ELGIN/FRANKLIN: 5 YEARS ON

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ABSTRACT

Background

The Elgin/Franklin HP/HT gas condensate fields are located some 120 miles east of Aberdeen in the Central Graben area of the UK North Sea and at the time of sanction in 1997 was the largest HP/HT development in the world with the highest pressures and temperatures requiring the application of new technology. The fields have now been onstream for some 5 years with first production from Elgin on 31st March 2001.

The Elgin/Franklin Project consisted of an integrated development of the Elgin & Franklin fields using a central processing facility on Elgin with wellhead platforms located on each field. A new pipeline, SEAL (Shearwater/Elgin Area Line), built jointly with the neighbouring Shearwater development, exports sales quality gas to the Shell operated terminal at Bacton in Southeast England. Access via the new build SILK (SEAL Interconnector link) link line or the National Transmission System (NTS) to the Interconnector provides direct access to European gas markets. Liquids are exported to the Forties Pipeline System (FPS) via a new build connecting pipeline, GAEL (Graben Area Evacuation Line).

Prior to project sanction in early 1997 the two steel jackets for the wellhead platforms were ordered thus allowing installation in the summer of 1997 and so ensuring that the 4 year drilling campaign was completed on schedule. The Elgin PUQ was designed, constructed, installed and commissioned between 1997 and 2001 under an Alliance contract between the operator and the contracting companies.

The initial design basis of the Elgin/Franklin project was for:

- Maximum Gas Export Rate of 14.6x10^6 scm/d
- Maximum Condensate Export Rate of 175,000 bbls/d (27,800 scm/d)
- Field life of 22 years

Aims

The purpose of this paper is to discuss the following subjects related to the Elgin/Franklin project and facilities:

- Lessons learnt from Elgin/Franklin project & production start-up phases for future HP/HT developments
- Major challenges faced to date
- The evolution of the Elgin/Franklin development from the initial basis of design to its present status
- The future of Elgin/Franklin and the surrounding area of the Central Graben from a Total E&P UK Plc perspective
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2. INTRODUCTION

The Elgin/Franklin project demonstrated that facing the challenge of new technology can be successful and deliver acceptable returns. It required innovation across the full range of operator activities from development concept definition, through subsurface modelling, HP/HT drilling and platform/facilities design to commercial negotiations and arrangements, including:

- PVT analysis & thermodynamic modelling
- Drilling fluid design to deal with the temperatures up to 200 °C
- Well and Completion design & operations, including equipment and materials qualification and testing
- Quick closure 12inch ESDVs rated to 12,500 psi (86.2 MPa) to form part of the OPPS (Over Pressure Protection System)
- Franklin Interfield Pipeline rated to 160 °C
- TPG500 Process/Utilities/Quarters Concept for Elgin PUQ processing gas to sales specification offshore
- Compact Titanium Heat Exchangers
- Equity equalisation as opposed to unitisation

Figure 1: Elgin PUQ and Elgin Wellhead Platform
Some key successes of the project included:

- **HP/HT development drilling within project schedule despite major technical challenges.** This was of particular importance to the project as the technology to drill wells in depleted HP reservoirs had not been developed and the development concept involved drilling all development wells prior to the reservoir pressure reducing by more than 100 barg. Therefore, a delay in the development drilling programme could have had a direct impact on either the production start-up or ultimate recovery from the reservoir.

- **The decision to process the gas offshore to commercial sales gas specification and provide a direct link to the European gas market via the SILK line allowing export to both the European and UK transportation systems.**

- **The TPG 500 jack-up platform concept for large offshore facilities which despite delays in the construction programme has proven to be successful by enabling onshore commissioning, minimising offshore hook-up and eliminating the requirement for a heavy lift (see figures 1 & 3).** It has also been able to accommodate significant weight growth including two additional living quarters and by providing the possibility to float away on abandonment it has significantly reduced de-commissioning costs.

### 3. LESSONS LEARNED

In order to deliver the Elgin/Franklin project a combination of innovation and existing technologies and processes were used. A selection of the key learning-points of the project are described in more detail in the sections below.

