Pakistan Journal of Hydrocarbon Research
Vol.13, (June 2003), p.37-58, 14 Figs., 4 Tables

An Integrated Reservoir Simulation Study of Fimkasser Oil Field

M. Saeed Khan Jadoon[1], Abdul Hameed[1], Mian M. Akram[1], Abid Hussain Bhatti[1], Asghar Ali[1] and Iftikhar Rizvi [1]

ABSTRACT

Fimkasser oil field was commercially discovered by OGDCL in Potwar basin in 1989. It is fractured carbonate reservoir and the producing formations are Sakesar & Chorgali. After production of six year with the cumulative production of about 6.0 million barrel of oil, reservoir pressure had gone below bubble point pressure in last quarter of 1995. Due to this rapid decline in reservoir pressure, oil production declined from 3800 - 1800 bbl/day. Water flooding was started in early quarter of 1996 to arrest the production decline by pressure maintenance. With the injection of water, production of oil increased from 1800 - 3800 bbl/day. After injection of two years, water break through occurred and that resulted in decline of production from 3800 to 550 bbl/day. An integrated reservoir simulation study was undertaken to address the problem of early water breakthrough, location of trapped oil and to define new depletion strategy for the field. In this paper, methodology, construction of new reservoir model and understanding of reservoir behavior will be explained.

INTRODUCTION

The Fimkassar structure is located in the eastern part of the Potwar Basin and is approximately 75 kilometers west of Islamabad. It's fractured carbonate reservoir comprises of two producing formations; Chorgali and Sakesar. The Fimkassar structure was first explored by the Gulf Oil Company in 1980. The company drilled Fimkassar well (Fim-1X) and hydrocarbon shows were observed in the Chorgali as well as in the Sakesar Formation. The well was tested and an oil production rate of 20 bbls/day was recorded. After a few months of observation, the Gulf Oil Company declared this well as non-commercial and Field was taken over by OGDC.

OGDCL drilled well (Fimkassar -1A) and was abandoned due to drilling complication in the Murree Formation before reaching to the target depth. Later on re-entery was made in Fim-1X to side track it and was renamed as Fim-1ST. This side tracked well Fim-1ST successfully tested commercial hydrocarbon in Sakesar Formation and lead to the discovery of the Fimkasser oil field in 1989.

The field came on regular production in October 1989 at the oil rate of 4000 bbl/day and the initial reservoir pressure of Sakesar was recorded as 5709 Psia. The bubble point pressure of the hydrocarbon fluid was measured at 2948 psia. Pressure survey conducted on 28th August 1995 showed that reservoir pressure had gone below the bubble point pressure and had declined from 5709 Psia to 2477 Psia. Consequently to arrest the decline in reservoir pressure and production, water injection was started in Sakesar Formation.

To-date, 4 wells have been drilled on this structure. Two of these wells (Fim-1ST and Fim-2) are producers while well Fim-3 is water injector. Fim-1x was abandoned due to mechanical problems. The cumulative production as of 30 April, 2002 was about 12 MMSTB oil from the field. Similarly the cumulative water injection and production as of this date in the field was about more than 14 million barrels and 2 million barrels respectively. An Integrated Reservoir Simulation Study was conducted to address the reservoir management problem of the field such as remaining recoverable reserves and requirement of the new wells for optimum recovery of the oil from the field. In the present study, geophysical evaluation was carried out and new map was generated which was entirely different from all the early studies. This new map was used in the construction of the new simulation model. Similarly Sedimentological study was a new addition in the current study which was also not carried out in all the previous studies.

GEOPHYSICAL EVALUATION

Seismic data was reinterpreted and the depth structure map was prepared as shown in figure 1. Interpretation results reveal the following features:

- Fimkassar structure is an anticline feature formed as a result of compression tectonic.
- The structure rests in the hanging wall being separated by northeast-southwest trending thrust fault from its Chaknaurang counterpart, which is situated in the down thrown block. The throw of this fault is about 2300 meters. Such structures are the product of major detachment. This detachment level lies within the Pre-Cambrian salt.
- Two north-south trending reverse faults confine the Fimkassar structure on its northern and southern flanks. These faults are younger than the major thrust fault. One of these faults separates Fimkassar from Turkwal structure on its northern flank. The throw of this fault is about 200 meters.
- The trend of the major thrust and axis of the structure follow the regional tendency.

[1] Oil and Gas Development Company Ltd., Islamabad.

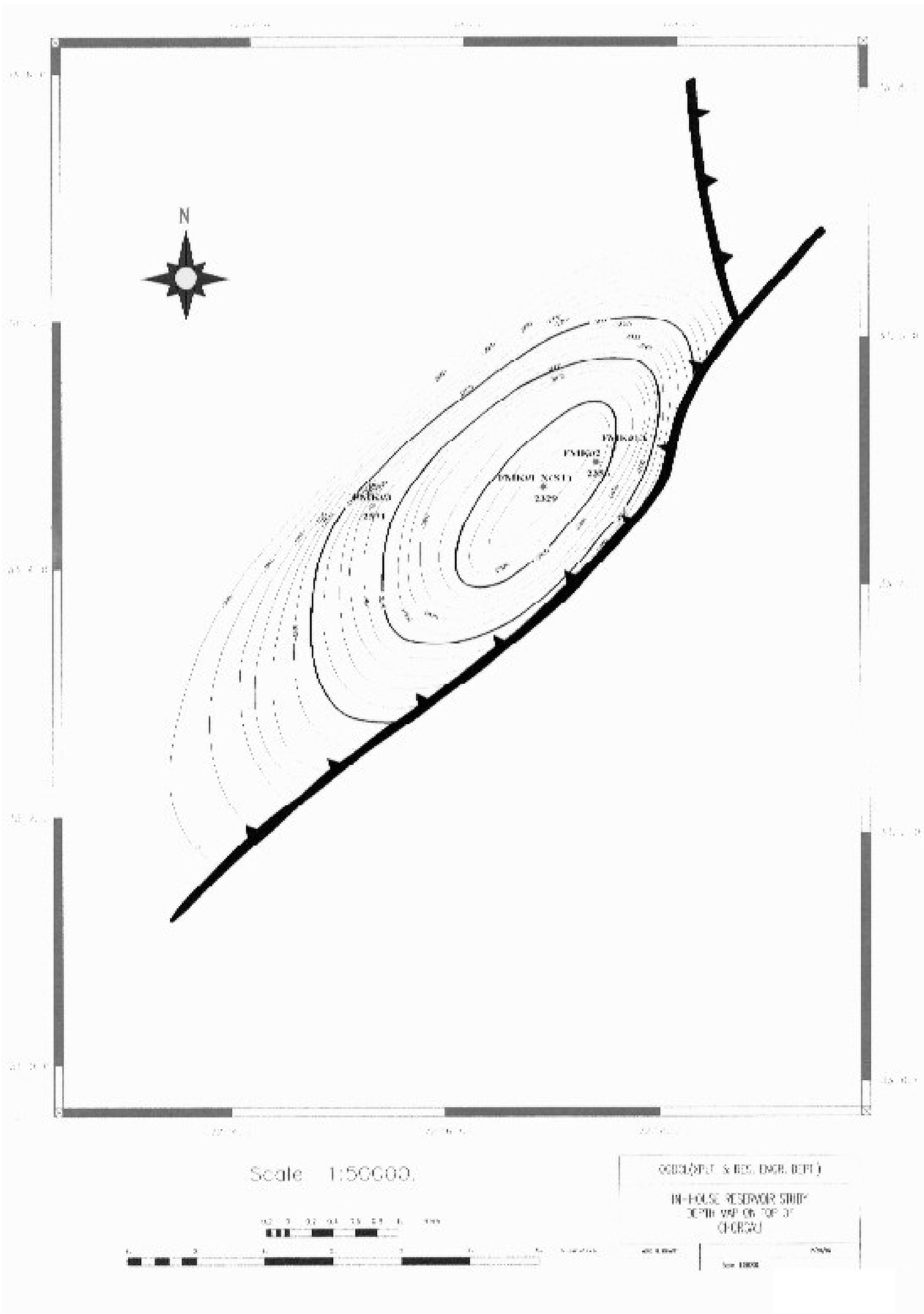

Figure 1- Depth map on top of Chorgali Fomration.

Following is a summary of the comparison from structural standpoint and its relevant aspects:

Structural Style

SSI: Fault bounded structure against major thrust to the east.

OGDC: A snake-head feature having four-way closure.

Fault as a Seal

SSI: Major thrust in the east is to be sealing, otherwise dysmigration had to occur.

OGDC: Aforesaid characteristic does not affect accumulation of the hydrocarbon as a snake-head anticline feature can retain hydrocarbon accumulation due to its style.

RESERVOIR GEOLOGY

The Fimkassar structure, created in the late phase of Himalayan Orogeny, is a northeast to southwest trending steeply dipping asymmetrical anticline with major thrust faults on its southern limb. However, the crestal part and both plunges are well preserved. This major fault, which marks its southern limit, is thrust with approximate throw of more than 100 meters. The depth structure map of the field on the top of the Sakesar Formation is shown in figure 1.

Chorgali and Sakesar Formations are the two main reservoirs while Murree shale provides the top seal. The other geological formation underlying the Sakesar is identified as Nammal Formation of Eocene age in all the wells. Chorgali Formation is primarily composed of dolomite and shale at its base. Dolomite is mainly dense, argillaceous and fossiliferous. The shale is medium hard, fissile, pyritic and slightly calcareous. Chorgali encountered in Fim-1ST and Fim-3 has very good matrix porosity ranging from 10 – 21% due to dolomitization but got very low permeability. This low permeability was proved by two open hole DST's on this formation which did not recover any hydrocarbon. This indicates that matrix has no conductivity of its fluid. Chorgali encountered in the Fim-2 is highly fractured and is responsible for the production of oil from this formation.

The Sakesar is predominantly composed of limestone of light gray to dark gray in color, containing fractures with minor amount of shale. The Sakesar Formation encounterd in all three wells are fractured without any correlation. In Injector, upper part of the formation is fractured while in the two producers, lower part of the formation is fractured. Water is being injected in the upper part of the Sakesar which is structurally 244 meters lower than the producer. The production from this formation is from the fractured area in both wells. All the isopachs for Sakesar reservoir are prepared using a reservoir limit of –2600 meters subsea. This is the last closing contour on the top of the Sakesar limestone.

Stratigraphic, structural cross sections and distribution of the fractures are shown in figure 2. The stratigraphic cross section shows thinning of the Chorgali and thickening of the Sakesar limestone towards west in the direction of well Fim-3 whereas in other wells thickness remain almost same. Fim-1ST was drilled with maximum deviation angle of 4° towards 240° azimuth on the crest of the anticline and was completed in lower part of the Sakesar Limestone as an oil producer. The well Fim- 2 was drilled as vertical well down to the Sakesar while it was completed in the Chorgali reservoir.

