sequence can be correlated over wide areas of the field, particularly in the north, and its effectiveness as a permeability barrier to water has been modelled as a function of its thickness and vertical continuity as seen in the wells.

The sequence between the "Odin Shale" and the "Intra Frigg Shales", at the boundary between the upper and lower Frigg members, consists of massive sands, probably channellized through the platform area of the field where this sequence is thickest. Thin shale sequences within these massive sands do give rise to pressure barriers in some of the wells, but these barriers are apparently of limited lateral extent and do not prevent water movement through the unit.

The "Intra Frigg Shales" (IFS) lie below an angular unconformity at the base of the massive sands. This unconformity marks the Palaeocene/Eocene boundary and is due to erosion probably linked to local tectonism in the Frigg area. This unit consists of laminated shales, blocky shales and debris flows with very coarse shale clasts. The unit can be defined by micropalaeontology. In all wells this unit has proved to be a pressure barrier and to the north-east of the platform area it is effectively blocking vertical water encroachment. To the centre and south of the field, however, water is encroaching through and over this unit (Fig. 14). For the purpose of simulation the transmissivity of this layer has been modelled in the same manner as the "Odin Shale".

The Lower Frigg Sands between the IFS and the Balder consist of spectacular debris flows, often with extremely coarse clasts of shale and tuffaceous siltstone, interbedded with massive, grain flow sands. This sequence is laterally impersistent and difficult to correlate lithostratigraphically and biostratigraphically but it appears to thicken dramatically to the north-west and south-east of the central part of the field.

Several cores have been recovered from the Balder Formation which is also very heterogeneous over the field varying in thickness from 10 m to more than 80 m. The tuff layers within the Balder are finely stratified, but these layers are often interbedded with both massive grain flow sands and debris flows. It appears from well logs and seismic that the Balder Formation has been faulted and eroded in the Frigg area. In some wells pressure barriers have been encountered at the top or base of the Balder, but in other wells there are no pressure differentials. Whether the Balder Formation is a barrier or not is probably dependent on the thickness of shales above or below the tuffs. The Balder has been simulated based on RFT results from the wells.

CONCLUSIONS

The results of the recent appraisal wells have demonstrated clearly that water encroachment into the Frigg reservoir is not a simple case of bottom water drive. There is now little doubt that parts of the field are being depleted by edge water drive. The water encroachment is being controlled to some extent by the presence of shale barriers within the reservoir sands. The description and prediction of these shale layers is of paramount importance to reservoir performance as it is possible that production will cease due to water encroachment rather than pressure depletion. The presence of isolated gas pockets in the field may be sufficient to warrant future development either from the present installations or from satellite wells. The accurate prediction of such remaining gas calls for an interdisciplinary approach to reservoir simulation.

The models presented here are the first stage in this approach and they will and must be improved to arrive at an optimal depletion policy. The results of our recent appraisal work are adding to the complexity of our geological model. It is apparent now that the reservoir sequence cannot be simplified in terms of either a deep-sea fan or a delta, and a detailed analysis of all the recently acquired data needs to be synthesized into a predictive model to allow us to simulate adequately a fairly complicated reservoir.

ACKNOWLEDGEMENTS

The opinions expressed herein are those of the authors and are not necessarily those of Elf Aquitaine Norge or of any of the owners of the Frigg Field. Much of the work presented is that of both the exploration and reservoir divisions of Elf.

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6 The Frigg Field reservoir: characteristics and performance

A. De Leebeeck

Elf Aquitaine Norge A/S, Stavanger, Norway

The Frigg Field is a large gas reservoir straddling the Norwegian–UK frontier which has supplied a significant percentage of British gas requirements since coming on stream in 1977. This chapter follows an examination of the Frigg Field production geology (Chapter 5) and reviews the reservoir factors involved in the determination of Frigg gas in-place and the uncertainties surrounding their resolution. After a review of the dynamic data leading to a determination of recoverable reserves, there follows a discussion of the various reservoir studies conducted through the phases of the field life (design, development, production and now reappraisal). The study results were a key element in the major decisions. Current studies as outlined will yield the elements required for determining Frigg future performance and related decisions.

INTRODUCTION

The Frigg Field straddles the Norwegian–UK frontier and is located primarily in Block 25/1 on the Norwegian side and Block 10/1 on the British side. The Frigg Field is unitized and is owned jointly by the Frigg–UK Association (Elf UK and Total Oil Marine) and the Frigg–Norwegian Association (Elf Aquitaine Norge (operator), Norsk Hydro, Total Marine Norsk and Statoil). The field was discovered in 1971 and brought on stream in September 1977. This chapter will review the reservoir characteristics of the Frigg Field, the reservoir studies conducted and their impact on field development and exploitation.

The primary function of the reservoir engineer is to determine the recoverable reserves, their quantity and the timing of their recovery (production profile). Throughout the chapter the term "accumulation" will be used to denote hydrocarbon-in-place while "reserves" will denote recoverable reserves. The determination of the reserves begins with the evaluation of the accumulation. The initial data are static data as the values should not change with time. These data consist of the rock volume from seismic analysis, the rock properties and fluid saturations from log and core analyses and their distribution from geological/reservoir studies and fluid properties from the laboratory.

Determination of reserves combines a knowledge of the *in situ* fluid flow characteristics (permeability, residual saturations) with the expected influence of reservoir barriers, aquifer activity and surface facility limitations (capacity, economics). The derivation of a production profile is an iterative process between reservoir potential, wells available and economics. Handling all the required data from a large field requires extensive reservoir simulation studies. Data which are certain or unavailable during facility design become less uncertain or change as the field is being produced. This necessitates a review of previous calculations/studies and any downstream decisions.

The Frigg Field is a giant gas reservoir with what was initially an aquifer of unknown activity. It has been on production for eight years. The confirmation of an active aquifer has lead to a complete re-analysis of all available data. An added element in the performance of this reservoir is the adherence to a gas sales contract.

RESERVOIR DESCRIPTION

Field setting

The Frigg Field is a large gas reservoir underlain by an oil disk of some 8–10 m. The reservoir consists of unconsolidated sands of the Lower Eocene. The field is located approximately 190 km off the Norwegian coast and is predominantly in Block 25/1 on the Norwegian side of the border and in Block 10/1 on the British side (Fig. 1). Gas reservoirs on the same aquifer include Odin (Esso operator) to the north, North-east Frigg and East Frigg Alpha and Beta (Elf operator on both).

The geological setting is described in the previous chapter by Brewster and Jeangeot. The reservoir ter-

North Sea Oil and Gas Reservoirs © The Norwegian Institute of Technology (Graham and Trotman, 1987) pp. 89–100.

