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OFFSHORE TECHNOLOGY

Lessons learned in North Sea oil field developments

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ABSTRACT

Continued progress in matters of frontier resource development is dependent on avoidance of past errors. The development of oil and gas fields in the hostile North Sea environment represents a major pioneering effort which has witnessed the successful introduction of many new technologies.

Evaluation of the success of North Sea ventures has, however, been confused by the impact of inflation and currency realignments. A recent analysis by Castle[1] of North Sea field economic performance suggests that these fields would have been 'underwater' (due to technical underperformance) if they had not been 'bailed out' by the crude oil price increases, particularly of 1979.

Examined are the technical factors responsible for Castle's observation for certain fields and it is concluded that greater care is needed in relating reservoir performance uncertainty to predevelopment appraisal well data. Attempts are made to highlight some of the potential problem areas encountered when defining a development plan with the help of reservoir simulation models. Analyzed are published data for two typical North Sea fields: Thistle and Beatrice, which are amplified with observations from personal experience.

Introduction

Table 1 is partly extracted from a recent article by Castle[1] where an attempt was made to estimate how profitable 19 North Sea fields would have been if prices had remained flat from the time development was initiated. These "proforma" rate-of-return estimates, which ignore petroleum revenue tax as well as corporate taxes, and only deduct the 12½% royalty, indicated that only 14 fields in fact yielded a positive cash flow and of these only 7 yielded a rate of return in excess of 15%. At first glance Castle's analysis leads one to conclude that the performance of the oil industry in the North Sea was, in real terms, an economic disappointment. Table 1 has been enlarged with technical performance data extracted from the United Kingdom Brown Book[2].

It is well known that the oil industry and various northwestern European National Treasuries have derived much benefit from the North Sea Oil Province. In terms of money of the day, the rates-of-return have been more than adequate to permit rapid payback of loans, a very large government "take", as well as to fund further developments. This is due, as Castle points out, to inflation and currency fluctuations 'bailing out' the North Sea projects most of which suffered from construction delays, cost overruns and production shortfalls.

In this paper an attempt is made to identify the main technical reasons for under-performance of two of Castle's fields: Thistle and Beatrice (Fig. 1). These fields are rather well documented (see reference list) and thus provide much study material. This sample moreover includes a typical "Brent Province" Jurassic field representing one of the pioneering developments, as well as a later, non-Brent "marginal discovery" benefitting from five years of offshore technological progress. It is, therefore, a representative sample, and gives a fair insight into the technical risks inherent in offshore developments. Within the context of U.K. offshore developments, both fields are successful.

What can we learn from these developments? How may similar future problems be avoided? In the following sections the two projects will be discussed in turn before drawing out some general observations.

The Thistle Story

The Thistle Story illustrates the risks inherent even in major offshore developments and the need for a more flexible and responsive development - planning approach. There is a need for appraisal well data to help define project parameters, but incorporating information obtained under 'static' reservoir conditions intelligently into reservoir simulation models so as to gain a realistic assessment of future dynamic reservoir behaviour, is a technically demanding exercise. The time required may be at variance with a project timing driven by present value calculations at high discount rates.

In the case of Thistle, high-cost, semi-submersible appraisal drilling continued after detailed design had started; the results could only have a minor impact on platform design, gave a false sense of security and arguably ought to have been deferred pending start-up of platform development drilling. The Thistle story illustrates the importance of incorporating into the development drilling phase a continuing element of appraisal. Important reservoir engineerinig questions can only be answered after production start-up; it is better to have these answers sooner than later, and more important to be aware of the potential problems, at the very outset.

Historical Background

A summary of discovery and appraisal well results is presented in Table 2 and in Table 3 are highlighted key milestone dates in project development.

The Signal Oil Company discovered Thistle with the second

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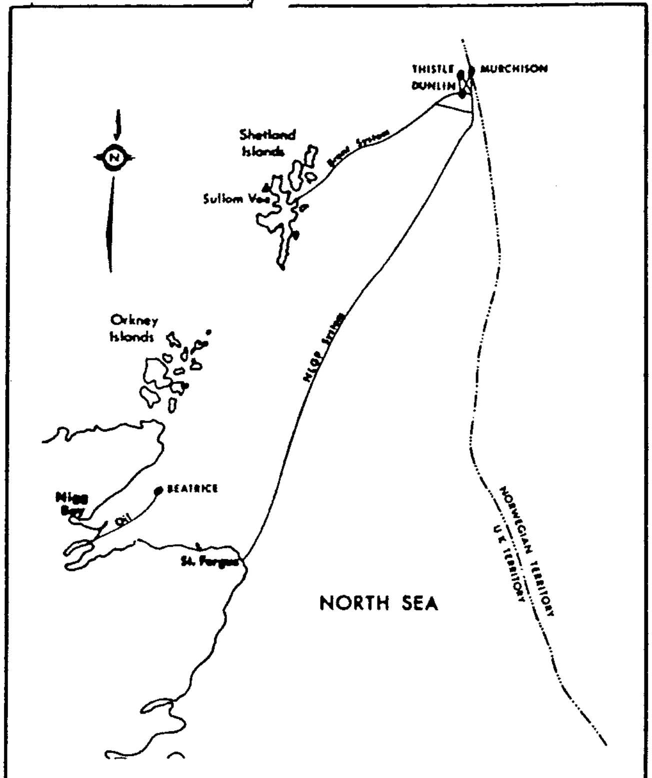

FIGURE 1. North Sea location map.

well drilled on a base Cretaceous Seismic feature in U.K. Block 211/18. The first well drilled 2 km further west on what appeared to be the crest of the main structural feature found a small 2.2 $\times$ 10^6 m^3 (14 mmSTB) pool now named Deveron. That it took a second attempt to find a 64 $\times$ 10^6 m^3 (400 mmSTB) field illustrates the nature of geological difficulties in the Brent province, discussed by various authors[3,4,5].

A schematic diagram (Fig. 2) relates project development to appraisal drilling activities. From this it can be noted that the field's commercial status was declared prior to any confirmatory drilling[6], and that within 8 months of discovery, the economic viability of this project had become so certain that major project expenditures appeared to be justified[7]. It is also to be noted that far-reaching development decisions were followed by drilling of three additional expendable appraisal wells. A fourth well, drilled in the block to the south early in 1974 proved separtion of the Thistle and Dunlin structures[4].

In 1978 production was started with dead crude export facilities provided by a Shuttle tanker loaded via a SALM (Single Anchor Leg Mooring) Buoy. Since then, the field has been connected to the Brent oil gathering system, the Sullom Voe crude stabilization facilities and also to the Northern Leg Gas Pipeline gathering system and the St. Fergus/Braefoot bay liquid recovery operation (Fig. 1).

Analysis

The key factor responsible for underperformance (in economic terms) of Thistle is the failure to meet oil production targets. In Figures 3 and 4, a comparison is made of the original 1976 forecast with actual performance to date. Not only was production start-up delayed by one year, but production levels never reached the planned target. By 1982, eight years after project commitment, only 28 $\times$ 10^6 m^3 had been recovered, some 16 $\times$ 10^6 m^3 less than the projected 114 $\times$ 10^6 m^3. This shortfall of 16 $\times$ 10^6 m^3 (100 mmB) goes far to explain Castle's economics!

Table 4 provides further comparison of project outcome with original projections. From this, it is clear that several project parameters changed during the intervening years but some changes in critical items such as reserves do not appear to be significant. It is noteworthy that water production requirements had been underestimated, a topic reviewed in some detail by Bond[8] and referred to by Bayat[9].

The fact that recovery to date falls 40% short of early forecasts, while reserves have only fallen by half that amount is compensated by longer projected field life times.

The technical reasons for the 16 $\times$ 10^6 m^3 production deferment experienced by the Thistle project is worthy of further discussion, in terms of two topics: (a) the development plan failed to anticipate subsurface reservoir continuity problems; (b) shortcomings in predictive simulation modelling.

TABLE 1. Comparison of profitability for nineteen U.K. North Sea fields

Field Name	Rate of return[1] Original (%)	1984 Revised (%)	"Proforma"[2] (%)	Ultimate Recovery[3] (10^6 $\times$ m^3)	Peak Production[3] (1000 $\times$ m^3/d)
Piper	39.5	60.8	53.7	141	43.1(79)
Argyll	101.0	47.7	3.6	9	3.1(80)
Forties	23.8	43.5	42.1	322	80.3(80)
Auk	27.4	40.0	16.6	17	2.5(79)
Beryl	31.2	35.2	*	79	17.6(80)
Claymore	31.7	34.2	14.4	64	16.4
Dunlin	31.8	34.1	8.4	49	18.6(79)
Fulmar	31.8	33.0	29.7	67	20.0
Ninian	16.9	30.2	*	170	49.0(82)
Thistle	27.2	29.6	7.6	64	19.6(82)
Murchison	20.5	29.5	17.2	51	51.7(83)
Stratfjord	33.0	25.2	37.3	477	46.3
Brent	27.9	24.6	9.1	275	65.2
Buchan	46.5	18.4	2.0	275	52.0
S. Brae	39.1	17.6	21.4	48	12.7
Cormorant	46.1	16.9	*	99	19.9
Magnus	16.6	16.6	6.3	89	18.3
Beatrice	22.7	8.1	*	20	8.0
Tartan	22.4	3.3	**	10	4.0

* Although cash flow is positive in certain years, at no point in life of the field does it show a positive cash flow or a cumulative basis.
** This field does not show a positive cash flow in any year.
1. Derived from Reference 1.
2. Proforma Pretax 1984 Revised Projections are based on Non Escalated Price for Sale of Oil and Gas.
3. Derived from Reference 2. For peak production the date is indicated: where no date is provided the 1984 rates are reported.

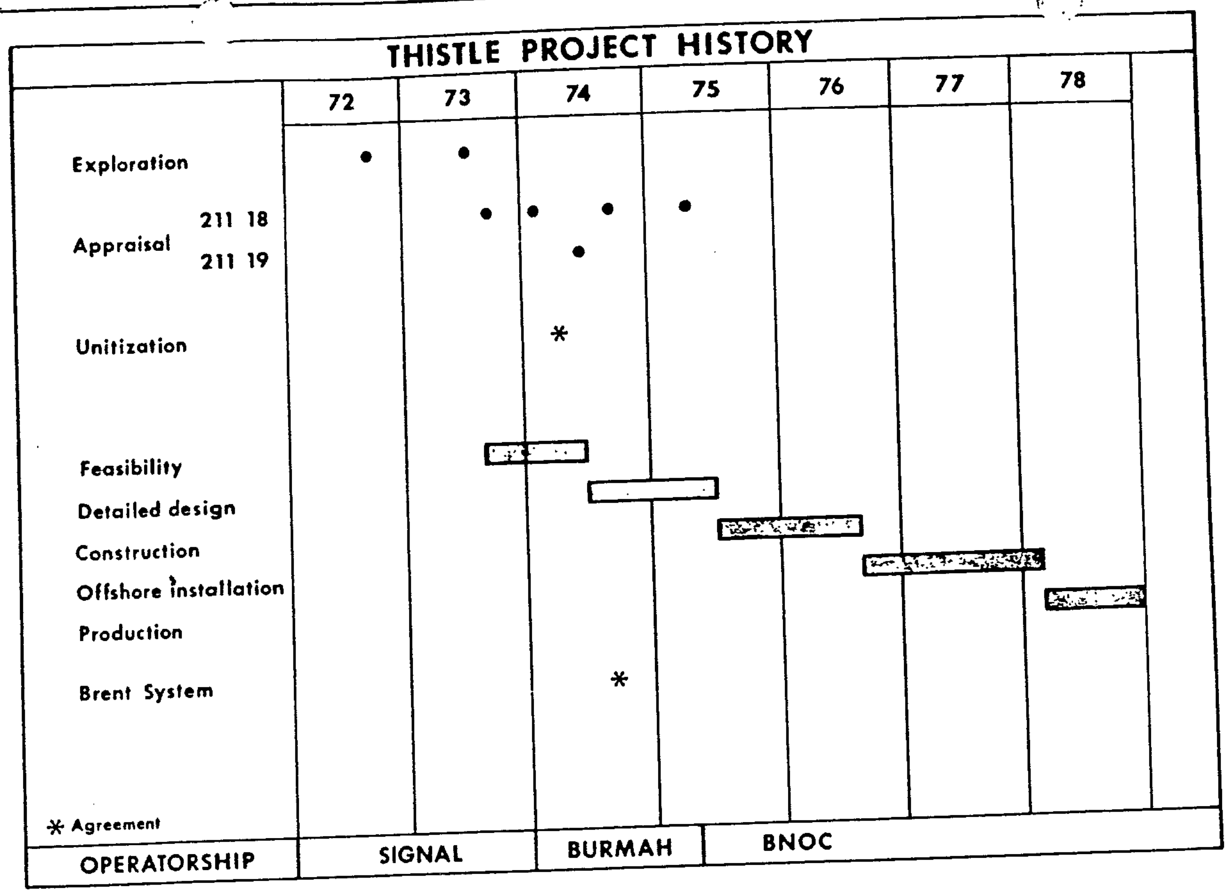

FIGURE 2. Thistle project history.

