

THE USE OF WATER FLOODING TO IMPROVE OIL RECOVERY BY USING RESERVOIR SIMULATION

Kriangkrai Trisarn

Received: Apr 1, 2008; Revised: Jun 26, 2008; Accepted: Aug 25, 2008

Abstract

There are 18 oilfields in the northern, central parts and Gulf of Thailand which produce an optimal production rate of 130,000 barrels per day accounting for 20% of the consumption of Thailand. It is necessary to do reservoir simulation to determine the most suitable and efficient patterns for individual water flooding projects. The objectives of this study are: 1) to compile oil reservoir data in Thailand; 2) to model oil reservoirs using "Eclipse office" software; 3) to determine oil recoveries and return on investments by various methods including primary recovery, conventional water flooding, and bottom water injection. Three sizes of oilfields were modeled with the oil in place of 109, 29, and 5.8 million barrels respectively. Many producing and injecting well patterns were modeled using Eclipse Office in DMF office to run simulations in each oil field. The oil productions in primary recovery ranged from 20 - 23% with the present profit per investment ratio (PIR) of 0.50 - 0.62 respectively. The total oil production recovery with conventional water flooding was at 35 - 39% with the PIR of 0.50 - 0.88. For bottom water injection, the total oil recovery was at 40 - 48% with the PIR of 0.53 - 1.25. The conclusion was that the bottom water injection method increased oil production and profits more than conventional water flooding and the primary recovery method.

Keywords: Water flooding, oil, recovery, improvement, simulation

Introduction

Petroleum is the most important energy source for social and economic development in Thailand. It is utilized in many sectors such as communications, industries, agriculture, and power generation, etc. Daily oil consumption in Thailand is about 800,000 barrels of which more than 700,000 barrels need to be imported while only 130,000 barrels is from indigenous production. Today, 18 oilfields are in production such as Sirikit and Bechamas oilfields, etc. Some of these oilfields have been producing oil

for many years and production which used the primary recovery method has started to decline. In order to maintain or increase the production rate, some companies are using water flooding, which is called secondary recovery. Water flooding is the most preferable method to improve oil recovery because it is simple and inexpensive. Reservoir simulation is a powerful and inexpensive tool, which can predict what is going on in the reservoir and the amount of production from alternative operations.

School of Geotechnology, Institute of Engineering, Suranaree University of Technology, Muang District, Nakhon Ratchasima, 30000 Thailand. Tel.: 0-4422-4310; Fax.: 0-4422-4611; E-mail: kriangkr@sut.ac.th

Reservoir simulation is necessary to find the most efficient water flooding pattern for an individual project. The bottom water injection method will give the most oil recovery because it yields highest displacement efficiency due to water-oil gravity segregation. The objectives of this study are: 1) to compile oil reservoirs data in Thailand; 2) to model oil reservoirs in computer using “Eclipse office” software; 3) to determine the improvement of oil recoveries and return on investments by various methods including primary recovery, conventional water flooding, and bottom water injection.

Methodology

Laboratory Experiment and Analysis

More than 30 tertiary rock samples were collected for random analyses from many areas in the central and northern parts of Thailand. The porosity and permeability were measured at the values of 1.2 - 36.6% with an average of 17% and 0.0002 to 51.38 md (millidarcies) with an average of 5.2 md. The porosity and permeability obtained from PTTEP Company are 11 - 23% and 0.1 - 500 md for the Uthong oil field and 12 - 30% and 1 - 1,000 md for Sirikit oil fields respectively.

Reservoir Simulation Model Development

Three sizes of reservoir simulation models of 109, 29, and 6 MMSTB oil in place were developed by utilizing “Eclipse Office” software. The details of each model are discussed as follows.

(1) SUT 1 Model

This model covers an area of 900 acres (39,000,000 ft²), contains 8 layers, 625 cells/layer, up to a total of 5,000 cells (Grid Blocks). The oil in place is about 109 MMSTB. The layers are separated by different porosity and permeability ranging from 19 - 26% and 9.2 - 586 md from the bottom to the top of the reservoir. There are 25 initial producing wells and some producing wells will turn to injection wells (IP wells) later as shown in Figure 1.

(2) SUT 2 Model

This model covers an area of 210 acres (9,000,000 ft²), contains 8 layers, 625 cells/layer, up to a total of 5,000 cells (Grid Blocks). The oil in place is about 29 MMSTB. The layers are separated by different porosity and permeability ranging from 18 - 25% and 30 - 100 md from the bottom to the top of the reservoir. There are 9 initial producing wells and some producing wells will turn to injection wells (EP wells) later as shown in Figure 2.

