Petroleum Res. J. Vol. 18 (2005); P. 17–26, 16 Figs.

Re-Development of a Mature Field For Production Acceleration, Intisar 103E Field

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إعادة تطوير حقل معمر لتعجيل الإنتاج - حقل انتصار 103 E

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تعرض هذه الورقة إعادة تطوير وتعجيل إنتاج ناجحة لحقل انتصار E مكامن تكوين الجير العليا A,B,C لشركة الزويتينة . بدأ تنفيذ هذا المشروع منذ سنة 1999-2002 على أساس دراسة نموذج محاكاة بحفر 6 آبار حقن إضافية عمودية وعدد 6 آبار إنتاج أفقية واستكمال ثمانية آبار موجودة أصلا بالحقل للمزج أو الإنتاج المزدوج. ونتيجة لهذا المشروع بلغ إنتاج الزيت الكامن لمكمن الجير العلوي زيادة تقدر بعدد 3 أضعاف بمتوسط قدره 6,400 برميل/لليوم سنة 1999 إلى 20,600 برميل/لليوم في سبتمبر 2002.
ومن المتوقع أن تكون الزيادة في احتياطي الزيت في هذا المشروع 33.4 مليون برميل حتى العام 2022.

Abstract: *This paper presents a successful re-development and production acceleration project of Intisar E Field, Upper Girs A, B and C reservoirs of the Zueitina Oil Company. The project was implemented from 1999 to 2002 on the bases of a reservoir simulation study. The re-development plan comprised drilling 6 vertical injectors and 6 horizontal producers, and re-completion of existing 8 wells as commingled and/or dual producers. As a result of this project, the oil production potential of Upper Gir reservoirs has been increased almost by three folds from an average of 6,400 STB/D in 1999 to 20,000 STB/D in September 2002. The incremental reserves are predicted at 33.4 MMSTB until the year 2022.*

INTRODUCTION

Intisar 103E Field is located approximately 260 km to the South of Benghazi in the Sirt Basin, Concession 103. The field was discovered in 1968 by drilling well E1-103 down to a total depth of 10,890 ft in Upper Sabil. The well was drilled on a structure similar to the giant reef fields at 103A and 103D. In 103E field, however, the reef proved to be wet. Figure 1 shows the location of the field in Concession 103 of the Zueitina Oil Company.

As of December 2002, a total of 40 wells have been drilled in the field. Among these wells, 23 are vertical producers, 6 horizontal producers and 11 water injectors. The well location map is shown in Figure 2.

The Intisar 103E Field comprises seven separate producing reservoirs, designated from top to bottom as Elgiza A and B, Upper Girs A, B and C, Lower Girs and Shoal. The reservoir structures are four way-dipping anticlines with varying closures from 50 ft to 150 ft. All reservoirs are carbonates, mainly limestone, stacking on top of each other. The cross-section shown in Figure 3

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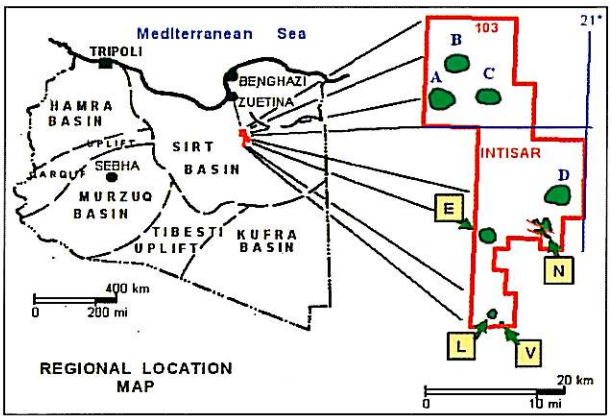

Fig. 1. 103E field location.

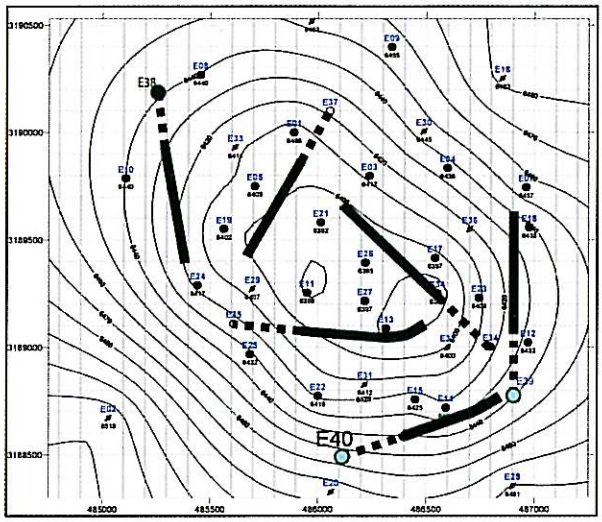

Fig. 2. 103E field well locations.

depicts all reservoir units from Elgiza down to Shoal (Upper Sabil).

Among the seven reservoir pools in the field, the Upper Girs are the largest reservoirs with respect to original oil in place and reserves. Table 1 presents the original oil in place and reserves distribution among the pools.

The Upper Gir A, B and C reservoirs comprise an OOIP (original oil in place) of 264 MMSTB, which constitute about 70% of the total field initial oil in place of 391 MMSTB and 89% of the field total initial reserves of 121.7 MMSTB.

The Gir A reservoir, with an OOIP of 168.4 MMSTB, is the largest compared to Gir B and C reservoirs having OOIPs of 79 MMSTB and 17 MMSTB respectively.

