005 THE DESIGN OF A MISCIBLE GAS FLOOD FOR THE WYTCH FARM SHERWOOD RESERVOIR

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Abstract
A miscible gas injection project has recently been sanctioned for the Wytch Farm Sherwood reservoir. Commencing during the second half of 1997, a total of 23mmscfpd of miscible gas will be injected into five wells in a Water Alternating Gas cycle, sweeping the reservoir through inverted nine-spot patterns. The project will be extended to a further five patterns over a ten year period to cover almost 50% of the reservoir. It is predicted that an incremental 12.6mmstb of oil reserves will be produced, but losing 10.6Bscf of sales gas and 443mtn of LPG to the reservoir.

As part of the project design programme laboratory studies were undertaken. The residual oil saturations to a waterflood and a miscible gas flood were measured on core samples. A calibrated Equation of State determined the degree of enrichment required to ensure that the injection gas will be miscible with the reservoir oil.

To predict the performance of the project a fine scale geological model of an inverted quarter nine-spot pattern was constructed. Using the Todd-Longstaff technique, simulations were undertaken on a number of different geological realisations, and the effects of reservoir parameters examined. Results were combined parametrically to obtain a range of incremental oil recoveries. Scale-up to a 10 pattern project was achieved by determining a number of scaling factors from the quarter nine-spot model. Patterns were then phased according to the volume of gas available for injection.

The design of the gas injection project has taken into account the existing production facilities and well completions. The Electric Submersible Pumps used will be upgraded to handle 40% free gas at the pump inlet. Phasing of the gas injection patterns will prevent returned gas bottlenecking the gas plant and pumping the LPG to injection pressure has minimised the size of the gas compressor.

Introduction
The Wytch Farm Sherwood Reservoir, situated in Southern England, was discovered in 1977. The formation is a Triassic sandstone, deposited in a fluvio-lacustrine environment[1]. The reservoir straddles the coastline line beneath Poole Harbour, see Figure 1, and production from the onshore region commenced in 1988. Development of the offshore extension began in 1993, using extended reach horizontal wells from onshore wellsites[2,3].

The reservoir is estimated to have an original oil in place of ca.750mmstb. Production is currently 95mstb/d. 198mmstb has been produced to mid-1997 and an ultimate recovery factor of approximately 50% is predicted with the existing drilling and waterflood development programme.

Geological Description
The Sherwood sandstone zonation scheme, derived by Badley-Ashton and Associates, is shown in Figure 2. Ten units have been defined, numbered 10 to 100. Zones 20, 40 and 90 are continuous field wide mudstones, correlateable between wells. Zone 60 is a 5m thick zone of floodplain

siltstone and mudstones, also of poor reservoir quality. These four zones act as partial barriers to vertical flow. The total thickness of the sandstone is between 140-160m and it holds an oil column of between 40 and 110m in the main part of the reservoir. The original oil-water contact is at 1623.5mTVDSS, and injection of produced and seawater into the underlying aquifer has provided the initial means of reservoir pressure support and sweep through a bottom waterdrive.

The Upper Sherwood reservoir is more stratified than the lower part of the reservoir and as such is less well swept by the bottomwater drive. To improve recovery a pattern waterflood is being implemented, with water injection wells being converted to inject directly into the oil-leg. Oil will be swept horizontally towards offset production wells. Similarly, gas will be injected directly into the oil-leg in a horizontal Water Alternating Gas flood (WAG).

To predict the performance of a miscible gas flood a numerical geological model of part of the reservoir was created. Ten rock types, or lithotypes, were identified which occur in seven groupings, or lithotype associations. Figure 3 shows the lithotype associations representative of the productive Zones 10, 30, 50 and 70 modelled. A high resolution grid was populated with these lithotype associations tied to the properties of the six wells in the part of the field modelled. The geological model was then upscaled to a size practical for numerical simulation. Particular attention was paid to capturing the properties of small scale shales and their impact on vertical permeability. The stratification and low vertical permeability of the Upper Sherwood will favour a gas flood by limiting gas over-ride.

Fluid Properties

The Sherwood reservoir contains a black-oil fluid system. The oil is of 38.3deg API, with a GOR of 357scf/stb and a saturation pressure of 1086psia. Initial reservoir pressure at datum was 2436psia, reservoir temperature is 150deg F and oil viscosity is 1cp at initial conditions. Current pressure in the onshore Sherwood reservoir varies between 1800 and 2600psia.

