

Depositional pattern and reservoir heterogeneity of Tipam Sand-2, Lakwa Field, India

Lakshman Singh,¹ A. Elias Ahmed,¹ R.P. Verma² & R.V.S. Murthy¹

¹ *Institute of Reservoir Studies, Oil and Natural Gas Commission, Chandkheda, Ahmedabad-380 005 India;*

² *Oil and Natural Gas Commission, Nazira-785685, Assam India*

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Abstract

This paper describes the importance of the braided channel environment for the entrapment of hydrocarbons, the porosity pattern, the reservoir heterogeneity, the sweep efficiency and the identification of bypassed oil areas, in the Miocene Tipam Sand-2 of the Lakwa Oilfield. The growth-faulted structure has an oil bearing area of 20 km². The oil gravity varies from 20.7 to 32° API.

The Tipam Sand-2 oil pool is the largest among multiple pools in the Tipam Sandstone Formation. There is a marked coincidence of the structure of the field and the thickness of the sand within its depocentre. The sandstone was deposited in a composite braided channel river system. The sand member is characterised by longitudinal and transverse bars which are flanked by marginal, abandoned and slough channel facies. The bars are covered by overbank shales of flood periods.

The porosity pattern is dominated by high porosity areas within the longitudinal and transverse bars. The low porosity areas along the flanks of the structure are marked by low energy deposits.

Two preferential permeability trends are parallel to the E-W running bar crests, the primary trend, and to the secondary NE-SW or accretionary trend. These areas correlate well with the well production rates, advance of waterfront and areas of better sweep efficiency. The rise in oil-water contact is controlled by reservoir rock permeability trends and oil withdrawal rates.

Infill drilling electrolog data indicate a significantly differential rise of the oil-water contact from the initial oil-water contact (5–8 m), as compared to the nearby wells (10–15 m). Integrating the depositional pattern, the reservoir heterogeneity and the withdrawal rates, a reservoir zoning is attempted to identify areas of bypassed mobile oil, especially along the southern part of the structure. Watercut analysis indicates that the preferential paths are along the permeability trends. Water coning is controlled by the presence of the overbank shales, larger clearance of perforations from oil-water contact, presence of shaly sands, laminations of silt, mica and cross-bedded foreset laminae.

Introduction

With the strike of oil in 1890, in the Digboi field, near the Naga thrust, the Upper Assam Basin became the first proven hydrocarbon-bearing basin discovered in India. The commercial oil fields discovered within Oligocene Barail Group reservoirs are Nahorkatiya, Moran and Rudrasagar and those

within the Miocene Tipam Sandstone are Digboi, Lakwa, Geleki, etc. The Lakwa and Geleki fields contain oil in Barail reservoirs also (Fig. 1).

The Lakwa field, the biggest field in Upper Assam in terms of hydrocarbon reserves, hosts oil in multiple pay sands within Barail and Tipam reservoirs. The Tipam Sandstone is about 1000 m thick in the Lakwa field. Different members within this

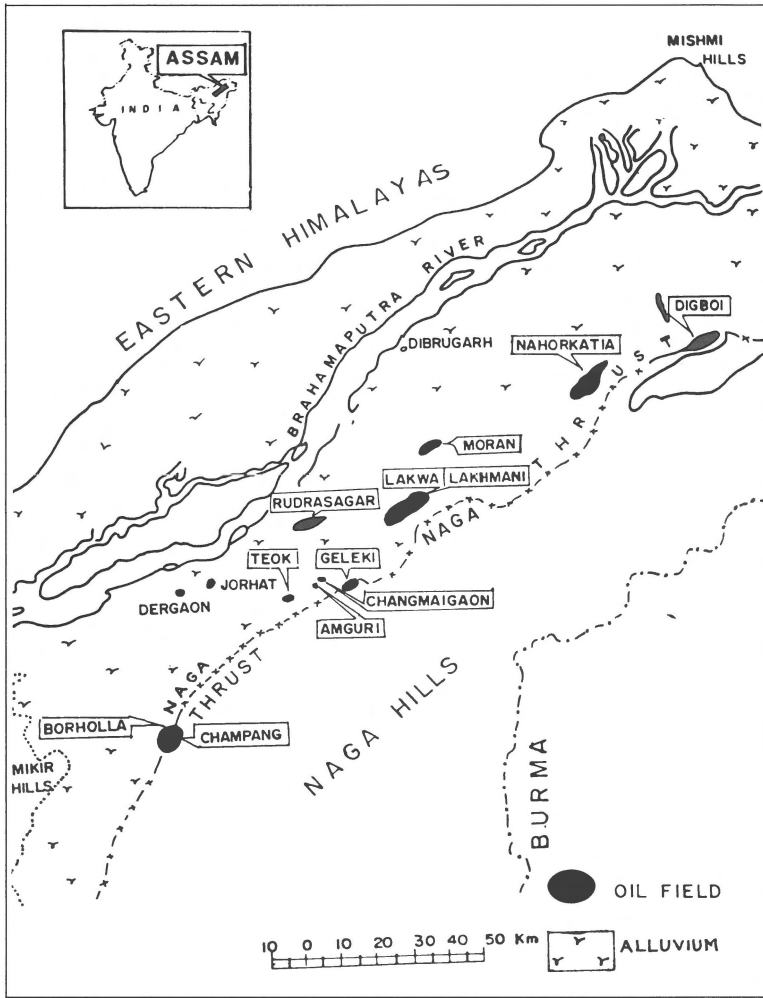


Fig. 1. Index map of Upper Assam Basin.

formation are identified and designated from old to young as Tipam sands 6, 5, 4, 3, 2 and 1 (Table 1). These are separated by continuous shales. Sands occurring within the shales above Tipam sands 5 and 2 are referred to as TS-4 and TS-1, respectively. Tipam pools comprise the bulk of the proved reserves and are hydrocarbon-bearing in different sand members. Among these the TS-2 Sand forms the principal reservoir containing about 50 MMm³ of STIOIP reserves. The field has been exploited in TS-2 Sand since 1968 and is currently producing at the rate of 2900 m³/day from about 80 wells. The maximum gross thicknesses of oil and water columns in this sand are 85 and 35 m,

respectively. Salient reservoir particulars are given in Table 2.

Analyses of the performance of the Lakwa field by Sant Kumar et al. (1985) and by Hazarika et al. (1986) and the present data indicate (i) the presence of bottom water, (ii) a marginal pressure drop of 11 kg/cm² for a cumulative oil production of 11.5 MMm³, (iii) water coning in many wells including the crestal wells, (iv) the need for infill drilling to improve the drainage efficiency (v) differential movement of waterfront between wells drilled earlier and infill wells drilled subsequently, and (vi) shale layers within TS-2 Sand are effective

barriers to arrest water coning.

For the purpose of development, the field is considered to comprise two major fault blocks namely the Main Block (blocks IV to I, from west to east), and the Northern Block (containing fault blocks VI & V, west to east) as indicated in Fig. 2. About 90% of reserves of TS-2 Sand are within the Main Block, of which Block-II contains 70%.

