USE OF ADVANCED TECHNOLOGIES FOR IMPROVING THE PRODUCTION AND RECOVERY OF HYDROCARBON RESERVES

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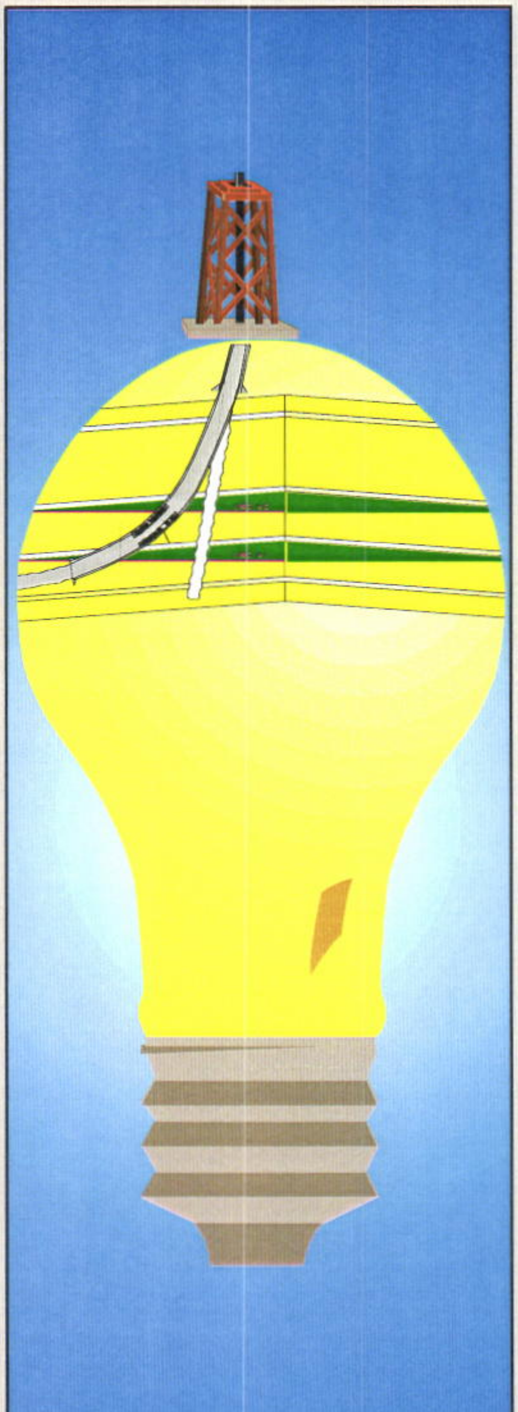

GIAR / MOGI - RESERVOIR CHARACTERIZATION & MODELING

ENI S.p.A.
Agip Division

USE OF ADVANCED TECHNOLOGIES FOR IMPROVING THE PRODUCTION AND RECOVERY OF HYDROCARBON RESERVES

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Rev	**Date**	**Description**	**Prepared**	**Checked**	**Approved**

INTRODUCTION

The study evaluates the impact of advanced technologies in reservoir exploitation through numerical simulation.
The technical problems and the risks related to the exploitation scheme chosen are analysed.

The reservoir department contributed to this study with the preliminary screening of the input data, the simulations and the economic analysis while the drilling department studied the well pre-feasibility.

During a first phase the problems relevant to gas reservoirs were studied since the results obtained have a wider range of applicability than in oil reservoirs. This is due both to the high gas mobility and the type of production mechanism, mainly by simple expansion.

CONCLUSIONS

The use of horizontal wells in gas reservoirs leads to the minimisation of the risks related to the drive and the type of aquifer (lateral or bottom).

The key parameter to choose the type of exploitation is the degree of layering of the reservoir; in the case of gas reservoirs, however, the higher gas mobility tends to minimise the water fingering phenomenon. In fact sensitivities carried out on horizontal wells completed only in top layers demonstrated that only in the case of very low vertical permeabilities (lower than 0.01 md) there are significant recovery decreases.

The exploitation of gas reservoirs through horizontal wells can lead to remarkable increases in the economic results (doubling of the Present Value ratio) affecting both the cash flow increase (higher reserves) and the decrease in investments (fewer wells and platforms).

The reduction of the number of wells in the case of reservoirs with lateral aquifer is about 4-5 times with respect to the conventional solution. The maximum saving can be obtain with multilateral wells. In this case the possibility of carrying out selective completions in the case of water arrival eliminates the risks of premature loss of the well. The interference phenomena did not prove to be such as to affect the spacing. This enables us to limit the area in which locate the well with consequent savings on drilling costs.

In the case of reservoirs with bottom aquifer, the "replacement ratio" between conventional and horizontal wells tends to reduce (about 2). However, horizontal wells offer better production profiles (longer times at plateau rate and higher reserves).

The analytical approach devised by TEOP department proved to be valid for a quick evaluation of the productivity of the conventional well with respect to the horizontal one.
The application of this technology, which assumes to use commingled completions on hydraulically separated levels, does not penalise reservoir exploitation.

However, in the case of gas reservoirs, the use of horizontal wells is very convenient. Of course, local conditions (geological characteristics, lithologies, number of layers, presence or not of loose sands, reservoir depth, type of completion envisaged) must always be considered before taking decisions.

The range of applicability and the benefits of exploitation through horizontal wells is so wide and important that at least one or several cases with horizontal/slanted/multibranch wells should be considered in all the feasibility studies of hydrocarbon reservoirs.

1. "OFFSHORE RAVENNA" RESERVOIR

1.1. Description of the production area and petrophysical characteristics of the levels

The off-shore reservoir is considered gas bearing. The reservoir is at a depth of about 3450 m.s.s.l, 50 Km from the coast, with a water depth of about 30 meters
It is composed of two NNW-SSE elongated anticlines and forming an ellipsoid having a main axis 15Km long and a minor one of 6 Km for a total of 90 Km2. A weak lateral aquifer is present. The GOIP is about 55E+9 Smc. The reservoir is composed of consolidated sandstones subdivided into 4 hydraulically separated levels, called, from top to bottom A1, A2, B, C, (figs. 1-2-3)
The characteristics are as follows:

Level	Thickness (mt.)	Porosity (%)	N/G (%)	Permeability horiz. (md)	vert.	Pressure (barsa)	Datum m.s.s.l.	Goip E+9Smc
A1	5	18.0	55.0	13	8	412.5	3490	3.2
A2	9	21.0	54.0	13	8	412.5	3490	4.6
B	43	20.0	73.0	25	10	416.2	3515	43.5
C	9	16.0	72.5	11	3	430.1	3630	3.5

Three different exploitation schemes have been considered:

- Scheme A) conventional wells (reference case);
- Scheme B) dedicated horizontal wells;
- Scheme C) multilateral horizontal wells;

Fig. 1

STRUCTURE 3-D View

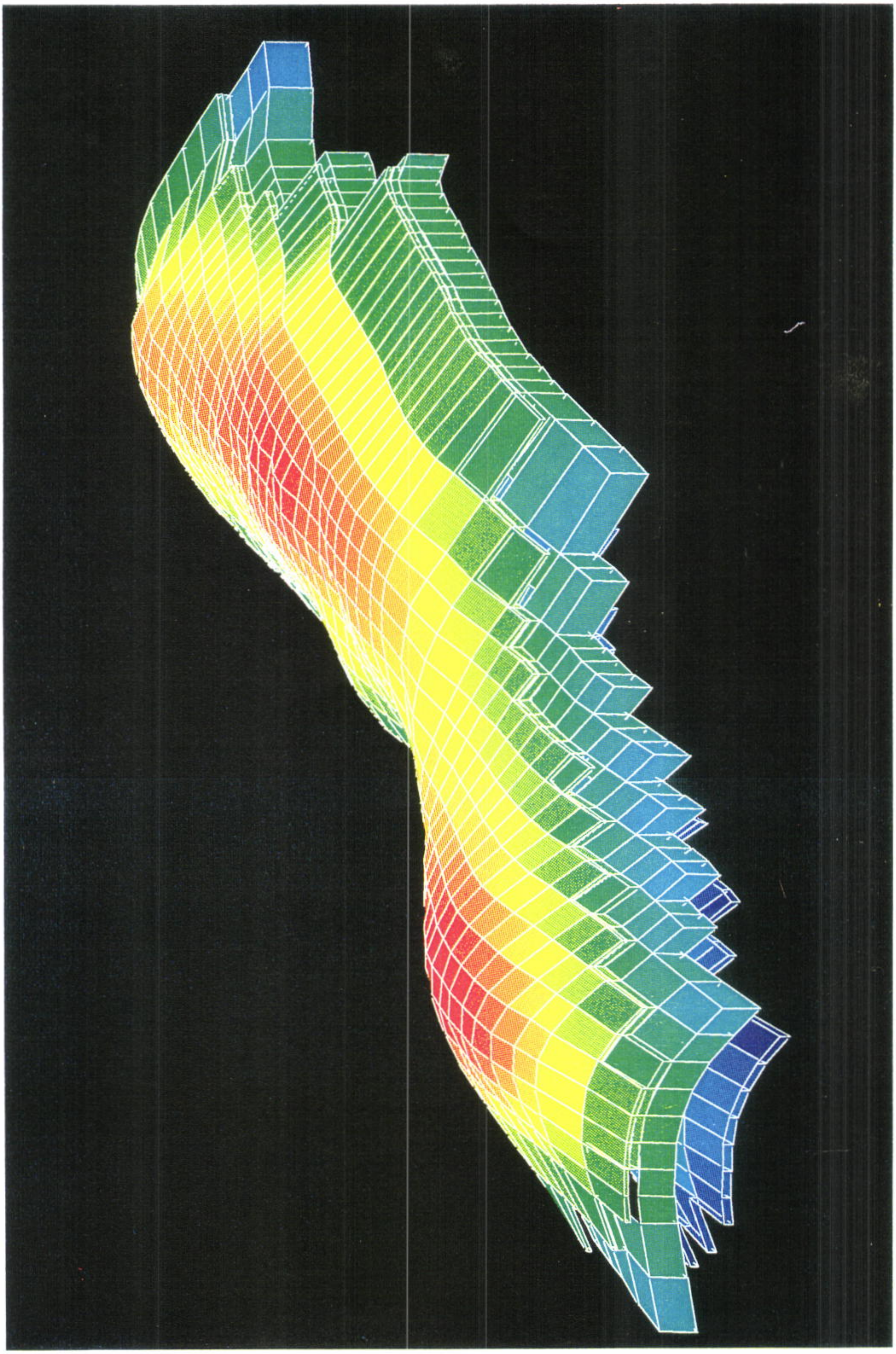


Fig. 2

Cross-section YZ = 9

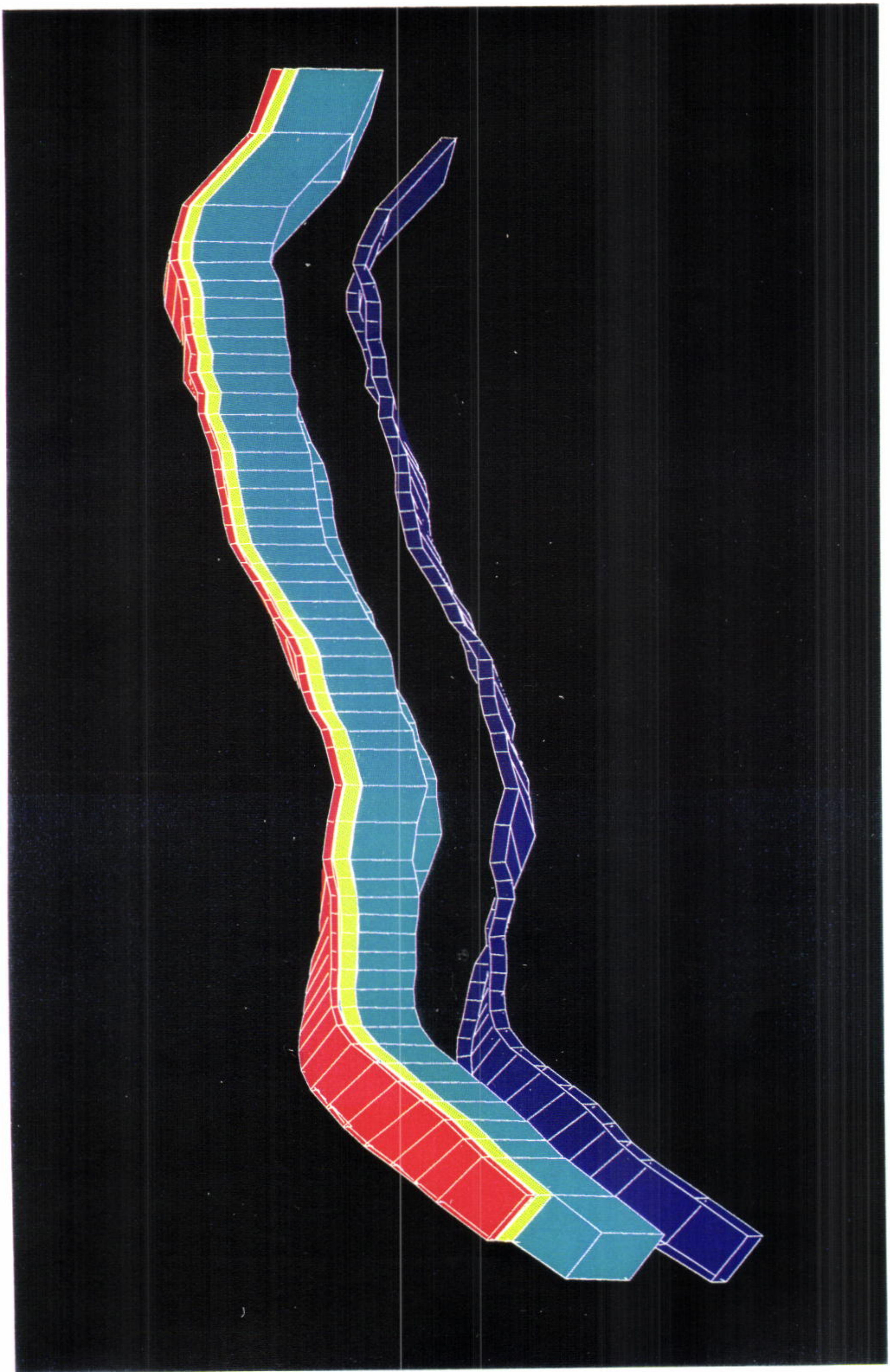
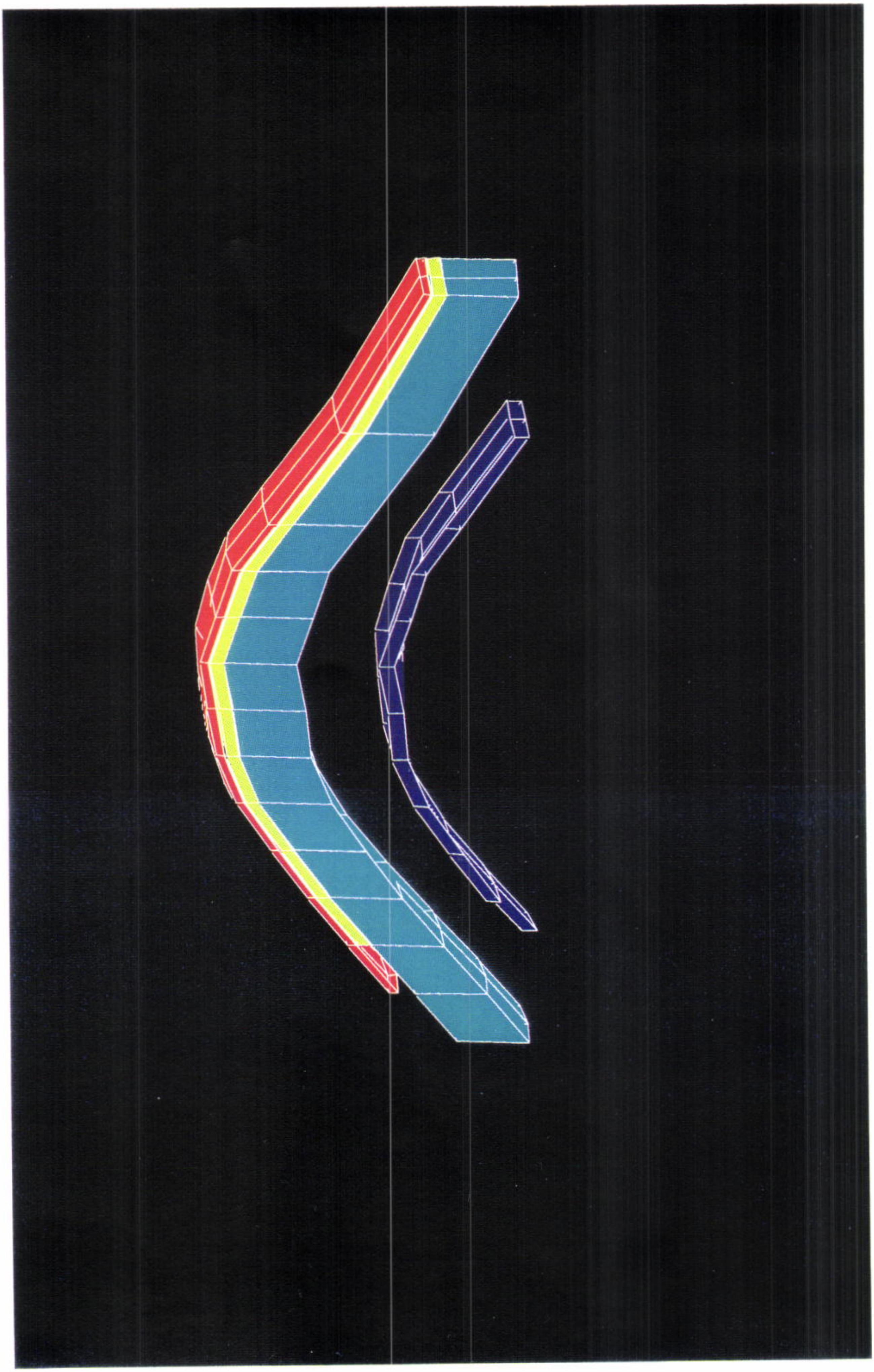