The reservoir rock is limestone with a rather high porosity of 23-28%, but low permeability of 10 – 20 md. These reservoirs are not in communication and stacking on top of each other. They are separated by non-communicating tight layers. Figure 4 illustrates the cross-section indicating the thickness, porosity and relative vertical layout of the subject reservoirs, which were subdivided into several layers for the simulation modeling. Gir A was subdivided into 5 layers designated as A1, A2, A3, A4, A5; Gir B into 3 layers as B1, B2 and B3 and; Gir C into 2 layers as C1 and C2. The accumulation of the oil in these separate reservoir pools has taken place due to presence of

Table 1. 103E Field OOIP and reserves distribution.

	OOIP MMSTB	Oil Reserves MMSTB
Elgiza A & B	28.5	2.3
Upper Girs, A, B & C	264.2	108
Lower Girs	91.2	9.4
Shoal	7.1	2
Total	391	121.7

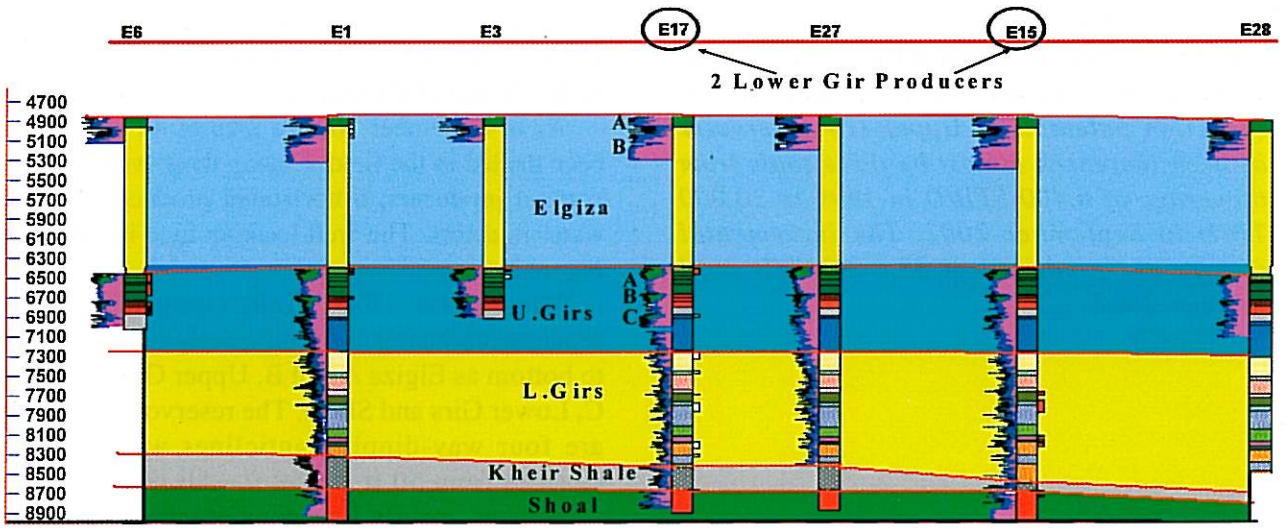

Fig. 3. Cross-section along the field (E6 to E28).

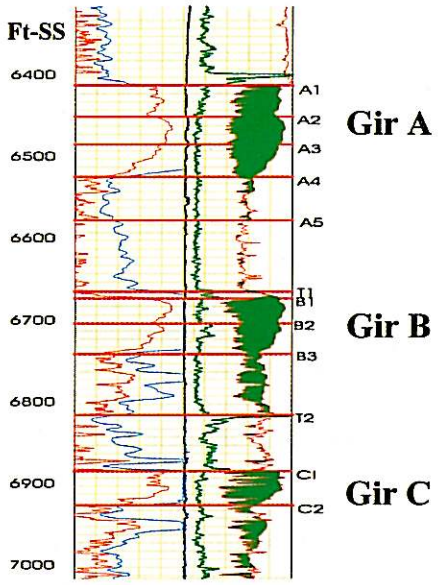

Fig. 4. E23 open hole log interpretation in Gir A, B and C.

tight formations (cap rocks) at the reservoir tops designated here as T1 for Gir B and T2 for Gir C.

STRATIGRAPHY AND TRAPPING MECHANISM

The general stratigraphy and structure has been controlled in the 103 area by its presence in the area of the shelf edge in Upper Palaeocene times between the Marsa Brega trough and the Gialo/Amal high. Reefal bioherms developed on this shelf edge through the Upper Palaeocene after which there was a transgression or subsidence in the very late Palaeocene resulting in the deposition of the Kheir marls and shale. During the Eocene, there was predominantly shelf carbonate deposition with the grain size being determined by provenance and water depth. Locally the sedimentation has been influenced by drape over the reef resulting in locally shallow water depths in the immediate area of the reef resulting in rather gentle homoclines providing up to 150 feet of closure. The oil accumulated in 103E in the Shoals, Gir and Elgiza formations being trapped by the above homoclines. Figure 5 illustrates the generalized stratigraphic section of 103E area.

