A Case Study on Reservoir Management and Performance Prediction of an Indian Oilfield for Enhanced Oil Recovery

Tiene Bema Komba, **Rakesh Kumar Vij**, and **Achinta Bera***, Pandit Deendayal Energy University, Gandhinagar, India

Abstract

Kalol has nine pay zones and is a multi-layered field in Gujarat, India. Oil and gas are found in pay zones II, III, and IV, while oil is found in pay zones V, VI + VII, VIII, IX + X, XI, and XII. Water injection was being done through 104 wells at 2119 m^3/d in pay zones K-III, V, VI+VII, IX+X, and XII. Horizontal, multi-lateral, and high-angle wells, microbial enhanced oil recovery technologies, PDB technology, hydrofracturing, stimulations of tight sandstone layer, and increasing the quantity and quality of water injection for effective pressure maintenance and improving the recovery factor are some of the technologies that have been tried to maintain the oil production rate from this Brownfield. This research has examined novel ways for developing the field to maintain and improve production levels in order to maximize the recovery from the field with minimal capital and operating expenditure.

Introduction

Currently, global energy demand is increasing and the US IEA report predicts that 2050 will require 47% more energy than it does today with oil remaining the largest source just ahead of surging renewables as shown in **Figure 1** (International Energy Agency 2021). Additional demand needs to be catered to by enhanced production either from new or the existing matured fields. The discovery rate for the giant fields peaked in the late 1960s and early 1970s and declined remarkably in the last two decades (Ivanhoe 1997; Blaskovich 2000). About thirty giant fields comprise half of the world's oil reserves and most of them are classified as the mature field (Babadagli 2007). The average oil recovery factor in the world is estimated to be only between 20% and 40% (Muggeridge et al. 2014). Enhancement of recovery over this “easy oil” depends on the availability of proper economic viability, technologies, and effective reservoir management strategies. Most oil and gas reservoirs demand proper management as this can increase the productivity of the reservoir, thereby increasing in recovery factor (Hickman 1995; Raza 1990; Satter 1994). To efficiently produce from petroleum reservoirs, sound reservoir management practices need to be implemented. Pressure maintenance and enhanced oil recovery (EOR) techniques can yield higher recovery than a reservoir with only primary recovery (Ayoub 2015; Ahmed 2010; Vishnyakov et al. 2019).

Globally oil is distributed in a random way more resources in the Middle East and developing countries like the USA, Russia, Canada, and China (Rempel 2006; International Energy Agency 2004). In India, in spite of the large area and large population hydrocarbon resources are scarce and during the last 60 years aggressive exploration and exploitation only 15% of the demand for crude oil is being met by indigenous production. 80% of the demand is being met by importing from various countries. The hydrocarbon sector is mostly in the state sector wise mostly however after the liberalization of the economy private players and MNCs (multinational

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*Corresponding author: achinta.bera@spt.pdpu.ac.in

companies) are playing significant roles. Therefore, national oil companies (NOC) like ONGC (Oil and Natural Gas Corporation) and OIL (Oil India Limited) are managing old and mature fields producing for 50 years and aggressively pursuing IOR and EOR methods to enhance recovery from these fields. India continues to produce more than 80% of its production from mature fields and pressured by the government on enhancing the production is greater day by day (Gyani and Mitra 2021).

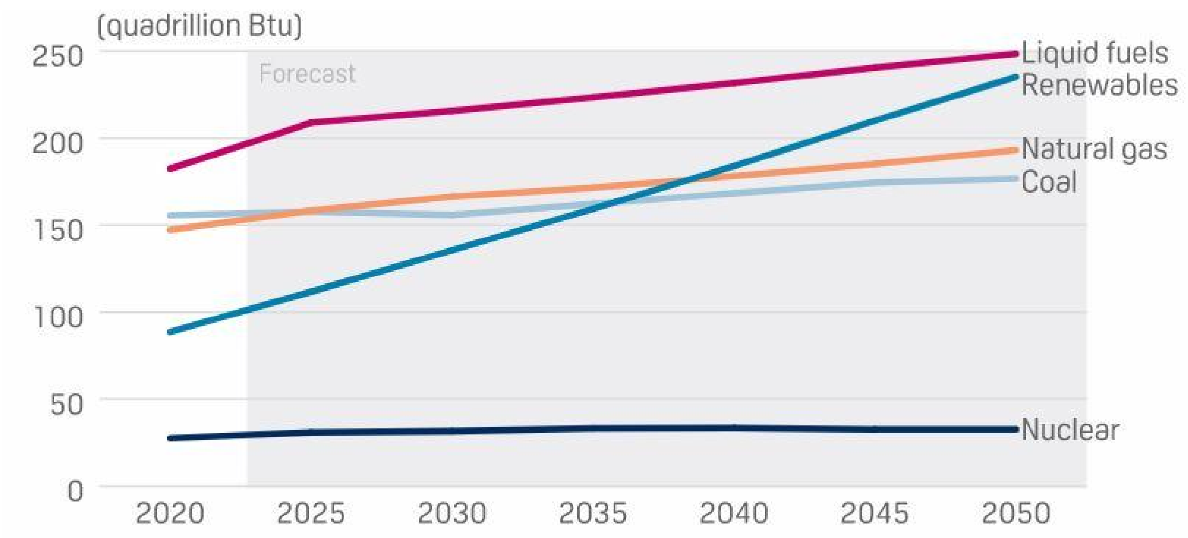

Figure 1—Global oil demand to grow through 2050 despite surging renewables (Source: US Energy Information Administration 2021).

Ganguli et al. (2016) examined the feasibility of CO_2-EOR following by CO_2 storage in Ankleshwar oil field which is a mature field at Cambay basin. Based on the characteristics of the present field encouraging results on the basis of good response from the conceptual model, the field has the potential to produce additional 10.4% of original oil in place and sequestrate about 15.04×10^6 metric ton of CO_2. Oliveira et al. (2019) reported on the use of optimal reservoir management (ORM) to reduce water production and/or excess water during oil recovery in an offshore mature field from Brazil's Campos basin. Results often reveal a near 4% increase in oil production with a corresponding decrease in total water production and overall water injection. Eson (1997) related the use of different artificial lift technologies to optimize the Whittier oil field in Los Angeles. The progressing cavity pump (PCP) was chosen as an alternative lift system for this established oil field because, when compared to other possible lift system choices, it provided the best operational and financial advantages for this mature field. Lawrence et al. (2002) emphasized using nitrogen tertiary recovery to manage mature fields. The residual reserves were doubled and the field life was increased by more than 10 years as a result of studies for modelling and simulation of the Jay field in Southeast United States. These improvements have enabled the tertiary nitrogen WAG project to recover an additional 10% of the OOIP compared to waterflood alone. Qiannan et al. (2019) carried out experiments on surface-active polymer flooding for enhanced oil recovery by detection analysis and modern physical simulation technique based on reservoirs and fluids in Daquing placanticline mature oil field NE China. The experiments show that Surface-active polymer is a novel chemical agent with both viscosity-increasing ability and surface activity suitable for high water-cut mature oilfields. The surface-active polymer differs obviously from ordinary polymer and polymer-surfactant binary system in molecular aggregation, performance of viscosity and flow capacity which has larger molecular coils, higher viscosity and viscosity-increasing property, and poorer transmission and flow capacity. Moreover, surface-active polymer can improve interface chemical properties, reduce oil-water interfacial tension, and make the reservoir rock turn water-wet. Lall et al. (2021) investigateed the feasibility using condensate for EOR in a mature field in Trinidad Tobago (TT). The overall methodology to accomplish the objectives required involves; selection of appropriate well, developing a pilot test using compositional reservoir model (CMG-GEM) and finally conducting an economic analysis of the strategy. The results of this study demonstrated that the injection of produced condensate can result in a 33% increase in permeability. Tuning of the simulator to factor the increase in permeability from 300 to 420 md due to condensate treatment demonstrated an increase in the permeability will result in an increase in the rate of production of almost 46% (24 to 35 bopd) translating in an overall gain of 30,531 bbls of oil associated with a significant financial gain of approximately $4.7 MM TT over the 16-year period for one well. This study offers compelling evidence that the use of produced condensate in EOR is an economically and environmentally friendly strategy for EOR in Trinidad.

Reservoir management in a mature field is therefore a challenge for professionals working in this area in E&P (exploration and production) industries. Most of the mature fields are in the state of Gujarat Western onshore and in Assam in North East area of India. In addition, Western offshore fields like Mumbai High, Neelam, Heera, and a few others are also mature fields. Kalol field, the biggest onshore field in India is situated in the Cambay basin about 16 km NNW of Ahmedabad city. The field was discovered in 1961 and is on production for the last 60 years. Spreading in an area of 400 sq. km, Kalol is a multi-layered sandstone reservoir field with geological complexities in view tectonically active area. Hydrocarbon is present in tertiary sequence mainly in Oligo-Miocene sands. In view of the challenges faced in the management of this mature field, Kalol has been chosen for my research work in this report.

Kalol field has large well inventories, installations, and surface facilities. In the field, over 800 wells have been drilled so far. And the majority of sands are operating under depletion drive whereas in others, partial/active water drives are operative. In general, the sands are highly heterogeneous except for a few and very tight in nature with poor transmissibility (Vij et al. 2010; Das et al. 2006; Jena 2008). The productivity is very low and the wells come into production only after hydrofracturing in most cases. The reservoir is characterized by poor facies dominated by siltstones. From a vintage point of view, the field is classified as mature whereas still young as has produced only 10% of initial oil in place (IOIP) (Vij et al. 2010; Das et al. 2006; Hanotia et al. 2015). Induction of various technologies are been attempted to maintain the oil production rate from this Brown (mature) field.

The objective of this research is to identify the problems encountered during the production of mature fields and to discuss the innovative approaches conceptualize and implemented in the field for maintaining and enhancing the production level and improving the reservoir. This maximizes the recovery from the field with minimal capital and operating expenditure.

Description of Kalol Field

Kalol field is the largest onshore field in India located about 16 km NNW of Ahmedabad city. Spread over an area of 300 sq. km, the field was discovered in June 1961, when the first well drilled on the structure was produced from the pay zone K-IX+X. It is a multi-layered oil field, with half of its reserves trapped between horizons IX and X. It has 11 pay zones from K-II to K-XII corresponding to the middle Eocene age at depth of 1250-1600 m MSL. The upper layers like K-II, K-III, and K-IV are oil and gas producers while K-V to K-XII are oil producers. K-IX+X is the main oil producer in the area with K-VII being the next best layer.

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Kalol field is one of the first few fields explored and developed by ONGC. It is a major producing field of Ahmedabad Asset. The first well was drilled in 1961 and regular production started in 1966. It has an IOIP of 140.54 MMt with an ultimate component of 21.54 MMt and after 43 years of production, a cumulative of 13.4 MMt has been produced which is 9.34% of IIOP.

Technological schemes of development for pay zones IX+X and XII were prepared in 1964, and for II, III, & IV in 1971. The Final Development Plan (FDP) of the Kalol field was prepared by the Indo-Soviet team in 1982. FDP recommended drilling 140 wells, covering all pay zones. Various measures for production enhancement such as water injection, work-over jobs, and artificial lift etc. were also recommended in the plan. As of follow-up action, a total of 127 out of planned 140 wells were drilled by 1990 and resulted in oil production of 1700 tpd which was double of pre-FDP. To date, 628 wells have been drilled with 359 flowing and 86 are water injectors. As on 01.01.10, the field is being produced oil with a rate of 1217 tpd and gas at 285000 m^3/d.

Reservoir Geology. The Kalol field is located in the Ahmedabad Asset-Mehsana Tectonic block of the North Cambay basin which is approximately 300 sq. km within India. **Figure 2** shows the location of Kalol field in Cambay basin. The field is multi-layered and highly heterogeneous with various faulted reservoirs. This field contains 11 producing sand sequences that have full field coverage. It has tight silts with very low permeability and sand has an inter-bedded coal layer.

Kalol structure is a longitudinal of length about 30 km and a width of 6-10km. The Kalol structure is characterized by a set of two faults at 60° intersections namely Kalol and Sabarmati trends, the parallelism of the synclinal axis to the fault trend, and the acute angle intersection of the culmination to the field.

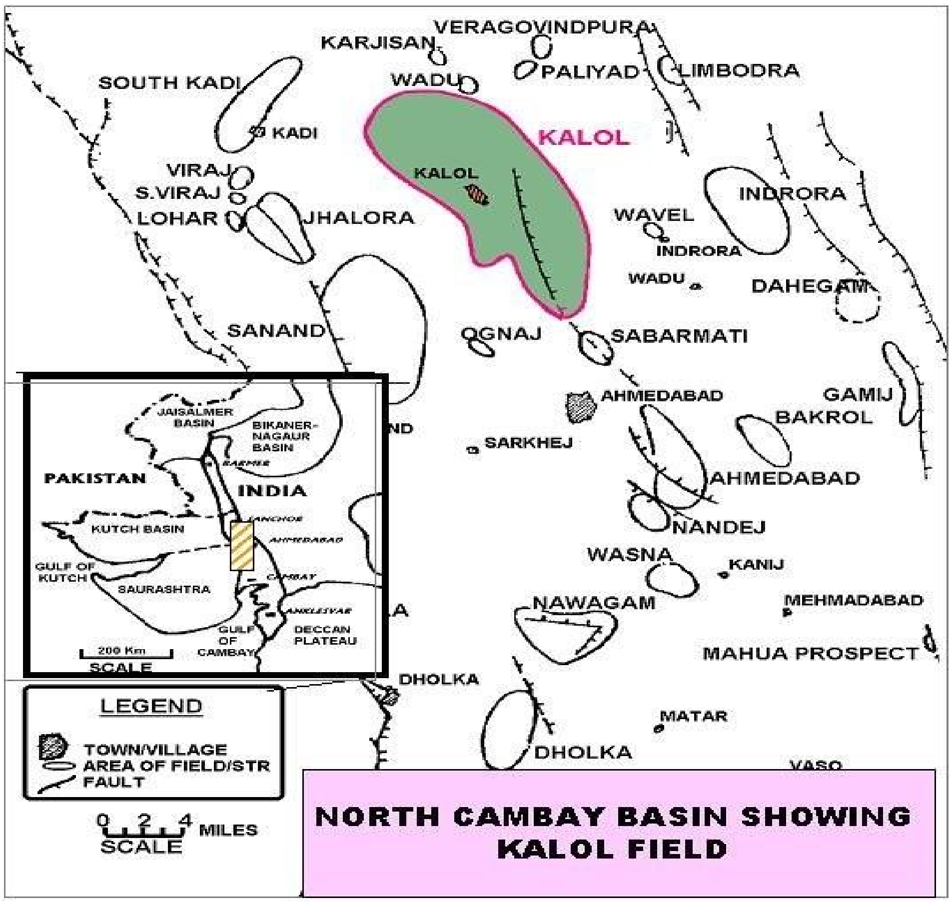


Figure 2—Location map depicting Kalol field in Cambay Basin (Jena 2008).

