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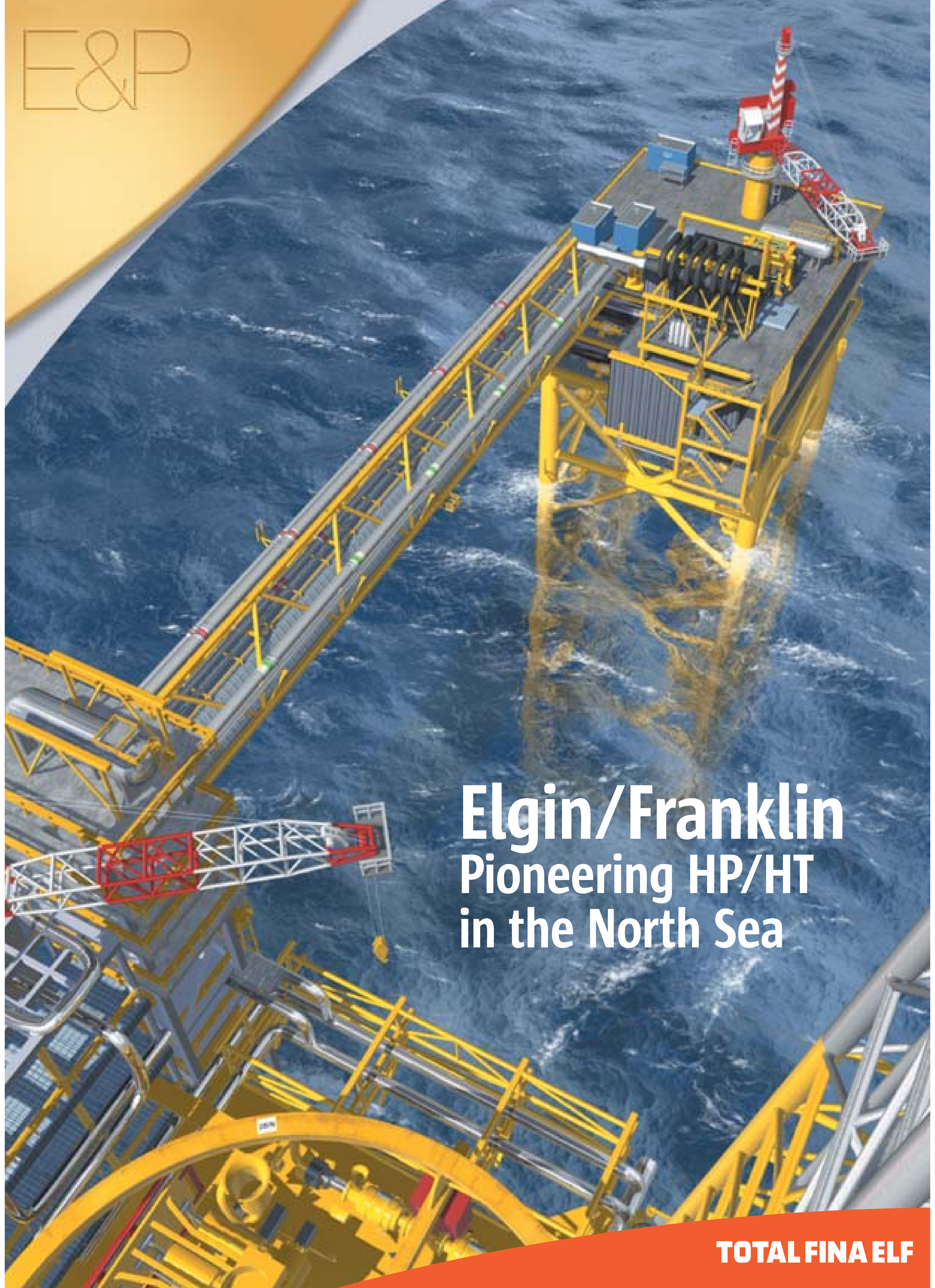
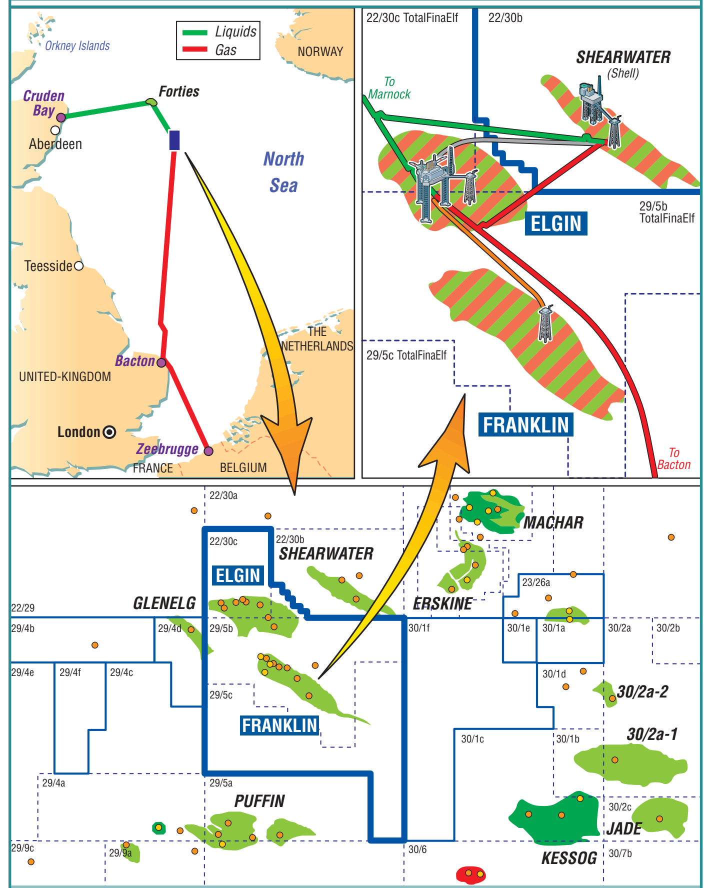


Elgin/Franklin
Pioneering HP/HT in the North Sea

AN EXCEPTIONAL OFFSHORE ACHIEVEMENT



In the heart of the Central Graben area, the Elgin/Franklin fields produce oil and gas exported to both UK and Continental markets.

There are more than 150 oil and gas fields spread across the North Sea Continental Shelf between the Netherlands and the Shetland Islands. Production of these resources began relatively recently, with legislation governing operations in the area only being passed in 1958-1964.
Right from the start, tapping these resources was a huge industrial undertaking, from both a technical and a financial point of view, and was carried out under extreme conditions, making the North Sea a proving ground for a number of offshore technologies. Then, starting in the mid-1980s, the North Sea threw down a new challenge, with the discovery in 1986 of a major high-pressure/high-temperature (HP/HT) condensate gas field in the Central Graben zone. Two appraisal wells drilled in 1988/89 and 1991 confirmed the huge size of the reservoir, which was named Franklin. Then in 1991, TotalFinaElf discovered another HP/HT reservoir only six kilometres away; this was named Elgin. These two fields were exceptionally deep compared to most North Sea oil and gas fields, resulting in much higher reservoir pressures and temperatures. Elgin and Franklin are located in a structurally complex zone, with the reservoirs lying more than 5 km below the seabed, meaning that reservoir pressure rises as high as 1,100 bar (16,000 psi) while temperatures can reach 190°C. This made Elgin/Franklin project the largest joint HP/HT development ever undertaken anywhere in the world.

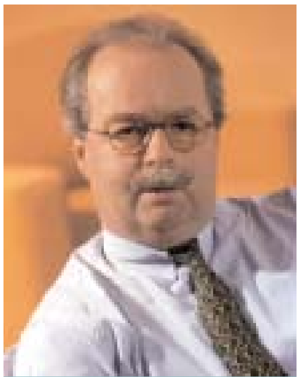
CONTENTS

Elgin/Franklin

PROJECT MILESTONES

1964	The Continental Shelf Act is passed by the UK Parliament.
Oct 1986	Discovery of Franklin on Block 29/5b by Ultramar and Ranger Oil (well 29/5b-4).
May 1988	Acquisition by the future TotalFinaElf, from RTZ Oil & Gas, of a 15% partnership share in Franklin.
Sept 1988	Discovery of Shearwater by Shell.
1989	Acquisition of new 3D seismic data (further seismic survey in 1996). Award of an exploration licence for Block 22/30c.
1991	Launch of HP/HT studies.
May 1991	Discovery of Elgin by Elf Exploration UK PLC (well 22/30c-8).
April 1993	Launch of joint development studies covering five fields in the Central Graben zone: Shearwater and Puffin (Shell), Elgin and Franklin (TotaFinaElf) and Erskine (Texaco).
1995	Increased interaction between the Elgin/Franklin and Shearwater project teams. Agreement among partners concerning joint development of Elgin/Franklin.
Mid-1996	Construction of Elgin and Franklin wellhead platforms begins.
Feb 1997	Unitisation agreement covering the Elgin and Franklin fields.
Mar 1997	Final go-ahead for Elgin/Franklin project after approval by Dept. of Trade and Industry. Start of the drilling campaign on Elgin.
May 1997	Construction of the PUQ platform begins.
Jan 1998	Start of development drilling on Franklin.
Mid-1999	Installation of the wellhead platforms on both fields and the interfield pipeline between Franklin and the future PUQ platform.
July 2000	Tow-out and installation of the PUQ platform on Elgin.
Mar 2001	Elgin brought into production.
Sept 2001	Franklin brought into production.

A MILESTONE PROJECT


Christophe de Margerie,
President Exploration & Production.

The largest development launched in the North Sea since 1980, Elgin/Franklin is a milestone in the history of the oil industry.

The Elgin field is located astride Blocks 22/30b and c in the UK sector of the North Sea, 240 km east of Aberdeen. The Franklin field lies 5.5 km to the southeast on Block 29/5b in the same Central Graben zone, at a similar water depth, i.e. 93 m. The proximity of the two fields led planners to envisage joint development of the combined reserves.

The two reservoirs, lying some 5,500 m below the seabed, are not only the deepest ever produced in the North Sea, but their development also constitutes an unprecedented technical achievement due to the extreme conditions of pressure (1,100 bar) and temperature (190°C). A further challenge was posed by the acidity of the condensate gas (average carbon dioxide content 3.5% and up to 40 ppm hydrogen sulphide), which required purpose-designed production equipment as well as innovative treatment to ensure that the gas was delivered ex-platform in compliance with commercial specifications.

An unprecedented technological challenge

The technical parameters involved in developing Elgin/Franklin had no equivalent in previous industry experience, even the expertise acquired by the Group from 1951 in developing the Lacq deep reservoir. In order to develop Elgin/Franklin, the project team had to overcome a number of technological obstacles and implement several management and marketing innovations. In addition to delicate negotiations aimed at unitising the permit areas (see inset), the project involved a research and development programme spanning five years, requiring the confidence of all co-venturers and drawing on the know-how of Group technical staff in the UK, Norway and France as well as the numerous contractors working on designing and certification of the equipment.

For example, it was necessary to create methods of study using pressure-volume-temperature (PVT) cells that enabled the laboratory team to simulate the PVT parameters encountered during production and so predict fluid behaviour within the reservoir. Apart from the development of new seismic techniques, drilling and completion equipment as well as suitable processing and control procedures, one of the main technical challenges on Elgin/Franklin was to evaluate with sufficient accuracy the possible field production levels, both on individual wells and on a field-wide basis.

Complex partnership

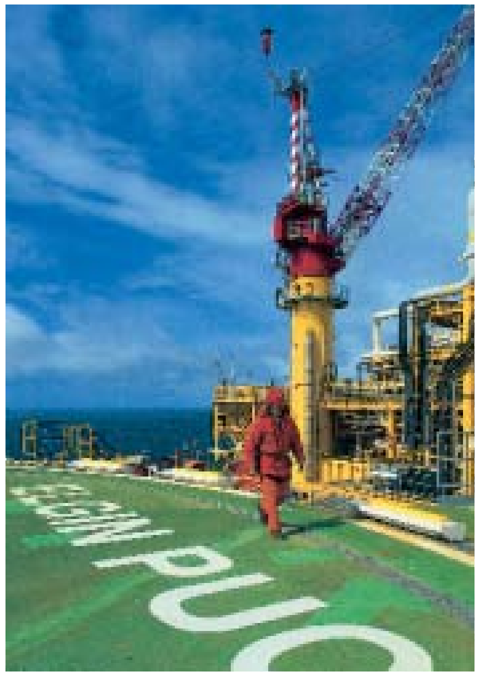
TotalFinaElf's stake in this part of the Central Graben has grown from an interest of just 15% in the Franklin field in 1988 to the Group's current position as operator and major shareholder within EFOG* (46.173%) for the combined fields.