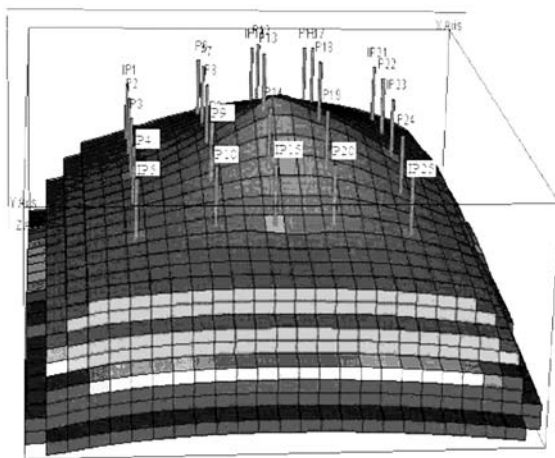


Figure 1. SUT 1 model

(3) SUT 3 Model

This model covers an area of 360 acres (15,681,600 ft²), contains 8 layers, 400 cells/layer, up to a total of 3,200 cells (Grid Blocks) (Figure 3). The oil in place is about 5.8 MMSTB. The layers are separated by different porosity and permeability ranging from 18 - 25% and 30 - 100 md from the bottom to the top of the reservoir. There are 6 initial producing wells (P wells) and after three years of production two water injection wells (W wells) will be added.

Reservoir Simulation Input Data

The input data for each model were collected and obtained from a review of concessionaire results, laboratory measurement, and from assumptions. Many sets of input data were input into the models, however only one set of data for SUT 1 model will be illustrated in this paper as follows.

(a) Fluid properties

°API oil gravity = 39.4°API

Solution gas gravity = 0.8

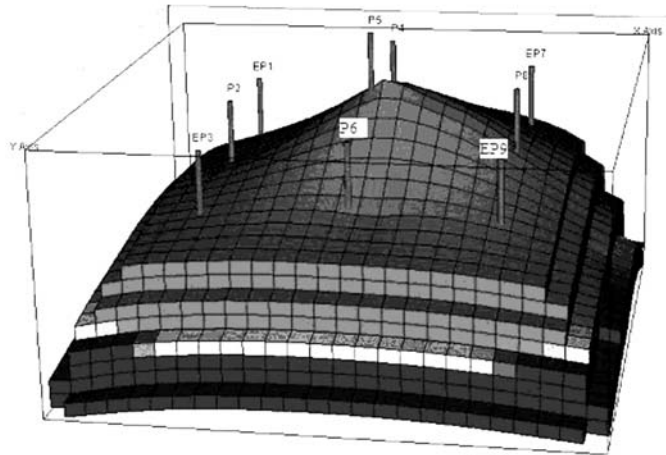


Figure 2. SUT 2 model

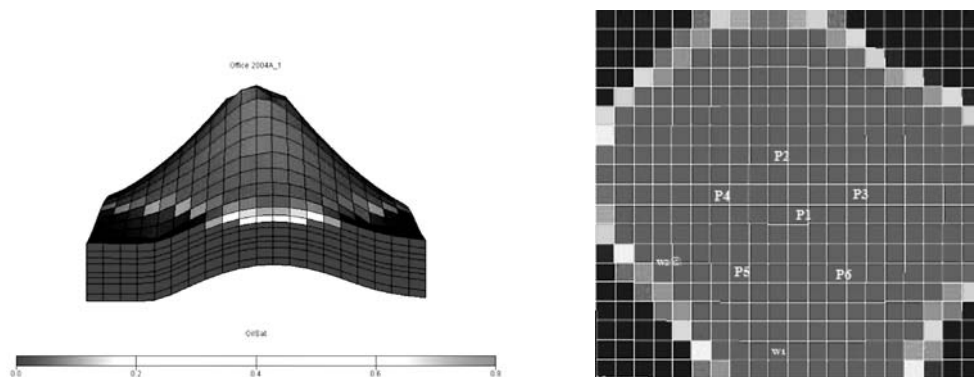


Figure 3. SUT 3 model

Water density = 62.428 lb/cu.ft. Water compressibility @ 3,500 psi = 3.081×10^{-6} psi⁻¹

Water viscosity = 0.296 cp

Oil formation volume factor = 1.055 - 1.286 bbl/STB

Solution gas oil ratio = 0.001 - 0.482 MSCF/STB

Oil viscosity = 2.1 - 6.7 cp

Gas viscosity = 0.013 - 0.024 cp

And other calculated fluid properties were obtained from built in software of Eclipse Office software.