Stratigraphy and Lithology. In the Kalol interval, there are prominent markers such as coal at the top of Kalol, shale above Sand II, coal at the base of Sand IV, and coal at the top of Sands IX and XII. Most of the sands are on depletion drives except for the partial aquifer support in sands II, IV, and XII. The field has a wide variety of lateral and vertical permeability from to sand, from 1 mD to around 100 mD. The Kalol field comprises a series of rollover structures developed on the hanging wall of NNW-SSE trending, left-stepping listric normal faults. A system of NE-SW trending transfer faults delimits the individual anticlines or dissects them. Hydrocarbon accumulation in the middle Eocene deltaic clastic reservoirs (Kalol Formation) is found both in the hanging wall and footwall sides with differential fluid contacts. Thickness distribution Kalol Formation (Plate 1) shows an overall thinning along the trend of these rollover structures, thus signifying their synsedimentary nature. Nearly uniform thickness of the overlying Tarapur Shale was observed over the Oligocene. Thus the trapping mechanism in the Kalol field appears to have evolved during Middle Eocene-Oligocene. The syndepositional roll-over features in the reservoir Kalol sands are capped by Tarapur Shale, providing a regional top seal.

Synthesis of the available source rock and geochemical data of Olpad, Cambay Shale and intervening shale layers in the middle Eocene-Early Oligocene sequence was done for the Broach and Ahmedabad blocks. Representative source rock log for Ahmedabad block was prepared from data of well Kalol-263. In the Ahmedabad block, the upper part of Olpad formation contains oil-prone organic matter-rich source rock layers. The Cambay Shale has fair to excellent organic matter richness for the most part. The organic matter richness improves toward the upper part of Cambay Shale and is also, generally in the excellent range in the Kalol and Tarapur Formation. The onset of oil generation was at 1475 m. Trap generation in the Kalol field structure is almost concomitant with the deposition of the reservoir sequence, including the intervening organic-rich shale. These structures were finally draped over by the Tarapur Shale (top seal) in the Early Oligocene. The stratigraphy (**Figure 3**) as illustrated below shows the break out of intervals in the Kalol formation.

Oils in this field show a great degree of genetic variation. Such variations are observed between the oils of different fields, as also between various pools within a single field. This suggests a different source for different oils. Good to excellent source rock characteristics are found not only in the Cambay Shale but also in the Kalol and Tarapur formations. Thus the investing, organic-rich, shale layers of these formations may have sourced the oil in the adjacent reservoir sands.

These evidences support the possibility of early generation and entrapment in the Ahmedabad block. Although oil accumulations above the oil generation window are found in most of the structures, biomarker studies on these oils suggest that they have attained only early to moderate maturity levels.

The Kalol reservoir is composed of alternating laminae of fine sand or silt and argillite on a scale ranging from greater than 1 mm sand/silt laminae to occasionally to less than 10 cm. Most typically the laminae are seen to be of the order of 1 to 5 mm in thickness. Shale/mudstone laminae tend to be more continuous, and although some bioturbation is present in the form of occasional sand-filled Thallassinoides type horizontal ichnofossils and rare vertical Skolithos burrows, the widespread preservation of unmodified bedding indicated that burrowing was probably quite sparse. Also, vertical burrows are seen to be quite rare.

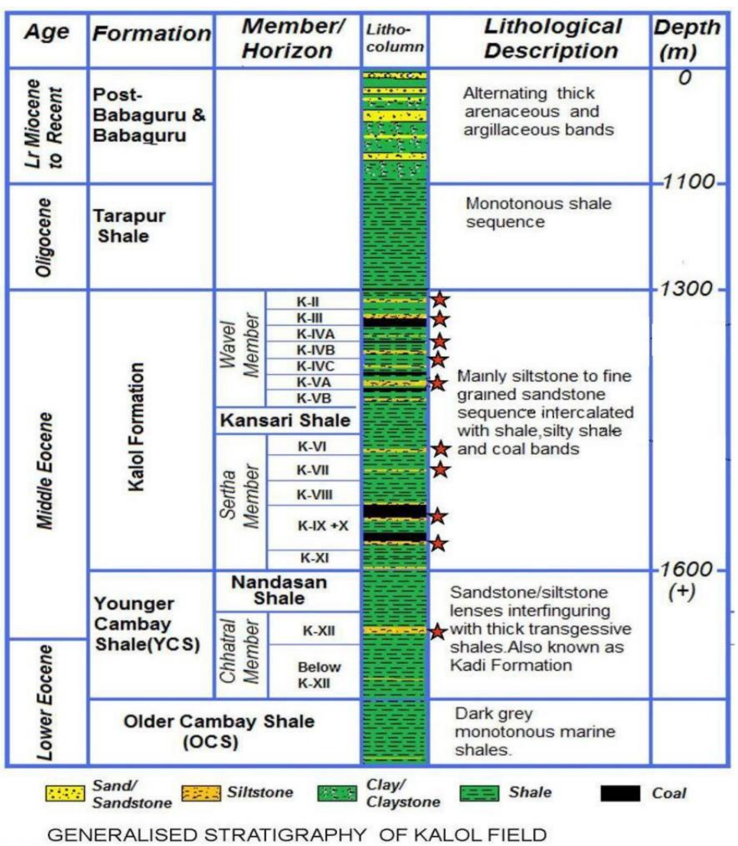


Figure 3—Generalized stratigraphy of the Kalol Field (Vij 2022).

Structural Pattern. The Kalol field is an NW-SE trending anticline and dissected several NW-SE trending longitudinal and NE-SW trending Cross faults as shown in **Figure 4**. At Wavel member pays these faults played a major role in hydrocarbon entrapment. These have less significance in the fluid distribution in Sertha member pays. This anticline is bounded by Wamaj-Wadsar low at West and Nardipur low towards East. Many culminations and lows are observed within the anticline. The area is gently dipping at < 2˚.

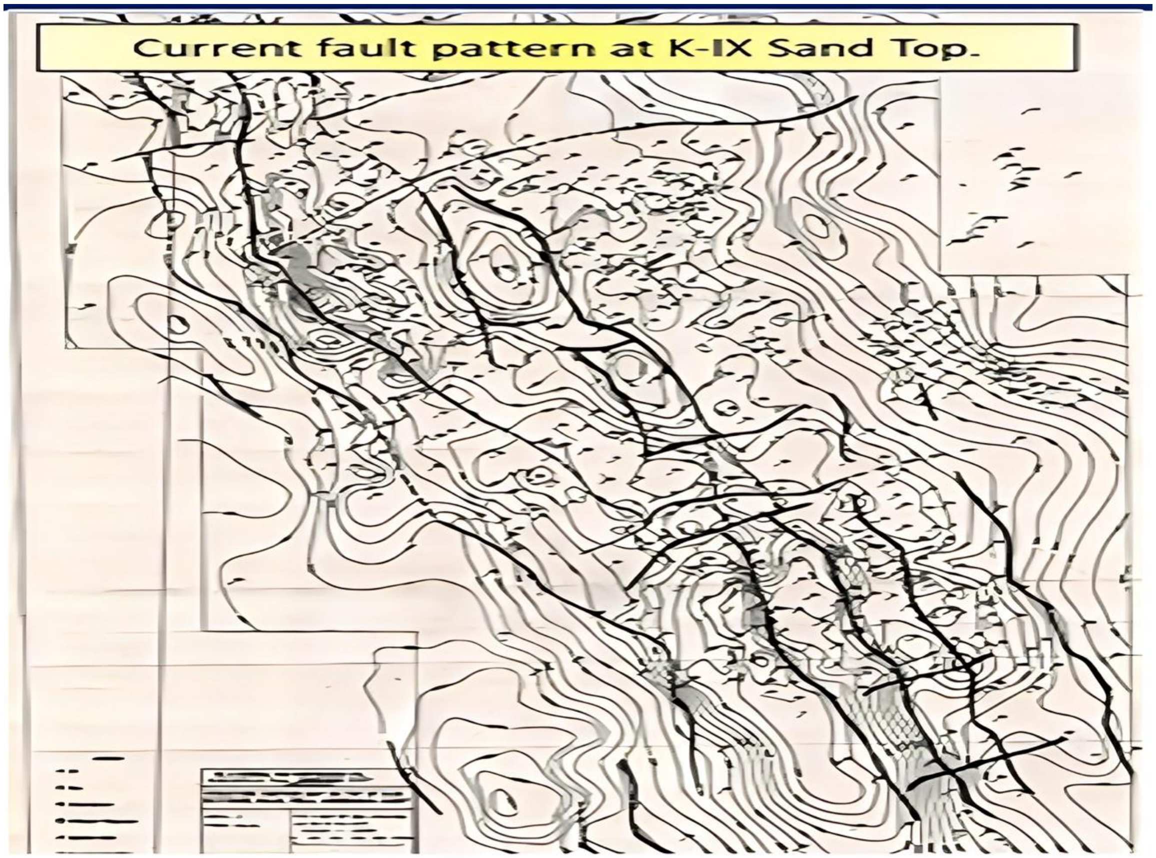


Figure 4—Current fault pattern at the top of K-IX sand.

Reservoir Parameters. The Sands in the Kalol field are found at a depth of about 1000 m having thick oil of gravity 17º API. The sands represent a significant variety in reservoir characteristics (i.e., mineralogy, porosity, and permeability). Kalol sands are argillaceous, silty, and sandy shale occasionally sideritic sandstone (Sharma 2009). In Kalol Sands, due to active aquifer support, oil contribution from self-flowing wells is almost double compared to the production from wells on the artificial lift (Das et. al. 2006). **Tables 1** and **2** show the lithology, petrophysical properties, drive mechanisms of various pay zones. The field is developed through various schemes and reviews over the past 60 years (**Table 3**). The reservoirs are essentially tight and heterogeneous with moderate to poor permeability. The primary drive mechanism is depletion (Table 2). The reservoir pressure has depleted from super-hydrostatic to sub-hydrostatic at present. Water injection is essentially instrumental in pressure maintenance for such reservoirs.

Pay zone K-XII. This pay zone is on production since 1966 and is developed mainly in the north-western part of the field. The area is dissected by a number of NNW-SSE trending Strikes slips faults and has an anticline structure, having an axis NW-SSE. Gas oil contact (GOC) has been established in the eastern and northern part of the sand. Its channel axis runs NNW-SSE and the facies and thickness deteriorate western and eastern flanks of the block. The sand has varying from 2 m to 8 m. The porosity ranges from 12-20% whereas the permeability is between 50-200 mD.

It has in place reserves of 12.98 MMt of oil in the PD category with an ultimate component of 5.50 MMt as on 1/4/2009. The cumulative production as on 1/4/2009 is 3.70 MMt of oil leading to a recovery of 28.9%.

Water injection in this pay zone was initiated very early in 1972 and is now in the mature stage. Good response to injection is observed in the majority of the area. ASP (alkali-surfactant-polymer) EOR is going in Kalol XII.

Table 1—Lithology, porosity and permeability of Kalol Sands.

Pay Zone	Lithology	Porosity (%)	Permeability (mD)	Coverage
K-II	Sandstone to Siltstone, Silty Shale	20-27	5-10	Central Part of the field
K-III	Upper part is sand Silt facies while lower part is sandy	13-30	8-150	Throughout the field
K-IV	Sandstone to Siltstone with coal streaks	15-25	30-60	Throughout the field
K-V	Sandstone	20-25	30-50	East and South-East Part of Field
K-VI+VII	Siltstone, Occasionally Carbonaceous	12-25	5-40	Throughout the field
K-VIII	Siltstone, Occasionally Carbonaceous	12-20	5-30	Southern Part of field
K-IX+X	Siltstone/ Sandstone	15-20		Throughout the field
K-XI	Highly Shaly Sand	15-24	5-8	North-West part of field
K-XII	Sandstone	12-20	50-200	North-West part of field

Pay zone K-XI. This pay zone is developed in NW block of the field. Its thickness varies from 2 to 4 m and has channel axis that runs NNW-SSE. Pay zone XI has a porosity that varies from 15% to 24% and permeability ranging 5-8 mD. The sand is highly shaly, heterogeneous and very tight in nature.

It has in place reserves of 6.86 MMt of oil in PD category with an ultimate component of 1.22 MMt as on 1/4/2017. The cumulative production as 1/4/2017 is 0.28 MMt of oil leading to a recovery of 4.08%.

