaft system has a gas turbine and a steam turbine driving a common generator. In a multi-shaft system, each turbine has its own generator. The single shaft design has slightly better efficiency however the multi-shaft system allows two or more gas turbines to operate in conjunction with a single steam turbine. This means that there only needs to be one steam turbine, condenser and condensate systems for up to three turbines. This also allows the use of a large steam turbine which can handle high pressures and has a more efficient steam cycle than a smaller turbine. Therefore, if the amount of power needed can be supplied by just one set, it is better to use a single shaft system but if more than one gas turbine is needed then a multi-shaft system will be more economical. The larger plant sizes also benefit from economies of scale and have a lower initial cost per kW.

**Processing Plant**

Before the raw natural gas produced from the wellhead can be used as fuel in the gas turbines, it needs to be cleaned. The composition of the raw natural gas extracted from producing wells depends on the type, depth, and location of the underground deposit and the geology of the area. Raw natural gas will typically consist of methane however there will also be varying amounts of impurities and non-methane hydrocarbons. Natural gas processing is where these impurities and non-methane hydrocarbons and fluids are separated out to produce what is known as 'pipeline quality' dry natural gas.

Figure 2-26 shows a typical configuration for the processing of natural gas from non-associated gas fields.

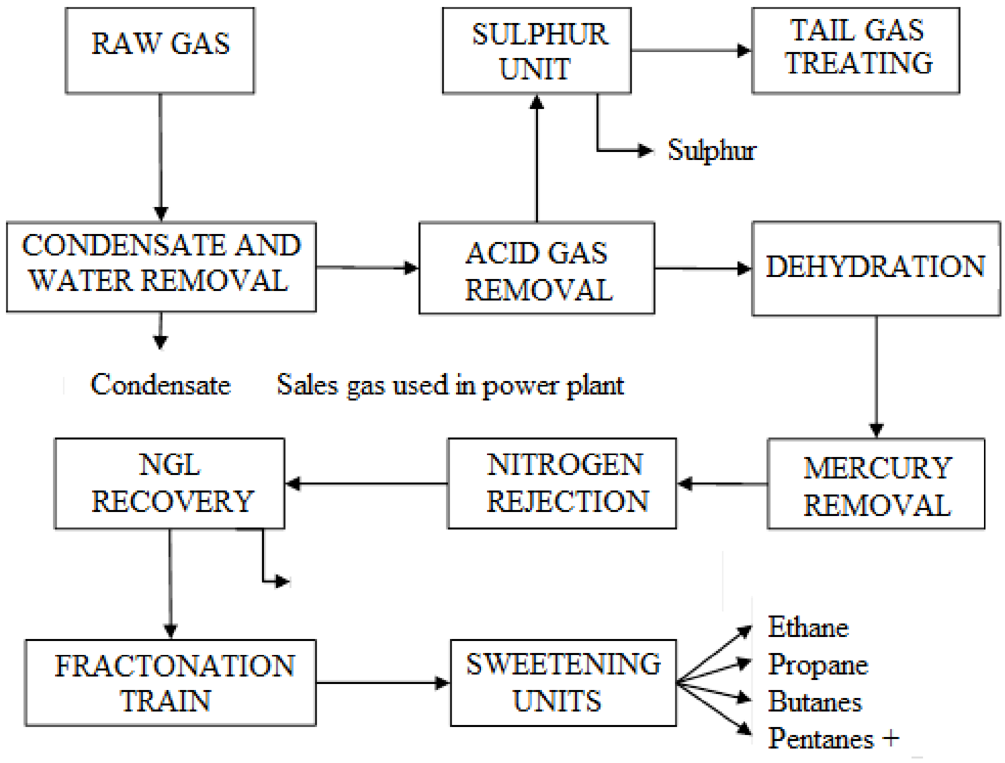


Figure 2-26: Typical Natural Gas processing flow diagram

Raw natural gas is collected from the production well and is processed to remove free liquid water and natural gas condensate. The condensate is usually transported to an oil refinery and the water is disposed of as wastewater. Initially, the raw gas is purified by removing the acid gases (hydrogen sulfide and carbon dioxide). There are several ways in which this can be done;

- Amine treating
- Benfield process
- Pressure Swing Adsorption unit
- Sulfinol process

The most common method is amine treating however the use of polymeric membranes to separate the carbon dioxide and hydrogen sulfide from the natural gas stream is gaining increasing acceptance. Once the acid gases have been removed, they can be routed into a sulphur recovery unit which converts the hygrogen sulphide into either elemental sulphur or sulphuric acid. The most widely used process for recovering elemental sulphur is the Claus process whereas the Contact process or the Wet Sulphuric Acid (WSA)process are usually used for recovering sulphuric acid. The residual gas from the Claus process is usually called the tail gas. This gas is processed in a tail gas treating unit to recover and recycle the residual compounds containing sulphur back into the Claus unit. The WSA process can be used for this.

The next step is to remove the water vapour from the gas. This can be done using several different methods;

- Regenerable absorption in liquid triethylene glycol
- Delinquescent chloride desiccants
- Pressure Swing Adsorption
- Membranes

Adsorption processes such as activated carbon or regenerable molecular sieves are then used to remove the mercury. If necessary, Nitrogen can also be removed using one of the following three processes;

- Cryogenic process using low temperature distillation.
- Absorption process using lean oil or a solvent
- Adsorption process using activated carbon or molecular sieves. This process may result in the loss of butanes and heavier hydrocarbons.

Next, the Natural Gas Liquids (NGL) are recovered. Most modern gas processing plants use a cryogenic low temperature distillation process involving the expansion of the gas through a turbo-expander. This is followed by distillation in a demethanising fractionation column. Some plants use lean oil absorption instead of the cryogenic turbo-expander process. The residue gas from the NGL recovery section is the purified gas needed to fuel the power plant.

Sometimes, the recovered NGL stream is processed through a fractionation train to recover ethane, butane, propane and other heavier hydrocarbons. The butane and propane can then be sweetened in a Merox process unit to convert mecaptans into disulphides. These, along with the recovered ethane are the final NGL by-products from the processing plant. Most cyrogenic plants do not include this fractionation for economic reasons. Instead the NGL stream is transported as a mixed product to a standalone fractionation site or to a chemical plant for use as a feedstock.

Typically, at this point the natural gas and the by-products are transported; either by pipeline or by ship. In this study, the gas processing plant will be placed offshore. This will remove the need to transport the natural gas although the by-products will still need to be removed by ship. There are two options for the construction of the gas processing plant.

One option is to place the gas processing plant on a separate floating structure to the power plant. This option is already being considered for Liquefied Natural Gas (LNG) production. Whilst there are currently no floating LNG facilities, Royal Dutch Shell has ordered an FLNG with a delivery date of 2017 known as the Shell Prelude (Shell 2009). The facility will theoretically produce, liquefy, store and transfer LNG (and potentially LPG and condensate) at sea. Ships will then be used to transfer the LPG and by-products ashore. Whilst this concept is for LNG, the only major difference will be that the natural gas does not need to be condensed and cooled to become LNG. In addition some FPSOs could be converted to solely process gas as in mixed oil and gas fields some level of gas processing is already required.

The alternative to a separate facility is to place the gas processing plant on the same floating structure as the power plant. This has the advantage of being cheaper as only one hull will have to be constructed. It will also be easier to connect the fuel gas to the turbines as the differing motions between floating platforms will not be an issue. The disadvantage is that the gas processing facility will take up space that could be used for another turbine set.

When considering which option to select, it is important to consider how the decision will affect the end cost of the electricity. As there are no current facilities in operation, cost data has been taken from a case study contained within a report from the Gas Processors Association Europe LNG Working Party (Sheffield 2005).

The vessel considered is 300m in length with a beam 60m and a depth of 30m (draught 15m). This gives a usable deck area of around 15 000m$^2$ and an LNG production capacity of 1.5 million metric tonnes. This equates to 2.07 billion cubic metres of natural gas produced every year. The capacity factor is 0.96 based on 8450 hours of operation per year. Table 2-13 shows the capital costs associated with a FLNG gas processing facility. Originally, costs were included for the liquefaction and transfer of LNG; these were considered unnecessary for the floating gas facility.

TABLE 2-13
CAPITAL COSTS OF A FLOATING GAS PRODUCTION FACILITY

| Capital Costs | Lower Range Million US$ | Upper Range Million US$ |
|---|---|---|
| Hull & Accommodation | 200 | 240 |
| Mooring | 50 | 60 |
| Risers | 45 | 60 |
| Towing | 40 | 50 |
| Gas reception/cleaning | 80 | 120 |
| Utilities | 60 | 80 |
| Total | 475 | 610 |

Table 2-14 shows the operating costs; again costs associated directly with the liquefaction process have been removed. The cost of shipping the LNG has also been removed.

TABLE 2-14
OPERATING COSTS OF A FLOATING GAS PRODUCTION FACILITY

| Operating Costs | Lower Range US$ MM | Upper Range US$ MM |
|---|---|---|
| Raw Gas | 45 | 65 |
| Maintenance | 30 | 40 |
| Staffing | 30 | 40 |
| Sundries | 25 | 35 |
| Total | 130 | 180 |

Two different options are compared in Table 2-15. The values were obtained by calculating the total costs over the life of the facility where the life is assumed to be 20 years. This was then divided by the amount of LNG produced over this life span. A production value of 1.5 million metric tonnes of LNG per year was used. A discount rate of 5% (interest) was applied to both options and a value in US$ per metric tonne LNG was calculated. The detailed calculations are presented in Appendix A.

TABLE 2-15
COST OF DIFFERENT FLOATING GAS PRODUCTION OPTIONS

| Option | Lower Range | Upper Range | Units |
|---|---|---|---|
| Separate floating facility (1) | 113 | 154 | US$/tonne |
| Use power plant facility (2) | 91 | 127 | US$/tonne |

Option one uses all the costs listed in Table 2-13 and Table 2-14 however option two only includes the gas reception/cleaning capital cost. As expected the most expensive option is to build and operate a separate floating platform for the gas production.

Another consideration is the fuel requirement of the gas turbines. Using a thermal efficiency of 53%, a 500MW combined cycle gas turbine facility will typically consume 392 million $m^3$ of natural gas per year. This is roughly 284 000 metric tonnes of LNG. The example concept assumes a production capacity of 1.5 million tonnes of LNG per year. The Shell Prelude is designed to produce 3.5 million tonnes of LNG per year. This then presents an issue if option one is selected. It is logical to maximise the exploitation of the gas field which means selecting the largest possible facility however if more natural gas is processed than the power plant needs, then feeder ships will be needed to transport LNG ashore. This means that the costs associated with LNG itself would have to be added back into the costs of the facility. Another option is to run the processing plant at part load.

Finally, the energy requirements of the gas processing facility should be considered. The example assumes a power requirement of between 50 – 60 MW for a one million metric tonne of LNG production capability. This increases to 70 - 80 MW for a 1.5 million metric tonnes of LNG production capability. According to the California Environment Protection Agency (CEPA 2009), 26 234 British Thermal Unit (Btu) of natural gas is required for fuel in order to process one million Btu of natural gas. This equates to 0.28 kWh per $m^3$ natural gas. If 2.07 billion cubic metres of natural gas is produced then the energy penalty would be 577 500 MW per year. This results in a power requirement of 66 MW.

### *2.3.3 Carbon Capture & Storage System*

**Carbon Capture**

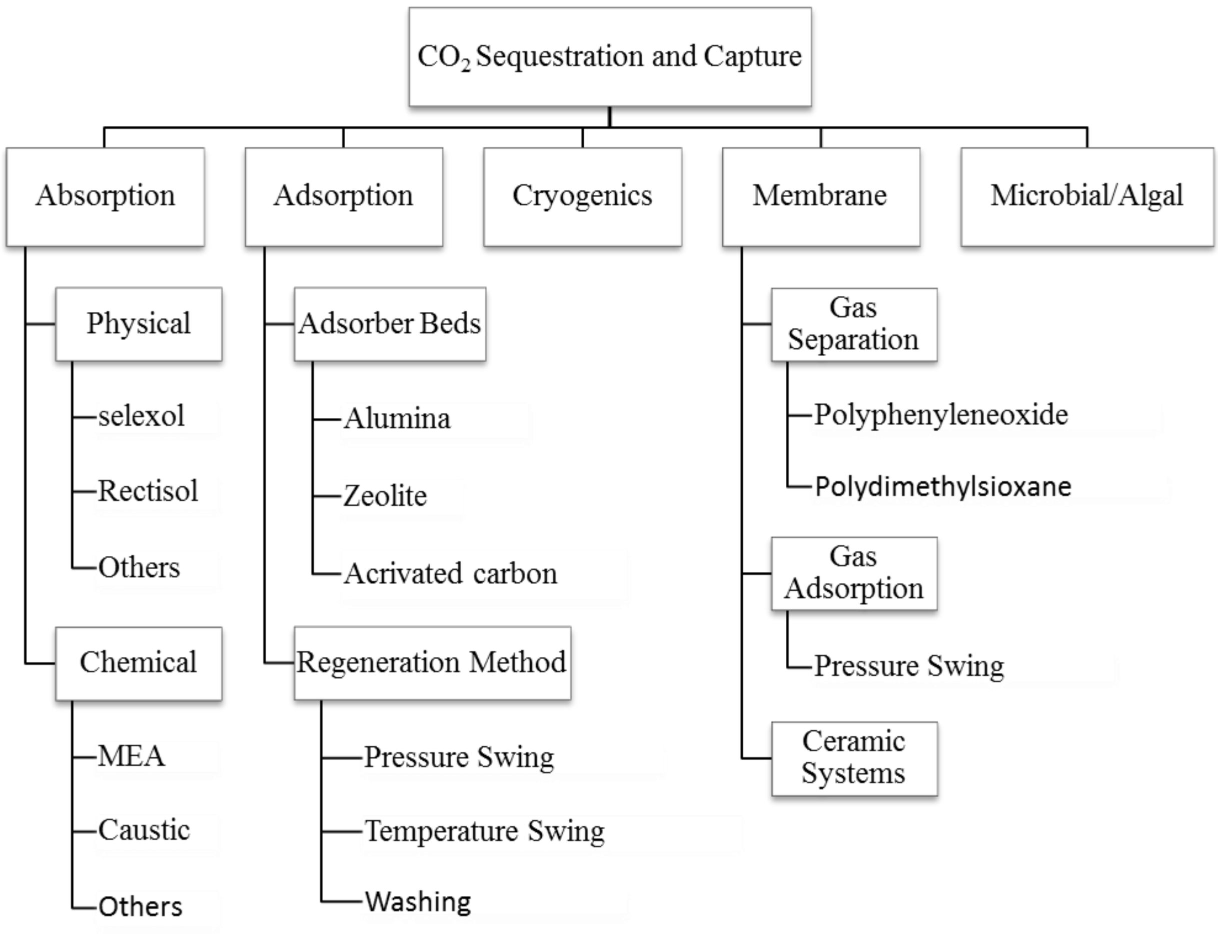


Figure 2-27: Post-combustion options

Since the post-combustion carbon capture method is the most mature of all the capture processes, this is the method that will be most easily utilised for the offshore power plant concept. There are four main options that could be used and each of these options has its own variations. Figure 2-27 shows the different post-combustion processes.

Chemical absorption is suited for low or nearly atmospheric pressure. The chemical absorption of $CO_2$ from flue gases is usually done using mono-ethanol amine (MEA). Other chemical solvents commercially available are di-ethanol-amine (DEA), tri-ethanol amine (TEA), activated methyl di-ethanol-amine (aMDEA[2]) and $K_2CO_3$. These solvents are commonly used in gas processing (IPCC 2005). Figure 2-28 shows the post-combustion process.

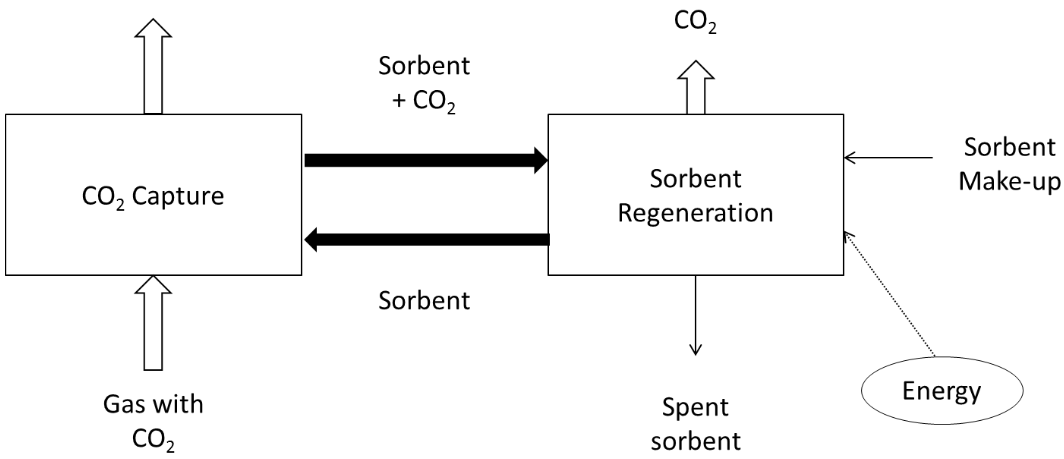


Figure 2-28: Chemical absorption system

Prior to entering the absorber, the flue gas needs to be cooled and impurities need to be removed. Reduction of NOx and SOx is essential because these components form heat-unstable, corrosive salts and cause solvent losses.

The following list summarises the features of chemical absorption processes.

- Suitable for low pressure gas.
- Applied to $CO_2$ capture from flue gas of pulverized coal boilers.
- Thermal energy is required to recover the absorbent (high cost).
- Sufficient desulfurization is required in advance.
- Large scale commercial experience (over 1000 $tCO_2/d$).

Physical absorption is the best process for large-scale $CO_2$ capture when the $CO_2$ partial pressure is high because this process is less energy intensive than chemical absorption processes. Physical absorption is used commercially to remove acid gas from natural gas and to remove $CO_2$ from syngas in the production of hydrogen, ammonia and methanol. Several physical solvents are commercially available, e.g. di-methyl ether and polyethylene glycol (Selexol), cold methanol (Rectisol) and N-methyl pyrollidone (Purisol). By physical absorption with Selexol, a $CO_2$ recovery of up to 90% can be achieved (IPCC 2005). Figure 2-29 shows this process.

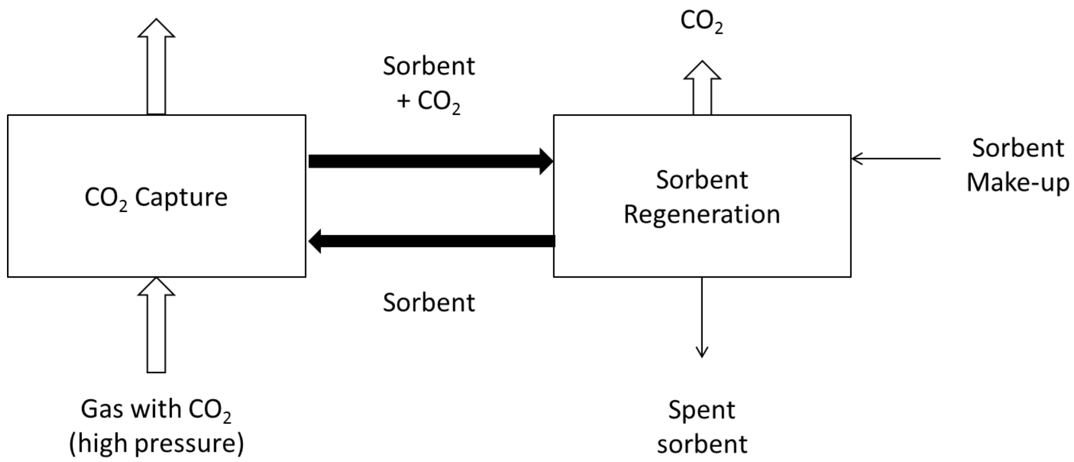


Figure 2-29: Physical absorption system

$CO_2$ capture from natural gas is very similar to the Syngas process. At the Sleipner platform $CO_2$ separation from natural gas is being achieved to reduce $CO_2$ concentrations from 4-9.5% to less than 2.5%. The module weighs 8200 tonnes and measures 50 x 20 x 35 m (EUROPEAN CARBON DIOXIDE NETWORK 2004).

The following summarises the features of physical absorption processes.

- Suitable for high pressure gas.
- Applied to $CO_2$ capture from coal gasification.
- Costs will be smaller compared to chemical absorption.
- $H_2S$ and $CO_2$ can be removed at the same time.
- Commercial experience.

Adsorption is the removal of $CO_2$ from a gas stream to the adsorbent. Adsorbents are solids (zeolite, activated carbon or aluminium oxide) that have the capacity to capture $CO_2$ on their surface and can be reused in a cyclical process (Bailey and Feron 2005). In these cycles, the $CO_2$ is released from the adsorption material by reducing the pressure, increasing temperature or hybrids of the two. These are known as Pressure Swing Adsorption (PSA) and Temperature Swing Adsorption (TSA) and Process Hybrids Swing Adsorption (PTSA). These adsorbents are tested at about 250°C, higher feed gas temperatures than the other processes. This may lower the capture cost because of reducing the need to cool the gas for capture and reheat it for entry into the gas turbine in a power plant. Figure 2-30 shows the adsorption system (PSA).

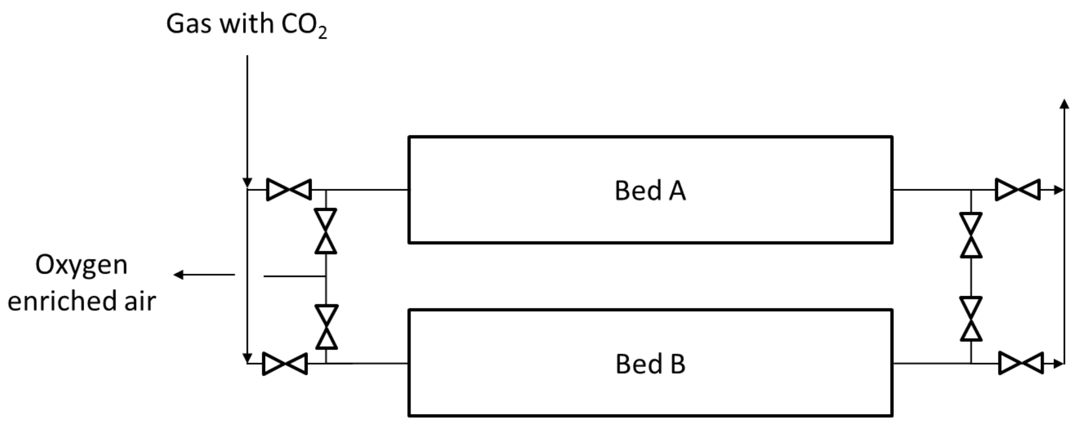


Figure 2-30: Adsorption system (PSA)

The following summarises the features of adsorption processes.

- Adsorption processes can be scaled up by arranging a number of adsorption towers.
- Based on the pressure of the gas, $CO_2$ separation is expected to consume less energy.

The membrane process is the method for separating the $CO_2$ and capturing it by transmitting the gas into a porous polymer membrane and using the difference in the transmitting speed to facilitate the process (de Montigny 2008). This process has some issues; the low recovery rate of $CO_2$, the durability of the membrane material and the high cost of the material. However, it is anticipated that this process will be used in the future because the process is simple and easy to operate and is able to save energy and space and can be scaled up. Figure 2-31 shows the membrane process.

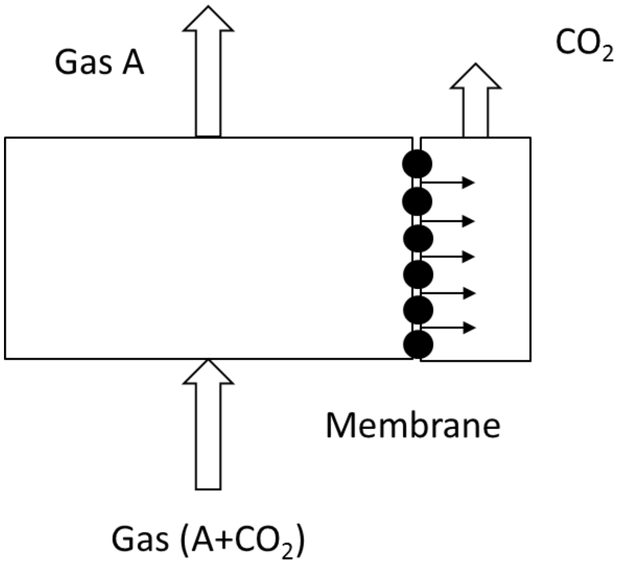


Figure 2-31: Membrane system

The following summarises the features of membrane processes.

