REDUCTIONS OF GREENHOUSE GAS EMMISSIONS FROM OFFSHORE OIL AND GAS INSTALLATIONS

Report Number PH3/9
August 1999

OFFSHORE OIL & GAS - CASE STUDIES OF POTENTIAL RETROFIT ABATEMENT TECHNOLOGIES

Background to the Study

The offshore oil and gas industry is a significant emitter of greenhouse gases. In recent years, some offshore installations and design practices have undergone modifications, which have resulted in lower emissions of greenhouse gases. The IEA Greenhouse Gas R&D Programme (IEA GHG) decided to produce some descriptive case studies of ways of reducing emissions of greenhouse gases. The purpose of these case studies is to influence project managers and others concerned with specification, design and operation of offshore installations, giving them knowledge about options available for reducing emissions and confidence that the technology exists and can be used effectively.

This report includes case studies of offshore installations with reduced greenhouse gas emissions and an overview of related technology developments. The report was prepared by Woodhill Engineering Consultants in the United Kingdom. It was originally intended that the study would consider only retrofits. However, commercial restrictions on the availability of information meant that the scope had to be widened to include some new installations where the techniques could also, in principle, be applied as retrofits.

Case Descriptions

Operators of offshore installations and equipment suppliers were approached and asked to supply information on offshore installations with reduced emissions of greenhouse gases. Five cases were selected, representing a wide range of emission reduction techniques. The operators provided descriptions of their installations and data on greenhouse gas emissions reduction and other changes and benefits, including safety and emissions of non-greenhouse gases. In all cases the operators were unwilling to divulge cost information as this was regarded as commercially sensitive. Woodhill Engineering has estimated the costs of the retrofits, using their extensive experience in the offshore oil and gas industry, and has asked the operators for their comments. In four of the cases the operators were willing to approve and in some cases provide more accurate cost data after Woodhill provided them with a baseline.

The cases studies are summarised in the following table:

Table 1 Summary of case studies

Technique	Field/installation	Country	Operator
Treatment and export of associated gas	Roller/Skate fields	Australia	WAPET
CO_2 capture and underground sequestration	Sleipner	Norway	Statoil
Flare gas recovery retrofit	Gullfaks A and C	Norway	Statoil
Gas turbine combined cycle retrofit	Snorre B and TLP	Norway	Saga Petroleum
Process optimisation	Åsgard B	Norway	Statoil

Four of the five installations are in the Norwegian sector of the North Sea. This is partly because this area is at the forefront of developments in offshore technology in general and partly because there is a CO_2 emission tax in the Norwegian offshore sector, which has stimulated the development of techniques for reduction of greenhouse gas emissions. The techniques developed in the North Sea could be applied to many other offshore oil and gas production locations. The case studies cover a wide range of oil and gas production rates, ranging from 9,000 barrels per day for the Roller/Skate fields to 504,000 barrels per day for the Gullfaks field.

Brief descriptions of the individual cases are presented below.

1) Treatment and export of associated gas

This project is in the Roller and Skate fields, situated about 6 km from the mainland coast of Western Australia, 1200 km north of Perth. The average water depth is 9 metres. The field is operated by West Australian Petroleum (WAPET) as a joint venture on behalf of participants Shell, Chevron, Texaco and Mobil.

The original Roller/Skate design proposed that the associated gas would be flared. A gas marketing strategy was adopted later as a consequence of higher estimated gas reserves and pressure from the State Government. The sales gas project required the addition of a 16 kilometre pipeline, a gas treatment package and gas compression. As a result, annual emissions of CO_2 that would have been produced by the flare were avoided.

2) CO_2 capture and underground sequestration

This project concerns production from the Sleipner field in the Norwegian sector of the North Sea. Gas from the Sleipner Vest field contains 9% CO_2 but, for sale, the CO_2 content must be reduced to a maximum of 2.5% . The normal practice would be to vent the CO_2. Excess CO_2 is separated on the Sleipner T platform by amine absorption. CO_2 from amine regeneration is passed to the Sleipner A platform, from where it is injected into the Utsira formation, a saline aquifer about 800m below the seabed. The amine absorption unit is not considered to be part of this case study, as it would be required anyway to meet the sales gas specification. Only the costs of injection into the underground reservoir are considered. CO_2 injection is part of the original Sleipner platform design.

3) Flare gas recovery retrofit

This case study considers flare gas recovery on two platforms, A and C, in the Gullfaks field, in the Norwegian sector of the North Sea. On most offshore platforms some gas needs to be flared to ignite emergency discharges. The flare gas recovery system on the Gullfaks platforms avoids continuous flaring by isolating the flare system and injecting the recovered gas into the gas export line. In the event of an emergency requiring blowdown, a valve opens in the flare line allowing the gas into the flare stack. To ignite the flare, a pellet is fired at the flare tips. The pellet hits a striker plate and explodes, showering the tips with sparks. This flare gas technology was developed by Statoil and is marketed by Umoe Process Technology. Gullfaks was the first installation of this technology; more recent projects have benefited from a significant reduction in cost. The Gullfaks flare gas recovery scheme was a retrofit and costs should be lower if it was part of an original platform design.

4) Combined cycle gas turbine retrofit

The Snorre field in the Norwegian sector of the North Sea is currently produced using a Tension Leg Platform (TLP). In 2001 a new platform, Snorre B, will be installed to exploit the southern sector of the field. Snorre B will include a combined cycle power generating system consisting of two 29 MW gas turbines and a 16 MW steam turbine. Some of the power from Snorre B will be exported via a sub-sea cable to Snorre TLP. This will facilitate the decommissioning of a 22 MW open-cycle gas turbine on Snorre TLP. The combined cycle unit on Snorre B will have a higher efficiency than the open-cycle gas turbine on Snorre TLP so there will be a significant reduction in fuel gas consumption and greenhouse gas emissions.

5) Process optimisation

The Åsgard development is 260 km off the Norwegian cost, north west of Trondheim. The production facilities cover the world's largest subsea field, with reserves of 830 million barrels of crude, condensate and natural gas liquids and 212 billion m^3 of gas. The Åsgard development includes three production and storage units. Åsgard B is a semi-submersible platform, intended for gas production, which is expected to start producing in the year 2000. A number of energy efficiency and emissions reduction features have been included in the design of Åsgard B to reduce greenhouse gas emissions. Costs and emissions reductions for the following features were evaluated:

- Condensate stabilisation and heat integration
  The Åsgard development uses heat instead of pressure for condensate stabilisation (boiling off the lighter hydrocarbon components of the condensate mixture, to allow the liquid to be kept at ambient conditions with minimal evaporation). This saves re-compression power of 10 MW. Extensive heat integration has been installed to reduce the requirements for heating the condensate to stabilise it and for product cooling.

- Gas export interstage cooling
  Interstage cooling is usually only installed on gas-export compressors having higher compression ratios than are used on Åsgard. The addition of an additional compact interstage cooler and scrubber reduced the compression power requirement by approximately 10 MW.

- Warmed coolant used to heat colder streams
  The cooling water return is used to provide pre-heating for gas production, saving 32 MW of heat which would normally be provided by fired heaters.

- Optimised sea -water -lift pump location
  Optimised location of the sea-water -lift pumps provided a saving of 70m in the pump head requirement. This reduces the pump power requirement by 2.2 MW.

Other significant emissions reduction features were also included in the Åsgard design, including flare gas recovery, use of selective amine and 'ReadCycle' glycol regeneration. The operator did not provide emissions reduction data for these features, so they are not included in the case study. Flare gas recovery on a different offshore installation is the subject of another case study in this report.

Emerging technologies

In addition to the case studies, a brief review was carried out of emerging technologies that could be used for future retrofits to reduce greenhouse gas emissions. The following technologies were briefly described:

- Air bottoming cycle
- ReadCycle glycol regeneration
- Membrane gas/liquid contactors
- Pre-combustion decarbonisation
- Combustion of fuel with recycled CO_2
- Conversion of hydrocarbon gas to methanol
- Sequestration of CO_2
- Flare tip efficiency

As these technologies are progressed, more information is likely to become available, thus allowing their viability to be assessed.

Results and Discussion

Emissions reduction

The annual emissions reductions for each of the cases are summarised in figure 1. Percentage emissions reductions are shown in figure 2.

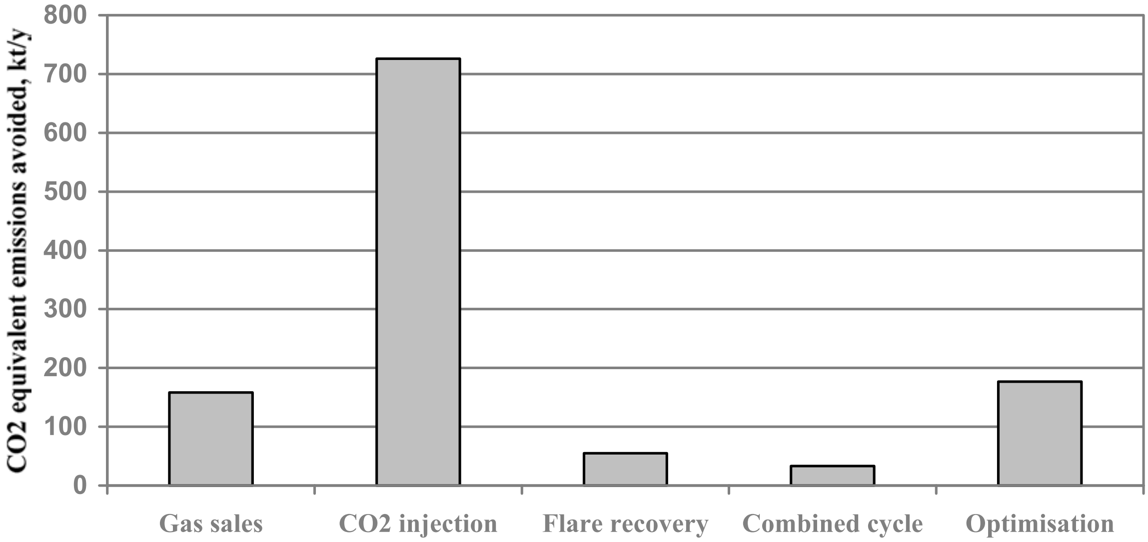


Figure 1 Annual emissions reductions

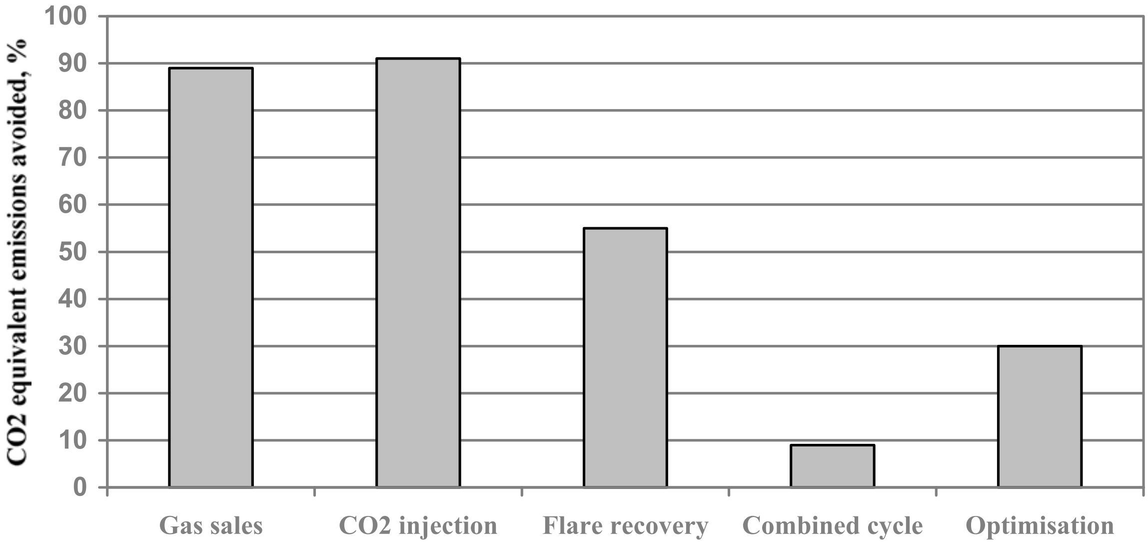


Figure 2 Percentage emissions reductions

The largest emissions reduction is achieved by the Sleipner project. Annual CO_2 emissions are reduced by more than 700 kt. The other cases have smaller but nevertheless significant emissions reductions, particularly in percentage terms.

In all of the cases the main emissions reduction was for CO_2. Emissions of non-CO_2 greenhouse gases were converted to a CO_2-equivalent basis using IPCC's relative global warming potentials. Conversions were calculated for the three time horizons used by IPCC, i.e. 20, 100 and 500 years. The data quoted in this summary are based on a 20 year horizon. If a 500 year horizon were used, the CO_2-equivalent emissions would change by a maximum of 2.3%.

Costs

Costs of greenhouse gas emissions reduction in US$ per tonne of CO_2-equivalent were calculated using IEA GHG's normal levelised cost basis. These costs are summarised in figure 3. Three annual discount rates were used in the report; 10% (IEA GHG's standard), 5% (IEA GHG's normal sensitivity case) and

12% (to represent the higher discount rates normally used in the oil and gas production industry). Figure 3 shows costs at a 10% discount rate. A comparable graph based on 5% discount rate is included in the main report. Costs are also presented on a net present value (NPV) basis in the main report, as offshore operators may be more familiar with this basis.