These judgments are, of course, made with the undoubted benefit of hindsight.

Development Drilling

The original development drilling plan was very much based on "optimization" of a predictive reservoir simulation model[10]. The model contained a reservoir description based on 1975 vintage seismic data and information from 4 to 7 extensively cored and logged wells. The database, by contemporary standards, was large and according to Nadir[10] appraisal wells yielded results agreeing with prognosis. The reservoir description, therefore, seemed highly reliable: the computer models were moreover sophisticated and used "state-of-the-art" techniques. Pressure maintenance by water injection was assumed at the outset for this highly (35 000 kPa) undersaturated reservoir.

TABLE 2. Thistle field exploration/appraisal drilling results

Date	Well	Comments
1972 Sept.	211/18-1 *	Deveron discovery (satellite)
1973 July	211/18-2 *	Thistle discovery
1973 Aug.	211/18-3 *	2.25 km northern outstep
1973 Oct.	211/18-4 *	1.5 km southern O/S
	211/23-4 d/h	3 km southern outstep: proves separation of Dunlin from Thistle field
1974 May	211/19-1 *	OWC-defined, 0.5 km southeast of 211/18-2
1974 Sept.	211/18-6 *	4.25 km O/S northwest (discovers a separate accumulation in an adjacent fault block)
1975	211/18-8 *	3.75 km outstep northwest

*Wells tested in flow rates of 700 m³/d to 990 m³/d from limited perforated intervals.
d/h - dryhole

What does optimization consist of? A development drilling sequence is defined maximizing oil recovery rates within the following constraints: (a) a geological model of the field itself; (b) the gap perceived to exist between an initial reservoir pressure (42 000 kPa) and some maintained reservoir-pressure target (32 000 kPa) related to well performance requirements; and (c) drilling capabilities.

TABLE 3. Key dates—Thistle field

1973 July	Thistle discovered by Signal wells 211/18-2
1973 August	Declared commercial
1974 April	Unitization
1974 April	Project manager appointed
1974 May	Detail design contract awarded
1974 September	Brent pipeline agreement signed
1975 January	Operating agreement
1975 August	Jacket construction contract award
1976 August	Development plan approved
1976 September	Float out of Jacket
1978 February	Production start-up
1979 May	Start water injection

TABLE 4. Comparison of project forecast with outcome

	1976 Forecast	1983 Forecast	
OIP	159	135	$10^6 \times m^3$
Ultimate recovery	72	64	$10^6 \times m^3$
Date of start-up	1977	1978	
Peak oil production	29-32	20	$1000 \times m^3$
Date achieved	end 1978	1982	
Field life time	18	23	Years
Peak water production	19	40	$1000 \times m^3$
Peak water injection	40	41	$1000 \times m^3$

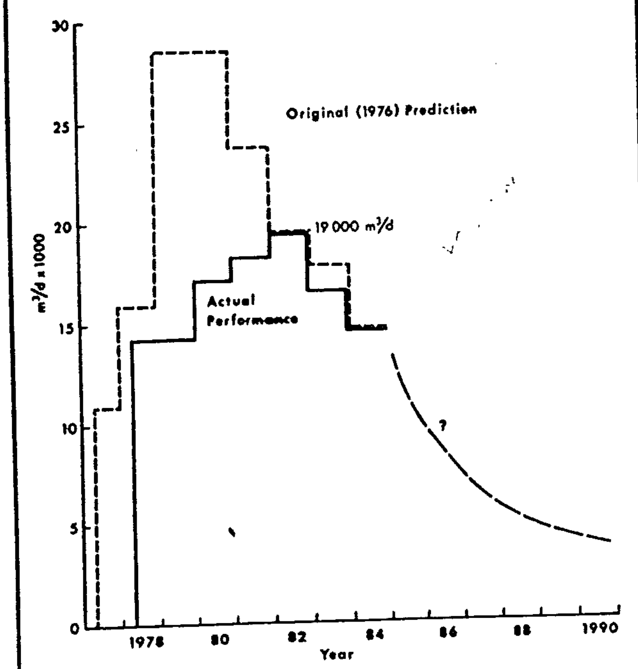

FIGURE 3. Thistle oil production profile.

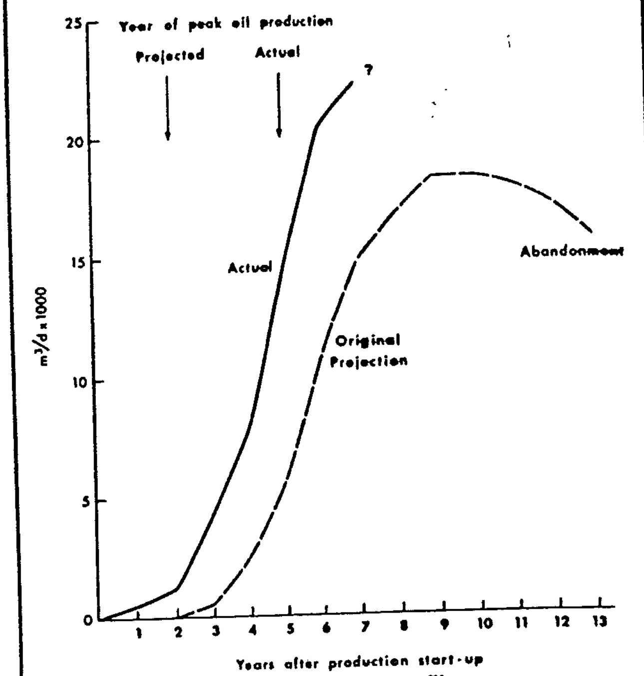

FIGURE 4. Thistle water production profile.

Hay and Nadir discuss in some detail the drilling objectives, priorities and underlying reservoir assumptions at the time of earliest predictive modelling.

A key constraint in doing this type of modelling is the geological description, which turned out to be oversimplified. The original reservoir geological model contained no noteworthy faults, because none had been detected on seismic sections, nor were inferred from well data. This data included sophisticated pressure build-up analyses conducted on extensive appraisal well test information (Table 2) with the aim of identifying faults. Offshore test flow periods, however, seldom last longer than 24 hours and, hence, sample a tiny part of the reservoir.

The Thistle structure consists of an eastward dipping middle Jurassic fault block (Fig. 5a), described by various authors[2,8], and which, logically suggested during the planning phase, a crestal production, flank water injection scheme.

The 14 000 kPa overpressured reservoir containing a 35 000 kPa under-saturated reservoir fluid (Pb = 7000 kPa) and the likelihood of a modest aquifer, allowed the simulation model to indicate a deferred need for pressure maintenance operations. This, furthermore, had the attractive consequence that technically demanding, high angle deviation drilling programs for water injection wells, could be deferred until ten or eleven low deviation angle oil producers had been drilled.

Production experience with some of the earliest wells was disappointing. Table 5 presents results for the first six oil producers which according to Nadir[10] appeared to be so promising. Rapid pressure drops, in some cases accompanied by early water production, came as a major setback. Most dramatic was the performance of well A6, which came on stream in May 1978, cut water within two months and soon thereafter ceased to produce. In May 1979, the well was converted to water injection status.

Even more disappointing was the subsequent discovery that some initial water injection wells were ineffective. Nadir[11] describes how only one of the first three targetted water injection wells was successful, while the other two encountered missing geological sections or poor reservoir rock.

Because even in 1979 no help could be obtained from seismic data to define possible fault configurations, an element of doubt remained as to the cause of the apparently poor communication. Was it caused by poorer than estimated vertical permeability? Nadir[11] describes the simulation modelling work carried out which led to the conclusion that a major sealing fault was the principal cause: although later work confirmed that vertical permeability problems are also a concern, the earlier conclusion has proved to be correct. Subtle crude property variations across the field are now attributed to this fault, which to date remains a seismic mystery.

Figure 3 demonstrates how, in spite of a vigorous two rig drilling program there was no production build-up during 1979 from levels established mainly by the initial six wells brought on-stream in 1978. Performance since then, with a gradual increase of production levels to 20 000 m³/d in 1982, (some 30% below design peak) is the result of gradual improvement in pressure support.

The scale of change of the drilling program is illustrated by the following table:

Thistle Waterflooding Plan

	1976	Actual 1984
Production wells	20	37
Injection wells	22	9
Total	42	46
Other slots (various purposes)	18	14
Total	60	60

Early reservoir engineering projections turned out to be excessively cautious with respect to water injection well expectations. Only half of the water injection wells were finally required, but locating them proved more difficult.

Far more oil production wells were required, however, to drain the complex rock mass; consequently greater well bore congestion occurred beneath the platform than originally foreseen. Although some spare slots remain unused today, it is relatively difficult now to identify worthwhile drillable locations, partly because of the unforeseen evolution of drainage plans.

Can Reservoir Continuity Problems be Anticipated in the Planning Phase?

The reservoir development concept for Brent province fields relies on the assurance of high well flow rates by means of waterflooding pressure-maintenance operations. A key assumption here is one of hydrodynamic reservoir continuity, and appraisal wells drilled into a reservoir under static conditions are unlikely to help define this parameter.

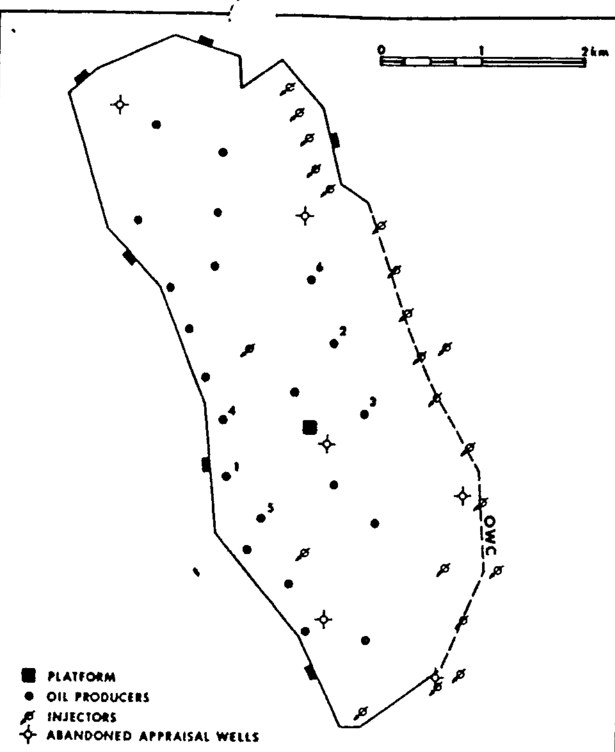

FIGURE 5a. Thistle 1976 original plan.

