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TITLE

Offshore gas power with CO_2 removal supplied from a plant located on an abandoned platform. A pre-study.

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SUMMARY

A pre-study of a concept for power production offshore on an old petroleum platform has been performed. A net delivered 300 MW combined cycle power plant and a CO_2 sequestering plant are located on a single Condeep platform. The power will be supplied to Statfjord, Gullfaks and Snorre by AC sea cables. The sequestered CO_2 is compressed and dried, and injected into an underground formation. By replacing the present gas turbine power production on these fields, the CO_2 emissions will be reduced with 1.6 Mt per year, corresponding to 4.4% of the total Norwegian CO_2 emissions. Equipping the gas compressors with speed controlled electrical motors also represents a technical advantage, improving energy utilisation compared to present turbine drive.

The concept appears to be technically feasible. The internal rate of return is estimated to 17.6%. The net present value is 2211 MNOK from a total capital investment of 3190 MNOK. A similar concept with central power production *without* CO_2 removal, gives an internal rate of return of 32.2%, provided that all the power (360 MW) can be sold offshore. This solution reduces the CO_2 emissions with 0.7 Mt, which corresponds to 2.0% of the present Norwegian emissions.

The economic figures presented above are first estimates, and have large uncertainties. The results obtained justifies further studies including more detailed analyses.

KEYWORDS ENGLISH	KEYWORDS NORWEGIAN
Offshore power production	Kraftproduksjon til havs
CO_2 deposition	CO_2 deponering
Abandoned platforms	Forlatte oljeinstallasjoner
Economic analyses	Økonomiske analyser
CO_2 emission	CO_2-utslipp

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1. Background

1.1 International concern regarding the risk of climate change

There has been a growing concern with both local and global environmental issues during the last decades. One important question has been the risk that anthropogenic emission of greenhouse gases could cause climate change. This has led to a number of international initiatives to regulate these emissions, notably from the energy sector. The most significant is the UN Framework Convention on Climate Change (FCCC) which was conceived in 1990 and negotiated in Rio in 1992. Norway is one of more than 170 countries that has adopted and signed the FCCC text which came into force in March 1994. Norway, along with all other OECD/IEA countries and the European Commission, is committed to present plans on how to stabilise and reduce emissions of greenhouse gases according to the FCCC text.

1.2 Abandonment of platforms in the North Sea

Offshore abandonment is fast becoming an important issue as an increasing number of oil and gas fields are approaching the end of their productive life, and operators consider how to dispose of the redundant installations. At the end of 1995 there were more than 420 producing fields in the Norwegian, UK, Danish, Dutch and Irish waters (Terdre *et al.* 1995). Eventually, all will cease production and the facilities installed upon them will have to be decommissioned, creating a great challenge to the technical and scientific community to find environmentally and economically acceptable solutions for their abandonment.

The legislative framework is still in the process of formation, and the result will depend on international negotiations.

Approximately 70 installations are placed on the Norwegian continental shelf. The cost of abandoning these structures has been estimated to a total of 50 billion NOK (NPD 1994). Many of the structures are relatively small units (less than 40 000 tonnes), typically on a steel jacket, while others are floaters. These are easy to remove completely and recycle for a moderate cost, *e.g.* the Odin steel jacket platform (250 million NOK) and the UK Emerald floater (100 million NOK, Offshore Engineering March 1996). About ten of the Norwegian platforms are, however, large concrete gravity base structures consisting of more than 500 000 tonnes of steel and concrete with the base pressed into the sea-floor. The abandonment of these large units provides the real challenge.

1.3 Power production from fossil fuels combined with CO_2 sequestering and disposal

It has previously been suggested that CO_2 from a gas power plant could be sequestered and used as injection gas in oil reservoirs for improved oil recovery (Holt and Lindeberg 1988, Bolland *et al.* 1990, Holt and Lindeberg 1993). In an economic environment where the credit could taken both on a CO_2 tax saving, the sale of electric power and enhanced oil recovery (EOR), this concept was proven to be economically interesting even with a CO_2 tax savings credit of only half the present Norwegian offshore and transportation CO_2 tax (360 NOK/tonne CO_2). In addition to the power and CO_2 separation plant, the major investment costs were a high voltage direct current (HVDC) transport system for power and a large offshore carrier if the power plant was to be located offshore near the oil field. For an onshore location of the power plant, an extra CO_2 pipeline from the shore to the injection wells was required.

In the concept presented in this report, all these extra investments can be omitted compared with previous studies, because the power plant is assumed located on an abandoned oil platform and the power is distributed to nearby platforms on less expensive AC cables. A combined cycle power unit with a gross generating capacity of 360 MW is considered. This corresponds to one of the two units Naturkraft has applied a concession for. When CO_2 separation is combined with this power plant, the net energy output will be approximately 300 MW. The power is sold at a competitive price compared to the present cost for offshore power production. The power cost offshore is high due to the CO_2 tax, and low generating efficiency compared to a combined cycle plant. The sequestered CO_2, approximately one million tonne per year, will be injected into some of the existing wells, but no EOR credit is accounted for this injection in the base case economic calculations.

1.4 **Selection of platform**

The first large platform to be abandoned is the Ekofisk Tank Centre platform (1998). This platform is conveniently located near many other platforms with significant future power demand and has a large carrying capacity. It is, however, questionable whether the tank is suited as a future power plant site due to the subsidence of the field (0.35m/year). The subsidence has urged the abandonment of the Ekofisk Tank Center.

In 1999 the Frigg TCP-2 platform goes out of production. It is located right on top of potential CO_2 deposit sites, but in 1999 both the offshore local power demand and gas supply would have ceased. Gas could possibly be supplied from the Oseberg field through the 82 km long Frostpipe. This pipeline has a 16” diameter and is large enough to supply sufficient amounts of gas for a power plant. To deliver the power from Frigg to Oseberg is possible with use of AC cables, but it is more costly than other alternatives and the power demand near Oseberg is relatively small (about 100 MW). Also the production on Heimdal platform will end in about year 1999 and this platform has a gas line connected to the Norpipe. This field is, however, located more than 100 km from Oseberg.

Both Frigg and Heimdal fields are therefor ruled out as potential sites for offshore power plants based on power delivery to other platforms.

