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EOR Screening for Ekofisk

T.B. Jensen, K.J. Harpole, and A. Østhus, Phillips Petroleum Company

ABSTRACT

An investigation of alternative EOR processes having potential application in the giant Ekofisk chalk field is presented. Technical feasibility, process readiness, oil recovery potential, and related uncertainties and risks of five selected EOR processes, namely hydrocarbon (HC) WAG, nitrogen (N_2) WAG, carbon dioxide (CO_2) WAG, air injection and microbial EOR (MEOR), are assessed for possible application at Ekofisk. The objective of the screening study was to evaluate and rank the EOR alternatives and to select the most attractive process(es) on which to pursue further work toward possible field pilot testing. The focus of the paper is on the technical assessment of the relative oil recovery potential of each process, and on the importance of identifying critical operational and logistical considerations for implementation of an EOR processes in the offshore North Sea operating environment.

Estimates of potential EOR incremental oil recovery for the Ekofisk field can be quite significant. However, key project development and implementation issues and additional cost elements must be weighed equally with oil recovery forecasts in any EOR process ranking. Some of these issues (e.g. injection gas supply, facilities requirements, and the impact of EOR on chalk compaction, subsidence and wellbore integrity) may be significant enough to eliminate a process from further consideration.

In addition, there are significant differences in the quantity and quality of key laboratory and field data supporting the viability of the various EOR processes being considered. Only a limited amount of field-specific data are available to calibrate the performance predictions for some of the processes. There is also a wide variation in the technical readiness of each process to begin field pilot design studies. Table 1 summarizes the state of technical readiness for field implementation of each process and identifies some of the major risk elements and remaining work required to progress these EOR processes at Ekofisk.

BACKGROUND

The Ekofisk Field is located in the Norwegian Sector of the North Sea, Figure 1. The reservoir is an elongated anticline with the major axis running North-South covering roughly 12,000 acres, Figure 2. It produces from two fractured chalk horizons, the Ekofisk and Tor Formations, separated by a tight zone. The overlying Ekofisk Formation has a depth of about 9,600 feet and thickness varies from 350 - 500 feet with porosities from less than 30% to 48%. The underlying Tor Formation thickness varies from 250 - 500 feet with porosities from less than 30% to 40%. About two thirds of the 6.4 billion STB OOIP is in the Ekofisk Formation. The initial reservoir pressure was 7135 psia at a depth of 10,400 feet. The field initially contained an undersaturated volatile oil with a bubble point pressure of 5560 psia at the temperature of 268°F.

Ekofisk[1] was discovered in 1969 and test production was started in 1971 from the discovery well and three appraisal wells. Commercial test rates prompted development of the field from three platforms. Permanent facilities with 54 well slots and 300,000 STB/D (design capacity) process facilities were operational in May 1974. Development drilling was started June 1974. Oil production peaked at 350,000 STB/D in October 1976. Produced gas was reinjected[2] until a gas pipeline was installed to Emden, Germany, September 1977.

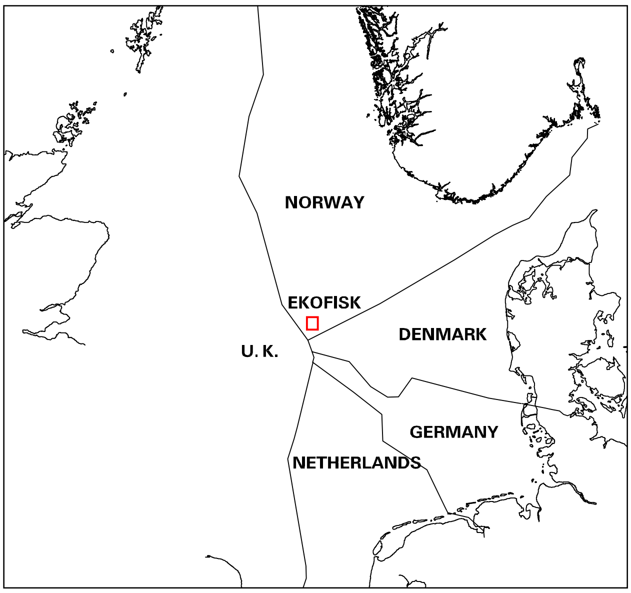

Figure 1. Map of North Sea with Ekofisk location.