Fig. 3



Cross-section YZ=9

1.2 DESCRIPTION OF THE EXPLOITATION SCHEMES

1.2.1 Scheme A

An optimised exploitation scenario (reference case) was simulated with vertical/deviated wells in single or double completion: 25 wells drilled from 2 platforms (fig.4). The optimisation of the number of wells was obtained with a rationalisation of the completions and the drainage schemes. The type of wells is as follows:

- 25 wells with an average length of 4100 m.

of which :

- 13 drilled from platform P1;
- 8 drilled from platform P2;

subdivided as follows:

- 11 wells with 3"1/2 tubing single completed in level B;
- 14 wells with 2"3/8 and 2"7/8 tubings double completed in levels A1, A2, C of which:
- 8 wells double completed in levels A1, A2 and single completed in level B;
- 6 wells double completed in level B and single completed in level C;

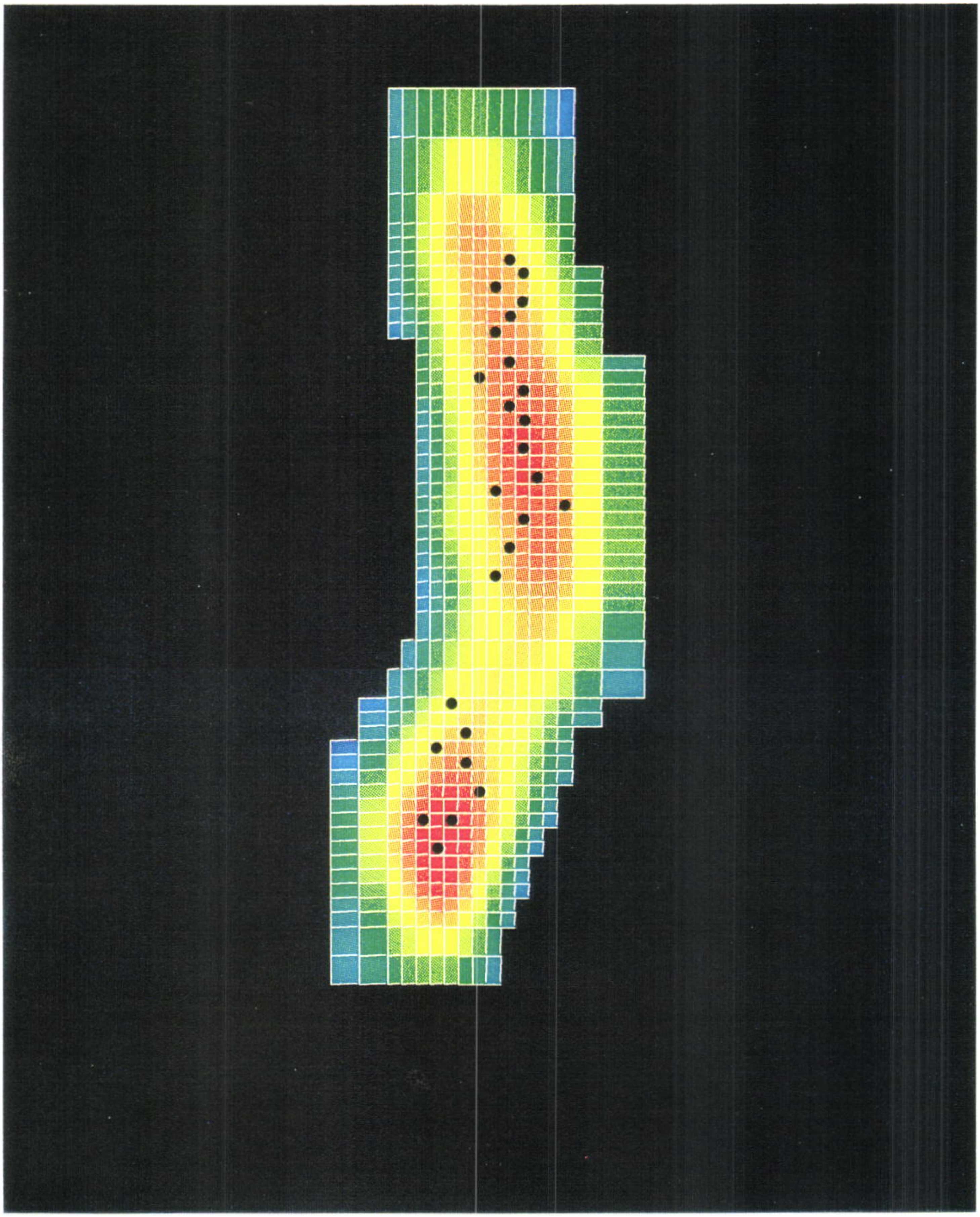
The following constraints were imposed for production and well control:

- production plateau at 5E+6 Sm3/day for at least 20 years;
- control on THPwell head pressure fixing a limit of 40 bar;
- control on the well WGR fixed at 0.00001 Sm3/Sm3 and shut-in of the well (if violated);

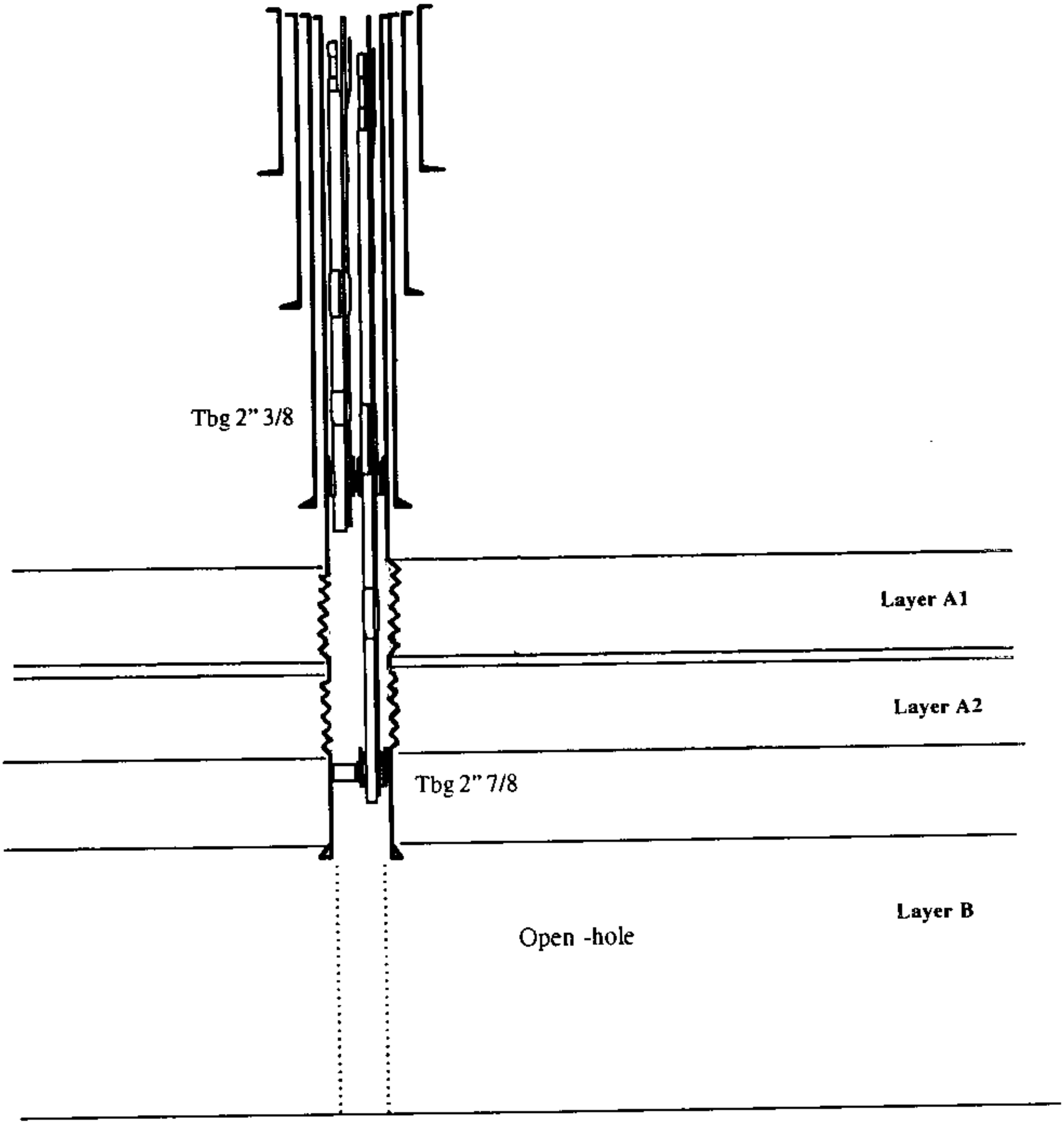
Fig. 4

VERTICAL WELL LOCATION

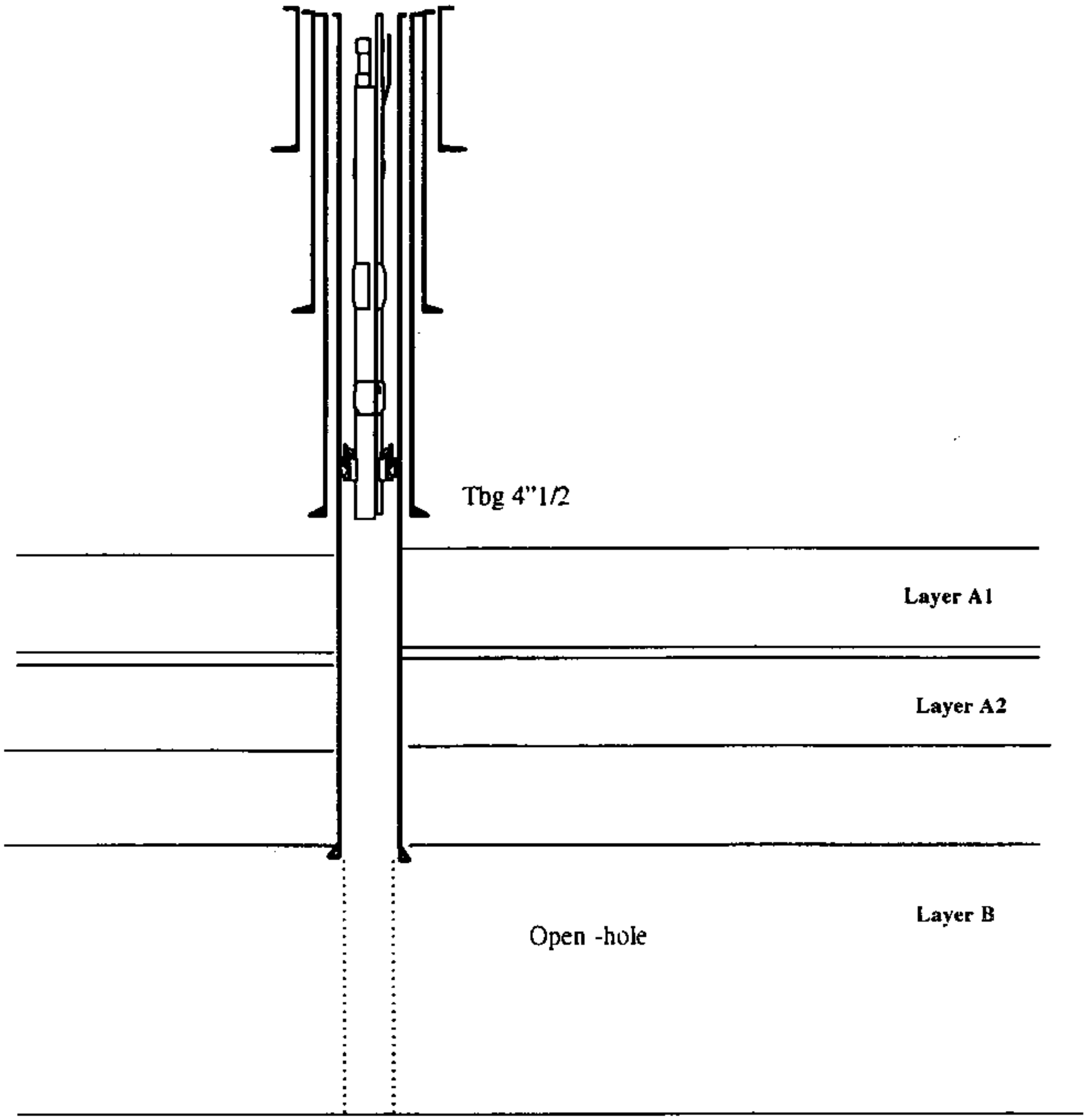
PATTERN A



SCHEMATIC PLANE CONVENTIONALWELL DOUBLE STRING



SCHEMATIC PLANE CONVENTIONAL WELL SINGLE STRING



1.2.2 Scheme-B

After carrying out an analysis on the productivity of the typical horizontal well through an analytical approach, an exploitation plan was defined. It envisages 7 horizontal wells drilled from a single platform located in an intermediate position with respect to the two reservoir culminations (fig.5). Since from the lithological point of view, we are in the presence of consolidated sands we considered open hole wells in the horizontal portion commingled completed in the different levels. The well type is as follows:

- 7 wells with an average length of about 4780 mt.

of which:

- 5 wells with horizontal portion of 750 m with a diameter of 8"1/2 dedicated to level B; single completed also on levels A1, A2 with a tubing of 4"1/2;
- 2 wells with horizontal portion of 500 m with a diameter of 8"1/2 dedicated to level C; single completed also on levels A1, A2, B with a tubing of 4"1/2;

The same constraints as in scheme A were imposed for production and well control; they are as follows:

- production plateau at 5E+6 Sm3/day for a period of at least 20 years;
- control on the THP well head pressure fixing a limit of 40 bar;
- control on the well WGR fixed at 0.00001 Sm3/Sm3 and shut-in of the well (if violated);

1.2.3 Scheme-C

In this case, the number of horizontal wells was reduced from 7 to 5. The wells are always drilled from a single platform in an intermediate location with respect to the two culminations (fig.6) Also in this case, the open hole wells produce in commingle. The type of well is as follows:

- 5 wells with an average length of 4780 m, with a horizontal portion of 750 m with a diameter of 8"1/2 dedicated to level B and single completed also in the levels A1 and A2 with a tubing of 4"1/2.

of which:

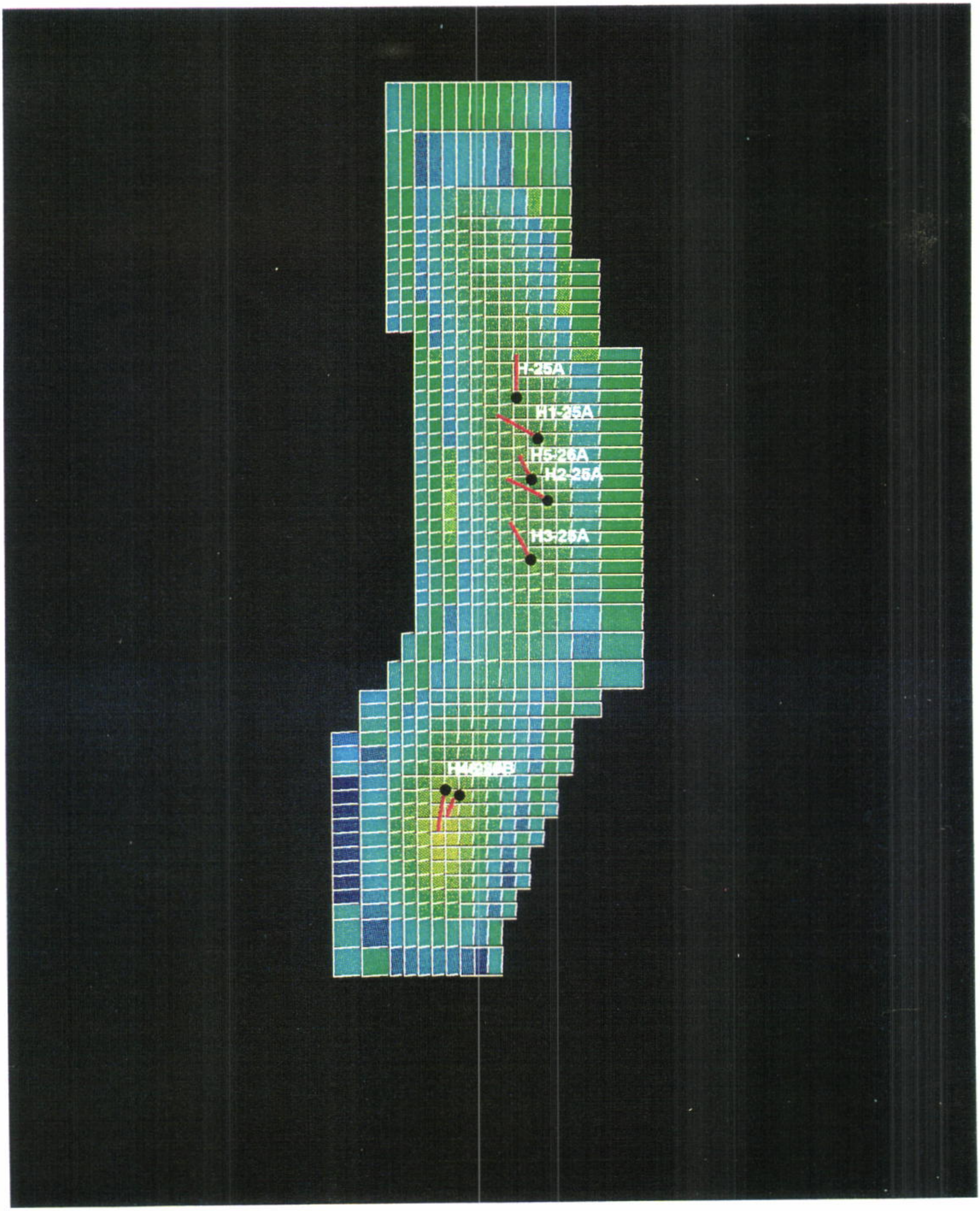
- 3 wells with horizontal portion of 750 m with a diameter of 8"1/2 dedicated to level B single completed in levels A1, A2 with a tubing of 4"1/2.
- 2 multi-lateral wells with 2 horizontal sections; one 750 m long dedicated to level B and one 500 m long dedicated to level C, both with a diameter of 8"1/2 and both single completed also in levels A1, A2 with a tubing of 4"1/2.