Residual Oil Saturations

A number of waterflood residual oil saturation measurements had been made on core plugs prior to field development and two more measurements were made as part of the gas injection study. Figure 4 shows the measured data. A degree of continued slow drainage was observed from the cores, but at a residual oil saturation to water (Sorw) of 23% the relative oil permeability was 0.0001 (i.e. one ten thousandth of the original). Lower oil saturations would only be achieved outside of the fields economic lifetime, or in zones of particularly high throughput.

Three further sets of core flood measurements were made to gauge the effect of a gas flood:

Well	Core Condition	Gas Flood Type	Swi (%)	Porosity (%)	Sw at Water Breakthrough (%)	Sorw (%)	Sorm (%)
F8	Preserved	Tertiary	23.0	14.0	41	34	7
F13	Restored	Tertiary	17.7	20.9	30	30	13
F13	Restored	Secondary	16.5	20.8	---	---	4.5

The different values of residual oil saturation to miscible gas (Sorm) seen from the three floods are attributed to varying degrees of water blocking. The secondary gas flood on core from well F13 was conducted in the presence of an immobile water saturation (Swi). The two tertiary gas floods, with a mobile water saturation, showed higher values of Sorm as a result of water blocking. The restoring process on core from well F13 left the core strongly water wet as evidenced by the lack of further oil production from the core post water breakthrough. Strongly water wetting character tends to increase water blocking. However, the use of preserved core can cause the rock to be too oil wet and exhibit a reduced water blocking effect. A base value of 10% Sorm was used in the evaluation.

Equation Of State Development

To investigate the process efficiency at a microscopic scale using compositional modelling an Equation of State(EOS) is required for the fluid system. A ten component Peng-Robinson[4] equation was derived, matching its predictions to gross reservoir fluid properties and the results of swelling test measurements, see Figure 5. The EOS was then used to predict combinations of sales gas, propane and butane which would be miscible at reservoir conditions.

Simulation Modelling

A sector model was built of a quarter inverted nine-spot pattern, with an injection well at one corner and three production wells at the other corners, see Figure 6. The model was run using the Todd-Longstaff/Chase-Todd formulations[5,6] and the incremental oil recovery by miscible gas injection over a waterflood investigated. It was recognised that there was a lot of uncertainty in many aspects of the model and a sensitivity analysis was undertaken to determine the range in project outcome. Figure 7 lists the variables investigated, each case being run with 0.3HCPV of miscible gas injected. The values of oil recovery were analysed parametrically[7] by associating probabilities with each of the sensitivities and deriving a relationship between the incremental oil recovery and cumulative probability. The incremental recovery at a 50% probability is 11%, with a 90% probability of 8.7% recovery and a 10% probability of 13.8%.

Compositional Modelling

The Todd and Longstaff (T&L) model was converted to run compositionally as a sensitivity. Initially the compositional model, accounting for gas hysteresis effects, was found to have a higher gas retention than the T&L model. This was found to be a gridding phenomena, the comparatively coarse model having insufficient blocks to achieve the true miscible process, resulting in gas retention by three phase effects. Increasing the gridding in equivalent 2D compositional models removed this effect and a similar gas retention was found.

Upscaling

It was recognised that constructing a simulation model of the whole of the onshore Sherwood to model the gas flood in detail would be impractical. With over 40 wells in an area of 4km by 8km grid block size would be coarse and the model unwieldy, inaccurate and time consuming to run. Instead, the performance of the seven gas injection patterns identified, see Figure 8, was modelled using scaling factors determined from the quarter pattern sector model. The response of the individual quarter patterns was related to the pore volume, throughput rate, skew, aeolian sand content (effective vertical permeability) and throughput volume, see Figure 9. To predict the returned gas profile a relationship between the gas returned/gas injected and the oil recovered/total recovery was derived, relating the trapped gas in each quarter to the volume injected to the TPV and the oil recovery.

The performance of each of the seven full patterns was determined by summing the response of the component quarters. The overall project profile was determined by phasing gas injection into the patterns according to the volume of gas available. This was dependant on the base field oil production rate, determined from the full field model, and the returned gas profile. In addition, the total volume of gas returning to the central processing facilities must remain below the gas handling capacity. Figure 10 summarises the upscaling process. Note that three generic patterns with injection wells yet to be allocated were added to the seven explicitly modelled so that the project would cover the majority of the onshore area.

The resulting project profiles are shown in Figure 11, illustrating the incremental oil, gas injected and gas returned, and the impact on the sales gas and LPG export profiles.

