A SIMULATION STUDY OF STEAM AND STEAM-PROPANE INJECTION USING A NOVEL SMART HORIZONTAL PRODUCER TO ENHANCE OIL PRODUCTION

A Thesis

by

JORGE EDUARDO SANDOVAL MUÑOZ

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

August 2004

Major Subject: Petroleum Engineering

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Approved as to style and content by:

Daulat D. Mamora (Chair of Committee)	Akhil Datta-Gupta (Member)
Luc T. Ikelle (Member)	Stephen A. Holditch (Head of Department)

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ABSTRACT

A Simulation Study of Steam and Steam-Propane Injection Using a Novel Smart Horizontal Producer to Enhance Oil Production. (August 2004)

Jorge Eduardo Sandoval Muñoz, B.S., Universidad Industrial de Santander

Chair of Advisory Committee: Dr. Daulat D. Mamora

A 3D 8-component thermal compositional simulation study has been performed to evaluate the merits of steam-propane injection and a novel vertical-smart horizontal well system for the Lombardi reservoir in the San Ardo field, California. The novel well system consists of a vertical steam injector and a horizontal producer, whose horizontal section is fully open initially, and after steam breakthrough, only one-third (heel-end) is kept open.

A 16x16x20 Cartesian model was used that represented a quarter of a typical 10-acre 9-spot inverted steamflood pattern in the field. The prediction cases studied assume prior natural depletion to reservoir pressure of about 415 psia. Main results of the simulation study may be summarized as follows.

First, under steam injection, oil recovery is significantly higher with the novel vertical-smart horizontal well system (45.5-58.7% OOIP at 150-300 BPDCWE) compared to the vertical well system (33.6-32.2% OOIP at 150-300 BPDCWE). Second, oil recovery increases with steam injection rate in the vertical-smart horizontal well system but appears to reach a maximum at about 150 BPDCWE in the vertical well system (due to severe bypassing of oil). Third, under steam-propane injection, oil recovery for the vertical-smart horizontal well system increases to 46.1% OOIP at 150 BPDCWE but decreases to 51.6% OOIP at 300 PDCWE due to earlier steam breakthrough that resulted in reduced sweep efficiency. Fourth, for the vertical well system, steam-propane injection results in an increase of oil recovery to 35.4-32.6% OOIP at 150-300 BPDCWE. Fifth, with steam-propane injection, for both well systems, oil production acceleration increases with lower injection rates. Sixth, the second oil

production peak in the vertical-smart horizontal well system is accelerated by 24-50% in time for 150-300 BPDCWE compared to that with pure steam injection.

DEDICATION

To God and my family.

ACKNOWLEDGEMENTS

I wish to express my gratitude to Dr. Daulat D. Mamora, chair of my advisory committee, for his help and support.

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TABLE OF CONTENTS

LIST OF FIGURES

Page

Page

Page

Page

LIST OF TABLES

CHAPTER I

INTRODUCTION

Thermal recovery methods, even though their application may have peaked in the United States, will continue growing elsewhere in the world, where massive heavy oil and tar sands are found and where environmental restrictions may not be as severe as those in the United States. As the world's conventional oil production starts to decline within 30 years, attention will be focused on the large quantities of heavy oil and tar sands, much of which can only be produced by thermal methods.[1]

Heavy oil resources are abundant. In fact, heavy and extra heavy oil resources are estimated to be more than 2.5 trillion STB. The vast resources of the Orinoco and Canada extra heavy oil or bitumen regions are well documented, and offer large targets for in-situ and surface development techniques. Potential recoverable heavy and extra-heavy is projected to be 856 MMSTB with current technology. There is no shortage of heavy and extra heavy oil in the world today. The challenge is how to produce this resource profitably, an energy resource that will play a large role in our future. [2]

The understanding of most early thermal recovery operators was limited to the concept of "heat reduces heavy oil viscosity, and reduced viscosity means more production." Steam injection was attempted in almost any reservoir having viscous oil with little appreciation of other recovery process considerations. Although several early pilot projects were steamfloods, most early applications were cyclic stimulations. During the late 1970's, steamflooding became predominant, and many people considered steamflooding to be a displacement process (hence the term "steam drive"). With this paradigm and high oil prices, there was little impetus to understand efficient use of heat.

The predominant philosophy was "If you want more oil, inject more steam." With the later collapse of oil prices, operators returned to review process fundamentals and to determine how to more efficiently operate steam projects.[3]

This thesis follows the style and format of the *Journal of Petroleum Technology.*

Oil production from thermal operations has remained stable in most of the mature producing areas through technological advances. Heat management has improved through the use of thermal analytical models, simulation software, and the combination of the two technologies. Comprehensive steamflood surveillance programs are an integral part of all highly efficient thermal projects.

There are two forms of steam injections, namely, steamflooding or steam drive, and cyclic steam injection also known as huff-and-puff. In steamflooding, steam is continuously injected into fixed well patterns of injection wells, while fluids are produced in designated wells. When steam is injected into a reservoir, the resulting phase distribution forms five distinct zones. The first zone -nearest to the injector- corresponds to the steam zone, where water in liquid and vapor phase and mainly residual oil are present. The light fractions of the oil are vaporized and condense ahead of the steam front creating a solvent bank, which comprises the second zone. The solvent bank is miscible with the oil, thereby reducing its interfacial tension and viscosity. The third zone consists of the hot water zone where steam and volatile oil condense upon contact with the cooler matrix. As a result of oil viscosity reduction and displacement in the first three zones, an oil bank (fourth zone) is formed. The fifth zone (farthest away from the injector) is composed of original oil.

In cyclic steam injection, the primary objective is to provide thermal energy in the vicinity of the wellbore, using the steam as the heat transport medium and allowing the rock to act as a heat exchanger for storage of the injected energy. This heat may then be used effectively to decrease the viscosity of the oil flowing through the heated region. The process involves three phases: the rapid, but temporary, injection of wet steam (quality around 70 to 85%) for a specific period of time (one to six weeks) into a producing well; a short soak period (three to six days), in which most of the latent heat of the steam is transferred into the formation surrounding the well; and finally, a period where the well is put back on production for several months. During the last period, the production rate of hot fluids starts higher than that of the primary cold production. However, the rate declines with time to near the pre-stimulation values, as heat is removed with produced fluids and dissipated into nonproductive formations. These three phases are repeated cycle by cycle, until the process becomes unprofitable.

From a technical point of view, two main factors are necessary for the success of this kind of process: a significant effect of temperature on the viscosity of the heavy crude oil, to reduce the flow resistance around the producing well; and a natural production mechanism or a driving force present in the reservoir initially. Typically, gravity drainage and solution-gas drives are the most important mechanisms in providing driving forces during the production phase. In addition, rock compaction might be particularly effective when an extensive area of the reservoir is subjected to thermal operations.

From an operational point of view, cyclic steam injection was immediately accepted because the application of the process is simple: a single steam generator may service a large number of wells. In addition, if the process is successful, increased oil production happens immediately, since the oil remains hot as it flows to the well.

In virtually all historical vertical-well steamflood, the well geometry is not optimized with respect to either the expected steam zone shape or the reservoir architecture. The result is that it has been extremely difficult to achieve maximum sweep efficiency prior to steam breakthrough in producers. To further complicate matters, after breakthrough, it becomes quite difficult to operate these wells very efficiently due to high temperatures and steam interference. This has driven operators quite often to consider additional expenditures to recover remaining reserves.[4]

One of the most important characteristics in miscible displacements of oil in porous medium when a less dense fluid displaces a more dense fluid is gravity. At low rates, gravity override will occur, leading to early breakthrough of the injected fluid and poor oil recovery. However, at high rates, due to unfavorable viscosity ratio, viscous fingering will dominate the displacement resulting in bypassing of oil. In general, poor steam drive recoveries at breakthrough are caused by strong override, channeling through high permeability zones, and cusping towards the production well as a result of the pattern geometry.[5]

Oil recovery with steam injection has been enhanced with the incorporation of horizontal wells. The main advantages of horizontal wells are improved sweep efficiency, increased producible reserves, increased steam injectivity, and decreased number of wells required for field development. The use of horizontal wells for cyclic steam injection in the last years has been one of the technologies used to achieve higher production in the heavy oil fields. A horizontal well allows us to manage higher injection rates and the contact area opened to flow is larger than in vertical wells. Thus, the heat zone around the horizontal well is larger than that around the vertical well. That means a higher oil viscosity reduction and therefore typically higher oil production is reached since horizontal well will access a large volume of the reservoir compared to a vertical well. Finally, because of their geometric flexibility, horizontal wells should be able to mitigate the problems of steam breakthrough, allowing improved heat distribution and a lower operating temperature. This should make horizontal wells in steamfloods produce longer and at lower operating costs than their vertical counterparts.

This work performs a numerical thermal compositional simulation to analyze oil production by steam and steam-propane injection, comparing results using a vertical well system and that of a novel system consisting of a vertical injector with a smart horizontal producer.[6] In the novel system, the horizontal producer will have completion intervals which are selectively opened and closed. Initially, the interval nearest the toe will be opened. It is then closed when the steam front reaches it. The next interval is then opened, and so on. The project considers the simulation study of different cases involving a quarter of a 9-spot inverted pattern, using rock and fluids properties from San Ardo field, California.[6]

CHAPTER II

BACKGROUND

The novel vertical injector-smart horizontal producer for steamflood was developed in response to the need to minimize steam over-ride and thus steam injection costs. The background leading to this novel steamflood method is described in the following.

2.1 Background of the Problem

The traditional field completion approach for steam injection operations suggests perforating and injecting steam at the bottom of the reservoir. As steam enters the reservoir, the clustered set of perforations forces the formation of a "line source" of heat. The injected steam quickly rises toward the top of the reservoir generating a "convection dominated" near wellbore region that favors the generation of a heat chest of reduced volume. The extent and size of the heat chest is naturally governed by the relative permeabilities, vertical permeability, permeability contrast, flow barriers, and initial water saturations.

Once the steam reaches the top of the interval, it flows toward the producers due to pressure differential, creating and bypassing an unheated heavy oil bank with high oil saturation, in the lower portion of the reservoir as shown in **Fig. 2.1**. Typically steam override mainly occurs in clean sands with high horizontal-vertical permeabilities, small aspect ratios due to close well spacing and large density differences caused by heavy oils. This results in early steam breakthrough in the upper portion of the reservoir and low sweep efficiencies. After steam breaks through, it is common production practice to keep injecting steam (at lower rates) and do selective plugging to improve recovery while extending the life of the project. Injecting steam at lower rates attempts to keep more of the steam in the reservoir, heat transfer into the unheated oil bank takes place throughout a large surface area of a pseudo-steady and nearly horizontal steamcondensed steam-oil interface. The heated oil migrates toward the top of the steam-oil interface (due to its now lower density) and flows toward the producers through the steam zone – drag flow. If override is particularly severe, most of the oil is produced with steam through drag flow.[7]

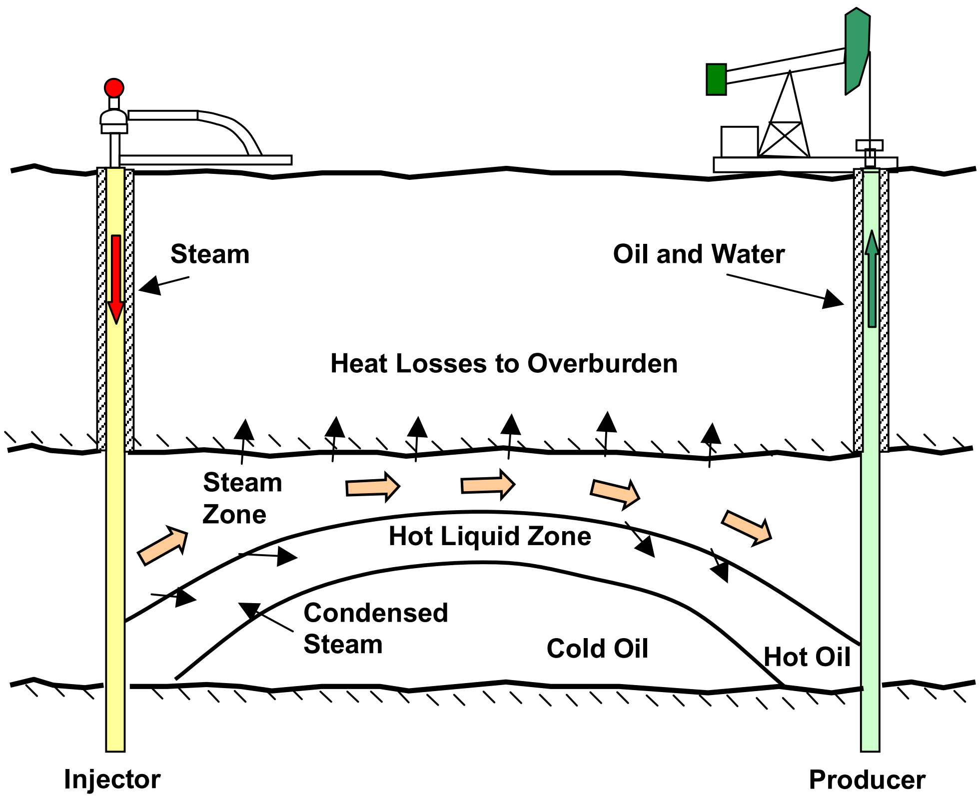

Fig. 2.1–Steamflood cross section showing gravity override (adapted from K.C. Hong [8]).

Methods for improving steamflood performance have concentrated on the problem of reservoir conformance. These methods rely on the use of surfactants to form steam-foam in situ that reduce steam mobility, thereby modifying the injection profile.[9] A majority of field tests have reported technical success in decreasing steam mobility and improving reservoir conformance by the injected steam, but poor economics resulted due to the large quantity and high cost of chemicals required.[10-11] Recent developments involve use of inexpensive chemicals such as high temperature polymer or lignosulfonate gels to improve reservoir conformance. A polymer gel system was used to divert steam from pre-existing channels, thus improving areal sweep efficiency.[12] A lignosulfonate gel system was used to improve steam injection profiles in injection wellbores to cover larger portions of the target interval in a West Coalinga steamdrive project.[13] These chemicals are becoming increasingly popular in use to mitigate steam conformance problems in mature steam-flood projects in California.

The use of horizontal wells provides a different method to mitigate the problems of early steam breakthrough. In general, thermal oil recovery processes have been improved with the incorporation of horizontal wells. The main advantages of the horizontal wells are improved sweep efficiency, increased producible reserves, increased steam injectivity and decreased number of wells required for field developments.[14-20]

As stated before, this work performs a thermal compositional simulation to analyze oil production by steam and steam-propane injection, comparing results using a vertical well system and that of a novel system consisting of a vertical injector with a smart horizontal producer. In the novel system, the horizontal producer will have completion intervals which are selectively opened and closed. Initially, the interval nearest the toe will be opened. It is then closed when the steam front reaches it. The next interval is then opened, and so on, as shown in **Fig. 2.2**.[6] The project considers the simulation study of different cases in space and time, involving a quarter of a 9-spot inverted injection pattern, using rock and fluids properties from San Ardo field, California.[6]

2.2 Research Objectives

The main objective of this work is to conduct a thermal compositional simulation study of steam and steam-propane injection in a vertical well system and a novel vertical injector - smart horizontal well system using information available from San Ardo field. Aspects of the study include the following.

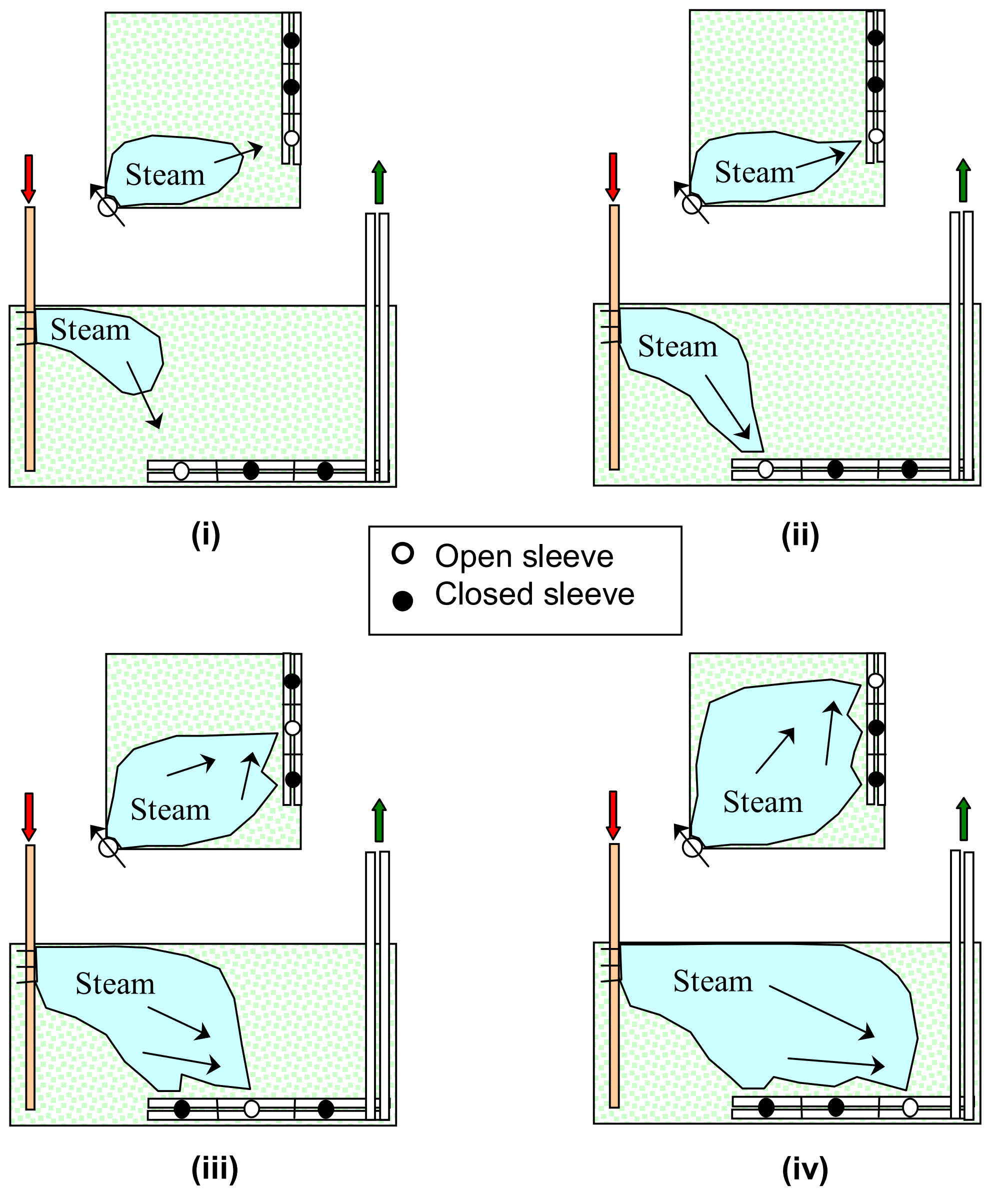

Fig. 2.2–Proposed vertical injector-smart horizontal producer (areal view at top, section at bottom of each set of four figures). (i) Toe-end sleeve open, start of steam injection, (ii) steam breakthrough in first sleeve, (iii) steam breakthrough in second sleeve, and (iv) steam breakthrough in heel-end sleeve. [6]

- A quarter of a 10-acre 9-spot inverted pattern based on the San Ardo field development.
- One vertical injection well and three vertical producers.
- One vertical injection well and one horizontal producer well.
- Cyclic steam injection.
- Continuous steam injection.
- Continuous steam-propane injection.
- Different cases (sections or sleeves and time) to optimize the sweep efficiency and oil recovery by selective shut-in of the horizontal well from toe up according to the advance of the steam front.

Results of simulations, principally oil production rate and recovery, have been analyzed to determine if the vertical-horizontal system is better than the vertical-vertical system and to define the best conditions of injection in space and time.

2.3 Literature Review

Several studies have been carried out to study steam injection using horizontal wells. Numerical simulations applied to specific reservoirs, along with conceptual cases representative of non-depleted, conventional heavy oil, have noted the improvement in oil recovery obtained with the application of cyclic steam injection using horizontal wells.[16-17] Some field applications of cyclic steam injection using horizontal wells have been reported in the literature.[16-21] Most of these applications have shown favorable performance.

Additionally, a few cyclic steam injection projects using horizontal wells have been conducted to evaluate the performance of the steam front and to establish a comparison between vertical and horizontal wells.[14-17,20-24] The Petroleum Engineering Department at Texas A&M University have been carrying out a series of studies to investigate the performance of horizontal and vertical wells under cyclic steam injection, the shape of the steam zone for an horizontal wells during cyclic steaming, the optimum injection rate and injection time for cyclic steam injection using horizontal wells, the oil production during cyclic steam injection using horizontal wells, the comparison between the performance of cyclic steam injection against that of steamflooding using horizontal wells and others. These investigations have shown encouraging results; however, further analyses are required to validate the results. A literature review covering previous experiences with the combined use of steam injection and horizontal wells will be presented.

Butler *et al.* (1981)[22] presented an analytical model for a new horizontal steamflood technique, the steam assisted gravity drainage (SAGD) method. In a SAGD pattern, two horizontal wells are utilized, namely, a horizontal injector above a horizontal producer. In this study, the growth of the steam zone is significantly affected by gravity drainage of the oil to the horizontal producer, so that the steam zone has the shape of an inverted pear in a cross sectional view. In this model oil drains down to the production well along the sides of the steam zone. The amount of oil production is calculated basically using Darcy's law and material balance equation. Fractional recovery of oil calculated by the model is in good agreement with scaled pressurized experimental results.

Toma *et al*. (1984)[23] conducted an experimental study for cyclic steam injection in a horizontal well. The experimental results showed that oil recovery of cyclic steaming in horizontal wells is affected by the axial and radial components of recovery. The growth of the steam zone along the well as a function of time and injection rate was not modeled.

Reis (1992)[24] presented an improved model of the SAGD process. In this model the steam zone shape is approximated by an inverted triangle with its vertex fixed at the production well. The oil drains downward along the interface of a laterally expanding steam zone. Using cumulative oil production along the horizontal well and combined with the material balance equation, the steam zone interface angle can be calculated. Oil production rate and steam zone interface angle calculated by the model are in good agreement with the experimental data of Chung and Butler.[25]

Fernandez and Zerpa (1995)[18] conducted a numerical simulation study to investigate the performance of cyclic steam injection using horizontal wells. The main objective of the study was to history match the horizontal well performance during cold production, and to investigate the feasibility of introducing a cyclic steam injection scheme to enhance productivity. Results showed that cyclic steam injection increases the oil production rate up to twice that under cold production. Oil recovery by cyclic steam injection with horizontal wells was 62% higher than that with vertical wells.

Escobar and Valera (1997)[19] presented experiences with surface completions and completion equipment for steam injection wells, fluid for thermal insulation, offshore equipment, steam injection with additives and the good results of cyclic steam injection into two horizontal wells completed in Bachaquero reservoir.

Rodriguez (1999)[16] conducted a three dimensional thermal compositional simulation study to evaluate the performance of horizontal wells under cyclic steam injection and steamflooding. The results show that the oil recovery of the field can be increased by steamflooding with additional producer wells around the horizontal wells injector. The main advantages of the steamflooding are re-pressurization and improved thermal efficiency.

Sasaki *et al.* (1999)[26] carried out SAGD experiments using 2-D scaled reservoir models, to investigate production process and performance. The results suggest that the vertical well spacing between two wells can be used as a governing factor to evaluate production rate and lead-time in the initial stage of the SAGD process. Based on these experimental results, the SAGD process was modified: the lower production well as intermittently stimulated by steam injection, in conjunction with continuous steam injection in the upper horizontal injector. Using the modified process (named SAGD-ISSSLW), the time to generate near breakthrough condition between two wells was shortened, and oil production was enhanced.

Escobar *et al.* (2000)[20] developed a new methodology for optimizing the cyclic steam injection process for vertical and horizontal wells. The procedure integrates oil production characterizations using numerical simulations, net present value maximization through a Quasi-Newton method, and model validation/tuning. The three-stage procedure provides the optimum number and/or duration of cycles, the optimal amounts of steam to be injected in each cycle and the optimal value of the overall economic indicator. The optimization algorithm was successfully validated with published results obtained from the discrete maximum principle. The methodology was applied to determine the optimal conditions of cyclic steam injection for a horizontal well located in Bachaquero field, Venezuela.

Marpriansyah (2003)[21] performed a comparative analysis of oil production using vertical and horizontal wells with cyclic steam injection. The results indicate that oil recovery for the best horizontal well case is not significantly higher than for the best vertical well case. Also for both types of well, the highest oil recovery is obtained when the completion interval is at the bottom of the reservoir. The difference between the NPV at 10% discount rate for the best vertical well case, compared to the horizontal well case is not significant.

On the other hand, several studies have been carried out to test the effect of injecting steam along with other gaseous additives. In this section, previous experiences with the combined use of steam and gaseous additives are presented.

Redford (1982)[27] conducted experiments to study the effect of adding carbon dioxide, ethane and/or naphtha in combination with steam. Results showed that the addition of carbon dioxide or ethane improved oil recovery. Further recovery was reached when naphtha was added.

Harding *et al*. (1983)[28] presented both experimental and simulation results suggesting that the co-injection of carbon dioxide or flue gas with steam yielded higher recoveries when compared to pure steam injection.

Stone and Malcolm (1985)[29] performed several tests to study the benefit of injecting carbon dioxide along with steam. Higher production rates were obtained for the case of steam-carbon dioxide injection. Good agreement was found between the experimental data and numerical simulations results.

Stone and Ivory (1987)[30] carried out further investigations using the model from Stone and Malcolm.[29] This time, experiments with CO_2 presoak and CO_2 co-injection with a solvent were conducted. They found that under certain conditions, carbon dioxide pre-soaking increased oil recovery above the conventional CO_2-steam injection.

Nasr *et al*. (1987)[31] presented results of experiments conducted to test the effect of injecting CO_2, N_2 and flue gas with steam. Both continuous and cyclic injections were tested. The addition of gasses increased bitumen recovery. The use of CO_2 resulted in higher oil recoveries when compared to that with N_2 and flue gas injection.

Frauenfeld *et al*. (1988)[32] presented results showing that for oils without an initial gas saturation, co-injection of CO_2 with steam was capable of improving oil recovery over that obtained with steam alone. On the other hand, when an initial non-zero gas saturation was present, co-injection of CO_2 was not beneficial.

Metwally (1990)[33] employed cores from the Lindbergh Field to investigate the effect of carbon dioxide and methane on the performance of steam processes. The experiments were carried out to determine the differences in performance of simultaneous injection of steam and gaseous additive and an injection of a gas slug prior to steam injection. The results showed that injecting a CO_2 slug prior to the steam improved injectivity. However, the presence of a non-condensable gas with steam did not improve steam drive recovery and resulted in higher residual oil saturation compared to pure steam injection.

Gumrah and Okandan (1992)[34] performed linear and 3D displacement experiments to evaluate the performance of CO_2-steam injection on the recovery of 24^{o}API, 12^{o}API and 10.6^{o}API oils. The 1D tests indicated that the oil recovery increased with increasing CO_2/steam ratios until an optimum value was reached. The addition of CO_2 did not produce a significant increase in the recovery of the lighter oil. However, for the heavier oils, the oil production rate was increased considerably.

Bagci and Gumrah (1998)[35] performed experiments with both linear and 3D models to investigate the effects of injecting methane and carbon dioxide along with steam for a 12.4°API heavy oil. The results showed that the use of CO_2 or methane combined with steam yielded a higher incremental oil recovery than pure steam tests.

Butler and Mokrys (1991)[36] described a new oil recovery concept related to the steam-assisted gravity drainage (SAGD) process. The process was intended to be used in thin reservoirs, were the application of SAGD alone was uneconomical due to the high heat losses to the formations above and below the reservoir. The process, called VAPEX, used a solvent, such as propane, which would form a vapor-filled chamber within the reservoir. Vapor dissolves in the oil around the chamber and the resulting solution drains, driven by gravity, to a horizontal production well placed low in the formation. A horizontal well, located at the top of the reservoir, is used to inject hot water or steam and the solvent. Additional work by Butler and Mokrys[37-39] presented results of further investigations conducted on the VAPEX process. Their results showed that the process could be applied economically for heavy oil recovery. Additional advantages derived from VAPEX are a partial in situ deasphalting and a reduction of the content of heavy metals. The resulting oil can be lighter, of a higher quality and better suited for direct refining.

Goite (1999)[40] conducted experiments to determine the influence of propane as an additive during steam injection for 12.5°API crude oil from the Morichal field, Venezuela. Results showed that the optimal concentration of propane appears to lie somewhere in the region of 5 wt %.

Ferguson (2000)[41] continued Goite's experiments using a constant steam mass rate. Tests were performed using Morichal oil to determine the optimum propane:steam mass ratio. Oil production was accelerated in the steam-propane runs when compared to those of pure steam. The optimum propane:steam mass ratio was found to be around 5:100. The acceleration in oil production was thought to be due to the dry distillation process in which the lighter oil fractions are vaporized and carried by propane. On contact with the colder part of the cell, the light fractions condense and are miscible with the oil, thus lowering the interfacial tension and decreasing the viscosity of the oil.

Tinns (2001)[42] carried out steam-propane experiments using 5:100 propane:steam mass ratio on 21°API oil. The same effect of production acceleration was observed in these experiments. Viscosity and density measurements indicated an increase in API gravity and a reduction of viscosity in the produced oil. Furthermore, injectivity was improved with the addition of propane to the steam. A reduction in the maximum injection pressure from 85 psig to 78 psig was observed in the experiments.

Diaz (2001)[43] performed a numerical simulation study on a heavy oil reservoir with the main objective of evaluating possible development options beyond the existing cold production method. One of the options studied was steam-propane injection, where with constant propane:steam mass ratio of 5:100, the oil recovery factor is further increased to 26% OOIP.

Rivero (2002)[44] conducted an experimental study to evaluate the role of propane as a steam additive to enhance injectivity and accelerate oil production in the Hamaca field in Venezuela. This study also assessed in-situ oil upgrading during the steam-propane injection experiments that were conducted using propane:steam mass ratios ranging from 0:100 (pure steam) to 10:100. The main findings for this study are as follows. Oil production was accelerated by 23% with steam-propane injection compared to pure steam injection. The use of propane as an additive to steam resulted in an increase of steam injectivity of up to three times compared to pure steam injection. No evidence was found to confirm that the addition of propane to steam increases or decreases oil recovery. The API gravity of the oil produced was increased from 10 to 14-16°API.

Venturini (2003)[45] performed simulation studies to better understand and verify the beneficial effects of steam-propane injection for Hamaca heavy oil. The results showed oil production acceleration of 20% using propane:steam mass ratio of 5:100 compared to pure steam injection. For the case studied, propane:steam mass ratios higher than 5:100 resulted in propane bypassing the oil.

CHAPTER III

NUMERICAL SIMULATION OF STEAM INJECTION

The simulator used to perform this study was CMG's STARS version 2003. It is a three-phase multi-component thermal simulator that can handle a wide range of processes such as steam drive, cyclic steam injection, in-situ combustion, polymer flooding, foam and emulsion flow, etc.

3.1 Reservoir Description

The simulation study was conducted with the available information from Lombardi reservoir in San Ardo field, investigating ways for additional development of the resrvoir.[6]

The San Ardo field is located in the Central Coastal region of California, about 217 Km (135 miles) roughly due west of Bakersfield (**Fig. 3.1**). Oil originally-in-place is estimated to be in excess of one billion barrels with oil gravity of 11-12^{o}API.[46] The field has two producing zones, the shallow Lombardi zone and the deeper Aurignac zone. The field has been steamflooded since 1968. The shallower Lombardi reservoir, the objective of this study, lies at about 2100 ft with an average net pay thickness of 115 ft in the Main Area (40 ft in North Area), oil gravity of 11^{o}API and current in-situ oil viscosity of 3000 cp. **Table 3.1** presents the initial reservoir conditions of Lombardi zone as used in the simulator. The steam injection phase in San Ardo field has been mainly developed with 10-acre inverted 9-spot injection patterns. An example of this pattern is shown schematically in **Fig. 3.2**. This pattern is utilized in the basic grid model during the simulation.

3.2 Grid Model

A Cartesian 3 dimensional model was constructed based on the 10-acre inverted 9-spot pattern in the San Ardo field. A model of one quarter of that pattern was finally used in the simulation, with a reservoir thickness of 115 ft, following the three dimensional symmetry of all elements in the system.

Fig. 3.1–Map showing location of San Ardo field.[6]

Symmetry elements are used frequently in thermal simulation for a number of reasons:

- Compared with black-oil models, thermal models require much more CPU time and storage per grid block. Therefore, fewer grids blocks will save CPU time and also prevent exceeding the computer storage limit.

- Thermal EOR processes require more grid blocks per well or per pattern, since fronts are sharp and distinct.
- Accuracy can be maximized for use in test and sensitivity runs.
- Some results from one element may be generalized to other elements and patterns.
- Pattern interference can be investigated by sensitivity runs with different injection share or production share.
- Full-pattern or multi-pattern runs can be done once an acceptable coarse grid is obtained.

TABLE 3.1–LOMBARDI INITIAL RESERVOIR PROPERTIES

Oil gravity	^{o}API	11
Formation top	ft	1900
Initial pressure at 1957 ft	psia	845
Initial temperature	^{o}F	127
Net oil sand thickness	ft	115
Initial gas-oil ratio	SCF/STB	78
Initial oil saturation	%	73.3
Initial water saturation	%	26.7
Permeability	md	6922
Porosity	%	34.5
In-situ oil viscosity at 275 psia	cp	3000

Fig. 3.3 presents the one quarter symmetrical model for the vertical-vertical and vertical-smart horizontal producer system as used in the simulator. The model has a surface area of 330 x 330 square ft with 115 ft of thickness. To select the best number of grid cells to use in the simulation, a sensitivity analysis was made to ensure accuracy and stability in the simulator. A total of five Cartesian grid models from 1000 to 6480 cells were compared and they are presented in **Table 3.2**.

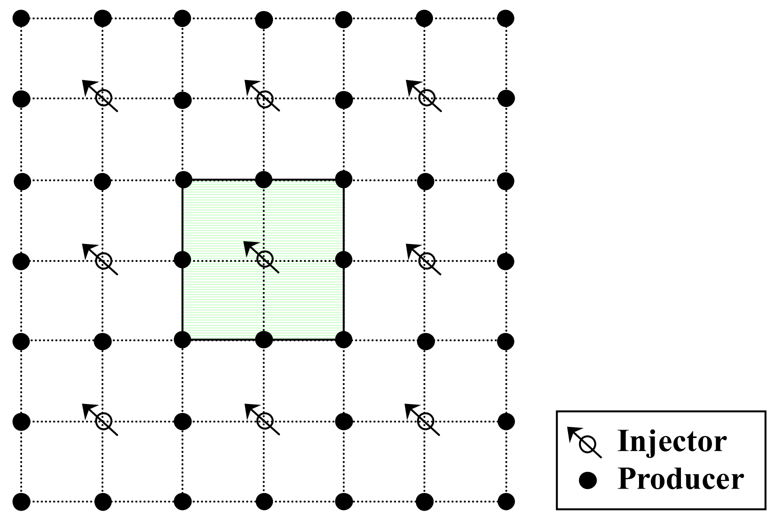

Fig. 3.2–Schematic diagram of a 9-spot inverted pattern.

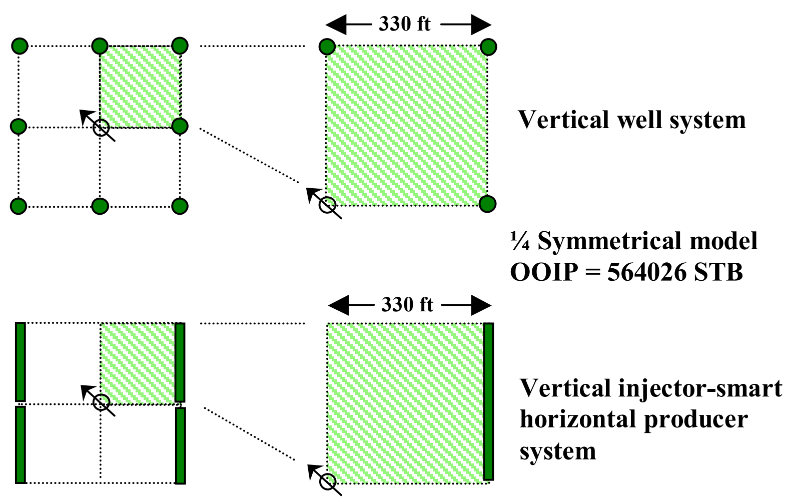

Fig. 3.3–Vertical well system and Vertical injector-smart horizontal producer system.

The grid of 4500 cells (15x15x20) was selected because the simulation results were practically unchanged when the number of grid cells was increased. Additionally, the 4500 grid model presented the highest stability.

TABLE 3.2–GRID MODELS AND DIMENSIONS USED FOR SENSITIVITY

Total number of cells	Number of cells in i-direction	Number of cells in j-direction	Number of cells in k-direction	Cell dimensions (ft)		
				i	j	k
1000	10	10	10	33	33	11.5
2000	10	10	20	33	33	5.75
4500	15	15	20	22	22	5.75
5120	16	16	20	20.625	20.625	5.75
6480	18	18	20	18.333	18.333	5.75

Fig. 3.4 compares the results for the different grid models included in the sensitivity analysis. The 4500 grid model is a 15x15x20 total grid cells with uniform cell dimensions of 22’x22’x5.75’. **Fig. 3.5** presents the final 3D reservoir grid model for a quarter of a 10-acre inverted 9-spot pattern, which has an OOIP of 564026 STB.

3.3 Fluid Model

In the pure steam injection simulation model, a live, black-oil model is used (2 pseudo components and water). The initial oil phase is made up of 78.9% by mole dead oil component and 21.1% by mole gas component to obtain an initial solution gas-oil ratio (GOR) of about 78 SCF/STB to simulate the initial condition of Lombardi reservoir in the San Ardo field.

Available information of fluid composition for Lombardi reservoir was limited to dead oil. To obtain live oil composition a pseudo fluid was created by recombination of Lombardi dead oil and a gas sample from Hamaca field to match the initial GOR in Lombardi reservoir.

Hamaca is a heavy oil field of 8°API in Venezuela. The gas composition of Hamaca fluid sample is presented in **Table 3.3**.[45] The Lombardi reservoir dead oil composition is shown in **Table 3.4**.[46]

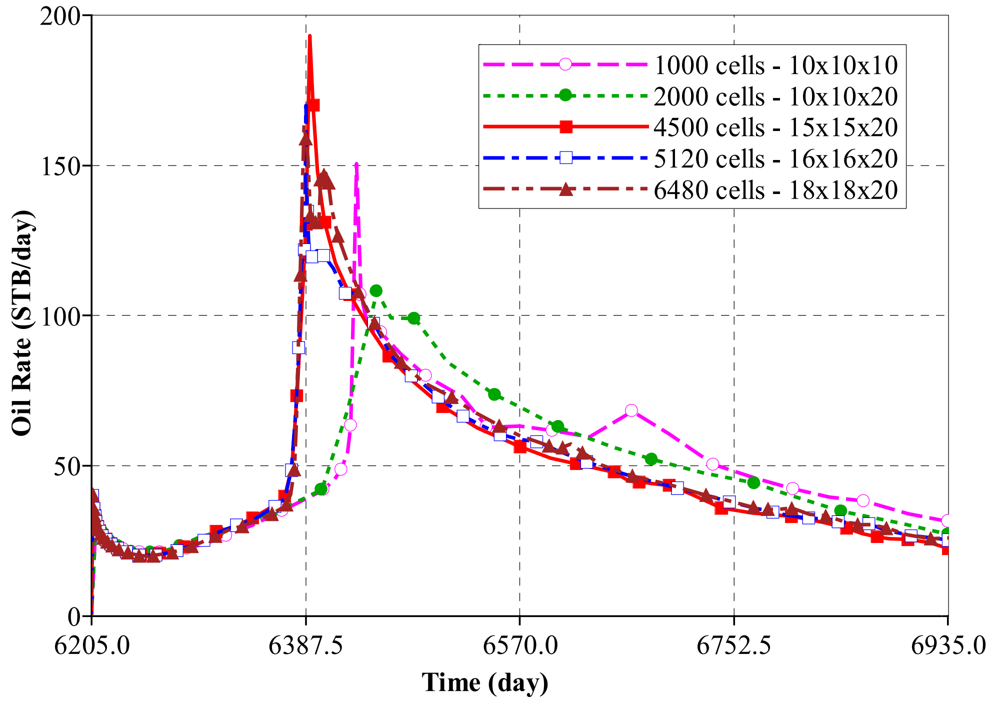

Fig. 3.4–Grid model sensitivity analysis.

The compositions of San Ardo dead oil and Hamaca gas were input in WinProp. WinProp is CMG's equation of state multiphase equilibrium property package. WinProp can be used to analyze the phase behavior of reservoir gas and oil systems, and to generate properties for CMG's steam and additives thermal simulator STARS. WinProp is also used to generate the fluid model for the simulation of propane-steam injection, with 8 pseudo components, whose results are analyzed later. To obtain the initial GOR of 78 SCF/STB for Lombardi reservoir, the San Ardo dead oil and Hamaca gas sample were recombined with 78.9% by mole of dead oil and 21.1% by mole of gas.

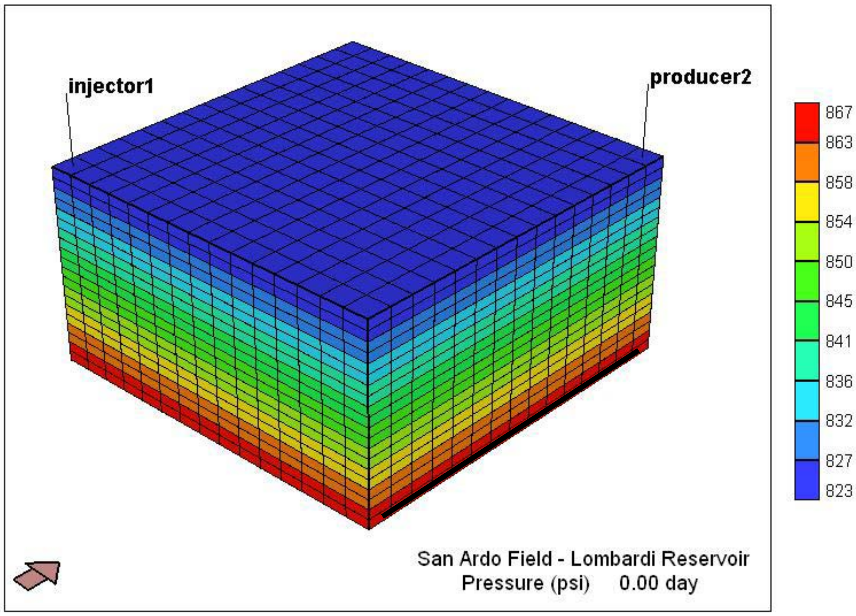

Fig. 3.5–Lombardi 3D reservoir grid model.

TABLE 3.3–HAMACA FIELD HYDROCARBON GAS COMPOSITION

Component	Gas composition, mole %	Normalized gas composition, mole %
C1	91.918	97.8840
C2	0.864	0.9201
C3	0.389	0.4142
i-C4	0.143	0.1523
n-C4	0.202	0.2151
i-C5	0.08	0.0852
n-C5	0.068	0.0724
C6	0.113	0.1203
C7	0.108	0.1150
C8	0.015	0.0160
C9	0.004	0.0043
C10	0.001	0.0011
Total	**93.905**	**100.00**

TABLE 3.4–SAN ARDO LOMBARDI ZONE DEAD OIL COMPOSITION

Component	Oil composition, mole %
C7	0.2
C8	0.5
C9	1.2
C10	2.1
C11	3.2
C12	4.2
C13	5.0
C14	4.9
C15	5.1
C16	4.5
C17	4.9
C18	4.4
C19	3.9
C20	4.0
C21	3.5
C22	3.0
C23	2.9
C24	2.7
C25	2.4
C26	2.3
C27	2.6
C28	2.0
C29	2.4
C30	2.1
C31	1.7
C32	1.5
C33	1.3
C34+	21.5
Total	**100.0**

Table 3.5 presents the properties generated from WinProp to use in the simulation fluid model. The fluid viscosity for Lombardi dead oil is presented in **Table 3.6**. The gas viscosity information was used in the simulation model as generated from WinProp. **Table 3.7** shows the additional rock and fluids properties for Lombardi reservoir included in the final model.

TABLE 3.5–COMPONENT PROPERTIES FOR LIVE BLACK-OIL MODEL

Component name	Oil	Gas
Molecular weight, (CMM)	456.015	16.7278
Critical pressure (PCRIT), psia	179.02	670.46
Critical temperature (TCRIT), ^{o}F	1036.21	-107.35
First coefficient in the correlation for gas-liquid K value (KV1), psi	5.165E+6	1.534E+5
Fourth coefficient in the correlation for gas-liquid K value (KV4), ^{o}F	-15362.5	-1914.1
Fifth coefficient in the correlation for gas-liquid K value (KV5), ^{o}F	-459.67	-459.67
Partial molar density at reference pressure and temperature (MOLDEN), lbmol/cft	1.356E-01	4.515E-02
Liquid Compressibility at constant temperature (CP), 1/psi	3.805E-06	3.754E-03
First coefficient of the thermal expansion coefficient (CT1), 1/^{o}F	1.660E-04	1.910E-03

TABLE 3.6–LOMBARDI DEAD OIL VISCOSITY

Temperature, ^{o}F	Oil viscosity, cp
50	500000
100	20000
150	1500
200	240
250	60
300	20
350	8
400	3.5
450	1.8
500	1
550	0.6
600	0.35
650	0.2
700	0.13

TABLE 3.7–LOMBARDI ROCK AND FLUIDS PROPERTIES

Effective formation compressibility, 1/psi	9.0E-05
Rock heat capacity, Btu/cft-^{o}F	35.02
Thermal conductivity of reservoir rock, Btu/ft-day-^{o}F	1
Thermal conductivity of the water phase, Btu/ft-day-^{o}F	0.36
Thermal conductivity of the oil phase, Btu/ft-day-^{o}F	1.2
Thermal conductivity of the gas phase, Btu/ft-day-^{o}F	0.0833
Porosity, %	34.5
Horizontal permeability, md	6922
Vertical permeability, md	692.2

3.4 Relative Permeability Curves

The concept of relative permeability is very simple, the measurement and interpretation of relative permeability versus saturation curves is not. For example, there is evidence that relative permeability may be a function of many more parameters than fluid saturation. Temperature, flow velocity, saturation history, wettability changes and the mechanical and chemical behavior of the matrix material may all play roles in changing the functional dependence of the relative permeability on saturation.

Relative permeability is believed to depend primarily on the volume occupied by a phase and so is expressed as a function of saturation. Potentially reducing effective permeability by an order of magnitude in some cases, relative permeability can have a dramatic effect on fluid flow and thus is an important parameter to determine in reservoir engineering. The relative permeability relations involving oil, water, and gas are well known and have been established in laboratory experiments. These curves have been used successfully in flow modeling for petroleum reservoir engineering.

In this simulation a set of relative permeability curves was based on actual relative permeability curves measured for Lombardi reservoir in San Ardo field. The temperature dependence of relative permeability is an important parameter to take in account in steam injection projects and it was measured for San Ardo field and included in this simulation study. **Figs. 3.6** and **3.7** show the water-oil and gas-oil relative permeability curves including temperature dependence as used in the simulator.