The next really large platform that goes out of production is the Statfjord A platform. This is a platform of the Condeep type. This was one of the last platforms of this type which was not designed to be refloated, and a removal may therefor be particularly difficult. It is located on the Tampen bank 220 km north west of Bergen with many major producing fields nearby. The production on these fields will also decline, but a significant production will be maintained for two decades by utilising their infrastructure for processing oil and gas from sub-sea well head platforms and from neighbouring fields. The topside carrying capacity of the Statfjord A is 50 000 tonnes and it has an expected additional lifetime of at least 20 years.

In this report only Statfjord A is considered, but the technical and economical considerations will be very similar for other locations provided that both a CO_2 deposit site, gas supply and local power market are close to the platform.

An overview over the first platforms to be abandoned is shown in Table 1.1. Other platforms may be abandoned within few years, but it would be highly speculative to schedule a particular year for abandonment for any of these.

Table 1.1 The first platforms going out of production

Platform/Field	**Last production year**	**Carrying capacity (tonne)**
Odin/Frigg	1994	10 000
Ekofisk Tank Centre	1998	40 000
Frigg TCP-2	1999	21 000
Heimdal	1999	17 000
Statfjord A	2003	50 000

2. Location and offshore power production

2.1 Present and future power production in the Tampen province

Statfjord A is located in between the platforms Statfjord B and C. Three other fields are located in the same province. It is approximately 20 km to Gullfaks, 25 km to Snorre and 30 km to Visund. A map of the fields is shown in Figure 2.1, and a sketch of the major installations is shown in Figure 2.2 (not in scale). Visund is not yet a producing field, but it is likely that the field will come on stream in July 1998. All these fields have their own power production and will be considered as a market for an offshore gas power plant. If the Statfjord A platform is excluded, turbines with a producing capacity of 450 MW are installed. The turbines are equally divided between electricity generation and generation of mechanical power for compression. The gas turbines, mostly General Electric LM2500, are aeroplane derivated turbines with a nominal efficiency of between 30 and 37 %. The average efficiency will vary with age, condition, the turbine and load, and will be significantly lower than the nominal efficiency. Much less than the installed capacity is utilised. Based of fuel gas consumption data from NPD (1979 to 1994) the power production has been calculated. If it is assumed that the average efficiency is 30% and that the average gas heating value is 40.6 MJ/Sm^3, the present total energy demand is more than 300 MW. This is illustrated in Figure 2.3.

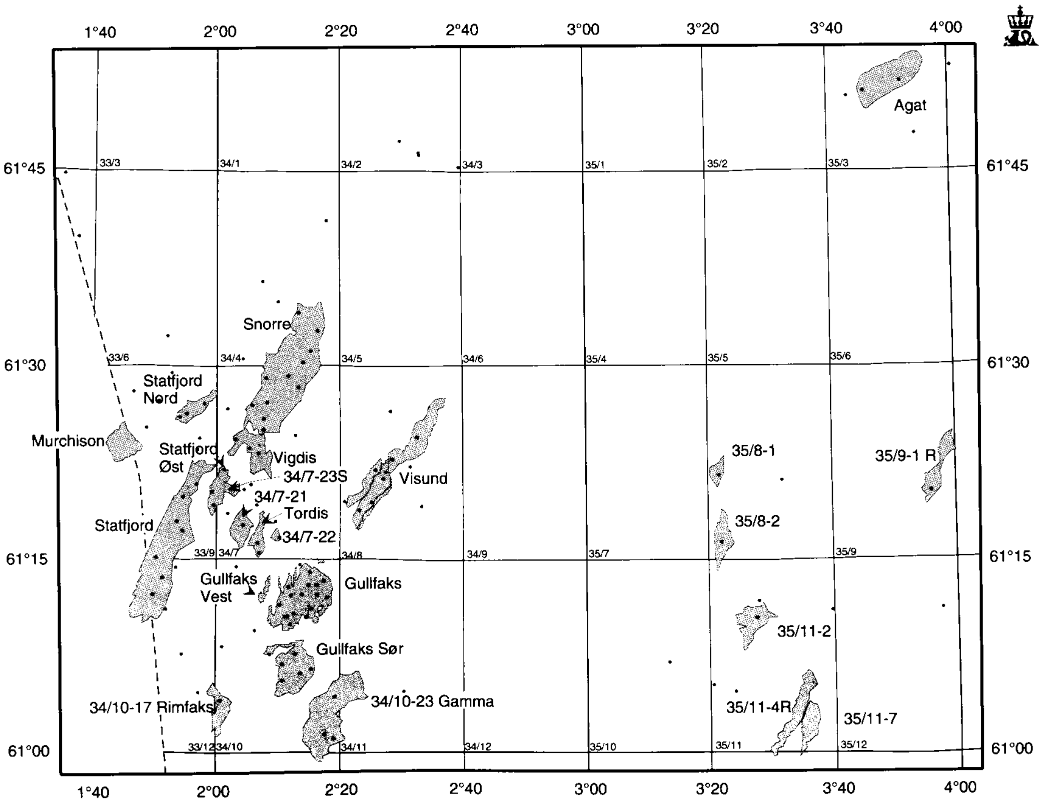

Figure 2.1 Fields and discoveries in the Gullfaks, Statfjord, Snorre province (NPD 1995).