Incremental oil recovery is predicted to be 12.6mmstb, equivalent to an incremental recovery factor of 7.5% over that part of the field swept. The range in recovery is from 9.9 to 15.8mmstb. A total of 60Bscf of miscible gas will be injected, trapping 22Bscf in the reservoir. Gross project efficiency is 4.8mscf/stb, or at reservoir conditions 3.3rbMI/rboil. Net project efficiency is predicted to be 1.7mscf/stb or at reservoir conditions 1.2rbMI/rboil. To validate the evaluation technique and the performance predictions, comparisons were made with the reported performance of miscible gas floods and the experiences of operators of similar projects taken into account[8,9].

Facilities Design and Well Operations

Oil, gas and water produced from the field are processed at a central gathering station from which oil, gas, propane and butane are exported. Retaining these processing facilities allows propane and butane to be pumped into the compressed gas stream. This reduces the compressor loading and allows for the composition of the miscible injectant to be varied to meet miscibility criteria and to supply the remaining relative market demands for propane and butane. The C5+ components extracted from the separator gas can continue to be exported within the oil stream.

The injection facilities, see Figure 12, were designed to ensure continued operation of the oil processing facility in event of failure of any of the injection pumps or the gas compressor. The low pressure LPG pumps are considered to be reliable, and major pump components are to be stocked to facilitate repair before onsite LPG storage facilities are filled. The high pressure LPG pump, with a discharge pressure of 190barg, is thought to be less reliable and has been twined. In the event of failure of the gas compressor, gas can be diverted to sales at short notice, and injection of LPG can continue. In this manner, oil production should not be interrupted by failure of the gas injection system.

All wells are produced using Electric Submersible Pumps (ESPs). Injection gas breakthrough at the production wells will cause the pumps to run with free gas at the pump inlet. A review showed that existing pumps can run with up to 20% free gas, and new pumps will be upgraded to handle 40% free gas. The free gas will produce a gas lift benefit, although with the existing completions and at water cuts greater than 50% this will not be sufficient to supplant the ESPs.

Conclusions

A miscible gas flood of the onshore part of the Sherwood reservoir is a commercially viable project and injection is planned to commence in the second half of 1997. The project forms part of an integrated reservoir management strategy and is one of many options being progressed to maximise reserves and value from the field.

Injection of 60Bscf of miscible gas is predicted to recover 12.6mmstb of incremental oil over a 15 year period, with an upside of 15.8 and downside of 9.9mmstb.

A detailed reservoir description, laboratory corefloods, fluid analyses and simulation modelling has been undertaken to predict the performance of a miscible flood. The experience gained from a study of analogue projects has been applied.

Processing plant, injection facilities and well completions are an integral part of the design of a miscible gas injection project and have been considered at an early stage in the project evaluation.

Acknowledgements

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All views expressed in this paper are those of the authors alone, and not necessarily of the above mentioned companies.

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Figure 1
Sherwood Reservoir Showing Well Locations