(b) Rock properties

Porosity = 19 - 26%

Permeability = 9.2 - 586 md

$k_v = k_h$ for bottom water injection cases

$k_v = 0.1k_h$ for conventional (edge) water injection cases

(c) Reservoir properties

Depth Oil-Water contact = 3,915 ft

Initial reservoir pressure @ 3,850 ft = 3,500 psia

Bubble point pressure = 1,800 psia

Reservoir temperature = 203°F

The relative permeability is generated by Eclipse.

Simulation Patterns

Many producing and injecting wells patterns were run for each model as follows.

(a) SUT 1 Model (109 MMSTB oil in place)

Pattern 1: There are 25 oil producing wells for 25 years of production (only primary recovery).

Pattern 2: There are 25 oil producing wells initially and later 8 wells will be converted to water injection wells (Figure 1).

Pattern 3: There are 25 oil producing wells initially and later 9 wells will be converted to water injection wells.

(b) SUT 2 Model (29 MMSTB oil in place)

Pattern 1: There are 9 oil producing wells, no water injection (only primary recovery)

Pattern 2: There are 9 oil producing wells initially, then 4 wells will be converted to water

injection wells (Figure 2).

(c) SUT 3 Model (5.8 MMSTB oil in place)

Pattern 1: There are 6 oil producing wells, no water injection (only primary recovery)

Pattern 2: There are 6 oil producing wells initially, then 2 water injection wells will be added after three years of production (Figure 3).

Results and Discussion

The results of some pattern simulations are listed in Table 1, and all pattern simulation results are reported in the author's full research report.

A brief discussion follows.

(1) The primary recovery methods such as SUT 1 Model LKB Noinj, SUT2 Model SP Noinj, and SUT3 SUT Noinj yielded oil recovery of 20 - 23%.

(2) The early conventional (edge) water flooding (2 - 4 years after the production started) methods such as SUT 1 Model LKB Inj8 2yr, SUT 2 Model SP Inj4 4yr, and SUT 3 SUT Inj2 3yr, etc., yielded oil recovery of 35 - 39%.

(3) The bottom water injection methods such as SUT 1 Model LKB Inj8 2yr BWD, SUT 2 Model SP Inj4 4yr BWD, and SUT 3 SUT Inj2 3yr BWD, etc., yielded oil recovery of 40 - 48%.

(4) The oil production and water injection rates for each case resulted from trial and error to obtain the optimal recovery.

The earlier water injection is used (after starting oil production) the more oil recovery there is, because of the reservoir pressure is still high allowing more oil displacement efficiency. The time when the reservoir pressure drops close to the bubble point pressure should be the suitable injecting time. The suitable number and location of injectors will yield the optimal recovery, which can be obtained by trial and error. The bottom water flood yields most recovery due to the higher specific gravity of water than oil displacing from the bottom yields higher displacement efficiency. Two sets of simulation results are illustrated below namely SUT 1 Model Pattern LKB Noinj and SUT 1 Model Pattern Model LKB Inj8 2yr BWD.

SUT 1 Model Pattern 1 (No water injection). The following graphs show

a. Fluid production rate vs. Time plot (Figure 4).

b. Cumulative fluid production vs. Time plot (Figure 5)

The oil production rate was maintained at the rate of 10,000 barrels/day for four years then declined and ended at the rate of 308 barrels/

day (Figure 4).

The cumulative oil production is 25.4 million barrels at the end of the 25th year of production with the recovery of 23.3% of original oil in place (Figure 5).

SUT 1: Model Pattern 2.1b (LKB Inj8 2yr BWD Bottom water flooding injection started at