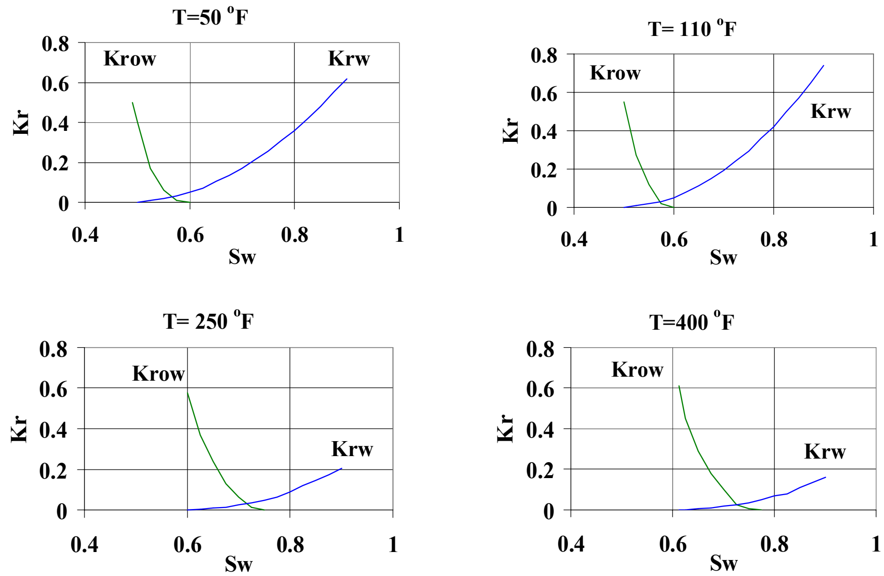

Fig. 3.6–Water-oil relative permeability curves with temperature dependence.

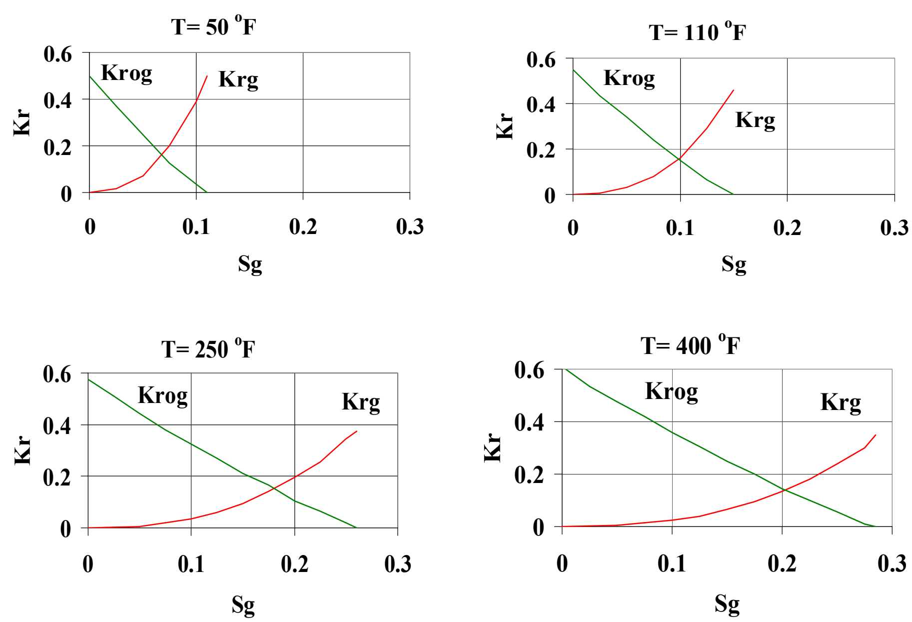

Fig. 3.7–Gas-oil relative permeability curves with temperature dependence.

CHAPTER IV

STEAM INJECTION SIMULATION RESULTS

To simulate similar conditions of the San Ardo field development, the pressure history was matched as shown in **Fig. 4.1**. The primary depletion was from 845 to 415 psia during 17 years, with a cumulative production of 67916 STB (12% OOIP) as presented in **Fig. 4.2**.

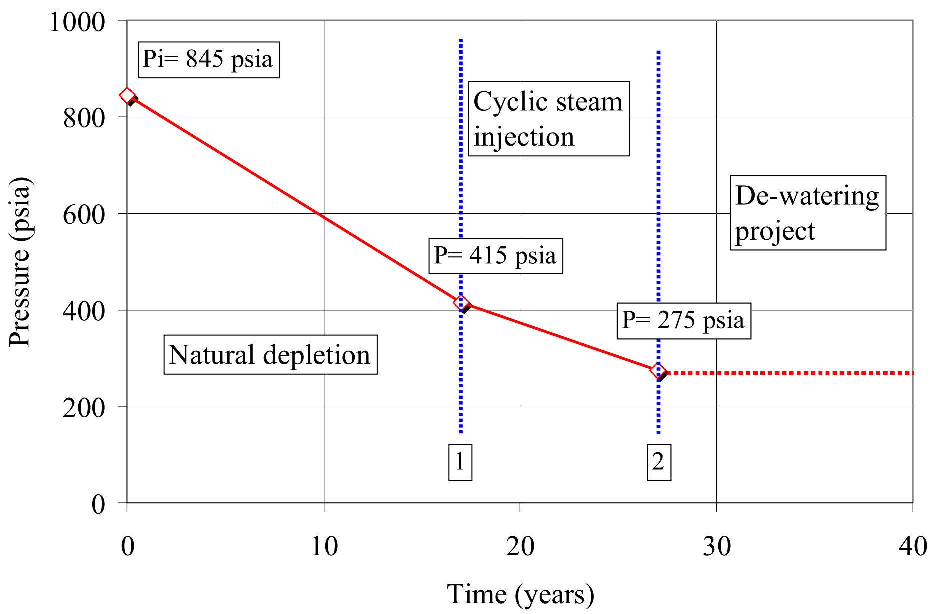

Fig. 4.1–Pressure history in Lombardi reservoir.

When the average reservoir pressure was about 415 psia, cyclic steam injection was implemented in the field. From this point (after primary depletion), the simulation study includes an analysis of cyclic and continuous steam injection with the vertical well system and vertical-smart horizontal system to compare and define the best development strategy after natural depletion.

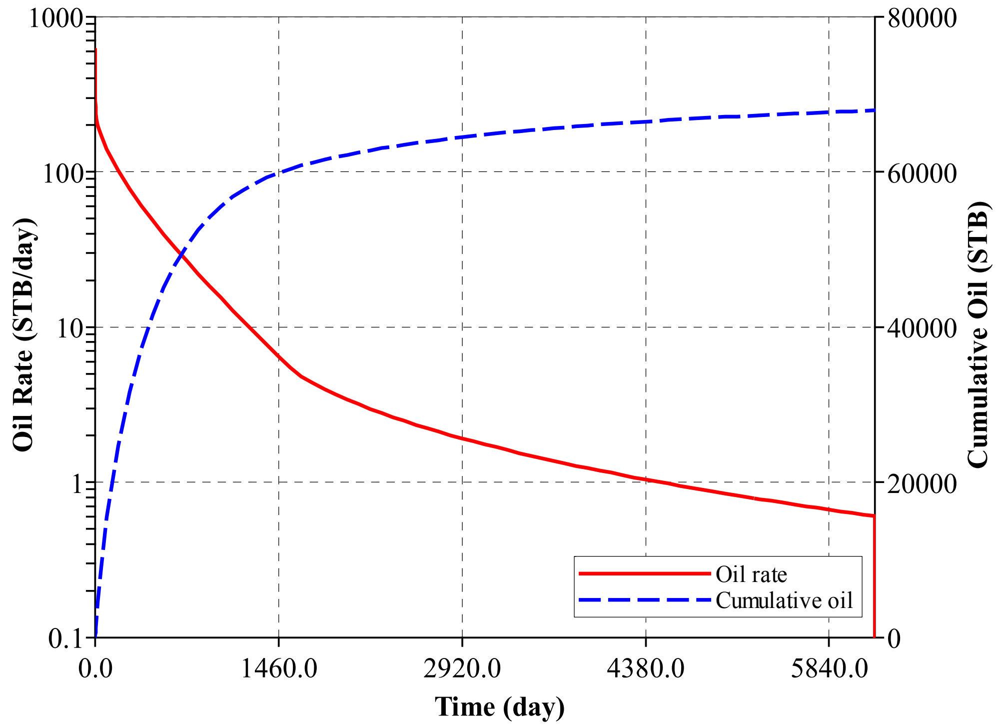

Fig. 4.2–Natural depletion simulation.

The current average reservoir pressure in Lombardi zone is about 275 psia (**Fig. 4.1**). This condition is after cyclic steam injection and after a de-watering project implemented when the deeper Aurignac zone was developed in the field.

To simulate from the current pressure (point 2 in **Fig 4.1**) a match with cyclic steam injection was performed from 415 psia after natural depletion to 275 psia. **Fig. 4.3** presents the oil production during the cyclic steam injection (after natural depletion) to match the current pressure of 275 psia. It took only two injection cycles (one year) to reach that pressure under the simulated conditions with the vertical-smart horizontal system as presented in **Fig 4.4**.

Once the reservoir reached an average pressure of 275 psia (point 2 in **Fig. 4.1**), additional simulations were performed using the best scenarios obtained in the previous simulations (from 415 psia after natural depletion), to simulate similar development conditions of Lombardi reservoir.

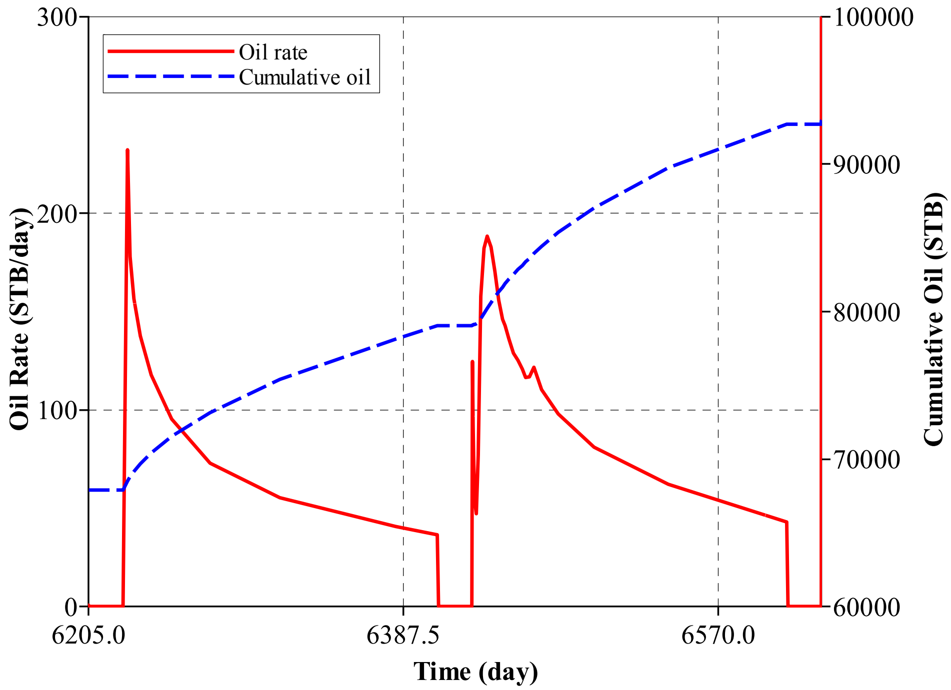

Fig. 4.3–Cyclic steam injection to match reservoir pressure.

In short, the simulations in this part of the study were performed as follows:

- Primary depletion presented in **Fig 4.2**.
- Cyclic steam injection after natural depletion.
- Continuous steam injection after natural depletion.
- Continuous steam injection after cyclic steam injection.

Finally, additional scenarios were analyzed to enhance sweep efficiency and oil recovery taking into account the San Ardo field development conditions. The scenarios mentioned before will be explained and developed in detail in the next sections. **Table 4.1** presents the basic injection parameters used in the simulation model. The thermal reservoir simulation files for pure steam injection using the vertical well and the vertical-smart horizontal well systems are presented in **Appendix A** and **Appendix B**.

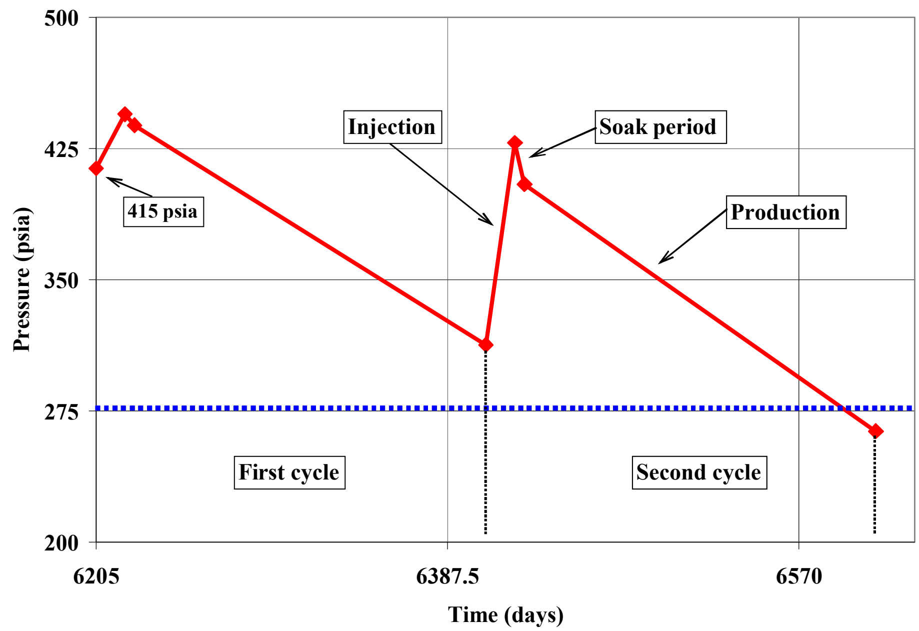

Fig. 4.4–Simulation match of average reservoir pressure.

TABLE 4.1–STEAM INJECTION PARAMETERS

Maximum injection pressure	psia	1350
Steam temperature	^{o}F	582
Steam quality	%	80

4.1 Cyclic Steam Injection After Natural Depletion

The simulation of cyclic steam injection was performed from 415 psia using the vertical well system and the vertical-horizontal well system as presented in **Fig 3.3**. For a quarter of a 9-spot inverted pattern, the vertical well system has 4 vertical wells and the vertical-horizontal well system has one vertical and one horizontal well. The steam injection rate was 300 BPDCWE for each vertical well (4 wells in the quarter of 9-spot pattern) and 1700 BPDCWE for the horizontal well (equivalent to its length). For the cyclic steam injection, steam is injected into the production wells for a period of 15 days.

The wells are shut in and allowed to soak for a period of 5 days and returning to production during 6 months (**Fig. 4.4**).

Fig. 4.5 shows the comparison between the two systems. For the vertical well system the cumulative oil production including the natural depletion was 210907 STB (37.4% OOIP) and for the vertical-horizontal system was 262190 STB (46.5% OOIP) in 10 years of cyclic steam injection. The vertical-horizontal system produces 9.1% OOIP more than the vertical well system.

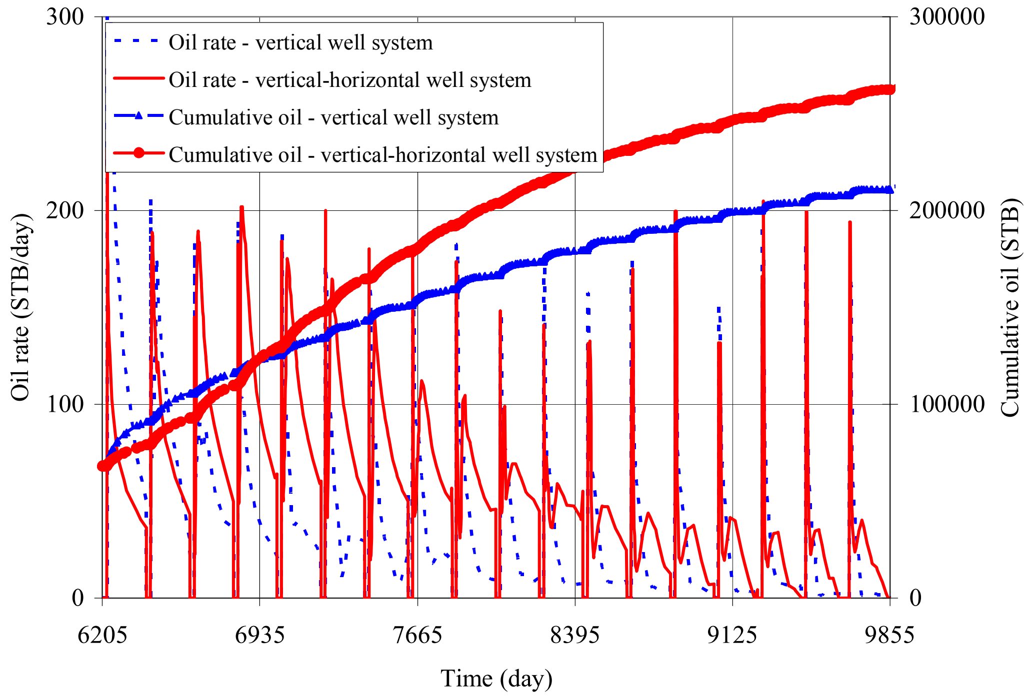

Fig. 4.5–Oil production in cyclic steam injection for vertical-vertical and vertical-horizontal systems after natural depletion.

4.2 Continuous Steam Injection after Natural Depletion

Production performance and oil recovery behavior were examined in different simulation scenarios from point 1 in **Fig. 4.1** (end of natural depletion). Continuous steam injection after natural depletion was analyzed with the vertical well system and compared to vertical-smart horizontal system. These scenarios were defined to determine the best production strategy for the smart horizontal well, including variation of steam injection rate and selective shut in sections (sleeves) with different time after steam breakthrough.

4.2.1 Scenario 1

In this scenario the smart horizontal producer is divided into three sections as shown in **Fig. 4.6**. Each section has a length of 110 ft. At the start of production, all three sections are open (**Fig. 4.6** a). After steam breakthrough, only section 3 in the heel-end of the smart horizontal well is kept open (**Fig. 4.6** b).

Several cases in this Scenario 1 were performed. These cases include different injection rates and shut in times after breakthrough to find the best production performance. **Table 4.2** presents the cases simulated in Scenario 1.

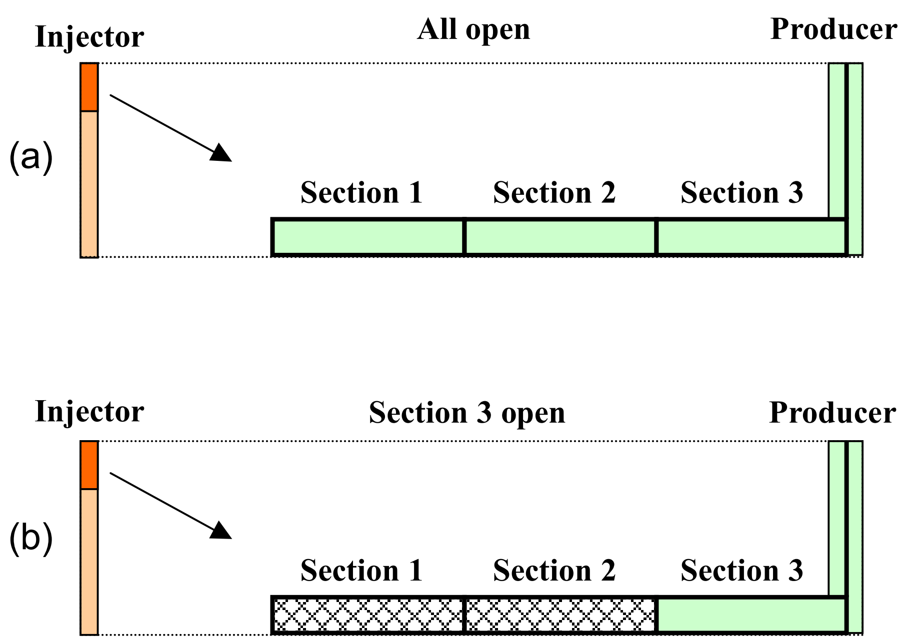

Fig. 4.6–Scenario 1, smart horizontal starts all open (a) and after breakthrough only section 3 is kept open (b).

TABLE 4.2–SCENARIO 1, SIMULATION CASES

Case 1	Injection rate = 150 BPDCWE, Well all time open
Case 1a	Shut in sections 1-2 at breakthrough
Case 1b	Shut in sections 1-2, 3 months after breakthrough
Case 1c	Shut in sections 1-2, 6 months after breakthrough
Case 1d	Shut in sections 1-2, 9 months after breakthrough
Case 2	Injection rate = 200 BPDCWE, Well all time open
Case 2a	Shut in sections 1-2 at breakthrough
Case 2b	Shut in sections 1-2, 3 months after breakthrough
Case 2c	Shut in sections 1-2, 6 months after breakthrough
Case 2d	Shut in sections 1-2, 9 months after breakthrough
Case 3	Injection rate = 250 BPDCWE, Well all time open
Case 3a	Shut in sections 1-2 at breakthrough
Case 3b	Shut in sections 1-2, 3 months after breakthrough
Case 3c	Shut in sections 1-2, 6 months after breakthrough
Case 3d	Shut in sections 1-2, 9 months after breakthrough
Case 4	Injection rate = 300 BPDCWE, Well all time open
Case 4a	Shut in sections 1-2 at breakthrough
Case 4b	Shut in sections 1-2, 3 months after breakthrough
Case 4c	Shut in sections 1-2, 6 months after breakthrough
Case 4d	Shut in sections 1-2, 9 months after breakthrough

Figs. 4.7 through **4.14** present the results for the Scenario 1. **Table 4.3** compares the cumulative oil production and recovery factor for all cases. The best case in this scenario was Case 4d in which the injection rate was 300 BPDCWE and sections 1 and 2 in the smart horizontal well were closed 9 months after steam breakthrough (**Fig. 4.6**). The cumulative oil production for Case 4d was 343625 STB with a total oil recovery factor of 60.9% of the original oil in place for 8 years of steam injection.

TABLE 4.3–SCENARIO 1, CUMULATIVE OIL PRODUCTION AND RECOVERY FACTOR

Scenario 1	Cumulative oil, STB	Oil recovery, % OOIP
Case 1	223335	39.6
Case 1a	265350	47.0
Case 1b	268828	47.7
Case 1c	271361	48.1
Case 1d	281100	49.8
Case 2	241846	42.9
Case 2a	287004	50.9
Case 2b	296537	52.6
Case 2c	310772	55.1
Case 2d	306958	54.4
Case 3	267479	47.4
Case 3a	282158	50.0
Case 3b	310464	55.0
Case 3c	330024	58.5
Case 3d	330621	58.6
Case 4	278522	49.4
Case 4a	287993	51.1
Case 4b	323785	57.4
Case 4c	334301	59.3
Case 4d	**343625**	**60.9**

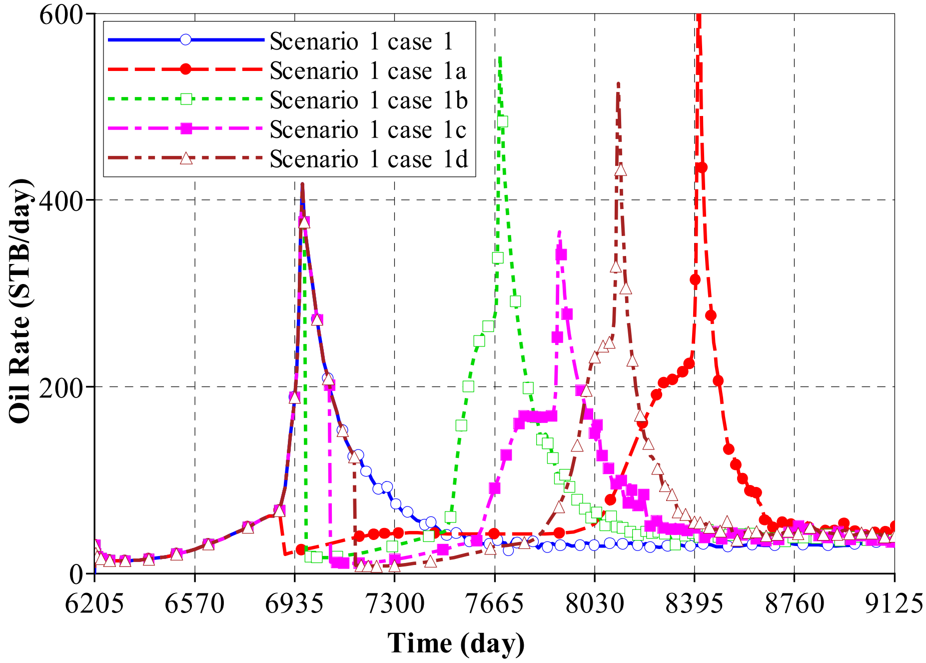

Fig. 4.7–Oil production rate, Scenario 1, cases for 150 BPDCWE injection rate.

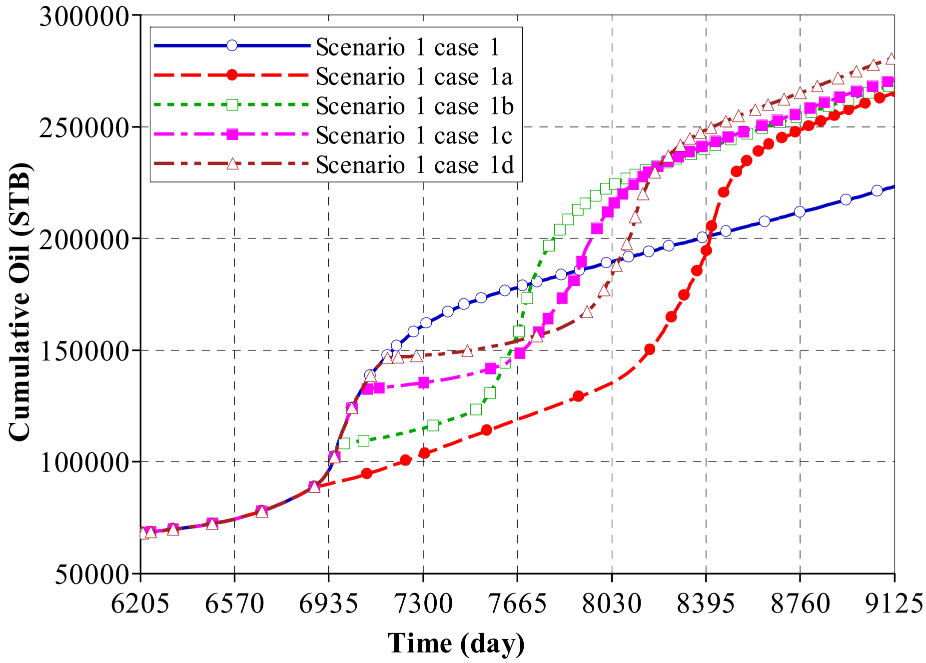

Fig. 4.8–Cumulative oil, Scenario 1, cases for 150 BPDCWE injection rate.

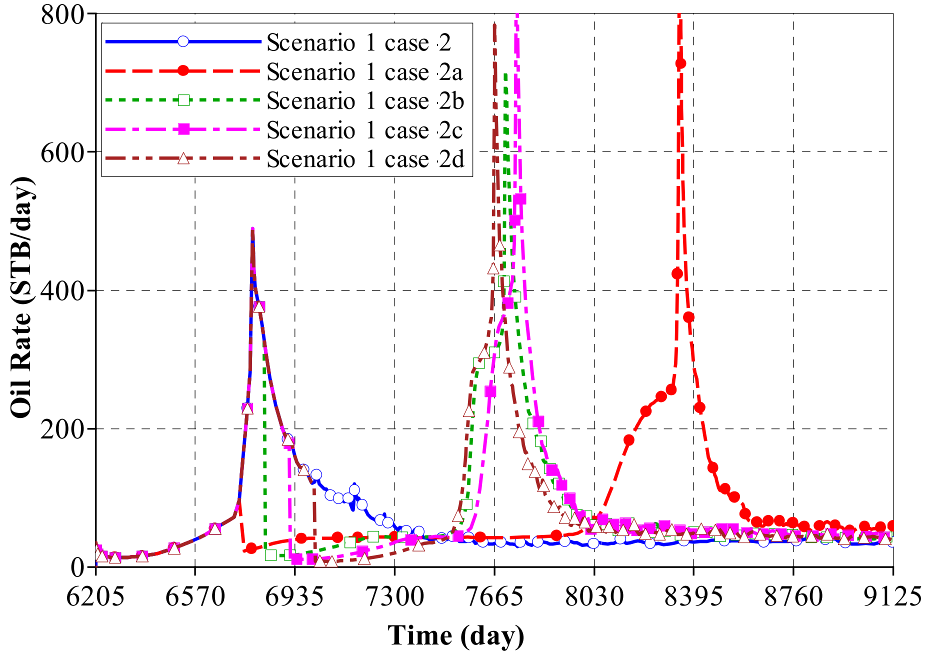

Fig. 4.9–Oil production rate, Scenario 1, cases for 200 BPDCWE injection rate.

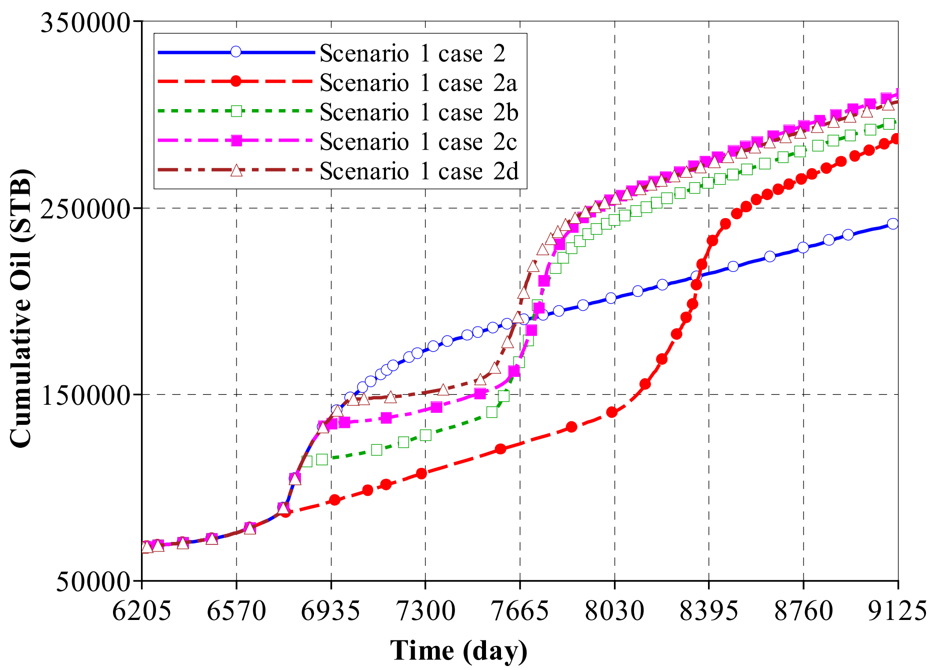

Fig. 4.10–Cumulative oil, Scenario 1, cases for 200 BPDCWE injection rate.

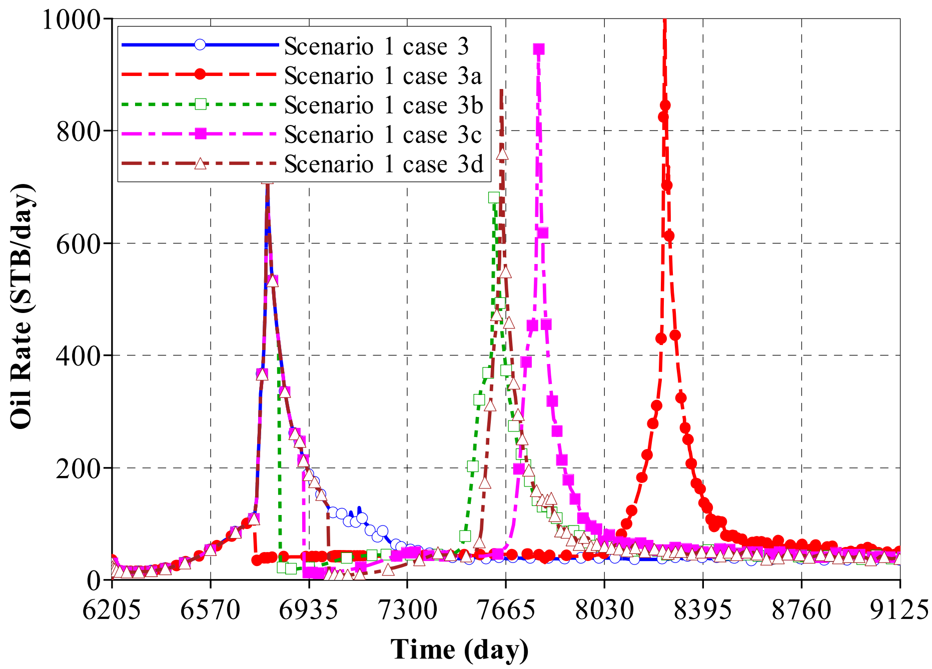

Fig. 4.11–Oil production rate, Scenario 1, cases for 250 BPDCWE injection rate.

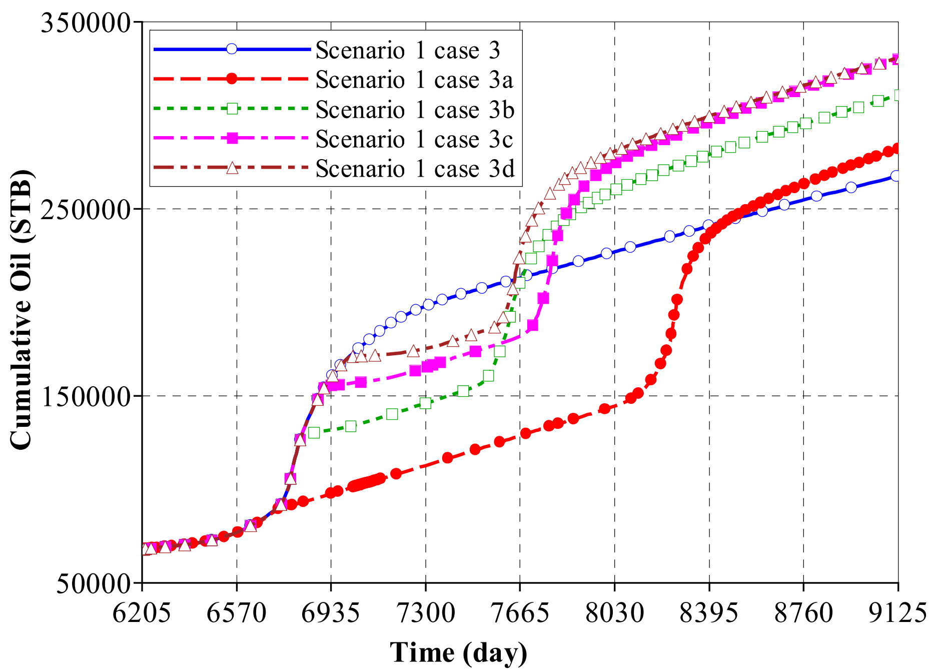

Fig. 4.12–Cumulative oil, Scenario 1, cases for 250 BPDCWE injection rate.

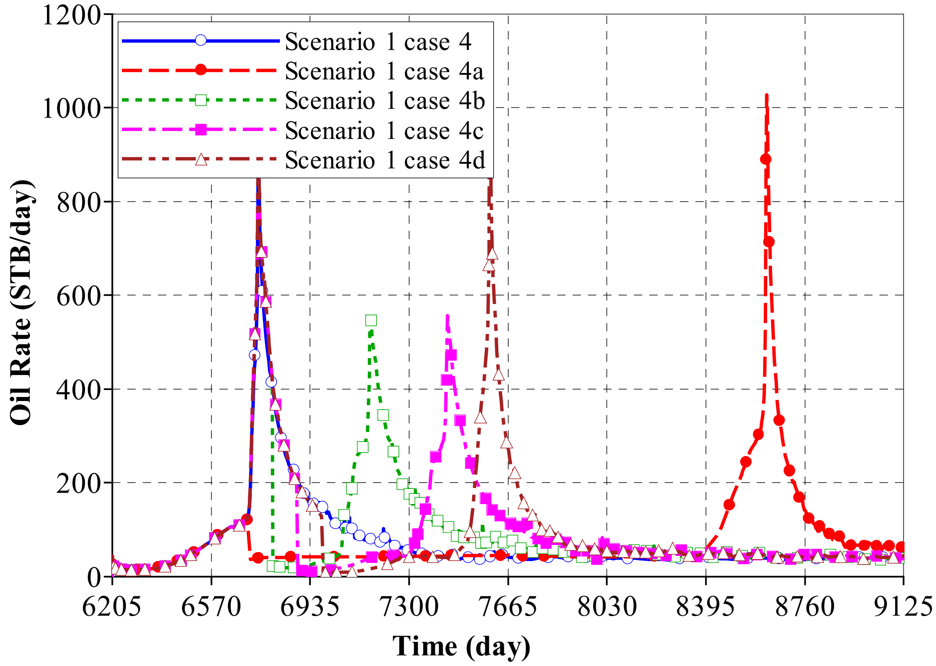

Fig. 4.13–Oil production rate, Scenario 1, cases for 300 BPDCWE injection rate.

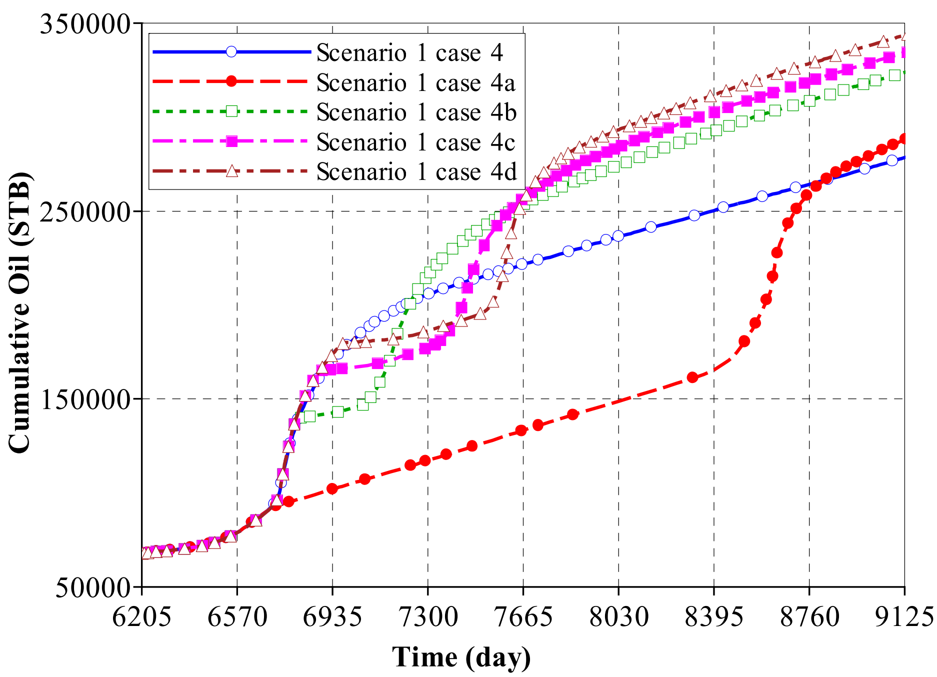

Fig. 4.14–Cumulative oil, Scenario 1, cases for 300 BPDCWE injection rate.

4.2.2 Scenario 2

In this scenario the smart horizontal producer is divided into three sections as shown in **Fig. 4.15**. Each section has a length of 110 ft. The smart horizontal well initially produces only with section 1 open (**Fig. 4.15** a). After steam breakthrough section 3 in the heel-end of the smart horizontal well is open and section 1 is closed (**Fig. 4.15** b).

Several cases in this Scenario 2 were performed. These cases include different injection rates and shut in times after breakthrough to find the best production performance. **Table 4.4** presents the cases simulated in Scenario 2.

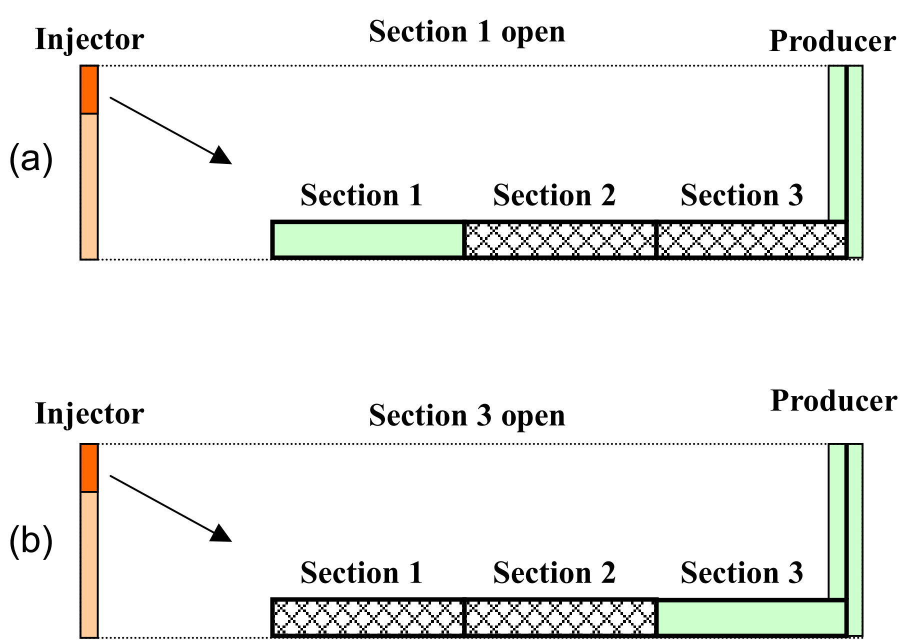

Fig. 4.15–Scenario 2, section 1 is open first (a) and after breakthrough section 3 is open and section 1 is closed (b).

TABLE 4.4–SCENARIO 2, SIMULATION CASES

Case 1	Injection rate = 150 BPDCWE, Section 1 all time open
Case 1a	Shut in section 1, open section 3 at breakthrough
Case 1b	Shut in section 1, open section 3, 3 months after breakthrough
Case 1c	Shut in section 1, open section 3, 6 months after breakthrough
Case 1d	Shut in section 1, open section 3, 9 months after breakthrough
Case 2	Injection rate = 200 BPDCWE, Section 1 all time open
Case 2a	Shut in section 1, open section 3 at breakthrough
Case 2b	Shut in section 1, open section 3, 3 months after breakthrough
Case 2c	Shut in section 1, open section 3, 6 months after breakthrough
Case 2d	Shut in section 1, open section 3, 9 months after breakthrough
Case 3	Injection rate = 250 BPDCWE, Section 1 all time open
Case 3a	Shut in section 1, open section 3 at breakthrough
Case 3b	Shut in section 1, open section 3, 3 months after breakthrough
Case 3c	Shut in section 1, open section 3, 6 months after breakthrough
Case 3d	Shut in section 1, open section 3, 9 months after breakthrough
Case 4	Injection rate = 300 BPDCWE, Section 1 all time open
Case 4a	Shut in section 1, open section 3 at breakthrough
Case 4b	Shut in section 1, open section 3, 3 months after breakthrough
Case 4c	Shut in section 1, open section 3, 6 months after breakthrough
Case 4d	Shut in section 1, open section 3, 9 months after breakthrough

Figs. 4.16 through **4.23** present the results for Scenario 2. **Table 4.5** compares the cumulative oil production and recovery factor for all cases. The best case in this scenario was Case 4d in which the injection rate was 300 BPDCWE and section 1 in the smart horizontal well was closed 9 months after steam breakthrough and section 3 was open (**Fig. 4.15**). The cumulative oil production for Case 4d was 324920 STB with a total oil recovery factor of 57.6% of the original oil in place for 8 years of steam injection.

TABLE 4.5–SCENARIO 2, CUMULATIVE OIL PRODUCTION AND RECOVERY FACTOR

Scenario 2	Cumulative oil, STB	Oil recovery, % OOIP
Case 1	225242	39.9
Case 1a	223420	39.6
Case 1b	270367	47.9
Case 1c	278968	49.5
Case 1d	278117	49.3
Case 2	242537	43.0
Case 2a	264346	46.9
Case 2b	282982	50.2
Case 2c	295268	52.4
Case 2d	300500	53.3
Case 3	253853	45.0
Case 3a	275345	48.8
Case 3b	298945	53.0
Case 3c	313514	55.6
Case 3d	325785	57.8
Case 4	263415	46.7
Case 4a	285411	50.6
Case 4b	316110	56.0
Case 4c	315819	56.0
Case 4d	324920	57.6

Scenario 2 results in lower oil recovery than Scenario 1 because the smart horizontal well produces a higher oil rate when it starts to produce with all the sections open. In Scenario 2, the horizontal well produces only from section 1 at start of production.

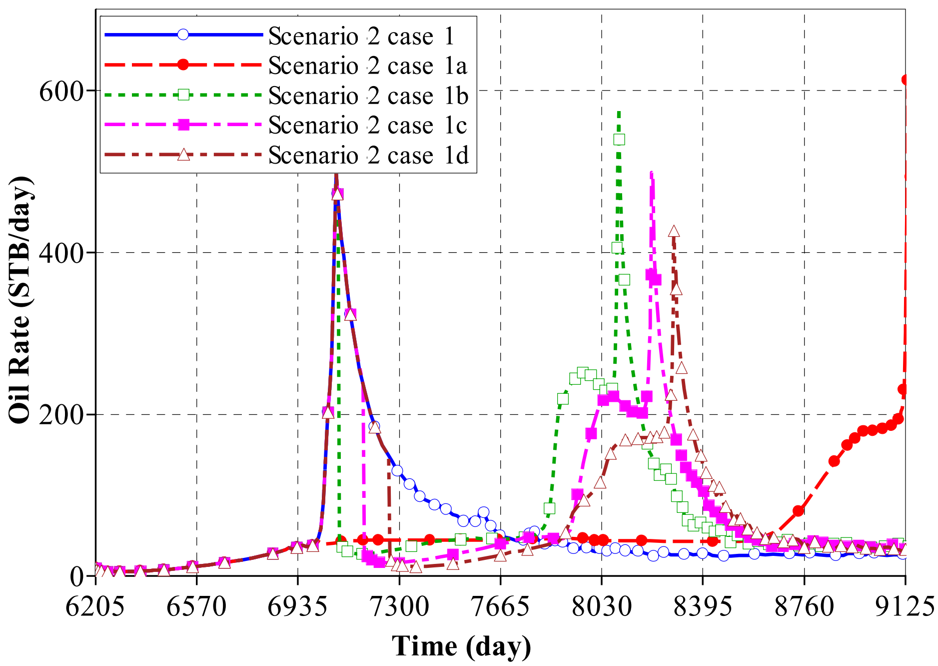

Fig. 4.16–Oil production rate, Scenario 2, cases for 150 BPDCWE injection rate.