GEOLOGY OF THE GIR 'A', 'B' AND 'C' IN THE 103E AREA

Several cross-sections in the area indicate that the geology of the Upper Girs in the 103E area is

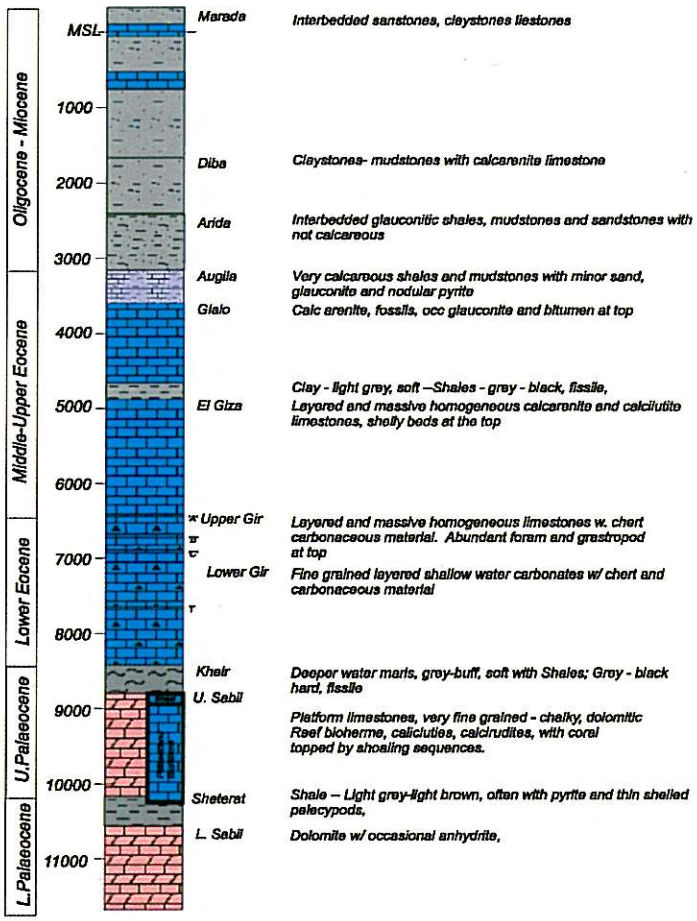

Fig. 5. Generalized stratigraphic section, 103 E area.

quite monotonous. The same sequence exists at other fields in the area, however, the thickness varies. Table 2 compares the relative thickness of Upper Girs in the 103E and 103D fields, which are about 15 km apart.

Table 2. Thickness of Upper Girs in the area.

Zone	103E Field Thickness at E13	103D Field Thickness at D4
Gir 'A'	268	134
Tight Zone '1'	10	15
Gir 'B'	135	220
Tight Zone '2'	82	95
Gir 'C'	Not defined	Not defined

In the area of interest, there appears to be little faulting above the Palaeocene. The traps that have been found in the Gir and El Giza at 103A, 103D, and 103E are formed by gentle domes draped over an underlying reef with up to 150 feet of closures. The sedimentation, however, was influenced mainly by underlying old structure on the shelf edge and by the overall deformation of the Sirt Basin.

PETROPHYSICAL PROPERTIES OF THE RESERVOIR LAYERS

The gross thickness of Gir 'A' at 103E averages 270 feet and thickens to the west towards E2. The net oil pay of Gir A is estimated at 80 feet. The average gross and net oil pay thickness of Gir B are 135 feet and 60 feet respectively. The net oil pay in Gir C is estimated at 25 feet.

The petrophysical properties of the sub divided layers in each reservoir are shown in Table 3.

Table 3. Petrophysical properties of sub-layers.

Gir A					
Layer	A1	A2	A3	A4	A5
Thickness. ft	44.7	34.4	32.5	62.3	96.3
Porosity (log%)	23.8	28	25.8	21.7	21.4
Sw (log%)	34.3	26.1	54.2	100	100
Core Kh (mD)	0.2-3.1	7.7-10.7	7.2-7.7	4.8	N/A
Core Ky (mD)	1.1-3.8	5.8-8.4	6.2-7.5	3.7	N/A
Gir B & C					
Layer	B1	B2	B3	C1	
Thickness.ft	27.9	28.2	75.3	31.7	
Porosity (log %)	25.2	23.2	21	24.6	
Sw (log%)	32.2	42.8	78.7	49.9	
Core Kh(mD)	6.4-17.2	3.9-9.6	11.3	N/A	
Core Ky (mD)	0.9-16.2	0-5.6	2.3	N/A	

The C2 zone in the Gir C reservoir is considered the top of the shallow water carbonates, which extends toward the Kheir Formation and has been termed the Lower Gir.

RESERVOIR DRIVING MECHANISM

The porosity is, in general, high, above 20%, in all reservoirs but contrary to that, the permeability is relatively low, particularly in Gir A at a neighborhood of 3 md to 8 md. The range of permeability of Gir B and Gir C are relatively higher than Gir A at ranges of 10-15 md. Due to the low reservoir and aquifer permeability, the strength and response of the aquifer to the production is not significant. Therefore, particularly at early production stages, the reservoir pressures in each reservoir declined significantly and, consequently, a peripheral water injection scheme was initiated after 1980 to arrest the declining pressure. Figures 6 and 7 show the history and decline trends of reservoir pressures in the Gir A and Gir B reservoirs. In spite of low early production rates, the reservoir pressures declined by 40% percent from around 3000 psia to 1800 psia in the centre of the reservoir. It is obvious that initial peripheral water injection did not help too much in arresting the pressure