- Additional energy is not required.
- Requires the development of new membranes.
- Amount of $CO_2$ captured is less than chemical absorption

In the Cryogenics system, flue gas is cooled below the boiling point of $CO_2$, so that it condenses and can be separated from other gaseous compounds (de Montigny 2008). The advantage of cryogenic separation is that liquid $CO_2$ is produced which can be pumped directly to the injection site. However, the process is energy intensive and would result in large efficiency reductions when applied for capture from flue gas at power plants. This process is mainly used when $CO_2$ concentrations are high (50-70%). Figure 2-32 shows the cryogenic system.

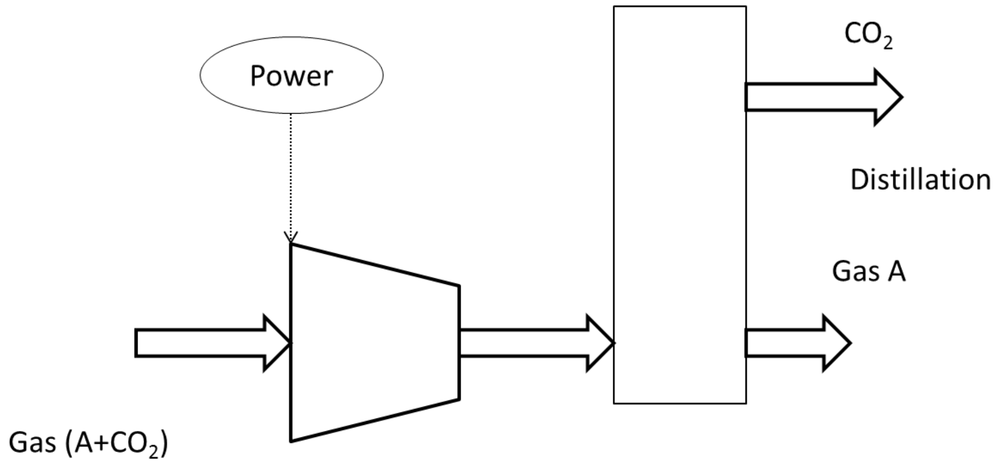


Figure 2-32: Cryogenic system

The following summarises the features of cryogenic processes.

- Useful for injection because liquid $CO_2$ is produced.
- High cost.
- Suitable for high $CO_2$ concentrations.

At present for larger commercial $CO_2$ recovery plants, chemical absorption systems are used. There are currently three commercially available systems (Bailey & Feron 2005) and their typical capacity is up to 1200 $tCO_2$/day. This suggests that in order to carry out large-scale mitigation of $CO_2$ emissions, experience is required with larger units integrated into power plants. In order to capture 90% of the $CO_2$ emitted by a 400 MW natural gas fired combined cycle plant, capture rates of about 3200 $tCO_2$/day are required; almost three times larger than the biggest MEA units.

In the future, the ideal method of capturing $CO_2$ will be to use membranes. However, given the technological immaturity of this system when compared to the chemical absorption systems the most viable solution at present is to use MEA.

**$CO_2$ Storage**

Figure 2-33 lists the main factors which govern the selection of a $CO_2$ storage option. The proposed concept of the offshore thermal power plant needs to be near a gas field or an operating FPSO where a quick and cheap fuel supply can be achieved. In addition, the location of the offshore thermal power plant needs to be near the final location for $CO_2$ storage. Therefore, the power plant location is critical when choosing an appropriate storage method. In addition, storage costs and capacity need to be investigated to find out the most cost-effective way to store $CO_2$. Other considerations such as the geological condition (including reservoir conditions), seabed topography and seismic surveys, need to be considered in the design stage. Furthermore, potential environmental risks need to be considered and minimized to pursue a safe way for long-term isolation of $CO_2$ from the atmosphere. Technology maturity will also influence the final decision of the storage method since storage methods may not be practical at present but could be available in the near future.

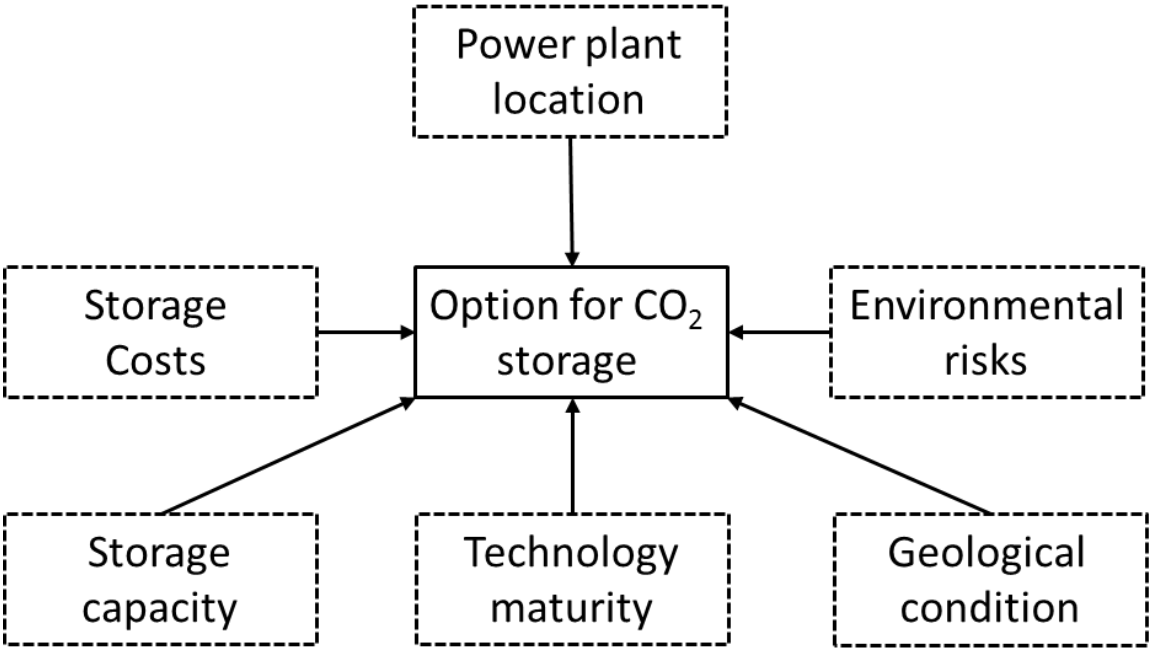


Figure 2-33: Main factors for selecting $CO_2$ storage option

There are two types of storage available for the offshore thermal power plant with CCS; offshore geological storage and ocean storage. A number of options have been proposed in the literature (IPCC 2005) for these two storage options which are summarised in the following table:

TABLE 2-16
OPTIONS FOR $CO_2$ STORAGE IN OCEAN SPACE

| Offshore geological storage | Ocean storage |
|---|---|
| Deep saline formations | Dissolution type(rising plume) |
| Depleted oil/gas fields | Dissolution type (sinking plume) |
| Geological storage with EOR/EGR | "Lake" deposits |

In general, offshore geological storage of $CO_2$ is more understood since technologies developed in the oil & gas exploration and production industry can be directly applied. There is already one pilot CCS project deployed. The Sleipner project is the first CCS project which stores $CO_2$ into an offshore deep saline formation (IPCC 2005). The project started in 1996 and it is estimated that a total of 7 $MtCO_2$ will be stored over the lifetime of the project. In this project, the $CO_2$ separated from Sleipner West Gas Field is transported to Sleipner A and then injected into a deep saline formation which is 800 m below the seabed of the North Sea (IPCC 2005).

The characteristics for different options for offshore geological storage (Bock, Bert et al. 2002; Anderson and Newell 2004; IPCC 2005) can be summarised in Table 2-17.

TABLE 2-17
CHARACTERISTICS OF GEOLOGICAL STORAGE OPTIONS

| Options | Characteristics |
|---|---|
| Deep saline formations | • A better option in the longer term<br>• Better matched to sources of emissions implying relatively lower costs<br>• The potential storage capacity is quite large |
| Depleted oil/gas fields | • Considered as the best-near term solution<br>• Better understood<br>• Demonstrated ability to store pressurized liquids for millions of years<br>• Least potential environmental risks<br>• EOR/ EGR may cause negative costs for $CO_2$ storage<br>• Most current EOR/EGR do not contribute to the reductions of $CO_2$ emissions<br>• Opportunities for EOR/EGR are insufficient |

From this it can be seen that in the long-term, saline aquifers present a more viable storage site however in the short-term using depleted oil/gas fields presents a more viable alternative. In addition, EOR/EGR can be used which may offset some of the costs of CCS.

The costs for ocean storage are comparable with geological storage of $CO_2$ (Anderson and Newell 2004). Therefore, ocean storage of $CO_2$ must be considered as a potential storage method for the offshore thermal power plant with CCS. However research is still on-going into ocean storage and this solution has never been demonstrated (IPCC 2005). In addition, there are concerns over the environmental impacts of ocean storage and in many countries, it could be technically considered illegal if the $CO_2$ is defined as a waste product.

Whilst the on-going research pursuing the storage of $CO_2$ in the oceans may be suitable in the future, currently, storage of $CO_2$ in offshore geological formations is considered to be a more practical solution since it is more developed. In addition, the practice of underground injection of waste liquids provides experience that can be applied in this case. The decision as to which type of geological storage option is selected will also depend on the location of the offshore power plant.

### *2.3.4 Risk relating to offshore structures, power plants & CCS*

The general definition of risk is the chance of damaging structures, facilities, humans, reputations, the environment or profitability. The most effective way of reducing risk is to assess the level of severity and identify ways of reducing it. Generally risk assessments are composed of qualitative risk assessment and quantitative risk assessment. Quantitative risk assessment means predicting the frequency of events that pose a risk. This is done by assessing the probable frequency of an occurrence; this is then compared to the consequences of that occurrence. Many different risk factors can be taken into account simultaneously and the total risk of an occurrence that has unacceptable consequences can be estimated. This has the benefit of being able to see a broader picture of risk but lacks detailed studies into the phenomena that cause the occurrences. Qualitative risk assessment is a more precise way of predicting specific risks. It involves detailed studies of a certain phenomenon and judgements of risk that are typically based on a priori estimates. This is too time consuming to do for all the factors in a project which is why it is often used for risks with a high level of uncertainty whilst quantitative assessment is used for more well-known risks. To gather more knowledge of the probability and severity of different occurrences associated with offshore operations, many studies have been performed such as the SAFEDOR project for risk-evaluation for offshore design, operation, environment and human safety (Skjong, Vanem et al. 2005).

The assessment of risk should be part of an iterative design process so that potential design flaws leading to increased risk are removed Many such processes have been proposed but an example adapted from guidelines by IMO (2002) is shown in Figure 2-34. The characteristics of the different steps described in this figure will be discussed below.

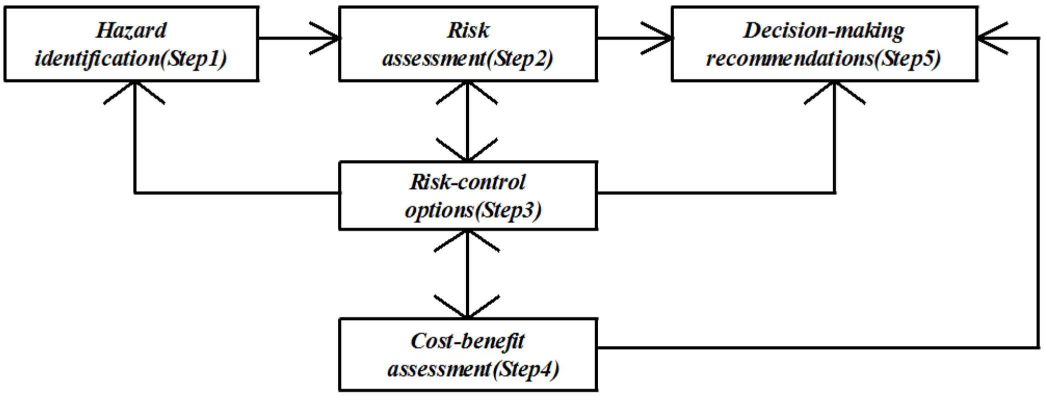


Figure 2-34: Process chart for Formal Safety assessment (FSA)

*Hazard Identification (HAZID)*

A hazard is something that has the potential of damaging human life or property. The purpose of this step is to identify the hazards so that the risk can be evaluated based on the severity of the consequences and the probability of occurrence.

*Risk Assessment (RA)*

The principal role of the risk assessment is to evaluate the risk level (frequency and consequence), from the HAZID step for each accident scenario. The risk is usually defined as frequency multiplied by consequence

*Risk Control Option (RCO)*

This step involves controlling the risk by changing the design or adding features such as safety devices..

*Cost Benefit Assessment (CBA)*

The cost benefit assessment shows the risk for the costs and benefits of the system. It provides the basics for the previous section (Risk control option). This part is divided into a cost benefit analysis and a cost effectiveness analysis. The function of this step is to halt the risk control option when the benefit exceeds the cost.

*Decision Making Recommendations (DMR)*

In this part, risk is considered as acceptable or unacceptable by using the ALARP (Risk = As Low As Reasonably Practicable) decision making method. This provides a reasonable judgement of the risk level and the implications of changing the design. The concept of ALARP is a general method to gauge the acceptance of risk (HSE 1998).

The ideal situation is one where risk is eliminated. This is not possible since there will always be a level of uncertainty and things that are left to chance. The purpose of this process is thus not to eliminate risk but to conceive a rational design based on the risk assessment.

**Risks relating to offshore power plants**

The risk associated with operating an offshore power plant with CCS can be classified as follows:

- Risk relating to the marine environment and offshore structures in general.
- Risk relating to the power plant (turbines, high voltages and fuel).
- Risk relating to the carbon capturing (leakages and hazardous chemicals).
- Risks relating to the $CO_2$ storage (leakage, pressure variations and protests).
- Risks to the environment (leakage of fuel and chemicals as well as the temperature of the ejected cooling water).
- Risks encountered in the construction process (onshore and offshore).
- Economical risks associated with operating an expensive facility in a variable economic climate.

Each of these areas involves both personal risk, structural risk and economical risk.

*Risk relating to offshore structures and the marine environment*

A good statement of some of the major risks relating to offshore structures is given by (CMPT 1999). This represents an overview of some of the most severe risks associated with operating an offshore platform. Many other minor risks exist and must be considered when designing operating protocol and policy. The risks are classified as

- Leaks
- Fires/explosions
- Spills
- Collisions
- Structural events
- Marine events
- Dropped objects
- Transport accidents
- Construction

All of the important aspects of these are presented in Table 2-18 and some further elaboration is given below.

TABLE 2-18
HAZARDS ASSOCIATED WITH OFFSHORE FLOATING STRUCTURES

| Event | Cause/Source |
|---|---|
| Riser/pipeline leaks | Leakage at import flow lines, export risers, subsea pipelines and well head manifolds |
| Process leaks (leaks of gas and/or oil on-board) | Well-head equipment, separators and other process equipment, compressors and other gas treatment equipment, process piping, flanges, valves, pumps, etc. topsides flowlines, flare/vent system, storage tanks, loading/unloading system, turret swivel system |
| Non process fires | Fuel gas fires, electrical fires, accommodation fires, methanol/diesel /aviation fuel fires, generator/turbine fires, heating system fires, machinery fires, workshop fires |
| Non process spills | Chemical spills, methanol/diesel/aviation fuel spills, bottled-gas leaks, radioactive material releases and accidental explosive detonation |
| Marine collisions and impacts | Supply vessels, stand-by vessels, other support vessels (diving vessels, barges, etc.), passing merchant vessels and fishing vessels, naval vessels (including submarines), flotel; drilling rig, drilling support vessel (jack-up or barge), offshore shuttle tankers, drifting offshore vessels (e.g., semisubmersibles, barges, storage vessels) and icebergs |
| Structural events | Structural failure due to fatigue or design error; extreme weather, earthquakes, foundation failure, derrick, crane, and mast collapse and disintegration of rotating equipment |
| Marine events | Anchor loss/dragging (including winch failure), capsize (due to ballast error or extreme weather), incorrect weight distribution (due to ballast or cargo shift), collision, grounding or loss of tow during transit and icing |
| Dropped objects | Construction, crane operations, cargo transfer, rigging up derricks and drilling |
| Transport accidents involving a crew change or in-field transfers | Helicopter crash into sea/platform/ashore, fire during helicopter refuelling, aircraft crash on platform (including military), personal accidents during transfer to boat, road traffic accident during mobilization |
| Construction accidents | Construction onshore or offshore, marine installation, hook-up and commissioning, pipe laying |

Collisions

For commercial ships, there are several causes of casualties such as grounding, collision etc. exist. Collision accidents can occur for offshore floating structures due to shuttle tankers or other ship shape structures (Daughdrill and Clark 2002). Grounding accident cannot happen during operation unless the platform is moved to more shallow water for repairs, for relocation or as an emergency measure to avoid storms.

Dropped objects

Due to the complexity of the facility, the risk of heavy objects being dropped is high. For example, in the process of installing a riser, the dropping a heavy pipe is likely. Risk assessments of dropped objects are currently being extensively researched (Paik and Czujko 2009).

Extreme weather and structural failure effects

Commercial ships operate in open waters for about 70% of their lifetime whilst offshore floating structures spend almost 100% of their time at sea (Paik and Thamballi 2007). This means that offshore floating units have a higher exposure frequency to extreme environmental conditions. Consequently, the possibility of structural collapse due to extreme loading will be increased.

Green-water risk

Green-water risk relates to extreme weather in terms of waves and wind. As a result of the increased exposure to wind and waves, the risk of green-water on deck is higher than for other commercial ships. Designing the structure to safely handle green-water on deck is therefore important to reduce the risk to deck components and -personnel.

Helicopter accidents

The helicopter deck is generally located at the upper part of the residential area where it is easily accessible by the crew. However the most important factor in placing the helideck is to avoid interference at landing. This is important since the risks associated with landing helicopters on offshore helidecks are high because the offshore floating units are moving due to wind and waves. This is the reason why a lot of research has been performed on accidents that have occurred at helicopter decks, and why solutions to reduce risk levels are currently being developed (HSE).

Fires and explosions

Fires and explosions have very high levels of risk. This is because the consequences of large fires on offshore structures are much more severe since there is no safe way of escape. Even for smaller fires and leakages, smoke and gas ingress into areas of safe refuge pose a large risk to the crew. Furthermore, since a large number of expensive facilities are concentrated in a small area, the economic destruction can be devastating. Many research projects have been performed to better understand these risks and their causes (Paik and Czujko 2009; Paik and Czujko 2010).

Loss of mooring and station-keeping ability

Fatigue of mooring lines caused by waves, currents and wind can cause failure. This would mean the loss of stability and the station-keeping capability of the platform leading to potentially disastrous consequences.

*Risk relating to the power plant*

As there are added facilities on an offshore power plant as compared to a conventional production facility, some further risks have to be taken into account. The process by which the hydrocarbon fuels are handled will be different and more electrical components will be present. The main additional concerns compared to a floating production facility include the following.

Air pollution and exhausts

$SO_X$ and $NO_X$ have the potential to lead to acid rain if not contained before the flue gas is released. Depending on the type of fuel used, heavy metals, halogenated compounds and volatile organic compounds can be generated in the combustion. The release of hazardous gases and particulates pose both a risk to the environment but also to the crew on the platform if wind directs the exhaust fumes towards the accommodation area. It is therefore important to design the stacks so that this risk is

minimised. This is also important when considering the helideck since smoke from the stacks can interfere with helicopter landings.
Noise and vibration

Noise and vibration for thermal power plants are not as large as those associated with wind power and noise and vibration is generated mainly by turbines, boilers, diesel generators etc. In order to prevent the degradation of equipment due to vibration and noise, measures such as installing soundproof walls and silencers should be taken.

Electrical hazards

Electrical hazards can lead to fires and explosions in switchgear as well as failure of circuit breakers, insulators, fuses, and busbars etc. Open arcing, overloading and failure of the air cooling system etc. can cause accidents in the transformer. In normal power plants the electrical systems are usually kept separate from the main fuels; this is not possible offshore so the increased proximity of spark hazards to combustible fuels must be considered.

Fire and explosion hazards

In a power plant the fuel is handled in additional stages to those already covered by the production plant. To mitigate the risk of fire or explosion, careful handling in these steps is needed. The possible locations of fires and explosions can occur are the turbines, generators, boilers, pipework, storage tanks etc.

***Risk relating to carbon capture and storage***

Whilst amines in themselves are not particularly harmful, when amines are used for $CO_2$ capture, there is a hazard associated with the release of nitrosamines which can be harmful to health. This has led to concerns for projects proposing to use amine-based post combustion, for example in Norway (SINTEF 2010). The energy penalty of the capture process and the negative attitude towards burning more fossil fuels also risk sparking protests both on land and at sea against the use of this process.

The risk that is discussed the most when dealing with CCS is that of the storage. This is due to the large uncertainties in dealing with the storage location and equipment that cannot be properly inspected as it would be for any other reservoir containing hazardous substances. Furthermore, the long time-scales of storage and geological storage in particular mean that these uncertainties become even worse. The main concerns regarding $CO_2$ storage are listed below.

Risk during injection

- Over-pressurising the reservoir causing cracks and failure of the cap rock
- Leakage in injection equipment
- Blow-out

Risks post injection

- Long term migration into ground water
- Long term shifting of geological conditions
- Poor sealing of injection well leading to leakage

Risks during and post injection

- Migration from reservoir either vertically, horizontally or both
- Opening of new faults (earthquakes)
- Leakage through existing faults
- Protests
- Changes in the legal framework

Even though $CO_2$ injection into underground formations has a proven record of accident free operation in projects such as North American EOR operations and the Sleipner project, there is a lack of understanding of the long term consequences which is why the risks are considered high but uncertain. There is therefore a need for good monitoring of the movements of $CO_2$ in the formation.

*Other risks*

The cooling water from the power plant will have an elevated temperature since the process is not successful in extracting 100% of the energy from the combustion. It is uncertain how this may affect both the local marine environment and also the global marine environment as offshore power plants will operate in large bodies of water. A further risk associated with the addition of power generation and $CO_2$ storage to an offshore platform is the increased number of connections. This increases the risk of entangling and dropping of these connections.

The economic risk is substantial because of the high costs, the smaller margins and the legal uncertainties associated with generating power offshore and operating a CCS scheme. The specifics of this will however not be discussed further but is left for further detailed economic analysis.

## 3. APPLICATION OF THE CONCEPT

The purpose of this study is to evaluate the concept of offshore thermal power with CCS as an alternative to transporting $CO_2$. It is therefore important to compare the cost of carrying out CCS when the $CO_2$ is being transported to the storage site with the onshore CCS activity. To do this, a case study will be created where a location will be chosen for the site of the offshore thermal power plant. The cost of this offshore system with CCS will then be compared with the cost of building the same power plant with CCS onshore.

### *3.1 Selection of Location*

Australia is chosen as the location for this case study. This is based on several things.

- Australia has recently introduced a tax on $CO_2$ emissions which shows the governments motivation to back reductions of such emissions. The tax has been announced at 23 AU$/tonne of $CO_2$ emitted (Farr 2011).
- The same tax allows for CCS to become a more attractive and cost-competitive alternative for new power stations.
- The Australian government has passed a bill outlining a regulatory framework for the capture and geological storage of $CO_2$ (MCMPR 2005). The purpose of the bill is, among other things, to make CCS more attractive for companies by defining the legal context.
- Australia has large reserves of natural gas many of which are unexploited.
- Dealing with a single government and operating in a single country’s territorial waters simplifies the concept.
- Australia has had good mapping of the country’s potential for storing $CO_2$ in geological formations through the Geodisc project (Bradshaw, Bradshaw et al. 2002).
- Australia surpassed the US as the largest emitter of $CO_2$ per capita in 2009 (van Loon and Morales 2009).

#### *3.1.1 Location candidates*

Australia has a very long coastline and the current and potential locations for gas exploitation are spread over a wide range of this coastline. For the purposes of this study, a more specific location will be chosen. The choice of the specific location for this case study is based on several things.

- Suitability for the concept at the offshore location. This includes proximity of the storage location to the gas extraction sites.
- Prospect of connecting to major electricity consumers such as industry and populated areas.
- Competitiveness with other possible exploitation alternatives. These include FLNG, onshore processing plants and “do nothing”.
- Any other factor given in Figure 2-6 that applies to the region.

The Australian offshore reserves of natural gas are located mostly off the west coast in the Carnarvon, Browse and Bonaparte basins. There are however significant findings off the coast of Victoria in the south east in the Gippsland basin (Australian Energy Regulator 2010). The locations of these fields are shown in Figure 3-1.