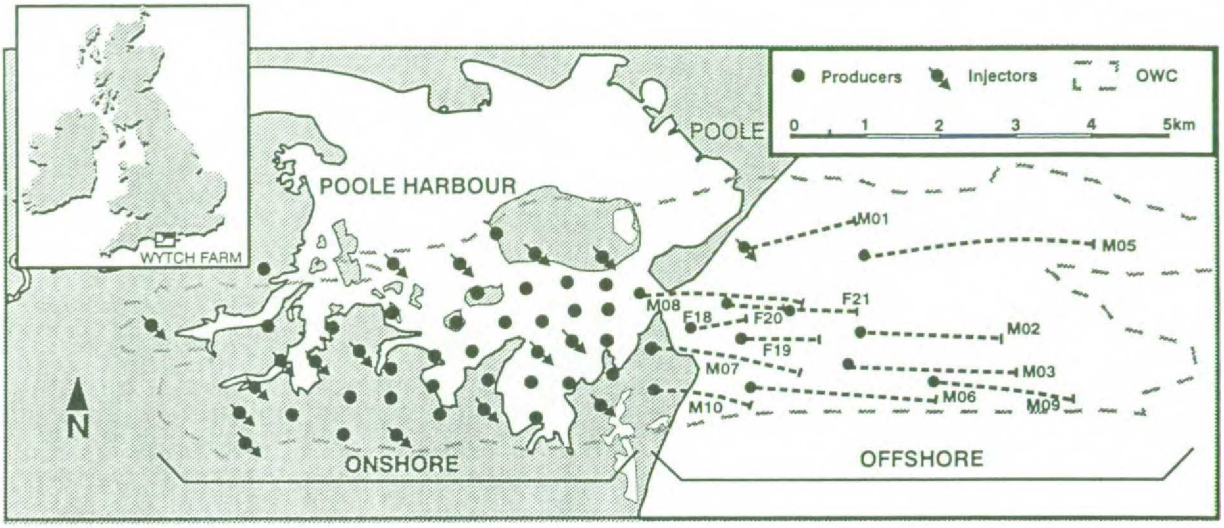


Figure 2
Sherwood Reservoir Geological Zonation

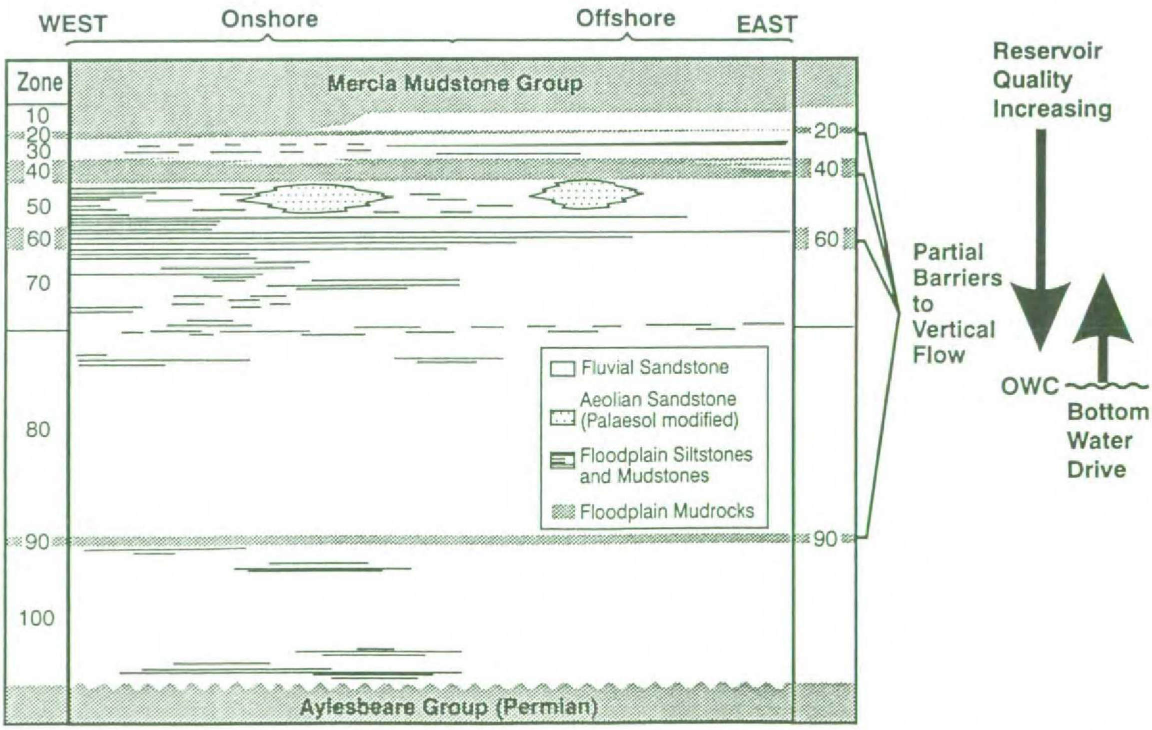


Figure 3
Integrated Reservoir Description