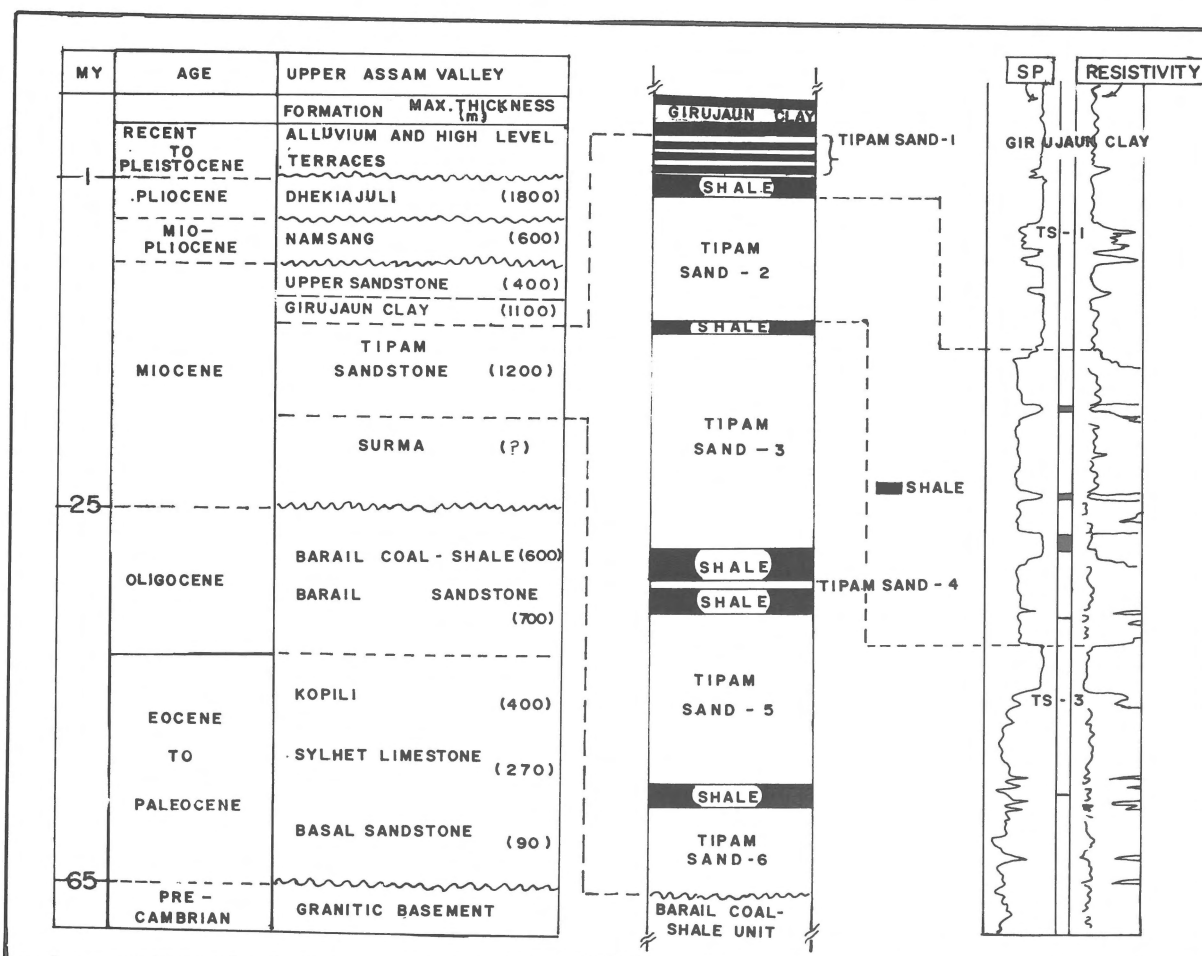
Structure and hydrocarbon entrapment

The entrapment of oil in the Tipam sands of the Lakwa field, is controlled by synsedimentary faults. Two sets of intersecting faults (NE-SW & W-E) control the areas of subsidence and subse-

quent structural deformation (Figs 2 and 3). The mobilisation and shift of the Barail and the Tipam depocentres were controlled by movement along pre-existing zones of weakness. There is a marked coincidence of each depocentre with associated structure and sand thickness. The hydrocarbon pools of the Tipam Sandstone are aligned more towards the seaward side of the hydrocarbon pools of the Barail Group in the Lakwa field and elsewhere.

The TS-2 Sand is the biggest among the multiple pools of the Tipam Sandstone, both in vertical and areal closure. The multiple-type structure comprises a rollover (Block-II), updip fault closures (Block-V & VI) and parallel fault blocks (III & IV), in order of priority with respect to hydrocar-

Table 1. Tertiary stratigraphy of Upper Assam Basin



bons (Fig. 2). Within each sand, the topmost part only holds significant hydrocarbons.

Depositional environment

This paper deals with the work undertaken to decipher the sedimentary facies and sequence of fa-

cies and to understand their lateral and vertical continuity in the Lakwa field. The study is mainly based on well log derived facies, geological cross sections, well log correlation, iso-porosity, isopach and reservoir heterogeneity maps with special emphasis on the recognition of continuous and 'stochastic' shales within the TS-2 Sand of the Lakwa field. Textural characteristics as well as sedimentary structures inferred from the unfortunately in-

Table 2. Summary of oil field data of the Tipam Sand-2, Lakwa field

Trap	
Trap type	Growth faulted structure
Area	20.5 km ²
Depth to crest	2310 mss
Lowest closing contour	2395 mss
Oil-water contact	2385 to 2390 mss (average)
Oil column	85 m
Pay zone	
Formation	Tipam Sandstone
Age	Middle Miocene
Max. gross thickness	120 m (including aquifer)
Net thickness	60 m (max.)
Porosity	23.5% (average)
Hydrocarbon saturation	76% (bar crest) to 65% (bar flank)
Permeability (buildup analysis)	800 md (bar crest) to 90 md (bar flanks)
Productivity index	0.9 MMt/kg/cm ²
Hydrocarbons	
Oil gravity (API°)	20.77 (block-I) to 32.0 (blocks V & VI)
Oil type	Undersaturated
Bubble point	110 kg/cm ²
Formation volume factor	1.07 (block-I) to 1.27 (block-IV)
Mobility ratio	1.2 to 4.1 (NW to SE)
Salinity of formation water	1000 to 2000 ppm NaCl equivalent
Resistivity of formation water	1.5 to 2.0 ohm · m at 74° C
Reservoir conditions	
Temperature	74° C
Pressure	243.6 kg/cm ² (initial)
Field size	
Net area	20.5 km ²
Geological reserves	51 MMm ³
Recoverable reserves	24 MMm ³
Drive mechanism	Bottom water
Production	
Started	1968
Present rate	2900 m ³ /day
Cumulative production	11.5 MMm ³

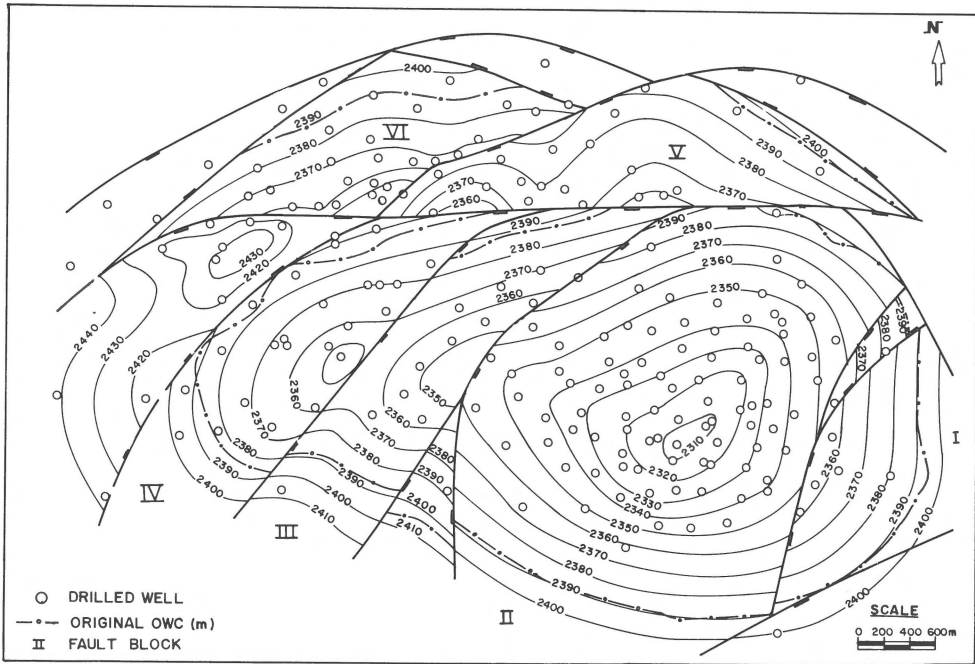


Fig. 2. Structure contour map on top of TS-2 Sand.