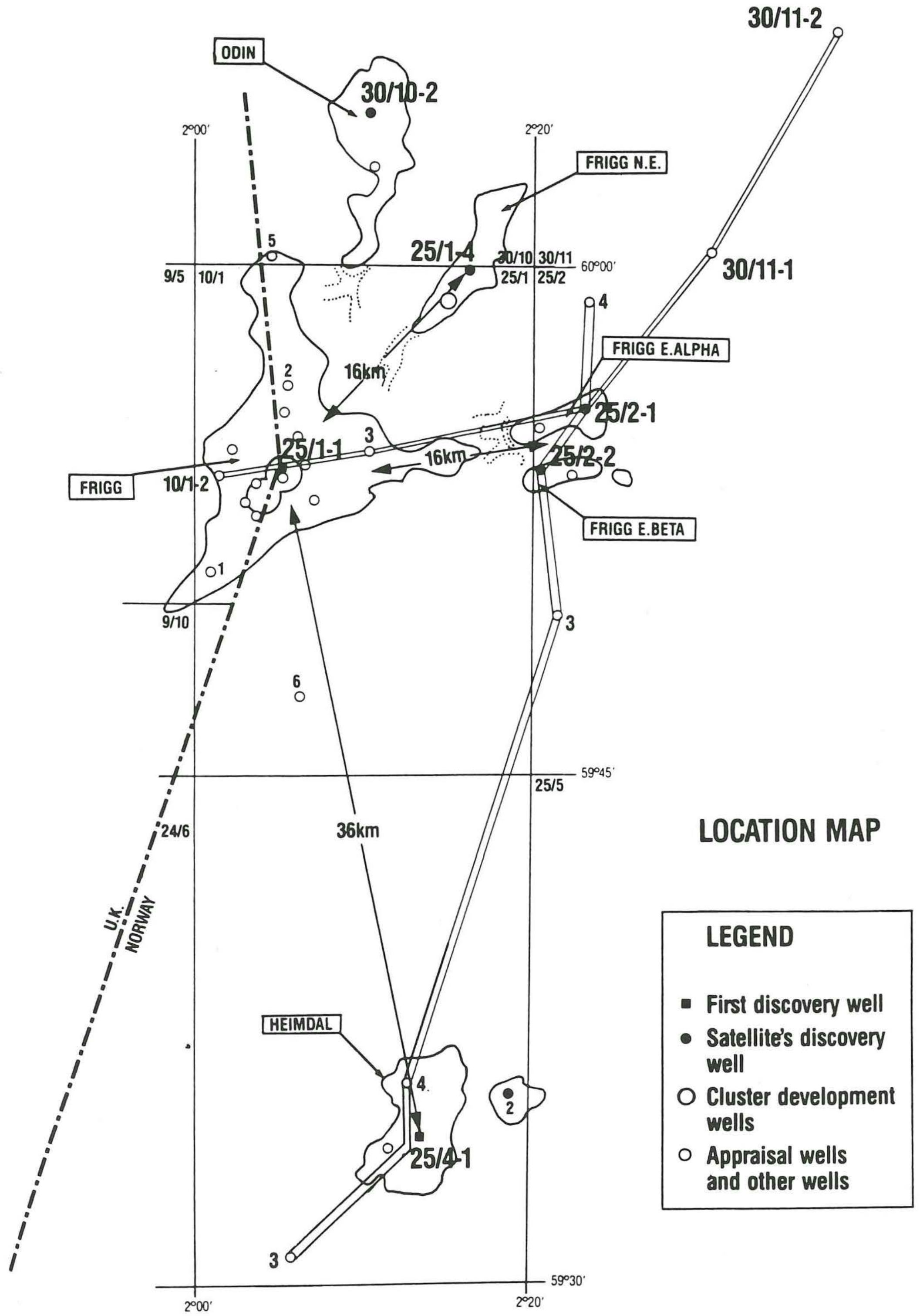

Fig. 1 Location map Heimdal—Frigg and satellites.

minology for the formations differs somewhat from the recognized geological nomenclature. The hydrocarbon-bearing sands of the Lower Eocene are the Frigg Formation, the Paleocene sand immediately below are the Frigg aquifer, the interbedded sands shales and tuff of the Balder Formation become the Tuff while all deeper formations become the Cod aquifer (see Fig. 2).

The top of the reservoir is at approximately 1800 m MSL. From seismic and well control the maximum gas height is about 160 m covering over 100 km² at the gas–oil contact. The gas is underlain by an oil disk ranging from 2 to 10 m in thickness, averaging 8.6 m. Uncertainties stem from the determination of the structural top, as the seismic marker does not correspond to the top of sands, and also from the variable oil disk thickness. The rock volume is calculated from the accepted maps to be $5454 \cdot 10^6$ m³.

The reservoir temperature is 60°C at the datum depth of 1900 m MSL with an initial pressure of 196.9 bars at datum. The Frigg and Cod aquifers had the same pressure regime.

Rock properties

The Frigg sands are clean, unconsolidated sands with occasional stringers of limestone or silt. These layers were not readily correlateable from one well to another. The sand consistency is much like beach sand and con-

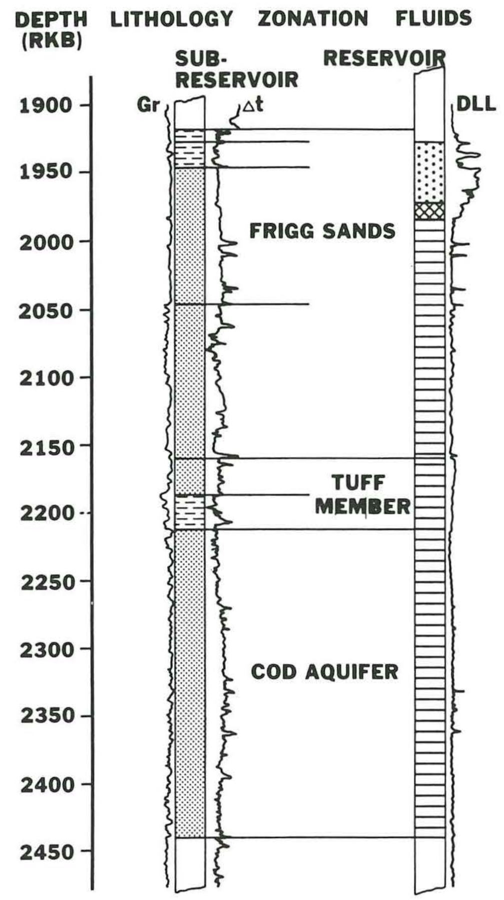

Fig. 2 Frigg Field—typical reservoir zonation.

ventional coring techniques such as steel barrel core led to the recovery of non-representative samples. Later coring techniques such as rubber sleeve, and now fibre glass, result in much better recoveries and representative samples. The first cores arrived in the laboratory in bags and measurement results from packed columns are not reliable. Due to the unconsolidated nature of the sands, laboratory measurements for porosity, permeability and density are conducted at reservoir pressures. Measurements available at laboratory conditions show a 3–4 porosity units (pu) increase in porosity and a four-fold increase in permeability over reservoir condition measurements.

Porosities from core are comparable to porosities from logs, corrected for gas effect. The porosity, which ranges from 26–32%, is considered correct to within 1 pu. Permeabilities from core (arithmetic mean) have been compared with well test permeabilities on two wells and show the same trends, an average 2480 mD from core and 1800 mD from well test for one and 610 mD and 820 mD respectively for the other well. Permeability in a clean sand (ϕ=32%) ranges from 2–4 D. The porosity and particularly the permeability are sensitive to the shale content with permeabilities reduced to 400 mD at 10% shale. Measured permeabilities within the Tuff range from 0.001 mD to 0.01 mD. Field average properties are presented in Table I.

Table I Frigg Field—rock properties

	Gas sands	*Oil sands*
Average porosity	28.9%	25.6%
Average permeability	1300 mD	1300 mD
Average net/gross pay	0.945	0.93
Rock compressibility	3.4×10^{-5} bar⁻¹	

Because porosity and permeability are linked to shale content their distribution is partially controlled by the depositional model accepted at the time of interpretation. The net-to-gross pay distribution is also conditioned by the depositional model.

With the well-sorted nature of the sand it was presumed that the vertical k equals horizontal k in the clean sands. k_v is reduced as a function of the net-to-gross pay ratio.

Fluid properties

The Frigg Field gas is a retrograde gas condensate with an estimated 4.3 g/m³ of condensate at initial conditions. To obtain a representative gas sample the production of one of the production clusters CDP1 was put through one of the production trains of the treatment platform TP1. In this way fluid metering could be performed on the large quantities of gas essential to accurately measure the small liquid flow rates.

The Frigg oil was tested on Well 25/1-3. An interesting feature of the oil is the near absence of any C4 to C8 components (Table II). The solution gas–oil ratio was determined to be about 61 m³/m³. Hydrocarbon properties are listed in Table III.

