Figure 3.16  Polygons used during assessment of GIIP and reserves
Figure 3.17  HCPT map generated using Base Case reservoir property maps and Base Case top reservoir depth structure map
Figure 3.18  HCPT map generated using Alternative Mid Case reservoir property maps and Base Case top reservoir depth structure map
Figure 3.19  HCPT difference map (difference between HCPT maps presented as Figures 3.17 and 3.18)
Figure 3.20 **HCPT map generated using Upside reservoir property maps and Base Case top reservoir depth structure map**
Figure 3.21  HCPT map generated using Downside reservoir property maps and Base Case top reservoir depth structure map
Figure 3.22  GIIP cumulative probability function from the Monte-Carlo model
Figure 3.23  Map showing location of existing wells and indicative top reservoir location of future wells
Figure 3.24  **Photograph of outcrop of Sherwood Sandstone and corresponding interpretation showing high level of reservoir heterogeneity**
Figure 3.25  Map of pressure in reservoir layer E2 at end of field life (P50 model)
Figure 3.26  P90, P50 and P10 sales gas production profiles
Figure 3.28  **Effect of sensitivities on P50 sales gas production profiles**
Figure 3.29  **Effect of sensitivities on P90 sales gas production profiles**
Table 3.2  Zonal Parameters for reservoir property mapping - well 18/20-2z
Table 3.4  **Zonal Parameters for reservoir property mapping - well 18/20-4**
Table 3.6  Base Case, Upside and Downside layer average reservoir properties used as back-ground values for mapping
Table 3.7  Dimension of elliptical areas of influence of wells used in base-case and upside/downside mapping
Table 3.8  Minimum and maximum permeability values used to clip grids in trend-gridded permeability mapping
Table 3.9  **Results of the deterministic GIIP calculations**
(for location of polygons see Figure 3.16)
Table 3.10  Comparison of mapped HCPT at the wells and petrophysical HCPT
### Table 3.11  **Inputs to probabilistic volumetrics calculations**
Table 3.12  Corrib well fluid composition
Table 3.12  (continued)
Notes: NM-Not Measured; 0.0000 means less than 0.0005
Table 3.13 Parameters used and assumptions made in the construction of the P90, P50 and P10 reservoir models
Table 3.14  **Predicted P90, P50 and P10 sales gas production profiles and corresponding water profiles (sales gas in MMscfpd; water in barrels per day)**
Table 3.15  Production profiles for water of condensation and formation water
Table 3.16  Sensitivities on P90 and P50 full field simulation models
4. FIELD DEVELOPMENT

4.1 PRODUCTION SYSTEM

4.1.1 PROPOSED CONCEPT AND ALTERNATIVE CONCEPTS CONSIDERED

4.1.1.1 Introduction

In terms of production facilities engineering, the area in which Corrib is located is characterised by a harsh marine environment (being directly exposed to the Atlantic fetch), a lack of existing hydrocarbon production infrastructure, and the presence of active fishery industry interests.

4.1.1.2 Concepts considered

A number of development concepts to exploit the reserves in the Corrib Field were identified by the field development team which undertook a series of screening exercises in order to select and define the preferred development strategy.

The principal alternative development concepts considered were:

1. Construction and installation of a deepwater fixed steel jacket or guyed tower with processing, drilling and accommodation facilities together with the installation of an associated gas export pipeline to shore;

2. Construction and installation of a "shallow water" (<100m depth) fixed steel jacket (at a location between Corrib and the shore) with minimum facilities together with the installation of associated subsea infrastructure (feeding gas from Corrib) and an export pipeline transporting gas to shore;

3. Construction and installation of a buoyant "spar" platform, deep draft semi-submersible floating platform, or tanker-based floating production vessel.

All of the above options would be provided with processing and accommodation facilities and be combined with subsea completions, subsea production infrastructure and an offshore gas export pipeline transporting gas to shore.