Table1. A summary of the simulation results

Model	Pattern	Water flooding style	Number of oil producing wells before/after water injection	Number of water injecting wells	Year of starting water injection	Total oil production (barrels)	Oil recovery (%)
	LKB Noinj		25/25	0		25,438,270	0.23
SUT 1	LKB Inj8 2yr	Conventional	25/17	8	2	42,911,256	0.39
Model	LKB Inj8 2yr BWD	Bottom	25/17	8	2	52,563,296	0.48
109 mmstb	LKB Inj8 4yr	Conventional	25/17	8	4	41,981,916	0.38
Oil in place	LKB Inj8 4yr BWD	Bottom	25/17	8	4	52,503,728	0.48
	LKB Inj8 8yr	Conventional	25/17	8	8	38,664,156	0.35
	LKB Inj8 8yr BWD	Bottom	25/17	8	8	43,385,244	0.40
	LKB Inj9 4yr	Conventional	25/9	9	4	42,085,068	0.39
	LKB Inj9 4yr BWD	Bottom	25/9	9	4	52,283,176	0.48
SUT 2	SP Noinj		9/9	0		5,725,796	0.20
Model	SP Inj4 4yr	Conventional	9/5	4	4	10,866,865	0.37
29 MMSTB	SP Inj4 4yr BWD	Bottom	9/5	4	4	13,670,438	0.47
SUT3	SUT Noinj		6/6	0		1,520,000	0.22
5.8MMSTB	SUT Inj2 3yr BWD	Bottom	6/6	2	3	3,080,000	0.45

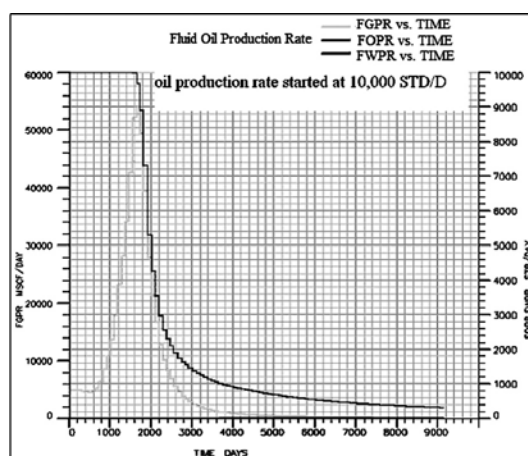


Figure 4. Model pattern 1 LKB Noinj fluid production rate vs. time

the third year of oil production in 8 injection wells). The results are shown in the following graphs.

a. Fluid production rate vs. Time plot (Figure 6)

b. Cumulative fluid production vs. Time plot (Figure 7)

The oil production rate was maintained at the rate of 7,500 barrels/day for thirteen years then declined and ended at the rate of 2,900

barrels/day (Figure 6).

The cumulative oil production is 52.6 million barrels at the end of the 25th year of production with the recovery of 48.2% of original oil in place (Figure 7).

Economic Analysis

The objective of an economic analysis is to study the commerciality of each pattern which

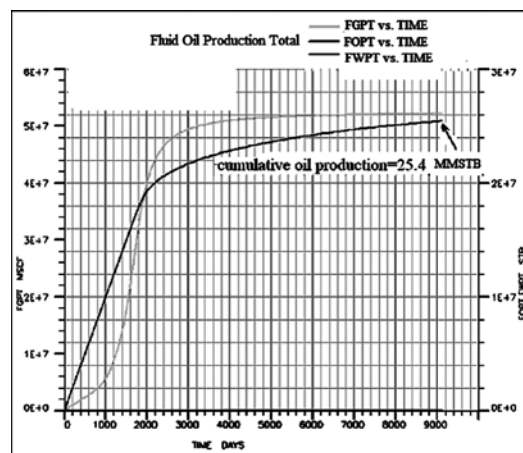


Figure 5. Model pattern 1 LKB Noinj cumulative fluid production rate vs. time

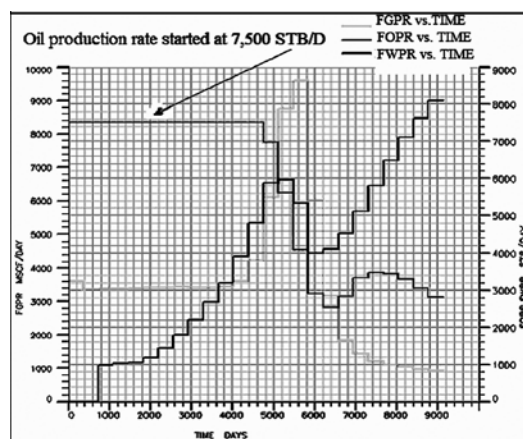


Figure 6. Model pattern 2 LKU Inj8 2yr BWD fluid production rate vs. time

results from reservoir simulation. The analysis includes

1. Cash flow in-out
2. Internal rate of return (IRR) and net present value (NPV) of each project
3. Return on investment period (Pay out period)
4. Net profit and Taxes
5. Internal rate of return and net present profit per investment comparison

The Excel program was developed to carry out an economic analysis based on the following regulations and assumptions.