#### 3.1 Alliance Contract

The contract arrangement for the TPG500 design, construction, hook-up and commissioning was awarded to an alliance of three companies; TPG UK who designed the TPG500, McDermott who were the engineering contractor and BARMAC (50:50 McDermott’s and Brown & Root) who owned and ran the Nigg yard where the Elgin PUQ was built. The contract awarded to this Alliance was based on an incentive scheme which maximised the reward to all three contractors if the Elgin PUQ was installed for a specified price. However, the initial schedule and costs proved insufficient for several reasons, including the inclusion of a requirement to upgrade the blast wall as a result of the Cullen inquiry after steel erection had already commenced and late delivery of the compact heat exchangers (see section 4.5). As the Alliance contract was structured to minimise cost the incentive for the contractor was to minimise expenditure rather than schedule. A lesson learned is that **accurate and realistic cost estimates are vital when creating an Alliance type contract and schedule incentives are at least as important as cost.** This lack of financial incentive for completion on schedule, coupled with the imminent closure of the McDermott Nigg Yard resulted in the Elgin PUQ sail away missing the 1999 weather window and being delayed until 2000. Nevertheless, there were some benefits of the Alliance Contact arrangement, such as, the degree of integration between the contractors and the company enabling a smoother commissioning process and rapid resolution of problems as they arose.

#### 3.2 Offshore Accommodation

The offshore accommodation required during the production phase was underestimated with only 69 beds being initially installed. The core crew requirement was initially set at 42, whereas the actual average core crew is approximately 65. Therefore, additional bedding allocated for non-routine maintenance, construction and well servicing operations was inadequate even in an optimistic case. In reality, whilst the competencies of the operators allows multi-skilling as planned during the project phase, the full range of emergency response duties required and the area operator philosophy whereby an operator is assessed as competent on each of the 4 areas (wellheads, utilities, gas processing and oil
processing) mean that more than one additional operator and technician are required on each shift in order to cover sickness, holidays and Franklin Interventions. The Franklin interventions have also been more frequent than was envisaged during the project phase and there have been protracted periods of 24 hr interventions due mainly to the need to control the well annuli (see section 4.1) and a large volume of construction activity on the Franklin platform. There have been further requirements for remedial workscopes not anticipated during the project, such as vibration and stress corrosion cracking corrective actives (see section 4.3), that have required an integrity team be offshore for prolonged periods. The decision to install only 69 beds was made at the time of the CRINE (Cost Reduction in the New Era) initiative and as described above was wholly unrealistic. In order to manage the increase in manning requirements a 40% increase in bedding and 30% increase in lifeboat capacity has been installed in two phases since platform installation and given the continuing offshore bedding constraint further future accommodation is potentially required. The lesson learned is that whilst the project costs are increased by additional bedding, the operational difficulties and extra costs incurred by retrofitting accommodation are such that additional bedding, over and above the requirement assessed during the project is worth the extra cost.

3.3 Risk Mitigation

Identified risks should be continually reviewed during construction, commissioning, start-up and operations and contingency plans put in place. In the case of Elgin/Franklin the risks identified included sand control, compact heat exchangers, piling and settlement and pipework vibration. All avenues of expertise were utilised in order to gain relevant expertise in all of the identified risk areas, from internal Total Group Specialists to Partner specialists and Universities.

The titanium gas/seawater compact heat exchangers were advanced and untested technology at the time of project sanction. Problems were identified during manufacturing and a review team considered a range of scenarios in detail including abandoning the use of the compact heat exchangers and installing shell and tube exchangers in their place, a contingency that has not been required to date, and which had a significant structural impact to the platform that had to be evaluated in full. This was a large body of work that required significant engineering and management resources to be available during the construction phase of a complicated project with a tight delivery schedule. Therefore, the lesson learned for future projects is, if possible, to ensure back-up options have been considered when selecting advanced technology.