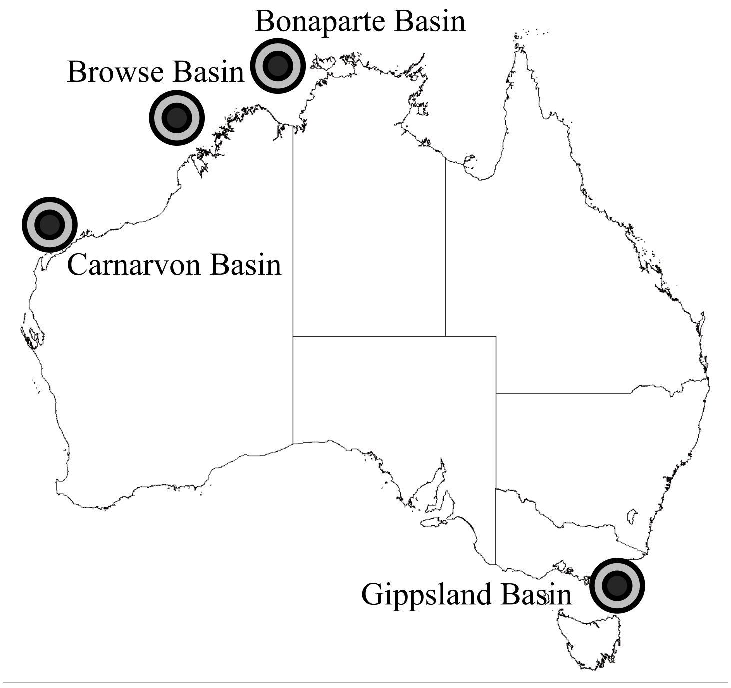


Figure 3-1: Location of major offshore gas fields in Australia

The suitability of the Australian sedimentary basins for geological storage of $CO_2$ has been extensively mapped by the Geodisc project (Bradshaw, Bradshaw et al. 2002). The project has identified certain sites as more suitable than others in terms of storage capacity, injection potential, economical and technical viability of the site, containment risk (quality of the seal) and the risk of compromising other natural resources. The sites that, when all these factors has been taken into account, can store more than 1000 Tcf (1 Tcf = 53.65 Mt) of $CO_2$ with acceptable risk are shown Figure 3-2.

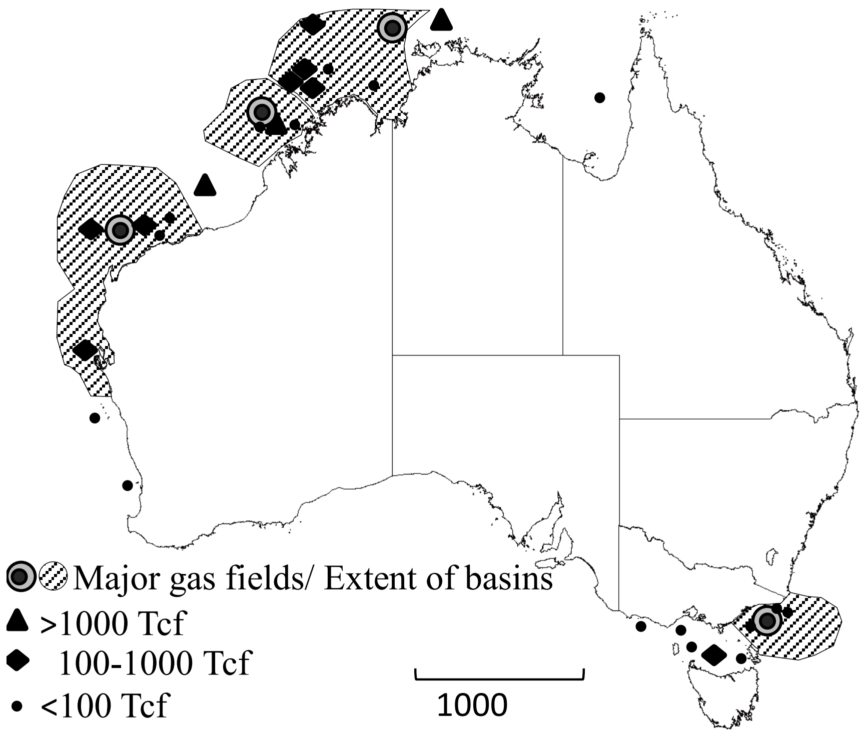


Figure 3-2: Location of prospective offshore storage sites in Australia

The current major gas discoveries are also marked in Figure 3-2. However, since new discoveries may be made and since the concept of offshore power plants could be more attractive for marginal gas fields, the full extent of the four basins are also shown.

All of the four basins are currently being exploited for their gas reserves. The exploitation of the Browse basin has only started in recent years with the Prelude FLNG starting large scale production in 2016 (Shell 2009).

### *3.1.2 Marine environment*

All of the gas fields except the Gippsland Basin are located in sea state area 78 as defined by the British Maritime Technology, Global Wave Statistics (Hogben, Dacunha et al. 1985). This area experiences an annual maximum significant wave height of 7-8 m where waves in the maximum range were recorded at 0.9% of the total observations. 89.1% of the observations were of sea states with a significant wave height of less than 4 m. The Gippsland Basin is located in a more protected location (at the very edge of area 93 in *Global Wave Statistics*) so estimations of probable sea states is not straight forward. In any case, area 93 has a maximum significant wave height of 8-9 m occurring at 0.2% of the observations. 88.1% of the observations were of sea states with a significant wave height of less than 4 m. These figures would be likely to apply to the outer ends of the Gippsland Basin but for the locations of the major gas fields closer to shore; the situation is very likely to be less severe. A separate study has assessed the risks associated with development in the Gippsland Basin in terms of environmental conditions (Freij-Ayoub, Underschultz et al. 2007). This study gives the area where the maximum significant wave height a 50-year period is likely to be in the range of 7-8 m as extending almost all the way to the coast. This area covers all of the major gas fields in the region. This means that, in terms of the maximum allowable significant wave height, all areas are roughly equal.

### *3.1.3 Connections to grid*

The usage of offshore power plants as a way to produce electricity locally at the sources of gas can be seen as a part of the Distributed Generation (DG) concept where electricity is produced wherever there are local sources of energy. The applicability of this concept depends on the development of effective nation/continent wide electricity transmission to supply energy to the consumers. One of the major factors influencing the applicability of the DG concept is the de-regulation of the electricity market (Ackermann, Andersson et al. 2000). Australia operates a de-regulated energy market which may thus complicate the introduction of remote electricity sources. Furthermore the de-regulated market means that there is little connection between different parts of the country’s grids which tend to be confined to the separate populated areas.

Due to Australia’s large potential for generating renewable energy, there is already a motivation for improving these conditions by laying long transmission cables to connect different parts of the country (Kamel 2009). However, since no such expansion is scheduled at the time, the proximity to large populated areas and industries has to be considered as important. An overview of Australia’s major population centres and industrial areas is given in Figure 3-3.

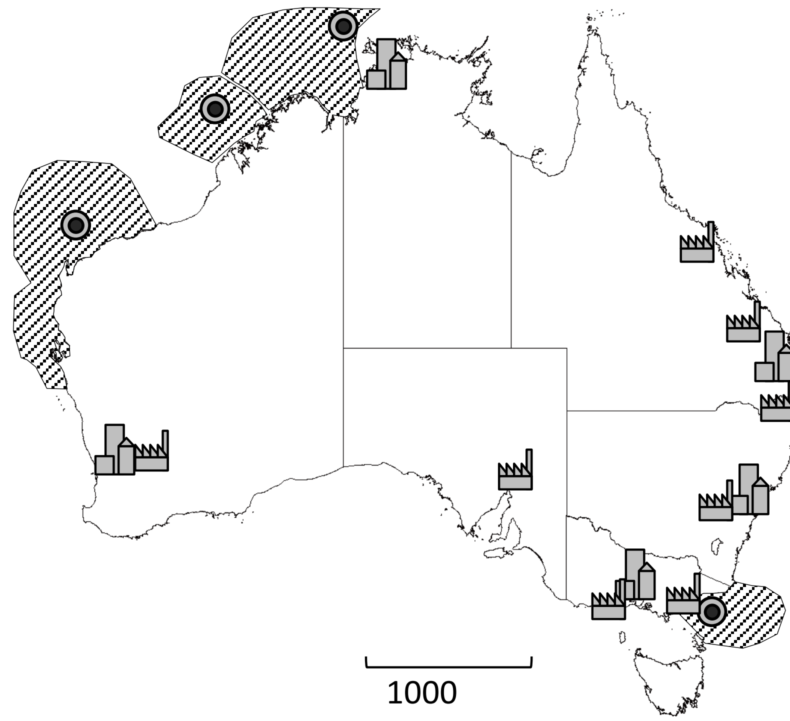


Figure 3-3: Location of major population centres and industrial areas in relation to gas field locations

Based on this distribution, the Gippsland Basin would be the most attractive option if only electricity transmission was considered. There is also relatively close proximity between the gas fields in the Bonaparte Basin and the city of Darwin which makes it an attractive alternative in this respect. The gas fields in the Carnarvon and Browse basins are not located near any major consumers and would need development of new long distance transmission lines to benefit a larger population.

### *3.1.4 Licensing*

Licenses for the exploration of offshore hydrocarbon resources are released each year by the Australian government under the *Offshore Petroleum Exploration Acreage Release.* In the latest (2011) release, owners of licenses in the newly released areas (and in some cases surrounding areas) can be found (Australian Government Department of Resources Energy and Tourism 2011).

The major licenses in the Browse Basin are owned by Woodside, Shell, A&E and Inpex. The newest acquisitions have been by Inpex but Shell and Woodside holds the licenses to the most substantial fields. In the Carnarvon Basin, licenses are held by a large variety of companies including BHP, BOP, Chevron, Esso, Hess, Shell, ExxonMobil, BP, Woodside and Marathon. A joint venture between Shell and Chevron holds the license to a substantial amount of the gas findings in the area. No gas findings are recorded in the newly released areas of the Bonaparte Basin. There are however substantial gas findings in other areas owned by mainly Shell and Santos. The Gippsland basins' findings of gas are owned by Moby Oil and Gas, Shell, Petrofina and Esso.

A large level of development exists in most basins with a large number of companies involved. The exception is the Browse Basin which has remained undeveloped up until recent years and with a relatively small number of companies owning the different licenses. From the point of view of a venture into offshore power, it would be preferable to depend on fewer secondary operators to provide infrastructure and raw gas. For this reason, the Browse Basin seems more suitable from this perspective.

### *3.1.5 Public perception*

There is currently large scale protest action being taken against plans to develop an onshore LNG hub at James Price Point to serve the future development of the gas fields of the Browse Basin (Harvey and Prior 2011). A system completely confined to ocean space would potentially prevent future such protests against developments in the area. The proposed concept may thus be an attractive option for companies looking to further exploit the Browse and Bonaparte basins.

### *3.1.6 Choice of specific location*

This study aims at proving the suitability of the offshore power generation concept for reducing future $CO_2$ emissions. It is therefore deemed as more important to show that it has merit as a way to remove the need for the transport of $CO_2$ in the carbon cycle. The carbon cycle is defined here as the extraction and conversion of natural gas to electricity and the storage of the resulting $CO_2$. From this perspective, the Browse Basin and the Southern parts of the Bonaparte Basin seems more suitable. An offshore power plant located here would be more likely to demonstrate the capabilities of the concept to introduce CCS in thermal power plants with reduced transportation costs. This is considered more important than a location that would provide clean power to a larger population which would be the case if the Gippsland Basin was chosen. The Carnarvon Basin is discarded on the grounds that it lacks many of the prerequisites for the concept that that other locations possess. Furthermore, it already has an active CCS project which may reduce the motivation to introduce new concepts.

Based on this, the focus area is chosen as the area in the immediate vicinity of the gas fields in the Browse Basin as well as the potential storage sites nearby and in the southern Bonaparte Basin. A detailed map of these areas showing storage sites (with the same notation as in Figure 3-2) as well as the location of current findings of natural gas is shown in Figure 3-4 .

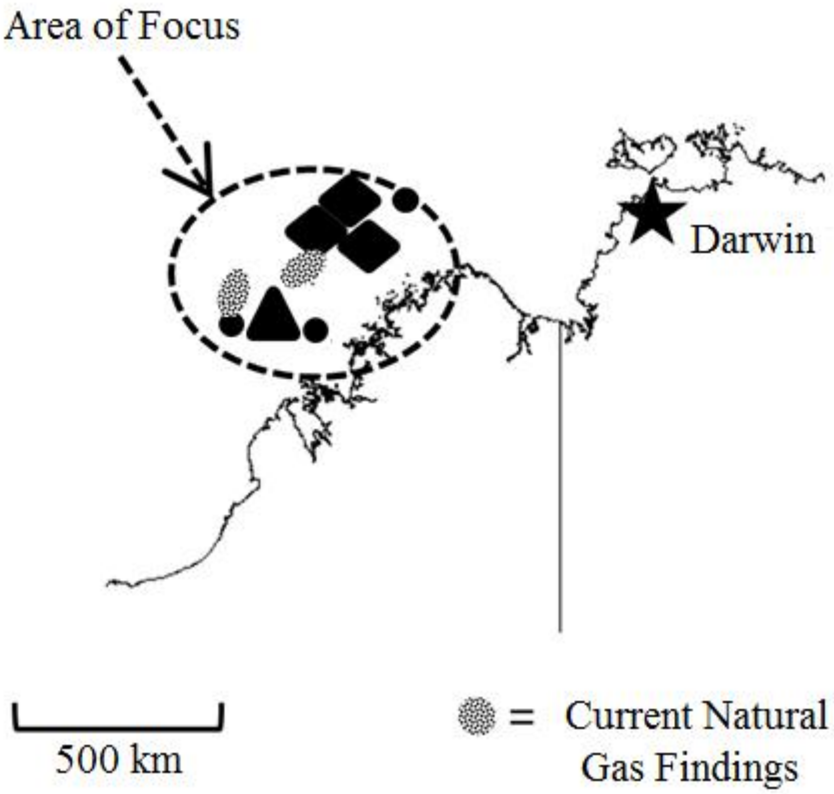


Figure 3-4, Detail of chosen focus area

The easternmost area of natural gas findings includes the Prelude field and is located c: a 200 km from Bigge Island which is the closest possible location for the landing of an offshore cable. The westernmost area is located about 300 km from Augustus Island which could also provide the landing site of an offshore cable. The distance between the centres of both areas is 130 km. The offshore distance to the nearest city, Darwin is 960 and 830 km respectively.

The development of the western fields which include Torosa, Brecknock and Calliance is mainly in the research stage (Gaffney Cline & Associates 2008). This is mainly because of the great water depth and distance from shore. The eastern fields are currently being developed or have plans for development. They include the Ichthys, Prelude and Crux fields. The details of all fields are given in Table 3-1. The numbers come from Gaffney Cline & Associates report on developing the Browse Basin (Gaffney Cline & Associates 2008).

TABLE 3-1
DETAILS OF GAS FIELDS IN THE BROWSE BASIN

| | Gas content (Tcf) | Condensate content (MMbbl) | $CO_2$ content | Water depth (m) | Owner |
|---|---|---|---|---|---|
| Torosa, Brecknock and Calliance | 20.7 | 317 | 4-12% | 400-700 | Woodside 40%, BHP 13%, BP 18%, Chevron 18% Shell 11% |
| Ichthys | 12.8 | 527 | 8.5-17% | 260-280 | Inpex 76% E&P 24% |
| Crux | 2 | 66 | ? | 190 | Nexus 85% Osaka Gas 15% |
| Prelude | 2-3 | ? | 9% | 250 | Shell |

The large gas content of the western fields and the difficulty of exploiting them using conventional methods make them attractive for the concept. The chosen location is therefore the western fields of the Browse Basin.

The location can either be chosen based on flexibility or by initial simplicity. If more than one field and storage location is to be utilized for more flexibility, it is preferable to position the plant so that the total distance is minimised. If only one field and storage location is to be utilised, the plant would be placed more centralised on that field. The flexible alternative is a site 45 km south-east of the centre of the Torosa field and 38 km east of the centre of the Brecknock field. The single-field alternative is a location above the indicated storage site at the Torosa field. For this study the single-field alternative is chosen. This location is 285 km from Augustus Island which will be the length of the HVDC transmission required. The details of the chosen location are shown in Figure 3-5.

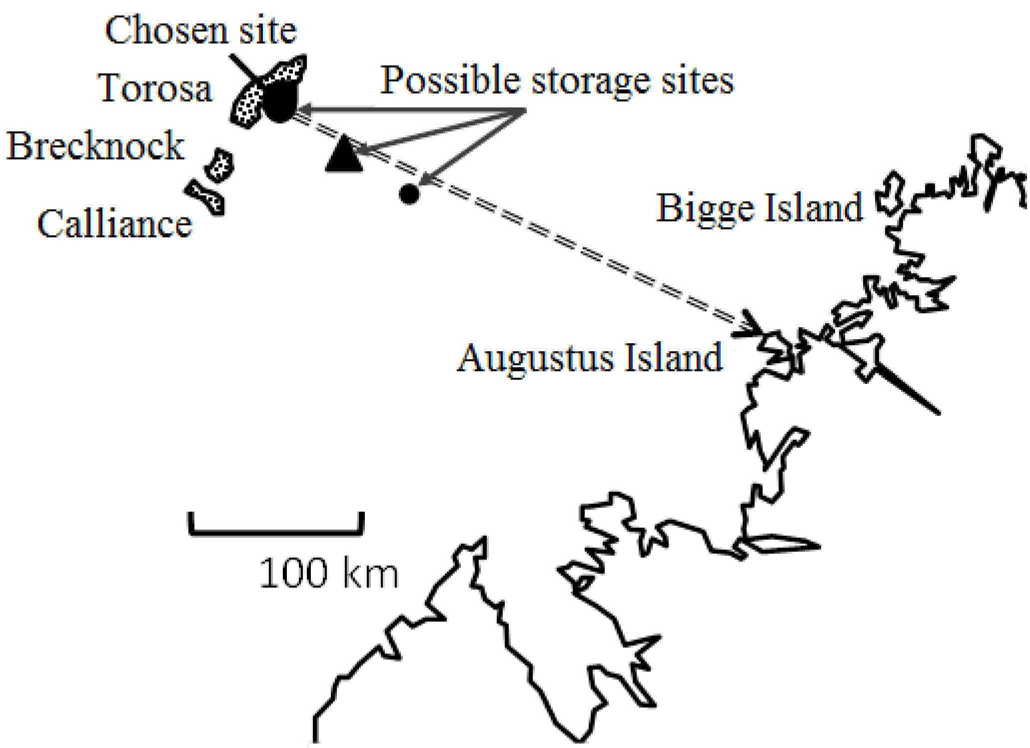


Figure 3-5, Detail of chosen location

An additional 950 km of onshore cable would be required to connect to Darwin (assuming no existing infrastructure close to Darwin may be used.) Even though the onshore connection would be associated with a substantial cost, is assumed to be available to connect to for a standard charge only. This is justified by the fact that the costs will be compared to a conventional power plant located 285km from the field. This means that any additional pipelines that would have been required to transport the gas to a more suitable location for a conventional power plant will be ignored.

The Torosa field is 50% owned and fully operated by Woodside which currently has plans to develop the field together with the Brecknock and Calliance fields in the Browse LNG project. This includes the disputed James Price Point LNG processing facility and ~900 km of subsea pipelines. The final investment decision on this project will be taken in 2012 (Woodside 2011). The development of the onshore infrastructure for the project has met with public protests as mentioned but also with environmental concerns (Prior 2010). This is something that speaks for pursuing the GTW concept for future developments in the area.

In case a landing at Augustus Island is not possible, the alternative of landing at James Price Point is also investigated. This site has already been considered suitable for a major LNG facility so a transformer station could be constructed there without major issues. The distance from the chosen location to James Price Point is 405 km. Both this distance and the original distance of 285 km will be considered in the cost analysis.

### $CO_2$ storage capacity

Although the specifics of the chosen storage site are not explicitly given and more detailed surveys should be conducted before the site is finalised, some conclusions can be drawn about storage capacity. The Geodisc study (Bradshaw, Bradshaw et al. 2002) gives the capacities of the three storage sites in the vicinity of the chosen location as shown in Figure 3-5 as:

- Site 1: 0.1-1 Trillion Cubic Feet (Tcf)
- Site 2: 1000-4600 Tcf
- Site 3: 1-10 Tcf

Site one is the closest to the power plant and site three is the furthest away. From this, the potential timeframe for storage can be estimated. Since the storage volumes are only estimates, the lower range is used to get a conservative estimate. Using 356 g CO2/kwh (UK SDC 2006) with the 540 MW plant, the storage capacity for the three sites are calculated and presented in Table 3-2. The "potential power served" is based on electricity generated using the same levels of emissions (356 g/kWh.) It is shown that site one, which is located in the local area of operation, would provide more than enough storage for the duration of this project. It is also shown that the general area of the chosen location has the ability to store $CO_2$ from a large number of additional power plants.

TABLE 3-2
$CO_2$ STORAGE CAPACITY OF SITES IN THE VICINITY OF THE CHOSEN LOCATION

| Site | Capacity of storage (Tcf) | Years of storage | Potential power served for 100 years (GW) |
|---|---|---|---|
| 1 | 0.1 | 1009 | 5 |
| 2 | 1000 | 10089004 | 54481 |
| 3 | 1 | 10089 | 54 |

### *3.2 Power Generation & Carbon Capture System*

The power will be generated by eight Siemens SGT-800 gas turbines and four Siemens SST-700 steam turbines. These will be arranged in blocks of four. Each block will comprise of two gas turbines, two heat recovering steam generators and one steam turbine. Each gas turbine is capable of generating 47 MW with an efficiency of 37.5% (Siemens 2009) and when combined with a steam turbine, each block will generate 135 MW with an efficiency of 54.4%. The combined generated power of the four blocks will be 540 MW. This power generation arrangement is based on the SEVAN GTW concept (Hetland, Kvamsdal et al. 2010). Figure 3-6 and Figure 3-7 show a generalised arrangement of a power generation block with the inputs and outputs to the system as well as the entire power generation system.

The required fuel consumption based on a Capacity Factor of 0.5 will be approximately 425 million $m^3$ of natural gas per year. This will require around 1.25 million $m^3$ natural gas per day based on 340 days per year operational use. The energy penalty associated with the turbines includes the auxiliary systems as well as the power required to scrub the nitrous oxides and sulphur dioxides.