Pay Zone K-IX + X. Pay Zone K-IX + X is extensively developed throughout the field. Although K-IX and X are two different dynamic units, they have been good developed together in the field. In general, the sands are highly heterogeneous with good development of sand in the form of various independent pools. It has two prominent trends such as NNW-SSE and NE-SW cross faults. The lithology of pay zone K-IX varies in different parts of the field. There is mainly the presence of Siltstone and Sandstone in the central and northeastern part. K-IX is widely spread throughout the field and it is developed towards the central region. K-IX + X together contain the major reserve of Kalol field. The maximum pay thickness of K-IX is 8 m and that of K-X is 12 m. The porosity of the pay zone ranges from 15-20%. The pay zone K-IX+X has in-place reserves of 57.14 MMt of oil and 164.2 MMm^3 of free gas PD category with an ultimate component of 7.34 MMt and 79.3 MMm^3 respectively as on 1/4/2017. The cumulative production of oil and gas as on 1/4/2017 is 4.69 MMt of oil and 10.1 MMm^3 of gas leading recovery of 8.2% and 6.15% respectively.

Pay Zone K-VIII. This pay zone is developed in patches in Main Block, Southern Block, and Western Block. The sand is highly shaly, heterogeneous, and tight in nature. The structure is dissected by a number of NW-SE trending longitudinal and NE-SW cross faults. The sand thickness varies from 2 m to 6 m and has porosity varying from 12-20%. It consists of siltstone which is occasionally carbonaceous. K-III is heterogeneous and requires hydraulic fracturing on regular basis. Its permeability ranges from 5-30 mD. It has in place reserves of 7.45 MMt of oil as in the PD category with an ultimate component of 0.34 MMt as on 1/4/2017. The cumulative production as on 1.1.2017 is 0.05 MMt of oil leading to a recovery of 0.67%.

Pay Zone K-VI + VII. Pay zone K-VII is one of the main producing sand of Kalol field. It is developed throughout the field along with localized development of K-VI in the Southern and Main Blocks. The structure is dissected by number of NW-SE trending longitudinal and NE-SW cross faults. The sand thickness varies from 2 m to 8 m and has porosity varying from 12-25%. It consists of siltstone which is occasionally carbonaceous. In general, the sand is highly heterogeneous and very tight in nature with poor transmissibility. The productivity of the wells is very low. The permeability ranges between 5-40 mD and the well produces oil only after hydro-fracturing. The reservoir is producing under depletion drive and is under pressure maintenance in the southern and main blocks. Pay zone K-VI + VII has in place reserves of 32.55 MMt of oil in PD category with an ultimate component 6.16 MMt as on 1/4/2017. The cumulative production as on 1/4/2017 is 2.46 MMt of oil leading to a recovery of 7.6%.

Pay Zone K-V. The development of pay zone K-V is confined to Southern and Eastern part of the field. The sand is developed as two sub layers K-VA and VB. Sand K-VA is the main producing sand developed locally in the eastern flank of the field whereas K-VB is developed in southern part and is very tight with poor productivity. Pay zone K-V has in place reserves of 8.03 MMt of oil with an ultimate component of 2.05 MMt as on 1/4/2017. The cumulative production as on 1/4/2017 is 1.5 MMt of oil leading to a recovery of 18.00%.

Sand K-VA. Pay zone KV-VA is the main producing sand developed in a low, with rising flanks toward East, West, and south part of the field. It has been discovered in 1997 through testing of K-VA in exploratory well KL#484. The area is dissected by a number of NNE-SSE trending normal faults. Gas cap is observed at 1350 m MSL towards South and East and OWC is observed at 1350 m MSL which gives partial support. Sand appears to be deposited as distributary mouth bars in deltaic regime and its thickness varies from 4 m to 8m. The porosity and permeability range from 20-25% and 30- 50 md respectively. The sand development is very good with high productivity. The sand is operating under depletion and is under pressure maintenance by water injection which was implemented in 2002.

Pay Zone K-IV. Pay zone IV is developed throughout the field forming separate blocks. Major part of the Main block is gas bearing whereas Western block is oil bearing with a small gas cap. It is further subdivided into two litho units namely K-IVA, K-IVB from the top to bottom. Sub layer K-IVA is prominently gas bearing, however small quantity of oil is present. Sub layer K-IVB is mainly oil bearing. OWC and GWC have been observed. The lithology varies from sandstones to siltstone however coal streaks are very common. There is vertical variation in facies and the pay thickness varies from 2 m to 15 m. It is producing under mixed drive with active aquifer support and gas cap with some blocks on depletion. Pay zone- IV has in place reserves of 15.32 MMt of oil and 3435.95 MMm^3 of gas in PD category with an ultimate component of 1.27 MMt and 2973.40 MMm^3 as on 1/4/2017 respectively. The cumulative production as on 1/4/2017 is 1.06 MMt of oil and 1610.06 MMm^3 of free gas leading to recovery of 6.9% and 46.9% respectively.

Pay Zone K-III. It is mainly developed in ENE-WSW trending lobes Northern, Central and southern part of the field comprising both oil and gas. Three prominent structures high are present in southern, central and north part of the area. The area is dissected by several longitudinal and transverse faults. Pay zone K-III is gas bearing in the north-central and south-west areas whereas in south east and north-west part is mainly oil bearing with small gas cap. The sand is mainly operating under strong aquifer support in northern part whereas in south it is under partial aquifer support and partly on depletion. K-III covers almost the entire field and its upper part consists of sand-silt facies while lower part is more sandy. The degradation of the facies separates the channels and the thickness varies from 2.5 m to 6 m. The porosity and permeability of the pay zone range 13-30% and 8-150 md respectively. It has in-place reserves of 7.63 MMt of oil and 2755.69 MMm^3 of free gas with an ultimate component of 1.6 MMt and 2354.2 MMm^3 as on 1/4/2017 respectively. The cumulative production as 1/4/2017 is 1.42 MMt of oil and 2350.71 MMm^3 of gas leading to a recovery of 20.6% and 85.3% respectively.

Pay Zone K-II. The development of pay zone-II is confined is developed in E-W trend in the central part of the field. Major part of the main block is gas bearing whereas western block is oil bearing with a small gas cap. The area is dissected by number of NNE-SSW trending faults and the lithology varies from sandstone to siltstone, silty shale. Shale is out in the northern and southern margin of the block. Kalol main fault separates gas bearing eastern block from oil bearing western block. Gas water contact (GWC) is observed at 1300 m MSL toward the eastern margin of sand whereas Oil water contact (OWC) is observed toward the western margin. The pay thickness varies from 2.5 m to 9 m while the porosity and the permeability range from 20-27% and 5-

10 md respectively. It has in place reserves of 3.92 MMt of oil and 1797.39 MMm^3 of free gas in PD category with an ultimate component of 0.50 MMt and 1160 MMm^3 as on 1/4/2017 respectively. The cumulative production as on 1/4/2017 is 0.25 MMt of oil and 1148.27 MMm^3 of gas leading to a recovery of 6.9 % and 64% respectively.

Issues Related to Kalol Field. Table 3 shows the development history of Kalol field. The following issues are the challenges faced during the development of Kalol field.

- Multilateral sandstone reservoir having isolated 11 pay zone.
- Variation in the lithology of the field from sandstone, siltstone and shale.
- Presence of coal streak.
- Tight sand required HF at a regular interval of time.
- Wide range of porosity and permeability of the reservoir.
- The field is very heterogenous having a large number of sealing and communicating fault
- Lateral facies changes.
- The crude oil property varies from layer to layer.
- In some layer paraffin and resin content are significant high.

Table 2—Drive mechanisms of various pay zones (Das et al. 2006).

Pay Zone	Producing Fluid	Drive Mechanism	Pressure Maintenance	≈Area Sq.Km
K-II	Oil and Gas	Combination Drive	None	49
K-III	Oil and Gas	Northern Part- Strong Aquifer Southern Part- Weak Aquifer and depletion Drive	Water Injection	84
K-IV	Oil and Gas	Combination Drive with Active Aquifer Support and some blocks on Depletion	None	173
K-V	Oil	Depletion Drive with Weak Water Aquifer	Water Injection	46
K-VI+VII	Oil	Depletion Drive	Water Injection	142
K-VIII	Oil	Depletion Drive	None	40
K-IX +X	Oil	Depletion Drive	Water Injection	199
K-XI	Oil	Depletion Drive	None	32
K-XII	Oil	Depletion Drive	Water Injection	30

Table 3—Field development history (Vij et al. 2010).

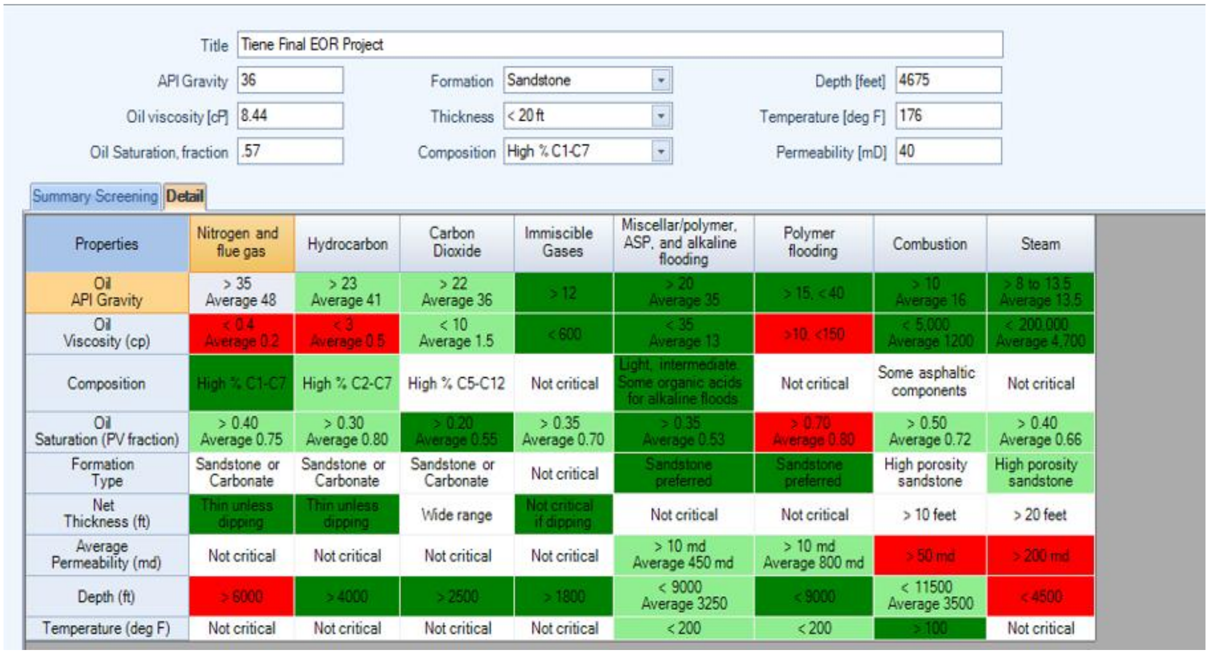
Year	Plan implemented
1961	First well drilled
1964	Trial production started
1971	Technological scheme for K-II, III IV, XII
1982	Final development plan (FDP)
1996	Integrated development plan for kalol
2000	IOR- Kalol
2003, 2007, 2009, 2011	Performance review of sands K-IV & VI + VII , VA, K-VII NW, K-VII
2011-2012	Integrated Study to review and update Geological Model of K-IX + X
2012-2013	Released & dev. Location for K-IX + X in 11th ADB
2013-2014	Released 4 locations for K-VA Sand
2013-2014	Released 6 locations for K-X Sand
2014-2016	Geo cellular model under preparation by G & G team at INTEG- DDN
2016-2017	Released 5 locations for K-X Sand
2016-2017	Released 9 locations for K- XI Sand
2017- 2018	Released 3 locations in K-VA Sand, 6 Locations in K-X Sand , 2 Locations in K-VII Sand, 3 Locations in K-IX & KVB, 1 Location in KVIII Sand
2017-2018	Performance review of sand K-XII & KXI (5 Locations released for K-XII Sand, 11 Locations released for K-XI Sand

Enhanced Recovery Screening of the Field

Screening of KV-B using EORgui. The below data is provided:

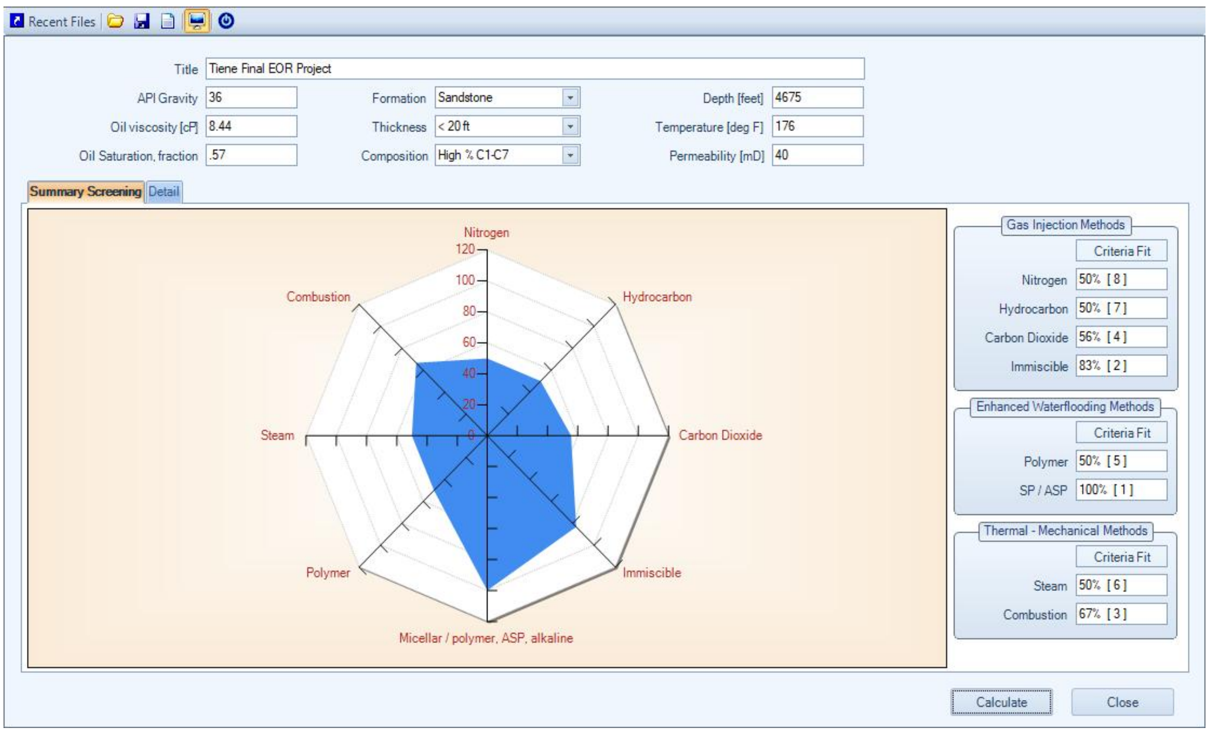
- API = 36 (Degrees)
- Oil Viscosity = 8.44 (Cp)
- Oil Saturation = 0.57
- Formation Type = Sandstone
- Reservoir Thickness = < 20 (ft)
- Fluid Composition = High % C1-C7
- Reservoir Depth = 4675 (ft)
- Reservoir Temperature = 176 (Deg F)
- Reservoir Permeability = 40 (mD)

The ranking percentage is on the side bar of the window, whereas the highest percentage is Surfactant Polymer/Alkaline Surfactant Polymer method (100%), Immiscible (83%) and Combustion (60%). **Figure 5** shows the preferred chemical EOR for Kalol VB.