There is a CO_2 emissions tax of about $55/tonne in the Norwegian offshore oil and gas sector. The costs for the Norwegian case studies are presented with and without this tax. The costs with the tax are the actual project costs. The costs without the tax give an indication of what the costs would be in other countries where there are no CO_2 taxes.

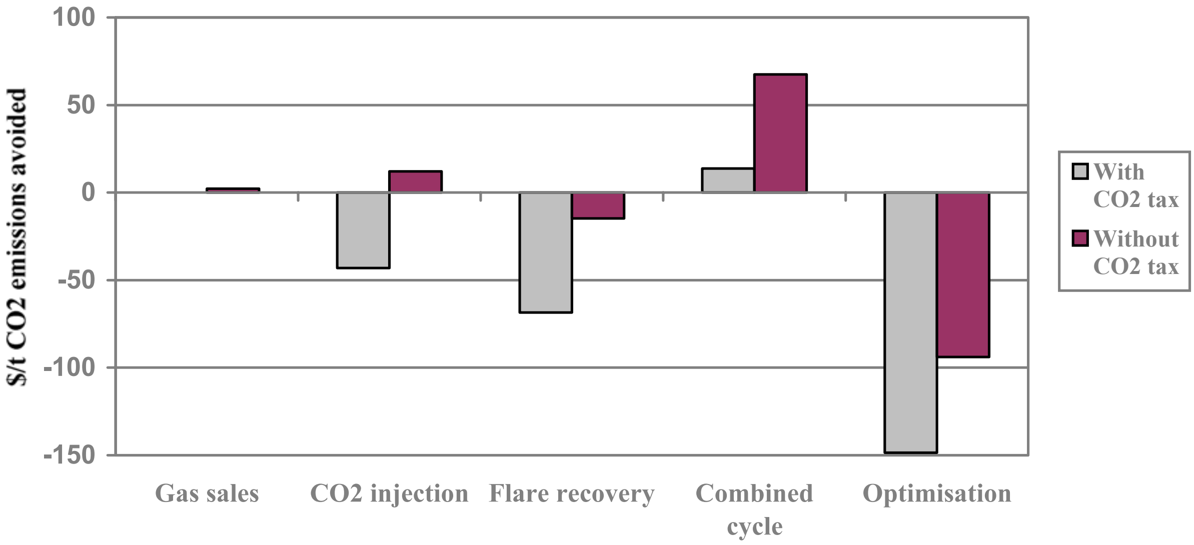


Figure 3 Costs per tonne of CO_2–equivalent emissions avoided

The sale of gas that would otherwise be flared at the Roller/Skate field shows a very small net cost of emissions avoided. The Sleipner CO_2 sequestration project has a cost of about $10/tonne of CO_2 emissions avoided but after allowing for avoidance of the Norwegian CO_2 emissions tax there is a net saving of about $45/tonne. The flare gas recovery scheme at the Gullfaks field results in a cost saving of about $15/tonne of CO_2-equivalent emissions avoided, rising to about $70/tonne after allowing for avoidance of the Norwegian emissions tax. The combined cycle retrofit at the Snorre field has a net cost of emissions avoidance of nearly $15/tonne, even after allowing for avoidance of the emissions tax. This project is, however, economically attractive at a 5% discount rate. The various process optimisations at the Åsgard field are the most economically attractive of the case studies. These options result in cost savings between 75 and 120 $/tonne of CO_2-equivalent emissions avoided; the average saving is about $95/tonne; this rises to about $150/tonne after allowing for avoidance of the Norwegian emissions tax.

Expert Group Comments

The individual case studies were passed to the project operators for comment and approval. The draft version of this overall report was then passed to IEA GHG's own expert reviewers. Seven of these experts, mainly in the oil industry, provided comments. The general opinion of these experts was favourable and most of the comments were editorial or points of detail. The contractor took these comments into account as far as practical when preparing the final report.

Major Conclusions

The following conclusions may be drawn from the case studies.

- A variety of techniques are available for reduction of greenhouse gas emissions from offshore oil and gas installations.

- Most of the cases in this study result in cost savings or small net costs of greenhouse gas emissions avoidance.

- The least cost means of reducing greenhouse gas emissions offshore was found to be optimising platform process design in the Åsgard B case study.

- In Norway, which is the only country to have introduced an offshore CO_2 emission tax, avoidance of paying the CO_2 emission tax is a significant factor in improving the cost benefits for the operator, associated with reduction of CO_2 emissions offshore.

- Reducing emissions of greenhouse gases also tends to reduce emissions of non-greenhouse gases. This may have benefits with respect to other environmental sensitivities.

- As a number of the measures considered in these case studies represent the first installation of a given technology, it is reasonable to assume that future use of the technologies will be more cost efficient, thereby increasing the attractiveness to offshore operators.

- In general, greenhouse gas emission reduction measures introduced to 'new builds' are expected to cost less than retrofits but these case studies serve to demonstrate the range of possible techniques available

- While a number of technologies to reduce greenhouse gas emissions are currently under development, commercial sensitivities tend to discourage manufacturers from providing detailed information. As these technologies are progressed, more information is likely to be available, thus allowing their viability to be assessed.

Recommendations

- A follow-on study could be carried out to produce case comparable studies for on-shore oil and gas production. Before starting such a study, it would be necessary to ensure that information could be obtained from operators of oil and gas production facilities. Active support from IEA GHG's oil industry sponsors and supporters would be needed to obtain the required information.

- Explore with the IEA CADDET Agreement (which focuses on demonstrated energy efficiency technologies), whether there would be merit in making joint presentations of these case studies for greenhouse gas abatement with some of CADDET's studies on energy efficiency improvements.

DOCUMENT SUBMITTED TO

IEA GREENHOUSE GAS R&D PROGRAMME

CASE STUDIES OF GREENHOUSE GAS ABATEMENT OFFSHORE POTENTIAL RETROFIT TECHNOLOGIES

PREPARED BY

WOODHILL

CASE STUDIES OF GREENHOUSE GAS ABATEMENT OFFSHORE

POTENTIAL RETROFIT TECHNOLOGIES

submitted to

IEA Greenhouse Gas R&D Programme
CRE Group Limited
Stoke Orchard
Cheltenham
Gloucestershire GL52 4RZ

by

Woodhill Engineering Consultants
St Andrew's House
West Street
Woking
Surrey GU21 1EB
Tel: +44 1483 717600
Fax: +44 1483 717630
www.woodhill.co.uk

CONTENTS **PAGE**

LIST OF KEY FIGURES AND TABLES

Section 4

ABBREVIATIONS

ABC	Air Bottoming Cycle
AAF	Average Annual Fatalities
AFR	Average Fatality Rate
AIR	Average Individual Risk
AUS$	Australian Dollars
BBL	Barrels
BCF	Billions (10^9) Standard Cubic Feet
BPD	Barrels per Day
BTX	Benzenes, Toluenes and Xylenes
DNV	Det Norske Veritas
EPC	Engineering, Procurement and Construction
FPSO	Floating Production, Storage and Offloading Facility
FWKO	Free Water Knock out
GWP	Global Warming Potential
HFCs	Hydro-fluorocarbons
hp	Horse Power
HP	High Pressure
HIPPS	High Integrity Pressure Protection System
IEA	International Energy Agency
IEA-GHG	International Energy Agency Greenhouse Gas
KO	Knock Out
LP	Low Pressure
MBPD	Thousands of Barrels per Day
MMBBLS	Millions of Barrels
MMBPD	Millions of Barrels per Day
MMSCF	Millions of Standard Cubic Feet
MMSCFD	Millions of Standard Cubic Feet per Day
MW	Mega (10^6) Watts
NAC	Net Annual Cost
NAS	Net Annual Saving
NGL	Natural Gas Liquids
NOK	Norwegian Kroner
NO_x	Nitrogen Oxides
NPV	Net Present Value of Investment
OLF	Oljeindustriens Landsforening - The Norwegian Oil Industry Association
psig	Pounds per Square Inch Gauge
PSV	Pressure Safety Valve
R&D	Research and Development
QRA	Quantified Risk Assessment
SCF	Standard Cubic Feet
Sm^3/d	Standard Cubic Metres per Day
SO_x	Sulphur Oxides
t/d	Tonnes per Day
t/y	Tonnes per Year
TLP	Tension Leg Platform
VOCs	Volatile Organic Compounds

SUMMARY

The purpose of this study is to provide information to operators on measures currently available for reducing the emission of greenhouse gases from offshore installations. This has been achieved by selecting a number of case studies where platform design or modifications have resulted, or will result, in reduced greenhouse gas emissions. The measures for emissions reduction were evaluated in terms of the net present value (NPV) and the net annual cost/saving (NAC/S) per equivalent tonne of CO_2 emissions avoided. A summary of each of the five case studies is presented below.

Case 1 reviewed the installation of gas treatment and export/injection facilities for the Roller and Skate Fields. The forecast reduction in greenhouse gas emissions is equivalent to 482 t/d CO_2 in a 20 year time horizon. The net annual saving of the project, based on 12 years remaining field life, and a 5% interest rate, is estimated at US$ 0.33 million. This is equivalent to savings (US$/tonne CO_2 emission avoided) of 2.08 over a 20 year time horizon. The project does not have the benefit of a CO_2 tax incentive.

Case 2 reviewed the separation, compression and injection of CO_2 into an aquifer formation in the Statoil Sleipner Field. This has resulted in a reduction in greenhouse gas emissions equivalent to 2011 t/d CO_2 in a 20 year time horizon. The net annual saving of the project based on 10 years remaining field life and a 5% interest rate, is estimated at US$ 32.22 million with a CO_2 tax incentive, and a net annual cost of US$ 7.80 million without a CO_2 tax. This is equivalent to a net annual saving (US$/equivalent tonne CO_2 emission avoided) of 44.38 with a CO_2 tax and a cost of (10.74) without a CO_2 tax over a 20 year time horizon. CO_2 injection was part of the design concept for Sleipner. The reduction in greenhouse gas emissions is based on a comparison with emissions which would have occurred had the CO_2 been vented.

Case 3 reviewed the retrofit of a flare gas recovery system to remove the need for continuous flaring at the Statoil Gullfaks A and C Platforms. This has resulted in a reduction in greenhouse gas emissions equivalent to 158 t/d CO_2 in a 20 year time horizon. The net annual saving of the project based on 15 years remaining field life and a 5% interest rate, is estimated at US$ 4.20 million with a CO_2 tax and US$ 1.23 million without a CO_2 tax. This is equivalent to a saving (US$/equivalent tonne CO_2 emission avoided) of 75.97 with a CO_2 tax and 22.18 without a CO_2 tax over a 20 year time horizon. This was the first installation of this technology and more recent projects have seen significant reduction in costs.

Case 4 reviewed the installation of a power transmission cable from the combined cycle generator on the new Saga Petroleum Snorre B facility to the existing Snorre tension leg platform (TLP). This will enable the decommissioning of a gas turbine on Snorre TLP resulting in a reduction in greenhouse gas emissions equivalent to 93 t/d CO_2 in a 20 year time horizon. The net annual cost/saving of the project based on 20 years remaining field life and a 5% interest rate, is estimated at US$ 0.70 million with a CO_2 tax and US$ (1.05) million without a CO_2 tax. This is equivalent to a saving (US$/equivalent tonne CO_2 emission avoided) of 21.57 with a CO_2 tax and (32.20) without a CO_2 tax over a 20 year time horizon.

Case 5 reviewed the process design optimisation of the Statoil Åsgard B semi-submersible. The forecast reduction in greenhouse gas emissions is equivalent to 506 t/d CO_2. The net annual saving of the project based on 18 years remaining field life and a 5% interest rate, is estimated at US$ 26.33 million with a CO_2 tax and US$ 16.64 million without a CO_2 tax. This is equivalent to savings (US$/tonne CO_2 emission avoided) of 148.73 with a CO_2 tax and 94.01 without a CO_2 tax.

This study also presents a brief overview of technologies which are currently being developed and which may, in the future, provide alternative means of reducing offshore greenhouse gas emissions. It should be noted that manufacturer information on some processes was limited due to the commercial sensitivity of such information.

Table 1 Conversion Factors

Typical Oil and Gas Industry Units	S.I. Units
1 SCF	0.0283168 m^3
1 bbl	0.159 m^3
1 tonne	1000 kg

1. INTRODUCTION

Emissions of greenhouse gases resulting from man's activities are generally thought to be causing harmful global climate change. The International Energy Agency Greenhouse Gas (IEA GHG) Research and Development (R&D) programme was established in 1991 to evaluate technologies that can be used to mitigate greenhouse gas emissions from the use of fossil fuels and identify target areas for useful R&D. It is an international organisation supported by fifteen countries world-wide, the European Commission and several industrial organisations.

The offshore oil and gas industry emits significant quantities of greenhouse gases. Methane emissions occur at most stages of production and use. Emissions from the offshore oil industry are primarily due to power generation and the venting or flaring of unused associated gas. The contribution from oil transportation, refining and distribution is relatively small. Emissions from the natural gas industry are larger than those from the oil industry. One of the largest contributors comes from gas compression, required in the production and transportation of gas. Current emissions are estimated to be 47 million t/y CO_2, which are expected to rise to 78 million t/y CO_2 by the year 2025.

In recent years, some offshore installations and design practices have undergone modifications, which have reduced emissions of greenhouse gases. This study contains five case studies where a reduction in greenhouse gas emissions has been or will be achieved either by platform modifications or improved design features on new facilities. Typical measures considered were; separation and re-injection of CO_2 gas, re-injection or export of previously flared gas and improved power generation efficiency.