This position was achieved through a number of asset acquisitions and exchanges and by a successful bid for the exploration block where the Elgin field was to be discovered two years later. Since the Elgin and Franklin fields were located astride several separate blocks with different shareholders, the immediate priority was to regroup them into coherent permit areas to allow joint development and long-term production of the two fields.

Negotiations were made more complex by the differential in value between the two accumulations (Elgin showed a higher oil content) and by the particularities of the UK tax system. Negotiations started in 1994, and by early 1997 a complex contractual framework had been arrived at which would provide a reasonable and definitive return on investment for all the different partners.

Company	% Share (August 2002)
E.F. Oil and Gas Ltd *	46.173
BG International (CNS) Ltd	14.110
AGIP (U.K.) Ltd	13.867
AGIP Elgin/Franklin Ltd	8.000
Ruhrgas UK Exploration & Production Ltd	5.200
Esso Exploration & Production UK Ltd	4.375
Texaco Britain Ltd	3.900
Dyas UK Ltd	2.1875
Oranje-Nassau (UK) Ltd	2.1875

* Elf Exploration UK PLC 77.5% /
Gaz de France 22.5%



The Elgin production, utilities and quarters platform (PUQ), is the largest platform of its type.

An ambitious production plan

In November 1995, the project partners reached agreement on the selected production plan. The Franklin field has an unmanned wellhead platform connected to the Elgin PUQ by a subsea interfield pipeline system. The two fields are served by a common central unit, a process, utilities and quarters (PUQ) platform located at Elgin and linked to the Elgin wellhead platform by a 90-metre bridge.

The 41,000-tonne PUQ, with its innovative jack-up design based on the TPG concept, is the largest structure ever built for North Sea operations. Like all the other elements of the project architecture, the PUQ complies with the stringent safety and environmental regulations applying to North Sea operations. The basic role of the PUQ is to collect, separate and treat the produced hydrocarbons. The liquids are exported ashore via the existing Forties Pipeline System (BP) to Kinneil, near Edinburgh. The fully-treated gas is transported via the newly-built SEAL pipeline (Shearwater Elgin Area Line) shared with the neighbouring Shearwater platform to the Bacton terminal 468 km to the south, where it can either be distributed via the UK's National Transportation System (NTS) or exported to Europe via the Interconnector gas pipeline.

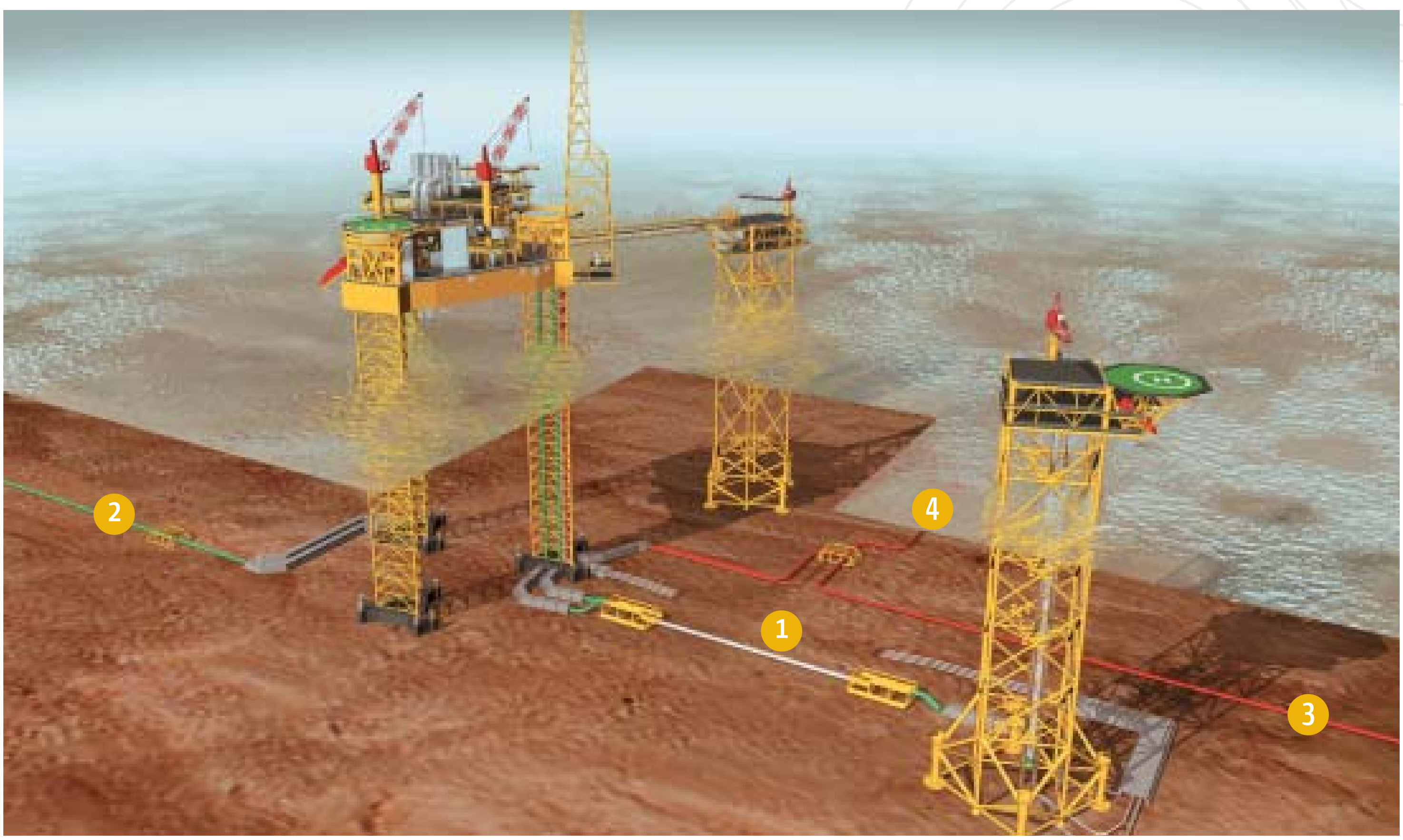
Elgin/Franklin was brought onstream in only four years and within budget, demonstrating TotalFinaElf's ability to manage large-scale projects. The project also demonstrates technical solutions that can be used to develop other HP/HT fields in this major hydrocarbon province that accounts for a quarter of the Group's proven reserves.

Elgin/Franklin

KEY FIGURES

Overall investment	**€2.8 billion** (incl. €33 million for R&D)
Production plateau	**220,000 boe/d** (140,000 b/d condensate gas and 13 million m^3 gas), accounting for about 5% of British production.
Production life	**Decommissioning planned for 2022**

In addition to the Elgin/Franklin interfield connections (1), the two wellhead platforms and the PUQ platform consist of 3 main subsea pipelines, built for purpose: a liquid export line to Kinneil (2), a commercial gas export line to Bacton (3), connected with the neighbouring Shearwater platform export line (4).

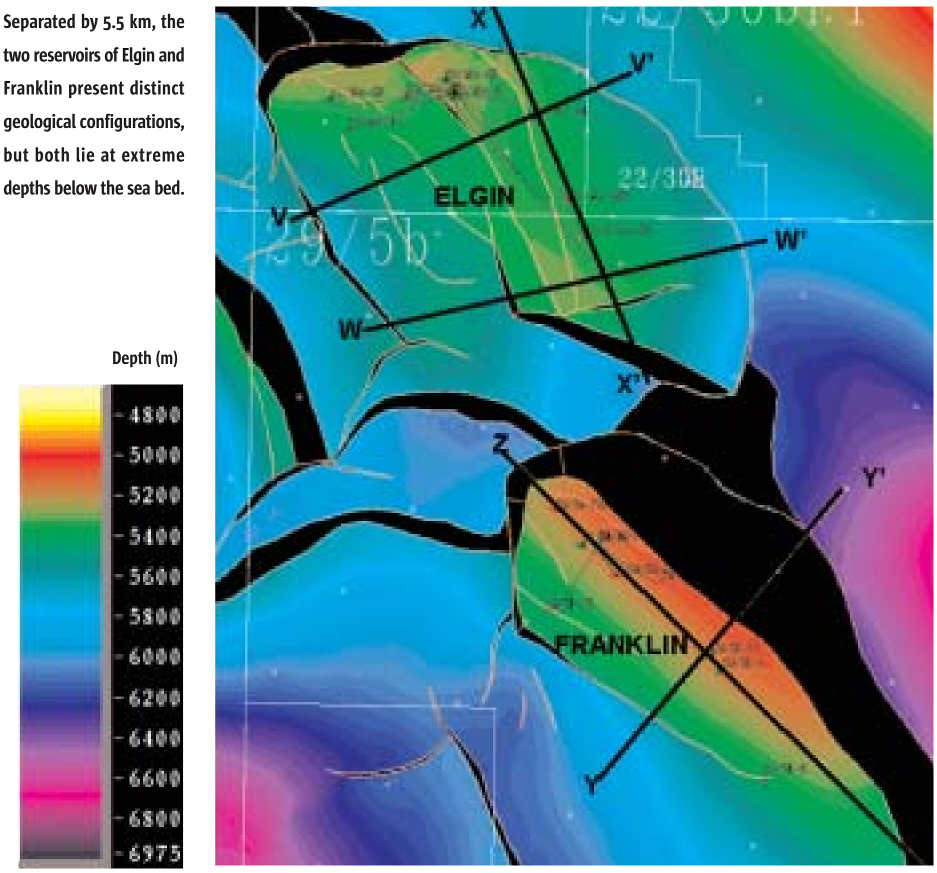


Overview of the Elgin/Franklin production facilities

COMPLEX GEOLOGY

Developing Elgin and Franklin involved a double challenge due to the complex geological structure of the reservoirs and the unusual HP/HT conditions.

Separated by 5.5 km, the two reservoirs of Elgin and Franklin present distinct geological configurations, but both lie at extreme depths below the sea bed.



At the time of the Elgin discovery, two 3D seismic surveys had been carried out, on Franklin in 1987 and on Elgin in 1989. These were subsequently merged and reprocessed prior to drilling the third Elgin appraisal well. In 1996, a new 3D seismic survey was carried out jointly with Shell (operator of the adjacent Shearwater field) to provide a homogenous seismic data-set with higher resolution than the two previous studies. The first phase of processing, which resulted in a time-migrated data-set, was completed by CGG London in March 1997. The following depth migration phase (anisotropic) was completed by Elf's seismic department in Pau in August 1997. This data-set was used to locate all subsequent development wells.

Analysing Elgin/Franklin seismic datas.

Reservoir structure

The Elgin and Franklin fields are located in the South Central Graben of the UK North Sea. The reservoirs comprise shallow marine sandstones of the Fulmar/Puffin formations deposited during the Late Jurassic, and older fluvio-lacustrine sandstones of the Pentland formation belonging to the Middle Jurassic. The sandstones were subsequently affected by a combination of extensional tectonics and the movement of underlying salt deposits during late Upper Jurassic times. The faulting and refolding that resulted created the structures of both fields (see figures, right).

In the Elgin structure, the withdrawal of the salt at depth led to the grounding of the overlying sediments [on the Rotliegendes fault block beneath]. Consequent faulting during this process has created an internal structural segmentation in Elgin. By contrast, Franklin remained underlain by salt, and the tilted fault block structure resulting from the extensional tectonics is much simpler than Elgin, with minimal internal faulting.

The Franklin reservoir reflects three major regressive-transgressive depositional cycles leading to the deposition of three main sandstone units: Franklin A, B and C sands. It is probable that these cycles were controlled by regional sea-level changes. The A sand seems to have been largely deposited in a very shallow marine environment. The B sand (where the best quality reservoirs are located) is again shallow marine, but with depositional reworking by tidal currents forming very large-scale tidal bars. The C sand represents a more distal equivalent of the B sand, but with weaker current activity and more wave influence. The original depositional setting (see facies, p.6) is to a large extent responsible for variations in reservoir quality, which deteriorates as the sedimentary environment moves to progressively deeper water from upper shoreface to offshore.