The same constraints as in schemes A and B were imposed for production and control of the wells.

Fig. 5

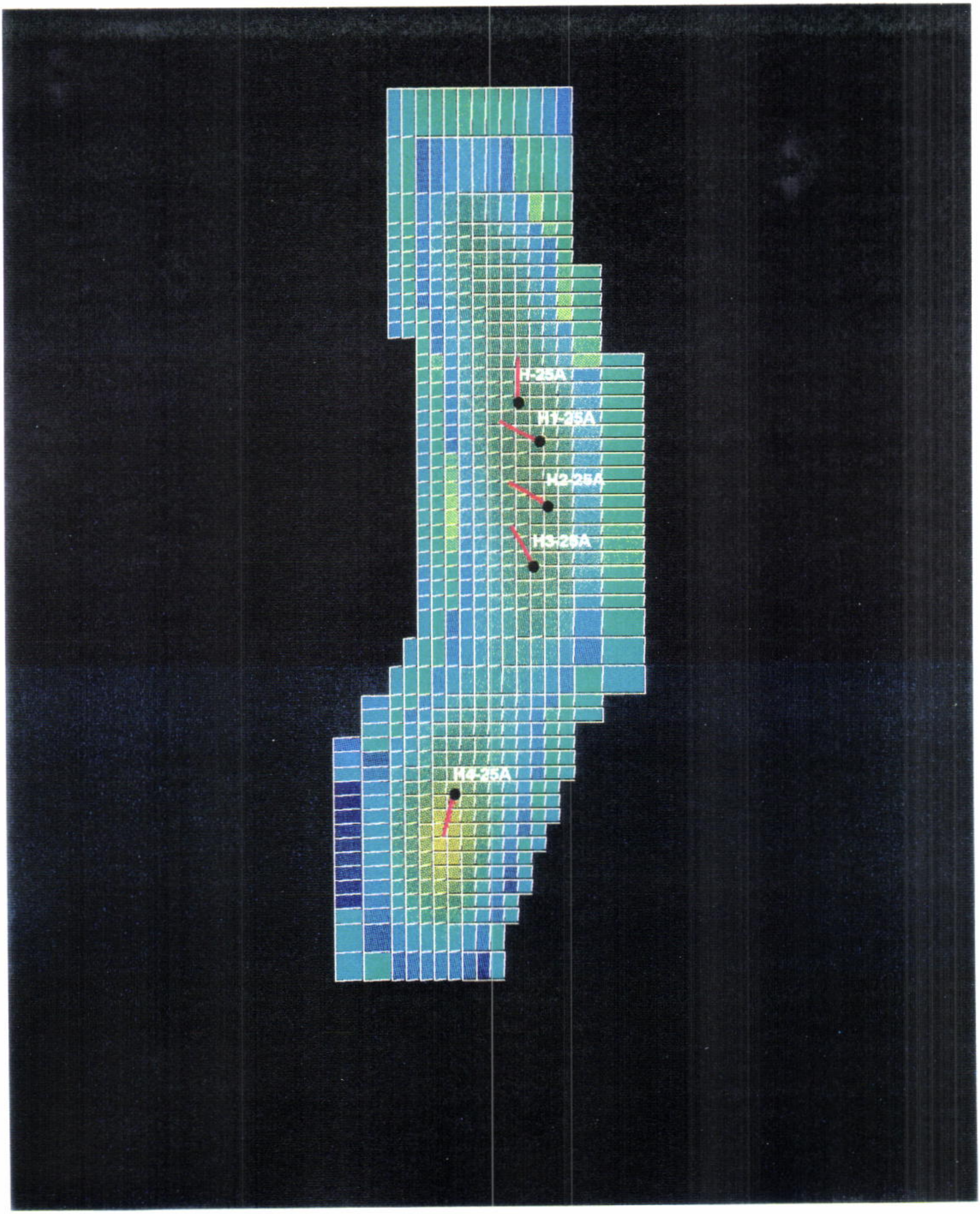
HORIZONTAL WELL LOCATION

PATTERN B

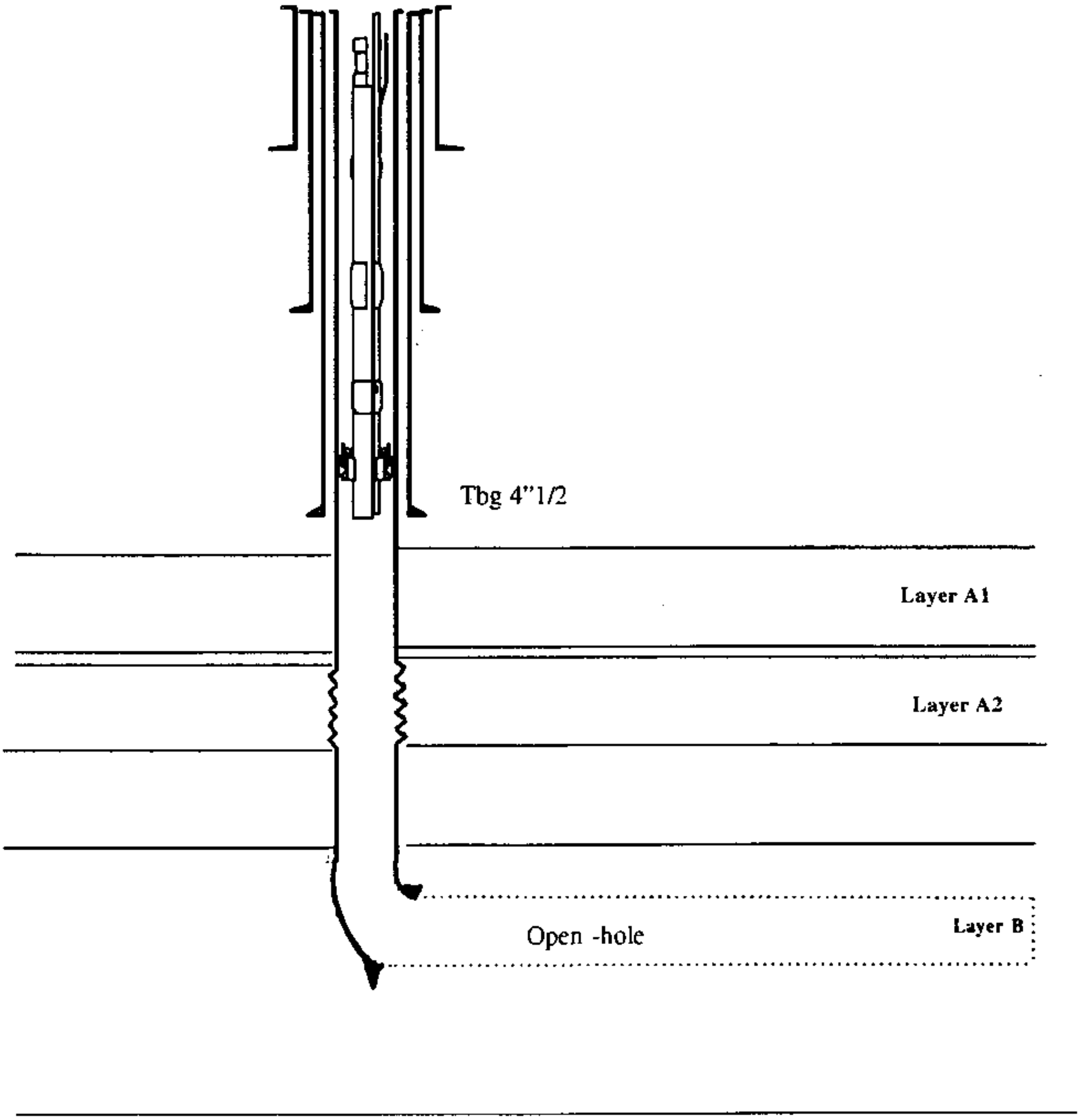


MULTILATERAL WELL LOCATION

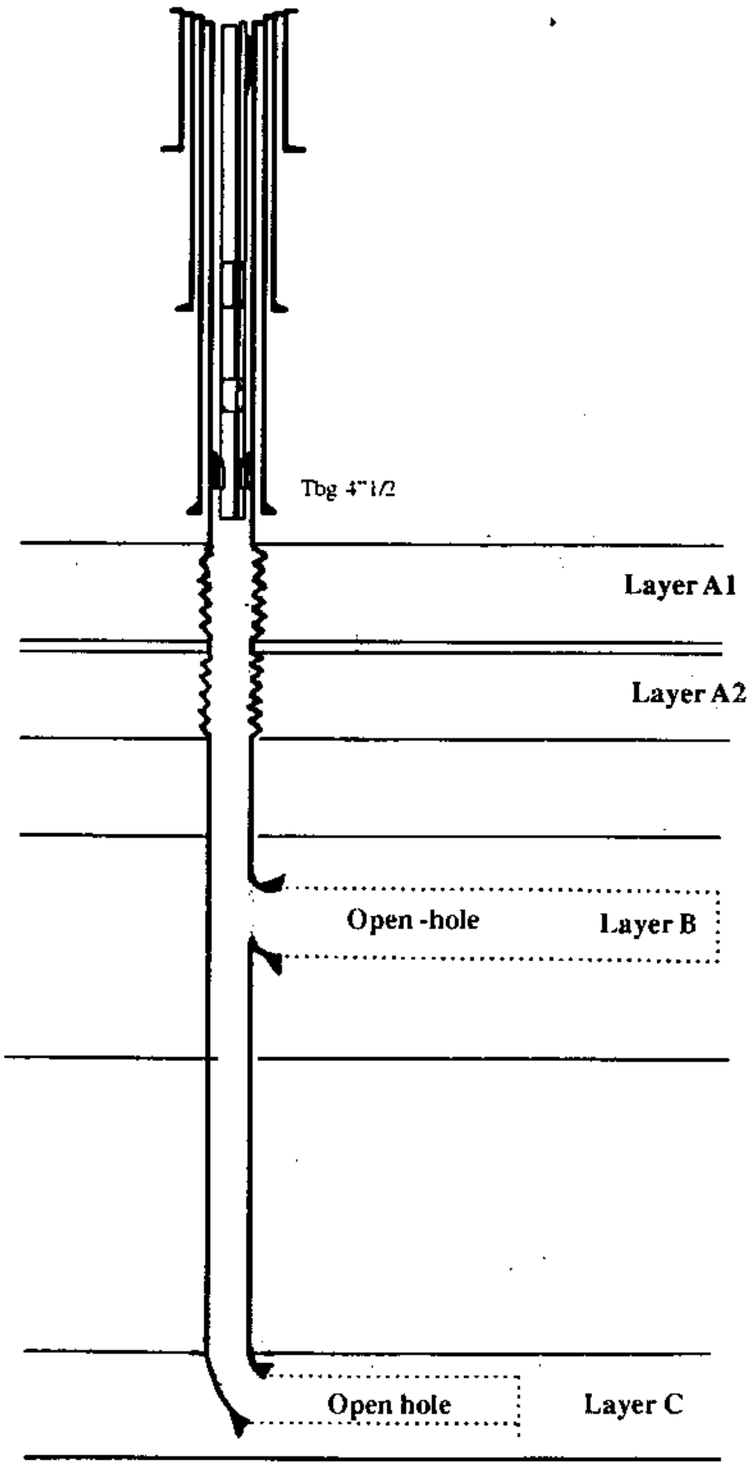
PATTERN C



SCHEMATIC PLANE HORIZONTAL WELL



SCHEMATIC PLAN MULTI-LATERAL WELL



1.3 PRODUCTION PROFILES

The three exploitation schemes gave very similar production profiles (see following table and figs 7-8-9-10). Most probably, extending the simulation even after 2038 the results obtained would have been different. However, the reliability of the results would be debatable.

The case with conventional wells, **SCHEME-A**, keeps the production plateau of 5000000 Sm3/day for about 20 years, with total reserves of about 45.5 E+9 Smc.(R.F.= 83 %) as of 01/01/2028.

The case with dedicated horizontal wells, **SCHEME-B**, keeps the production plateau of 5000000 Sm3/day for about 22 years, with total reserves of about 46.7 E+9 Smc.(R.F.=85%) as of 01/01/2028.

The case with multibranch wells, **SCHEME-C**, keeps the production plateau of 5000000 Sm3/day for about 20 years, with total reserves of about 46.0 E+9 Smc.(R.F. = 84%) as of 01/01/2028.

A weak aquifer was considered in the base case.

A situation with stronger lateral aquifer was simulated for the same cases, keeping the same well constraints. The results are as follows:

AQUIFER	WELLS	PLATEAU year	RECOVERY @2028 E+9 Smc	N° WELLS	PLAT.
Base	Conventional	20	45.5	25	2
Base	Horizontal	21	46.2	7	1
Base	Multi-lateral	19	45.2	5	1
Stronger	Conventional	19	44.6	25	2
Stronger	Horizontal	20	45.5	7	1
Stronger	Multi-lateral 1	10	38.7	5	1
Stronger	Multi-lateral 2 with WGR on connections	20	45.3	5	1

The multi-lateral 2 well envisages the possibility to isolate the horizontal portion if interested by water. On the contrary, the multi-lateral 1 envisages the complete well shut-in after the first water arrival. This explicates the remarkable difference of the two profiles.

1.4 Economic evaluations

This evaluation is aimed at comparing the three different development hypotheses in the base case with weak aquifer. With recoverable reserves of the same order of magnitude the hypotheses analysed are as follows:

1. Development with 25 conventional wells drilled from 2 platforms, gas compression starting from the 16th year of production;
2. Development with 7 horizontal wells drilled from a platform, gas compression starting from the 19th year of production;
3. Development with 3 horizontal wells and 2 multi-lateral horizontal wells drilled from a platform, gas compression from the 19th year of production.

The start-up of the compression is related to the achievement of a dynamic pressure of 75 kg/cm2.

The investment and the operative costs used in the economic evaluation are listed in tab.1. The investments comprise the costs for the installation of platforms, the well drilling and completion costs, the installation of compressors and a sealine of 20" for 50 Km. A plant for gas treatment has been considered already available; thence the relevant capex were not calculated.
Tables 2, 3 and 4 present the production profiles (30 years), capex and opex used as input data for the economic model of Italian fields.
A value of 176.3 Lire/Sm3 as of 1998 is used as gas price; this datum comes from the conservative scenario of the long term plan.
Table 5 presents the results of the evaluation.
It can be observed that the **Net Present Value @ 10% (N.P.V.)** for the different development hypotheses is:

- **hypothesis 1) 936 Billions of Italian £**
- **hypothesis 2) 1033 Billions of Italian £**
- **hypothesis 3) 1032 Billions of Italian £**

The most significant economic indicator is the **Present Value Ratio @ 10% (P.V.R.)**:

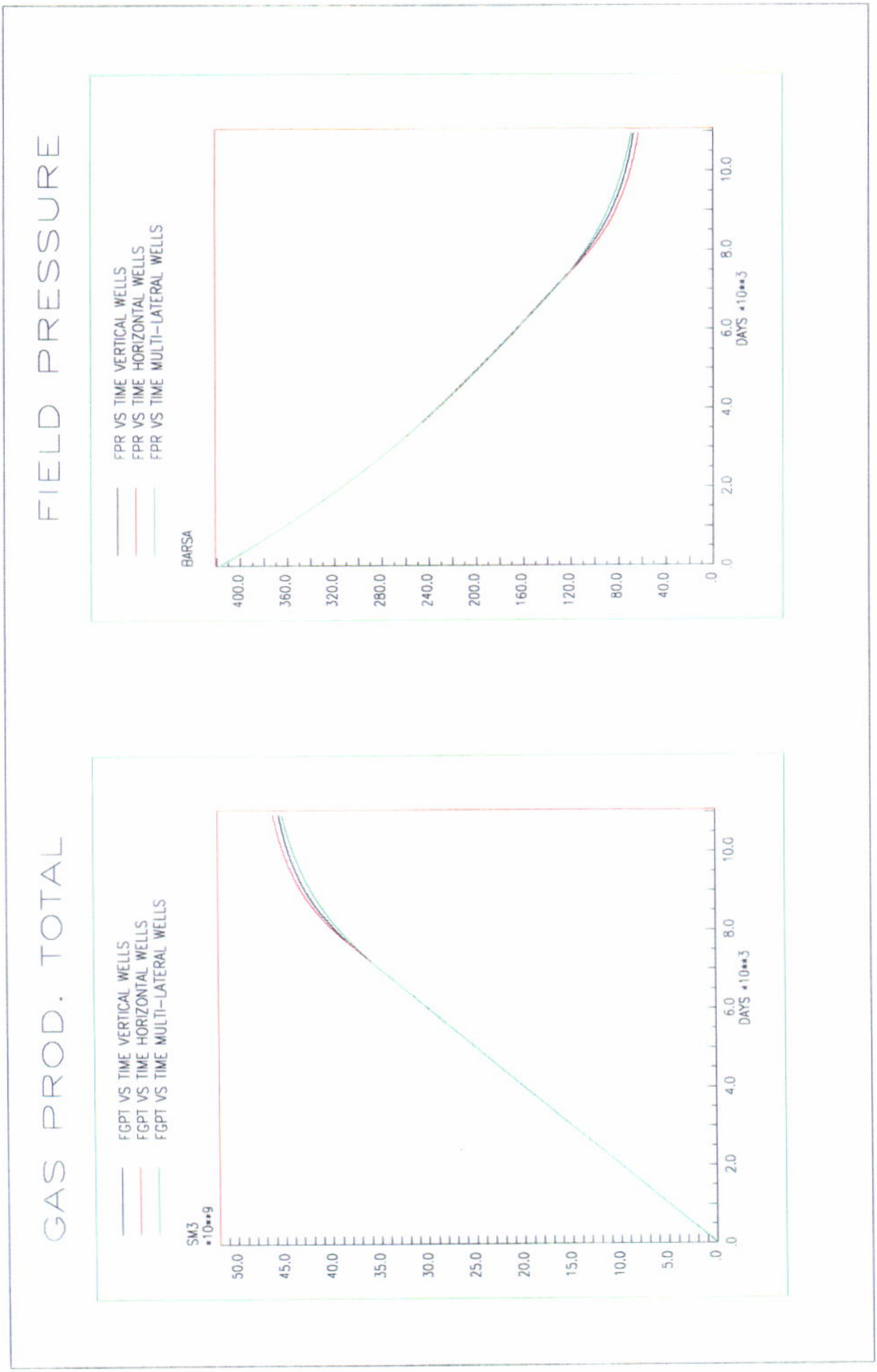
- **hypothesis 1) 4,87 £/£**
- **hypothesis 2) 9,71 £/£**
- **hypothesis 3) 10,50 £/£.**

This means that: **the hypotheses with horizontal and multilateral well offer an about double return for each lira invested with respect to the hypothesis with conventional wells.** The multi-lateral hypothesis is slightly better than the one with the horizontal wells.