For sand control it had always been known that sand production could be an issue on Elgin/Franklin after a certain level of depletion. As no form of downhole sand control was available at the time of project sanction the project management made the bold decision to drill wells that might experience sand failure during their lifetime with the knowledge that there was also no methodology for drilling wells in depleted HP/HT reservoirs to replace these sanding wells. To mitigate this risk, once the development drilling programme was complete a project team was set-up using many of the personnel involved in the completed drilling programme to investigate the key enabling technologies for managing sand production, i.e. infill drilling in depleted HP/HT reservoirs, downhole sand control in HP/HT reservoirs and retrofitting downhole sand control methods to existing production wells. Whilst the subsurface team investigated these crucial areas, a surface sand control project was also kicked off to look at removing sand at surface and determine which facilities require protection from sand by removal and which facilities it is most effective to monitor for sand erosion and replace when necessary. These studies have not only enabled a sand management strategy to be developed (to date not required) but as a by-product have opened the door to future development drilling in the Elgin and Franklin reservoirs and downhole sand management in subsea HP/HT wells.
3.4 Duplex stainless steel (22Cr) versus Carbon Steel: Chloride Stress Corrosion Cracking.

Duplex stainless steel was selected in preference to carbon steel due to the high corrosivity of the produced fluids. Duplex stainless steel is not susceptible to chloride stress corrosion cracking under formation water chemistry conditions and Elgin/Franklin topsides operating temperatures (up to 140 °C), however, it is susceptible to stress corrosion cracking if local evaporation leads to concentration of chlorides at these temperatures.

It was known in design that if small quantities of formation water were produced then evaporation of this formation water could occur at locations of high pressure drop such as across the topside chokes due to the gas being under saturated with respect to water. To ensure that the gas remained saturated, wash water injection facilities were installed upstream of the production chokes. Unfortunately the availability of these facilities was initially low due to wash water injection choke and pump design. Therefore, whilst the water condensed from the gas in the first stage separators ensured that the water in the produced water outlet lines remained below the chloride concentration at which stress corrosion cracking would occur, the small volumes of water entrained in the oil stream became a highly saline solution when the pressure was reduced by 40 barg across the condensate level control valve and much of the water flashed off. This saline solution was sufficiently concentrated to initiate internal stress corrosion cracking of piping components immediately downstream of these valves.

To counteract this effect the following three actions were taken:

i. reliability of the wash water pumps was improved by replacing with stainless steel the carbon steel body of the pump
ii. wash water injection choke internals were modified in order to improve reliability
iii. duplex stainless steel spools installed downstream of the level control valves were replaced in carbon steel.

The first two actions improved wash water availability and the third prevented repeat chloride cracking at the area identified during production as highly susceptible. No corrosion of the new carbon steel spools has been found up to 2 years following installation and it is likely that the very high operating temperatures produce a protective corrosion product film on the internal carbon steel surfaces. The lesson learned is that the entire process and not just the formation water stream should be considered as susceptible to internal stress corrosion cracking during material selection.

In addition to the internal stress corrosion cracking described above, external stress corrosion cracking also occurred at a point where hot (>100 °C) duplex pipework was supported by a unsealed trunnion. In the investigation following the discovery of the crack, it was identified that the environment within the trunnion (hot and humid) initiated pitting corrosion and enabled external stress corrosion cracking to propagate from these pits (see figure 2). Unlike the internal stress corrosion cracking problem, external chloride stress corrosion cracking of duplex stainless steel in aerated marine environments is more understood and more predictable. It is usual to apply external coating systems to prevent this problem and thermally sprayed aluminium has been applied to duplex stainless steel on Elgin/Franklin with good success. However, in this case the piping item has to be coated after welding of the trunnion to the gas line and so it was not possible to coat the external surface of the gas pipe adjacent to the trunnion. In order to prevent future occurrences of external stress corrosion cracking all trunnions have been effectively sealed. In addition the practice of washing down the decks with seawater has been abandoned with all seawater utility stations converted to freshwater and any salt deposition from the marine environment on pipework >100 °C is removed on a monthly basis. The lessons learned here are that all areas of Duplex pipework at risk of external stress corrosion cracking, no matter how small, should be protected and monitored if at all possible and when a platform includes significant amounts of Duplex pipework operating at temperatures above 100 °C then it may be worth considering freshwater for washing down the decks, despite the increase in freshwater usage that this will incur.
3.5 Elgin PUQ (TPG500) Piling Operations