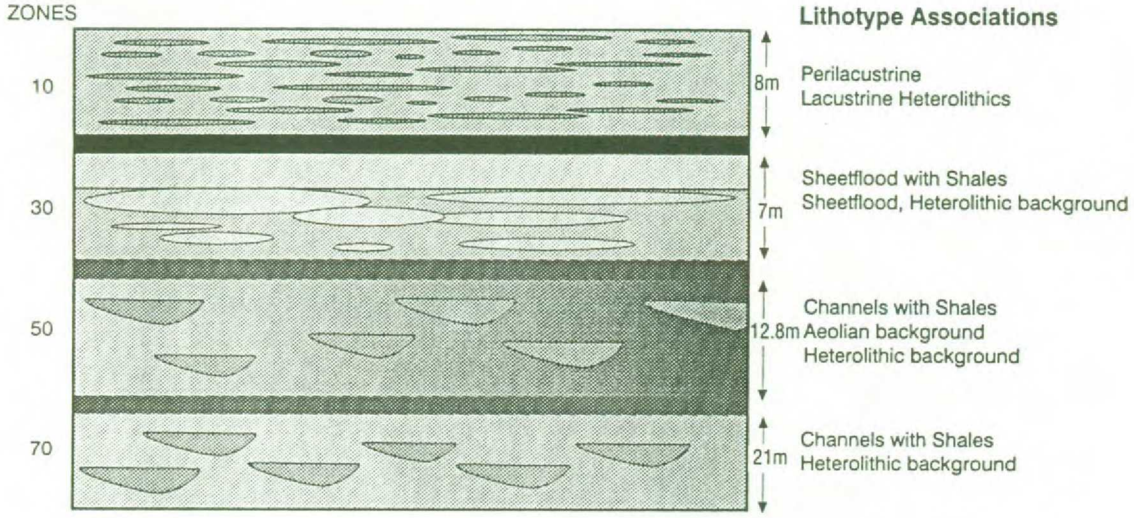


Figure 4
Core Flood Measurements: Waterflood Residual Oil

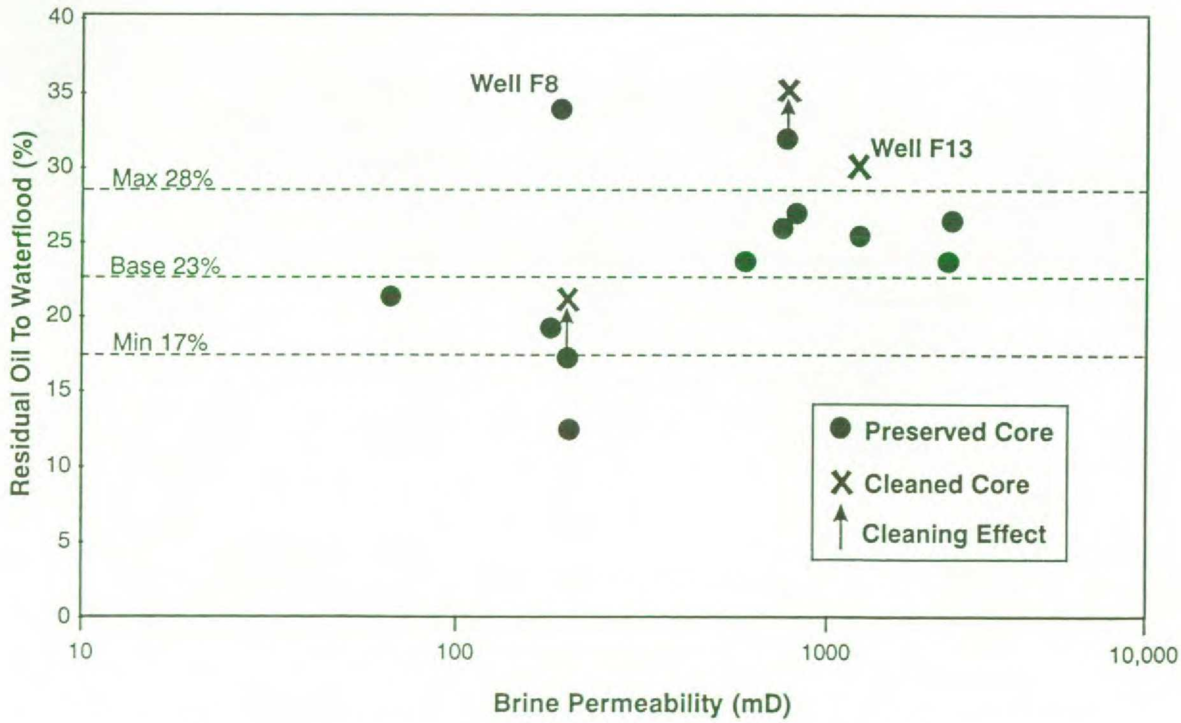
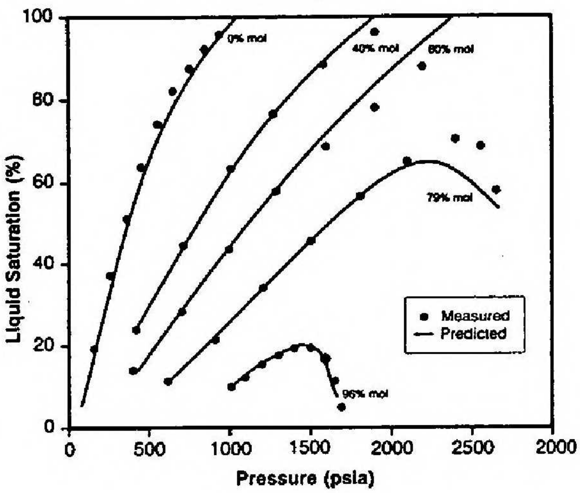