- Oil price 80 US\$/STB

- **Capital investment**

1. Concession application

- Big reservoir 150 MMB
- Medium 100 MMB

2. Geological & Geophysical Exploration

- Big size 200 MMB
- Medium size 150 MMB

3. Exploratory and Appraisal wells

- Big size 420 MMB
- Medium size 240 MMB

4. Production wells

- Big size 60 MMB/well
- Small-Medium 40 MMB/well

5. Production Facilities

- Big size 10000 MMB
- Medium size 2000 MMB

6. Production Cost 600 B/STB (Lifting Cost)

7. Water Injection Cost

- Facilities 2 MMB/well
- Well Completion & Conversion 0.2 MMB/well
- Facility Maintenance
Big size 2.4 MMB/year
Small size 1.2 MMB/year
- Water Injection Cost 10 B/bbl

8. Exchange Rate 35 B/US Dollar

9. Discounted Rate (Interest Rate) 8%

- Escalation 2%

10. Sliding Scale of Royalties

(Production Level) (Rate)(%)

0 – 2,000 BPD 5.00

2,000 – 5,000 BPD 6.25

5,000 – 10,000 BPD 10.00

10,000-20,000 BPD 12.50

> 20,000 BPD 15.00

11 Income Tax 50%

Many different sized models and patterns were analyzed for a comparison of economic

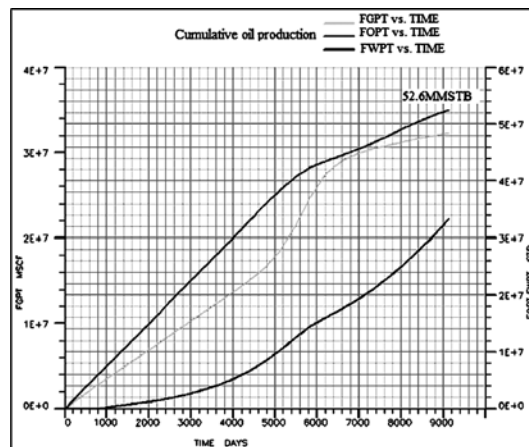


Figure 7. Model pattern 2 LKU Inj8 2yr BWD cumulative fluid production vs. time

expectations. Some examples are shown in Table 2. However, the analysis leads to the following conclusions. For primary recovery only, the internal rate of return (IRR) after tax and 8% discounted ranges between 25 - 46% with net present value profit per investment ratio of 0.50 - 0.62 from small to large oil fields. If the conventional water flooding is included, the IRR becomes 14 - 37% with net present value profit per investment ratio of 0.50 - 0.62, while the bottom water injection earns IRR of 14 - 37% with net present value profit per investment ratio of 0.53 - 1.25. The net present value profit after tax of the project including water flooding will be 1.1 - 1.8 times that of the project which is produced using only primary recovery. Some of the economic results are presented in Table 2.

Conclusions

Reservoir simulation is a powerful tool to predict reservoir performance in many operational options, especially in water flooding projects. The most efficient and suitable water flooding pattern for individual projects can be

achieved by reservoir simulation. In this study, the oil recovery from primary recovery only ranged from small to large oil fields with a size of 20 - 23% of the size of the original oil in place, when including water flooding the oil recovery increased to 35 - 48%. The bottom water flood yields most recovery due to the higher specific gravity of water yields higher oil displacement efficiency by displacing up from the bottom. The earlier water injection is used (after starting oil production) the more oil recovery there is, because of the reservoir pressure is still high allowing more oil displacement efficiency. The internal rate of return of the water flooding project seems to be less compared to the primary oil recovery alone, but the net present value profit and net present value profit/investment ratio will be higher in water injection projects. When primary production has been underway for some time, converting suitable producing wells to water injection wells at a suitable time might cost less money and earn considerable profits. More studies are needed using trial and error to get the best fit for individual water flooding projects.