Properties	Nitrogen and flue gas	Hydrocarbon	Carbon Dioxide	Immiscible Gases	Miscellar/polymer, ASP, and alkaline flooding	Polymer flooding	Combustion	Steam
Oil API Gravity	> 35 Average 48	> 23 Average 41	> 22 Average 36	> 12	> 20 Average 35	> 15, < 40	> 10 Average 16	> 8 to 13.5 Average 13.5
Oil Viscosity (cp)	< 0.4 Average 0.2	< 3 Average 0.5	< 10 Average 1.5	< 600	< 35 Average 13	>10, <150	< 5,000 Average 1200	< 200,000 Average 4,700
Composition	High % C1-C7	High % C2-C7	High % C5-C12	Not critical	Light, intermediate. Some organic acids for alkaline floods	Not critical	Some asphaltic components	Not critical
Oil Saturation (PV fraction)	> 0.40 Average 0.75	> 0.30 Average 0.80	> 0.20 Average 0.55	> 0.35 Average 0.70	> 0.35 Average 0.53	> 0.70 Average 0.80	> 0.50 Average 0.72	> 0.40 Average 0.66
Formation Type	Sandstone or Carbonate	Sandstone or Carbonate	Sandstone or Carbonate	Not critical	Sandstone preferred	Sandstone preferred	High porosity sandstone	High porosity sandstone
Net Thickness (ft)	Thin unless dipping	Thin unless dipping	Wide range	Not critical if dipping	Not critical	Not critical	> 10 feet	> 20 feet
Average Permeability (md)	Not critical	Not critical	Not critical	Not critical	> 10 md Average 450 md	> 10 md Average 800 md	> 50 md	> 200 md
Depth (ft)	> 6000	> 4000	> 2500	> 1800	< 9000 Average 3250	< 9000	< 11500 Average 3500	< 4500
Temperature (deg F)	Not critical	Not critical	Not critical	Not critical	< 200	< 200	> 100	Not critical

(a) Input



(b) output

Figure 5—EORgui result on KALOL-VB.

CMG Simulation of Kalol-VA. Reservoir model is used to predict flow of fluids through porous media, performance prediction of producing fields, making business decision as well as techniques to improve the reservoir performance by hydraulic fracturing, water injection and EOR processes.

Five spot patterns, 4 injectors and one producer were used. The simulation data is provided in Table 4. The model was run for 10 years for surfactant polymer flooding. **Figure 6** shows the 3D model of representing oil per unit area. The flooding was done at 50˚C. The graphs obtained as a result were compared to the water flooding and steam flooding using CMG.

Table 4—CMG simulation data.

Geometry	5 spots
Reference depth	4600 ft
Reference pressure	2062 psi
OWC	4658.7 ft
Porosity	24%
Permeability Kx, Ky, Kz	50, 50, 25 mD
Gross thickness	19.68 ft
Net pay	13.12

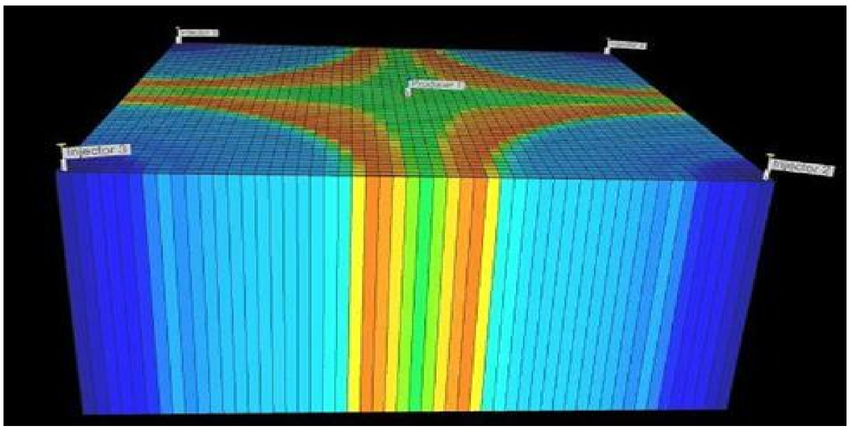


Figure 6—3D model of representing oil per unit area.

Figure 7 shows results for the surfactant-polymer (SP) flooding simulation which was run for 10 years. Cumulative oil, rate, and water cut trends are shown in the graph. From the graph, it can be seen that the cumulative oil tends to increase whereas the oil rate starts to decline and become linear from 2025 onwards. Water cut is increased in the initial years of simulation and then it follows a linear trend.

Figure 8 shows cumulative oil, water cut and oil rate trends for 10 years in case of implementation of steam injection at 150˚C. Oil rate starts to decline and become linear from 2024, while water cut and cumulative oil gradually increase but less compared to Surfactant Polymer flooding.

Figure 9 shows how water injection will affect the reservoir parameters. In the case of water injection, oil rate declines early and cumulative oil tends to increase till 2024 rapidly. Water cut is very high and indicates that excess water production can be encountered.

Comparison. From the results obtained for the three recovery methods; Surfactant Polymer (SP) flooding, steam injection and water injection, it can be clearly seen that water cut is delayed in case of SP flooding. Cumulative oil which tends to increase is highest in case of surfactant polymer flooding and oil rate also is maintained higher in this method compared to other recovery methods. So if Surfactant Polymer flooding is implemented then additional 15% recovery can be made however it is less than the ASP flooding which is additional 18% or more.

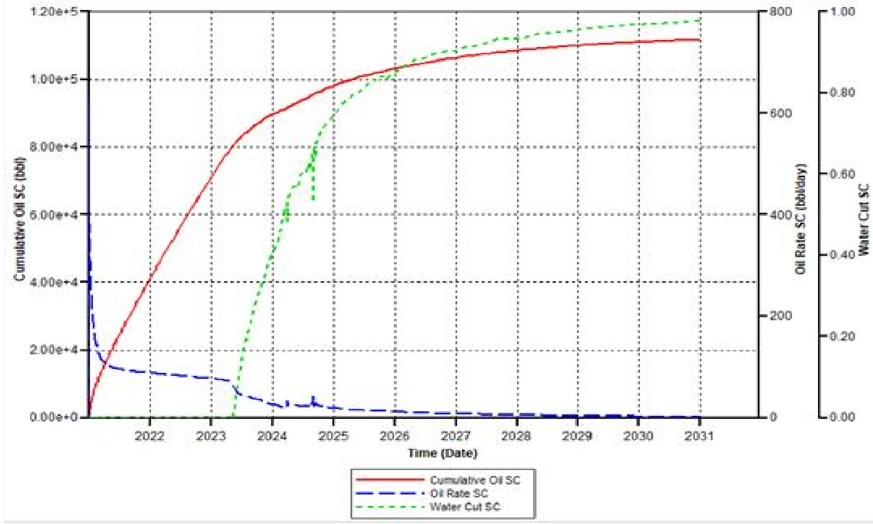


Figure 7—Prediction of surfactant polymer flooding.

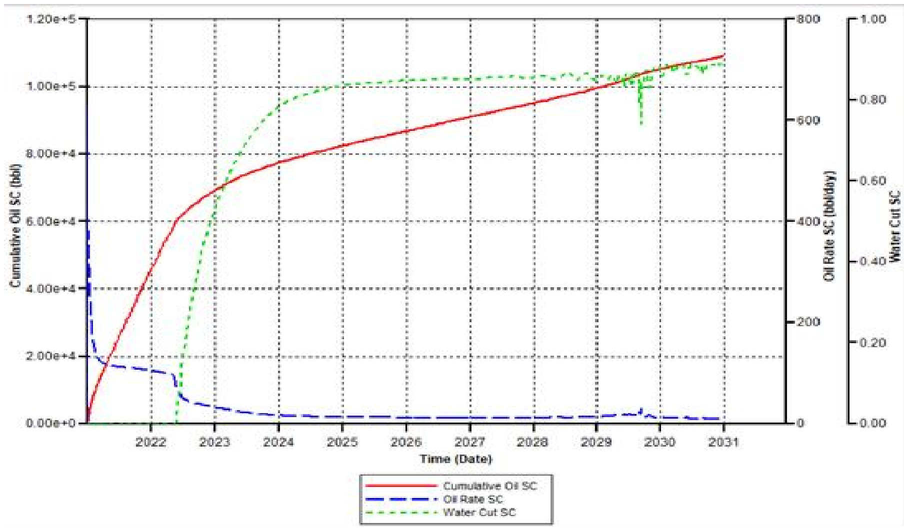


Figure 8—Steam injection simulation.

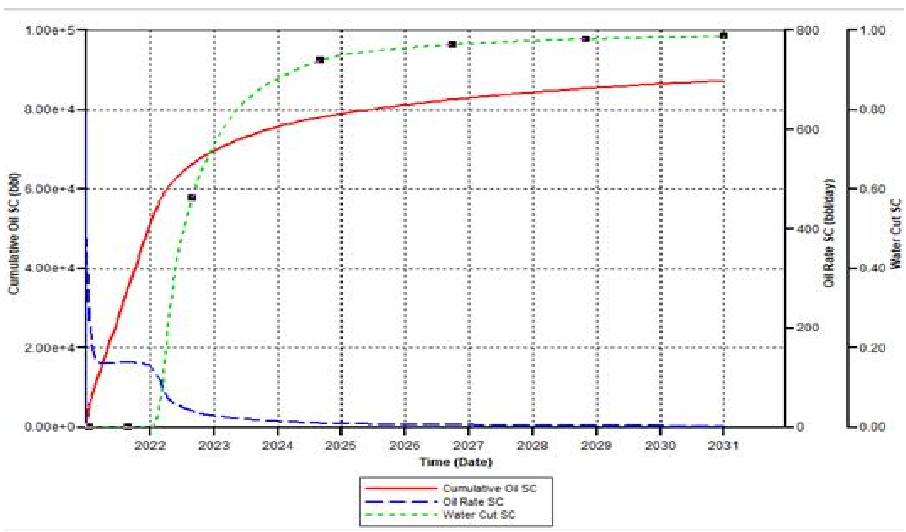


Figure 9—Water injection simulation.

Performance Prediction of the Field

Reservoir performance analysis of oil and gas fields is a continuous process to reassess the present state of the reservoirs. The review helps in taking decision for enhancement of oil and gas production to exploit the reservoir optimally and maximize ultimate oil recovery. The production performances analyzed based on oil, water and gas production data and corresponding pressure drop from the initial reservoir pressure with reservoir facies, by the way of cross plots of different variables. The greatest complexity is due to multiple factors, such as

- Completion in varying type of reservoirs such as pay sands , coal or multiple combination with wide permeability contrast
- Continuous or discontinuous reservoir type
- Types of completion such as casing perforation or slotted casing
- Nature of damage due to drilling/workover
- The degree of accuracy of the production indices/measurement, and
- Adequate/inadequate pressure data.

The present study is based on production, water cut and GOR data available from inception to 1/4/2017. The production performance graphs have been collected through annual activity report, Ahmedabad Asset, ONGC, 2017. Using OFM, graphs for cumulative oil production, oil production rate, liquid production rate, water cut and gas oil ratios are generated.

In this part of our research we will firstly analyse and interpret the production performance of each of 11 layers of Kalol field and we will finally perform the production performance of the whole field.