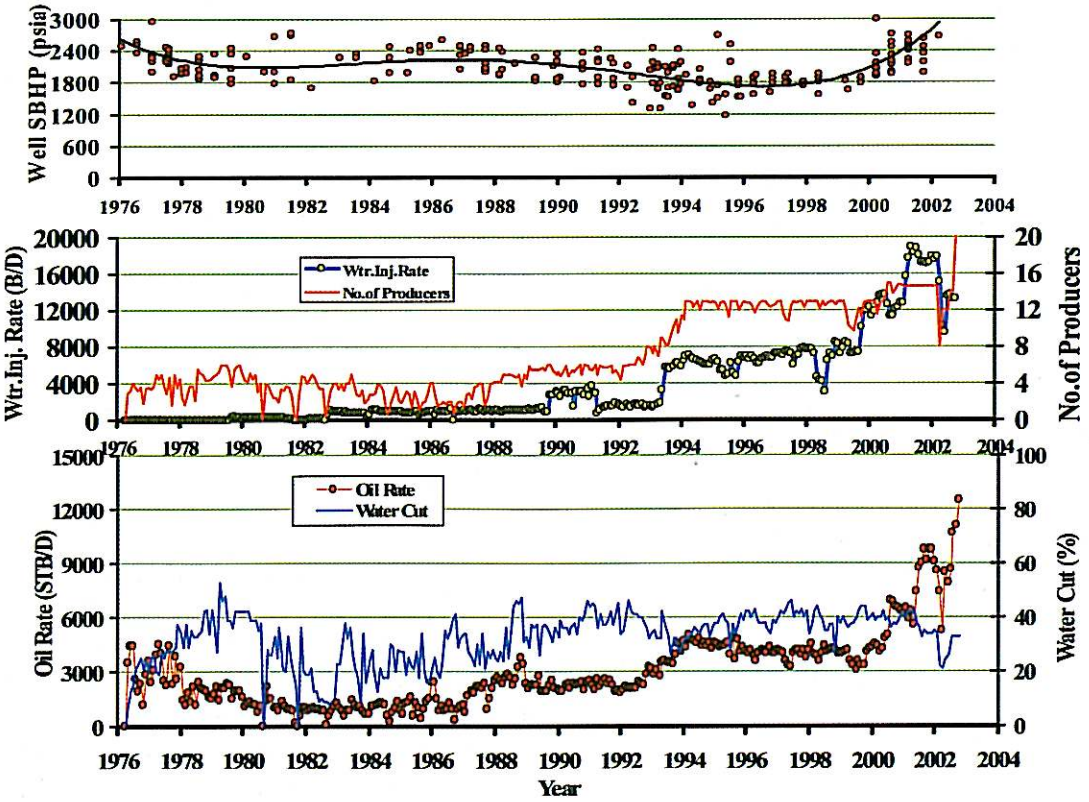

Fig. 6. Gir A production/injection/pressure performance history.

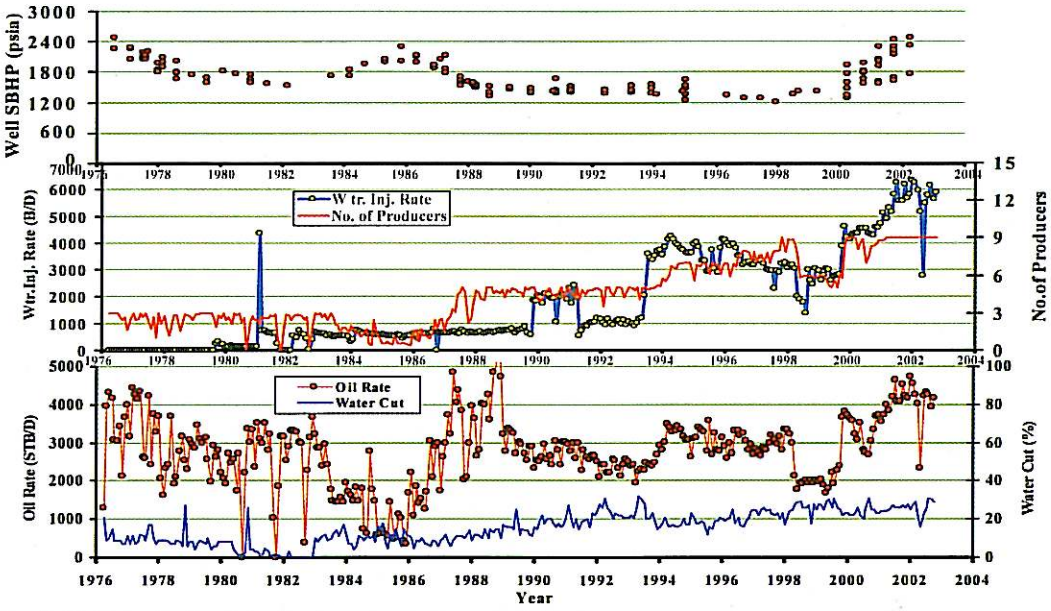

Fig. 7. Gir B production/injection/pressure performance history.

decline or in improving the production rate of the field. This was mainly due to; 1) poor injectivity due to low permeability and 2) distant proximity of the injectors to the main producers in the centre of the reservoir.

OIL PROPERTIES

The following table (Table 4) shows the range of PVT properties in the Gir A, B, and C:

Table 4. Reservoir oil properties.

	Deg. API	Pb psia	GOR SCF/STB
Gir A	35	390	185
Gir B	36	560	282
Gir C	39	460	346

FIELD DEVELOPMENT HISTORY

The field development is comprised of three phases as follows:

Phase 1 – 1968 to 1976. A total of 12 wells were drilled during this period. The first 2 wells, E1 and E2, were drilled deep down to the Lower Sabil and the other 10 wells were drilled shallow, down to Upper Girs. Initially, Upper Gir reservoirs were developed with 4 producers in Gir A and 3 producers in Gir B. Due to lack of aquifer strength and the consequent depletion of reservoir pressures, two peripheral wells, E2 and E6 were completed in 1980 as commingled injectors in Gir A and B to arrest the declining pressures. The production from Upper Girs utilized artificial Gas Lift. The gas was provided by the associated gas produced from the nearby giant fields, 103D and 103A.