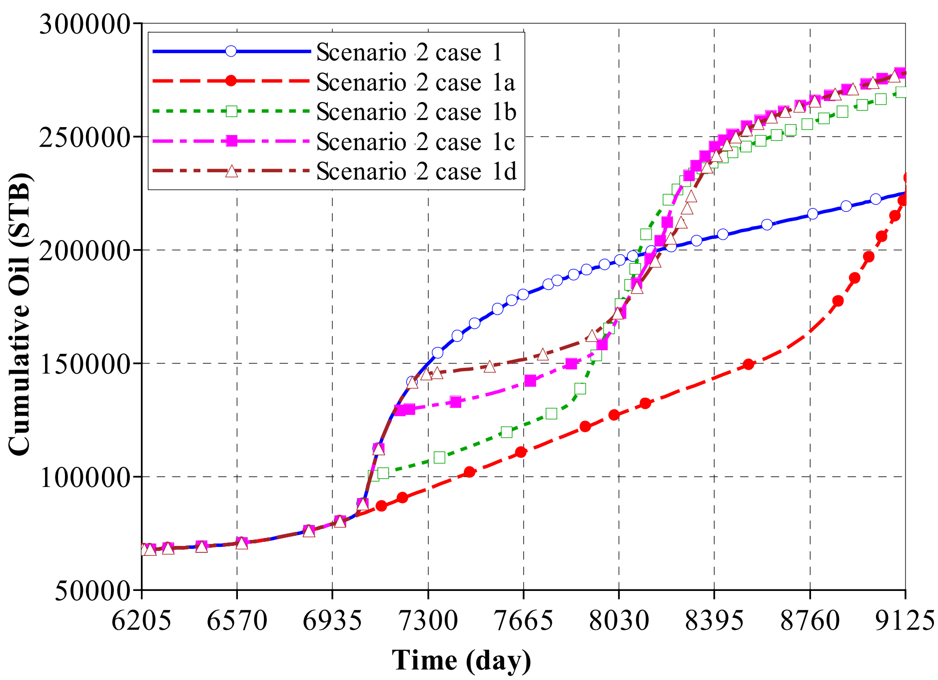

Fig. 4.17–Cumulative oil, Scenario 2, cases for 150 BPDCWE injection rate.

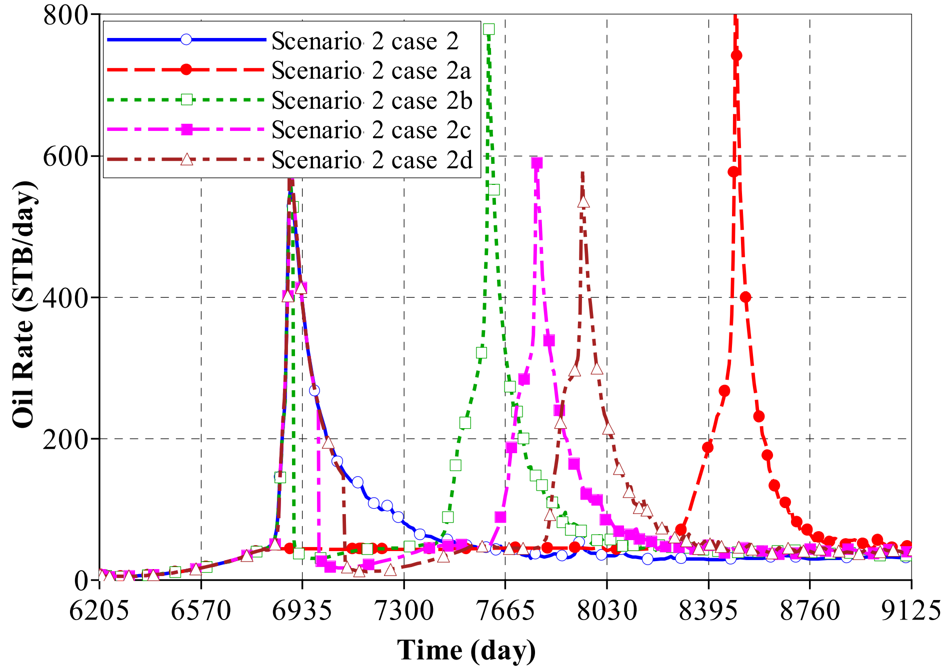

Fig. 4.18–Oil production rate, Scenario 2, cases for 200 BPDCWE injection rate.

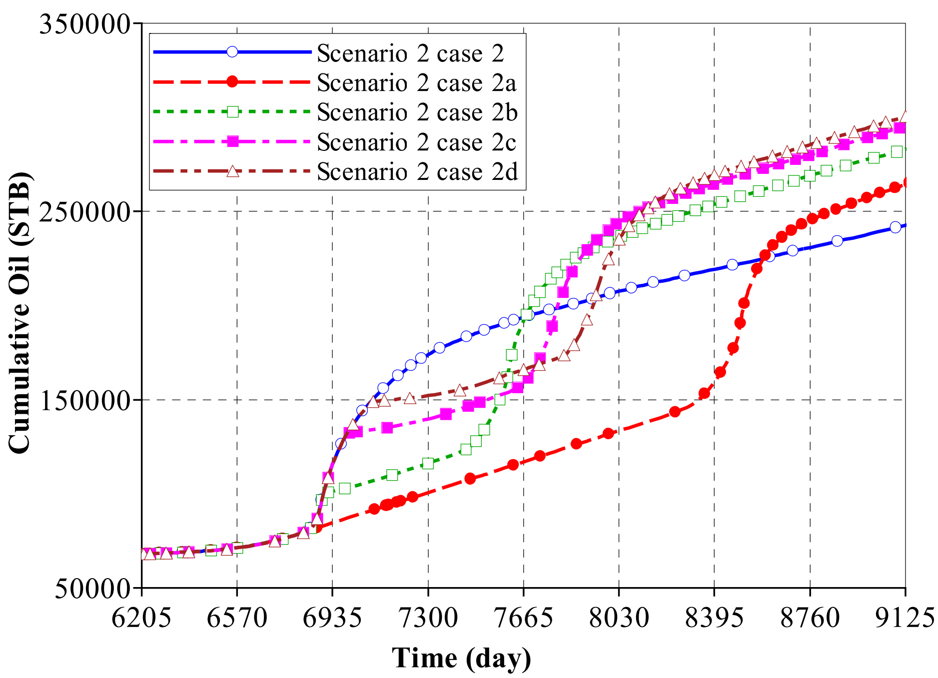

Fig. 4.19–Cumulative oil, Scenario 2, cases for 200 BPDCWE injection rate.

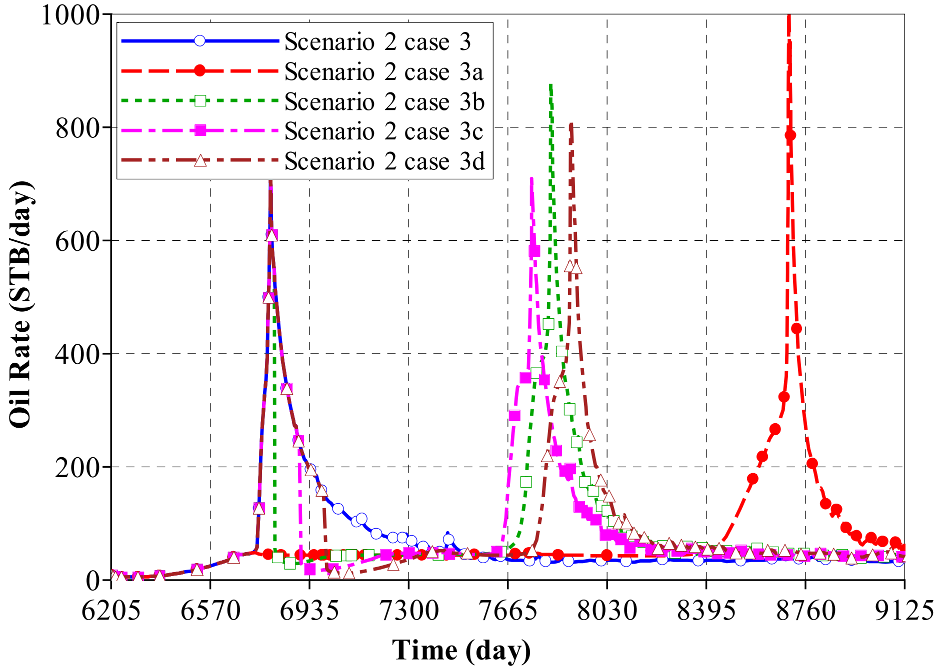

Fig. 4.20–Oil production rate, Scenario 2, cases for 250 BPDCWE injection rate.

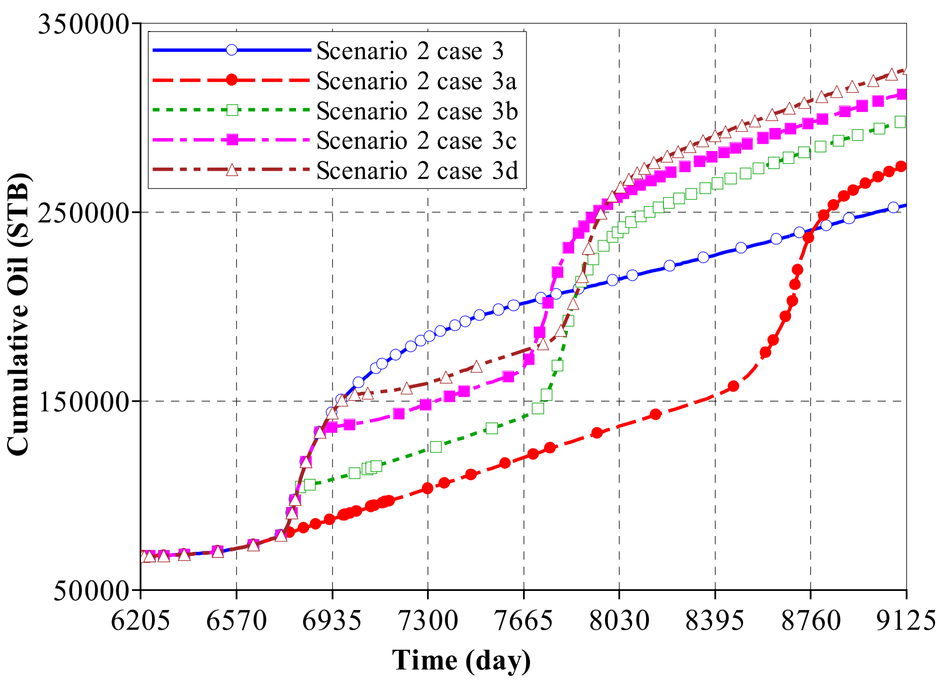

Fig. 4.21–Cumulative oil, Scenario 2, cases for 250 BPDCWE injection rate.

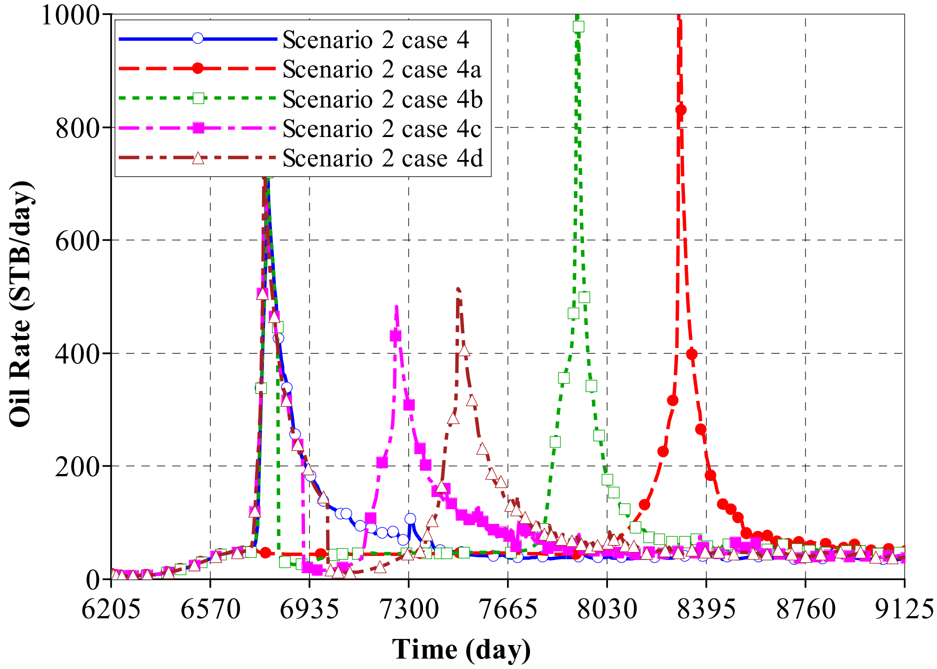

Fig. 4.22–Oil production rate, Scenario 2, cases for 300 BPDCWE injection rate.

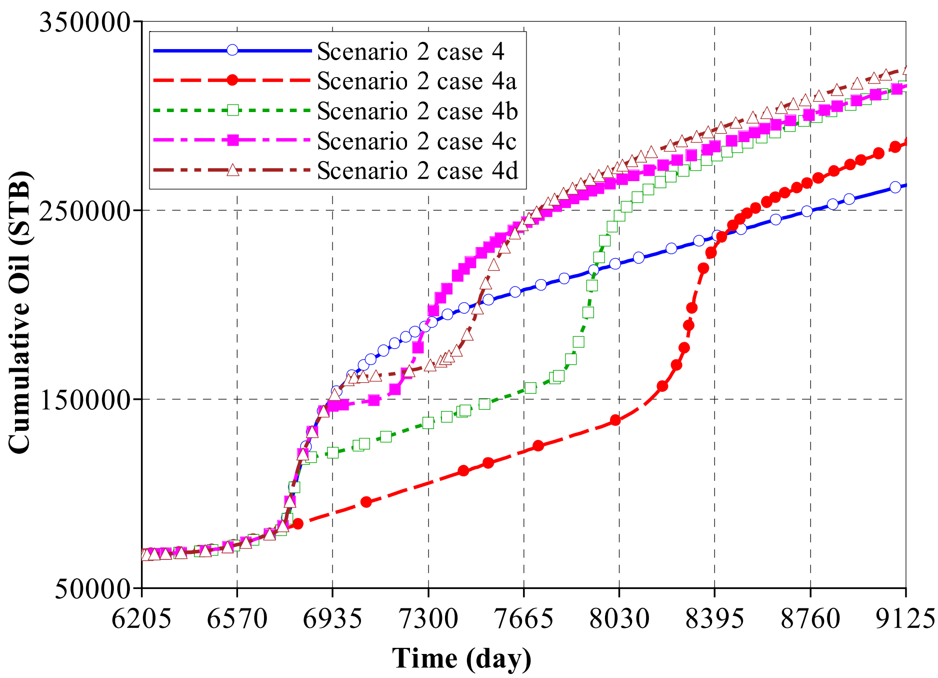

Fig. 4.23–Cumulative oil, Scenario 2, cases for 300 BPDCWE injection rate.

4.2.3 Scenario 3

In this scenario the smart horizontal producer is divided into three sections as shown in **Fig. 4.24**. Each section has a length of 110 ft. The smart horizontal well initially produces with all sections open. After breakthrough, section 1 is closed and the well produces from sections 2 and 3 (**Fig. 4.24** b). After the second breakthrough, section 2 is then closed and the horizontal well produces only from section 1 in its heel-end location (**Fig. 4.24** c).

Several cases were performed in this Scenario 3. These cases include injection rates of 200 and 250 BPDCWE and different shut in times after breakthrough in order to find the best production performance. **Table 4.6** presents the cases simulated in Scenario 3. For this scenario, only two injection rates were analyzed because the results showed a lower oil recovery than cases in Scenario 1.

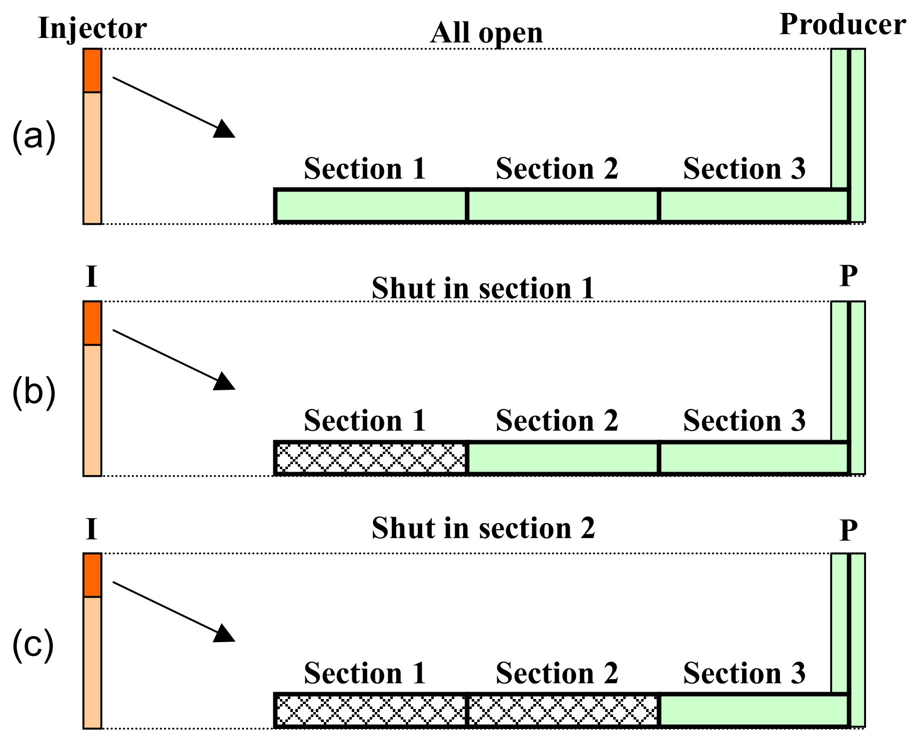

Fig. 4.24–Scenario 3, smart horizontal starts all open (a), after 1st breakthrough section 1 is closed (b), and after 2nd breakthrough section 2 is closed (c).

TABLE 4.6–SCENARIO 3, SIMULATION CASES

Case 1	Injection rate = 200 BPDCWE, Well all time open
Case 1a	Shut in section 1, 3 months after 1st breakthrough
Case 1b	Shut in section 1, 6 months after 1st breakthrough
Case 1c	Shut in section 1, 9 months after 1st breakthrough
Case 1d	Shut in section 1, 3 months after 1st breakthrough and shut in section 2, 3 months after 2nd breakthrough
Case 1e	Shut in section 1, 6 months after 1st breakthrough and shut in section 2, 6 months after 2nd breakthrough
Case 1f	Shut in section 1, 9 months after 1st breakthrough and shut in section 2, 9 months after 2nd breakthrough
Case 2	Injection rate = 250 BPDCWE, Well all time open
Case 2a	Shut in section 1, 3 months after 1st breakthrough
Case 2b	Shut in section 1, 6 months after 1st breakthrough
Case 2c	Shut in section 1, 9 months after 1st breakthrough
Case 2d	Shut in section 1, 3 months after 1st breakthrough and shut in section 2, 3 months after 2nd breakthrough
Case 2e	Shut in section 1, 6 months after 1st breakthrough and shut in section 2, 6 months after 2nd breakthrough
Case 2f	Shut in section 1, 9 months after 1st breakthrough and shut in section 2, 9 months after 2nd breakthrough

Figs. 4.25 through **4.28** present the results for Scenario 3. **Table 4.7** compares the cumulative oil production and recovery factor for all cases. The best case in this scenario was Case 2f in which the injection rate was 250 BPDCWE and section 1 in the smart horizontal well was closed 9 months after the first steam breakthrough and section 2 was closed 9 months after the second steam breakthrough (**Fig. 4.24**). The cumulative oil production for Case 2f was 317057 STB with a total oil recovery factor of 56.2% of the original oil in place for 8 years of steam injection.

TABLE 4.7–SCENARIO 3, CUMULATIVE OIL PRODUCTION AND RECOVERY FACTOR

Scenario 3	Cumulative oil, STB	Oil recovery, % OOIP
Case 1	241846	42.9
Case 1a	259641	46.0
Case 1b	277844	49.3
Case 1c	263347	46.7
Case 1d	284388	50.4
Case 1e	266714	47.3
Case 1f	293034	52.0
Case 2	267479	47.4
Case 2a	281303	49.9
Case 2b	301463	53.4
Case 2c	287283	50.9
Case 2d	305804	54.2
Case 2e	292338	51.8
Case 2f	317057	56.2

Although the smart horizontal well presents three production peaks in Scenario 3, the cumulative oil production is lower than in Scenario 1 and Scenario 2 in which the production presented two peaks. This is due to the second breakthrough in Scenario 3 being earlier because there is less spacing to delay steam breakthrough and the additional production peak is low. This results in the sweep efficiency of oil to be decreased.

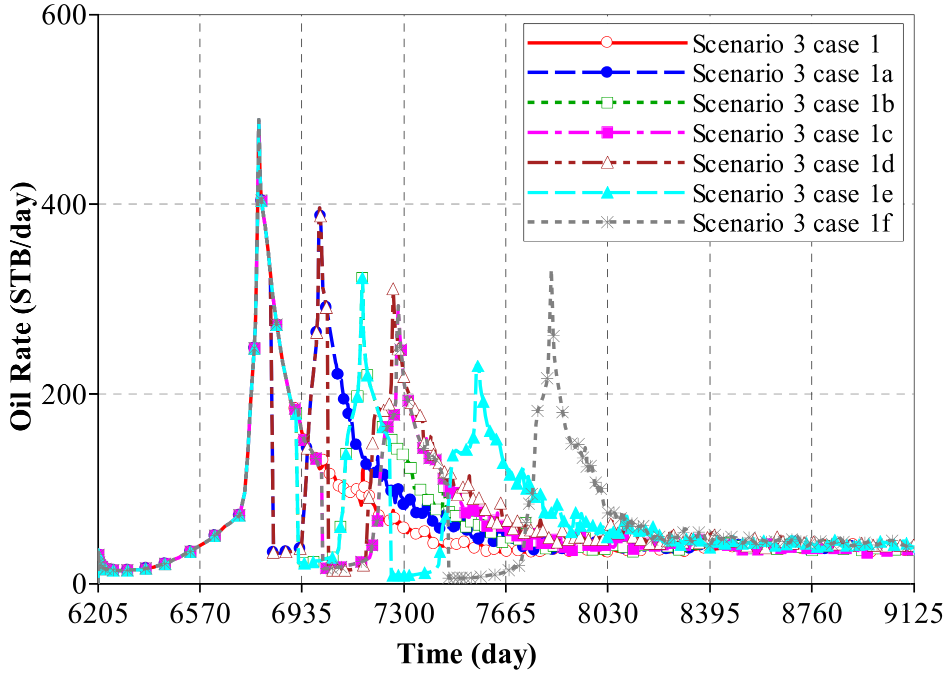

Fig. 4.25–Oil production rate, Scenario 3, cases for 200 BPDCWE injection rate.

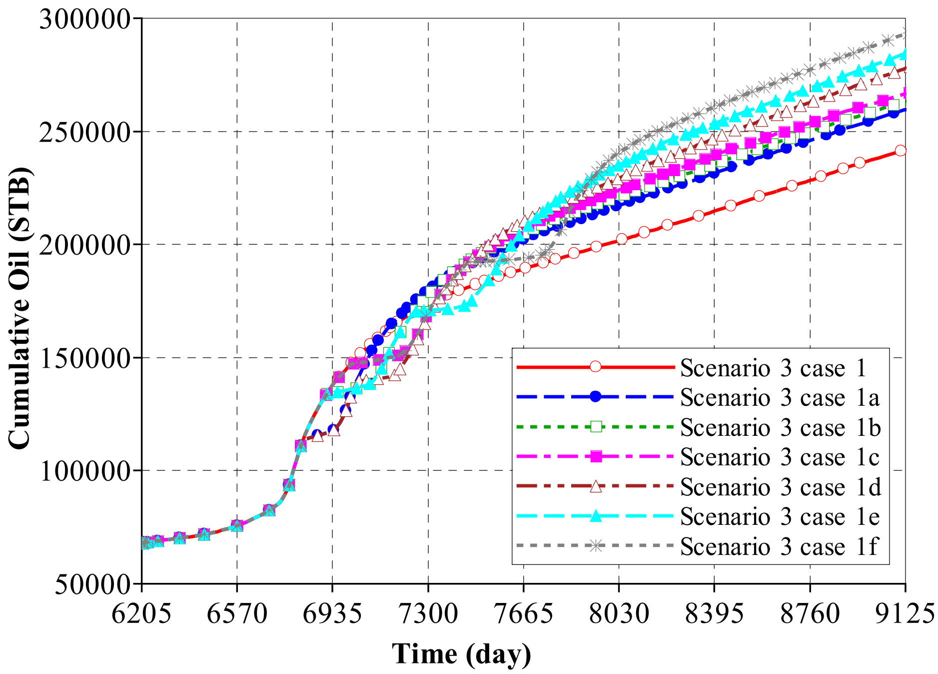

Fig. 4.26–Cumulative oil, Scenario 3, cases for 200 BPDCWE injection rate.

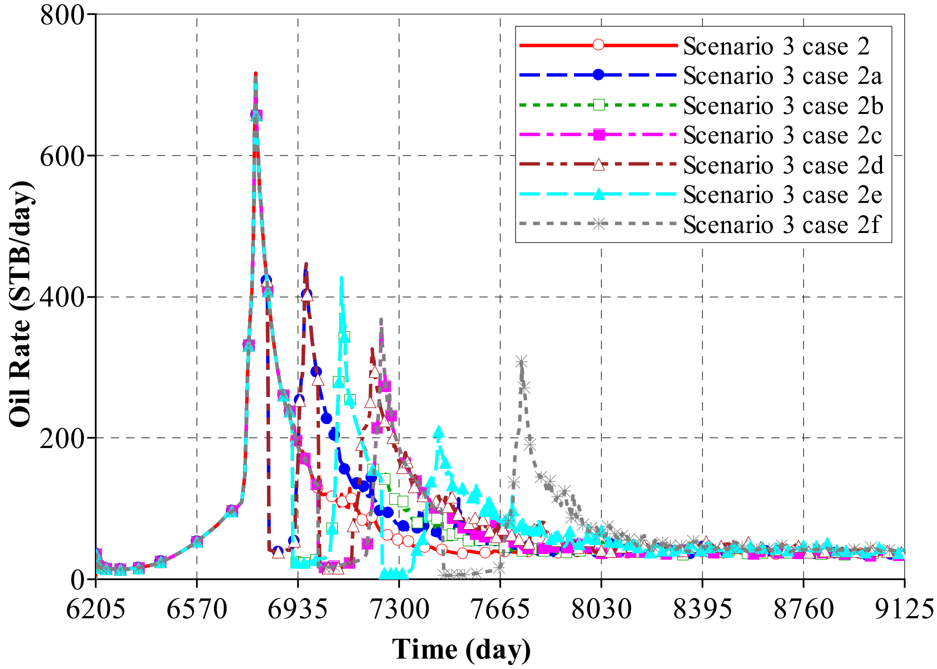

Fig. 4.27–Oil production rate, Scenario 3, cases for 250 BPDCWE injection rate.

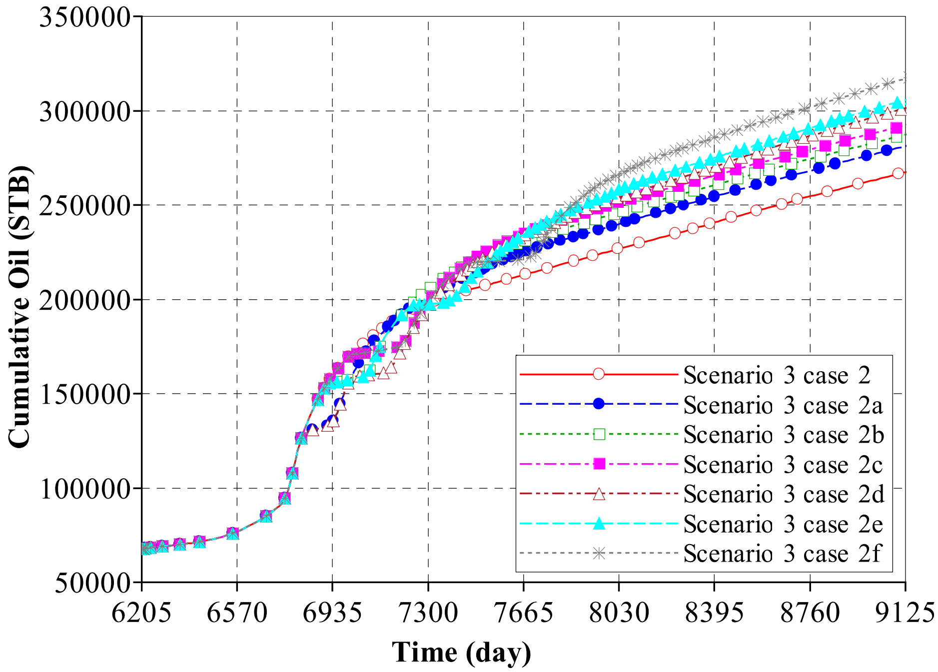

Fig. 4.28–Cumulative oil, Scenario 3, cases for 250 BPDCWE injection rate.

4.2.4 Scenario 4

In this scenario the smart horizontal producer is divided into three sections as shown in **Fig. 4.29**. Each section has a length of 110 ft. The smart horizontal initially produces only with section 1 open (**Fig. 4.29** a). After the first steam breakthrough, section 2 is open and section 1 is closed (**Fig. 4.29** b). After the second breakthrough, section 2 is closed and section 3 in the heel-end of the smart horizontal well, is open (**Fig. 4.29** c).

Several cases were performed in Scenario 4. These cases include injection rates of 200 and 250 BPDCWE and different shut in times after breakthrough in order to find the best production performance. **Table 4.8** presents the cases simulated in Scenario 4. For this Scenario 4 as in Scenario 3, only two injection rates were analyzed because the results showed a lower oil recovery than cases in Scenario 1.

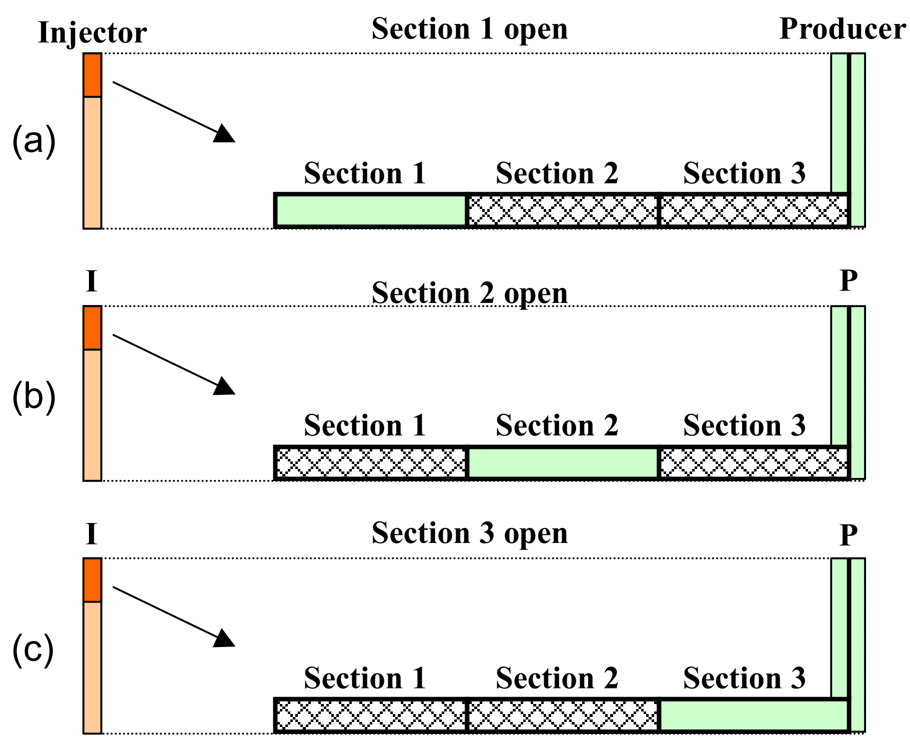

Fig. 4.29–Scenario 4, section 1 is open first (a), after 1st breakthrough section 2 is open and section 1 is closed (b), after 2nd breakthrough only section 3 is open (c).

TABLE 4.8–SCENARIO 4, SIMULATION CASES

Case 1	Injection rate = 200 BPDCWE, section 1 all time open
Case 1a	Shut in section 1, open section 2, 3 months after 1st breakthrough
Case 1b	Shut in section 1, open section 2, 6 months after 1st breakthrough
Case 1c	Shut in section 1, open section 2, 9 months after 1st breakthrough
Case 1d	Shut in section 1, open section 2, 3 months after 1st breakthrough; shut in section 2, open section 3, 3 months after 2nd breakthrough
Case 1e	Shut in section 1, open section 2, 6 months after 1st breakthrough; shut in section 2, open section 3, 6 months after 2nd breakthrough
Case 1f	Shut in section 1, open section 2, 9 months after 1st breakthrough; shut in section 2, open section 3, 9 months after 2nd breakthrough
Case 2	Injection rate = 250 BPDCWE, section 1 all time open
Case 2a	Shut in section 1, open section 2, 3 months after 1st breakthrough
Case 2b	Shut in section 1, open section 2, 6 months after 1st breakthrough
Case 2c	Shut in section 1, open section 2, 9 months after 1st breakthrough
Case 2d	Shut in section 1, open section 2, 3 months after 1st breakthrough; shut in section 2, open section 3, 3 months after 2nd breakthrough
Case 2e	Shut in section 1, open section 2, 6 months after 1st breakthrough; shut in section 2, open section 3, 6 months after 2nd breakthrough
Case 2f	Shut in section 1, open section 2, 9 months after 1st breakthrough; shut in section 2, open section 3, 9 months after 2nd breakthrough

Figs. 4.30 through **4.33** present the results for cases in Scenario 3. **Table 4.9** compares the cumulative oil production and recovery factor for all cases. The best case in this scenario was Case 2f in which the injection rate was 250 BPDCWE, the section 1 in the smart horizontal well was closed 9 months after the first steam breakthrough and section 2 was open, then section 2 was closed 9 months after the second breakthrough and section 1 was open (**Fig. 4.29**). The cumulative oil production for Case 2f was 302699 STB with a total oil recovery factor of 53.7% of the original oil in place for 8 years of steam injection.

TABLE 4.9–SCENARIO 4, CUMULATIVE OIL PRODUCTION AND RECOVERY FACTOR

Scenario 4	Cumulative oil, STB	Oil recovery, % OOIP
Case 1	242537	43.0
Case 1a	255751	45.3
Case 1b	272913	48.4
Case 1c	258126	45.8
Case 1d	277831	49.3
Case 1e	260283	46.1
Case 1f	281511	49.9
Case 2	253853	45.0
Case 2a	270615	48.0
Case 2b	292137	51.8
Case 2c	276144	49.0
Case 2d	301223	53.4
Case 2e	278805	49.4
Case 2f	302699	53.7

As in Scenario 3, although the smart horizontal well presents three production peaks in this Scenario 4, the cumulative oil is lower than in Scenario 1 and Scenario 2 in which the production presented two peaks. The second breakthrough in Scenario 4 is faster because of lesser spacing and the additional production peak is low. In this way, the sweep efficiency of oil is decreased.

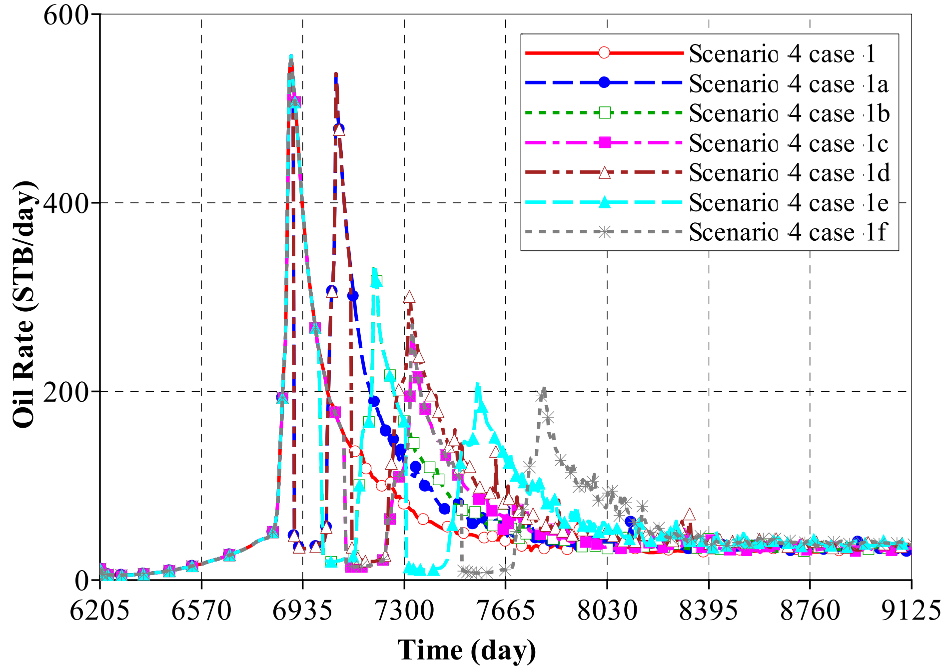

Fig. 4.30–Oil production rate, Scenario 4, cases for 200 BPDCWE injection rate.

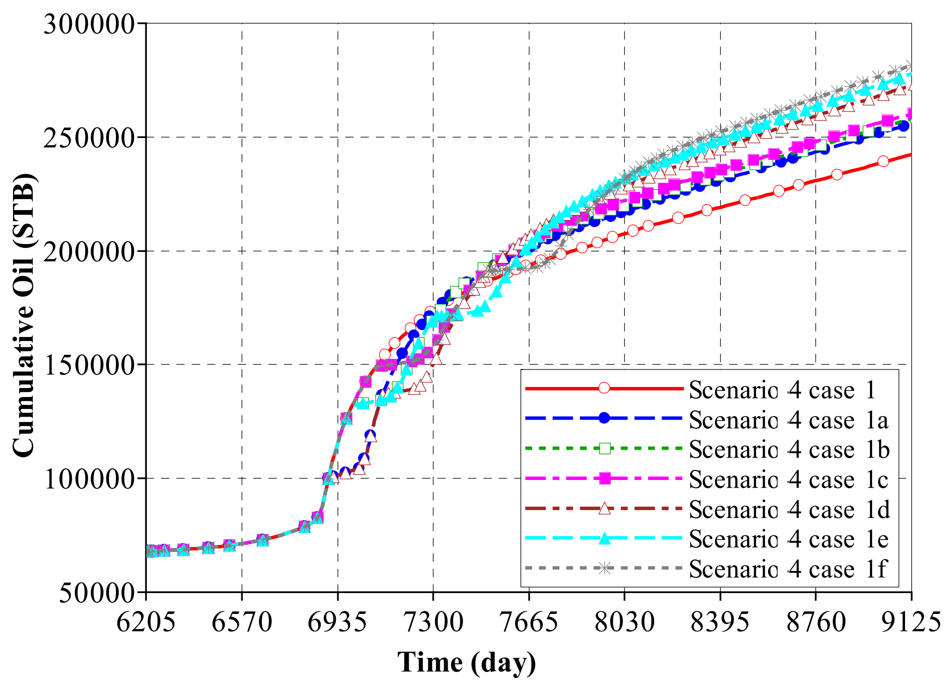

Fig. 4.31–Cumulative oil, Scenario 4, cases for 200 BPDCWE injection rate.

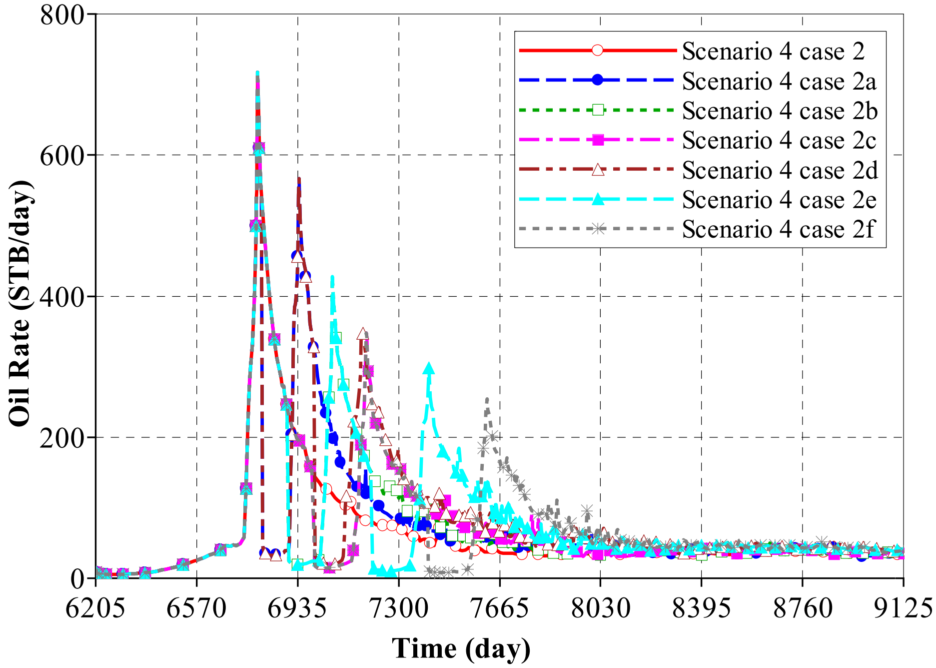

Fig. 4.32–Oil production rate, Scenario 4, cases for 250 BPDCWE injection rate.

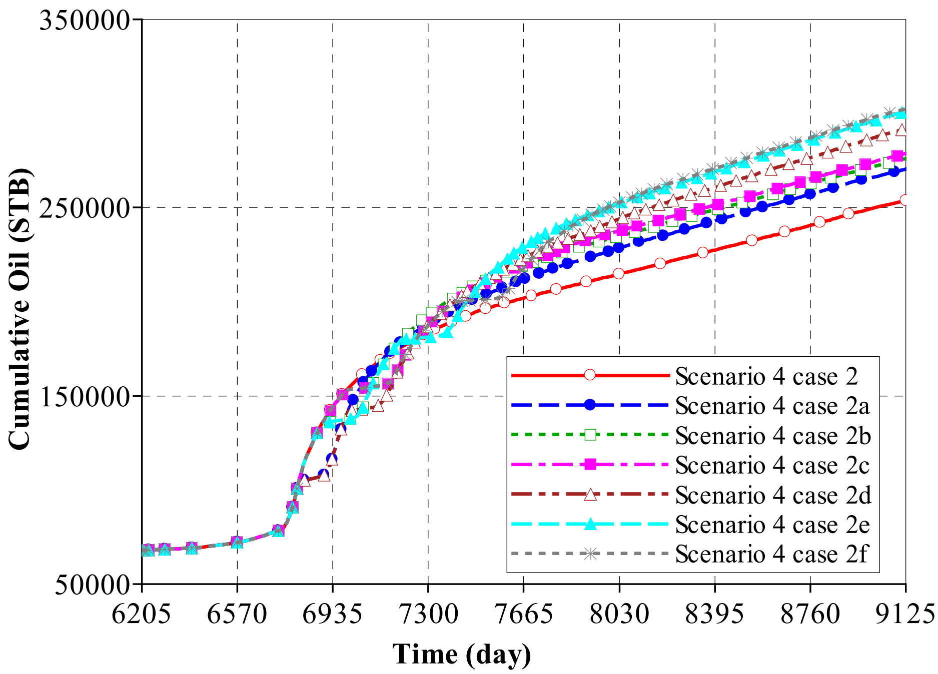

Fig. 4.33–Cumulative oil, Scenario 4, cases for 250 BPDCWE injection rate.

4.2.5 Scenario 5

In this scenario the smart horizontal producer is divided into five sections as shown in **Fig. 4.34**. Each section has a length of 66 ft. The smart horizontal producer begins production with all sections open (**Fig. 4.34** a). After the first steam breakthrough sections 1 and 2 are closed (**Fig 4.34** b). After the second breakthrough sections 3 and 4 are closed and section 5 in the heel-end of the smart horizontal well is kept open (**Fig. 4.34** c).

Similar to Scenario 1, several cases in Scenario 5 were performed. These cases include different injection rates and shut in times after breakthrough to find the best production performance. **Table 4.10** and **Table 4.11** present the cases simulated in Scenario 5.

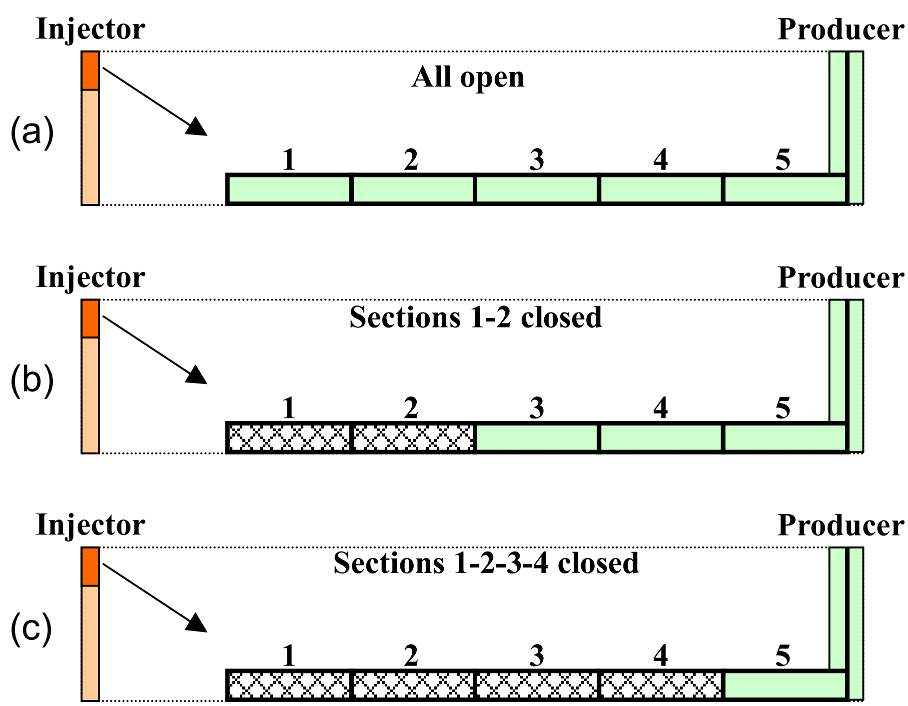

Fig. 4.34–Scenario 5, smart horizontal starts all open (a), after 1st breakthrough section 1 and 2 are closed (b), after 2nd breakthrough sections 3 and 4 are closed (c).

TABLE 4.10–SCENARIO 5, SIMULATION CASES FOR 150 AND 200 BPDCWE INJECTION

Case 1	Injection rate = 150 BPDCWE, Well all time open
Case 1a	Shut in sections 1-2 in the 1st breakthrough
Case 1b	Shut in sections 1-2, 3 months after 1st breakthrough
Case 1c	Shut in sections 1-2, 6 months after 1st breakthrough
Case 1d	Shut in sections 1-2, 9 months after 1st breakthrough
Case 1e	Shut in sections 1-2 in the 1st breakthrough, shut in sections 3-4 in the 2nd breakthrough
Case 1f	Shut in sections 1-2, 3 months after 1st breakthrough; shut in sections 3-4, 3 months after 2nd breakthrough
Case 1g	Shut in sections 1-2, 6 months after 1st breakthrough; shut in sections 3-4, 6 months after 2nd breakthrough
Case 1h	Shut in sections 1-2, 9 months after 1st breakthrough; shut in sections 3-4, 9 months after 2nd breakthrough
Case 2	Injection rate = 200 BPDCWE, Well all time open
Case 2a	Shut in sections 1-2 in the 1st breakthrough
Case 2b	Shut in sections 1-2, 3 months after 1st breakthrough
Case 2c	Shut in sections 1-2, 6 months after 1st breakthrough
Case 2d	Shut in sections 1-2, 9 months after 1st breakthrough
Case 2e	Shut in sections 1-2 in the 1st breakthrough, shut in sections 3-4 in the 2nd breakthrough
Case 2f	Shut in sections 1-2, 3 months after 1st breakthrough; shut in sections 3-4, 3 months after 2nd breakthrough
Case-2g	Shut in sections 1-2, 6 months after 1st breakthrough; shut in sections 3-4, 6 months after 2nd breakthrough
Case-2h	Shut in sections 1-2, 9 months after 1st breakthrough; shut in sections 3-4, 9 months after 2nd breakthrough

TABLE 4.11–SCENARIO 5, SIMULATION CASES FOR 250 AND 300 BPDCWE INJECTION

Case 3	Injection rate = 250 BPDCWE, Well all time open
Case 3a	Shut in sections 1-2 in the 1st breakthrough
Case 3b	Shut in sections 1-2, 3 months after 1st breakthrough
Case 3c	Shut in sections 1-2, 6 months after 1st breakthrough
Case 3d	Shut in sections 1-2, 9 months after 1st breakthrough
Case 3e	Shut in sections 1-2 in the 1st breakthrough, shut in sections 3-4 in the 2nd breakthrough
Case 3f	Shut in sections 1-2, 3 months after 1st breakthrough; shut in sections 3-4, 3 months after 2nd breakthrough
Case 3g	Shut in sections 1-2, 6 months after 1st breakthrough; shut in sections 3-4, 6 months after 2nd breakthrough
Case 3h	Shut in sections 1-2, 9 months after 1st breakthrough; shut in sections 3-4, 9 months after 2nd breakthrough
Case 4	Injection rate = 300 BPDCWE, Well all time open
Case 4a	Shut in sections 1-2 in the 1st breakthrough
Case 4b	Shut in sections 1-2, 3 months after 1st breakthrough
Case 4c	Shut in sections 1-2, 6 months after 1st breakthrough
Case 4d	Shut in sections 1-2, 9 months after 1st breakthrough
Case 4e	Shut in sections 1-2 in the 1st breakthrough, shut in sections 3-4 in the 2nd breakthrough
Case 4f	Shut in sections 1-2, 3 months after 1st breakthrough; shut in sections 3-4, 3 months after 2nd breakthrough
Case 4g	Shut in sections 1-2, 6 months after 1st breakthrough; shut in sections 3-4, 6 months after 2nd breakthrough
Case 4h	Shut in sections 1-2, 9 months after 1st breakthrough; shut in sections 3-4, 9 months after 2nd breakthrough

Figs. 4.35 through **4.50** present the results for the Scenario 5. **Table 4.12** and **Table 4.13** compare the cumulative oil production and recovery factor for all cases. The best case in this scenario was Case 4h in which the injection rate was 300 BPDCWE, the sections 1 and 2 in the smart horizontal well were closed 9 months after the first steam breakthrough, and sections 3 and 4 were closed 9 months after the second breakthrough (**Fig. 4.34**). The cumulative oil production for Case 4h was 340722 STB with a total oil recovery factor of 60.4% of the original oil in place for 8 years of steam injection.