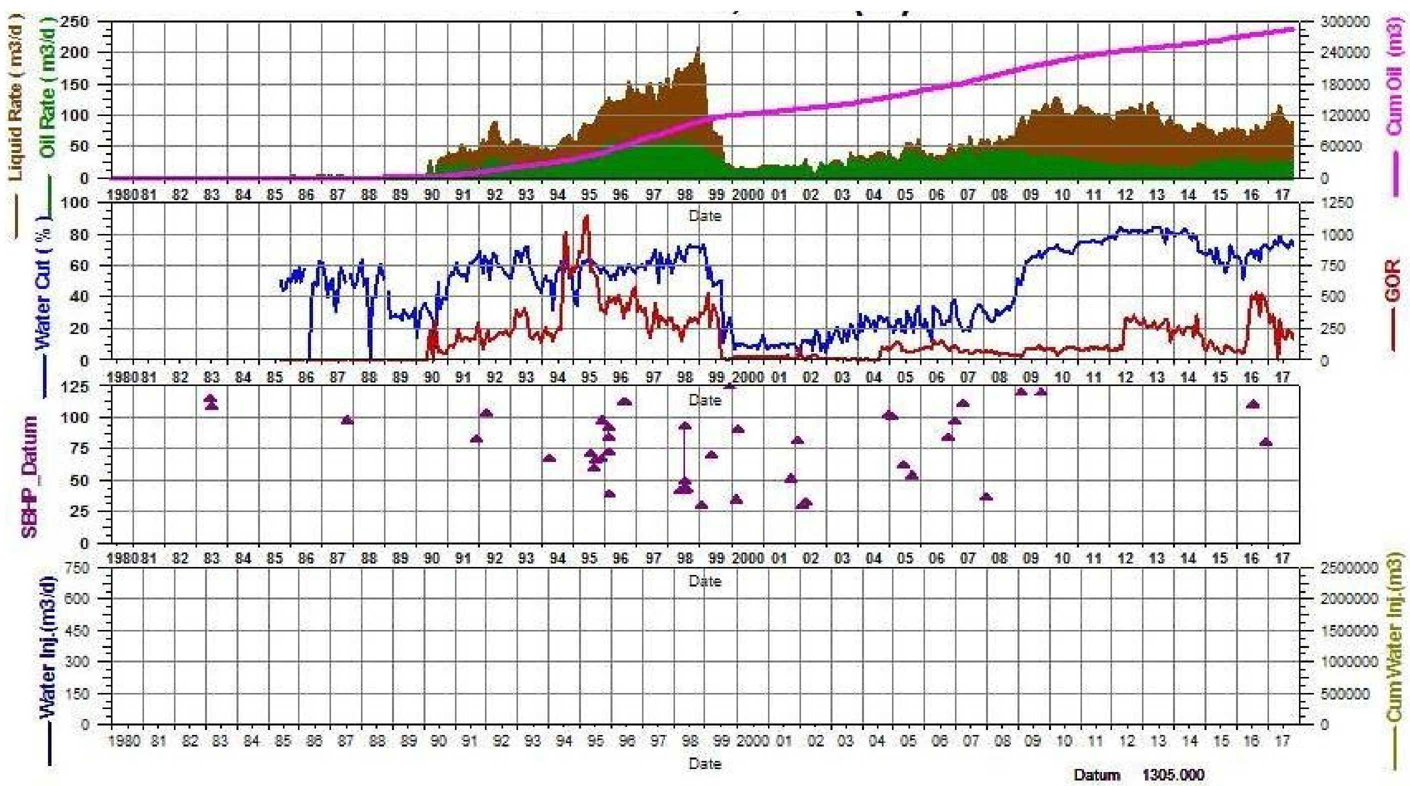


Figure 10—Performance plot of K-II pay zone.

K-**II Pay Zone**. This pay zone is on production since 1980 and the production peaked in 1997 to around 55 m3/day but could not sustain and average production remained around 49 m^3/day as shown in **Figure 10**. No commercial water injection has been developed in the field. Water breakthrough started in 1985 and result to water cut of 45%. In the late 1990 the GOR increased and reached its peak in 1995 to approximately 1100 v/v and became stable at average of 150 v/v from 1999. The water cut reached its peak in 2012 with the value of

80%. As on 1/4/2017 there are 8 oil flowing wells and no injection wells. It has in place reserves of 3.92 MMt of oil and 1797.39 MMm^3 of free gas in PD category with an ultimate component of 0.50 MMt and 1160 MMm^3 as on 1/4/2017 respectively. The cumulative production as on 1/4/2017 is 0.25 MMt of oil and 1148.27 MMm^3 of gas leading to a recovery of 6.9 % and 64% respectively.

K-III Pay Zone. The pay zone K-III is on production since 1964 and the production peaked in 2002 to around 300 m^3/day and sustain to an average rate of 100 m^3/day. In 1986 the pay zone experienced water breakthrough leading to an increased water cut to around 80%. Commercial water injection has started in 1990 in the field. Water cut drastically increased from 1990 and became stable later on during the field production. In 1980, the GOR started increasing and reached its peak in 1984 to approximately 2400 v/v and drastically decreased to an average minimum value of 50 v/v from 2002. As on 1/4/2017 the pay zone was under 12 oil flowing wells and 9 water injection wells. The performance plot of K-III pay zone is shown in **Figure 11**.

It has in-place reserves of 7.63 MMt of oil and 2755.69 MMm^3 of free gas with an ultimate component of 1.6 MMt and 2354.2 MMm^3 as on 1/4/2017 respectively. The cumulative production as 1/4/2017 is 1.42 MMt of oil and 2350.71 MMm^3 of gas leading to a recovery of 20.6% and 85.3% respectively.

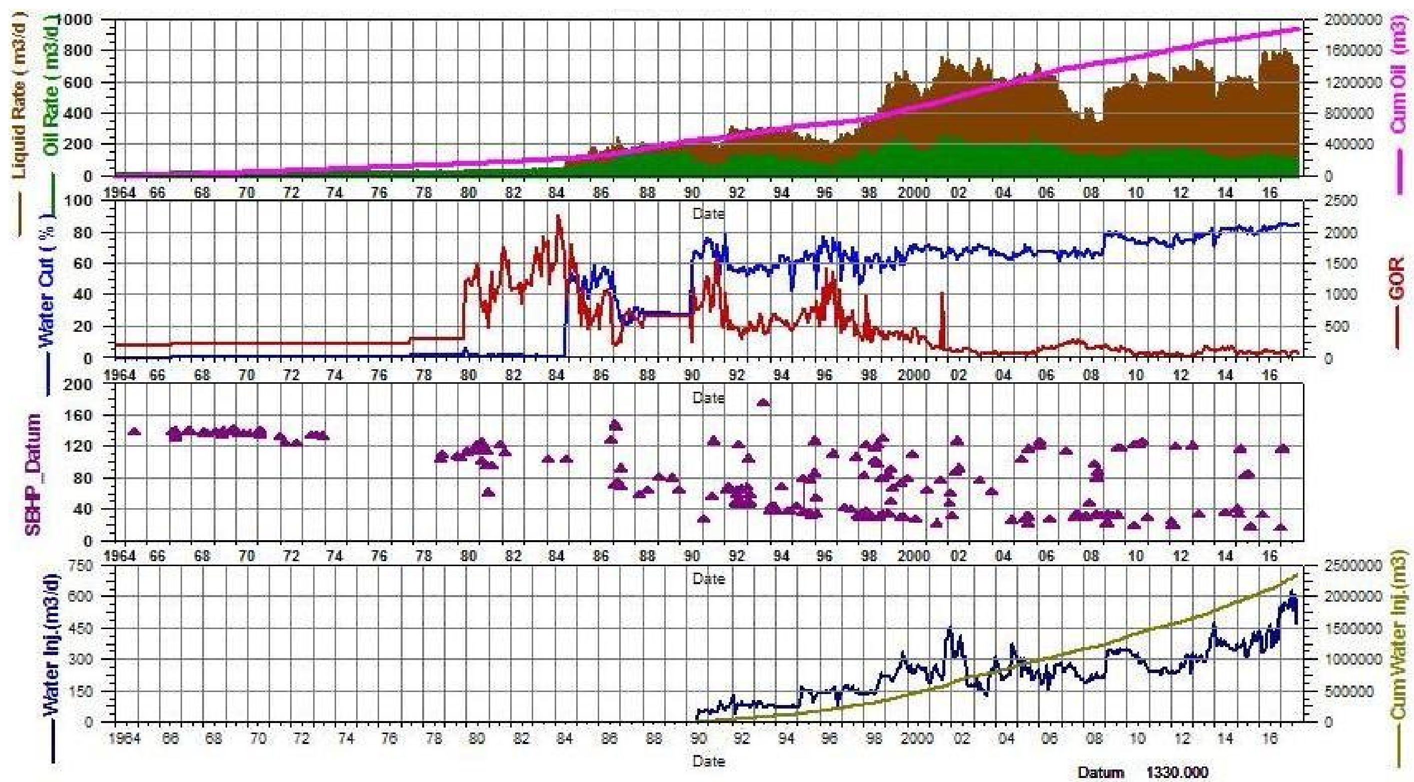


Figure 11—Performance plot of K-III pay zone.

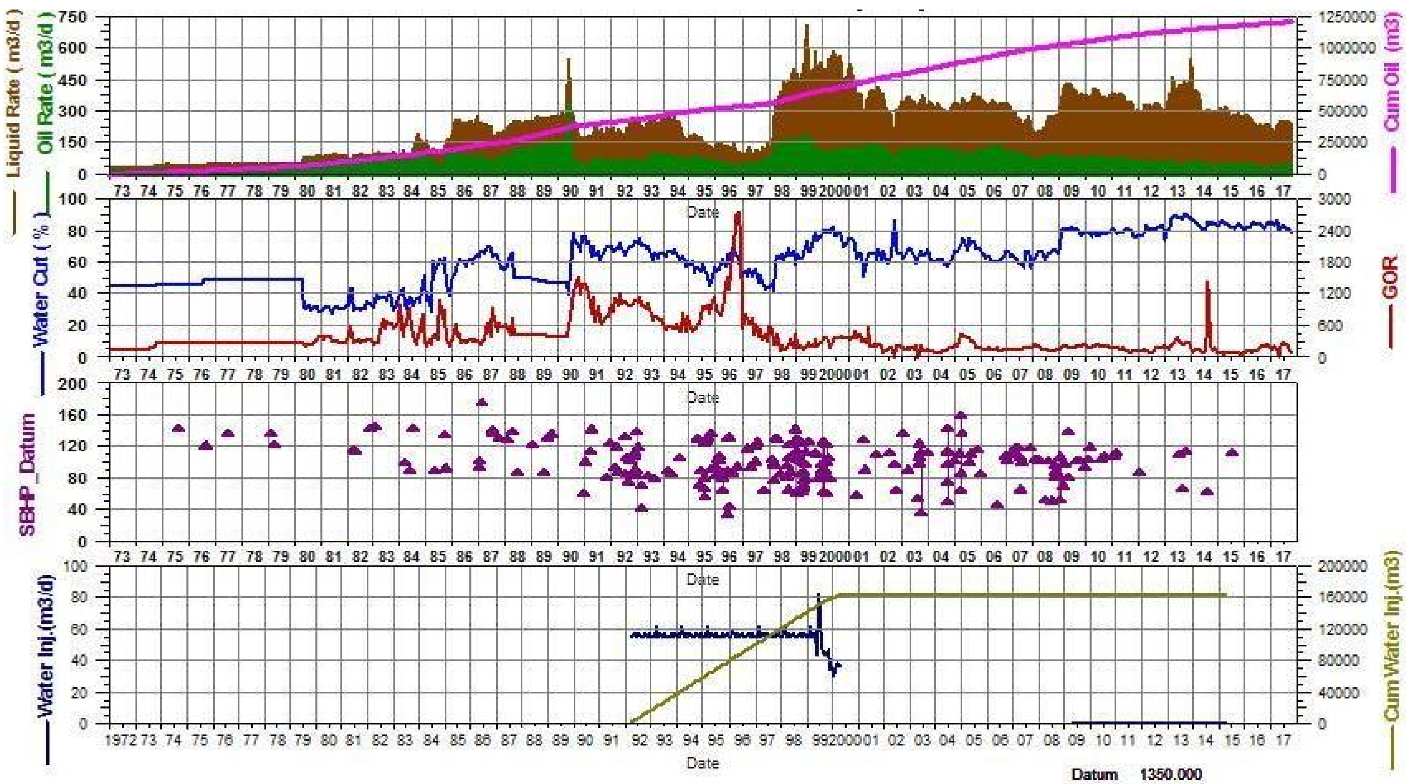


Figure 12—Performance plot of K-IV pay zone.

K-IV Pay Zone. This pay zone is on production since 1972 and the production peaked in 1990 to around 300 m^3/day but could not sustain and average production remained around 40-45 m^3/day. The production started with high water cut of 42% which has been increased and stabilized at higher value of 80%. The field is producing with high water production. The commercial water injection has been developed in the field from 1991 and stopped in 1999. From 1980 the GOR increased and reached its peak in 1996 to approximately 2900 v/v and drastically decreased to an average value of 200 v/v from 1999. As on 1/4/2017 there are 12 oil flowing wells and no injection wells. **Figure 12** shows the performance of K-IV pay zone.Pay zone- IV has in place reserves of 15.32 MMt of oil and 3435.95 MMm^3 of gas in PD category with an ultimate component of 1.27 MMt and 2973.40 MMm^3 as on 1/4/2017 respectively. The cumulative production as on 1/4/2017 is 1.06 MMt of oil and 1610.06 MMm^3 of free gas leading to recovery of 6.9% and 46.9% respectively. The performance plot of K-IV pay zone is shown in Figure 12.

K-V Pay Zone. The pay zone K-V is on production since 1980 and the production peaked in 2003 to around 600 m^3/day and sustain to an average rate of 102 m^3/day from 2013. In 2001 the commercial water injection has started in the field. Water cut sharply increased from 2005 to an average of 50-60%. In 1997, the GOR started increasing and reached its peak in 1998 to approximately 1900 v/v and drastically decreased to an average minimum value of 100 v/v from 2000. As on 1/4/2017 the pay zone was under 17 oil flowing wells and 4 water injection wells. Pay zone K-V has in place reserves of 8.03 MMt of oil with an ultimate component of 2.05 MMt as on 1/4/2017. The cumulative production as on 1/4/2017 is 1.5 MMt of oil leading to a recovery of 18.00%. **Figure 13** shows the performance plot of K-V pay zone.

K-VI+VII Pay Zone. Pay zone K-VI+VII started producing from is on production since 1969 and the production started increasing considerably from 1987 and peaked in 1998 to around 460 m^3/day to an average rate of 187 m^3/day. Commercial water injection started in the field from 1991. The initial GOR was about 39 v/v which peaked in 1974 at around 1900 v/v and drastically decreased to an average of 100 v/v. The combined pay zone has low water cut at approximately 40%. As on 1/4/2017 there are 80 oil flowing wells and 25 injection wells. Pay zone K-VI + VII has in place reserves of 32.55 MMt of oil in PD category with an ultimate component 6.16 MMt as on 1/4/2017. The cumulative production as on 1/4/2017 is 2.46 MMt of oil leading to a recovery of 7.6%. The performance plot of K-VI+VII pay zone is shown in **Figure 14**.