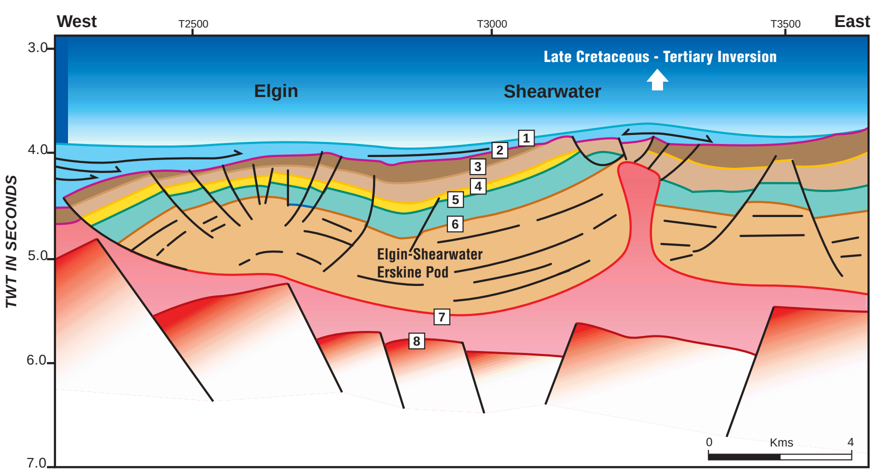
The Pentland formation in the Elgin and Franklin fields consists of a succession of fluvial and lacustrine deposits that are about 500 m thick in the southern part of the Franklin field structure. This formation comprises an interbedded and heterogeneous assemblage of deposits attributed to fluvial channels, crevasse splays, overbank flood pools and peat bogs. Deposition is considered to have taken place on a laterally extensive alluvial plain cut by sinuous mixed-load fluvial channels forming meanders (see model, p.6). Significant reservoir quality is largely confined to the fluvial channels. In contrast to the laterally extensive shallow marine sands of the Fulmar, sandstone connectivity in the Pentland has a major influence on reservoir performance, leading to slightly lower than predicted recovery factors.

Elgin/Franklin
THE RESERVOIRS

	Elgin	Franklin (Fulmar)	Franklin (Pentland)
Depth (m)	5 364	5 364	5 472
Static pressure (bar)	1 106	1 093	1 122
Pressure gradient (bar/10 m)	2.06	2.04	2.06
Temperature (°C)	189	189	192
Permeability (mDarcy)	0.01 - 1000	0.01 - 400	0.01 - 10
Mean porosity (%)	17	16	12.5
Mean water saturation (%)	38	40	43

Exceptional reservoir characteristics...

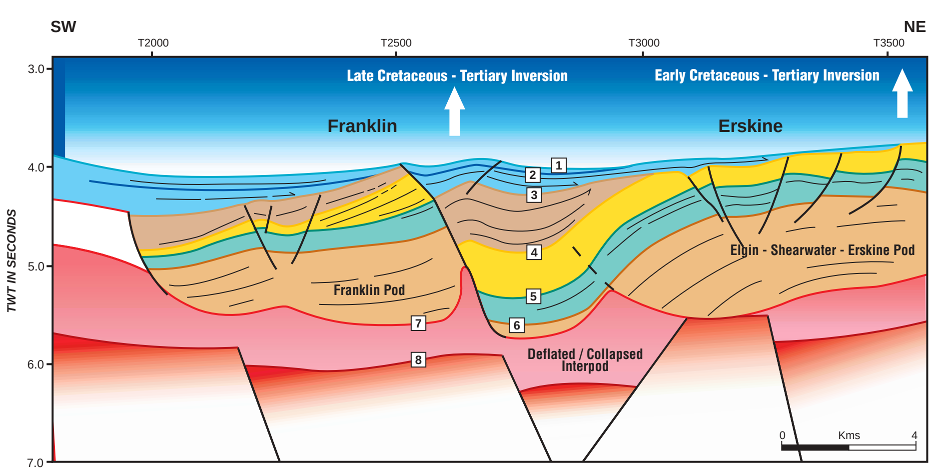
The reservoir characteristics are not typical of gas-condensate reservoirs, either in the North Sea or in other producing sectors worldwide. Despite lying more than 5,000 m below the seabed, the reservoirs show exceptional porosity and permeability. They also involve very



Elgin field West-East geoseismic section

LEGEND

1 NEAR TOP PLENUS MARL
2 BASE CRETACEOUS UNCONFORMITY
3 TOP HEATHER
4 TOP FULMAR
5 TOP PENTLAND
6 TOP TRIASSIC
7 TOP ZECHSTEIN SALT
8 TOP ROTLIEGENDES

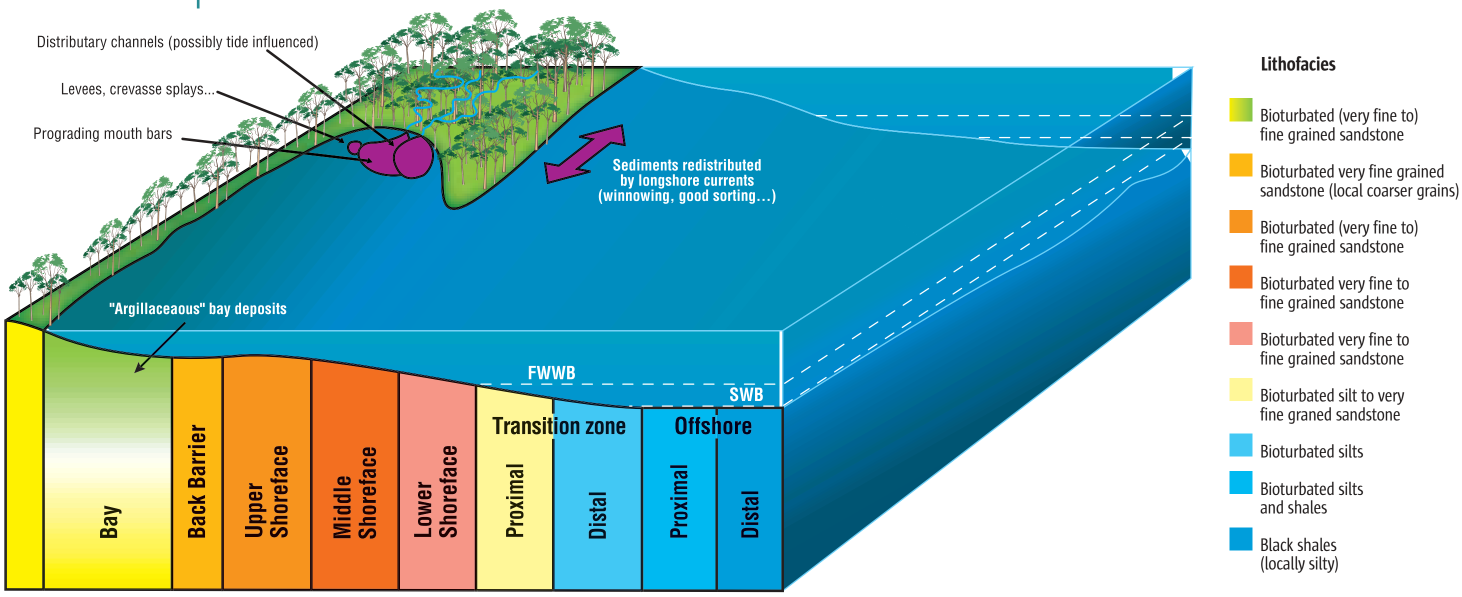


Franklin field SW-NE geoseismic section

LEGEND

1 NEAR TOP PLENUS MARL
2 NEAR TOP SOLA
3 BASE CRETACEOUS UNCONFORMITY
4 TOP FULMAR
5 TOP PENTLAND
6 TOP TRIASSIC
7 TOP ZECHSTEIN SALT
8 TOP ROTLIEGENDES

Franklin sandstone - Depositional facies (paleogeographical reconstruction)



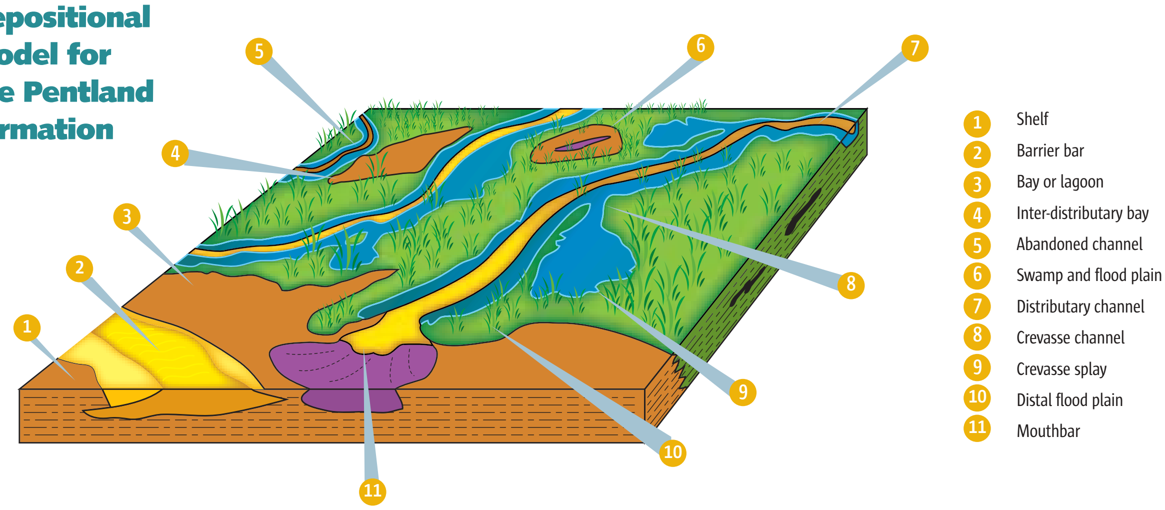
high pressures and temperatures: about 1,100 bar and 190 °C in the Fulmar, and 1,150 bar and 200 °C in the Pentland.

Despite the intense chemical activity in HP/HT reservoirs, involving multiple transformations, degradation and recomposition between the various constituents, the presence of compounds with a remarkably wide range in the number of carbon atoms can result in a significant amount of liquid production as well as remarkable apparent stability. This stability means that, even when the reservoir has been depleted, the fluids affected by high temperatures (i.e. higher than 175 °C) will remain as a single phase from the initial pressure down to 400 bar, thus delaying the onset of production degradation due to the condensate drop-out effect.

...creating numerous technical challenges

Several of the physico-chemical particularities of these HP/HT reservoirs have a major impact on the choice of recovery technique and equipment to be used. For example, right from the very early stages of depletion, engineers had to cope with a rapid drop in reservoir pressure due to volumetric factors (i.e. the ratios between the volumes of fluid recovered and stored and the corresponding volumes in the reservoir). With Elgin, the oil produced under surface conditions takes up only about one third of the volume of the same oil at depth. The gas produced takes up 230 times the downhole volume once at the surface. When producing from a “normal” gas pool, engineers can obtain an approximate value for the volumetric factor of the gas assuming a value of unity for the compressibility factor, Z. However, under the initial conditions found in the Elgin reservoir, the compression factor is about 2.3, meaning that once 10% of the fluid has been produced, the reservoir pressure will fall by 23%. This will naturally affect the way the deposit is to be managed.

Depositional model for the Pentland formation



Sailaway of the PUQ platform from the Nigg yard, July 2000.