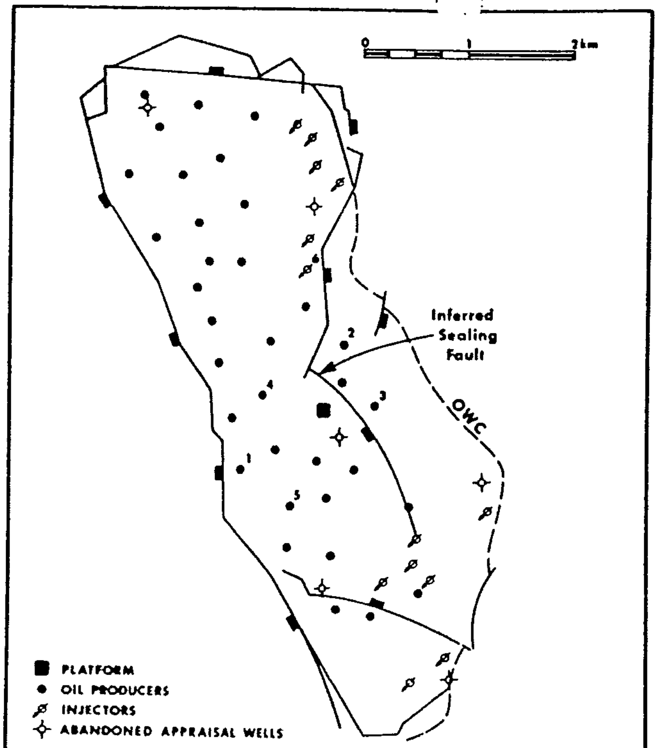

FIGURE 5b. Thistle 1982 actual plan.

The only information available from appraisal drilling that could indicate the presence of pressure barriers are oil-water contact, reservoir pressure and fluid composition differences. The Thistle experience demonstrates, however, that absence of such indications does not preclude reservoir continuity problems: identifying faults from pressure build-up interpretation only is possible if the fault occurs within the radius of the temporary pressure sink. The advent of the RFT (repeated formation tester) has provided a powerful tool for obtaining valuable pressure data, but mainly after production has commenced. Dake[12] describes a successful application of this tool to identify faults in new Thistle development wells using vertical pulse testing. The RFT is most versatile in open hole conditions and hence a policy of target selection after production start-up, in order to obtain information about pressure depletion in reservoir areas remote from wells which have produced at high rates, appears wise.

Development Policies

Two possible development policies are now suggested for avoiding this type of problem.

Any predrilling activity (whose main attraction is early production potential build-up) must have associated production and injection potential substantially discounted. This will make an allowance for wells lacking pressure support for some time, and for the possible need to re-allocate a production well to injection service.

A second approach to planning which appears to have merit is to avoid the temptation of letting a simulation model, incorporating an inevitably simplified geological description (as was the case in Thistle) dictate where wells ought to be targetted. A development plan which identifies target areas for all available drilling slots in a reasonably regular pattern, and thus ignores geology to some extent, will ensure maximum flexibility through the drilling program, and full utilization of resources. Unless geophysical tools are developed capable of distinguished sealing from non-sealing faults, wells targetted according to model predictions will be doomed to disappoint. This policy was forced upon the Beatrice field development plan (see below) and resulted in some tangible benefits.

Simulation Problems in Thistle

A second major reason for over-optimistic performance predictions for Thistle was caused by simulation modelling problems. The whole idea of placing faith in this technology for purely predictive work has been offensive to some reservoir engineers, but it is doubtful whether Thistle-style projects could have been financed without this type of technological support. The 3D three-phase simulation models used for the Thistle project for ten years gave optimistic predictions, for reasons other than the geological description problem discussed so far.

Water Saturation

3D simulation models provide an attractive tool for estimating

TABLE 5. Early development well results (to December 31, 1984)

Well	Date Start Production	Productivity Index (m³/d·kPa)	Months Dry Production	Cumulative Oil ($m^3 \times 10^6$)	Cumulative BSW ($m^3 \times 10^6$)	Comments
01 A	78/02	30	36	2.1	36	Immediate pressure drop.
02 A	78/03	14	1	0.6	24	Well shut in after 9 months.
03 A	78/02	8	13	0.3	54	Rapid increase in w.c.
04 A	78/03	53	43	3.5	20	
05 A	78/05	49	24	0.3	58	
06 A	78/05	27	2			Rapid increase in w.c.—converted to water injection in May 1979.

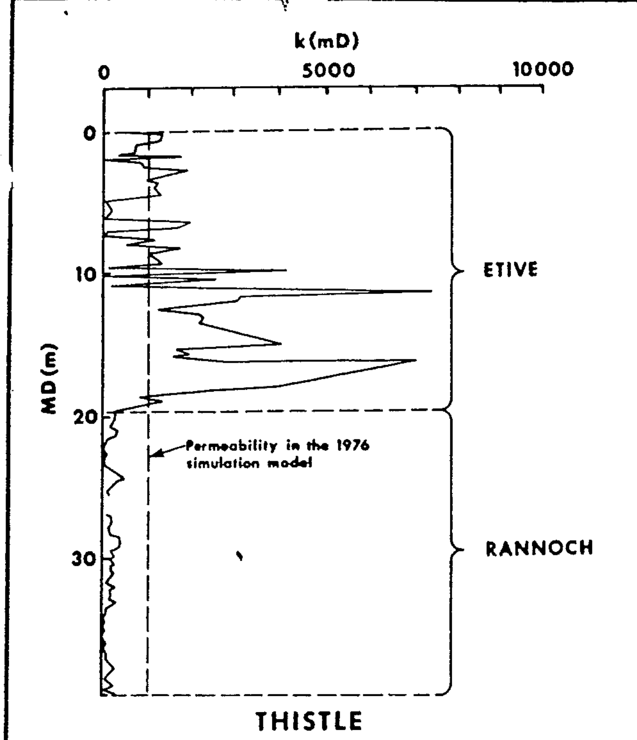

FIGURE 6. Typical permeability distribution across the Etive-Rannoch sands.

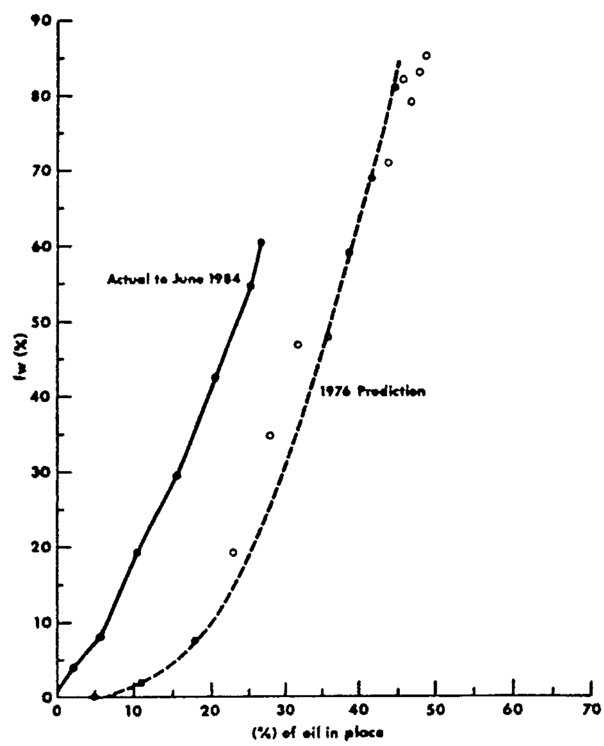

FIGURE 7. Thistle-field fractional flow curves.

oil-in-place because they usually estimate water saturation variations with the help of capillary pressure curves derived from special core analyses. Contouring saturation trends based on log data is by comparison subjective. Variations in rock properties are huge, however, and, special core analyses are rare and, therefore, perhaps unrepresentative of the reservoir, and laboratory capillary pressure measurements may not always be representative of reservoir conditions. Log interpretation problems associated with pyrite, mica and clay mineral occurrences caused the successive Thistle operators to discount log derived saturation estimates.

By 1976 the pre-development exploration wells had defined, with the help of available seismic data, a gross rock volume estimate which has largely stood the test of time. But water saturation estimates derived from log data appeared to be greater than those derived and used in 3D simulation models using available capillary pressure measurements. For purposes of volumetric reserves estimates resistivity-based water saturation estimates were ignored for reasons outlined above.

By 1983, after a history of repeated production shortfalls, all available water saturation data was thoroughly re-examined and model-derived estimates at wells were compared with log-derived estimates; the conclusion was reached that the capillary pressure data had given misleading low saturation estimates particularly in the transition zone and for less permeable formations. This latter condition unfortunately applied mainly to the massive lower middle Jurassic Brent, Etive-Rannoch sequence which in the earliest development concept accounted for 25% to 30% of reserves. Bayat's paper describes the revised model initialization policies in some detail[9].

Modelling Frontal Advance

The earliest Thistle reservoir simulation modelling treated the reservoir as a three-layer unit for the D (Tarbert), Ç (Ness) and B/A (Etive-Rannoch) sequence of sands. The lower sand body appeared to be vertically continuous and contained 50% to 60% of the total hydrocarbons. The future producton performance of the field clearly hinged on the performance of this massive sand unit.

Nadir[10] describes the initial modelling concept which treated this 30 m to 50 m thick sand unit as a uniform 1000 md sand. Vertical performance of this sand was modelled using detailed 2D models to define pseudo relative permeabilities with the help of 3 m thick layers to model vertical effects. It was a sophisticated approached.

Presented in Figure 6 is a typical Thistle Etive-Rannoch permeability profile from which the following observations can be made:

1. Although the permeabilities in the upper portion are spectacular, those measured in the lower section still suggest respectable waterflooding opportunities.
2. Given the absence of significant shale breaks[10] there was no reason to propose an alternative modelling procedure treating the Etive and Rannoch sands separately.
3. Any doubts about Rannoch recovery could have been dispelled by observing that a combination of gravity slumping and imbibition would assist flooding of the Rannoch from a water- swept overlying Etive.

These predictions did not materialize. The Rannoch appears to be unfloodable and its recovery appears to be limited to depletion forces. Gravity does play a prominent role but only for the highly permeable Etive where water tonguing has caused early water breakthrough. Bayat discusses the Rannoch problem in some detail in the context of recent history matching work, but from his discussion it is clear that reservoir performance for these sands is an unresolved enigma.

layered NX FL.

Bayat attributes the problem largely to the complex mineralogical and sedimentary (cross bedded) nature of these reservoir sands. These geological issues were recognized in 1976[10]. The history matching techniques used by Bayat involves the use of a highly contrived Rannoch model involving numerous permeability barriers to isolate the completions in question from floodwater, thus allowing the model to give the observed oil recovery.

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What this shows is that in spite of having made great advances not only in reservoir simulation model construction, but also in operating techniques, we are still running the risks of severe misrepresentations when dealing with purely predictive situations: the variety of geological reservoir settings is too great, and the

not so

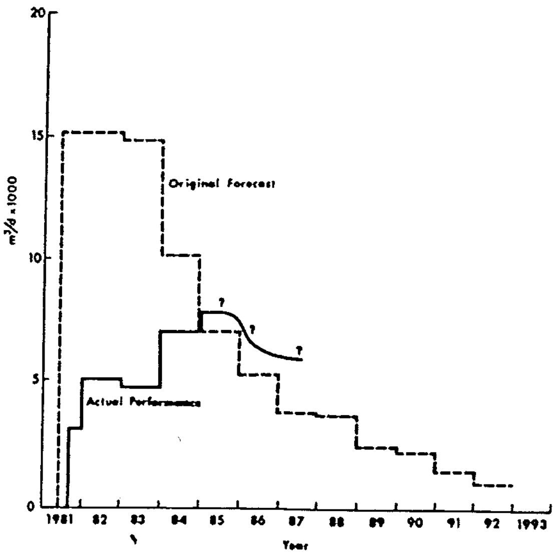

FIGURE 8. Beatrice field oil production forecast and performance.

