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Improved Hydrocarbon Recovery in the United Kingdom Continental Shelf: Past, Present and Future

A J Jayasekera, SPE, United Kingdom Department of Trade and Industry, S G Goodyear, SPE, AEA Technology plc

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Abstract

Gas production from the UKCS commenced in 1967 and oil production in 1975. The North Sea area is now very much a mature province with the large fields in the Southern, Central and Northern North Sea producing at significantly below their early plateau production rates. Here the drive is to maximise the overall economic hydrocarbon recovery from the province, by making the best use of the infrastructure that has been built up to bring in new discoveries and improve recovery from the mature fields. New areas (deeper, harsher climate) are being opened up for exploration on the Atlantic Margin.

This paper reviews the evolution of the mature areas of the UKCS, with case studies to illustrate the technical challenges that have been overcome. Over the years government and industry have expended considerable resources in developing innovative techniques for improved hydrocarbon recovery. These range from developments in the application of EOR processes to advances in drilling and reservoir management technology, including novel seismic techniques to identify new or bypassed oil. Technological advances have also unlocked reserves in heavy oils and in high-pressure high-temperature (HPHT) condensate fields, which were left undeveloped until the 1990s.

Finally the potential for further exploitation and life extension of the UKCS as a significant hydrocarbon province will be reviewed. This will cover perceived technology gaps in opening up the new areas in deeper water, opportunities for redeveloping mature fields using new technology, combining IOR with carbon dioxide sequestration, and the need to drive down costs to be competitive in the international arena, while honouring environmental commitments.

Introduction

Oil exploration and production in the UK began onshore in the early part of the 20th century in the East Yorkshire, Lincolnshire and East Midlands areas. Later the interest extended to include the Dorset basin in the south of England. These were typically mechanical pump assisted fields producing a few 100 bbls/day/well. The first offshore gas field, West Sole in the Southern North Sea (SNS), was discovered in 1965 and brought onstream in 1967. Oil was first discovered in the Central North Sea (CNS) in 1969 and the first oilfield to come onstream was Argyll in 1975, followed soon after by the Forties field. The UK became self-sufficient in oil around 1980.

Oil production on the UKCS has followed a typical exploitation path for a hydrocarbon producing area with large conventional fields being developed first and thereafter smaller fields utilising the infrastructure. It has now entered a third phase with the development of technically more difficult fields such as heavy oil fields and High Pressure High Temperature (HPHT) fields. A recent paper[1] reviewed the UKCS heavy oil fields, so the primary focus of this paper is light oil fields.

In the early days the industry used the term Enhanced Oil Recovery (EOR) to describe the deliberate injection of an alternative fluid to displace further oil from reservoir rock, over and above the standard pressure maintenance strategy (waterflooding for most UKCS oil fields). In the 1990s the industry began to use the term Improved Oil Recovery (IOR) to cover any operation (including the EOR techniques) that increased oil recovery above the figure that had been initially accepted as economically and technically exploitable. ‘Improved Hydrocarbon Recovery’ is a more general term that will cover all hydrocarbon types, including gas, but it is not commonly used as an acronym.

The EOR techniques relevant to light oil fields involve the use of chemicals (surfactants, polymers, microbes) or injection of gases. There were two notable onshore UK demonstration pilot EOR projects in the early 1980s. A carbon dioxide miscible flooding project was undertaken in the Egmanton oilfield[2]. This had to be terminated due to the low injectivity of the formation extending the project timeframe beyond the planned schedule. A surfactant flooding project was conducted in the Bothamsall oilfield[3,4], with the intention of demonstrating the feasibility of using low concentration surfactant flooding to release oil held in the formation by capillary forces. It was thought that this process could be logistically possible for eventual offshore application, as well as being more economically attractive than conventional surfactant flooding. Although a lot of practical experience was gained in the handling of such surfactants, a clear enough response was not detected at the producing wells to make conclusions about the effectiveness of the process.

When it comes to the application of EOR processes offshore the conditions prevailing in UKCS oilfield installations impose specially stringent constraints. In the early 1980s when oil prices in real terms were very high, a number of small scale pilot projects were undertaken, including polymer injection in Beatrice[5] and Thistle and solvent injection in Ninian. However, the results of these did not have a significant enough impact to encourage their widespread use. The EOR processes that have subsequently been implemented successfully at full field scale in the UKCS are hydrocarbon gas WAG projects and post-waterflood reservoir depressurisation. These are discussed in more detail in later sections.

IOR techniques have made a significant impact on UKCS production. Since the early 1990s, the rapid advances made in drilling and well technology have enabled the exploitation of oil accumulations that had previously been uneconomic to develop. Advances made in reservoir management techniques have greatly helped in understanding risks, and hence unlocking additional reserves. The most notable of these is the use of seismic techniques for better reservoir definition and characterisation and for tracking fluid movement. There are several examples in the UKCS where a change in 'mode of operation' has resulted in significant increase in recovery and extension of field life. All of these are considered as IOR methods and are described in some detail in this paper. Dry gas fields are not discussed, since most of the applicable improved recovery technologies are already illustrated by the oil field examples in the well technology and reservoir management sections.

Fig. 1 shows the boundaries of the UKCS and names of the key areas for development activity[6]. The North Sea is now very much a mature province with the large fields in the Southern, Central and Northern North Sea at significantly below their early plateau production rates. **Fig. 2** shows the annual UKCS oil and water production from 1975. The rising trend in water production, which is typical of a mature province, is indicative of the IOR challenges that have to be faced in order to keep up current oil production levels. **Fig. 3** shows the split of oil production from fields grouped by their ultimate reserves – large (> 500 MMSTB), medium (100-500 MMSTB) and small (0-100 MMSTB). This highlights that the fields being discovered and brought onstream in recent times, and which have helped to maintain the overall UKCS production, are mostly in the latter category. **Fig. 4** shows the number of oil and gas fields in production in any given year since 1975. Presently there are 231 fields in production (118 oil, 94 gas and 19 condensate). **Fig. 4** also shows the cumulative number of fields that have ceased production. The drop from 21 to 20 in the year 2001 is because the Angus field that ceased production in 1993 was restarted in 2001.

New areas being opened out in the Atlantic Margin, where the climate is harsher and the water depths go from 500m to 1500m or more, should help to extend the life of the UKCS as a major oil province. Foinaven (350 MMSTB) and Schiehallion (560 MMSTB) have been brought onstream successfully from the West of Shetlands (WoS) area, and there is an active ongoing exploration programme. The 'White Zone', further out into the Atlantic between the Shetland and the Faeroe islands, has been opened out for exploration, with the award of licences in UK's 19th offshore licensing round in 2001.

The IOR challenge

Most UKCS oil fields have been developed under waterflooding, from early in field life, either by water injection or aquifer influx. Therefore, waterflooding is the baseline development strategy on which the other techniques are applied to improve recovery. The exceptions to this include small accumulations where the additional cost of water injectors cannot be justified and difficult fields, especially low permeability and fractured reservoirs. The full field development of the Machar fractured chalk reservoir using waterflooding following a successful pilot water injection project, is a good example of how waterflooding can be applied as an IOR technique in these situations.

The application of waterflooding has resulted in good recovery factors and maintenance of the high production rates needed to make projects economically attractive. The volume averaged recovery factor for producing oil fields in the Central and Northern North Sea is currently predicted to be 45**%** (including fields with EOR projects). **Fig. 5** shows the distribution of recovery factors. In some fields waterflooding on its own can achieve recovery factors approaching 70%.

Despite the success of waterflooding, on average over half of the oil in place will be left in the reservoir unless improved recovery techniques are applied. The selection of appropriate IOR techniques depends on a good description of the distribution of the remaining oil (e.g. local regions of bypassed oil at high saturations compared to large volumes of "residual" oil to waterflooding) and a good understanding of the reasons for it not being recovered by the waterflood (e.g. mobile oil bypassed due to permeability contrasts between communicating layers or trapped by pinch-outs of sand bodies).

Residual oil saturations. Earlier in the life of the UKCS waterflood SCAL studies suggested that the remaining oil saturation in well flooded zones would typically be 25 to 35%, and that there would be a significant target for classical EOR techniques which primarily target residual oil to water flooding. However, this view of "residual oil" saturation was often based on SCAL data obtained with core biased to water-wet conditions, following core cleaning. Experience has shown that lower "residual oil" saturations are often achieved in practice, consistent with oil relative permeabilities with the long tails measured in modern SCAL measurements using ageing with live crude to restore “representative wettability” following core cleaning. In the high permeability UKCS fields, gravity forces can be significant, so that along-dip and cross-layer drainage allow lower effective residual oil saturations to be achieved than could be reached simply on the basis of viscous forces alone. In favourable circumstances effective residual saturations of 10-20% are not unusual in well-swept zones.

The impact on the perceived IOR target of changes in the “residual” oil saturation can usefully be illustrated in a simple model in which the reservoir is locally either unswept by water or swept to a constant “residual” oil saturation. The overall recovery factor is then the product of the volumetric sweep efficiency and the microscopic sweep efficiency. **Fig. 6** shows combinations of volumetric and microscopic sweep efficiency giving the same overall recovery factor. For the example illustrated, depending on whether the residual saturation is 30% or 15%, the remaining mobile oil varies from only 9.7% to 27.4% STOIIP. With the high residual saturation, IOR techniques will need to directly address the capillary trapped waterflood residual oil. In contrast, with the low residual saturation there could be a significant target for infill drilling or well workovers.

Operating environment. Operating in the UKCS creates an additional set of challenges that need to be overcome in IOR projects compared to onshore developments, especially those based on classical EOR methods:

- higher OPEX and CAPEX
- platform weight and space restrictions on retrofitted IOR facilities
- relatively high well spacing and large scale of pilot projects, leading to higher exposure and longer timescales to see benefits
- high cost of well interventions, especially fields operated from floating production facilities
- generally high reservoir temperatures reduce options for chemical IOR
- limited window of opportunity to implement schemes within existing facilities lifetime
- environmental constraints (e.g. emissions to atmosphere or discharge of chemicals to sea).

Market demand for gas and its relationship to UKCS IOR projects. So far hydrocarbon gas injection is the most successful classical EOR technique applied in the UKCS. Experience elsewhere may suggest that CO_2 is the best miscible injectant, however, there are no natural sources of high concentration CO_2 in the UKCS. The development of the UK natural gas market has led to steadily increasing average hydrocarbon gas prices since oil production first began in 1975. **Fig. 7** shows historical average oil prices (£/bbl) and gas prices (£/MSCF), together with the ratio of the oil to the gas price (MSCF/bbl). This shows that early in the life of the UKCS gas was relatively cheap compared to oil. Dates when the various wet gas pipelines to shore came into operation are highlighted along the time axis. Clearly, associated gas from offshore has become an easily marketable product. With the exception of the year 2000 with its high oil prices, UK gas prices have approached a level where on calorific value gas is comparable to oil. The increased demand for gas for power generation, the liberalisation of the UK gas market and the introduction of the gas interconnector to continental Europe governs this trend in gas price.