Figure 5
Equation Of State Development

10 Component EOS

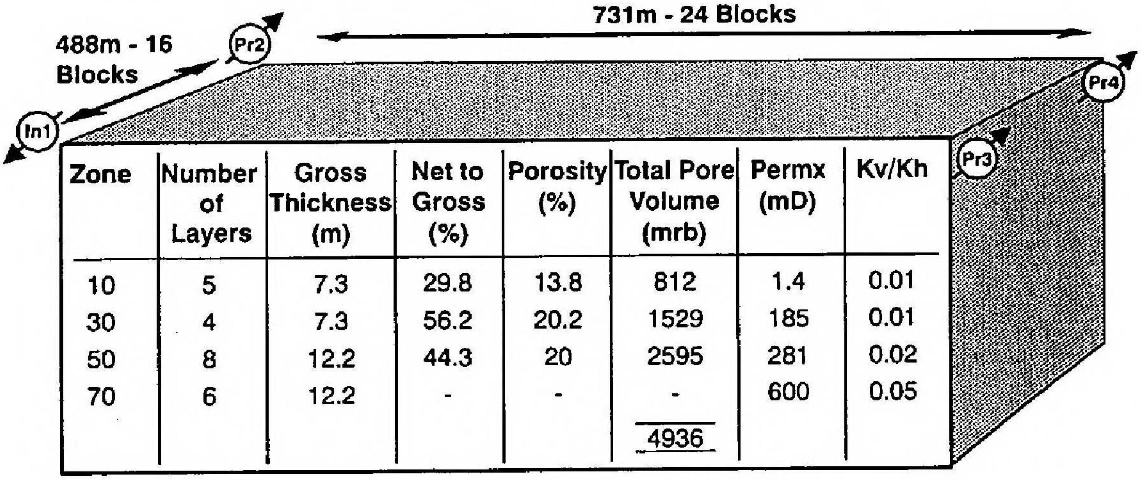
Components	MW
C1N2	17.85
CO2C2	30.27
C3	44.10
C4	58.12
C5	72.15
C6PC1	92.18
PC2	135.84
PC3	206.65
PC4	319.83
PC5	500.00



Base Miscible Gas Composition

	Mol%
N2	6.34
C02	0.33
C1	36.36
C2	17.18
C3	23.79
C4	16.00

Figure 6
Simulation Model Average Properties



Zone	Number of Layers	Gross Thickness (m)	Net to Gross (%)	Porosity (%)	Total Pore Volume (mrb)	Permx (mD)	Kv/Kh
10	5	7.3	29.8	13.8	812	1.4	0.01
30	4	7.3	56.2	20.2	1529	185	0.01
50	8	12.2	44.3	20	2595	281	0.02
70	6	12.2	-	-	-	600	0.05
					4936		

Figure 7
Sensitivity Analysis of Quarter Nine Spot Incremental Oil Recovery

Parameter	Base	Upside	Downside
Sorw (%)	23	28	17
Total Sorm (%)	10	8	14
Omega	0.8	1	0.5
Alpha	600	1000	400
3 Phase Rel Perms	Cheshire	Stone 1	Stone 2
Miscibility	MCM	FCM	
Pseudo Rel Perm	Pseudo	No Hold-Up	
Zone 20 & 40 Barriers	Barrier	No Barrier	
Aeolian Sand Content	Mean	Min	Max
Hetrolithic Kv/Kh	Base	*4	*20
Modified Permeability	Base	Higher	
Channel Descriptions	Sinuosity & Orientation Varied		
Well Rate	Base	High	Low
Skew	Skewed	Balanced	
Initial Water Cut	Base	50%	