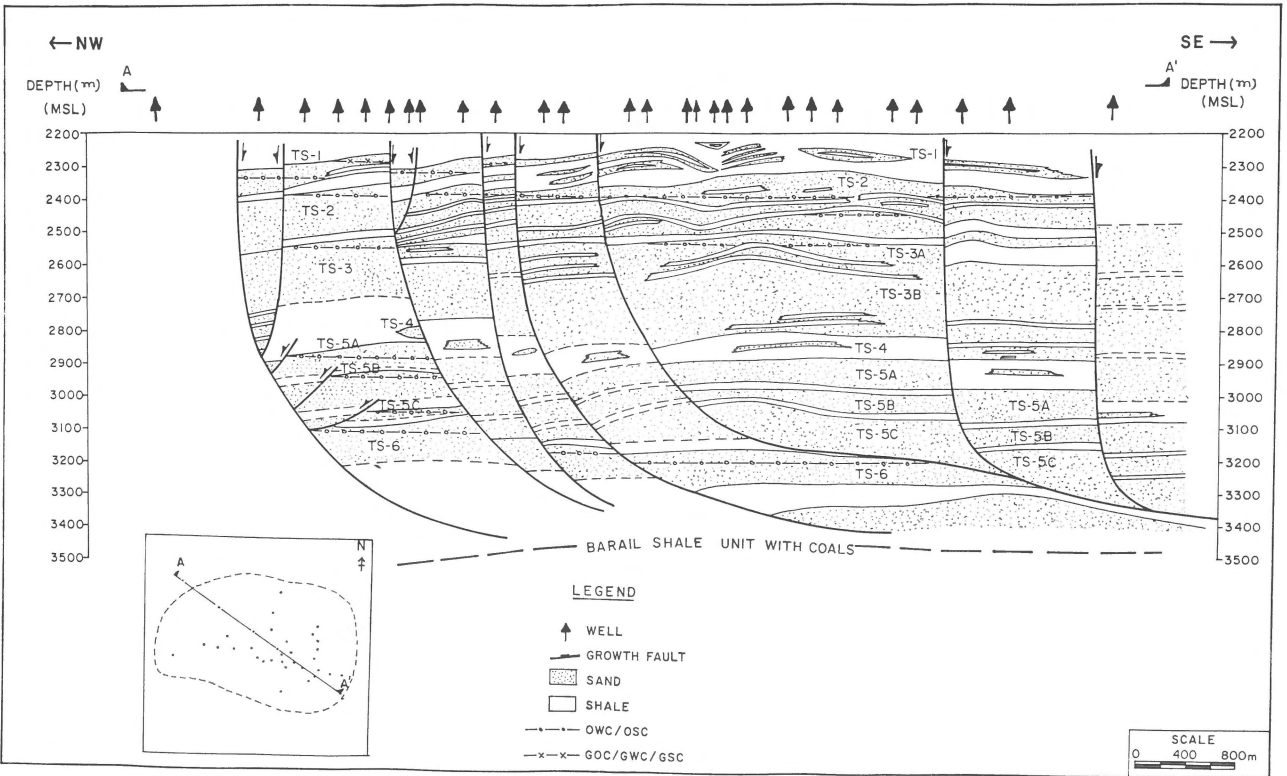


Fig. 3. Geological cross-section across Lakwa field (NW-SE).

adequate core data are summarised in Table 3. Based on this analysis, a depositional environment map has been prepared.

The wide areal extent, length/width ratio, continuity, the nature of divisions and confluence of fluvial channels around islands of sand bars, the absence of fossils and the rare preservation of organic matter favoured the choice of a fluvial, depositional environment of stacked braided channels. The main consideration, however, is the geometry of the sand body. Attempts have been made to understand the layering effects within the TS-2 Sand. Different genetic components have been recognised with the aid of electrofacies, porosity maps and core data. The presence of these units in turn has been correlated with the reservoir behaviour and the production pattern to understand the influence of reservoir heterogeneity. The maximum variability in the depositional environment towards the top of TS-2 is indicated by the contrasting well log finger prints. Significant observations on electrofacies are summarised in Table 4.

The isoporosity map has been prepared by transforming sonic time with core porosities since sonic logs are most commonly available in the wells (Fig. 4). This map indicates a number of high porosity areas around longitudinal and transverse bars. The flanks of the structure are characterised by lower porosity. The maximum porosity variability in the central part in Block-II (cf. Fig. 2) is due to the presence of several porosity islands. In general, except at the bar crests, there is a decrease in

porosity upwards, within each cycle. The low porosity trend, in the NW part of Block-II is conspicuous (abandoned channel). The two preferential high porosity trends coincide with the E-W and NE-SW axes of bar crests, the former indicating the primary longitudinal bar direction and the latter the transverse bar axes. There is a good match between these axes and the structural axes, especially in Block-II (Fig. 2). The isopach map shows the 'thicks' in the crestal part of the structure and bar crests emphasise the syndepositional faulting and the resulting depositional pattern.

The TS-2 Sand in Lakwa field is a case history of the deposition of a stacked composite braided bar complex (Fig. 5). An east to southeasterly flowing stream develops channels characterised by a high degree of mobility giving rise to multiple channels/bars of diverse type and orientation. The bed load deposits are confined to active channels/bars and abandoned channels are indicated by dominance of suspension load during waning currents (low porosity area in the NW and SE parts of Block-II).

The electrofacies, geological cross section and well log correlation analyses indicate a complex history reflecting multiple episodes of erosion, deposition and switching of channels, which lead to difficulties in tracing shale continuity within each sand, indicating shales to be of a 'stochastic' nature. However, correlation is possible only in the case of overbank shales of high water stage. Three such shale layers are traced within the TS-2 Sand (Fig. 6).

Table 3. Petrographic data of Tipam Sand-2

Rock type	Sandstone with wackes towards the top
Texture	Predominantly coarse to medium grained sandstone, pebbly towards the basal part as well as towards the top, fine grained varieties insignificant
Sedimentary structure	Channel facies: Tabular cross bedding, massive bedding, scour surfaces (cut and fill sequences) Overbank facies: Ripple lamination, undulatory bedding. Layered bedding of sand and silt alternations, lenticular bedding. Mud drapes, convolute laminations
Porosity	Mostly primary; intergranular
Diagenesis	Clay matrix forms coating and bridges on grains. Montmorillonite is of diagenetic type. Quartz overgrowth, deformation of mica and calc. feldspars (minor), diagenetic kaolinite, dissolution of frame work minerals, calcite cement, fracturing of detrital grains (limited) Cement is mostly siliceous

The incipient TS-2 Sand bar complex in the Lakwa field was attached to the right bank of the river and the flow was mainly along the southern part. The bar accretion was perhaps confined to the inner convex side of the flow channel. Reading (1986) identified bars associated with an outer curvature as well as with the sinuous inner curvature. These two types are shown in the depositional pattern map (Fig. 5), the former on the northern part of the structure (blocks V & VI) and the latter along the southern flank.

The final stage of deposition of TS-2 was marked by a progressive increase in water level, with the last episode submerging the composite TS-2 Lakwa braided bar system resulting in extensive deposi-

tion of flood plain shales. The onset of this stage was quite significant in view of its future oil content, variability in texture and composition of sediments, which are reflected in complex signatures of well logs especially with respect to the low resistivity layers and wandering SP behaviour (Table 4).