RESERVOIR ZONATIONS OR LAYERING

The producing formations are Sakesar and Chorgali and can be represented by the two geologically layers or zones. In order to improve the reservoir description in the simulation model, each formation is divided into three layers that constitute six layers from top to bottom of the reservoir. This division of the layers was based on lithology, fracture concentration and frequency, shale breaks, gamma ray and density logs. There was a strong correlation between average reservoir permeability and fracture frequency and inverse of shale break frequency. Fracture frequency data were obtained from various sources, including FMS, visual observation of cores, etc. Reservoir characterization constitutes the biggest challenge in modeling complex reservoirs. This challenge was met by integrating petrophysical data, fracture frequency, cutting observations, core data, and well test data. For each formation, one layer was dedicated to high density fractures. The orientation of fractures was determined from analysis of the geophysical data, tectonic information, and visual observations of cores. The final layering in this simulation was compatible with the completion of existing and new wells as well as the monitoring of water saturation.

FRACTURE MECHANICS

Nelson (1985) and Nurmai et al. (1991) proposed a fracture distribution model for Himalayan-Zagros and Anatolia fold and thrust belt. In case of anticlinal structures, most of the fractures run parallel to the fold axis in the crest of the anticline as illustrated in figure 3. These types of fractures are formed at the point of maximum curvature and are caused by tension on the upper side of the folded bed. Another set of cross fractures develops on the inflection point known as cross fractures or conjugate fractures. In case of a fault, intensity of fractures is greater near a fault and decreases as the distance increases from the fault. Fractures are created by a number of different causes such as flexuring, regional tension and shear, zones of weakness in the earth's crust, removal of overburden by erosion and shrinkage due to induration. Most fractures are formed shortly after induration of the sediments and are successively formed in each new layer of rock as soon as it is capable of fractured.

The fractures of Fimkassar structure are mainly controlled by fold stresses, faults and bed thickness. FMS logs indicated two types of fracture's sets exist in both Chorgali and Sakesar reservoirs. The principal stress direction of fracture in Sakesar Formation of Fim-1ST is in northeast southwest direction, which is roughly parallel to the strike of the axis of the Fimkassar structure. In the Sakesar reservoir of Fim-2, two sets of fractures are developed. The major fractures are roughly sub perpendicular to the strike of the bedding and are extensional in nature whereas the other set is in northwest-southeast direction bisecting the major fracture set, forming conjugate shear fractures. This second

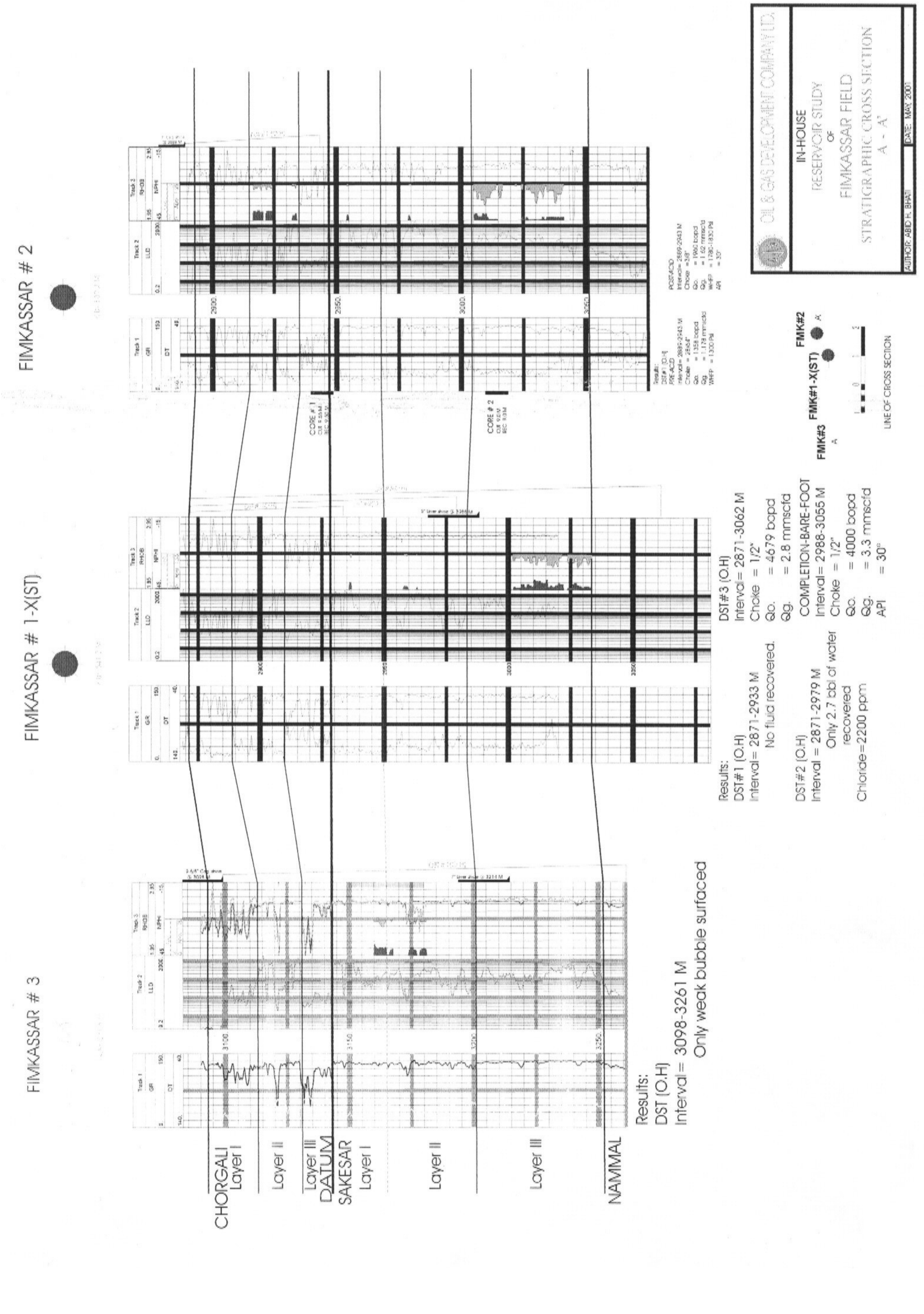

Figure 2- Fimkassar Oilfield, stratigraphic cross-section.

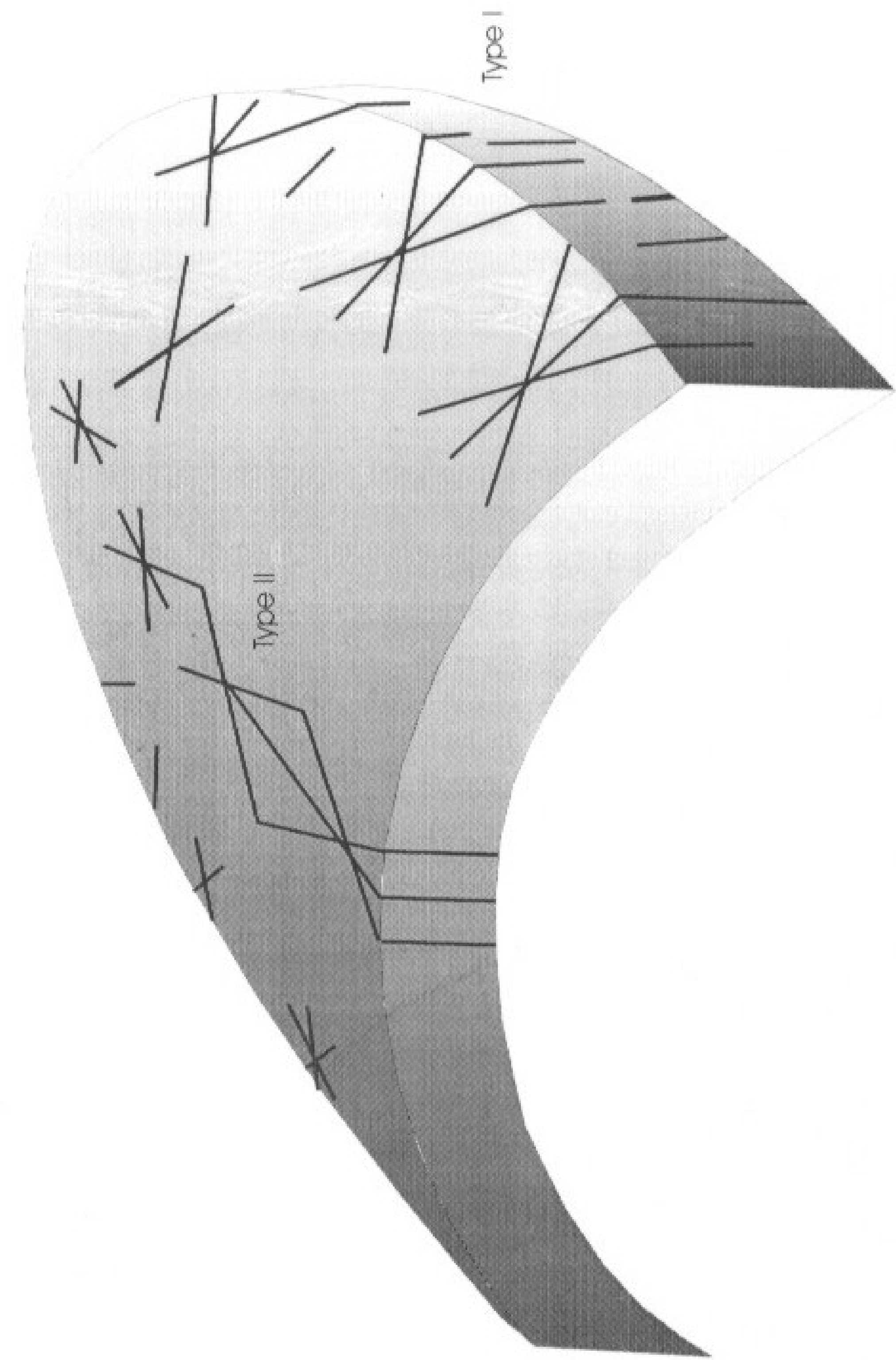

Figure 3- Typical fracture system in anticlines.

set of fractures is only developed in Sakesar reservoir of Fim-2. The difference in fracture orientation between the Chorgali and Sakesar reservoirs is due to differences in lithologies and bed thickness. FMS logs shows that the maximum fractures are developed in those zones where the carbonates are slightly argillaceous and have bed thickness ranging from 15 to 25 cm. The fractures orientation in Fimkasser structure are shown on the map illustrated in figure 4.

The available Fracture logs and cores were studied to understand the fracture mechanism. The followings were observed from these studies.