Hydrocarbon gas injection EOR projects will have to compete more and more against the alternative option of selling gas to the market. Although this would be difficult based on average gas prices, local conditions may provide additional drivers: the need to store the excess hydrocarbon gas until an export line is constructed or ullage becomes available in an existing pipeline, low gas prices to the producer due to gas quality (e.g. presence of CO_2 or H_2S) or tariffs imposed for transport over gas export infrastructure.

EOR techniques applicable to the UKCS

This summarises the classical EOR techniques that have been considered or are being deployed in UKCS light oil fields

Gas injection. Gas injection can be considered in three types of application:

- Downdip injection (usually in conjunction with water injection as a WAG project), targeting residual oil to waterflooding (requiring miscibility to be developed in the reservoir) and attic oil. Even where miscibility is not achieved there may be benefits from three phase relative permeability effects. UKCS field projects include Magnus, Miller, North Alwyn and South Brae.
- Crestal injection using gravity forces to help stabilise displacements using miscible or immiscible gas to increase sweep. Crestal gas injection has been employed in the UKCS, but this has usually been driven by the need for gas storage or to manage the position of oil rims under gas caps. Examples include the Beryl field (injected gas subsequently back produced), Bruce (miscible gas injection to displace oil), Fulmar (temporary gas storage) and Andrew, Gannet A, Gryphon, Harding and Lennox (oil rim management with horizontal producers).
- Gas recycle mode for improved liquid recovery from rich gas condensates. Examples include Bruce, North Brae and East Brae.

Gas injection is favoured by the generally high quality of UKCS oils, which promotes miscibility, and good vertical permeability which assists gravity drainage. However, high permeabilities can cause rapid segregation of water and gas in WAG schemes and the need to maintain high production rates may make it difficult to achieve gravity stability in crestal schemes.

So far all the gas injection projects have used hydrocarbon gas. Alternative sources of gas have been considered including offshore cryogenic generation of nitrogen[7] and air injection[8].

During air injection, if the oil is of an appropriate reactivity, oxygen will be consumed and to a first approximation the reservoir undergoes a nitrogen flood. To minimise the risk of oxygen breakthrough at producers injection would probably be in a crestal gravity stable mode. Carbon dioxide would be attractive from a technical standpoint, with many reservoirs expected to be above the minimum miscibility pressure (MMP) as predicted by the Glaso correlation[9] , **Fig. 8**, and with typical reservoir CO_2 densities within the range encountered in onshore projects.

To reduce gas compression requirements and operational costs, simultaneous injection of gas and water (SWAG) is being considered where small quantities of hydrocarbon gas need to be injected to avoid gas flaring. Some limited near well bore production well foam treatments have been undertaken, without significant success.

Depressurisation. In a field with a high solution GOR a significant volume of gas is dissolved in the remaining oil left behind after waterflooding. Depressurising the field significantly below the bubblepoint will liberate gas from both the bypassed oil and the waterflood residual oil. Depending on the critical gas saturation, gas can then be produced, along with additional oil expelled from bypassed regions or swept to producers with any ongoing low pressure waterflood. The Brent field redevelopment has pioneered the implementation of this technique.

Polymers and gels. In light oil fields, the low reservoir oil viscosity means that polymer injection opportunities are limited to improving volumetric sweep in heterogeneous reservoirs, targeting mobile oil that can often be recovered simply through water cycling or infill drilling. Polyacrylamide is not well suited because of the high temperatures and the salinity of the injected water (almost always seawater or more saline produced water). Xanthan is at the upper limit of temperature stability and requires partial cooling of the high permeability zones by injected sea water to achieve a sufficient viscosity half life in the reservoir. For polymer flooding to be viable in UKCS light oil reservoirs, improvements in temperature stability and viscosity yield would be needed.

Near well bore gel treatments are used as an alternative to cement squeezes or mechanical workovers, especially where cement bonds are poor. The limited chemical volumes required and the cost of operational aspects of treatments make it possible to use specialised polymers and cross-linkers with good thermal stability.

Surfactants. Although many of the surfactants considered for EOR are stable at UKCS reservoir temperatures, the requirement to use a polymer postflush precludes their use on temperature stability grounds. The complexity of the process (including the impact of temperature and salinity changes) and the basic cost of the surfactant and its linkage to the oil price, make it difficult to envisage a scenario in which it could be applied economically, unless suitable non-petroleum based surfactants can be developed.

Microbial. Many claims have been made for the benefits of microbial flooding. A recent review[10] highlights the difficulties in using MEOR especially for the insitu generation of EOR agents and suggests that projects aiming to reduce permeability with biomass may have a better chance of success. Some microbial treatments have been undertaken, including in Beatrice[11], but there are no published results which demonstrate measurable recovery improvements.

Case studies. The successful application of EOR techniques is illustrated with projects in the Brent and Brae fields.

South Brae WAG. South Brae is an oil field in the Brae complex[12], **Fig. 9**, operated by Marathon, in the western margin of the South Viking Graben. The other fields in the complex are West Brae (oil, with a gas cap), Central Brae (oil), North Brae (gas condensate), Beinn (gas condensate) and East Brae (gas condensate). There are three platforms, Brae A, Brae B and East Brae. Liquids are exported through the Brae A/Forties line to Forties and then on to Cruden Bay. Gas is exported through a line from East Brae to the SAGE line and then on to St. Fergus. The Brae group also purchases third party gas from surrounding fields – T-Block (Agip), Birch and Larch (Venture) and Kingfisher (Shell). The Brae group owns 50% of the SAGE line, which is a sour gas line, with a maximum capacity of approximately 1.1 BSCF/D wet gas with up to about 10% CO_2. Onshore processing removes the CO_2 and gets the gas to sales specifications. The three relatively high GOR oilfields and two high liquid yield gas condensate fields, the option to buy third party gas and the availability of pipeline capacity places the Brae complex in a very flexible position, to be responsive to the gas market and also to manage the gas to optimise liquids recovery by WAG or gas cycling schemes in the appropriate reservoirs (see later section on East Brae).

South Brae[12] started production in 1983 and attained a peak rate of over 115,000 BOPD in 1986. Although there is partial aquifer support, the reservoir has been under water injection since 1984 to improve areal sweep and to maintain reservoir pressure. Early in field life 133 BSCF of gas was injected into the crestal part of the reservoir, but this ceased in 1991 when gas broke through into the producing wells.

The evaluation of South Brae for a possible WAG[13,14] began in the early 1990s. A pilot project was carried out between 1994 and 1997, by injecting gas into well A20. Over 2.3 MMSTB of incremental recovery from the pilot project has been produced from wells A5, A16, A27 and A36. Gas injection for the full field WAG project started in November 1998 with well A26. **Fig. 10** shows the response to the gas injection in producer A16. Injection into wells A15, A19 and A26 followed and is expected to continue into 2002 and beyond. The WAG process is effective in mobilising residual oil towards updip producers through miscibility. By using existing water injectors the knowledge of the connectivity between downdip injectors and updip producers helps minimise risks. The full field WAG is expected to continue into 2007, and realise a significant volume of incremental oil, while injecting nearly 200 BSCF gross gas. Studies show that the oil recovery is not sensitive to the duration of the WAG cycles, so gas injection can be fitted around seasonal gas sales requirements to maximise the economic value of the project. The project is economic without the need to include the value of returned injected gas.

Brent late life depressurisation. The Brent field[15] operated by Shell has a STOIIP of 3.8 billion STB and GIIP of 7.5 TSCF. The field began production in 1976, with oil production peaking in 1984 at 410,000 BOPD. Since the mid- 1980s, oil production has been declining, but, because of the high solution GOR (ranging from 1400 to 5500 SCF/STB), substantial gas reserves remain, dissolved in the residual and bypassed oil.

In 1992 Shell decided to depressurise the field to release solution gas from bypassed (unswept) and remaining (swept) oil, and to produce the gas, once it had migrated to the crest of the structure, **Fig. 11**, with the objective of recovering an additional 1.5 TSCF gas and 34 MMSTB oil and extending field life by 5-10 years.

This is the largest and most comprehensive field redevelopment undertaken in the UKCS at a total cost of £1.3 billion. Three of the four platforms were redeveloped to install process facilities for low pressure operation, to reduce operating costs, to implement safety upgrades and to refurbish facilities. The fourth platform was also upgraded but no low-pressure facilities were installed.

On 1st January 1998 some 450,000 bbl/D water injection, representing 90% of the field total, was switched off leaving the Alpha platform injecting some 50,000 bbl/D into areas which are not part of the depressurisation project. Meeting gas production targets is dependent on extracting sufficient gross liquid production, and has necessitated the provision of artificial lift. Gas lift has been installed in a number of wells to allow sufficient high water-cut wells to be produced. On the fourth platform, where high backpressure means gas lift is less efficient, ESPs have been used in low GOR wells to increase lift. As the reservoir pressure declines further, a number of high rate ESPs will be installed to enhance voidage (EV). The original concept was to place all these EV wells below the OOWC to minimise free gas production. This concept has since been modified with a number of EV wells being located in the waterflooded oil leg, with the intention of gaining some additional oil production.

The reservoir pressure has declined in line with the 1992 plan, **Fig. 12.** Brent is currently yielding 750 MMSCF/D dry gas output, equivalent to an offshore wet gas volume of 900 MMSCF/D, a production level well in excess of the original plan[16]. In conjunction with the depressurisation, an intensive surveillance programme has allowed the identification of potential infill targets, which are actively being developed with modern well technology (including through tubing drilling and multi-target designer wells).

East Brae condensate recyling. North Brae and East Brae (**Fig. 9**) are gas condensate fields operated by Marathon where gas cycling has been used from the outset to maximise the economic recovery of liquids. As East Brae is the larger of the two it is presented as a case study below:

The East Brae reservoir lies in the distal portion of a sandy turbidite fan system of Upper Jurassic age at 4,100 m TVDSS. The average field porosity is 14.5%, and permeability 145 md. The reservoir fluid is a rich gas condensate with a thin oil leg at the base of the hydrocarbon column. There is a compositional gradient with consequential variation in fluid properties. Extensive reservoir fluid sampling and analysis during the pre-development stage established that in general the reservoir contains a single fluid whose composition is a function only of depth.

The wet gas initially in place is estimated at 1.8 TSCF, with an initial liquid yield in excess of 200 STB/MMSCF. As the reservoir fluids exhibit retrograde behaviour, the most suitable development option was a gas cycling scheme by re-injecting residue gas for partial pressure maintenance and additional liquid recovery, rather than straight blowdown. The North Brae development which preceded this also uses a gas cycling scheme and provided valuable experience.