The case studies are presented in Section 3 of this report. The purpose of the case studies is to make available knowledge about options for reducing emissions, with confidence that the technology exists and can be effectively used. Each offshore installation case study has been analysed and considered on a common basis. Each case study contains:

- a description of the field and platform before the modification;
- a description of the modifications;
- an analysis of the reduction in emissions;
- the net costs of carrying out the modifications;
- cost per equivalent tonne CO_2 emission avoided;
- any other changes and benefits which were identified.

This report also contains some information on emerging technologies currently being developed which may allow reduced emissions of greenhouse gases in the future. This is presented in Section 4.

Section 5 presents the conclusions of the study.

2. SCOPE OF WORK AND BASE DATA

2.1 Scope of Work

The scope of work is in accordance with the International Energy Agency (IEA) Technical Specification.

This scope of work had to be modified as a result of the limited data available from the operators. This required in-house cost estimation of the modifications rather than use of installation specific cost data. Each case study was reviewed by the operator, whose permission was obtained for release of the information presented.

2.2 Emissions Data

Where data were available, reductions in the following greenhouse gases were quantified: CO_2, CH_4, N_2O.

The effectiveness of these compounds in contributing to global warming is typically measured relative to CO_2 and is referred to as the compound's global warming potential (GWP).

Since the relative GWP for each gas is dependent on the average residence time in the atmosphere, the GWP is presented for three time horizons: 20, 100 and 500 years.

The relative GWP used to assess each Case Study was provided by IEA and is presented in Table 2.1.

In addition to greenhouse gas emissions, reductions in emissions of non-greenhouse gases such as volatile organic compounds (VOCs), Benzenes, Toluenes and Xylenes (BTX), NO_x, SO_x, H_2S, CO, HFCs, SF_6 or others were recorded where data were available.

2.3 Retrofit Data

Potential offshore installation modifications that would result in lower greenhouse gas emissions include:

- Use of flaring to reduce emissions of CH_4.
- Reduction or avoidance of flaring to reduce CO_2 emissions.
- Re-injection of associated gas for storage, future recovery or improved oil production.
- Export of gas to shore instead of venting or flaring.
- Separation of CO_2 from production gases or from flue gases and re-injection for long term storage or to increase production.
- Installation of more efficient rotating equipment; e.g., turbines, pumps, compressors etc.
- Transmission of electricity to offshore platforms from more efficient generators onshore.

2.4 Selection of Case Studies

The selection of case studies was based on:

- Suitability of retrofit.
- Adequacy and detail of information provided.
- Project originality.

The following five case studies are presented in Section 3:

1. Western Australian Petroleum, Roller/Skate Fields, Treatment and Export/Injection of Associated Gas.
2. Statoil Sleipner Platform, Separation and Injection of CO_2.
3. Statoil Gullfaks Field, Flare Gas Recovery System.
4. Saga Petroleum, Snorre B Project, Combined Cycle Gas Turbine.
5. Statoil Åsgard B Semi-Submersible Installation, Process Optimisation.

2.5 Near Operational Technologies

A brief review of near operational technologies to reduce offshore greenhouse gas emissions was produced from public domain data and information provided by IEA. This is presented in Section 4. It should be noted that due to commercial sensitivity associated with this information, manufacturers were generally reluctant to provide specific data.

2.6 Basis of Assessments

Each case study listed in Section 2.4 was assessed on a common basis.

The following information is included in each case study:

- An introduction presenting the location of the installation and a brief overview of the associated facilities and operations.
- A description of the installation facilities prior to modification.
- A description of the modification.

  These were all sourced from the operator and, where necessary, public domain sources.

- An assessment of the reduction in greenhouse gas emissions as a result of the modification.

  Where an operator has not supplied full emissions data, the emissions have been estimated. Each estimate uses the standard emission factors from Oljeindustriens Landsforening (OLF), which are presented in Table 2.2.

In most of the case studies, the figures for fuel usage only consider the change in quantity as a result of the modification. They do not include the constant base line usage.

Emissions of greenhouse gases other than CO_2 have been converted to a CO_2 equivalent using the relative global warming potential factors presented in Table 2.1.

- Where relevant, an assessment of any safety implications resulting from the modification.

- A description of any site specific factors affecting the potential for retrofit to other installations.

- A cost analysis including:

    - capital costs;
    - changes to operating costs;
    - income from increased production rates;
    - costs associated with plant downtime for modifications;
    - increased revenue from CO_2 tax avoidance.

For each case study, the project economics were assessed using two methodologies. Initially the project net present value (NPV) per equivalent tonne CO_2 emission avoided was calculated. The NPV calculation discounts the annual costs and revenues to the present and adds that to the capital cost to give a total project NPV.

In addition to the project NPV, the net annual cost/saving per equivalent tonne CO_2 emission avoided was calculated. An annual capital charge was calculated and this was added to the incremental annual operating cost/saving to give a net annual cost/saving. (The NPV and net annual cost/saving is shown in ( ) when the value is negative, ie. a cost).

To ensure that the cost analysis for each case study was completed on a similar basis the economic data presented in Table 2.3 were used for each of the case studies. The economic data used are third quarter 1998.

In cases where cost data were not supplied by the operator, cost estimation methods were used to predict a cost for the modifications. The cost data for these estimates were based on historical data or supplied by vendors/manufacturers.

It should be noted that a number of the case studies are for new or proposed installations and therefore, the CO_2 reduction measures are not modifications to the facility but form part of the original design. In these cases the incremental costs of the associated purchase and installation of more efficient and environmentally friendly equipment are compared with those for more traditional equipment.

Table 2.1 Relative Global Warming Potential, Per Unit Mass

Greenhouse Gas	20 Years	100 Years	500 Years
CO_2	1	1	1
CH_4	56	21	6.5
N_2O	280	310	170

Table 2.2 Standard Emission Factors

Component	Factor (kg/SCF gas burnt)
CO_2	6.60 E-02
CH_4	2.65 E-05
SO_x	0
NO_x	2.53 E-04
CO	4.81 E-05

Table 2.3 Economic Data

Interest Rates	5%, 10%, 12%
Gas Price	0.0031 US$/SCF 2.76 US$/GJ
Oil Price	12 US$/BBL
Diesel Price	27 US$/BBL
Exchange Rates	7.7 NOK/US$ 1.65 US$/UK£
CO_2 tax	55 US$/tonne CO_2 emitted

3. CASE STUDIES

3.1 Case Study 1

Operator: West Australian Petroleum (WAPET)
Installation: Roller/Skate Fields
Technology: Treatment and export/injection of associated gas.

SUMMARY

The original Roller/Skate design proposed that the associated gas would be flared. By including facilities for separation, treatment and compression of associated gas it can be sold or injected into the reservoir formation. The reduction in flaring leads to a reduction of greenhouse gas emissions equivalent to 482 t/d CO_2 in a 20 year time horizon. The project economics have been assessed using net present value (NPV) per equivalent tonne CO_2 emission avoided. In addition an annual capital repayment has been calculated and added to the incremental annual operating cost/saving to give a net annual cost/saving per equivalent tonne CO_2 emission avoided.

Based on a 12 year remaining field life and a 5% interest rate, the project NPV is US$ 2.92 million. This corresponds to US$ 1.54 per equivalent tonne CO_2 emission avoided. Using the same field life and interest rate, the net annual saving (NAS) is US$ 0.33 million, which corresponds to US$ 2.08 per equivalent tonne CO_2 emission avoided.

There is no carbon tax in Australia, and therefore this has not been considered in the analysis.

3.1.1 Introduction

The Roller/Skate oil field is situated offshore within the Carnarvon Basin, 1,200 kilometres north of Perth, Australia. The field is located 22 kilometres south of the production facilities at Thevenard Island and 6 kilometres from the mainland coast of Western Australia. The Skate reservoir is located 1 kilometre northeast of the Roller reservoir. The average water depth over the field is 9 metres. The field location is shown in Figure 3.1.1.

The field is operated by West Australian Petroleum (WAPET) as a joint venture on behalf of participants Shell, Chevron, Texaco and Mobil.

The Roller reservoir was discovered in January 1990. A total of five appraisal wells, five deviated delineation wells and six horizontal development wells were drilled into the Roller reservoir.

The Skate reservoir was discovered in October 1991. A total of two appraisal wells, one deviated delineation well and three horizontal development wells were drilled into the Skate reservoir.

The original oil in place at Roller is 54 million barrels and original gas in place is 7 billion cubic feet. The original oil in place at Skate is 23 million barrels and original gas in place is 11 billion cubic feet. (Gas in place estimates includes free gas only.)

The facilities screening study proposed flaring all produced gas from the Roller/Skate field. This was partly due to the relatively small amount of gas in place (as determined at the time), and the high cost for the construction of a gas treatment plant and an additional 16 kilometre pipeline to market the gas. At the time Roller/Skate original oil in place was 44 million barrels and original gas in place was only 1 billion cubic feet.

Gas in place estimates increased as a result of interpretation of new 3-D seismic data. A gas marketing strategy was then adopted as a consequence of both the upgrade and also because of pressure from the State Government.

3.1.2 Description of Facilities

Each production well is tied back to one of four monopod production platforms, which are equipped with a test separator and corrosion control equipment. Figure 3.1.2 shows the Skate monopod production platform. Produced fluids are commingled and piped through a 20” production line to separation facilities on Thevenard Island. Produced oil is sent to an offshore tanker-loading buoy to the north of the island, and produced water is injected into a formation approximately 2,600 feet beneath the island. Before the decision to proceed with a sales gas project, the associated gas was to be flared.

3.1.3 Description of Modification

The sales gas project required addition of the following facilities:

- 16 kilometre, 6” pipeline.
- Gas treatment package to meet sales gas specifications.
- Gas compression.

The gas is used for gas-lift, injection and sales gas. The injection gas is injected into the nearby Saladin field and the Roller reservoir and some gas is used for gas lift. The sales gas is exported to shore through a 6 inch gas line from Thevenard Island.

The gas treatment package is installed between the second and third stages of the K-105/K-106 Roller compressors. It has a capacity of 20 million standard cubic feet per day. The package consists of hydrogen sulphide removal, glycol dehydration, hydrocarbon dewpoint control (using propane refrigeration) and mercury removal facilities. There is also a slot available to install a carbon dioxide treatment package (using an amine process) within the existing gas treatment package.

3.1.4 Reduction in Greenhouse Gas Emissions

The inclusion of sales gas facilities reduces greenhouse gas emissions. These have been quantified as the CO_2 that would normally be produced by flaring, less that generated by burning the fuel gas required to power the compressors.

The hydrocarbon production and consumption data are shown in Table 3.1.1. The corresponding greenhouse gas emission data are shown in Table 3.1.2.

Without sales gas export, the facility would have an equivalent CO_2 emission rate of 542 t/d.

The inclusion of the sales gas facilities reduces the equivalent CO_2 emissions to 59.9 t/d, which comprises 58.6 t/d CO_2, and CH_4 emissions equivalent to 1.31 t/d CO_2, on a 20 year time horizon. These emissions are estimates based on the emission factors presented in Table 2.2 and 35% thermal efficiency in the gas turbines used to drive the compressors.

Therefore, the inclusion of sales gas facilities reduces equivalent CO_2 emissions by 482 t/d CO_2 on a 20 year time horizon.

Emissions of non-greenhouse gases with and without sales gas export facilities are shown in Table 3.1.3 and are further discussed in Section 3.1.6.2.

3.1.5 Net Cost of Modification

The additional costs associated with including sales gas facilities are for the 16 km 6” gas export pipeline, the additional compressor requirement and the gas treatment package. WAPET were unable to provide cost data, therefore the costs have been developed on behalf of the IEA using historical cost data for similar modifications and vendor supplied cost data.

The cost of the installed pipeline is estimated as approximately US$ 12.8 million. The gas treatment system is estimated to cost approximately US$ 7.0 million.

The annual operating costs associated with the compressors and gas treatment package, not including fuel gas, are estimated as US$ 4.75 million, and are shown in Table 3.1.5. The operating costs comprise: an annual lease cost of US$ 1.0 million for the gas compression unit; US$ 0.6 million each year for chemicals (scavengers, glycol, methanol etc.); and US$ 3.15 million for the additional personnel required to operate the gas compression, treatment, injection and export facilities.

The cost of fuel gas required to drive the compressor was estimated as US$ 0.91 million per annum, based on an export sales gas value of US$ 0.0031/SCF. The costs/savings are presented in Table 3.1.6.

The net annual cost/saving associated with the project has been assessed. Using a 12 year field life and interest rates of 12%, 10% and 5%, the project would have a net annual saving (NAS) of US$ (0.63), (0.34) and 0.33 million respectively. The net annual cost/savings are presented in Table 3.1.7. Numbers in parentheses ( ) are negative numbers, ie. costs rather than savings.

The project net present value (NPV) was calculated using the same field life and interest rates. The figures are presented in Table 3.1.9. The NPVs for 12%, 10% and 5% interest rates are US$ (3.92), (2.34) and 2.92 million respectively.

3.1.6 Other Changes and Benefits

3.1.6.1 Operations

Eliminating gas flaring has not increased the field life or the reserves, in this case, but it has provided a greater degree of flexibility, and has reduced the company greenhouse gas emissions. The Saladin field will not require gas injection in the longer term, and therefore the facility to market gas will become more important in the future, for both economic and environmental reasons.