K-VIII Pay Zone. In pay zone VIII, the production started from 1970 with the rate around 30 m^3/d and peaked 1989 at around 145 m^3/d. The production could not sustain at this rate, and average production remained stable at 10 m^3/d. In 1986 the pay zone experienced the water breakthrough leading to water cut of 10 %. The water cut reached its peak in 2014 at 85% and the average water cut in this layer is estimated to be 70%. At the initial stage of the production through the pay, the Gas Oil Ratio (GOR) was very low up to negligible. GOR suddenly increased and peaked to 4800 v/v in 1980, then decreased to minimal value. The average GOR is estimated to be 200 v/v. No commercial water injection has been developed in the pay. As on 1/4/2017 the pay zone was under 3 oil flowing wells and no water injection wells. It has in place reserves of 7.45 MMt of oil as in PD category with an ultimate component of 0.34 MMt as on 1/4/2017. The cumulative production as on 1/1/2017 is 0.05 MMt of oil leading to a recovery of 0.67%. The performance plot of K-VIII pay zone is shown in **Figure 15**.

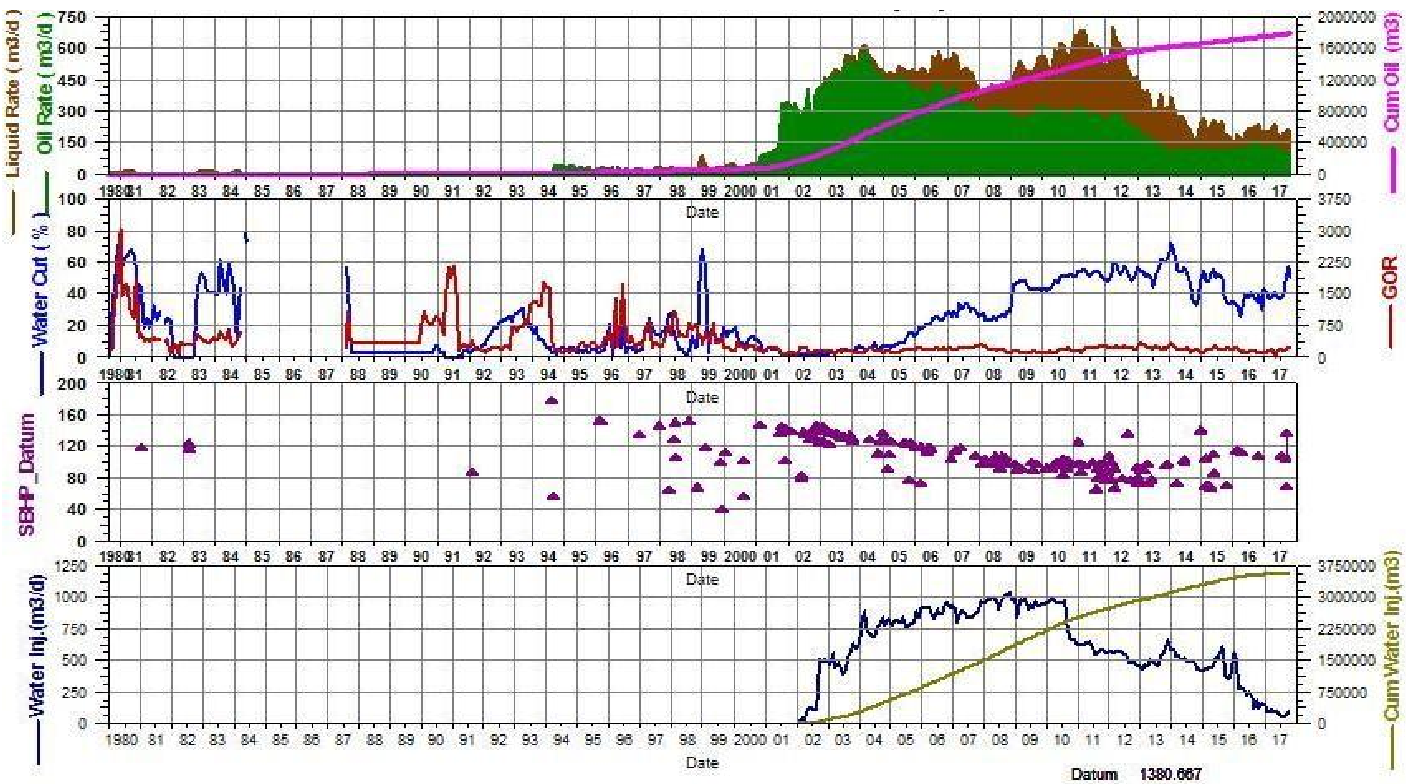


Figure 13—Performance plot of K-V pay zone.

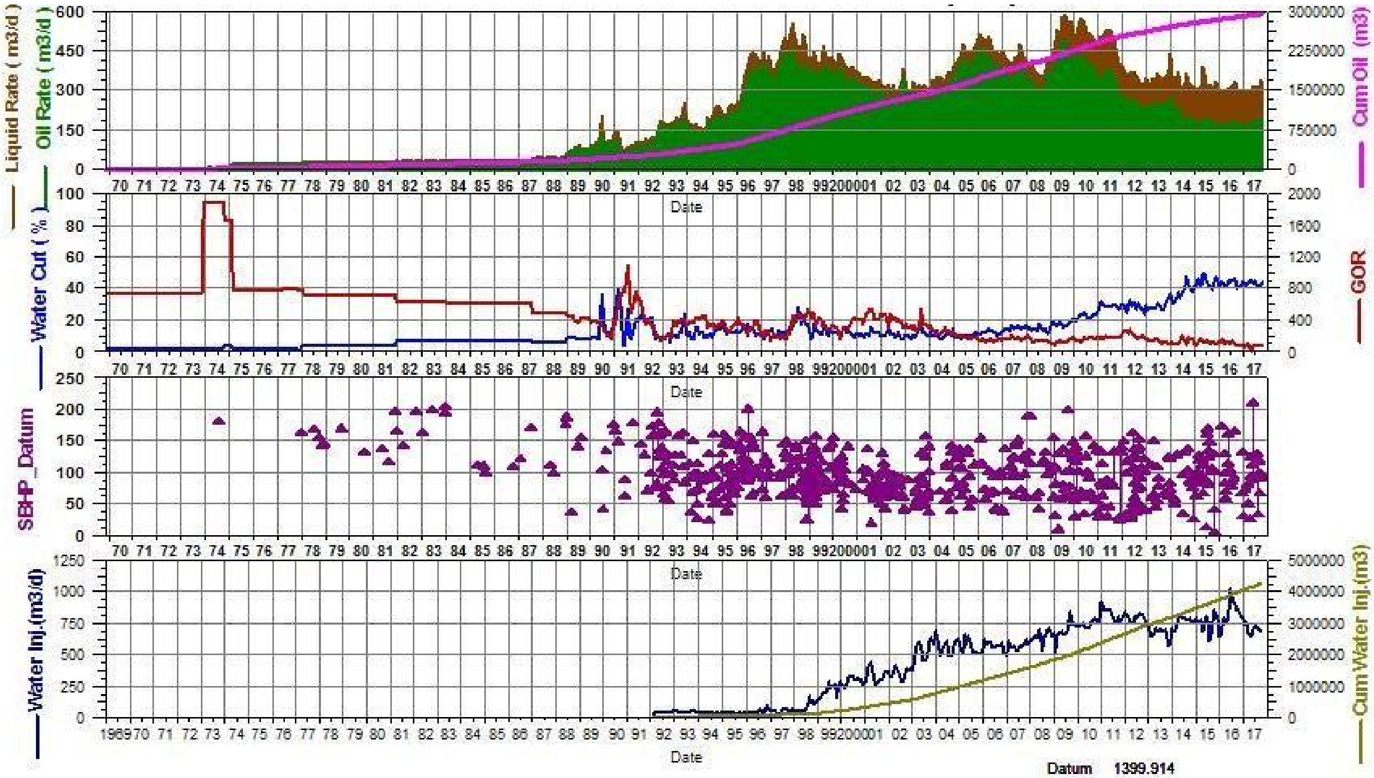


Figure 14—Performance plot of K-VI+ VII pay zone.

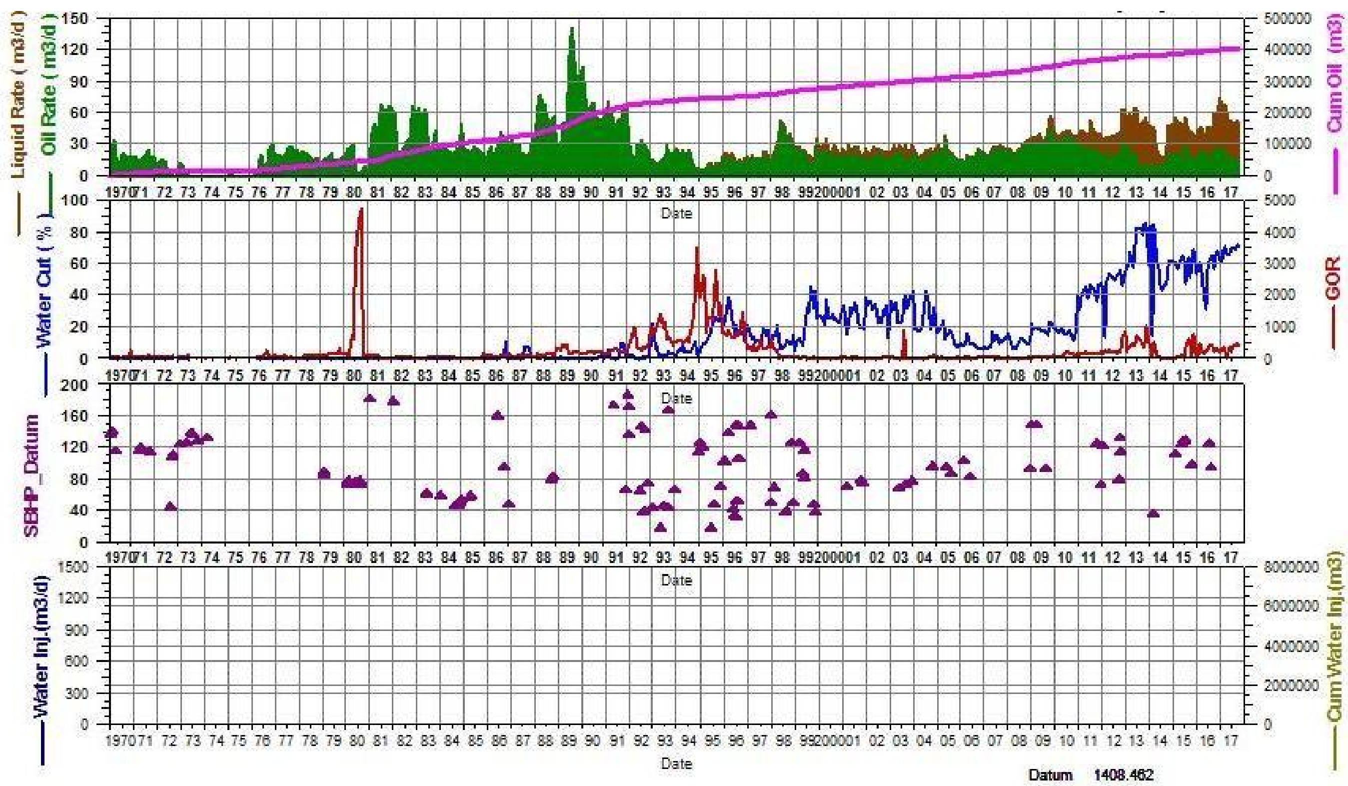


Figure 15—Performance plot of K-VIII pay zone.

K-IX+X Pay Zone. The combined pay zone IX+X started producing from is on production since 1961 and the production started increasing considerably from 1969 and stated at an average rate 280 m3/day for a long period of time (1969-1983). The production rate then increased very highly and peaked in 1990 to around 1300 m3/day. The average production rate through the layer is estimated to be 314 m^3/day. The commercial water injection started in the field from 1991. The layer has been produced for long period time with considerable amount of oil without water cut. The water breakthrough significantly started in 1980 and the average water cut is stated around 37-45%. The initial GOR was about 250 v/v which peaked in 1967 at around 1450 v/v and drastically decreased to an average of 85 v/v. As on 1/04/2017 there are 76 oil flowing wells and 21 injection wells. The pay zone K-IX+X has in place reserves of 57.14 MMt of oil and 164.2 MMm^3 of free gas PD category with an ultimate component of 7.34 MMt and 79.3 MMm^3 respectively as on 1/4/2017. The cumulative production of oil and gas as on 1/4/2017 is 4.69 MMt of oil and 10.1 MMm^3 of gas leading a recovery of 8.2% and 6.15% respectively. The performance plot of K-IX+X pay zone is shown in **Figure 16**.