Table II Frigg Field fluid compositions (mole fraction)

	Reservoir gas	*Reservoir oil*	*Condensate (surface)*
CO_2, N_2	0.7	0.3	0.2
C_1	95.5	45.5	25.8
C_2–C_4	3.7	4.2	8.1
C_{5+}	0.1	50.0	65.9

Table III Frigg Field fluid properties

	Gas	*Oil*
Formation volume factor at P_i	0.005	1.15
Density	0.138	0.834 g/cm³
Viscosity	0.02	4.38 centipoise

Water samples obtained from a water test on Well 25/1-3 were initially accepted as representative. Log analysis gave an average connate water saturation of 9.4% in the gas sands and 26% in the oil sands. The initial water saturation is another parameter sensitive to the shale content. In clean gas sands the log derived S_{wi} can be as low as 2–3% possibly due to dehydration, but direct measurement becomes questionable due to tool limitations at low S_{wi}. The results are summarized in Table IV.

Table IV Frigg Field water properties

Salinity	60 g/l
R_w	0.07 at 60°C
C_w	4.54×10^{-5} bar⁻¹
S_{wi}	Gas sands 9.4% Oil sands 26.2%

Hydrocarbon accumulation

With the Frigg gas–oil contact at a depth of 1947.4 m, the water–oil contact at 1956 m and using the "average" properties presented in the rock and fluid property sections, the officially accepted gas-in-place is 268.7×10^9 Sm³. This was determined by De Golyer and McNaughton (1976) based on structural maps from a seismic survey conducted in 1973. Their 1976 report provided the basis for a unit agreement which gave 60.82% to the Norwegian partners and 39.18% to the British partners. Small differences in gas properties give in-house figures of 265×10^9 Sm^3 of gas-in-place. An in-house study conducted in 1983 gave an oil-in-place of 135.6 M tonnes. In 1972 a study was undertaken to look into the possibility of commercial oil exploitation. To avoid coning problems it was decided that over 300 wells would be required and such a project was deemed uneconomic (Hamre, 1984).

The Frigg satellites have in excess of 75×10^9 Sm^3 of gas-in-place and share a common aquifer with Frigg and must, therefore, be taken into account in Frigg Field exploitation studies.

Dynamic properties

To determine the reserves it is necessary to know the recovery mechanism. The recurring question with regard to a gas reservoir is: is there an active aquifer? If not, a P/Z plot is sufficient. If there *is* an active aquifer, several factors need to be accounted for of which the most important are residual gas saturation (S_{grw}) after waterflood and water coning. Because of the oil disk in Frigg the residual oil saturation (S_{orw}) and the residual hydrocarbon saturation (S_{HR}) must also be determined.

Recognizing the potential for an active aquifer Elf embarked on a special core analysis programme early in the field appraisal. The first samples were reconstituted from available Frigg sand. The runs were at laboratory condition and gave an S_{grw} of 19% and an S_{orw} of 25%. Later work with more representative samples (cores cut with rubber-sleeves) was done at reservoir conditions. Interpretation of the results gave a correlation of S_{grw} as a function of porosity (Fig. 3). At the field average porosity of 29%, S_{grw}=29% and S_{orw}=20%. More recent work has shown that despite interfacial tension and initial water saturation this correlation remains constant. Determination of the influence of depletion and shale content continues to be analysed. Field results will be given later in the chapter.

The 1973 seismic survey ensured that the field structure was well understood when production began. The reservoir, based on nine appraisal wells, was considered a clean homogeneous sand with well-known distributions of porosity and permeability. Laboratory analyses gave the residual hydrocarbon saturations. The most important remaining unknown was the aquifer activity. Given an active aquifer calculation of the reserves requires a determination of the sweep efficiency. As this involves many different factors which are difficult to incorporate in a hand calculation the reservoir engineer resorts to a numerical simulator.

Pertinent Frigg simulation studies will be reviewed after a short section on Reservoir Performance.

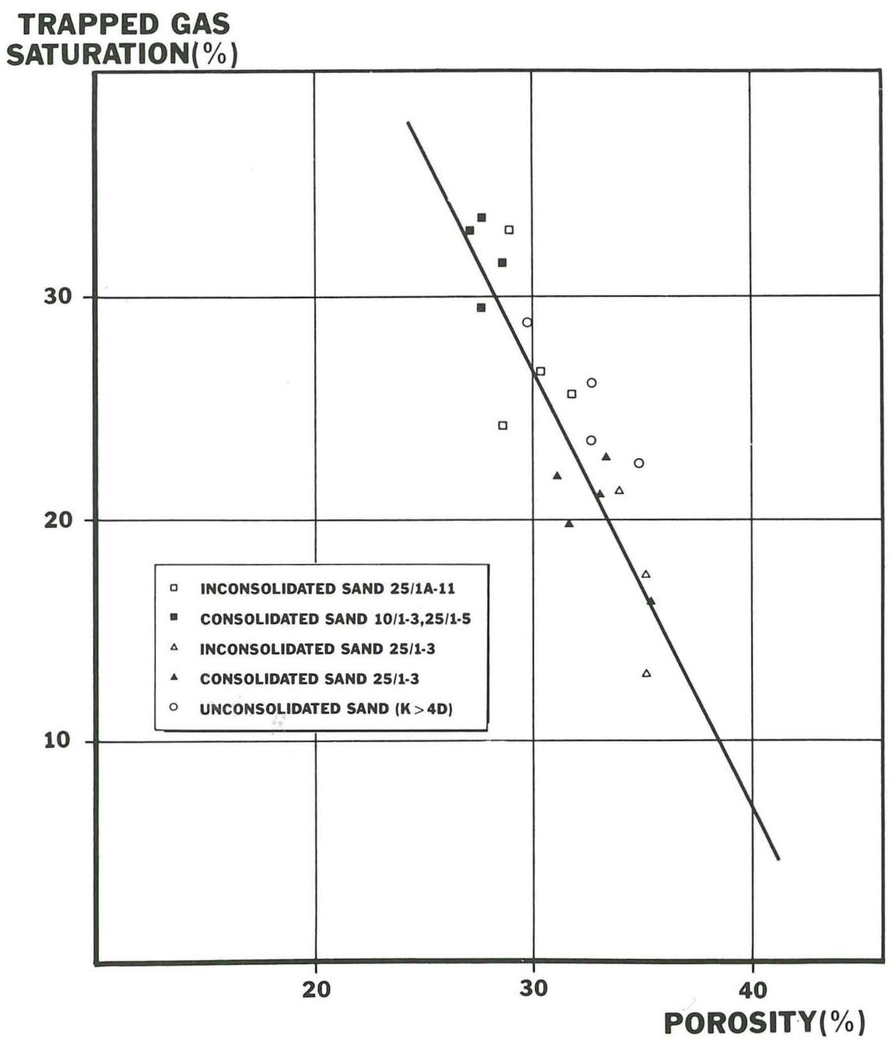

Fig. 3 Frigg cores—correlation of residual gas to water *vs* porosity.

RESERVOIR PERFORMANCE

Development

The Frigg complex consists of five platforms: two drilling/production platforms (CDP1 and DP2), two treatment platforms (TP1 and TCP2) and a quarters platform (QP). Gas is transported to St Fergus, Scotland, via two 32 in. lines. There is an intermediate compression platform 186 km from Frigg (Plate 12). Each drilling platform has 24 wells grouped into two clusters of 12 wells each. Interconnecting pipelines allow production to either treatment platform. Development drilling started in 1976 on CDP1 and was completed by 1979. Gas sales started in 1977. Compression facilities were added by 1982.

Initially it was uncertain whether Frigg had an active aquifer; it was even more uncertain whether there was communication between the local Frigg aquifer and the regional Cod aquifer. However, recognizing the potential existed, Well 25/1-A22, located on the north-east corner of the DP2 platform (Fig. 4), was drilled through to the Cod sands and completed as an observation well with a permanent downhole pressure gauge. The remaining 47 wells were drilled only 60 m into the gas reservoir, spaced at 250 m at top reservoir level. This shallow penetration was designed to avoid water coning problems.