Observation

Since the recompression can partially mask the production characteristics of the different cases, table 6 indicates the data of the three above mentioned hypotheses without considering compression. It increases the difference both in reserves and economic indicators between development with horizontal/multilateral wells and development with conventional wells. The results as concerns N.P.V. and P.V.R. are lower as absolute value. However, they confirm the conclusions reached in the case with compression, i.e. the hypotheses 2 and 3 are, as concerns P.V.R., much better than hypothesis 1. This is due to the best productivities of the wells with advanced technology with respect to the conventional ones.

Fig. 7



FIELD PRESSURE
FPR VS TIME VERTICAL WELLS
FPR VS TIME HORIZONTAL WELLS
FPR VS TIME MULTI-LATERAL WELLS
BARSA
DAYS *10**3
GAS PROD. TOTAL
FGPT VS TIME VERTICAL WELLS
FGPT VS TIME HORIZONTAL WELLS
FGPT VS TIME MULTI-LATERAL WELLS
SM3 *10**9
DAYS *10**3

Fig. 8

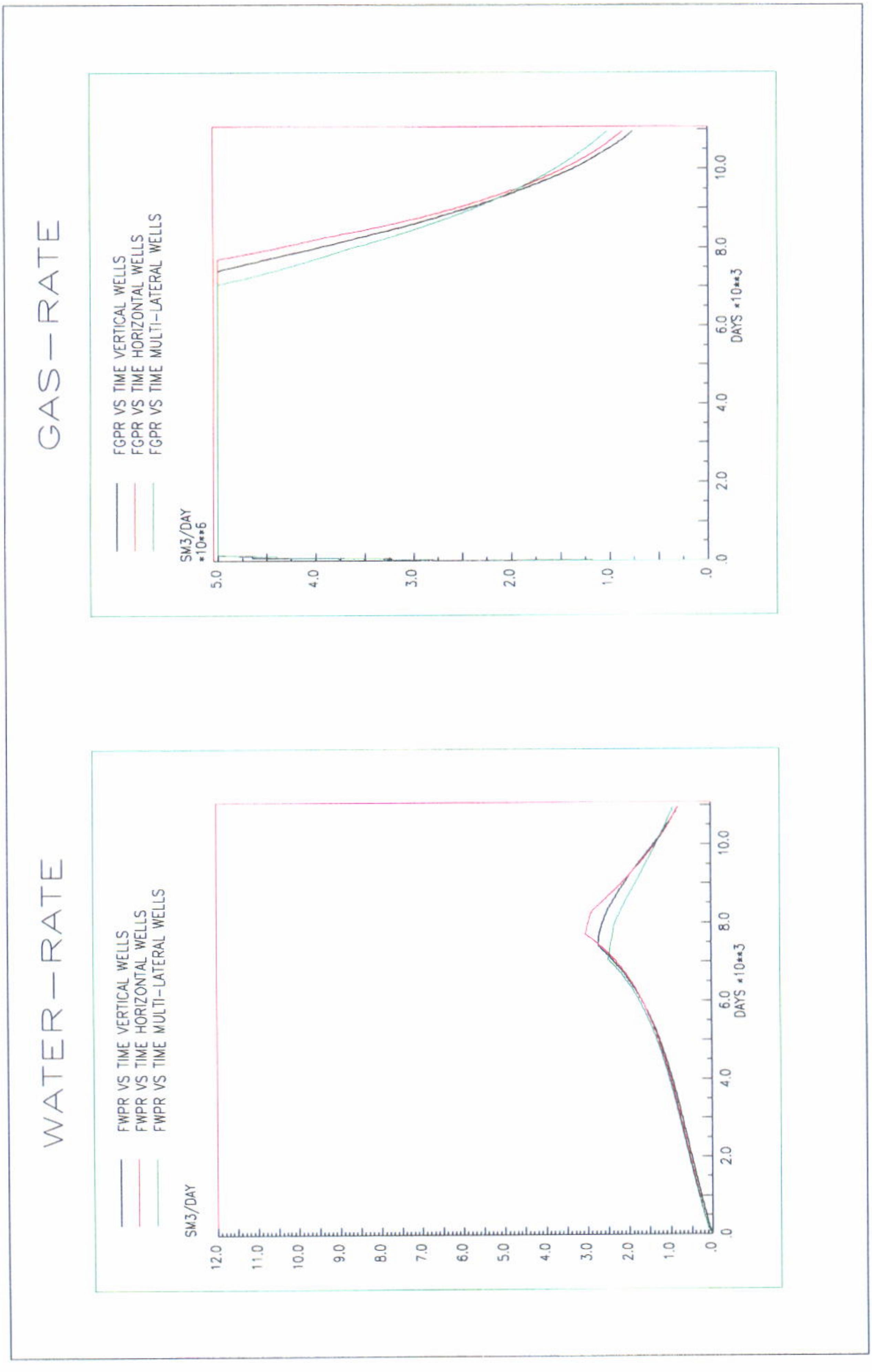
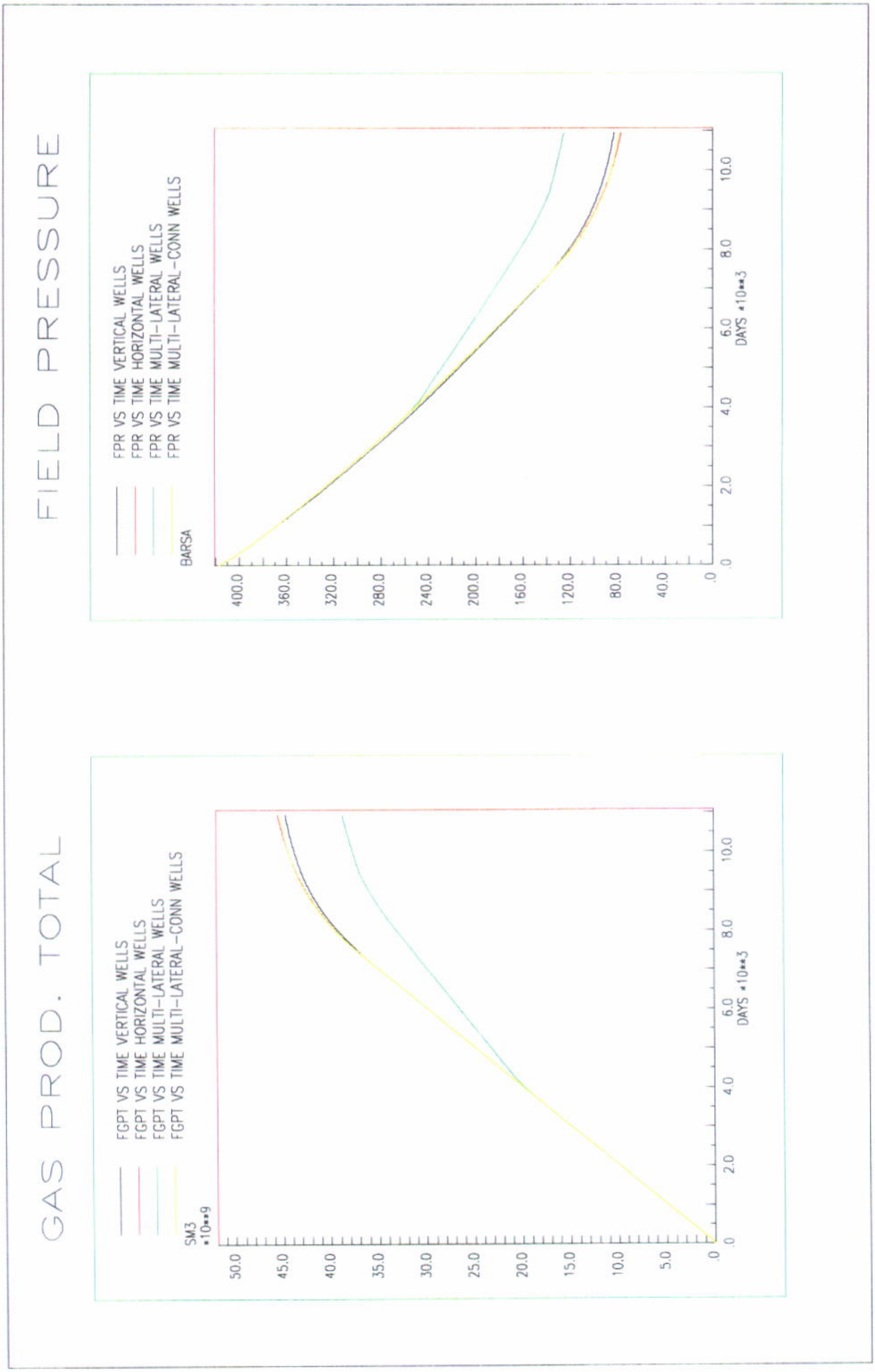
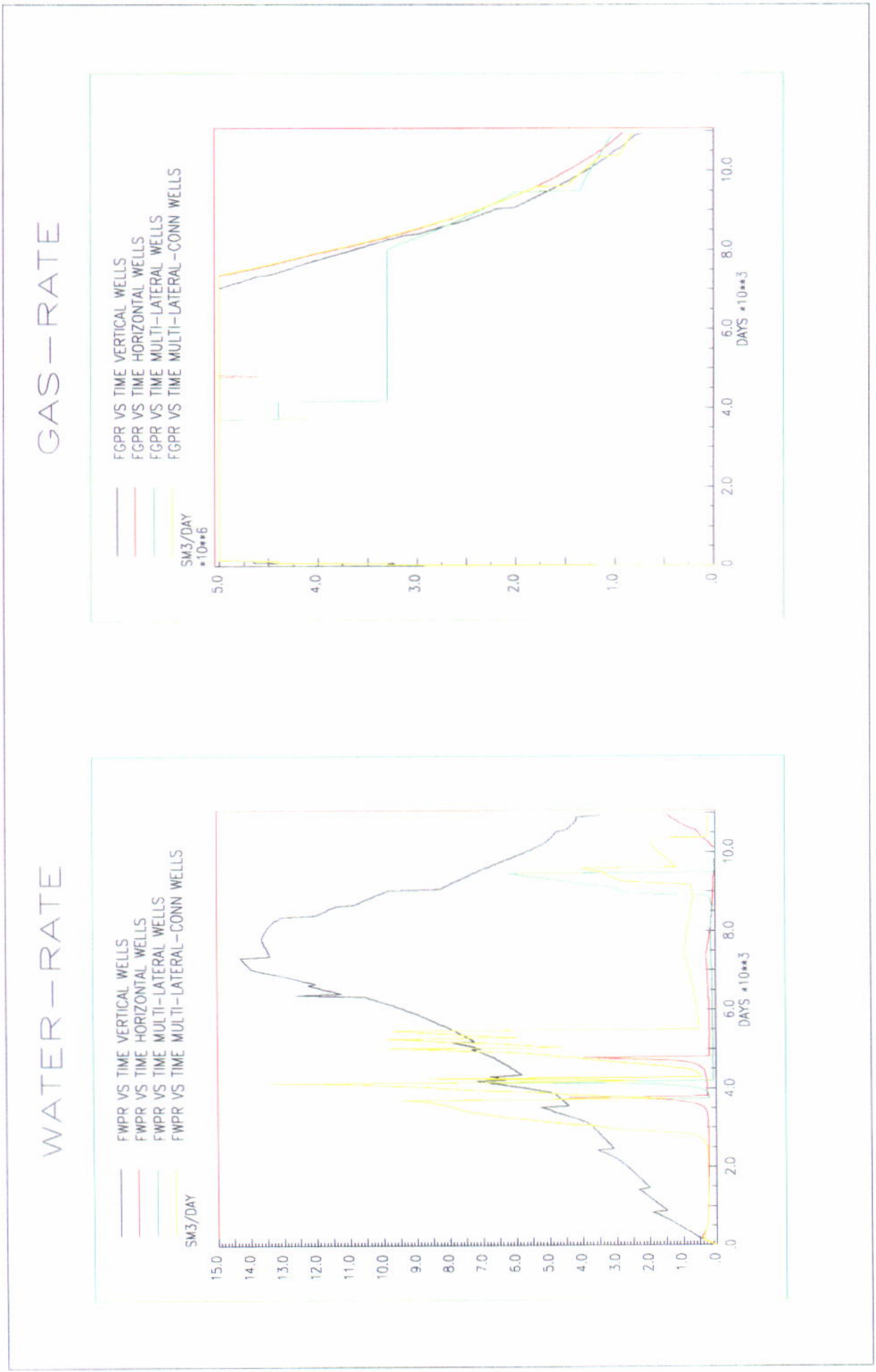

GAS-RATE
FGPR VS TIME VERTICAL WELLS
FGPR VS TIME HORIZONTAL WELLS
FGPR VS TIME MULTI-LATERAL WELLS
SM3/DAY
*10**6
5.0
4.0
3.0
2.0
1.0
.0
2.0
4.0
6.0
8.0
10.0
DAYS *10**3
WATER-RATE
FWPR VS TIME VERTICAL WELLS
FWPR VS TIME HORIZONTAL WELLS
FWPR VS TIME MULTI-LATERAL WELLS
SM3/DAY
12.0
11.0
10.0
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
.0
2.0
4.0
6.0
8.0
10.0
DAYS *10**3

Fig. 9



FIELD PRESSURE
FPR VS TIME VERTICAL WELLS
FPR VS TIME HORIZONTAL WELLS
FPR VS TIME MULTI-LATERAL WELLS
FPR VS TIME MULTI-LATERAL-CONN WELLS
BARSA
400.0
360.0
320.0
280.0
240.0
200.0
160.0
120.0
80.0
40.0
.0
2.0
4.0
6.0
8.0
10.0
DAYS *10**3
GAS PROD. TOTAL
FGPT VS TIME VERTICAL WELLS
FGPT VS TIME HORIZONTAL WELLS
FGPT VS TIME MULTI-LATERAL WELLS
FGPT VS TIME MULTI-LATERAL-CONN WELLS
SM3
*10**9
50.0
45.0
40.0
35.0
30.0
25.0
20.0
15.0
10.0
5.0
.0
2.0
4.0
6.0
8.0
10.0
DAYS *10**3

Fig. 10


GAS-RATE
FGPR VS TIME VERTICAL WELLS
FGPR VS TIME HORIZONTAL WELLS
FGPR VS TIME MULTI-LATERAL WELLS
FGPR VS TIME MULTI-LATERAL-CONN WELLS
SM3/DAY
*10**6
5.0
4.0
3.0
2.0
1.0
0
0
2.0
4.0
6.0
8.0
10.0
DAYS *10**3
WATER-RATE
FWPR VS TIME VERTICAL WELLS
FWPR VS TIME HORIZONTAL WELLS
FWPR VS TIME MULTI-LATERAL WELLS
FWPR VS TIME MULTI-LATERAL-CONN WELLS
SM3/DAY
15.0
14.0
13.0
12.0
11.0
10.0
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0
0
2.0
4.0
6.0
8.0
10.0
DAYS *10**3

Tab. 1

Field: Offshore Ravenna

CAPEX

		Conventional wells			Horizontal wells			Multi Lateral wells		
		Number	Unit cost *10*6 Lire*	Total *10*6 Lire*	Number	Unit cost *10*6 Lire*	Total *10*6 Lire*	Number	Unit cost *10*6 Lire*	Total *10*6 Lire*
Platforms		2	48000	96000	1	48000	48000	1	48000	48000
Wells	Drilling cost	25	4200	105000	7	5000	35000	5	5000	25000
	Dreno costs (750 m)				5	1200	6000	5	1200	6000
	Dreno costs (500 m)				2	800	1600	0	800	0
	Lateral costs (500 m)							2	1000	2000
Completions	Single	11	800	8800	7	1000	7000	5	1000	5000
	Double	14	1200	16800	0	1400	0	0		0
Compressors	(capex between 16° and 19° years)	3+1		15000			15000			15000
Sealine	20" x 800x10*6 Lire x 50 Km			40000			40000			40000
Total				**281600**			**152600**			**141000**