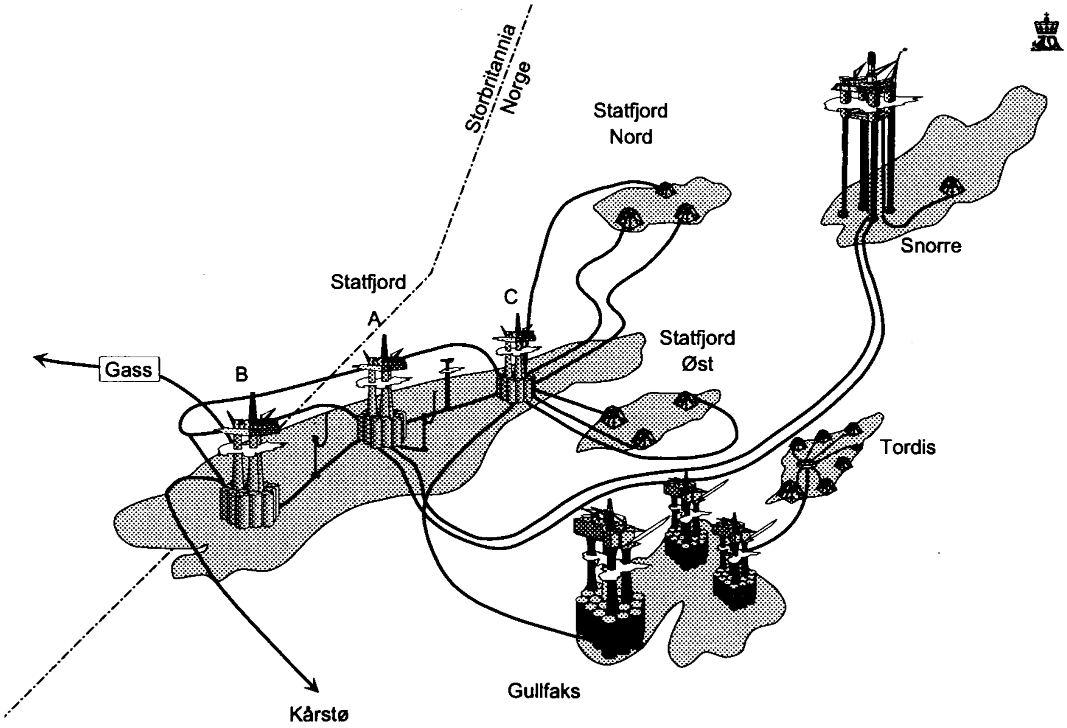

Figure 2.2 *Major installations and infrastructure in the Gullfaks, Statfjord, Snorre province. The sketch is not in scale (NPD 1995).*

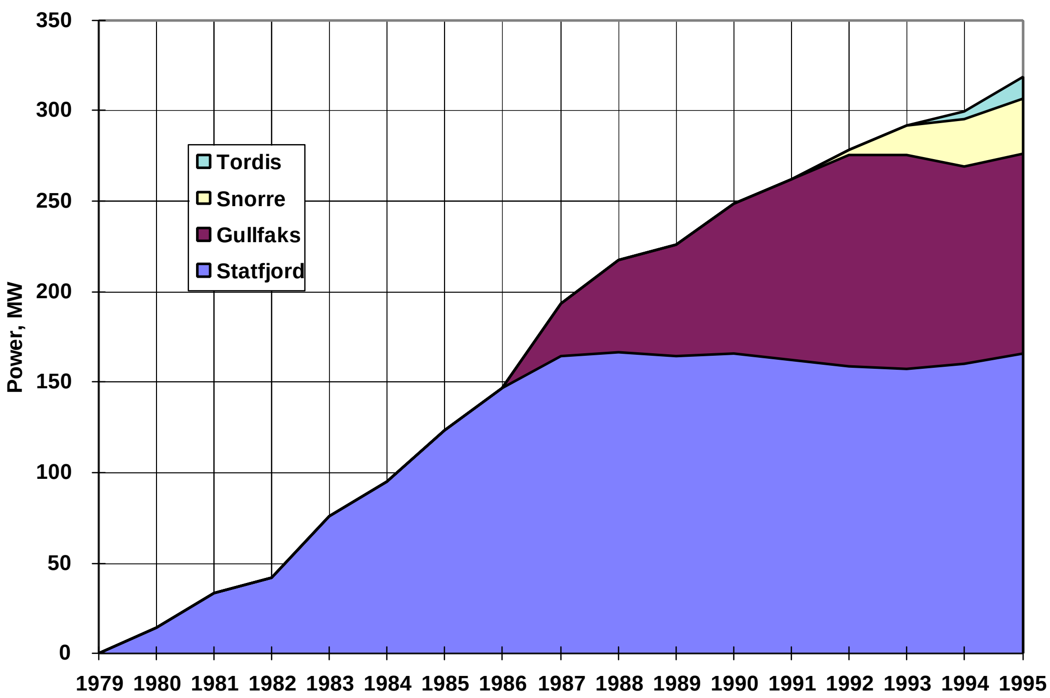

Figure 2.3 *Calculated power consumption on Statfjord, Gullfaks, Snorre and Tordis. Tordis is a satellite connected to Gullfaks. The other satellites are included in the account for their respective mother field.*

A ten years production prognosis broken down on individual fields, has been available from the Norwegian Ministry of Industry and Energy up to 1995. From the last prognosis (February 1996) the Ministry has adjusted upwards future petroleum production due to a corresponding adjustment of the total resources. From the same time on, the ten year estimates for each individual field are no longer publicly available. The future power demands for the fields in this province are therefore difficult to estimate with a high degree of accuracy.

The estimate for future power demand must therefore be based on some general considerations. The production from Statfjord and Gullfaks is on plateau and has been assumed to decrease slowly over the next ten years according to previous prognosis. There are, however, new fields in the same province to be developed, and these fields will according to the plans be developed as satellites with all the fluid processing on the existing platforms (Vigdis, Gullfaks South, Rimfaks and the Delta Discovery). Also the Visund field will partly process its oil in existing platform, and partly have its own power production (44 MW will be installed). There are also other discoveries in the province (34/7-21, 34/7-22, 34/10-23 Gamma) and probably more will come as a result of exploration. When oil production from the Statfjord formation in the Statfjord field has ceased, the formation will contain a lot of gas which has been injected for more than a decade. If the demand situation allows, it would also be possible to connect the Visund field with a cable after some years (30 km). In this study it is therefore assumed that the total power demand in the province will be sufficient to justify a size of a 300 MW power plant for 15 years operation time starting in the beginning of the next millennium.

2.2 A flexible and reliable power system

If some of the existing generators are kept in place, they can both be used as a local backup, and also to fill the gap if the total demand is larger than the supply. The whole concept is therefor very flexible and reliable. If the production on a platform has to be turned down (this happens frequently), the power is also lost and a backup system based on diesel generators has to be started before the production can start again. A special feature for this concept is that the power supply will be independent of the production status on each individual field.

The supply of gas to the central power plant does not rely on gas supply from a particular field, but on all the fields connected to the Statpipe system. This provides a very reliable gas supply.