East Brae came onstream in 1993 and reached peak production in 1994. **Fig. 13** shows the annual liquid production and ratio of injected to produced gas for North and East Brae. The ultimate level of liquids recovery from the reservoir will depend, among other factors, upon the quantity of gas cycled through it. Hence the relationship between gas sales and ultimate liquid recovery needs to be recognized. The current estimate for recovery efficiency for liquids is approximately 55% and for dry sour gas is 75-80%. If it was a straight depletion process the liquids recovered is estimated to be lower by some 25-30%. As the field depletes and becomes leaner, the sensitivity of liquid recovery to injected volume decreases, and there comes a point where it is better to start blowdown, because the gain in gas recovery outweighs the loss in liquids.

Well technology

Developments in drilling and well technology have made an enormous impact on UKCS developments, both improving recovery factors and reducing costs through lower well numbers.

Horizontal wells. Horizontal wells have given major benefits in the management of gas and water coning, allowing a number of oil rim developments to come forward to development. In addition they provide options for increased productivity in low deliverability reservoirs. The long term management of the wells in the presence of water and gas breakthrough presents a challenge, since well workover options for the control of unwanted fluids are more limited. Smart well technology may provide solutions if the technology can be made sufficiently reliable. Routine vertical well operations such as scale squeeze treatments may be difficult because of fluid placement issues and the large treatment volumes needed

Multilateral technology. Multilateral wells can provide the same advantages as horizontal wells with the additional benefit of increasing the number of targets that can be accessed from a single well slot. To realise the full potential from multilateral wells, the offtake from individual branches needs to be managed, creating another opportunity for smart well technology.

Extended reach drilling. Access to undeveloped STOIIP locating some distance away from host platforms can be limited by the drilling radius, leaving subsea completions and tieback as the alternative more expensive option. Improvements in drilling reach have allowed the development of satellite fields that would otherwise have been left unexploited and the better utilisation of host facilities.

Designer wells. Designer wells have more than one intended target or purpose, making them more cost effective, since the same objectives would have required several wells in the past. The objectives may be to traverse more than one fault block or to cross known extensive shale barriers. In a category of designer well called J-wells, the trajectory may be designed to go above horizontal and re-enter the formation, and even exit at the formation top to get a fix on the reservoir structure at this location. In mature fields, multi-target infill wells can increase the probability of accessing an economic volume of mobile oil. Designer wells are usually cased and cemented to allow selective perforation.

Cost reduction. Reductions in well cost, through more efficient operations and the application of new technology such as through tubing rotary drilling (TTRD) and coiled tubing drilling (CTD), are contributing to improved recovery by allowing smaller water flood bypassed oil targets to be drilled.

Case studies. The application of advances in drilling technology are illustrated with a range of field examples.

Andrew horizontal wells. The Andrew field, **Fig. 14**, was discovered by BP in 1974, and for two decades lay dormant as a small Palaeocene development option which consistently fell below the economic thresholds. The application of horizontal well technology allowed a development plan to go forward to sanction in 1994. The Andrew structure is a simple four way closure resulting from drape over a salt diapir at depth, with the oil column being akin to a pancake floating on water with almost all the oil zone having active gas above and active water below. So major concerns are coning of gas and water, oil leg instability, and inadvertent displacement of oil into the gas leg. To mitigate against the latter possibility, the gas cap pressure needs to be maintained by re-injecting surplus produced gas.

The facilities consist of a single production, drilling and quarters platform. Oil is exported via a link into the Brae/Forties pipeline system whilst gas is exported to shore through the Central Area Transmission System (CATS). Andrew commenced production in 1996 and reached plateau production of 58,000 BOPD in 1997. Presently there are 12 horizontal producing wells and one crestal gas injector. Currently there is no water injection, the voidage replacement coming from a relatively well connected and extensive aquifer, which is a situation that is common in Palaeocene reservoirs in the UKCS. There is provision to retrofit water injection facilities if required. At the end of the oil production phase the gas cap is expected to be blown down and used to provide the continued sales gas stream.

The availability of the Andrew facility has given a new lease of life to BP's small Cyrus field as well. This is also a Palaeocene reservoir, located about 8 km away. Cyrus had been partially depleted using the ship-based Single Well Oil Production System (SWOPS) where some 4.5 MMSTB had been produced. Substantial reserves were remaining and Andrew provided an economic means of recovering these. Cyrus has been brought on with two new horizontal wells with subsea tie-back to Andrew.

Extended Reach Drilling (ERD). The leading example of the use of ERD wells is in the development of the offshore part of the Wytch Farm field[17] operated by BP, where a substantial part of the reserves are in the offshore part of the Sherwood Sand reservoir. The offshore extension of Wytch Farm is into Poole Bay in Dorset, an area of outstanding natural beauty where any drilling activity has to satisfy stringent environmental constraints. The decision to develop the offshore extension with ERD wells from an unobtrusive onshore drilling site in the Studland peninsula, **Fig. 15**, circumvented this problem. Another key driver was of course the considerable reduction in cost when compared with the next best option of constructing an artificial island for a drilling and production centre. At the time of development sanction of the offshore extension in 1993 the prevailing drilling technology could only promise a stepout of some 6 km from the drilling centre, with the reservoir depth of the Sherwood Sand at 1,600 m TVDSS. By application of sufficient R&D effort in drilling technology much greater stepouts have been achieved in the development wells. In 1999 a producing well to the eastern extremity of the reservoir achieved a stepout of 10.7 km.

In the Alba field operated by ChevronTexaco, the original development plan sanctioned in 1991 had a second drilling and production platform located some 7 km from the northern platform to exploit the reserves in the south of the field. However, in 1996 the advances made in ERD technology enabled a large portion of the southern development to go ahead with ERD wells drilled from the existing platform, resulting in considerable cost saving. ERD wells having stepout of 4 to 5 km have been drilled since then, but the key feature in these wells is the need to keep the track as close to the top of the reservoir as possible. Development of this area is now being completed with a subsea tieback of the southernmost area (Alba Extreme South).

ERD wells are also being used to develop smaller fields through the facilities of nearby larger fields that are past their production plateau period. A typical example is the development of the Columba Terraces operated by Ranger, that adjoin the Ninian field operated by Kerr-McGee. **Fig. 16** shows the location of Columba B, D and E fields in relation to the Ninian Central and Southern platforms. The longest reach ERD well so far to the Columba Terraces is the water injection well BW3 (7,200 m measured depth, 5.7 km stepout) from Ninian South to Columba B. A water injection well EW3 is being drilled from Ninian South to Columba E, with a planned stepout of some 6.5 km.

Brent designer wells. Designer wells are being drilled in the UKCS, and an example of a multitarget well is shown in **Fig. 17**. This is a well targeted to pass through the slump blocks in the Brent and Statfjord formations on the eastern margins of the Brent field.

Reservoir management

Improvements in reservoir management technology and particularly reservoir imaging are increasingly making an impact on both mature and new field developments. The impact of changes in operatorship are discussed later.

Reservoir characterisation. The importance of an adequate understanding of reservoir heterogeneity to underpin the design of EOR projects and guide the selection of infill targets is increasingly recognised. The models used in the 1980s to assess potential IOR projects often seem inappropriate when compared to the much more realistic models that can be built using up to date modelling techniques and software. In particular, gas injection techniques are more sensitive to the detail of the heterogeneity compared to base case water floods.

Although much more realistic static models can be built, computer hardware prevents dynamic modelling being performed at the underlying fine scale. Inevitably models need to be upscaled, which introduces complications when comparing different recovery processes[18]. Detailed simulation of small sectors of the field is recommended to underpin the validity of the upscaling process. Streamtube simulation provides another approach, although some of the benefits are lost when applied to field-scale models with frequent well rate changes.

Seismic. The use of 3-D and four component (4-C) seismic combined with attribute analysis is allowing a much more accurate picture of the subsurface to be developed, with seismic attribute analysis providing a powerful constraint on the construction of detailed geological models. The application of the relatively new 4-C ocean-bottom cable (OBC) seismic technology has allowed the use of the converted shear waves to obtain a clearer image of the reservoir than the conventional P-wave seismic data, when the acoustic impedance contrast at the reservoir top is not large enough. This is particularly so in the Tertiary sand reservoirs in the North Sea and is the primary benefit of this technology. Time lapse seismic is being used as a reservoir management tool to identify regions of bypassed or unconnected oil. The Foinaven project, with the installation of permanent ocean bottom cables demonstrates the value of this additional data. The resolution of surface seismic is limited to approximately 20m, and research continues into the application of downhole seismic sources and detectors in uniwell or cross-well configurations.

Other techniques. The potentially viable IOR techniques also include facilities related changes which can improve recovery simply by increasing the total volume of injected water into the reservoir over its economic life. These include drag reduction agents to improve injectivity in THP constrained wells, additional water handling facilities, produced water reinjection and downhole separation**.**

Case studies. The use of new seismic techniques in Foinaven and Alba illustrates the application of techniques in the reservoir management category.

Foinaven time lapse seismic. Foinaven, operated by BP, is located 190 km WoS, in a water depth of c.500m, with the reservoir between 2000 and 2200m TVDSS, consisting of turbidite sands in complex stacked channel systems. The reservoir is cut by faults and sealed by up-dip sand pinch-outs. The oil is near the bubble-point at reservoir conditions and exhibits good AVO-DHI (Amplitude Variation with Offset - Direct Hydrocarbon Indicator) characteristics[19,20] on seismic data. This makes it possible to use time lapse 3-D surveys to provide field-wide surveillance of pressure and fluid movements, compartmentalisation and saturation changes. For example, amplitude brightening is indicative of increasing GOR or pressure (with no change in phase) and dimming is indicative of increasing water saturation or reduction in GOR. Comparison of 4-D synthetic seismic derived from reservoir simulation with actual surveys, allows better history matches to be obtained and is assisting in the identification of infill well targets. **Fig. 18** shows a comparison between actual and synthetic seismic amplitude differences.

Alba 4-C seismic. The contrast in P wave velocity between the Alba reservoir[21] and the surrounding shales is low, making it extremely difficult to map the reservoir, although the difference in compressibility between oil and water does give rise to a strong seismic event corresponding to the oil water contact. Shear wave velocities have a significant contrast at the top and bottom of the sand, and synthetic seismic models showed that a strong converted wave (P converted to S) seismic event would occur at the top and base reservoir. A full OBC survey was undertaken in 1998, providing the clearest image of the Eocene Alba sand reservoir ever seen, **Fig. 19**. It identified structurally high ‘wings’ to the channel sands not previously seen. It helped in geo-steering new ERD development wells, and identified several new well locations. The analysis of the time-lapsed P-wave data helped identify movement in the OWC and production related saturation changes.