During this period, Elgiza A and B reservoirs were also produced from three wells with electrical submersible pumps for a short time between 1976 to 1978. Figure 8 presents the field well lay out during this phase.

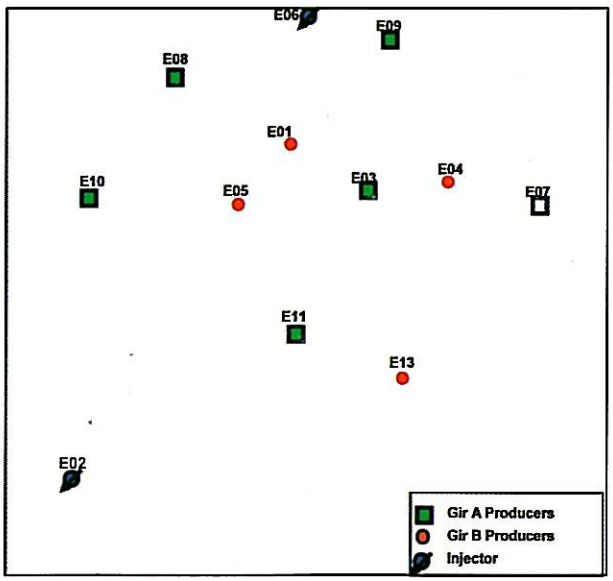

Fig. 8. Well lay out from 1968 up to 1985.

Phase 2: 1985 to 1995. The field was further developed by drilling additional 16 vertical wells of which 6 were drilled deep to the Upper Sabil Shoal reservoir. Due to continuing decline of reservoir pressure in Upper Girs, particularly towards the

centre, an additional three wells, E16, E20 and E28, were completed as peripheral commingled water injectors.

During this period, the deeper reservoirs, Lower Girs and Shoal were tested extensively. The Shoal reservoir was completed and produced from the wells E15 and E27. The potential of Shoal proved to be limited with about 2 MMSTB of reserves, however, Lower Girs proved to contain around 10 MMSTB of reserves. Lower Gir was developed after 1996 with two wells, E15 and E17. Figure 9 presents the field well lay out during this phase.

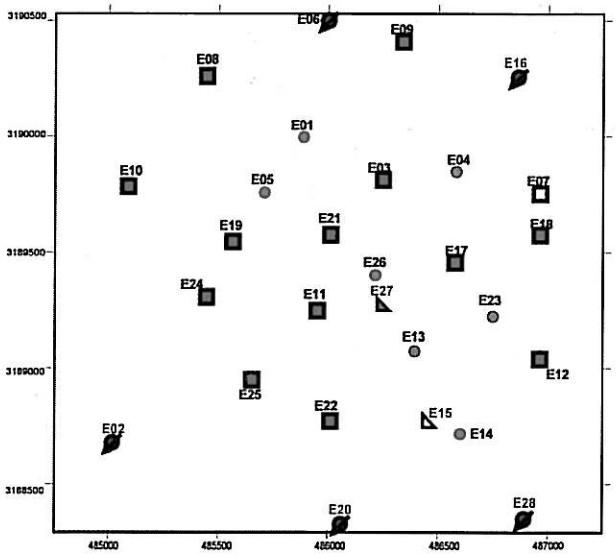

Fig. 9. Well lay out from 1985 up to 1995.

Phase 3: Production Acceleration Phase from Upper Girs, 1999 to 2002. In 1998, a simulation study was performed for Upper Girs, A, B and C in order to better define the remaining reserves, reservoir production mechanisms, aquifer responses, effect of peripheral water injection and investigate better production scenarios including horizontal wells for further developments. On the basis of this study, additional 6 vertical injectors and 6 horizontal producers were drilled and 8 existing wells were re-completed as multiple zone producers from 1999 until 2002. Figure 2 presents the field well lay out during this latest phase, which is referred to as 'Production Acceleration Project'.

UPPER GIRS A,B,C SIMULATION STUDY

A reservoir simulation study for Upper Girs was performed by HOT Engineering using their SURE simulator in 1998. The simulation model covered the three Upper Gir reservoirs A, B and C with three separate aquifers as shown in Figure 10. Prior to full field implementation of the study recommendations, the simulation model was set up, further modified and updated in-house. The orientations of the horizontal wells were optimized using the new in-house model, which included the later SURE version with PEBI gridding technique. The model proposed to drill horizontal wells for an optimum and accelerated production scenario.

During this study, the model indicated that the peripheral injection from five wells, E2, E6, E16, E20 and E28, was not effective in pressure maintenance and displacement of oil towards the producers in the centre. In order to establish an effective recovery efficiency, and accelerate the production from the field it was necessary to; 1) drill infill injectors to support the pressure in all three reservoir units 2) drill horizontal wells in Gir A to sweep significant oil remaining and, 3) re-complete some single zone producers as multiple zone producers (commingled and/or dual completions). The model indicated that the Gir A sill retains the major remaining oil reserves in the field. Therefore, the study proposed that all horizontal wells should be drilled in the Gir A.