- Fractures are either absent or rarely present in clean and tight limestone whereas the fracture zone shows relatively high gamma rays which indicates that argillaceous limestone are more fractured. Further fine grained and poor porosity limestone are less fractured
- Fractures are more frequently developed in the medium to thick bed as compared to fine and massive bedding;
- Within the same set of fractures, high angle fractures are open as compared to low angle fracture
- In case of limestone, fracture density increases in the crestal part of the anticline (Fim–1 and Fim-2), and again increases on the inflection point (position of Fim-3).
- Fractures intensity sharply decreases at a depth of 4500m in limestone while the fracture intensity increases in dolomites at the same depth, as it is observed in the adjacent wells like Daiwal –01
- Fractures tend to follow regional alignments and be aligned according to regional stresses
- Fractures tend to develop perpendicular or sub perpendicular to the strike of the bedding.
- The open fractures are excellent conduits to fluid flow and are mainly present in mudstone and wackestone.
- Low angles fractured are mostly filled with calcite resulting reduction in conductivity of the fluid
- Aperture of the fracture is difficult to measure on both FMS/FMI.

DEPOSITIONAL ENVIRONMENTS

An attempt was made to analyse the well cutting in order to understand the depositional environment of these producing formations in the Fimkasser oil field. This study indicates that top of the Chorgali Formation was eroded before the deposition of Fatehjang member of Murree. Fatehjang is deposited in fluvial environments with some local phases of transgression, which resulted thin seems/beds of limestone alongwith beds of dominated reworked limestone.

Shale and limestone beds of Chorgali are a result of shallow marine and/or marginal marine depositional environments. Shale is deposited in high water, low energy environments. Limestone was deposited in lagoonal environments of marginal marine. Post depositional penetration of or submergence under hypersaline/saline water of this formation due to transgression has catalyzed the dolomitization.

The study of well cuttings from Sakesar Formation revealed that the carbonates of this formation are deposited in shallow water, high energy environments near the shoreline.

The Nammal Formation is deposited in deep water in low energy. Cuttings of calcarinite are a sign of transportation of reworked limestone grains during a number of the regression cycles.

High fossility of shale cuttings at the depth of 4072-81m (Patala) is an indicator of deep marine depositional environments.

FIELD OBSERVATIONS OF CHORGALI FORMATION

In the first week of April 2001, a field trip of Chorgali Pass was conducted by OGDCL professionals. Following observations can be helpful for porosity point of view of Chorgali Formation.

- Paleosol, karstification, and stylolites are observed, which are more frequent on the top parts of the formation;
- Dolomitization of the Upper Chorgali and upper Lower Chorgali has enhanced the porosity of limestone in these horizons;
- Various generations of (upto seven) fracturation and vein calcite infill are observed, their frequency reduced with the increase of depth within the formation;
- In the middle limestone of the Chorgali, columnar fractures are more prominent, dissolution evaporites are found in the upper and lower middle limestones.

RESERVE ESTIMATION

As carbonate is fractured reservoir with very low matrix porosity, volumetric method was not considered as reliable method for the reserve estimation. Material balance was used to determine the oil in place and drive mechanism. The oil in place determined by the material balance from both formations is 35.55 MMSTB while simulation gave 37.50 MMSTB oil in place. No oil water contact was seen in this reservoir during drilling and material balance also confirms the depletion derive mechanism for the reservoir without aquifer support. In this type of the reservoir, formation compressibility is major factor in determination of the oil in place. Number of sensitivity analysis were carried out in the material balance to illustrate the effect of the formation compressibility on the oil volume.

WATER FLOODING

After regular production in October 1989, reservoir was continuously monitored through pressure survey. The pressure survey conducted on 28th August 1995 showed that reservoir pressure had declined from 5670.5 psia to 2477 which is lower than the bubble point pressure of 2948 psia.. As a result of this depletion below bubble point pressure, production declined from 3800 to 2000 bbl/day. Consequently to arrest the decline in reservoir pressure and production, well Fim-3 was drilled for water injection and was completed in Sakesar Formation.

Water injection was started in March 1998 with the maximum rate of 85,00 bbl/day. Within four month of water injection, increase in oil production and pressure was observed. The water injection was kept continue with this

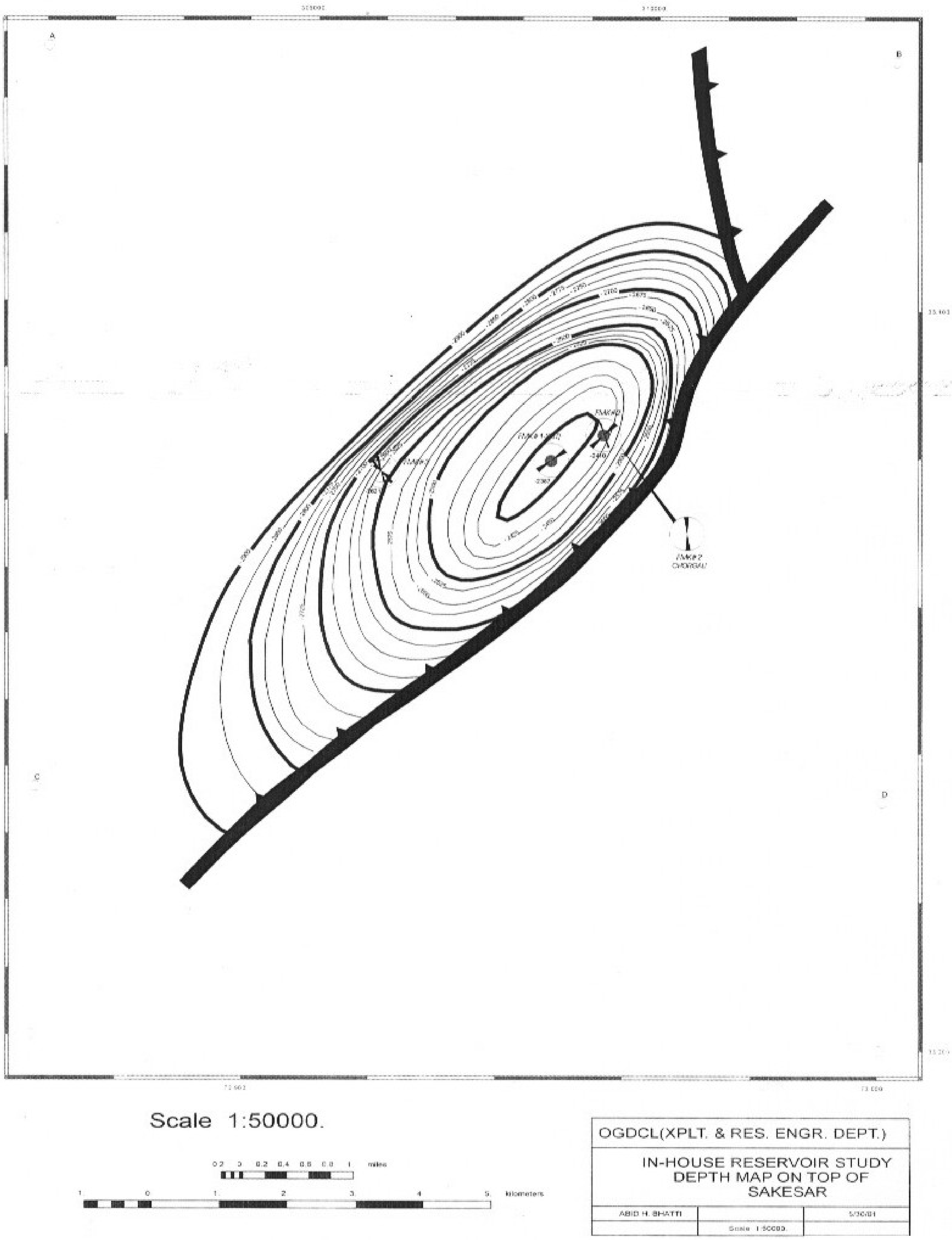

Figure 4- Fracture orientation in Sakesar Formation.

rate and the oil production of 3800 bbl/day from the Fim-1ST was restored. This sudden increase in the oil production is attributed to the oil in the fracture that was pushed by the injected water. On the other hand no effect of increase in the oil production was seen in the Fim-2 well that was completed in Chorgali Formation. After the two years of the water injection, water break through occurs and resulted decline in production. After the water break through, water cut was continuously increasing with declining oil production from 3800 bbl/day to 350 bbl/day. This early water breakthrough in the Fim-1ST was not envisaged by the early studies. It is also difficult to predict the behaviour of the fractured reservoir as the distribution of the fractures is not certain. Because of this difficulty in the prediction of the distribution of the fracture in the reservoir, water breakthrough time was not accurately predicted by the early studies. At present, oil production from both wells Fim-1ST & Fim-2 are 350 and 145 bbl/day respectively while water production from Fim-1ST and Fim-2 are 85% and 35 % respectively. Figures 5 & 6 illustrate the production profile of both wells of the field. Due to this fracture system, the oil and water production from both wells remain constant for last two years. In this scenario of constant production of reservoir fluids, the water injection is providing pressure maintenance to the reservoir rather than increasing oil production. It was observed in the study that unswept oil is present in the Chorgali and Sakesar Formation and new well is required to drain these reserves.

CORE DATA

Core data provides an important source of direct information about the nature of reservoir and its rock properties. Two cores were obtained from the Chorgali and Sakesar Formation from the well, Fim-2. Both cores were sent to the CoreLabs for special core analysis. According to the core reports, the two cores were too tight for conducting relative permeability measurements. This is expected because the bulk of the flow is considered to be through fractures and a typical core is invariably retrieved from no-fracture zones. The core report confirms these cores represent matrix and porosity value obtained from the core is in the range of 1.5-3.5%. However, when it came to saturations, the oil saturation was reported to be only 8%, making the water saturation as high as 92 %. This 8% oil saturation falls below the residual saturation value and cannot be made mobile in existing production system. Any fluid if moved from the matrix will be water.

RELATIVE PERMEABILITY DATA

No relative permeability data of Chorgali or Sakesar formation were available to be used for the respective formations in reservoir simulation. In previous studies (conducted by D&S and SSI), straight-line relative permeability values (ranging from 0 to 1) were used. This choice was justified by stating that the fracture system, such as the one prevailing in the reservoir in question, is likely to yield straight-line relative permeability curves. Initially, straight-line relative permeability data were used for both formations. In the history match phase, it was observed that this relative perm data did not prove effective in matching post-water break through production in the producing well. Obviously, the previous studies did not have to perform history matching with the post-waterflood regime and the validity of the straight-line permeability assumption could not be tested. Now the post-waterflood data are available, it was clear that the straight-line relative permeability data are not adequate for representing a fractured formation. The relative perm data that was finally decided are shown in figure 7.

Permeability obtained from the well test data of Fimkasser # 1 and Fimkasser # 2 was 4200 and 935 md respectively. This permeability was used as reference value and was changed in the history match. The geometric average was also used for determining X,Y,Z permeability. All these permeability were changed according to the orientation of the fracture. The fracture orientations are in both direction X and Y and balanced policy of changing the permeability was adopted in history match.