3.1.6.2 Emissions of Non-Greenhouse Gases

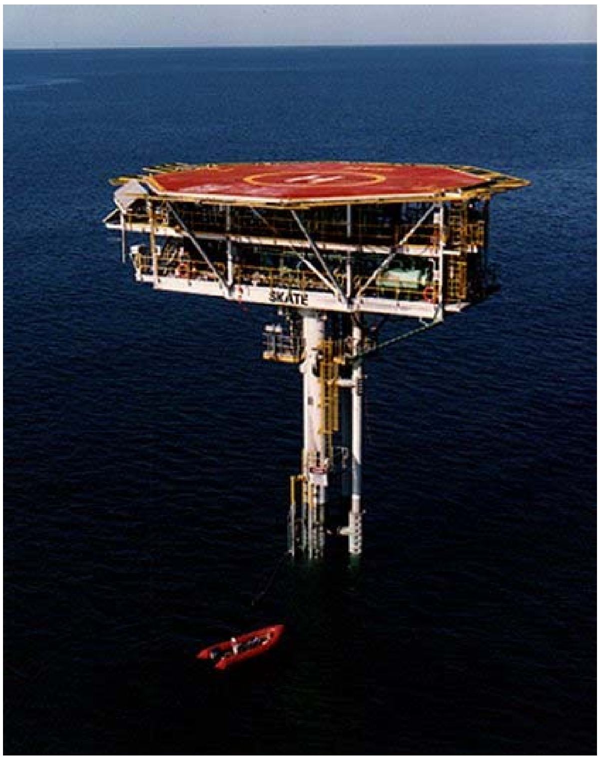
Table 3.1.3 presents non-greenhouse gas emissions (NO_x, SO_x and CO). The data are based on the standard emission factors presented in Table 2.2. The emissions of non-greenhouse gases are reduced as a result of the reduction in gas flaring.

3.1.7 Site Specific Factors

In this case, the gas treatment facilities have been installed on Thevenard Island, an existing onshore processing facility. If the facilities had to be installed on an offshore platform, the capital costs would likely be greater due to space and weight restrictions.

Figure 3.1.1: Location of Roller/Skate Fields

Figure 3.1.2: Skate Monopod Production Platform



3.2 Case Study 2

Operator: Statoil
Installation: Sleipner Project
Technology: Separation and Injection of CO_2.

SUMMARY

Separation, compression and injection of CO_2 into an aquifer formation in the Statoil Sleipner Field results in a reduction in greenhouse gas emissions equivalent to 2011 t/d CO_2 in a 20 year time horizon. The project economics have been assessed using net present value (NPV) per equivalent tonne CO_2 emission avoided. In addition an annual capital repayment has been calculated and added to the incremental annual operating cost/saving to give a net annual cost/saving per equivalent tonne CO_2 emission avoided. The project economics are also presented both with and without CO_2 tax.

Based on a 10 year remaining field life, a 5% interest rate and a CO_2 tax set at US$ 55/tonne CO_2 emitted, the project NPV is US$ 248.83 million. This corresponds to US$ 34.27 per equivalent tonne CO_2 emission avoided. Using the same field life, interest rate and CO_2 tax rate, the net annual saving (NAS) is US$ 32.22, which corresponds to US$ 44.38 per equivalent tonne CO_2 emission avoided. Without the imposed CO_2 tax, the project NPV is US$ (60.22) million corresponding to US$ (8.29) per equivalent tonne CO_2 emission avoided. Similarly, without the CO_2 tax, there is no net annual saving, and the net annual cost (NAC) is US$ (7.80) million, which corresponds to a cost of US$ (10.74) per equivalent tonne CO_2 emission avoided.

CO_2 injection was part of the design concept for Sleipner, therefore the reduction in greenhouse gas emissions is based on a comparison with emissions which would have occurred if the CO_2 had been vented.

3.2.1 Introduction

The Sleipner field is located in blocks 15/6, 15/8 and 15/9 of the Norwegian sector in the North Sea as shown in Figure 3.2.1. It lies near the UK/Norway border, approximately 240 km west of Stavanger, in a water depth of 80 to 110 m. The field is separated into two distinct areas, Ost and Vest. The CO_2 concentration in the reservoir gas exceeds the sales gas specification so the excess CO_2 is removed and injected into the Utsira aquifer formation. One of the major reasons for injection of the CO_2 gas is that CO_2 emissions are taxed in Norway. If the CO_2 gas from Sleipner was vented it would add 3% to Norway's total CO_2 emissions.

It should be noted that CO_2 injection was part of the original design concept for Sleipner. The CO_2 emission reduction assessment presented in this case study compares CO_2 injection with CO_2 venting which could have been an alternative option to meet sales gas requirements.

3.2.2 Description of Facilities

The field comprises six platforms: Sleipner A, T and R in the Ost field, and C, B and N in the Vest field. Figure 3.2.2 shows the three main platforms Sleipner A, T and B. Most processing is carried out on the Sleipner A platform. A major part of the gas produced from Sleipner Vest is reinjected in the Ost field to improve condensate recovery. The maximum export production rate in 1997 was 887 MMSCFD of sales gas and 141 MBPD of condensate.

The Sleipner Vest gas contains 9% CO_2, but the sales gas may only contain a maximum of 2.5% CO_2. The excess CO_2 is separated on the Sleipner T platform by amine absorption and then compressed for injection into a well drilled into an aquifer, refer to Figure 3.2.3. As outlined above, normal practice would be to vent the CO_2. Compressed CO_2 from Sleipner T crosses to the A platform, from which the CO_2 injection well has been drilled.

A maximum of one million tonnes of CO_2 per year can be injected into the aquifer, which is 1,000 m below the seabed and 3 km from the platform. Injection commenced in September 1996. This is the first use of this type of technology anywhere in the world.

3.2.3 Description of Modification

CO_2 injection is part of the original platform design, therefore no modifications have been carried out on the facility. The amine absorption unit is not considered as part of the CO_2 emission reduction system as it would also have been required to meet sales gas specifications.

3.2.4 Reduction in Greenhouse Gas Emissions

The inclusion of CO_2 compression and injection equipment in the design of the Sleipner platform has resulted in reduced greenhouse gas emissions, which can be quantified as the amount of CO_2 that would normally be vented less that generated by combustion of fuel gas required to power the CO_2 compressor.

The hydrocarbon production and consumption data for 1997, with CO_2 venting ‘prior to modification’ and without CO_2 injection ‘post modification’, are shown in Table 3.2.1. The corresponding greenhouse gas emission data are shown in Table 3.2.2.

Without CO_2 injection the facility would have vented CO_2 at an emission rate of 2216 t/d. This is based on the Sleipner 1998 data which show that 800,000 tonnes CO_2 were injected during the year at a production availability of 99%.

The inclusion of the CO_2 injection facility results in an equivalent CO_2 emission rate of 204.8 t/d, which comprises 200.3 t/d CO_2 and CH_4 emissions equivalent to 4.5 t/d CO_2, on a 20 year time horizon. These emissions are estimated based on the emission factors presented in Table 2.2 and fuel gas burned to power the compressor turbines, assuming a 35% thermal efficiency of the turbines.

Therefore, the inclusion of the CO_2 injection facility has resulted in a reduction in emissions equivalent to 2011 t/d CO_2 on a 20 year time horizon.

Emissions of non-greenhouse gases with and without CO_2 injection are shown in Table 3.2.3 and are further discussed in Section 3.2.6.2.

3.2.5 Net Cost of Modification

CO_2 injection was part of the original platform design, rather than a modification to an existing facility. The additional costs associated with inclusion of the CO_2 injection facilities in the design are the tie-in and installation of the CO_2 compressor and drilling of the injection well. Only the costs of the CO_2 disposal have been included. The costs of CO_2 capture have been excluded as the gas would have to be treated and the CO_2 partly removed before being exported to market whether or not there was CO_2 reinjection. Statoil were unable to provide cost data, therefore the costs have been developed on behalf of the IEA using historical cost data for similar modifications and vendor supplied cost data.

The estimated additional capital cost of the CO_2 injection facility is US$ 30.0 million as shown in Table 3.2.4. The annual operating costs associated with the compressors, not including fuel gas, are estimated at US$ 0.5 million to cover maintenance requirements and are shown in Table 3.2.5. Fuel gas costs are considered separately in Table 3.2.6.

Significant savings are obtained through avoidance of the CO_2 tax by not venting the gas, amounting to US$ 40.02 million based on a CO_2 tax of $55/tonne. The cost of fuel gas required to operate the CO_2 compressor was estimated as US$ 3.41 million, based on the export sales gas value of US$ 0.0031/SCF. The costs/savings are presented in Table 3.2.6.

The net annual cost/saving associated with the project has been assessed using a 10 year field life, interest rates of 12%, 10% and 5% and a CO_2 tax set at US$ 55/tonne CO_2 emitted. Taking credit for the CO_2 tax incentive, the project has a NAS of US$ 30.80, 31.23 and 32.22 million for each of the respective interest rates. Without the CO_2 tax, the project would have a NAC of US$ (9.22), (8.80) and (7.80) million respectively. The net annual cost/saving are presented in Table 3.2.7.

The project NPV was calculated using the same field life, interest rates and CO_2 tax level. The figures are presented in Table 3.2.9. The NPVs for 12%, 10% and 5% interest rates are US$ 174.03, 191.88 and 248.83 million respectively with a CO_2 tax incentive. Without a CO_2 tax incentive, the project NPVs are US$ (52.11), (54.05) and (60.22) million respectively. Numbers in brackets ( ) are negative numbers, ie. costs rather than savings.

3.2.6 Other Changes and Benefits

3.2.6.1 Development of Technology

As this project is the first of its kind, it will provide valuable data and operating experience for future developments.

3.2.6.2 Emissions of Non-Greenhouse Gases

Table 3.2.3 presents non-greenhouse gas emissions (NO_x, SO_x and CO). The data are based on the standard emission factors presented in Table 2.2. The emission of non-greenhouse gases increases slightly when CO_2 is injected due to the extra fuel requirement of the CO_2 injection compressor.

3.2.7 Site Specific Factors

Injection of CO_2 for other fields would depend on the availability of a suitable geological formation.

Figure 3.2.1: Location of Sleipner Field

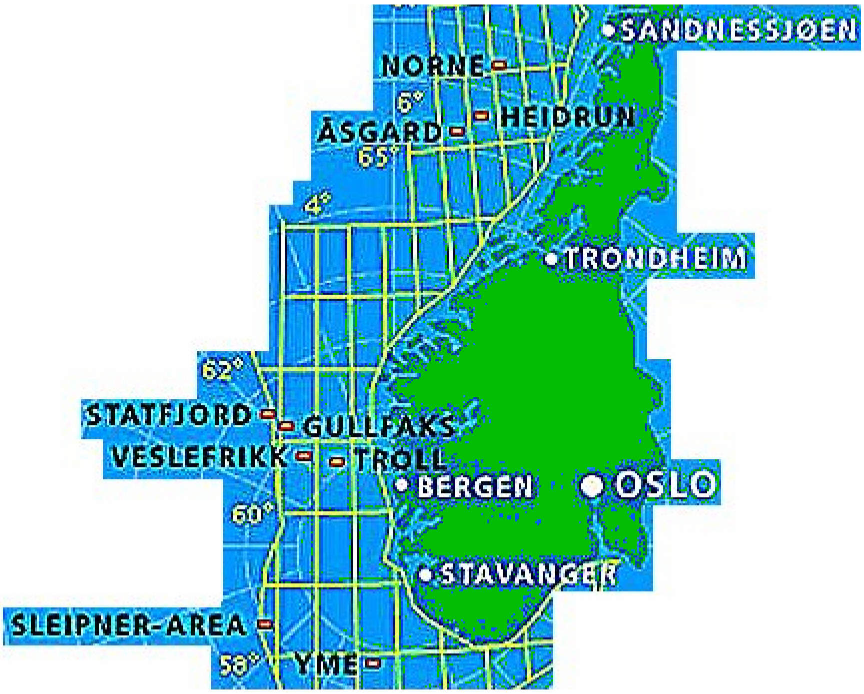


Figure 3.2.2: Schematic of Sleipner Development

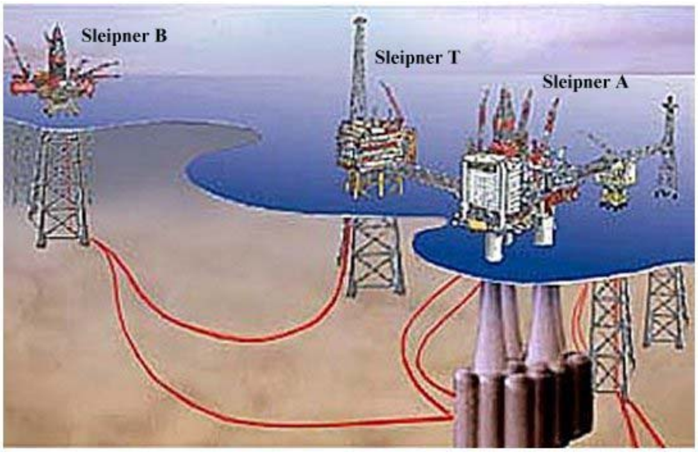
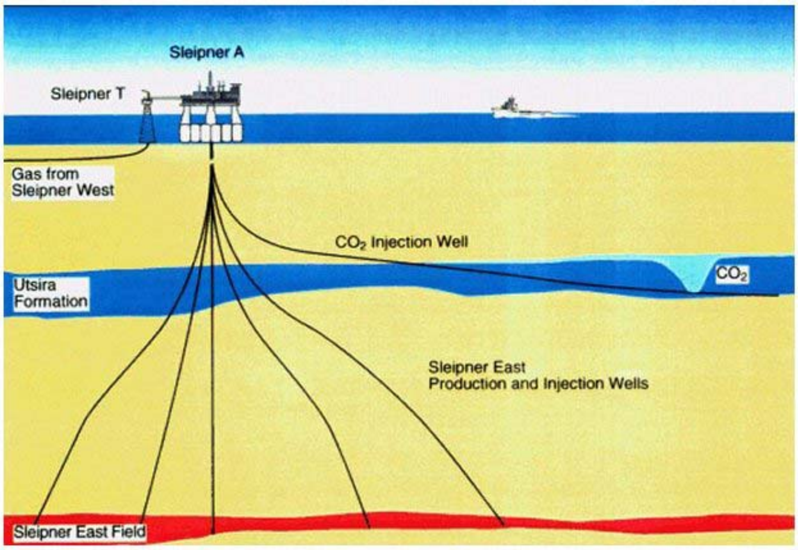


Figure 3.2.3: Cutaway of Sleipner Wells



3.3 Case Study 3

Operator: Statoil
Installation: Gullfaks A & C
Technology: Flare Gas Recovery System

SUMMARY

The retrofit of a flare gas recovery system to remove the need for continuous flaring at the Statoil Gullfaks A and C Platforms results in a reduction in greenhouse gas emissions equivalent to 158 t/d CO_2 in a 20 year time horizon. The project economics have been assessed using net present value (NPV) per equivalent tonne CO_2 emission avoided. In addition, an annual capital repayment has been calculated and added to the incremental annual operating costs/savings to give a net annual cost/saving per equivalent tonne CO_2 emission avoided. The project economics are also presented both with and without CO_2 tax.