RE-DEVELOPMENT (PRODUCTION ACCELERATION) PLAN *VS.* ACHIEVEMENTS

The re-development plan (or Production Acceleration Project) was based on the optimum depletion scenarios of the Simulation Study and its in-house updates. The plan involved; (1) Re-completion of some single zone producing wells either commingled or dual, and (2) Drilling 12 new wells as explained below.

1. Well Re-completions

This plan was comprised of:

a) Re-completion of 7 Upper Gir single zone producers (E1, E3, E4, E13, E14, E19 and E26) as multiple zone (dual zone) producers. Among these wells; E1, E4, E13 and E26 were completed in 2000 and the remaining in 2001 and 2002.

b) Re-completion of the Upper Gir A producer, E17, in Lower Gir as a producer. This well was re-completed in 2001.

c) Re-completion of the Shoal low oil producer, E27, as a dual zone injector in Upper and Lower

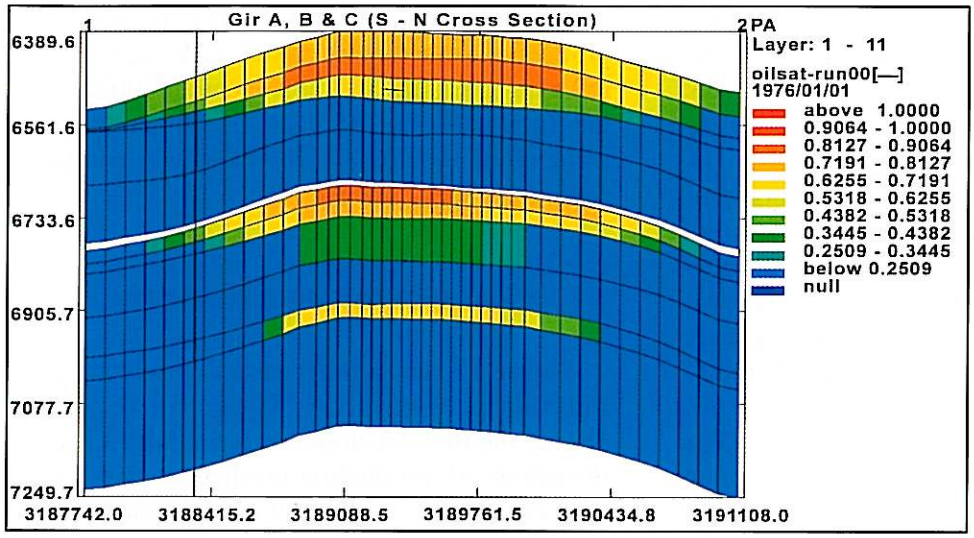

Fig. 10. Upper Gir ABC simulation model.

Girs. This job was also completed in 2001 and injection started in both reservoirs.

It is important to note that two wells, E21 (dual) and E23 (co-mingled) had been re-completed before the re-development plan.

The re-completions increased the production capacities in the subject wells significantly. Figure 11 indicates the increased production trend from well E21, which was converted from Gir A producer to a dual (multiple) zone producer in Gir A and Gir B.

In addition to the effect of re-completions, the oil production of the existing wells increased significantly after 1999 due to the good response to the new infill injection system. The following Figure 12 indicates the production performance of well E19, which shows a steady increase of the oil rate after 1999 mainly due to the effect of the nearby new injectors, E29 in the south-east and E33 in the north.

2. Development Drilling

Prior to the re-development phase there were 28 wells drilled up to E28. The re-development drilling

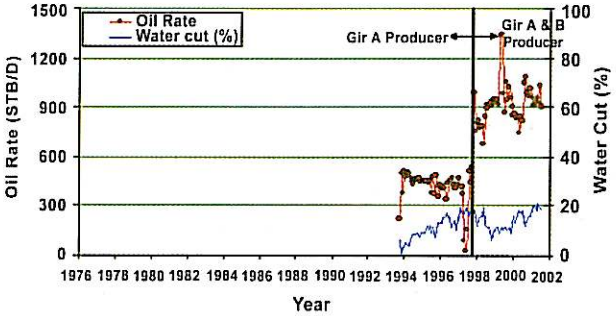

Fig. 11. Well, E21, production performance.

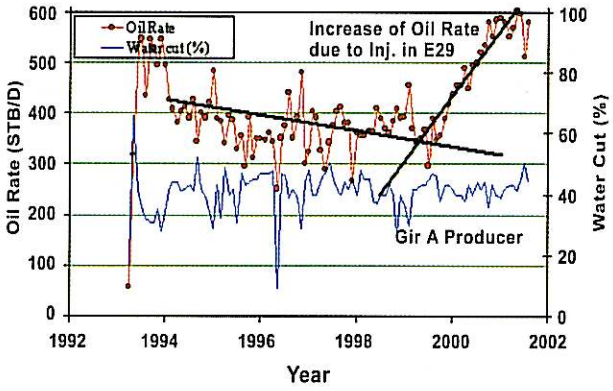

Fig. 12. Well, E19, production performance (103E, Gir ABC, well E19).

plan included the drilling of 12 new wells (6 infill water injectors, 6 horizontal producers) as shown on the map in Figure 2. The drilling of these 12 wells was completed at the end of September 2002 as shown in Table 5.

Table 5 – Actual drilling schedule.