OPEX

		Number	Unit cost	Total	Number	Unit cost	Total	Number	Unit cost	Total
Fixed			*10*6 Lire/Year*	*10*6 Lire/Year*		*10*6 Lire/Year*	*10*6 Lire/Year*		*10*6 Lire/Year*	*10*6 Lire/Year*
	Platform	2	350	**700**	1	175	**175**	1	175	**175**
Variable										
	With compression			10 Lire /Smc /Year			5 Lire /Smc /Year			5 Lire /Smc /Year
	Without compression			3 Lire /Smc /Year			1.5 Lire /Smc /Year			1.5 Lire /Smc /Year

Abbandonment costs

	Number	Unit cost	Total	Number	Unit cost	Total	Number	Unit cost	Total
		*10*6 Lire*	*10*6 Lire*		*10*6 Lire*	*10*6 Lire*		*10*6 Lire*	*10*6 Lire*
Platform	2	4000	8000	1	4000	4000	1	4000	4000
Well	25	750	18750	7	750	5250	5	750	3750
Total			**26750**			**9250**			**7750**

Tab.2

Field: Offshore Ravenna

Conventional wells						
Years	Gas Production 10*6 mc	Capex 10*6 Lire	Opex			
			Fixed 10*6 Lire	with comp. 10*6 Lire	without compr. 10*6 Lire	Total 10*6 Lire
1	0	241400	700		0	700
2	1699		700		5098	5798
3	1830		700		5490	6190
4	1825		700		5475	6175
5	1825		700		5475	6175
6	1825		700		5475	6175
7	1830		700		5490	6190
8	1825		700		5475	6175
9	1825		700		5475	6175
10	1825	25200	700		5475	6175
11	1830		700		5490	6190
12	1825		700		5475	6175
13	1825		700		5475	6175
14	1825		700		5475	6175
15	1830		700		5490	6190
16	1825	15000	700		5475	6175
17	1825		700	18250		18950
18	1825		700	18250		18950
19	1830		700	18300		19000
20	1825		700	18250		18950
21	1825		700	18250		18950
22	1760		700	17600		18300
23	1537		700	15371		16071
24	1309		700	13087		13787
25	1096		700	10964		11664
26	910		700	9101		9801
27	750		700	7497		8197
28	607		700	6072		6772
29	484		700	4844		5544
30	389		700	3890		4590
Total	**45•242**	**281•600**	**21•000**	**179•725**	**81•808**	**282•533**

Note:The drilling schedule is:
19 wells in the 1° year
6 wells in the 10° year

Field: Offshore Ravenna

Horizontal wells						
Years	Gas Production 10*6 mc	Capex 10*6 Lire	Opex			
			Fixed 10*6 Lire	with comp. 10*6 Lire	without compr. 10*6 Lire	Total 10*6 Lire
1	0	137600	175		0	175
2	1688		175		2532	2707
3	1830		175		2745	2920
4	1825		175		2738	2913
5	1825		175		2738	2913
6	1825		175		2738	2913
7	1830		175		2745	2920
8	1825		175		2738	2913
9	1825		175		2738	2913
10	1825		175		2738	2913
11	1830		175		2745	2920
12	1825		175		2738	2913
13	1825		175		2738	2913
14	1825		175		2738	2913
15	1830		175		2745	2920
16	1825		175		2738	2913
17	1825		175		2738	2913
18	1825		175		2738	2913
19	1830	15000	175		2745	2920
20	1825		175	9125		9300
21	1825		175	9125		9300
22	1825		175	9125		9300
23	1698		175	9009		9184
24	1432		175	7800		7975
25	1173		175	6507		6682
26	955		175	5327		5502
27	781		175	4252		4427
28	634		175	3351		3526
29	516		175	2645		2820
30	420		175	2072		2247
Total	**45•822**	**152•600**	**5•250**	**68•339**	**49•107**	**122•696**

Field: Offshore Ravenna

Multi Lateral wells						
Years	Gas Production 10*6 mc	Capex 10*6 Lire	Opex Fixed 10*6 Lire	Opex with comp. 10*6 Lire	Opex without compr. 10*6 Lire	Total 10*6 Lire
1	0	126000	175		0	175
2	1688		175		2532	2707
3	1830		175		2745	2920
4	1825		175		2738	2913
5	1825		175		2738	2913
6	1825		175		2738	2913
7	1830		175		2745	2920
8	1825		175		2738	2913
9	1825		175		2738	2913
10	1825		175		2738	2913
11	1830		175		2745	2920
12	1825		175		2738	2913
13	1825		175		2738	2913
14	1825		175		2738	2913
15	1830		175		2745	2920
16	1825		175		2738	2913
17	1825		175		2738	2913
18	1825		175		2738	2913
19	1830	15000	175		2745	2920
20	1825		175	9125		9300
21	1765		175	9125		9300
22	1562		175	8506		8681
23	1385		175	7492		7667
24	1198		175	6581		6756
25	1031		175	5660		5835
26	885		175	4821		4996
27	761		175	4102		4277
28	647		175	3449		3624
29	552		175	2883		3058
30	471		175	2407		2582
Total	44•820	141•000	5•250	64•150	49•107	118•508

Tab.5

Offshore Ravenna Fields: ECONOMIC EVALUATION
DEFLATED VALUES after TAXES

Case	With compression cases												Notes
	Input Data				Output Data								
	Gas reserves (10^6 Smc)	Capex (10^6 Lit)	Opex (10^6 Lit)	Abband. costs (10^6 Lit)	Cash Flow (10^6 Lit)	Net Present Value @10% (10^6 Lit)	P.V.R. (*) @ W.A.A.C. (N.P.V./Capex)	A.A.R.R. (%)	Maximum negative Exposure (10^6 Lit)	Maximum negative Exposure (Anno)	Cost When Produced 10% (Lit/Smc.)	Pay Out Time (Anni)	
1	45,242	281,600	282,533	26,750	2,950,176	936,529	4.87	59.00	-241,728	1998	21.8	2.71	Development by 25 convetional wells Compression after 16° years
2	45,822	152,600	122,696	9,250	3,140,410	1,033,126	9.71	100.00	-137,682	1998	11.3	2.05	Development by 7 horizontal wells Compression after 19° years
3	44,820	141,000	118,508	7,750	3,079,471	1,032,581	10.50	108.00	-126,082	1998	10.6	1.97	Development by 5 multi lateral wells Compression after 19° years

(*) Present Value Ratio = $\frac{\text{N.P.V. @ W.A.A.C.}}{\text{Capex @ W.A.A.C.}}$; WACC= 10 %

Gas price @ 1998 = 176.3 Lire/Smc

Tab.6

Offshore Ravenna Fields: ECONOMIC EVALUATION
DEFLATED VALUES after TAXES

	Without compression cases												
	Input Data				Output Data								
Case	Gas reserves (10^6 Smc)	Capex (10^6 Lit)	Opex (10^6 Lit)	Abband. costs (10^6 Lit)	Cash Flow (10^6 Lit)	Net Present Value @10% (10^6 Lit)	P.V.R. (*) @ W.A.A.C. (N.P.V./Capex)	A.A.R.R. (%)	Maximum negative Exposure (10^6 Lit)	Maximum negative Exposure (Anno)	Cost When Produced 10% (Lit/Smc.)	Pay Out Time (Anni)	Notes
1	27,269	266,600	93,008	26,750	1,788,533	775,490	3.89	59.00	-241,728	1998	23.8	2.71	Development by 25 convetional wells without compression
2	32,738	137,600	52,432	9,250	2,267,621	933,590	8.69	100.00	-137,682	1998	11.8	2.05	Development by 7 horizontal wells without compression
3	32,738	126,000	52,432	7,750	2,274,376	941,176	9.56	108.00	-126,082	1998	10.9	1.97	Development by 5 multi lateral wells without compression

(*) Present Value Ratio = $\frac{\text{N.P.V. @ W.A.A.C.}}{\text{Capex @ W.A.A.C.}}$; WACC= 10 %

Gas price @ 1998 = 176.3 Lire/Smc

2. RESERVOIR WITH BOTTOM AQUIFER

2.1. Description of the production area and petrophysical characteristics of the levels

The gas bearing reservoirs is at a depth of about 3500 meters; it is composed of an elongated NNW-SSE anticline forming an ellipsoid whose main axis is about 10 m long and minor axis is about 4 km long, for a total of 40 Km2. A strong bottom aquifer is present. The GOIP is about 57E+9 Sm3 (figs. 11-12-13).
The reservoir was assumed to be composed of consolidated sandstones subdivided into 13 homogeneous levels communicating between them. The characteristics are as follows:

Depth (mt.)	Porosity (%)	N/G (%)	Permeability hor. (md)	vert.	Pressure (barsa)	Datum m.s.s.l.
130	18.0	78.0	25	5	416.2	3550

Three different exploitation schemes were taken into account:

- Scheme A) conventional wells;
- Scheme B) optimised conventional wells;
- Scheme C) horizontal wells;

2.2. DESCRIPTION OF THE EXPLOITATION SCHEME

2.2.1 Scheme A

The exploitation scheme (fig.14) is based on 10 conventional wells single completed with tubing of 3"1/2, in the first eight levels:

- 5 wells open in the first 7 levels;
- 5 wells open in the first 8 levels;

The following constraints were imposed for the production and control of the wells:

- production plateau at 4000000 Sm3/day for at least 25 years;
- control on THP wellhead pressure fixing a limit of 40 bar;
- control on the well WGR at 0.00001 Sm3/Sm3 with water shut-off if violated;

Fig. 11

STRUCTURE 3-D View

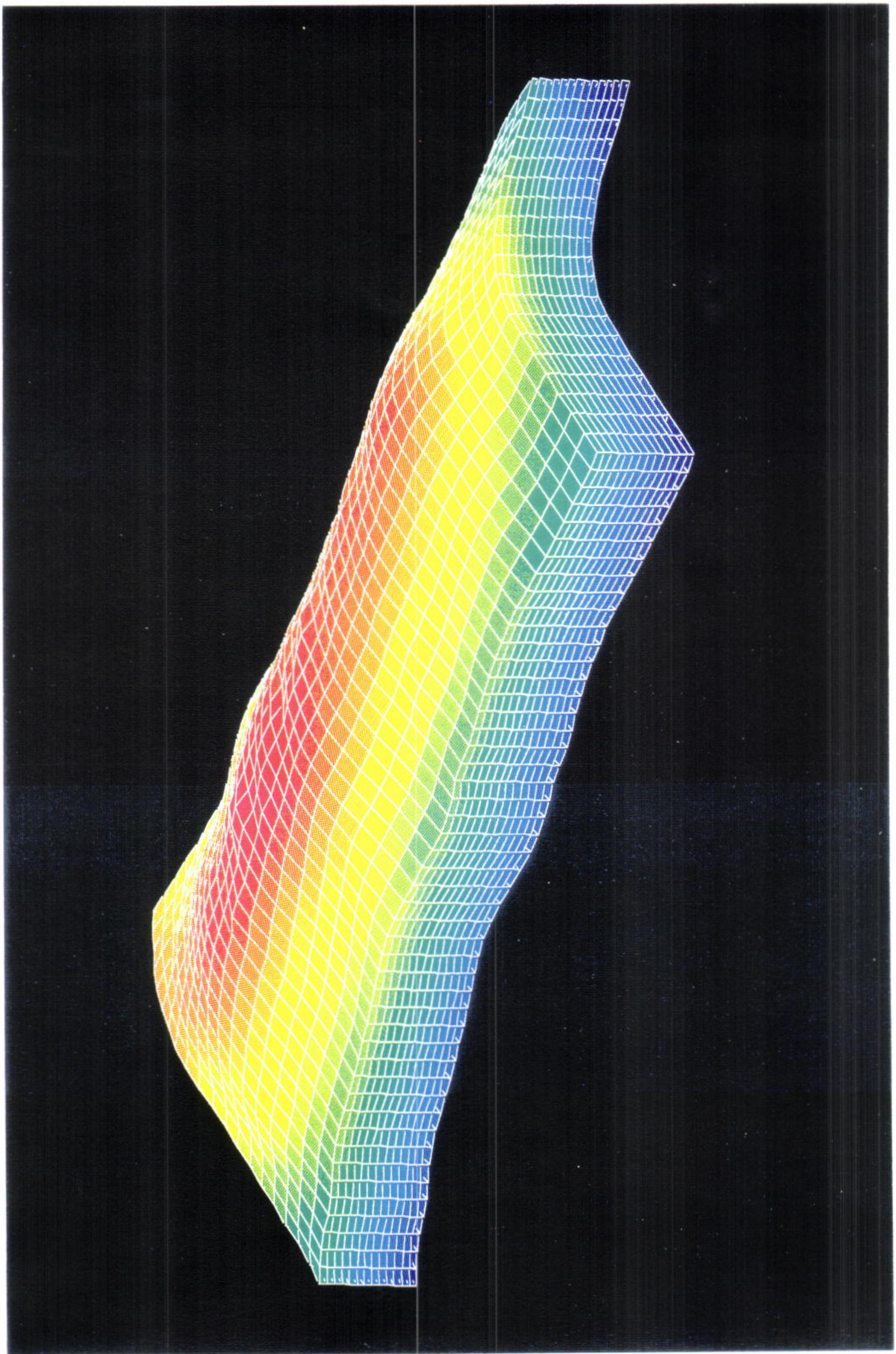
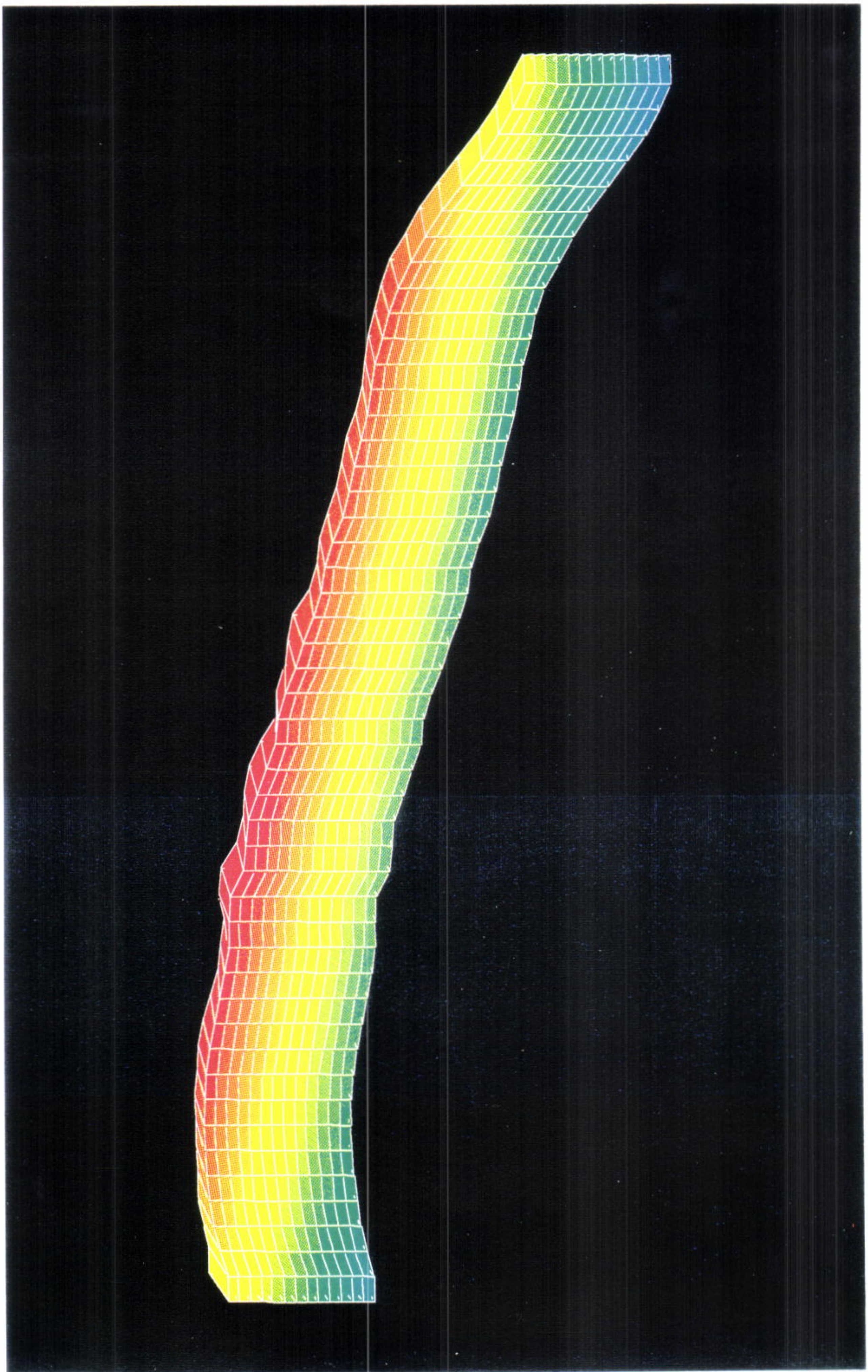