Reservoir heterogeneity, sweep efficiency & leftover oil islands

Reservoir heterogeneity is related to variation in sedimentary parameters from pore throat size to bedding. It depends on the nature and type of discontinuity within a reservoir, the nonuniformity

Table 4. Well log response of genetic units

Genetic units	Bar facies	Bar flank/channel facies	Abandoned channel facies
Parameter			
SP/Gamma log shape	Cylindrical type of homogenous sand content, thick bedded. Trough within bar complex is indicated by poor development of SP and thin bedded sands.	Cylindrical shape towards base and fining up 'bell' type towards top. Reduction in thickness of vertical sequences upwards. Special type of wandering SP response (negative towards top and shift towards positive scale downward). This pattern is associated with different type of resistivity responses; probably a product of flood cycle.	Sharp positive deflection of SP line towards the top and a well developed SP towards base; thin bedded, alternate laminations (bedding) of shale and sand.
Resistivity log (oil bearing)	Low resistivity layers rare. Conductivity spikes due to limonite.	Low resistivity part towards the top (due to increase in montmorillonite clay content).	
Vertical contact	Blunt top and base, scoured surface often filled with pebbles denoted by resistivity, sonic and also density spikes (only in case of heavy mineral).	Abrupt basal contact and gradational top.	
Stacking of sand bodies and hydrologic continuity	Good vertical and lateral stack leading to better hydrodynamic continuity.	Moderately stacked; erosional contacts improve reservoir properties.	Poor stacking, isolated lenses, stacking worsens with increase in compaction.
Porosity	Uniform good porosity	Deteriorates upward	Very good at the base and worst towards the top.
S_{wi}	Uniformly low values.	Low to moderate.	Highest toward the top
Grain size	Decreases →	Decreases →	→

Note: Slough channel facies is indicated by poor development of SP within sands and by an only marginal difference in shale and sand base lines as compared to other facies.

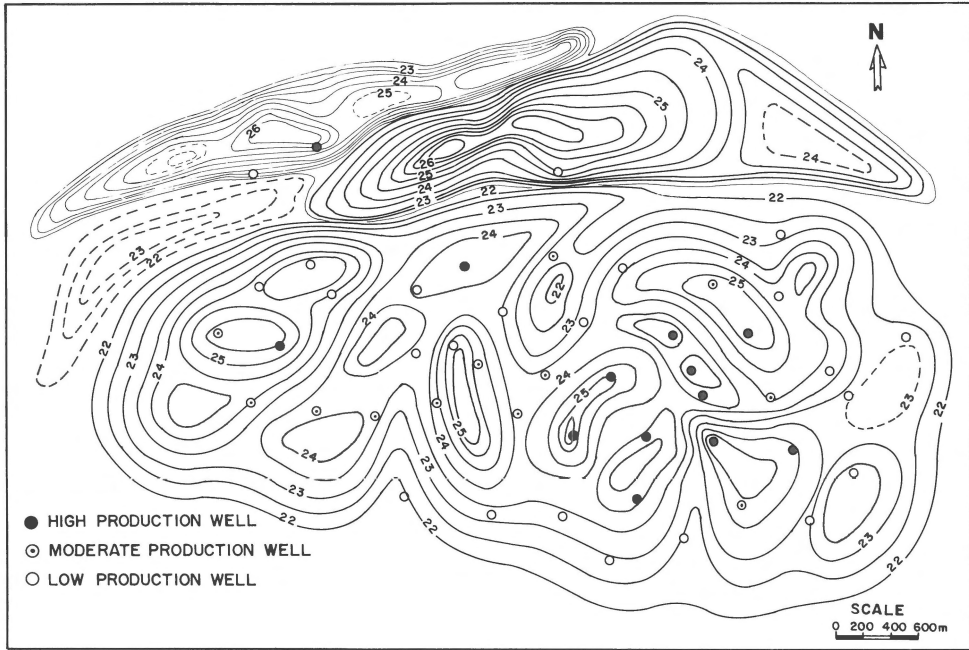


Fig. 4. Isoporosity (%) map of TS-2 Sand.

in a reservoir, the variation in the textural properties of framework and pore geometry, internal structures, and post depositional processes.

The heterogeneity in the TS-2 Sand can be well visualised with the help of porosity, depositional pattern and heterogeneity maps, and well spacing (Figs 4, 5 and 8). Table 5 summarises the variation in oil properties in different fault blocks of the TS-2 Sand. The study of this aspect is aimed at tracing the differential movement of the waterfront and relating it to depositional facies and ultimately at identification of areas of poor or ineffective drainage.

The analysis of the reservoir continuity involves certain assumptions in the interpretation of the continuity of the overbank shale layers and of the sands below the shales as continuous sheet sand bodies. Core data and production performance, however, indicate that the seemingly continuous sheet sands are collections of different horizontal and crossbedded 'lenses' which are laterally stacked. The stacking pattern is good and predictable in active channel/bar sands and poor in abandoned/slough channels and troughs within the bars.

Haldorsen & Chang (1986), while describing

nonreservoir rocks, have highlighted the importance of correct barrier length/width/thickness statistics and interdependence in the identification and interpretation of various reservoir flow units. The major gross inhomogeneity in many sandstone reservoirs may well be the discontinuous shales embedded within and the continuous shales that separate the sandstone units. These shales either divide the reservoir into separate hydraulic units or in case of discontinuity, set a tortuous path through which the fluid flows. The former shales are handled with ease, whereas discontinuous shales have historically presented a difficult reservoir engineering problem in terms of their description and their effect on fluid flow.

The nonreservoir rocks within the TS-2 Sand are shales, shaly sands, shale pebbles and silty shales and micaceous laminations. Overbank shales are probably the continuous shales and separate the flow units except where they are eroded and sands are in vertical contact (Figs 3 and 6). 'Stochastic' shales have extensions sometimes less than the well spacing and their continuity interpretation is subjective. Whether continuous or discontinuous, the shales and sandy shales restrict fluid flow. Hutchin-