SINGLE POROSITY SYSTEM

All the geological and well test data were reviewed for understanding the fracture system. As it has been explained in the geological section that two type of the fracture system exist in the Fimkasser reservoir in both the producing formation (Sakesar and Chorgali). The present production is only from the fracture part of the both formations. Well test and DST results showed that single porosity system exist in the Fimkasser reservoir. Analysis of the pressure build up does not indicate any dual porosity or permeability system. In addition to this non-fracture part of Chorgali was physically tested through DST and no flow of hydrocarbon was observed. Similarly core report showed that matrix has porosity range of 1-3.5% and permeability from 0-0.03 md. This indicates that matrix is too tight for the flow of any fluid. The core report also shows that it contains 92% water and 8% oil which is considered as residual oil and cannot be made mobile in any case. The report also indicates that matrix contain 92 % water and any fluid come out of the matrix will be water. Due to these convincing reasons Fimkasser reservoir was considered as single porosity system for simulation. As the petrophysical analysis did not adequately compute the fracture porosity due to their software limitation, the porosity value was taken from the lithological and core analysis. The sensitivity on the different values of porosity was run with oil volume and depletion of the field. Due to this rigorous exercise, porosity value of 1.8 % was used for the Sakesar and 6.5 % was used for the Chorgali.

RESERVOIR HYDROCARBON FLUID

Two samples of hydrocarbon fluid were collected from the well, Fim-1 and were analyzed in the CoreLabs facility of Abu Dhabi. The PVT analysis was carried out on these samples. The fluid properties are also given in table 1. No complete PVT analysis of fluid from Chorgali was available. The previous study with surface fluid properties have derived the subsurface fluid properties for Chorgali. According the report, bubble point pressure of the hydrocarbon fluid was determined as 2968 psi at 226^{o}F. The same PVT properties were used in the study.

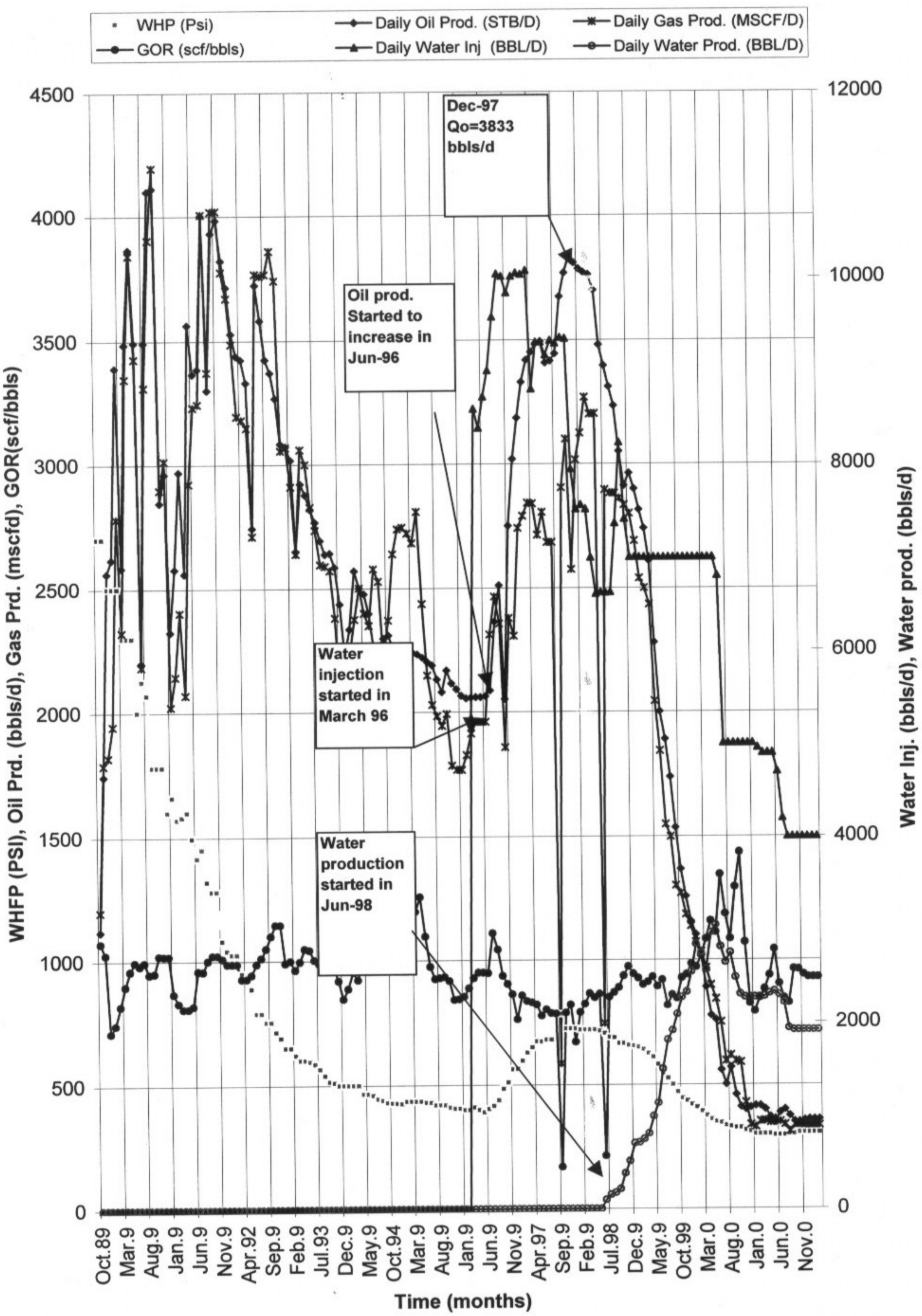

Figure 5- FIM-1[ST] well performance.

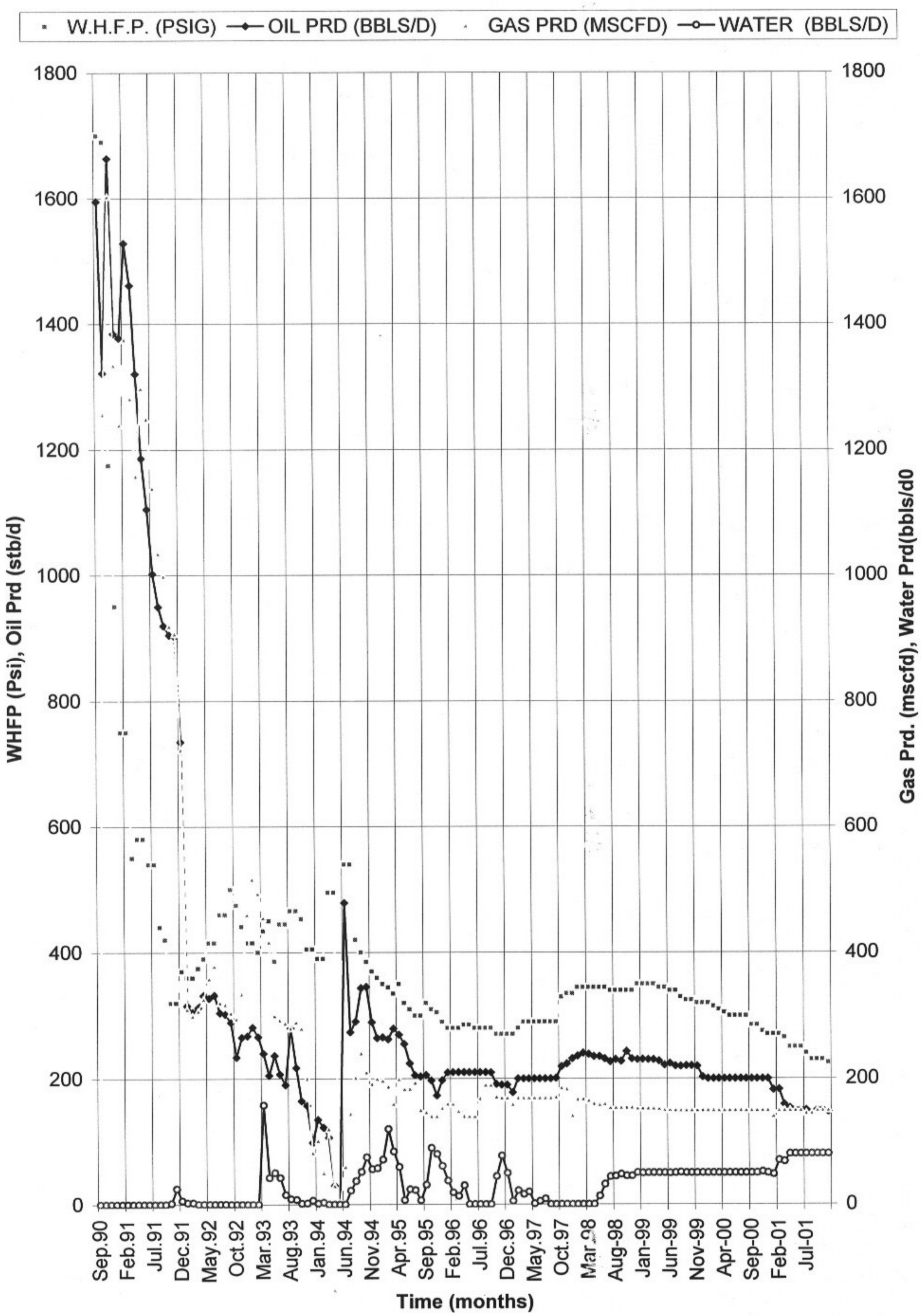

Figure 6- FIM-2 well performance.