When the Elgin PUQ TPG500 platform was installed it was floated out to the field and jacked-up on its three triangular legs when in position. At the base of these three legs are spud cans which are positioned around the outside of the leg structures. Between these spud cans and beneath the leg structure is a mud mat that spreads the load of the leg (see figure 3). After the jacking operation piling began, where 6 piles were hammered through the spud cans for each, 2 per side of the leg structure. When the piles had been driven down so that the top was level with the spud cans a swaging tool was used to expand the dogs within the piles so that they locked into the mouth of the spud can. However, during the jacking operation the bottom of the legs, including the spud can structure sank more than one metre deeper than anticipated and mud rose to a height of 5 metres within the piles making it impossible to access the top of the piles with the swaging tool, a risk that had not been identified during preparation of the Elgin PUQ installation procedure. It is not known what caused the settlement of the legs to be greater than was calculated, although it was suggested at the time that the wave motion as the legs were just above the seabed may have caused fluidisation of the mud. In order to lock the piles into position a “Mud Hog” dredging tool operated from the Elgin PUQ and Sonsub jetting system operated from an adjacent supply vessel were lowered into the piles to remove the mud build-up and allow access for the swaging tool. The “Mud Hog” equipment had to be sourced at short notice from Louisiana, a process that took 3-4 weeks, so a lesson learned from this project is that such equipment should be available on site as a contingency measure when installing a large fixed jack-up structure.
4. MAJOR CHALLENGES

In the months following production start-up several issues developed, some related to the HP/HT nature of Elgin/Franklin, which had not been identified during the project as significant risks. A brief discussion of the major challenges which may be experienced by similar, future projects will be discussed in this section.

4.1 Annulus Management

Due to thermal expansion within the annuli and ingress of hydrocarbons from a higher reservoir into the B annulus there has been a requirement to maintain a constant pressure within the annuli. The root cause of this problem is the loss of cement isolation integrity around the Production casing leading to communication with deep low permeability formations above the reservoir. This loss of integrity is considered to be primarily via a micro-annulus created by a reduction in fluid density inside the casing prior to completion. The annuli are maintained at a constant pressure, within the design limits of the casing, by an active system that compensates for temperature related volume changes in the annulus by bleeding and filling the annuli to maintain a preset surface pressure. Initially this system was manually operated requiring attention within 12-18 hours of an unplanned shutdown. For Elgin wells the operators are available from the Elgin PUQ within minutes, however, for Franklin wells it required additional helicopter flights to shuttle operators across from the Elgin PUQ. Therefore, a permanent, remotely operated system has been installed and operating effectively on Franklin for the last 18 months and a similar system is scheduled to be installed on Elgin soon.
4.2 Well Growth

Growth of the wells was predicted to occur due to thermal changes in the well casings caused by production. These growth predictions were used to design the flowline support systems to allow a range of movement during production. Given the size of the HP flowlines this range was necessarily limited. In reality well growth exceeded prediction by up to 100% with observed well growth of up to 270 mm. The cause of this additional growth is the apparent movement, due to thermal changes, of well casings below the mudline, which had previously been considered immobile due to cementation. The flowline system had sufficient excess range to accommodate the increased movement however the system operates near the limit of its capacity and the clashes between the flowlines and other locally installed pipework/structure at high production rates meant that the wells could not operate at their full potential until these clashes were resolved.