Table 2. Economic analysis summary

Producing Patterns	Total Oil production (bbl)	Recovery Factor	Profit after Income tax (8% Discount) (Million Baht)	Internal Rate Of Return After income tax (8% Discount)	PIR	Remark	
					Net present value profit per Investment ratio (8% Discount)	Water Injection Rate : I_w (bbl/d)	Oil Production Rate : Q_o (bbl/d)
LKB Noinj	25,438,270	0.23	7,632	46.28%	0.62	-	10,000
LKB Inj8 2yr	42,911,256	0.39	10,768	36.24%	0.88	10,000	7,500
LKB Inj8 2yr BWD	52,563,296	0.48	12,601	36.91%	1.03	10,000	7,500
LKB Inj8 4yr	41,981,916	0.38	9,390	28.53%	0.77	10,000	6,250
LKB Inj8 4yr BWD	52,503,728	0.48	10,595	28.59%	0.86	10,000	6,250
LKB Inj8 8yr	38,664,156	0.35	6,136	13.54%	0.50	10,000	3,750
LKB Inj8 8yr BWD	43,385,244	0.40	6,472	13.53%	0.53	10,000	3,750
LKB Inj9 4yr	42,085,068	0.39	7,366	26.59%	0.60	10,000	6,250
LKB Inj9 4yr BWD	52,283,176	0.48	8,259	26.74%	0.67	10,000	6,250
SP Noinj	5,725,796	0.20	1,502	33.80%	0.50	-	3,950
SP Inj4 4yr	10,866,865	0.37	2,486	33.56%	0.82	3,200	3,950
SP Inj4 4yr BWD	13,670,438	0.47	2,697	28.09%	0.89	3,200	3,950
SUT Noinj	1,520,000	0.22	547	24.87%	0.54	-	1,200
SUT Inj2 3yr BWD	3,080,000	0.45	1,273	35.33%	1.25	1,500-1,200	1,200

Acknowledgement

I am grateful to Suranaree University of Technology for granting the budget for this research, and to all SUT personnel who supported the study, especially Mr. Chetha and Mr. Narin, who ran reservoir simulations.

The author would like to thank DMF (Department of Mineral Fuel) and personnel for supporting data and the software "Eclipse Office". I would also like to thank the concessionaires who were very kind in providing the necessary data and support.

References

- Aziz, A. Kadir, A., Hamid, M.F., and Ikhan, A. (1995). Permeability prediction: core and log-derived values. *Proceedings of International Conference on Geology, Geotechnology and Mineral Resources of Indochina (Geo-Indo'95)*; Nov 22-25, 1995, Khon Kaen, Thailand, p. 609-617.
- Barber, Jr. A.H., Stile, L.H., and Thompson, B.B. (1983). Infill drilling to increase reserves actual experience in nine fields in Texas, Oklahoma, and Illinois. *JPT.*, 35:1,530-1,538.
- Chapman, L.R. and Thompson, R.R. (1989). Waterflood surveillance in Kuparak river unit with computerized pattern analysis. *JPT.*, 41:277-282.
- Chrichlow, H.B. (1977). *Modern Reservoir Engineering - A Simulation Approach*. 1st ed. Prentice-Hall, Eaglewood Cliffs, New Jersey, 235p.
- DesBrisay, C.L. (1972). Supplemental recovery development of the intisar "A" and "D" reef fields. *Libyan Arab Republic. JPT.*, 24:785-796.
- Franchi, J.R. (1997). *Principles of Applied Reservoir Simulation*. 1st ed. Gulf Publishing Company, Houston, Texas, 294p.
- Franchi, J.R. (2000). *Integrated Flow Modeling*. 1st ed. Elsevier, Netherlands, 350p.
- Ghauri, W.K. (1980). Production technology experience in a large carbonate waterflood. *Denver Unit, Wasson San Andres Field. JPT.*, 32:1,493-1,502.
- Graves, K.S., Valentine, A.V., Dolma, M.A., and Morton, E.K. (2001). Design and implementation of horizontal injector program for the Benchamas waterflood -gulf of Thailand. In *CD of The 6th Mining, Metallurgical, and Petroleum Engineering Conference*; Oct 24-25, 2001; Bangkok, p.1-18.
- Harpole, K.J. (1980). Improved reservoir characterization - A key to future reservoir management for the West Seminole San Andres Unit. *JPT.*, 32: 2,009-2,019.
- Irwin, R.A., Tucker, C.W., and Jr. H.E. (1972). A case history of the postle area - computer production control and reservoir simulation. *JPT.*, 24: 775-781.
- Mattax, C.C. and Dalton, R.L. (1990). *Reservoir Simulation*. 1st ed. Monograph 13 SPE. Series. Society of Petroleum Engineers, Richardson, TX, 173p.
- Nicholls, C.A., Boom, W., Geel, J., Khodori, S.A., and Lawati, M.A. (1999). Fracture modeling as a key to waterflood development. Paper SPE 53211 presented at the 1999 SPE Middle East Oil Show, Bahrain, p. 1-15.
- Smith, J.T. and Cobb, W.M. (1997). Predicting Waterflood Recovery Performance. Based on a Workshop Sponsored by PTTC's Midwest Region on Feb 17-21, 1997, Evansville, IN., p. 1-25.