The gas turbines with mechanical drive will, however, be replaced by electrical motors. These are much smaller and lighter than the corresponding gas turbines and their accessories. Some of these motors can be supplied by converting existing surplus generators (a generator and a motor is the same machine). This represents an extra investment, but this will also increase flexibility because almost all power will be supplied by electricity. At the present it is not possible to trade between power to the gas compressors and the rest of the power system.

3. Technical and economical description

A simplified flow diagram for the concept gas power without release of CO_2 is shown in Figure 3.1. Descriptions of each main element including technical characteristics and yields, and investment and running costs, are given in this chapter.

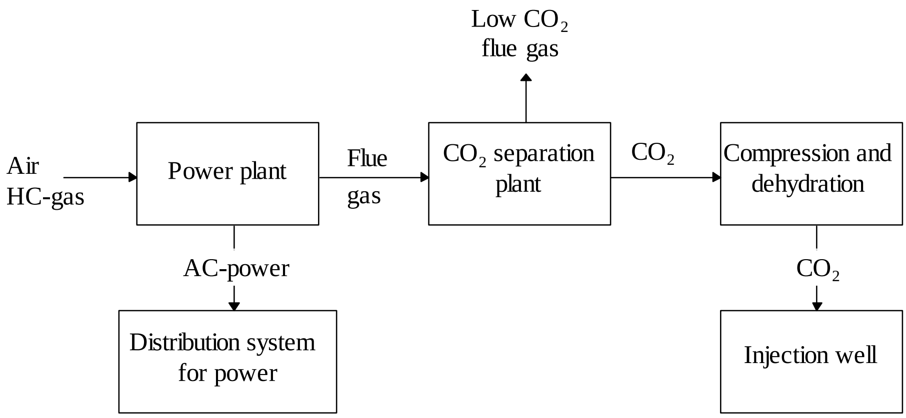

Figure 3.1 Power production with CO_2 separation and deposition. Simplified flow diagram of the concept.

3.1 Carrier

The Statfjord A platform is a large concrete, gravity base structure consisting of several hundred thousand tonnes of steel and concrete with the base pressed into the sea-floor at 146 m depth. When the present process equipment is removed it offers a 90m × 70m base construction area with a total carrying capacity of 50 000 tonnes. For this concept the power and the CO_2 separation plants represent the main mass loads. As will be shown below, the total mass of these plants is well below the carrying capacity of the Statfjord A platform.

The space requirement of the process equipment represents a larger uncertainty as placement on a limited area available will require a different plant layout compared to ordinary land based installations where space limitations are no important factor. In this pre-study it is assumed that it is possible to place the equipment on the available space. This assumption is justified by the fact that the weight carrying capacity of the platform is almost twice the weight of the process equipment. Whereas the mass restriction of the platform is an absolute limit, the space requirement of a standard plant can be relaxed by a more compact layout of the process equipment, and if necessary by building in height. It is beyond the scope of this study to show how a more compact layout of the plants can be realised. This is a topic for an extended study of the concept. The possibility of reducing the size is, however, indicated in Chapter 3.2, where it is shown that the space requirements of a combined power plant can be reduced by a factor of three or more.

In order to take the carrier into use for the present purpose the existing installations topside on the platform has to be removed. This is a task that most likely will have to be done as the first stage of abandonment, independent of what is the planned faith of the main installation. Costs of topside removal will thus not be included as a cost factor in the present concept, although offshore removal is likely to be more expensive than a possible onshore removal prior to onshore demolition.

Following removal of topside equipment, the main construction may either be dumped in deep water or demolished and the steel recovered. It has not been possible to acquire reliable cost data for these operations, although several inquiries have been made both to the industry and the authorities. One reason for this is that abandonment is still far ahead for most installations in the North Sea. In a study by NPD (1994) the average cost of abandoning each of the about 70 large and small installations placed on the Norwegian Continental Shelf was 700 MNOK. Since the Statfjord A platform belongs to the small group of large installations, and is not designed to be refloated, the cost of abandonment will be considerable larger than the average. In this work it will be assumed that one billion NOK can be saved if only the platform is cleared for existing process equipment compared to complete abandonment. This is an uncertain, but most likely conservative estimate. For comparison, the cost of abandonment of a 92 000 tonnes steel gravity base, and 19 000 tonnes topside weight platform at Maureen (UK) is estimated to 450 MNOK or 650 MNOK, for dumping or full recovery, respectively. This platform is designed to be refloated (Terdre *et al.* 1996).

A postponed expense can be regarded as an income at time zero for the economic analyses, but must be added as a cost at the end of the project period. The present value of an expense forward in time is, however, reduced, and developments in technology may lead to reduced future costs.

The saved abandonment costs are considered as a negative investment cost at the start of the project. The costs of operating and maintain the platform are estimated to 0.5% of the saved investment costs. The cost data are summarised in Table 3.1.

Table 3.1 Investment cost and yearly running costs for carrier.

Investment cost (MNOK)	-1000
Yearly running costs (MNOK)	5

3.2 Power plant

3.2.1 Plant description

A modified standard combined cycle power plant with a net output of 360 MW forms the basis for the power plant calculations. The modifications, compared to a standard plant, are that low pressure steam is extracted from the process to feed the MEA-reboiler in the CO_2 separation plant (see below). Further, a fraction of the exhaust gas from the steam boiler is cooled and recirculated to the inlet of the gas turbine compressor where it is mixed with air before compression. Based on previous work, 40% of the exhaust gas is assumed recirculated (Bolland *et al.*1991, Kværner 1995). This increases the CO_2 concentration in the exhaust gas from approximately 3% to 6%, and thus allows a reduction in the size of the CO_2 separation plant. Based on theoretical considerations, 40% of the flue gas can be recycled with only minor modifications of the power plant. Bolland *et al.*(1991) assumed a 0.3% increase in the investment costs for the necessary modification). The feasibility of recycling of flue gas has not been demonstrated in test plants, however. Recycling of flue gas is in any case not a critical factor for the present concept.