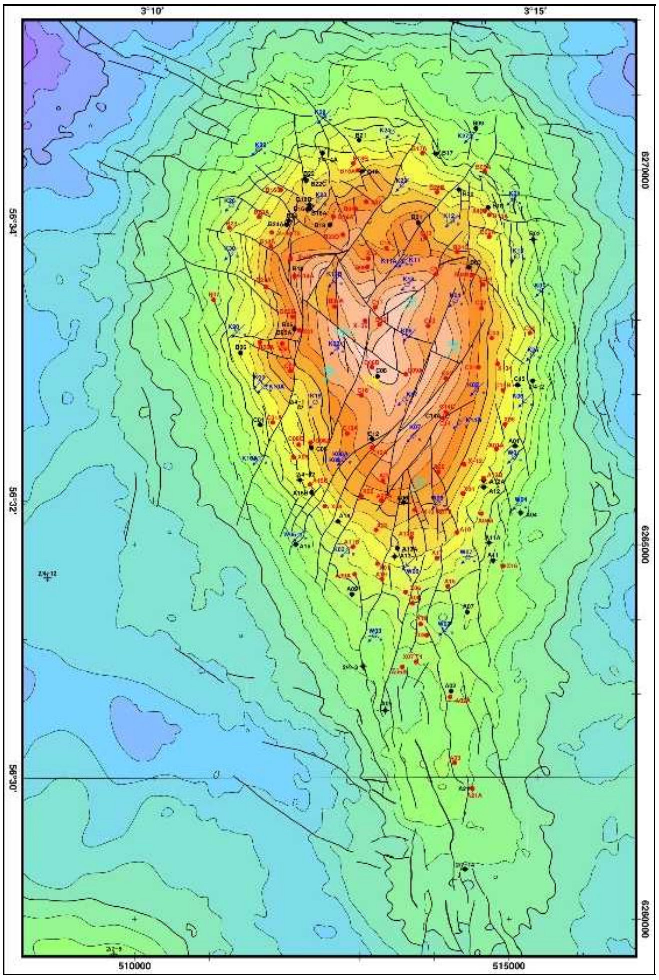

Figure 2. Top structure map for Ekofisk field

Ekofisk went through the bubble point in 1976 and GOR went from 1,500 to 9,000 SCF/STB by 1986. Primary depletion recovery (with reinjection of gas in excess of contract quantities) was initially estimated to be 18% of OOIP of which 6-8% was produced above bubble point. Improved recovery studies were initiated soon after start of primary production.[3] Favorable water imbibition results prompted a decision in 1983 to waterflood the northern Tor Formation using unheated, 42°F, seawater. A 30 slot water injection platform with 375,000 BWPD injection capacity was approved. Water injection started in 1987 to develop 162 MMBOE. Favorable waterflood response prompted fieldwide water-flood expansion[4]. Water injection capacity was increased to 820,000 BWPD which added almost 300 MMBOE.

Reservoir compaction and seabed subsidence continue to be a very important consideration in Ekofisk reservoir management strategy. A 1992 field study[5] concluded that the optimum strategy for Ekofisk would be to minimize future seabed subsidence by arresting pressure decline with pressure maintenance. Due to the age of the Ekofisk facilities and continued seabed subsidence, a decision was made in 1994 to gradually phase out existing facilities and install a new 50 slot wellhead platform and new process and transportation facilities. Drilling from the new wellhead platform started in October 1996. The new process and transportation facilities were commissioned in August 1998.

The current ultimate oil recovery estimate from Ekofisk is 38% of OOIP. The increase in recovery from the initial estimate of 18% is due primarily to the extensive water flooding, implementation of effective well monitoring and stimulation techniques, compaction drive, aggressive infill drilling, the Ekofisk redevelopment and extended field life, and overall field optimization.

Current plans for Ekofisk include continued water injection until 2012. At that point water injection will cease, and the field will be depressurized to the end of the license period in 2028. Opportunities to optimize the waterflood with continued infill drilling exist. Also, a major recompletion/sidetrack program is being evaluated for a number of existing water injection wells. This ongoing optimization of the Ekofisk waterflood has the potential for significant incremental oil recovery. Opportunities also exist for optimization of reserves during blowdown, being primarily associated with acceleration of reserves with additional production wells and enhanced compaction drive due to pressure depletion. Enhanced recovery methods also continue to be investigated as means of significantly increasing reserves and accelerating recovery.

Several enhanced oil recovery (EOR) methods have been considered for improving oil recovery beyond the Ekofisk waterflood scenario. Recognizing that 1% enhanced oil recovery represents about 64 million barrels of oil on Ekofisk, significant resources have been used in studying various EOR processes. Crestal gas injection, mainly for operational swing gas purposes, has been ongoing since 1975. A total of 1.3 TSCF of gas, around 21% of the cumulative produced gas, has been reinjected in Ekofisk as of June 2000. Analysis of early production behavior above the bubble point suggest that no immediate production of free gas was experienced. Less than 1% of the injected tracers were recovered following gas tracer injection tests in 1986 to 1988 which led to the conclusion that the injected gas has covered a large area. Review of well performance below the bubble point pressure has provided little clear evidence of oil production response to variation in gas injection rates. Based on numerous laboratory evaluations of oil phase continuity and field performance the assumption of capillary continuity has been used in modeling work to evaluate gas injection processes.

A major crestal nitrogen injection study[6] was completed in the late 1980's. Project economics were not favorable, due mainly to the significant costs of nitrogen rejection from the gas sales stream. Efforts were also put into a study of enhanced imbibition processes in the mid 1990's in order to determine the potential for increased oil recovery by injection of low concentration surfactants. The project was terminated in 1997 due to laboratory measurements of high surfactant adsorption, especially at the reduced reservoir temperatures around existing Ekofisk water injection wells.

WAG processes have been evaluated in the laboratory, through mechanistic simulations, and in one limited field injection test at Ekofisk. A single-well WAG pilot test was initiated in 1996 to test hydrocarbon gas injectivity into an Ekofisk well which had injected a total of 44 million barrels of water since 1991. Gas injection rates dropped to zero in a matter of hours. Subsequent analysis of the injection test showed that hydrate formation in the cold region around the injector was the most likely reason for the loss of gas injectivity. Various remedial measures are under considerations for gas injection in a possible future hydrocarbon WAG scenario.

APPROACH AND PREMISES

In 1998 the decision was made to conduct a broad scoping study to assess enhanced oil recovery potential for the Ekofisk Field. The objective was to evaluate and rank various EOR alternatives and to select the most attractive process(es) on which to pursue further work toward possible field pilot testing. Two underlying premises were adopted in the approach to evaluating EOR alternatives for Ekofisk. First, in the absence of definitive data to the contrary, any minor technical or logistical uncertainties were assumed to be favorably resolved prior to process implementation. Second, in the absence of sufficient Ekofisk-specific laboratory or field performance data, EOR process performance in the Ekofisk reservoir was assumed to be consistent with typical performance demonstrated in other field applications or calculated based on industry field and laboratory performance data. One consequence of these premises is that those less mature, emerging technologies (i.e. MEOR and air injection) may tend to be represented more favorably relative to the more extensively studied and tested technologies (HC WAG) where process performance is more constrained by Ekofisk-specific lab testing and/or field performance data.

Injectant Contact with Waterflood Residual Oil

One of the key issues determining incremental oil recovery by any EOR process being considered for application at Ekofisk is the ability of the EOR injectant to contact and mobilize waterflood residual oil in the fractured chalk. The premise for the process performance modeling used to generate the forecasts in this screening study is that injected gas will be able to move into the chalk matrix to contact and viscously displace water flood residual oil. This modeling premise is based on performance of the imbibition/viscous displacement of oil by water under current water flood operations as represented in the current full-field Ekofisk model.