The decision to implement sand control was taken for two reasons: first, because of the unconsolidated nature of the sand; and, second, because at the time there was no known production from such sands greater than 1 M m^3/d. Many factors were considered and screens were preferred to gravel packs; no sand production problems have been encountered. Initially a through screen velocity of 15 cm/sec. was imposed but has since been discarded following further study. A typical completion is shown in Fig. 5.

Production/monitoring history

The gas production from Frigg has been trouble-free since production start-up (Fig. 6). The monitoring programme was set up to address three main concerns (Maritvold, 1985):

(1) sand production;
(2) aquifer activity;
(3) gas movement from the satellites.

All wells have been production logged at least once and show that initially sand/mud particles smaller than the screen size caused some sediment fill and screen blockage. All wells have stabilized and more than 70% of the screen length on each well contributes to production. A typical profile is shown in Fig. 7.

Pressures are monitored continuously using downhole recorders with periodic checks with wireline gauges.

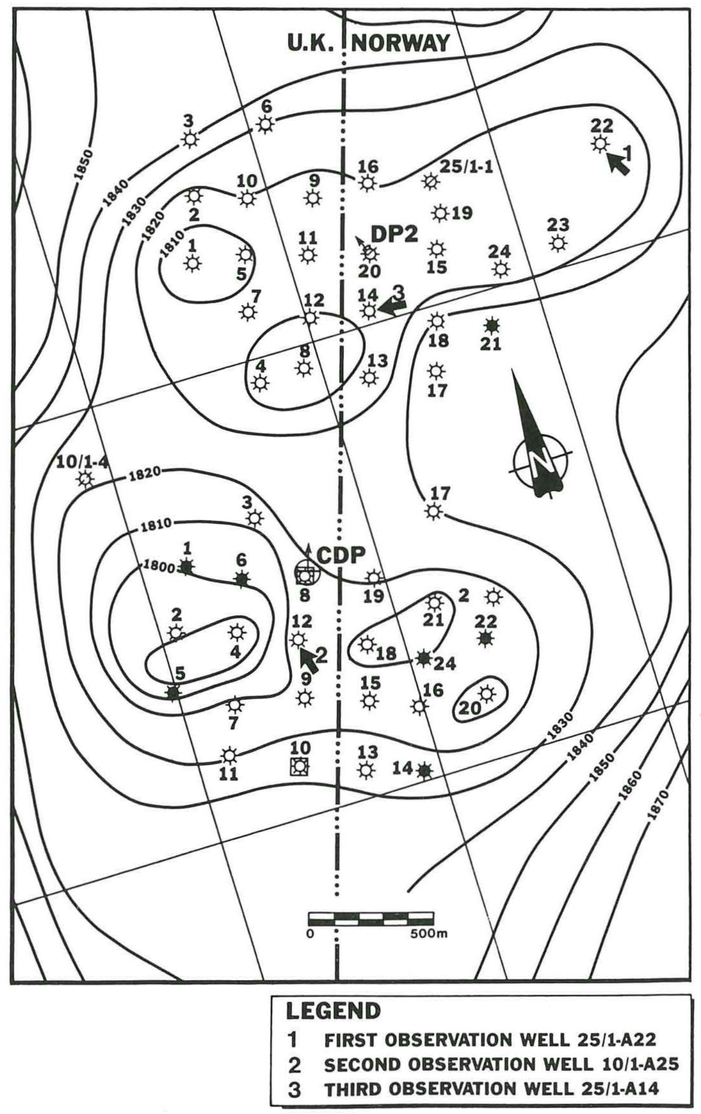

Fig. 4 Location map—Frigg production wells at the top of gas pay.

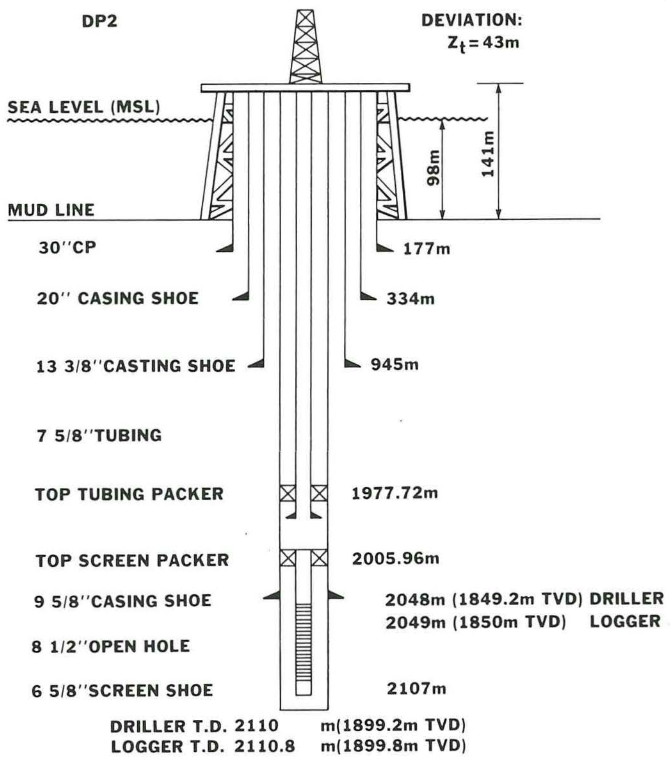

Fig. 5 Frigg production well—typical completion.

Figures 8 and 9 show the pressure decline in the Frigg and Cod sands respectively. Well 25/1-A22 has been logged with a TDT (thermal neutron decay time tool) regularly to monitor the water rise. Figure 10 shows the observed contact rise. Subsequent observation wells (discussed below) are also regularly logged.

Biannual seismic surveys have been performed to monitor any possible gas movements from the satellite fields. Some gas movement has been detected at North-east Frigg and is suspected at East Frigg (Revoy, 1984).

More specific comments on the interpretation of the field monitoring results are presented in the next section.

RESERVOIR STUDIES

Design phase (1972–1975)

The first studies conducted were based on the following assumptions:

(1) gas-in-place: 270×10^9 Sm^3;
(2) well productivity: 4×10^6 m^3/d with maximum through screen velocity of 15 cm/s and minimum wellhead pressure of 65 bars;
(3) field life: 20 years, later modified according to the sales contract;