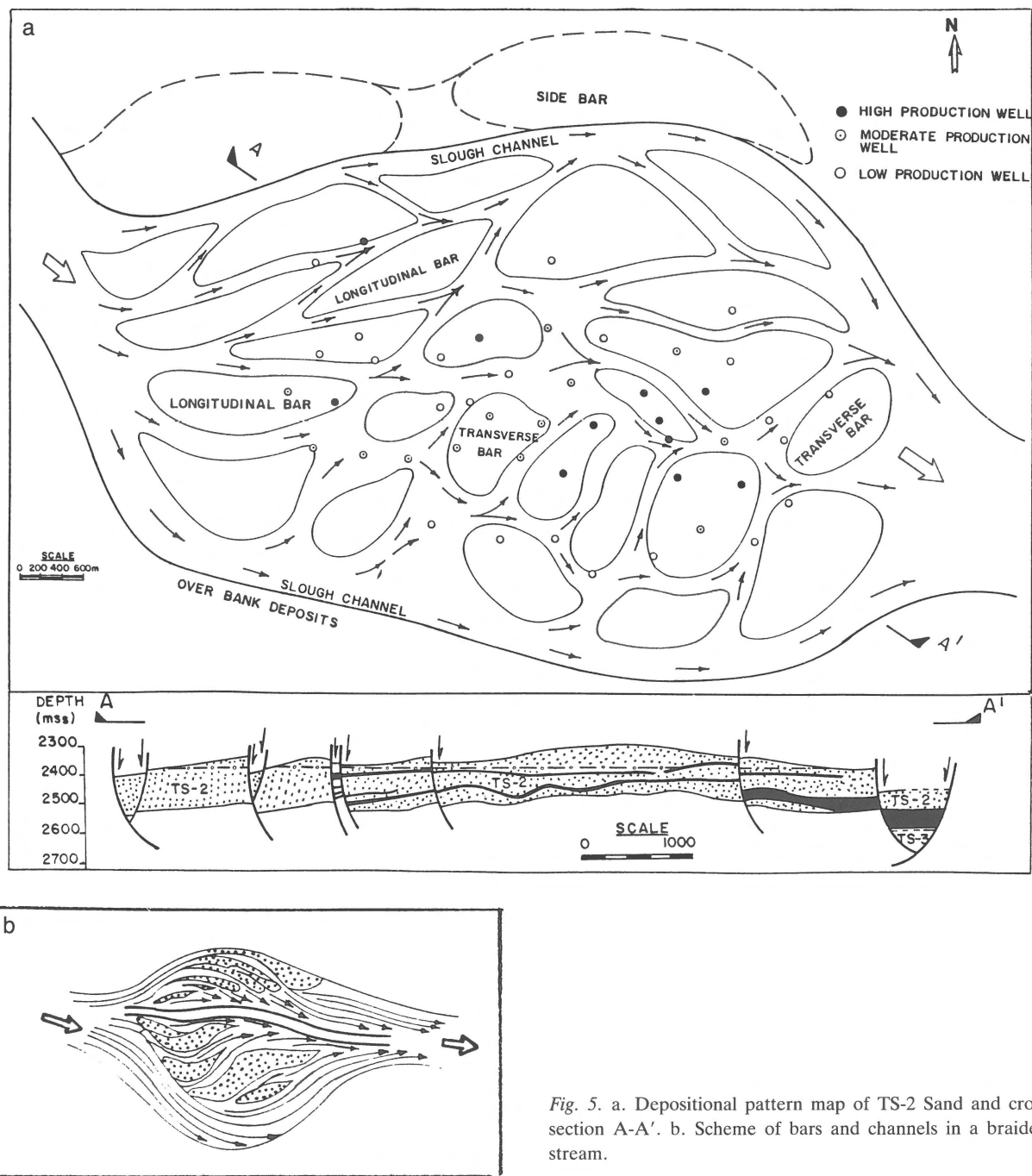


Fig. 5. a. Depositional pattern map of TS-2 Sand and cross section A-A'. b. Scheme of bars and channels in a braided stream.

son et al. (1961) report better continuity in case of horizontal and ripple laminated sections. Figure 7 indicates the distribution of the shale separating layers 2 & 3 of the TS-2 Sand which makes these two layers different hydraulic units.

The reservoir heterogeneity is analysed by pre-

paring nonreservoir thickness, nonreservoir to reservoir percentage and thickness of shale maps from well data pertaining to the oil zone. (However, while interpreting the data the thickness and frequency of occurrence of shales in the aquifer part also were taken into account). Figure 8 indicates

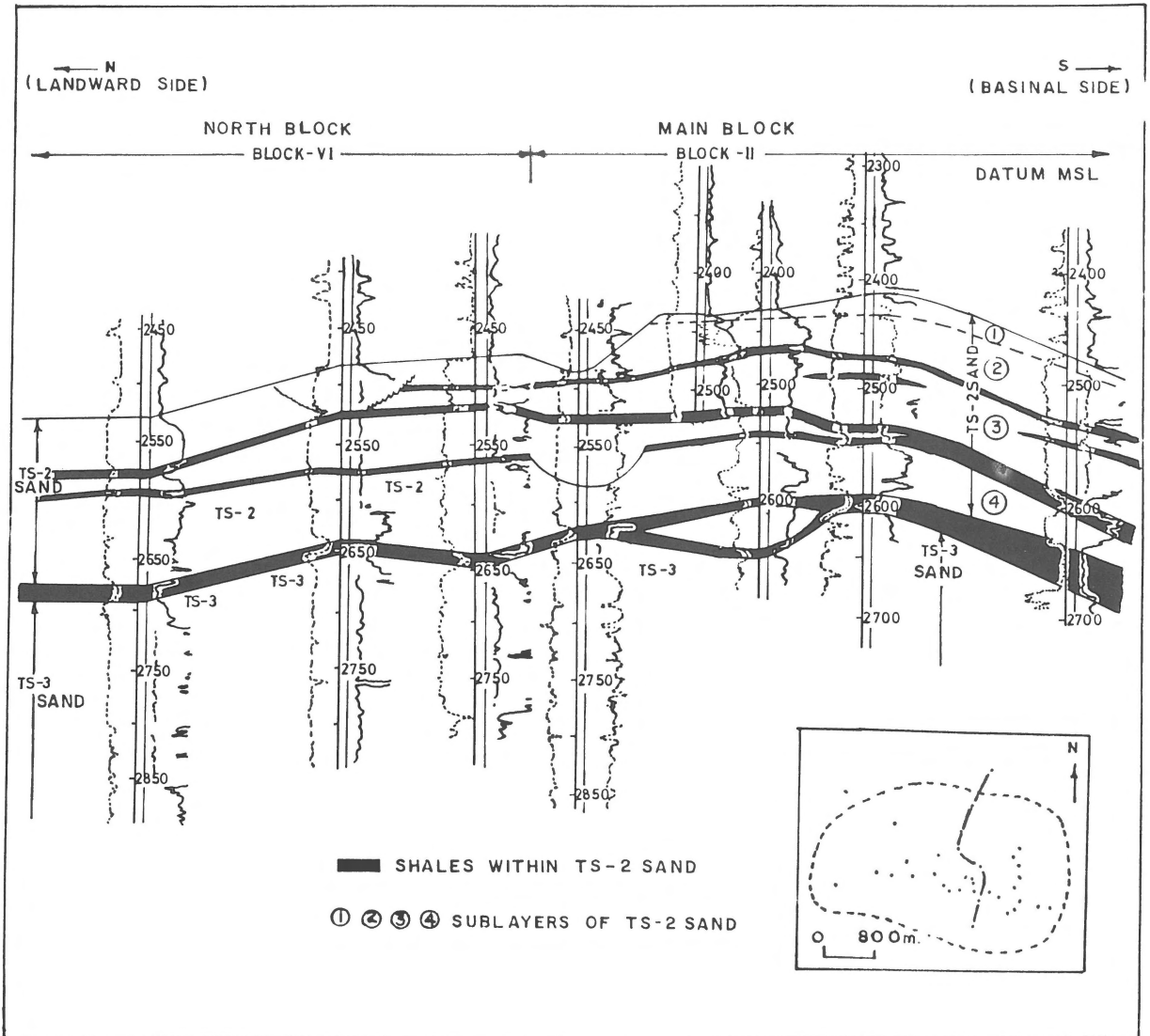


Fig. 6. Correlation in Lakwa wells of TS-2 Sand (N-S).

the higher frequency and thickness of shales in blocks II and I located downstream. The areas within the crestal part showing absence of shales assume greater importance with reference to watercut behaviour of wells. This map also brings out the possible channel (transverse) along the western edge of Block-II. Nonreservoir thickness and ratio maps indicate the E-W longitudinal bar axes and the NE-SW transverse bar axes.

Yadav (1986, 1987) established a sonic time and core porosity transform and a linear relationship for core derived porosities and permeabilities from

about 1000 core samples of the Tipam Sandstone of the Upper Assam Basin. The permeability contrast for the TS-2 Sand is worked out using similar criteria, and is also based on inferences from well log facies and porosity maps as well as production and pressure data.