However, any gas injection EOR process following waterflood at Ekofisk will operate under a different (dominantly gas/water) flow system than that which is dominant under water flooding. If gas preferentially flows through the fracture system and its contact with residual oil in the matrix blocks is either prevented by capillary threshold entry pressures or is severely rate-limited by a relatively slow process such as gas-water diffusion, then the incremental oil recovery could be dramatically lower than forecasted. *The field simulation model forecasts and laboratory experimental work to date were all conducted under the implicit premise that injection gas will be able to contact residual oil in the chalk matrix.*

Although studied in the past,[2] additional study of gas flow and displacement mechanisms in fractured Ekofisk chalk is needed to validate this premise. This involves studies to understand the relative importance of viscous, capillary and diffusion dominated mechanisms in fractured Ekofisk chalk gas injection processes. While this issue may to some extent be examined in laboratory experiments, it is a field-scale issue and one of the central questions to be addressed in a field pilot test of any gas injection EOR process. Additional mechanistic modeling work would be useful in further examination of this question and will be needed to help design and interpret any field pilot test.

The Incremental Impact of Compaction

Any incremental impact (positive or negative) of a specific EOR process on the mechanical properties of the chalk, have not been incorporated into the process performance modeling forecasts or project implementation scenarios presented in this screening study. Such incremental compaction impacts on recovery and/or subsequent impacts on seabed subsidence may be caused by chalk dissolution, alteration or compaction.

Modeling Approach Used To Generate EOR Forecasts

The SENSOR[7] compositional simulator was used to model gas injection phase behavior and the ability of HC and non-HC injection gases to mobilize and recover incremental oil in water flooded portions of Ekofisk. A sector model having representative Ekofisk layer properties and well spacing was used for the EOR process simulations. The sector model was a 7x7x14 five-spot configuration with layer properties taken from the central water flood area of Ekofisk. The residual oil saturation under water-oil displacement was 30% and the residual oil saturation under gas-oil displacement was 25%. The EOR process simulations used a 15-component EOS tuned to available laboratory PVT data on Ekofisk fluids and the specific injection gas.

All EOR simulation modeling used a single porosity model with effective properties and viscous displacement characteristics tuned to match the primary depletion and waterflood performance in the history-matched full-field Ekofisk model. This provides the EOR injectant unrestricted access to water flooded residual oil in the chalk matrix. If gas preferentially flows through the fracture system and its access to residual oil in the matrix blocks is limited, then the incremental oil recovery could be dramatically lower. However, the effect should be similar for all the gas injection processes.

The air injection oil displacement process involves first a combustion effluent gas front (N_2/CO_2) which moves ahead of the thermal reaction front, followed by a thermal reaction zone with a complex of possible mechanisms including steam distillation and low or high-temperature oxidation reactions, depending on local reservoir conditions, O_2 flux rates, etc. Air injection was modeled in Sensor using a hybrid approach by first forecasting the effect of the combustion reaction effluent gas front. Following this, the effect of the thermal front was simulated using a first-contact miscible gas flood with displacement parameters set to model those of the thermal displacement front (as determined from prior industry combustion tube experiments with North Sea oils). The velocity of the miscible front was calibrated to the air utilization requirement and velocity of the “thermal” front, and the fuel requirement of the thermal reaction was modeled using a miscible residual oil saturation of 5% PV.

Detailed modeling of the thermal reaction mechanisms require laboratory data from reservoir core material and fluids (combustion tube experiments using Ekofisk oil and chalk) and a rigorous-physics thermal simulator, neither of which were available or within the scope of this preliminary study. Subsequent simulation modeling using the STARS™ thermal simulator produced incremental oil recovery results very close to those obtained using the hybrid modeling approach.

Microbial (MEOR) oil recovery forecasts were generated by up-scaling a composite of typical field project results. It was necessary to use this empirical approach to estimate MEOR performance as the exact mechanisms of microbial oil recovery are still poorly understood and consequently there are no simulation models available to make reliable MEOR field performance forecasts.

Scaling of forecasts from sector model to full field

The various EOR production forecasts and relative injection and production volumes were scaled up from the individual sector model process simulations for comparison and ranking in a hypothetical full-field EOR project development. Scaling factors were chosen such that the final upscaled incremental cumulative oil, cumulative gas injection, and cumulative gas production for the HC WAG process sector model matched earlier full-field model HC WAG simulation forecasts for a premised full-field project development having a total injection rate of 350 MMSCF/D. All the other EOR process sector model forecasts were then upscaled using the identical scaling factors such that key process-related differences in the magnitude and timing of production responses were preserved and would be properly reflected in any subsequent comparative analyses. *Obviously such a scaling procedure is not rigorous, and the resulting incremental EOR production forecasts are hypothetical and intended for comparative ranking purposes only.*

The final comparative process performance forecasts for a hypothetical full-field implementation of each of the five EOR processes are shown in Figure 3. Keep in mind that the character of the upscaled, full-field response retains the profile of the underlying mechanistic sector model and would generally not be expected to be the same as if a comprehensive full-field modeling study had been conducted for each individual EOR process. The most notable difference is that the EOR response is much sharper in the sector model than would be expected from a full field model, even though the final incremental recoveries should be very close. The scaled-up forecasts provided realistic full-field volumes and relative injection/production rates to allow gas supply and facilities needs to be assessed for the various EOR alternatives.

The EOR performance forecasts shown in Figure 3 all premise the same hypothetical, full-field EOR development plan. These forecasts honor both the relative process performance characteristics from the mechanistic sector modeling and existing field facilities constraints. WAG cycle sizes and operating schedules were adjusted slightly as needed to keep upscaled field production rates within existing facilities capacity limits. Also there was no optimization performed for any individual EOR process. Each EOR process is premised to be implemented beginning in 2004. EOR injection continues for 13 years, with blowdown of the reservoir beginning in 2017. The hypothetical full-field WAG development plan premises 30 current water injection wells being converted to EOR (WAG) service. A gas injection capacity of 350 MMSCF/D is premised for all WAG processes based on facility concerns.