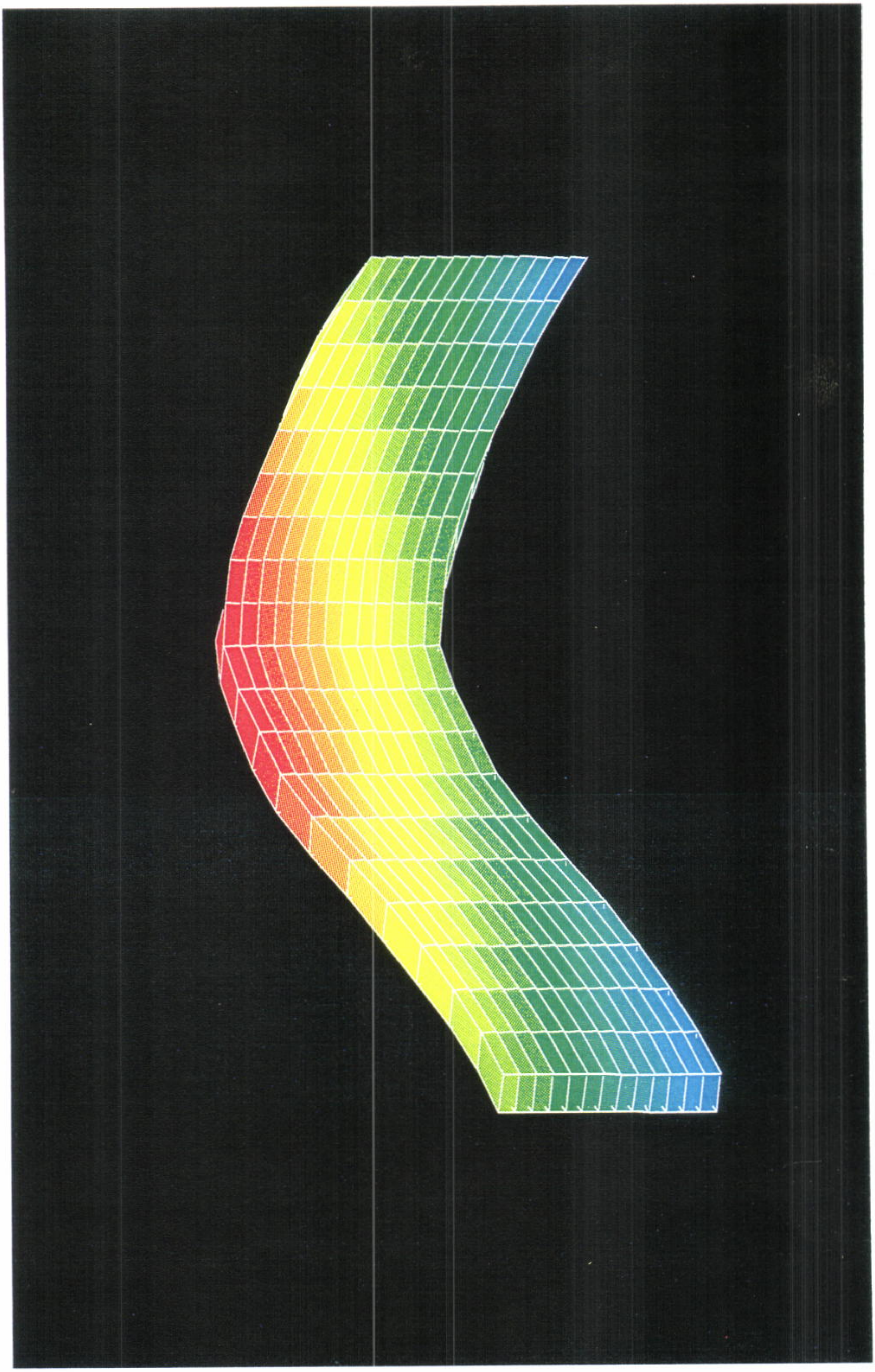
Fig. 12



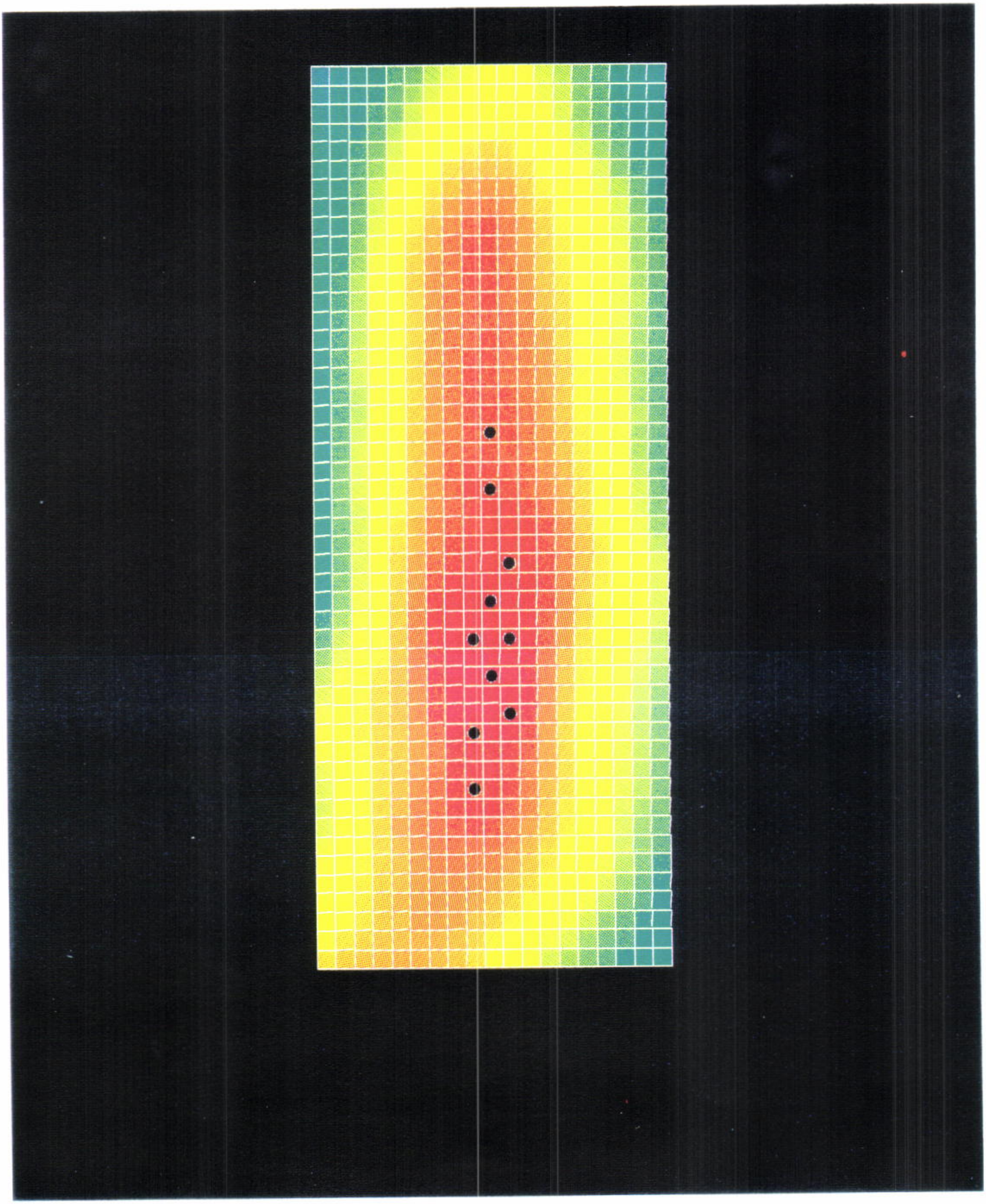
Cross-section YZ = 10

Fig. 13

Cross-section XZ = 33



VERTICAL WELL LOCATION
PATTERN A



2.2.2 Scheme-B

The optimised exploitation scheme (fig. 15) is based on 13 conventional wells, 3 more with respect to the previous case to enable us to operate with lower well rates so as to delay the formation of the water-coning at the wells as much as possible, trying to keep the production plateau of 4000000 Sm3/day. The wells are single completed with tubing of 3"1/2 in the first eight levels :

- 2 wells open in the first 6 levels;
- 6 wells open in the first 7 levels;
- 5 wells open in the first 8 levels;

The same constrains as in scheme A were imposed for the production and well control.

2.2.3 Scheme-C

In this case the reservoir is produced by 7 wells with a horizontal portion 800 mt long (fig.16) and a diameter of 8"1/2 dedicated to the second level and single completed also on the first level with a tubing of 4"1/2.
The same constraints as in scheme A were imposed for production and well control.

2.3 PRODUCTION PROFILES

The three exploitation schemes gave different production profiles (see next table and figs 17-18-19-20).

The case with conventional wells, Scheme-A, keeps the production plateau of 4000000 Sm3/day for about 25 years, with total reserves of about 44.2 E+9 Sm^3, as of 01/01/2038.

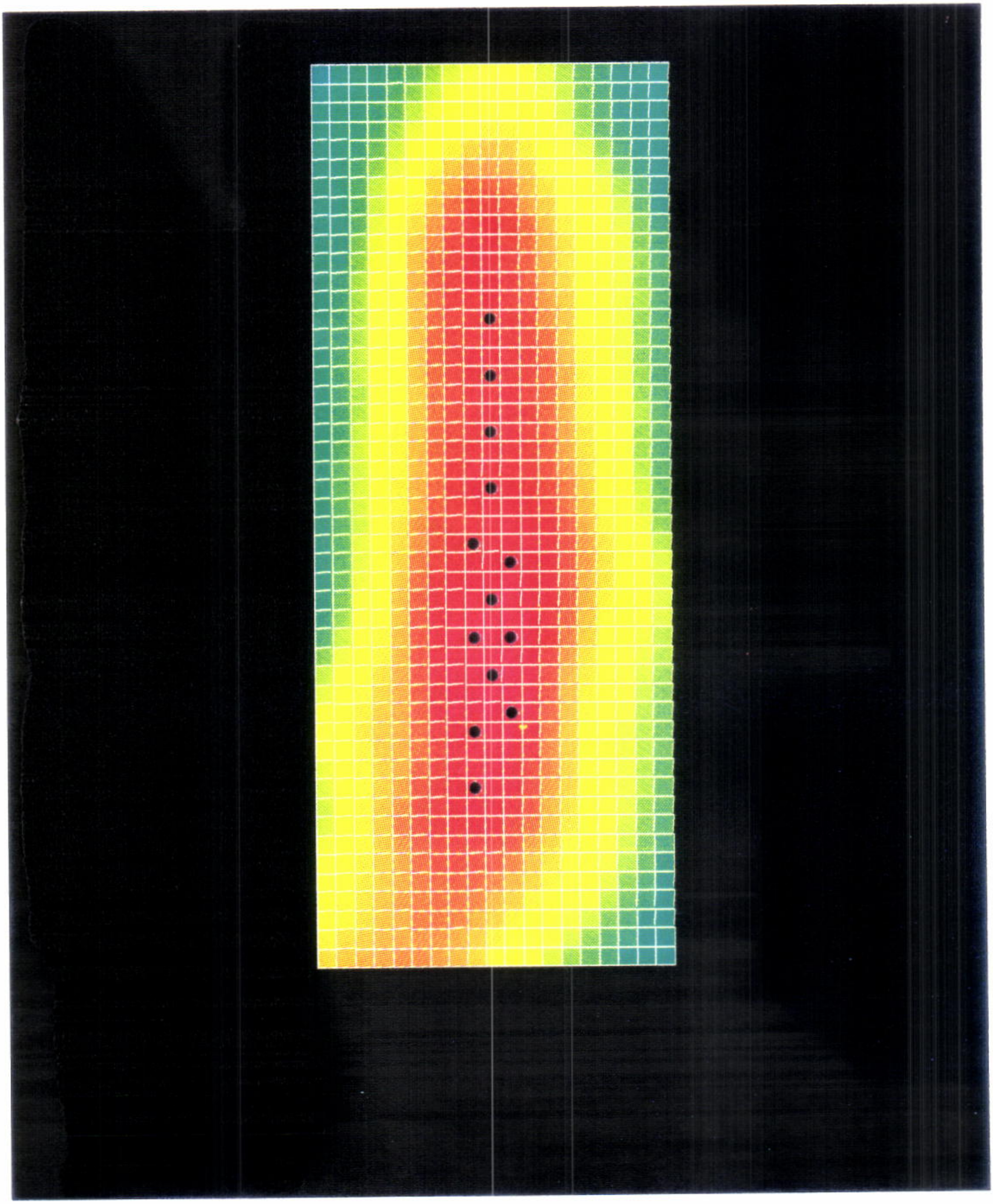
The case with optimised conventional wells, Scheme B, keeps the production plateau of 4000000 Sm3/day for about 27 years with total reserves of about 48.9 E+9 Sm^3 at the end of the simulation.

The case with multi-lateral wells, Scheme-C, keeps the production plateau of about 4E+6 Sm3/day for about 32 years, for total reserves of about 51.3 E+9 Sm3.

CASE	N° WELLS	RECOVERY@2038 years	PLATEAU E+9 Smc
Conventional	10	44.2	25
Conventional opt.	13	48.9	27
Horizontal	7	51.3	32