HPHT fields

In the UKCS HPHT fields are defined as those with reservoir pressure exceeding 10,000 psi and reservoir temperatures above 300^{o}F. HPHT fields were not looked for at first and then avoided from the mid eighties when it was difficult to drill and test them let alone produce. The drawbacks at the time were mainly in equipment limitations and materials technology, as the surface temperatures and pressures to contend with are much higher than normal. Since then advances have been made in high temperature equipment, and drilling vessels capable of working at these depths and handling up to 20,000 psi BOP stacks have become available. Early HPHT discoveries were Rhum (1977), Puffin (1981) and Franklin (1986). The first UK producing HPHT field (1997) was Texaco's Erskine gas condensate field which opened up the deep Central Graben area and showed the use of a not normally manned platform and an insulated full fluids line. By the end of 2001 seven UKCS fields are in production, three of these fields are volatile oilfields and the others are gas condensate fields. A further 16 HPHT fields have been discovered to date and their estimated oil and gas reserves appear in the 'possible' totals for the UK[22].

Heavy oil fields

In the UKCS heavy oils are taken as those having in-situ viscosities greater than 5 cp. When the heavy oil plays were first discovered and appraised, wells were vertical, or at a moderate angle to the vertical. In most cases, high enough oil rates could not be achieved and sustained long enough to justify commercial development. The development of technology for drilling very high offset/true vertical depth horizontal wells with adequate sand control has been crucial to the development of heavy oil fields. The Captain field, which commenced production in 1997, has the highest in-situ oil viscosity (90 cp) of the producing 'heavy oil' fields in the UKCS and is entirely dependent on long horizontal wells for production and injection. This will be the case for the even heavier oil fields (Mariner, Bressay) awaiting development, where very closely spaced horizontal wells or multilateral wells will be needed to achieve commercial rates. There is also scope for further innovative IOR techniques to improve the overall recovery and economics of heavy oil developments. A conservative estimate of the heavy oil reserves in addition to those currently under development is 1.5 to 3 billion STB[1].

A holistic view of IOR opportunities

The high cost operating conditions of the UKCS can make the economics of some stand alone IOR projects unattractive. For example an IOR scheme may not be economic on a stand alone basis if it is implemented too close to the planned end of field life and is required to bear the costs of field life extension to fully capture the incremental oil. However, combined with other projects, such as satellite developments in the window created by extended platform life, the overall project may be economic.

Therefore, the value of implementing an IOR project may extend beyond the direct benefit of improved recovery and so it is important to view potential IOR projects "holistically". This means recognising that the overall benefit of an IOR scheme will be a combination of the direct economic value of the incremental oil, production from satellite development activity, together with any monetary benefits from associated gas and CO_2 disposal. From a national perspective, the increased level of activity to the general economy and the improvements in security of supply from IOR/gas storage schemes needs to be viewed as additional benefits.

This section summarises a range of additional value drivers and illustrates the holistic approach to IOR with the Magnus miscible gas injection project.

IOR value drivers. The value from implementing IOR schemes can extend beyond the direct benefit of improved recovery, and it is important to consider all the value drivers, that combined can make an IOR project attractive.

Extension of field life. Extending field life provides opportunities to capture additional value from:

- extra reserves from host field by capturing more of the production tail unrelated to IOR activities
- extra reserves from satellite fields
- additional third party business
- deferral of abandonment
- option to deploy new technology in the future.

Hydrocarbon gas storage. Although hydrocarbon gas is valuable if it can be brought to market, there may be additional value that can be created from storage in IOR schemes:

- bringing forward development of fields with stranded gas
- acceleration of condensate liquid production
- exploitation of market dynamics e.g. through provision of storage for peak shaving, differences between summer and winter prices or overcoming infrastructure bottlenecks.

Environmental. IOR can also provide environmental benefits through:

- flaring reduction (through gas injection)
- adding value to CO_2 sequestration schemes (CO_2 flooding projects)
- reduced overboard oil discharge (with produced water injection)
- maximum use of existing infrastructure.

Magnus EOR. An excellent illustration of the way IOR can be combined with other value drivers is given by the Magnus EOR project operated by BP, **Fig. 20**, which was sanctioned in 2000. This highly innovative project[23] involves an investment of $420 million to transport gas from WoS to the Northern North Sea. The Foinaven and Schiehallion fields are the first developments in the deepwater WoS region and have no gas export infrastructure. Environmental considerations prevent any sustained flaring of produced gas. Magnus is a mature waterflooded field on the edge of the existing infrastructure. BP's early studies and the DTI's Meteor screening[24] had highlighted the technical potential for WAG injection, but there was no practical way of implementing it economically.

The Magnus EOR scheme involves a new 116 mile 20 inch export line from Foinaven/Schiehallion to the onshore processing facilities at Sullom Voe. Part of the lean gas displaces liquid fuels used for power generation at Sullom Voe, which allows gas to be enriched for export to Magnus. The enriched gas is transported in a new 131 mile 20 inch pipeline to Magnus. This is an example of where combining several separate projects has resulted in an extremely attractive overall scheme.

The scheme has a range of benefits, which go beyond the incremental recovery in Magnus. WoS there is no requirement for long term operation of gas disposal wells and opportunities to accelerate oil production. Eventually gas can be exported to market once ullage becomes available in the gas export lines from the Northern North Sea to the UK mainland. The pipeline is strategically important, providing a means of managing associated gas production in future WoS developments, as shown by the Clair development sanctioned in 2001. In the Magnus field 50MMSTB incremental oil is expected to be produced directly by the EOR scheme. Additionally, field life will be extended to 2015 and possibly beyond and there will be additional recovery from the ongoing development of Magnus reservoirs. Environmental benefits will be achieved because the Sullom Voe Terminal will burn clean fuel gas instead of diesel during periods of low throughput from the incoming oil pipelines. CO_2 emissions will be reduced by 600,000 metric tonnes over the lifetime of the project[25].

Government involvement

In the mid 1970s when N Sea oil production was in its infancy, the responsibility for policy and the necessary regulatory framework for licensing, exploration, production safety and environmental protection lay primarily with the then Department of Energy. As oil production built up to high levels in the 1980s with world oil prices at around $30/bbl, oil revenue made a significant contribution to GDP (reaching nearly 8%). With such a valuable natural resource within its territorial waters the UK government saw the need to build up a local infrastructure for providing the expertise in exploitation technology and an R&D capability to maximise recovery. Sizeable amounts of government funds were channelled annually through the Department of Energy to fund the setting up of centres of expertise within the UK, to provide training, simulation software development, and research groups covering areas such as SCAL, PVT and EOR techniques.

The subsurface engineering group at the UKAEA (now part of AEA Technology plc) and the Petroleum Engineering Department at Heriot-Watt university resulted from these early initiatives. The Royal School of Mines at Imperial College was in existence before the N Sea oil boom and they too enhanced their petroleum engineering capability meet this challenge.

Since 1985 government oil revenues have declined sharply, although the level of investment activity is still significant. The Department of Energy is now subsumed within the Department of Trade and Industry, but still carries the remit for maximising the return from hydrocarbon assets. For this the DTI undertakes strategically selected field specific studies as well as maintaining an overview of IOR potential. In addition government funding of hydrocarbon recovery research is channelled through UK research councils, the DTI's Sustainable Hydrocarbons Additional Recovery Programme (SHARP) and its programme to support oil industry development (mainly directed to small to medium sized companies). Many of the research activities are in the form of Joint Industry Projects (JIPs), with oil companies contributing the major proportion of the funding.

IOR Screening. In the early 1990s a systematic assessment of EOR potential was undertaken by the DTI for 63 oilfields using the Meteor 1 analytical screening tool, based on layer cake geological models[25]. Subsequently important fields coming forward for development were also screened for EOR potential Since the original screening there have been significant advances in reservoir description and field development technology and the screening methods have recently been updated (Meteor 2) and are now being applied to fields. The screening has two stages: "Performance Indicators" and "Rapid Simulation".

Performance Indicators. This uses binary screening criteria and analytical models to estimate key performance indicators for a range of IOR processes including: water flooding, polymer flooding, crestal gas injection (gravity stable) and water alternating gas injection. Gas injection options are evaluated for immiscible and miscible flooding, based on lean hydrocarbon gas, enriched hydrocarbon gas, nitrogen, carbon dioxide and air.

Performance indicators are used to assess the suitability of the reservoir to the different processes, taking into account the properties of the IOR agents (chemicals or gas) and a simplified representation of the reservoir geology, and include:

- Gravity/viscous balance over the full reservoir interval and subgroups of layers
- Estimation of MMPs
- Assessment of optimal reservoir pressure for operating miscible and immiscible gas injection
- Thermal stability of chemical IOR agents.

The impact of uncertainty in reservoir or fluid properties on the performance indicators is assessed using Monte Carlo methods. The performance indicators help generate an understanding of the type of displacement that can be expected, and allows some IOR techniques to be eliminated because they are not technically viable.

Rapid Simulation. The objective is to obtain a preliminary quantitative estimate of the performance of the remaining process/reservoir combinations. The exponential advances in computing power, make it possible to perform simulations of IOR processes on a PC using a multi-purpose reservoir simulator driven by Excel for data input and results analysis. This has a number of benefits including:

- Better representation of the detailed distribution of remaining oil in mature fields
- Treatment of vertical and horizontal wells and associated water and gas coning issues
- Evaluation of complex processes such as WAG (miscible and immiscible)
- Evaluation of temporary and long-term storage of injected gas.

The geometry of the simulation model is based on a 3-D layering system or a sector model directly imported from a conventional reservoir simulation model or underlying geological model. Each IOR technique is defined by a simple set of process variables.

This provides a means of rapidly performing screening simulations for the IOR techniques still under consideration, while fully honouring the best current understanding of the reservoir structure and geology. Within the simulation phase it is normal to consider some important process optimisation issues at a conceptual level, such as: timing of injection, slug length, WAG ratio, reconfiguring of injection or production wells.

Future trends

Oil and Gas Industry Task Force and PILOT. The oil price crash in 1998 brought home to the industry the vagaries of the market and how low prices can fall, if even for a limited period. This prompted companies to apply strict criteria for the sanction of new projects – even the pessimistic case having to stand up to an oil price of 10-12 $/bbl is now common. The UKCS, which is traditionally a high cost oil province, has to compete for investment funds in this arena. The UK government and the oil industry realised that the key to the long term survival of the UKCS as a major oil province lay in taking a joint initiative to drive down UK's offshore cost base. They also saw the need to foster the innovative technology that is required to exploit these mostly difficult reserves and to have it available to the industry while 'the window of opportunity' is still open. These objectives are embodied in the PILOT initiative, which will be a major driving force behind future IOR activity in the UKCS.