Air injection is premised as continuous gas injection into 30 injection wells at an injection capacity of 650 MMSCF/D. MEOR premises treatment of 30 injection wells with nominal capacity of 800,000 BWIPD.

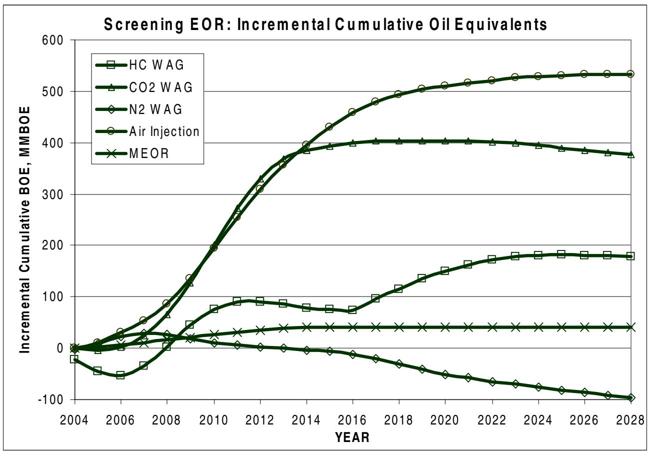

Figure 3. Comparative full-field cumulative incremental oil equivalent forecasts for the five EOR processes.

COMPARATIVE EOR PROCESS EVALUATIONS

The key technical and logistical issues associated with each EOR process are addressed in the individual process discussions which follow. Each discussion includes: (1) a summary of major process mechanisms and the sources and quality of data available to characterize the process, (2) examination of key premises and issues regarding implementation of the EOR process at Ekofisk, and (3) a discussion of major cost/benefit elements associated with each process. If not resolved, some of the issues raised may be significant enough to eliminate an EOR process from further consideration.

HC WAG

Summary of Major Process Mechanisms, Data Sources, and Data Quality

The initial displacement of water flood residual oil by injected HC gas takes place as a viscous displacement of the oil by the injected gas. The residual oil saturation following WAG displacement is lower than the residual oil saturation to water flooding. This viscous displacement mechanism is volumetrically relatively minor over the project life, and progressive vaporization of intermediate oil components by injection gas becomes the dominant oil recovery mechanism as cumulative injected gas volume increases.[8] Laboratory experiments have shown that HC gas efficiently vaporizes intermediate Ekofisk oil components in the C5 to C13 range under field operating conditions.

Specific laboratory PVT data were available to describe the phase behavior and fluid properties of mixtures of prospective HC injection gas and Ekofisk crude. These data were used to tune the EOS in the compositional simulation model. Gas injection core flood data from imbibed core vaporization experiments were available to validate the displacement mechanisms of HC gas displacing water flood residual oil in chalk matrix.

Major Process Implementation Issues and Premises

Successful implementation of any HC WAG project requires a source of HC gas for injection. The project performance forecasts premise that a supply of HC gas will be available to be taken from the gas sales line at Ekofisk. Note that this EOR process involves the injection of HC gas and thus deferment of net HC gas sales.

A major technical issue remaining for implementation of HC WAG is resolution of injectivity problems in cooled regions around Ekofisk water injectors where hydrates are expected to form based on thermodynamic considerations. This study premises that an effective solution or "work around" will be found for the gas hydrate problem.

The performance forecast does not include any impact of or on chalk mechanical compaction due to the HC gas WAG process. This premise should be evaluated further if this process is selected to be progressed towards a field pilot.

Major Cost Elements

Some of the additional cost elements for the HC WAG process in large-scale application at Ekofisk are:

Potential Incremental Costs

a) Acquiring HC gas for injection (product costs & pipelines),
b) Upgrading of existing compression facilities,
c) Additional CO_2 tax for added compression/operations,
d) Upgrading of injection system and wells for high pressure gas injection,
e) Incremental operating costs (including costs to mitigate gas hydrate problem), and
f) Opportunity costs – produced gas capacity constraints.

Potential Benefits

a) Reduced costs for gas lift. Injection of HC gas, with the resulting decrease water injection relative to the base forecast will cause reduced water production over time. Figure 4 shows a comparison of water production at Ekofisk with and without HC WAG. A significant reduction in produced water with HC WAG injection is observed which will result in the need for less gas-lift gas. This in turn reduces operating costs and will allow for increased gas sales in periods when gas processing is plateaued at facility capacity.
b) Reduced future costs/penalties associated with produced water handling. The decreased amount of produced water as a result of gas injection will reduce costs associated with cleaning and disposing and/or reinjection of produced water under a National Zero Discharge Order as expected to be in effect from 2005.
c) Increased capacity for oil. Currently, Ekofisk is total liquid capacity limited. If this capacity constraint continues, we should see an increased capacity for oil with a reduction of produced water. This will allow further acceleration of oil recovery as long as the base forecast is total liquid constrained.

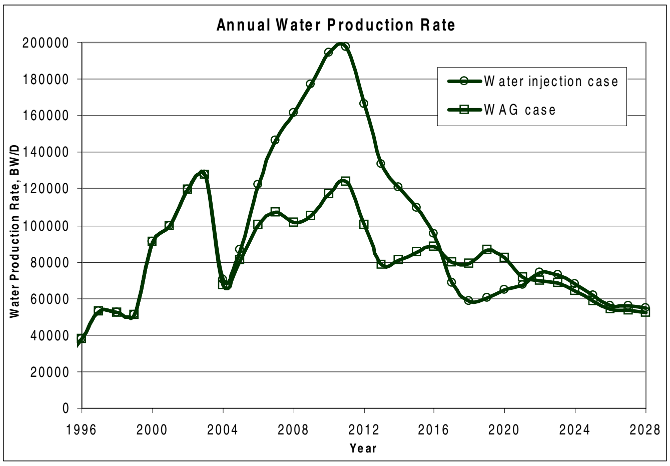

Figure 4. Comparison of Water Production for Water Injection Case Versus HC WAG Injection Case.