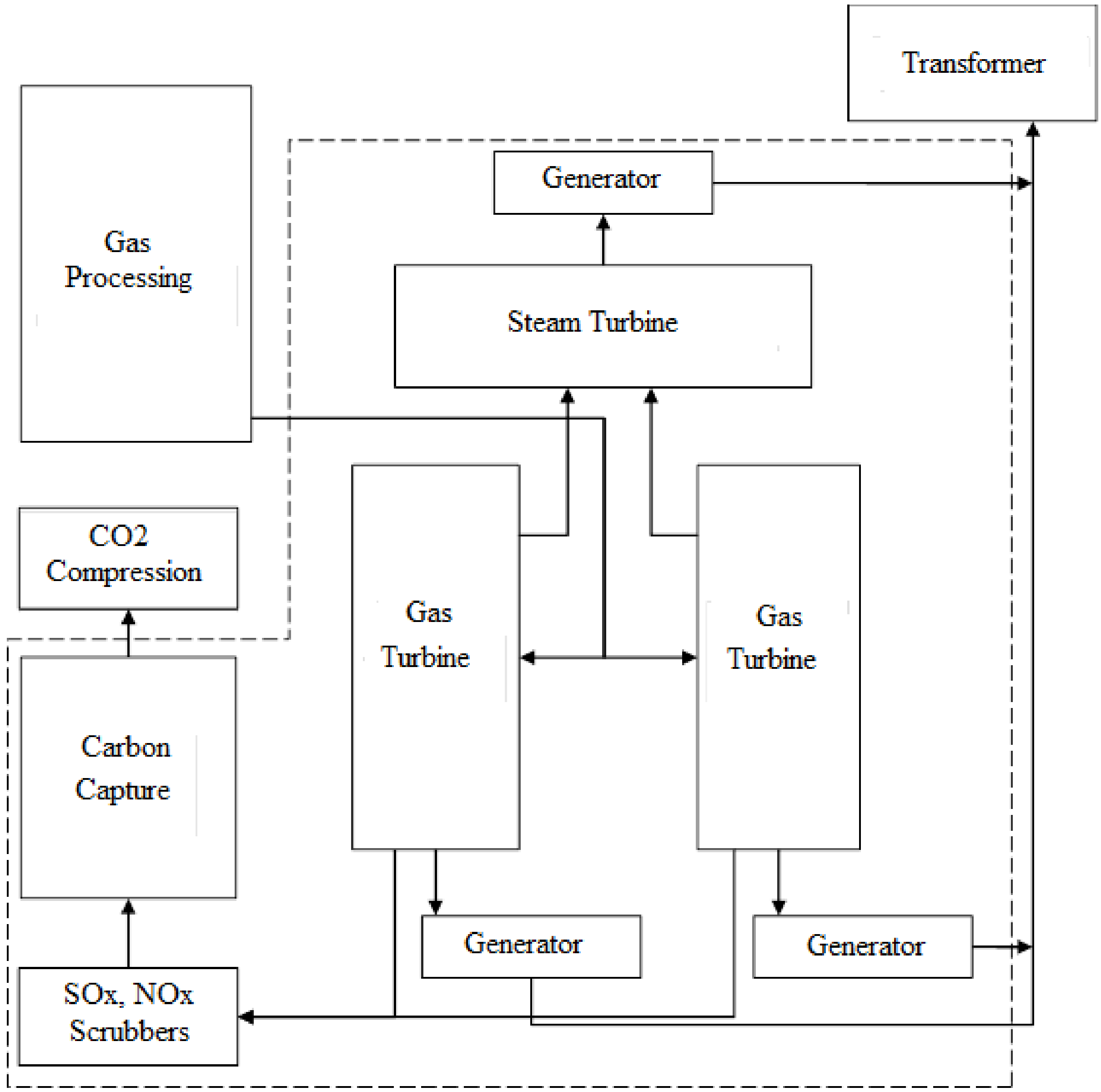


Figure 3-6: Arrangement of one Power Generation Block

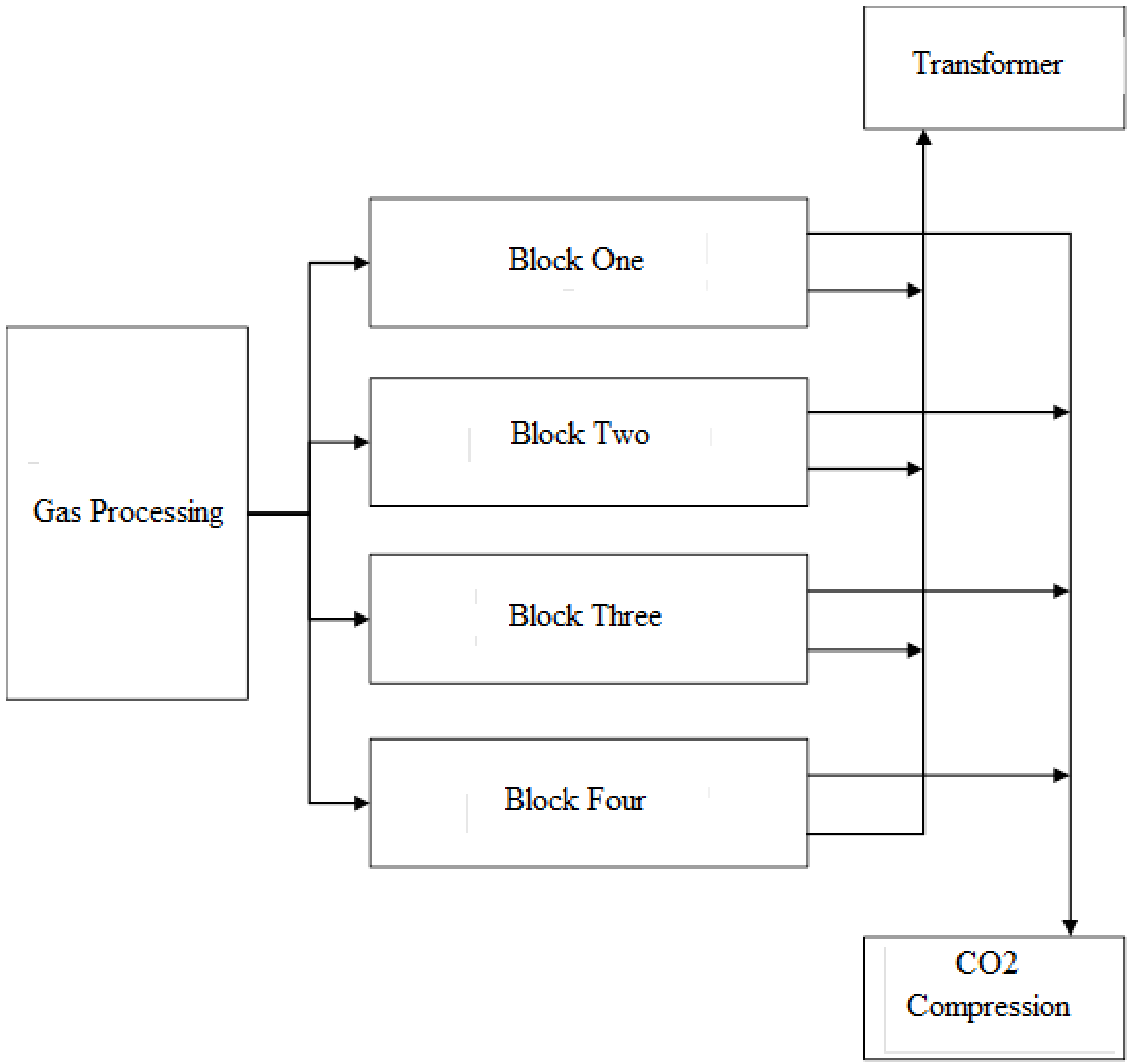


Figure 3-7: Arrangement of the four Power Generation Blocks

Gas processing will be carried out using a three-phase separator using amine. There will also be an amine sweetener, glycol dehydration plant and storage capacity for the condensate produced. In addition a buffer of natural gas will be used to ensure that fluctuations in the gas supply from the field are not passed on to the gas turbines. The power required for the gas processing system will be supplied by the main gas turbines. Based on the assumption that 0.28 kWh are needed to produce 1m$^3$ of gas (CEPA 2009) and a heat rate of 6444.883 Btu/kWh, 18 MW will be needed to maintain a gas flow rate to the turbines of 62837.6 m$^3$/h.

The $CO_2$ emissions will be captured using an aqueous solution of mono ethanol amine (30% MEA). It is assumed that 90% of the emissions will be captured. Four absorber units will be used to capture the $CO_2$ and one common desorber unit will be used to separate the $CO_2$ from the solvent. The $CO_2$ will then be compressed and dehydrated in four stages. This will ensure that the $CO_2$ is sufficiently clean before entering the injection system. Again, this arrangement is based on the SEVAN GTW concept. There are varying figures for the energy penalty of a carbon capture unit. According to the IPCC, the increase in fuel consumption will be between 11 and 22% (IPCC 2005) whereas according to ACIL Tasman the increase in the percentage of power used by the auxiliary systems will increase from 2.4% to 4.5% (ACIL Tasman 2008). For the purposes of this study it will be assumed that the energy penalty associated with the carbon capture will be 10%.

The generated power will be transmitted to shore using high voltage direct current cables. In order to convert the voltage from AC to DC, a rectifier will be used in combination with a transformer. The volume of these can be estimated from the figures discussed in Chapter 2. It is assumed here that an integrated transformer module would take up 50% of the space of a standalone module.

TABLE 3-3
VOLUME & ENERGY PENALTY ASSOCIATED WITH PROCESSES

| Equipment | Number | Approx Volume | Energy Penalty |
|---|---|---|---|
| Gas turbines | 8 | 16000 $m^3$ | 2.4% |
| Steam Turbines | 2 | 4000 $m^3$ | |
| Gas Processing | 1 | 15000 $m^3$ | 3.25% |
| Carbon Capture Absorbers | 4 | 9000 $m^3$ | 10% |
| Carbon Capture Desorber | 1 | 700 $m^3$ | |
| CO2 Compression | 1 | 270 $m^3$ | |
| Electrical Transmission | 1 | 26000 $m^3$ | 5% |
| Total | | 70970 $m^3$ | 20.7% |
| Power Generated | | | 540 MW |
| Power Sent Out | | | 430 MW |

Table 3-3 shows the total volume required by the power plant, gas processing, CCS and electrical transmission systems as well as the energy penalty associated with each system. From this it can be calculated that the total energy penalty will be around 21%. This will result in around 430 MW of power being transmitted.

### *3.3 Selection of platform*

In order to give an overview of the factors influencing the selection of the platform, the previously acquired data concerning location and plant requirements are summarised in Table 3-4. The large variation in water depth is due to the existence of the Scott Reef under which some of the Torosa field is located.

TABLE 3-4
SUMMARY OF FACTORS INFLUENCING THE SELECTION OF THE PLATFORM

| | |
|---|---|
| Water depth | ~100-400 at chosen site (30-700 for entire field) |
| Maximum significant wave height | 7-8 m |
| Volume required for on-board systems | 75.000 $m^3$ |
| Total volume of structure needed | 150.000 $m^3$ |
| On board storage needed | yes |

The deck area needed, based on an assumed maximum equipment height of about 30 m (selected to not stack large components on top of each other) will be approximately 5000 $m^2$. Based on Figure 2-23 all types of platforms except the Spar can provide the given deck area.

The TLP is discarded because it cannot provide on board storage. This is also true in some sense for the semi-submersible; however there is a possibility to store liquids and gases in the columns and possibly the pontoons. However, the construction costs are likely to be higher for a semi-submersible compared to a FPSO-type structure (Husky Energy 2001). For these reasons, the ship-shape platform is chosen as the base of the power station. This also allows for a broader impact of the case study since the FPSO is shown to be the most versatile platform and the conclusions drawn here will be applicable in most environments. Furthermore, the use of FPSOs dominates the exploitation (using floating structures) of resources in Australian waters as shown in Figure 2-14. This supports the conclusion that the FPSO is the most suitable floating platform in this case.

It is assumed that two thirds of the total volume must be below the main deck which gives 50.000 $m^3$ as the volume of the topsides structure and 100.000 $m^3$ as the volume of the hull. A typical FPSO would have a block coefficient of about 0.85 which gives the *LxBxD* as ~120.000 $m^3$ where *D* is the total height of the hull to the main deck. This can be combined to get the dimensions of the hull; a length to beam ratio of around five is desirable to achieve good stability which gives the dimensions as: L=150m, B=32m and H=25m. A couple of meters have been added to the beam to further increase stability. The deck area will then be roughly 4800 $m^2$. If 80% of this is assumed to be taken up by topsides structures, the average height of these will be 13 m. The remaining 20% of the deck (~980 $m^2$) will include space for an accommodation module and various other facilities. A general layout of the facilities is shown in Figure 3-8 which is based roughly on the volumes given in Table 3-3. The vessel will use a swivel turret for mooring to better cope with the environmental conditions of the chosen site.

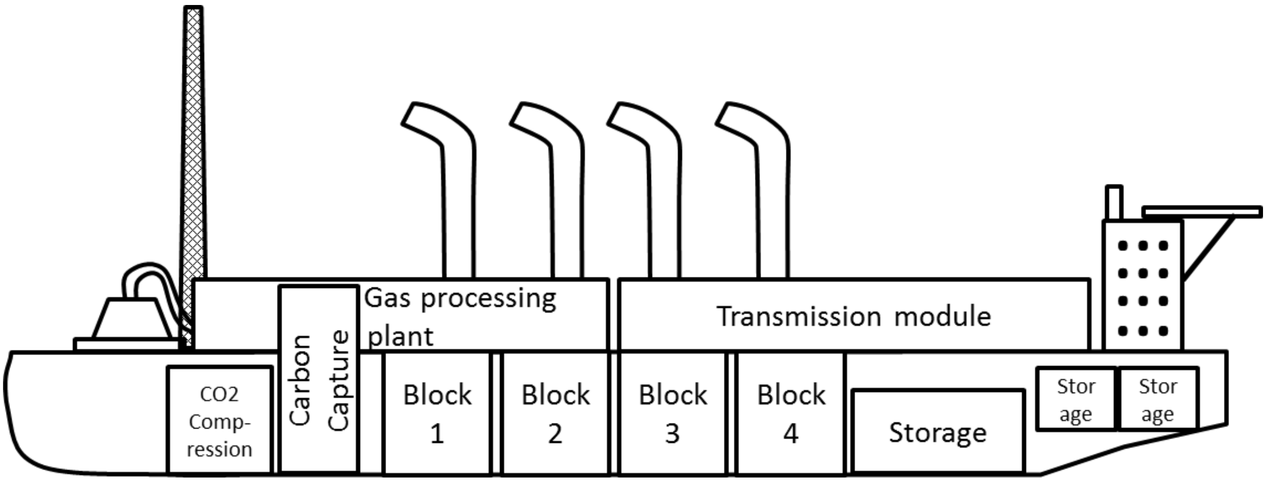


Figure 3-8: Layout of Offshore Thermal Power Plant (OTPP)

### *3.4 Methodology*

In order to establish the cost of a particular system a variety of factors have to be considered such as capital costs, fuel costs, expected hours of run-time, revenue recovered from heat sales, the cost of waste, works power and taxes and subsidies. One way in which the energy costs can be calculated is the Levelised Cost of Energy (LCOE). This is the price at which electricity must be generated from a specific source to break even.

$$LCOE = \frac{total\ lifetime\ expenses}{total\ expected\ output} \tag{3.1}$$

The total lifetime expenses include the capital costs, fuel costs and the annual fixed and variable operating and maintenance costs. The total expected output is based on the power output combined with the capacity factor. A discount factor is applied to give the annual costs which are then summed over the life-time of the plant. The discount factor can be based on just interest rates or can include measures of risk and tax as well.

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}} \tag{3.2}$$

Where;

LCOE = Average lifetime Levelised Electricity Generation Cost
$I_t$ = Investment expenditures in the year t
$M_t$ = Operations and maintenance expenditures in the year t
$F_t$ = Fuel expenditures in the year t
$E_t$ = Electricity generation in the year t
$r$ = Discount rate
$n$ = Life of the system

### *3.4.1 Transportation cost of GTW versus conventional approaches*

To get an idea of the range of applicability of GTW for a gas fired plant with CCS, a transportation cost analysis can be carried out. The costs of transferring electricity from an offshore power plant via HVDC cables is compared to the cost of transporting natural gas from an offshore field to an onshore power plant and return the produced $CO_2$ to the same field.

First; some assumptions must be made. The emissions from a typical gas fired power plant are taken as 356g $CO_2$/kWh based on the UK Sustainable Development Commission report 2006 (UK SDC 2006). A 570 MW Siemens SCC5-8000H combined cycle power plant (Siemens 2011) is used for a reference fuel consumption of 5700 Btu/kWh. From these figures, the total required transportation capacities for both $CO_2$ and natural gas can be found.

The cost of transporting one Btu of natural gas by offshore pipelines and LNG tankers has been stated by (Cornot-Gandolphe, Appert et al. 2003) and the cost of transporting one tonne of $CO_2$ is given by the IPPC (2005). Combining these two sources gives an estimate of the yearly transportation costs per MW for an onshore power plant depending on the distance to the gas field.

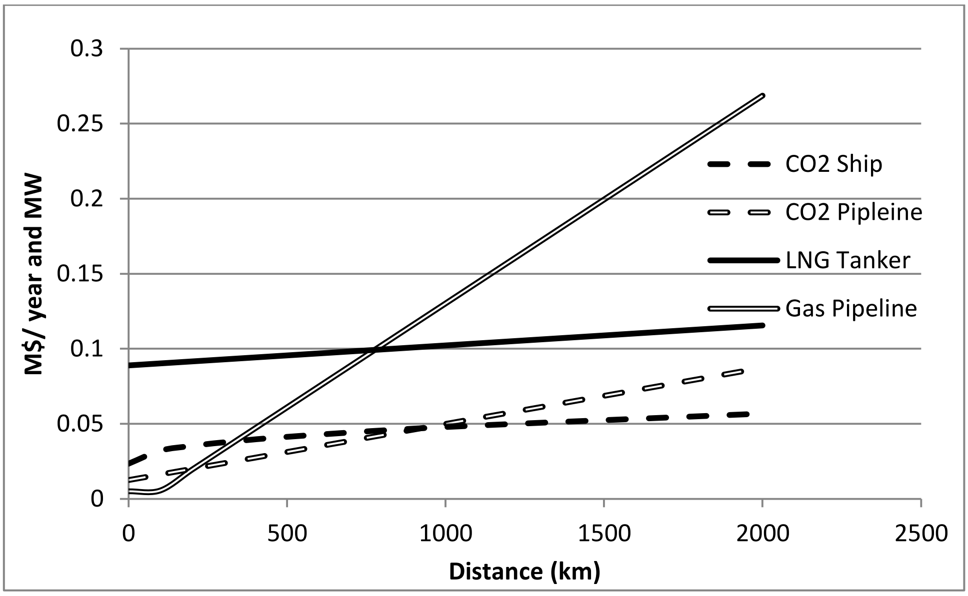


Figure 3-9: Estimate of transportation costs per year and MW for an onshore power plant

Assuming 100% uptime of the plant, the total transportation cost over the projected lifetime can be calculated. The investigated options are HVDC transmission, gas pipelines combined with $CO_2$

pipelines and LNG tankers combined with $CO_2$ tankers. The total cost of transmission is assumed to be in the range of 0.002-0.004 MM$/MWkm; initially an average value of 0.003 MM$/MWkm is chosen. The results are shown for a 500 MW power plant in Figure 3-10 to Figure 3-13, for 10, 15, 20 and 25 years of operation respectively. In all cases, the maintenance costs have been omitted and the onshore power plant has been assumed to be located close to the coast.

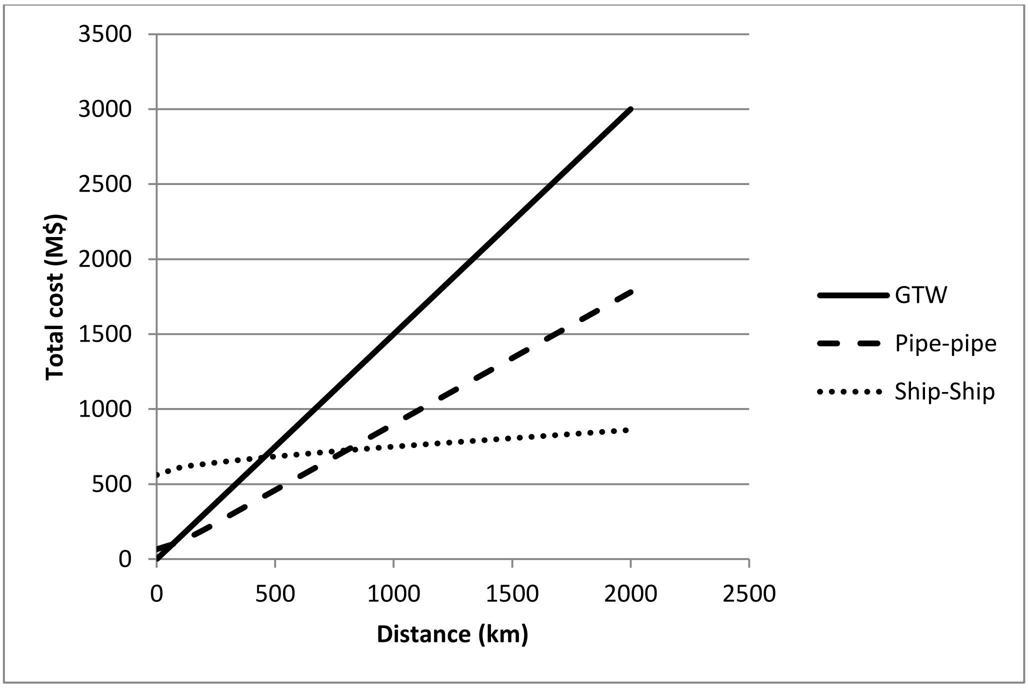


Figure 3-10: Comparison of total transportation cost (10 year period)

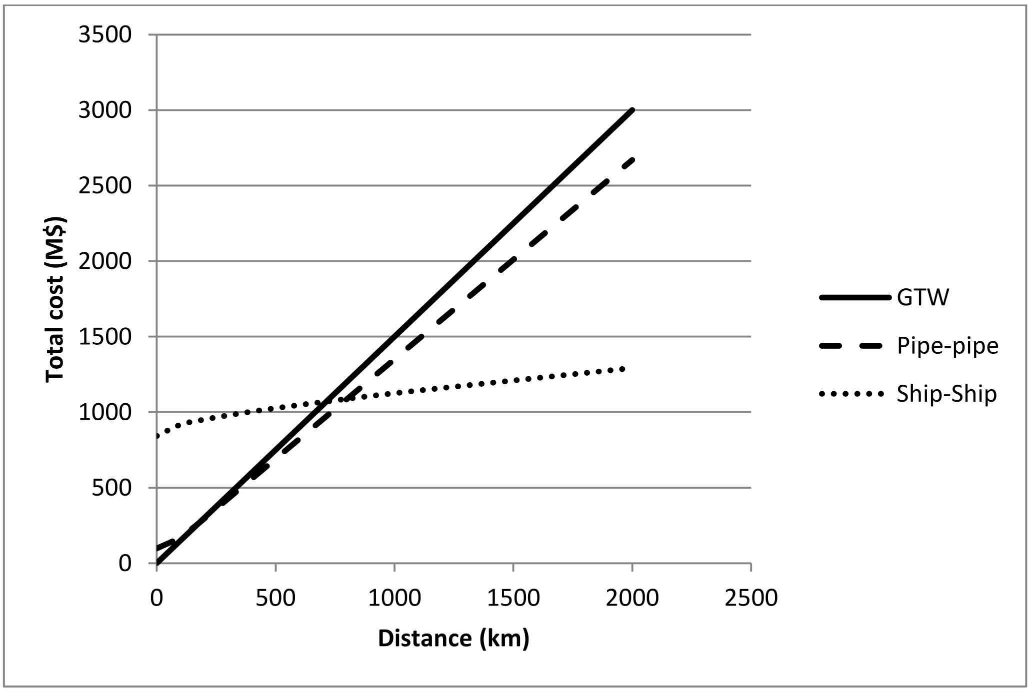


Figure 3-11: Comparison of total transportation cost (15 year period)

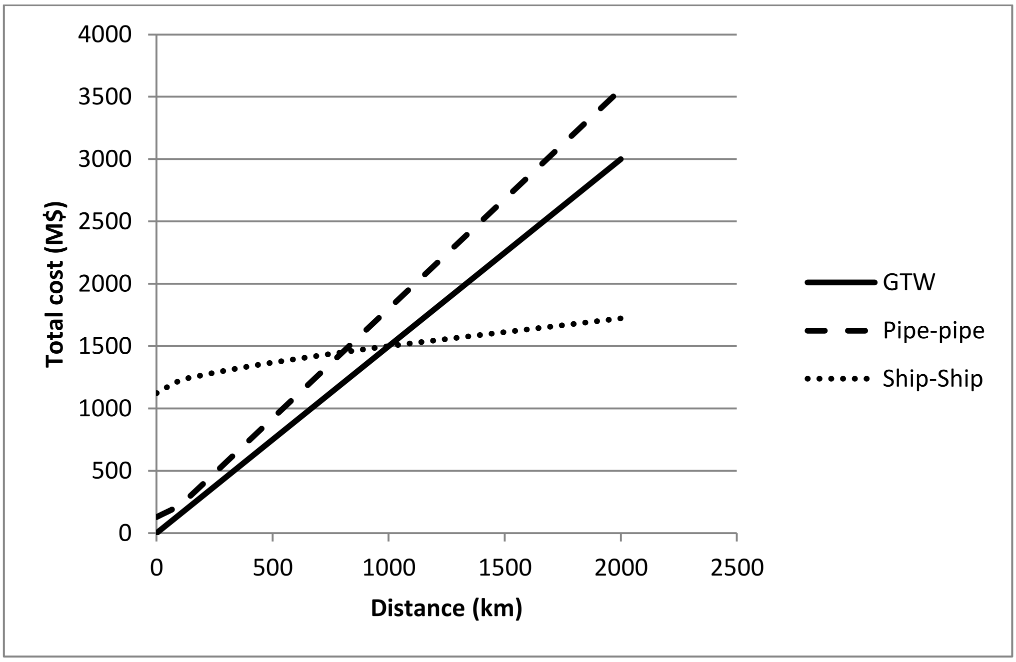


Figure 3-12: Comparsion of total transportation cost (20 year period)

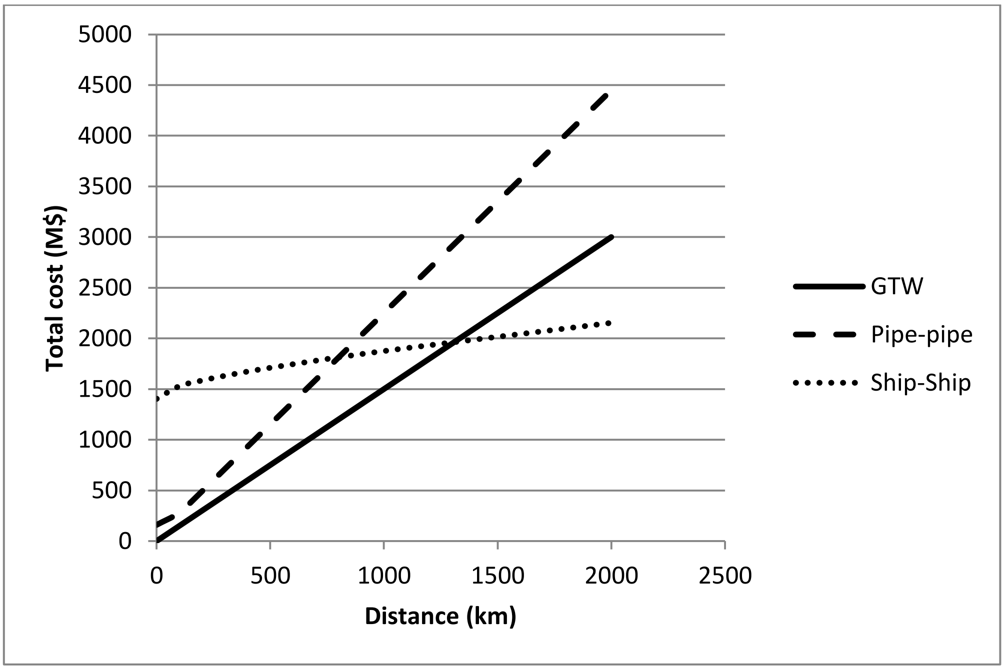


Figure 3-13: Comparison of total transportation cost (25 year period)

The break-even point between pipelines and GTW (on longer distances) happens at around 15 years of operation. The total cost benefit of GTW compared to conventional transportation methods (least costly option) is shown in Figure 3-14.