The permeability distribution of the TS-2 Sand derived from pressure buildup tests is shown in Fig. 9. This map corroborates the geological model comprising active channel-bar sequences, marginal channels, troughs within bars, abandoned channels and slough channels, indicating that the depo-

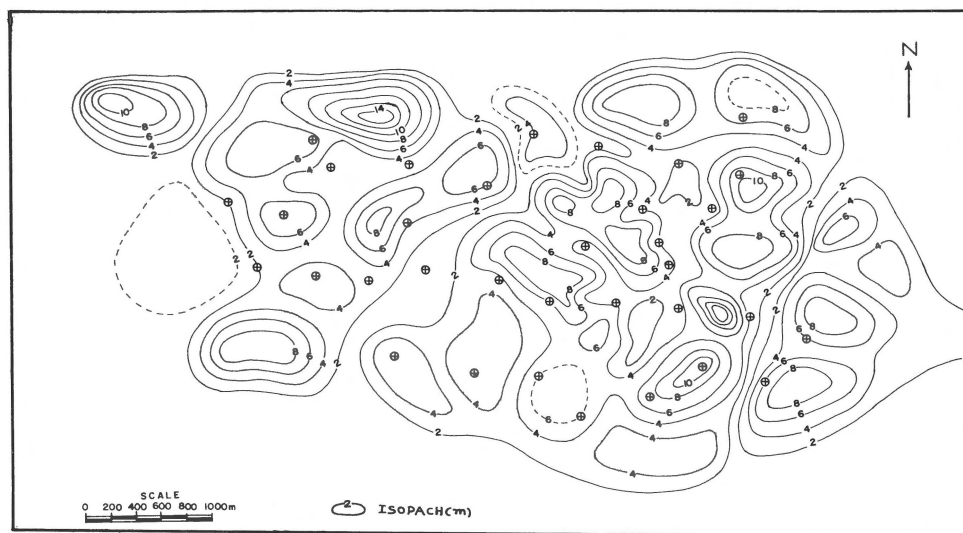


Fig. 7. Isopach map of shale between layers 2 & 3 of TS-2 Sand, Lakwa field.

sitional pattern and textural variations control the heterogeneity of the TS-2 Sand. The degree and pattern of heterogeneity are primarily expressed in terms of permeability contrast. The variation in permeability is between 90 and 800 md in different parts of the field. The high permeability trends within the main block of the Lakwa field coincide with the axes of E-W and NE-SW bar crests (Figs 4 and 9). These areas correlate well with areas of greater oil production, sweep efficiency and waterfront movement (Fig. 10). The islands on either side of the bar crests behave otherwise (Fig. 11).

Infill well drilling has been resorted to since 1985 to achieve uniform drainage and higher oil produc-

tion rates. The infill drilling locations, especially in Block-II, indicated significantly lower oil-water contacts (average 5 to 6 m shifts from the original oil-water contact) as compared to an average shift of 10 to 15 m in earlier drilled wells. These differences were more apparent in the southern part of the field, sometimes even within one well spacing. Attempts were made to trace the movement of the waterfront with time, by fixing the oil-water contacts in the wells drilled since 1968 to present time. The withdrawal rates were integrated with these data and the movement of the oil-water contact was correlated with the permeability contrast. The cumulative oil production map is shown in Fig. 10 which indicates that the reservoir facies control the production rates. The bar crests indicate the best production rates. Where the abandoned channels are perforated in the lowest channelised part, the rate of production is good. Therefore, production rates are controlled by planned perforations also.

The major problem faced during the study was related to the fixing of the oil-water contact and the estimation of oil saturation in 'seemingly' flushed zones and their distinction from the 100% water saturated zone. This is mainly due to the fresh connate water of the sands (1 to 2 g/l salinity), to a complex mineralogy (quartz, feldspars, mica, rock

Table 5. Variations in oil properties in different fault blocks of the Lakwa field

Block	API ^o (gravity)	GOR (m ³ /m ³)	FVF	Mobility ratio
I	20.77	21	1.07	} 4.1
II	22.8	44	1.15	
III	25.7	67	1.19	} 1.2
IV	28.4	93	1.27	
V & VI	32	128	1.24	

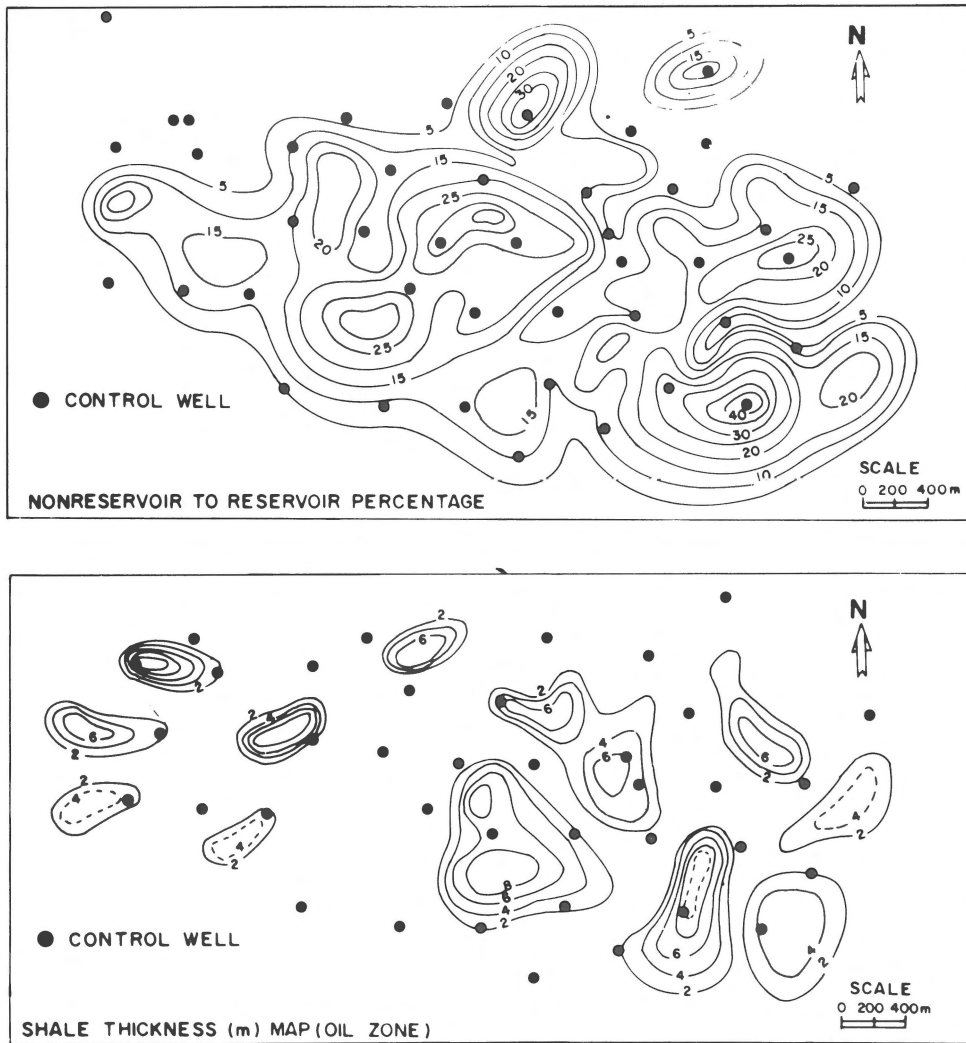


Fig. 8. Nonreservoir to reservoir percentage and Shale thickness maps (oil zone), Main Block.

fragments, clays and heavy minerals) and to the conductance of the clays. A few wells were selected for quantitative evaluation of porosity and S_w based on Dual water, Indonesian and Archie's formulae. The Dual water model enabled prediction of the oil saturation in a more rational manner than hitherto obtained by any other method. An analysis of water saturation vs. depth of these wells indicated (i) the S_{wi} values in different wells, (ii) the location and thickness of the transition zones, and (iii) separate oil-water contacts in individual layers. These results, in general, showed oil saturations to be 5 to 8% lower as compared to those derived from mer-

cury capillary pressure curves. The S_{wi} values, when correlated with the sedimentary facies, indicated 5 to 8% less water saturation in bar crests/marginal channels than in abandoned/slough channels, reflecting the effect of different grain sizes and sorting in these facies.