N_2 / FLUE GAS WAG

Summary of Major Process Mechanisms, Data Sources, and Data Quality

The displacement of water flood residual oil by injected N_2 is much the same as that described for HC WAG, although N_2 (or flue gas) is less efficient than HC gas in vaporizing intermediate Ekofisk oil components. Laboratory experiments have shown that N_2 is able to efficiently vaporize intermediate Ekofisk oil components only up to about C8 under field operating conditions. N_2 injection is volumetrically more efficient (in terms of voidage replacement) than other injection gases being considered for EOR application at Ekofisk. Furthermore, no injectivity problems (hydrates) are expected with N_2 gas injection based on thermodynamic considerations.

Specific laboratory PVT data were available to describe the phase behavior and fluid properties of mixtures of N_2 with Ekofisk crude. PVT results and mechanistic simulation modeling of N_2 injection as a secondary recovery IOR injectant[7] was available to guide the work in this study. These data were used to tune the equation of state (EOS) in the compositional simulation model. Injected N_2 interacts with and dissolves in Ekofisk oil, replacing light HCs and forming a methane-rich gas front at the leading edge of the displacement. This results in significant shrinkage of the remaining oil volume and reduction in the oil formation volume factor. The remaining N_2-contacted oil is less mobile and more difficult to displace due to higher oil viscosity and higher interfacial tension.

Compositional simulations with flue gas (N_2/CO_2 mixture) indicated that adding up to 20% CO_2 provided only marginal improvement in oil recovery performance.

Major Process Implementation Issues and Premises

N_2 supply would be obtained using a cryogenic (or other) air separation process. Size and weight requirements for air separation facilitates and associated compression require an additional process platform with related pipeline tie-ins, etc. Injection wells would need to be upgraded for high-pressure WAG injection service. Significant additional facilities would also be required on the production side to handle rejection of N_2 contaminated produced gas and recovery of associated NGLs.

The N_2 WAG injection performance forecasts do not include any impact of or on chalk mechanical compaction due to a N_2/flue gas WAG process. This premise should be evaluated further if this process is selected to be progressed towards a field pilot. Flue gas, with its higher CO_2 content, would be of most concern in this regard.

Major Cost Elements

Some additional cost elements for the N_2 WAG process in large-scale application at Ekofisk are:

Potential Incremental Costs

a) Additional platform with air separation, compression, and rejection facilities,
b) Additional CO_2 tax for added compression/operations,
c) Pipelines to/from N_2 facilities,
d) Upgrading of injection system and wells for high pressure gas injection, and
e) Incremental operating costs for WAG injection/production.

Potential Benefits

a) Reduced costs for gas lift,
b) Reduced future costs/penalties associated with handling of produced water,
c) Increased capacity for oil during liquid constrained periods,
d) Acceleration of HC gas recovery, and
e) No gas hydrate problems expected.

CO_2 WAG

Summary of Major Process Mechanisms, Data Sources, and Data Quality

Minimum miscibility pressure correlations and phase behavior predictions indicate that CO_2 will likely be multi-contact miscible or near-miscible with Ekofisk crude over significant portions of the reservoir. Miscible displacement conditions are more likely in the low temperature regions surrounding existing water injectors. An initial, minor viscous displacement period will be followed by progressive vaporization of intermediate oil components with continued gas injection. CO_2 should be significantly more efficient than HC gas in vaporizing intermediate Ekofisk oil components. While no specific CO_2-oil PVT data has been measured for Ekofisk, significant extraction of oil components from C5 up to C20 could be expected based on industry experience. This behavior is supported by compositional simulation forecasts using an untuned equation of state.

The basic oil recovery mechanisms by which CO_2 is able to mobilize water flood residual oil include swelling of the residual oil volume and reduction in oil viscosity as CO_2 dissolves in the oil, strong vaporization and extraction of intermediate components in the oil into the CO_2-rich gas phase, and reduction in the interfacial tension forces allowing mobilization of the water flood residual oil. Both increasing temperature and the presence of contaminants (particularly N_2) in the CO_2 injection gas will have a negative impact on oil recovery efficiency.

Major Process Implementation Issues and Premises

Implementation of any CO_2 WAG project requires a CO_2 supply source for injection. The project performance forecasts premise that the required delivery rate of CO_2 will be available for the project. However, it is important to note that no supply source of CO_2 for any Ekofisk project has been identified at this time. A project evaluation at the Grane Field[9] premises that an onshore CO_2 supply of comparable delivery capacity will come from a HC gas fired power plant. A similar onshore CO_2 supply scenario for Ekofisk may be the most likely possibility, however the costs to deliver CO_2 from these types of sources could be quite high. The only natural CO_2 supply source identified in the North Sea is from the Sleipner Gas Field,[10] however it appears that only about 60-70 MMSCF/D would be available (which is currently reinjected at Sleipner). A CO_2 supply of the requisite purity, volume, and deliverablity must be identified for Ekofisk if this process is selected as one to be progressed toward a field pilot.

Implementation of a CO_2 project at Ekofisk would require a supply pipeline to deliver CO_2 from the source to the field. CO_2 is generally transported as a supercritical fluid, typically at pressures of 1500-2000 psi as it can be pumped much like a liquid at these conditions. Booster compression would be required at the field to bring the CO_2 to the required injection pressure. Rejection of produced CO_2 from produced fluids will be a major issue and will require extensive CO_2 separation, compression, and NGL recovery facilities. The size and weight requirements for the premised compression and recycle facilities will require an additional CO_2 facilities platform with related pipeline tie-ins, etc. Injection wells will need to be upgraded with special wellheads for high-pressure CO_2 WAG injection service. Additional expense for increased corrosion treating will also be required. Problems with injectivity due to CO_2-hydrate formation in cooled regions (below about 60°F) around existing water injectors may be anticipated based on thermodynamic calculations.

The CO_2 WAG injection performance forecasts do not include any impact of or on chalk mechanical compaction. Laboratory testing conducted to date indicates that introducing CO_2–charged injection water into Ekofisk chalk samples results in an immediate and vigorous dissolution reaction with large axial strains and high strain rates.