Due to the extraction of low pressure steam from the steam turbine, the efficiency of the power plant is reduced. Further, mechanical work and electricity are supplied to the CO_2 separation plant, to the CO_2 compressors and other auxiliaries. The net effect delivered from the plant is thus reduced compared to a standard set-up. The various factors for reduced delivery of electric power are summarised in Table 3.2. The calculations of output reductions due to steam extraction, and power consumption in absorption plant and compressors, are based on corresponding calculations by Bolland *et al.* (1991). Power production due to plant auxiliaries is the same as used by Bolland *et al.* (1991) who considered a plant with approximately double capacity. The loss of power in the transmission system is set to 2% of the power net delivered from the plant.

Table 3.2 Power production and consumption (MW).

Power plant output without heat extraction	360
Output reduction due to steam extraction	-27.6
Consumption in CO_2 absorption plant	-6.5
CO_2 compression	-13.7
Plant auxiliaries	-5
Loss in power transmission	-6.1
Net power production	301

In the calculations of gas consumption and CO_2 production, it was assumed that 360 MW could be produced from the plant at a thermal efficiency of 60% if heat was not extracted from the plant. This efficiency is somewhat higher than what is the rating of new plants delivered today. The efficiency of a 350 MW combined power plant from ABB (KA26-1) is 58.3%. Correspondingly a Siemens GUD 1S.94.3A (359 MW) has an efficiency of 58.1%. Siemens expects to attain their announced goal of 60% in the foreseeable future. Since the realisation of the present concept is some time ahead, the use of 60 % thermal efficiency is justified. The heating value of the combustion gas, the CO_2 coefficient, the yearly gas consumption and the yearly CO_2 production of the power plant are summarised in Table 3.3. The heating value and the CO_2 coefficient are based on a gas composition given by Naturkraft. A yearly running time of 8000 hours is used in the calculations.

Table 3.3 Physical data and mass flows of combustion gas and CO_2.

Quantity	Value
Min. heating value of combustion gas (kJ/kg)	46 684
CO_2 coeff. of combustion gas (kg CO_2/Sm^3gas)	2.386
Consumption of combustion gas (MSm ^{3}/year)	425
Production of CO_2 (Mt/year)	1.02

3.2.2 **Size and weight**

The size requirement for a 360 MW combined cycle power plant will strongly depend on the layout of the process equipment and the shaft arrangement. A standard single shaft arrangement of the GUD 1S.94.3 will require 130m $\times$ 47m $\times$ 40m (length $\cdot$ width $\cdot$ height). Correspondingly a single shaft arrangement of the ABB KA26-1 will require 120m $\times$ 50m $\times$ 60m, whereas a standard multiple shaft arrangement requires 92m $\times$ 82m $\times$ 60m.

The mass of a 723 MW combined cycle power plant was estimated to approximately 20 000 tonnes by Bolland *et al.* (1991). This corresponds to 13 200 tonnes when the mass is scaled down with a scaling exponent of 0.6. This is in good agreement with the mass of the 375 MW combined power plant (14 000 tonnes) proposed in the EPOS-concept (Electric Power on Sea, Kraftwerk Union AG 1981).

The EPOS power plant, comprising a three shaft arrangement of the two gas turbines and one steam turbine, was planned constructed on an area of 45m $\times$56m. The 2520 m^2 area of this plant can be compared to the 7544 m^2 plant area for the standard multiple shaft arrangement referred to above. Based on drawings of the layout of the EPOS-concept (Jeffs 1981), it is likely that the construction area of this plant could have been compacted further.

3.2.3 **Investment costs and running costs**

Investment costs for the power plant are estimated based on the average cost of standard turn key plants as given by ABB and Siemens. The total manning of this type of power plants is in the range of 40-45 persons. The yearly running costs, except combustion gas, are estimated to 2% of the turn key cost and the cost of 45 man years of 1.2 MNOK each. The high labour cost reflects extra costs to offshore operations. As is discussed in the next chapter, 90% of the CO_2 produced in the power plant will be removed from the flue gas released to the atmosphere. A CO_2 tax (0.85 NOK/Sm^3) corresponding to 10% of the gas consumption will thus have to be paid. This cost is also included in the yearly running costs. Insurance is set to 1% of the investment costs.

Investment costs and yearly running costs for a 360 MW power plant are summarised in Table 3.4, corrected for offshore operation. For the necessary modifications to place the plant on the carrier, the land based turn key cost is increased with 40%. This cost increase is a very uncertain estimate.

Table 3.4 Investment cost and yearly running costs, except gas, for power plant.

Item	Amount (MNOK)
Investment cost for power plant	1726
Yearly running cost except gas	137

3.3 CO_2 separation plant

3.3.1 Plant description

CO_2 can be removed from power plant exhaust gas commercially by means of several separation processes. Some of these methods, including chemical active separation processes, physical absorption processes, absorption by molecular sieves, membrane separation and cryogenic techniques are discussed by Riemer (1993) and Bolland *et al.* (1990). In this work only chemical active absorption based on use of mono ethanol amine (MEA) is considered. Development work to find better absorption fluids is in progress, but will not be discussed in this work.

In the MEA process CO_2 from the cooled power plant exhaust gas reacts with aqueous solution of MEA in a contacting device, usually an absorption tower. Most of the CO_2 is thus removed from the exhaust gas that is released to the atmosphere. The aqueous solution containing the MEA-CO_2 compound is pumped to a stripper section where the reaction is reversed through heating with steam. The CO_2 and water vapour leaving the stripper is next cooled and essentially pure CO_2 leaves the separation plant for further treatment (in this case compression and drying).

Two realisations of the MEA absorption process are considered, a standard plant where CO_2 and MEA are contacted in a standard absorption tower, and a contactor where the MEA solution is pumped through porous hollow membranes. This allows an increased specific contact area between gas and liquid, and the size of the contacting unit can thus be reduced. A membrane absorption unit is being developed by Kværner Water Systems. This unit is a part of a compact CO_2 separation plant that can be installed on oil platforms in operation in order to remove CO_2 from the existing gas turbines. The process is described in a report written for the State Pollution Control (Kværner 1995).