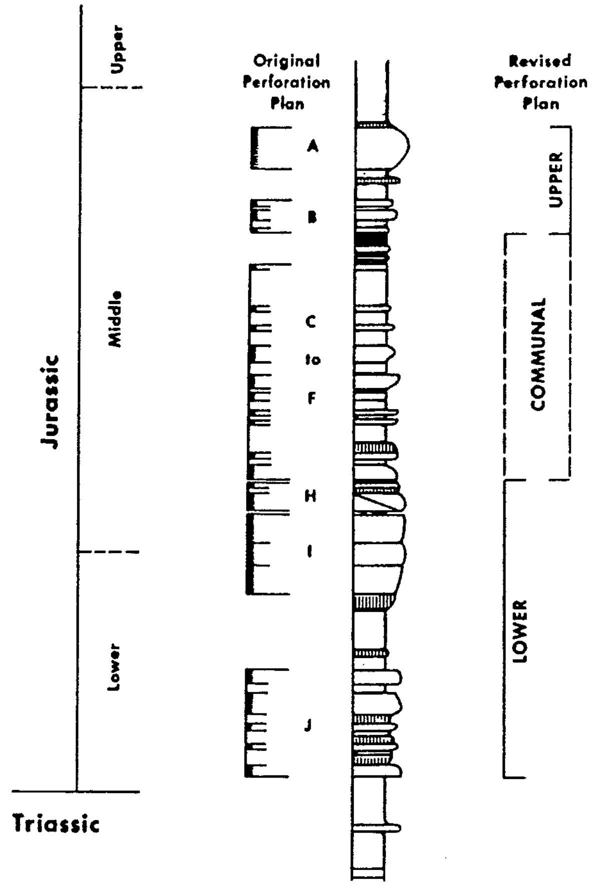

FIGURE 9. Beatrice field completion schemes.

TABLE 6. Key dates—Beatrice field

March 1972	Licence award
Sept. 1976	Drilled crestal discovery well (11/30-1) Successful outstep along the crest (11/30-21)
1977	2 successful outstep wells (11/30-3, 5). One dry hole
August 1978	Development plan approved. Commencement of development drilling.
Sept. 1981	Production start-up (6 months late)
Jan. 1982	Water injection start-up
June 1984	B platform on stream
Jan. 1985	C platform on stream

TABLE 7. Technical data—Beatrice field

Volumetric	1978 Plan	1984 Revision	
Oil in place	480	512	MMSTB
Recovery factor	34	25.2	%
Ultimate recovery	165	129	MMSTB
Projected water production	29		MMBW
Projected water injection	214		MMBW
Economic limit rate	9.6	4.6	%
Water cut at economic limit	35		
Peak production: oil	96	50	MBOPD
year in which achieved	1982	1985	
Plateau duration	2	1	Year
Commencement of oil production	1981	1981	
Commencement of water production	1982	1981	
Wells planned			
Production	27	28	
Water injection	10	13	
Number of platforms	3	4	

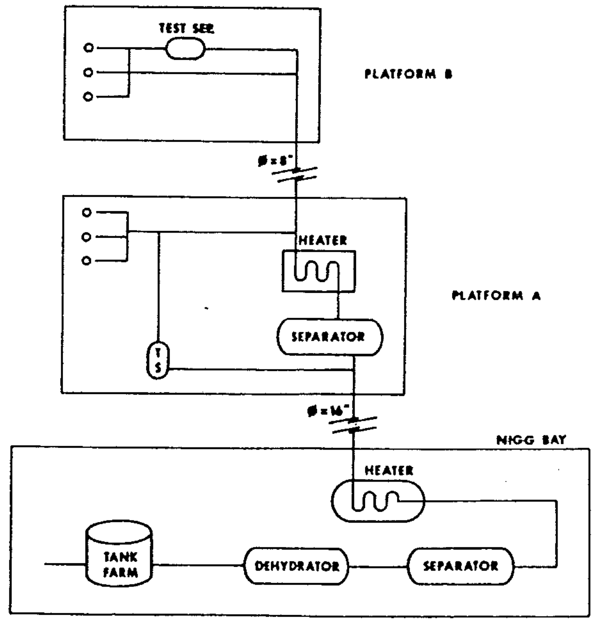

FIGURE 10. Beatrice—schematic process and transportation system.

consequent impact on performance too unpredictable to give us much faith in the reliability of purely predictive model results.

Impact on Predicted Reservoir Performance

Run both ways. ie ~~base~~ case HOXFL

These changes in simulation model assumptions assisted in making production forecasts reliable. Oil-in-place and reserves estimates were of course affected (in volumetric terms the difference was only in the order of 15%) but the impact on fractional flow was far more profound as illustrated in Figure 7: the higher resultant water saturation estimates in flooded zones made an additional contribution to the higher than predicted water production estimates in Figure 4.

The Beatrice Story

The story of discovery and development of the Beatrice field,

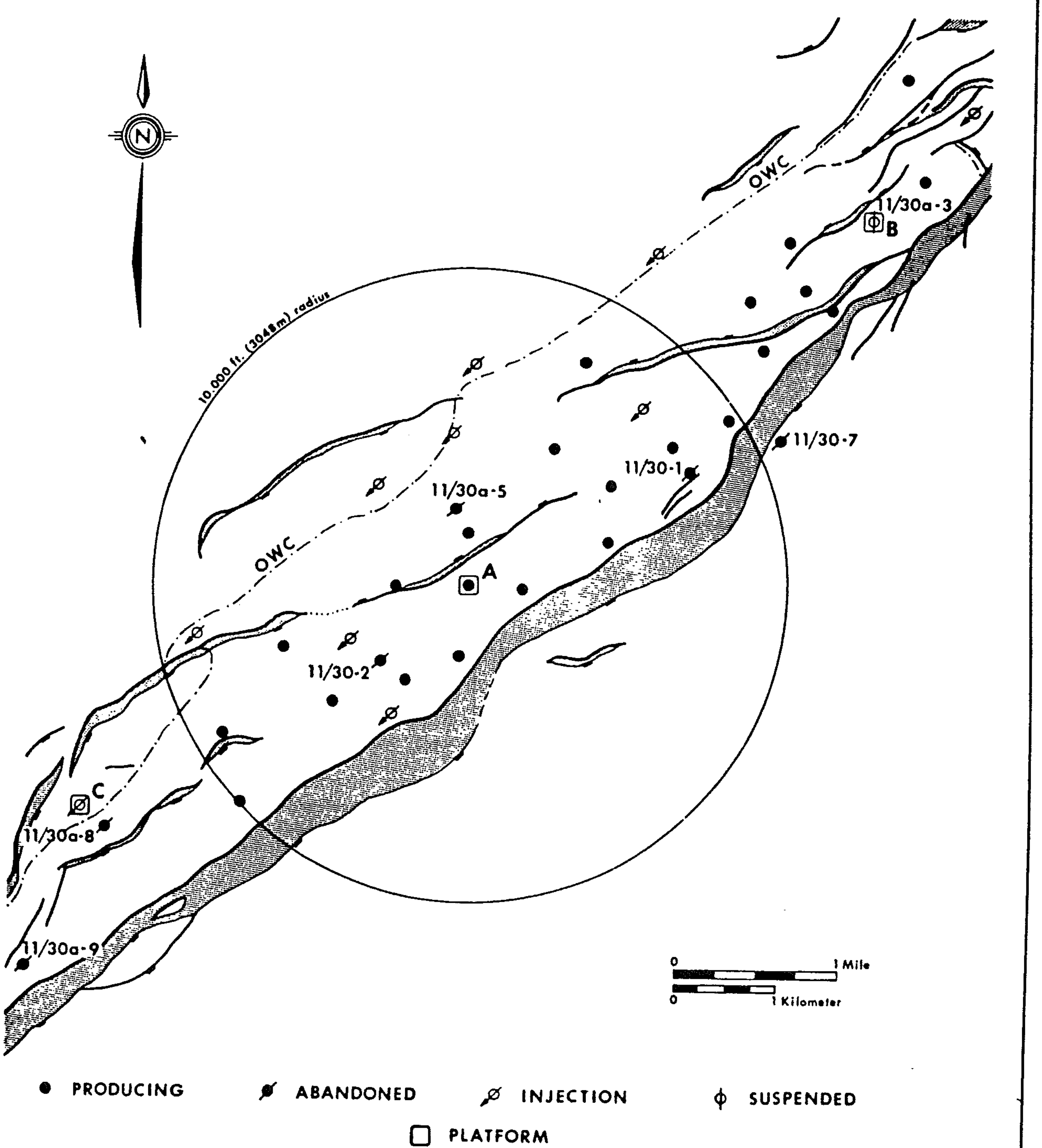

FIGURE 11. Beatrice field well location diagram.

located in the Moray Firth, within sight of the Scottish coastline (Fig. 1) has recentlty been reviewed by Johnson[13], and key events are reported in Table 6. Some important lessons about reservoir development planning can be learned from this complex project. When reservoir simulation models were first constructed a number of important operational matters were not fully taken into account causing pre-production start-up projections of recovery rates to be higher than subsequently proved to be realistic.

The original development plan[14] suggested that production rates of 13 000 m^3/d to 15 000 m^3/d could be achieved from a two platform development, and that these rates could be sustained for three years (Table 7). With the help of a considerably redesigned and enhanced second platform and installation of a third platform, production rates peaked at 8000 m^3/d for one year (1984) only (Fig. 8). Cash flow projections were altered considerably as a consequence!

Catering for Artificial Lift Offshore

The Beatrice development plan included a feature unique to date in offshore fields. From commencement, waterflooding pressure maintenance operations were to be augmented by artificial lift[14,15]. For this purpose use was made of electrical submersible pumps installed above the perforated interval in production wells, deviated at angles up to 70 degrees from the vertical. Because the Beatrice structure consists of at least 8 different oil-bearing sand bodies (Fig. 9) separated by distinct and substantial shale intervals[10], high projected (i.e. optimal) recoveries could only be obtained by reservoir engineers modelling separate waterflooding operations for each of the sand layers.

It was, therefore, clear from the outset that Beatrice wells would require more workovers than other North Sea Jurassic wells, not only to carry out many necessary recompletions required to obtain the 35% projected recovery efficiency, but also to service the pumps.

The design team accordingly made provision for the main platform (AD) to be equipped with a drilling rig capable of drilling 4000 m high angle wells, as well as a workover rig capable of carrying out completion and repair work.

In an effort to build production potential as soon as possible after commissioning of the process, transportation and terminal system, the development plan included provision for predrilling, through a subsea template, of a number of development wells[15], prior to jacket installation and piling. The workover rig would then complete these wells during the commissioning process while the main rig carried on with drilling operations. The operational constraints of employing two rigs on a compact (4 x 8) conductor slot arrangement on the main (AD) platform were under-estimated during project design phase, but became clear enough when the drilling platform was commissioned in the summer of 1981.

This prompted a reappraisal of reservoir development realities, and as a consequence, reserves dropped from 25 x 10^6 m^3 to 19 x 10^6 m^3 and a number of other parameters changed (Table 7).

A third constraint had a further negative impact on operational flexibility. The shallow (2000 m) depth of the reservoir, and the reliance on up to 70-degree deviation wells to cover the large areal extent (assisted by slanted conductors), effectively meant that individual platform slots had to be allocated to rigidly defined target areas to allow drilling engineers to plan well trajectories for the tophole section to assure minimial risk of collision.