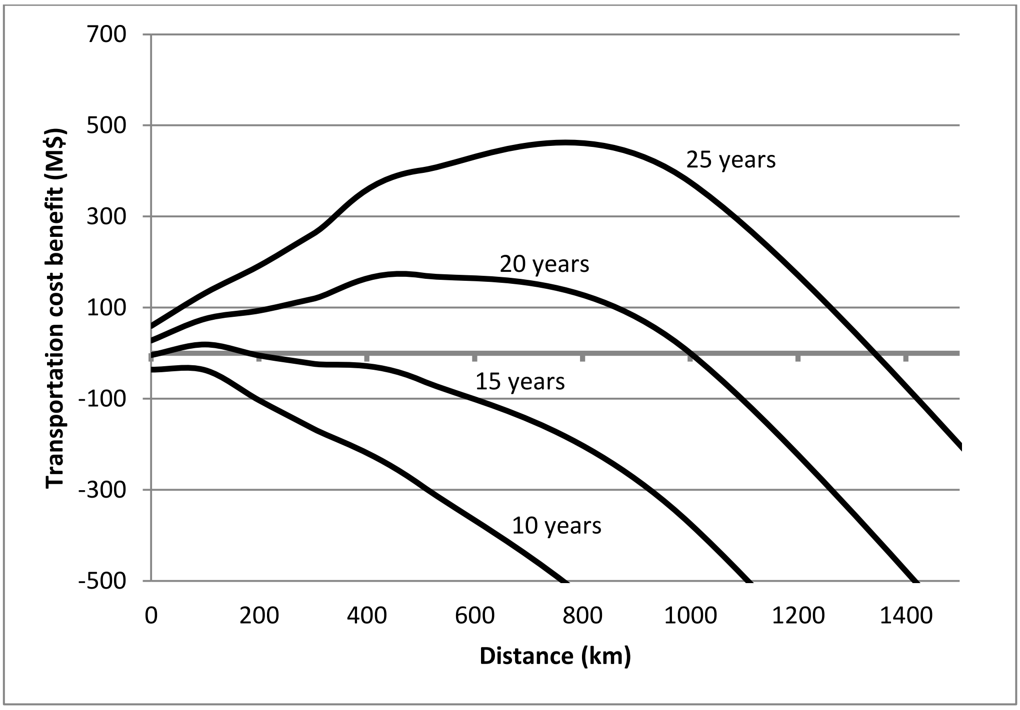


Figure 3-14: Cost reduction of GTW compared to conventional transportation

It must be noted that figures for distances less than 100 km should not be seen as reliable since the estimates are mostly based on more long-range scenarios. The whole range of possible HVDC transmission costs is now considered and Figure 3-14 is recreated for 0.004 and 0.002 MM$/MWkm in Figure 3-15 and Figure 3-16 respectively.

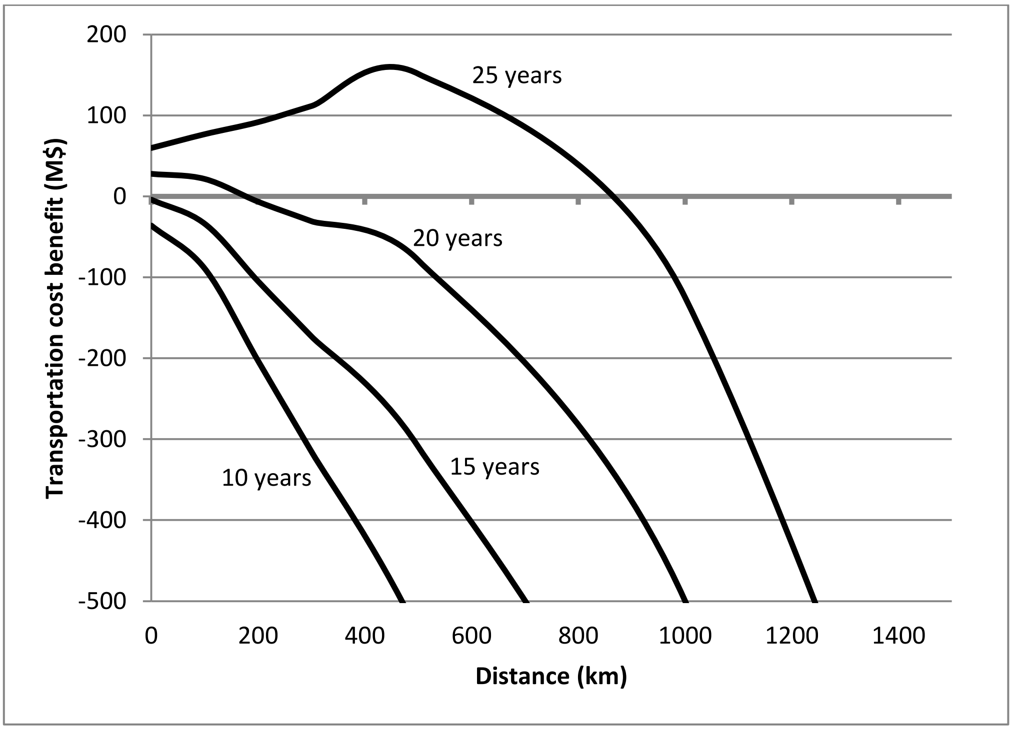


Figure 3-15: Cost reduction of GTW compared to conventional transportation at high estimation of cable cost

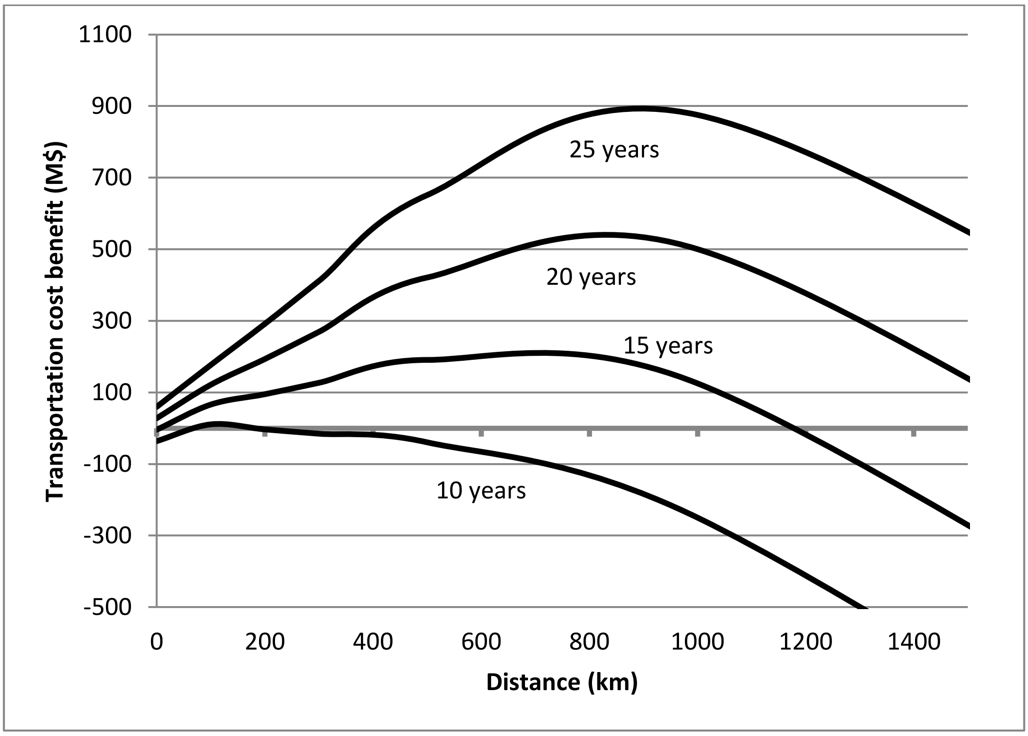


Figure 3-16: Cost reduction of GTW compared to conventional transportation at low estimation of cable cost

In reality, the output power to be transmitted would differ from the power used to calculate the fuel consumption of the plant. The plant would have to power all its ancillaries including the carbon capture unit leaving less power to be exported. This would reduce the specifications of the cable while leaving the transportation requirements for gas and $CO_2$ at the same level. This means that, for a plant with CCS and power-heavy ancillaries, the GTW option is even more attractive.

An example 550 MW power plant outputting 450 MW situated 300 km offshore and with a design life of 25 years is used to demonstrate the use of the comparison method. The cable cost would be between 270 and 540 MM$ and the cost of the pipe-pipe option would be ~840 MM$. This would mean a total potential saving in transportation costs of 300-570 MM$.

### *3.5 Cost Analysis*

In order to estimate the respective costs of building an offshore power plant and an onshore power plant, the costs were broken down into several sections. These sections are as follows;

- Capital costs including equipment, construction, infrastructure, engineering etc.
- Annual operating costs; these include fixed operations & maintenance (O&M), variable O&M, consumables, manning etc.
- Fuel costs
- Transportation costs of gas, $CO_2$ and electricity.
- Carbon capture
- Storage of $CO_2$

The costs were calculated in Australian dollars (AU$) in order to reflect the chosen location and several assumptions were made regarding exchange rates which are shown in Table 3-5.

TABLE 3-5
EXCHANGE RATES USED IN COST ANALYSIS

| AU$ | US$ | SGD |
|---|---|---|
| 1 | 1.042 | 1.256 |

Assumptions were also made for the components of power generation which are not directly cost based. These include the following;

- Year of implementation; the year 2020 was chosen based on giving a sufficient lead-time for development of technology, design time and construction time etc.
- Energy penalty
- Thermal efficiency
- Capacity factor
- Heat rate
- Life of the plant; the plant is expected to have a life of 25 years. All calculations will be based on this figure.

The difference between the amount of energy generated and the amount of energy sent out is the energy penalty. For the purposes of this case study, three penalties were assumed; auxiliary load, gas processing power requirements and CCS power requirements. The auxiliary load is the energy used in the making of electricity. This energy is used to drive equipment such as circulation pumps for cooling water and the equipment used to remove particulates and gases from exhaust fumes. A figure of 2.4% was assumed for the auxiliary load based on Australian figures (ACIL Tasman 2008).

There are a wide range of figures for the energy penalty associated with CCS, particularly for carbon capture (IPCC 2005). Since it is not actually important what this energy penalty is, just that it is applied to both the offshore and onshore systems, a figure of 10% was used for the energy penalty of the CCS system as a nominal figure.

The thermal efficiency of a plant measures the energy from the fuel required to generate electricity. It depends on several factors such as load factor, type of plant (e.g. CCGT, sub critical coal, super-critical coal, etc.), type of cooling, ambient temperature, type and quality of fuel, etc. In this case, a thermal efficiency of 54% was used based on the specification of the turbines and steam plants (Siemens 2009).

The capacity factor is the expected output from the station (in GWh) divided by the product of plant capacity and 8760 (the number of hours in a year). This assumption is required if the LCOE is to be expressed in $/MWh. A capacity factor of 0.65 was used as this is the projected factor used by ACIL Tasman in their report for the year 2020 (ACIL Tasman 2008)

### *3.5.1 Capital costs*

Capital investment for a new power station includes a variety of different costs which are then paid back over a number of years. Typical project costs are in the following areas;

- Engineering, procurement and construction (EPC).
- Planning and approval.
- Professional services.
- Land acquisition.
- Infrastructure costs (incl. water).

- Spares and workshop.
- Connection to the electricity network.
- Fuel connection, handling and storage.

The estimated capital costs of the onshore power plant are based on a report commissioned by the Energy Market Authority of Singapore (PA 2010). According to this report, the cost of building a 400MW combined cycle gas turbine plant is 710 million SGD. This equates to 1412.65 AU$/kW. Whilst there will be differences between Singapore and Australia regarding the breakdown of the capital costs, this was not considered to be important for the purposes of this case study.

TABLE 3-6
CAPITAL COSTS OF GENERATING POWER

| CAPEX | Onshore | | Offshore | |
|---|---|---|---|---|
| | SGD | AU$ | SGD | AU$ |
| EPC | 577743000 | 459883428 | 505259000 | 402186164 |
| Connection to grid | 31500000 | 25074000 | 31500000 | 25074000 |
| Through-life costs | 19130000 | 15227480 | 19130000 | 15227480 |
| Land & Site Costs | 13700000 | 10905200 | 0 | 0 |
| Owner's costs | 67800000 | 53968800 | 67800000 | 53968800 |
| Hull Construction | 0 | 0 | 211750000 | 168553000 |
| Risers | 0 | 0 | 54450000 | 43342200 |
| Mooring | 0 | 0 | 60500000 | 48158000 |
| Towing | 0 | 0 | 48400000 | 38526400 |
| Gas Processing | 0 | 0 | 25739120 | 20488340 |
| Total AU$ | 565058908 | | 815524383.5 | |
| Total AU$/kw | 1412.65 | | 2038.81 | |

Table 3-6 shows a break-down of the estimated capital costs. The engineering, procurement and construction (EPC) costs include the following;

- Equipment, civil, mechanical and electrical engineering.
- Buildings and structures.
- Contractor’s engineering and commissioning.
- Contractor’s miscellaneous costs.
- Transport.
- Adjustment for the OT C/W system.
- Jetty and unloading.
- Fuel tanks.

Of these, civil engineering, building and structures, jetty and unloading and the fuel tank costs were deducted from the EPC to determine this cost for the offshore power plant. The connection to the grid cost was assumed to be the same for both, as were the through life costs and owner’s costs. The onshore power plant has a cost for land and site costs which do not apply to the offshore power plant. Instead, costs were estimated for the hull construction, risers, mooring and towing. In addition, the capital costs of the gas processing plant were included as this system forms part of the offshore floating structure.

In order to estimate these costs, a report detailing the concept design of a FLNG vessel was used (Sheffield 2005). Since this vessel is 300m in length with a 60m beam and 30m depth, whereas the vessel dimensions required for this case study were 150m by 32m by 25m, it was necessary to scale down the numbers. To do this, an estimate of the proportion of the costs that were material and outfitting was required. This was obtained by making the assumption that the labour costs associated with the build were 63.75% (based on a 85% labour cost for the first vessel, reducing by 25% by the $10^{th}$ vessel) and that the material and outfitting costs were approximately 50% of the non-labour costs (Cooper, Burger et al. 2007). The scaling factor was calculated based on the ratio of the surface areas of the vessel hull envelopes. This factor was calculated to be 0.325 and the corresponding reduction hull cost was 25 million US dollars as shown below in Table 3-7.

TABLE 3-7
ADDITIONAL CAPITAL COSTS OF OFFSHORE POWER PLANT

| Type of Cost | FLNG (MM$) | Power Plant (MM$) |
|---|---|---|
| Hull and accommodation | 200 | 175 |
| Mooring | 50 | 50 |
| Risers | 45 | 45 |
| Towing | 40 | 40 |
| Gas reception/cleaning | 80 | 21.27 |

This table also shows a reduction in the cost for gas reception/cleaning cost. This was calculated using a factor of 0.27 which was arrived at by dividing the production capacity of the FLNG vessel by the fuel requirements of the power plant. Whilst the relationship between gas processing plant size and capacity is almost certainly not linear, this was felt to be an adequate assumption for this case study. Moreover, the cost estimates for the hull are likely to be higher than necessary as they are based on LNG requirements.

### *3.5.2 Annual operating costs*

The annual operating costs (not including fuel) consist of two types; fixed and variable. The fixed costs include the following;

- Manning.
- Fixed operations and maintenance.
- Other miscellaneous costs such as starts impact, fees, insurance, distillate usage impact and allowance for head office.

The fixed annual operating costs were also obtained from the Energy Market Authority of Singapore (PA 2010) and are shown in Table 3-8.

TABLE 3-8
FIXED OPERATING COSTS OF POWER GENERATION

| Fixed OPEX | Onshore | | Offshore | |
|---|---|---|---|---|
| | SGD | AU$ | SGD | AU$ |
| Manning Power Plant | 2100000 | 1671600 | 2100000 | 1671600 |
| Manning Floater | 0 | 0 | 4000000 | 3184000 |
| Fixed O&M | 8666145 | 6898251 | 30331508 | 24143880 |
| Miscellaneous | 5231650 | 4164393 | 3945150 | 3140339 |
| Total | 12734244.82 | | 32139819.37 | |
| Total AU$/kW | 31.84 | | 80.35 | |
| % CAPEX | 2.25 | | 3.94 | |

The manning costs were divided up into two parts; the manning costs of the power generation and the manning costs associated with offshore operations and gas processing. The former was assumed to be the same for both power plants. The additional offshore manning costs were assumed to be 10% of the total fixed operating costs. The additional crew required for offshore operations are assumed to be included in the crew for the gas processing as this was based on the FLNG crew.

The annual fixed operating and maintenance for the onshore power plant is 3% of the capital cost of the plant (PA 2010). However this is not the case for the offshore power facility. The cost of maintenance will be more expensive offshore as it is more difficult to carry out these activities. In addition, the cost of corrosion needs to be considered as typically, the cost of corrosion for offshore structures is higher than that of their onshore equivalents (Ruschau and Al-Anezi 2000).

Since it is difficult to obtain the fixed operating and maintenance costs for offshore platforms in general and impossible for offshore thermal power generation, data from the offshore wind industry has been used. Typically, the proportion of the cost of generating the electricity onshore is 0.49 pence per kWh (PB Power 2004). This increases to 1.7 pence per kWh offshore which is an increase of 347%. Based on this, the fixed O&M was multiplied by 3.5.

The fixed O&M costs include maintenance, operating, and overhead costs that are generally not dependent on the hour-by-hour level of generation from the power station. It should be noted that in this case the fixed O&M costs do not include any of the costs associated with the gas turbines or steam plants. These are included in the variable O&M costs.

Of the miscellaneous costs, the cost associated with the property tax and the emergency fuel was excluded from the offshore facility.

The variable annual costs include the variable O&M, consumables, town water and other fees. The variable O&M depends on a number of factors, including the way in which wear and tear builds up between scheduled maintenance and whether the power plant is operating on a base load basis. An allowance is also included for major maintenance of the gas turbines. This is because, rather than being periodic, this maintenance is based on hours of use and the number of starts-ups. As Table 3-9 shows, the only difference between the onshore and offshore facilities is the cost of the consumables. This is due to the town water cost being excluded for the offshore power plant.

TABLE 3-9
VARIABLE OPERATING COSTS

| Variable OPEX | Onshore | | Offshore | |
|---|---|---|---|---|
| | SGD/MWh | AU$ | SGD | AU$ |
| Gas Turbine | 4.64 | 11356442 | 4.64 | 11356442 |
| Steam Turbine | 0.25 | 611877.2 | 0.25 | 611877.2 |
| Consumables | 0.7 | 1713256 | 0.5 | 1223754 |
| Fees | 0.55635 | 1361672 | 0.55635 | 1361672 |
| Total | 15043246.7 | | 14553744.9 | |
| Total AU$/kW | 27.86 | | 26.95 | |

### 3.5.3 *Fuel cost*

The fuel costs are based on a combination of the raw gas price, the cost of extracting the gas, processing the gas and then transporting it to the power plant. In this case the raw gas is assumed to cover the investment in the field (drilling, surveys etc.) (Sheffield 2005).

As the capital costs of the gas processing plant were already included in the capital costs of the offshore power plant, the only fuel cost that was applied was the cost of the raw gas (The maintenance costs are also included in the power plant costs). Using the same factor of 0.27 that was calculated to estimate the cost of the gas processing plant, the annual raw gas cost used for the FLNG concept was scaled down. The cost of generating the power required for the gas processing was applied as an energy penalty as discussed in Section 3.2.

The cost of the feed gas for the onshore power plant was obtained from a report that included various gas costs in Australia (ACIL Tasman 2009). These gas costs are the delivered gas costs and were adjusted to include transportation by assuming a gas load factor of 80%. Since the transportation of gas needed to be considered separately from the cost of the gas, the final value was reduced by 20%. Since a range of gas costs were provided the average value was selected. The costs of both the raw gas and the feed gas are displayed below in Table 3-10.

TABLE 3-10
COST OF GAS SUPPLIED TO TURBINES

| Cost of gas | Onshore | | Offshore | |
|---|---|---|---|---|
| | AU$/GJ | AU$ | US$/year | AU$ |
| Feed Gas | 4.56 | 95298728 | 0 | 0 |
| Raw Gas | 0 | 0 | 11461889 | 11003413 |
| Total | 95298728.46 | | 11003413.28 | |
| Total AU$/kW | 176.48 | | 20.38 | |

### 3.5.4 *Transportation cost*

The transportation cost associated with supply of fuel was assumed to be zero in the case of the offshore facility. For the onshore power plant the cost of transporting the gas was calculated using the methodology in Section 3.4.1 using the prescribed power and heat rate and assuming a life-cycle of 25 years. The results are shown below for both the 285 km option and the 405 km option in Table 3-11.

TABLE 3-11
COST OF TRANSPORTING ELECTRICITY, GAS AND $CO_2$

| MMAU$/yr | 285 km | 405 km |
|---|---|---|
| Cables Hi | 18.82 | 26.75 |
| Cables Lo | 9.41 | 13.37 |
| Gas transport | 18.25 | 27.99 |
| $CO_2$ transport | 11.99 | 14.32 |

Also shown in the table above are costs for the transmission of electricity. Both a lower and an upper figure are given for each option which is estimated from the lower and upper estimates of the cable costs given in Chapter 3.4.1. For a 405km cable capable of carrying 420MW, 450 kV is sufficient based on previous projects.

Table 3-11 also shows the cost of transporting the $CO_2$ from the onshore power plant to the storage site. The figures for the transportation costs of $CO_2$ are based on the IPCC report on CCS which uses a benchmark figure of 6 $MtCO_2$ per year for the cost estimates (IPCC 2005).

### *3.5.5 Cost of carbon capture and storage of $CO_2$*

Since the purpose of this study is to evaluate whether the cost of transmitting electricity is cheaper than transporting gas and $CO_2$, single values were used for the carbon capture and the storage of $CO_2$ costs. This is because it was more important that the same costs were assumed for both systems so a direct comparison of the respective transportation systems could be made. According to the IPCC, the range of costs for carbon capture is between 15 and 75 US$ per tonne of $CO_2$ captured (IPCC 2005). The range for $CO_2$ storage is between 0.6 and 8.3 US$ per tonne of $CO_2$ stored. Values of 45 US$ per tonne $CO_2$ and 4.6 US$ per tonne $CO_2$ were used as these are the median values. Although there is an exchange rate of 0.96 US$ to the Australian dollar, these values were not altered. Table 3-12 shows the costs that were calculated for carbon capture and $CO_2$ storage.

TABLE 3-12
COST OF CARBON CAPTURE, $CO_2$ STORAGE AND CARBON TAXING

| | Carbon Capture | $CO_2$ Storage | Carbon Tax |
|---|---|---|---|
| $kgCO_2e$/MWh | 0.19224 | 0.19224 | 0.19224 |
| $CO_2$ emitted t/year before CCS | 1094614.56 | 1094614.56 | 1094614.56 |
| Capture rate | 90 | 90 | 90 |
| $CO_2$ emitted t/year post CCS | 109461.47 | 109461.47 | 109461.47 |
| Cost AU$/tonne $CO_2$ | 45 | 4.79 | 23 |
| Total Cost | 4925765.52 | 524320.37 | 2517613.49 |

In addition, since only 90% of the $CO_2$ emissions were assumed to have been captured, a carbon tax was calculated for the remaining ten per cent of $CO_2$ emissions. This is 23 AU$ per tonne of $CO_2$ as mandated by the Australian government.