Fig. 15

OPTIMIZED VERTICAL WEELL LOCATION
PATTERN B



HORIZONTAL WELL LOCATION
PATTERN C

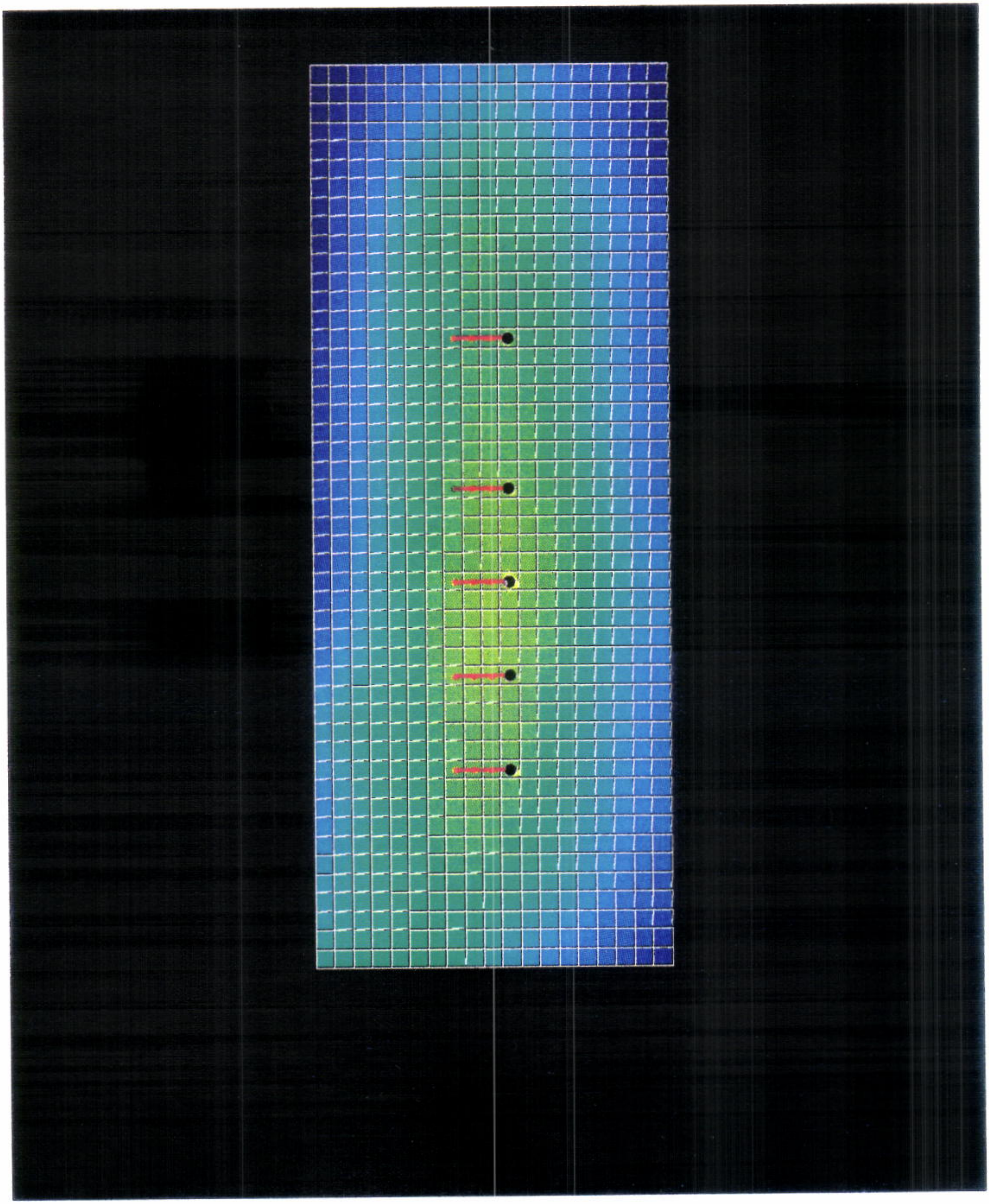
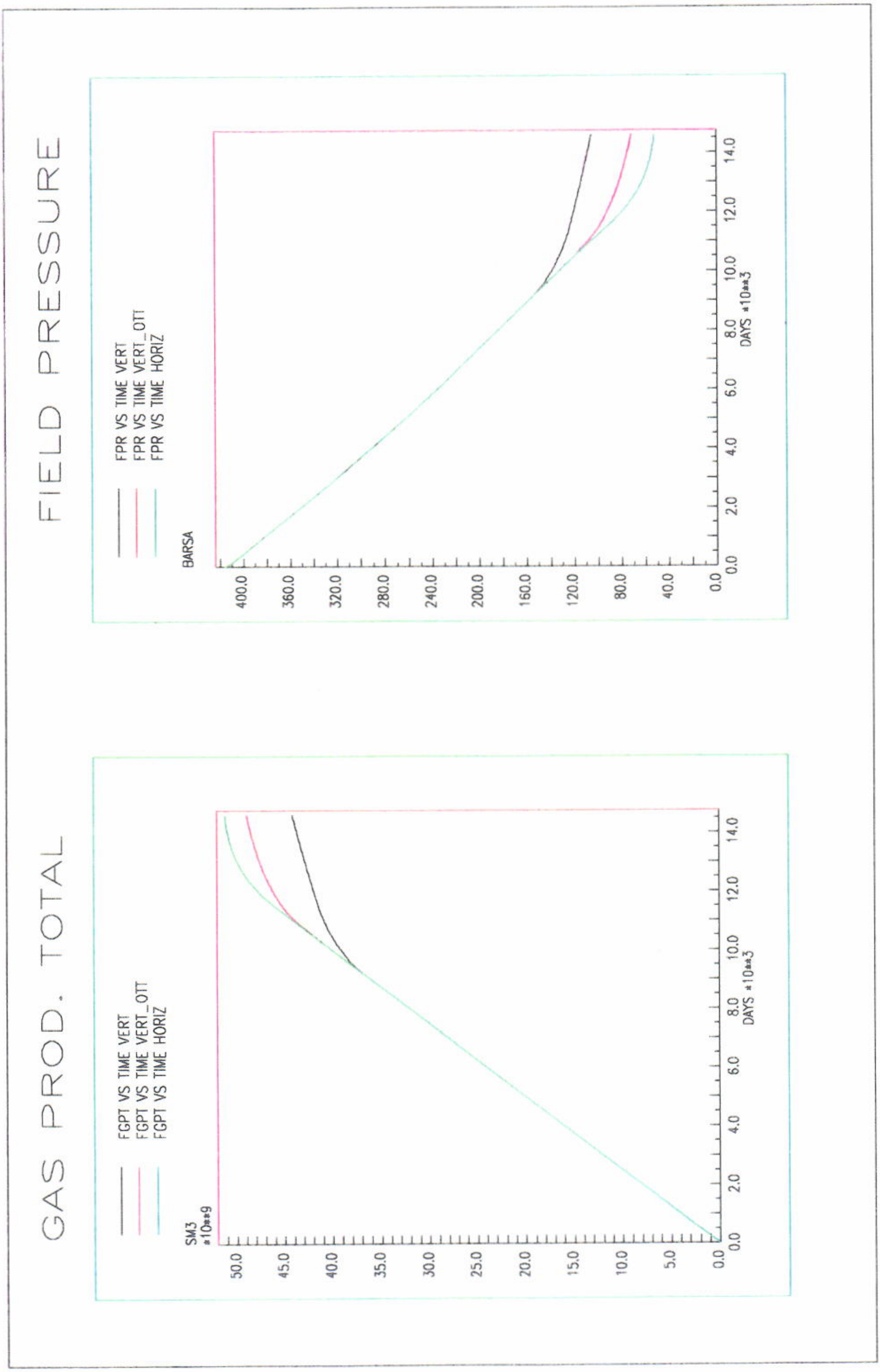
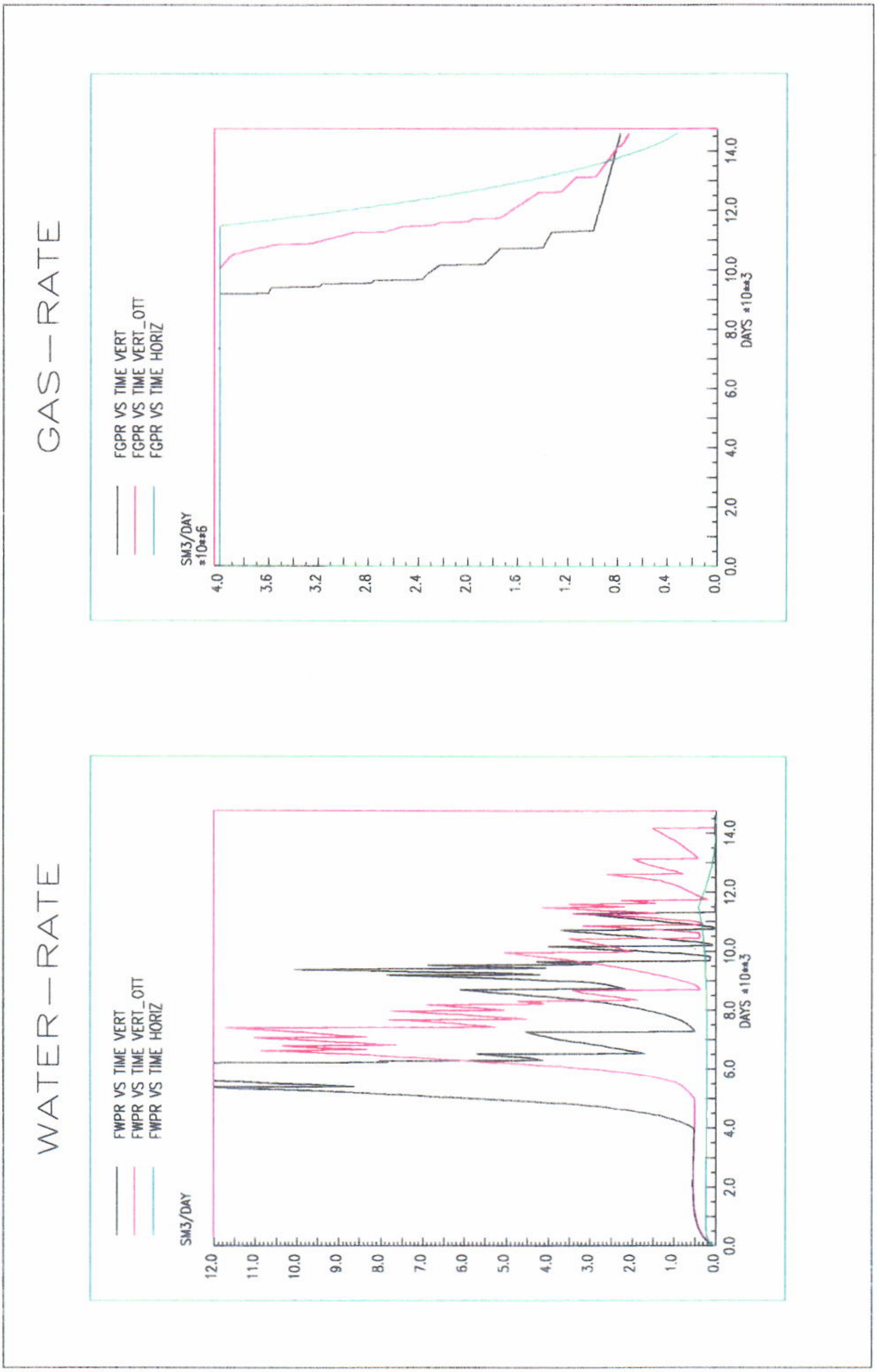


Fig. 17



GAS PROD. TOTAL
FGPT VS TIME VERT
FGPT VS TIME VERT_OTT
FGPT VS TIME HORIZ
SM3
*10**9
50.0
45.0
40.0
35.0
30.0
25.0
20.0
15.0
10.0
5.0
0.0
0.0
2.0
4.0
6.0
8.0
10.0
12.0
14.0
DAYS *10**3
FIELD PRESSURE
FPR VS TIME VERT
FPR VS TIME VERT_OTT
FPR VS TIME HORIZ
BARSA
400.0
360.0
320.0
280.0
240.0
200.0
160.0
120.0
80.0
40.0
0.0
0.0
2.0
4.0
6.0
8.0
10.0
12.0
14.0
DAYS *10**3

Fig. 18



GAS — RATE
FGPR VS TIME VERT
FGPR VS TIME VERT_OTT
FGPR VS TIME HORIZ
SM3/DAY *10**6
DAYS *10**3
WATER — RATE
FWPR VS TIME VERT
FWPR VS TIME VERT_OTT
FWPR VS TIME HORIZ
SM3/DAY
DAYS *10**3

WATER SATURATION SECTION YZ 10

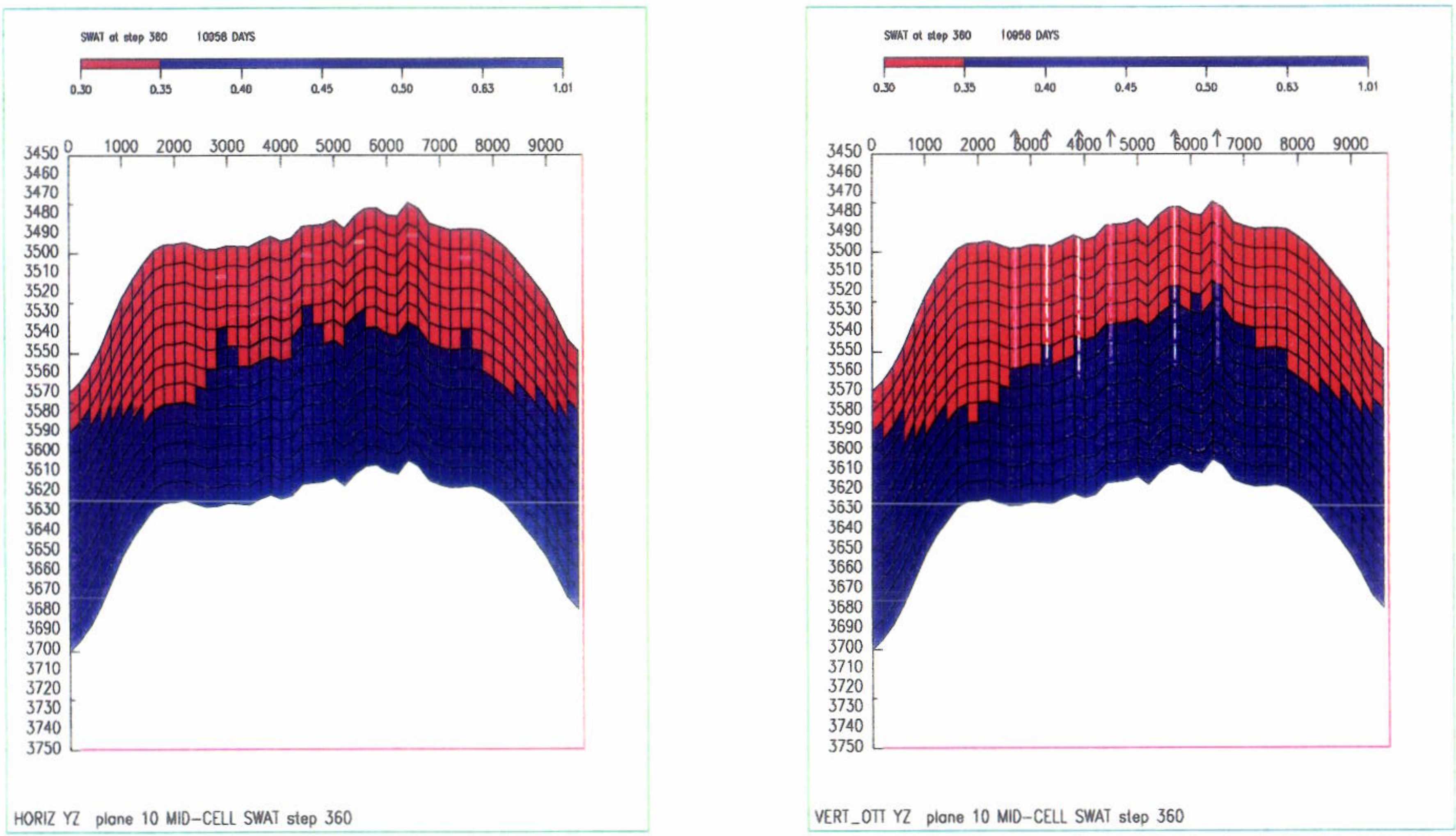
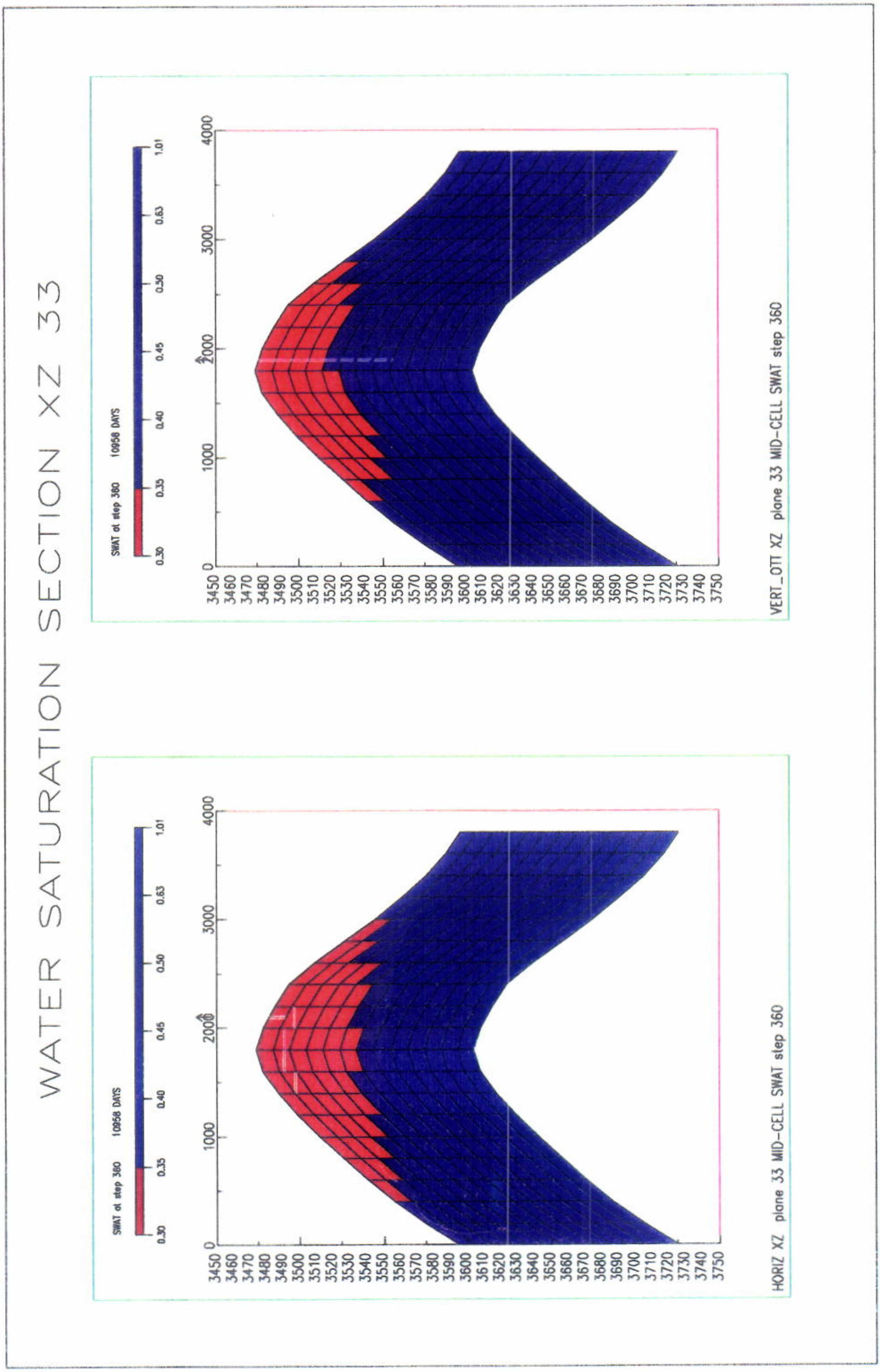


Fig. 19

Fig.20


WATER SATURATION SECTION XZ 33
SWAT at step 360 10958 DAYS
0.30
0.35
0.40
0.45
0.50
0.63
1.01
VERT_OTT XZ plane 33 MID-CELL SWAT step 360
HORIZ XZ plane 33 MID-CELL SWAT step 360

2.4 Sensitivity variation of Kz

In the case of homogeneous reservoir with bottom aquifer, it is evident that the use of horizontal wells minimises the risks of water production.
In the case of multi-layer reservoirs, the most important parameter to decide the exploitation scheme is vertical communication between the different levels. Thence vertical permeability is a fundamental parameter.
Thence, taking into account the same reservoir and using the exploitation scheme with conventional wells (scheme B) and horizontal wells (scheme C), situations with different vertical permeability values were simulated (figs. 21-22-23-24) :

- case 1) Kz = 0.0100 md
- case 2) Kz = 0.0025 md
- case 3) Kz = 0.0010 md
- case 4) Kz = 0.0006 md
- case 5) Kz = 0.0001 md