PILOT's governing board is chaired by the UK's Minister for Energy and is comprised of high ranking executives from the oil sector and government. PILOT has set measurable targets to aim for during the next 10 years. These are to achieve in the year 2010: 3 million BOE/D hydrocarbon production (current level is around 5 million BOE/D); sustained CAPEX level of £3 billion/year; 100,000 more jobs than would otherwise exist and £1 billion a year additional revenue for new business. In order to achieve PILOT's 2010 vision several independent bodies have been established. These are: Leading Oil and Gas Industry Competitiveness (LOGIC) to tackle supply chain management and achieve cost savings; Industry Technology Facilitator (ITF) for improving facilitation and flow of new technology to market; National Training Organization (NTO) for focusing on training activity and maximising commitment to skills; License Information Trading (LIFT), a website to promote licence trading for rationalisation and cost-effective development of UK's remaining reserves; Digital Energy Atlas and Library (DEAL), a website to inform on location and availability of UKCS well information and seismic data available to the industry.

PILOT also established several work groups to work on and point the way forward in areas where there are perceived obstacles to development. Presently the work groups are:

- Brown Fields Work Group to work on maximising recovery from fields that are past their production plateau.
- Undeveloped Discoveries Workgroup to foster activity and facilitate development activity within technology groupings picked from some 315 undeveloped discoveries in the UKCS.
- Progressing Partnerships Workgroup to identify significant commercial and behavioural barriers to increased activity and look at ways of improving relationships between licensees.

There is also the Satellite Accelerator initiative, which seeks to invite innovative technical and commercial solutions to challenging discoveries from the industry as a whole, with collaboration on a risk/reward share basis.

The 'Prize'. Since production commenced from the UKCS, some 28.5 billion BOE have been produced at year-end 2000, as reported in the DTI's 2001 Brown Book[6]. The Brown Book defines 'proven reserves' from current fields and discoveries as having a better than 90% chance of technically and economically being produced, 'probable reserves' are defined as having a better than 50% chance, and 'possible reserves' are defined to have a significant but less than 50% chance. On this basis the 'proven', 'proven + probable' and 'proven + probable + possible' estimates for remaining reserves (at year-end 2000) are 9.5, 15.5 and 21.5 BOE respectively. The Brown Book also addresses the exploration side and provides an estimated range for the undiscovered recoverable oil and gas reserves in the UKCS of some 3.5 billion BOE to 26.0 billion BOE. This is based on statistical analysis of the prospects to obtain the reserves within each basin, and it is updated with the new drilling and mapping that takes place during the year. The 2002 Brown Book had not been published at the time of submission of this paper.

The barriers to development of 'difficult' reserves (which are largely in the 'possible reserves' category in the Brown Book) as identified by the PILOT workgroups are mainly the availability of new technology, containing development and operating costs, access to infrastructure, and alignment of partnership in a particular field. The importance of the survival of the existing infrastructure in the UKCS for the exploitation of these incremental reserves, cannot be overemphasized. The capital expenditure that has gone into the construction of this infrastructure has mostly been amortised through the production from the host fields, and any excess capacity should be made available to new developments. Increasing the recovery from mature fields will no doubt extend the life of the facilities and infrastructure considerably. So will the development of additional satellite accumulations (the presently undeveloped discoveries or new discoveries) through these facilities. **Fig. 21** illustrates qualitatively the gradually contracting window of opportunity, based on a 30km radius drawn from currently sanctioned projects. Thus any improved hydrocarbon recovery initiative will have its 'window of opportunity', and this should not be missed. The impact of future projects and technology advances are expected to extend this window further into the future. However, all this depends on future oil price trends.

Technology innovation. The innovative technology that will have the largest impact on UKCS hydrocarbon recovery efforts is likely to be the use of seismic techniques in reservoir management. This may be for better mapping of reservoirs that are difficult to image, for improved reservoir characterisation through seismic attribute analysis, to identify fluid movement through time lapse seismic and so on. Improvements are being made in 4-C OBC seismic acquisition and processing. Acquiring seismic while drilling will help in the geosteering of complex extended reach wells. In drilling technology there is scope for a lot more work in CTD to access additional reserves at low cost. There is interest in underbalanced drilling offshore to minimise well damage and achieve high enough flowrates especially in the low permeability reservoirs. Faulting in reservoirs is a key uncertainty in the new high risk discoveries and prospects and this has been identified as an area that needs further work. In reservoir simulation work is being done in the development of streamline simulators and in appropriate circumstances these would offer a great improvement in speed, resolution and accuracy over conventional finite-difference based methods. Stress sensitive dynamic reservoir simulators are being developed and amongst others may have application in relating 4-D seismic results to reservoir changes.

Deep water fields. The deep water areas are in the Atlantic Margin (**Fig. 1**) where water depths vary from less than 500 m in the near WoS area to greater than 1500 m at the edge of UK waters. The exploration potential of the area has been continuously evaluated for the past 30 years or so. Drilling in the 1970s, based on 2D seismic, was restricted to the relatively shallow water on the SE edge of the basin, resulting in the discovery of the Clair oil field and Victory gas field. During the 1980s advances in drilling enabled the exploration activity to move further out into deeper waters (up to 750 m), still based mainly on 2D seismic and there were no major discoveries. Significant advances in seismic technology (especially 3-D and AVO-DHI) in the 1990s led to the discovery of Foinaven, followed by other Palaeocene fields (Schiehallion, Loyal, Suilven and near field satellites). Further out in the largely unexplored Faeroe-Shetland frontier area, there is a high chance of multiple reservoirs, containing hydrocarbons, being found in the Pre-Jurassic, Jurassic, Cretaceous, Palaeocene and Eocene. Tertiary reservoirs generally carry the lowest risks.

There is much synergy with similar deep water plays in the Gulf of Mexico and there will be plenty to be gained from the technological successes experienced there. However, certain problems will be more specific to the UKCS. In the future, further work will be needed to build on the experience gained through the Foinaven and Schiehallion developments in the areas of drilling, sub-sea completion technology and Floating Production, Storage and Offshore Loading (FPSO) vessels particularly suited to the harsh ocean conditions in the Atlantic margin. In seismic there is a major obstacle in the Rockall Trough area, where at present there is no seismic technology capable of imaging sedimentary rocks beneath the thick overlying basalts (ancient lava flows occurring over several million years). Possible solutions are still at the research stage[26]. Other relevant areas being worked are: handling of deepwater hydrates in drilling and production, and seabed located injection and separation facilities.

Transfer of operatorship. Depending on the nature of an operator's UKCS and worldwide field portfolio, mature assets may appear relatively unattractive, with high operating costs and demands for staff resources, but only modest profits. An emerging trend is the transfer of operatorship of these fields, to new operators who bring benefits from different cost structures and increased investment, for what to them are core assets. Fields that have transferred to date are: Heather to DNO, Hutton, Murchison and Ninian to Kerr-McGee, Beatrice, Buchan, Claymore, Clyde, Piper and Tartan to Talisman and the Trees complex to Venture. Increased investment has brought facilities upgrades, new seismic surveys, the application of new technology (e.g. CTD) and a greater focus on potential satellite developments. Talisman has summarised its UKCS strategy as[27] "to develop core areas consisting of commercial hubs around Talisman owned and operated infrastructure. Core areas typically include an existing production base, identified upside and under-utilised infrastructure. Once a hub is established Talisman creates value and extends the life of these assets through low risk development opportunities, nearby exploration, cost reduction, third party tariff revenues and expansion of our working interests". **Fig. 22** illustrates the result of changed operatorship on predicted production from a mature field, demonstrating increased reserves in the host field, satellite development and deferment of cessation of production.

Fig. 3 shows that small fields are coming forward to make up the production decline in the mature oil fields in the North Sea. These fields will have short life cycles from discovery to production peak and decline, and hence can be worked more profitably by smaller independents than the major integrated companies. In future years a larger proportion of such operators can be expected to be working the mature areas of the UKCS.

Redevelopment of abandoned fields. A field is sanctioned for cessation of production (COP) and abandonment when it is not economic to produce the remaining oil. Over time after COP two possible changes could take place. These are: (1) drilling and production technology can advance rapidly so that low cost wells can be employed to access the remaining areas with moveable oil, and a production method with low operating cost may become available, and (2) significant fluid re-distribution can take place. Fluid re-distribution can be estimated with some confidence by modeling the processes involved, if sufficient geological information and production and surveillance data were retained and are available.

An example of a field brought back on to production is the Angus field operated by Amerada Hess, which was originally developed from an FPSO. High operating costs led to early COP. Subsequently, the field was redeveloped using a sub-sea tie-back to the Fife facilities. Other COP fields that are being evaluated for possible redevelopment include Argyll, Crawford and Emerald.

Carbon dioxide injection. CO_2 may provide an alternative to hydrocarbon gas for EOR projects. There are environmental pressures in Europe to fully evaluate this option for application in North Sea fields. This is on account of the added benefits through CO_2 sequestration. Some operators in the UK have conducted screening studies on their fields to pick out the best candidates for this option and in one or two cases this has proceeded to detailed reservoir simulation. However, a lot of work needs to be done to evaluate the total picture - the source of CO_2 in the required quantities, the cost of capture to the required purity, its delivery offshore and the cost of refurbishment required on platforms. The indications are that it will be difficult to make such projects economically viable unless there are some new commercial incentives brought into play - this could be a comprehensive emissions trading scheme or an emissions tax that will assign a monetary value to reduction in CO_2 emissions. Another possibility is a larger Europe-wide CO_2 infrastructure that could collect CO_2 from power stations and deliver to the points of use, utilising economies of scale to offer attractive prices. Many legal, environmental and transboundary issues need to be addressed before this type of scheme could be implemented.

Conclusions

1. Despite the challenging operating and market conditions in the UKCS a number of significant EOR projects have been undertaken, and a large number of fields have benefited from IOR techniques, which have significantly deferred COP dates well beyond the initial expectations.
2. The UKCS has produced 28.5 billion BOE (at the end of 2000), and the total reserves to be produced from known fields and discoveries (proven + probable + possible) are estimated to be 21.5 billion BOE. The scope for finding more reserves in future discoveries is expected to be in the range 3.5 to 26 billion BOE.
3. To achieve the maximum recovery from the UKCS all areas have to be addressed. A holistic view of IOR opportunities combining brown fields and undeveloped discoveries and prospects is needed, together with the application of new technology to new basins (e.g. the Atlantic Margin) and difficult fields (HPHT, heavy oil and low deliverability fields).
4. It is important to keep a view of the remaining window of opportunity, although, with the successful application of IOR techniques this is likely to extend beyond the current expectation.
5. The UKCS is likely to remain a key producing region for decades to come, however the timeline and magnitude of these incremental activities will depend strongly on the trend in oil price.
6. PILOT has provided a framework for a joint effort between industry, government and academia to maintain the attractiveness of the UKCS for future investment.
7. The DTI has an important role in addressing regional and strategic issues, encouraging best practice and best use of infrastructure, dissemination of gathered data and knowledge, and promoting the UKCS in the international arena.