### *3.5.6 Levelised cost of energy; onshore power vs offshore power*

Using Equation 3.2, the Levelised Cost of Energy (LCOE) was calculated for both systems for four different scenarios. These scenarios are based on the cost of electricity transmission given in Table 3-11 where there are two distances (285km and 405km) and a low and high cost of electricity transmission for each distance. Table 3-13 gives a summary of each scenario. The costs associated with each scenario are given in Tables 3-14 to 3-17.

TABLE 3-13
SCENARIOS USED IN CASE STUDY

| Scenario | Distance Offshore (km) | Transmission cost |
|---|---|---|
| One | 285 | Low |
| Two | 285 | High |
| Three | 405 | Low |
| Four | 405 | High |

TABLE 3-14
SUMMARY OF COSTS OF SCENARIO ONE

| 285km Low | Onshore | | Offshore | |
|---|---|---|---|---|
| | AU$/kW | AU$ | AU$/kW | AU$ |
| CAPEX | 1412.647 | 762829525.8 | 2038.811 | 1100957918 |
| Annual Transportation Cost | 56 | 30240000 | 17.43 | 9410000 |
| Annual OPEX | 59.69 | 32234477 | 107.30 | 57942501 |
| Annual Fuel Cost | 176.47 | 95298728 | 20.38 | 11003413 |
| Carbon Capture Cost | 4925766 | 4925766 | 4925766 | 4925766 |
| $CO_2$ Storage Cost | 524320.4 | 524320.4 | 524320.4 | 524320.4 |
| Carbon Tax | 2517613 | 2517613 | 2517613 | 2517613 |

TABLE 3-15
SUMMARY OF COSTS OF SCENARIO TWO

| 285km High | Onshore | | Offshore | |
|---|---|---|---|---|
| | AU$/kW | AU$ | AU$/kW | AU$ |
| CAPEX | 1412.647 | 762829525.8 | 2038.81 | 1100957918 |
| Annual Transportation Cost | 56 | 30240000 | 34.85 | 18820000 |
| Annual OPEX | 59.69 | 32234477.2 | 107.30 | 57942501.05 |
| Annual Fuel Cost | 176.47 | 95298728.46 | 20.37 | 11003413.28 |
| Carbon Capture Cost | 4925766 | 4925765.52 | 4925766 | 4925765.52 |
| $CO_2$ Storage Cost | 524320.4 | 524320.37 | 524320.4 | 524320.37 |
| Carbon Tax | 2517613 | 2517613.49 | 2517613 | 2517613.49 |

TABLE 3-16
SUMMARY OF COSTS OF SCENARIO THREE

| 405km Low | Onshore | | Offshore | |
|---|---|---|---|---|
| | AU$/kW | AU$ | AU$/kW | AU$ |
| CAPEX | 1412.64 | 762829525.8 | 2038.81 | 1100957918 |
| Annual Transportation Cost | 59.69 | 32234477 | 24.75 | 13370000 |
| Annual OPEX | 59.69 | 32234477.2 | 107.30 | 57942501.05 |
| Annual Fuel Cost | 176.47 | 95298728.46 | 20.37 | 11003413.28 |
| Carbon Capture Cost | 4925766 | 4925765.52 | 4925766 | 4925765.52 |
| $CO_2$ Storage Cost | 524320.4 | 524320.3742 | 524320.4 | 524320.3742 |
| Carbon Tax | 2517613 | 2517613.488 | 2517613 | 2517613.488 |

TABLE 3-17
SUMMARY OF COSTS OF SCENARIO FOUR

| 405km High | Onshore | Offshore | | |
|---|---|---|---|---|
| | AU$/kW | AU$ | AU$/kW | AU$ |
| CAPEX | 1412.64 | 762829525.8 | 2038.81 | 1100957918 |
| Annual Transportation Cost | 59.69 | 32234477 | 49.53 | 26750000 |
| Annual OPEX | 59.69 | 32234477.2 | 107.30 | 57942501.05 |
| Annual Fuel Cost | 176.47 | 95298728.46 | 20.37 | 11003413.28 |
| Carbon Capture Cost | 4925766 | 4925765.52 | 4925766 | 4925765.52 |
| $CO_2$ Storage Cost | 524320.4 | 524320.3742 | 524320.4 | 524320.3742 |
| Carbon Tax | 2517613 | 2517613.488 | 2517613 | 2517613.488 |

Before the LCOE can be calculated, the discount rate needs to be chosen. ACIL Tasman provides information on a discount rate that can be applied to obtain the present value of the cash flow (NPV). This is the Weighted Average Cost of Capital (WACC) which allows for the inclusion of factors such as tax and risk (ACIL Tasman 2008). In deriving the WACC, the main component was systematic risk which can be reflected in a country's sovereign risk. Sovereign risk relates to the country's political and economic environment and includes currency fluctuations, changes in tax or local content laws, quotas and tariffs, and the sudden imposition of labour or environmental regulation. Risk free rates and corporation tax were also included.

The LCOE was calculated for each of the four scenarios and the results are presented below in Table 3-18. The detailed calculations for each scenario are presented in Appendix B

TABLE 3-18
LEVELISED COST OF ENERGY OF OFFSHORE VS. ONSHORE POWER

| Scenario | Offshore | | Onshore | |
|---|---|---|---|---|
| | Transmission Cost | LCOE | Pipe-pipe Cost | LCOE |
| | AU$ | AU$/MWh | AU$ | AU$/MWh |
| One | 9410000 | 73 | 30240000 | 85 |
| Two | 18820000 | 77 | 30240000 | 85 |
| Three | 13370000 | 75 | 32234477 | 89 |
| Four | 26750000 | 77 | 32234477 | 89 |

As the above table shows, transmitting electricity is cheaper than transporting gas and $CO_2$ by pipeline in all scenarios. In scenario one (where the distance offshore is 285km) the offshore option costs 73 AU$/MWh as compared to the onshore cost of 85 AU$/MWh. This is a difference of 12 AU$/MWh which falls to a difference 8 AU$/MWh in scenario two. This is because whilst the cost of transmitting electricity goes up, the cost of the pipelines remains the same. For the 405km distance, the difference between the onshore and offshore options rises to 14 AU$/MWh for scenario three. This then falls to a difference of 12 AU$/MWh for scenario four. This suggests that the greater the distance offshore, the more economical the electrical cable option becomes when compared to building two pipelines. However, according to the IPCC, at around 1000km ships become more economical than pipelines for transporting $CO_2$ (Figure 1-5) and the curve representing the cost of ships levels off with increasing distance. This suggests that at distances greater than 1000km, transporting $CO_2$ by ship will be more economical than transmitting electricity. This can be seen in Figure 3-13 where the point at which ships become cheaper than cables is at a distance of around 1300km. This could be further exasperated if the cost of transporting gas by ship versus the cost of a gas pipeline follows the same trend.

## 4. CONCLUSIONS

As a method of mitigating $CO_2$ emissions, Carbon Capture & Storage (CCS) is needed in the short-term (50 to 100 years). This is due to demands for energy increasing beyond the capabilities of alternative methods to reduce net emissions. A successful CCS project requires both financial and technical support from stakeholders. The most influential stakeholders are governments and the general public as they can make or break any CCS project. Based on this the recommended regions for the initial deployment of CCS needs to be in regions where there is general support for CCS from these groups. In the case of governments, there needs to be support in the form of incentives to encourage participation by industry. There also needs to be legislation and carbon taxation in place to force that participation. In the case of the public, they need to be aware of global warming and CCS and, more importantly, they need to be willing to support CCS. When taking these issues into account the regions that are most suitable are the EU, China and Australia.

Taking into account the relative merits of the different carbon capture methods, the most viable option is post-combustion using amine. However, in the future the other methods may be more suitable given an appropriate level of development. For most regions in the world, transporting the $CO_2$ by pipeline is the cheaper option as the majority of storage sites are either on land or are less than 1000km from the sources of $CO_2$. The most attractive option in terms of potential storage capacity is geological storage in saline aquifers; however using Enhanced Oil Recovery (EOR) could potentially reap the most economic benefit. Both of these options, as well as ocean storage will require monitoring to ensure that there are no leaks or release of the $CO_2$. It should, however, be noted that the development of legislation regarding the storage of $CO_2$ is very slow as neither governments nor industry have been willing to take the first step. The exceptions to this are in the EU and Australia. Both of these regions have laid down a framework that specifies how $CO_2$ should be classified.

Several novel concepts in the application of CCS were proposed based on the above conclusions; it was determined that the offshore thermal power (Gas to Wire) with CCS concept was the most promising. This concept has several benefits, including the ability to exploit stranded gas reserves, generate power with no need to purchase land and increased mobility enabling supply to meet demand. The most important benefit is that this concept eliminates the need to transport $CO_2$ from the point of capture to the storage location. In order to evaluate whether laying cable to transmit the electricity would be cheaper in principle than building two pipelines an economic study was carried out. It was found that the cable option would be cheaper in most regions.

There are several routes into the design process of this concept that produce slightly different outcomes. These are dependent on the motivation for selecting this concept in the first place. These motivations are power generation, $CO_2$ storage and exploitation of stranded gas reserves. The main differences are in how priorities are selected and what determines a suitable site. With all of these motivations, the key factors relate to location; whether this is the most $CO_2$ storage potential, a large gas reserve or a location close to the electricity market. All of these can drive the design process.

In addition to location in general, there other more specific sub-factors that affect the design process. These include the marine environment, government, types of platform that can be used, and the nature of the gas field amongst others. Based on these factors, Australia was identified as the most viable location as they have a developing oil and gas industry so there are still gas reserves to exploit. They are also the largest emitter of $CO_2$ per capita in the world and therefore have an interest in reducing their emissions. Consequently, they have introduced a carbon tax, legislation and are investing in CCS projects. All of these make Australia an attractive location for the deployment of CCS.

Based on this, the Torosa field in the Browse Basin was chosen as a suitable site and a system was specified. The offshore power plant proposed for this site consists of eight gas turbines and four steam plants capable of producing 540MW. The carbon capture system is amine based and there is also a gas processing plant onboard. With the inclusion of these systems the total output power is 430 MW. These systems were combined with an FPSO based structure for the floating platform. The reason for this decision is that FPSOs were found to be the most suitable structure for this region based on a comparison with other offshore structures.

The case study compared an onshore power plant with CCS with the offshore power plant concept and it was found that the offshore option was cheaper by between eight and fourteen Australian dollars per megawatthour depending on the landing site and assumed cost of the offshore electricity cables. More research needs to be done as several assumptions were made and it should be noted that the largest capacity of offshore thermal power plants is estimated to be in the order of 500 MW due to the limitation of deck areas and technology immaturity. However, this case study does demonstrate that the Gas to Wire concept could be economically viable provided that Carbon Capture & Storage becomes necessary for power stations.

## 5. FUTURE CONSIDERATIONS

This study shows that there is a prospect for future power being generated offshore from natural gas. However, it is unlikely that this concept will be the dominant source of electricity in all parts of the world. In addition, there are sources of $CO_2$ from transportation and other industries that need to be dealt with. It is, therefore, important to consider the $CO_2$ emitted by these onshore sources when envisioning the energy sector of the future. An offshore thermal power plant will have the infrastructure in place to inject the $CO_2$ into its final storage location. This means that there is potential, depending on the capacity of the storage site, to facilitate storage of $CO_2$ from these additional sources. This could be used as a further source of income in the economic analysis where storage space and processes are sold to onshore operators seeking $CO_2$ storage opportunities in ocean space.

As stated earlier, in most cases the cost of transporting $CO_2$ in pipelines will be lower than with the use of ships. However, because of the intended flexibility of the offshore thermal power plant system and the fact that it is likely to be used in marginal gas fields, a more flexible transport solution is needed. It is therefore envisioned that $CO_2$ could be transported by ships which could dock offshore facility and hence use existing infrastructure to inject $CO_2$. A schematic of the concept is shown in Figure 5-1.

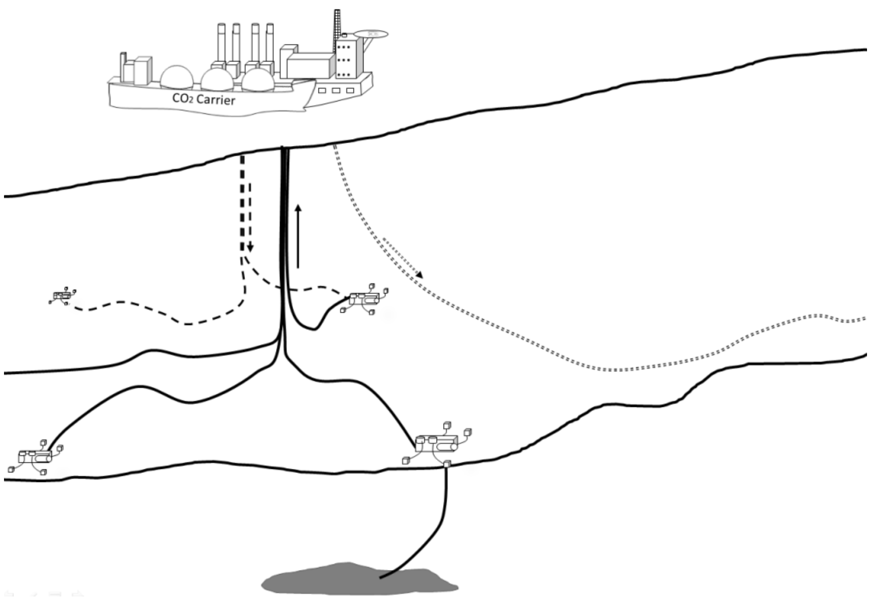


Figure 5-1: Schematic of $CO_2$ carrier utilising the injection capabilities of an offshore power plant

This shows the $CO_2$ carrier docking directly with the platform. This may not be practical for all types of platforms and/or conditions. Another possibility is to provide a separate injection buoy in the vicinity of the platform that contains compressors powered by the plant; this is illustrated in Figure 5-2. Such buoys are already in existence and are used for, amongst other things, injection with the purpose of maintaining the pressure in a field.

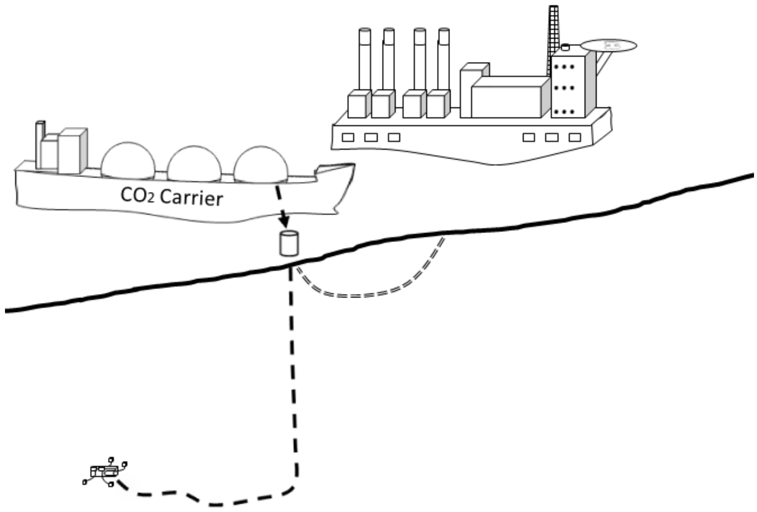


Figure 5-2: Schematic of injection buoy

The offshore $CO_2$ terminal operated by the owners of an offshore power plant has merit in several ways. It builds on one of the key principles of economics; namely that trade of services and materials allows each part in the trade to be more specialised which will benefit all (Mankiw 2007). This serves to avoid unnecessary repetition of infrastructure and competence. This will mean a greater financial gain for both parties than if they had not engaged in trade at all. In this case, the operator of the offshore plant can improve its financial performance in return for sharing the knowledge and technology needed for $CO_2$ storage. The onshore operator, on the other hand, can reduce the cost of storage by outsourcing it.

**TABLES**

TABLE 1-1: $CO_2$ AND $H_2$ SEPARATION TECHNOLOGIES FOR PRE-COMBUSTION ........ 5

TABLE 1-2: $CO_2$ SEPARATION TECHNOLOGIES FOR POST-COMBUSTION CARBON CAPTURE ........ 6

TABLE 1-3: SEPARATION TECHNOLOGIES FOR OXY-FUEL CARBON CAPTURE ........ 8

TABLE 1-4: ADVANTAGES AND DISADVANTAGES OF DIFFERENT CARBON CAPTURE SYSTEMS ........ 8

TABLE 1-5: RISKS ASSOCIATED WITH EACH CARBON CAPTURE SYSTEM ........ 8

TABLE 1-6: A SELECTION OF EXISTING PROJECTS INVOLVING GEOLOGICAL STORAGE ........ 14

TABLE 1-7: CARBON TAX BY COUNTRY ........ 27

TABLE 1-8: LIABILITY TIMEFRAMES AND ISSUES ........ 28

TABLE 1-9: MAIN COMMERCIAL SCALE PROJECTS ........ 33

TABLE 1-10: WEIGHTING USED TO EVALUATE IMPORTANCE OF DIFFERENT FACTORS ........ 34

TABLE 1-11: TABULATED SCORES FOR EACH OPTION ........ 37

TABLE 2-1: PERCENTAGE CONTRIBUTIONS OF EACH FUEL SOURCE TOWARDS ELECTRICITY GENERATION ........ 40

TABLE 2-2: PROJECTED INCREASE IN DEMAND FOR ELECTRICITY BY FUEL SOURCE ........ 40

TABLE 2-3: UK ENVIRONMENTAL LEGISLATION FOR OFFSHORE FACILITIES ........ 49

TABLE 2-4: CONSIDERATION PARAMETERS FOR OFFSHORE INSTALLATIONS ........ 50

TABLE 2-5: MAXIMUM SIGNIFICANT WAVE HEIGHTS FOR DIFFERENT REGIONS OF THE WORLD ........ 51

TABLE 2-6: SEA STATES AND MAXIMUM SIGNIFICANT WAVE HEIGHTS FOR DIFFERENT AREAS ........ 52

TABLE 2-7: TYPES OF OFFSHORE STRUCTURES ........ 53

TABLE 2-8: DESIGN CONSIDERATIONS OF DIFFERENT OFFSHORE FLOATING STRUCTURES ........ 54

TABLE 2-9: COMPARISON BETWEEN NEW-BUILD AND TANKER CONVERSION OPTIONS FOR FPSOS.. 55

TABLE 2-10: EXAMPLES OF OFFSHORE HVDC CABLES, ESTIMATED COST AND CAPACITY ........ 66

TABLE 2-11: COST COMPARISON FIGURES BASED ON TABLE 3.4 ........ 66

TABLE 2-12: SELECTION OF EXISTING HVDC OFFSHORE CABLES ........ 66

TABLE 2-13: CAPITAL COSTS OF A FLOATING GAS PRODUCTION FACILITY ........ 72

TABLE 2-14: OPERATING COSTS OF A FLOATING GAS PRODUCTION FACILITY ........ 72

TABLE 2-15: COST OF DIFFERENT FLOATING GAS PRODUCTION OPTIONS ........ 72

Table 2-16: Options for $CO_2$ storage in ocean space ... 78

Table 2-17: Characteristics of geological storage options ... 79

Table 2-18: hazards associated with offshore floating structures ... 82

Table 3-1: Details of gas fields in the Browse Basin ... 91

Table 3-2: $CO_2$ Storage capacity of sites in the vicinity of the chosen location ... 93

Table 3-3: Volume & energy penalty associated with processes ... 96

Table 3-4: Summary of factors influencing the selection of the platform ... 96

Table 3-5: Exchange rates used in cost analysis ... 103

Table 3-6: Capital costs of generating power ... 104

Table 3-7: Additional capital costs of offshore power plant ... 105

Table 3-8: Fixed operating costs of power generation ... 105

Table 3-9: Variable operating costs ... 106

Table 3-10: Cost of gas supplied to turbines ... 107

Table 3-11: Cost of transporting electricity, gas and $CO_2$ ... 107

Table 3-12: Cost of carbon capture, $CO_2$ storage and carbon taxing ... 108

Table 3-13: Scenarios used in case study ... 108

Table 3-14: Summary of costs of scenario one ... 109

Table 3-15: Summary of costs of scenario two ... 109

Table 3-16: Summary of costs of scenario three ... 109

Table 3-17: Summary of costs of scenario four ... 110

Table 3-18: Levelised cost of energy of offshore vs. onshore power ... 110

**FIGURES**

Figure 1-1: Carbon Capture & Storage flowchart ........ 3

Figure 1-2: Pre-combustion process flowchart ........ 4

Figure 1-3: Post-combustion process flowchart ........ 5

Figure 1-4: Oxy-fuel process flowchart ........ 7

Figure 1-5: Cost estimate for CO2 transport options (IPCC 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change, Figure TS.6 Cambridge University Press) ........ 10

Figure 1-6: Prospective areas for $CO_2$ storage (IPCC 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change, Figure TS.2b Cambridge University Press) ........ 10

Figure 1-7: Extent of current gas/oil fields in the Gulf of Mexico and the North Sea. ........ 11

Figure 1-8: Methods for storing CO2 in geological formations (IPCC 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change, Figure TS.7 Cambridge University Press) ........ 13

Figure 1-9: Methods of ocean storage (IPCC 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change, Figure TS.9 Cambridge University Press) ........ 16

Figure 1-10: Breakdown of regional climate change policy by type ........ 23

Figure 1-11: Breakdown of climate change policy type by region ........ 24

Figure 1-12: Percentage of climate change policies that are mandatory in 2009 ........ 24

Figure 1-13: Breakdown of mandatory climate change policy type by region ........ 25

Figure 1-14: Percentage investment of GDP in 2008 by region ........ 25

Figure 1-15: Large scale integrated project by industry sector and location ........ 29

Figure 1-16: Status of large-scale integrated projects by location ........ 30

Figure 1-17: Large-scale integrated projects by sector ........ 30

Figure 1-18: Large-scale integrated projects by carbon capture type ........ 31

Figure 1-19: Large-scale integrated projects by pipeline length ........ 31

Figure 1-20: Large-scale integrated projects by $CO_2$ storage type ........ 32

Figure 1-21: Comparison of CO2 and North Sea crude oil densities at different temperatures and within the working pressure range of most pipelines ........ 38

Figure 2-1: Schematic of offshore thermal power with CCS ..... 42

Figure 2-2: Schematic of offshore thermal power with FPSO ..... 43

Figure 2-3: Design selection flowchart for power output option ..... 44

Figure 2-4: Design selection flowchart for exploitation of gas field option ..... 45

Figure 2-5: Design selection flowchart for $CO_2$ storage option ..... 45

Figure 2-6: Factors affecting design of offshore power plants ..... 46

Figure 2-7: Location of global offshore gas reserves ..... 47

Figure 2-8: Map of Caspian Sea and surrounding countries ..... 48

Figure 2-9: Regulatory framework for offshore activities in the UK ..... 49

Figure 2-10: Relationship between location and platform type (FPSO) ..... 57

Figure 2-11: Relationship between location and platform type (semi-submersible) ..... 57

Figure 2-12: Relationship between location and platform type (spar) ..... 58

Figure 2-13: Relationship between location and platform type (TLP) ..... 58

Figure 2-14: Relationship between general location of oilfield and water depth ..... 59

Figure 2-15: Relationship between water depth and reserves for TLPs ..... 60

Figure 2-16: Relationship between water depth and reserves for spars ..... 60

Figure 2-17: Relationship between water depth and reserves for semi-submersibles ..... 61

Figure 2-18: Relationship between water depth and reserves for FPSOs ..... 61

Figure 2-19: Relationship between first production year and water depth for TLPs ..... 62

Figure 2-20: Relationship between first production year and water depth for spars ..... 62

Figure 2-21: Relationship between first production year and water depth for semi-submersibles ..... 63

Figure 2-22: Relationship between first production year and water depth for FPSOs ..... 63

Figure 2-23: Relationship between deck area and water depth for different types of offshore structure ..... 64

Figure 2-24: An Offshore Power Plant served by local subsea installations and a more distant source ..... 68

Figure 2-25: Combined cycle gas turbine ..... 69

Figure 2-26: Typical Natural Gas processing flow diagram ..... 70

Figure 2-27: Post-combustion options ..... 73

Figure 2-28: Chemical absorption system ..... 74

Figure 2-29: Physical absorption system ... 75

Figure 2-30: Adsorption system (PSA) ... 75

Figure 2-31: Membrane system ... 76

Figure 2-32: Cryogenic system ... 77

Figure 2-33: Main factors for selecting $CO_2$ storage option ... 78

Figure 2-34: Process chart for Formal Safety assessment (FSA) ... 80

Figure 3-1: Location of major offshore gas fields in Australia ... 87

Figure 3-2: Location of prospective offshore storage sites in Australia ... 87

Figure 3-3: Location of major population centres and industrial areas in relation to gas field locations . 89

Figure 3-4, Detail of chosen focus area ... 90

Figure 3-5, Detail of chosen location ... 92

Figure 3-6: Arrangement of one Power Generation Block ... 94

Figure 3-7: Arrangement of the four Power Generation Blocks ... 95

Figure 3-8: Layout of Offshore Thermal Power Plant (OTPP) ... 97

Figure 3-9: Estimate of transportation costs per year and MW for an onshore power plant ... 98

Figure 3-10: Comparison of total transportation cost (10 year period) ... 99

Figure 3-11: Comparison of total transportation cost (15 year period) ... 99

Figure 3-12: Comparsion of total transportation cost (20 year period) ... 100

Figure 3-13: Comparison of total transportation cost (25 year period) ... 100

Figure 3-14: Cost reduction of GTW compared to conventional transportation ... 101

Figure 3-15: Cost reduction of GTW compared to conventional transportation at high estimation of cable cost ... 101

Figure 3-16: Cost reduction of GTW compared to conventional transportation at low estimation of cable cost ... 102

Figure 5-1: Schematic of $CO_2$ carrier utilising the injection capabilities of an offshore power plant ... 113

Figure 5-2: Schematic of injection buoy ... 114

**REFERENCES**


ACIL Tasman (2008). Projected energy prices in selected world regions.