4.3 Vibrations

There has been a considerable amount of vibration on the Elgin PUQ since production start-up, especially at flowrates above $1.46 \times 10^6$ scm/d. Whilst some vibration is only established local to the source, such as at the Lean TEG pumps due to oversized pulsation dampeners, the vibration pulses generated in the export metering skid inlet pipework propagate throughout a large section of the plant due to the number of flowlines connected at this point. These vibrations were identified once full production had been achieved at an export gas rate of $14.6 \times 10^6$ Mscm/d and monitoring/analysis was commenced. However, soon after the full gas export design rate of $14.6 \times 10^6$ Mscm/d had been achieved the export gas rate was increased, firstly to $15 \times 10^6$ scm/d and then to $15.5 \times 10^6$ scm/d when it was noted that the amplitude of the vibrations increased significantly. Soon after the increase to $15.5 \times 10^6$ scm/d a small bore pipework connection to one of the export gas metering streams fractured resulting in a gas release and consequent platform shutdown. On analysis, the cause of this failure it was found to be due to fatigue cycling and it was identified that the natural frequency of the small bore connections on the export metering streams matched the frequency of the vibrations generated at the inlet pipework where the flow is divided into two streams. After further measurements and analysis it was found that the vibrations were being generated at this location due to high levels of turbulence and the geometry of the export metering skid inlet header and in order to stop the generation of the vibrations it would be necessary to change the inlet pipework from 12 to 16” diameter in order to match the inlet header and the export metering streams from 12 to 16”. The costs and shutdown length associated with a modification of the size were significant, and so an alternative, vibration management strategy was developed to limit the effect of the vibrations generated. This strategy included:

i. Operating on a single gas export stream and isolating the second (no production constraint). Figure 4 shows the effect of one and two stream operation on the amplitude of the vibrations.

ii. Limiting the operating pressure in the gas export metering skid to above 140 barg (14 MPa) rather than floating on pipeline pressure

iii. Reducing the weight installed on small bore connections by replacing heavy bleed valves with comparatively lightweight Parker 15kPsi (103.4 MPa) flanges containing integrated valves and, in some cases, reducing the length of the small bore pipework connected to the main process line

iv. Installing clamps on unsupported valves to reduce resonant, high amplitude vibration

v. Strengthening the mini-mezzanine deck above the gas export metering skid that was acting as a conduit by transmitting the vibrations throughout the plant.

Whilst this strategy does not address the root cause of the vibration problem, it did allow the production to be ramped back up to $15.5 \times 10^6$ scm/d after a reduction to $14.6 \times 10^6$ scm/d on the initial pipe work failures and did not involve a lengthy platform shutdown. It is recommended that in projects involving
a large amount of process pipework at high flowrates, dynamic simulation of pipework vibration is performed during the design to prevent a re-occurrence of a similar nature.

Figure 4: Amplitude of Vibrations Initiated in Gas Export Metering Skid

4.4 Gas Plant Optimisation

The Elgin well fluids were richer than had been thought during the project phase and in order to ensure gas export within NTS spec the gas plant was optimised with more NGLs put into the condensate exported via the Forties Pipeline System. In turn this led to an increase in light ends processed by BP at Kinnell. It was possible, by negotiation with BP and the diversion of other Total E&P UK Plc condensate production to other processing facilities, to increase the capacity for E/F condensate within the Forties Pipeline System. However, it is worth noting that the gas plant itself controls the WOBBE Index, H₂S and CO₂ of the gas within the required National Transmission System and Interconnector specification without any major problems. Operation outwith the spec is rare and is usually associated to restart of the plant following a shutdown. On restart it is usual to either minimise flaring by recycling whilst bringing up production slowly and remaining within the spec, or, by negotiating entry with the pipeline operator (Shell) with gas export outwith the required specification to a minor extent if the facility to blend with the Shearwater platform is available.