Developing special experimental tools

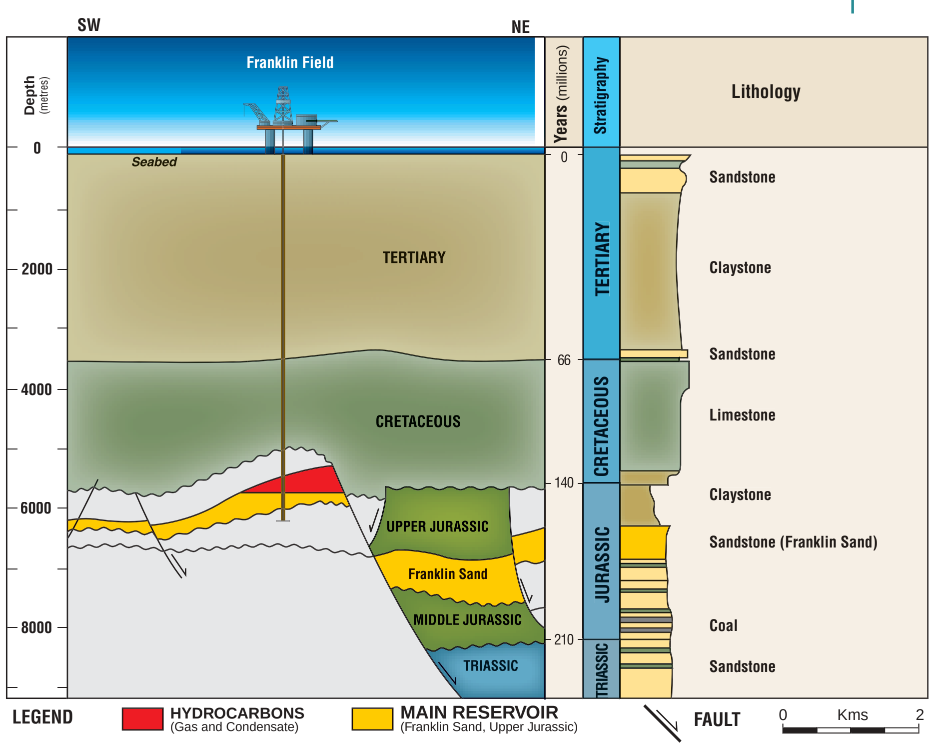
In the early 1970s, there was a major breakthrough in PVT equipment with the development of the Basset cell (now under license from TotalFinaElf) for studying condensate gases. However, the device was only reliable up to 1,200 bar and 200 °C, and it required large quantities of mercury.

With future needs in mind, the TotalFinaElf research laboratories set about developing specific cells suitable for studying HP/HT fluid behaviour at different pressures and temperatures. During the 1980s, a new generation of PVT tools became available including the Belenos system. This system was developed in collaboration with ROP and then Sanchez Technologies, and uses electrically-activated pistons instead of mercury and an infra-red detection system instead of a viewport. As a result, the system can be used at conditions up to 1,500 bar and 250 °C.

The study of phase equilibria and PVT behaviour of the Elgin/Franklin reservoir fluids would not have been possible without this equipment, which is now used by all Group laboratories.

Another characteristic of HP/HT reservoir fluids is the large amount of water vapour (at reservoir temperatures, the partial pressure of water vapour in the Elgin fluids is 12 bar). As well as taking this into account in the volumetric factor used to calculate the in-situ reserves, it is also necessary to model the equilibria between the water and hydrocarbon phases in order to predict the location of vaporisation and condensation zones involving higher risks for the tubing (salt deposition, corrosion, etc.).

Finally, one of the particular features of gas under high pressure is an inversion of the Joule-Thomson coefficient, meaning that the gas temperature rises when it decompresses (isenthalpic expansion). At the temperatures encountered in the Elgin reservoir, coefficient inversion occurs at a pressure of about 400 bar. Under initial reservoir conditions, the rise in temperature is 0.03 °C per bar of pressure drop due to depletion, which is far from negligible when considering the thermal resistance/service life of certain materials.



Franklin field - Structural cross section

AN AMBITIOUS DRILLING PROGRAMME

The characteristics of the Elgin/Franklin deposits required an ambitious and innovative development and drilling programme.

Aerial view of Global Santa Fe's Magellan drilling rig, working in cantilever mode to drill Franklin's production wells.

In 1997, when the development-drilling campaign was launched on Elgin/Franklin, three wells had already been drilled on each field: the discovery well and two appraisal wells. The Franklin wells were not suitable for production purposes and were subsequently abandoned. However on Elgin two of the wells were initially recovered for production use but have subsequently had to be abandoned because their characteristics did not meet the economic criteria set by the partners or the stringent safety standards required for this type of well.

The initial objective of the drilling campaign as specified in the Field Development Plan was to drill 5 production wells on Elgin and 5 on Franklin, all of them into the Fulmar sandstone formation.

Moreover, the first development well on Elgin was also planned to appraise the deeper Pentland reservoir that had been shown to be gas-bearing on Franklin. On Elgin, however, this well showed the Pentland to be non-productive.

Subsequently, all development wells on Franklin were deepened to appraise the Pentland reservoir at the same time.

A sixth development well was subsequently added to the drilling programme on each field, following reassessment of the production requirements versus reserves.

Multiple constraints

The major constraint on the drilling programme was the tight schedule. The development plan was to start up Elgin on its own with a high production rate from the outset. This meant that the resulting high depletion rate would cause a rapid drop in reservoir pressure, perhaps as much as 100 bar in the first 3 months. This fall in fluid pressure would probably lead to a mud weight window (MWW) problem that would be very difficult to handle (see inset, opposite).

If the problem were to be avoided, the drilling of all wells, particularly on Elgin, would have to be completed very soon after production start-up. In fact, mainly thanks to good management of the hydraulics aspects (see inset, p. 13) as well as accuracy in installing the critical tubing, the actual operations were completed 30% faster than was originally estimated. At production start-up, 6 wells had been drilled on Franklin and 5 on Elgin.

Drilling difficulties related to the mud weight window

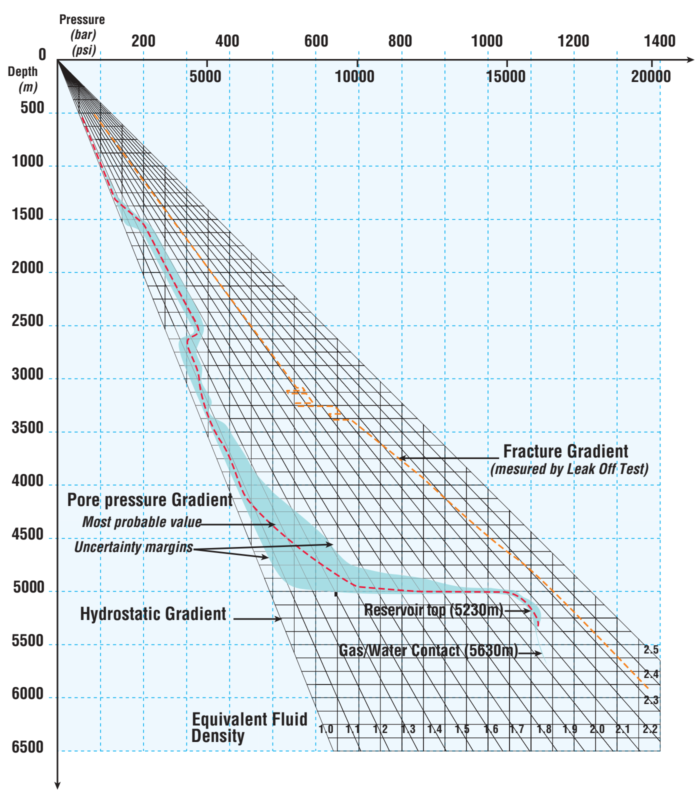
The choice of the density of drilling mud to be used during a given phase of drilling is governed by three basic parameters of the rock formations traversed:

- pore pressure (pressure in the fluid saturating the rock);
- fracture pressure (pressure at which a formation will fracture under tension);
- critical stability density (the drilling mud density required to maintain the mechanical integrity of the formation and prevent caving of the wellhole; the fracture pressure is generally higher than the pore pressure even if, as in the case of certain compact limestones or consolidated sandstones, the well can remain stable below the pore pressure).

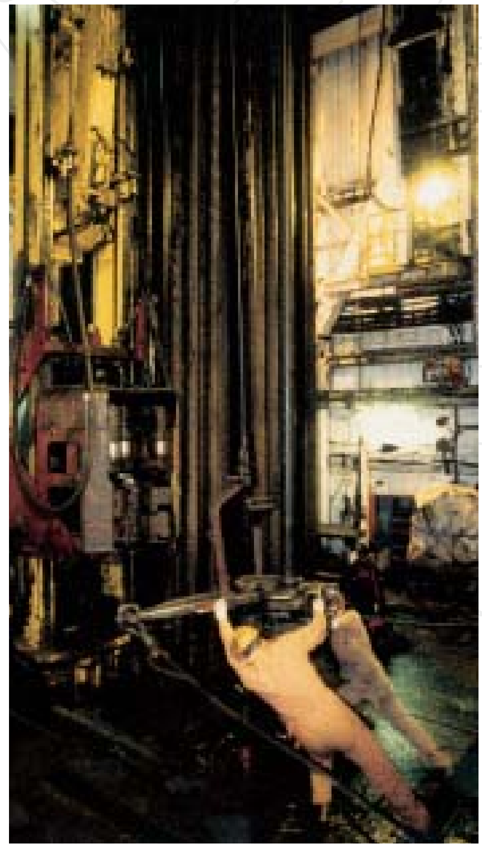
The pressure range between pore pressure and fracture pressure is called the mud weight window (MWW). In theory, both the static and dynamic density of the drilling mud must always remain within this window. Under normal conditions, the MWW is fairly wide, making it possible for engineers to adjust drilling mud density to avoid an inflow and ensure the mechanical stability of the well while also avoiding mud losses.

In the case of HP/HT deposits, the MWW is much narrower, thus making drilling particularly difficult. Furthermore, as the well approaches the reservoir, the acceptable “window” of drilling mud density is reduced even further by depletion (see diagram). The pressure of mud required in the overlying formations, which have remained at their initial pressure, is likely to exceed the fracture pressure of the reservoir below. The drilling operation then enters a loss-inflow cycle that is very hard to control at HP/HT, making it practically impossible to drill into the reservoir. This makes the drilling of infill wells after production start-up very problematic, and a project team has been set up to study this issue specifically.

Mud weight window in HP/HT reservoirs



Drilling HP/HT Elgin/Franklin wells demanded specific expertise, techniques and extensive equipment development.



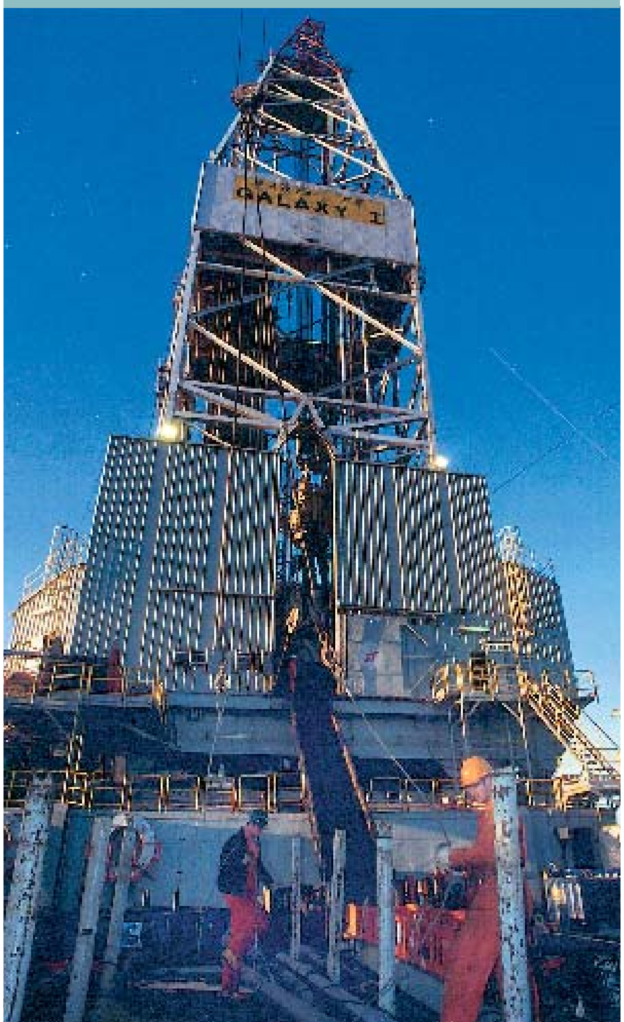
This drilling campaign also involved a number of technical constraints specific to HP/HT reservoirs: reservoir depth, “extreme” pressures and temperatures (830 bar and 175 °C at the Elgin wellheads and 860 bar and 165 °C on Franklin), very corrosive effluent due to the presence of CO_2 and H_2S, and highly productive reservoirs resulting in yields of about 2.5 MS cu.m/d per well, meaning very high flowrates at the wellheads.

Technical synergy among operators

Given all the constraints involved in developing Elgin/Franklin, the project required lengthy and detailed preparation, with particular emphasis on interactions with the companies operating the neighbouring fields, Erskine and Shearwater. In 1995, there were few operators or service companies with any experience of HP/HT fields under conditions as extreme as on Elgin/Franklin.