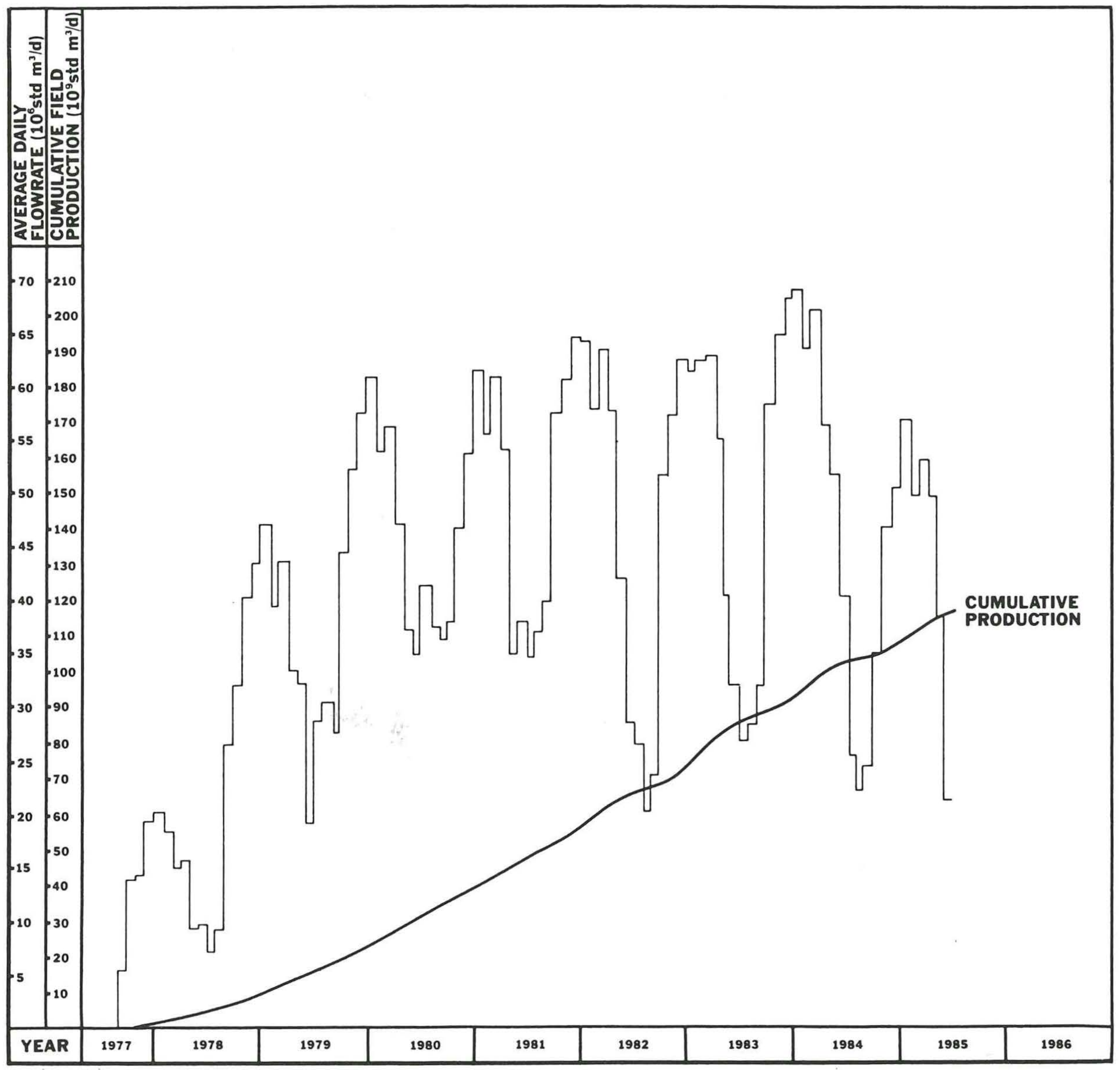

Fig. 6 Frigg Field production history.

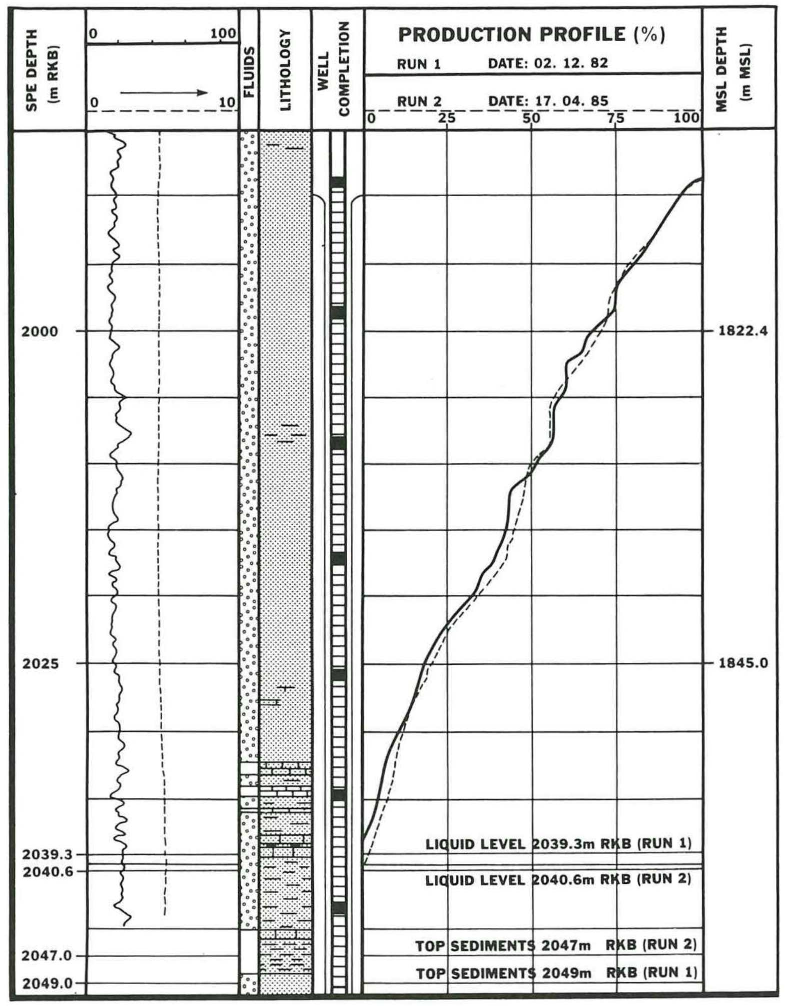

Fig. 7 Frigg production well—typical production profile.

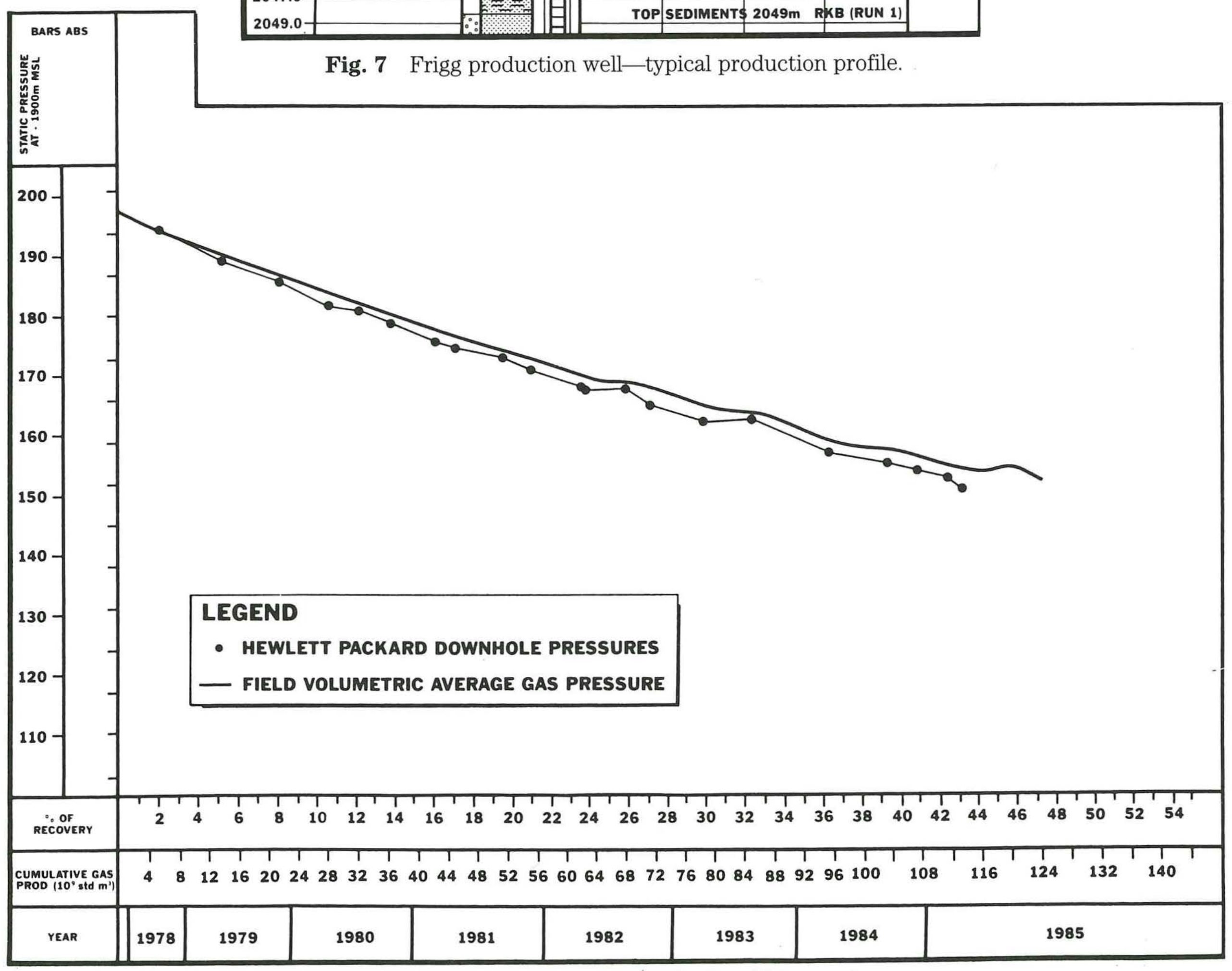

Fig. 8 Frigg Field—pressure decline: Frigg sands.