Well	Type	Drilled
E29	Injector	05/1999
E30	Injector	06/1999
E31	Injector	07/1999
E32	Injector	12/2000
E33	Injector	02/2001
E34	Hor.Producer	03/2001
E35	Hor.Producer	05/2001
E36	Injector	04/2001
E37	Hor.Producer	06/2002
E38	Hor.Producer	07/2002
E39	Hor Producer	08/2002
E40	Hor.Producer	09/2002

Wells E39 and E40 were initially planned to be drilled as vertical wells. However, as per the latest in-house updates of the simulation study, and successful results from the previous horizontal wells, the subject two wells were re-planned and drilled as horizontals.

New Water Injectors: Six water injectors were drilled as vertical infill wells in the three reservoirs Gir A, B and C. They were completed in all three reservoirs dually with two tubing strings and dual packers in such a way that water is injected in Gir A separately from one string and in Gir B and C commingled from the other string. Figure 13 illustrates a typical dual injection completion in the field. The injection proration between Gir B and C is verified with periodic spinner surveys.

Horizontal Wells: A total of six horizontal wells were drilled in the Gir A reservoir. The horizontal lengths of the wells ranged between 1800 ft and 2100 ft depending on wells locations. They were completed all in Gir A as 8.5" open holes in the upper most 15 – 20 ft of the reservoir, which has about 80-90 ft of net pay in the centre of the field. Figure 14 shows a cross section and layout of the horizontal well, E37.

The oil production rates from the horizontal wells ranged between 1750 STB/D to 2500 STB/D, which confirmed the simulation predictions. Compared to the existing vertical producers with average oil rates of about 350-450 STB/D, the incremental production from the horizontal wells is considered to be quite significant. In November 2002, out of the total 429,730 STB of Gir A monthly oil production, 310,290 STB (72%) was produced from the 6 horizontal wells.

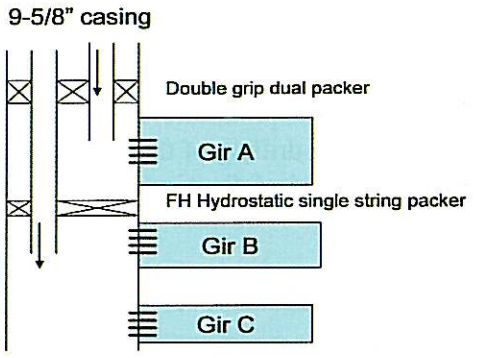

Fig. 13. Typical dual injection completions in Upper Girs.

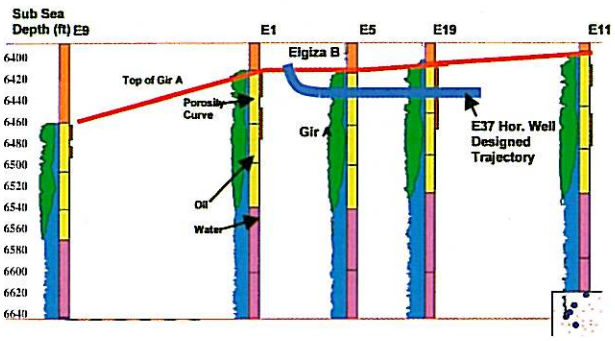

Fig. 14. Cross section around E37 trajectory.

PRODUCTION PERFORMANCE

Figure 15 shows the historical production and injection performance of Upper Gir reservoirs. During the first development phase with 12 wells, the initial oil production reached its peak rate at around 8000 STB/D in 1976 and consequently declined down to 2000 STB/D in 1986, mainly due to lack of pressure support. As new wells were further drilled after 1985 and put on stream during the second development phase, the oil rate gradually increased to its highest level of 8000 B/D in 1994 when a total of 28 wells were drilled in the field. From then on, the decline trend continued down to around 6000 STB/D until 1999. The Upper Girs average oil production rate from 1976 to 1999 is around 5000 STB/D.

Incremental Oil Production: The Upper Girs production potential has been increased from an average of 6400 STB/D in 1999 to 20,000 at the end of September 2002. The major incremental production has been achieved mostly from the 6 Gir A horizontal wells (10,500 STB/D), which constitute about 52% of the total field production. Table 6 compares the production potential before and after the production acceleration implementation.

Table 6. Comparison of production potential.

	Oil Production rate (STB/D)		
	In 1999	09/2002	Increment
Gir A	3.712	14.324	10.612
Gir B	2.497	3.576	1.079
Gir C	200	1.862	1.662
Total	6.409	19.762	13.353

Figure 16 demonstrates the actual *vs* production forecasts from the simulation study. It is obvious that the actual field production confirmed the simulation prediction to a very high degree.

After the pick oil rate at around 20,000 STB/D is reached, it would not be possible to maintain the high plateau rate and the decline will start immediately. In spite of this decline, the incremental reserves and economics are quite substantial from this project.