The amount of CO_2 that can be removed from the exhaust depends on the size of the absorption unit and the concentration of CO_2 in the exhaust. For a standard plant the economical recovery limit is approximately 85% for 3% CO_2 in the exhaust and 90-92% for 8% (Holt 1991). Bolland *et al.* (1991) considered a standard absorption plant with 90% CO_2 recovery from a similar power plant exhaust gas as in this work, and this plant is used as basis for the calculations here. The process developed by Kværner Water Systems is also based on recirculation of exhaust gas in the power production, but only 86% of the CO_2 is removed from the exhaust.

3.3.2 **Size and weight**

A conventional CO_2 absorption plant with capacity of treating CO_2 from a 723 MW power plant is estimated to have a mass and plant area of 25 000 tonnes and 110m $\times$ 110m, respectively. The treatment volume of exhaust gas from this plant is several times larger than the size of an optimal line in a CO_2 recovery plant (Holt 1991). The mass and area of a standard separation plant needed for the 360 MW power plant are thus estimated to 12 500 tonnes and 110m $\times$ 55m, respectively. The height of the absorption tower will typically be 45m.

The weight of a modified plant is estimated to 4885 tonnes by extrapolation of weight estimates given for smaller plant sizes considered by Kværner (1995). Since the main difference is due to a smaller absorption unit, the 12 500 tonnes estimate for a standard plant seems to be high.

3.3.3 **Investment and running costs**

Investment and running costs have been estimated both for a standard absorption plant and the modified plant proposed by Kværner Water Systems. The standard plant calculations are based on cost data as given by Bolland *et al.* (1991) with linear down-scaling with respect to CO_2 load. The 1991 costs are increased by 9.8% which is the estimated cost increase from 1991 to April 1996. This estimate is the average of the Chemical Engineering plant cost index (+7.0%) and the Marshall & Swift equipment cost index (+12.7%), extrapolated to April 1996 from data published in Chemical Engineering (January 1996). A 40% increase due to offshore location is also included. The running costs (operation and maintenance) for an offshore plant are set equal to 5% of the investment cost as used by Bolland *et al.* (1990), and the MEA costs are based on the MEA costs used by Bolland *et al.* (1991), adjusted with 9.8% for inflation. Insurance costs are set to 1% of the investment costs.

The investment and running costs for the modified plant are based on cost data given by Kværner (1995), extrapolated to the CO_2 load for the plant size of this study by fitting curves to the data given for three smaller plant sizes. No adjustments for inflation have been added to these cost data published late in 1995. Investment and running costs for the two alternatives are given in Table 3.5.

Table 3.5 Investment cost and yearly running costs, except insurance for two CO_2 recovery plants (MNOK).

Item	Standard CO_2 recovery plant	Modified CO_2 recovery plant
Investment costs	889	1534
Yearly running cost	63.8	78.2

3.4 Compression and dehydration

The CO_2 from the separation plant is cooled, compressed and dried before it is piped to the injection well. The necessary equipment, which includes a gas scrubber, multistage compressors and a drying plant based on the tri-ethylene glycol (TEG) process, is described by Bolland *et al.* (1991). The investment cost of the compressor and TEG plant are based on Bolland *et al.*'s figures, linearly down-scaled with compressor work and CO_2 load, respectively, and corrected for inflation as in Chapter 3.3.3. Running costs for offshore operation are set to 5% of the investment costs, and insurance 1%.

Investment and running costs for compressors, including CO_2 scrubber and inter-coolers, and the drying plant are given in Table 3.6.

Table 3.6 Investment cost and yearly running costs for CO_2 compressors and TEG drying plant.

Item	Compressors	Drying plant
Investment costs (MNOK)	59	38
Yearly running costs (MNOK)	3.5	2.3

3.5 Injection well

The dried and compressed CO_2 leaves the platform and is injected into an underground formation. The mass to be injected corresponds to 914 000 tonnes per year (90% of the CO_2 formed during power production). This amounts to 3426 m^3/day, or approximately 22 000 bbl per day, which is comparable to the amount to be injected into the Utsira formation in the Sleipner Vest CO_2 disposal project, where only one injection well is to be used (Korbøl and Kaddour 1995).

At the end of the petroleum production period there will be a large number of available wells on the platform. It is assumed that one existing well can be chosen for injection purposes, eventually after shutting off the well bore at the desired position and re-perforating. The CO_2 will be deposited in a location where there is no danger for the fluid to migrate to any of the petroleum producing reservoirs in the region. The optimal location for CO_2 deposition may be in an aquifer or an isolated part of an oil reservoir. This position will be determined after detailed analyses of the formations in the region.

The cost of taking a well into use for CO_2 injection is set to the same value as used for making a new injection well in a previous project (Holt and Lindeberg 1992). The cost of maintaining the injection well and tubing from the compressors/drying plant is set to 2% of the cost of making the well. As dried CO_2 is to be injected, no special corrosion problems are expected (Drugli and Rogne 1992). Investment and operating costs of the CO_2 injection well are summarised in Table 3.6.

Table 3.6 Investment and operating cost of CO_2 injection well.

Item	Amount (MNOK)
Investment costs	80
Yearly running cost	1.6

3.6 **Power system**

It will be necessary to lay two major AC cable links from the generating platform to the two neighbouring fields. It will also be necessary to connect Statfjord B and C to Statfjord A, but these cables are much shorter. Gullfaks A, B and C are already inter-connected, but it is possible that this line has to be upgraded. Only the inter-fields cables are given as individual items in Table 3.7, and connections within the field are included in these costs. It is assumed that there exists sufficient with J-tubes at the platforms for cable landing.

There are presently 11 gas turbine powered compressors on the platforms. These have to be powered with electric motors. There are 15 gas turbines with generators, and 11 of these generators will be converted to motors. These generators provide a superb resource because the units will work as synchronous motors ideally suited for speed control. This is achieved by equipping the units with transformers and converters (Figved 1992). This speed control will be superior to the present control of the existing gas turbines which work best at full load at fixed rpm. Electric motors have almost constant efficiency independent of the load. This will reduce the total power demand, but no credit for this is included in this simplified concept study.

The conversion of 11 generators to motors will leave four gas turbines with generators for backup and to cover possible extra power capacity (80 MW), making the whole concept very flexible and robust.

Conversion of generators to motors is investments on the power receiving platforms, but all these types of investments are included in the power plant project, to give a fair representation of the total economy. The investment costs for the various elements are given in Table 3.7. Maintenance costs are set to 1% of the cost of the cables.