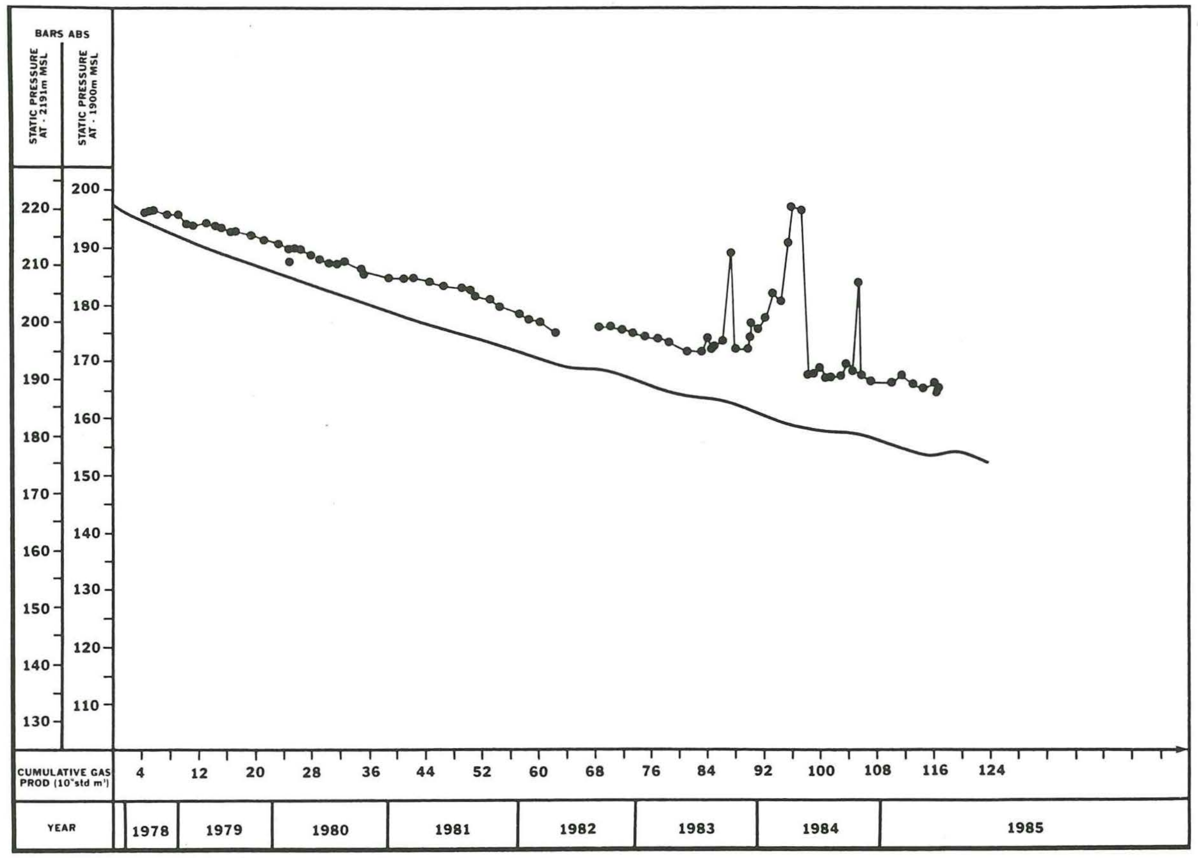

Fig. 9 Frigg Field—pressure decline: Cod sands.

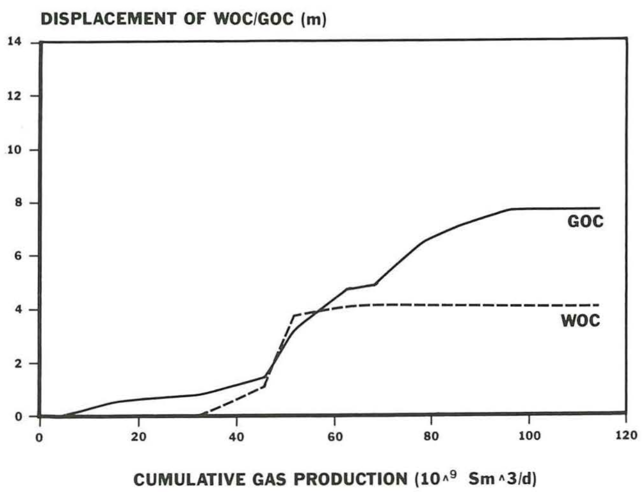

Fig. 10 Frigg observation Well 25/1-A22—fluid contact rise *vs* time.

(4) homogeneous reservoir, shale and limestone events were considered local.

A schematic section of the model is shown in Fig. 11. As aquifer activity was unknown both inactive and active aquifer cases were considered. The former gave recoveries close to 212×10^9 St m^3. The active aquifer cases allowed for Frigg–Cod communication via a uniformly low permeability Tuff layer and gave close to 230×10^9 Sm^3 of gas. Water rise was observed essentially at the edge of the structure and appeared to be limited elsewhere. Both scenarios showed the need for 30 production wells.

Based on these studies it was determined that the gas could be recovered from a centrally located cluster of wells. The wells would penetrate only 60 m of the gas zone. To ensure security of supply two platforms each with two clusters of twelve wells was decided upon. Recoverable reserves were set at 215×10^9 Sm^3.

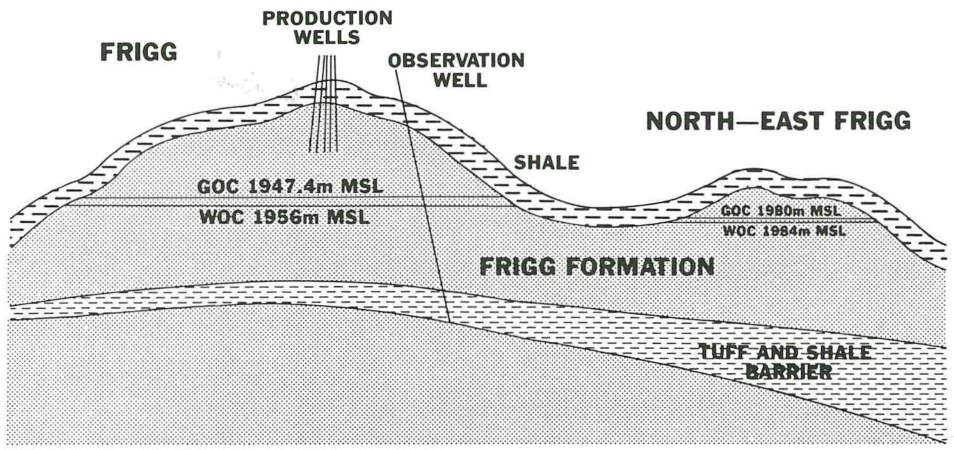

Fig. 11 Frigg Field schematic cross-section—development phase.