TABLE 4.12–SCENARIO 5, CUMULATIVE OIL PRODUCTION AND RECOVERY FACTOR, CASES FOR 150 AND 200 BPDCWE INJECTION

Scenario 5	Cumulative oil, STB	Oil recovery, % OOIP
Case 1	223335	39.6
Case 1a	263358	46.7
Case 1b	238150	42.2
Case 1c	243352	43.1
Case 1d	245675	43.6
Case 1e	269141	47.7
Case 1f	257960	45.7
Case 1g	260523	46.2
Case 1h	263881	46.8
Case 2	241846	42.9
Case 2a	282037	50.0
Case 2b	267634	47.5
Case 2c	274311	48.6
Case 2d	279857	49.6
Case 2e	284447	50.4
Case 2f	289945	51.4
Case 2g	294303	52.2
Case 2h	302948	53.7

TABLE 4.13–SCENARIO 5, CUMULATIVE OIL PRODUCTION AND RECOVERY FACTOR, CASES FOR 250 AND 300 BPDCWE INJECTION

Scenario 5	Cumulative oil, STB	Oil recovery, % OOIP
Case 3	267479	47.4
Case 3a	294805	52.3
Case 3b	290856	51.6
Case 3c	297159	52.7
Case 3d	307113	54.5
Case 3e	301519	53.5
Case 3f	316009	56.0
Case 3g	318075	56.4
Case 3h	329429	58.4
Case 4	278522	49.4
Case 4a	304105	53.9
Case 4b	301730	53.5
Case 4c	311130	55.2
Case 4d	314232	55.7
Case 4e	303629	53.8
Case 4f	330601	58.6
Case 4g	335550	59.5
Case 4h	340722	60.4

Although the best result in this Scenario 5 (60.4% of OOIP) is close to the best result in Scenario 1 (60.9% OOIP), so far Scenario 1 is the simplest and highest in order to be applied in the smart horizontal producer.

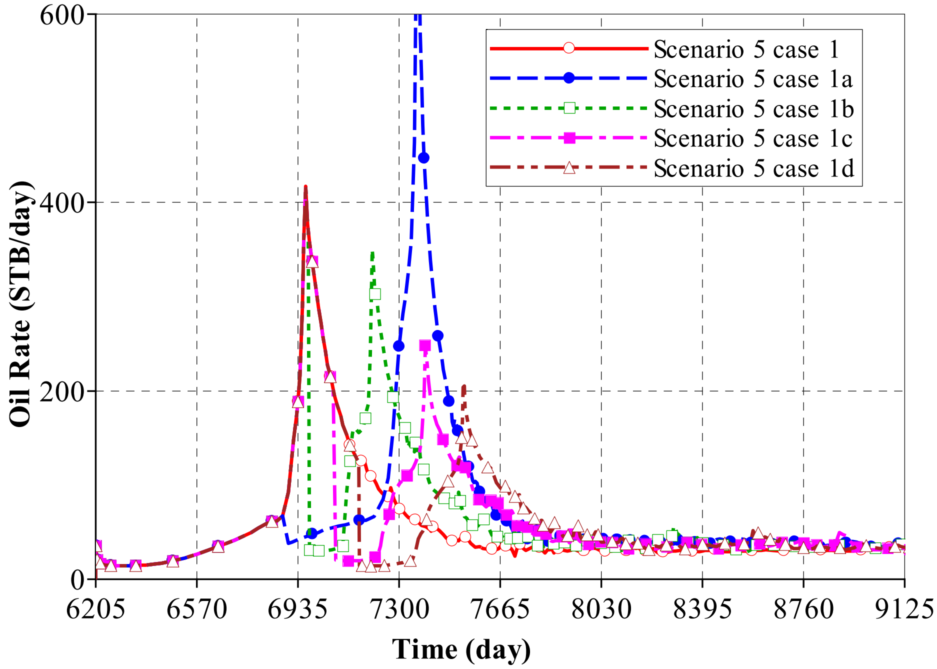

Fig. 4.35–Oil production rate, Scenario 5, 150 BPDCWE, Case 1a to Case 1d.

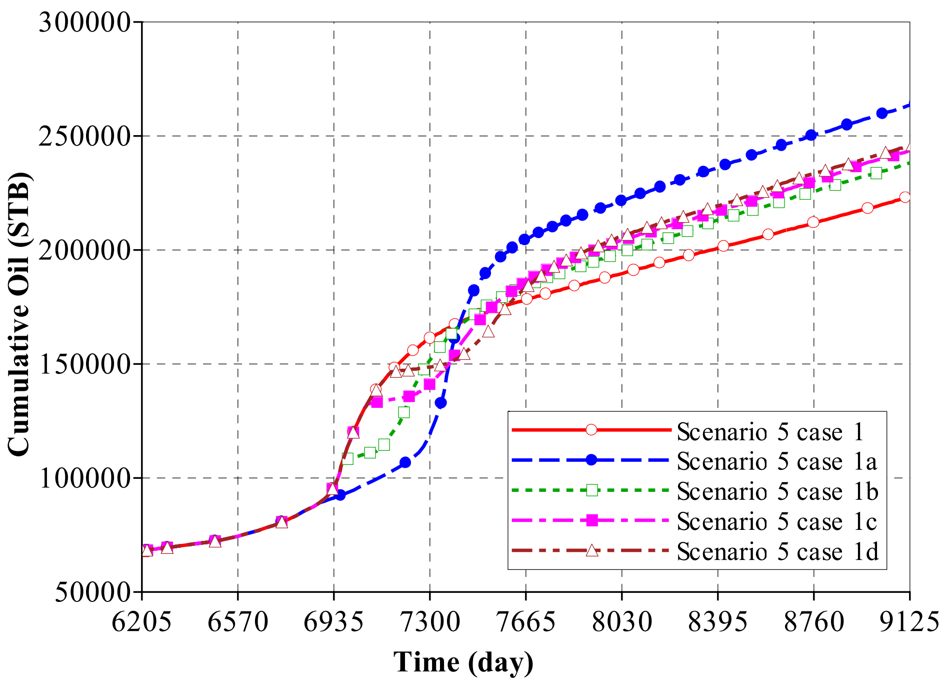

Fig. 4.36–Cumulative oil, Scenario 5, 150 BPDCWE, Case 1a to Case 1d.

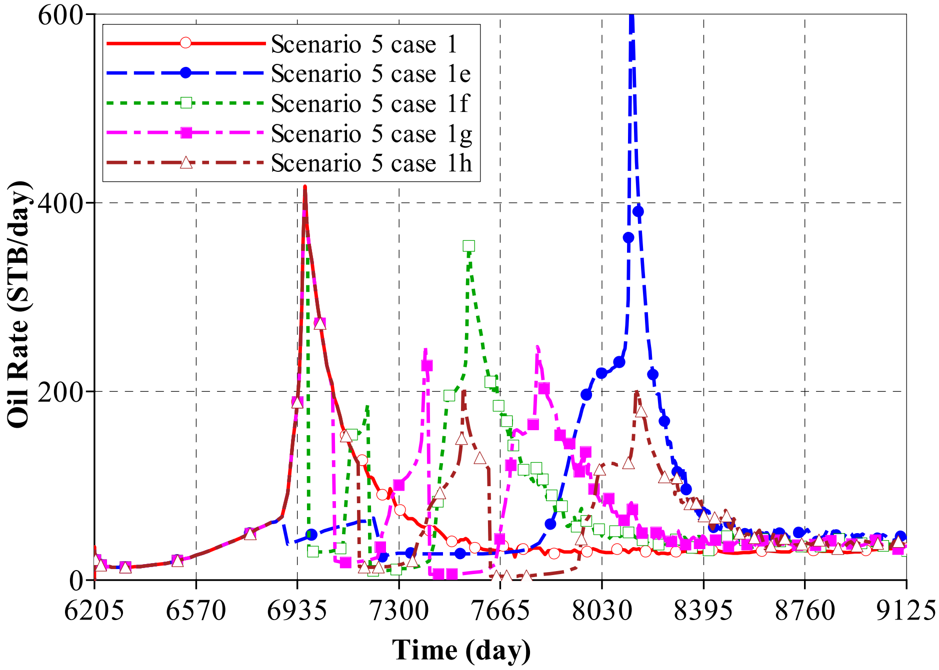

Fig. 4.37–Oil production rate, Scenario 5, 150 BPDCWE, Case 1e to Case 1h.

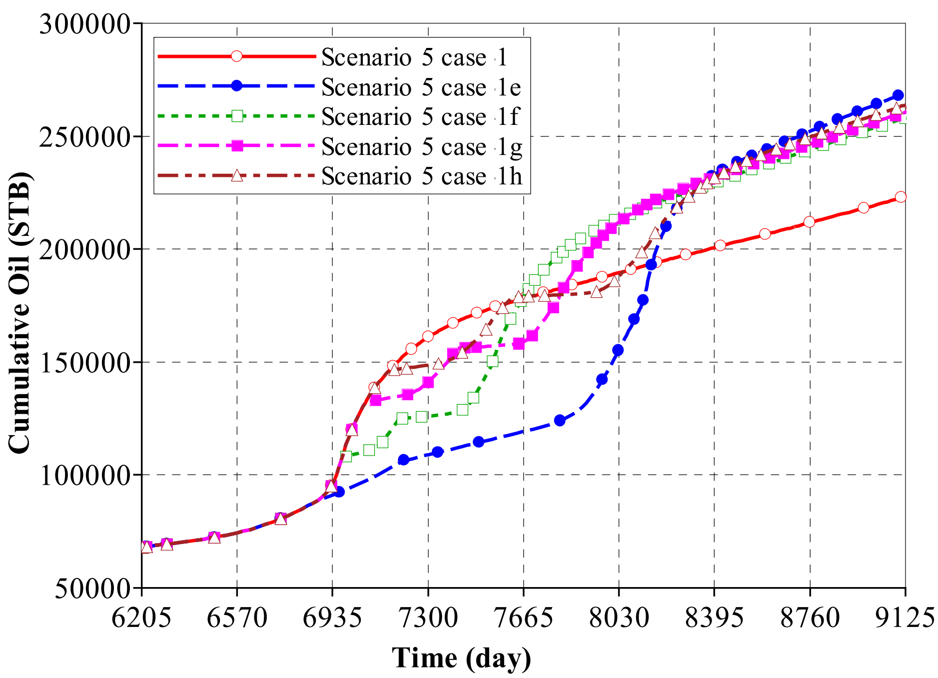

Fig. 4.38–Cumulative oil, Scenario 5, 150 BPDCWE, Case 1e to Case 1h.

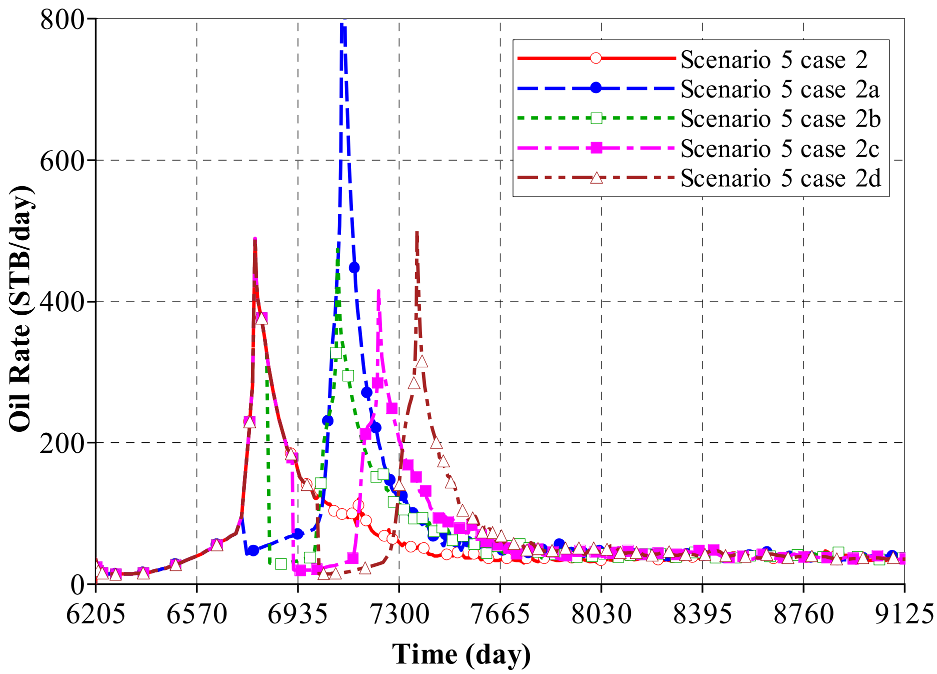

Fig. 4.39–Oil production rate, Scenario 5, 200 BPDCWE, Case 2a to Case 2d.

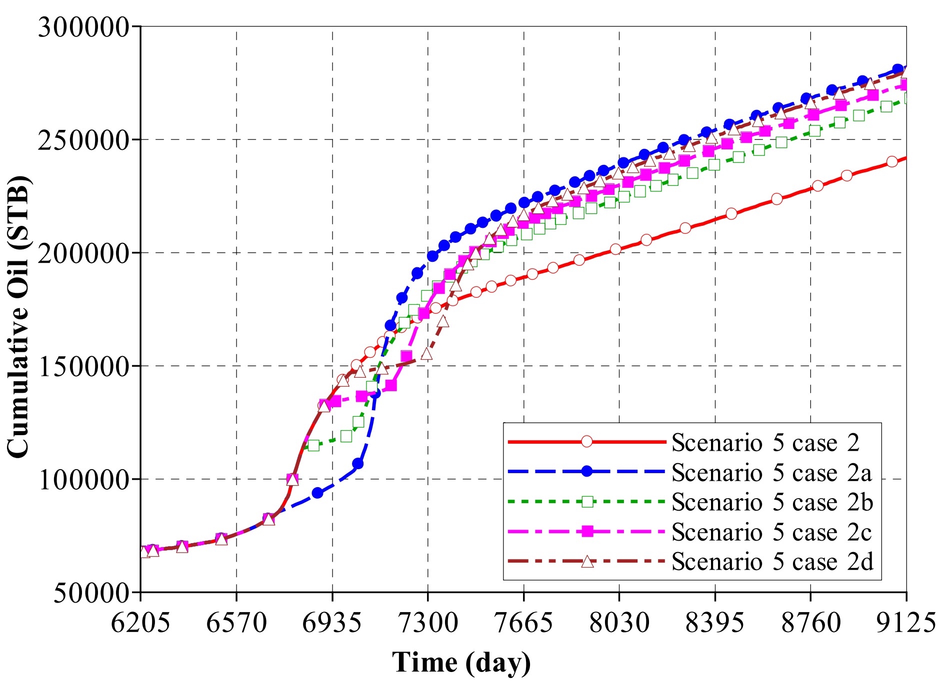

Fig. 4.40–Cumulative oil, Scenario 5, 200 BPDCWE, Case 2a to Case 2d.

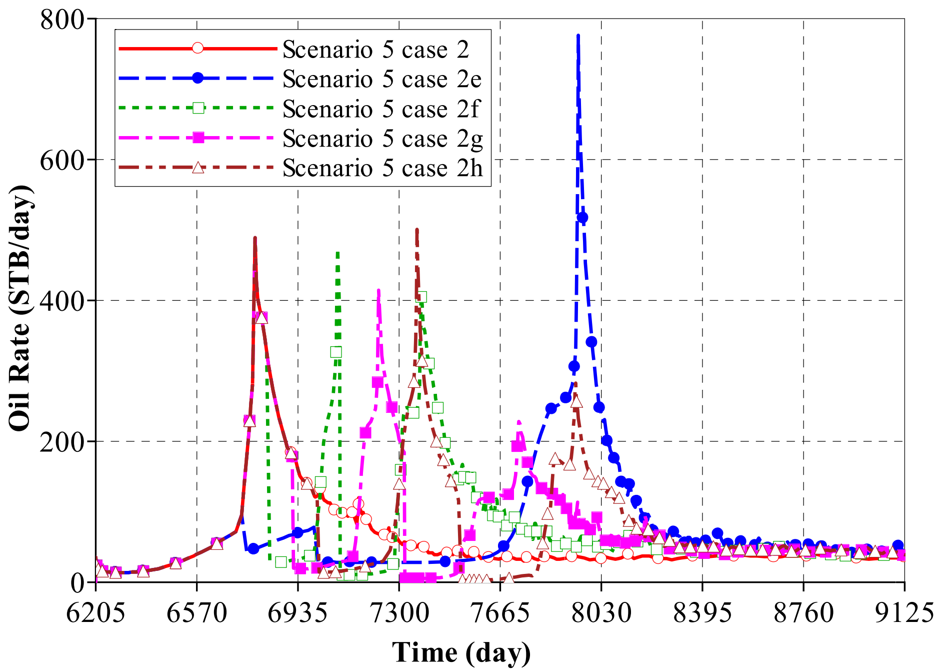

Fig. 4.41–Oil production rate, Scenario 5, 200 BPDCWE, Case 2e to Case 2h.

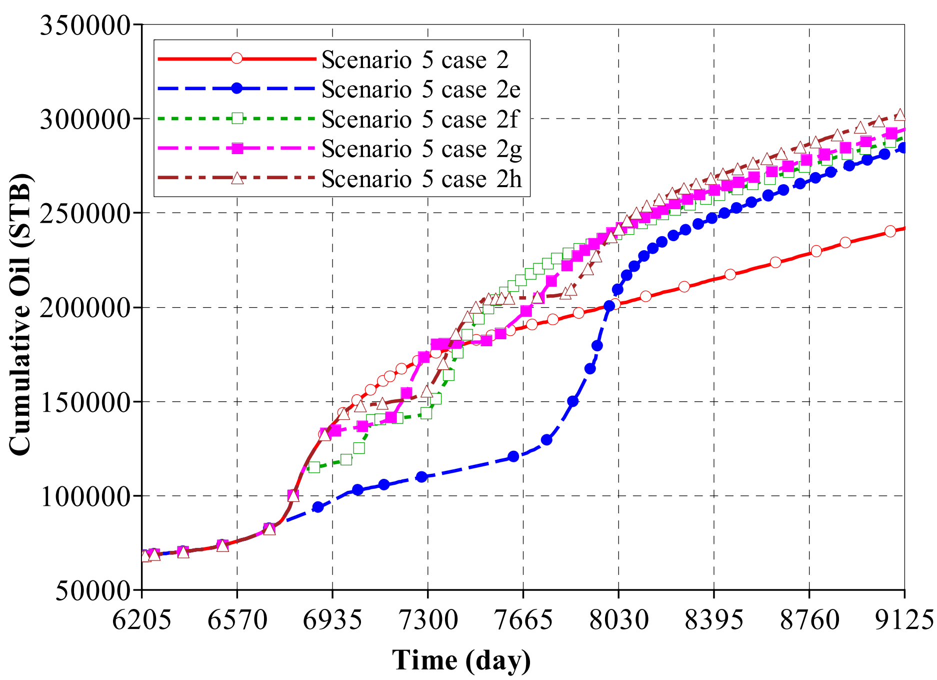

Fig. 4.42–Cumulative oil, Scenario 5, 200 BPDCWE, Case 2e to Case 2h.

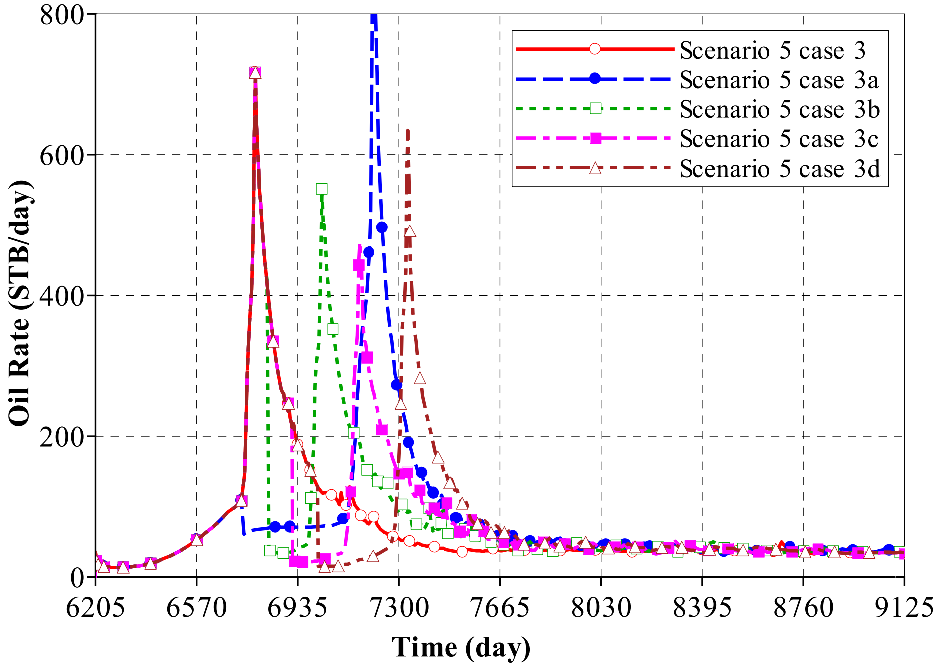

Fig. 4.43–Oil production rate, Scenario 5, 250 BPDCWE, Case 3a to Case 3d.

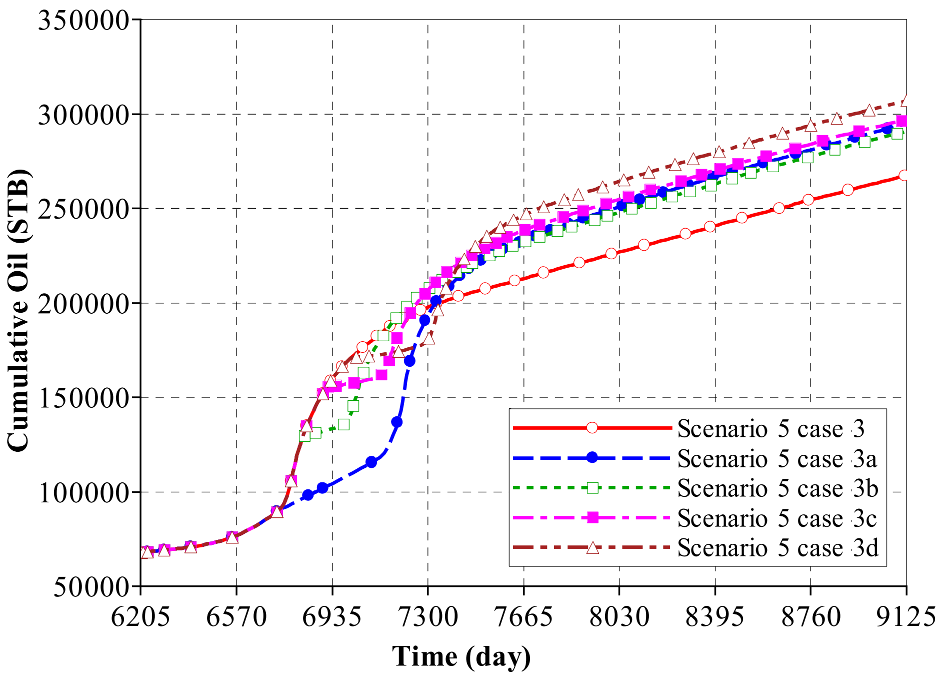

Fig. 4.44–Cumulative oil, Scenario 5, 250 BPDCWE, Case 3a to Case 3d.

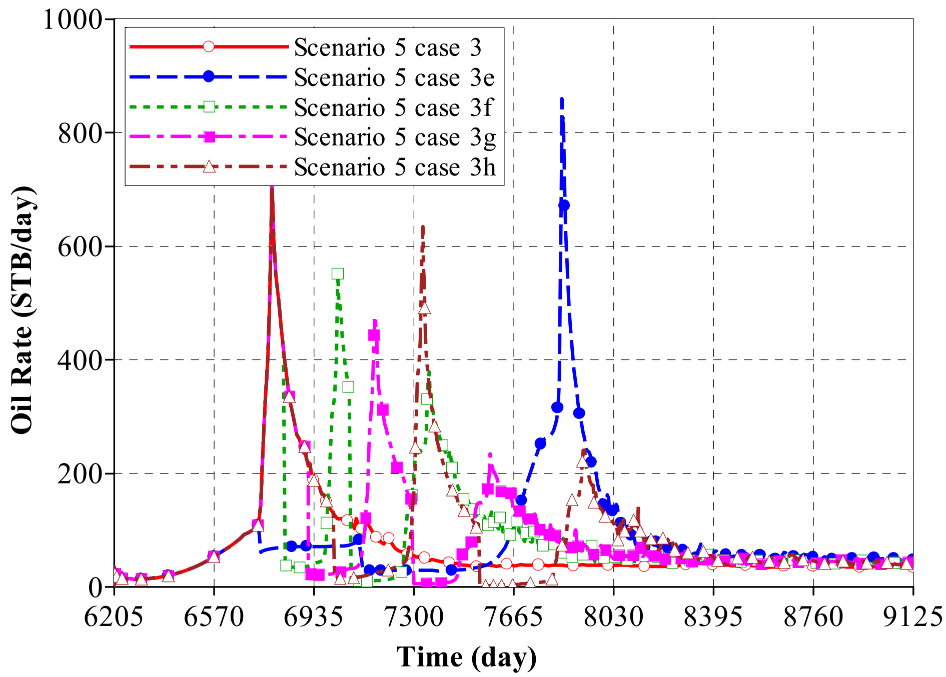

Fig. 4.45–Oil production rate, Scenario 5, 250 BPDCWE, Case 3e to Case 3h.

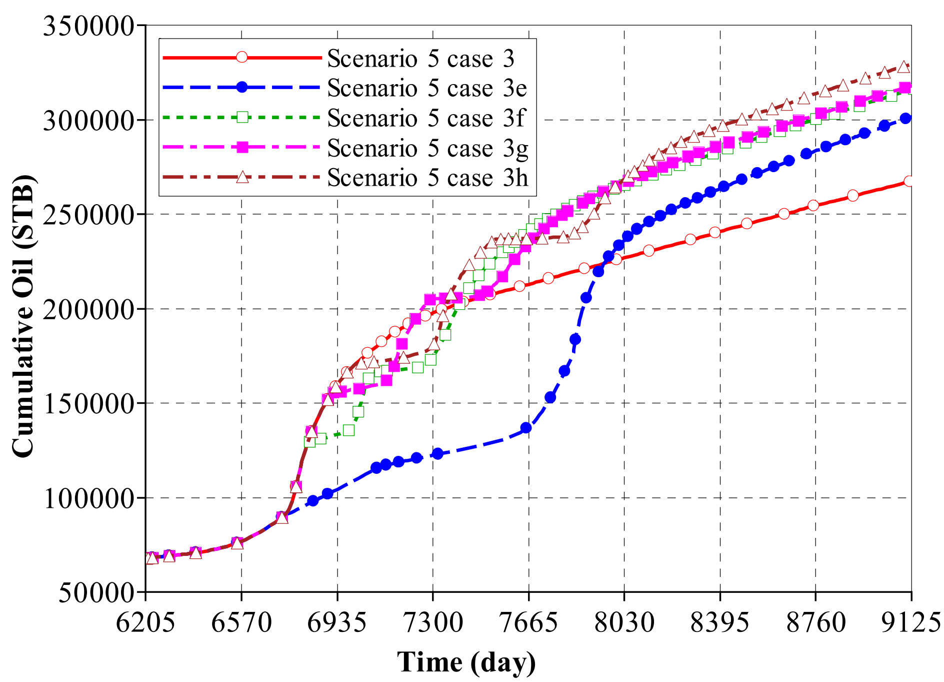

Fig. 4.46–Cumulative oil, Scenario 5, 250 BPDCWE, Case 3e to Case 3h.

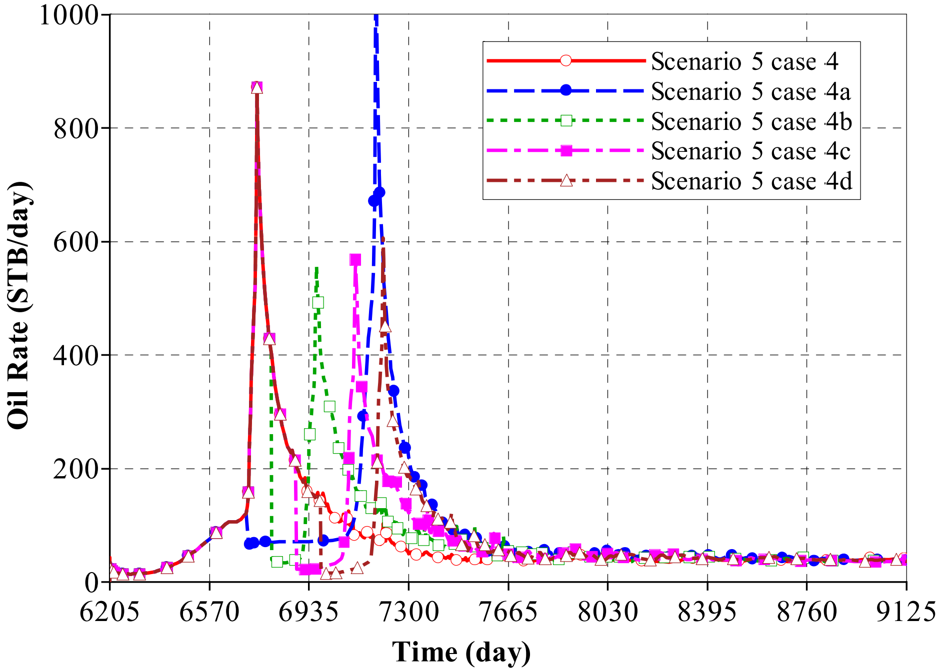

Fig. 4.47–Oil production rate, Scenario 5, 300 BPDCWE, Case 4a to Case 4d.

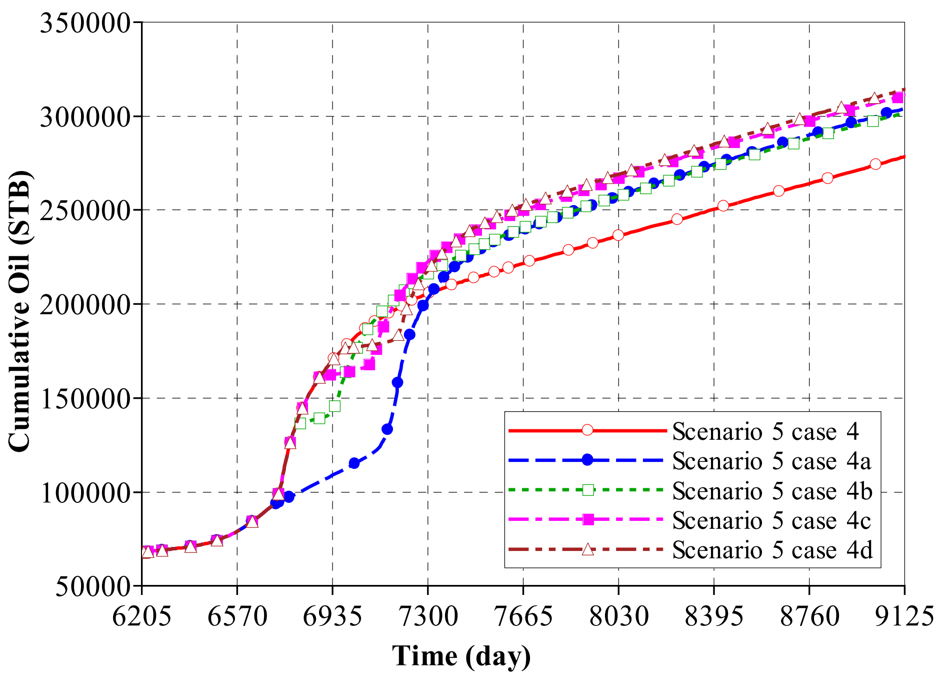

Fig. 4.48–Cumulative oil, Scenario 5, 300 BPDCWE, Case 4a to Case 4d.

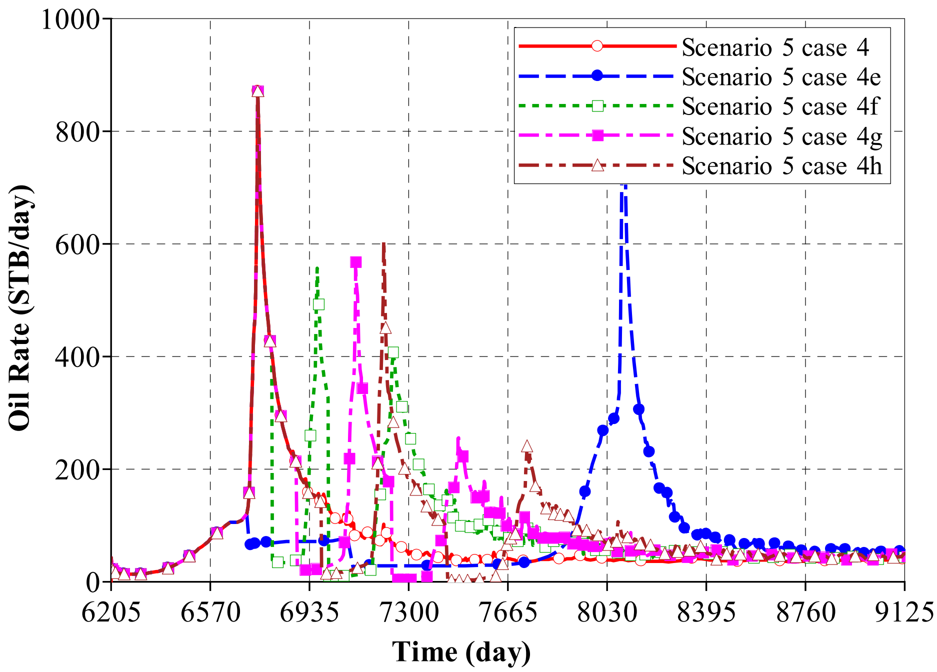

Fig. 4.49–Oil production rate, Scenario 5, 300 BPDCWE, Case 4e to Case 4h.

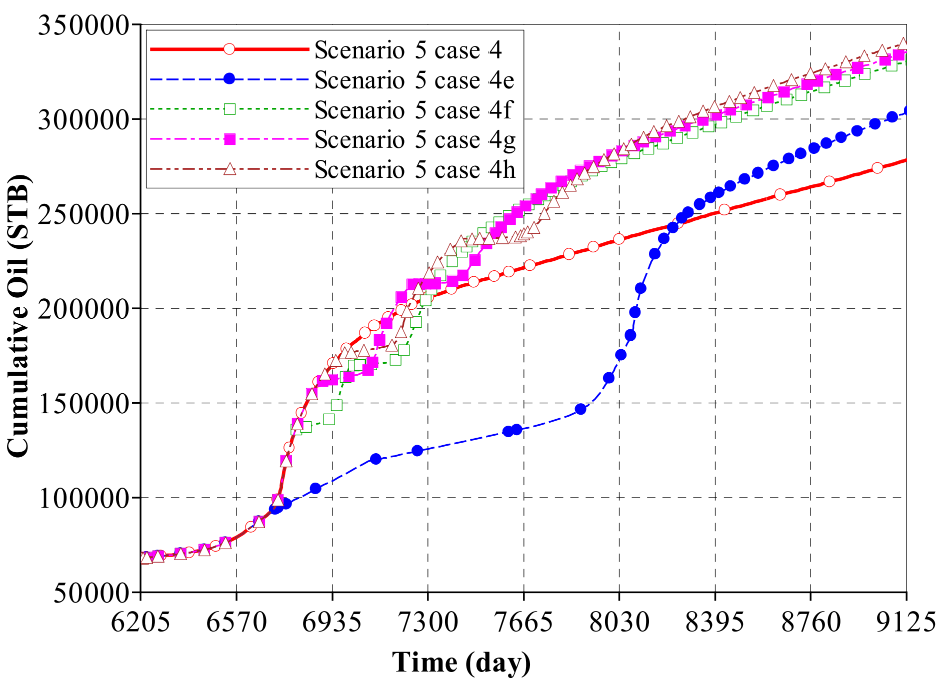

Fig. 4.50–Cumulative oil, Scenario 5, 300 BPDCWE, Case 4e to Case 4h.

4.2.6 Scenario 6

In this scenario the smart horizontal producer is divided into five sections as shown in **Fig. 4.51**. Each section has a length of 66 ft. The smart horizontal producer begins production from section 1 (**Fig. 4.51** a). After the first steam breakthrough, section 1 is closed and section 3 is open (**Fig 4.51** b). After the second breakthrough, section 3 is closed and section 5 in the heel-end of the smart horizontal well is open (**Fig. 4.51** c).

Similar to Scenario 2, several cases in Scenario 6 were performed. These cases include different injection rates and shut in times after breakthrough to find the best production performance. **Table 4.14** and **Table 4.15** present the cases simulated in Scenario 6.

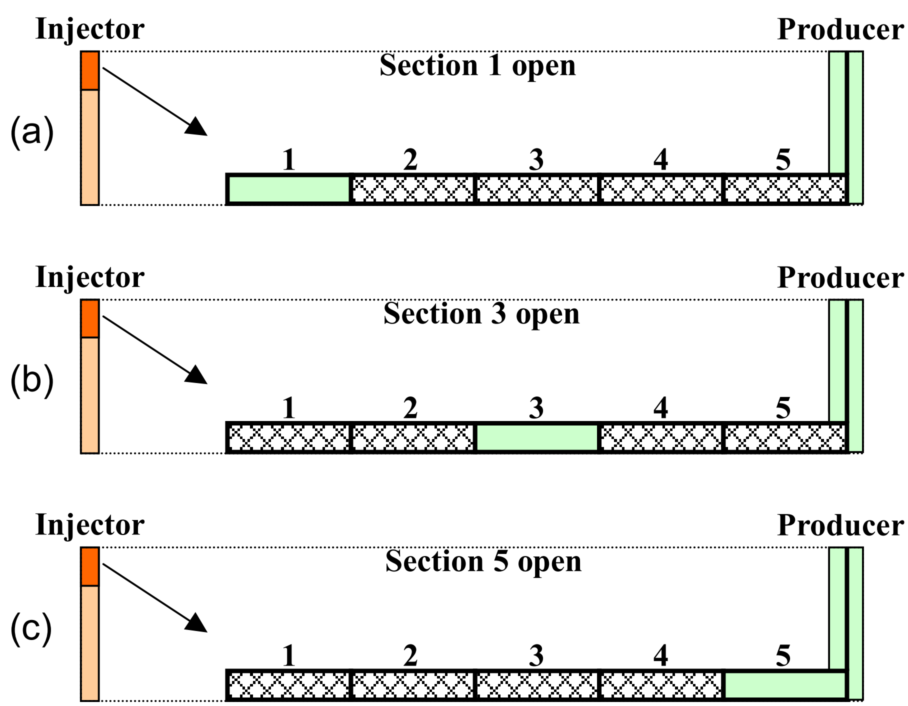

Fig. 4.51–Scenario 6, section 1 is open first (a), after 1st breakthrough section 1 is closed and section 3 is open (b), after 2nd breakthrough only section 5 is open (c).

TABLE 4.14–SCENARIO 6, SIMULATION CASES FOR 150 AND 200 BPDCWE INJECTION

Case 1	Injection rate = 150 BPDCWE, only section 1 is open
Case 1a	Shut in section 1, open section 3, in the 1st breakthrough
Case 1b	Shut in section 1, open section 3, 3 months after 1st breakthrough
Case 1c	Shut in section 1, open section 3, 6 months after 1st breakthrough
Case 1d	Shut in section 1, open section 3, 9 months after 1st breakthrough
Case 1e	Shut in section 1 and open section 3 in the 1st breakthrough, shut in section 3 and open section 5 in the 2nd breakthrough
Case 1f	Shut in section 1, open section 3, 3 months after 1st breakthrough; shut in section 3, open section 5, 3 months after 2nd breakthrough
Case 1g	Shut in section 1, open section 3, 6 months after 1st breakthrough; shut in section 3, open section 5, 6 months after 2nd breakthrough
Case 1h	Shut in section 1, open section 3, 9 months after 1st breakthrough; shut in section 3, open section 5, 9 months after 2nd breakthrough
Case 2	Injection rate = 200 BPDCWE, only section 1 is open
Case 2a	Shut in section 1, open section 3, in the 1st breakthrough
Case 2b	Shut in section 1, open section 3, 3 months after 1st breakthrough
Case 2c	Shut in section 1, open section 3, 6 months after 1st breakthrough
Case 2d	Shut in section 1, open section 3, 9 months after 1st breakthrough
Case 2e	Shut in section 1 and open section 3 in the 1st breakthrough, shut in section 3 and open section 5 in the 2nd breakthrough
Case 2f	Shut in section 1, open section 3, 3 months after 1st breakthrough; shut in section 3, open section 5, 3 months after 2nd breakthrough
Case 2g	Shut in section 1, open section 3, 6 months after 1st breakthrough; shut in section 3, open section 5, 6 months after 2nd breakthrough
Case 2h	Shut in section 1, open section 3, 9 months after 1st breakthrough; shut in section 3, open section 5, 9 months after 2nd breakthrough

TABLE 4.15–SCENARIO 6, SIMULATION CASES FOR 250 AND 300 BPDCWE INJECTION

Case 3	Injection rate = 250 BPDCWE, only section 1 is open
Case 3a	Shut in section 1, open section 3, in the 1st breakthrough
Case 3b	Shut in section 1, open section 3, 3 months after 1st breakthrough
Case 3c	Shut in section 1, open section 3, 6 months after 1st breakthrough
Case 3d	Shut in section 1, open section 3, 9 months after 1st breakthrough
Case 3e	Shut in section 1 and open section 3 in the 1st breakthrough, shut in section 3 and open section 5 in the 2nd breakthrough
Case 3f	Shut in section 1, open section 3, 3 months after 1st breakthrough; shut in section 3, open section 5, 3 months after 2nd breakthrough
Case 3g	Shut in section 1, open section 3, 6 months after 1st breakthrough; shut in section 3, open section 5, 6 months after 2nd breakthrough
Case 3h	Shut in section 1, open section 3, 9 months after 1st breakthrough; shut in section 3, open section 5, 9 months after 2nd breakthrough
Case 4	Injection rate = 300 BPDCWE, only section 1 is open
Case 4a	Shut in section 1, open section 3, in the 1st breakthrough
Case 4b	Shut in section 1, open section 3, 3 months after 1st breakthrough
Case 4c	Shut in section 1, open section 3, 6 months after 1st breakthrough
Case 4d	Shut in section 1, open section 3, 9 months after 1st breakthrough
Case 4e	Shut in section 1 and open section 3 in the 1st breakthrough, shut in section 3 and open section 5 in the 2nd breakthrough
Case 4f	Shut in section 1, open section 3, 3 months after 1st breakthrough; shut in section 3, open section 5, 3 months after 2nd breakthrough
Case 4g	Shut in section 1, open section 3, 6 months after 1st breakthrough; shut in section 3, open section 5, 6 months after 2nd breakthrough
Case 4h	Shut in section 1, open section 3, 9 months after 1st breakthrough; shut in section 3, open section 5, 9 months after 2nd breakthrough

Figs. 4.52 through **4.67** present the results for Scenario 6. **Table 4.16** and **Table 4.17** compare the cumulative oil production and recovery factor for all cases. The best case in this Scenario 6 was Case 4g in which the injection rate was 300 BPDCWE, section 1 in the smart horizontal producer was closed and section 3 was open 9 months after the first steam breakthrough, then section 3 was closed and section 5 was open 9 months after the second breakthrough (**Fig. 4.51**). The cumulative oil production for Case 4g was 327322 STB with a total oil recovery factor of 58.0% of the original oil in place for 8 years of steam injection.

TABLE 4.16–SCENARIO 6, CUMULATIVE OIL AND RECOVERY FACTOR, CASES FOR 150 AND 200 BPDCWE INJECTION

Scenario 6	Cumulative oil, STB	Oil recovery, % OOIP
Case 1	227135	40.3
Case 1a	244567	43.4
Case 1b	248687	44.1
Case 1c	254753	45.2
Case 1d	258903	45.9
Case 1e	242584	43.0
Case 1f	268320	47.6
Case 1g	273086	48.4
Case 1h	274528	48.7
Case 2	235034	41.7
Case 2a	250628	44.4
Case 2b	256885	45.5
Case 2c	263788	46.8
Case 2d	270146	47.9
Case 2e	250019	44.3
Case 2f	278023	49.3
Case 2g	284668	50.5
Case 2h	289507	51.3

TABLE 4.17–SCENARIO 6, CUMULATIVE OIL AND RECOVERY FACTOR, CASES FOR 250 AND 300 BPDCWE INJECTION

Scenario 6	Cumulative oil, STB	Oil recovery, % OOIP
Case 3	244856	43.4
Case 3a	259780	46.1
Case 3b	269535	47.8
Case 3c	274596	48.7
Case 3d	276042	48.9
Case 3e	273828	48.5
Case 3f	296424	52.6
Case 3g	301212	53.4
Case 3h	302444	53.6
Case 4	260644	46.2
Case 4a	270126	47.9
Case 4b	289464	51.3
Case 4c	299112	53.0
Case 4d	300461	53.3
Case 4e	258452	45.8
Case 4f	318512	56.5
Case 4g	327322	58.0
Case 4h	327288	58.0

As in Scenario 2 when compared to Scenario 1, Scenario 6 presents lower oil recovery than Scenario 5 because the smart horizontal well produces a higher oil rate when it starts to produce with all the sections open. In Scenario 6, the horizontal well produces only from section 1 at start of production.