Based on a 15 year remaining field life, a 5% interest rate and a CO_2 tax set at US$ 55/tonne CO_2 emitted, the project NPV is US$ 43.58 million. This corresponds to US$ 52.57 per equivalent tonne CO_2 emission avoided. Using the same field life, interest rate and CO_2 tax rate, the net annual saving is US$ 4.20 million, which corresponds to US$ 75.97 per equivalent tonne CO_2 emission avoided. Without the CO_2 tax incentive, the NPV is US$ 12.72 million, corresponding to US$ 15.35 per equivalent tonne CO_2 emission avoided. Similarly, without the CO_2 tax, the NAS is reduced to US$ 1.23 million, which corresponds to US$ 22.18 per equivalent tonne CO_2 emission avoided.

Gullfaks was the first installation to introduce this technology. More recent projects have benefited from a significant reduction in costs.

3.3.1 Introduction

The Gullfaks field is located in block 34/10 of the Norwegian sector of the North Sea in water depths of 135 metres (A/B) and 217 metres (C), as shown in Figure 3.3.1. The field consists of three concrete gravity base platforms. A and C are fully integrated drilling, production and accommodation platforms and Gullfaks B is a smaller producer with single stage separation. Further hydrocarbon processing is carried out on Gullfaks A. Gullfaks C receives production from the Saga Petroleum operated Tordis field. Gullfaks A has subsea satellite completions, see Figure 3.3.2, and there are plans for further development of the field. Oil is exported by tanker. Gas is exported via Statfjord C, through the Statpipe system to Kårstø, where the wet gas is separated and exported via the Ekofisk pipeline to Emden in Germany.

The Gullfaks A and C flare recovery packages were supplied by Umoe Process Technology AS, though the technology is owned by Statoil. This was the first use of this system, which removed the need for continuous flaring. The flare recovery and ignition system were commissioned in 1994.

3.3.2 Description of Facilities Prior To Modification

The Gullfaks field is produced from 71 wells (21 on A, 20 on B, 25 on C and 5 subsea wells producing to Gullfaks A). Further developments are planned, up to a total of 110 wells. Gullfaks A and C both have twin train, three stage separation. Gullfaks B has single stage separation, from where oil and gas are routed to the A platform for further processing. Gas from Gullfaks C is piped to Gullfaks A for export.

Gas is sent via a 14” pipeline to Statfjord C and into the Statpipe system to Kårstø. The gas is dried and then piped via the Ekofisk pipeline to Emden in Germany. Oil is stored in the base of both A and C platforms before offloading to tankers through two single point mooring systems.

3.3.3 Description of Modification

Both Gullfaks A and C have been retrofitted with a flare gas recovery system developed by Statoil and marketed by Umoe Process Technology AS. Gullfaks B does not have the system fitted, see Figures 3.3.3 and 3.3.4. The system avoids continuous flaring by isolating the flare system and injecting the recovered gas into the gas export line. In the event of an emergency requiring blowdown, a valve opens in the flare line allowing the gas into the flare stack. To ignite the flare, a pellet is fired at the flare tips. The pellet hits a striker plate and explodes, showering the tips with sparks. The system was installed in 1994 as the pilot installation of the technology.

The system has been designed to handle leakage of gas and small process upsets up to 6,000 kg/hr for high and low pressure systems.

The installation of flare recovery involved retrofitting the following equipment to the installations:

- Flare isolation valve.
- Crossover pipework (flare drum to gas export line).
- An ejector skid to increase the pressure.

In addition, the flare gas ignition package was installed. This involved the installation of two launching units on the deck and a striker plate on the flare.

3.3.4 Reduction in Greenhouse Gas Emissions

The inclusion of a flare gas recovery system on Gullfaks A and C has resulted in reduced gas flaring rates and therefore reduced greenhouse gas emissions. The hydrocarbon production and consumption data before and after the modification are shown in Table 3.3.1. The greenhouse gas emission data associated with gas flaring are shown in Table 3.3.2.

Prior to the modification Gullfaks A and C flares had an equivalent CO_2 emission rate of 287 t/d, which comprised 281 t/d CO_2, and CH_4 emissions equivalent to 6 t/d CO_2, based on a 20 year time horizon. This is based on an average flaring rate of 4.2 MMSCFD.

The flare gas recovery system reduces flaring by approximately 55%, resulting in an equivalent CO_2 emission rate of 129 t/d, which comprises 126 t/d CO_2, and CH_4 emissions equivalent to 3 t/d CO_2, on a 20 year time horizon. This is based on the standard emission factors presented in Table 2.2.

Installation of the flare gas recovery system has resulted in a reduction in emissions equivalent to 158 t/d CO_2 over a 20 year time horizon.

Emissions of non-greenhouse gases associated with gas flaring before and after the modification are shown in Table 3.3.3 and are further discussed in Section 3.3.6.2.

3.3.5 Net Cost of Modification

The capital cost for the installation of a flare gas recovery system on both Gullfaks A and C was about US$ 11.7 million (NOK 45 million/installation) as shown in Table 3.3.4. It should be noted that this cost included the costs of research and development. More recent projects have shown the cost to be lower and Umoe estimates that inclusion of a flare gas recovery system in a new installation would cost between US$ 0.6 to 1.6 million and for a retrofit US$ 1.9 to 3.9 million.

Operating costs were not supplied by Umoe or Statoil and have therefore been estimated on behalf of the IEA. Operating costs would include inspection and maintenance of any equipment and costs of firing of pellets. A nominal cost of US$ 200,000 per year for both installations has been included to cover these costs. Operating costs are shown in Table 3.3.5.

Other costs and savings are shown in Table 3.3.6. Annual savings of US$ 5.5 million are achieved from additional export gas sales and a reduction in CO_2 tax. An additional 2.3 MMSCFD of gas is available for export which is equivalent to US$ 2.55 million, based on a gas price of US$ 0.0031/SCF and an availability of 96%. The reduction in CO_2 tax is US$ 2.97 million, based on a CO_2 tax of US$ 55/tonne. Without the CO_2 tax incentive, the annual savings are reduced to US$ 2.55 million.

The net annual cost/saving associated with the project has been assessed using a 15 year field life, interest rates of 12%, 10% and 5%, and a CO_2 tax of US$ 55/tonne CO_2 emitted. Taking credit for the CO_2 tax incentive, the project has net annual savings of US$ 3.61, 3.79, and 4.20 million for each interest rate. Without the CO_2 tax, the savings are reduced to US$ 0.64, 0.81, and 1.23 million respectively. The net annual savings are presented in Table 3.3.7.

The project NPV was calculated using the same field life, interest rates and CO_2 tax level. The figures are presented in Table 3.3.9. The NPVs for 12%, 10%, and 5% are US$ 24.58, 28.81, and 43.58 million respectively with CO_2 tax incentives. Without a CO_2 tax incentive, the NPVs are US$ 4.33, 6.20 and 12.72 million respectively.

3.3.6 Other Changes and Benefits

3.3.6.1 Operation and Maintenance

As the flare no longer has to operate at the continuous low velocity load, the flare tips last longer, reducing the costs of flare tip replacement and repair.

Since installation, the system has also allowed controlled depressuring of equipment to the flare recovery system instead of depressuring directly to the flare.

3.3.6.2 Emissions of Non-Greenhouse Gases

Table 3.3.3 presents non-greenhouse gas emissions including NO_x, SO_x and CO. These emissions are based on the gas flaring rate and the emission factors presented in Table 2.2. The reduced gas flaring rate leads to a reduction in non-greenhouse gas emissions.

3.3.6.3 Safety

Safety studies carried out by DNV prior to the modification led to the following conclusions:

- Fatal Accident Rate increased by 1% (0.04 per year against an acceptance criterion of 0.05 per year)
- Changes to operating procedures included reduced crew size in drilling rig area during planned depressurisation, changes to helicopter maximum approach altitude and warning procedures to prevent helicopters flying into a possible gas cloud.
- Probability of flare valve and rupture disk failure on demand, at 0.5 bar over set pressure, was calculated as $2x10^{-6}$ for the low pressure system and $1x10^{-6}$ for the high pressure system.

3.3.7 Site Specific Factors

During installation, platform personnel were reluctant to use the system, as they felt it compromised platform safety. Additional training was required to ensure that personnel had confidence in the system.