The objective of attaining high, early production rates was known to be at risk for the following additional features peculiar to this project. (a) Since the field was linked by pipeline to a dedicated on-shore terminal, the entire process system was very complex (Fig. 10), particularly with regard to commissioning operations. The system was very vulnerable to emergency shutdowns with detrimental effect on the submersible pumps[14], and a consequent need for workovers. (b) The failure rate of the artifical lift system was during the first years of operation high. (The interested reader is referred to Brown's paper[15] for a discussion on technology improvements. (c) Failure to maintain reservoir pressure was known to significantly increase the risk of pump failure when pump intake pressure dropped below bubble point pressure[14]. In addition, high planned initial offtake rates, made possible by predrilling, together with low natural reservoir-drive energy expectations, had from project inception dictated the requirement of immediate pressure maintenance operations.

Limitations of Simulation Models

These complex operational considerations had not and could not be explicitly defined in predictive reservoir simulation models and it became obvious that it was pointless to allow a simulation model to dictate operations as was the tendency. Effort in 1981 was expended in letting the predictive modelling reflect what was operationally feasible from a congested, complex offshore platform. The following tactic was now employed:

1. The main rig was commissioned first and was dedicated to drilling all remaining southeastern slots targetted exclusively to crestal production well locations (Fig. 11).
2. The main rig was dedicated to the drilling of down-flank water injection wells. The work-over rig could now be assembled over the suspended producers and commence tie back and completion operations.

As a consequence the drilling of water injection wells, which mostly involved rapid angle build-up in order to attain the high deviations at the required shallow depth, were delayed and production had to commence without the benefits of water injection pressure support. It was a matter of good luck that enabled two wells (out of 9) to produce almost continuously during those first four months due to reliable pumps and a degree of natural acquifer pressure support which turned out to be rare in this field.

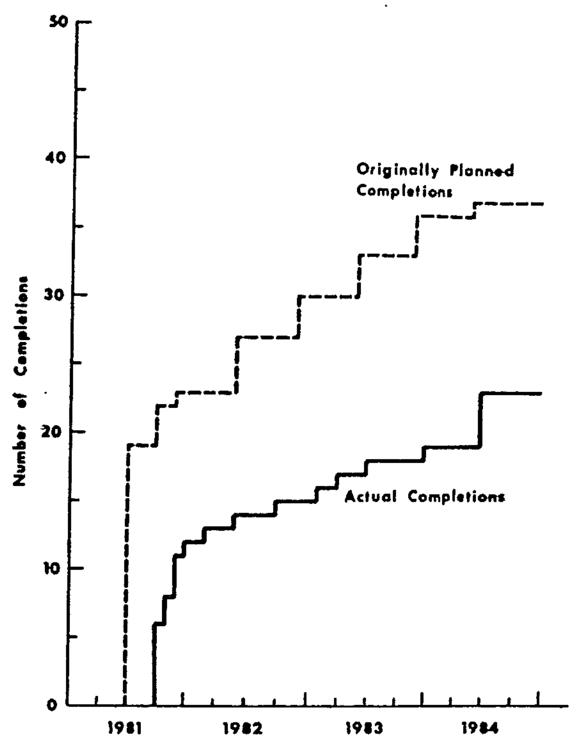

FIGURE 12. Beatrice well completion schedule.

It is, however, noteworthy that the enforced constraint of a predefined development drilling well pattern, together with an appreciation of the uncertainty of formation and fault behaviour under waterflooding conditions, allowed the definition of a revised pre-start-up production forecast, in 1981 which so far has stood the test of time.

In order to make field development and production start-up at all feasible, reservoir management policies had to be drastically revised with far greater emphasis placed on commingling production from various sand units (Fig. 9), thus reducing the need for workovers and recompletions but also reducing the projected recovery efficiency. It was recognized that even then, demands made of the drilling system were excessive and a third wellhead platform (C) was designed[13]. A comparison of original and final drilling plans is instructive (Fig. 12) for it clearly shows how the original plan envisaged what turned out to be an unrealistic buildup of well potential, thus contributing to expectations of high early production rates and cost recovery. The cumulative cash flow, as explained by Castle, had by 1983 fallen well behind prediction. Comments applied to Thistle are equally in place here: from the advantageous perspective afforded by hindsight—all difficulties, even for this immensely complex project, could have been avoided.

Conclusions

The Thistle and Beatrice projects can be counted among the foremost North Sea technical success stories. But there are some key issues raised which bear attention from the petroleum industry.

1. The conception and execution of North Sea style projects has been assisted by, and in turn stimulated the development of increasingly sophisticated but specialized and potentially incompatible, computer simulation models.

Ensuring a balanced, coherent project design among a plethora of computer output presents a notable management challenge.

2. The eventual limitations of appraisal drilling must be recognized as well as the costs.

If disposable appraisal wells continue to be required because of the unpredictable nature of past results, one may well ask what point there is in pursuing this activity. If on the other hand there is a high degree of reliability in appraisal well results, then equally a point is reached when further drilling is pointless. Either way it must be recognized that appraisal wells tell us little more than local geology, petrophysics and fluid properties. Little knowledge is gained about dynamic reservoir behaviour, and based as they are on this data, reservoir simulation models do little better. The risks associated with high front-end capital investment frontier development projects remain substantial.

Acknowledgment

The author is indebted to the *Petroleum Economist* for permission to reproduce Table 1 of this paper. For the remaining technical data the author has drawn heavily from published papers (as indicated) but also used information items scattered in various issues of the *Petroleum Economist* dating from 1972 onwards. The author is also indebted to the Ministry of Energy, Mines & Petroleum Resources of British Columbia to allow him the opportunity to prepare this paper, and in particular to Kathy Thomson and Ron Satterfield for patience with typing and drafting. The conclusions reached and opinions expressed in this paper are entirely the author's.

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From: #69M --BVOV1 Date and time 01/24/92 03:06:03
To: #8C5 --BVOV1

*** Reply to note of 01/20/92 07:39
FROM: Wiggo H. Holm
Woking
Ext. 2467
Subject: Commingled Layered Reservoirs
Sorry I have not replied ,but I have been out of the office for a couple of days. Regarding layered reservoir performance and testing, this subject is of interest to us. Last year we received your input on our questions regarding recommended testing of Ann development wells, which most likely is a layered no-cross flow reservoir. You have probably also seen the CPI for the 30/7a-11z well and Mike's PROFed comments on this reservoir. I had a discussion with him yesterday on this issue as we are putting together our preliminary plans for tetsing this well. We will transmit this programme to you and Mike for your comments. I believe he will come and see you.

Of course our main project over here, Judy and Joanne are all layered reservoirs, maybe with the exception of the Palaeocene. As I told Mike, as a matter of routine we always run our 3D models with kv/kh of zero as a senstivity case. However, we do not consider these cases necessarily to be the best technical cases, maybe somewhat opposite to what Mike's position is. It seems that his starting point is that all reservoirs are layered with no cross-flow. It will take a little more to bring us on board to accept this as general.

Most, if not all reservoirs we are dealing with are layered. The question is if and to what extent the layers will behave as no cross-flow layers. The Judy 11z well has a number of identified sand bodies. To predict no cross-flow boundaries will remain uncertain until performance data become available. To assume all large and small shale bodies are perm barriers at the outset may impose an unduly pessimistic premise and will have serious consequences regarding the gas-in place volume this well has 'proven' up, as sand in the aquifer at the well location raises above the conatct to the east. These areas will therefore never be drained if we assume a no-cross flow model. To premise all these sands to be independent reservoirs will obviously impact our completion strategy and performance predictions. At the end of the day, I believe that at least some of the sands communicate. The question is which ones and which of the shale breaks can be considered not to be continous.

However, you see our general concerns.

Regarding testing of layered reservoirs, we will probably propose to do a vertical interferance test on the Judy well. Before we discuss this, possibly before your lucnh time today, you may want to think about how we could design a test to evaluate kv/kh in a conclusive manner. The other aspect of testing this particular well is that, unless we perforate the complete hydrocarbon bearing section, any tested zone will be affected by neighbouring layers if cross flow exist. Can such a situation be identified during testing and used to infer vertical communication? We have built a 23 layer well model and are working on answering some of these questions, but would be happy if you all can also think about it.

cc: #233 --BVOV1 Michael J Fetkovic

Regards
W. H. Holm

* Deepening example

Production Technology Experience in a Large Carbonate Waterflood, Denver Unit, Wasson San Andres Field

W.K. Ghauri,* SPE, Shell Oil Co.

Introduction

The Denver Unit waterflood project in the Wasson San Andres field in West Texas ranks among the largest supplemental recovery projects currently operating in the U.S. (Fig. 1). Shell Oil Co. is the operator and holds the major working interest. The production technology experience highlighted in this paper has evolved through several phases of infill development drilling and flood pattern modifications that have been carried out in the course of conducting the waterflood project.

The paper is divided into two parts. The first deals with a brief history of the waterflood with the objective of providing the project setting for the production technology practices currently being followed. The emphasis is placed not on the statistical data per se but rather on the evolutionary process through which present procedures have been developed, as well as their interrelationship with the geologic, petrophysical, and reservoir aspects as they pertain to the project. The second part describes the specific practices of well completion, well stimulation, injection profile control, artificial lift, flood surveillance, and related drilling, remedial, and reconditioning operations now being used and how they have contributed to the enhancement of ultimate recovery from the project.

*Now with Kernridge Oil Co.

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Historical Background

The Wasson San Andres field was discovered in 1936. The bulk of primary development at 40-acre (162 000-m^2) well spacing was completed by the early 1940's. Supplemental recovery operations were initiated with unitization and commencement of water injection in 1964 (Fig. 2).

The producing horizon is the Permian San Andres dolomite formation at an average depth of 5,200 ft (1585 m). Gross oil pay thickness varies between 200 and 500 ft (60 and 150 m). The structure is an anticline capped by dense dolomite and underlain by an essentially inactive aquifer. Solution-gas drive has been the primary producing mechanism. Table 1 shows a summary of basic project data. The oil reservoir has an original gas cap. Although some production has occurred from the gas cap, primarily before unitization, Shell's policy during waterflooding operations has been to leave the gas cap unexploited to conserve reservoir energy and prevent waste by the migration of oil into the gas cap.

When unitization was effected in 1964, the geologic concept of the reservoir was a simplistic one and was markedly different from the rather complex model that has evolved today. The original definition of the San Andres reservoir was based on gross geologic correlations of reservoir-quality rock and the assumption that this rock largely was interconnected over the entire extent of the unit.

The old geologic concept led to the original peripheral injection design (Fig. 3) wherein existing

Shell Oil Co. currently is operating a large waterflood project in the Permian San Andres dolomite reservoir in west Texas. The project comprises 900 producers and 360 injectors. In addition to major infill drilling programs, a substantial remedial and reconditioning program has been carried out. Highlights of production technology experience are presented.

producers along the periphery of the unit were converted to injectors during 1964-66. As the waterflood progressed, it became apparent that the peripheral flood design was not effective; the water injection wells were located thousands of feet distant from the interior producers, which had no backup injection.

An in-depth geologic interpretation was made using detailed well log and core data as well as the environmental conditions that controlled original rock deposition. This investigation was focused on the rock continuity that can be expected between two adjacent wells. This distance for the Denver Unit was generally about 1,320 ft (400 m) – i.e., 40-acre (162 000-m^2) well spacing.