4.5 Compact Heat Exchangers

The titanium compact heat exchangers (CHEs) were selected due to their associated weight reduction over conventional shell and tube coolers. Cracks appeared in the initial, Mark 1 CHEs during installation due to brittle oxidised surface layer of the post-weld grade 5 titanium, and the decision was made at that stage to replace the Booster and Export Compressor aftercoolers with shell and tubes. The project also re-designed the platform to allow installation of 11 shell and tube heat exchangers as
replacements for the remaining CHEs on new decks built between Legs 2 and 3 of the Elgin PUQ and the existing decks, however these decks were never installed and a management strategy that included purchase of rotating spares in case of failures and installation of additional units at critical points was developed. During production continuous monitoring resulted in the observation of cracks developing in the key-ways between the different panels of the CHEs (figure 5). It is thought that these cracks are initiated in the same surface oxidised layer of titanium as the cracks observed during manufacture when stress is applied at this point due to differential temperature between adjacent panels. This temperature differential is only found in CHEs installed upstream of the gas dew point control and is due to the appearance of hydrates during periods of low production when the seawater flow does not reduce due to the poor function of the temperature control valves. To mitigate against these problems a number of changes have been put in place:

i. Regular monitoring of key-ways and “smoothing” of initiated cracks to prevent propagation
ii. Installation of methanol injection points upstream of wet gas CHEs
iii. Rotation of CHEs for onshore inspection and repair as required
iv. Installation of online spare CHEs
v. Proposed modification of temperature control valves to prevent hydrate formation

These mitigating measures have appeared successful and maintained some of the space and weight savings expected from the CHE installation during platform design. The CHEs themselves have also proved very effective coolers despite heavy fouling in the seawater system.

Figure 5: Titanium Compact Heat Exchanger
5. PRESENT STATUS

Following start-up, and resolution of the challenges identified above, it has been possible to gain an overall platform efficiency in excess of 96%. The challenge is now to maximise and prolong plateau production primarily through infill drilling and the development of nearby HP/HT satellite fields. This has been possible due to the increased understanding of the reservoir & plant and also the advance of new technology since the project sanction.

5.1 Increase in plant throughput

Soon after the production plateau rate of $14.6 \times 10^6$ scm/d was achieved a review was performed to assess the maximum export gas rate possible with minimum modification of the plant and export rates were ramped up, first to 15 and then to $15.5 \times 10^6$ scm/d where vibration concerns led to a temporary reduction to the plant nameplate capacity of $14.6 \times 10^6$ scm/d. However, once the vibration issues were closed out the production rate was increased back up to $15.5 \times 10^6$ scm/d.

5.2 Infill Drilling

At project sanction it was thought impossible to drill an HP/HT reservoir with more than 100 bars (10 MPa) depletion. Recent work on developing new drilling techniques has demonstrated the possibility of infill drilling. The ability to drill infill wells in the depleted HPHT reservoir is considered a critical issue given the potential for well damage due to compaction. A number of infill techniques have been progressed and developed to point where they are now considered ‘field ready’. An infill well is planned to be drilled in early 2006 in the Franklin field where these techniques will be utilised at a depletion level of 500bar.

5.3 West Franklin/Glenelg

These two new fields close to the Franklin and Elgin Wellhead Platforms respectively, are being developed from the existing wellhead platforms as high step-out wells, thus reducing project CAPEX by tying directly into the existing facilities. High step out wells in HPHT fields are particularly challenging due to the impact of the increased well angle on drilling fluid stability and equivalent circulating density in narrow drilling margins and to the impact of increased well depth on already highly loaded casings and rig systems.

5.4 Compaction Damage

Compaction of the reservoir is occurring with pressure depletion. This compaction, whilst predicted to cause some limited damage to well liners, has caused movement along bedding planes and potentially also along fault lines. These movements have a shearing action which is much more damaging to well liners than pure compaction. Calliper logs have been run and most wells in both Elgin and Franklin show the effects of shear action, primarily in the overburden but also to a lesser extent in the reservoir itself. The access to the perforations has become restricted to varying degrees. A Finite Element model of the well liners has been built and correlated against measured well damage in order to assess the potential liner failure point and the lifetime of specific wells. In the event of liner failure and potential well loss the primary remedy is a sidetrack involving drilling in depleted reservoirs. To date no wells have failed and an ongoing monitoring programme is in place.
5.5 Sand Control