Figure 3.3.1: Location of the Gullfaks Field

Figure 3.3.2: Schematic of Gullfaks A and Subsea Production Facilities

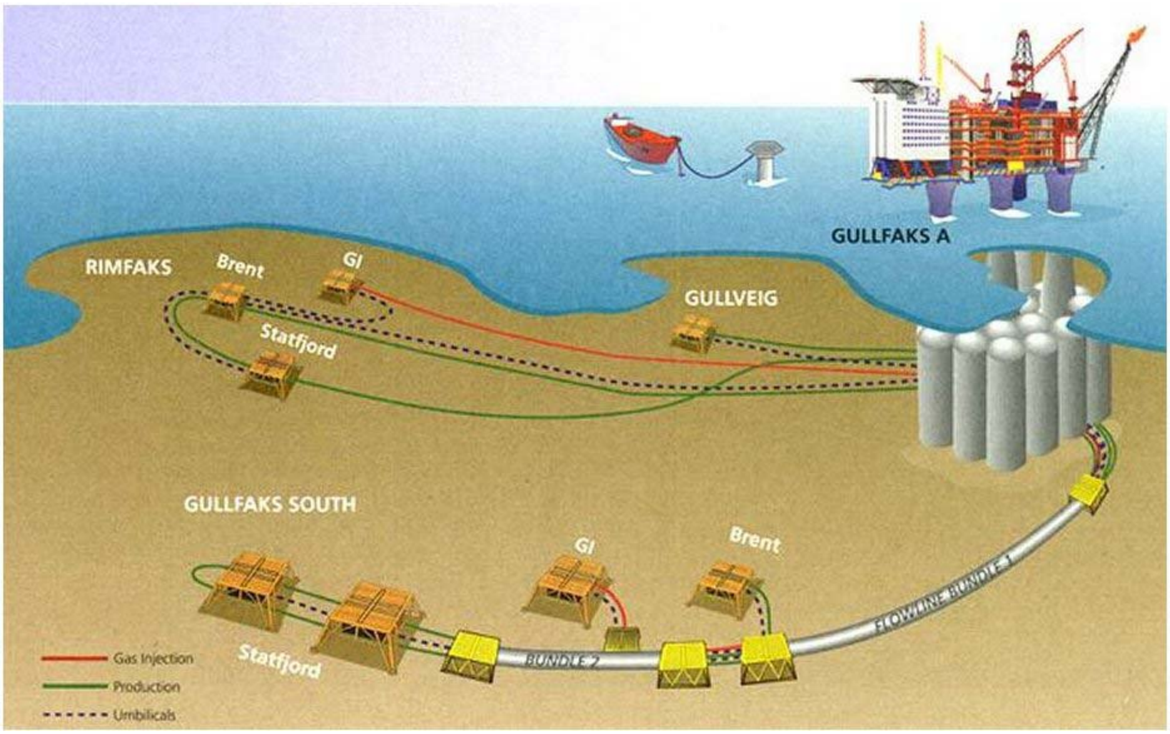


Figure 3.3.3: Schematic of Flare Gas Recovery and Ignition System

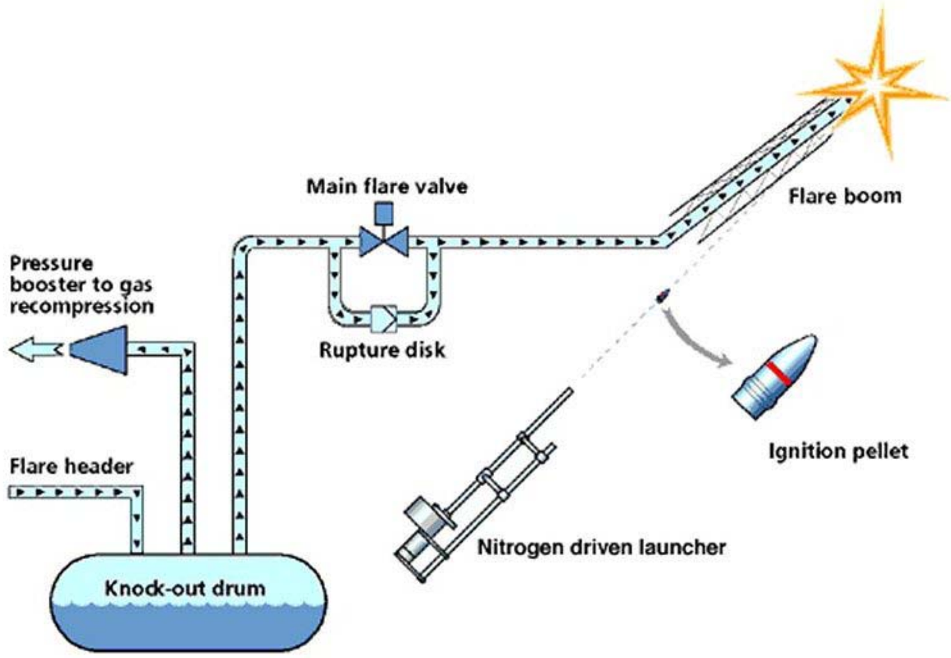
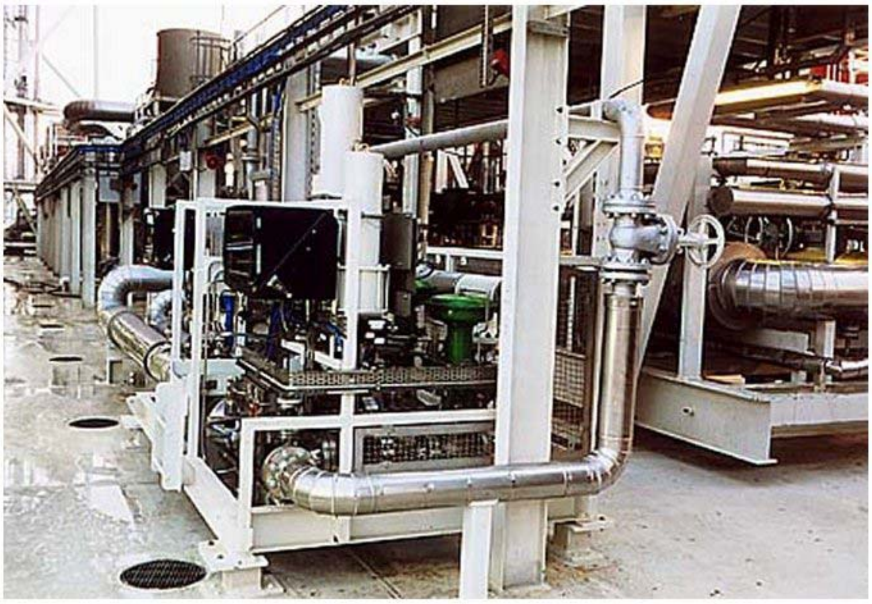


Figure 3.3.4: Flare Gas Recovery Skid Mounted on the Platform



3.4 Case Study 4

Operator: Saga Petroleum
Installation: Snorre B and Snorre TLP
Technology: Combined Cycle Gas Turbine

SUMMARY

The retrofit of a power transmission cable from the combined cycle generation system on Snorre B to the Snorre Tension Leg Platform (TLP) allows decommissioning of one of three 22 MW traditional gas turbines on Snorre TLP. This will result in a reduction in greenhouse gas emissions equivalent to 93 t/d CO_2 in a 20 year time horizon. The project economics have been assessed using net present value (NPV) per equivalent tonne CO_2 emission avoided. In addition, an annual capital repayment has been calculated and added to the incremental annual operating costs to give a net annual saving (NAS) per equivalent tonne CO_2 emission avoided. The project economics are also presented both with and without CO_2 tax.

Based on a 20 year remaining field life, a 5% interest rate and a CO_2 tax set at US$ 55/tonne CO_2 emitted, the project NPV is US$ 8.75 million. This corresponds to US$ 13.44 per equivalent tonne CO_2 emission avoided. Using the same field life, interest rate and CO_2 tax rate, the NAS is US$ 0.70 million, which corresponds to US$ 21.57 per equivalent tonne CO_2 emission avoided. Without the CO_2 tax incentive, the NPV is US$ (13.05) million, corresponding to US$ (20.06) per equivalent tonne CO_2 emission avoided. Similarly, without the CO_2 tax, the net annual cost (NAC) is US$ (1.05) million, which corresponds to a cost of US$ (32.20) per equivalent tonne CO_2 emission avoided. The project economics are presented both with and without CO_2 tax.

3.4.1 Introduction

The Snorre field is located in the Norwegian sector of the northern North Sea, see Figure 3.4.1 (Snorre is just south of Statfjord), approximately 140 km west of Florø. The water depth varies between 300 and 350 metres. At present, the northern section of the field is produced from a Tension Leg Platform (TLP) and a subsea production facility.

Future development of the southern section of the field will include the installation of a new platform, Snorre B, which is planned with a combined cycle containing two 29 MW gas turbines and one 16 MW steam turbine for power generation. Following Snorre B installation, a power transmission cable will be laid to export surplus power from Snorre B to the existing TLP, see Figure 3.4.2

The reduction in emissions associated with Snorre TLP production was provided by Saga Petroleum and was based on the difference in energy generating efficiency between Snorre B and Snorre TLP.

3.4.2 Description of Facilities Prior to Modification

The Snorre field is currently produced from a Tension Leg Platform (TLP) with a connected subsea production facility. The Snorre TLP is a drilling, production and accommodation platform with facilities for crude stabilisation, export and water injection.

The production facilities comprise:

- a 2-stage single train system for 3-phase separation,
- export pumps,
- a water injection system including seawater lift pumps, de-oxygenation system and water injection pumps,
- a produced water treatment system comprising skid mounted hydrocyclones and downstream degassers,
- a metering station,
- utilities including chemical injection, methanol injection and a fresh water system,
- gas compression by three, centrifugal type, compression modules.

Oil is exported to Statfjord A via a 28km, 20” pipeline. Similarly, gas is exported to Statfjord A via a 28km, 10” pipeline. The platform main power is generated by three 22 MW gas turbine packages.

Figure 3.4.3 shows the Snorre TLP.

3.4.3 Description of Modification

In 2001, the southern section of the Snorre field will be produced from a new production platform, Snorre B. Snorre B will use two 29 MW gas turbines and a 16 MW steam turbine in a combined cycle to generate power. This will generate more power than required on Snorre B. A cable will be installed between Snorre B and Snorre TLP to allow surplus power export from Snorre B to Snorre TLP. This will facilitate the decommissioning of one 22 MW traditional gas turbine on the Snorre TLP.

3.4.4 Reduction in Greenhouse Gas Emissions

The reduction in greenhouse gases associated with Snorre TLP production is achieved by importing power generated on Snorre B, using a high efficiency combined cycle, and decomissioning one traditional gas turbine on Snorre TLP.

The hydrocarbon production and consumption data before and after the modification are shown in Table 3.4.1. The greenhouse gas emissions associated with Snorre TLP production prior to and post modification were supplied by Saga Petroleum and are presented in Table 3.4.2. Prior to the Snorre B project, the Snorre TLP facility has an equivalent CO_2 emission rate of 1061 t/d, which comprises 1043 t/d CO_2, CH_4 emissions equivalent to 15.8 t/d CO_2, and N_2O emissions equivalent to 2.3 t/d CO_2 on a 20 year time horizon.

After the Snorre B platform is commissioned, the emission from Snorre TLP and the emission from Snorre B associated with generating power for TLP amount to

968 equivalent tonnes CO_2 per day. This comprises 952 t/d CO_2, CH_4 emissions equivalent to 14 t/d CO_2 and N_2O emissions equivalent to 2.2 t/d CO_2, based on a 20 year time horizon.

Emissions of non-greenhouse gases associated with Snorre TLP production before and after modification are shown in Table 3.4.3. Non-greenhouse gas emissions are discussed further in Section 3.4.6.2.

3.4.5 Net Costs of Modifications

The capital costs associated with power export from Snorre B to Snorre TLP are presented in Table 3.4.4. Saga Petroleum was unable to provide a cost breakdown, therefore costs have been estimated on behalf of IEA using typical combined cycle and traditional turbine costs.

The total capital cost of the modifications is approximately US$ 30.8 million. This cost comprises the additional costs associated with procurement and installation of a combined cycle unit that meets the Snorre B and Snorre TLP required duty, over a traditional turbine. Also included is the cost associated with decomissioning an existing turbine at Snorre TLP and supplying a power cable from Snorre B to Snorre TLP.

No incremental operating costs have been included for installing a combined cycle over traditional gas turbine. It is not anticipated that the platform manning will increase as a result of the modification.

Other associated costs and savings are shown in Table 3.4.6. This indicates that the reduction in the fuel gas requirements leads to a saving of US$ 1.42 million and the CO_2 tax avoidance realises a saving of US$ 1.75 million.

The net annual cost/saving associated with the project has been assessed using a 20 year field life, interest rates of 12%, 10% and 5%, and a CO_2 tax set at US$ 55/tonne CO_2 emitted. Taking credit for the CO_2 tax incentive, the project has a NAC/S of US$ (0.95), (0.44), and 0.70 million for 12%, 10% and 5% interest respectively. Without the CO_2 tax, the NAC is US$ (2.70), (0.19) and (1.05) million respectively. The net annual costs/savings are presented in Table 3.4.7.

The project NPV was calculated using the same field life, interest rates and CO_2 tax level. The figures are presented in Table 3.4.9. The NPVs for 12%, 10%, and 5% interest rates are US$ (7.10), (3.78), and 8.75 million respectively with CO_2 tax incentives. Without a CO_2 tax incentive, the NPVs are US$ (20.16), (18.68) and (13.05) million respectively.

3.4.6 Other Changes and Benefits

3.4.6.1 Operation and Maintenance

Decommissioning a generator on Snorre TLP is likely to result in reduced maintenance requirements on this platform. Whilst this may result in a saving on parts and materials, it is not expected to result in a reduction in manning of the platform.

3.4.6.2 Emissions of Non-Greenhouse Gases

Table 3.4.3 presents non-greeenhouse gas emissions including NO_x, SO_x and CO. The reduction in fuel gas requirements on Snorre TLP also leads to reduced emissions of non-greenhouse gases from the platform. Emissions are based on the fuel gas usage and standard emission factors presented in Table 2.2.

3.4.6.3 Safety

Decommissioning of a gas turbine on Snorre TLP will result in reduced risk levels on the platform as the number of fuel gas leak sources will decrease. This is not expected to have a major impact on personnel or asset risk.

3.4.7 Site Specific Factors

The project was feasible due to the installation of a new facility near to the Snorre TLP. The cable installation is therefore economically justifiable.

Figure 3.4.1: Location of Snorre and Statfjord Fields

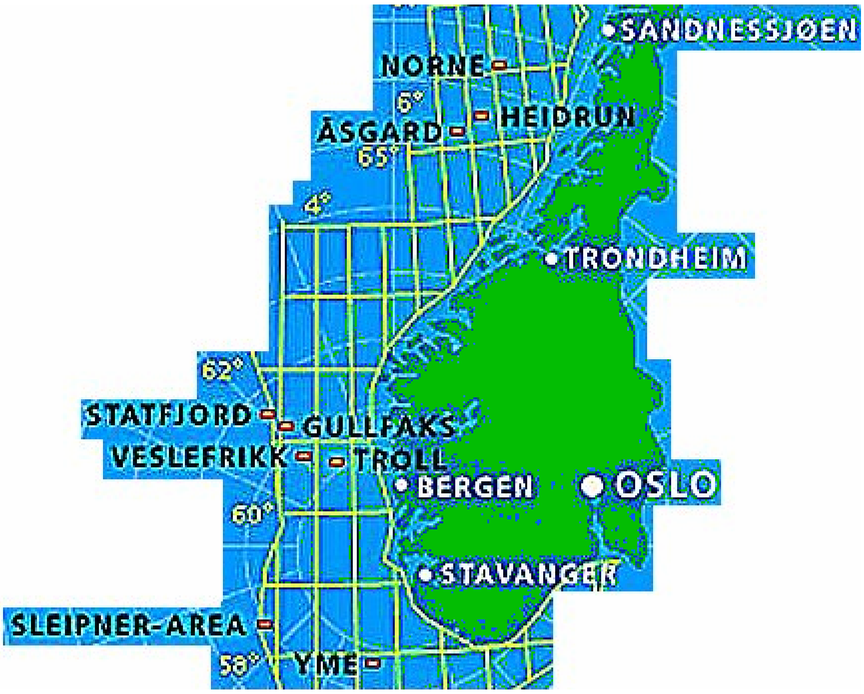


Figure 3.4.2: Schematic of Snorre Development

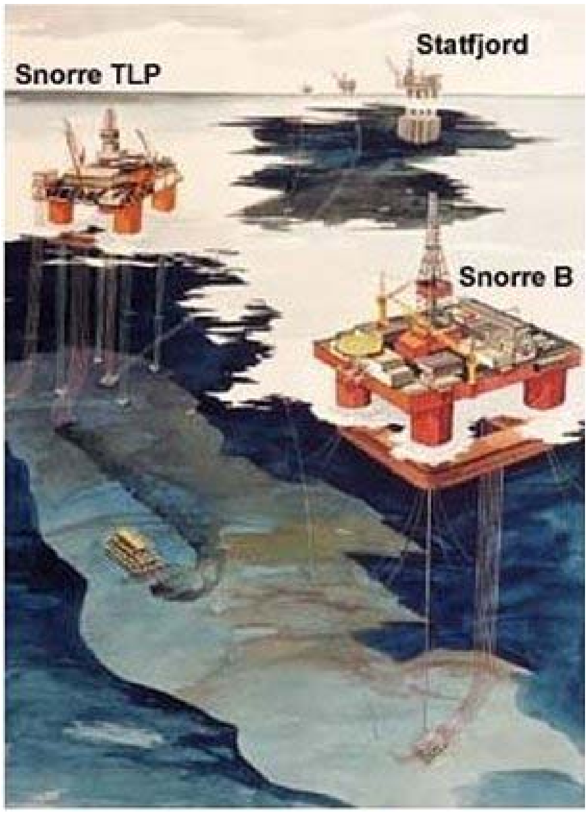


Figure 3.4.3: Snorre Tension Leg Platform

3.5 Case Study 5

Operator: Statoil
Installation: Åsgard B
Technology: Process Optimisation

SUMMARY

The design process optimisation of the Statoil Åsgard B semi-submersible results in a reduction in greenhouse gas emissions equivalent to 506 t/d CO_2. The project economics have been assessed using net present value (NPV) per equivalent tonne CO_2 emission avoided. In addition, an annual capital repayment has been calculated and added to the incremental annual operating costs/savings to give a net annual cost/saving per equivalent tonne CO_2 emission avoided. The project economics are also presented both with and without CO_2 tax.