The study indicated that the San Andres rock sequences are well-bedded and that impermeable barriers have relatively wide lateral extent. The permeable layers showed discontinuities and exhibited the highly varying permeability commonly associated with carbonates, but no ordered anisotropy was detected. These data suggested that waterflooding in this carbonate reservoir should be highly efficient at the proper producer/injector

TABLE 1 – SUMMARY OF DENVER UNIT PROJECT DATA

Formation	Permian San Andres dolomite
Structure	Anticline
Average depth, ft (m)	5,200 (1585)
Gas/oil contact, ft (m)	−1,325 (−404)
Oil/water contact, ft (m)	−1,400 to −1,650 (−427 to −503)
Average porosity, %	12
Average permeability, md	±5
Average net oil pay thickness,* ft (m)	137 (41.8)
Oil gravity, °API (g/cm^3)	33 (0.86)
Reservoir temperature, °F (°C)	105 (40.6)
Total acres (m^2) in entire reservoir	62,500 (253 × 10^6 m^2)
Number of acres (m^2)	27,848 (113 × 10^6 m^2)
Number of productive acres (m^2)	25,505 (103 × 10^6 m^2)
Date reservoir discovered	April 15, 1936 ← 28 years
Date Texas Railroad Commission approved injection	Oct. 14, 1964 ←
Date of first injection	Nov. 1, 1964
Date unitization effective	Nov. 1, 1964
Primary producing mechanism	Solution gas (depletion)
Flood pattern	Inverted nine-spot and peripheral
Number of wells (at completion of 1978 infill)	1,217
Producers	860
Injectors	343
Plugged and abandoned	14
Original reservoir pressure, psi (MPa)	1,805 (12.45) ←
Bubble-point pressure, psi (MPa)	1,805 (12.45) ←
Average pressure at start of secondary recovery, psi (MPa)	±800/±1,100 (±5.5/±7.6) 1000 psi P_i
Initial oil formation volume factor	1.312
Solution-gas/oil ratio at original pressure, cu ft/bbl (m^3/m^3)	420 (76)
GOR at start of secondary recovery, cu ft/bbl (m^3/m^3)	4,060 (731)
GOR at current conditions, cu ft/bbl (m^3/m^3)	±600 (±108)
Oil viscosity at 60°F (15.6°C) and ±1,100 psi (0.76 MPa), cp (Pa·s)	1.18 (1.18 × 10^{-3})
Original oil in place (Denver Unit Engineering Committee),* bbl (m^3)	2.108 × 10^9 (0.335 × 10^9)
Revised original oil in place,** bbl (m^3)	2.166 × 10^9 (0.344 × 10^9)
Cumulative oil production at initiation of unit, bbl (m^3)	185,643,000 (2.95 × 10^6)
Cumulative oil production since unitization as of Sept. 1, 1978, bbl (m^3)	421,748,000 (6.7 × 10^6)
1977 average daily oil production rate, B/D (m^3/d)	137,200 (21.8 × 10^3)
Cumulative gas production at initiation of unit, cu ft (m^3)	402 × 10^9 (11.4 × 10^9)
Cumulative gas production since unitization to Sept. 1, 1978, cu ft (m^3)	442 × 10^9 (12.5 × 10^9)
1977 average daily gas production rate, cu ft/D (m^3/d)	85 × 10^6 (2.41 × 10^6)
Cumulative water production at initiation of unit, bbl (m^3)	3,163,000 (503 × 10^3)
Cumulative water production since unitization Sept. 1, 1978, bbl (m^3)	241,570,000 (3841 × 10^3)
1977 average daily water production rate, B/D (m^3/d)	153,000 (24.3 × 10^3)
Cumulative water injection to Sept. 1, 1978, bbl (m^3)	1,382,190,000 (219.75 × 10^6)
1977 average daily water injection rate, B/D (m^3/d)	457,300 (72.7 × 10^3)
Source of injection water	Ogallala and produced

*Does not include deeper M_6 oil pay penetrated in one of the infill programs; does not include gas-cap pay.
**Includes M_6 pay.

↑ because there was no crossflow

spacing and that, in view of pay discontinuities, unflooded oil would be left behind in the reservoir at 40-acre (162 000-m^2) well spacing.

This type of work gave rise to the new geologic concept of "continuous" and "discontinuous" pay.[1,2] Continuous pay is that portion of the total net pay that is correlatable or connected between two adjacent wellbores at the well spacing existing in a particular reservoir. Discontinuous pay is the balance of the net pay not connected between two adjacent wellbores. In such a reservoir, if one were to drill infill wells at a spacing closer than existed previously, some of the discontinuous pay would become continuous in the sense that a larger percentage of the total net pay would be correlatable between closer-spaced adjacent wellbores in the waterflood development pattern.

A quantification of pay continuity for the Denver Unit suggested that if the well spacing were to be reduced from 40 to 20 acres (162 000 to 81 000 m^2) per well, pay continuity would be enhanced significantly and the reserves would be increased accordingly. Additionally, in a pattern drive project with impermeable barriers extending over distances of several well locations, the injected fluids in a permeable pay member will be contained and will provide the drive within the pay member with a minimum of crossflow occurring in the reservoir from one pay member to another. Fig. 4 is a type log showing the present subdivisions of the San Andres reservoir in the Denver Unit. Eleven pay members, F_1 through F_5 and M_1 through M_6, have been mapped and correlated.

In association with an improved geologic understanding of pay continuity, detailed reservoir engineering work was carried out by means of mathematical modeling and reservoir simulation predictive techniques to determine (1) how the flood design could be modified to provide drive response in the total net continuous and discontinuous floodable pay in the Wasson San Andres field and (2) how the supplemental recovery efficiency could be enhanced further in the Denver Unit waterflood project. Based on this work, a pattern approximating 20-acre (81 000-m^2) inverted nine-spot arrangement (theoretical producer/injector ratio of 3:1) was judged to be economically the optimum flood design for the Denver Unit.

Accordingly, in late 1969 Shell embarked on a 20-acre (81 000-m^2) infill development program that has continued until the present and should proceed through 1981. The current project status with 20-acre (81 000-m^2) infill development is shown in Fig. 5.

The modified pattern flood design has improved the areal sweep efficiency greatly. For example, Fig. 6 shows a section (640 acres or 2.59×10^6 m^2) in the central portion of the unit and illustrates how pattern uniformity and well spacing density have been realized in the project as a result of infill drilling and injector conversions. Our present estimate of areal sweep efficiency for the Denver Unit project is approximately 90%.

By the end of 1979, the infill programs and pattern modifications included the drilling of 481 new

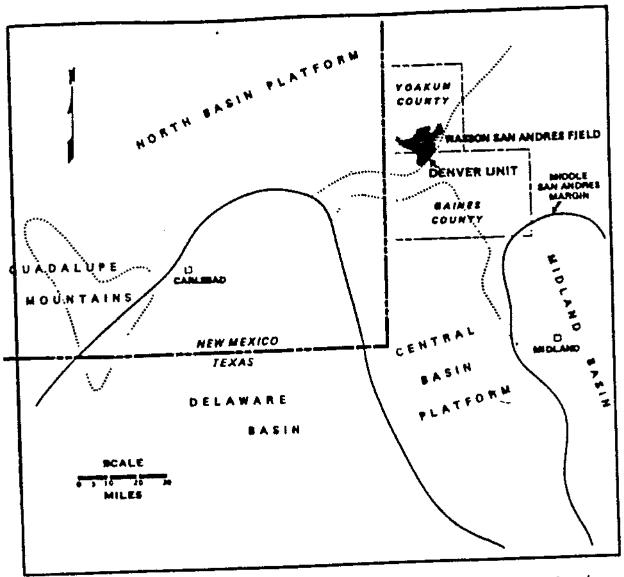

Fig. 1 – Location map – Denver Unit, Wasson San Andres field.

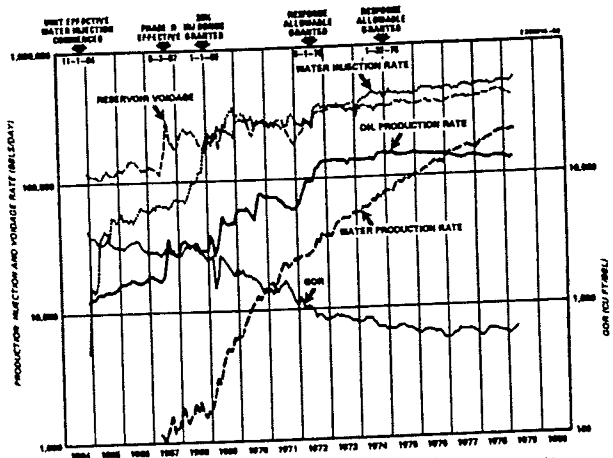

Fig. 2 – Project performance curves – Denver Unit.

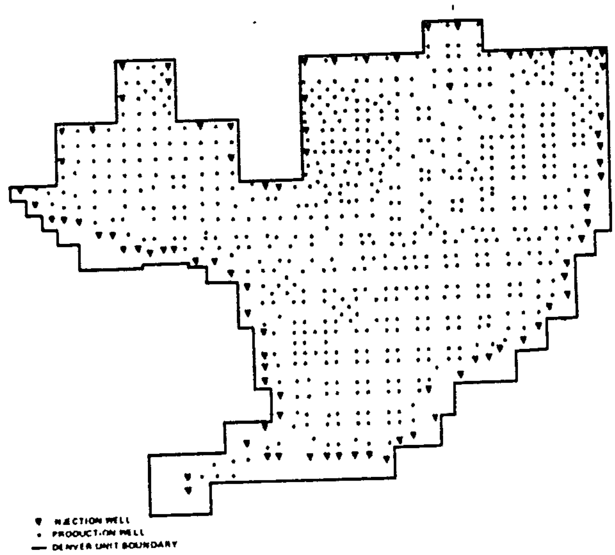

Fig. 3 – Original peripheral waterflood pattern.

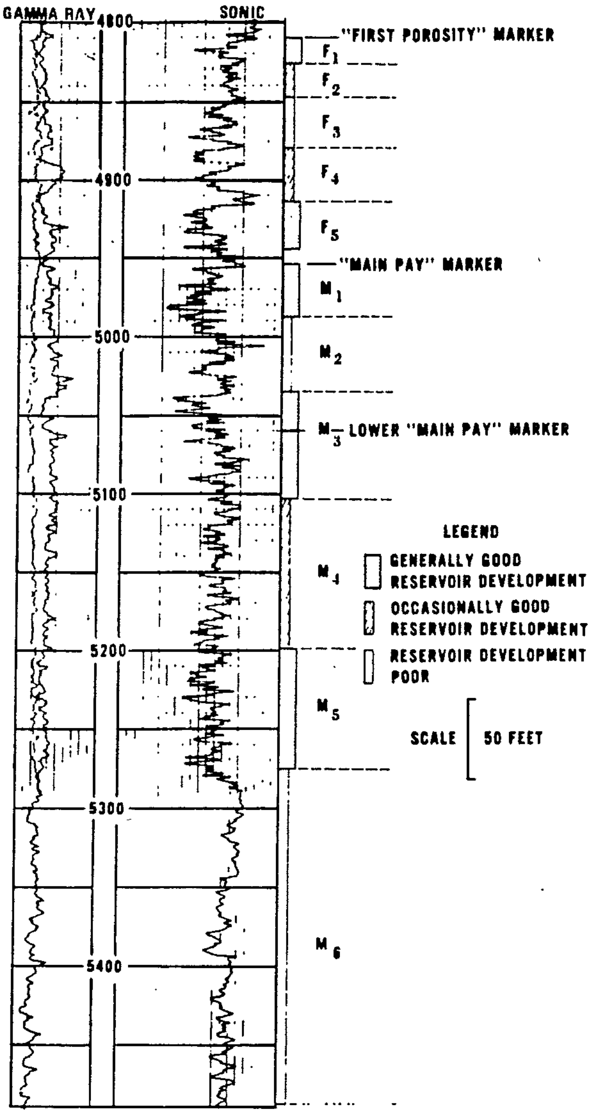

Fig. 4 – Zonal subdivisions of San Andres reservoir.