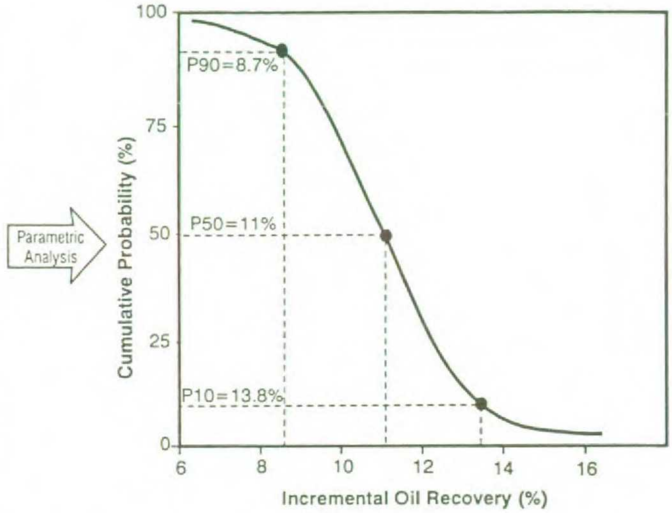


Figure 8
Gas Injection Patterns, Onshore Reservoir

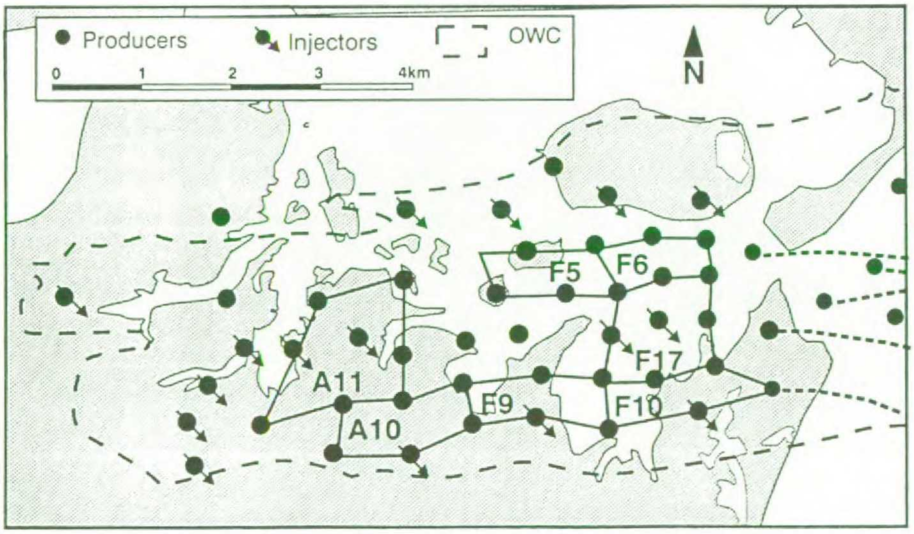


Figure 9
Scaling Factors Derived From Simulation Model

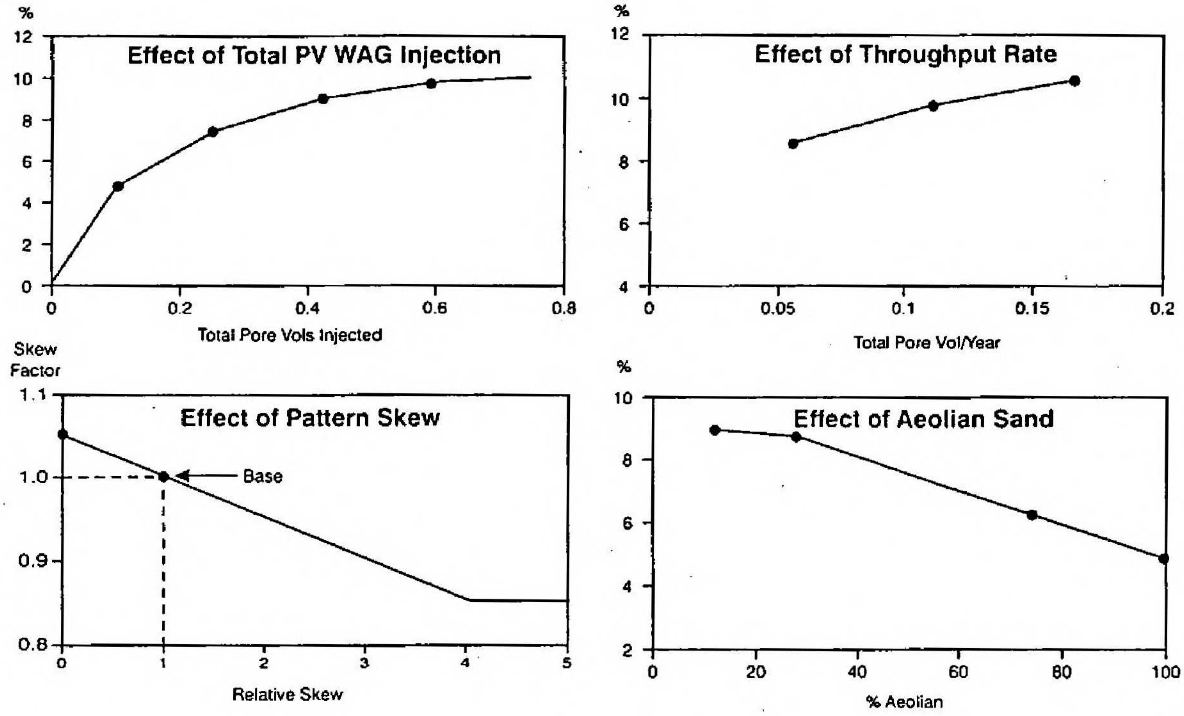


Figure 10