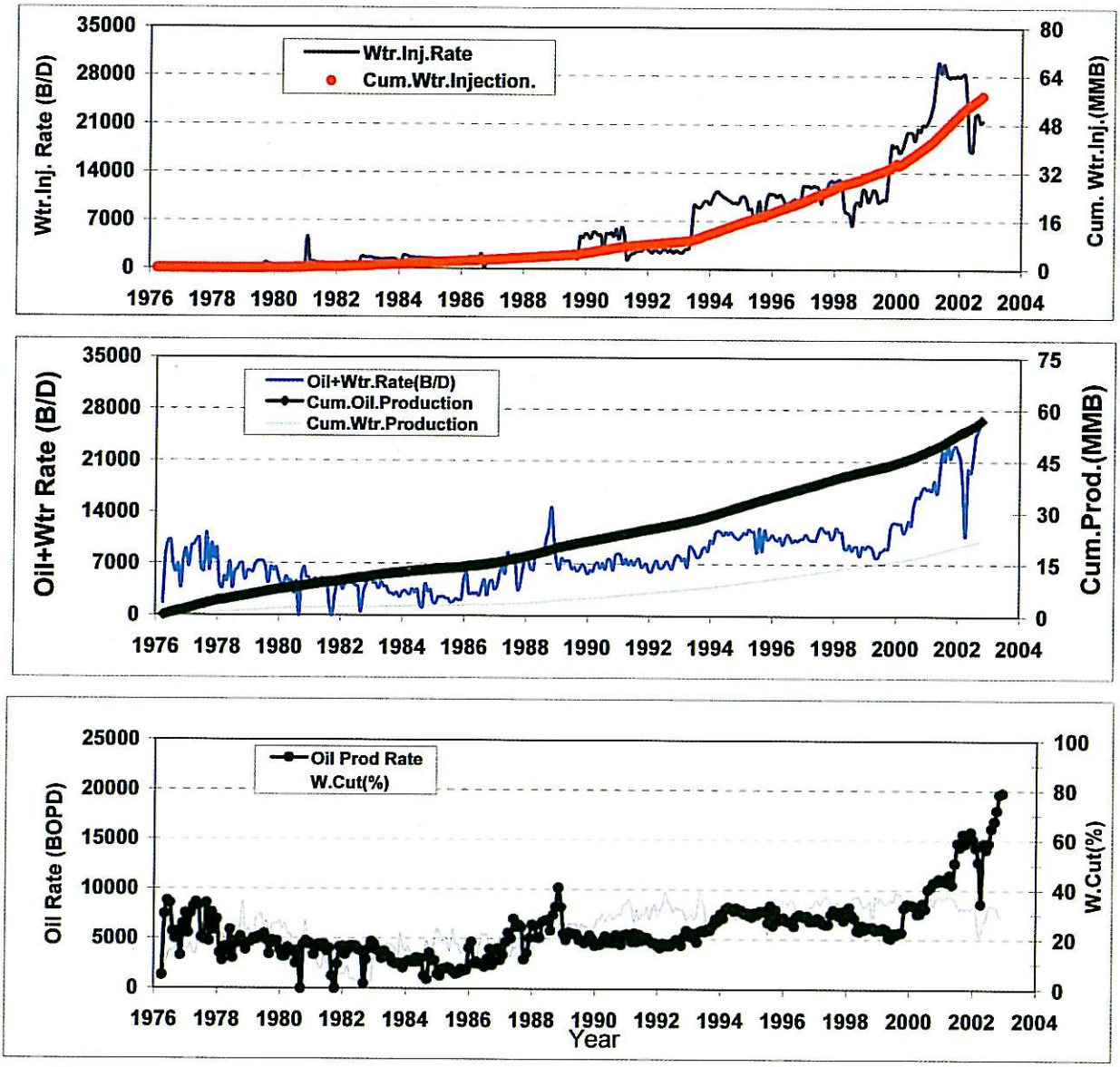

Fig. 15. Gir ABC production performance history.

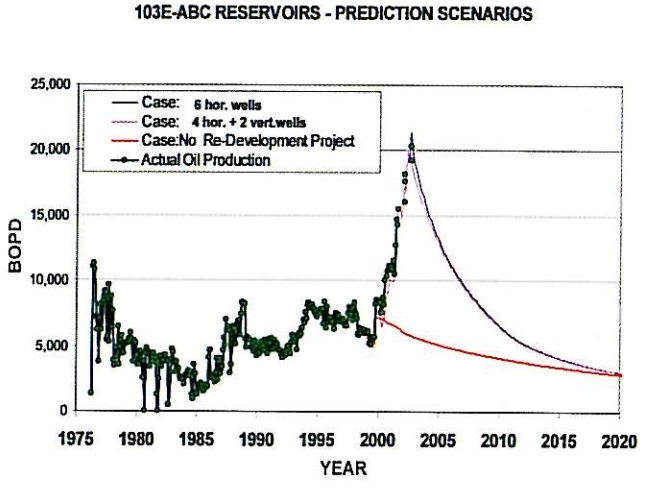

Fig. 16. Gir ABC simulation study oil rate predictions.

INCREMENTAL RESERVES AND ECONOMICS

The incremental oil reserves have been estimated at 33.4 MMSTB (*i.e.* from 74.6 MMSTB in the 'No Development Case' to 108 MMSTB in this re-development project).

The re-development project is quite attractive economically. Assuming an oil price of 20 US$/bbl at 2% escalation per year, the incremental economic returns are estimated at NPVs of MMUS$247 and MMUS$314 with 10% and 5% discount rates respectively until 2020.

CONCLUSIONS

1) The field performance after implementation of the re-development project confirmed the reservoir simulation study results and recommendations.

2) The project was implemented very successfully as the oil production potential has been increased from 6400 STB/D to 20,000 STB/D by;

- drilling 6 vertical water injectors, and 6 horizontal producers, and,
- converting 8 existing single zone producers to dual zone producers.

3) Re-completion of wells using the co-mingle/ dual completion has saved significant cost from drilling additional wells, thus improving the NPV.

4) The oil reserves increased by 33.4 MMSTB from 74.6 MMSTB to 108 MMSTB.

5) The incremental economic return is estimated at NPVs of MMUS$247 with 10% discount and MMUS$314 with 5% discount rates at an oil price of 20 US$/bbl.

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