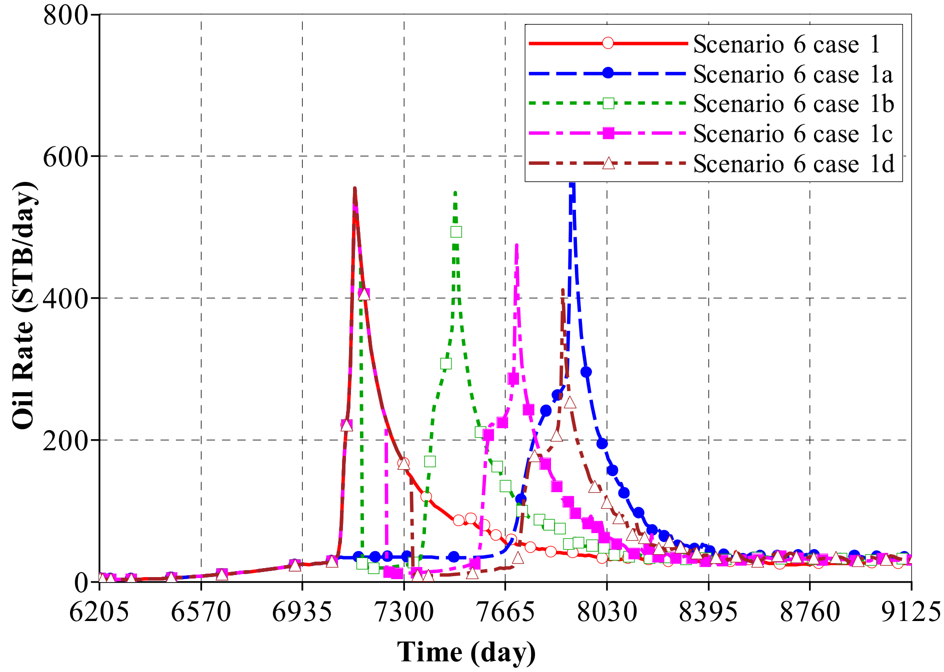

Fig. 4.52–Oil production rate, Scenario 6, 150 BPDCWE, Case 1a to Case 1d.

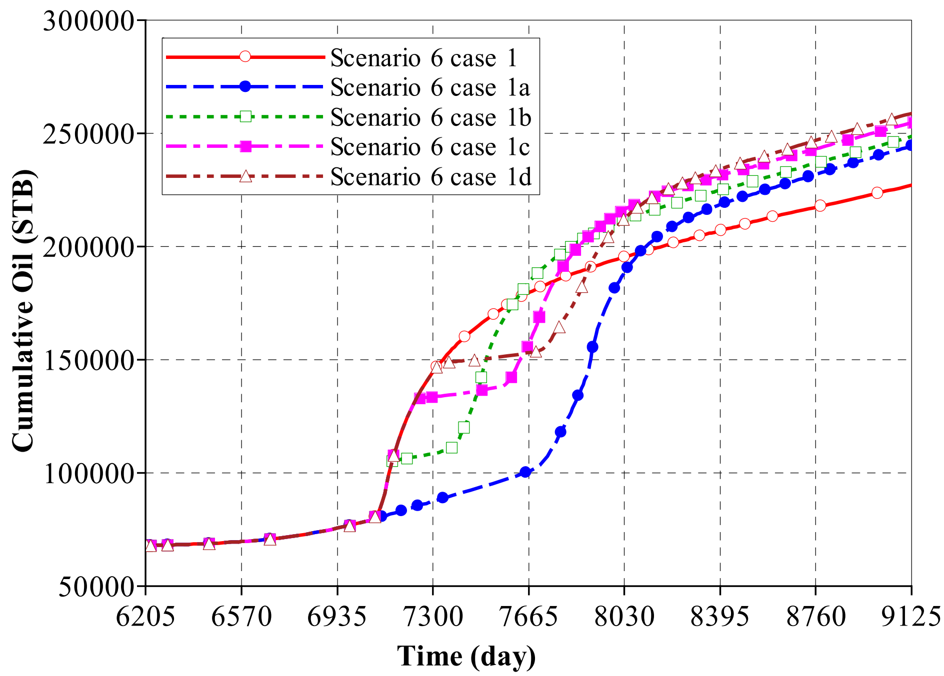

Fig. 4.53–Cumulative oil, Scenario 6, 150 BPDCWE, Case 1a to Case 1d.

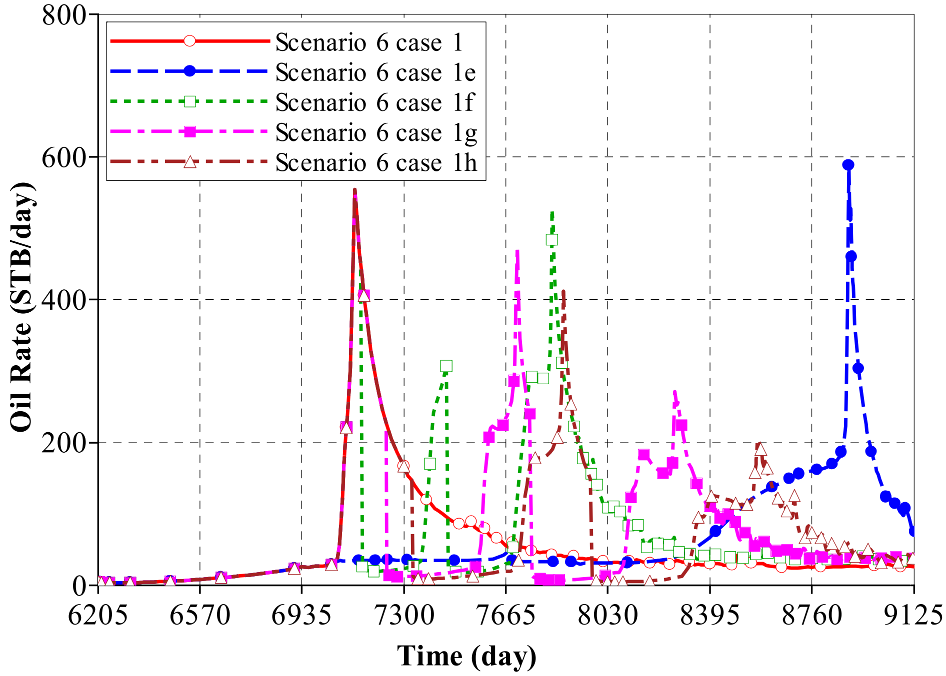

Fig. 4.54–Oil production rate, Scenario 6, 150 BPDCWE, Case 1e to Case 1h.

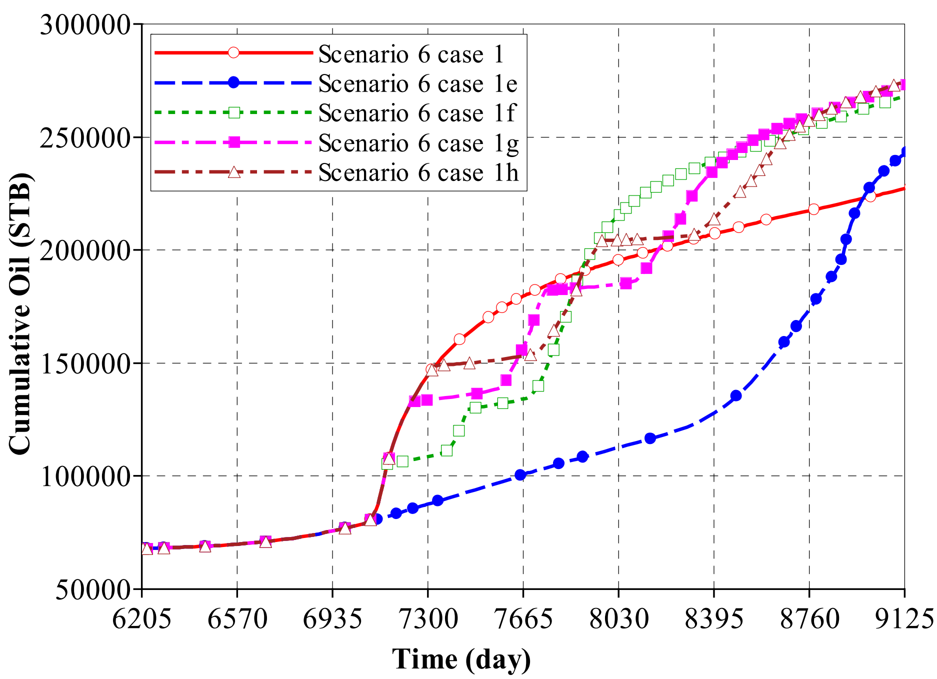

Fig. 4.55–Cumulative oil, Scenario 6, 150 BPDCWE, Case 1e to Case 1h.

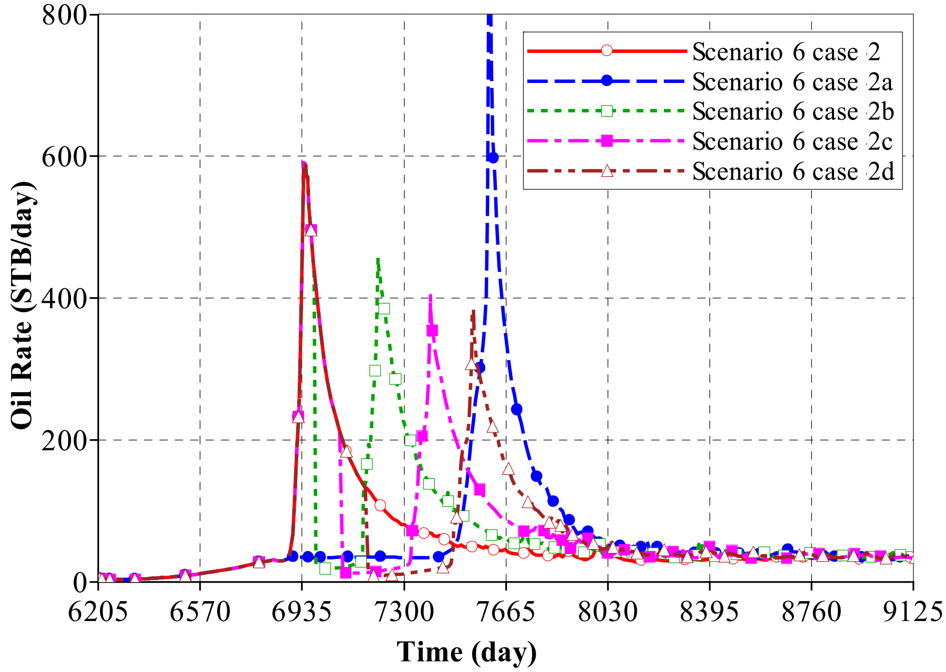

Fig. 4.56–Oil production rate, Scenario 6, 200 BPDCWE, Case 2a to Case 2d.

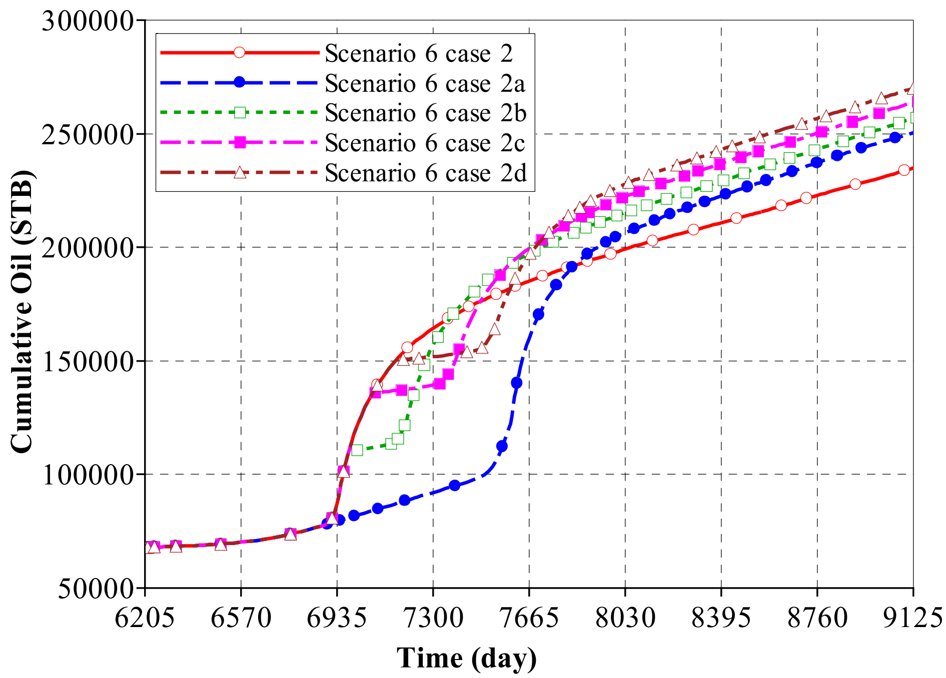

Fig. 4.57–Cumulative oil, Scenario 6, 200 BPDCWE, Case 2a to Case 2d.

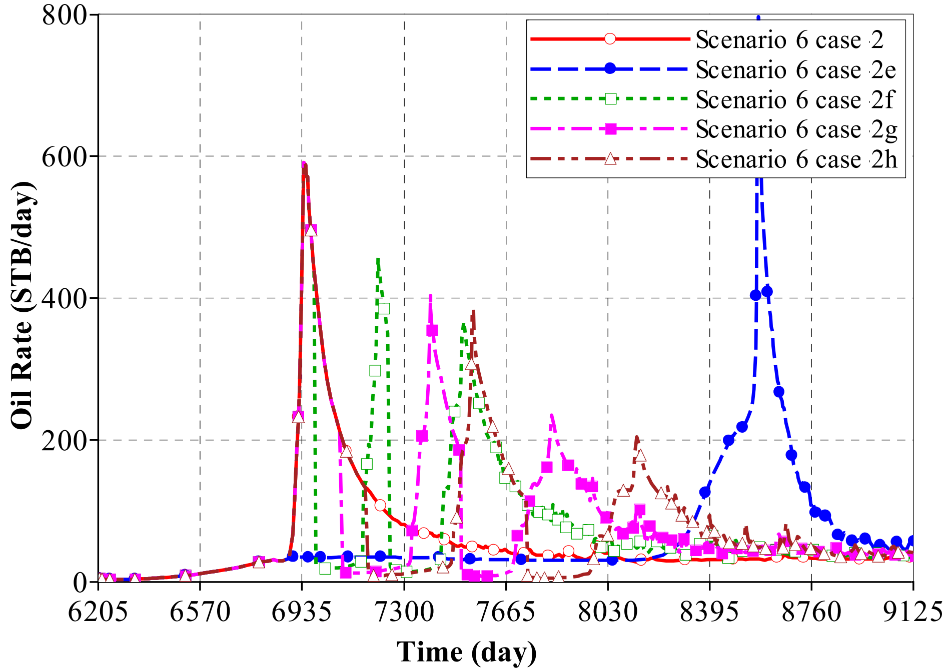

Fig. 4.58–Oil production rate, Scenario 6, 200 BPDCWE, Case 2e to Case 2h.

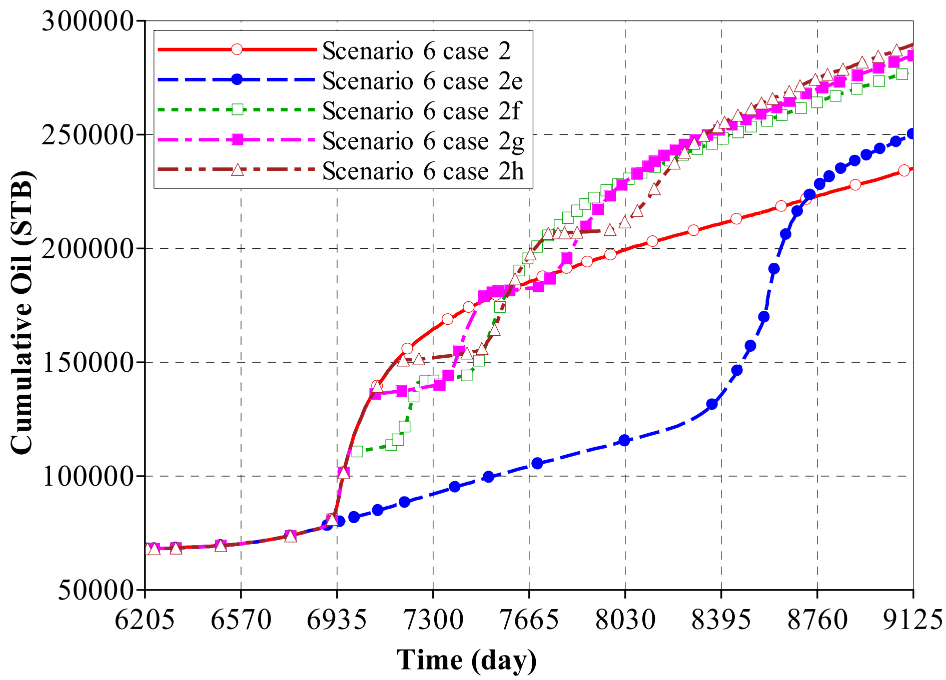

Fig. 4.59–Cumulative oil, Scenario 6, 200 BPDCWE, Case 2e to Case 2h.

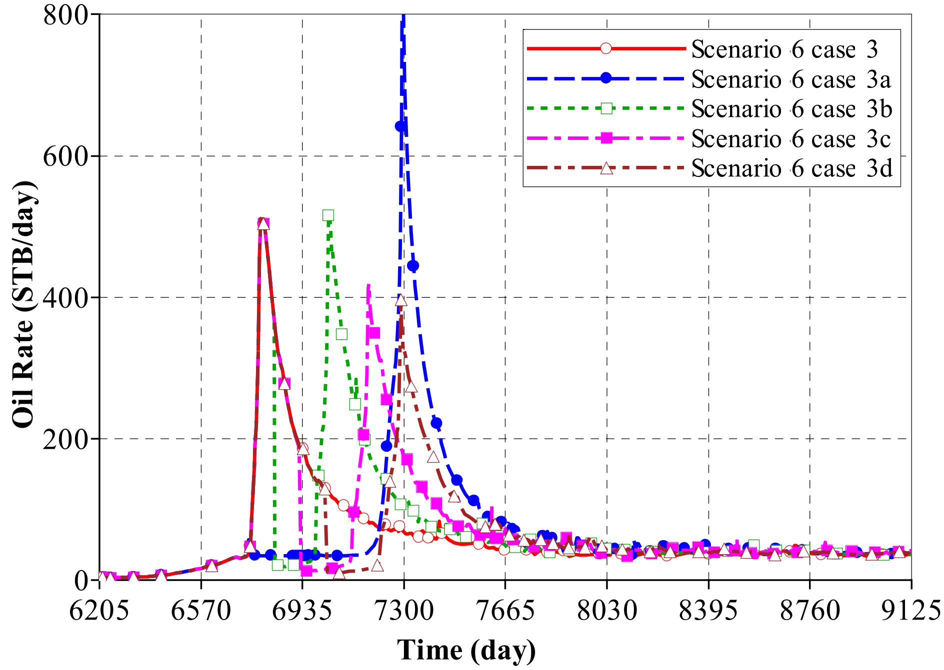

Fig. 4.60–Oil production rate, Scenario 6, 250 BPDCWE, Case 3a to Case 3d.

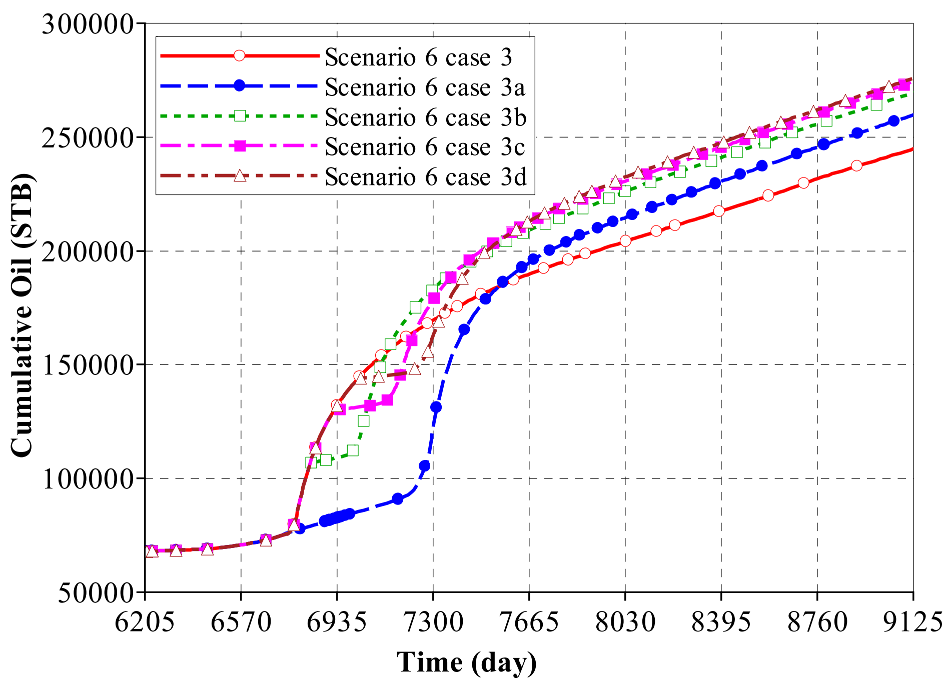

Fig. 4.61–Cumulative oil, Scenario 6, 250 BPDCWE, Case 3a to Case 3d.

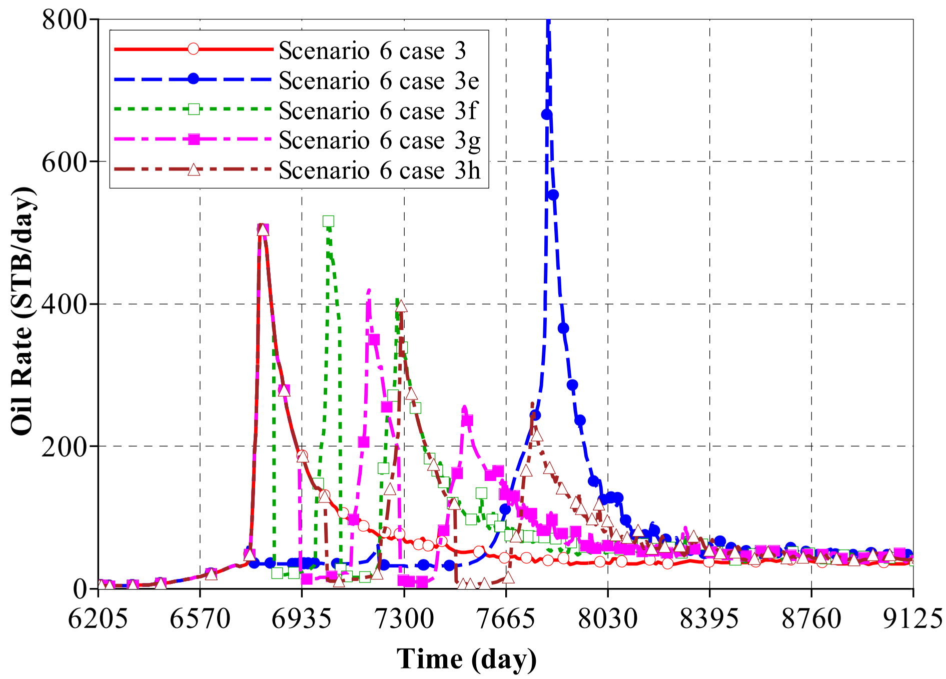

Fig. 4.62–Oil production rate, Scenario 6, 250 BPDCWE, Case 3e to Case 3h.

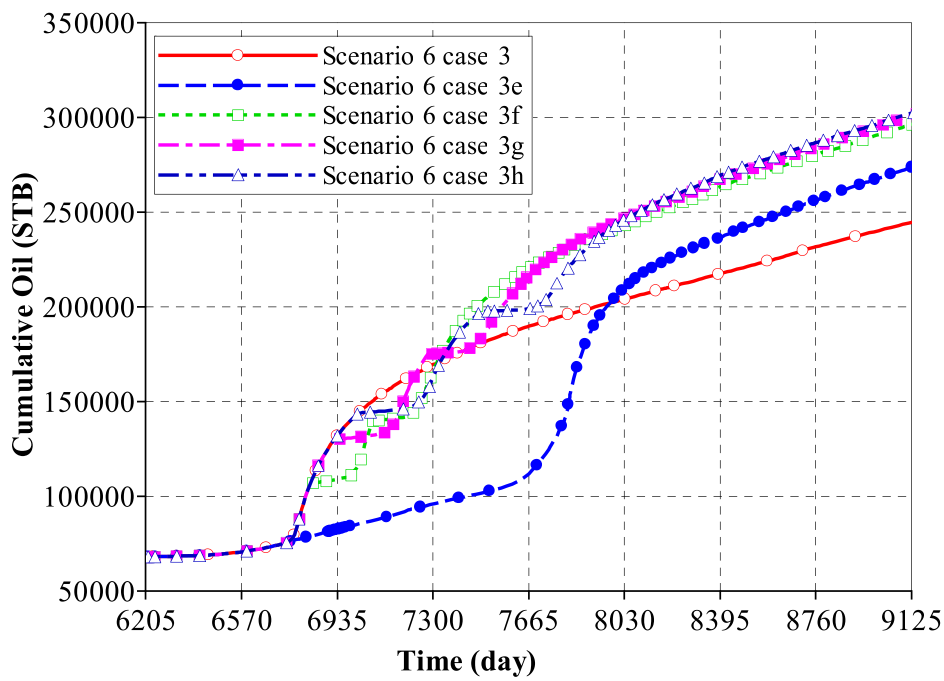

Fig. 4.63–Cumulative oil, Scenario 6, 250 BPDCWE, Case 3e to Case 3h.

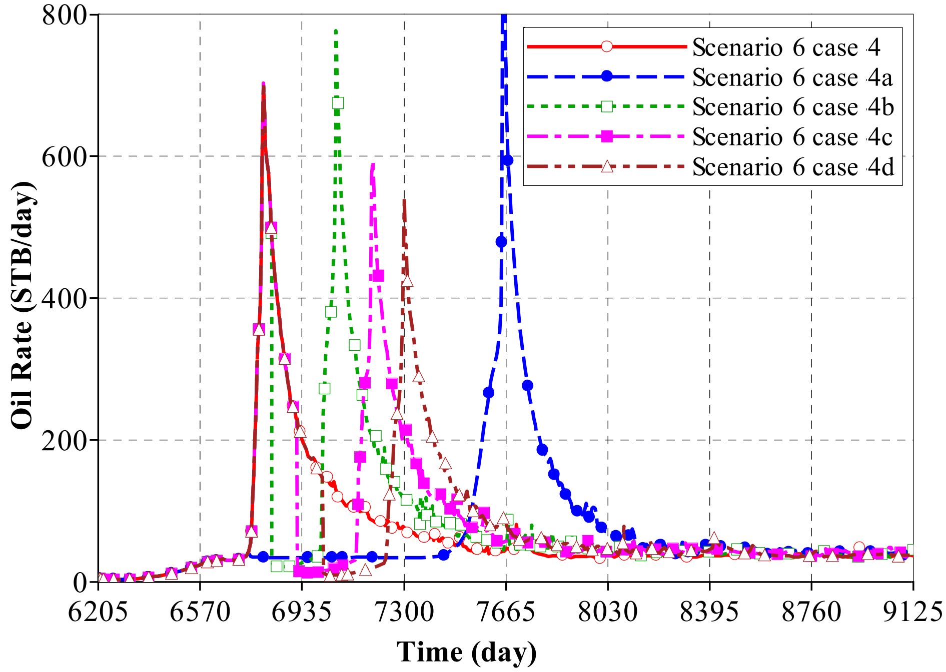

Fig. 4.64–Oil production rate, Scenario 6, 300 BPDCWE, Case 4a to Case 4d.

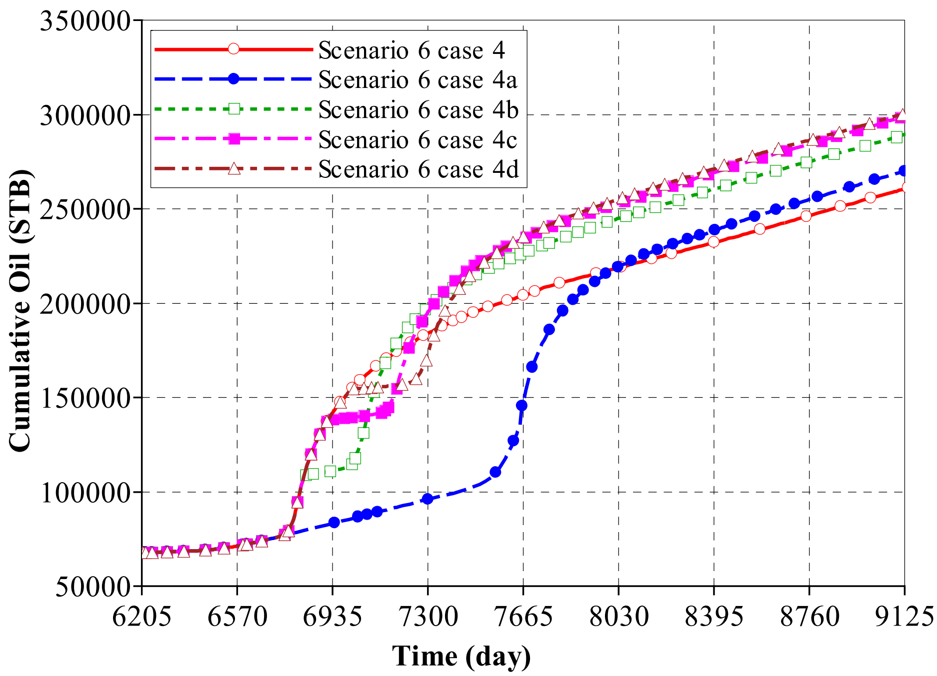

Fig. 4.65–Cumulative oil, Scenario 6, 300 BPDCWE, Case 4a to Case 4d.

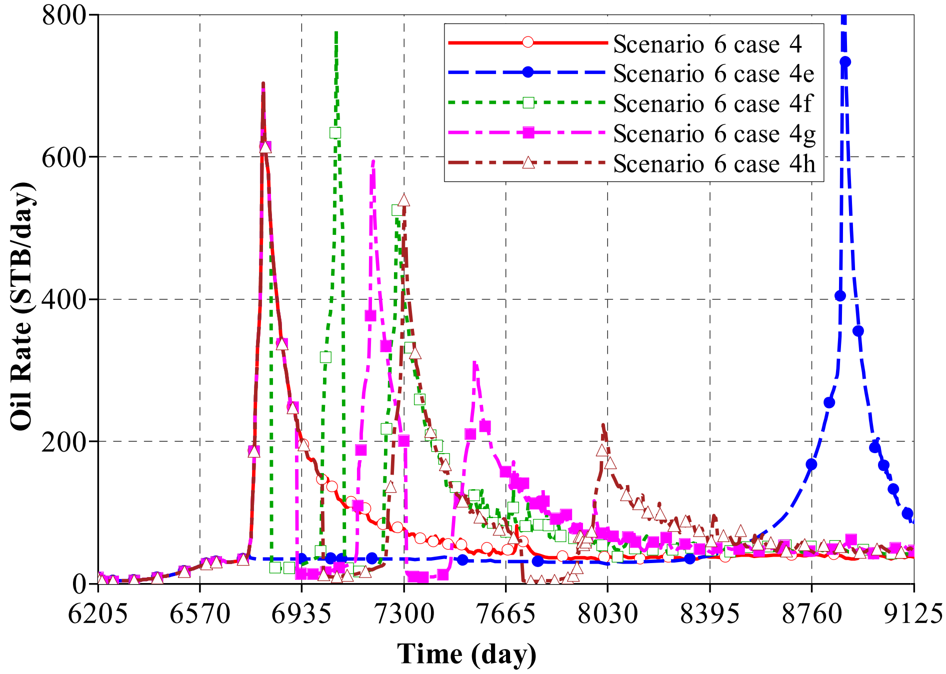

Fig. 4.66–Oil production rate, Scenario 6, 300 BPDCWE, Case 4e to Case 4h.

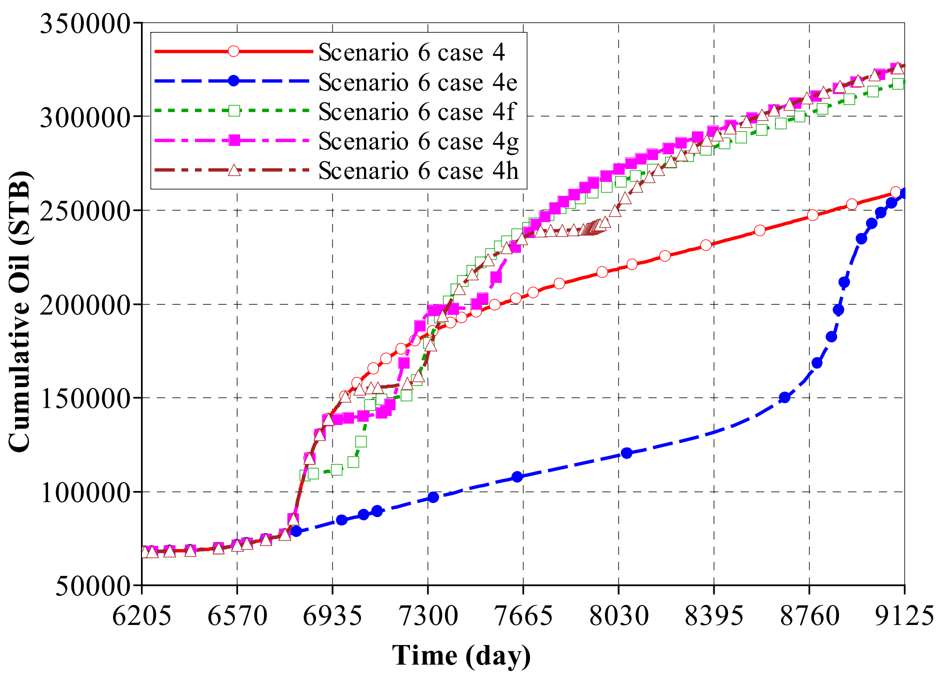

Fig. 4.67–Cumulative oil, Scenario 6, 300 BPDCWE, Case 4e to Case 4h.

4.2.7 Scenario 7

In this scenario the smart horizontal producer is divided into five sections as shown in **Fig. 4.68**. Each section has a length of 66 ft. The smart horizontal well initially produces with all sections open (**Fig. 4.68** a). After the first breakthrough, section 1 is closed (**Fig. 4.68** b). After the second breakthrough section 2 is closed (**Fig. 4.68** c). Then after the third breakthrough, section 3 is closed (**Fig. 4.68** d). Finally, after the fourth breakthrough section 4 is closed and the smart horizontal well produces only from section 5 at its heel-end location (**Fig. 4.68** e).

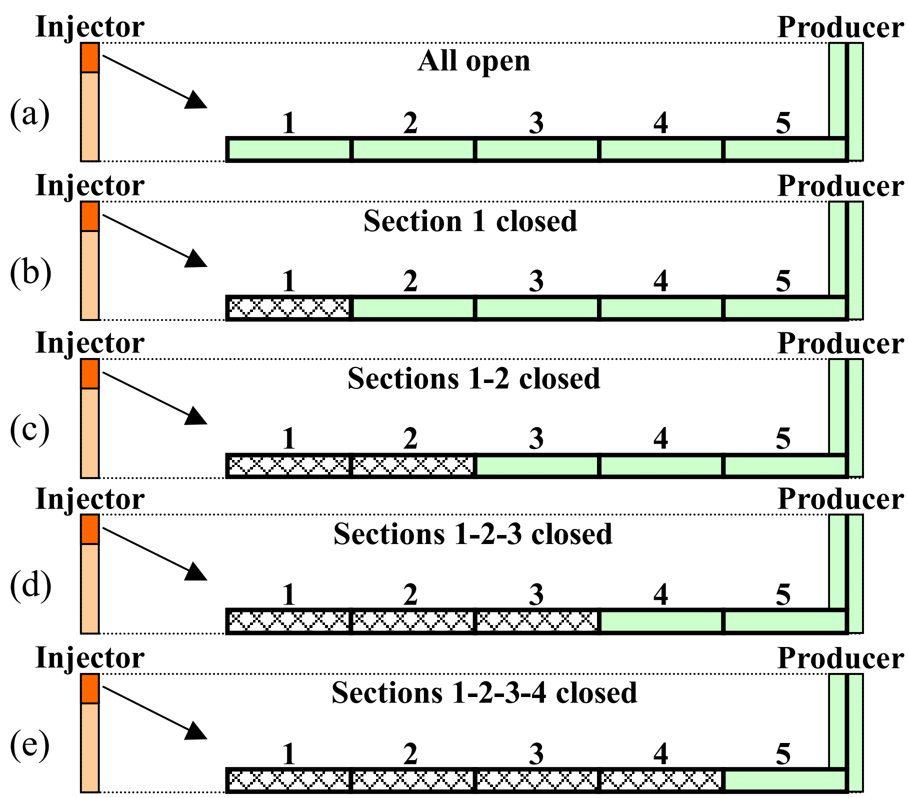

Fig. 4.68–Scenario 7, well is fully open (a), after 1st breakthrough section 1 is closed (b), after 2nd breakthrough section 2 is closed (c), after 3rd breakthrough section 3 is closed (d) and after 4th breakthrough section 4 is closed (e).

For Scenario 7, injection rate of 250 BPDCWE and shut in of each section in 6 months after steam breakthrough at each section were assumed to compare the production behavior with previous scenarios. It was not necessary to run additional cases because the results showed a lower oil recovery with a more complicated scheme (shut in sections) in the smart horizontal producer for Scenario 7. **Table 4.18** presents the cases simulated in this scenario.

TABLE 4.18–SCENARIO 7, SIMULATION CASES

Case 1	Injection rate = 250 BPDCWE, Well all open
Case 1a	Shut in section 1, 6 months after 1st breakthrough
Case 1b	Shut in section 1, 6 months after 1st breakthrough; shut in section 2, 6 months after 2nd breakthrough
Case 1c	Shut in section 1, 6 months after 1st breakthrough; shut in section 2, 6 months after 2nd breakthrough; shut in section 3, 6 months after 3rd breakthrough
Case 1d	Shut in section 1, 6 months after 1st breakthrough; shut in section 2, 6 months after 2nd breakthrough; shut in section 3, 6 months after 3rd breakthrough; shut in section 4, 6 months after 4th breakthrough

Fig. 4.69 and **Fig. 4.70** present the results for Scenario 7. **Table 4.19** compares the cumulative oil production and recovery factor for all cases. The best case in Scenario 7 was Case 1d (**Table 4.18**). The cumulative oil production for Case 1d was 302680 STB with a total oil recovery factor of 53.7% of the original oil in place for 8 years of steam injection. This recovery factor is 4.8% of the OOIP less than the same injection rate case in Scenario 1 (Case 3c).

TABLE 4.19–SCENARIO 7, CUMULATIVE OIL PRODUCTION AND RECOVERY FACTOR

Scenario 7	Cumulative oil, STB	Oil recovery, % OOIP
Case 1	267479	47.4
Case 1a	271554	48.1
Case 1b	282467	50.1
Case 1c	293010	51.9
Case 1d	302680	53.7

Although the smart horizontal well presents five production peaks in Scenario 7, the cumulative oil is lower than in Scenario 1 and Scenario 2 in which the production presented two peaks. The additional breakthroughs in Scenario 7 are faster because there is not enough spacing in order to delay the steam breakthrough and the additional production peaks are lower. Thus, the sweep efficiency of oil is decreased.

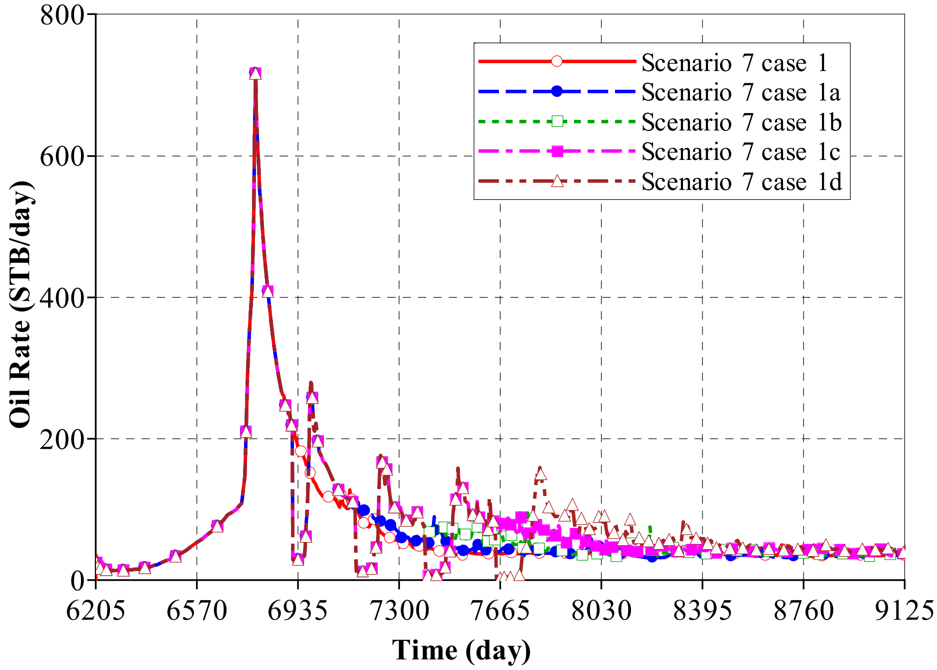

Fig. 4.69–Oil production rate, Scenario 7, cases for 250 BPDCWE.

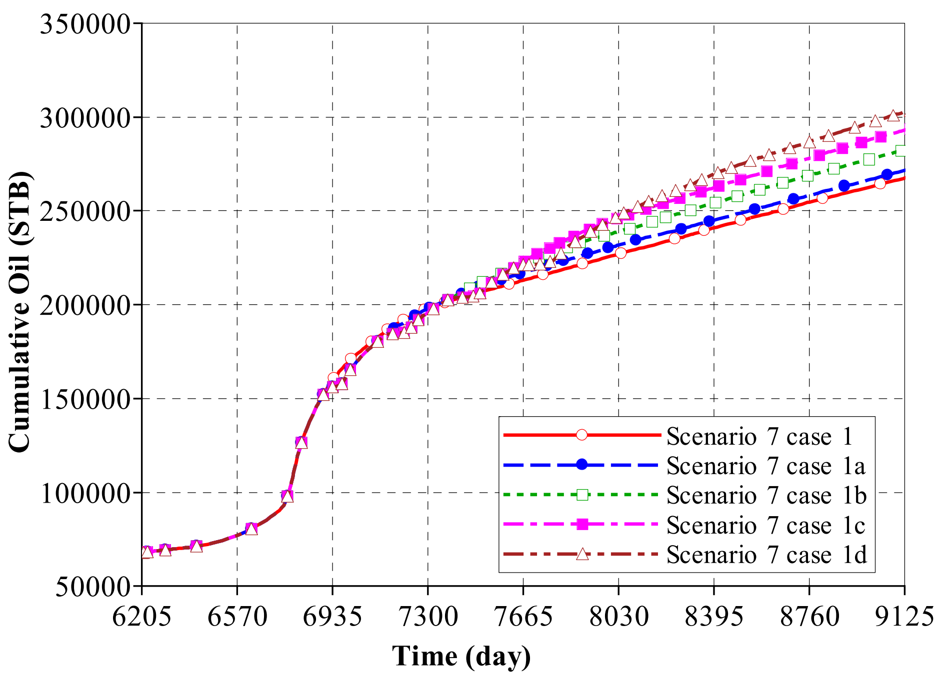

Fig. 4.70–Cumulative oil production, Scenario 7, cases for 250 BPDCWE.

4.2.8 Scenario 8

In this scenario the smart horizontal producer is divided into five sections as shown in **Fig. 4.71**. Each section has a length of 66 ft. The smart horizontal well initially produces only from section 1 (**Fig. 4.71** a). After the first breakthrough, section 1 is closed and section 2 is open (**Fig. 4.71** b). After the second breakthrough, section 2 is closed and section 3 is open (**Fig. 4.71** c). After the third breakthrough, the section 3 is closed and section 4 is open (**Fig. 4.71** d). Finally after the fourth breakthrough section 4 is closed and section 5 is open in the heel-end location of the smart horizontal producer (**Fig. 4.71** e).

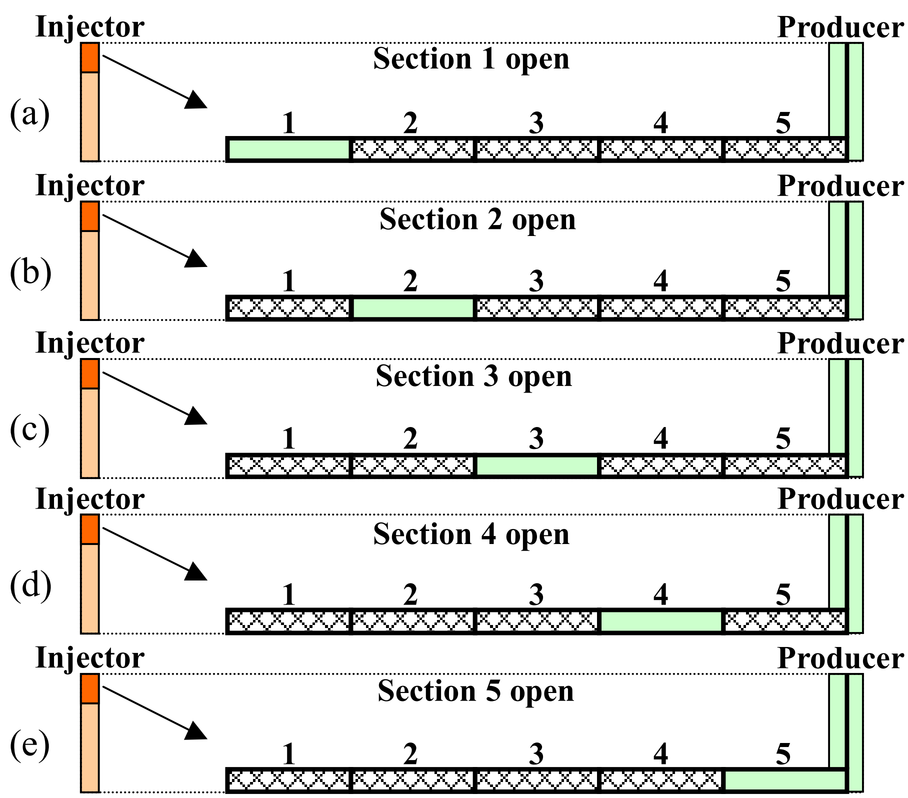

Fig. 4.71–Scenario 8, section 1 is open (a), after 1st breakthrough section 1 is closed and section 2 is open (b), after 2nd breakthrough section 2 is closed and section 3 is open (c), after 3rd breakthrough section 3 is closed and section 4 is open (d), and after 4th breakthrough section 4 is closed and section 5 is open (e).

As in Scenario 7, only the cases for injection rate of 250 BPDCWE and shut in sections in 6 months after the steam breakthrough time were performed to compare the production behavior with previous scenarios. It was not necessary to run additional cases because the results showed a lower oil recovery with a more complicated scheme (shut in sections) in the smart horizontal producer for this scenario-8. **Table 4.20** presents the cases simulated in this scenario.

TABLE 4.20–SCENARIO 8, SIMULATION CASES

Case 1	Injection rate = 250 BPDCWE, section 1 open
Case 1a	Shut in section 1 and open section 2, 6 months after 1^{st} breakthrough
Case 1b	Shut in section 1 and open section 2, 6 months after 1^{st} breakthrough; shut in section 2 and open section 3, 6 months after 2^{nd} breakthrough
Case 1c	Shut in section 1 and open section 2, 6 months after 1^{st} breakthrough; shut in section 2 and open section 3, 6 months after 2^{nd} breakthrough; shut in section 3 and open section 4, 6 months after 3^{rd} breakthrough
Case 1d	Shut in section 1 and open section 2, 6 months after 1^{st} breakthrough; shut in section 2 and open section 3, 6 months after 2^{nd} breakthrough; shut in section 3 and open section 4, 6 months after 3^{rd} breakthrough; shut in section 4 and open section 5, 6 months after 4^{th} breakthrough

Fig. 4.72 and **Fig. 4.73** present the results for the Scenario 8. **Table 4.21** compares the cumulative oil production and recovery factor for all cases. The best case in Scenario 8 was Case 1d (**Table 4.20**). The cumulative oil production for Case 1d was 278949 STB with a total oil recovery factor of 49.5% of the original oil in place for 8

years of steam injection. This recovery factor is 6.1% of the OOIP less than the same injection rate case in Scenario 2 (Case 3c).