The existing technologies and know-how did not generally extend beyond 900 bar and 170°C under reservoir conditions. Furthermore, it soon became apparent that the experience acquired during HP/HT operations in the Gulf of Mexico could hardly be transposed into the fundamentally different context of the •••

The Galaxy-1 rig reconnected 2 exploration wells and drilled 5 wells on Elgin.



THE DRILLING CAMPAIGN

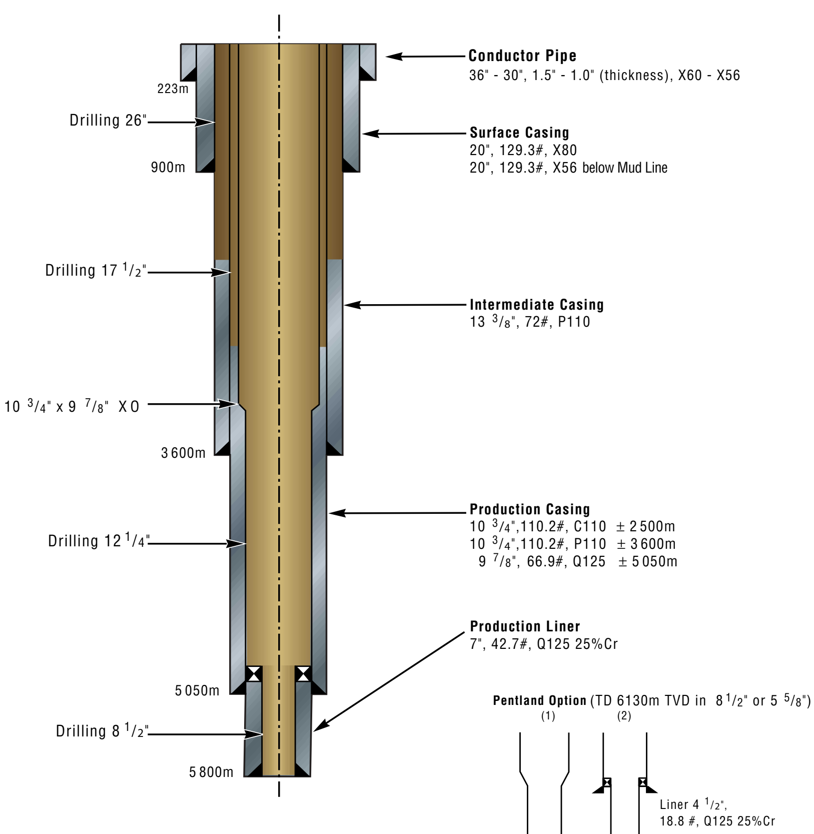
Duration	**2883 days**
Cost	**About £510 million** (estimate 554.2 million)
Equipment :	
• Elgin	**Galaxy-1 rig (Global Santa Fe), jack-up rig, max. water depth 400 ft, maximum variable load 10,400 kips**
• Franklin	**Magellan rig (Global Santa Fe), jack-up rig, max. water depth 350 ft, maximum variable load 10,400 kips**
Duration of drilling	**Average 90 days for depth of 5,500 m**

View of the Franklin wellhead platform and the Magellan drilling rig.

••• North Sea (production columns of smaller diameter and well-integrity management, safety barriers, bottom hole chokes, annulus pressure monitoring, killing systems, etc.). Cross-fertilization between operators involving know-how and experience was thus limited to North Sea conditions, resulting largely from the HP/HT Forum set up in 1996 by Shell, Texaco and TotalFinaElf as a successor to the HP/HT Club that was active in the 1990s.
This Forum resulted in some particularly fruitful exchanges in the area of drilling, giving rise to a "HP/HT information network" on operations underway in the Central Graben.
Synergy was also generated in the development of special equipment and products (bottom hole choke, 15,000 psi/204 °C Camco retrievable tubing, XP07 Baroïd drilling mud). On the other hand, it proved impossible to harmonise well architecture and technical specifications, which could have led to joint tendering and ordering.

Qualification of key equipment
Considering the combined stresses on the materials, with wellhead temperatures of nearly 175 °C, the injection of cold fluids (inhibitors for example) and reservoir pressures varying between 1,100 bar and 75 bar, the stresses are very close to the mechanical yield strength of the column.
Considerable efforts were devoted to pushing back these limits. All the elements making up the production columns (casing string, liner hangers, HP/HT shoe/collar, cement, annulus seals and wellhead valves/blow-out preventers, hangers, packers and safety valves) had to be specially designed, with specific qualification programmes drawn up particularly with regard to the various metals used.

Members of the 48 core crew arrive on the PUQ platform. They will work here for two weeks at a time.



General well architecture

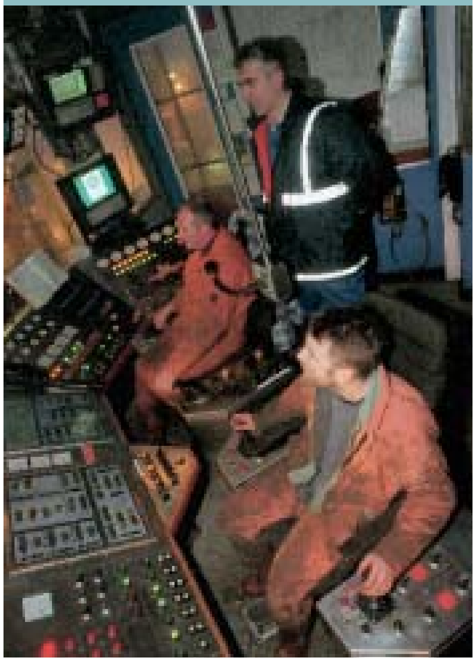
At the same time, other studies focused on the risk of sand inflow due to depletion, on the type of perforation required and the feasibility of stimulation, as well as definition of the most suitable drilling fluid, completion and packer. Similarly, the working temperature range of the MWD sensors and various logging tools was considerably extended, with the upper limit for the Sperry Sun MWD system raised to 175°C and that of the Schlumberger and Western Atlas logging tools raised to 204°C. However, since the sensors have a reduced service life at such high temperatures, suitable procedures had to be developed to cope with this.

In all, more than 30 different study programmes costing nearly £21 million (€33 million) were devoted to development and qualification of special equipment.

A selective drilling strategy...

The extreme depletion that the reservoirs would undergo during production meant that was advisable to pursue a selective drilling strategy so as to avoid the most fragile zones and prevent any rupture of the formation by shearing.

Furthermore, to allow for possible later implementation of sand-control measures, the perforated intervals had to be carefully spaced. Some of the perforated intervals were up to 200 m in length, meaning that •••



Doghouse on Galaxy-1 drilling rig.

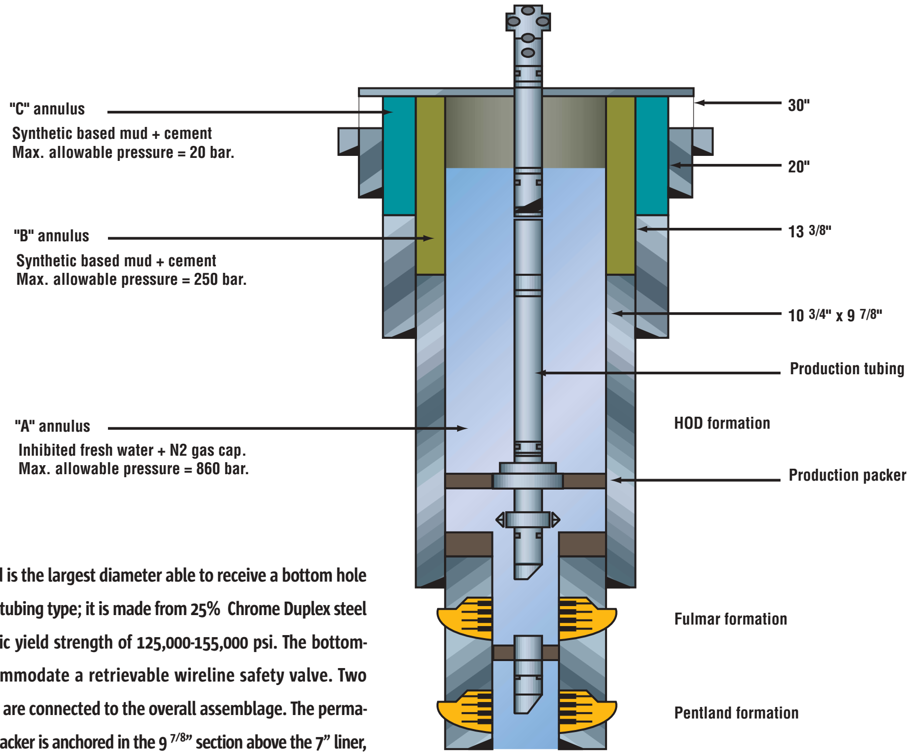
••• conventional techniques involved operational risks. Because of this, engineers developed a perforating system run-in with a coil-tubing unit, having the following parameters: surface equipment 15,000 psi and 150°C, drilling of a 200 m interval carried out in a single operation, depth control with precision of ± 2 m up to 6,500 m, without electrical cable inside coil tubing.

... crowned with success

The exploration wells were drilled by two powerful jack-up rigs operated by Global Santa Fe International Corp. The five producer wells on Elgin were drilled by the Galaxy–1 platform, which moved off location at the beginning of 2001.

All the 9 $^{7/8}$" and 10 $^{3/4}$" casings were installed at the planned depths, in a single operation despite the considerable weights (550 to 600 t). All the 9 $^{7/8}$" 15,000-psi production packers were anchored without problems and all the annulus and packer pressure tests were positive. All the production liners were cemented satisfactorily. Despite the fact that horizontal drift was sometimes as great as 2,500 m, no abnormal wear was detected on the casing and therefore no tie-backs were necessary. The highly stable fluid system performed particularly well. The core-

Typical completion architecture



The 5" tubing selected is the largest diameter able to receive a bottom hole choke of a retrievable-tubing type; it is made from 25% Chrome Duplex steel and rated at an elastic yield strength of 125,000-155,000 psi. The bottom-hole choke can accommodate a retrievable wireline safety valve. Two separate control lines are connected to the overall assemblage. The permanent-type production packer is anchored in the 9 $^{7/8}$" section above the 7" liner, and with a short extension acting as a guide during insertion.

The PUQ and Elgin wellhead platform with the Galaxy-1 drilling rig and Polyconcord flotel alongside. Positively influenced by giving incentives to key contractors, the average drilling time per well was far better than expected.

sampling operations were also more rapid than expected, particularly in the Fulmar, where teams twice used 45-m core-barrels successfully.

Despite the complexity and the critical nature of these operations, all wells were perforated safely and within the depth accuracy (± 2 m) required by the anti-sand strategy. The wells also proved to be more productive than expected. The only critical problem encountered during the well operations was the failure of the 10 $^{3/4}$" casing hangers.

After three months of work, special procedures and tools had been developed for replacing the defective items – a world first for the industry – and the hangers on all nine wells had been replaced by early 2000.

Pentland and Trias

Although testing at depth on Elgin proved negative, positive results in the Pentland on Franklin justified the deepening of all wells in that structure.

Despite the fact that new procedures and tools had to be developed for drilling, coring and logging under bottom-hole conditions of 1,200 bar and 215°C, this operation required only 10 days drilling per well (excluding core sampling). One of the development wells on Franklin was deepened to explore the Triassic formations beneath the Pentland.

Hydrocarbons were encountered but assessed to be uneconomic to bring into production. This well however did encounter an unexpectedly good reservoir in the Lower Pentland, which has subsequently been brought into production in two of the Franklin wells, and is being potentially appraised in a third.

ECDELF software

One of the characteristics of the HP/HT deposits in the Central Graben is the very rapid increase in pressure over a transition zone – no more than several tens of metres thick – just under the Upper Cretaceous. Therefore, it is crucial to set the required 9 $^{7/8}$" casing at the right level to ensure that the following 8 $^{1/2}$" phase benefits from a fracture pressure allowing it to be drilled down to the target depth with drilling mud of the appropriate density. However, even when the casing is installed correctly, it must not be placed too far down to avoid the risk of entering a loss-inflow cycle that will prevent successful cementation of the production column.