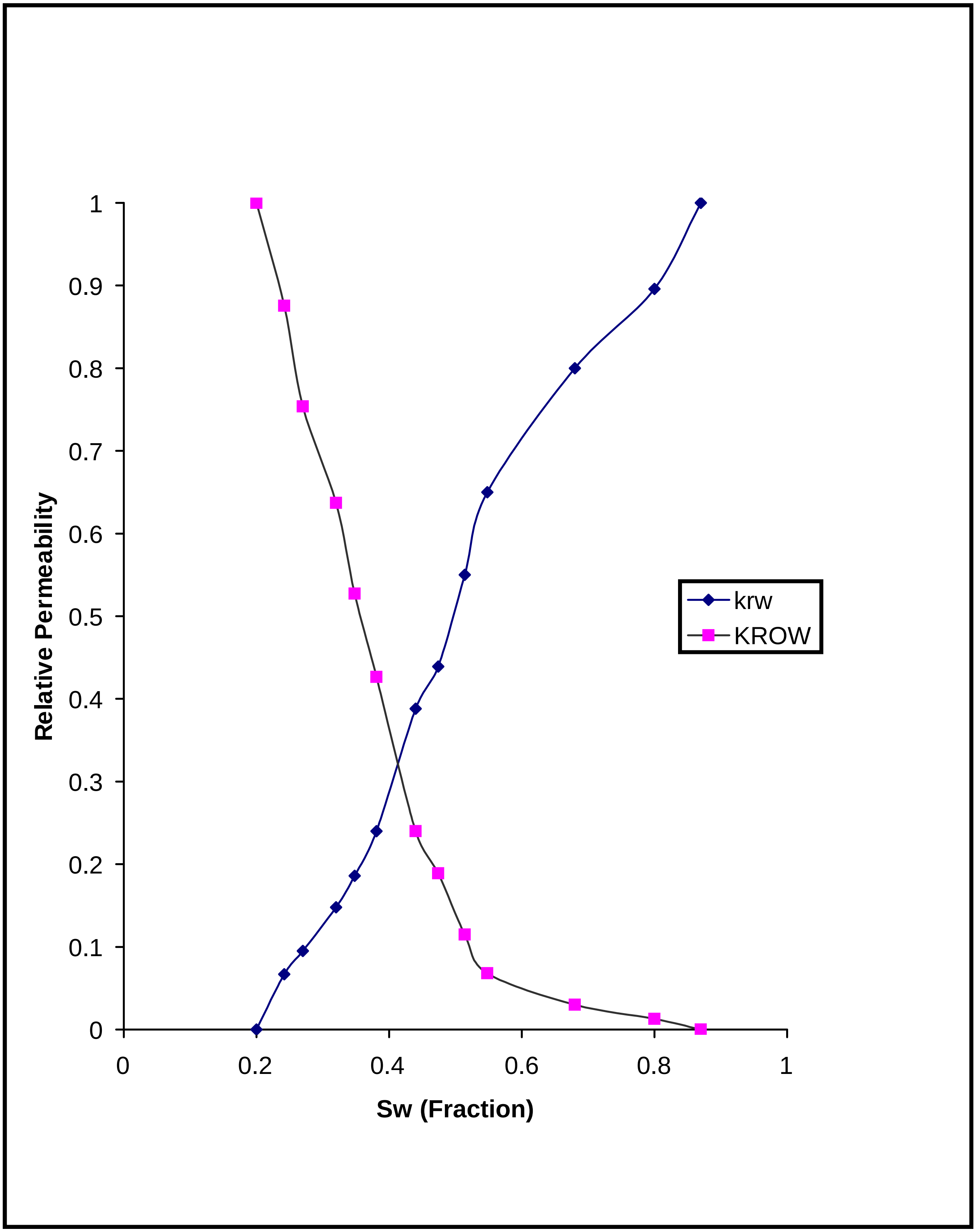

Figure 7- Relative permeability used for the Fimkasser reservoir.

Table 1. Fluid properties of sample collected from FIM-1.

Fluid Property	
Oil Gravity (° API)	33.5
Original Pb (Psig	2934
Rs @ Pb (SCF/STB)	989
Bo@ Pb (RB/STB)	1.622
μo (cp)	0.252
Gas Gravity	0.839
Bg @ Pb (RB/MSCF)	0.9735
μg @ Pb (cp)	0.0210

RESERVOIR SIMULATION

Reservoir Simulation is the virtual description of the reservoir, using numerical models to describe fluid flow performance. The accuracy of this performance prediction depends on how closely the virtual model simulates the actual Geophysical, Geological, rock and fluid properties of the reservoir. On the basis of the available information of the Fimkassar field, a model was set up to simulate reservoir behavior, to estimate oil volume and forecast its performance for the future. Great care was taken to improve the geophysical and geological description of the reservoir, using an integrated approach. Only after history matching of 12 years of production (including six years of water injection) and careful analysis, prediction phase was carried out.

GRIDDING

Orthogonal gridding was generated by using Grid Module of the ECLIPSE. The number of grid blocks was set as 50, 25, 6 in x, y, and z directions, respectively. The vertical distribution was based on lithology, while the areal distribution was selected to optimize the grid dimensions, based on accuracy and runtime. The orientation of the grid was based on dominant direction of flow in the reservoir. The length of grid blocks were set at 605 ft and 495 ft in x- and y-directions, respectively. Number of the grid blocks out of the reservoir boundary were made inactive. The Gridding on top of the depth structure map and locations of the wells are shown in figure 8 and 9. The structural setting obtained from the geophysical evaluation used in the simulation and its 3D view illustrated in figure 9a.

INITIALIZATION

Initialization of the model refers to the simulation of initial condition of the reservoir prior to any production. It is the most important step in the simulation to get confidence in the model to be used for history match that ultimately lead to the prediction performance of the field. The parameters used for the initialization was initial reservoir pressure, initial fluids saturation and reserves obtained from the material balance or volumetrics.

The oil-in-place determined at the initialization by the reservoir simulator with the given geological data did not readily match the values provided by material balance calculations as given in table 2. The material balance calculations, in themselves, had uncertainties due to the variability of rock compressibility. Rock compressibility in fractured reservoirs can exhibit a wide range of variations. The discrepancy between material balance results and numerical simulation results can be addressed by varying the porosity and the net to gross thickness ratio (NTG). Uncertainties in the NTG were minimized by incorporating analyses obtained from petrophysical data, core analysis results, and sedimentological studies. The NTG values obtained from these three sources were used for each layer in each well. Porosity values of the carbonate rocks bear some uncertainties. Initially, porosity values were computed from petrophysical and core analysis data. These values are listed in table 2. After having this initialization with some number of oil in place, history match was initiated in order to gain confidence on the initial oil reserve.

Table 2. Reserves with different porosity values.

Porosity %	Chorgali	Sakesar	Total (mmstb)
13	73.60		
5	36.70	89.55	126.26
2.5	18.35	66.77	63.13
1.5	11.01	26.86	37.83

HISTORY MATCHING

After the initialization of the model, simulated performance of the field was matched with actual field behavior by using dynamic data. The dynamic data used for the history match were reservoir pressure, oil, gas and water production. As the water flooding was being carried out from last five year, the produced water was used as an important parameter for history match. Note that the reservoir has initial water saturation that is at an irreducible level. Consequently, there is no water production during primary production of the reservoir.

The greater uncertainty was with the estimation of porosity value to be used for the oil volume in Chorgali and Sakesar Formation. All the data from core and log were evaluated. The average porosity computed from the petrophysical analysis was approximately 10-16 %. With average porosity of 13% for the Chorgali, oil volume was determined to be of 73 million STB. With this oil volume, Chorgali did not show any depletion as observed in the producing life of the reservoir (Figure 10). As we do not have any control on the evaluation of the porosity for the Chorgali, the pore volume was adjusted to simulate its performance in the history match. With the adjustment of pore volume, oil volume was determined for the Chorgali Formation that lead to the best match with the depletion behaviour of the field. By running the sensitivities of pore volume with oil volume, a reasonable oil volume of 13 MMSTB was achieved for the Chorgali Formation. Figure 7 illustrates the reservoir behaviour with different oil volume. Following the same procedure, an oil reserve volume of about 24 MMSTB was estimated for the Sakesar Formation. The oil volumes stated above for both formations correspond to the actual depletion of the field and material balance results. The oil volumes of both formations are shown in table 3. Reservoir oil volume was considered as

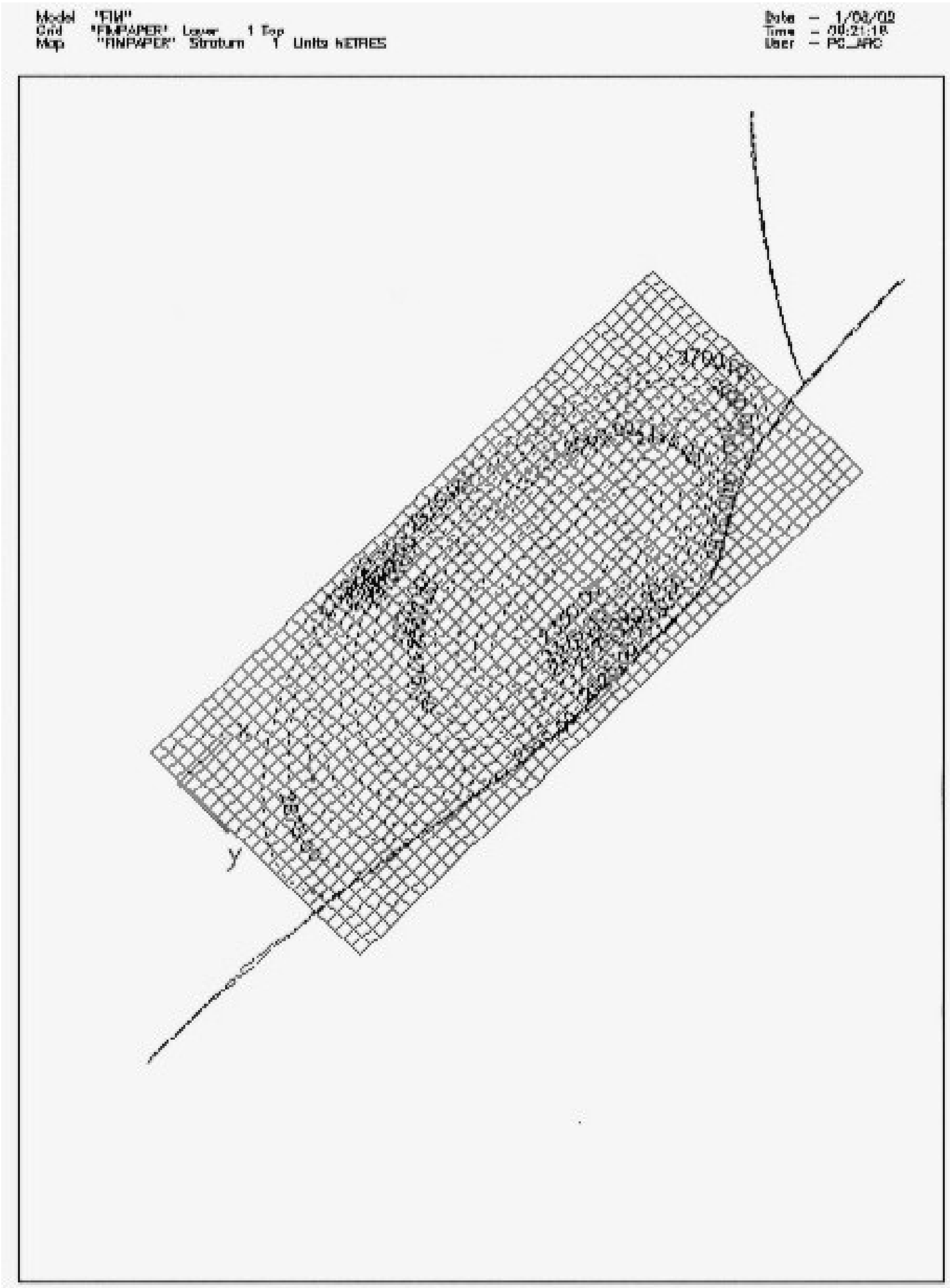

Figure 8- Griding on top of depth structure map on Chorgali.