The waterfront advance as deduced from the rise of the oil-water contact in different wells indicated its sensitiveness to rock permeability distribution in the field (dependent on the depositional system) and withdrawal rates (dependent on reservoir and human factors). The cumulative oil production was 22.5% of IOIP by 1989. It amounted to 9% of

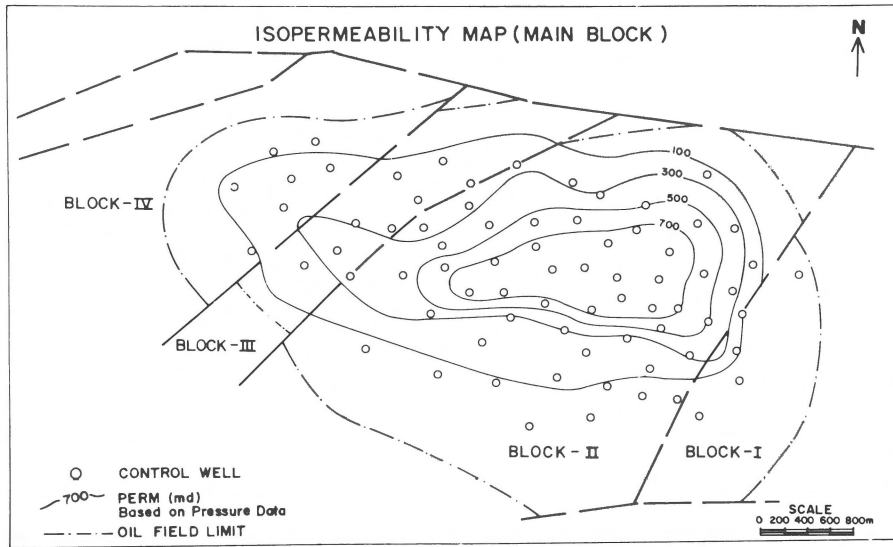


Fig. 9. Isopermeability map (Main Block) TS-2 Sand (after Sant Kumar 1985).

IOIP, in the last four years, mainly as a result of increased drilling activity. Consequently, there were wide fluctuations in the advance of the water-front, especially in Block-II. The map of the shifted oil-water contact as on 1989, considering the TS-2 Sand as a separate hydrodynamic system, showed a rapid rise of the oil-water contact around the bar axes in Block-II. A zonation was applied based on the drainage pattern to distinguish areas of rapid and slow movements reflecting the pattern of sweep efficiency. The resulting zones are designated as 1 to 28 (Fig. 11). The nonreservoir-dominated areas are zones of poor sweep efficiency (Fig. 8).

The infill drilling data especially in the southern part have revealed a significant factor related to areal sweep efficiency. The oil-water contact in the infill wells had moved less than in the nearby production wells. This shows that the lateral sweep is restricted to a drainage radius of about 200 m or less reflecting the combined effect of marked contrast in horizontal permeability, presence of baffles within flow units and poor stacking of sand bodies. This setup is likely in a braided channel system where pore geometries indicate a stratified and multidirectional pattern (Harris & Hewitt, 1977).

The cross-bedded nature of the sandstone and its arrangement in compartments introduce higher

heterogeneity. This is worse in the southern areas because in Block II the principal current direction and directional permeability are from W to E and the transverse bar accretion is from SW to NE. Therefore, in the farther southern areas the lateral sweep efficiency is much less, and the bypassed oil is likely to be more. Further, a laminated nature of bedding is expected as a result of quiet water deposition. This introduces a vertical variation in sweep as compared to the active channel/bar areas. The same situation resulted in a poor sweep in areas in the northwestern part of Block-II and also, to a lesser extent, in the southeastern part of Block-II. This has resulted in a preferential advance of the waterfront along the axes of the two bar crests and relatively slow advance on the sides of the bar crests. The latter areas might contain substantial bypassed oil. Infill drilling areas identified, fall outside the mid channel bar system and are mainly situated in or near the abandoned channel/slough channel areas of weak current energy.

Tyler (1988) highlighted the ineffective drainage in compartmental reservoirs of varying permeabilities. The areas of low-permeable layers when distributed at random are drained only by wells which contact these layers. Layers not contacted are left undrained. In areas of greater heterogeneity the streamlines follow a tortuous path resulting in poor

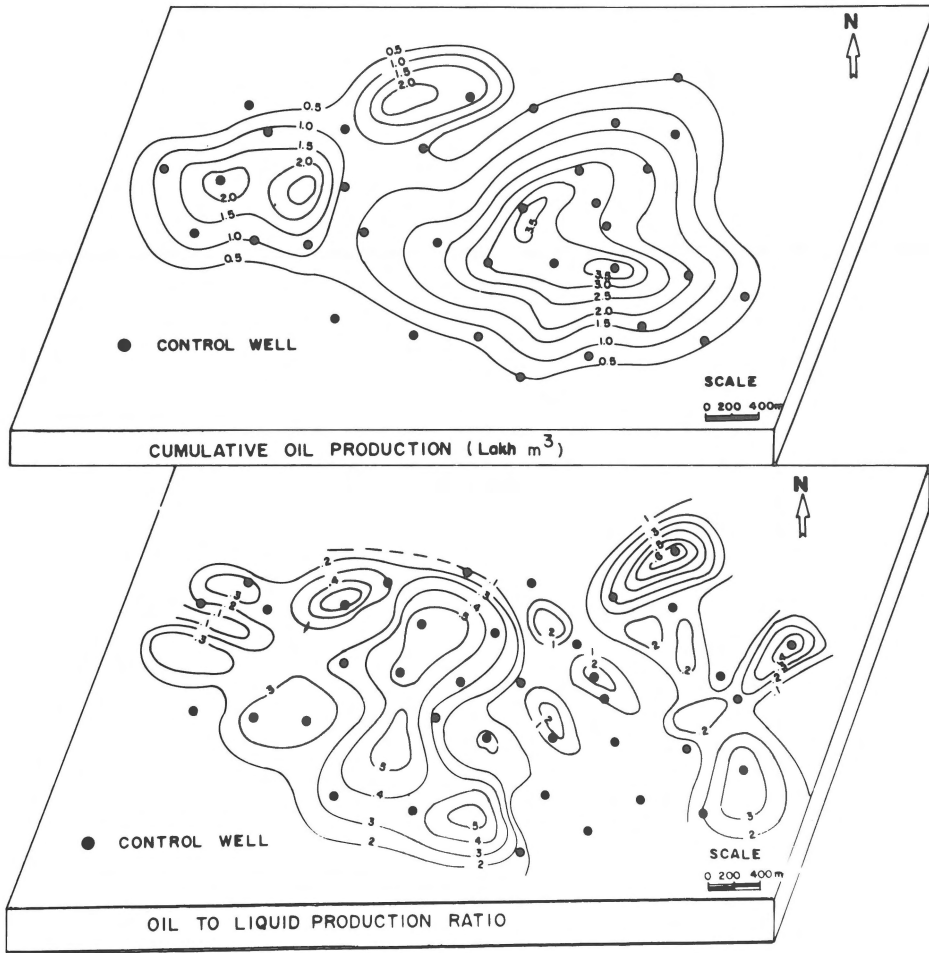


Fig. 10. Cumulative oil production and ratio of oil to liquid production maps, Main Block (1 lakh = 100,000). (See Editor's note, page 371.)

sweep efficiency (or rather, an inadequate drainage). Perforations in the initial stages of development of the field were generally confined to the upper parts (i.e. about 30-40% of the oil column), to avoid water coning problems. This resulted in a very low production from the lower oil bearing layer (layer-3).

Considering the shale, separating layers 2 and 3 as a continuous unit, the interpretation of different oil-water contacts (concomitant with the withdrawal rates) adds a new dimension to the widely prevalent view of a single hydrodynamic system. Each of these layers has developed its own waterfront, denoting the rapid advance of water within layer-2 and an almost stagnant position of the oil-water contact in layer-3, due to insignificant withdrawal.

This explanation might perhaps solve many anomalous oil-water interfaces and watercut behaviours in old wells.