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Conversion Factors

°API 141.5/(131.5+°API)		= g/cm^3
bbl x 1.589 874	E-01	= m^3
cp x 10	E-03	= Pa.s
°F (°F-32)/1.8		= °C
ft x 3.048*	E-01	= m
psi x 6.894 757	E+00	= kPa

*Conversion factor is exact

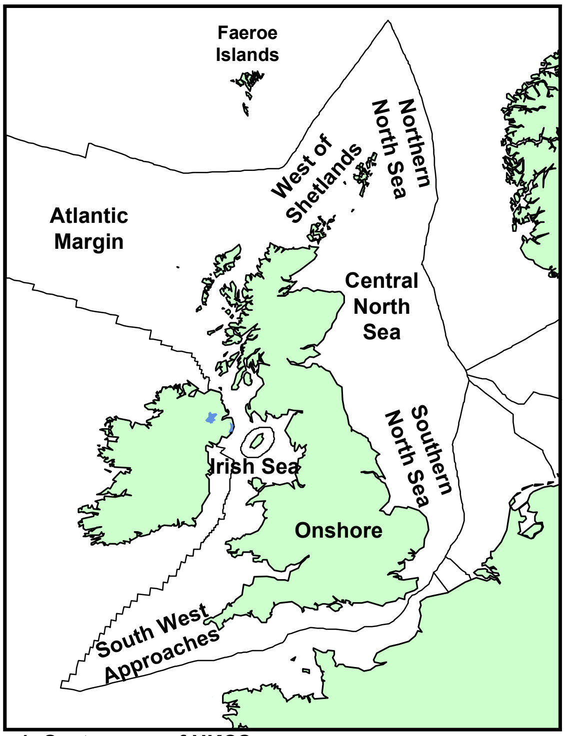

Figure 1: Sector map of UKCS.

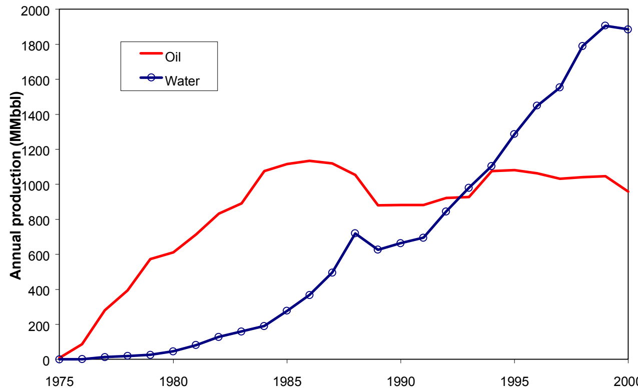

Figure 2: Evolution of total oil and water production as UKCS has become more mature.

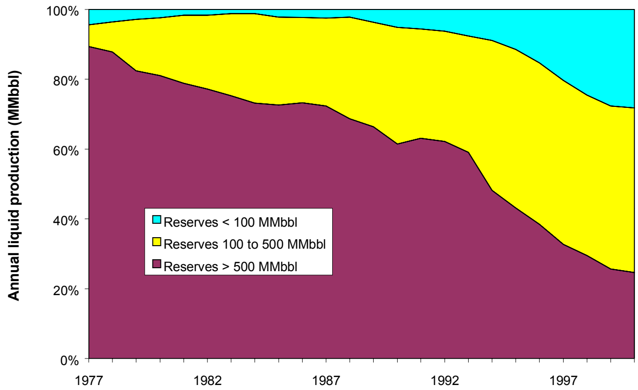

Figure 3: Contribution to UKCS oil production from fields in different reserves categories.

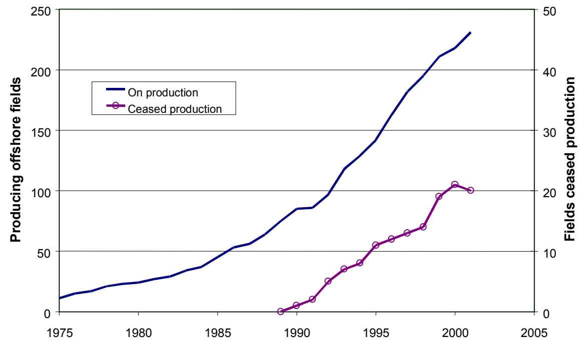

Figure 4. Number of producing UKCS oil and gas fields and cumulative number of fields where production has ceased.

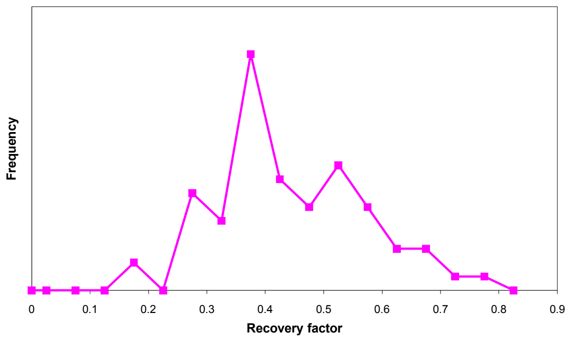

Figure 5: Distribution of recovery factors for CNS and NNS oil fields

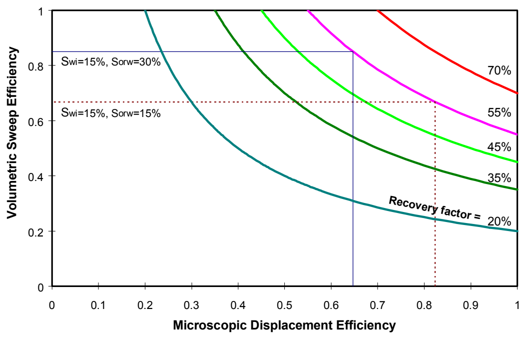

Figure 6: Illustration of importance of understanding residual oil saturation when defining the IOR target.

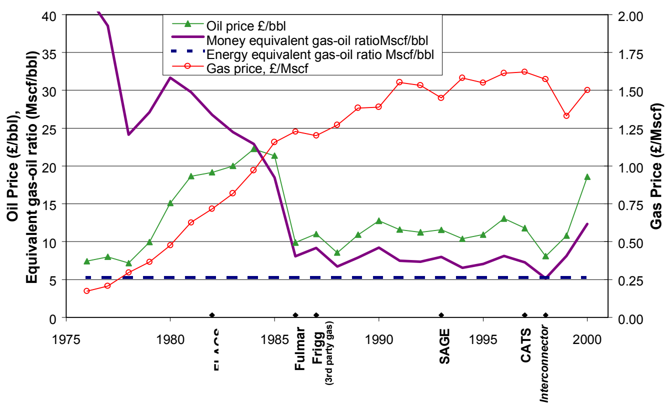

Figure 7: Comparison of average historical UKCS oil and gas prices

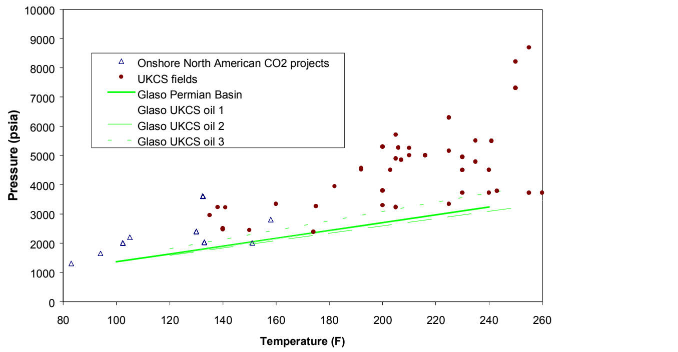

Figure 8: Estimation of CO_2 MMP for UKCS fields compared to operating projects in USA.

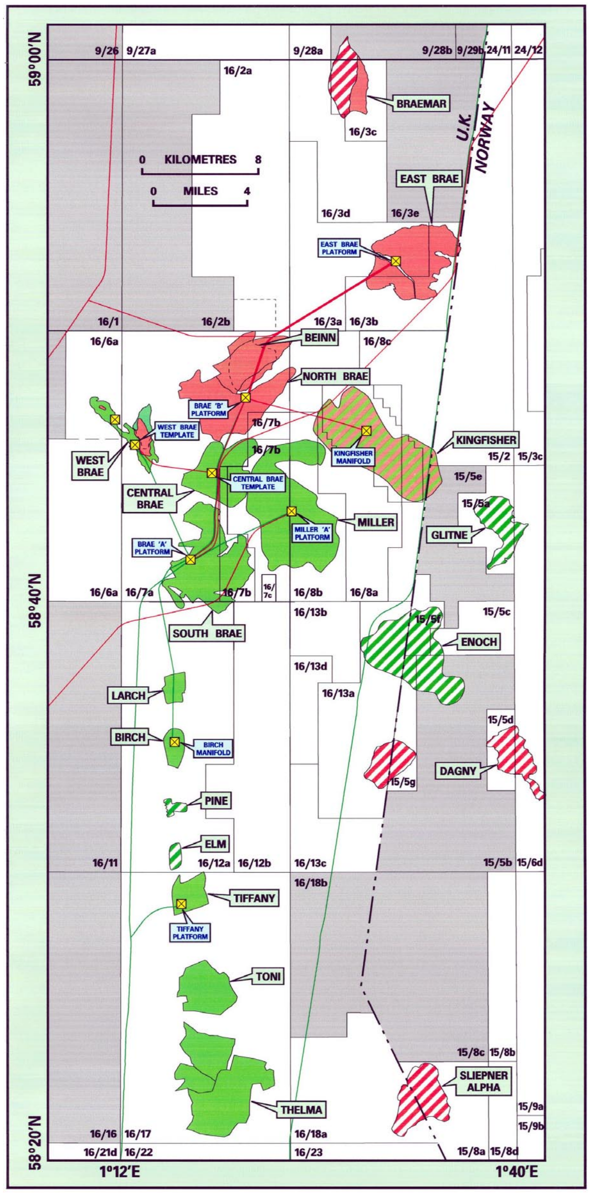

Figure 9: Map of fields in Brae complex.