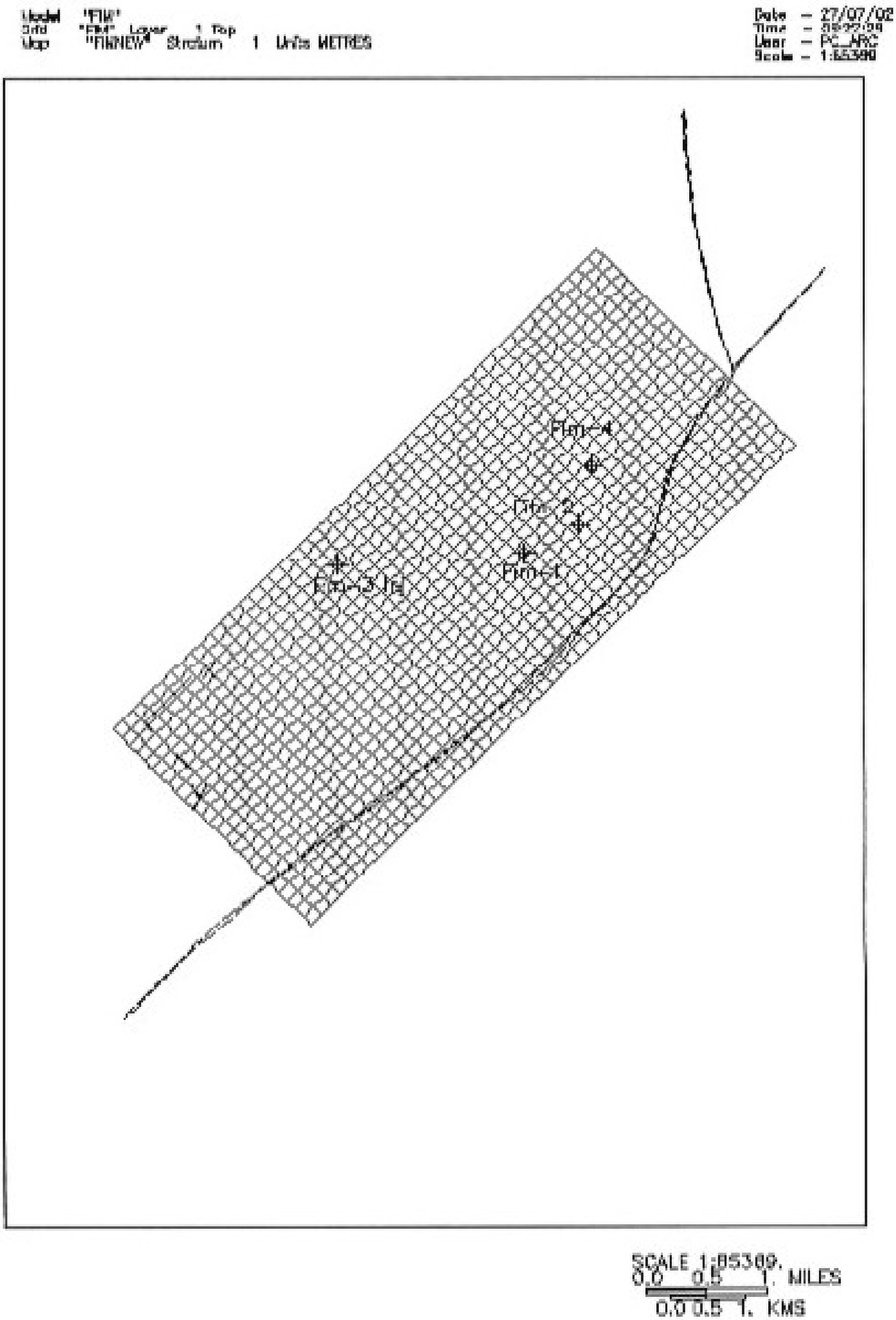

Figure 9- Grids showing location of wells.

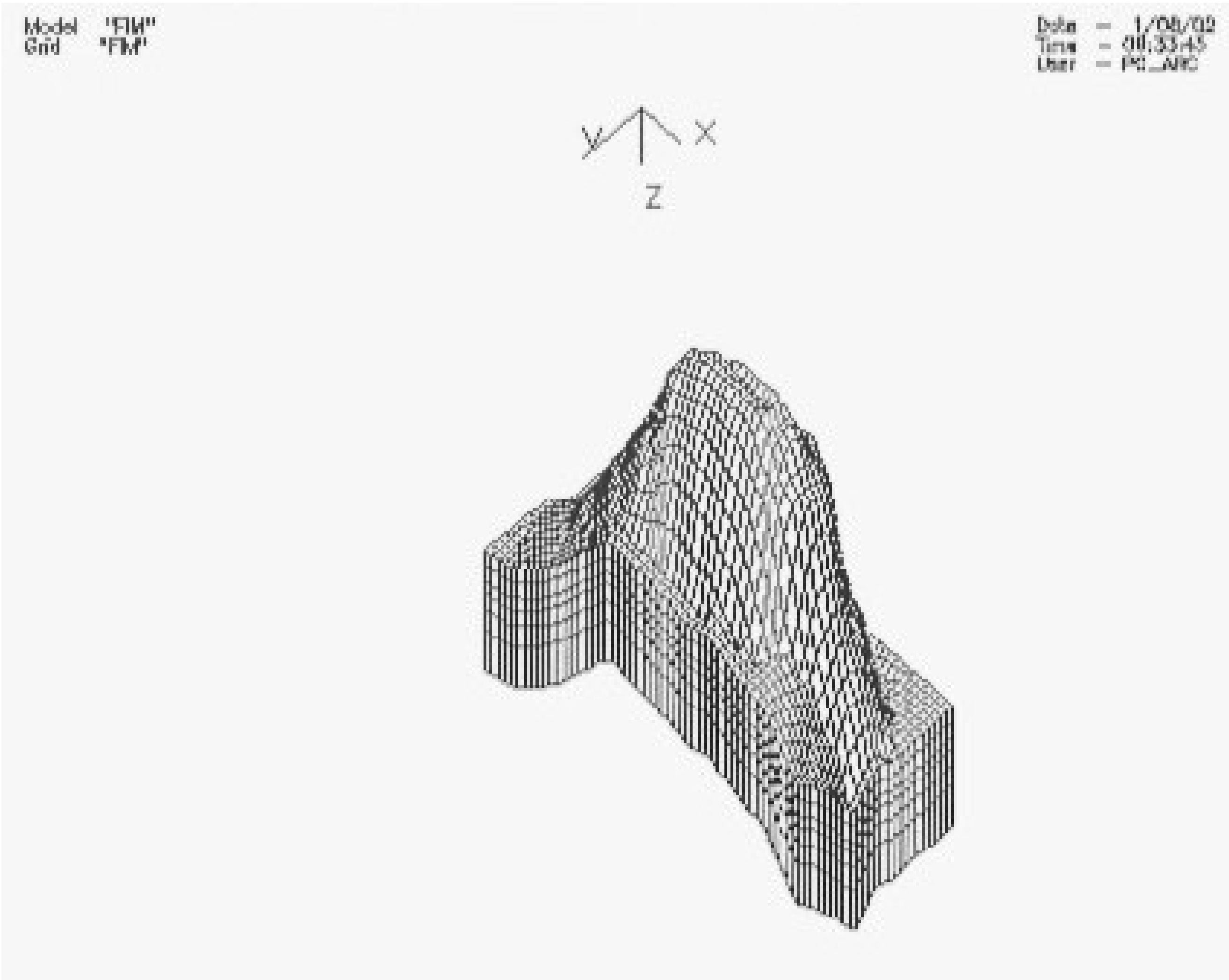

Figure 9a- 3D view of structural setting of the Fimkasser oil field.

most important parameter for the model in the history match of the primary depletion phase.

The actual oil production was also matched with the simulated production and a good match was obtained as shown in figure 11. This match has given confidence on the distribution of the permeability in the reservoir. With the initial setting of the model, simulated reservoir pressure was matched with the measured historical data of both wells and is shown in figure 12.

The other key parameter used for the history match was the time of water breakthrough and subsequent water production. At present, Fimkasser -1st producing 85% water while Fimkasser # 2 is producing 35 % water cut. The water cut was matched by introducing high permeability zone, or conduit between producer and water injector. This water cut matched with historical data is shown in figure 13. The conduit represents the existing fracture in the Sakesar and Chorgali Formation. As it has been explained earlier that two sets of fracture were observed in these two formations. Both set of fractures were dealt with the change of permeability in X & Y direction in the fracture direction. In Sakesar Formation, permeability was increased in x-direction while in Chorgali Formation permeability was increased in both x and y direction. In case of the Fim-2, the water production may not be from the Chorgali Formation as model did not produce any water from it. By communicating Fim-2 with the Sakesar Formation, flux of water was seen in the producing life of the reservoir which indicates the presence of water in the Sakesar Formation at Fim-2 level.

Table 3. Reserves of the Fimkasser oil field after history match.