4. Subsea development with a moored control buoy and telemetry link to an onshore control station.

5. Subsea development with electro-hydraulic control via an umbilical.
4.1.1.3 Reasons why alternative concepts were eliminated

The first four of the above development options were eliminated due to a number of considerations, including:

- The water depth and hostile nature of the environment at Corrib do not favour the use of a fixed steel jacket or guyed tower. (The latter has not been used outside the more benign environment of the Gulf of Mexico.)
- The floating production concepts are similarly not ideally suited to extended field life in the prevailing harsh environment, with large bore high pressure gas export risers being a particular design issue.
- Remote Control Buoy technology has not been developed for the extreme environmental conditions experienced at Corrib. Development of an acceptable, reliable system could not be guaranteed within the proposed project time scale.
- All the proposed manned facilities options incur high operational expenditure and have increased adverse safety implications, particularly with respect to offshore transfer of personnel.
- The high capital cost of all the floating or fixed platform options combined with the requirement for extensive gas transport infrastructure rendered the options sub economic with the predicted Corrib reserves and envisaged gas sale price.
- The required “lead time” construction schedule for the floating or fixed platform options (and the need to install in summer) was seen to delay the potential “first gas” date for Corrib.
- The relatively dry nature of the Corrib gas (eliminating the need for offshore processing) and the high reservoir productivity (reducing the number of wells) allow the use of much simplified production facilities with high reliability. This permits the practical adoption of subsea production technology for Corrib.

4.1.1.4 Development concept selected

The preferred and selected (and indeed only feasible) development scenario is a long-range subsea tie-back to a processing terminal onshore (Figure 1.4). It is expected that about seven subsea wells will be completed and tied back to a central gathering manifold which will connect to the main offshore pipeline. The offshore pipeline will carry gas from the manifold to the landfall at Broadhaven Bay, Co. Mayo, and from there to the gas processing terminal. The terminal will be located near Bellanaboy Bridge in the townland of Bellagelly South (Figures 1.5 and 1.6). Gas will be exported from the terminal via a BGE-owned and operated pipeline to the Galway area.
The facilities incorporated into the subsea scheme will include:

- Subsea christmas trees
- Subsea production chokes
- Pressure and temperature sensors
- Well gas flow meters
- Manifold isolation valves
- Pig launching facility (for future use)

All subsea facilities will be controlled and monitored from the onshore gas processing terminal via an electro-hydraulic remote control system. Electrical power and signals, along with hydraulic control and chemical injection fluids will be carried in an underwater umbilical cable, laid on the seabed.

The onshore reception and processing terminal will comprise:

- Slug catching and separation facilities
- Gas conditioning facilities
- Sales gas compression
- Fiscal metering and odourising
- Hydrate and corrosion inhibitor storage and pumping system
- Supporting utilities including power generation and fire fighting systems.

The anticipated field layout is shown in Figure 4.1.

4.1.2 POTENTIAL FOR ARTIFICIAL LIFT OR STIMULATION

4.1.2.1 Artificial lift

There is no potential for artificial lift. The concept is not applicable to a dry gas field.

4.1.2.2 Stimulation
4.1.5 SUBSEA PRODUCTION FACILITIES

4.1.5.1 Introduction and main technical challenges

The principal technical challenges faced in the design of production facilities for Corrib include:

- A hostile marine environment which severely restricts the effective working "weather window" for drilling, completion, production facilities installation and subsequent inspection maintenance and repair.

- The need to design production facilities with an extremely high degree of production efficiency (i.e. high system availability and component reliability). This being due to the need for guarantee of supply, the high cost of intervention in a remote area and the inability to schedule intervention in winter months.

- The need to provide extensive infrastructure (including offshore production, onshore treatment and onshore transportation facilities) while ensuring that expenditure will allow economic exploitation of the predicted hydrocarbon reserves.

- The need to bring Corrib gas online as quickly as possible to take advantage of perceived gas marketing opportunities and initiate cash flow to offset sunk costs.

Having identified a subsea tie-back as the favoured concept, specific technical challenges included:

- Subsea system control over a distance of 90km and the associated design of a suitably reliable yet installable umbilical link

- The optimised design of pipeline and onshore liquid handling facilities to accommodate
full wellstream transfer and multiphase flow over a broad range of operating scenarios

- The design of remotely (diverless) installed and maintained subsea production facilities which remain protected from fishing activities.

### 4.1.5.2 Field environment

The infield subsea production facilities will be installed in a prevailing water depth ranging from approximately 335m to 355m across the field. The Corrib area seabed soils are characterised by a surface layer (1m to 2m thickness) of soft to very soft silt overlaying glacial clays. The maximum seabed currents in the field range in speed from approximately 0.4 to 0.5 m/s (1 year and 100 year return period values respectively) with corresponding significant wave heights of 15.9m (1 year return) and 22.4m (100 year return).