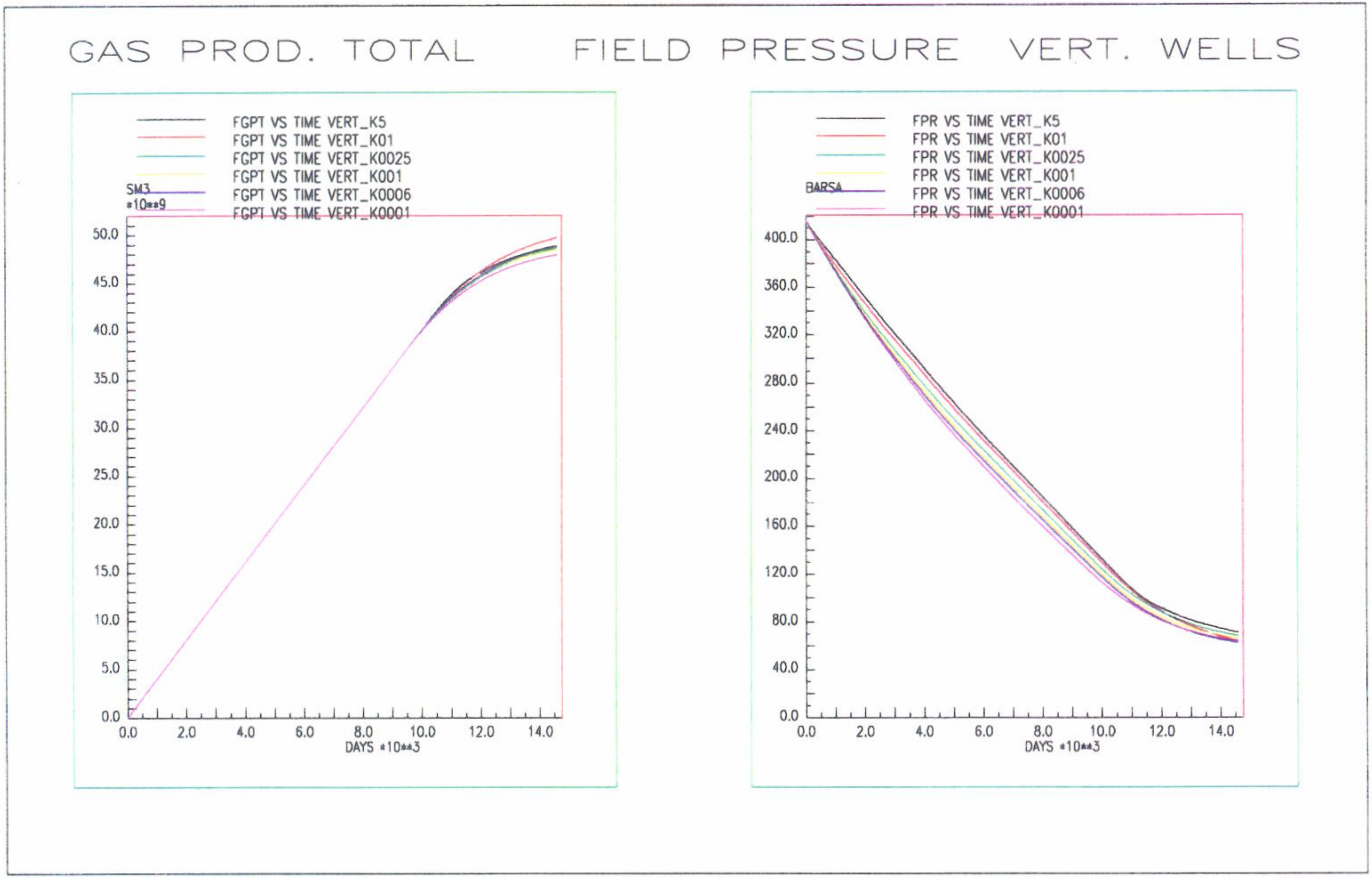
The following constraints were imposed for production and well control:

- production plateau at 4000000 Sm3/day for at least 25 years;
- control on well head pressure THP fixing a limit of 40 bar
- control on the well WGR at 0.00001 Sm3/Sm3 with water shut-off (if violated);

2.5 Production Profiles

	CONVENTIONAL WELLS		HORIZONTAL WELLS	
Kz (md)	PLATEAU years	RECOVERY@2038 E+9 Smc	PLATEAU years	RECOVERY@2038 E+9 Smc
0.0100	26.7	49.7	28.6	49.7
0.0025	25.8	48.7	25.7	47.7
0.0010	26.3	48.5	22.3	45.1
0.0006	25.9	48.7	19.6	42.8
0.0001	25.0	47.8	10.4	30.7

Fig.21



GAS PROD. TOTAL
FIELD PRESSURE VERT. WELLS
FGPT VS TIME VERT_K5
FGPT VS TIME VERT_K01
FGPT VS TIME VERT_K0025
FGPT VS TIME VERT_K001
FGPT VS TIME VERT_K0006
FGPT VS TIME VERT_K0001
SM3
*10**9
50.0
45.0
40.0
35.0
30.0
25.0
20.0
15.0
10.0
5.0
0.0
0.0
2.0
4.0
6.0
8.0
10.0
12.0
14.0
DAYS *10**3
FPR VS TIME VERT_K5
FPR VS TIME VERT_K01
FPR VS TIME VERT_K0025
FPR VS TIME VERT_K001
FPR VS TIME VERT_K0006
FPR VS TIME VERT_K0001
BARSA
400.0
360.0
320.0
280.0
240.0
200.0
160.0
120.0
80.0
40.0
0.0
0.0
2.0
4.0
6.0
8.0
10.0
12.0
14.0
DAYS *10**3

Fig.22

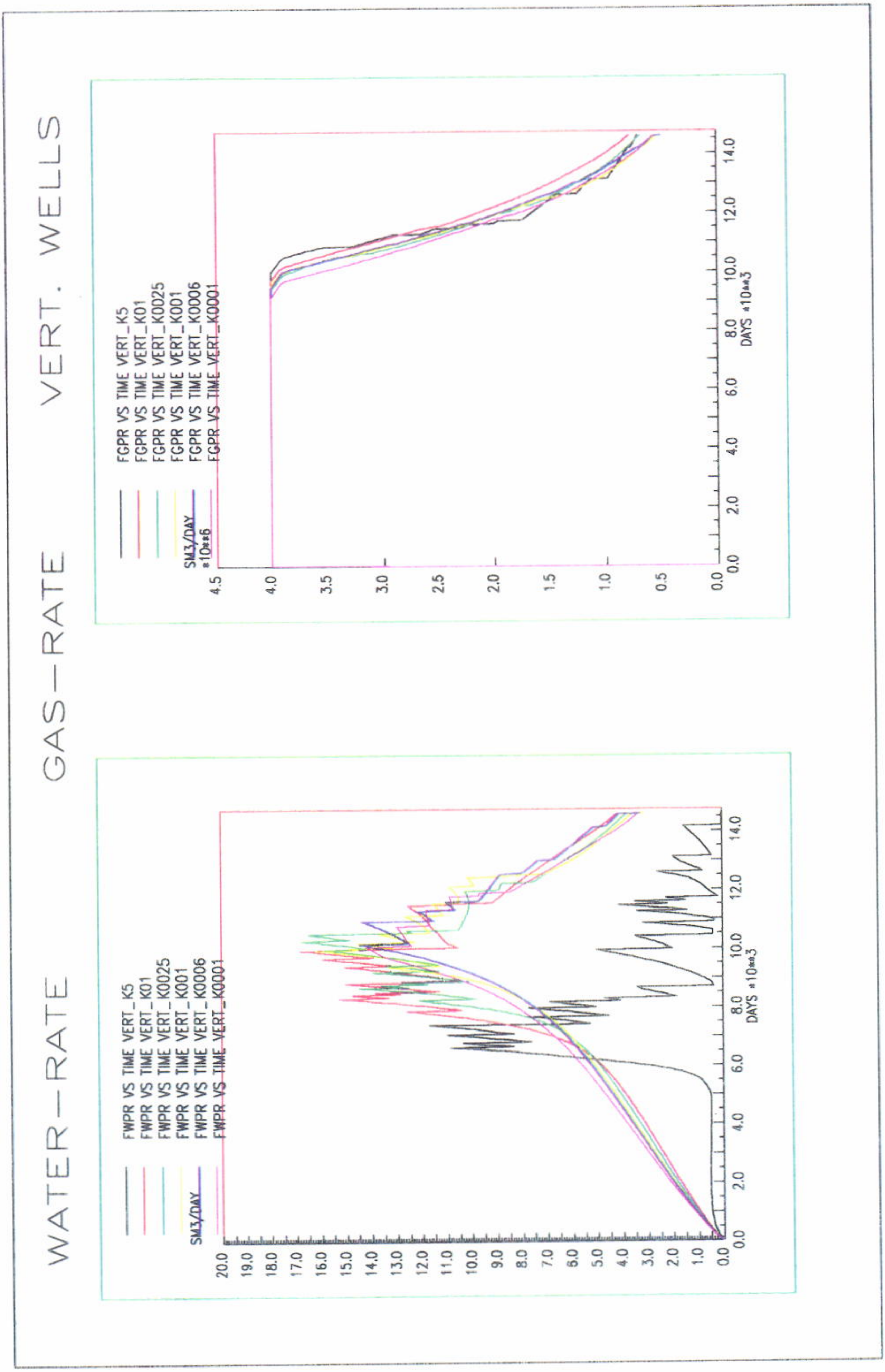
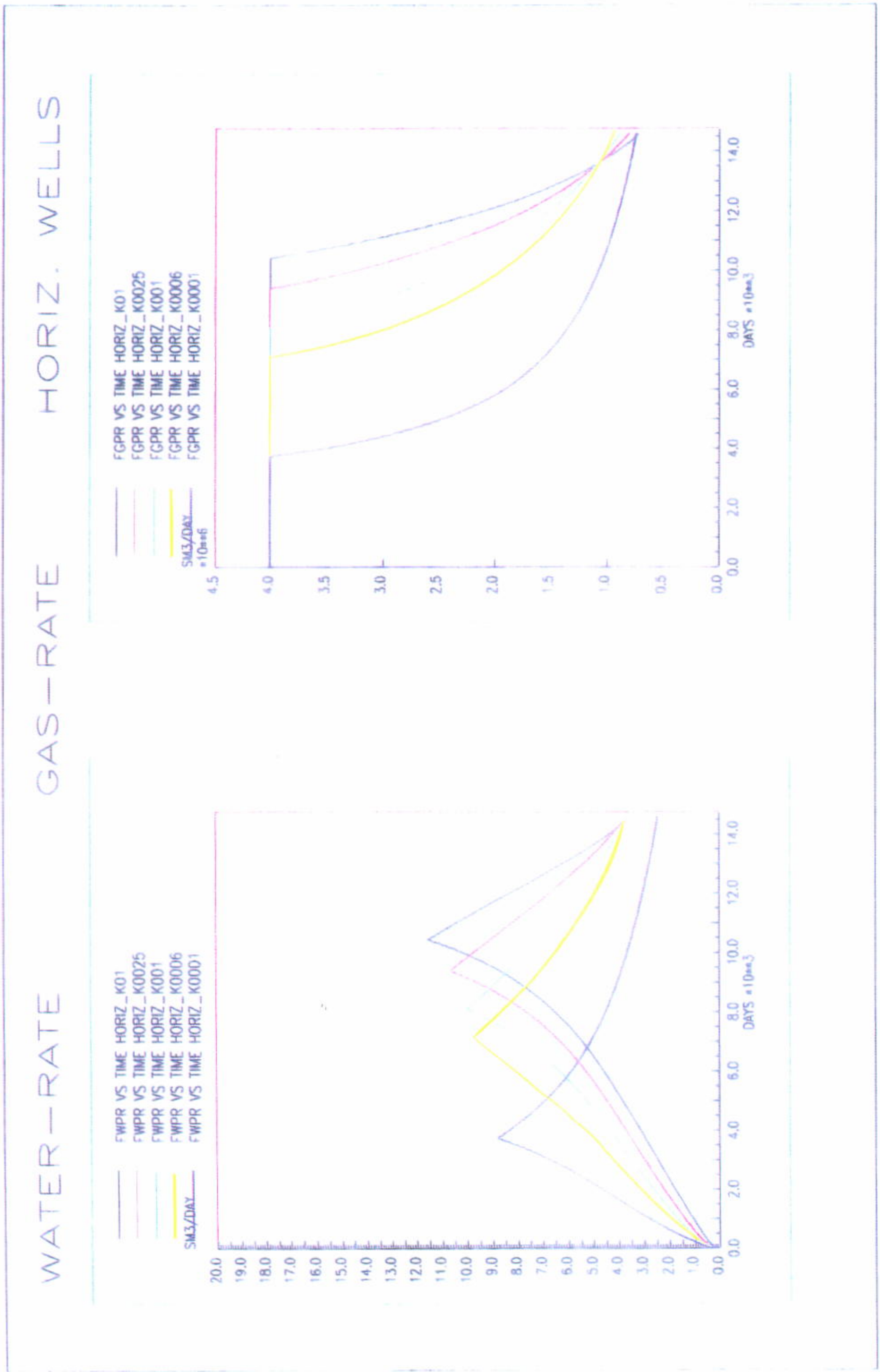

WATER-RATE
GAS-RATE
VERT. WELLS
FWPR VS TIME VERT_K5
FWPR VS TIME VERT_K01
FWPR VS TIME VERT_K0025
FWPR VS TIME VERT_K001
FWPR VS TIME VERT_K0006
FWPR VS TIME VERT_K0001
SM3/DAY
DAYS *10**3
FGPR VS TIME VERT_K5
FGPR VS TIME VERT_K01
FGPR VS TIME VERT_K0025
FGPR VS TIME VERT_K001
FGPR VS TIME VERT_K0006
FGPR VS TIME VERT_K0001
SM3/DAY
*10**6
DAYS *10**3

Fig.23


WATER—RATE
GAS—RATE
HORIZ. WELLS
FWPR VS TIME HORIZ_K01
FWPR VS TIME HORIZ_K0025
FWPR VS TIME HORIZ_K001
FWPR VS TIME HORIZ_K0006
FWPR VS TIME HORIZ_K0001
SM3/DAY
DAYS *10**3
FGPR VS TIME HORIZ_K01
FGPR VS TIME HORIZ_K0025
FGPR VS TIME HORIZ_K001
FGPR VS TIME HORIZ_K0006
FGPR VS TIME HORIZ_K0001
SM3/DAY
*10**6
DAYS *10**3

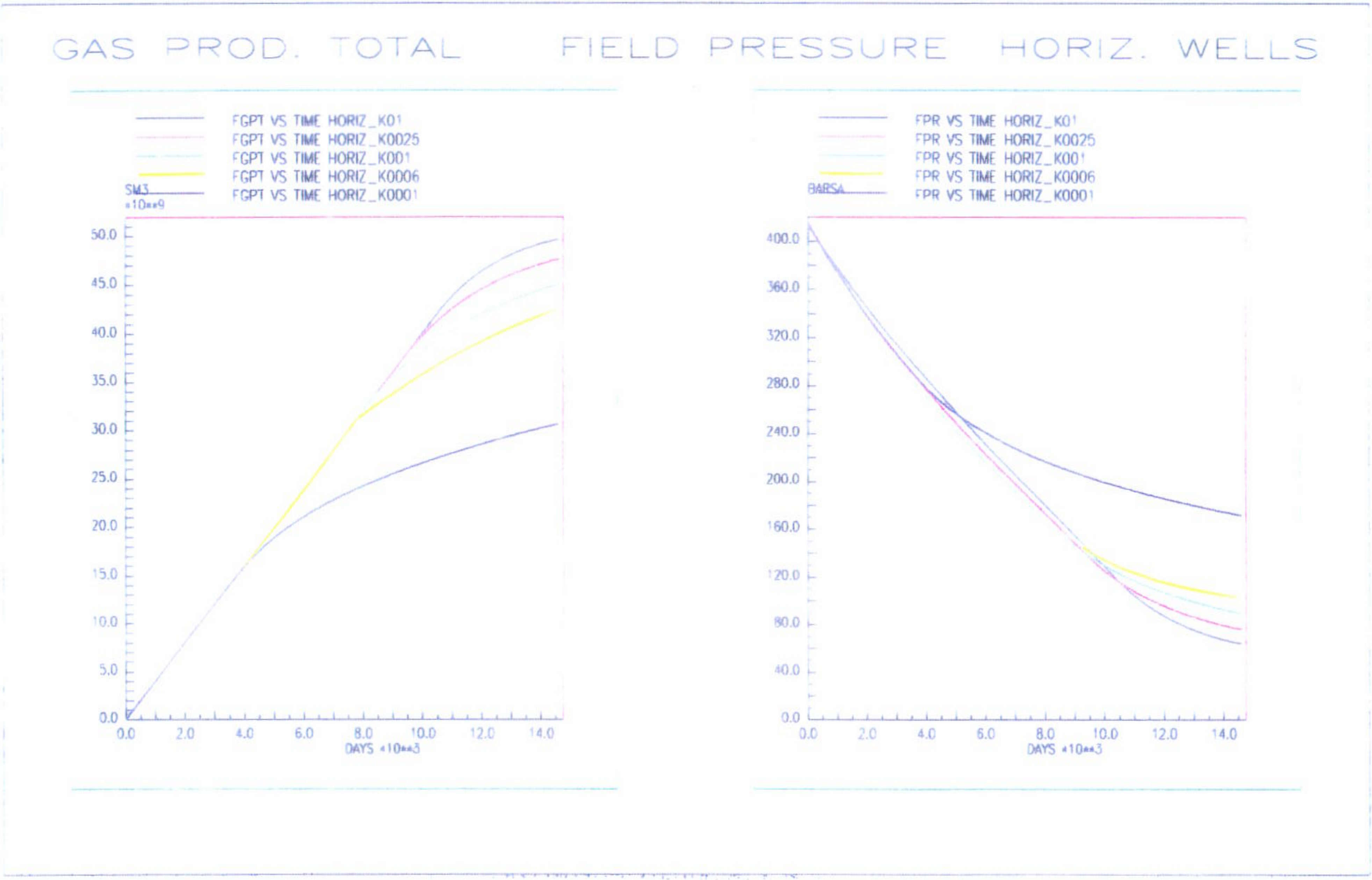

GAS PROD. TOTAL
FIELD PRESSURE
HORIZ. WELLS
FGPT VS TIME HORIZ_K01
FGPT VS TIME HORIZ_K0025
FGPT VS TIME HORIZ_K001
FGPT VS TIME HORIZ_K0006
FGPT VS TIME HORIZ_K0001
SM3 *10**9
50.0
45.0
40.0
35.0
30.0
25.0
20.0
15.0
10.0
5.0
0.0
0.0 2.0 4.0 6.0 8.0 10.0 12.0 14.0
DAYS *10**3
FPR VS TIME HORIZ_K01
FPR VS TIME HORIZ_K0025
FPR VS TIME HORIZ_K001
FPR VS TIME HORIZ_K0006
FPR VS TIME HORIZ_K0001
BARSA
400.0
360.0
320.0
280.0
240.0
200.0
160.0
120.0
80.0
40.0
0.0
0.0 2.0 4.0 6.0 8.0 10.0 12.0 14.0
DAYS *10**3

Fig.24