A contingency plan for dealing with sand production when/if it arrives has been developed that involves a combination of surface and downhole solutions depending on the mode of sand failure. The downhole solutions involved the development of retrofit gravel pack systems for HPHT conditions. Initially workover based systems were developed that would allow either squeeze or frac–pac techniques to be used. Latterly a thru-tubing squeeze pack system has been developed. However the original promise of these systems has been diluted by the increasing incidence of compaction related well liner damage which makes the installation of retrofit sand systems problematic. As an alternative the design of a surface de-sanding package for the Franklin wellhead platform is currently ongoing and will be installed within 16 months of sand breakthrough on a Franklin well in order to protect the Franklin Interfield pipeline.

5.6 Ongoing Challenges

**Scale:** water production in Elgin is leading to significant scale deposits with consequent reduced productivity and increased well downtime for remedial treatment. Scale removal and inhibition programmes have been performed and are being optimised or the exotic scaling species found in HP/HT well conditions (Lead, Zinc and Iron Sulphides).

**Reservoir Performance:** whilst the performance of the reservoir has exceeded the initial expectations estimated during the project there is significant uncertainty in how the reservoir will behave when the pressure falls below dew point and condensate drop-out occurs in the reservoir.

**Corrosion Under Insulation:** insulated pipework was coated in an impermeable membrane to prevent water ingress and consequent corrosion under insulation. However, the type of membrane used has proved to be ineffectual and corrosion under insulation has occurred necessitating a monitoring campaign that involves the removal of insulation and the impermeable outer sheathe prior to inspection, with reinstate following.

**Passive Fire Protection (PFP):** was installed on all the major vessels to reduce the impact of any fire. However, continuous cracking of the PFP has occurred since start-up and maintenance of its integrity is a full time occupation for 2 people. A trial of a new type of PFP will be undertaken this year, with the current PFP on the Test separator completely removed and replaced with the upgraded version.

**Control System:** the control system installed during the project had no extra capacity and very little room for expansion. The current projects, such as Glenelg, West Franklin and Sand Jetting will utilise most of the remaining capacity for expansion and so investigations are ongoing to define the future of the platform control systems in order to allow easy implementation of future projects. It is expected that this additional capacity will be available by the beginning of 2008.

6. CONCLUSIONS & THE FUTURE

Whilst the infill drilling, West Franklin and Glenelg projects will be progressed over the next 12 months, they are by no means the last projects that Total E&P UK Plc intends to implement in the Elgin/Franklin area. The possibility of an enhanced oil recovery scheme to increase the reserves of the Elgin field is currently being investigated and it is hoped that a 4D seismic survey acquired last year will identify additional drilling targets and enable optimised location of replacement wells if required. It is clear that future targets will be increasingly challenging to drill; with high departure from the well head platforms and increasingly depleted reservoirs.

However, it is expected that over the next 5 years the development of nearby HP/HT fields will be possible using subsea technology, releasing reserves not economic to develop using surface facilities.
There is sufficient redundancy of equipment to ensure high production efficiency on the Elgin PUQ and a programme of controls, electrical and utilities extension upgrades are being undertaken to ensure that the Elgin PUQ is an attractive host for future developments.

Elgin/Franklin has not only achieved the aims of the initial project, it has surpassed them. With over 300x10^6 boe (50x10^6 scm) produced to date and high production efficiency it is well placed to undertake the expansion necessary to extend the field life well beyond the 22 years envisaged at project sanction. Elgin/Franklin has not only been a valuable learning experience for the Elgin/Franklin Partnership, the Total Group and the industry but it is a valuable centre for development of unexploited hydrocarbons in the Central Graben area of the North Sea.

The authors would like to thank the Elgin/Franklin & Glenelg Association Partners for permission to publish this paper: Total E&P UK PLC, ENI Elgin/Franklin Limited, BG International (CNS) Limited, Dyas UK Limited, Esso Exploration & Production UK Limited, Gaz de France Britain Limited, E.ON Ruhrgas UK Exploration & Production Limited, Oranje-Nassau (UK) Limited and Chevron Upstream Europe Limited.

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