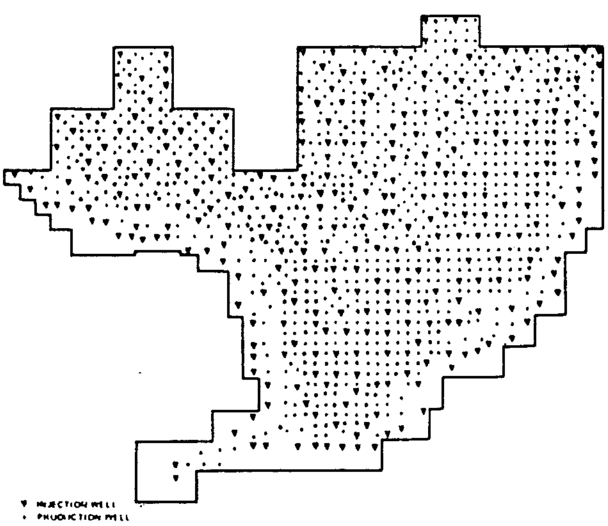

Fig. 5 – Project 1979 status.

producers and 42 new injectors, the purchase of 17 wellbores (15 producers plus two injectors), and the conversion of 135 existing producers to injectors – i.e., a total of 675 wells. The well count in the unit is now 902 producers and 363 injectors, or a total of 1,265 wells.

Production Technology Practices

Openhole vs. Cased-Hole Completions

Of the approximately 700 active wells in the unit in 1964 when water injection began, more than 90% had been completed barefoot or openhole, with the casing string cemented at the top of the productive San Andres zone. In view of the geologic and reservoir concepts discussed earlier, it became apparent that water injection must take place in correlative pay members. With this in mind, *all new* infill producers and injectors have been cased through the productive zone and have been perforated selectively in correlative pay members. Flood response and profile conformance are substantially superior to an openhole completion in such a carbonate reservoir.

To date, we have not attempted to install cemented liners in the old producers presently active in the unit. Part of the reason, of course, is the additional cost. However, more importantly, the profile control is being exercised at the injection wellbores.

Fiberglass vs. Steel Liner Installations in Injectors

In the early phase of the waterflood project, selected existing production wells (which were openhole completions) were converted to injectors by simply pulling out the downhole production equipment and running in an injection string with the packer set in the production casing immediately above the openhole productive zone. Dictated by the new geologic concepts and relevant project performance, the decision was made to install liners in nearly all of these injectors and to perforate selectively correlative pay intervals.[3] The only exception was the group of peripheral injectors along the limits of the accumulation where the rock quality was poor, the injectivity was low, and the reservoir pressure had built up to near formation-parting pressures.

Hole deterioration and resulting fill or bridging problems had been experienced in many openhole injectors. These hole problems were attributed to fresh injection water leaching out anhydrite lentils in the interbedded San Andres dolomite formation, causing the rock to slough into the hole. Concurrent with the hole deterioration was the lack of desirable injection profiles. Permeability variations were causing preferential drive in only the good-quality rock pay members.

Injection water in the Denver Unit project is either fresh water (200 ppm chlorides and 8 ppm oxygen) from a shallow sand formation or produced San Andres water with formation water salinities ranging from 30,000 to 120,000 ppm chlorides. Because of the corrosive nature of the injection waters, an innovation was made wherein fiberglass strings (fiberglass-reinforced thermal resin pipe) rather than steel strings were installed in these injectors. The use of fiberglass pipe in injectors was a first in the industry for carbonate waterfloods of west Texas and New Mexico. Our experience with fiberglass strings has been exceptionally good. Other operators in the area now are opting for this mode of completion for injectors in their waterflood projects. The fiberglass strings have been cemented opposite the productive zone either as a combination string in new injection wells or as a liner installation in existing well conversions. These strings have controlled formation fill, have provided injection profile control, and have been an insurance against tubular corrosion.

Injection tubing strings run in all of the injectors are internally plastic-coated steel tubing with packers to isolate the crossover between the steel and fiberglass casing. These have provided a protective system for corrosive waters. No problems have been encountered that are unique to using fiberglass tubulars in these applications. Other than perforating with a hollow carrier gun and using formation or cup-type packers inside the fiberglass, no special precautions have been necessary. The liners have been set with conventional liner-setting techniques.

Cements used have been Class H saturated salt cement and Class C cement with 0.25 lbm/sack (0.113 kg/sack) cellophane flakes. A friction-reducing additive also has been used to reduce pumping pressures. Since the epoxy resin on the exterior of the fiberglass has a very smooth, slick surface, the pipe is either sandblasted or rough-coated to assure adhesion of the cement to the pipe. Subsequent communication tests and injection profile surveys have shown similar success in realizing zonal segregation in fiberglass-cased injection wells as that obtained in steel-cased production wells.

Should the cement fail to circulate around the top of the liner, squeeze cementing around the liner top and drilling out cement inside the liner has been done satisfactorily. Thus, drilling cement inside the fiberglass liner with a rock bit has presented no problems. After being cemented, the liners have been loaded with fresh water and pressure-tested from 1,500 to 1,600 psi (10.34 to 11.04 MPa), the maximum surface injection pressure expected under normal operating conditions. The liners then have been perforated with steel hollow-carrier select-fire mechanically decentralized jet-perforating guns. (Surface perforating tests have shown that the hollow-carrier gun will absorb the energy of the shot and not damage the fiberglass, while expendable-type guns will damage the pipe.) We have had no indications of damage from perforating with the hollow-carrier gun under downhole conditions. The perforated intervals selectively have been acidized satisfactorily with hydrochloric acid using a closely spaced cup straddle packer assembly. Fiberglass pipe sizes available consist of 2⅜-in. (6.03-cm), 3½-in. (8.89-cm), and 4½-in. (11.43-cm) API 8rd EUE threaded and coupled, as well as 5½-in. (13.97-cm) and 7-in. (17.78-cm) 8rd LT&C.

Most conventional logs can be run inside fiberglass pipe. Radioactivity water tracer logs are run routinely to evaluate injection profiles. Gamma ray-compensated neutron logs also are obtainable to determine intervals to perforate and have proved to be comparable quantitatively with those run in openhole. A poor-quality acoustic log is interpreted to be the result of poor cement bonding. Acoustic cement bond logs have not been interpreted definitively in the applications to date. As sonic transit time through fiberglass is approximately 90 μs/ft (295 μs/m) and is greater than the transit time through steel (56 μs/ft or 184 μs/m) or through sandstone or carbonate rock (45 to 70 μs/ft or 148 to 230 μs/m), formation signals arrive before fiberglass casing signals at practical transmitter/receiver spacing. Induction-electrical logs can be run through fiberglass pipe because this device relies on propagation and detection of magnetic eddy currents and is not affected by the fiberglass. However, focused resistivity devices cannot be used because the highly resistive fiberglass pipe does not provide a conductive path for focused electrical current.

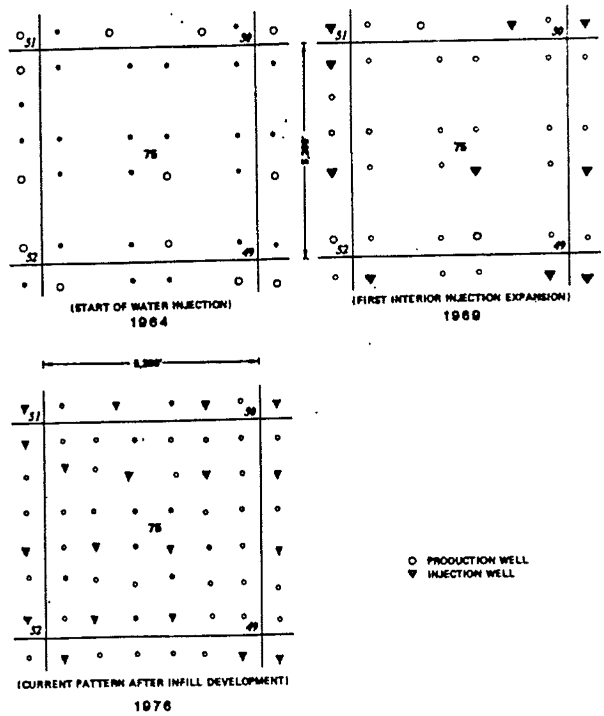

Fig. 6 – A small portion of the Denver Unit showing pattern uniformity by infill drilling and injector conversions.

Well Completion and Well Stimulation

The drilling of new wells has presented no special problem except in certain areas of the unit where a shallow high-pressure inert-gas zone exists. Hole problems caused by this zone have been handled by weighting up the mud to kill the flow and/or by running a long intermediate string. The basic mud system consists of a simple native brine (salt gel/starch) mud with water loss maintained at less than 15 cm^3 while drilling through the pay zone. To minimize communication behind the pipe, rough-coated or sand-blasted casing has been cemented through the pay interval. Other measures that have contributed to success are centralizers and scratchers across the pay zones, circulating a low-water-loss preflush ahead of the cement slurry and reciprocating the casing while cementing. The cement has consisted of a lightweight (12-lbm/gal or 1438-kg/m^3) filler cement followed by neat (15-lbm/gal or 1797-kg/m^3) cement slurry across the pay zone. In all wells, attempts are made to circulate the cement to the surface as an insurance against future casing failures.

To maintain separation or zonal segregation between the correlative pay members and across impermeable barriers, the pay zones have been perforated selectively, leaving blank pipe opposite the impermeable barriers between adjacent sets of perforations. The individual selective perforations have been acidized either singly or in pairs using closely spaced (6- to 10-ft or 1.83- to 3.05-m spacing) straddle packers while holding treating pressures below fracturing gradients – i.e., by low-rate, low-volume, low-pressure matrix acidization techniques. Extreme care is taken so that the rock adjacent to the wellbore and the cement sheath are not fractured during stimulation operations. Communication checks of adjacent perforations are made during treatment with the current success ratio in excess of 50%. As the flood has progressed, wells have been re-entered and additional correlative pay members have been perforated and treated, as dictated by the advance of the water banks around the injectors and the performance of responding producers.

In existing openhole wells, inflatable straddle packers with a maximum spacing of about 30 ft (9.14 m) have been used. If hole conditions will not permit satisfactory packer seats (i.e., if the hole is caved or washed out or if the well is an old cased completion with numerous closely spaced perforations), stimulation has been diverted mechanically or chemically. This has been done by use of ball sealers, rock salt, or benzoic acid flakes in 200- to 300-lbm (90.7- to 136.1-kg) stages mixed at 1 to 2 lbm/gal (120 to 240 kg/m^3) in gelled carrying fluid. This type of treatment is the only choice for such old openhole wells and is not considered to be the preferable type of stimulation inasmuch as individual perforations cannot be treated effectively.

Perforating is done with casing-carrier select-fire guns using deep penetrating jet charges in acid spotted opposite the zone, and there is a pressure overbalance on the formation. Data on underbalanced perforating are meager. Our operating policy has consisted of exceeding injection/voidage balance, as can be seen from the performance curves (Fig. 2). Accordingly, the pressure level in the reservoir has continued to rise with time. For example, the reservoir pressure ranged between 800 and 1,100 psi (5.52 and 7.58 MPa) at the commencement of water injection. Extensive buildup and falloff data obtained during 1977 showed the pressures to range between 1,480 and 2,630 psi (10.20 and 18.13 MPa). Thus, we believe that the productivity benefits to be derived from underbalanced perforating in such a situation of increasing reservoir pressure would not be too great and do not justify the additional risk and expense.

Most perforations will not take or give up significant volumes of fluid before stimulation. Therefore, stimulation is a must for all wells. The basic stimulation fluid is 15% HCl containing a corrosion inhibitor and a nonemulsifying agent. Although higher- and lower-strength acids have been used, our experience suggests that the 15% acid is a reasonable compromise between cost and production gain. Our current guidelines for new perforations are to use approximately 1,200 gal (4.54 m^3) of acid per 1.0 ϕh (fractional porosity times net pay thickness in feet) of treated interval or 400 to 800 gal (1.51 to 3.03 m^3) of acid per perforation. Normally, for a 10-ft (3.048-m) pay interval as interpreted from the sonic porosity log, the perforation density is about two perforations per 1.0 ϕh. The guidelines for old perforations are to use approximately 1.5 times new perforation design volume of 1,200 gal – i.e., 1,800 gal (6.81 m^3) of acid per 1.0 ϕh. The guidelines for treating pressures are previous treating-pressure history in the subject well and/or in nearby surrounding wells and average pattern pressure in the area of interest based on buildup and falloff surveys. The maximum allowable treating pressure normally is limited to 0.7-psi/ft (15.8-kPa/m) fracturing gradient at perforation depth.