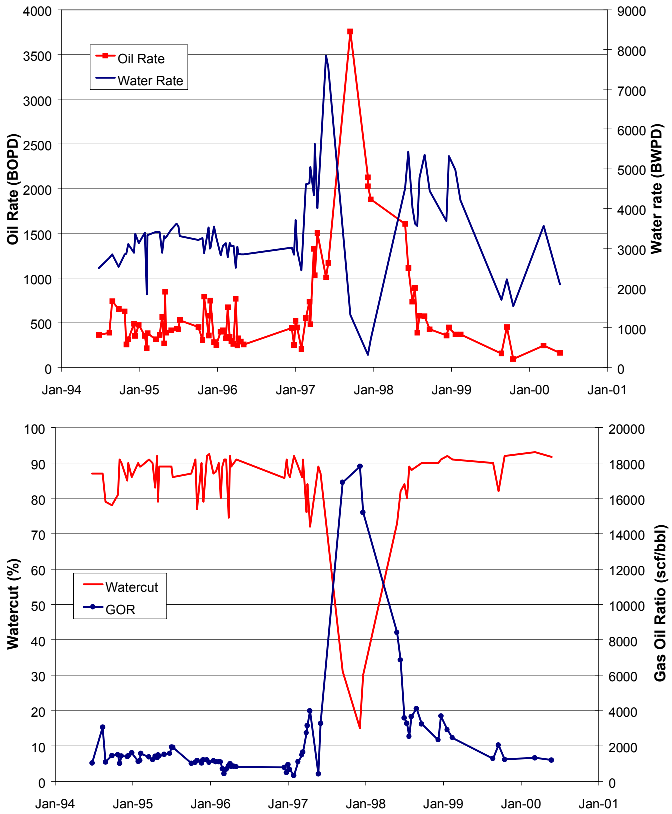

Figure 10: Response in Well A16 to South Brae WAG pilot.

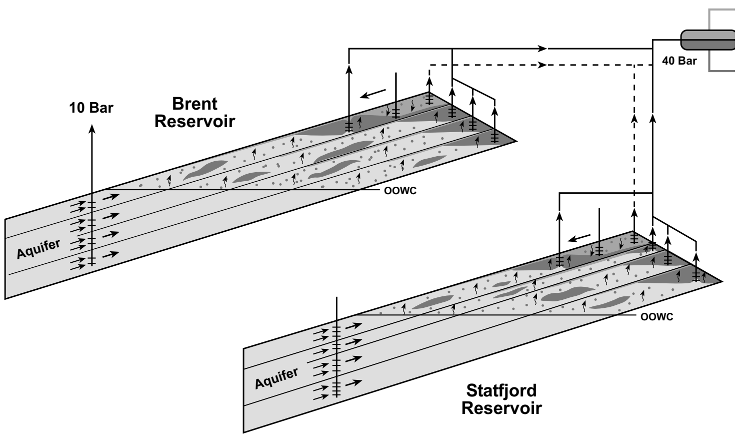

Figure 11: Schematic diagram of Brent depressurisation process.

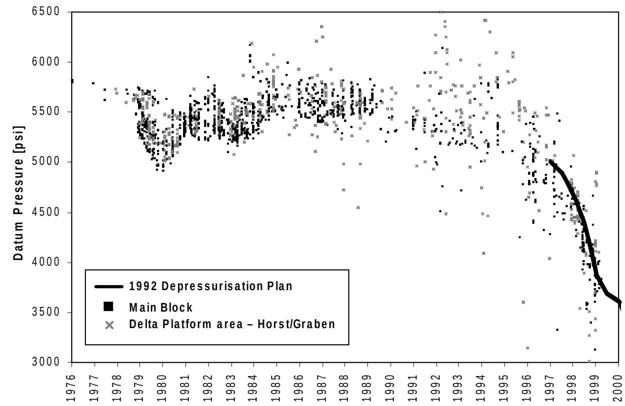

Figure 12: Brent actual reservoir pressure compared to 1992 depressurisation plan.

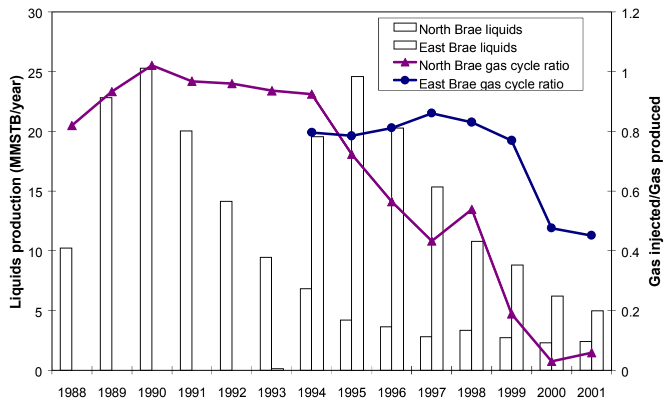

Figure 13: North and East Brae condensate recycle, produced and injected fluids.

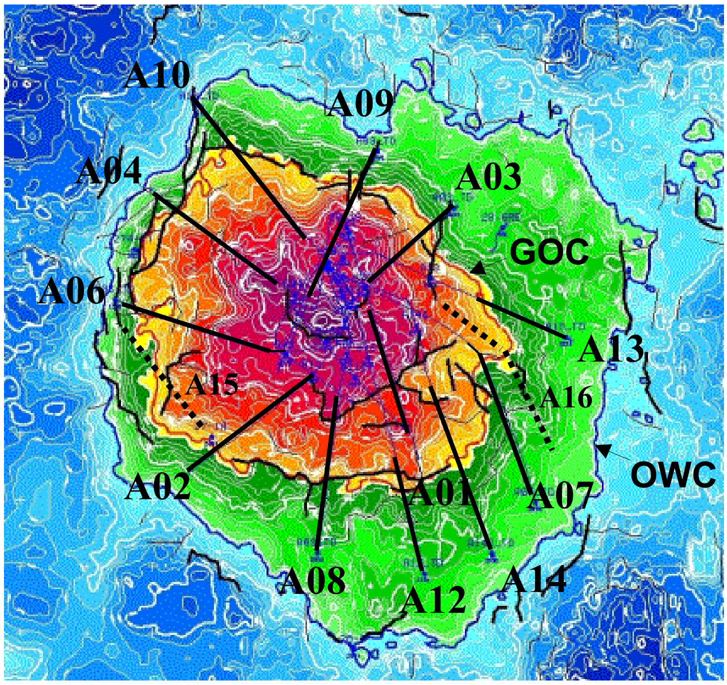

Figure 14: Andrew field development with horizontal wells.

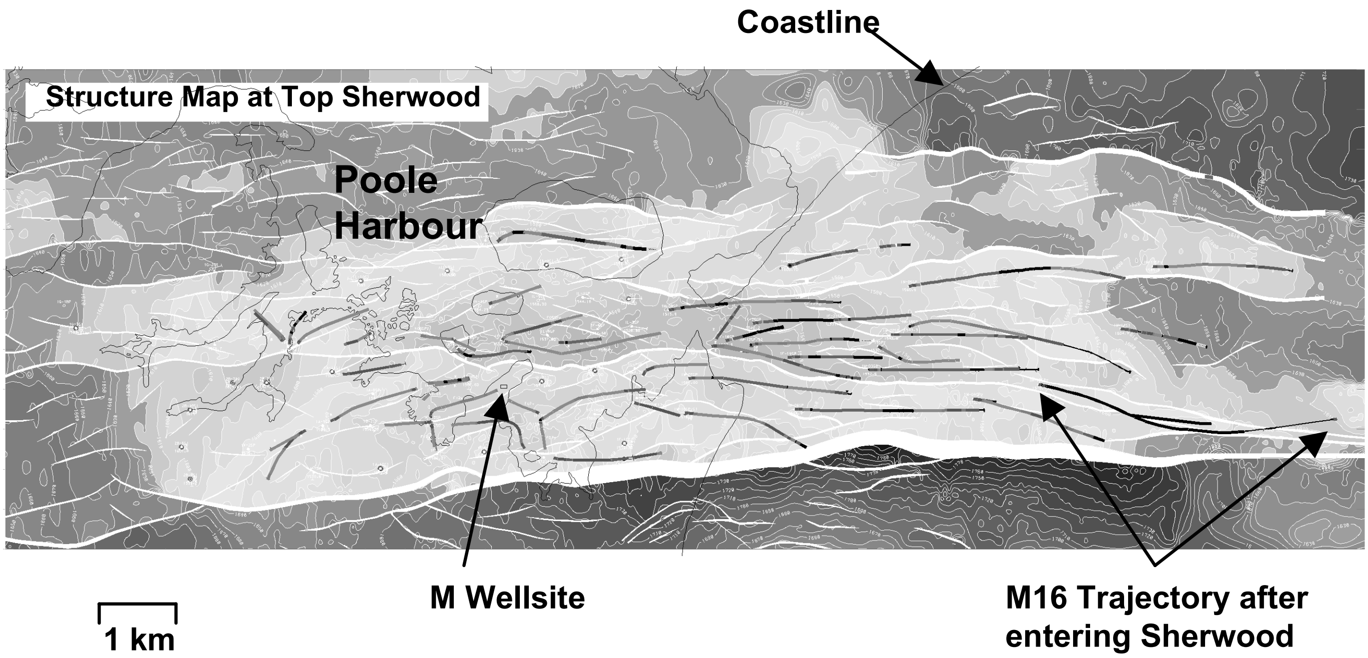

Figure 15: Plan showing location of Wytch Farm and trajectory of ERD wells

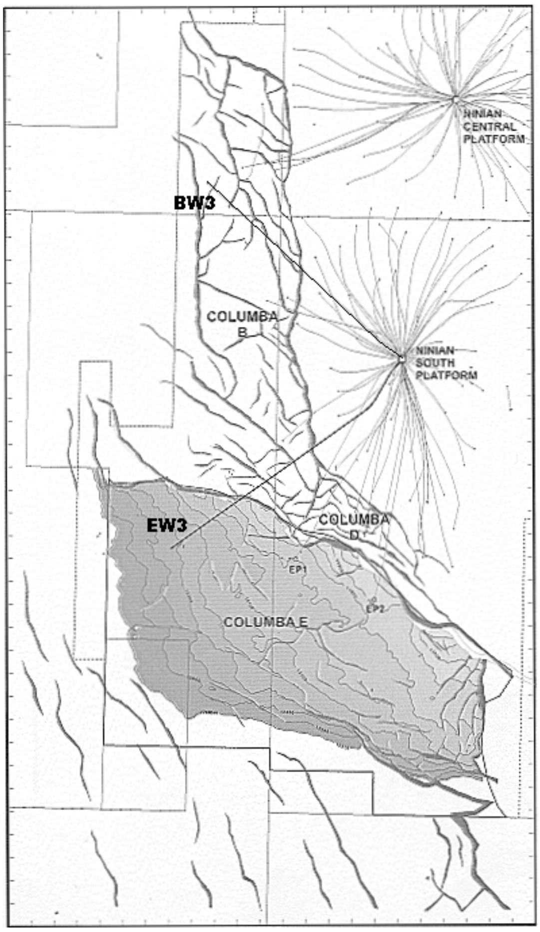

Figure 16: ERD well accessing Columba B and E from the Ninian South platform.