TABLE 4.21–SCENARIO 8, CUMULATIVE OIL PRODUCTION AND RECOVERY FACTOR

Scenario 8	Cumulative oil, STB	Oil recovery, % OOIP
Case 1	244856	43.4
Case 1a	248378	44.0
Case 1b	256932	45.6
Case 1c	268381	47.6
Case 1d	278949	49.5

As in Scenario 7, although the smart horizontal well presents five production peaks in Scenario 8, the cumulative oil production is lower than in Scenario 1 and Scenario 2 in which the production had two peaks. The additional breakthroughs in Scenario 8 are faster because there is not enough spacing in order to delay the steam breakthrough and the additional production peaks are lower. In this way, the sweep efficiency of oil is decreased.

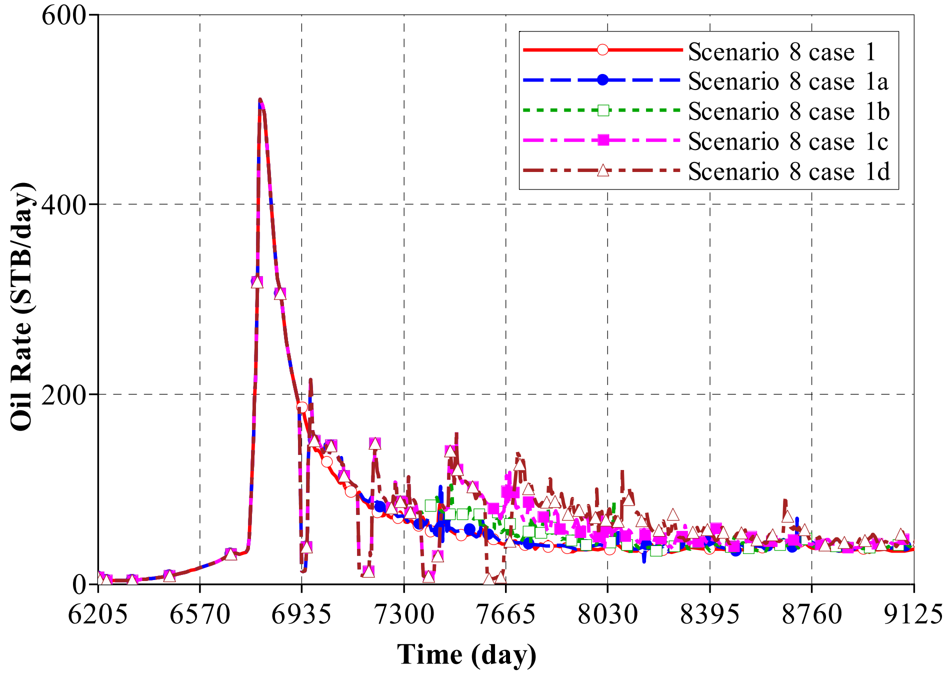

Fig. 4.72–Oil production rate, Scenario 8, cases for 250 BPDCWE.

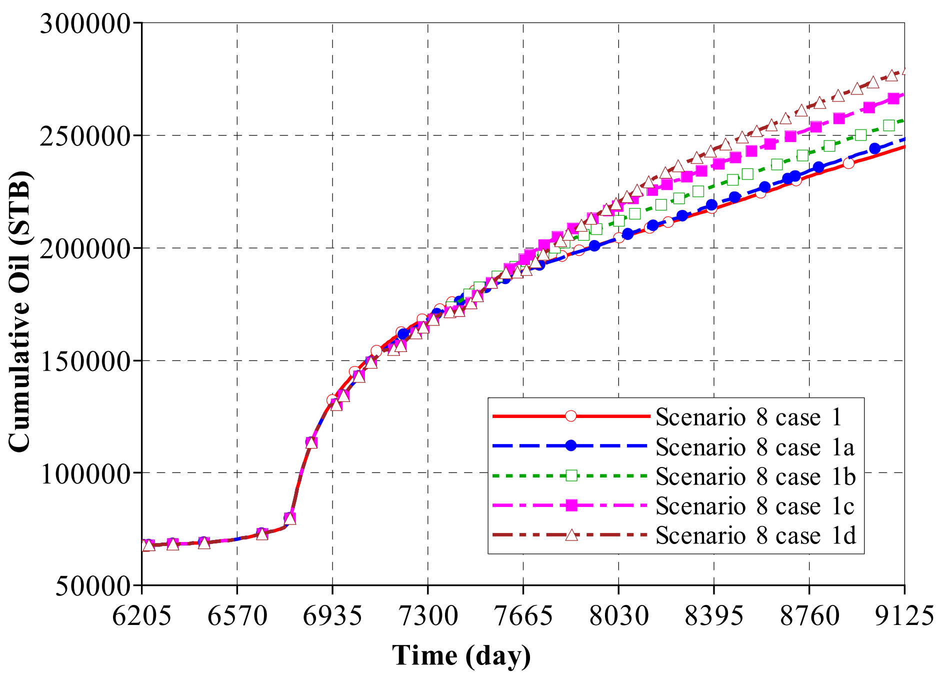

Fig. 4.73–Cumulative oil, Scenario 8, cases for 250 BPDCWE.

4.2.9 Scenario 9

In this scenario the smart horizontal producer is divided into four sections as shown in **Fig. 4.74**. The well has three sections of 88 ft and one section of 66 ft length in the heel-end location. The smart horizontal producer initially produces with all sections open (**Fig. 4.74** a). After the first steam breakthrough, section 1 is closed (**Fig 4.74** b). After the second breakthrough, section 2 is closed (**Fig. 4.74** c). Finally after the third breakthrough, section 3 is closed and section 4 in the heel-end of the smart horizontal well is kept open (**Fig. 4.74** d).

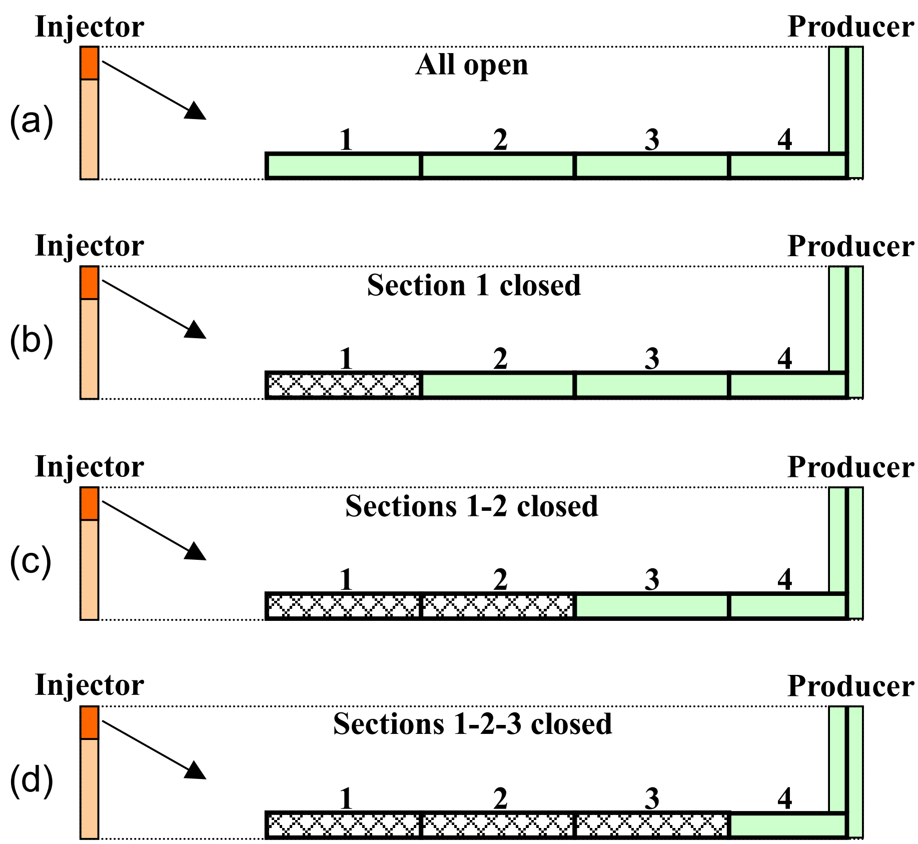

Fig. 4.74–Scenario 9, smart horizontal starts all open (a), after 1st breakthrough section 1 is closed (b), after 2nd breakthrough sections 1 and 2 are closed (c), and after 3rd breakthrough sections 1, 2 and 3 are closed (d).

As in Scenario 7, only the cases for injection rate of 250 BPDCWE and shut in of sections 6 months after the steam breakthrough were performed to compare the production behavior with previous scenarios. It was not necessary to run additional cases because the results showed a lower oil recovery with a more complicated scheme (shut in sections) in the smart horizontal producer for this Scenario 9. **Table 4.22** presents the cases simulated in this scenario.

TABLE 4.22–SCENARIO 9, SIMULATION CASES

Case 1	Injection rate = 250 BPDCWE, Well all open
Case 1a	Shut in section 1, 6 months after 1st breakthrough
Case 1b	Shut in section 1, 6 months after 1st breakthrough; shut in section 2, 6 months after 2nd breakthrough
Case 1c	Shut in section 1, 6 months after 1st breakthrough; shut in section 2, 6 months after 2nd breakthrough; shut in section 3, 6 months after 3rd breakthrough

Fig. 4.75 and **Fig. 4.76** present the results for the Scenario 9. **Table 4.23** compares the cumulative oil production and recovery factor for all cases. The best case in Scenario 9 was Case 1c (**Table 4.22**). The cumulative oil production for Case 1c was 308521 STB with a total oil recovery factor of 54.7% of the original oil in place for 8 years of steam injection. This recovery factor is 3.8% of the OOIP less than the same injection rate case in Scenario 1 (Case 3c).

As in scenario 7, although the smart horizontal well presents three production peaks in Scenario 9, the cumulative oil is lower than in Scenario 1 and Scenario 2 in which the production showed two production peaks. The additional breakthroughs in Scenario 9 are faster because there is not enough spacing to delay the steam breakthrough and the additional production peaks are low. Thus, the sweep efficiency of oil is decreased.

TABLE 4.23–SCENARIO 9, CUMULATIVE OIL PRODUCTION AND RECOVERY FACTOR

Scenario 9	**Cumulative oil, STB**	**Oil recovery, % OOIP**
Case 1	267479	47.4
Case 1a	276964	49.1
Case 1b	295822	52.4
Case 1c	308521	54.7

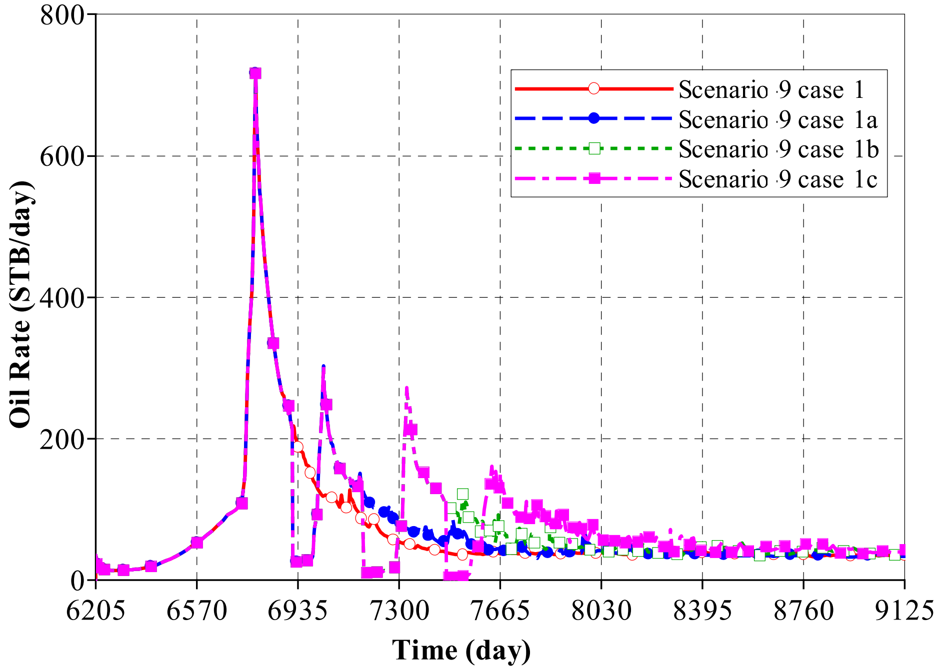

Fig. 4.75–Oil production rate, Scenario 9, cases for 250 BPDCWE.

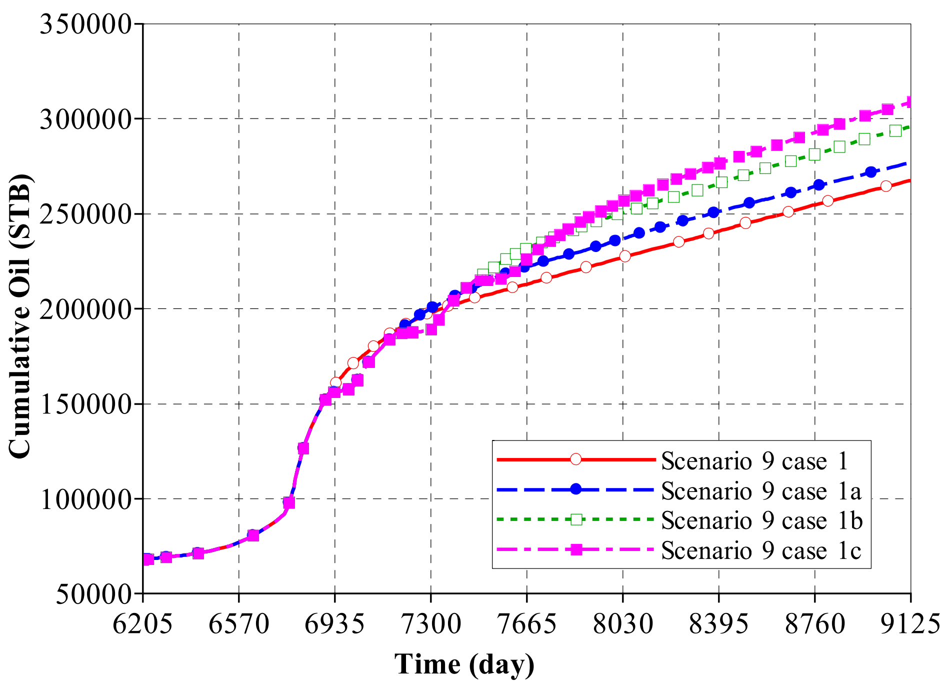

Fig. 4.76–Cumulative oil, Scenario 9, cases for 250 BPDCWE.

4.2.10 Comparison of Vertical Well and Vertical-Smart Horizontal Well Systems

In the previous analysis, it was concluded that after natural depletion, the best development strategy for continuous steam injection with the vertical-smart horizontal system was Case 4d in Scenario 1.

In this Case 4d, the smart horizontal well is divided into three sections of 110 ft length each. The smart horizontal producer begins production with all sections open (**Fig. 4.6** a). 9 months after steam breakthrough only section 3 in the heel-end of the smart horizontal well is kept open (**Fig. 4.6** b).

In order to compare with vertical-smart horizontal system, two cases with similar steam injection conditions was performed after natural depletion for the vertical well system and the results are presented in **Fig. 4.77** and **Fig. 4.78**.

In the vertical well system, in Case 1 the vertical producers are all opened. In Case 2 the vertical producer wells are opened at the bottom (one quarter of each well). These two cases were defined to show the effect of the steam override and how the spacing between injection and production zones can enhance the oil sweep efficiency, as shown in the analysis of vertical-smart horizontal well system.

Table 4.24 shows the final oil recovery factor and cumulative oil production for the two systems. The oil recovery factor in the vertical-smart horizontal well system is 9.8% of the OOIP higher than the Case 2 in the vertical well system, at the end of 8 years of steamflooding.

TABLE 4.24–CUMULATIVE OIL PRODUCTION AND RECOVERY FACTOR, COMPARISON BETWEEN VERTICAL WELL AND VERTICAL-SMART HORIZONTAL WELL SYSTEMS

System	Cumulative oil, STB	Oil recovery, % OOIP
Vertical well system		
Case 1	158546	28.1
Case 2	288327	51.1
Vertical-smart horizontal well system	343625	60.9

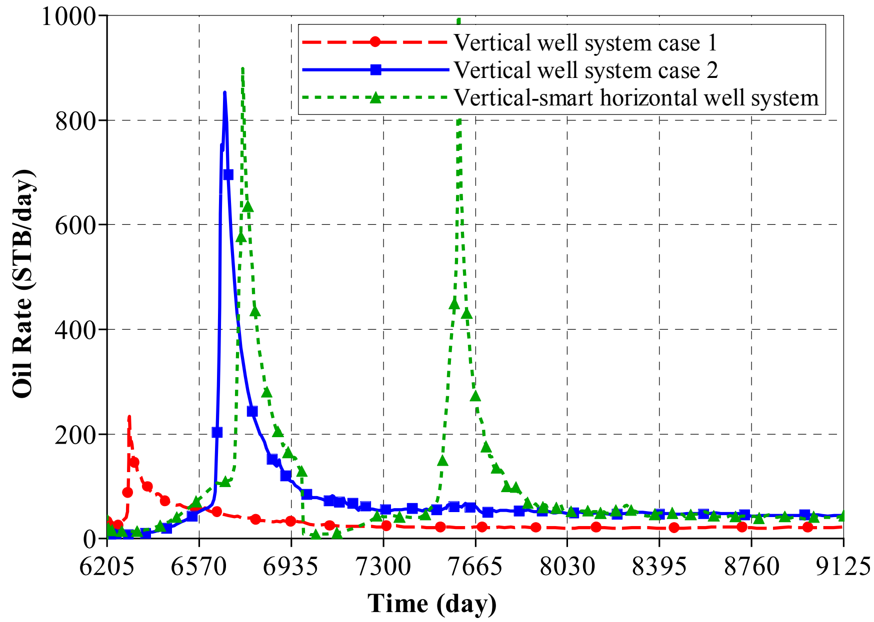

Fig. 4.77–Oil production rate, comparison of vertical well and vertical-smart horizontal well systems.

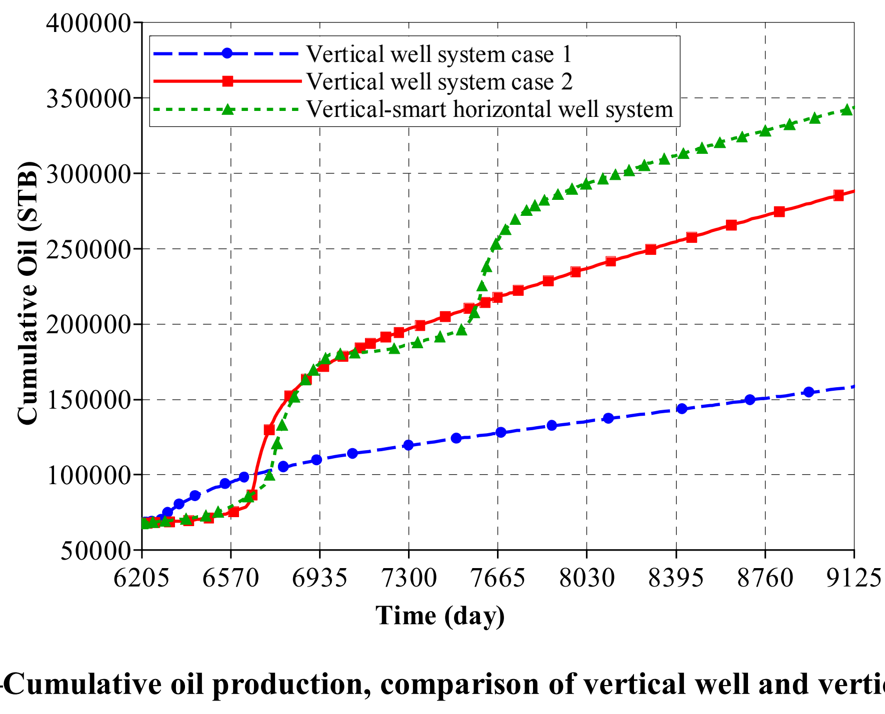

Fig. 4.78–Cumulative oil production, comparison of vertical well and vertical-smart horizontal well systems.

4.3 Continuous Steam Injection after Cyclic Steam Injection

To study the production performance under steamflooding after cyclic steam injection, three simulation cases were performed. These cases include the vertical well and vertical-smart horizontal well systems. Also, these results were compared with continuous steam injection after natural depletion to determine the best development strategy in a heavy oil field with similar conditions.

As shown in **Fig. 4.1**, the cyclic steam injection was simulated to match a pressure of 275 psia (point 2 in **Fig. 4.1**) and the results were presented in **Figs. 4.3** and **4.4**. The best case obtained in the previous analysis of steamflooding after natural depletion with the vertical-smart horizontal system is used from this part of the study (Case 4d in Scenario 1, presented in **Figs. 4.6**, **4.13** and **4.14**).

Table 4.25 presents the cases simulated during this analysis and **Figs. 4.79** and **4.80** show a comparison of the results. **Table 4.26** compares the cumulative oil production and oil recovery factor obtained during 8 years of simulation. The vertical-smart horizontal well system (Case 3) produces 6.6% of the OOIP more than the vertical well system (Case 1). In the Case 3 the oil recovery factor is 8.4% of the OOIP less than the best case when the steamflooding is implemented after natural depletion without cyclic steam injection (Scenario 1, case 4d included in **Table 4.26**).

The oil sweep efficiency is lower when the steamflooding is after cyclic steam injection because the cyclic injection has created a higher water saturation around the horizontal well. This higher water saturation facilitates the movement of the steam, accelerates the second steam breakthrough and decreases the oil sweep efficiency in the reservoir.

Figs. 4.81 and **4.82** show a comparison for the best case in the vertical-smart horizontal system with and without cyclic steam injection before steamflooding. **Figs. 4.83** and **4.84** present the 3D plots for water saturation before shut in sections in the smart horizontal producer (9 months after the first breakthrough). These plots compare the steamflooding with and without cyclic steam injection. The water saturation is higher around the smart horizontal well when the cyclic steam injection is implemented before the steamflooding.

TABLE 4.25–STEAMFLOODING AFTER CYCLIC STEAM INJECTION, SIMULATION CASES WITH 300 BPDCWE INJECTION

Case 1 Vertical well system	Cyclic steam injection (from 415 psia to 275 psia) and continuous steam injection
Case 2 Vertical-horizontal well system	Cyclic steam injection (from 415 psia to 275 psia) and continuous steam injection
Case 3 Vertical-smart horizontal well system	Cyclic steam injection (from 415 psia to 275 psia) and continuous steam injection; 9 months after the breakthrough the sections 1 and 2 are closed and section 3 in the heel-end of the smart horizontal is kept open (**Fig. 4.6**).

TABLE 4.26–CUMULATIVE OIL PRODUCTION AND RECOVERY FACTOR, SIMULATION CASES FOR STEAMFLOODING AFTER CYCLIC STEAM INJECTION

Simulation case	Cumulative oil, STB	Oil recovery, % OOIP
Case 1	259448	46.0
Case 2	269612	47.8
Case 3	296392	52.5
Scenario 1, Case 4d	343625	60.9

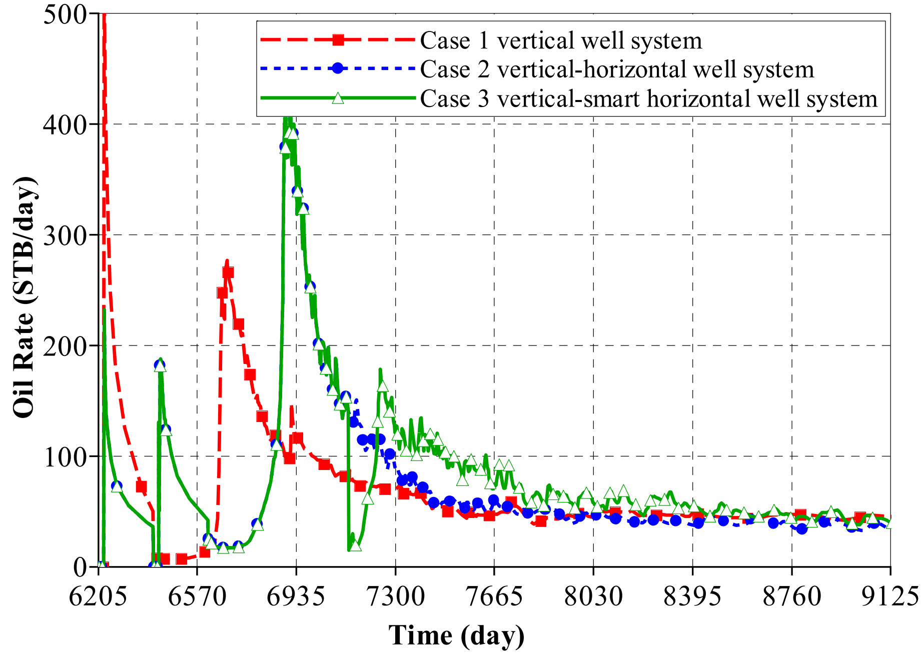

Fig. 4.79–Oil production rate, cases for steamflooding after cyclic steam injection.

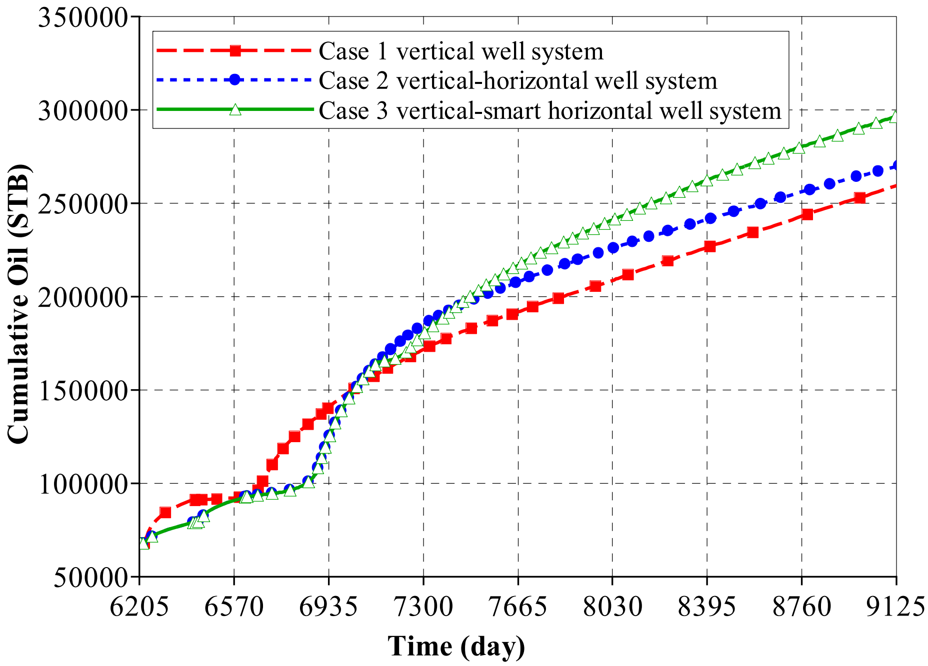

Fig. 4.80–Cumulative oil, cases for steamflooding after cyclic steam injection.

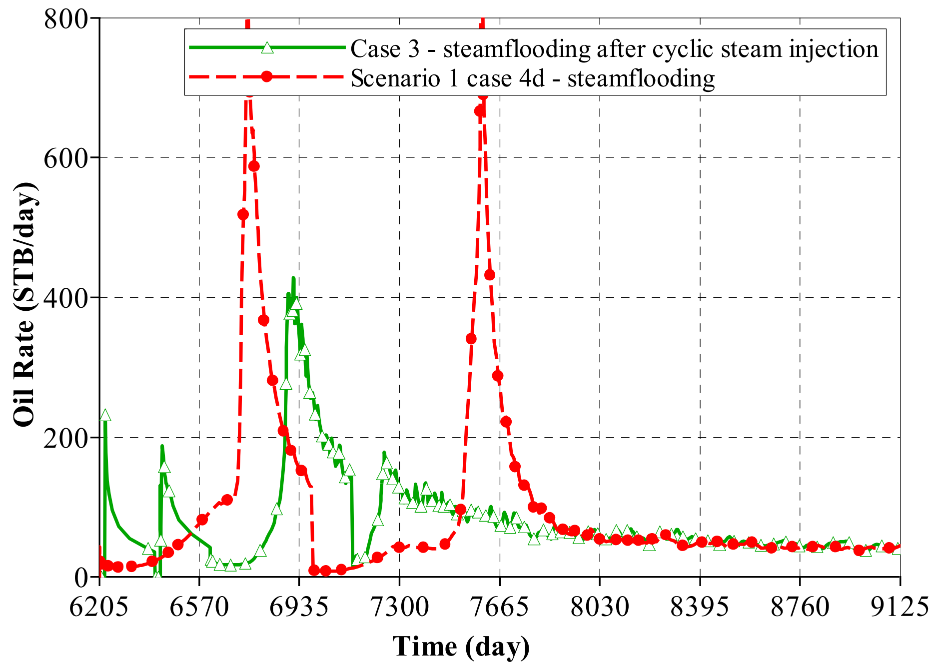

Fig. 4.81–Oil production rate, comparison with and without cyclic steam injection.

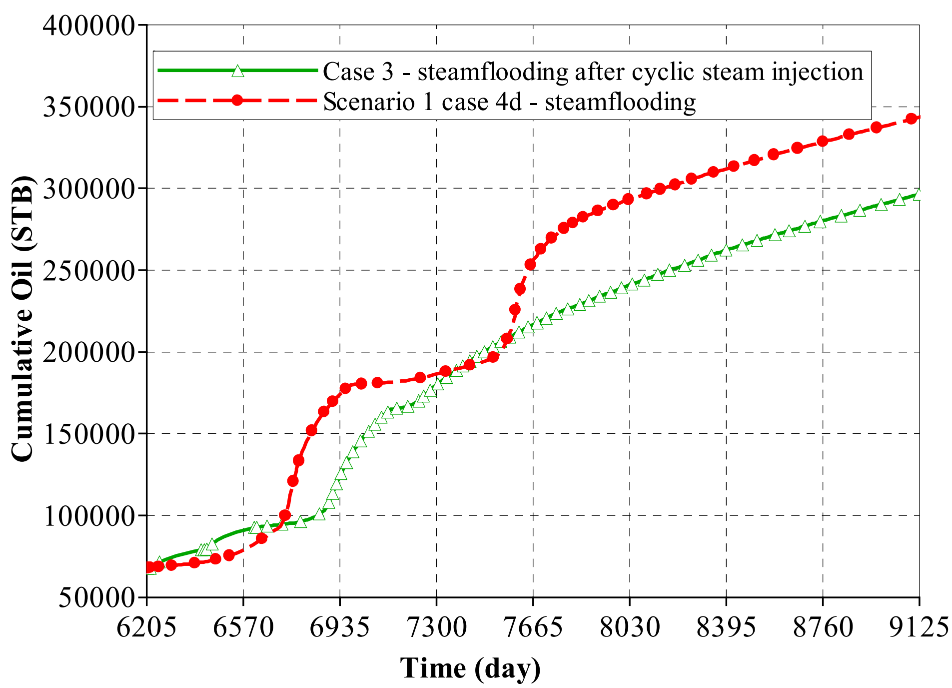

Fig. 4.82–Cumulative oil, comparison with and without cyclic steam injection.

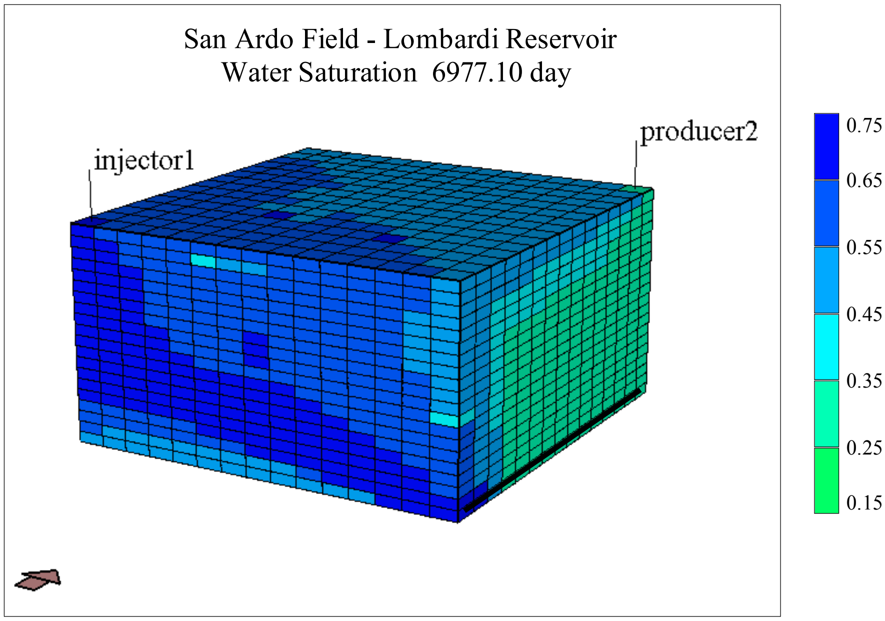

Fig. 4.83–Water saturation, Scenario 1 Case 4d, steamflooding after natural depletion, simulation time 9 months after first breakthrough.

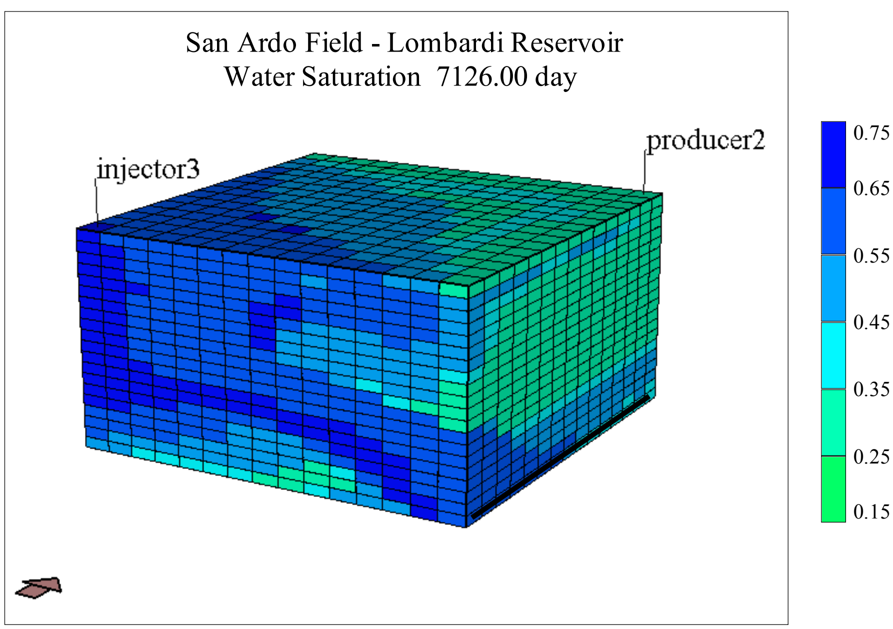

Fig. 4.84–Water saturation, Case 3, steamflooding after cyclic steam injection, simulation time 9 months after first breakthrough.

4.4 Additional Development Schemes

Two different schemes were performed to analyze additional development strategies in order to increase the oil sweep efficiency and consequently, to enhance the oil recovery factor. Again, the best case obtained from the previous simulation scenarios was used in this part of the study (Scenario 1, Case 4d). The second scheme was defined considering the actual San Ardo field development to take advantage of the well locations in the 9-spot inverted patterns and, to include the new smart horizontal producer in the analysis of the production behavior with this scheme.

The two schemes are applied 9 months after the second steam breakthrough time in Scenario 1, Case 4d. This time corresponds to 7789 days since start production. The analysis is performed for 8 years of continuous steam injection.

4.4.1 Scheme 1

As mentioned before, the Scenario 1 (Case 4d) is the base case in this scheme. From the base scenario, 9 months after the second breakthrough, section 3 in the heel-end of the smart horizontal well is closed and section 1 in the toe-end is again opened to production (**Fig 4.6**). **Fig 4.85** compares the oil rate and cumulative oil production of Scheme 1 and the base scenario. There is no additional oil recovery from Scheme 1.

Fig. 4.86 presents a 3D view of water saturation 9 months after the second breakthrough. The third breakthrough is instantaneous because the water saturation around the horizontal well is high; this facilitates the movement of the steam towards section 1 and, the third production peak is very low. **Table 4.27** compares the cumulative oil production and recovery factor in this scheme.

TABLE 4.27–SCHEME 1, CUMULATIVE OIL PRODUCTION AND RECOVERY FACTOR

Simulation case	Cumulative oil, STB	Oil recovery, % OOIP
Scheme 1	341500	60.6
Scenario 1, Case 4d	343625	60.9

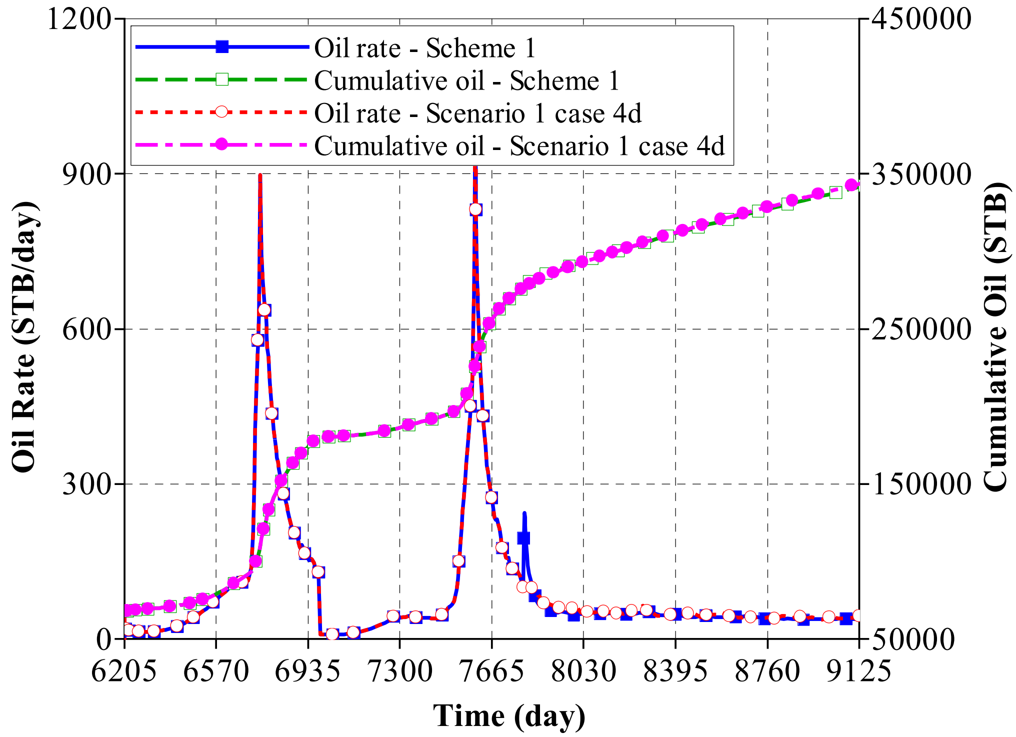

Fig. 4.85–Oil production rate and cumulative oil production, Scheme 1.

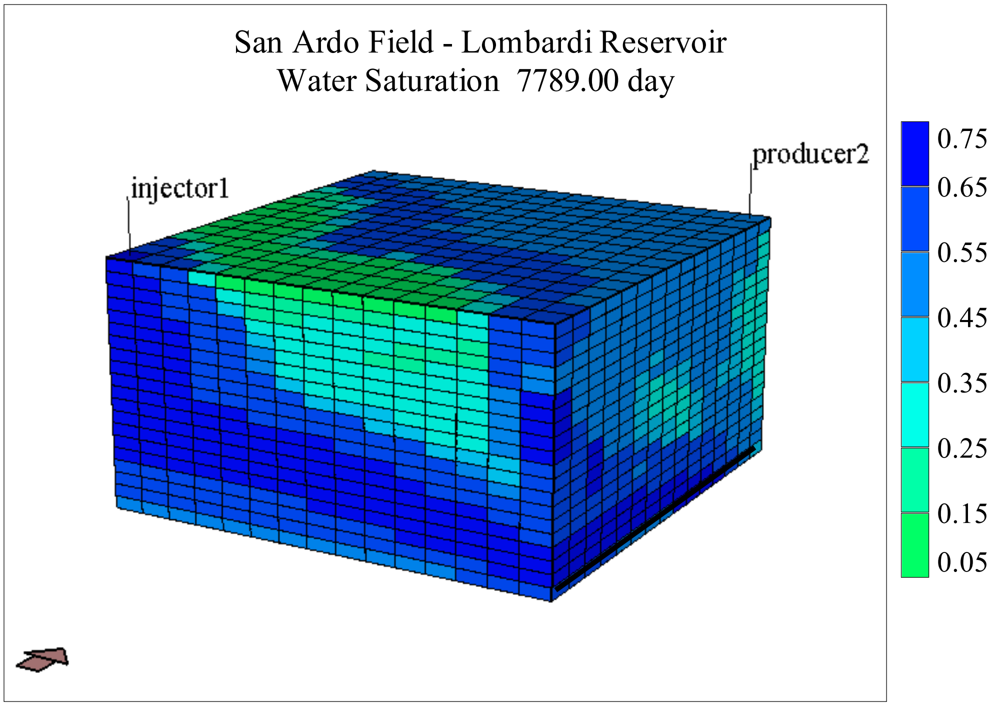

Fig. 4.86–Water saturation, 9 months after second breakthrough, Scheme 1.

4.4.2 Scheme 2

To take advantage of the well locations in the 9-spot inverted patter, three cases were analyzed in Scheme 2. **Fig. 4.87** presents the 9-spot inverted pattern as implemented in the San Ardo field and the one quarter simulation model with the new smart horizontal producer.

Figs. 4.88 and **4.89** present a 3D view of the oil saturation in the reservoir (below layer 15), 9 months after the second steam breakthrough (7789 days) and at the end of 8 years of steamflooding, respectively. These 3D views show the regions in the reservoir with high oil saturation. Because their location and the profile of the steam front advance in the reservoir, these regions have not been highly influenced for the steam injection.

To enhance the oil sweep efficiency from those regions of the reservoir, well P-1 (**Fig 4.87**) can be used as steam injector.

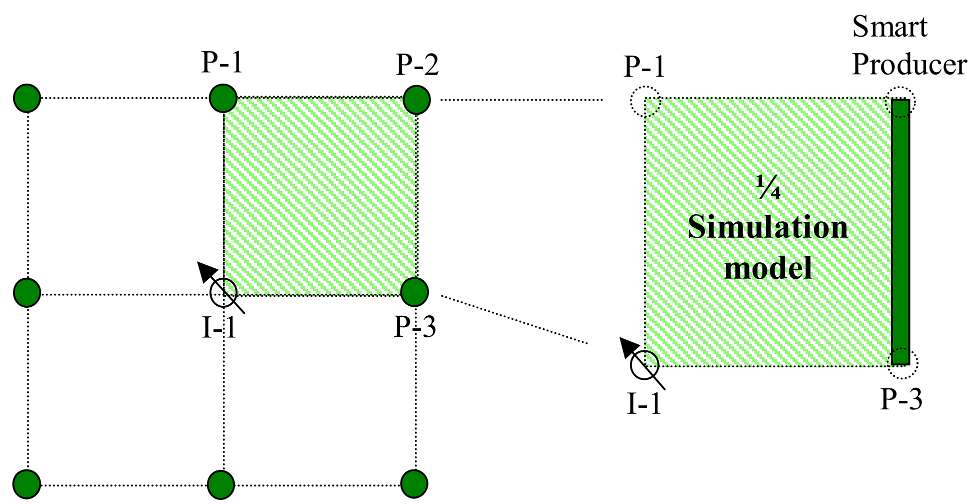

Fig. 4.87–San Ardo field, 9-spot inverted pattern and simulation model.

Three simulation cases were analyzed in Scheme 2. In the Case 1, 9 months after the second steam breakthrough, the injector well I-1 in **Fig. 4.87** is closed, and the well P-1 is opened as steam injector from the top section (one quarter of the well, layers 1 to 5). Case 2 is similar to Case 1, but now the well P-2 is opened as steam injector from the bottom section (one quarter of the well, layers 16 to 20).

Case 3 is similar to Case 2, but additionally the injector well I-1 in **Fig. 4.87**, is converted to producer from the bottom section (layers 16 to 20). Case 3 was performed to evaluate the possibility of improving the oil sweep efficiency in the direction from P-1 to I-1. **Table 4.28** details the cases simulated for Scheme 2.

Figs. 4.90 and **4.91** present a comparison of the results for the simulation cases in Scheme 2 and the base case (Scenario 1, Case 4d). **Table 4.29** shows the cumulative oil and oil recovery factor for the cases in Scheme 2. Case 3 resulted in the highest oil recovery factor with 65.0% of the OOIP after 8 years of steamflooding. This value is 4.0% higher than the base case.

TABLE 4.28–SCHEME 2, SIMULATION CASES

Case 1	From base case (Scenario 1, Case 4d), 9 months after the second breakthrough the injector well I-1 is closed and the well P-1 is opened as steam injector from layers 1 to 5 (**Fig 4.87**).
Case 2	From base case (Scenario 1, Case 4d), 9 months after the second breakthrough the injector well I-1 is closed and the well P-1 is opened as steam injector from layers 16 to 20 (**Fig 4.87**).
Case 3	From base case (Scenario 1, Case 4d), 9 months after the second breakthrough the injector well I-1 is closed, the well P-1 is opened as steam injector from layers 16 to 20, and the injector well I-1 is converted to producer and opened from layers 16 to 20 (**Fig 4.87**).

TABLE 4.29–SCHEME 2, CUMULATIVE OIL PRODUCTION AND RECOVERY FACTOR

Scheme 2	**Cumulative oil, STB**	**Oil recovery, % OOIP**
Case 1	352347	62.5
Case 2	359613	63.8
Case 3	366445	65.0
Scenario 1, Case 4d	343625	60.9

Case 3 in Scheme 2 was the best case obtained during this simulation study. Under this development strategy more than 70% of the OOIP can be recovered after 10.5 years of steamflooding as shown in **Fig. 4.92**. At this time, the cumulative oil production was 397694 STB or 70.5% of the OOIP.