ACIL Tasman (2009). Final Report Fuel resource , new entry and generation costs in the NEM.

Ackermann, T., G. Andersson and L. Söder (2000). Electricity market regulations and their impact on distributed generation. DRPT2000. International Conference on Electric Utility Deregulation and Restructuring and Power Technologies. Proceedings (Cat. No.00EX382), IEEE.

Adams, D., W.Ormerod, P. Riemer and A. Smith (1994). Carbon Dioxide Disposal from Power Stations. International Energy Agency Greenhouse Gas R&D Program, Cheltenham, United Kingdom.

AGS (2010). The complexity of climate change mechanisms - aspects to be considered in abatement strategy planning, AGS Pathways report 2010:EU2.

Alvarado, S., P. Maldonado and I. Jaques (1999). "Energy and environmental implications of copper production." Energy **24**: 307-316.

Anderson, S. and R. Newell (2004). "Prospects for carbon capture and storage technologies." Annual Review of Environment and Resources **29**(1): 109-142.

Australian Energy Regulator (2010). state of the energy market 2010.

Australian Government Department of Resources Energy and Tourism (2011). Offshore Petroleum Exploration Acreage Release 2011.

Bailey, D. W. and P. H. M. Feron (2005). "Post-combustion Decarbonisation Processes." Oil & Gas Science and Technology **60**(3): 461-474.

Blackstock, J. (2011). Direct Air Capture of $CO_2$ with Chemicals Panel on Public Affairs. Technology.

Bock, Bert, R. R., H. Herzog and P. TVA (2002). Economic evaluation of CO2 storage and sink enhancement options. Washington, DC, U.S., Department of Energy & Tennessee Valley Authority Public Power Institute.

Bolger, A. (2009). Scotland eyes carbon-capture for North Sea. Financial Times, August 16th.

Bradshaw, J., B. E. Bradshaw, G. Allinson, A. J. Rigg, V. Nguyen and L. Spencer (2002). "The potential for geological sequestration of CO2 in Australia: Preliminary findings and implications for new gas field development." APPEA journal **42**: 25.

Bravard, J. C. and C. Portal (1971). Energy expenditures associated with the production and recycle of metals. Report Number(s) ORNL-MIT-132 Resource Type Technical Report Research Org Oak Ridge National Lab., Tenn. (USA).

Brown, K., W. Jazrawi, R. Moberg and M. Wilson (2001). Role of enhanced oil recovery in carbon sequestration: the Weyburn Monitoring Project, a case study. Paper read at First National Conference on Carbon Sequestration, Washington,DC.

CEPA (2009). Detailed California-Modified GREET Pathway for Compressed Natural Gas ( CNG ) from North American Natural Gas. Energy.

Chargin, Anthony and R. Socolow (1997). Fuels Decarbonization and Carbon Sequestration: Report of a Workshop. Princeton University Center for Energy and Environmental Studies Report.

Chazan, G. (2009). Locals Try Sinking Plan to Store $CO_2$ Underground. the Wall Street Journal, October 6th.

Chestney, N. and G. Wynn (2011). Shell says must explain $CO_2$ storage better. Reuters online, June 14th.

CMPT (1999). A guide to quantitative risk assessment for offshore installations, The Center for Maritime and Petroleum Technology (CMPT), UK.

Cooper, S. L., D. P. G. Burger and T. P. McDonald (2007). CONCEPTS FOR A FLEET TANKER : AN EXPLORATION INTO OPTIONS AND PRICING. RINA Proceedings.

Cornelissen, R. L. (1997). Thermodynamics and sustainable development.

Cornot-Gandolphe, S., O. Appert, R. Dickel, M.-f. Chabrelie and A. Rojey (2003). The Challenges of Further Cost Reductions for New Supply Options (Pipeline , LNG , GTL ). 22nd World Gas Conference 1-5 June, Tokyo Japan.

Das, A. and T. Chandra Kandpal (1998). "CO2 emissions from aluminium manufacturing in India." Energy **23**: 145-152.

Daughdrill, W. and T. Clark (2002). Considerations in Reducing Risks in FPSO and Shuttle Vessel Lightering Operations. Offshore Techonlogy Conference, Houston, Texas.

de Figueiredo, M. A., D. M. Reiner and H. J. Herzog (2002). Ocean Carbon Sequestration : A Case Study in Public and Institutional Perceptions. the sixth conference on greenhouse gas control technologies, Kyoto, Japan.

de Montigny, D. (2008). Post-combustion Capture.

DECC (2011). Licensing: Legislative Background.

Deutsche Bank (2009). Global Climate Change Policy Tracker: An Investor's Assessment.

DOE (2006). Hydrogen Fuel Cells.

Elsherif, M. A., P. C. Taylor and D. P. Hampshire (2011). Power Loss Evaluation of HVDC and DC HTS Transmission Solutions for Round 3 Offshore Wind Farms in the United Kingdom. International Conference on Energy Systems and Technologies (ICEST 2011) 11-14 March, Cairo, Egypt.

Erlich, I. and H. Brakelmann (2007). Integration of Wind Power into the German High Voltage Transmission Grid. 2007 IEEE Power Engineering Society General Meeting, IEEE.

EUROPEAN CARBON DIOXIDE NETWORK (2004). Capturing and Storing Carbon Dioxide: Technical lessons learned, EUROPEAN CARBON DIOXIDE NETWORK.

Falconer, I. (2009). Metals Required for the UK's Low Carbon Energy System : The case of copper usage in wind farms. Matrix.

Farr, M. (2011). Julia Gillard unveils her plans for carbon tax. News.com.au 10 July.

Freij-Ayoub, R., J. Underschultz, F. Li, C. Trefry, C. Otto and K. Mcinnes (2007). Simulation of Coastal Subsidence and Storm Wave Inundation Risk in the Gippsland Basin, CSIRO Petroleum Report 07-003.

Gaffney Cline & Associates (2008). Browse Basin Gas Technical report, Development Options Study. Report 2 of 3, Development Concepts for Development of Browse Basin Gas.

Giorgi, A., A. Rendina, G. Georgantzis, C. Marchiori, G. Pazienza, S. Corsi, C. Pincella, M. Pozzi, K. G. Danielsson, H. Jonasson, A. Orini and R. Grampa (2002). The Italy-Greece HVDC Link. CIGRE 2002 General Session, Paper 14-116, Paris.

Global CCS Institute (2010). The Global Status of CCS : 2010.

Harvey, B. and F. Prior (2011). Broome caught up in a war of nerves over gas hub plan. The West Australian August 6.

Herzog, H., E. Drake and E. Adams (1997). CO2 capture, reuse, and storage technologies for mitigating global climate change, Energy Laboratory, Massachusetts Institute of Technology, A White Paper.

Hester, R. E. and R. M. Harrison (2010). Carbon capture: sequestration and storage, Royal Society of Chemistry.

Hetland, J., V. Kårstad and F. Major (2008). FLYTENDE GASSKRAFTVERK MED $CO_2$ RENSING. TEKNA KURSDAGENE, Trondheim, Norway.

Hetland, J., H. M. Kvamsdal, G. Haugen, F. Major, V. Kårstad and G. Tjellander (2009). "Integrating a full carbon capture scheme onto a 450 MWe NGCC electric power generation hub for offshore operations: Presenting the Sevan GTW concept." Applied Energy **86**(11): 2298-2307.

Hetland, J., H. M. Kvamsdal, G. Haugen, F. Major, V. Kårstad and G. Tjellander (2010). Integrating a Full Carbon Capture Scheme onto a 450MW NGCC Electric Power Generation Hub for Offshore Operations; Presenting the Sevan GTW Concept.

HITACHI. GTW (Gas to Wire) http://www.power-hitachi.com/products/ffp/gtw.html Retrieved 20/08, 2011.

Hogben, N., N. M. C. Dacunha and G. F. Olliver (1985). Global Wave Statistics.

HSE. Offshore Helideck Design Guidelines.(www.hse.gov.uk/offshore/guidance/helideck.pdf). Retrieved 15/08, 2011.

HSE (1998). Hazard management in structural integrity: Vol. 3 Hazard management measures, (Offshore Technology Report, OTO 1998/150), Health and Safety Executive, UK.

HSE (2001). Environmental considerations., OFFSHORE TECHNOLOGY REPORT.

HSE (2002). Regulating health and safety in the UK offshore oil and gas fields. Who does what ?

Husky Energy (2001). White Rose DA Volume 2 (Development Plan. Development. **1:** 363-371.

IEA (2008). CO2 emissions from fuel combustion - highlights.

IEA (2009). World Energy Outlook 2009. Outlook.

IEA (2010). International Energy Outlook. Outlook, Citeseer. **0484**.

IMO (2002). Guidelines for the application of formal safety assessment (FSA) for use in the IMO rule-making process., Marine Safety Committee MSC/Circ. 1023, MEPC/Circ. 392, International Maritime Organization, London, April.

Inglis, R. (1996). "Production facilities selection for deep water oil and gas field development." IESIS (Instn. Engnrs. and Shipbuilders in Scotland) **139**.

IPCC (2005). Carbon dioxide capture and storage, Cambridge University Press, UK.

IPCC (2007). IPCC Fourth Assessment Report: Climate Change 2007 (AR4).

Jacobs, M. A. (2005). Measurement and modeling of thermodynamic properties for the processing of polymers in supercritical fluids.

Johannesson, K., A. Gustafsson, J. Karlstrand and M. Jeroense (2009). HVDC Light Cables for long distance grid connection. Paper presented at the European Offshore Wind Conference 2009 , Stockholm , Sweden , Sept . 14-16.

Johnson, J. W. (2000). "A solution for carbon dioxide overload." Science & Technology Review.

Johnson, S. (2009). Nord Stream pipeline gets nod from Sweden, Finland. Reuters, 5th of november.

Kamel, F. (2009). Adequate Electrical Transmission and Distribution Networks capable to cater for extensive Renewable Energy Utilization in Australia. Solar09, the 47th ANZSES Annual Conference 29 September- 2 October, Townsville, Queensland, Australia.

Kermani, M. B. and D. Harrop (1996). "The Impact of Corrosion on Oil and Gas Industry." SPE Production & Facilities **11**: 186-190.

Koch, M. and J. Harnisch (2002). "CO2 emissions related to the electricity consumption in the european primary aluminium production a comparison of electricity supply approaches." International Journal of Life Cycle Assessment **7**: 283 - 289.

Koldby, E. and M. Hyttinen (2009). Challenges on the Road to an Offshore HVDC Grid. The Nordic Wind Power Conference 2009, Bornholm Denmark.

Lackner, K. S. (2009). "Capture of carbon dioxide from ambient air." The European Physical Journal Special Topics **176**: 93-106.

Lang, C. (2005). GM Trees: No Solution to Climate Change.

Lazaridis, L. P. (2005). Economic Comparison of HVAC and HVDC Solutions for Large Offshore Wind Farms under Special Consideration of Reliability. Electrical Engineering.

Lindeberg, E. and P. Bergmo (2003). The long-term fate of $CO_2$ injected into an aquifer. Proceedings of the 6th International Conference on Greenhouse Gas Control Technologies (GHGT-6), Kyoto, Japan.

Malone, E. L., J. A. Bradbury and J. J. Dooley (2009). "Keeping CCS stakeholder involvement in perspective." Energy Procedia **1**(1): 4789-4794.

MAN Diesel (2009). Two-stroke Low Speed Diesel Engines for Independant Power Producers and Captive Power Plants.

MCMPR (2005). Carbon Dioxide Capture and Geological Storage, Australian Regulatory Guiding Principles.

Moberg, R., D. Stewart and D. Stachniak (2002). The IEA Weyburn CO2 monitoring and storage project. 6th International Conference on Greenhouse Gas Control Technologies, Kyoto, Japan.

Morren, J., S. W. H. de Haan and J. A. Ferreira (2002). High-voltage DC-DC converter for offshore windfarms. Young Researchers Symposium in Electrical Power Engineering, Leuven, Belgium.

Nakicenovic, N. and T. U. Wien (2007). "World Energy Outlook 2007 : CO2 Emissions Pathways Compared to Long-Term CO2 Stabilization Scenarios in the Literature and IPCC AR4." Current **2**: 1-22.

National Grid (2009). 2009 Offshore Development Information Statement.

Negra, B., J. Todorovich and T. Ackermann (2006). "Loss Evaluation of HVAC and HVDC Tansmission Solutions for Large Offshore Wind Farms." Electric Power Systems Research **76**: 916-927.

NEXANT ChemSystems (2005). Stranded Gas Utilization: Methane Refineries of the Future.

Nian, L. (2009). Transients in the Collection Grid of a novel Wind Farm Topology.

Official Journal of the European Union (2009). DIRECTIVE 2009/31/EC OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 23 April 2009 on the geological storage of carbon dioxide and amending Council Directive 85/337/EEC, European Parliament and Council Directives 2000/60/EC, 2001/80/EC, 2004/35/EC, 2006/.

Offshore Magazine (2011). http://www.offshore-mag.com. Retrieved 22/08, 2011.

Okeefe, S. and H. J. Herzog (2010). Trends in Public Attitudes on Global Warming.

PA (2010). Energy Market Authority of Singapore: Review of the Parameters for Setting the Vesting Contract Price for 2011 and 2012 - Draft Report. Contract.

Paik, J. and J. Czujko (2009). Explosion and fire engineering and gas explosion of FPSOs (phase I): hydrocarbon releases on FPSOs –review of HSE's accident database, Final Report No. EFEF JIP-02. Busan, Korea: Research Institute of Ship and Offshore Structural Design Innovation, Pusan National University.

Paik, J. and J. Czujko (2010). Explosion and fire engineering of FPSOs (phase II): definition of fire and gas explosion design loads, Final Report No. EFEF JIP-04–R1. Busan, Korea: Research Institute of Ship and Offshore Structural Design Innovation, Pusan National University.

Paik, J. K. and A. K. Thayamballi (2007). Ship-shaped offshore installations: design, building, and operation, Cambridge University Press.

Pan, Y., R. A. Birdsey, J. Fang, R. Houghton, P. E. Kauppi, W. A. Kurz, O. L. Phillips, A. Shvidenko, S. L. Lewis, J. G. Canadell, P. Ciais, R. B. Jackson, S. Pacala, A. D. McGuire, S. Piao, A. Rautiainen, S. Sitch and D. Hayes (2011). "A Large and Persistent Carbon Sink in the World's Forests." Science **333**.

Parfomak, P. and P. Folger (2007). Carbon Dioxide ( $CO_2$ ) Pipelines for Carbon Sequestration : Emerging Policy Issues.

Park, S. D. (2009). "Technology of $CO_2$ capture and storage." Physics & High Technology: p19-23.

Parker, G. (1999). "The FPSO design and construction guidance manual." Houston: Reserve Technology Institute.

PB Power (2004). "The Cost of Generating Electricity." Engineering.

Poldervaart, L. (2010). The import / export of electrical power from / to FPSO ' s. Foating Production 2010, Tekna, Oslo Norway.

Prior, F. (2010). Worldwide groups join fight against gas hub. The West Australian December 15th.

Reiner, D. and X. Liang (2009). Stakeholder Perceptions of Demonstrating CCS in China. Electricity Policy Research Group, University of Cambridge

Reiner, D. M., T. E. Curry, M. A. de Figueiredo, H. J. Herzog, S. Ansolabehere, K. Itaoka, M. Akai, F. Johnsson and M. Odenberger (2006). An International Comparison of Public Attitudes towards Carbon Capture and Storage Technologies. the 8th International Conference on Greenhouse Gas Control Technologies, Trondheim, Norway.

Ren 21 (2011). Renewables 2011 Global Status Report.

Robb, D. (2010). Gas turbines breaking the 60% efficiency barrier. power engineering international.

Ruschau, G. R. and M. A. Al-Anezi (2000). "Oil and Gas exploration and production." Optimization.

Ryynänen, R. P. (2010). Contractors chosen for new submarine cable connection between Finland and Estonia:total value of contracts almost 300 million euros (Fingrid press release).

Scaroni, P. (2006). World Oil and Gas Review, 2006. ENI.

Schmidt, K. A. G., S. E. Quiñones-Cisneros and B. Kvamme (2005). "Density and Viscosity Behavior of a North Sea Crude Oil, Natural Gas Liquid, and Their Mixtures." Energy & Fuels **19**: 1303-1313.

Seljom, P. and E. Rosenberg (2011). "A study of oil and natural gas resources and production." International Journal of Energy Sector Management **5**: 101-124.

Shackley, S., D. Reiner, P. Upham, H. de Coninck, G. Sigurthorsson and J. Anderson (2008). "The acceptability of CO2 capture and storage (CCS) in Europe: An assessment of the key determining factors:: Part 2. The social acceptability of CCS and the wider impacts and repercussions of its implementation." International Journal of Greenhouse Gas Control **3**(3): 344-356.

Shackley, S., D. M. Reiner, P. Upham, H. de Coninck, G. Sigurthorsson and J. Anderson (2009). "The acceptability of CO2 capture and storage (CCS) in Europe: An assessment of the key determining factors." International Journal of Greenhouse Gas Control **3**: 344-356.

Sheffield, J. (2005). Offshore LNG Production – How to Make it Happen. Business**:** 1-9.

Shell (2009). Prelude Floating LNG Project Draft Environmental Impact Statement.

Siemens (2009). "SGT-800 Industrial Gas Turbine."

Siemens (2011). Siemens SGT5-8000H Broshure.

SINTEF (2010). "Avoiding CO2 capture health risks is possible." Carbon Capture Journal, 25th of October.

Skjong, R., E. Vanem and Endresen (2005). SAFEDOR project: Design, operation, and regulation for safety-Risk evaluation criteria., Det Norske Veritas, Oslo.

Soares, C. (1998). "GAS TURBINES IN SIMPLE CYCLE & COMBINED CYCLE APPLICATIONS."

Steeneveldt, R., B. Berger and T. Torp (2006). "CO2 Capture and Storage:: Closing the Knowing-Doing Gap." Chemical Engineering Research and Design **84**(9): 739-763.

Stevens, S. H., V. A. Kuuskraa, D. Spector and P. Riemer (1998). CO2 Sequestration in Deep Coal Seams: Pilot Results and Worldwide Potential. 4th International Conference on Greenhouse Gas Control Technologies, Interlaken, Switzerland.

Tanaka, N. E. (2010). $CO_2$ emissions from fuel combustion.

Thomas, R. J. (2009). Application of High Voltage DC for Utility-Scale Wind.

UK SDC (2006). The UK Sustainable Development Commission Annual Report.

UN (1996). London Convention 1996 Protocol to the Convention on the Prevention of Marine Pollution by Dumping of Wastes and other Matter.

UN (2011). World Population Prospects: The 2010 Revison. Population (English Edition).

van Eeckhout, B. (2008). The economic value of VCS HVDC compared to HVAC for offshore wind farms. Offshore (Conroe, TX).

van Hertem, D. and M. Ghandhari (2010). "Multi-terminal VSC HVDC for the European supergrid: Obstacles." Renewable and Sustainable Energy Reviews **14**: 3156-3163.

van Loon, J. and A. Morales (2009). Australia Overtakes U.S. in Per Capita CO2 Emissions. Bloomberg Online September 10.

Voosen, P. (2010). A Town's Lonely Struggle Shows CO2 Fears Here to Stay. The New York Times, May 11th.

Wainer, D. and M. A. Derhally (2010). Israel Offshore Gas Find Triggers Dispute with Lebanon, Cyprus Questions Boundary. Global Research.

WALLER MARINE. Floating Power Plants www.WallerMarine.com Retrieved 20/08, 2011.

Woodside (2011). Woodside press releases.

Worzyk, T. (2009). "Submarine Power Cables." Power Systems **51-104**.

Zhao, J. (2000). Diffusion, Costs and Learning in the Development of International Gas Transmission Lines.

## APPENDIX A

TABLE A-1
GAS PROCESSING OPTION ONE - CAPITAL COSTS

| Capital Costs | US$ MM |
|---|---|
| Hull & Accommodation | 200 |
| Mooring | 50 |
| Risers | 45 |
| Towing | 40 |
| Gas reception/cleaning | 80 |
| Utilities | 21.6 |
| Total | 436600000 |

TABLE A-2
GAS PROCESSING OPTION ONE - FIXED COSTS

| Fixed Costs | US$ MM |
|---|---|
| Raw Gas | 45 |
| Maintenance | 30 |
| Staffing | 30 |
| Sundries | 25 |
| Total | 130000000 |

TABLE A-3
GAS PROCESSING OPTION ONE – RESULTS

| Results | |
|---|---|
| US$/tonne LNG | 111 |
| US$/$m^3$ NG | 0.08 |
| US$/BTU | 3.09E-06 |
| US$/J | 2.93E-09 |
| US$/GJ | 2.93 |
| A$/GJ | 2.81 |

TABLE A-4
GAS PROCESSING OPTION ONE - DETAILED RESULTS

| Year | Expenses (AU$) | | | Discount Factor | Output (MWh) | |
|---|---|---|---|---|---|---|
| | Capital | Annual | Present Value | | Annual | Present Value |
| | 436600000 | | | | | |
| 0 | | | 436600000 | 1 | | |
| 1 | | 130000000 | 121974104 | 0.938262 | 1500000 | 1407394 |
| 2 | | 130000000 | 114443708 | 0.880336 | 1500000 | 1320504 |
| 3 | | 130000000 | 107378221 | 0.825986 | 1500000 | 1238979 |
| 4 | | 130000000 | 100748941 | 0.774992 | 1500000 | 1162488 |
| 5 | | 130000000 | 94528937 | 0.727146 | 1500000 | 1090719 |
| 6 | | 130000000 | 88692941 | 0.682253 | 1500000 | 1023380 |
| 7 | | 130000000 | 83217246 | 0.640133 | 1500000 | 960199 |
| 8 | | 130000000 | 78079608 | 0.600612 | 1500000 | 900919 |
| 9 | | 130000000 | 73259156 | 0.563532 | 1500000 | 845298 |
| 10 | | 130000000 | 68736307 | 0.528741 | 1500000 | 793111 |
| 11 | | 130000000 | 64492688 | 0.496098 | 1500000 | 744146 |
| 12 | | 130000000 | 60511060 | 0.46547 | 1500000 | 698205 |
| 13 | | 130000000 | 56775249 | 0.436733 | 1500000 | 655099 |
| 14 | | 130000000 | 53270078 | 0.40977 | 1500000 | 614655 |
| 15 | | 130000000 | 49981308 | 0.384472 | 1500000 | 576707 |
| 16 | | 130000000 | 46895579 | 0.360735 | 1500000 | 541103 |
| 17 | | 130000000 | 44000355 | 0.338464 | 1500000 | 507696 |
| 18 | | 130000000 | 41283876 | 0.317568 | 1500000 | 476352 |
| 19 | | 130000000 | 38735106 | 0.297962 | 1500000 | 446944 |
| 20 | | 130000000 | 36343691 | 0.279567 | 1500000 | 419350 |
| 21 | | 130000000 | 34099917 | 0.262307 | 1500000 | 393461 |
| 22 | | 130000000 | 31994668 | 0.246113 | 1500000 | 369169 |
| 23 | | 130000000 | 30019392 | 0.230918 | 1500000 | 346378 |
| 24 | | 130000000 | 28166065 | 0.216662 | 1500000 | 324993 |
| | | | 1984228198 | | | 17857248 |

TABLE A-5
GAS PROCESSING OPTION TWO - CAPITAL COSTS

| Capital Costs | US$ MM |
|---|---|
| Hull & Accommodation | 0 |
| Mooring | 0 |
| Risers | 0 |
| Towing | 0 |
| Gas reception/cleaning | 80 |
| Utilities | 0 |
| Total | 80000000 |

TABLE A-6
GAS PROCESSING OPTION TWO - FIXED COSTS

| Fixed Costs | US$ MM |
|---|---|
| Raw Gas | 45 |
| Maintenance | 30 |
| Staffing | 30 |
| Sundries | 25 |
| Total | 130000000 |