Thus, particular attention was paid to controlling fluid circulation during drilling and cementing in order to predict accurately the pressure exerted by the drilling fluid at the bottom of the well during all the different phases of drilling, especially during the approach to, and the passage through, HP zones. The result was new simulation software called ECDELF (ECD for equivalent circulating density), which was specially developed for the Elgin/Franklin project.

This new software, which can take into account the variations in mud density over a very broad range of pressure and temperature, allowed drilling teams to increase the safety parameters significantly while drilling through the transition zone and the reservoir. This is a rather delicate phase of operations because bottom-hole MWD and PWD sensors are rendered inoperative by the high temperatures. ECDELF also proved invaluable in helping to optimise the speed at which the drill string was raised and lowered again, thus leading to a considerable saving in the trip time used for bit change.

INNOVATIVE PRODUCTION FACILITIES

From initial engineering studies to start-up, the Elgin/Franklin project presented a number of technological challenges.

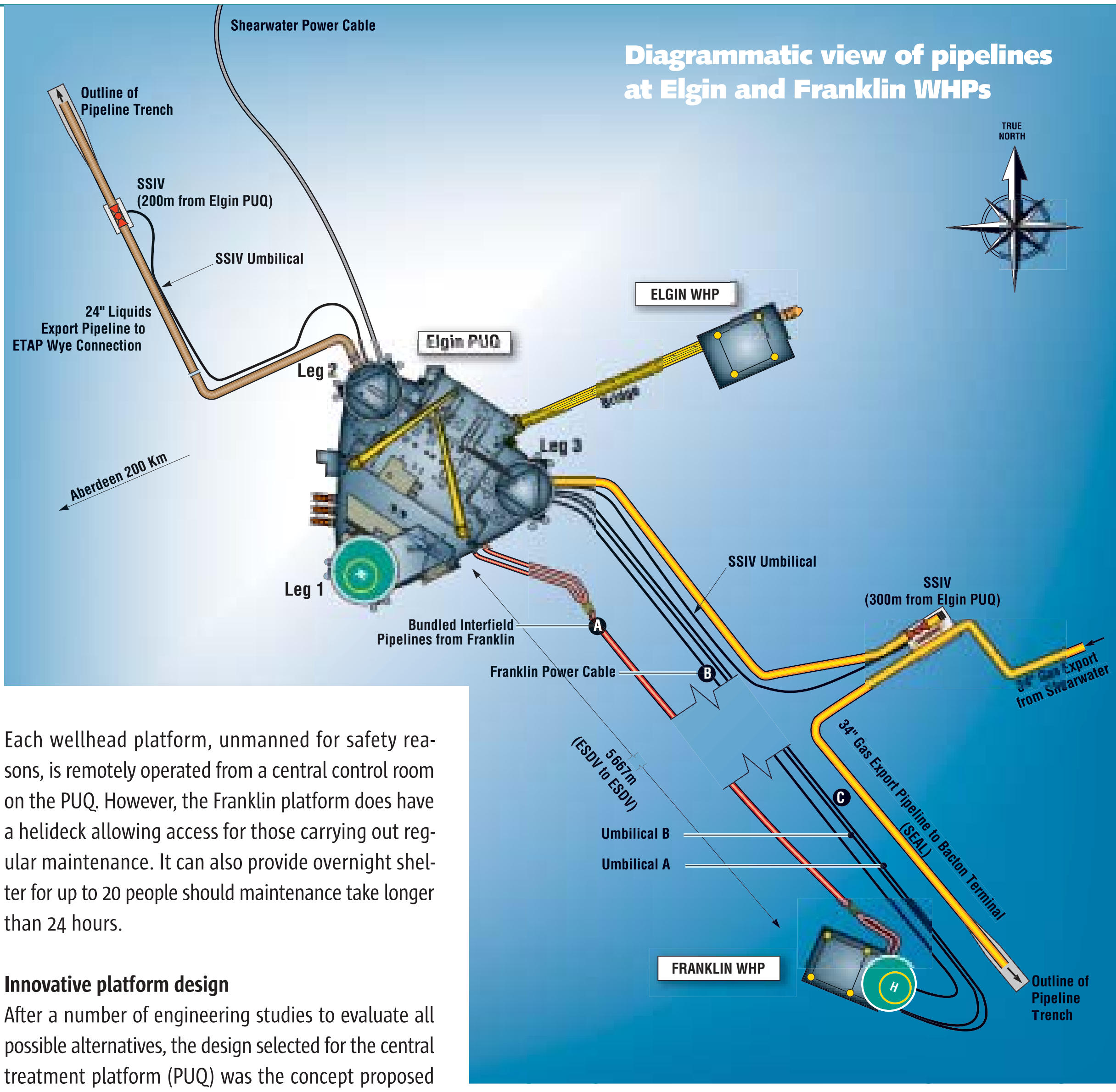
The PUQ jack-up platform, a mini oil and gas refinery with a sophisticated process system onboard to produce commercial quality gas.

The Elgin and Franklin fields have wellhead platforms (WHP) of similar design, with a steel jacket mounted on four piles. Both platforms were towed to the site and installed in the summer of 1997. The Elgin WHP is tied-in to the adjacent production, utilities and quarters (PUQ) platform and connected to it by a 90-m bridge providing access for personnel and a route for gas and condensate flowlines along with utilities such as power cables and water. The Franklin wellhead platform is linked to the PUQ, more than 5 km away, by a multi-phase pipeline comprising a 42" bundle of two 12" pipelines to carry the gas and condensates to the PUQ for treatment. The product leaves the Franklin wellhead platform at design temperatures as high as 165°C, the highest design temperature for a subsea field line. The design of the bundle had to take account of stringent heat-insulation and anti-corrosion parameters, made even more complex by the fact that the product temperatures will vary significantly over the production life of the field. Two umbilicals from the PUQ to the Franklin wellhead platform carry the chemicals and hydraulic fluid necessary for well operations and a further cable carries electric power and the fibre-optic production-control system.

Elgin/Franklin

THE WELLHEAD PLATFORMS

	Elgin	Franklin
Type	Steel jacket, 4 legs	Steel jacket, 4 legs
Jacket weight	2,715 t	2,800 t
Topsides weight	1,842 t	1,975 t
Deck dimensions	25.5 x 34 m (3 levels)	25.5 x 34 m (3 levels)
Drilling slots	12	9
Max. productivity:		
• Gas	14.6 MS cu.m/d	10 MS cu.m/d
• Condensates	175,000 b/d	60,000 b/d
Max. wellhead pressure	830 bar (closed w/head)	880 bar
Max. wellhead temperature	174°C ± 5°C (when flowing)	162°C ± 5°C



Each wellhead platform, unmanned for safety reasons, is remotely operated from a central control room on the PUQ. However, the Franklin platform does have a helideck allowing access for those carrying out regular maintenance. It can also provide overnight shelter for up to 20 people should maintenance take longer than 24 hours.

Innovative platform design

After a number of engineering studies to evaluate all possible alternatives, the design selected for the central treatment platform (PUQ) was the concept proposed by McDermott /Technip-Geoproduction: an innovative jack-up platform using technology based on the Technip TPG 500. The design offered numerous advantages: the platform could be produced, assembled and delivered ashore, thus allowing substantial savings in terms of offshore commissioning. In March 1997, a contract for construction of the PUQ was awarded to the TMB consortium, comprising Technip UK, McDermott and Barmac, with TotalFinaElf a member of the partnership. The 41,000-tonne giant – the largest platform of its type in the world – was built at the Nigg yard (in northern Scotland, near Inverness), the largest facility in Europe. Construction required 11.5 million man-hours of work, with 3,600 workers involved at the peak of activity. In July 2000, the platform was towed to the Elgin site and its three 140-m legs hoisted the structure 22 m out of the water directly over the field.

The PUQ jack-up platform is in reality an oil and gas mini-refinery, equipped with sophisticated systems enabling it to produce commercial quality gas right at the offshore production site. The PUQ's 5,500-sq.m workspace is manned by teams working 2 weeks on/2 weeks off. The facility has a treatment capacity of 14.6 million cu.m/d of gas and 175,000 b/d of condensates. The condensates account for two thirds of the production value.

Crossing the bridge from the Elgin wellhead platform to the Elgin PUQ. As well as giving access for personnel, this 90-metre structure provides a route for process pipework and utilities.

The launch of the Elgin/Franklin interfield pipeline bundle in Tain, 16 May 1999.

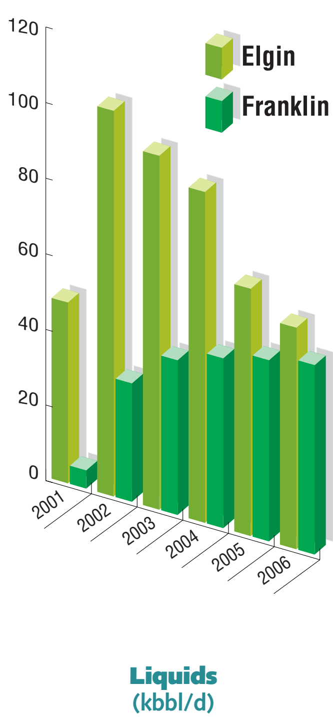
Elgin/Franklin

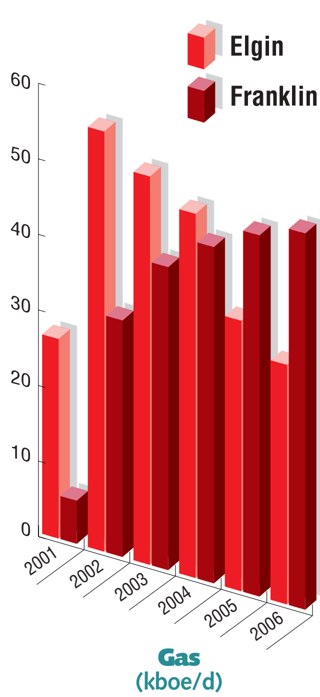
THE PUQ PLATFORM

Type	TPG 500, steel jacket, 3 legs
Total weight	41,000 t
Topsides weight	16,000 t
Total height	239.40 m
Main deck area	5,500 sq.m
Treatment capacity:	
• Gas	14.6 MS cu.m/d
• Condensates	175,000 b/d
• Water	1,200 cu.m/d
Electricity production	2 x 27 MW
Compression power	130 MW
Heat exchange power	250 MW

Production profiles

With 8 wells on Elgin and 6 on Franklin to date, the recovery strategy is to produce both fields by primary depletion, and Elgin preferentially, as the gas in its reservoirs is richer in condensates and thus more valuable.