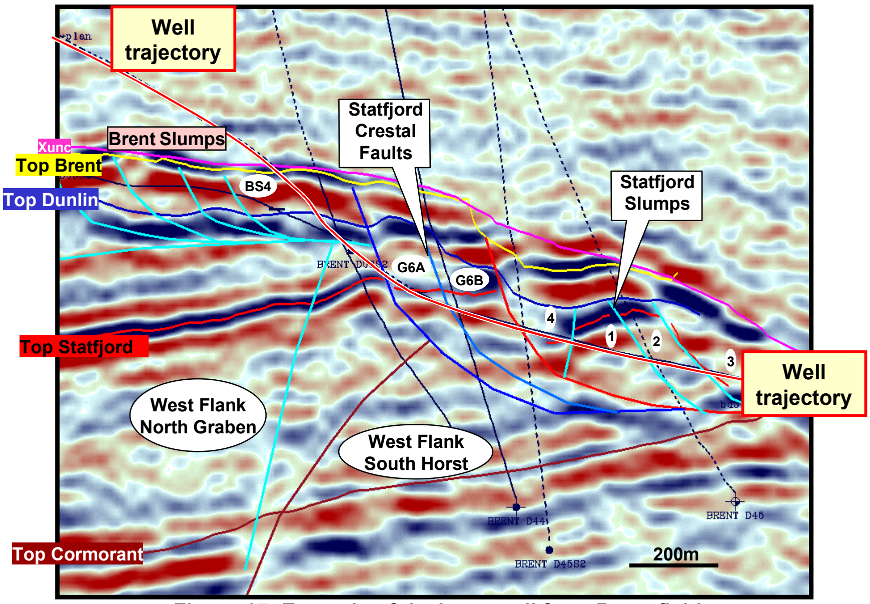

Figure 17: Example of designer well from Brent field.

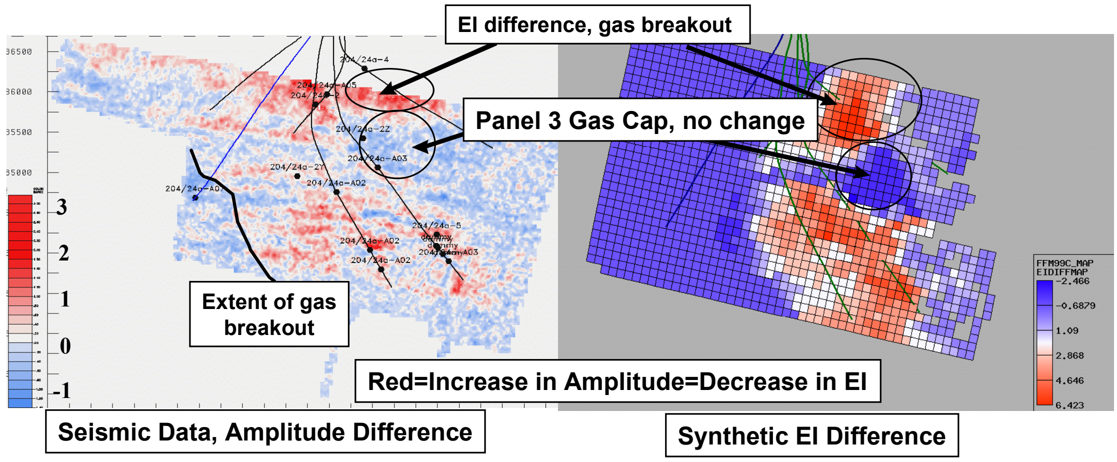

Figure 18: Comparison of seismic amplitude difference map obtained for Foinaven with synthetic results from simulation model.

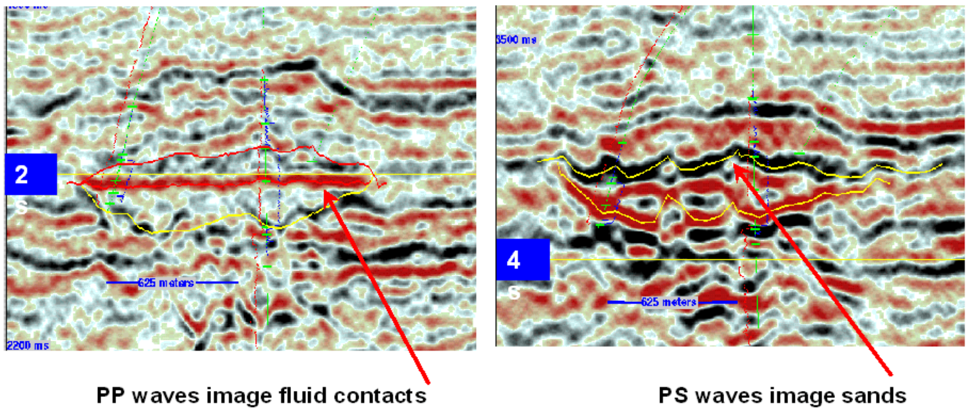

Figure 19: Images of the Alba reservoir comparing PP (left) and PS (right) seismic data showing the improved structural interpretation.

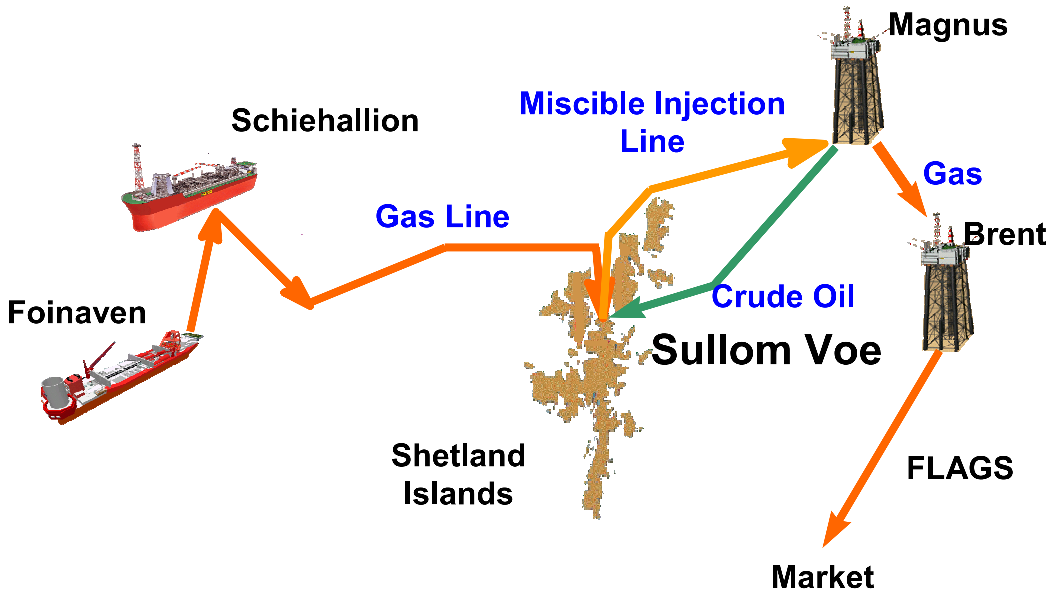

Figure 20: Schematic of Magnus EOR project.

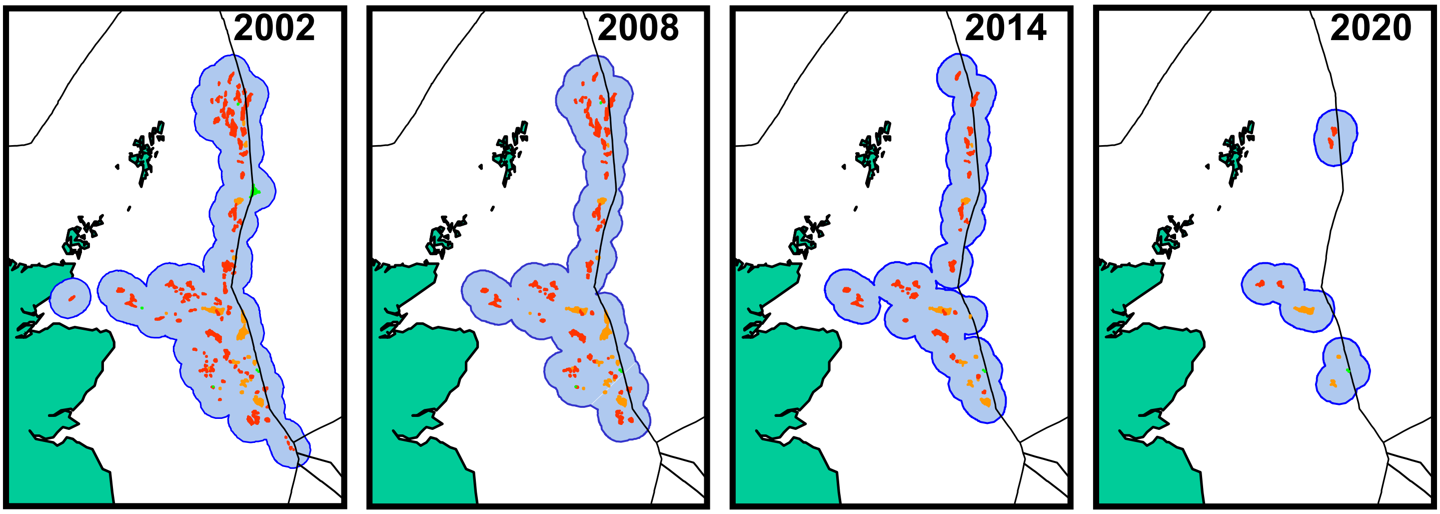

Figure 21: Regions of CNS and NNS within 30km of fields currently under production taking into account expected COP dates.

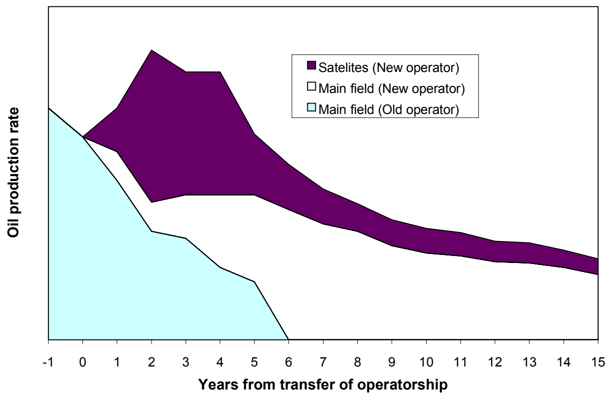

Figure 22: Impact of change of operatorship on a mature UKCS field