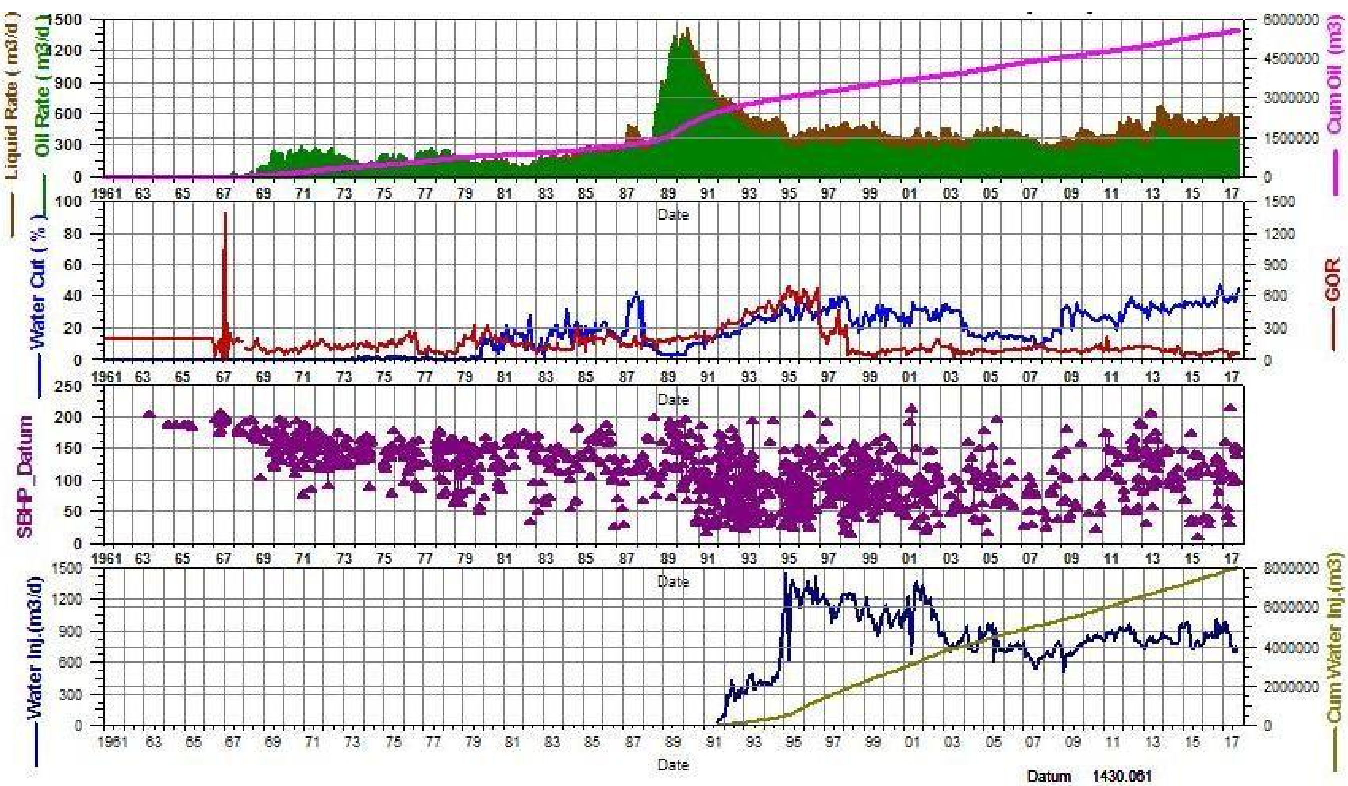


Figure 16—Performance plot of K- IX+X pay zone.

K-XI Pay Zone. In 1969 the production started in pay zone XI with the rate around 20 m^3/d and peaked 1989 at around 80 m^3/d. The production could not sustain at this rate, and average production remained stable at 13 m^3/d. At initial age of production there was considerable water cut from the layer at around 30%. This water cut remained constant for long period of time and significantly increased from 1990. The water cut from the production of the pay is then stated to be very high at around 80-90%. At the initial stage of the production through the pay, the Gas Oil Ratio (GOR) was low as 100 v/v. GOR considerably increased in 1991 and peaked to 2000 v/v, then decreased to minimal value. The average GOR is estimated to be 100 v/v. No commercial water injection has been developed in the pay. As on 1/4/2017 the pay zone was under 5 oil flowing wells and no water injection wells. It has in place reserves of 6.86 MMt of oil in PD category with an ultimate component of 1.22 MMt as on 1/4/2017. The cumulative production as 1/4/2017 is 0.28 MMt of oil leading to a recovery of 4.08%. The performance plot of K-XI pay zone is shown in **Figure 17**.

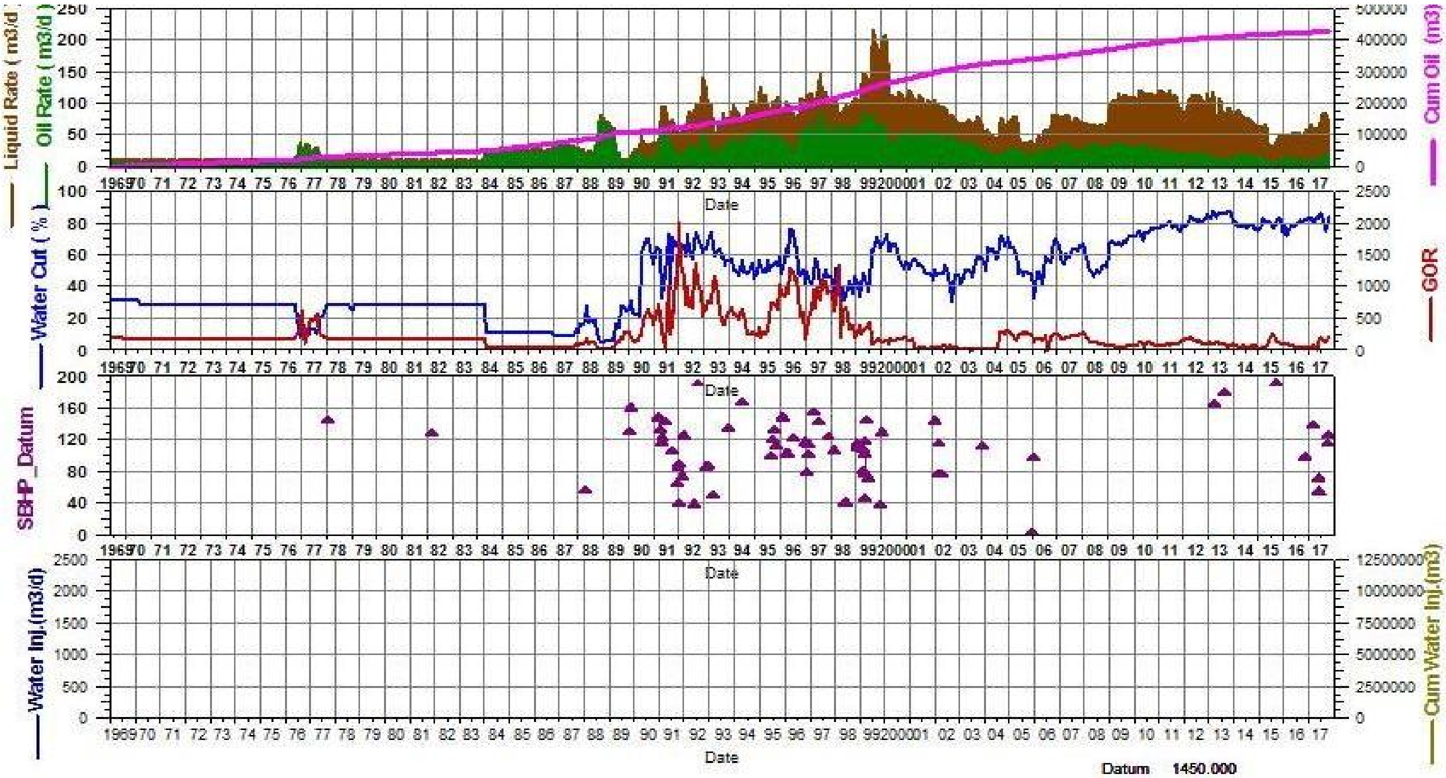


Figure 17—Performance plot of K- XI pay zone.

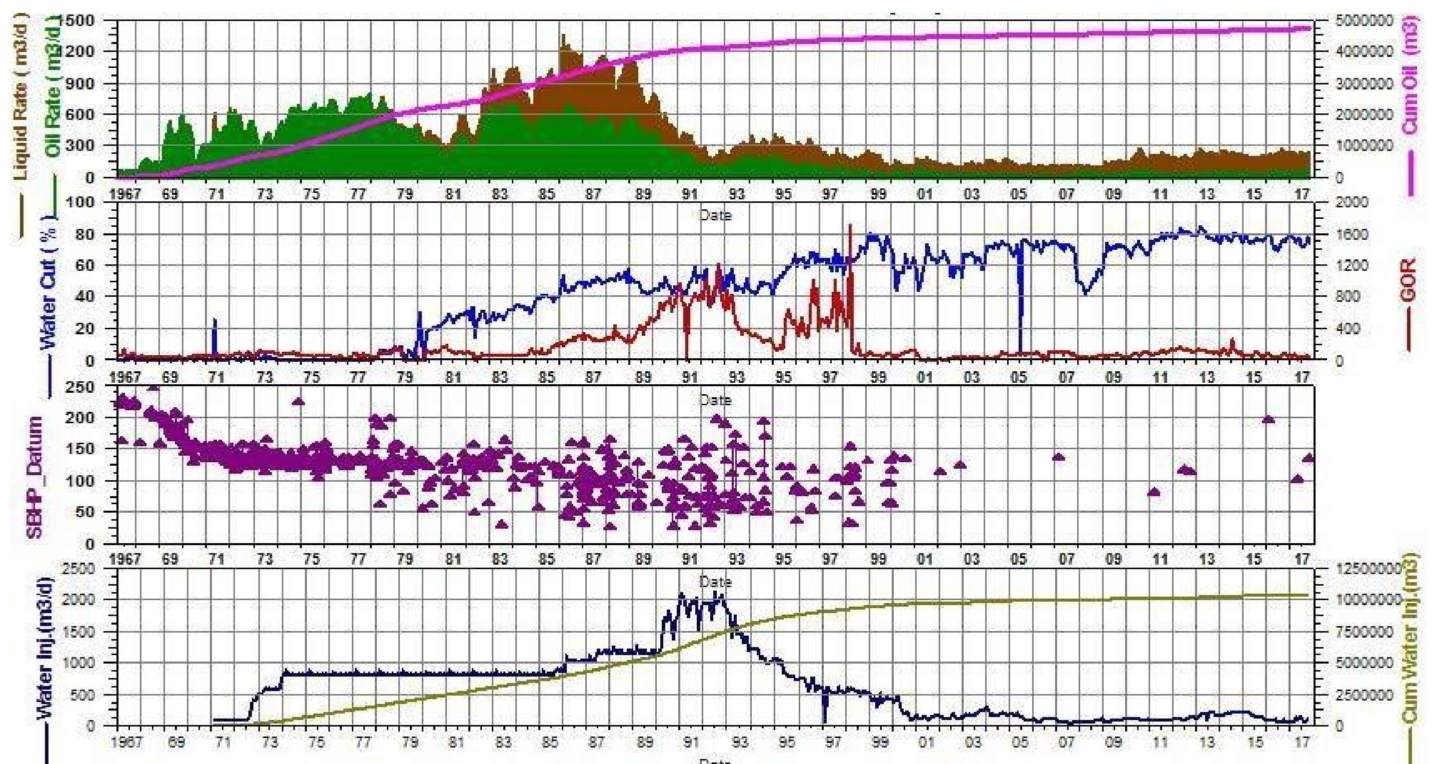


Figure 18—Performance plot of K- XII pay zone.

K-XII Pay Zone. In K-XII, the production started from 1967 with the rate around 100 m^3/d and increased significantly to peak in 1977 at around 800 m^3/d. The production could not sustain at this rate, so it stated decreasing from 1989 and average production remained stable at 73 m^3/d. The initial stage of the pay production is remarked by negligible water cut. In 1971, the commercial water injection started. In 1979 the pay zone experienced the water breakthrough leading to water cut of 30 %. The water cut reached its peak in 2011 at 85% and the average water cut in this layer is estimated to be 80%. At the initial stage of the production through the pay, the Gas Oil Ratio (GOR) was very low up to negligible. GOR suddenly increased and peaked to 1800 v/v in 1998, then decreased to minimal value. The average GOR is estimated to be 49 v/v. As on 1/4/2017 the pay zone was under 13 oil flowing wells and 1 water injection wells. It has in place reserves of 12.98 MMt of oil in PD category with ultimate component of 5.50 MMt as on 1/4/2009. The cumulative production as on 1/4/2017 is 3.70 MMt of oil leading to a recovery of 28.9%. Water injection in this pay zone was initiated very early in 1972 and is now in mature stage. Good response of injection is observed in majority of the area. The performance plot of K-XII pay zone is shown in **Figure 18**.

Whole Kalol Field. Here, the current status and performance of Kalol field is provided by combining all the layer together and depicted in **Table 5**. The field has been producing since 1961, with exploration and exploitation resulting in lateral and vertical field growth. In 1989, production reached the peak to around 2100 m^3/day, but it could not be sustained, and average production stayed around 877 m^3/day. Additional accretion and exploitation could keep the rate at this level for longer time. Despite the fact that water injection was started at an early stage in 1972 for a few reservoirs due to depletion, Commercial water injection, on the other hand, could begin in 1990, resulting in low pressure areas in most reservoirs. The average field water cut is roughly 40%, with GOR ranging from 100 to 250 v/v. However, the average GOR is around 150 v/v. It has in place reserves of 151.9 MMt of oil in PD category with an ultimate component of 25.15 MMt as on 1/4/2017. The cumulative production as 1/4/2017 is 15.7 MMt. In the last 56 years, cumulative production has been 10.3% of in-place oil, indicating a lower exploitation index. Various initiatives over the last two years have increased production from 825 to 975 m3/d. This could be accomplished by adopting proper reservoir management practices improving the number of flowing wells, frequent zone transfers in light of the reservoir's multilayered nature, effective water injection in a few layers, prioritization of potential development in field wells, aggressive hydrofracturing campaigns, artificial lift optimization, and ultimately proper layer-wise reservoir management. The performance of the Kalol field is shown in **Figure 19**.

Table 5—Reserves status of Kalol field as on 1/4/2017.