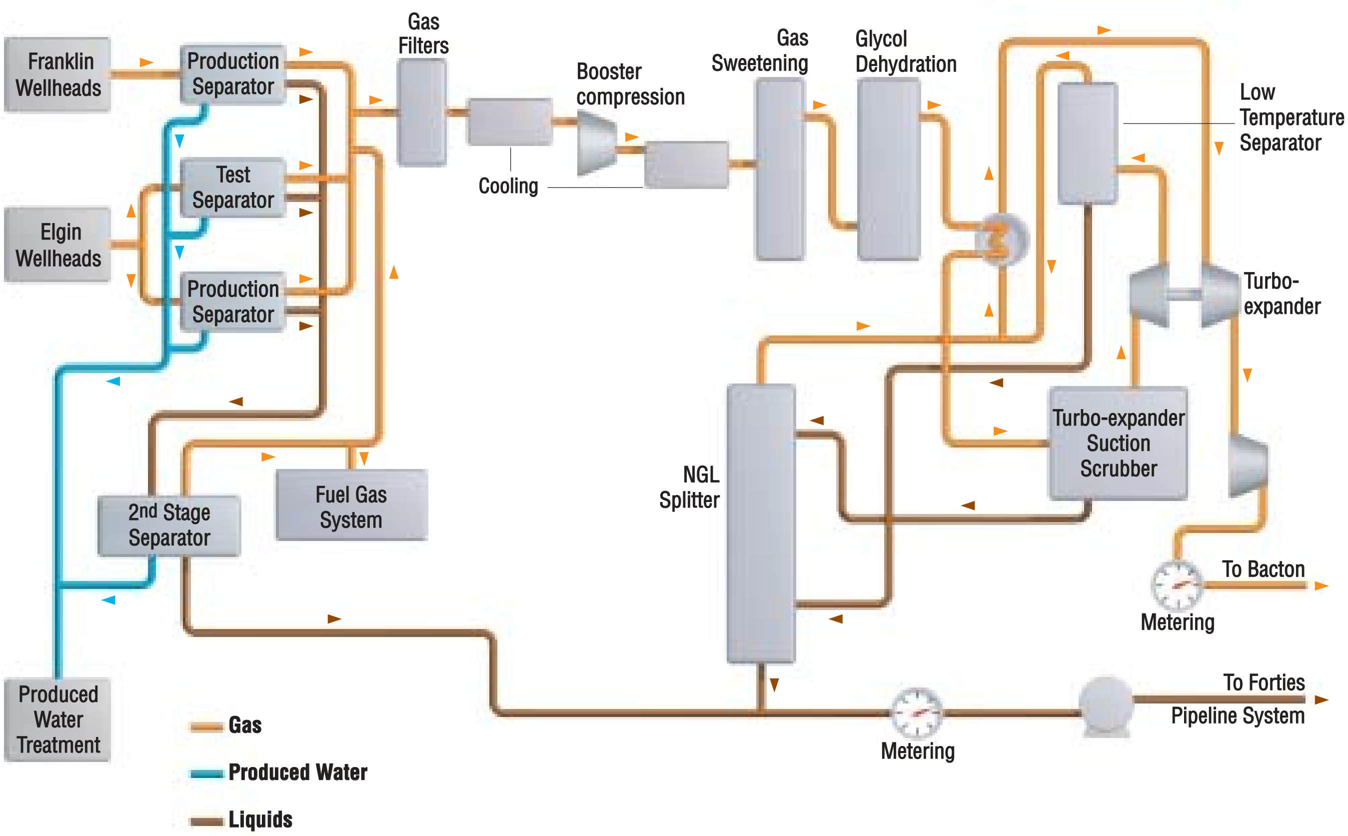


Special HP/HT technologies

The Elgin and Franklin wellhead platforms must be able to control the product at high pressure and temperature before sending it to the PUQ platform for treatment. As the Elgin wellhead is adjacent to the PUQ with its gas-flaring capabilities, lower specifications were possible for the production and test valves. However, the absence of flaring facilities on Franklin necessitated differences in equipment design, particularly regarding the pipes upstream of the valves, which had to handle static wellhead pressure as high as 860 bar, and the systems designed to prevent overpressurisation of the pipelines linking the two platforms. The acidity of the gas, combined with the high reservoir temperatures, also meant that all tubing and associated valves had to be made from corrosion-resistant alloys. The alloy finally selected for the topside pipeline was Super Duplex with a chrome content of 25%. Extra-thick walls were also specified for all tubing and associated equipment (37 mm for the tubing and up to 150 mm for the manifold), making the heat-treatment process particularly delicate.

Another crucial technological challenge was to develop valves able to withstand the extreme HP/HT conditions, operating reliably at pressures of 860 bar and temper-

Simplified diagram of the Elgin PUQ process



atures ranging from -35°C to +190°C. Two types of device were critically important: the choke valves and the two emergency shut-down valves (ESDVs) linking the Franklin platform to the pipeline bundle leading to Elgin.
Designing and manufacturing this equipment required nearly 5 years of work. In fact, the 293-mm calibre ESDVs, qualified to 860 bar (12,500 psi) and 190°C, are the largest HP/HT valves in the world. Apart from well architecture, the main design impact of the high-pressure conditions was on the pipelines and the wellhead platform equipment, all which required exceptionally thick walls. The extreme thickness of the walls made the equipment very heavy. On the Franklin platform, for example, the two ESDVs together with their closing systems weigh 32 tonnes each.

A purpose-designed treatment process

Apart from the desulphurisation process implemented (see inset p. 18), the treatment process on the Elgin/Franklin PUQ has a number of special features:
• On arrival at the PUQ, the high temperature of the product demands special cooling equipment. Light and compact titanium-alloy heat exchangers were an obvious solution here, particularly as their excellent resistance to corrosion meant that seawater could be used for cooling.

Even though titanium-alloy exchangers are widely used in the aeronautics industry, delicate modifications were untertaken to adapt the units for use in oil production. Indeed, the process required access to the computing facilities of the Rolls-Royce nuclear division for a whole year, use of the largest vacuum heat-treatment furnace in Europe and the services of a number of inter- •••

The wellhead area on the Elgin wellhead platform.

The Group's expertise in acid gases

The PUQ platform is designed to treat fluids coming from two reservoirs that are relatively heterogeneous in composition. Consequently, the input to the treatment plant will vary in composition as more and more producer wells come onstream. More specifically, the CO_2 content of the input may vary between 2.8% and 4%. To handle this variation, while still complying with the commercial gas specifications, engineers opted for partial sweetening and decarbonation by a process using activated MDEA (methyldiethanolamine).
In the offshore context, this process was considered likely to generate considerable savings. Another determining factor in the decision was the Group's experience using processes based on selective sweetening. Indeed, TotalFinaElf was confronted with the problem of treating sour gas many years ago and has now gained considerable experience in sweetening processes using amine absorption, particularly MDEA-based technologies, which have been used at Lacq and in Middle East projects (Qatar, Abu Dhabi, etc.).
The Elgin/Franklin project has demonstrated the potential of using solvents such as activated MDEA in cases where the sweetening process does not require full decarbonation to allow it to comply with commercial specifications. Admittedly, Elgin/Franklin also required considerable know-how in other areas such as gas-liquid transfer modelling, equipment technology and automatic process control.

The treatment facilities. The gas is brought into contact with the solvent in a column called an absorber, thus increasing the gas/solvent exchange and the absorption of the acid gases.

The control room on the Elgin PUQ platform.

••• national experts, as well as a long programme of tests and the development of high-tech inspection techniques. Since their commissioning, the exchangers have operated remarkably well. The largest unit (only a tenth the size of a classic tubular heat exchanger) delivers a heat-exchange power of 34 MW, while the combined units can deliver 250 MW and process 10,000 cu.m of liquids per hour.

• The use of large-scale compression facilities, which may seem paradoxical on a high-pressure field but can be explained by the fact that at first, the pressure of the fluid arriving on the treatment platform must be reduced so as to boost productivity per well and also ensure the efficiency of the gas/condensate separation process. Subsequently, the cooled gas must be recompressed to the optimum pressure for the selective sweetening and the drying processes. And finally, the gas is recompressed once more before entering the export pipeline.

• Compliance with the Wobbe index, which is achieved by separating the gas and liquid phases after cooling the gas by passing it through a turbo-expander and using an NGL splitter to optimise certain contents (C_2, C_3).

Because of its efficiency, the overall process functioning on Elgin/Franklin since 2001 is fully adaptable to different CO_2 contents and will certainly find applications on other fields, in the North Sea or elsewhere.

Successful start-up

The start of the operational phase on 31 March 2001 led to a number of achievements by an integrated team including personnel from both the operator (TotalFinaElf) and the contractor (Kvaerner Oil & Gas). Firstly, thanks to thorough engineering studies, the Integrated Control and Safety System (ICCS) has made a significant contribution to the safety performance of the facilities. In particular, this is due to a remarkable ability to reach and maintain the required specification levels despite the complexity of the processes, whether during the start-up itself or following maintenance down-time.
In addition, in compliance with the stringent UK environmental restrictions, flaring has always remained within the consent levels.
Another laudable technical achievement is that, during the first six months of 2002, the fields have produced an average of between 210,000 and 220,000 boe/d (SEC figures).
A final cause for merit is that, despite the peculiar characteristics of the HP/HT environment, which is a veritable challenge, actual reservoir behaviour closely matches the model predictions, particularly regarding the very rapid drop in pressure and the inverted Joule-Thomson effect.

Safety first

Every effort has been made to continually improve those factors having an impact on human health, operational safety and environmental protection. The safety of all project workers was taken into account right from the design stage of the facilities. Human safety was a major factor in the decision to separate the wellhead platforms from the PUQ. On the PUQ platform itself, these considerations led to the safety-partitioning of functional spaces, and all high-risk zones were located as far as possible from the living quarters. The crew space is separated from zones devoted to treatment or storage of hydrocarbons by a series of fire- and blast-walls, with the latter designed for pressures as high as 3.1 bar

In accordance with UK law, which is particularly strict with respect to safety on offshore platforms, the Elgin/Franklin facilities are subject to a Safety Case identifying all potential risks involved in the operation of the facilities. Appropriate measures, both active and passive, have been taken to reduce these risks as far as possible: gas and fire detection systems, automatic shut-down valves and pressure control, protection against falls, an anti-collision system including radar surveillance and stand-by vessel, and evacuation facilities including lifeboats and life-rafts.

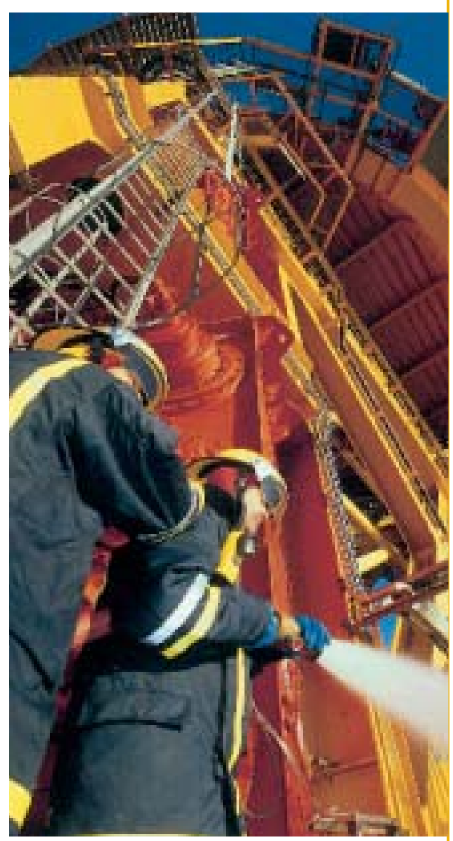
Current capacity is for 84 people, with an additional lifeboat planned in 2002 to allow flexibility for additional personnel during shutdowns. In addition to specific fire, explosion and evacuation programmes, the project has included some 7,000 hours of training courses – some using sophisticated simulators – designed to ensure that technicians can operate the facilities in complete safety.

All operations are monitored from the PUQ's central control room, via the ICSS covering 33,000 separate control points throughout the three platforms. The ICCS relays data in real time via satellite to onshore assistance teams.

The PUQ platform's communal recreation room, designed to make off-duty hours as relaxing as possible; there is also a fitness suite onboard.

Each day, these teams analyse the data on processes and other platform functions and then supply the offshore facilities with the necessary logistic support. As an added safety measure, the living quarters are equipped to ensure complete rest and relaxation for off-shift personnel, with private two-man cabins, communal spaces and leisure facilities of the very highest standards in today's offshore facilities.

(Below) The Elgin and Franklin wellhead platforms are unmanned, with maintenance usually taking no longer than a day. Both are equipped with a free-fall lifeboat, life-rafts and a temporary refuge for 20 people.



(Above) Fire-fighting training on the PUQ.

CHOOSING THE RIGHT EXPORT OPTION

Production from Elgin/Franklin will find outlets in several markets, benefiting from an efficient treatment and export system that gives maximum added value.

Newly built gas metering and heating facilities within the Bacton terminal (Norfolk).