The additional compaction would provide additional drive energy in the system, the high local strain rates may result in well failures and in ultimate sea bed subsidence beyond acceptable limits. The impact of CO_2 on compaction must be evaluated extensively if this process is selected to be progressed further. Also, reaction of CO_2-rich injection water with calcium carbonate in the rock matrix will consume some (potentially significant) fraction of the total injected CO_2 volume, thus making it unavailable to participate in the oil recovery process. The impact of this reduced effective CO_2 slug size has not been quantified or included in the screening forecasts and would need to be evaluated in any future work on application of this process.

Major Cost Elements

Some additional cost elements for the CO_2 WAG process in large-scale application at Ekofisk are:

Potential Incremental Costs

a) CO_2 supply gas acquisition costs, CO_2 supply pipeline and transportation costs,
b) Additional platform with CO_2 compression and rejection/recycle facilities,
c) Additional CO_2 tax for added compression/operations,
d) Pipelines to/from CO_2 facilities,
e) Upgrading of injection system and wells/wellheads for high pressure CO_2 service,
f) Incremental operating costs (incl. corrosion) for CO_2 WAG injection/production, and
g) Possible increased well failures & subsidence mitigation costs.

Potential Benefits

a) Reduced costs for gas lift,
b) Reduced future costs/penalties associated with handling of produced water,
c) Increased capacity for oil,
d) Acceleration of HC gas recovery, and
e) Possible increased reserves due to enhanced compaction drive.

AIR INJECTION

Summary of Major Process Mechanisms, Data Sources, and Data Quality

The air injection process involves continuous injection of air resulting in an exothermic reaction of oxygen with residual oil and generation of a thermal reaction front that propagates through the reservoir. Laboratory accelerating rate calorimetry (ARC) tests conducted with Ekofisk crude showed favorable reaction profiles indicating that a thermal reaction front could be generated and maintained in the reservoir. It is likely that an enriched air (30% O_2) process could be used to improve the process performance characteristics at Ekofisk and to provide spontaneous ignition around cooled water injectors. Specific laboratory combustion tube (CT) tests have not been conducted with Ekofisk chalk core material to date, however a significant amount of ARC and CT data are available for similar systems. These industry laboratory data, along with oil recovery and air utilization data from industry field projects,[11-12] formed the database for the air injection performance forecasts for Ekofisk.

Major Process Implementation Issues and Premises

Air compression/enrichment facilities capable of injecting up to 650 MMCFPD were premised for the field-scale project performance forecasts. Additional facilities would be required on the production side to handle rejection of produced gas contaminated with N_2/CO_2/CO/etc reaction products and for recovery of a significant volume of associated NGLs in the produced gas stream. The size and weight requirements for the premised air separation facilities, produced gas processing facilities, and associated compression would likely require an additional facilities platform with related pipeline tie-ins, etc.

Two different scenarios were considered for the air injection process. Scenario 1 involves no separation of salable gas from flue gas. All produced gas will be reinjected in this case. There will be a significant capital cost saving in this case as the gas separation/rejection unit will not be needed, but there will also be a significant loss of revenue from loss of the salable gas. Scenario 2, which is perceived as the more realistic, involves complete separation of salable gas from flue gas with export and sales of sales gas and reinjection of flue gas. Evaluations showed that separation of sales gas from flue gas (i.e. reinjection of only flue gas) is the preferable option.

Injection wells and lines would need to be upgraded for high-pressure air injection service. Injection and production wells would probably need to be upgraded to handle exposure to the elevated temperatures. Additional expense for increased corrosion treating should also be anticipated.

The air injection performance forecasts do not include any impact of or on chalk mechanical compaction due to the thermal effects of the high-temperature air injection process and the effects of combustion gases on the chalk matrix. Possible high-temperature calcination reactions may substantially alter and weaken the rock. Preliminary data from one combustion tube test on an outcrop chalk showed that the rock matrix may be weakened by 25% through exposure to this high-temperature process. The CO_2 in the combustion products generated by the thermal reactions would likely have a significant impact on the mechanical integrity of the matrix also, as discussed for the CO_2 WAG process. The impact of this process on mechanical integrity of the Ekofisk chalk and resulting compaction/subsidence effects must be evaluated more thoroughly if this process is selected to be progressed further.

The air injection process might be considered an alternative to blowdown as the final stage in the exploitation process. Air injection can potentially be implemented following any of the other processes.

Major Cost Elements

Some additional cost elements for the air injection process in large-scale application at Ekofisk are:

Potential Incremental Costs

a) Additional platform with air compression and enrichment facilities,
b) Additional CO_2 tax for added compression/operations,
c) Upgrading of injection system and wells for high pressure air injection,
d) Upgrading of injection & production wells for high-temperature service,
e) Incremental operating costs for high volume gas handling and corrosion treating, and
f) Possible increased well failures & subsidence mitigation costs.

Potential Benefits

a) Reduced costs for gas lift,
b) Reduced future costs/penalties associated with handling of produced water,
c) Increased capacity for oil during liquid constrained periods,
d) Acceleration of HC gas recovery, and
e) Possible increased reserves due to enhanced compaction drive.

MICROBIAL EOR

Summary of Major Process Mechanisms, Data Sources, and Data Quality

Microbial enhanced oil recovery (MEOR) is still an emerging technology and the exact mechanisms by which microbial agents are able to effect mobilization and recovery of incremental oil in a given reservoir are not clearly understood. MEOR processes likely act through a complex of different mechanisms, including wettability alteration, IFT reduction, oil viscosity reduction, and others. As a consequence, there are no robust predictive models available to effectively simulate MEOR process applications and oil recovery potential at Ekofisk. Moreover, at this time, there are no specific laboratory data to support or refute claims of oil recovery potential by MEOR in the Ekofisk reservoir. Estimates of recovery potential in this paper are made by analogy under the premise that a viable MEOR system can be developed for application at Ekofisk which will have performance characteristics analogous to other field results reported to date.