Based on an 18 year remaining field life, a 5% interest rate and a CO_2 tax set at US$ 55/tonne CO_2 emitted, the project NPV is US$ 308 million. This corresponds to US$ 96.59 per equivalent tonne CO_2 emission avoided. Using the same field life, interest rate and CO_2 tax rate, the net annual saving (NAS) is US$ 26.33 million, which corresponds to US$ 148.73 per equivalent tonne CO_2 emission avoided. Without the CO_2 tax incentive, the NPV is US$ 195 million, corresponding to US$ 61.05 per equivalent tonne CO_2 emission avoided. Similarly, without the CO_2 tax, the NAS is reduced to US$ 16.64 million, which corresponds to US$ 94.01 per equivalent tonne CO_2 emission avoided.

Process optimisation to reduce CO_2 emissions was part of the design concept for Åsgard B, therefore the reduction in greenhouse gas emissions is based on comparison with a conventional process design.

3.5.1 Introduction

The Åsgard development lies 260km off the Norwegian coast, north-west of Trondheim, in blocks 6507/11, 6407/2 and 6506/11 as shown in Figure 3.5.1. The production facilities cover the worlds largest subsea field, with reserves estimated at 830 MMBBLS of crude, condensate and NGL and 7490 BCF of gas. The Åsgard development comprises three fields, Midgard, Smρrbukk and Smρrbukk South. Oil production is forecast to begin in early 1999 and gas production due to start in the second half of 2000.

The Åsgard facilities design incorporated measures that would result in lower greenhouse gas emissions when compared with a conventional design.

3.5.2 Description of Facilities Prior to Modification

The fields are being developed using the Åsgard A Floating Production, Storage and Offloading (FPSO) facility for oil production, the Åsgard B semi-submersible for gas production and the Åsgard C floating storage vessel. The Åsgard development is shown in Figure 3.5.2 and Åsgard B is shown in Figure 3.5.3.

The field will be developed using the most extensive group of subsea wells in the world, including a total of 58 wells grouped in 17 seabed templates. Production is forecast at: 1211 MMSCFD of gas; 200,000 BPD of oil and 94,000 BPD of condensate.

3.5.3 Description of Modification

The Åsgard project incorporated a number of energy saving and emission reducing measures into the Åsgard B, semi-submersible design. This was part of Statoil's aim to achieve the lowest emissions per unit hydrocarbon produced on the Norwegian shelf.

The environmental and energy saving initiatives on Åsgard B that result in emission reductions are:

i. **Condensate stabilisation and heat integration:** The Åsgard development uses heat instead of pressure for condensate stabilisation. This saves re-compression power of 10 MW. In addition extensive heat integration has been installed to reduce condensate stabilisation heating and product cooling requirements. The integrated preheating of condensate prior to stabilisation provides 37 MW of power which would normally be provided by fired heaters.

ii. **Gas export interstage cooling:** Gas export interstage cooling is usually only installed on export compressors with higher compression ratios than exist on Åsgard. By the installation of an additional compact interstage cooler and scrubber, the export compression power requirement is reduced by approximately 10 MW.

iii. **Warmed coolant used to heat colder stream:** The cooling water return is used to provide pre-heating for the Midgard gas production, saving 32 MW of power which would normally be provided by fired heaters.

iv. **Optimised sea water lift pump location:** Optimised location of the sea water lift pumps provided a saving of 70m pump head requirement. This reduces the pump power requirement by 2.2 MW.

v. **Flare gas reduction:** The platform uses the closed flare system (discussed in Case Study 3, Gullfaks A & C). A High Integrity Pressure Protection System (HIPPS) has been included to further reduce flaring and other gaseous emissions. The HIPPS shuts down production, so as to avoid flaring during process upsets, as would be the case when using a traditional pressure relief system.

vi. **Use of selective amine:** A selective amine is used to remove H_2S from the natural gas. This significantly reduces CO_2 discharges from the regeneration process when compared with a non-selective amine.

vii. **'ReadCycle' glycol regeneration:** The stripping gas in the glycol regenerator is recovered by cooling and separating the condensed water and recycling the gas to the stripper. No data are currently available on expected emissions reduction.

3.5.4 Reduction in Greenhouse Gas Emissions

The inclusion of the environmental and energy saving designs described in Section 3.5.3 for Åsgard B will result in reduced greenhouse gas emissions.

The reduction in CO_2 emissions has been estimated by Statoil, for modifications i to iv only, at 177,000 tonnes per year. This equates to an approximate saving of 30% when compared with conventional designs. This can be attributed to the following:

- Condensate stabilisation: 41,000 tonnes/year
- Heat integration: 46,000 tonnes/year
- Gas export interstage cooling: 40,000 tonnes/year
- Warmed coolant used to heat colder stream: 40,000 tonnes/year
- Sea water lift pumps: 9,100 tonnes/year.

Significant reductions in CO_2 emissions are also expected from the HIPPS and flare recovery system, though these have not been quantified by Statoil. Additional, unquantified, reductions are also expected due to the choice of selective amine stripping and the ReadCycle glycol regeneration unit.

The hydrocarbon production and consumption data for 1997 for modifications i to iv are shown in Tables 3.5.1.1 to 3.5.1.4. Fuel gas consumption rates have been estimated based on the energy (MW) savings forecast by Statoil. The energy and emission reduction data, forecast by Statoil, are shown in Table 3.5.2.

Design measures i to iv reduce the CO_2 emissions by approximately 506 t/d when compared with a conventional design. This does not include the reductions due to flare gas recovery, HIPPS, amine selection or the glycol regeneration design.

No data are available for greenhouse gas emissions other than CO_2. However, reductions in fuel gas consumption will reduce emissions of other greenhouse gases such as CH_4 and N_2O, which have higher global warming potentials. Therefore, the reduction in equivalent CO_2 emissions will be significantly higher than the forecast reduction of actual CO_2 emissions of 506 t/d.

No data are available to assess the reduction in emissions of non-greenhouse gases.

3.5.5 Net Costs of Modifications

Statoil was unable to provide cost data for the modifications. Cost data were therefore estimated on behalf of IEA. The capital costs of additional equipment required to implement the energy saving measures were estimated. Therefore the costs reported are incremental capital costs rather than the total cost of all facilities. The capital costs were estimated for modifications i to iv, using historical data for similar facilities and equipment supplier information. The incremental capital cost of these modifications was US$ 0.64 million as shown in Table 3.5.3. These modifications were introduced at the design stage. If they had been incorporated as a retrofit, costs would have been significantly higher due to offshore transportation, installation and additional project management costs.

Operating costs are not expected to be significantly higher as a result of installation of this equipment in place of more traditional equipment. Therefore, the increase is assumed to be zero, as shown in Table 3.5.4.

Other associated costs and savings are shown in Tables 3.5.5.1 to 3.5.5.4 for each of the four measures. The total savings for these four modifications, shown in Table 3.5.5.5, amounts to US$ 26.4 million, which includes savings from reduced fuel gas and diesel consumption, and a reduction in CO_2 tax. It is expected that 14.8 MMSCFD less fuel gas is required which is equivalent to a saving of US$ 16.2 million, based on a gas price of US$ 0.0031/SCF and an availability of 96%. Savings in diesel costs are estimated at about US$ 0.5 million, based on a diesel price of US$ 27/BBL. The reduction in CO_2 tax is about US$ 9.7 million, based on a CO_2 tax of US$ 55/tonne.

The net annual cost/saving associated with the project has been assessed using an 18 year field life, interest rates of 12%, 10% and 5%, and a CO_2 tax of US$ 55/tonne CO_2 emitted. Taking credit for the CO_2 tax incentive, the project has a NAS of US$ 26.29, 26.30, and 26.33 million for each interest rate. Without the CO_2 tax, the savings are reduced to US$ 16.61, 16.62 and 16.64 million respectively. The NAS for each of the modification measures i to iv is shown in Tables 3.5.6.1 to 3.5.6.4. The overall NAS is presented in Table 3.5.6.5.

The project NPV was calculated using the same field life, interest rates and CO_2 tax level. The NPVs for each of the modification measures i to iv are shown in Tables 3.5.8.1 to 3.5.8.4. The figures for the overall project are presented in Table 3.5.8.5. The NPVs for 12%, 10%, and 5% are US$ 190.61, 215.72, and 307.73 million respectively with CO_2 tax incentives. Without a CO_2 tax incentive, the NPVs are US$ 120.39, 136.28 and 194.51 million respectively.

3.5.6 Other Changes and Benefits

3.5.6.1 Operation and Maintenance

Several of the modifications incorporated into the design require additional equipment such as exchangers for heat integration, an interstage cooler and a scrubber for the gas export compressor, a flare gas recovery ignition system and a HIPPS. These will increase maintenance requirements. No associated costs were provided by the operator and so could not been taken into account in the quantitative assessment.

3.5.6.2 Safety

Using heat integration for condensate stabilisation instead of a fired heater results in a safer operating environment by removing a potential ignition source and a number of gas leak sources. This is not expected to have a significant impact on personnel or asset risk levels.

3.5.7 Site Specific Factors

Emission reduction measures i to vii were introduced at the design stage of Åsgard B. Of these, measures v and vii are known to have been retrofitted to other installations. Measure v, flare gas reduction, is estimated to cost between US$ 1.9 and 3.9 million to retrofit. Measure vii, 'ReadCycle' glycol regeneration, is estimated to cost between US$ 265 and 530 thousand.

The remaining emission reduction measures are potentially all suitable for retrofit to existing installations. Measures i, ii, iii and iv are dependent on the existing installation layout and space available for relocating equipment, installing additional equipment and interconnecting pipework. Measure vi, to change out the amine, would require a more detailed process study to determine the feasibility for a particular installation.

All the emission reduction measures would cost more to introduce as a retrofit than to a new installation.

In the design of Åsgard B the reduction of greenhouse gas emissions was specifically addressed due to the CO_2 tax in force in Norway.