THE SEAL GAS EXPORT LINE

Length	468 km
Diameter	34”
Internal diameter	828.2 mm
Thickness	25–17 mm
Carbon steel grade	API-5L-X 70
Design pressure	153 bar
Max. export pressure	145 bar
Design temperature range	-10 to +90 °C (opt: < 80 °C)

THE GAEL LIQUIDS EXPORT LINE

Length	38 km (Elgin to Forties) + 8 km Shearwater spur
Diameter	24”
Internal diameter	558.1 mm
Thickness	27.5–22.4 mm
Carbon steel grade	API-5L-X 70
Design pressure	250 bar
Design temperature range	-10 to +90 °C (opt: < 80 ± 5 °C)
Wax inhibitor + CI injection system	

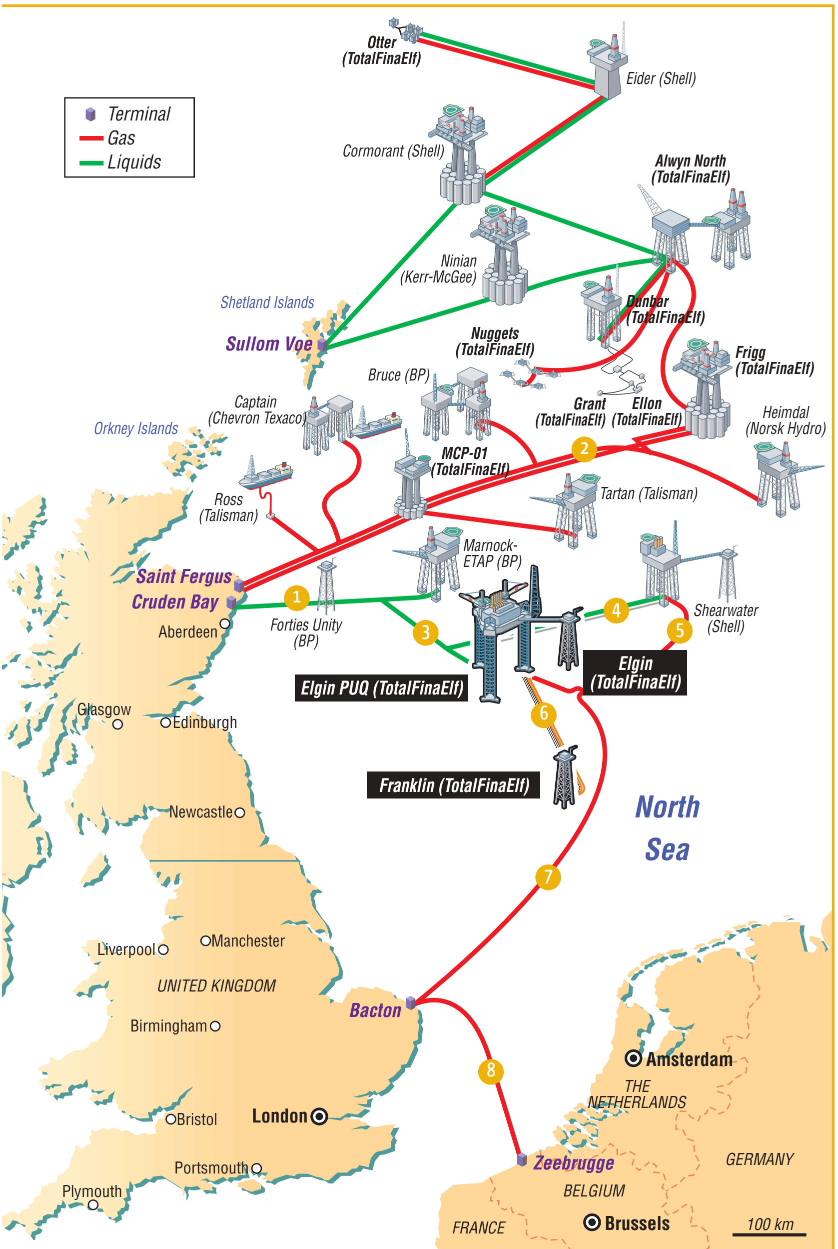
A number of marketing options were open to the gas and condensates from Elgin/Franklin. Traditionally, hydrocarbons produced in the North Sea are either piped ashore for separation and treatment or – in the case of liquids – loaded directly onto tankers for export. However, during pre-project studies for Elgin/Franklin, a third option was soon envisaged: separation and treatment to commercial specifications at the offshore site itself. Both TotalFinaElf (as operator of Elgin/Franklin) and Shell (as operator of Shearwater, a neighbouring HP/HT deposit only 7 km away) preferred this option as a way of making significant cost savings by exploiting synergy during both the development and the operational phases, particularly by means of joint hydrocarbon export infrastructures.

514 km of new export pipelines

Elgin/Franklin planners soon realised that the possibility of exporting gas to Europe via the Interconnector would be a major driving force in developing Elgin/Franklin; the European market was an attractive alternative to the UK domestic market, which was close to saturation. Given the loads already being carried by existing gas pipeline systems, TotalFinaElf and Shell finally decided to lay a new 34” (84 cm) gas pipeline running from the Shearwater and Elgin/Franklin fields 468 km south to the Bacton receiving terminal in Norfolk. The new pipeline, called SEAL (Shearwater Elgin Area Line), has a capacity of 31 Mcu.m/d., and was laid at a rate of 3 km/d at a total cost of £290 million. TotalFinaElf, as development operator, has now transferred operational responsibility to Shell, with SEAL being jointly owned by the Elgin/Franklin partnership (55.725%) and the Shearwater partnership (44.275%). It is worth noting that the SEAL line was designed using the DNV 96 code, a technical first that led to a cost saving of some £10 million on the pipeline.

At the Bacton terminal, jointly operated by Shell and Exxon-Mobil, specific facilities were built to carry out final onland treatment before the Elgin/Franklin gas is fed into a gas grid. These facilities also include metering and equipment for checking pressure and temperature parameters. From Bacton, the gas is either fed into the UK grid via the Transco terminal or piped through the new SILK (SEAL Interconnector LinK) link-up to the Interconnector terminal.

Liquids from Elgin/Franklin and Shearwater are transported by a new pipeline to join the existing Forties



Oil and Gas Transport Networks in the Central Graben area

Legend

1. 36” Forties Pipeline System
2. Frigg Pipelines
3. 24” GAEL Liquids Export Line (Southern Spur)
4. Shearwater Spur
5. Shearwater - T connection
6. Franklin to Elgin interfield bundle
7. 34” Shearwater Elgin Area Line (SEAL)
8. Interconnector

Pipeline System operated by BP, which comes ashore at Cruden Bay north of Aberdeen. Elgin/Franklin is served by a spur line called GAEL (Graben Area Export Line), a 24” (61 cm) gas line running 38 km to the Elgin site, with an 8-km additional spur serving Shearwater.

As well as using a common export infrastructure, Elgin/Franklin and Shearwater also share a submarine high-voltage power cable, thus optimising electricity supply to platforms at both sites, and a fibre-optic link carrying operational data concerning the export lines and power supply.

Technical and marketing challenges

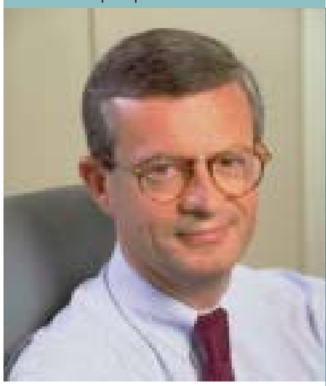
Even though the export network option required considerable capital investment, it was the result of a rigorous technical and commercial approach aimed at maximising the value of production over the long term. The selected option had two main consequences:

• Implementation of a sophisticated offshore treatment process to bring the Elgin/Franklin gas up to commercial specifications, particularly regarding the following parameters: H_2S content <3.3 ppmV, CO_2 content < 2%, calorific value between 36.9 and 42.3 MJoules/cu.m, and Wobbe index between 48.2 and 51.2 MJoules/cu.m. Given the difference in CO_2 content of the gas produced by the Elgin and Franklin fields, the PUQ platform had to be equipped with an efficient sweetening/decarbonation process in order to guarantee these parameters (see inset p. 18).

• At the same time, it was necessary to finalise long-term sales agreements. As a result, a package deal was concluded in 1998 with the French gas utility Gaz de France covering delivery of 70% of gas production via the Interconnector. In addition, the Elgin/Franklin partnership agreement makes the allocation of each partner’s condensates subject to the allocation of sales gas.

View of Bacton reception facilities from which gas is exported to the National Transmission System or to the Interconnector.

ADDRESSING NEW CHALLENGES


Yves-Louis Darricarrère, Senior Vice-President Northern Europe Exploration & Production.

The Group's pioneering development of the Elgin/Franklin fields ushers in a new era for the North Sea

As the energy industry heads into the 21st century, development of the world's HP/HT fields is still considered a marginal activity, even though mastery of the techniques involved could lead to a renewal of interest in a number of older deposits, such as in the Gulf of Mexico.

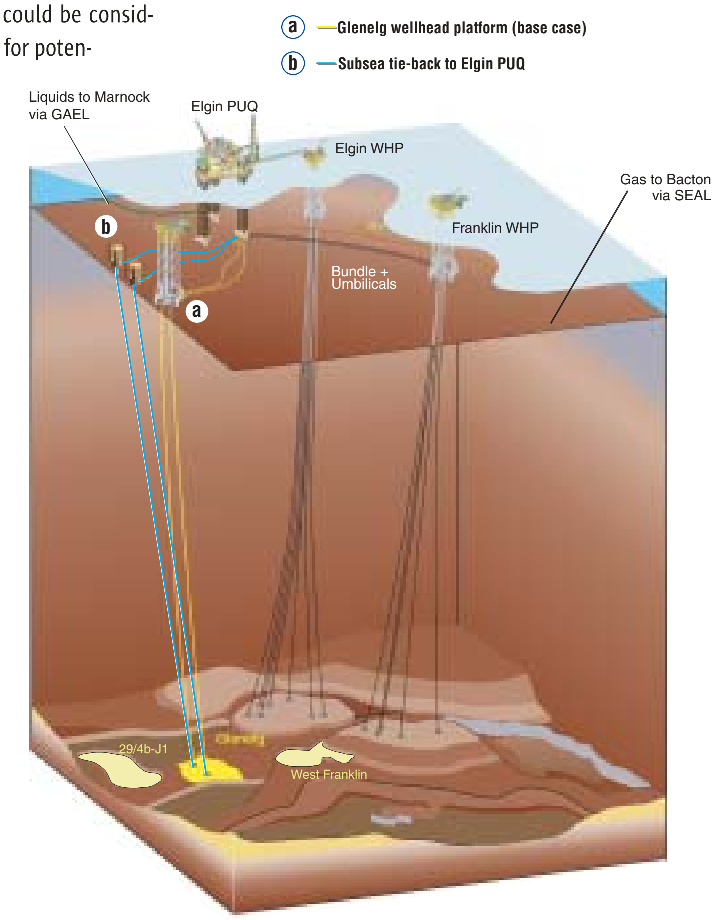
However, in the North Sea (where there are no fewer than 25 HP/HT fields), the cutting-edge know-how developed by operators such as TotalFinaElf opens up more immediate opportunities. One field in the Central Graben, Glenelg (discovered in 1999 on Block 29/4d adjacent to Elgin/Franklin) could be considered as a satellite to Elgin/Franklin for potential development in the near future.

Other prospects, such as West Franklin immediately adjacent to Franklin, open up new potential. They will probably use the treatment and transport infrastructure already set up for Elgin/Franklin.

Further HP/HT developments are likely in other zones of the North Sea, for instance Kristin in Norway, where production should begin by 2005. The challenge of producing from these deposits should drive further developments in a number of as yet immature technologies (annulus management, wellhead design, drilling techniques for depleted HP/HT reservoirs, metallurgy, cement formulation, deposit control, secondary recovery, etc.).

The development of Elgin/Franklin has provided invaluable experience and demonstrated that innovative industrial projects can also be profitable, while also opening the way to new challenges that were unimaginable only a decade ago. Such challenges include going deeper into the Trias formations lying at depths of 6,500 m and involving pressure of 1,350 bar and temperatures as high as 235°C.

Glenelg
Development options



TotalFinaElf E&P UK: a major player in the UK North Sea

Exploration & Production comprises the mainstay of TotalFinaElf's activities in the UK. TotalFinaElf Exploration UK PLC is one of the Group's largest subsidiaries and one of the leading oil and gas field operators in the North Sea. Based in the Scottish port of Aberdeen, employing more than 600 people throughout the UK, TotalFinaElf is now the fourth-largest producer in the UK North Sea.

This is partly due to production from the Elgin/Franklin fields, which averaged between 210,000 and 220,000 boe/d (SEC figures) during the first six months of 2002. The UK accounts for nearly 15% of the Group's overall production of oil and gas, generated by 3 main zones: Alwyn (Alwyn North, Dunbar, Ellon-Grant and Nuggets), where the Group has a 100% interest; Bruce (Bruce, Western Area, Keith), where the Group has a stake of more than 40%; and now Elgin/Franklin (more than 46%) as well as Nelson (11%).

In addition, TotalFinaElf operates the Frigg gas transport system, which mainly carries gas from the Alwyn and Bruce areas to the St Fergus receiving terminal. The Group also has a minority stake in the Sullom Voe terminal to which it sends liquids from the Alwyn zone. The Elgin/Franklin fields on the UK Continental Shelf, which began production in 2001, comprise the largest high pressure/high temperature development ever carried out, setting a new worldwide industry standard.

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