Table 3.7 Investment and running costs of the power transmission system.

Item	Amount (MNOK)
Cables 120 MW	160
Cables 30 MW	105
Converters and transformers	88
Retrofitting existing 11 generators, other installations	100
Maintenance costs	2.7

3.7 Connection to the national grid

Instead of power delivery to offshore installations, the produced power can be rectified and sent to shore using a HVDC-cable. On shore the power will be derectified and connected to the national grid. The transport system for electric power has been described previously (Holt and Lindeberg 1988, Bolland *et al.* 1990).

The investment and running costs for the transport system is summarised in Table 3.8. The investment costs are based on the figures given by Bolland *et al.*(1991), adjusted for inflation. The cable costs are for a 183 km 500 MW sea cable, corresponding to the distance between Statfjord A and Kolsnes. The costs of the rectifying and derectifying stations are linerarly downscaled from 500 MW. The power loss by rectifying, transportation and derectifying are comparable to the loss in the offshore distribution system.

The sales price of electric power delivered at Kolsnes can be compared to the production costs of power from an onshore located combined cycle gas power plant. For a gas cost of 0.60 NOK/Sm^3, the power cost is 0.22 NOK/kWh (Sæther and Bolland 1995). A cost of 0.11 NOK/kWh, estimated for CO_2 removal and deposition (Holt and Lindeberg 1990), must be added to this figure. The sales price for electric power is thus reduced from the offshore price of 0.46 NOK/kWh (see Chapter 4.2) to 0.33 NOK/kWh.

Table 3.8 Investment and running costs for transmission of electric power to land.

Item	Amount (MNOK)
183 km sea cables	617
Rectifying/derectifying stations	361
Running costs	2

4. Economic analyses

4.1 Investment costs

The investment costs for the various elements are summarised in Table 4.1 based on the figures given in Chapter 3. In addition to the basic equipment costs for the separate elements, come interest in the building period (two years), engineering costs, administration costs, training, testing and start up costs and contingency. These additional costs are calculated as percentages of the total equipment costs following guide lines given by Bjøntegård (1971). Since the total process consists of an integration of equipment delivered as turn key plants, low percentages are used in calculation of the additions. The total addition amounts to 22% of the total equipment costs. This is higher than the 12% additions used by Bolland *et al.* (1991), when their site costs and investment costs, which are not relevant in the present case, are excluded.

Table 4.1 Calculation of total capital investment.

Component	Amount (MNOK)
1. Power plant	1726
2. CO_2 separation plant	889
3. Compressors	59
4. Dehydration plant	38
5. Power distribution system	453
6. Injection well	80
7. Total costs of equipment	3245
8. Interests	231
9. Engineering costs (5 % of 7)	162
10. Administration costs (5 % of 7)	162
11. Training, testing and start up costs (2% of 7)	65
12. Contingency (10% of 7)	324
13. Carrier	-1000
14. Total capital investment	3190

4.2 Running costs and incomes

The costs of operation and maintenance (running costs) are found by adding the costs for the individual elements as given in Chapter 3. In addition come costs of gas feed to the power plant, calculated based on a gas price of 0.60 NOK/Sm^3. The running costs are summarised in Table 4.2. Costs and incomes to the project are based on a yearly running time of 8000 hours.

The incomes to the project are due to the delivery of electric power to the petroleum installations in the region. The price of electric power is estimated based on the gas price, CO_2 tax and running costs of the gas turbines presently in operation. The running costs are set to 0.03 NOK/kWh (Holt and Lindeberg 1991). The thermal efficiency of the gas turbines presently in operation is on average estimated to be 0.3. This implies that 0.295 Sm^3 of gas is consumed per kWh of produced turbine power. With a CO_2 tax of 0.85 NOK/Sm^3 the power costs amounts to 0.46 NOK/kWh.

Table 4.2 Running costs.

Item	Running cost (MNOK)
1.Gas	255
2. Power plant	137
3. CO_2 separation plant	64
4. Compressors	3.5
5. Dehydration plant	2.3
6. Power distribution system	2.7
7. Injection well	1.6
8. Carrier	5
9. Total running costs	471

No credits from sale of CO_2 for enhanced oil recovery (EOR) in the neighbouring oil fields are included in the base case calculations. The value of CO_2 for EOR purposes depends on the efficiency of CO_2 injection in the oil reservoirs in question. Taber (1989) related the value of CO_2 to the oil price through the formula:

$$CO_2\text{-value (NOK/Sm}^3\text{)} = 0.125 + 0.00625 \cdot \text{oil price (USD/bbl)}$$

With an oil price of 20 USD/bbl the formula gives a CO_2 value of 0.25 NOK/Sm^3. Project incomes are summarised in Table 4.3.

Table 4.3 Incomes from sale of power and a possible CO_2 sales.

Type of income	Income (MNOK/year)
Sale of electric power	1104
Possible sale of CO_2	(123)

4.3 Net present value and internal rate of return

The calculated net present value (NPV) and internal rate of return (IRR) will depend on total capital investments at the start of the project, possible capital investments during the project time, yearly running costs and incomes, possible shut down costs at the end of the project and the lifetime of the project. Conditions for the base case calculations are summarised in Table 4.4. Sensitivities to some changes in these conditions are presented in the next section.

The lifetime of the project is set to 15 years in the base case calculations. This is less than the expected lifetime of the process equipment (20-25 years). The relatively low economic lifetime chosen reflects the large uncertainty in the petroleum production activity in this petroleum province beyond a period of approximately 20 years from now. At the end of the project the carrier will have to be abandoned. The costs of abandonment are set equal to the corresponding income at the start of the project.

NPV and IRR of the base case project calculation are given in Table 4.4. The discount rate used in the calculation of NPV is 7%.

Table 4.4 Base case quantities used in the NPV and IRR calculations.