Development phase (1976–1979)

The development wells only partially penetrated the reservoir and covered a limited area of it (250 m spacing) and so did not provide any information to justify changing the geological model. Shale and limestone stringers were deemed not correlateable.

Frigg came on production in September 1977 and the pressure response confirmed the presence of an active aquifer. Continued studies showed the need for compression (implemented in 1982). Other studies were conducted to determine the development potential of the satellites. An extensive study in 1979 aimed primarily at determining the risk of gas movement from the satellites assumed the following details:

- gas-in-place 265×10^9 Sm^3;
- homogeneous reservoir;
- active aquifer via increased permeability across the Tuff;
- trapped gas saturation S_{grw}=19%.

The increased aquifer support gave an increased recovery pushing reserves to 227×10^9 Sm^3. Field abandonment was still linked to abandonment pressure. Water encroachment/coning at the platform was concurrent with the pressure limitation.

Production phase (1977–1984)

By 1978 it was evident that Frigg Field gas recovery was affected by aquifer support and it became apparent by the Autumn of 1980 that the Cod aquifer was giving a great deal of support. Water coning below the platforms was not a concern because the observations on Well 25/1-A22 showed a limited water rise (Fig. 10).

The support from Cod was greater than expected and could not be explained by an increased permeability across the Tuff as laboratory measurements suggested the Tuff was nearly impermeable (0.001 mD). Earlier geological reports suggesting the absence of Tuff in some wells were investigated further. A permeability window was introduced to the west and south-west of the platforms (Fig. 12).

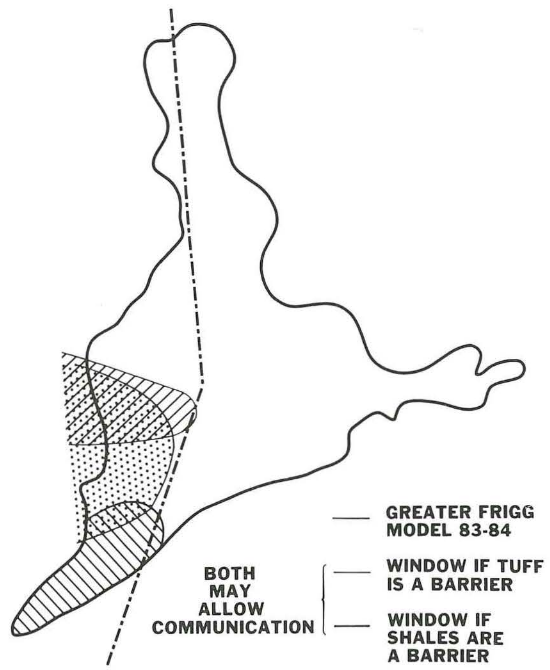

Fig. 12 Frigg Field—Cod aquifer to Frigg sand communication possibilities.

Concurrently, laboratory results were suggesting that the level of the trapped gas saturation varied with porosity and that the value was 29% at a porosity of 29% rather than 19% as previously accepted. New reservoir simulations were run assuming the following:

- gas-in-place 265×10^9 Sm^3
- homogeneous reservoir
- active aquifer via permeability windows in the Tuff
- trapped gas saturation between 19 and 29%

The increased aquifer support meant a higher abandonment pressure but also earlier water breakthrough at the platforms. The models showed a significant water rise below the platforms and a potential for unrecovered reserves with existing facilities.

The location and strength of the model water rise was a direct consequence of the supposed location of the permeability windows through the Tuff and the permeability assigned to them. The observation Well 25/1-A22 continued to show no significant water rise. This could be explained by the presence of shales which blocked the water locally. In August 1984 Well 10/1-A12 (now A25) was deepened to validate the geological model and confirm the simulation results. The reservoir model gave between 38 m and 42 m of water rise. The measured rise was near 55 m. The consequences of this well were significant:

(1) the absence of any pressure shift across the Tuff confirmed the existence of permeability windows but, at the same time, questioned the concept of the Tuff as a permeability barrier;
(2) the expected water rise was confirmed but the time to possible water breakthrough at the platform was shorter than forecast;
(3) log evaluation of the swept gas zone gave residual saturations in agreement with lab measurements (S_{grw}=29%).

Reappraisal phase (1984–1986)

The results of Well 10/1-A25 questioned some of the basic input to the reservoir model but, more importantly, they questioned the productive lifetime of the platforms. An appraisal programme, detailed by Brewster and Jeangeot in the previous chapter, was set up to determine the nature and extent of the water encroachment. The production capacity of the platforms was of immediate concern. Therefore, Well 10/1-5 was drilled on the south-west corner of the DP2 cluster and confirmed a significant water rise (though less than A25) and confirmed the presence of shale events within the Frigg sands and not the Tuff which controlled the water rise into the Frigg gas sands.

By December 1985 two more production wells, 25/1-A14 and 10/1-A22 (now A26), had been deepened to determine the water rise. Two remote wells, 25/1-7 and 25/1-8, were drilled to determine the remaining gas distribution away from the platforms. All deepened platform wells were maintained as observation wells and the remote wells were temporarily abandoned to allow for possible re-entry. Re-entry will allow dynamic monitoring of distant water movement. The possible confirmation of future reservoir models will be fundamental to future decision making. Well locations are indicated on Fig. 13.

The wells have been extensively cored and logged. VSPs have been conducted on all wells. RFT runs have

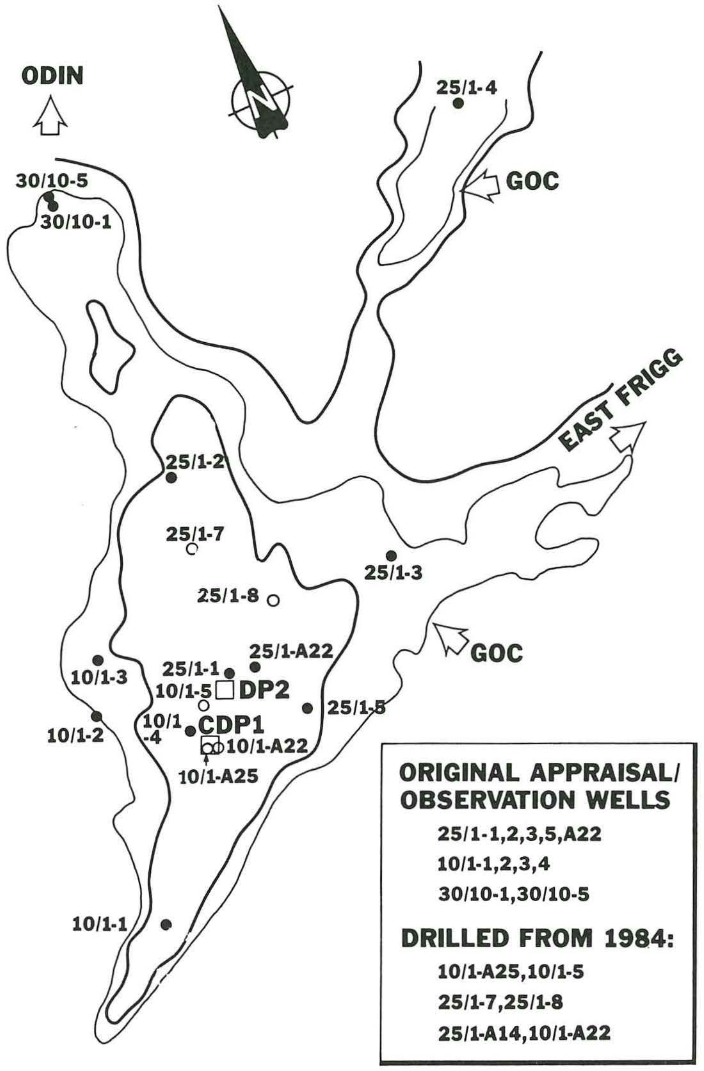

Fig. 13 Location map—Frigg exploration and appraisal wells to December 1985.