OIIP (PD)	151 MMt
Ultimate Reserves (PD)	25.15 MMt
Cumulative production	15.7 MMt
Reserves (PD)	9.5 MMt
Recovery	10.3 %
Wells drilled	702
Oil+ gas wells	502
Water Injectors	104
Oil production rate	877 m^3/d
Water Injection rate	2119 m^3/d
Pay zones	9
Oil + Free Gas pay	3
Oil Pays	6

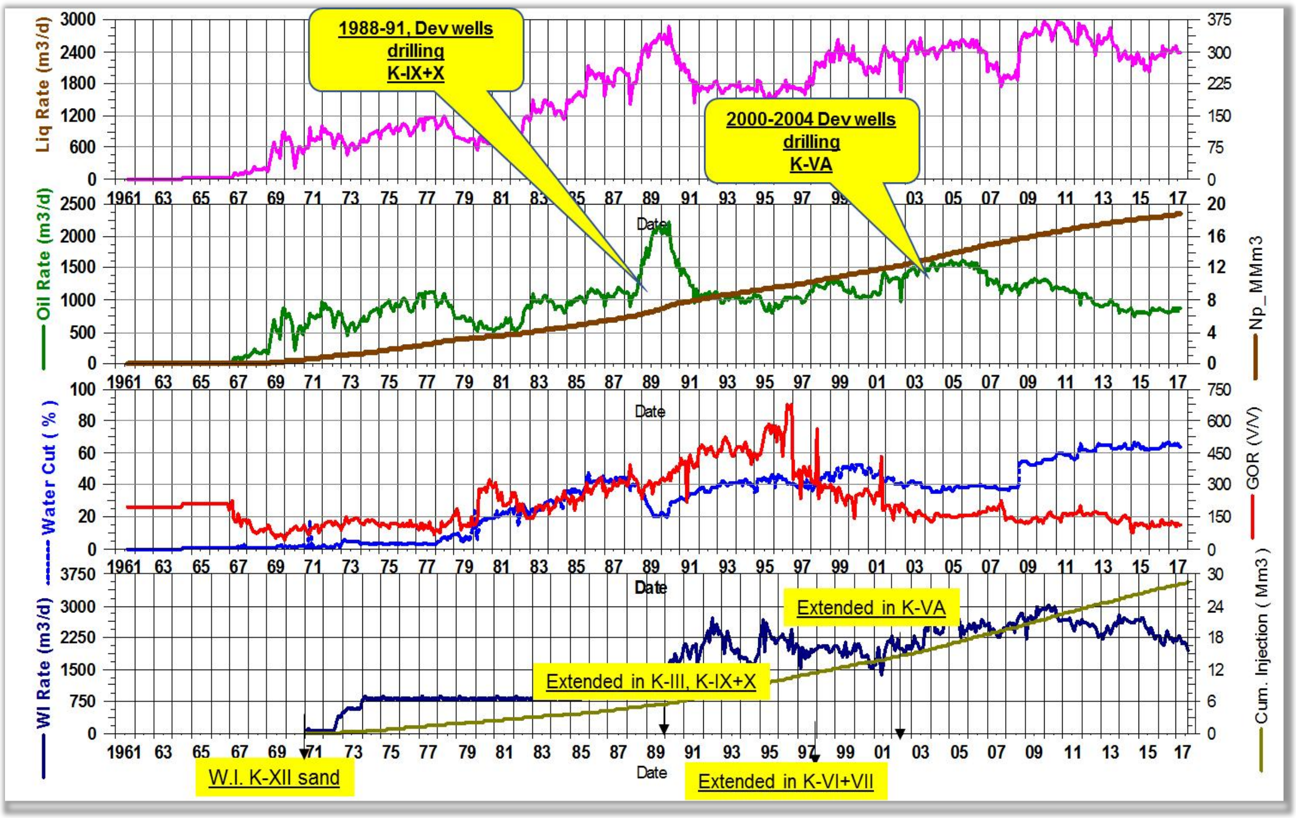


Figure 19—Performance graph of Kalol Field.

Figure 20 shows the production of different layers of Kalol field from the inception to 2017. Between the years 1964-1987, the sand K-XII was dominant in the term of production, followed by K-IX + X. The production was higher in K-IX+X from 1987 to 1995 then from 1995 to 2000, the total field production was equally shared through the pays K-VI+KVII, KIX+X and KIII. From 2000-20017 the exploitation throughout the field is dominated by the layers K-III, K-VA, KVI+VIII. Since the inception of the field up to 2017, the pay zones K-XII and K-IX +X have produced the maximum amount of crude.

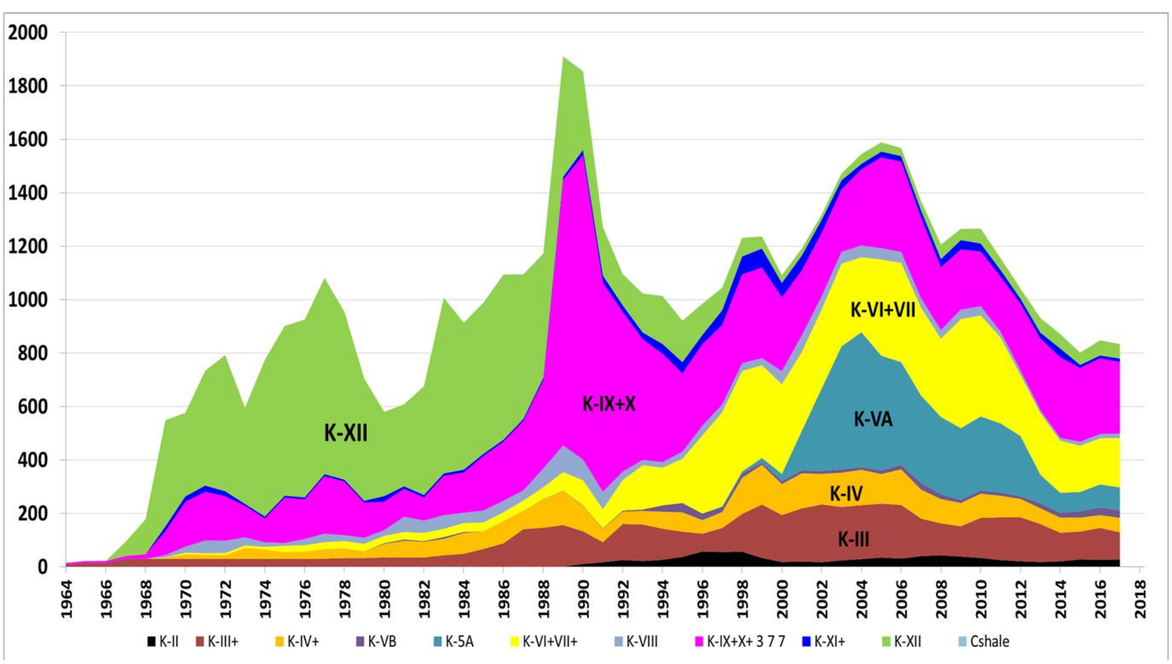


Figure 20—Exploitation of different sands in different time periods.

Techno-economic Feasibility Analysis

As on 1/4/2019, a total of 752 wells have been drilled in the Kalol field, of which 464 wells are currently oil producers, 118 wells are water injectors, 8 wells are effluent disposal, 28 wells are gas wells, 1 well is polymer injector, 83 wells are abandoned, 10 wells are yet to be abandoned, 10 wells are observation wells, 25 wells are future utility wells. **Table 6** shows economics analysis of the Kalol field.

Table 6—Economics analysis of the Kalol field.

Revenues	
Crude oil, MM$	4407.32
Natural gas, MM$	99.74
Other income, MM$	235.17
Change in stock, MM$	7.31
Total Revenue, MM$	**4749.54**
Expenses	
Stationaries levies, MM$	1453.46
Operating expenses, MM$	1468.41
Recouped Cost, MM$	423.40
Provisions and write offs, MM$	22.03
Others, MM$	3285
Total Expenses, MM$	**3400.15**
Profit/Loss	**1349.39**

Drilling Project Costs. 162 wells are planned to be drilled in various fields of Kalol from 2019 to 2026. The incremental oil gain from the drilling of these development wells is estimated to be 0.949 MMt and incremental gas gain is 122.18 MMSCM. ONGC is oil major and strives to continually hike the production of hydrocarbon to meet the ever-growing national demand. In Ahmedabad asset, about 905 MMt (3P) reserve as 1/4/2019 is available for exploitation in fields. Development drilling is one of the main activities to the available reserve. **Table 7** shows the drilling projects and costs.

Table 7—Drilling projects and costs.

Year	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	Total
No of wells to be drilled	27	27	25	23	20	20	20	162
Average cost of drilling, $/m	35744	37174	38660	40593	42623	44754	46992	
Average depth, m	1600	1600	1600	1600	1600	1600	1600	
Drilling cost, MM$/well	57.2	59.5	61.9	64.9	68.2	71.6	15.2	
Drilling cost for the year, MM$	1544.4	1606.5	1547.5	1490.4	1364.0	1432.0	1504.0	10488.8

Chemical Injection Projects and Costs. **Table 8** depicts the available chemicals and their costs per barrel of incremental oil from the surveyed ASP projects. In the chemical injection project, the pre-slug was designed to have 0.097 of slug and 1450 ppm of polymer. The main flush is composed of 0.308 of slug where 1350 ppm of polymer, 1.25% of alkaline agents and 0.27% of surfactants. The post slug composed of 0.242 and 800 ppm of polymer. The individual chemical slug cost in US$/bbl incremental oil of pre-slug, main flush and post-slug was 0.42, 7.43, 0.53 respectively. The average chemical cost in US$/bbl incremental oil is 6.32 and the total drilling cost from 2019 to 2026 is estimated to be 10488.8 MM$.

Table 8—Chemicals and costs.

Item	Chemical		
	Pre-Slug	Main flush	Post-Slug
Slug size, PV(1L)	0.097	0.308	0.242
Polymer, ppm	1450	1350	800
Alkiline agents, %		1.25	
Surfactants, %		0.27	
Alkiline cost , US $/lb		0.15	
HPAM cost , US $/lb		1.5	
Surfactant cost, US $/lb		3	
Individual chemical slug cost, US $/bbl Inc. oil	0.42	7.43	0.58
Total chemical cost, US $/bbl Inc. oil		8.44	
Average chemical cost, US $/bbl Inc. oil		6.32	

Conclusions

The Kalol field, India's largest onshore field, is located in the central part of the prolific Cambay basin and has been operated by ONGC, a national oil firm, for the past 60 years. Continual exploration and exploitation activities resulted in field expansion both laterally and vertically, resulting in continuous growth of the Initial Oil in Place, ultimate, and recovery factor improvement. Although the field is old in terms of vintage, it is still young, having produced only 10.3% of in place Oil. In light of the current operating strategies, the field is experiencing a mid-life crisis; however, recent efforts to focus attention on individual wells, induction of technologies, and water injection surveillance and monitoring have paid off handsomely in terms of increasing, sustaining, and maintaining production levels. The objective of our research was to maximize the recovery from the field with minimal capital and operating expenditure.

The following conclusions are reached based on reservoir simulation and comparison of several IOR approaches in the pay K-VA:

- Since 2005, Kalol V-A has been producing with secondary recovery via water injection, and continuing usage of water injection will result in a recovery of 39% until 2030.
- If water injection is substituted by gas injection, the recovery rate will climb to 41% by 2030, resulting in a higher production rate.
- ASP Flooding is proposed to boost the oil recovery from based on preliminary EOR Screening and analogy to a similar reservoir K-XII sand in the same field. We took the work a step further by doing a study on SP simulation and comparing the two ways.
- It has been determined that while SP flooding can avoid the detrimental effects of alkali, it is not cost competitive with ASP flooding and has a lower recovery rate.

- In other hand, Kalol layers are very tight and heterogeneous so the injectivity of is very less. Thereby injection of ASP was very difficult due to low injectivity and failed during the pilot test. So the most effective method for the recovery of the field becomes the immiscible gas injection.

The data for the simulation was collected from reference articles and assumed whenever necessary. Fields offer a tremendous potential for increasing the recovery factor from individual layers, and obtaining 20% recovery on a field scale does not appear to be a Herculean task. The fundamental requirement for the field to sustain production is pressure maintenance through effective water injection and the introduction of EOR technologies. A better knowledge of the geological and reservoir heterogeneity can help pave the road for future Brown Field utilization.

Conflict of Interests

The author(s) declare that they have no conflicting interests.

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Tiene Bema Komba is working as a Field Engineer Trainee in Baker Hughes, Côte d'Ivoire, West Africa. He holds B.Tech. and M.Tech. in Petroleum Engineering from Jawaharlal Nehru Technological University, Kakinada, India and Pandit Deendayal Energy University, Gandhinagar, Gujarat, India, respectively. His research interest includes reservoir engineering, enhanced oil recovery, and subsea production system. He did his internship in ONGC India.

Rakesh Kumar Vij is a Professor of Practice of Petroleum Engineering at Pandit Deendayal Energy University, Gandhinagar. He also served as Director-School of Petroleum Technology and Dean-Placement at the same university. He holds B.Sc., M.Sc., and M.Phil. from University of Delhi and Ph.D. from Dibrugarh University, India. He has 39 years' experience in ONGC India. His research interest includes reservoir management, enhanced oil recovery, CO2 sequestration, and green hydrogen.

Achinta Bera has been working as an Assistant Professor of Petroleum Engineering at Pandit Deendayal Energy University, Gandhinagar, Gujarat, India since 2019. He holds B.Sc. and M.Sc. from University of Calcutta and Ph.D. from Indian Institute of Technology (ISM) Dhanbad, India. His research interest includes reservoir characterization and modeling, enhanced oil recovery, unconventional energy resources, drilling fluids & cementing, CO_2 sequestration, and underground hydrogen storage. He has been listed as world's top 2% scientists by Stanford University ranking system.