Figure 3.5.1: Location of Åsgard Field

Figure 3.5.2: Schematic of Åsgard development

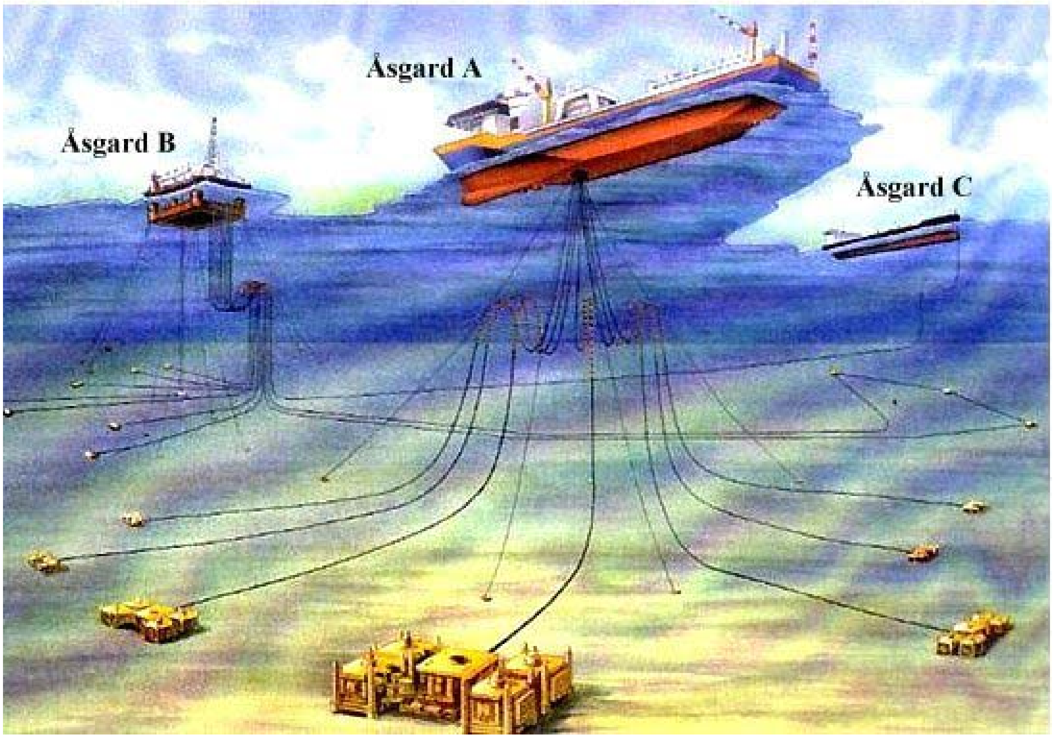
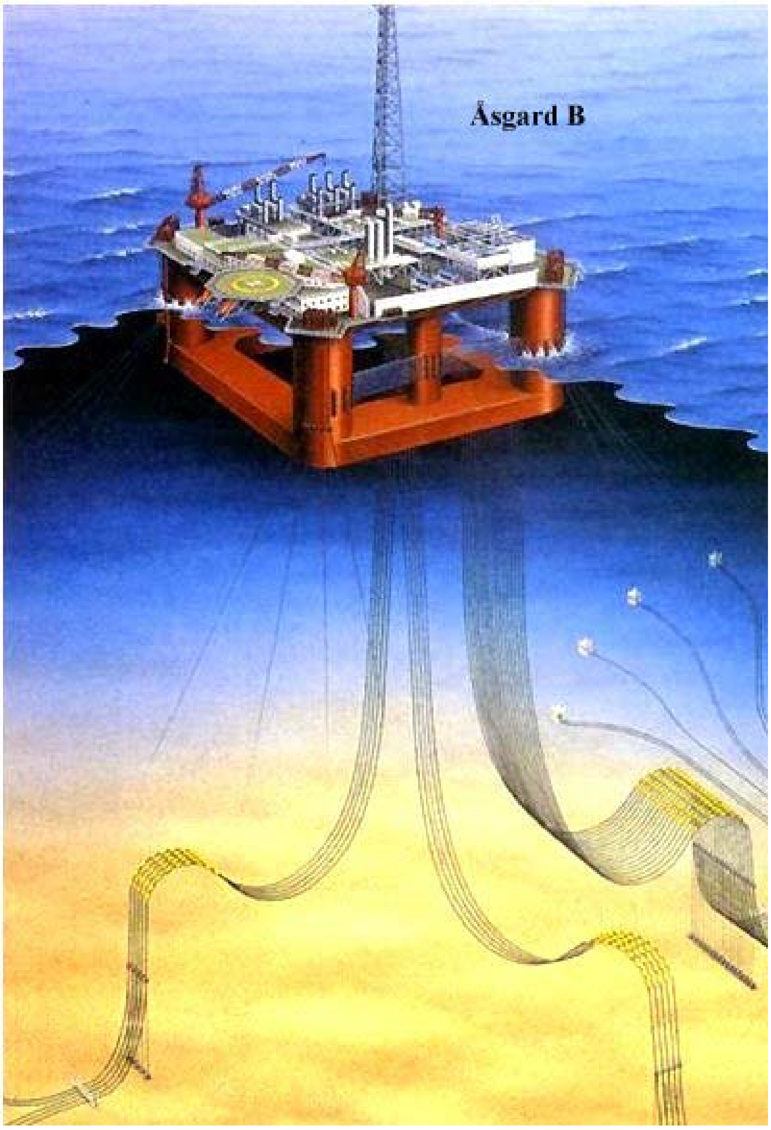


Figure 3.5.3: Åsgard B Semi-Submersible Facility



4. EMERGING TECHNOLOGIES

The following is a brief description of emerging technologies which could be considered for future retrofit applications to reduce greenhouse gas emissions from offshore installations.

4.1 Air Bottoming Cycle

Sources: *IEA supplied document "Kvaerner Air Bottoming Cycle Project" (Kvaerner Energy has not confirmed the accuracy of this information or the current status of the development of this technology.)*
GeminiMagazine, November 1994 - "Turning exhaust into electricity". www.oslo.sintef.no/gemini/1994-02E

Kvaerner Energy AS has been involved in developing a technology for increasing gas turbine efficiency in co-operation with the Norwegian government and several Oil & Gas companies. The new technology is known as the Air Bottoming Cycle (ABC) turbine.

The ABC turbine is similar in many respects to a traditional combined cycle (steam bottoming cycle) turbine and can be used in several configurations with existing gas turbines. Performance improvements are comparable to the traditional combined cycle turbine, though the ABC turbine is simpler and lighter. Benefits of the ABC include reduced space requirements and lower installation costs making it well suited to offshore applications.

The process involves the use of waste heat from a gas turbine to heat compressed air. This heated air is then expanded through a turbine to produce power to drive the air compressor and provide a net surplus of energy.

The technology is expected to give a 25% reduction in fuel consumption resulting in a 25% reduction in both CO_2 and NO_X emissions. Additional benefits include a 25% increase in power output.

4.2 ReadCycle Glycol Regeneration

Source: *READ Process Engineering A/S (UK); "Glycol Regeneration: The Environmentally Friendly "ReadCycle" Solution"*

Glycol is used in numerous offshore facilities to dehydrate gas. The glycol must be very pure, 99.7 - 99.9% by volume. A traditional glycol regeneration system uses fuel gas to remove the volatile water fraction from the glycol. Normally, this stripping gas is lost to the atmosphere by vent or flare.

The ReadCycle recovers the stripping gas by cooling and separating the condensed water and recycling the gas to the stripper column. Depending upon the capacity of the unit, typical fuel gas consumption for glycol regeneration is around 5,000 - 15,000 Sm³/day.

The ReadCycle is expected to reduce fuel gas consumption by 80-90%. Figure 4.1 shows the ReadCycle glycol regeneration process flow diagram.

The ReadCycle is well suited to retrofit application, as it will use existing connections on the stripper column, thus reducing the cost of modification to the column. Additional equipment required includes a condenser, separator and return gas blower. The cost of such a retrofit is estimated between US$ 265,000 to US$ 530,000.

4.3 Membrane Gas/Liquid Contactors

Source: *Offshore Engineer, September 1997; "Exhaustive Offshore Hunt for CO_2"*

As part of the Norwegian government initiative to reduce CO_2 emissions, Kvaerner Engineering Environmental initiated a joint industry programme in 1992 for CO_2 separation involving major North Sea operators and the Norwegian authorities.

A preliminary study identified that amine absorption used with membrane gas/liquid contactors in the absorber and the desorber, in combination with a combined cycle power generation unit with 40% recycle of the exhaust gas, had significant potential to reduce emissions. The CO_2 recovered from the flue gas would have to be compressed and reinjected for enhanced oil recovery or disposed of either in aquifers or by some alternative means.

The advantages of using a membrane gas/liquid contactor over conventional contacting equipment include:

- Reduced contactor size due to high packing density.
- Operation is independent of gas and liquid flowrate.
- No foaming, channelling, entrainment or flooding.

The work was progressed to a testing phase using external organisations to evaluate the technology. The main conclusions of the test work were:

- The membrane is chemically stable and not wetted by the hot absorption liquid.
- The mass transfer is relatively high.
- The size is reduced by 78% and the weight by 66% compared with conventional units.

In September 1997, this project was still under development with a full scale demonstration plant scheduled for the turn of the century. Development of the technology is economically driven by the CO_2 tax and the availability and value of electricity on the facility.

4.4 Pre-Combustion Decarbonisation

Source: *IEA "Greeenhouse Issues" – Number 37, July 1998*

Technology is available, and has been used in onshore power generation facilities, to remove CO_2 post-combustion from exhaust gases. The primary limitation for post-combustion removal of CO_2 from exhaust gases on offshore facilities is the size of the adsorption equipment required.

Pre-combustion decarbonisation is an alternative approach which removes the carbon content of the fuel gas to produce a hydrogen or hydrogen rich gas mixture. This process relies upon air and steam for partial oxidation of natural gas followed by steam reforming in a catalytic partial oxidation reactor (CAPO). The process relies on relatively high pressures (18 bar) and temperatures (600 °C) and the availability of steam. It is unlikely that this process will be applicable to offshore facilities as steam is not generally available.

4.5 Combustion of Fuel with Recycled CO_2

Source: *CANMET Energy Technology Centre (CETC)* - www.nrcan.gc.ca/geos; *"Advanced O2/CO2 Recycle Combustion System Tackles Greenhouse Gas Pollution"*

Researchers at CETC in Canada are developing an emissions-free O_2/CO_2 recycle combustion system. By recycling the exhaust gases from the turbine combustion the concentration of CO_2 in the exhaust increases making it easier to recover.

The process, which is shown schematically in Figure 4.2, burns carbon based fuels in a nitrogen-free medium composed of O_2 and CO_2. The CO_2 required for diluting the feed gas is recovered from the flue gas and recycled back to the burner. Not all of the flue gas CO_2 is required for recycling. What is not used is virtually undiluted by nitrogen, making disposal more economical. The process requires an air separator at the front end of the unit to separate oxygen from nitrogen in air. The nitrogen is released to atmosphere.

Coal fuel is the current focus of the testing, however, the process should be applicable to natural gas and oil. The project is currently in the pilot plant phase and no large scale operation has been planned. In addition to the reduction in CO_2 emissions there are reductions in NO_x emissions as nitrogen is present in very low concentrations in the combustion air.

4.6 Conversion of Hydrocarbon Gas to Methanol

Source: *APPEA – Australian Petroleum Production and Exploration Association "Greenhouse Challenge; Cooperative Agreement"*
www.dpie.gov.au/resources.energy/environment/greenhouse/challenge/

BHP Petroleum in Australia constructed a research plant to prove the feasibility of converting hydrocarbon gases to methanol. If successful, small scale methanol production units could be used to produce otherwise uneconomic offshore gas fields. The units could also be used to process some offshore oil field associated gas which is normally flared. Considerable savings in greenhouse gas emissions would result if the development was successful.

BHP has spent US$ 55 million on research and development for reducing greenhouse gas emissions. Of this US$ 45 million was spent on construction of the Methanol Research Plant. This is part of BHP Australia's initiative to reduce greenhouse gas emissions by 8 million equivalent tonnes of CO_2 by the year 2000 compared with the 1996 emissions of approximately 29.7 million tonnes.

4.7 Sequestration of CO_2

Sources: *IEA "Greeenhouse Issues" – Number 37, July 1998*
IEA Greenhouse Gas R&D Programme Annual Report 1997

In developing the technology to remove CO_2 from gas streams the problems associated with what to do with the CO_2 once it has been removed have been receiving attention. Several options are being developed including ocean sequestration.

CO_2 accumulates naturally in the ocean, but the process is slow and cannot keep up with the rising atmospheric levels of CO_2. The use of deep sea sequestration by injecting CO_2 into the sea at a sufficient depth so that the CO_2 remains in solution is one possibility for CO_2 storage. There are several concerns over the implications of such a process which are still being reviewed through a series of IEA workshops.

Other sequestration techniques which could potentially be used are storage of CO_2 in unminable coal seams. This is unlikely to be a feasible option for offshore installations.

4.8 Flare Tips

Sources: *Kaldair Limited; communication*
Birwelco Limited; communication

Flare tip technology has made several advances in recent years, but these have been more in the field of operability and reliability. Contact with flare vendors suggests that the burning efficiency of flares has reached a point where further improvement is not economically feasible.

Currently vendors are reporting flare combustion efficiency at approximately 98%. Increasing flare tip efficiency would convert any remaining unburned CH_4 to CO_2. Whilst this increases the direct CO_2 emissions it does result in lower equivalent CO_2 emissions when the global warming potential of the two gases is considered.

There is insignificant, if any, financial incentive to improve flare efficiency beyond current levels and it is not expected that there will be any further developments in flare tip technology in the near future. It is expected that the focus of developments will continue along the lines of reducing flaring through developments such as HIPPS, flare gas recovery and pilotless flare systems.

5. CONCLUSIONS

The following conclusions may be drawn from the case studies presented in Section 3.

1. The most cost effective means of reducing equivalent CO_2 emissions offshore is by optimising platform process design as indicated in Case Study 5, Statoil Åsgard B.

2. In Norway, which is the only country to have introduced CO_2 emission tax, avoidance of paying CO_2 emission tax is a significant factor in improving the cost benefits for the operator, associated with reduction of CO_2 emissions offshore. All installations subjected to CO_2 emission tax showed a net saving from reducing greenhouse gas emissions.

3. Reducing emissions of greenhouse gases also tends to reduce emissions of non-greenhouse gases. This may have benefits with respect to impact on other environmental sensitivities.

4. As a number of the measures considered in these case studies represent the first installation of a given technology, it is reasonable to assume that future use of the technology will be more cost efficient, thereby increasing the attractiveness to offshore operators.

5. In general, greenhouse gas emission reduction measures introduced to ‘new builds’ are expected to cost less than retrofits.

6. While a number of technologies to reduce greenhouse gas emissions are currently under development, commercial sensitivities tend to discourage manufacturers from providing detailed information. As these technologies are progressed, more information is likely to be available, thus allowing their viability to be assessed.