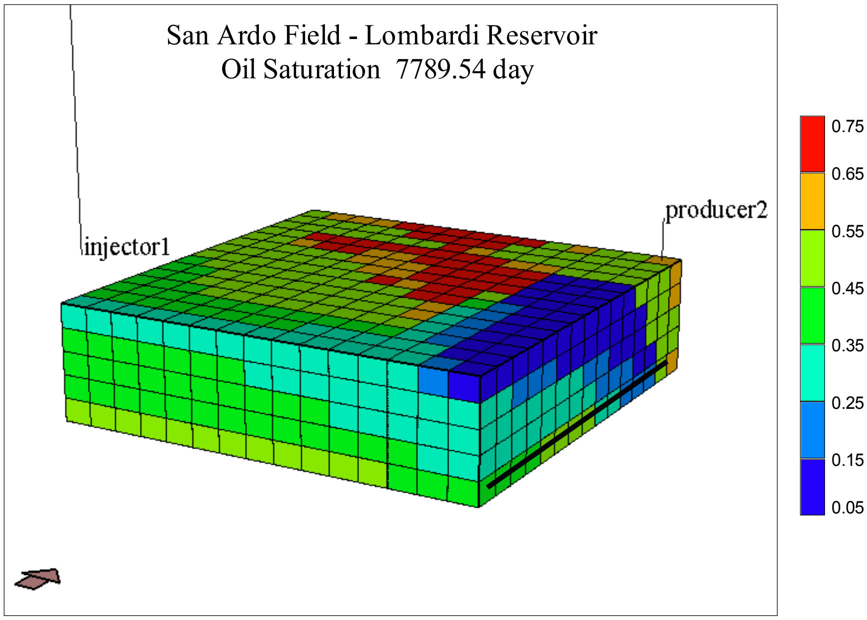

Fig. 4.88–Oil saturation, 9 months after second breakthrough, top of layer 16.

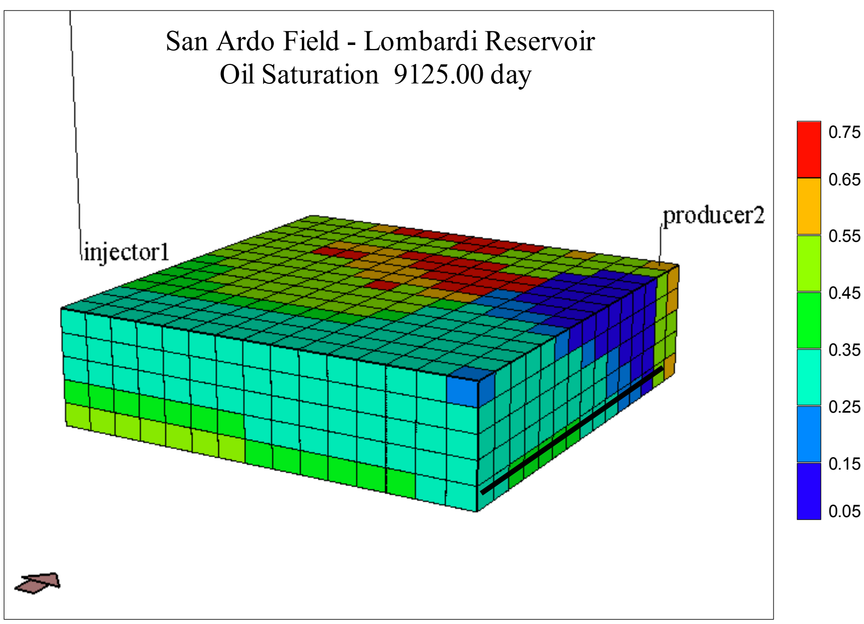

Fig. 4.89–Oil saturation, after 8 years of steamflooding, top of layer 16.

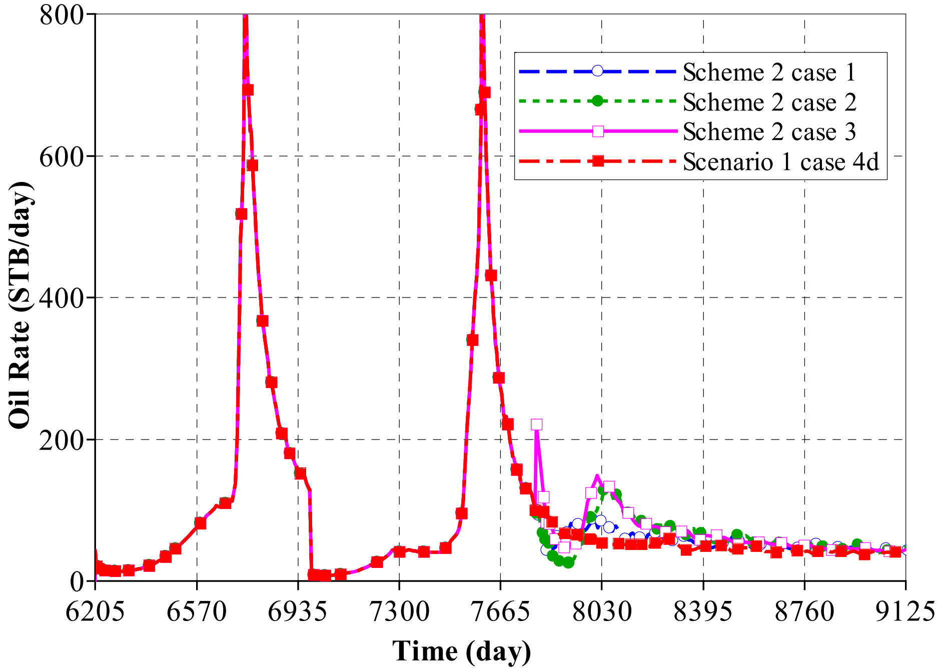

Fig. 4.90–Oil production rate, simulation cases in Scheme 2.

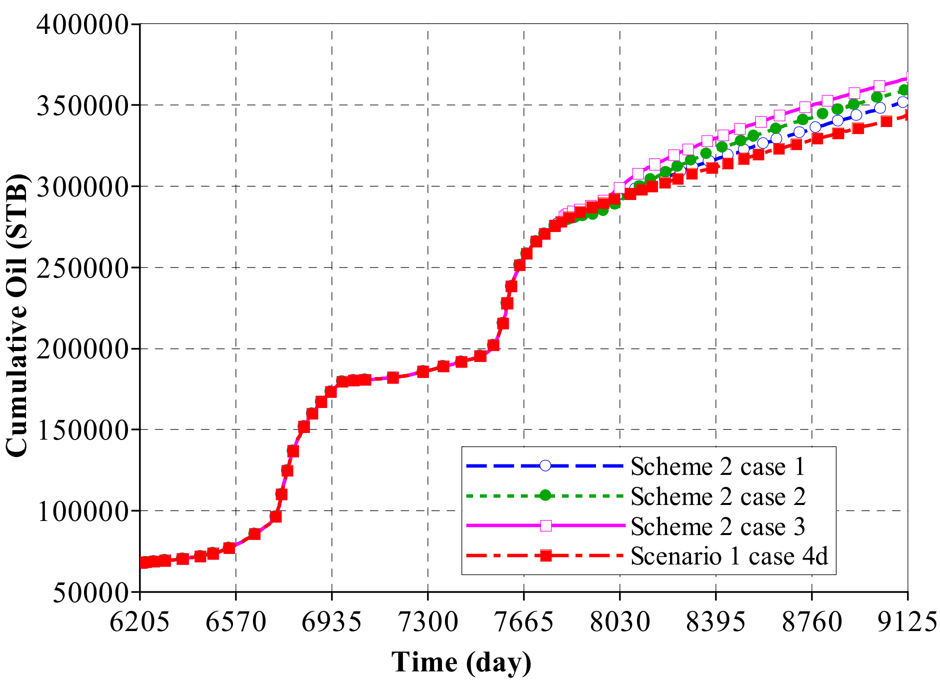

Fig. 4.91–Cumulative oil production, simulation cases in Scheme 2.

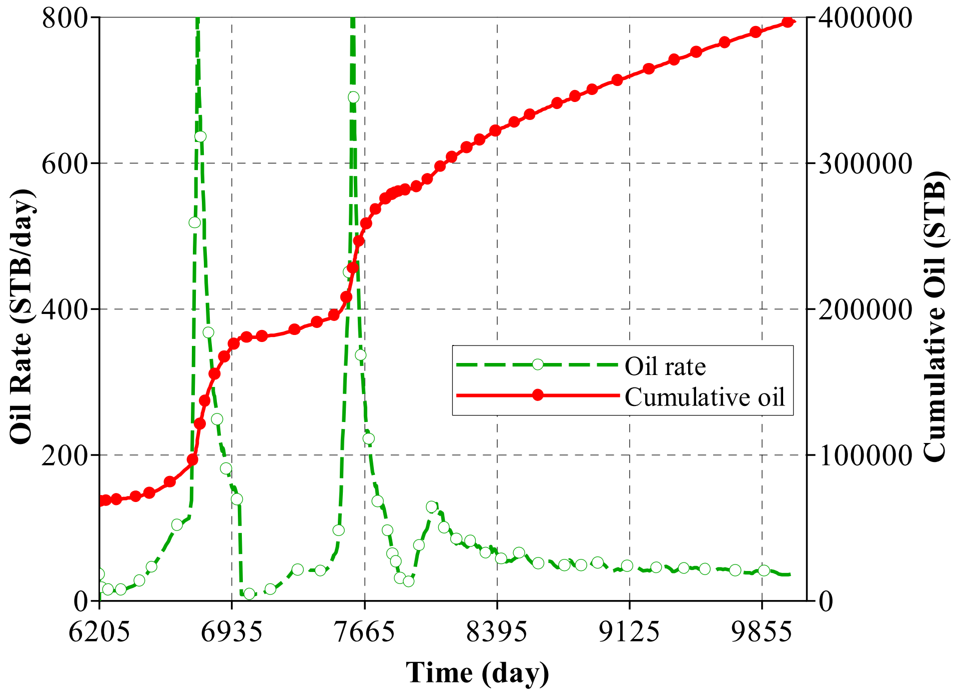

Fig. 4.92–Oil rate and cumulative oil production, 10.5 years of steamflooding, Scheme 2, Case 3.

4.5 Sensitivity Analysis

To gain better understanding of other reservoir parameters, and their effect on production performance, a sensitivity analysis of steam quality and horizontal to vertical permeability anisotropy were analyzed in this part of the simulation study.

All simulations in the sensitivity cases include the best case obtained in the vertical-smart horizontal system analysis (Scenario 1, Case 4d).

4.5.1 Sensitivity to Steam Quality

Simulation cases were carried out considering steam quality variation from 50% to 80%, using Scenario 1, Case 4d as a base case with 80% of steam quality.

Figs. 4.93 and **4.94** present the results for the oil production behavior in the steam quality sensitivity analysis, using the vertical-horizontal well system (without shut in zones during the steamflooding) and the vertical-smart horizontal well system. **Table 4.30** shows the cumulative oil production and recovery factor obtained in the steam quality sensitivity analysis.

As steam quality increases at constant mass flow rate (300 BPDCWE injection), the total heat carried by the vapor increases. Hence, there is greater reservoir volume heated as the quality increases, thereby increasing the quantity of heated oil flowing towards the horizontal production well. An increase in the steam quality from 50% to 80% produces an additional 4% of the OOIP in 8 years of steamflooding.

The additional oil recovery is similar between the vertical-horizontal system and the vertical-smart horizontal well system, when the steam quality is increased (**Fig 4.94**). This indicates that the vertical-smart horizontal well system does not give additional advantage with the steam quality variation when compared to the vertical-horizontal well system.

TABLE 4.30–SENSITIVITY TO STEAM QUALITY, CUMULATIVE OIL PRODUCTION AND RECOVERY FACTOR, 300 BPDCWE INJECTION RATE

System	Steam quality, %	Cumulative oil, STB	Recovery factor, % OOIP
Vertical-horizontal well	50	260654	46.2
	60	265630	47.1
	70	273918	48.6
	80	282558	50.1
Vertical-smart horizontal well	50	321056	56.9
	60	328563	58.3
	80	343625	60.9

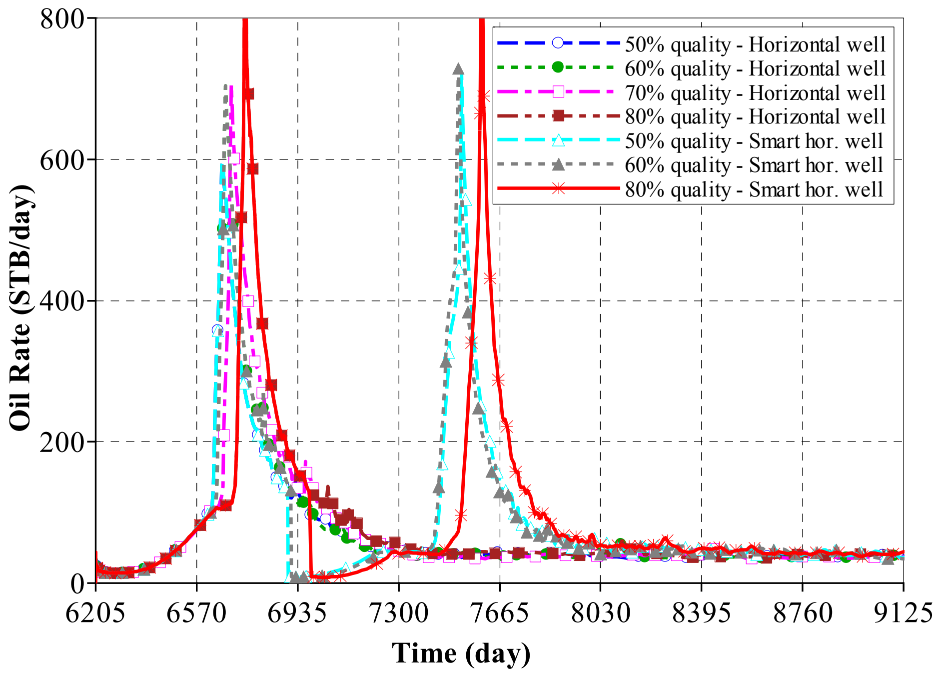

Fig. 4.93–Oil production rate, sensitivity to steam quality from 50% to 80%.

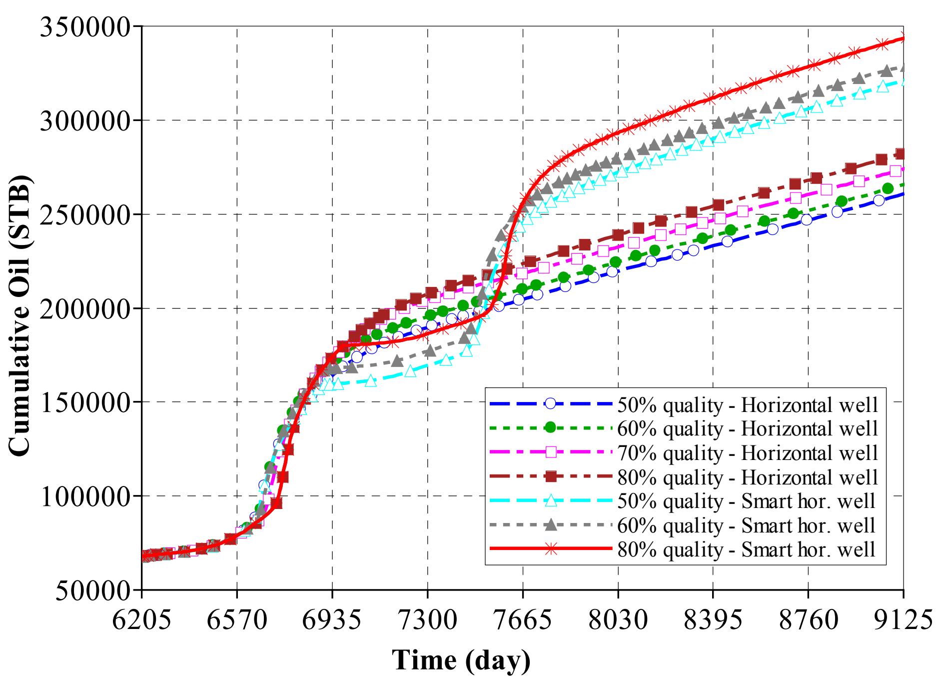

Fig. 4.94–Cumulative oil production, sensitivity to steam quality from 50% to 80%.

4.5.2 Sensitivity to Vertical Permeability

To analyze the effect of vertical to horizontal permeability anisotropy, various cases were simulated for vertical to horizontal permeability ratio, Kv/Kh, ranging from 0.1 to 0.75. Runs were made for vertical-horizontal well system (without shut in zones during the steamflooding) and the vertical-smart horizontal well system.

The base vertical to horizontal permeability ratio, Kv/Kh, is 0.1. The vertical permeability was adjusted to create three more cases with ratios of 0.25, 0.5, and 0.75. In all cases, the horizontal permeability remained fixed at 6922 md (Lombardi reservoir).

Although the vertical-smart horizontal system presents the highest oil recovery, the results show that lower Kv/Kh ratios present even more favorable conditions when this system is implemented. **Table 4.31** shows the cumulative oil production and recovery factor obtained in the vertical permeability sensitivity analysis. **Figs. 4.95** and **4.96** present the results for the oil production behavior in the sensitivity analysis of vertical to horizontal permeability anisotropy. In this specific situation, oil recovery improves as the permeability anisotropy increases. It shows that the steam override effect is lower when the vertical to horizontal permeability ratio, Kv/Kh, decreases.

As presented in **Fig. 4.96**, the vertical-smart horizontal well system gives a higher oil recovery when the permeability anisotropy increases. As stated before, the vertical-smart horizontal well system is even better when this permeability anisotropy is greater.

The difference in oil recovery factor between Kv/Kh ratio of 0.1 and 0.75 becomes more than 4.0% of OOIP when comparing the vertical-horizontal well and vertical-smart horizontal well systems (**Table 4.31**).

TABLE 4.31–SENSITIVITY TO Kv/Kh RATIO: CUMULATIVE OIL PRODUCTION AND RECOVERY FACTOR, 300 BPDCWE INJECTION RATE

System	Kv/Kh ratio	Cumulative oil, STB	Recovery factor, % OOIP
Vertical-horizontal well	0.75	281445	49.9
	0.5	278125	49.3
	0.25	273872	48.6
	0.1	282558	50.1
Vertical-smart horizontal well	0.75	318077	56.4
	0.5	322768	57.2
	0.25	337460	59.8
	0.1	343625	60.9

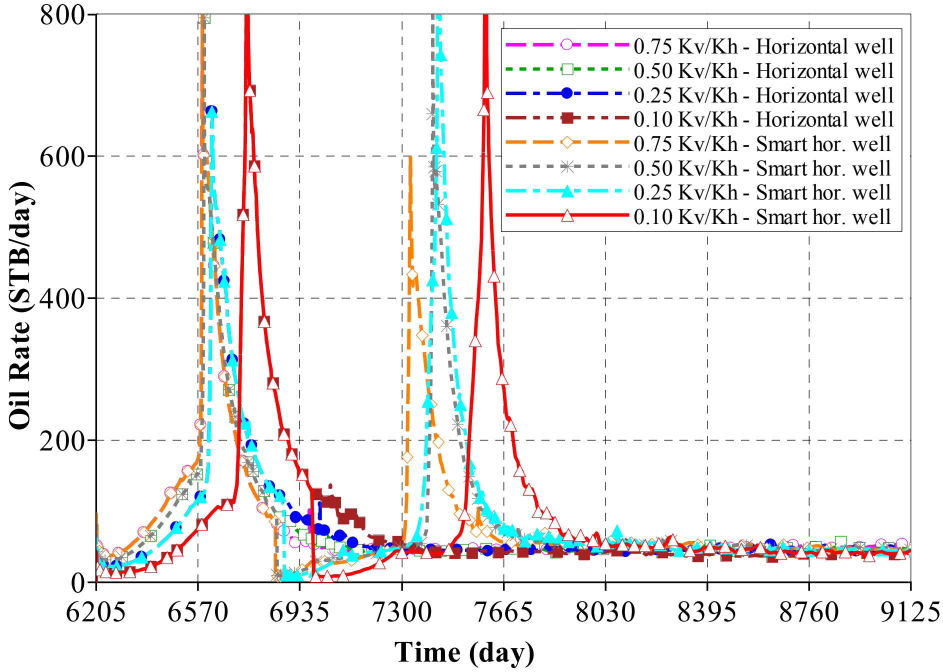

Fig. 4.95–Oil production rate, sensitivity to Kv/Kh ratio.

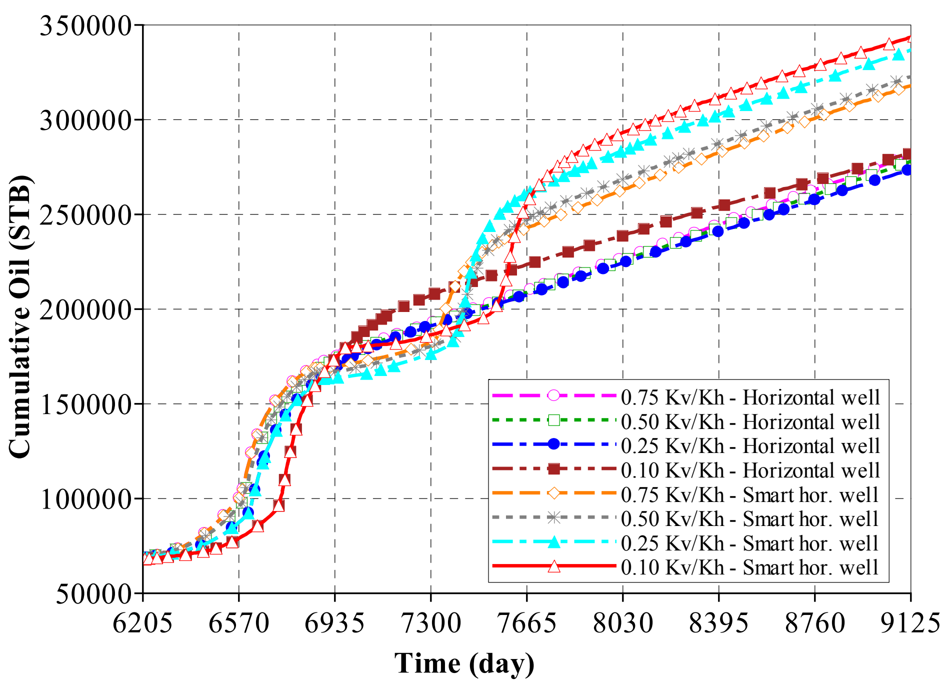

Fig. 4.96–Cumulative oil production, sensitivity to Kv/Kh ratio.

CHAPTER V

NUMERICAL SIMULATION OF STEAM-PROPANE INJECTION

The objective of this part of the simulation study is to evaluate the effectiveness of using steam-propane injection to improve oil production rate and recovery with the vertical-smart horizontal system. A new fluid model was defined to include propane and its interaction with the reservoir fluid. Also, to select the best number of grid cells with this fluid model, a new sensitivity analysis was made to ensure accuracy and stability in the simulator.

Constant propane:steam mass ratio of 5:100 is used because it has been the best ratio obtained by previous researchers.[41-45] In this case, for the steam injection rate of 600 BPDCWE the equivalent propane injection rate is 90568 SCF/day. A comparative analysis was performed between pure steam and steam-propane injection with the vertical-smart horizontal system and additionally, with the vertical-vertical system as this currently exists in the San Ardo field.

5.1 Fluid Model

A fluid model of eight pseudo components was defined (7 hydrocarbon pseudo components and water). This is based on previous research where the best match between reservoir and laboratory results was obtained using this fluid model.[45]

As discussed in the simulation model of pure steam injection, to obtain the initial GOR of 78 SCF/STB in Lombardi reservoir, it was necessary to create a pseudo fluid by recombination of Lombardi dead oil and gas whose composition is based on the Hamaca field.[45,46] The compositions of San Ardo dead oil and Hamaca gas were loaded in WinProp (CMG's equation of state package) and the recombination results are presented in **Table 5.1**. The Peng-Robinson equation of state was used for all phase behavior calculations. Peng-Robinson is generally the equation of choice because of its more accurate prediction of liquid phase volumes and its easily solved cubic form.

TABLE 5.1–SAN ARDO DEAD OIL AND HAMACA GAS, RECOMBINATION

Component	San Ardo oil, mole %	Hamaca gas, mole %	Recombined fluid, mole %
C1	0	97.884	20.2508
C2	0	0.9201	0.1904
C3	0	0.4142	0.0857
iC4	0	0.1523	0.0315
nC4	0	0.2151	0.0445
iC5	0	0.0852	0.0176
nC5	0	0.0724	0.015
C6	0	0.1203	0.0249
C7	0.2	0.115	0.1824
C8	0.5	0.016	0.3999
C9	1.2	0.0043	0.9526
C10	2.1	0.0011	1.6658
C11	3.2	0	2.538
C12	4.2	0	3.3311
C13	5.0	0	3.9656
C14	4.9	0	3.8863
C15	5.1	0	4.0449
C16	4.5	0	3.569
C17	4.9	0	3.8863
C18	4.4	0	3.4897
C19	3.9	0	3.0931
C20	4.0	0	3.1725
C21	3.5	0	2.7759
C22	3.0	0	2.3793
C23	2.9	0	2.3
C24	2.7	0	2.1414
C25	2.4	0	1.9035
C26	2.3	0	1.8242
C27	2.6	0	2.0621
C28	2.0	0	1.5862
C29	2.4	0	1.9035
C30	2.1	0	1.6655
C31	1.7	0	1.3483
C32	1.5	0	1.1897
C33	1.3	0	1.031
C34	1.2	0	0.9517
C35	1.2	0	0.9517
C36	1.1	0	0.8724
C37	1.0	0	0.7931
C38	0.9	0	0.7138
C39	1.0	0	0.7931
C40	0.8	0	0.6345
C41	0.7	0	0.5552
C42	0.7	0	0.5552
C43	0.7	0	0.5552
C44	0.6	0	0.4759
C45	0.9	0	0.7138
C46+	10.7	0	8.4863

After the recombination of the fluid, a grouping was performed to obtain the 8 pseudo-component fluid model. In order to simulate the viscosity data, the Pedersen viscosity correlation was used. A viscosity of 3000 cp at initial reservoir conditions was matched. Also, a saturation pressure of 845 psia at initial reservoir temperature (127^{o}F) and oil gravity of 12^{o}API were matched using the regression option in CMG's WinProp.

Table 5.2 shows the equation of state parameters obtained after regression. **Table 5.3** presents the pseudo components properties, and **Table 5.4** includes the viscosity information to use in the CMG's STARS simulator as generated from CMG's WinProp.

TABLE 5.2–EQUATION OF STATE PARAMETERS, SAN ARDO FLUID MODEL (WinProp)

Parameter	**C1-C2**	**C3**	**iC4-C9**	**C10-C17**	**C18-C25**	**C26-C33**	**C34+**
AC	8.84E-3	1.52E-1	3.58E-1	6.01E-1	8.52E-1	1.062	1.197
VCRIT	9.94E-2	2.03E-1	4.33E-1	7.21E-1	1.063	1.361	1.719
TB	-257.39	-43.69	249.9	471.53	663.48	818.22	977.87
SG	0.30082	0.5070	0.75041	0.82614	0.8718	0.90273	0.93201
BIN	0.4907	0.5469	0.4817	0.4800	0.4800	0.4800	0.4800
ZRA	0.2875	0.2763	0.2639	0.2526	0.2432	0.2307	0.3209
VISVC	0.09945	0.203	0.4343	0.72344	1.06394	1.362311	1.719398
OMEGA	0.45723	0.45723	0.45723	0.45723	0.45723	0.45723	0.45723
OMEGB	0.07779	0.07779	0.07779	0.07779	0.07779	0.07779	0.07779
PCHOR	77.2887	150.3	319.419	520.9489	736.0384	901.7201	85.6709
Composition, mole %	0.20441	0.0008569	0.016684	0.26887	0.21255	0.12611	0.17052

TABLE 5.3–PSEUDO COMPONENT PROPERTIES, SAN ARDO FLUID MODEL (REFERENCE PRESSURE 64.7 psia, REFERENCE TEMPERATURE 122^{o}F)

Property	C1-C2	C3	iC4-C9	C10-C17	C18-C25	C26-C33	C34+
CMM	16.1736	44.097	110.57	190.1146	288.694	383.0189	1087.3628
PCRIT	668.33	615.76	4818.52	285.18	203.22	153.62	122.12
TCRIT	-114.5	205.97	576.42	799.89	969.48	1098.28	1239.14
KV1	1.51E+5	3.002E+5	6.18E+5	1.554E+6	4.255E+6	9.934E+6	1.63E+7
KV4	-1870.9	-4119.9	-7560.9	-10836.2	-14219	-17257.4	-20048.7
KV5	-459.67	-459.67	-459.67	-459.67	-459.67	-459.67	-459.67
MOLDEN	1.102	0.7427	0.4055	0.2461	0.1602	0.1127	0.08271
CP	5.13E-5	3.02E-5	1.31E-5	6.61E-6	3.91E-6	3.10E-6	3.06E-6
CT1	1.92E-3	1.19E-3	5.57E-4	3.05E-4	1.87E-4	1.37E-4	1.12E-4

TABLE 5.4–VISCOSITY DATA, cp (WinProp)

Temperature, ^{o}F	C1-C2	C3	iC4-C9	C10-C17	C18-C25	C26-C33	C34+
50	2.47E+4	4.52E+4	8.48E+4	1.36E+5	2.23E+5	3.61E+5	8.80E+5
100	1.41E+3	2.49E+3	4.38E+3	6.57E+3	1.01E+4	1.53E+4	3.53E+4
150	1.86E+2	3.17E+2	5.31E+2	7.54E+2	1.09E+3	1.58E+3	3.46E+3
200	4.28E+1	7.12E+1	1.14E+2	1.55E+2	2.14E+2	2.95E+2	6.22E+2
250	1.45E+1	2.36E+1	3.64E+1	4.75E+1	6.29E+1	8.36E+1	1.70E+2
300	6.45E+0	1.03E+1	1.54E+1	1.94E+1	2.47E+1	3.18E+1	6.29E+1
350	3.48E+0	5.46E+0	7.94E+0	9.72E+0	1.20E+1	1.50E+1	2.89E+1
400	2.17E+0	3.35E+0	4.74E+0	5.66E+0	6.80E+0	8.27E+0	1.56E+1
450	1.50E+0	2.28E+0	3.16E+0	3.68E+0	4.31E+0	5.13E+0	9.45E+0
500	1.11E+0	1.67E+0	2.27E+0	2.59E+0	2.97E+0	3.46E+0	6.26E+0
550	8.70E-1	1.30E+0	1.73E+0	1.94E+0	2.17E+0	2.48E+0	4.42E+0
600	7.06E-1	1.04E+0	1.37E+0	1.50E+0	1.66E+0	1.86E+0	3.26E+0
650	5.86E-1	8.56E-1	1.11E+0	1.20E+0	1.30E+0	1.44E+0	2.49E+0
700	5.05E-1	7.32E-1	9.32E-1	9.96E-1	1.06E+0	1.16E+0	1.98E+0

5.2 Grid Model

As in the pure steam simulation model, a Cartesian three dimensional model was constructed to represent the 10-acre inverted 9-spot pattern in the San Ardo field. Again, a model of one quarter of this pattern was finally used in the simulation, with a reservoir thickness of 115 ft, following the three dimensional symmetry of all elements in the system (**Fig. 3.3**).

To select the best number of grid cells to use in the simulation model of steam-propane injection, a sensitivity analysis was made to ensure accuracy and stability in the simulator. A total of five Cartesian grid models from 1000 to 8000 cells were compared and they are presented in **Table 5.5**.

Fig. 5.1 compares the results for the different grid models included in the sensitivity analysis. The grid of 5120 cells (16x16x20) was selected because the simulation results were practically unchanged when the number of grid cells was increased further.

Fig 5.2 presents the final 3D reservoir grid model for a quarter of a 10-acre inverted 9-spot pattern; it has an OOIP of 564026 STB or 2.256 MMSTB for the whole 10-acre pattern.

TABLE 5.5–GRID MODELS AND DIMENSIONS USED FOR SENSITIVITY

Total number of cells	Number of cells in i-direction	Number of cells in j-direction	Number of cells in k-direction	Cell dimensions (ft)		
				i	j	k
1000	10	10	10	33	33	11.5
2000	10	10	20	33	33	5.75
4500	15	15	20	22	22	5.75
5120	16	16	20	20.625	20.625	5.75
8000	20	20	20	16.5	16.5	5.75

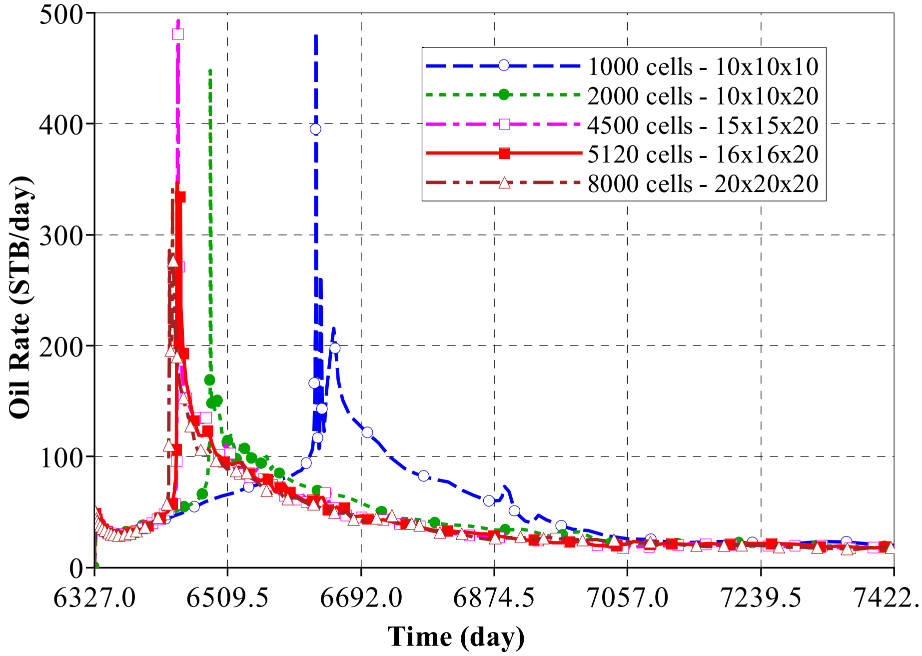

Fig. 5.1–Grid model sensitivity analysis.

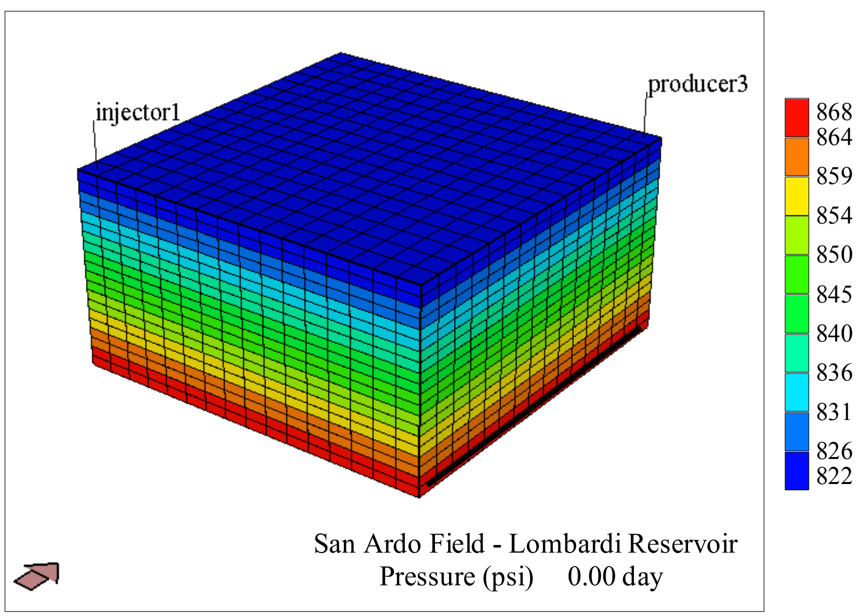

Fig. 5.2–Lombardi 3D reservoir grid model, steam-propane injection.

CHAPTER VI

STEAM-PROPANE INJECTION SIMULATION RESULTS

To study the effect of steam-propane injection under the conditions mentioned in Chapter V, three different injection rates were analyzed, taking into account the oil production performance with high, moderate and low steam-propane injection rates.

The best case obtained for pure steam injection (Scenario 1, case 4d), with the smart horizontal producer, is used as the basic scenario in this steam-propane injection analysis. The smart horizontal producer is divided into three sections and nine months after the steam breakthrough, two sections are closed leaving the section at the heel-end of the horizontal well kept open (**Fig. 4.6**). Injection rates of 50, 150 and 300 BPDCWE in the quarter of 9-spot inverted pattern were analyzed. Runs were made for both the vertical-smart horizontal well and the vertical well systems. The thermal reservoir simulation files for steam-propane injection using the vertical well and the vertical-smart horizontal well systems are presented in **Appendix C** and **Appendix D**.

6.1 Vertical-Smart Horizontal Well System

It was found that the oil production performance with steam-propane injection is highly influenced by the injection rate. Due to the close distance between the injector and producer wells, viscous forces dominate the steam-propane front advance when 300 BPDCWE steam is injected. At high injection rate of 300 BPDCWE, severe cusping occurs, so that the propane has little contact with the bulk of the oil. Thus, the first breakthrough time is virtually the same when steam-propane or pure steam is injected into the reservoir.

Fig. 6.1 presents the oil production rate when 300 BPDCWE is injected. It compares the vertical-smart horizontal well system with pure steam and steam-propane injection. It can be seen that the second oil production peak is accelerated by about 50% of the time. After the first breakthrough, when the two sections of the smart horizontal well are closed, the volume contacted by steam-propane has now more influence over the steam-propane front advance towards the heel-end section of the smart horizontal producer. At this time, the effect of the propane interaction is higher than the viscous forces, and the second breakthrough is accelerated.

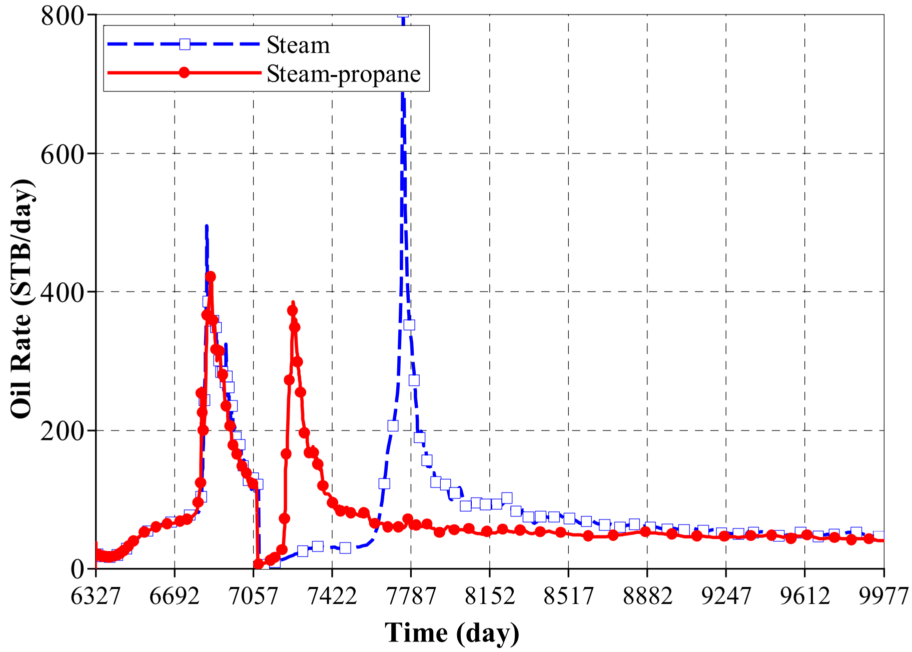

Fig. 6.1–Oil production rate, steam and steam-propane injection, 300 BPDCWE using smart horizontal well system.

A simulation case with 150 BPDCWE injection rate was performed to evaluate the effect of propane interaction with reservoir fluids at lower injection rate. **Fig. 6.2** shows the results for 150 BPDCWE injection rate. In this case, the time of the first oil production peak is accelerated by 10% and the second oil production peak by about 24% compared to that with pure steam injection.

The first oil production peaks for pure steam and steam-propane injection are close together. However, due to subsequent propane interaction with the reservoir fluid, the second oil production peak with steam-propane injection occurs significantly earlier. **Fig. 6.3** presents the cumulative oil production for pure steam and steam-propane injection using the vertical-horizontal well and the vertical-smart horizontal well systems for 150 BPDCWE injection rate. Even though the oil recovery factor after ten years of steam-propane injection is almost the same when compared to pure steam injection, the acceleration in the oil production peaks, provides a significant benefit in earlier revenue and lower steam injection costs.

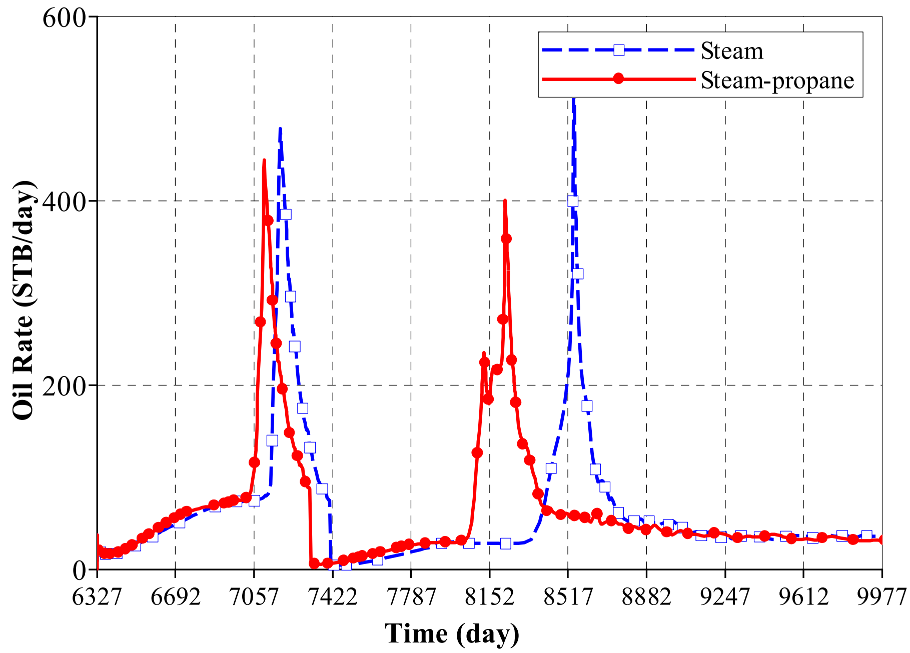

Fig. 6.2–Oil production rate, steam and steam-propane injection, 150 BPDCWE using smart horizontal well system.

Fig. 6.4 shows the average viscosity and temperature in the reservoir with pure steam and steam-propane injection for 150 BPDCWE injection rate. Because of the interaction between propane and reservoir fluid, the viscosity decreases more than that with pure steam injection. This effect with steam-propane injection improves the oil production performance after the first breakthrough because more reservoir fluid volume is interacting with propane when the smart horizontal producer is only kept open in its heel-end section.

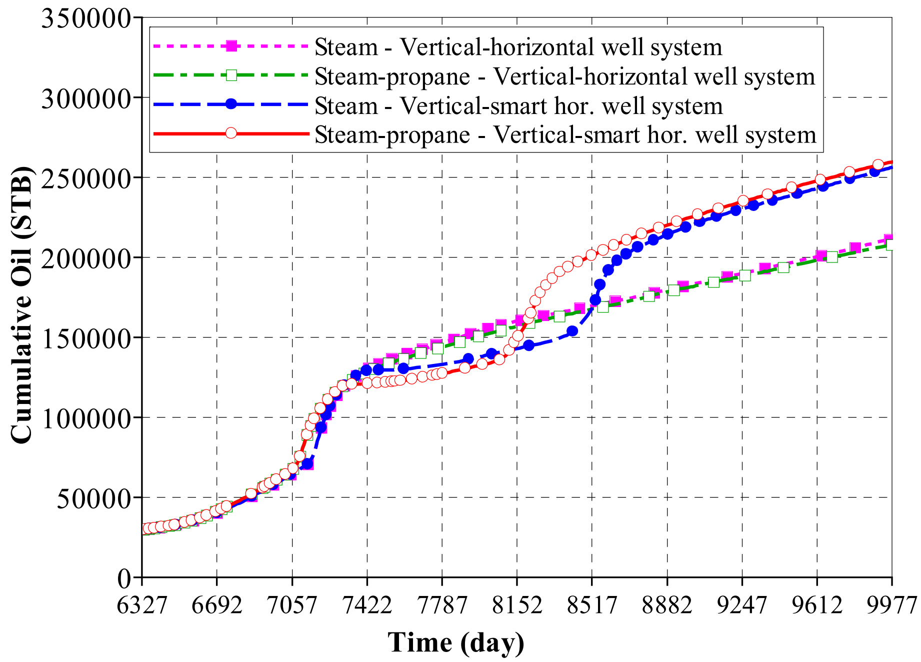

Fig. 6.3–Cumulative oil production, steam and steam-propane injection, 150 BPDCWE.

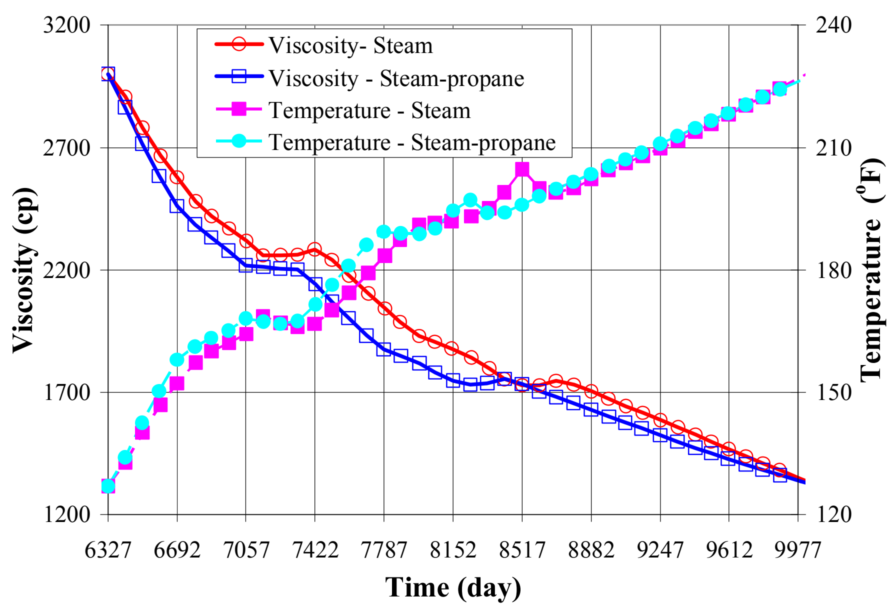

Fig. 6.4–Viscosity and temperature in the reservoir, steam and steam-propane injection, 150 BPDCWE.

To show the effect of a low steam-propane injection rate, a simulation case was performed using 50 BPDCWE. **Fig. 6.5** presents the oil production rate behavior extended for fourteen years of injection to observe the second breakthrough time. Three different cases with the smart horizontal producer are shown. In the first case, pure steam is continuously injected. In the second case, steam-propane is injected continuously. In the third case, pure steam is injected until nine months after the first breakthrough, and thereafter only steam-propane is injected with the smart horizontal well producing only from its heel-end section.