Major Process Implementation Issues and Premises

The microbial oil recovery forecasts were generated by up-scaling a composite of typical field project results. It was necessary to use this empirical approach to estimate MEOR performance as the exact mechanisms of microbial oil recovery are still poorly understood and consequently there are no simulation models available to make reliable MEOR field performance forecasts. The nature of microbial transport in a fractured chalk reservoir has not been evaluated. Reduced reservoir temperatures near the water injection wells would probably be favorable for microbial growth. Issues of the viability of microbes over the wide range of temperatures existing in Ekofisk, and particularly the impact of higher reservoir temperatures on the MEOR process, needs to be investigated further.

Several of the possible mechanisms suggested for oil mobilization in MEOR involve wettability alteration and/or IFT reduction. These are mechanisms similar to those of surfactant flooding, which has been considered previously but is not being actively pursued as an EOR method at Ekofisk because of low oil recovery forecasts. This raises the question of how and why the MEOR process is different from surfactant processes considered earlier and therefore merits continued interest?

The MEOR process is not just a surfactant process – the mechanisms suggested as being important in MEOR are varied and complex (e.g. oil viscosity reduction, gas production, solvent production) and are not fully understood. Another key difference between MEOR and surfactant flooding lies in the envisioned method of surfactant delivery to the point of contact with residual oil. Microbes would tend to move preferentially through the fracture system, being excluded from directly entering the chalk matrix because of their size relative to the pore throat size distribution of the chalk. Microbes have the ability to seek out and adhere to any films of residual oil at the fracture/matrix interface or residing in larger pores adjacent to the fracture system. Thus, microbes may penetrate fairly deep into a fractured chalk reservoir and generate surfactant in situ, thereby avoiding much of the potential adsorption losses expected with surfactant flooding. Since the microbes would use residual oil as a food source, total injection volumes and costs would be substantially reduced.

The MEOR performance forecasts represent an extension of limited laboratory and field results to a full-scale MEOR project at Ekofisk. The oil recovery projections are based on the following premises: (1) a viable microbial system will be identified for application at Ekofisk; and (2) the oil recovery potential of that process will be comparable to that of successful MEOR processes seen in other laboratory and field studies (with adjustments for reservoir conditions at Ekofisk). Potential regulatory and environmental issues/concerns with injecting microbes into a reservoir in the North Sea have not been addressed. Also, the potential for reservoir souring must be closely evaluated before implementing injection of any microbes into Ekofisk.

The material and equipment requirements and logistics of implementing a full-field microbial oil recovery project in an offshore North Sea operating environment do not appear to be a limiting factor. Equipment requirements are modest, operating costs are fairly low, and there would appear to be only minimal impact on existing operations. The real issue with this process is the viability of the oil recovery process itself under Ekofisk reservoir conditions. Additional "proof of concept" laboratory work is required to establish the viability of any claims for incremental oil recovery potential. MEOR is the most uncertain of any of the EOR processes being considered for application at Ekofisk.

Major Cost Elements

Some additional cost elements for the MEOR process in large-scale application at Ekofisk:

Potential Incremental Costs

a) Microbial culture generation tanks (small, inexpensive)
b) Small, low-volume chemical injection pumps,
c) Laboratory facilities for quality control and process monitoring, and
d) Possible environmental/regulatory costs or concerns.

Potential Benefits

a) Relatively easy and inexpensive process to implement and operate,
b) Compatible with existing water injection facilities and operations, and
c) Could possibly be used in combination with a gas injection EOR process.

EOR DEVELOPMENT & OPERATIONAL PREMISES

Injection Gas Availability

It is assumed the gas can be made available in sufficient quantities for the gas injection processes. For air injection this is a compressor sizing issue. For N_2 injection, the gas availability also premises separation (cryogenic or other) of N_2 from air.

HC gas availability on the Norwegian Continental Shelf (NCS) is as always quite uncertain and variable. The availability depends on off-take to the European market, variations in price, and development of new gas reserves. Gas for HC WAG will be taken from the sales gas stream at Ekofisk. HC gas is available in sufficient quantities at Ekofisk, but substitute gas for sales commitments may have to be acquired through a different source and supplier. The only effect accounted for with respect to HC gas injection was the economic effect of deferring the gas sales as a result of gas injection.

On the CO_2 availability issue, there is not much known. The only concept studied is the Grane field[9] where CO_2 was premised to be separated from flue gas at an onshore gas power plant before being piped offshore for injection into the reservoir. The Grane operator has not been able to find viability in such a scenario and the concept has been shelved. The only known significant natural source of CO_2 gas on the NCS is at the Sleipner field.[10] However, the volumes/rates at Sleipner are only one sixth of that required for full field CO_2 WAG at Ekofisk.

For CO_2 injection, we assume that the CO_2 can be made available from a gas power plant onshore Norway and that a pipeline has to be built to transport the gas to Ekofisk with associated compression facilities. The price estimate for CO_2 was taken from a SINTEF study.[13] Price for CO_2 was estimated to range from $1.13/MCF to $1.69/MCF. Here, we premise that the CO_2 gas is available at an average price of $1.5/MCF at the wellhead.

Injection and Well premises

Gas injection will be at the main water injection facility into 30 wells. The WAG scenarios (HC, N_2 and CO_2) premise 30 injection wells divided into 3 well groups. Gas is premised to be injected in 6 month WAG cycles into 10 injection wells at the time at a nominal injection rate of 350 MMSCF/D at 6000 psia wellhead pressure. The remaining 20 injection wells will be on water injection. For air injection, we premise that all 30 injection wells will receive continuous air injection at a nominal rate of 650 MMSCF/D at a wellhead pressure of 6000 psia.

For HC and N_2 WAG the injection well upgrade premise redrill of 20 injection wells and tubing replacement in 10 injection wells. For CO_2 WAG there will be a need to sidetrack all 30 injectors and complete with chrome tubing. For air injection, 30 injection wells and 30 production wells need to be upgraded (sidetracked and chrome tubing completed). Chrome tubing for the CO_2 and air injection scenarios is required as a corrosion prevention measure.

For MEOR, there will be no change in the injection pattern or volumes. No wells will require workover beyond that which is required in the base case. Microbe solution is premised to be commingled with the current injection water topside. No additional cost for sour service in the event of reservoir souring was accounted for.