By far the majority of stimulation is done for calcium carbonate scale removal. In certain areas of the unit, however, calcium sulfate (gypsum) scale impairment has been encountered. Commonly used dissolvers of gypsum scale are manufactured brine solutions in which the solubility of gypsum increases due to salinity (ionic strength) effects and chelating agents. Thus, the gypsum-scale removal operations have employed manufactured brine water (9.2 lbm/gal or 1102 kg/m^3 density) as well as commercial scale removers: 5% NaOH + 15% sodium gluconate and NH_4HCO_3 – EDTA.

Downhole scale inhibition of pumping wells with some scaling problems has been done satisfactorily by batch-treating or continuous injection down the casing/tubing annulus by means of a small positive displacement surface pump.

Injection Profile Control

A significant effort has been made to improve the vertical sweep efficiency in both existing production wells converted to injectors and new wells drilled as injectors. The technique mainly has been mechanical – i.e., cementing liners opposite the openhole productive zone in the former type of wells and completing with solidly cemented casing opposite the productive zone in the latter type of wells. The correlative zones then have been perforated and acid-treated selectively. Our operating strategy has been to attempt to distribute the injected water in accord with each zone's porosity-thickness product, ϕh. Treating pressures during acid stimulation jobs have been kept below formation fracturing pressures to maintain zonal isolation behind pipe in the vicinity of the wellbore. Likewise, water injection rates and pressures have been kept below fracturing gradients.

Our premise has been that the impermeable barriers will prevent crossflow within the reservoir from one permeable layer to another, at least over several patterns. Injection profile analyses based on radioactivity tracer surveys routinely run in injection wells have borne this out, corroborated by the performance of surrounding producers as well as log, core, production test, and pressure buildup data obtained in the 10-acre (40 469-m^2) pilot and the CO_2 pilot. The key to success appears to be the proper profile control in the immediate vicinity of the wellbore. We now know that the percentage of the total water volume being injected into each pay zone is more nearly proportional to the oil in place contained in the individual pay members than had been the case previously. Fig. 7 illustrates this improvement in profile conformance. It is evident that the vertical sweep efficiency has been enhanced greatly by our completion and operating practices. Our present estimate of vertical sweep efficiency for the Denver Unit project is approximately 90%.

Additional techniques employed toward the improvement of injection profiles have included sand injection to reduce water receptivity of permeable pay members, high-rate/high-pressure tank truck acidization to improve overall injectivity, and string shot/acidization of poor-quality rock as well as selective acidization treatments. These will be discussed briefly.

The sand injection technique for profile improvement in a carbonate reservoir was an innovation in the Denver Unit project. The results have been highly satisfactory. The treatment has been inexpensive and the procedure very simple. For the most part, the sand has been obtained from the waste pit at the desander plant of the Wasson water supply system. The sand (100 Tyler mesh, 0.006-in. or 0.015-cm diameter) is being produced from the shallow Ogallala freshwater source wells that provide a percentage of the injection water for the project. (The balance of the injection water is produced formation water.)

A truck-mounted jet-type mixer and pump arrangement has been used for creating the sand/water slurry ($\pm$1 lbm/gal or $\pm$120 kg/m^3) and injecting it into the well through a nipple screwed into the top of the wellhead. The ability of the wells to accept the sand has been due primarily to the anhydrite dissolution in the dolomite formation as a result of continuing water injection in the project. Volumes of sand have been injected into the perforations that have exceeded the calculated volume of the borehole in an injection well. Inasmuch as the San Andres dolomite formation in the Denver Unit project does not have in-situ fracturing based on extensive coring, and we have been careful not to induce fractures during our injection and stimulation practices, it is interpreted that the dissolution of the anhydrite has created sufficient void in the dolomite rock. By and large, the sand has gone into the pay members having excessive water receptivity, regardless of their depth within the total pay interval. Of course, should the thief zone be located toward the bottom of the pay interval, the sand purposely

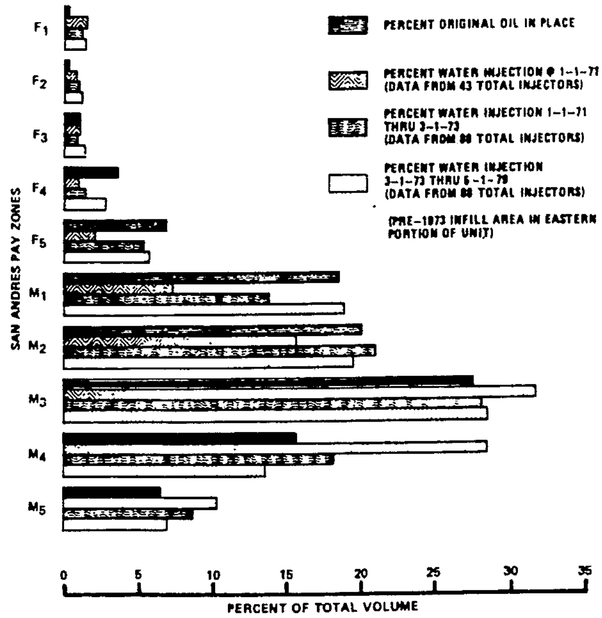

Fig. 7 – Injection profile status.

can be dropped out at the tail end of the job to provide a plug inside the wellbore. Normally, the overall injection rate after the job has decreased somewhat, the surface injection pressure has increased correspondingly, and the injection profile has improved to coincide more nearly with the ϕh-derived ideal profile. Additionally, the treated wells have continued to match or exceed the pattern production voidage. In light of the prospects for the CO_2 tertiary recovery process in the Denver Unit, consideration must be given to the long-term effects of any remedial operation. Limited experience so far suggests that significant injectivity can be regained by backflowing the sand and subsequent acidization. By contrast, squeeze cementing or injection of other plugging materials (which, incidentally, would be more expensive techniques) might permanently impair the injectivity of a particular zone. To date, some 30 sand injection jobs have been done, most with very satisfactory results as interpreted from a comparison of radioactivity injection profile surveys run at periodic intervals before and following the job, as well as related pattern performance data. The reason we have not done more jobs of this type is primarily because thief-zone problems thus far have been minimal in the project.

High-rate/high-pressure tank truck acidization and string shot/acidization normally have been employed in the poor-quality rock. For example, the limits of the accumulation along the southern periphery of the unit are defined by rock quality deterioration. Injectors along the periphery have low injection rates, with bottomhole pressures having built up to >3,000 psi (>20.7 MPa). In such injectors, the majority of which are still openhole completions, expensive stimulation treatments are not warranted. Accordingly, these inexpensive methods have been employed with good results. The tank truck acid jobs occasionally have been done on ratio in the unit. The typical producer and injector jobs cost \$10,000 and \$8,000 per job, respectively. The average gain in production per producer job is about 40 BOPD (6.36 m^3/d oil) or an average expense of about \$240 per 1 BOPD (0.159 m^3/d oil) increase.

Acknowledgments

I am indebted to my colleagues in the Wasson Section, Mid-Continent Div., Western E&P Region, of Shell Oil Co. who have contributed to the success of this project. Their ideas, concepts, and innovations are presented in this paper. Acknowledgments also are due C.R. Reiter, who directed the field operations, and his personnel for their contributions to the project's success.

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SI Metric Conversion Factors

bbl	×	1.589 873	E−01	=	m^3
cu ft	×	2.831 685	E−02	=	m^3
ft	×	3.048*	E−01	=	m
mile	×	1.609 344*	E+00	=	km

*Conversion factor is exact.

JPT

November 6, 1991

INTER-OFFICE CORRESPONDENCE / SUBJECT:
BARTLESVILLE, OKLAHOMA

Trip Report
GRI-Bureau of Economic Geology

TO: M. J. Fetkovich

FROM: D. E. Reese DER

If you want more reserves and a higher production rate; just infill drill the Frio gas sands maybe all the way down to 40 acre spacing. This is the promotion which was presented in Houston last month by the GRI, and more importantly, the Texas Bureau of Economic Geology. For those who do not want to go through the entire "story", the simple conclusion presented by the Bureau is this:

> "All gas wells that have decline curve exponents (b values) greater than zero are experiencing pressure and rate support from partially drained compartments. These compartments are high quality but are separated from the main compartment by a thin tight barrier. Infill drill into this partially drained compartment for higher rates and economic reserves."

This conclusion is loony and will cause companies adopting this "technology" to waste their resources on drilling infill wells.

I have attached to this report, as figures, several of the sheets from the short course handout. A full set of the short-course handouts is available in my office. Figures 1 and 2 give the definition of the various Reservoir/Compartment categories. Figure 3 has an interesting set of statistics concerning reserve growth, what we in Phillips have learned to call recomputations. The point that I believe the sponsors want to miss is that by using a b = 0 as their decline exponent, there will naturally be positive recomputations as the more correct b values (b > 0) mitigate the decline rate. The fact that reserve growth/infill well increased by a factor of 2.5x between the periods of 1979-85 and 1986-89 has little to do with technology as the sponsors proposed, but is a more or less constant amount of positive recomputations divided by a greatly reduced amount of wells in the period 1986-1989. Figure 4 is the sponsors' key point which I feel misses the point entirely; the point as I see it is that the decline rate has been dramatically slowed by the physical forces which govern these wells. Low pressure gas wells operating with low line pressure have b values between 0.3-0.4 while wells producing either with vertical or regional layer effects may have b values greater than 0.5.

The physical model developed by Dr. Collins in conjunction with the sponsors is shown on Figure 5. This physical model produces many

of the characteristics that Phillips has shown to be the case with layered no-crossflow reservoirs and for which Phillips has shown little or no reserves growth with infill drilling. I have two general comments concerning his model: 1) geologically, I feel his system is unrealistically complicated as compared with the easier to visualize layered systems, and 2) he ignores the importance of deliverability in his supporting compartments (i.e., his V_2 always has good deliverability). One of his field examples is the Wardner Lease well 80 shown in Figures 6 and 7. His model generated a pressure profile for the undrained compartment which he said was confirmed by the drilling of well 182. Only upon questioning did he reveal this well to have low, disappointing rates as would be predicted from a regional layering model.

Figure 8 shows the sponsors' interpretation of a semilog straight line being the expected decline for a gas well and any b value > 0 implying that an infill well is needed. Figure 9 is from another field example which can more realistically be interpreted as a layered no-crossflow system.

A small amount of time was spent on the subject of new logs which can assist in finding gas pay behind the pipe and some time was spent on untapped small gas accumulations which may be identified through seismic. These subjects probably do identify new but small additional reserves, but they were not the primary thrust of the one day short course, which was the identification of partially drained compartments.

Again, to summarize, the presentation given by the Texas Bureau of Economic Geology was loony and used an unrealistically complicated model to justify infill drilling. This compared to the ten man years of work by Phillips which uses a more realistic geologic model, and shows that in most cases infill drilling to be unnecessary.

Also attached are the attendance lists for the short course as well as the two SPE papers presented at the Fall Meeting in Dallas concerning this issue. One interesting aspect was that Phillips had the most attendees for the session which I attended. I did inform all of those who did attend from Phillips that the Reservoir Engineering Branch did not want the sponsors' "technology" to be used and that we were available to discuss the issues involved.

DER:kp
Attachments

cc: R. G. Ceconi
R. B. Needham
J. F. Griggs /r/ Reservoir Group
D. R. Wier
G. D. Gillham
H. J. Robinson
J. P. Johnson
B. C. Nolen