### 4.1.5.3 System configuration

The proposed configuration of the subsea facilities is a "central", eight well slot, manifold (Figure 4.1). This functions to gather gas production from each well in the Corrib field and will be located in close proximity to the existing 18/20-2z and 18/20-4 wells. These existing wells plus a further two or three wells (to be drilled from a top hole location close to the manifold) will form the principal production "cluster", each well being tied back to the central manifold by means of a flexible production jumper.

The remaining two vertical wells (18/20-3 and 18/25-1) are located to the north and south of the central cluster at distances of approximately 1.9km and 2.3km respectively. These wells will also be linked to the central manifold by means of either flexible or rigid infield flowlines.

The central gas gathering manifold is linked, in turn, to the gas pipeline via a rigid spoolpiece allowing transportation of produced fluids to shore.

The manifold is provided with remotely and "manual" actuated isolation valves plus connection points for the christmas tree production jumpers, the main gas export pipeline spool and the temporary subsea pig launcher. In addition it includes a methanol injection system, pressure and temperature sensors and an accompanying control module. The proposed manifold design will allow for the retrieval of all active and pressure containing components and pipework. The envisaged manifold is estimated to weigh approximately 250 tonnes and measure approximately 15m by 13m and to be about 4.5m high.

### 4.1.5.4 Control and monitoring

Control and monitoring of the Corrib subsea system will be achieved by a single electro-hydraulic control and chemical injection umbilical. This will link the subsea facilities (manifold and christmas trees) with the onshore control room located at the gas processing terminal.

The umbilical will consist of a robust bundle of steel tube conduits and cables with an overlaying protective armour sheath. Conduits will be required for high and low pressure
hydraulic fluid to power the subsea valve actuators. Additional steel tubes will be used to transport the hydrate and corrosion inhibitor chemical mix to the field, for injection into the system. The electrical cables will provide power for the subsea system and will facilitate multiplex communication with the subsea control system.

The resulting bundle is expected to consist of ten steel tubes and five cables (including all spares). The offshore section(s) of the main umbilical will extend approximately 83km between Corrib and the shore and have an outside diameter of approximately 140mm. The umbilical will weigh approximately 1600 tonnes in total. A typical umbilical cross-section is shown in Figure 4.3.

The two remote satellite wells (18/20-3 and 18/25-1) are also linked to the field umbilical distribution unit but for these wells, it is necessary to install two dedicated infield umbilicals.

4.1.5.5 Protection

In order to ensure the safety and integrity of the subsea production facilities, all equipment will be secured and protected from possible dropped objects, and potential incidents arising from marine activities including fishing and anchor deployment. Accordingly all equipment packages including the christmas trees, manifold, and control distribution unit will be provided with steel or composite protective structures which provide overhead protection and present an over-trawlable profile for fishing gear.

The main umbilical, infield umbilicals and flowlines will all be trenched for protection. Remaining equipment, including the control and flexible production jumpers, will be protected by the installation of overlaying protective mattresses.

4.1.5.6 Flow assurance

The proposed production profile and selected operating regime for the Corrib development results in the production flow experiencing pressures and temperatures where there is the risk of gas hydrate formation and ultimately this could lead to blockages in the system.

The selected means of hydrate mitigation (and thereby flow assurance) is through the constant injection of methanol into the upstream facilities in the field. To achieve this additional conduits are provided within the umbilical to deliver methanol to the field's subsea equipment, the methanol is injected into the flowstream and travels back to the terminal so that hydrate formation is inhibited. At the terminal methanol is regenerated and stored prior to re-supplying the injection points offshore.

Formation of scale is not expected to present a problem as only minimal volumes of formation water are expected to be produced (Section 3.4.3.3 and Table 3.15). However the possibility that the production of formation water will be greater than forecast obviously cannot be entirely discounted. The chemical injection lines in the subsea umbilical have therefore been sized to accommodate the methanol flowrates for a 'worst-case' water production scenario. These lines may also be used to carry other chemicals, such as corrosion inhibitor, which may be mixed with methanol, or scale inhibitor, which could be