Hydrate Prevention

HC gas/water hydrate was thought to cause the failure of the first WAG pilot performed at Ekofisk. This is believed to be a general problem with any future HC WAG scenario. Prolonged injection of cold sea-water results in reservoir temperatures and pressures such that gas hydrates form if HC gas is subsequently injected in the same well.

Several possible alternatives for hydrate prevention have been discussed, including:

1. Chemical heating of the near wellbore area prior to gas injection,
2. Heating of the injection water to raise near wellbore temperature outside of the hydrate envelope,
3. Sidetrack injectors to outside of the cooled zone prior to gas injection,
4. Co-injection of water and gas, and
5. Chemical inhibition to prevent and/or retard the onset of hydrate formation.

The chemical heating option was selected for field testing in 1998. The chemicals showed great promise, but the test failed as the reservoir pressure was too high to be overcome with the current top-side wellhead and pipeline pressure limitations.

For screening purposes, we assumed that a combination of chemical heating and heating of the injection water would suffice to prevent hydrates in a full field WAG implementation as follows:

A. Heating 60,000 bbl/d to 85-90°C and mix with cold sea water to achieve proper temperature level
   - Other heating options, e.g. incorporating waste heat recovery, is an upside.

B) Chemical treatment (exothermic reactions).
   - This elevates the near wellbore temperature, for a designed treatment depth, to a level above the hydrate formation temperature.
   - The chemical treatment is once per well only for the first cycle of water injection.

CONCLUSIONS

1. Incremental oil recovery forecasts for the five processes at Ekofisk were as follows:
   - HC WAG: 3.3% OOIP
   - N_2 WAG: -2.2% OOIP
   - CO_2 WAG: 5.6% OOIP
   - Air Injection: 6.5% OOIP
   - MEOR: 0.6% OOIP
2. Only Hydrocarbon WAG and Air Injection show sufficient promise for application at Ekofisk to be carried forward into further studies. Key conclusions and recommendations regarding each process are as follows:
   - <u>N_2 WAG injection:</u>
     - Negative reserves potential.
     - Eliminated from further consideration.

- *CO_2 WAG injection:*
  - Large reserves potential.
  - Significant dissolution/compaction concern.
  - No CO_2 source is available in the foreseeable future.
  - Dropped from consideration until CO_2 can be secured at cost significantly less than $1.50/ MCF at the wellhead.
- *Microbial EOR*:
  - Limited reserves potential.
  - The MEOR process lacks definitive proof of technical ability to economically mobilize waterflood residual oil in Ekofisk or similar chalk.
  - Dropped from further consideration.
- Air Injection
  - Large reserves potential.
  - Significant risk and uncertainty.
  - If air injection is to be employed at Ekofisk it will most likely be late in the field life, potentially after some other EOR process has been employed. Hence, further studies of air injection are not time-critical but should be progressed in a timely manner in order to understand the risk areas and 'show stoppers' associated with this process.
  - Recommended further study of risk areas (O_2 breakthrough, compaction, and flue gas separation & reinjection).
- *HC WAG injection*
  - Significant reserves potential.
  - Most mature and technically ready process.
  - Recommended updating of full field WAG development forecasts with progress towards pilot feasibility if full field economics are sufficient.

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Table 1. Technical Readiness of EOR implementation at Ekofisk.

	HC WAG	CO2 WAG	N2 WAG	AIR INJECTION	MEOR
SHOWSTOPPERS - Currently unresolved technical or logistical issues which are potentially severe enough to eliminate an EOR process from consideration for application at Ekofisk.	If EOR injectant flows preferentially through the fracture system and has only limited ability to contact waterflood residual oil in the chalk matrix. <--------- This could occur if contact between EOR injectant and matrix residual oil is limted by a slow or inefficient process, such as gas-water diffusion.---------> Our ability to evaluate this matrix-fracture interaction effect in the laboratory is limited --- it would be a primary objective of any EOR field pilot test.				
	Inability to secure required supply of HC injection gas	Inability to secure a CO2 supply with required volumes, deliverability, and cost. CO2-chalk dissolution results in catastrophic subsidence or well failures	Oil production is reduced below waterflood forecast oil recovery	Thermal effects destroy the mechanical integrity of reservoir or wells CO2-chalk dissolution results in catastrophic subsidence or well failures	Proof-of-concept laboratory work shows that MEOR will not work as premised Reservoir Souring Potential Environmental Concerns
GENERAL EOR PROCESS READINESS FACTORS:	Process Assessment Scale: (ability to recover contacted oil) 10 = Fully ready Process ... High Technical confidence ... Field Proven, Industry Accepted 0 = Unproven, Untried Process .... Concept Only .... Not Yet Accepted in Industry				
Level of Industry Data/Experience/Confidence? (excluding the issue of oil contact in fractured chalk)	9	8	8	5	2
Sufficient Ekofisk Lab/Field Data Available?	9	4	10	4	0
Sufficient data to begin Field Pilot Design?	10	2	10	4	0
INDEX OF TECHNICAL READINESS TO BEGIN FIELD PILOT DESIGN WORK ---	28 93%	14 47%	28 93%	13 43%	2 7%
RISK TO CURRENT RESERVES / ECONOMICS:	LOW-MOD	MOD-HIGH	HIGH	MOD-HIGH	LOW
TECHNICAL OR LOGISTICAL ISSUES WHICH REMAIN TO BE SOLVED PRIOR TO INITIATING A FIELD EOR PILOT TEST	Gas Hydrates Impact on compaction	Obtain Viable CO2 Supply No Ekofisk Lab Data CO2 Hydrates Subsidence Well Integrity	Poor Oil Recovery	Combustion Tube Tests Subsidence Well Integrity	No Ekofisk Lab Data Unproven Process
NEXT STEP(S) TO PROGRESS THIS PROCESS?	Evaluate Gas Supply Solve Hydrate Problem Begin Field Pilot Design	Secure CO2 Supply Laboratory PVT Studies Lab Compaction Studies	ELIMINATE THIS OPTION	Combustion Tube Tests Lab Compaction Studies Feasibility Simulations	Lab Work to Prove Concept of microbial oil recovery