Watercut analysis

Watercut studies by radial coning model were attempted by Sant Kumar et al. (1985) and Hazarika et al. (1986). The major source of water, in different wells, was considered as the coning water due to an extensive bottom water aquifer. It was also opined that water coning was the major production problem of the field. The critical rates calculated (water free oil production) were as low as less than

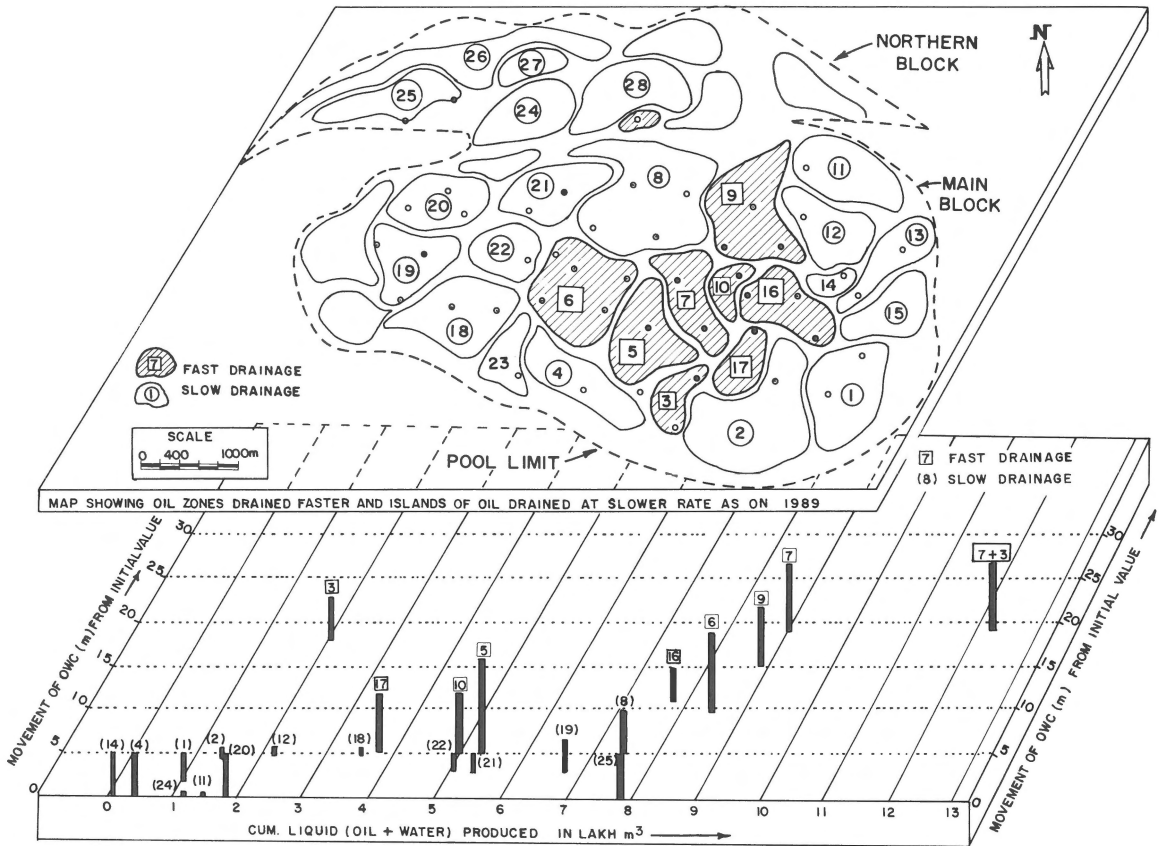


Fig. 11. Map showing vertical rise in oil-water contact, cumulative production and pattern of oil drainage. Numbers 1–28 refer to production zones mentioned in the text. (1 lakh = 100,000)

5 m³/day. In 1985, as many as 46 wells out of 59 were cutting water. Hazarika et al. (1986) predicted the oil recovery as 47% at 85% watercut.

This aspect is analysed by the study of the depositional environments and the sedimentary facies. The other variables considered are the presence of shale in different parts within the oil zone, clearance of the perforations relative to the oil-water contact, heterogeneity within the oil-bearing zone and cumulative water production.

It is interesting to note that wells located in the E-W and NE-SW bar axes started to cut water earlier (although the clearance of perforations to OWC was large), due to the higher vertical permeability. The water centres were around wells close to the central thalweg part of the channel.

The shale thickness map (within oil column) in-

dicates the maximum number of shale areas (thicks) away from the main bar axis (W-E). Shales, in Block-II, are more numerous, have a greater area and are aligned in an en-echelon pattern adjacent to the bar axis (Fig. 8). Water production centres, in general, are outside these shale areas. The relationship of lower nonreservoir percentage and higher watercut is evident. Alternations of shaly sands, sandy shales and fine grained sandstones are arranged in a cyclic pattern towards the upper part of each sandy sequence. They are of a relatively greater frequency of occurrence in Block-II. It is expected that these laminated layers also would effectively restrict water coning.

The fraction of water (F_w) in the flowing stream depends on the ratio of viscosities of water and oil and on the ratio of relative permeability of oil to

water. If the viscosity of the oil is higher than water, it results in an adverse mobility ratio. This causes fingering of water. Further, a variation in permeability contrast aggravates fingering of water. Once water breaks through into the producing wells, the water moves laterally. In blocks I & II (especially in the south) the mobility ratio is adverse compared to the other blocks.

The following conclusions are based on the watercut analysis: Blocks III & VI are prone to early breakthrough of water due to a lesser thickness of the oil column. There is in a few cases a good match of anomalously high oil-water contacts with marginal channels adjoining bars and troughs within the bars. In the crestal area the high clearance of perforation relative to the oil-water contact restricts the water coning. This has helped in relatively clean oil production from the crestal wells of Block II. In general, the shales underlying the oil sands and occurring within the oil zone restrict the vertical flow of water. The water coning is restricted by the laminated shales/sandy shales in the crestal part of Block-II, at least locally. Available data indicate a few wells where the shales have developed and which are prone to a higher watercut (the reasons may be a preferential lateral advance of water in zones above and below the overbank shales). The resistivity logs of recently drilled wells indicate two present-day oil-water contacts in layers 2 & 3. Major withdrawal is mainly from layer 2 and the persistent shale separating these sub-reservoirs caused faster advancement in layer 2, perhaps giving rise to an edge water system in this layer. This aspect needs further confirmation.

Since F_w is a function of S_w , K_{ro} and K_{rw} , poorly permeable zones, as in the western part of Block-II, are prone for early water breakthrough. The critical saturation is reached faster in these areas. A thicker transition zone and higher S_{wi} are also observed in these areas. Due to the curved nature of the fault plane many wells cut through the fault plane and the western fault of Block-II might have served as an avenue of water for a few wells in this part. The adverse mobility ratio as observed by the deterioration of oil properties in Block-II and I (especially in the south) results in increased watercuts. The watercut and production rates of wells

are markedly different in areas of poor and good permeability. The advance of the waterfront is faster in the latter areas (analysis of oil-water contacts in infill wells).

Conclusions

The TS-2 Sand of the Lakwa field is a case history of a stacked braided channel river deposit whose diverse sedimentary facies govern the porosity distribution. High porosity areas around the longitudinal and transverse bars are surrounded by low porosity areas of quiet water sedimentation on the flanks of the structure. Two distinct trends of high permeability are recognised along the principal, E-W, and secondary, NE-SW bar axes. There is a good correlation of the reservoir heterogeneity with the advancement of waterfront, production performance as well as sweep efficiency, in different parts of the field.

Infill wells have indicated a marginal rise in the oil-water contact as compared to the marked shift in earlier wells. This is governed by permeability patterns and oil withdrawal rates in the respective areas. A slower movement of the water front is linked with areas to either side of the intersecting bar axes. This has resulted in inadequate drainage, especially on the southern flank of the structure. Zones of poorly swept mobile-oil areas are identified for infill drilling to improve the recovery efficiency.

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Editor's note: Fig. 10 Decimal points partly disappeared during reproduction. Values are from 0.5 to 3.5 in upper map and from 0.1 to 0.6 in lower map.