Scaling from Simulation Models to Full Project Profiles

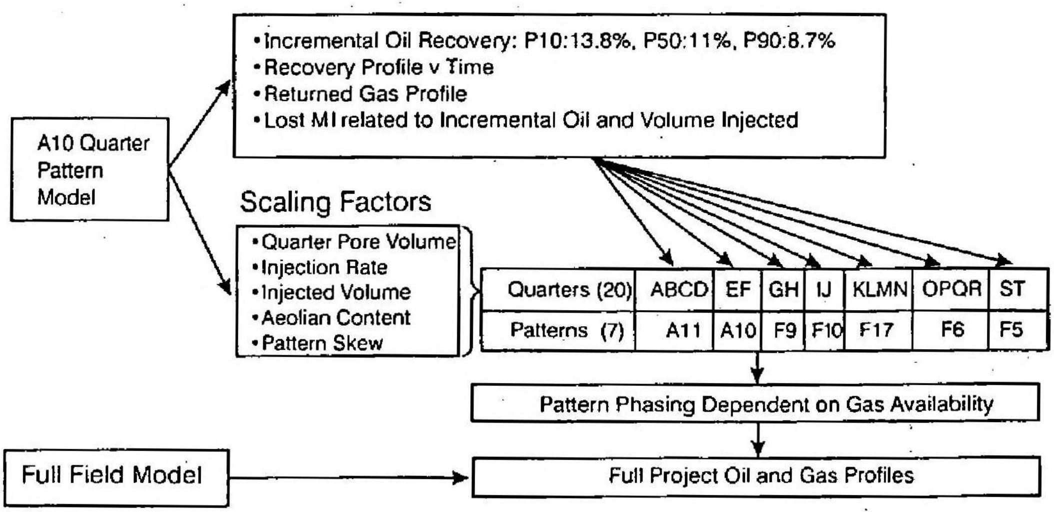


Figure 11
Gas Injection Project: Production/Injection Profiles

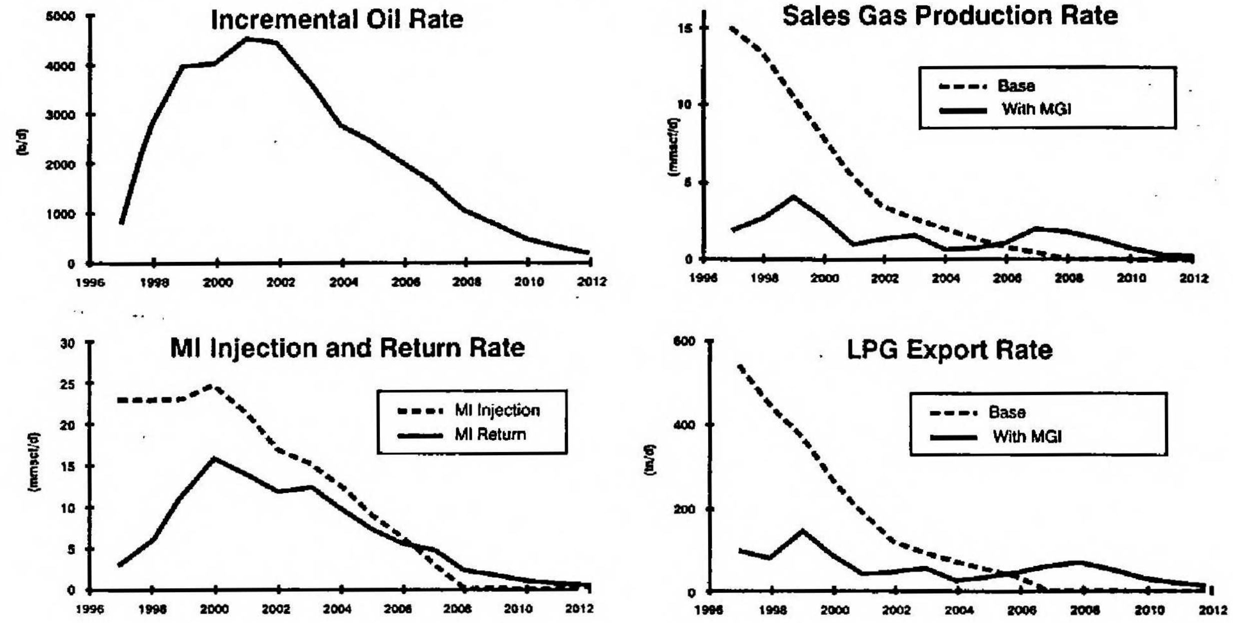


Figure 12
Miscible Gas Injection Facilities Schematic