Quantity	Value
Total capital investments (Table 4.1)	3190 MNOK
Running costs (Table 4.2)	471MNOK
Incomes (Table 4.3)	1104 MNOK
Running time	8000 hours
Project lifetime	15 years
Shut down costs	1000 MNOK
Net present value	2211MNOK
Internal rate of return	17.6%

The net present value is the present value of the project over the total capital investment when all future incomes and expenses are discounted with 7% interest to zero time. The internal rate of return is the discount rate that gives a zero NPV. Since the future cash flows are not adjusted for inflation, or any other future expected cost changes, the interests used are interests above the general inflation. If the main costs and incomes in the projects develop significantly different from each other, and/or the general inflation, the cost indicators (NPV and IRR) lose some of their absolute relevance. They are, however, still useful in comparing different investment alternatives, and for use in sensitivity analyses. No income taxes are included in the calculations. This implies that no attempts are made to divide the profits of the project between the state and the owners of the project.

4.4 Sensitivity analyses

In the sensitivity analyses, the effect on NPV and IRR on changes in some of the economic factors is studied. Large uncertainties are included in several factors, but the largest uncertainties are related the capital investments. Changes in incomes, running costs, technology, value of CO_2 and lifetime of the project will, however, also be considered. The concept with CO_2 injection will also be compared with offshore power with full release of CO_2 to the atmosphere and a scenario where the power is transmitted to land. All changes are made relative to the base case conditions given in Tables 4.1 to 4.4. The results are summarised in Table 4.5, and are discussed below.

Table 4.5 Sensitivity analyses.

Factor and change relative to base case	NPV (MNOK)	IRR (%)
1. Base case	2211	17.6
2. Power and CO_2 plant extra costs varied ± 30%	1316/3106	12.4/25.2
3. CO_2 recovery plant technology changed	1247	12.0
4. Platform abandonment cost ± 50%	2530/1892	21.6/14.7
5. Sales price of electric power ± 20%	4222/200	25.6/8.1
6. Running costs ± 20%	3069/1353	21.1/13.9
7. Sales of CO_2 for EOR purposes	3453	22.7
8. Change in project lifetime +5 /+ 10 years	3255/4000	19.1/19.5
9. Full CO_2 release to the atmosphere	3265	32.2
10. Transport of power to land, 15/25 years oper.	-1291/-287	-0.1/6.1

In the calculation of the power plant and CO_2 recovery plant costs the onshore turn key investment costs were increased with 40% due to offshore location. These extra costs should reflect extra costs due transporting and building the plants offshore, which also requires a different and more compact plant layout than standard plants. Table 4.5 shows the effect of decreasing the extra cost to 10%, and increasing the extra cost to 70% of land based investment costs. These changes correspond to total capital investments of 2466 MNOK and 3914 MNOK, respectively.

If a conventional CO_2 recovery plant can not be used offshore *e.g.* due to space limitations, one option can be to use a modified plant as suggested by Kværner Water Systems. This change in technology increases the capital investment to a total of 4023 MNOK.

Higher abandonment costs of the platform strengthens the economy of the project due to delay of an expense. It is likely that the project will profit on developments in technology since the platform is not anymore likely to be among the first to be abandoned. Costs of removing the process equipment have not been included since it is likely that the process equipment represents a substantial value after only 15 years of service. This can cancel the removal costs.

The economy of the project is sensitive to the sales price of electric power. A ± 20% variation in the estimated price will be obtained if *e.g.* the gas price is increased to 0.90 NOK/kWh or reduced to 0.30 NOK/kWh. The price of electric power is also sensitive to the thermal efficiency of the present gas turbines, possible new investments in equipment, and in the value of the CO_2 tax.

The sensitivity to the running costs is less than for the sales price of power, but still significant improvements can be made if the running costs are reduced. The estimated running costs used are higher than the values used by Bolland *et al.* (1991), who did not distinguish much between onshore and offshore operations neither in investment costs nor in operating costs. Possible advantages of operating integrated plants have not been included. The maintenance costs of the platform are a very uncertain estimate.

If the CO_2 produced can be used for EOR, extra incomes improve the economy considerably. The estimated income from sales of CO_2 corresponds to an increase in the price of electric power of 12%. CO_2 injection can be a powerful process for enhanced oil recovery in North Sea sandstone reservoirs (Lindeberg and Holt 1994).

If the CO_2 is not separated and disposed, full CO_2 tax must be paid. The power delivered from the plant will, however, increase, and the sale of this extra power will almost compensate the increased CO_2 tax. The total capital investments are reduced by 1376 MNOK. The improvement in the NPV is less than 1000 MNOK, and the almost doubling of the IRR is due to the lover total capital investment. The increased payment of CO_2 tax can be compensated by the increased sale of electricity due to the high power price offshore. With a power price of 0.23 NOK/kWh, the NPV are almost identical for the two projects, but none of the projects are profitable.

Transmission of the electric power to land has also been considered. The longer transport distances involved, and the use of DC power transmission technology, result in higher investment costs. Further, the sales price of electric power delivered to the national grid is expected to be less than offshore. The net result of this is a weakened economy. For 15 years project period the internal rate of return is negative. This means that the net present value is negative irrespective of the value of the discount rate. For 25 years life time the NPV is still negative with a discount rate of 7% as the IRR now is 6.1%. In this case, however, the invested capital is not lost, but the project must compete with other projects that can give higher profits. A commercial life time of 25 years, corresponding to the technical life time, is considered as most relevant for this scenario due to the low uncertainty in the future market for electric power on land.

5. Conclusions

One single Condeep platform has a carrying capacity for building a net 300 MW combined cycle power plan with CO_2 removal. This power production is sufficient to replace the existing power production from gas turbines on the three major Norwegian oil fields Statfjord, Gullfaks and Snorre.

Power production with CO_2 disposal from a 300 MW central unit will reduce the emissions of CO_2 with 1.6 Mt per year compared to the present use of gas turbines. These reductions represent 4.4% of the total Norwegian CO_2 emissions.

The present concept is technically feasible. The internal rate of return is estimated to 17.6%. The net present value is 2211 MNOK from a total capital investment of 3190 MNOK.

Central power production without CO_2 removal gives and internal rate of return of 32.2% provided that all the power (360 MW) can be sold offshore. This solution reduces the CO_2 emissions with 0.7 Mt, which corresponds to 2.0% of the present Norwegian emissions.

The economic figures presented above are first estimates and have large uncertainties. Conservative estimates are, however, mostly used throughout the calculations, and the results justify further studies that should include more detailed analyses.

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