Chorgali	Sakesar	Total (MMSTB
13.60	24.0	37.60

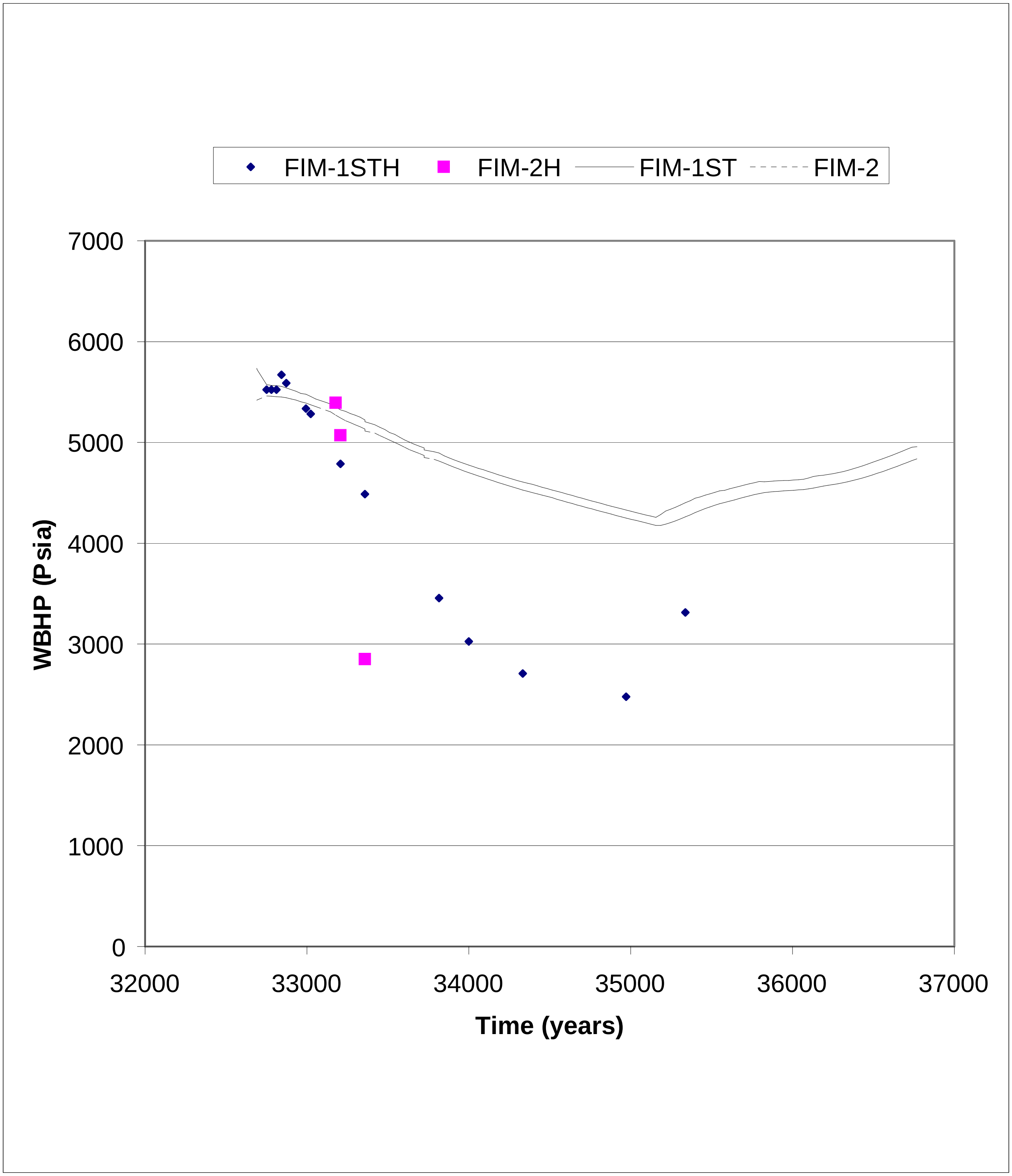

Figure 10- Comparison of large oil volume with depletion behaviour of the Reservoir (H-refers to the historical data).

PREDICTIONS

After validation of the model with the historical data, number of prediction cases were run to forecast the behavior of the field. Drilling of new well was assumed in first quarter of year 2003 in both reservoirs of the field in different cases. The production of the new well was achieved from individual reservoir to monitor their depletion respectively. In all cases, economic limit was set at production of 20 bbl/day with 95% water cut and these limit resulted in closure of the Fim-1ST in year 2005. Six cases with different options were run to determine the optimum depletion plan for the field. These options are outlined below:

- Case1: Existing well completion @ existing constant rate of production.
- Case1a: Existing well completion with the option of closure of Fim-1st at economic limit
- Case2:Existing well + One more well in Chorgali Formation.
- Case 3 : Existing well + One more well in Chorgali Formation
- Case 4h: Existing well + One Horizontal well in Chorgali Formation
- Case 6: Existing well + One Vertical well down to Sakessar Formation

The predictions indicate that Chorgali and Sakesar reservoirs have potentials and required a new well vertical or horizontal to drain the remained recoverable reserves. The Sakesar Formation has already produced about 10 million barrels while Chorgali has produced about 2 Million barrels in their production life. The maximum achievable oil rate in horizontal well is about 1700 bbl/day that resulted highest ultimate oil recovery as shown in table 4. The cumulative production and ultimate recovery of the oil from the field in each case is given in table 4. It was also observed in the prediction cases that with existing constant rate of production, the existing wells (Fim-1ST & Fim-2) can produce for long time with the ultimate recovery of 42 %. The predicted oil production rate in all prediction cases are illustrated in figure 14.

Table 4. Cumulative oil production and its ultimate recovery in different prediction cases.

Prediction cases	Oil Recovery (MMSTB)	Recovery %
Case1: Existing well completion @ existing constant rate of production.	15.94	42.52
Case1a:Existing well completion @ Fim-1st Ceased production	14.19	39
Case2:Existing well + One more well @ 500 bbl/d (Chorgali	16.30	45.5
Case 3 : Existing well + One more well @ 1200bbl/d. With shutting wells at economic limit 10 bbl/d or 99% W.Cut.	21.74	57.97
Case 4h: Existing well + One Horizontal well @ 1700 (Chorgali Formation) with Increase in Water Injection rate & with shutting the wells at economic limit at 10 bbl/d or 99% W.cut	23.94	63.83
Case 5h: Existing well + One Horizontal well @ 1700 bbl/d (Chorgali Formation) with no increase in water injection with shutting the wells at economic limit at 10 bbl/d or 99% W.cut	23.56	62.83
Case 6: Existing well + One Vertical well down to Sakesar	20.32	54.2

CONCLUSIONS

- Field has a potential of oil reserves of about 11 Million barrels
- A new well is required to drain the recoverable oil reserves
- Single porosity system can be used for the simulation of the fractured reservoir if matrix has no conductivity
- Water flooding has not completely swept the Sakesar & Chorgali Formation
- Both formations are in week communication
- Water has reached to the Sakesar Formation at Fim. # 2 level.
- Chorgali is not being swept by the injected water even the West of the structure.
- The present water production in Fim-1ST is due to the direct connection of injector with producer through fracture.
- The present water production in Fim-2 is from the Sakesar Formation.
- The most dominant fracture conductivity is in the Y-direction, although permeability was also increased in the X direction as well.
- Probability of more fractures is towards NE of the structure near to the fault
- Oil is still left to be drained by a new well NE of the Fimkassar structure and it will be only successful if the fractures were encountered.
- Straight line relative permeability is not enough to have better history match.

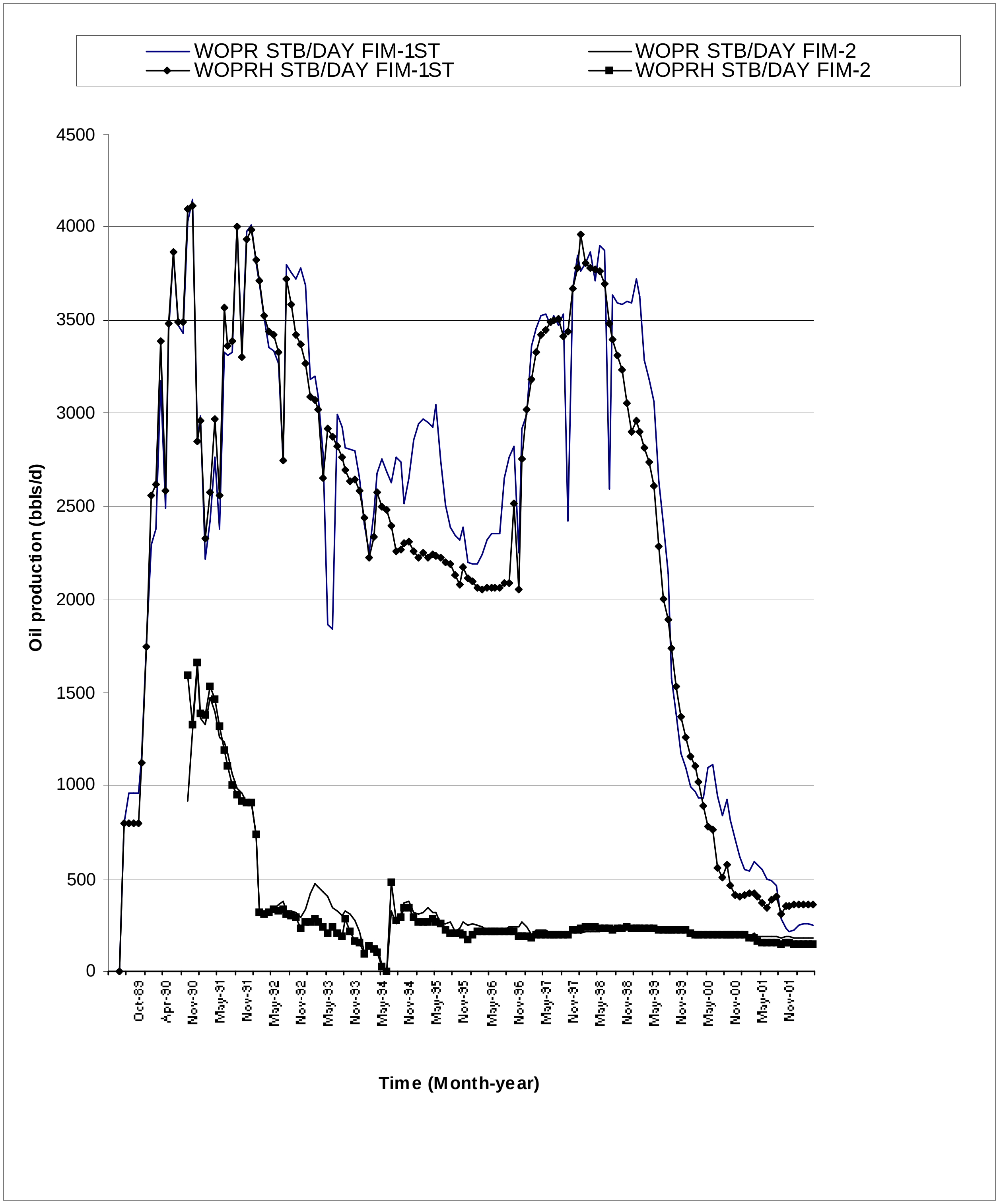

Figure 11- Historical oil production vs simulated oil production of both wells (H-refers to the historical data).