TABLE A-7
GAS PROCESSING OPTION TWO – RESULTS

| Results | |
|---|---|
| US$/tonne LNG | 91 |
| US$/$m^3$ NG | 0.07 |
| US$/BTU | 2.53E-06 |
| US$/J | 2.40E-09 |
| US$/GJ | 2.40 |
| A$/GJ | 2.30 |

TABLE A-8
GAS PROCESSING OPTION TWO - DETAILED RESULTS

| Year | Expenses (AU$) | | | Discount Factor | Output (MWh) | |
|---|---|---|---|---|---|---|
| | Capital | Annual | Present Value | | Annual | Present Value |
| | 80000000 | | | | | |
| 0 | | | 80000000 | 1 | | |
| 1 | | 130000000 | 121974104 | 0.938262 | 1500000 | 1407394 |
| 2 | | 130000000 | 114443708 | 0.880336 | 1500000 | 1320504 |
| 3 | | 130000000 | 107378221 | 0.825986 | 1500000 | 1238979 |
| 4 | | 130000000 | 100748941 | 0.774992 | 1500000 | 1162488 |
| 5 | | 130000000 | 94528937 | 0.727146 | 1500000 | 1090719 |
| 6 | | 130000000 | 88692941 | 0.682253 | 1500000 | 1023380 |
| 7 | | 130000000 | 83217246 | 0.640133 | 1500000 | 960199 |
| 8 | | 130000000 | 78079608 | 0.600612 | 1500000 | 900919 |
| 9 | | 130000000 | 73259156 | 0.563532 | 1500000 | 845298 |
| 10 | | 130000000 | 68736307 | 0.528741 | 1500000 | 793111 |
| 11 | | 130000000 | 64492688 | 0.496098 | 1500000 | 744146 |
| 12 | | 130000000 | 60511060 | 0.46547 | 1500000 | 698205 |
| 13 | | 130000000 | 56775249 | 0.436733 | 1500000 | 655099 |
| 14 | | 130000000 | 53270078 | 0.40977 | 1500000 | 614655 |
| 15 | | 130000000 | 49981308 | 0.384472 | 1500000 | 576707 |
| 16 | | 130000000 | 46895579 | 0.360735 | 1500000 | 541103 |
| 17 | | 130000000 | 44000355 | 0.338464 | 1500000 | 507696 |
| 18 | | 130000000 | 41283876 | 0.317568 | 1500000 | 476352 |
| 19 | | 130000000 | 38735106 | 0.297962 | 1500000 | 446944 |
| 20 | | 130000000 | 36343691 | 0.279567 | 1500000 | 419350 |
| 21 | | 130000000 | 34099917 | 0.262307 | 1500000 | 393461 |
| 22 | | 130000000 | 31994668 | 0.246113 | 1500000 | 369169 |
| 23 | | 130000000 | 30019392 | 0.230918 | 1500000 | 346378 |
| 24 | | 130000000 | 28166065 | 0.216662 | 1500000 | 324993 |
| | | | 1627628198 | | | 17857248 |

**APPENDIX B**

TABLE B-1
SCENARIO ONE DETAILED RESULTS - OFFSHORE

| Year | Expenses (AU$) | | | Discount Factor | Output (MWh) | |
|---|---|---|---|---|---|---|
| | Capital | Annual | Present Value | | Annual | Present Value |
| | 1100957918 | | | | | |
| 0 | | | 1100957918 | 1 | | |
| 1 | | 86323613.71 | 80994196 | 0.938262 | 2438285 | 2287751 |
| 2 | | 86323613.71 | 75993803 | 0.880336 | 2438285 | 2146510 |
| 3 | | 86323613.71 | 71302124 | 0.825986 | 2438285 | 2013990 |
| 4 | | 86323613.71 | 66900097 | 0.774992 | 2438285 | 1889651 |
| 5 | | 86323613.71 | 62769842 | 0.727146 | 2438285 | 1772988 |
| 6 | | 86323613.71 | 58894578 | 0.682253 | 2438285 | 1663528 |
| 7 | | 86323613.71 | 55258565 | 0.640133 | 2438285 | 1560826 |
| 8 | | 86323613.71 | 51847030 | 0.600612 | 2438285 | 1464464 |
| 9 | | 86323613.71 | 48646116 | 0.563532 | 2438285 | 1374051 |
| 10 | | 86323613.71 | 45642818 | 0.528741 | 2438285 | 1289221 |
| 11 | | 86323613.71 | 42824937 | 0.496098 | 2438285 | 1209627 |
| 12 | | 86323613.71 | 40181026 | 0.46547 | 2438285 | 1134948 |
| 13 | | 86323613.71 | 37700343 | 0.436733 | 2438285 | 1064879 |
| 14 | | 86323613.71 | 35372812 | 0.40977 | 2438285 | 999135 |
| 15 | | 86323613.71 | 33188978 | 0.384472 | 2438285 | 937451 |
| 16 | | 86323613.71 | 31139968 | 0.360735 | 2438285 | 879575 |
| 17 | | 86323613.71 | 29217459 | 0.338464 | 2438285 | 825272 |
| 18 | | 86323613.71 | 27413641 | 0.317568 | 2438285 | 774322 |
| 19 | | 86323613.71 | 25721187 | 0.297962 | 2438285 | 726517 |
| 20 | | 86323613.71 | 24133221 | 0.279567 | 2438285 | 681664 |
| 21 | | 86323613.71 | 22643293 | 0.262307 | 2438285 | 639579 |
| 22 | | 86323613.71 | 21245349 | 0.246113 | 2438285 | 600093 |
| 23 | | 86323613.71 | 19933711 | 0.230918 | 2438285 | 563045 |
| 24 | | 86323613.71 | 18703050 | 0.216662 | 2438285 | 528284 |
| | | | 2128626062 | | | 29027370 |
| | | | | LCOE A$/MWh | | 73 |
| | | | | LCOE A$/kWh | | 0.073 |

TABLE B-2
SCENARIO ONE DETAILED RESULTS - ONSHORE

| Year | Expenses (AU$) | | | Discount Factor | Output (MWh) | |
|---|---|---|---|---|---|---|
| | Capital | Annual | Present Value | | Annual | Present Value |
| | 762829526 | | | | | |
| 0 | | | 762829526 | 1 | | |
| 1 | | 165740905 | 155508449 | 0.938262 | 2705789 | 2538740 |
| 2 | | 165740905 | 145907721 | 0.880336 | 2705789 | 2382004 |
| 3 | | 165740905 | 136899720 | 0.825986 | 2705789 | 2234945 |
| 4 | | 165740905 | 128447851 | 0.774992 | 2705789 | 2096964 |
| 5 | | 165740905 | 120517781 | 0.727146 | 2705789 | 1967503 |
| 6 | | 165740905 | 113077295 | 0.682253 | 2705789 | 1846034 |
| 7 | | 165740905 | 106096167 | 0.640133 | 2705789 | 1732064 |
| 8 | | 165740905 | 99546038 | 0.600612 | 2705789 | 1625130 |
| 9 | | 165740905 | 93400298 | 0.563532 | 2705789 | 1524798 |
| 10 | | 165740905 | 87633982 | 0.528741 | 2705789 | 1430661 |
| 11 | | 165740905 | 82223665 | 0.496098 | 2705789 | 1342335 |
| 12 | | 165740905 | 77147368 | 0.46547 | 2705789 | 1259463 |
| 13 | | 165740905 | 72384470 | 0.436733 | 2705789 | 1181706 |
| 14 | | 165740905 | 67915622 | 0.40977 | 2705789 | 1108751 |
| 15 | | 165740905 | 63722670 | 0.384472 | 2705789 | 1040299 |
| 16 | | 165740905 | 59788582 | 0.360735 | 2705789 | 976073 |
| 17 | | 165740905 | 56097374 | 0.338464 | 2705789 | 915813 |
| 18 | | 165740905 | 52634054 | 0.317568 | 2705789 | 859273 |
| 19 | | 165740905 | 49384550 | 0.297962 | 2705789 | 806223 |
| 20 | | 165740905 | 46335664 | 0.279567 | 2705789 | 756449 |
| 21 | | 165740905 | 43475008 | 0.262307 | 2705789 | 709747 |
| 22 | | 165740905 | 40790963 | 0.246113 | 2705789 | 665929 |
| 23 | | 165740905 | 38272624 | 0.230918 | 2705789 | 624816 |
| 24 | | 165740905 | 35909762 | 0.216662 | 2705789 | 586242 |
| | | | 2735947204 | | | 32211962 |
| | | | | LCOE A$/MWh | | 85 |
| | | | | LCOE A$/kWh | | 0.085 |

TABLE B-3
SCENARIO TWO DETAILED RESULTS – OFFSHORE

| Year | Expenses (AU$) | | | Discount Factor | Output (MWh) | |
|---|---|---|---|---|---|---|
| | Capital | Annual | Present Value | | Annual | Present Value |
| | 1100957918 | | | | | |
| 0 | | | 1100957918 | 1 | | |
| 1 | | 95733613.71 | 89823244 | 0.938262 | 2438285 | 2287751 |
| 2 | | 95733613.71 | 84277767 | 0.880336 | 2438285 | 2146510 |
| 3 | | 95733613.71 | 79074655 | 0.825986 | 2438285 | 2013990 |
| 4 | | 95733613.71 | 74192771 | 0.774992 | 2438285 | 1889651 |
| 5 | | 95733613.71 | 69612282 | 0.727146 | 2438285 | 1772988 |
| 6 | | 95733613.71 | 65314583 | 0.682253 | 2438285 | 1663528 |
| 7 | | 95733613.71 | 61282213 | 0.640133 | 2438285 | 1560826 |
| 8 | | 95733613.71 | 57498793 | 0.600612 | 2438285 | 1464464 |
| 9 | | 95733613.71 | 53948952 | 0.563532 | 2438285 | 1374051 |
| 10 | | 95733613.71 | 50618270 | 0.528741 | 2438285 | 1289221 |
| 11 | | 95733613.71 | 47493216 | 0.496098 | 2438285 | 1209627 |
| 12 | | 95733613.71 | 44561096 | 0.46547 | 2438285 | 1134948 |
| 13 | | 95733613.71 | 41809998 | 0.436733 | 2438285 | 1064879 |
| 14 | | 95733613.71 | 39228746 | 0.40977 | 2438285 | 999135 |
| 15 | | 95733613.71 | 36806855 | 0.384472 | 2438285 | 937451 |
| 16 | | 95733613.71 | 34534486 | 0.360735 | 2438285 | 879575 |
| 17 | | 95733613.71 | 32402408 | 0.338464 | 2438285 | 825272 |
| 18 | | 95733613.71 | 30401959 | 0.317568 | 2438285 | 774322 |
| 19 | | 95733613.71 | 28525013 | 0.297962 | 2438285 | 726517 |
| 20 | | 95733613.71 | 26763945 | 0.279567 | 2438285 | 681664 |
| 21 | | 95733613.71 | 25111602 | 0.262307 | 2438285 | 639579 |
| 22 | | 95733613.71 | 23561270 | 0.246113 | 2438285 | 600093 |
| 23 | | 95733613.71 | 22106653 | 0.230918 | 2438285 | 563045 |
| 24 | | 95733613.71 | 20741840 | 0.216662 | 2438285 | 528284 |
| | | | 2240650534 | | | 29027370 |
| | | | | LCOE A$/MWh | | 77 |
| | | | | LCOE A$/kWh | | 0.077 |

TABLE B-4
SCENARIO TWO DETAILED RESULTS – ONSHORE

| Year | Expenses (AU$) | | | Discount Factor | Output (MWh) | |
|---|---|---|---|---|---|---|
| | Capital | Annual | Present Value | | Annual | Present Value |
| | 762829525.8 | | | | | |
| 0 | | | 762829525.8 | 1 | | |
| 1 | | 165740905 | 155508449 | 0.938262 | 2705789 | 2538740 |
| 2 | | 165740905 | 145907721 | 0.880336 | 2705789 | 2382004 |
| 3 | | 165740905 | 136899720 | 0.825986 | 2705789 | 2234945 |
| 4 | | 165740905 | 128447851 | 0.774992 | 2705789 | 2096964 |
| 5 | | 165740905 | 120517781 | 0.727146 | 2705789 | 1967503 |
| 6 | | 165740905 | 113077295 | 0.682253 | 2705789 | 1846034 |
| 7 | | 165740905 | 106096167 | 0.640133 | 2705789 | 1732064 |
| 8 | | 165740905 | 99546038 | 0.600612 | 2705789 | 1625130 |
| 9 | | 165740905 | 93400298 | 0.563532 | 2705789 | 1524798 |
| 10 | | 165740905 | 87633982 | 0.528741 | 2705789 | 1430661 |
| 11 | | 165740905 | 82223665 | 0.496098 | 2705789 | 1342335 |
| 12 | | 165740905 | 77147368 | 0.46547 | 2705789 | 1259463 |
| 13 | | 165740905 | 72384470 | 0.436733 | 2705789 | 1181706 |
| 14 | | 165740905 | 67915622 | 0.40977 | 2705789 | 1108751 |
| 15 | | 165740905 | 63722670 | 0.384472 | 2705789 | 1040299 |
| 16 | | 165740905 | 59788582 | 0.360735 | 2705789 | 976073 |
| 17 | | 165740905 | 56097374 | 0.338464 | 2705789 | 915813 |
| 18 | | 165740905 | 52634054 | 0.317568 | 2705789 | 859273 |
| 19 | | 165740905 | 49384550 | 0.297962 | 2705789 | 806223 |
| 20 | | 165740905 | 46335664 | 0.279567 | 2705789 | 756449 |
| 21 | | 165740905 | 43475008 | 0.262307 | 2705789 | 709747 |
| 22 | | 165740905 | 40790963 | 0.246113 | 2705789 | 665929 |
| 23 | | 165740905 | 38272624 | 0.230918 | 2705789 | 624816 |
| 24 | | 165740905 | 35909762 | 0.216662 | 2705789 | 586242 |
| | | | 2735947204 | | | 32211962 |
| | | | | LCOE A$/MWh | | 85 |
| | | | | LCOE A$/kWh | | 0.085 |

TABLE B-5
SCENARIO THREE DETAILED RESULTS – OFFSHORE

| Year | Expenses (AU$) | | | Discount Factor | Output (MWh) | |
|---|---|---|---|---|---|---|
| | Capital | Annual | Present Value | | Annual | Present Value |
| | 1100957918 | | | | | |
| 0 | | | 1100957918 | 1 | | |
| 1 | | 90283614 | 84709714 | 0.938262 | 2438285 | 2287751 |
| 2 | | 90283614 | 79479935 | 0.880336 | 2438285 | 2146510 |
| 3 | | 90283614 | 74573029 | 0.825986 | 2438285 | 2013990 |
| 4 | | 90283614 | 69969065 | 0.774992 | 2438285 | 1889651 |
| 5 | | 90283614 | 65649339 | 0.727146 | 2438285 | 1772988 |
| 6 | | 90283614 | 61596302 | 0.682253 | 2438285 | 1663528 |
| 7 | | 90283614 | 57793490 | 0.640133 | 2438285 | 1560826 |
| 8 | | 90283614 | 54225455 | 0.600612 | 2438285 | 1464464 |
| 9 | | 90283614 | 50877702 | 0.563532 | 2438285 | 1374051 |
| 10 | | 90283614 | 47736632 | 0.528741 | 2438285 | 1289221 |
| 11 | | 90283614 | 44789484 | 0.496098 | 2438285 | 1209627 |
| 12 | | 90283614 | 42024286 | 0.46547 | 2438285 | 1134948 |
| 13 | | 90283614 | 39429805 | 0.436733 | 2438285 | 1064879 |
| 14 | | 90283614 | 36995501 | 0.40977 | 2438285 | 999135 |
| 15 | | 90283614 | 34711485 | 0.384472 | 2438285 | 937451 |
| 16 | | 90283614 | 32568479 | 0.360735 | 2438285 | 879575 |
| 17 | | 90283614 | 30557777 | 0.338464 | 2438285 | 825272 |
| 18 | | 90283614 | 28671212 | 0.317568 | 2438285 | 774322 |
| 19 | | 90283614 | 26901118 | 0.297962 | 2438285 | 726517 |
| 20 | | 90283614 | 25240306 | 0.279567 | 2438285 | 681664 |
| 21 | | 90283614 | 23682029 | 0.262307 | 2438285 | 639579 |
| 22 | | 90283614 | 22219955 | 0.246113 | 2438285 | 600093 |
| 23 | | 90283614 | 20848147 | 0.230918 | 2438285 | 563045 |
| 24 | | 90283614 | 19561031 | 0.216662 | 2438285 | 528284 |
| | | | 2175769198 | | | 29027370 |
| | | | | LCOE A$/MWh | | 75 |
| | | | | LCOE A$/kWh | | 0.075 |

TABLE B-6

SCENARIO THREE DETAILED RESULTS – ONSHORE

| Year | Expenses (AU$) | | | Discount Factor | Output (MWh) | |
|---|---|---|---|---|---|---|
| | Capital | Annual | Present Value | | Annual | Present Value |
| | 762829525.8 | | | | | |
| 0 | | | 762829525.8 | 1 | | |
| 1 | | 177810905 | 166833276 | 0.938262 | 2705789 | 2538740 |
| 2 | | 177810905 | 156533379 | 0.880336 | 2705789 | 2382004 |
| 3 | | 177810905 | 146869374 | 0.825986 | 2705789 | 2234945 |
| 4 | | 177810905 | 137802003 | 0.774992 | 2705789 | 2096964 |
| 5 | | 177810905 | 129294429 | 0.727146 | 2705789 | 1967503 |
| 6 | | 177810905 | 121312093 | 0.682253 | 2705789 | 1846034 |
| 7 | | 177810905 | 113822568 | 0.640133 | 2705789 | 1732064 |
| 8 | | 177810905 | 106795429 | 0.600612 | 2705789 | 1625130 |
| 9 | | 177810905 | 100202129 | 0.563532 | 2705789 | 1524798 |
| 10 | | 177810905 | 94015884 | 0.528741 | 2705789 | 1430661 |
| 11 | | 177810905 | 88211563 | 0.496098 | 2705789 | 1342335 |
| 12 | | 177810905 | 82765587 | 0.46547 | 2705789 | 1259463 |
| 13 | | 177810905 | 77655834 | 0.436733 | 2705789 | 1181706 |
| 14 | | 177810905 | 72861544 | 0.40977 | 2705789 | 1108751 |
| 15 | | 177810905 | 68363243 | 0.384472 | 2705789 | 1040299 |
| 16 | | 177810905 | 64142656 | 0.360735 | 2705789 | 976073 |
| 17 | | 177810905 | 60182638 | 0.338464 | 2705789 | 915813 |
| 18 | | 177810905 | 56467103 | 0.317568 | 2705789 | 859273 |
| 19 | | 177810905 | 52980956 | 0.297962 | 2705789 | 806223 |
| 20 | | 177810905 | 49710036 | 0.279567 | 2705789 | 756449 |
| 21 | | 177810905 | 46641054 | 0.262307 | 2705789 | 709747 |
| 22 | | 177810905 | 43761545 | 0.246113 | 2705789 | 665929 |
| 23 | | 177810905 | 41059809 | 0.230918 | 2705789 | 624816 |
| 24 | | 177810905 | 38524873 | 0.216662 | 2705789 | 586242 |
| | | | 2879638530 | | | 32211962 |
| | | | | LCOE A$/MWh | | 89 |
| | | | | LCOE A$/kWh | | 0.089 |

TABLE B-7

SCENARIO FOUR DETAILED RESULTS – OFFSHORE

| Year | Expenses (AU$) | | | Discount Factor | Output (MWh) | |
|---|---|---|---|---|---|---|
| | Capital | Annual | Present Value | | Annual | Present Value |
| | 1100957918 | | | | | |
| 0 | | | 1100957918 | 1 | | |
| 1 | | 95695914 | 89787872 | 0.938262 | 2438285 | 2287751 |
| 2 | | 95695914 | 84244579 | 0.880336 | 2438285 | 2146510 |
| 3 | | 95695914 | 79043516 | 0.825986 | 2438285 | 2013990 |
| 4 | | 95695914 | 74163554 | 0.774992 | 2438285 | 1889651 |
| 5 | | 95695914 | 69584869 | 0.727146 | 2438285 | 1772988 |
| 6 | | 95695914 | 65288862 | 0.682253 | 2438285 | 1663528 |
| 7 | | 95695914 | 61258081 | 0.640133 | 2438285 | 1560826 |
| 8 | | 95695914 | 57476150 | 0.600612 | 2438285 | 1464464 |
| 9 | | 95695914 | 53927707 | 0.563532 | 2438285 | 1374051 |
| 10 | | 95695914 | 50598336 | 0.528741 | 2438285 | 1289221 |
| 11 | | 95695914 | 47474513 | 0.496098 | 2438285 | 1209627 |
| 12 | | 95695914 | 44543548 | 0.46547 | 2438285 | 1134948 |
| 13 | | 95695914 | 41793533 | 0.436733 | 2438285 | 1064879 |
| 14 | | 95695914 | 39213298 | 0.40977 | 2438285 | 999135 |
| 15 | | 95695914 | 36792361 | 0.384472 | 2438285 | 937451 |
| 16 | | 95695914 | 34520887 | 0.360735 | 2438285 | 879575 |
| 17 | | 95695914 | 32389648 | 0.338464 | 2438285 | 825272 |
| 18 | | 95695914 | 30389987 | 0.317568 | 2438285 | 774322 |
| 19 | | 95695914 | 28513780 | 0.297962 | 2438285 | 726517 |
| 20 | | 95695914 | 26753406 | 0.279567 | 2438285 | 681664 |
| 21 | | 95695914 | 25101713 | 0.262307 | 2438285 | 639579 |
| 22 | | 95695914 | 23551992 | 0.246113 | 2438285 | 600093 |
| 23 | | 95695914 | 22097947 | 0.230918 | 2438285 | 563045 |
| 24 | | 95695914 | 20733672 | 0.216662 | 2438285 | 528284 |
| | | | 2240201729 | | | 29027370 |
| | | | | LCOE A$/MWh | | 77 |
| | | | | LCOE A$/kWh | | 0.077 |

TABLE B-8

SCENARIO FOUR DETAILED RESULTS – ONSHORE

| Year | Expenses (AU$) | | | Discount Factor | Output (MWh) | |
|---|---|---|---|---|---|---|
| | Capital | Annual | Present Value | | Annual | Present Value |
| | 762829526 | | | | | |
| 0 | | | 762829525.8 | 1 | | |
| 1 | | 177810905 | 166833276 | 0.938262 | 2705789 | 2538740 |
| 2 | | 177810905 | 156533379 | 0.880336 | 2705789 | 2382004 |
| 3 | | 177810905 | 146869374 | 0.825986 | 2705789 | 2234945 |
| 4 | | 177810905 | 137802003 | 0.774992 | 2705789 | 2096964 |
| 5 | | 177810905 | 129294429 | 0.727146 | 2705789 | 1967503 |
| 6 | | 177810905 | 121312093 | 0.682253 | 2705789 | 1846034 |
| 7 | | 177810905 | 113822568 | 0.640133 | 2705789 | 1732064 |
| 8 | | 177810905 | 106795429 | 0.600612 | 2705789 | 1625130 |
| 9 | | 177810905 | 100202129 | 0.563532 | 2705789 | 1524798 |
| 10 | | 177810905 | 94015884 | 0.528741 | 2705789 | 1430661 |
| 11 | | 177810905 | 88211563 | 0.496098 | 2705789 | 1342335 |
| 12 | | 177810905 | 82765587 | 0.46547 | 2705789 | 1259463 |
| 13 | | 177810905 | 77655834 | 0.436733 | 2705789 | 1181706 |
| 14 | | 177810905 | 72861544 | 0.40977 | 2705789 | 1108751 |
| 15 | | 177810905 | 68363243 | 0.384472 | 2705789 | 1040299 |
| 16 | | 177810905 | 64142656 | 0.360735 | 2705789 | 976073 |
| 17 | | 177810905 | 60182638 | 0.338464 | 2705789 | 915813 |
| 18 | | 177810905 | 56467103 | 0.317568 | 2705789 | 859273 |
| 19 | | 177810905 | 52980956 | 0.297962 | 2705789 | 806223 |
| 20 | | 177810905 | 49710036 | 0.279567 | 2705789 | 756449 |
| 21 | | 177810905 | 46641054 | 0.262307 | 2705789 | 709747 |
| 22 | | 177810905 | 43761545 | 0.246113 | 2705789 | 665929 |
| 23 | | 177810905 | 41059809 | 0.230918 | 2705789 | 624816 |
| 24 | | 177810905 | 38524873 | 0.216662 | 2705789 | 586242 |
| | | | 2879638530 | | | 32211962 |
| | | | | LCOE A$/MWh | | 89 |
| | | | | LCOE A$/kWh | | 0.089 |