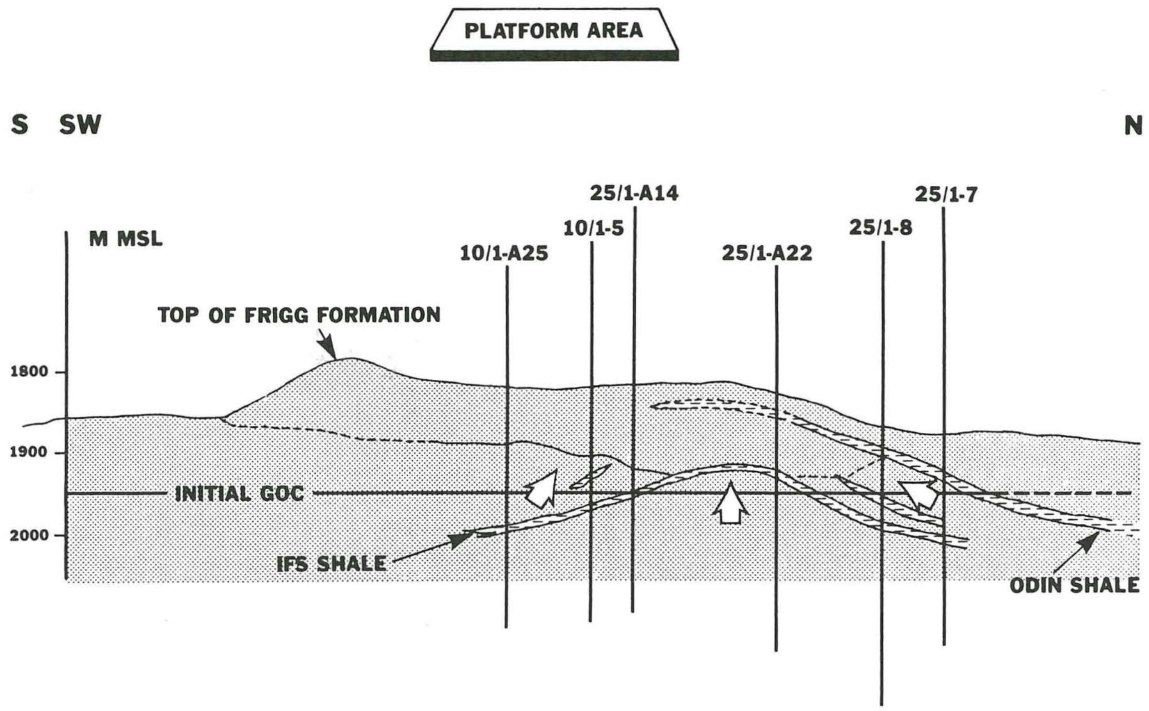

Fig. 14 Frigg Field schematic cross-section—water influx model.

proved very valuable in identifying shale layers which act as permeability barriers. The additional wells have confirmed that:

(1) the Frigg reservoir is not homogeneous;
(2) shale events within the Frigg sands control the water rise (schematic Fig. 14).

The hypotheses on the nature and extent of the shale events control the simulation results. Differing hypotheses change the productive lifetime of the platforms and the distribution of the remaining gas. The level of trapped gas saturation is known as a function of porosity in clean sands but needs to be determined in shaly sands. This will aid in determining the quantity of movable gas.

Log interpretation results suggest that laboratory S_{gr} results may be a little pessimistic (Fig. 15).

The uncertainties elaborated in the "Reservoir description" section remain and become more significant when considering remaining reserves. Results to date suggest a range of ±10–15% on the median reserves figure which translates to ±30–35% on the remaining reserves. Studies continue to quantify the uncertainties.

The future

Through time the nature of the certainties and uncertainties have changed. The existence of an aquifer is now confirmed. The level of the trapped gas saturation is known with some confidence (as it was previously) but not at the same level. And what was once accepted as a homogeneous reservoir now has as its prime unknown the distribution of the shale barriers within it.

The interpretation of the newly acquired 3D seismic lines combined with the geological correlations being developed should provide the basis for one or more geological models. All petrophysical (log and core) data are being reanalysed in order to obtain a uniform interpretation and reduce the uncertainties as much as possible. The simulation results combined with continued field monitoring will provide the basis for determining the need for and nature of further field development.

The objective of any future reservoir studies will be to determine the quantity and distribution of remaining reserves and the best means of recovery. The expected production profile must be known to meet contractual obligations. The consequences for management are discussed further in Barril, 1985.

CONCLUSIONS

1. The image of a field based on the initially available static data will necessarily be modified as more dynamic data become available. This reinterpretation often leads to the need for more precise static data and leads inevitably to a more complicated reservoir/geological model.
2. The determination of the uncertainties linked to a field evaluation becomes more critical as the remaining recoverable reserves decrease and even more so when linked to a gas contract.
3. The Frigg Field geological model and, consequently, the field's future performance is not yet definitive, but the data acquisition and studies programme currently underway should provide the elements for determining the need for and nature of further field development.

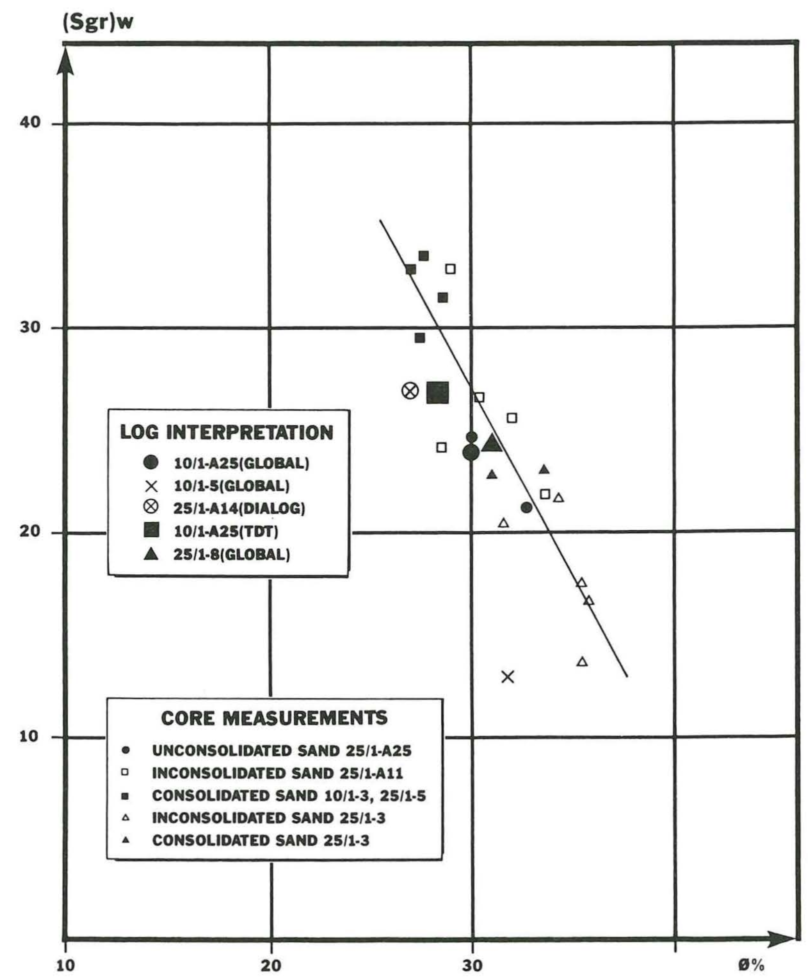

Fig. 15 Frigg cores and logs—correlation of residual gas to water *vs* porosity.

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Part II

Reservoir Geophysics