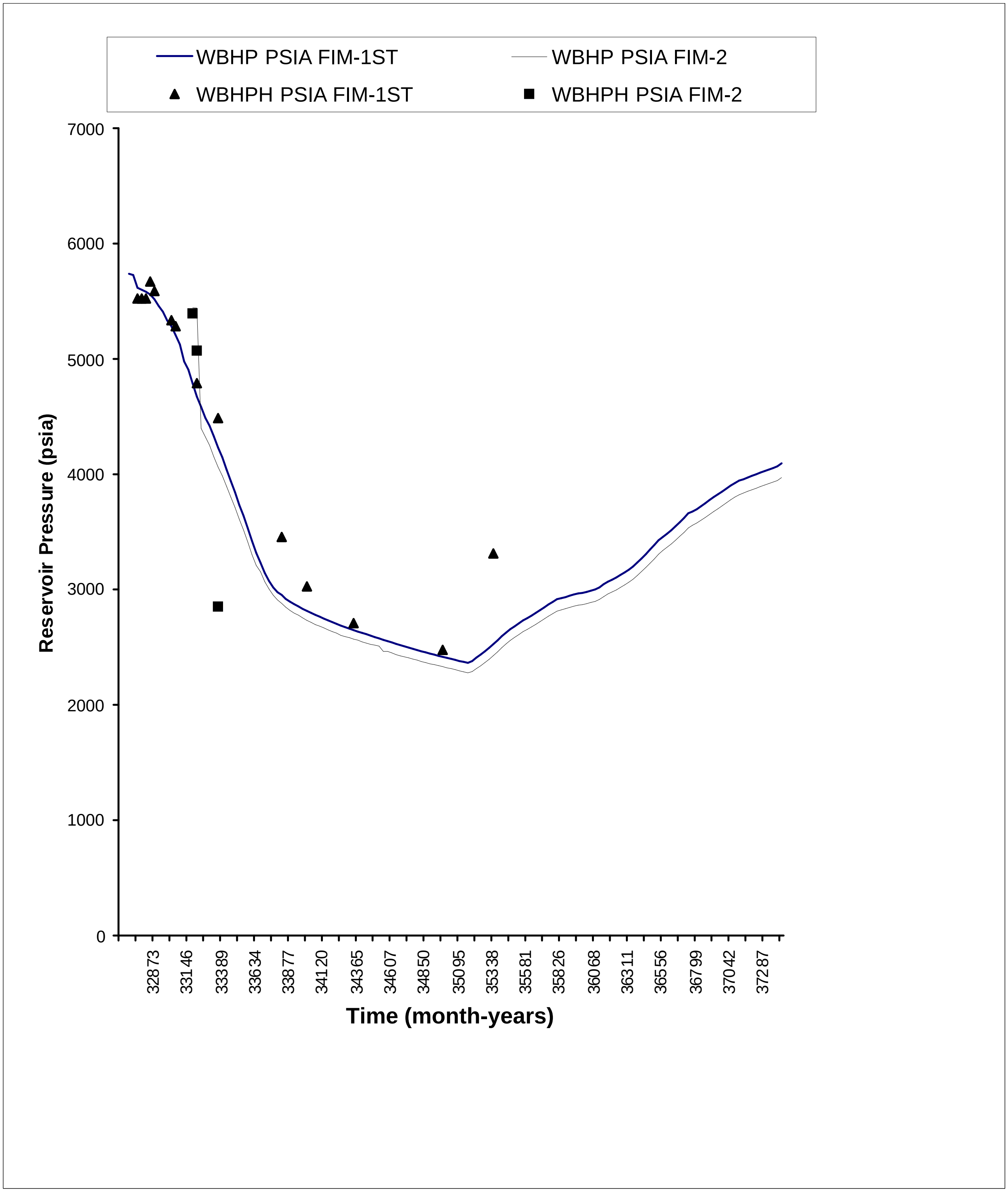

Figure 12- Reservoir Pressure Match of both wells (H-refers to the historical data).

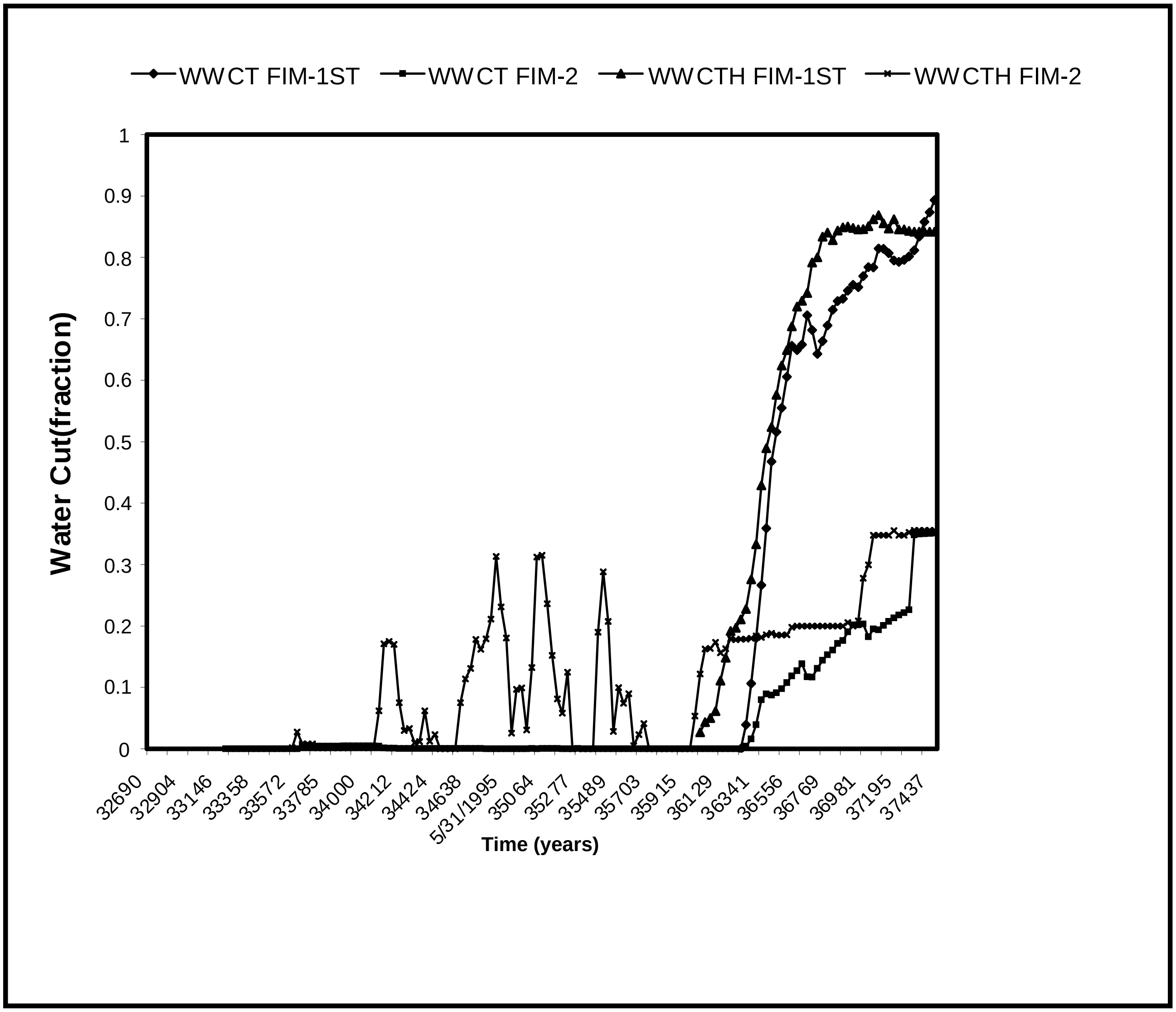

Figure 13-: Water-cut match of both wells (H-refers to the historical data).

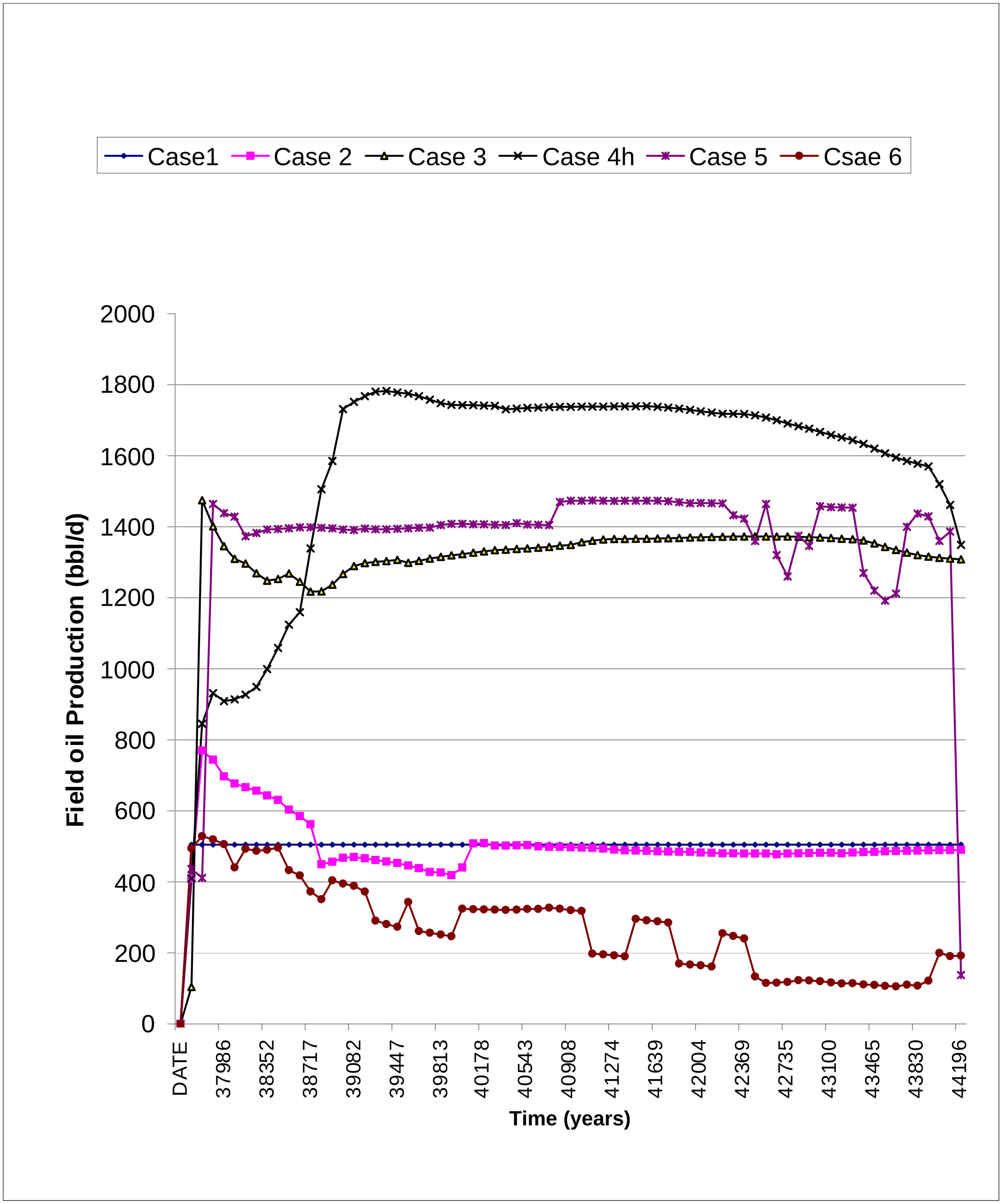

Figure 14- Field oil production rate in different cases.

ACKNOWLEDGEMENT

We are thankful to the Management of the OGDCL for permission of the publication of this paper. We are also grateful to Shoukate E. Qazi Manager Exploitation Department for its valuable suggestions in conducting this study. We also acknowledge the useful input of professionals of the Exploitation Department in the preparation of this paper.

REFERENCES

D & S Canada, 1991, Reservoir simulation study of the Fimkasser oil field.

Nelson R.A., 1985, Geological analysis of naturally fractured reservoir, Gulf Publishing Company, Houston, Texas.

Nurmai R., R. Park, M. Taha and M. Akbar, 1991, High hopes for fracture, Middle East Well Evaluation Review.

SSI Canada, 1996, Reservoir simulation study of the Fimkasser oil field.