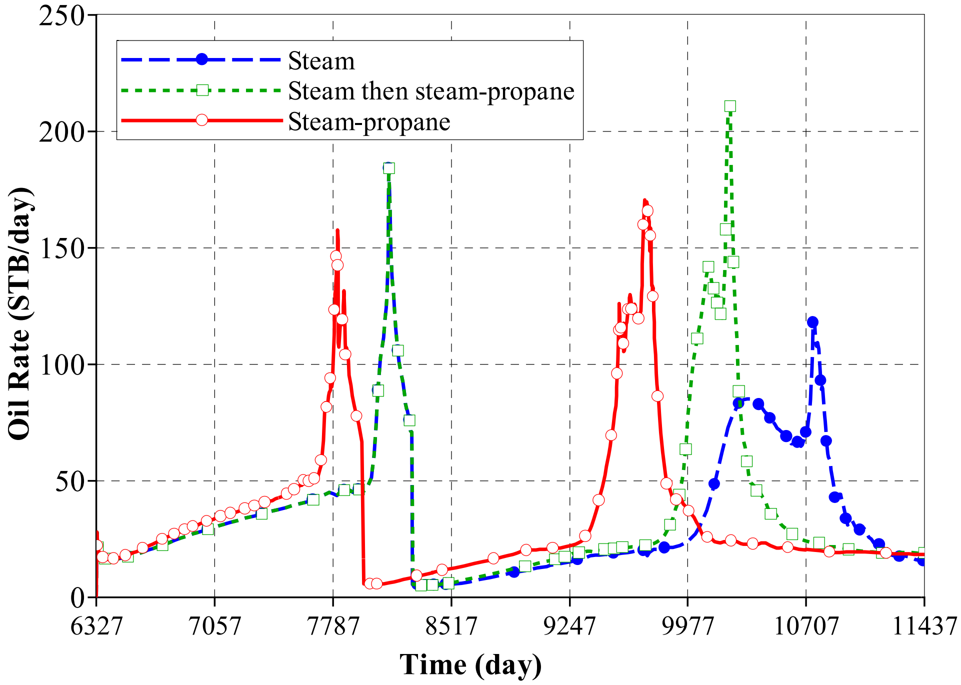

Fig. 6.5–Oil production rate, steam and steam-propane injection, 50 BPDCWE using smart horizontal well system.

Due to the low steam injection rate, the effect of the interaction between propane and reservoir fluid is enhanced, as can be seen in the first oil production peak. The first and second production peaks are accelerated by about 20% and 30% with steam-propane injection compared to pure steam injection (**Fig. 6.5**). As expected, when steam-propane was injected nine months after the first pure steam breakthrough, the second oil production peak was accelerated by about one half of the time compared with the case of steam-propane being injected from the beginning. In this third case, the interaction between propane and reservoir fluids is delayed and the second oil production peak is therefore reached later.

6.2 Comparison between Vertical Well and Vertical-Smart Horizontal Well Systems

This section compares the cumulative oil production between the vertical well system and the vertical-smart horizontal well system under steam and steam-propane injection. Injection rates of 50, 150 and 300 BPDCWE were used to evaluate the effect of steam-propane injection under different injection rates for the two systems. Comparison was made for a ten-year injection period.

Figs. 6.6 through **6.13** present the results for the oil production performance and **Table 6.1** compares the cumulative oil production, recovery factor, and peak production time for the two well systems under pure steam and steam-propane injection.

Comparison between the two well systems is best shown in **Fig. 6.12**, and may be summarized as follows.

(1) Oil recovery is significantly higher with the vertical-smart horizontal well system, 58.7% OOIP (steam) and 51.6% OOIP (steam-propane) compared to 21.9% OOIP (steam) and 35.4% OOIP (steam-propane) for the vertical well system.

(2) For the range of steam injection rates studied, oil recovery factor increases with increasing injection rate using the vertical-smart horizontal well system. In

contrast, for the vertical well system, oil recovery factor appears to be maximum at about 150 BPDCWE steam injection rate. This appears to be due to severe bypassing of oil at higher injection rates.

(3) Although, there is a significant difference in the oil recovery factor between the two systems, as mentioned before, an additional advantage is the acceleration in oil production peaks when steam-propane is injected using the vertical-smart horizontal well system.

One of the most important findings in the steam-propane injection simulation study is that although the propane can accelerate the oil production peaks, equilibrium between acceleration and steam propane injection rate must be found to avoid that the acceleration causes early breakthrough which can affect the oil sweep efficiency into the reservoir.

As shown in **Figs. 6.11** and **6.12**, at high injection rate (300 BPDCWE), the steam-propane injection presents a lower oil recovery in ten years of steamflooding. In this case, the earlier second breakthrough decreases the oil sweep efficiency into the reservoir when compared to pure steam injection at high rate.

In this study, a good equilibrium between oil production peak acceleration and oil recovery at ten years of steamflooding was found when injecting 150 BPDCWE steam-propane (**Figs. 6.8**, **6.9**, and **6.12**).

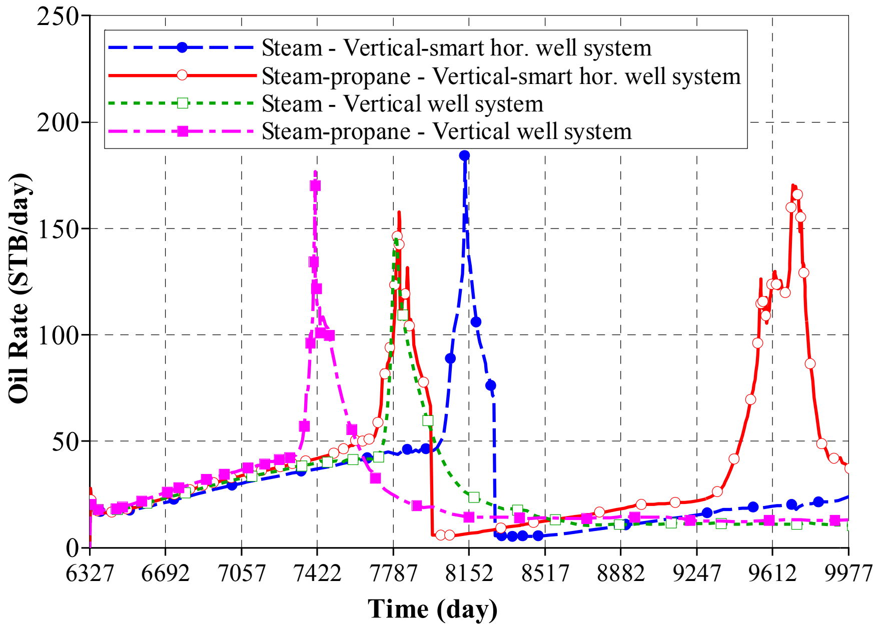

Fig. 6.6–Oil production rate, vertical well and vertical-smart horizontal well systems, steam and steam-propane injection, 50 BPDCWE.

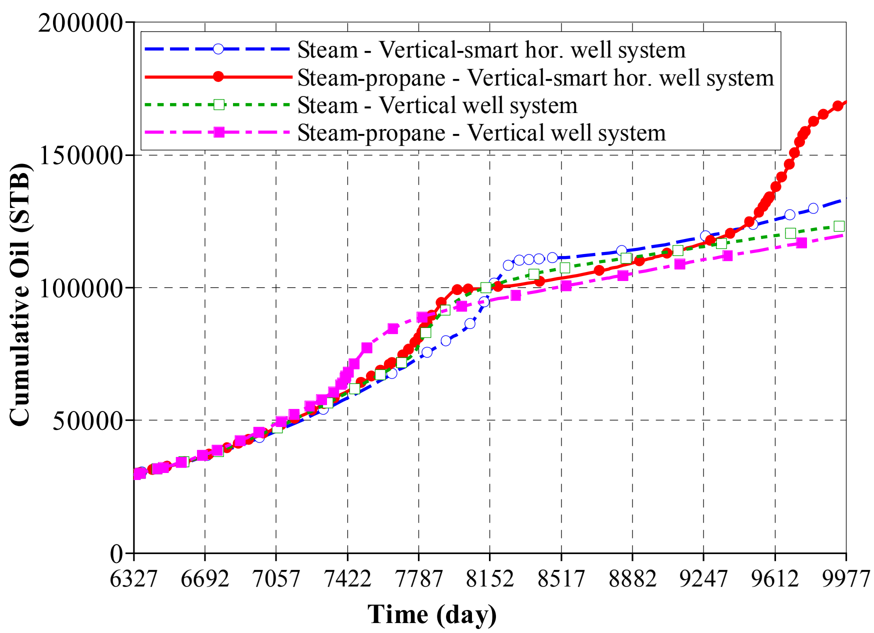

Fig. 6.7–Cumulative oil production, vertical well and vertical-smart horizontal well systems, steam and steam-propane injection, 50 BPDCWE.

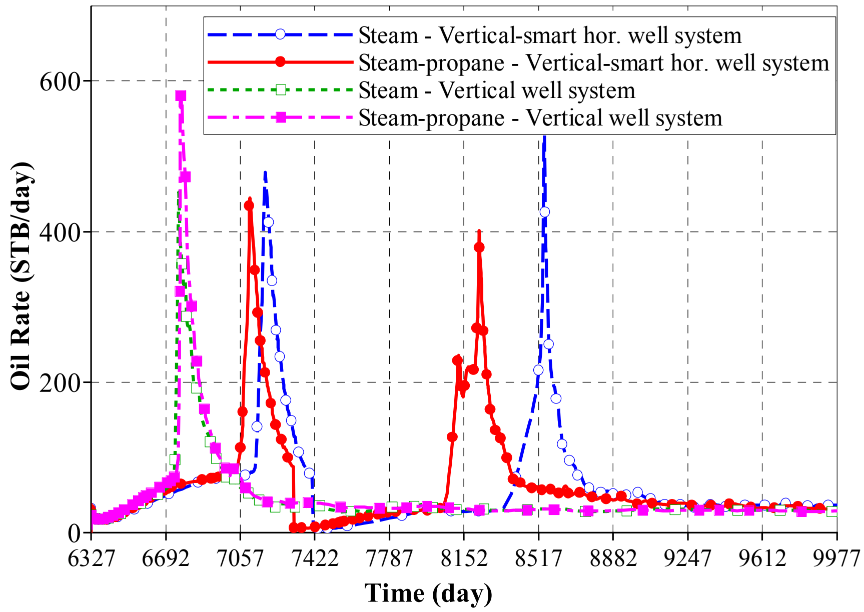

Fig. 6.8–Oil production rate, vertical well and vertical-smart horizontal well systems, steam and steam-propane injection, 150 BPDCWE.

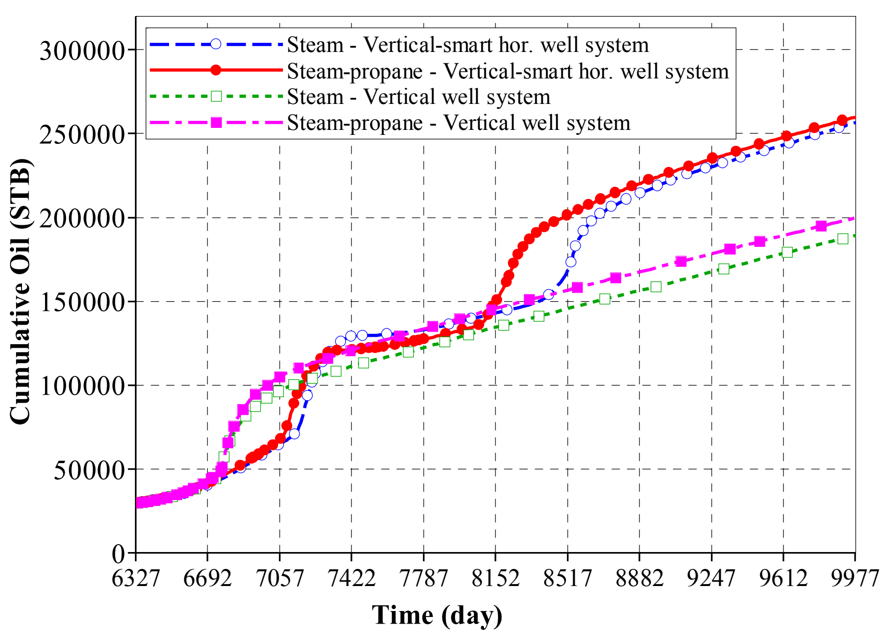

Fig. 6.9–Cumulative oil production, vertical well and vertical-smart horizontal well systems, steam and steam-propane injection, 150 BPDCWE.

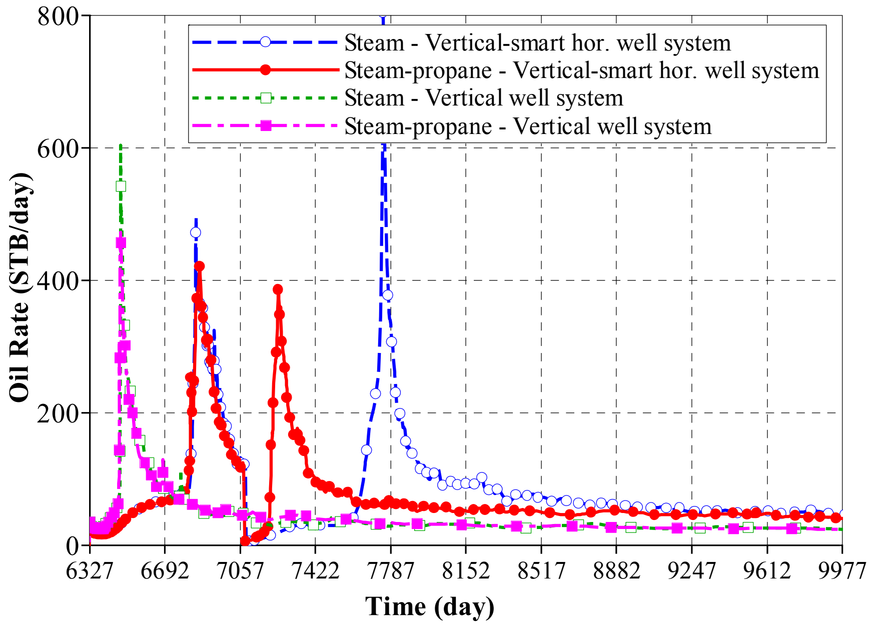

Fig. 6.10–Oil production rate, vertical well and vertical-smart horizontal well systems, steam and steam-propane injection, 300 BPDCWE.

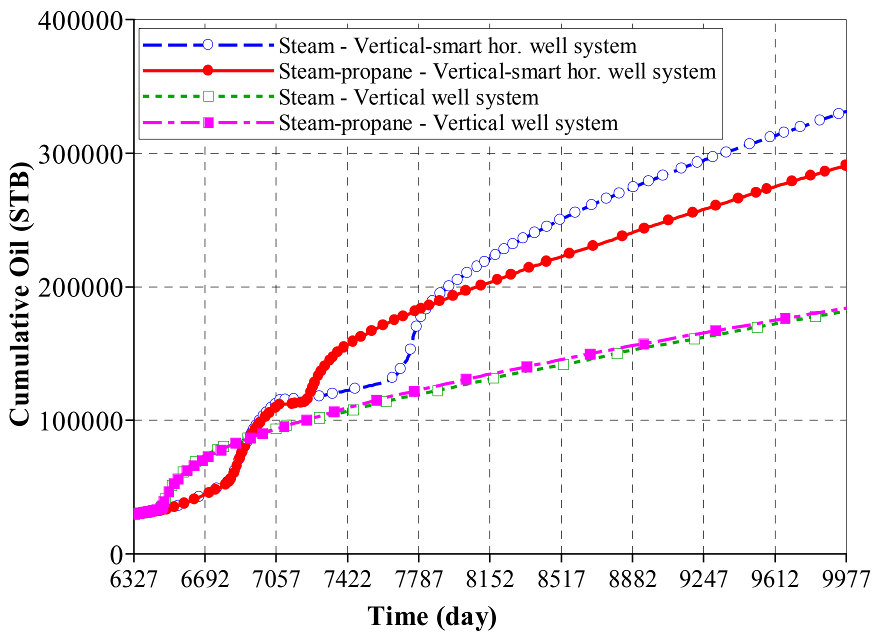

Fig. 6.11–Cumulative oil production, vertical well and vertical-smart horizontal well systems, steam and steam-propane injection, 300 BPDCWE.

TABLE 6.1–CUMULATIVE OIL PRODUCTION, RECOVERY FACTOR, AND PEAK PRODUCTION TIME, VERTICAL WELL AND VERTICAL-SMART HORIZONTAL WELL SYSTEMS, FOR 10 YEARS STEAM AND STEAM-PROPANE INJECTION

Case	Cumulative oil, STB	Oil recovery, % OOIP	Peak prod. time, days	
Vertical well system, pure steam injection, 50 BPDCWE	123674	21.9	7803	
Vertical well system, steam-propane injection, 50 BPDCWE	119814	21.2	7410	
Vertical-smart horizontal well system, pure steam injection, 50 BPDCWE	133361	23.6	8132	10342
Vertical-smart horizontal well system, steam-propane injection, 50 BPDCWE	169887	30.1	7816	9709
Vertical well system, pure steam injection, 150 BPDCWE	189275	33.6	6757	
Vertical well system, steam-propane injection, 150 BPDCWE	199729	35.4	6768	
Vertical-smart horizontal well system, pure steam injection, 150 BPDCWE	256438	45.5	7180	8546
Vertical-smart horizontal well system, steam-propane injection, 150 BPDCWE	259783	46.1	7105	8225
Vertical well system, pure steam injection, 300 BPDCWE	181699	32.2	6476	
Vertical well system, steam-propane injection, 300 BPDCWE	184133	32.6	6476	
Vertical-smart horizontal well system, pure steam injection, 300 BPDCWE	331233	58.7	6842	7750
Vertical-smart horizontal well system, steam-propane injection, 300 BPDCWE	290848	51.6	6861	7242

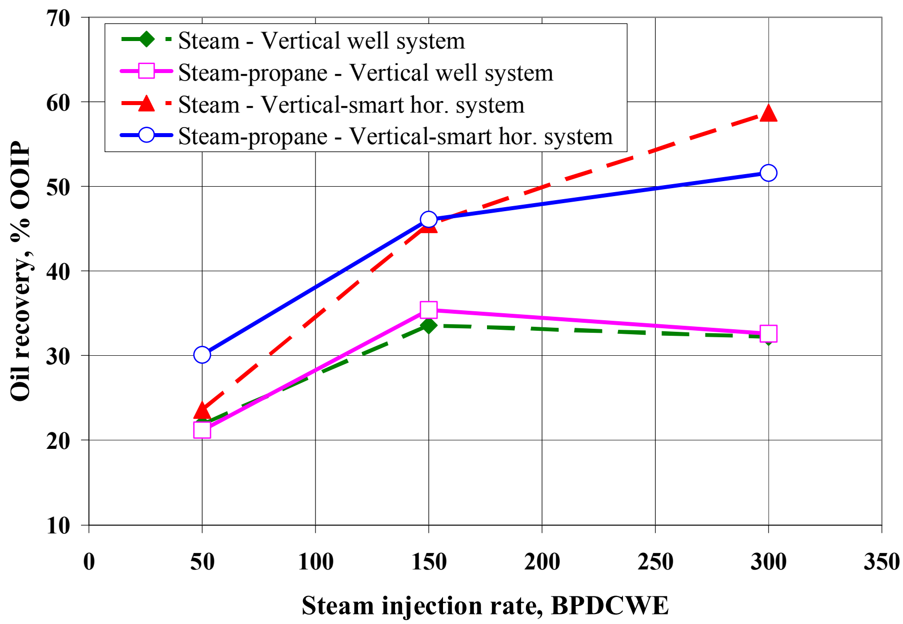

Fig. 6.12–Comparison between vertical well and vertical-smart horizontal well systems, steam and steam-propane injection, oil recovery vs. injection rate.

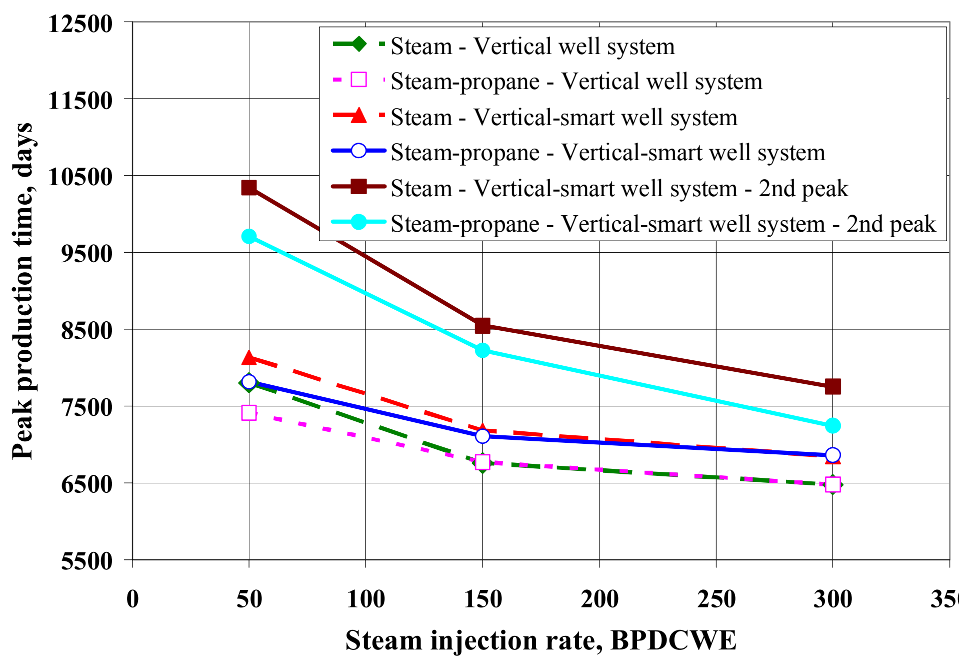

Fig. 6.13–Comparison between vertical well and vertical-smart horizontal well systems, steam and steam-propane injection, peak production vs. injection rate.

CHAPTER VII

SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

7.1 Summary

A thermal compositional simulation study of steam and steam-propane injection was carried out for a quarter of a 10-acre 9-spot inverted pattern that closely represents steamflood patterns in the Lombardi reservoir, San Ardo field, California. The reservoir fluid was modeled using eight pseudo-components: seven hydrocarbon pseudo-components and water.

Three well systems were investigated: existing vertical well system, a vertical injector-horizontal producer system and a novel vertical injector-smart horizontal well system. For each of these systems, simulation runs were made to evaluate oil production under steam and steam-propane injection. A 5:100 propane:steam mass ratio was used in all steam-propane runs.

7.2 Conclusions

Main conclusions from the study may be summarized as follows.

1. For cyclic steam injection, the vertical-horizontal well system produces 9.1% OOIP more than the vertical well system in 10 years of cyclic steam injection.
2. For pure steam injection, maximum oil production is obtained with the vertical-smart horizontal well system when it is divided into three equal sections. At the start of production, all three sections are open. Nine months after steam breakthrough, only the section at the heel-end of the smart horizontal well is kept open. For 300 BPDCWE injection rate, oil recovery is 60.9% OOIP for 8 years of steamflooding with the vertical-smart horizontal well system. This is 11.5% OOIP more than the vertical-horizontal well system (all sections open) and 9.8% OOIP more than the vertical well system.

3. The best condition to implement the vertical-smart horizontal well system is after natural depletion, when the water saturation in the reservoir has not been increased as a result of cyclic steam injection.
4. When steamflooding follows cyclic steam injection, the vertical-smart horizontal well system produces 52.5% OOIP in 8 years of steam injection. This is 4.7% OOIP more than the vertical-horizontal well system and 6.5% OOIP more than the vertical well system during the same period of steam injection.
5. Using the vertical-smart horizontal well system and converting one vertical producer to injector and injector to producer, the oil recovery is increased to 65.0% OOIP in 8 years of steamflooding and up to 70.5% OOIP in 10.5 years.
6. Steam quality sensitivity analysis showed that an increase in the steam quality from 50% to 80% produces an additional 4% OOIP in 8 years of steamflooding using the vertical-smart horizontal well system and 3.9% OOIP using the vertical-horizontal well system.
7. Although the vertical-smart horizontal well system presents the highest oil recovery factor, the permeability anisotropy sensitivity analysis showed that lower Kv/Kh ratios present even more favorable conditions to implement this system. When Kv/Kh ratio is 0.1 the oil recovery reaches 4.5% OOIP more than that for Kv/Kh ratio of 0.75 with the vertical-smart horizontal well system. With the vertical well system the difference is only 0.2% OOIP.
8. Oil production performance with steam-propane injection is influenced by the steam injection rate. The interaction between propane and reservoir fluids is better when the injection rate is lower. This is due to better sweep efficiency and larger contact area at lower injection rates.
9. There is practically no acceleration in the first oil production peak when 300 BPDCWE is injected. However, the second oil production peak obtained with the vertical-smart horizontal well system is accelerated by about 50% in time when compared with the pure steam injection case.

10. Steam-propane injection with 150 BPDCWE injection rate resulted in the first oil production peak being accelerated by 10% and the second by 24% when compared with pure steam injection using the vertical-smart horizontal well system.
11. Oil recovery factor with steam and steam-propane injection is about the same at injection rate of 150 BPDCWE. However, the advantage with steam-propane injection is the acceleration in oil production and its economic benefit.
12. Oil recovery under steam-propane injection is dependent of steam injection rate. There appears to be a balance between production acceleration and sweep efficiency (thus oil recovery).

7.3 Recommendations

1. Oil recovery is dependent on steam-propane injection rate. Research should be conducted to investigate the benefits of a smart injector.
2. Based on the results obtained in this study, it is recommended to perform an economic evaluation should be performed to determine the best conditions to implement the vertical-smart horizontal well system, taking into account facilities and resources in each specific field.
3. To achieve better understanding of the steam-propane interaction with reservoir fluids at reservoir conditions, it is recommended to conduct laboratory experiments to model the three dimensional network for different injector and producer well locations and injection rates, using propane as an additive and the novel vertical-smart horizontal well system.
4. Additional technical and economical studies must be carried out for different reservoir properties (rock and fluids) to investigate how to obtain a good balance between oil production peak acceleration and final oil recovery factor using steam and steam-propane injection.

NOMENCLATURE

AC = Acentric factor

BIN = Binary interaction coefficient

BPDCWE = Barrels per day, cold water equivalent

CMM = Molecular weight, lb/lbmole

CP = Liquid Compressibility at constant temperature, 1/psi

CT1 = First coefficient of the thermal expansion coefficient, $1/^{o}F$

Kh = Horizontal permeability, md

Kv = Vertical permeability, md

KV1 = First coefficient in the correlation for gas-liquid K value, psi

KV4 = Fourth coefficient in the correlation for gas-liquid K value, ^{o}F

KV5 = Fifth coefficient in the correlation for gas-liquid K value, ^{o}F

MOLDEN = Partial molar density at reference pressure and temperature, lbmol/cft

OMEGA = Omega A (Ωa), equation of state parameter

OMEGB = Omega B (Ωb), equation of state parameter

PCHOR = Parachor, interfacial tension parameter

PCRIT = Critical pressure, psia

SG = Specific gravity (water = 1)

TB = Normal boiling point, ^{o}F

TCRIT = Critical temperature, ^{o}F

VCRIT = Critical volume, l/mol

ZRA = Rackett's compressibility factor

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APPENDIX A

THERMAL RESERVOIR SIMULATION FILES: STEAM INJECTION USING VERTICAL WELL SYSTEM

```
RESULTS SIMULATOR STARS
RESULTS SECTION INOUT
*TITLE1  'San Ardo Field - Lombardi Reservoir'
*TITLE2  'Vertical Well System'
*TITLE3  'Continuous Steam Injection'
*CASEID  'Case 2'
*INUNIT *FIELD

*INTERRUPT *INTERACTIVE
*RANGECHECK
*WPRN *GRID  *TIME
*WPRN *SECTOR  0
*WSRF *GRID 1
*WSRF *SECTOR  0
*WPRN *ITER *TIME
*OUTPRN *WELL *ALL
*OUTPRN *GRID *ALL
*OUTPRN *RES *ALL
*OUTPRN *ITER *BRIEF
*OUTSRF *WELL *COMPONENT *ALL *LAYER *ALL
*OUTSRF *GRID *PRES *SO *SW *SG *TEMP *VISO

*XDR *ON
*PRINT_REF *ON
*OUTSOLVR *OFF
*MAXERROR  20
*SR2PREC *DOUBLE


RESULTS XOFFSET 0.
RESULTS YOFFSET 0.
RESULTS ROTATION 0

GRID VARI 15 15 20

KDIR DOWN

DI CON 22

DJ CON 22

DK CON 5.75

DTOP
```

```
          225*1900.


**$ RESULTS PROP NULL  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 1  Maximum Value: 1
**$ 0 = NULL block, 1 = Active block
NULL CON 1.

**$ RESULTS PROP PINCHOUTARRAY  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 1  Maximum Value: 1
**$ 0 = PINCHED block, 1 = Active block
PINCHOUTARRAY CON 1.
RESULTS SECTION GRID

**$ RESULTS PROP POR  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 0.345  Maximum Value: 0.345
POR CON 0.345
RESULTS SECTION PERMS

**$ RESULTS PROP PERMI  Units: md
**$ RESULTS PROP Minimum Value: 6922  Maximum Value: 6922
PERMI CON 6922.

**$ RESULTS PROP PERMJ  Units: md
**$ RESULTS PROP Minimum Value: 6922  Maximum Value: 6922
PERMJ CON 6922.

**$ RESULTS PROP PERMK  Units: md
**$ RESULTS PROP Minimum Value: 692.2  Maximum Value: 692.2
PERMK CON 692.2

RESULTS SECTION THTYPE
END-GRID

ROCKTYPE 1
  CPOR 9.E-05
  ROCKCP 35.02
  THCONR 1
  THCONW 0.36
  THCONO 1.2
  THCONG 0.0833
  HLOSSTDIFF 0.01
  HLOSSPROP +k 60. 60. -k 60. 60.


RESULTS SECTION GRIDOTHER
RESULTS SECTION MODEL

** PVT UNITS CONSISTENT WITH *INUNIT *FIELD

MODEL  3  3  3 **  3 components, with water (default) first
COMPNAME       'WATER'  'OIL'     'GAS'
**           --------   --------   --------
```

```
   CMM        0.0000    456.015    16.7278
   PCRIT        0.00     179.02     670.46
   TCRIT        0.00    1036.21    -107.35
   KV1      0.000E+0   5.165E+6   1.534E+5
   KV2      0.000E+0   0.000E+0   0.000E+0
   KV3      0.000E+0   0.000E+0   0.000E+0
   KV4           0.0   -15362.5    -1914.1
   KV5          0.00    -459.67    -459.67
   MOLDEN   0.000E+00  1.356E-01  4.515E-02
   CP      0.000E+00  3.805E-06  3.754E-03
   CT1      0.000E+00  1.660E-04  1.910E-03


VISCTABLE
** T, deg F      'WATER'   'OIL'    'GAS'
**              --------  -----  --------
    50.000    0.0000E+00 500000  1.1018E-02
   100.000    0.0000E+00  20000  1.1882E-02
   150.000    0.0000E+00   1500  1.2721E-02
   200.000    0.0000E+00    240  1.3536E-02
   250.000    0.0000E+00     60  1.4326E-02
   300.000    0.0000E+00     20  1.5094E-02
   350.000    0.0000E+00      8  1.5840E-02
   400.000    0.0000E+00    3.5  1.6566E-02
   450.000    0.0000E+00    1.8  1.7273E-02
   500.000    0.0000E+00      1  1.7962E-02
   550.000    0.0000E+00    0.6  1.8635E-02
   600.000    0.0000E+00   0.35  1.9293E-02
   650.000    0.0000E+00    0.2  1.9937E-02
   700.000    0.0000E+00   0.13  2.0568E-02


PRSR    275.000 ** reference pressure,     corresponding to the density
TEMR    127.000 ** reference temperature,  corresponding to the density
PSURF    14.696 ** pressure at surface,    for reporting well rates, etc.
TSURF    60.000 ** temperature at surface, for reporting well rates, etc.

SURFLASH KVALUE

RESULTS SECTION MODELARRAYS
RESULTS SECTION ROCKFLUID

**  =============  ROCK-FLUID PROPERTIES  =====================

*ROCKFLUID


*RPT 1 *WATWET *STONE2       **
*SWT                **WATER-OIL
**    Sw     Krw       Krow
**   ----   -------   -------
0.500000  0.000000  0.550000  0.000000
0.525000  0.010000  0.275000  0.000000
```

```
0.550000  0.020000  0.120000  0.000000
0.575000  0.030000  0.020000  0.000000
0.600000  0.050000  0.000000  0.000000
0.625000  0.080000  0.000000  0.000000
0.650000  0.115000  0.000000  0.000000
0.675000  0.150000  0.000000  0.000000
0.700000  0.195000  0.000000  0.000000
0.725000  0.245000  0.000000  0.000000
0.750000  0.295000  0.000000  0.000000
0.775000  0.360000  0.000000  0.000000
0.800000  0.420000  0.000000  0.000000
0.825000  0.495000  0.000000  0.000000
0.850000  0.570000  0.000000  0.000000
0.875000  0.650000  0.000000  0.000000
0.900000  0.740000  0.000000  0.000000
1.000000  1.000000  0.000000  0.000000

*SLT  *NOSWC
**    SL    KRG    KROG
**  ------  ------  --------
0.850000  0.460000  0.000000  0.000000
0.875000  0.290000  0.065000  0.000000
0.900000  0.160000  0.150000  0.000000
0.925000  0.080000  0.240000  0.000000
0.950000  0.030000  0.340000  0.000000
0.975000  0.005000  0.435000  0.000000
1.000000  0.000000  0.550000  0.000000

*KRTEMTAB    *SWR    *SWCRIT    *SORW     *SOIRW    *SORG    *SOIRG    *KRWIRO
*KROCW    *KRGCW
**  Temp     Swr      Swcrit   Sorw        Soirw    Sorg     Soirg      Krwiro    Krocw     Krgcw
   110.     0.5       0.5       0.4       0.4       0.85      0.85      0.05      0.55      0.46
   255.     0.6       0.6       0.25      0.25      0.74      0.74      0.05      0.575     0.375
   400.     0.6125    0.6125    0.225     0.225     0.715     0.715     0.05      0.61      0.35


RESULTS SECTION ROCKARRAYS

**$ RESULTS PROP KRTYPE  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 1  Maximum Value: 1
KRTYPE CON 1.
RESULTS SECTION INIT
*INITIAL
*VERTICAL *ON
*REFPRES 845
*REFDEPTH 1957.5


RESULTS SECTION INITARRAYS

RESULTS SECTION INITARRAYS

**$ RESULTS PROP SW  Units: Dimensionless
```

```
**$ RESULTS PROP Minimum Value: 0.267  Maximum Value: 0.267
SW CON 0.267

**$ RESULTS PROP SO  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 0.733  Maximum Value: 0.733
SO CON 0.733

**$ RESULTS PROP TEMP  Units: F
**$ RESULTS PROP Minimum Value: 127  Maximum Value: 127
TEMP CON 127.


 MFRAC_OIL 'OIL' CON  0.78904
 MFRAC_OIL 'GAS' CON  0.21096


RESULTS SECTION NUMERICAL

*NUMERICAL
**MAXSTEPS 6000
*DTMAX 90.      **140.

**CONVERGE *TOTRES *NORMAL
*AIM *STAB

*ITERMAX 200
*NCUTS 400
*NORM *PRESS 200.
      *TEMP 180.
** SATUR 0.1
*MAXPRES 1.450377E+05


RUN

TIME 0

DTWELL 0.0005


WELL  1 'producer1'  **Primary Depletion
PRODUCER 'producer1'
**OPERATE MAX STO  1000. CONT
OPERATE MIN BHP  420 CONT

GEOMETRY K 0.292 0.249 1.0 0.
PERF GEO   'producer1'
** i  j  k   ff
          8 8  1  1.
          8 8  2  1.
          8 8  3  1.
          8 8  4  1.
          8 8  5  1.
```

```
          8 8  6  1.
          8 8  7  1.
          8 8  8  1.
          8 8  9  1.
          8 8 10  1.
          8 8 11  1.
          8 8 12  1.
          8 8 13  1.
          8 8 14  1.
          8 8 15  1.
          8 8 16  1.
          8 8 17  1.
          8 8 18  1.
          8 8 19  1.
          8 8 20  1.


WELL  2 'producer2'    **9-spot pattern
PRODUCER 'producer2'

OPERATE MIN BHP  145. CONT

GEOMETRY K 0.292 0.377 0.25 0.
PERF GEO   'producer2'
** i  j  k ff
          1 1 16  1.
          1 1 17  1.
          1 1 18  1.
          1 1 19  1.
          1 1 20  1.


WELL  3 'producer3'  **9-spot pattern
PRODUCER 'producer3'

OPERATE MIN BHP  145. CONT

GEOMETRY K 0.292 0.377 0.25 0.
PERF GEO   'producer3'
** i  j  k ff
          15 1 16  1.
          15 1 17  1.
          15 1 18  1.
          15 1 19  1.
          15 1 20  1.


WELL  4 'producer4'  **9-spot pattern
PRODUCER 'producer4'

OPERATE MIN BHP  145. CONT

GEOMETRY K 0.292 0.377 0.25 0.
```

```
PERF GEO   'producer4'
** i  j  k ff
        15 15 16  1.
        15 15 17  1.
        15 15 18  1.
        15 15 19  1.
        15 15 20  1.


WELL  5 'injector1' **FRAC 0.25  **9-spot pattern - Steam Injection
INJECTOR MOBWEIGHT 'injector1'
TINJW 582.3
QUAL 0.8
INCOMP WATER  1.0 0.0 0.0 **Steam
OPERATE MAX STW  300. *CONT
OPERATE MAX BHP  1350.

GEOMETRY K 0.292 0.377 0.25 0.
PERF GEO   'injector1'
** i  j  k ff
        1 15 1  1.
        1 15 2  1.
        1 15 3  1.
        1 15 4  1.
        1 15 5  1.

OPEN 'producer1'    **primary depletion
SHUTIN 'producer2'
SHUTIN 'producer3'
SHUTIN 'producer4'
SHUTIN 'injector1'

TIME    365
*OUTSRF *GRID *TEMP *SW *SO
TIME    730
TIME    1095
TIME    1460
TIME    1825
TIME    2190
TIME    2555
TIME    2920
TIME    3285
TIME    3650
TIME    4015
TIME    4380
TIME    4745
TIME    5110
TIME    5475
TIME    5840
TIME    6205

SHUTIN  'producer1'   **end primary depletion
OPEN  'injector1'
```

```
OPEN  'producer2'
OPEN  'producer3'
OPEN  'producer4'

TIME    6570
TIME    6935
TIME    7300
TIME    7665
TIME    8030
TIME    8395
TIME    8760

TIME    9125
TIME    9490
TIME    9855
TIME    10037.5

STOP
***************************** TERMINATE SIMULATION *****************************
```

APPENDIX B

THERMAL RESERVOIR SIMULATION FILES: STEAM INJECTION USING VERTICAL-SMART HORIZONTAL WELL SYSTEM

```
RESULTS SIMULATOR STARS
RESULTS SECTION INOUT
*TITLE1  'San Ardo Field - Lombardi Reservoir'
*TITLE2  'Vertical-Smart Horizontal Well System'
*TITLE3  'Continuous Steam Injection'
*CASEID  'Scenario 1 Case 4d'
*INUNIT *FIELD

*INTERRUPT *INTERACTIVE
*RANGECHECK
*WPRN *GRID  *TIME
*WPRN *SECTOR  0
*WSRF *GRID 1
*WSRF *SECTOR  0
*WPRN *ITER *TIME
*OUTPRN *WELL *ALL
*OUTPRN *GRID *ALL
*OUTPRN *RES *ALL
*OUTPRN *ITER *BRIEF
*OUTSRF *WELL *COMPONENT *ALL *LAYER *ALL
*OUTSRF *GRID *PRES *SO *SW *SG *TEMP *VISO

*XDR *ON
*PRINT_REF *ON
*OUTSOLVR *OFF
*MAXERROR  20
*SR2PREC *DOUBLE


RESULTS XOFFSET 0.
RESULTS YOFFSET 0.
RESULTS ROTATION 0

GRID VARI 15 15 20

KDIR DOWN

DI CON 22

DJ CON 22

DK CON 5.75

DTOP
```

```
        225*1900.


**$ RESULTS PROP NULL  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 1  Maximum Value: 1
**$ 0 = NULL block, 1 = Active block
NULL CON 1.

**$ RESULTS PROP PINCHOUTARRAY  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 1  Maximum Value: 1
**$ 0 = PINCHED block, 1 = Active block
PINCHOUTARRAY CON 1.
RESULTS SECTION GRID

**$ RESULTS PROP POR  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 0.345  Maximum Value: 0.345
POR CON 0.345
RESULTS SECTION PERMS

**$ RESULTS PROP PERMI  Units: md
**$ RESULTS PROP Minimum Value: 6922  Maximum Value: 6922
PERMI CON 6922.

**$ RESULTS PROP PERMJ  Units: md
**$ RESULTS PROP Minimum Value: 6922  Maximum Value: 6922
PERMJ CON 6922.

**$ RESULTS PROP PERMK  Units: md
**$ RESULTS PROP Minimum Value: 692.2  Maximum Value: 692.2
PERMK CON 692.2

RESULTS SECTION THTYPE
END-GRID

ROCKTYPE 1
  CPOR 9.E-05
  ROCKCP 35.02
  THCONR 1
  THCONW 0.36
  THCONO 1.2
  THCONG 0.0833
  HLOSSTDIFF 0.01
  HLOSSPROP +k 60. 60. -k 60. 60.


RESULTS SECTION GRIDOTHER
RESULTS SECTION MODEL

** PVT UNITS CONSISTENT WITH *INUNIT *FIELD

MODEL  3  3  3 **  3 components, with water (default) first
COMPNAME       'WATER'  'OIL'     'GAS'
```

```
**          --------  --------  --------
   CMM        0.0000    456.015    16.7278
   PCRIT        0.00     179.02     670.46
   TCRIT        0.00    1036.21    -107.35
   KV1      0.000E+0   5.165E+6   1.534E+5
   KV2      0.000E+0   0.000E+0   0.000E+0
   KV3      0.000E+0   0.000E+0   0.000E+0
   KV4           0.0   -15362.5    -1914.1
   KV5          0.00    -459.67    -459.67
   MOLDEN   0.000E+00  1.356E-01  4.515E-02
   CP      0.000E+00  3.805E-06  3.754E-03
   CT1      0.000E+00  1.660E-04  1.910E-03


VISCTABLE
** T, deg F     'WATER'   'OIL'    'GAS'
**            --------  -----  --------
    50.000    0.0000E+00 500000  1.1018E-02
   100.000    0.0000E+00  20000  1.1882E-02
   150.000    0.0000E+00   1500  1.2721E-02
   200.000    0.0000E+00    240  1.3536E-02
   250.000    0.0000E+00     60  1.4326E-02
   300.000    0.0000E+00     20  1.5094E-02
   350.000    0.0000E+00      8  1.5840E-02
   400.000    0.0000E+00    3.5  1.6566E-02
   450.000    0.0000E+00    1.8  1.7273E-02
   500.000    0.0000E+00      1  1.7962E-02
   550.000    0.0000E+00    0.6  1.8635E-02
   600.000    0.0000E+00   0.35  1.9293E-02
   650.000    0.0000E+00    0.2  1.9937E-02
   700.000    0.0000E+00   0.13  2.0568E-02


PRSR    275.000 ** reference pressure,     corresponding to the density
TEMR    127.000 ** reference temperature,  corresponding to the density
PSURF    14.696 ** pressure at surface,    for reporting well rates, etc.
TSURF    60.000 ** temperature at surface, for reporting well rates, etc.

SURFLASH KVALUE

RESULTS SECTION MODELARRAYS
RESULTS SECTION ROCKFLUID

**  =============  ROCK-FLUID PROPERTIES  =====================

*ROCKFLUID


*RPT 1 *WATWET *STONE2       **
*SWT                 **WATER-OIL
**    Sw    Krw      Krow
**   ----   -------   -------
0.500000  0.000000  0.550000  0.000000
```

```
0.525000  0.010000  0.275000  0.000000
0.550000  0.020000  0.120000  0.000000
0.575000  0.030000  0.020000  0.000000
0.600000  0.050000  0.000000  0.000000
0.625000  0.080000  0.000000  0.000000
0.650000  0.115000  0.000000  0.000000
0.675000  0.150000  0.000000  0.000000
0.700000  0.195000  0.000000  0.000000
0.725000  0.245000  0.000000  0.000000
0.750000  0.295000  0.000000  0.000000
0.775000  0.360000  0.000000  0.000000
0.800000  0.420000  0.000000  0.000000
0.825000  0.495000  0.000000  0.000000
0.850000  0.570000  0.000000  0.000000
0.875000  0.650000  0.000000  0.000000
0.900000  0.740000  0.000000  0.000000
1.000000  1.000000  0.000000  0.000000

*SLT  *NOSWC
**    SL    KRG     KROG
**  ------  ------  --------
0.850000  0.460000  0.000000  0.000000
0.875000  0.290000  0.065000  0.000000
0.900000  0.160000  0.150000  0.000000
0.925000  0.080000  0.240000  0.000000
0.950000  0.030000  0.340000  0.000000
0.975000  0.005000  0.435000  0.000000
1.000000  0.000000  0.550000  0.000000

*KRTEMTAB   *SWR   *SWCRIT   *SORW    *SOIRW   *SORG   *SOIRG   *KRWIRO
*KROCW   *KRGCW
** Temp    Swr     Swcrit  Sorw      Soirw   Sorg    Soirg     Krwiro   Krocw    Krgcw
   110.    0.5      0.5      0.4      0.4      0.85     0.85     0.05     0.55     0.46
   255.    0.6      0.6      0.25     0.25     0.74     0.74     0.05     0.575    0.375
   400.    0.6125   0.6125   0.225    0.225    0.715    0.715    0.05     0.61     0.35


RESULTS SECTION ROCKARRAYS

**$ RESULTS PROP KRTYPE  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 1  Maximum Value: 1
KRTYPE CON 1.
RESULTS SECTION INIT
*INITIAL
*VERTICAL *ON
*REFPRES 845
*REFDEPTH 1957.5


RESULTS SECTION INITARRAYS

RESULTS SECTION INITARRAYS
```

```
**$ RESULTS PROP SW  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 0.267  Maximum Value: 0.267
SW CON 0.267

**$ RESULTS PROP SO  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 0.733  Maximum Value: 0.733
SO CON 0.733

**$ RESULTS PROP TEMP  Units: F
**$ RESULTS PROP Minimum Value: 127  Maximum Value: 127
TEMP CON 127.


 MFRAC_OIL 'OIL' CON  0.78904
 MFRAC_OIL 'GAS' CON  0.21096


RESULTS SECTION NUMERICAL

*NUMERICAL
**MAXSTEPS 6000
*DTMAX 90.      **140.

**CONVERGE *TOTRES *NORMAL
**AIM *STAB

*ITERMAX 200
*NCUTS 400
*NORM *PRESS 300.  **200
      *TEMP 180.   **180
** SATUR 0.1
*MAXPRES 1.450377E+05


RUN

TIME 0

DTWELL 0.0005


WELL  1 'producer1'  **Primary Depletion
PRODUCER 'producer1'
**OPERATE MAX STO  1000. CONT
OPERATE MIN BHP  420 CONT

GEOMETRY K 0.292 0.249 1.0 0.
PERF GEO   'producer1'
** i  j  k   ff
          8 8  1  1.
          8 8  2  1.
          8 8  3  1.
          8 8  4  1.
```

```
        8 8  5  1.
        8 8  6  1.
        8 8  7  1.
        8 8  8  1.
        8 8  9  1.
        8 8 10  1.
        8 8 11  1.
        8 8 12  1.
        8 8 13  1.
        8 8 14  1.
        8 8 15  1.
        8 8 16  1.
        8 8 17  1.
        8 8 18  1.
        8 8 19  1.
        8 8 20  1.


WELL  2 'producer2'  **Horizontal Well - 9-spot pattern
PRODUCER 'producer2'

OPERATE MIN BHP  145. CONT

GEOMETRY J 0.292 0.363 0.5 0.
PERF GEO   'producer2'
** i  j  k ff
        15  1 20  1.
        15  2 20  1.
        15  3 20  1.
        15  4 20  1.
        15  5 20  1.
        15  6 20  1.
        15  7 20  1.
        15  8 20  1.
        15  9 20  1.
        15 10 20  1.
        15 11 20  1.
        15 12 20  1.
        15 13 20  1.
        15 14 20  1.
        15 15 20  1.


WELL  3 'injector1' **FRAC 0.25  **9-spot pattern - Steam Injection
INJECTOR MOBWEIGHT 'injector1'
TINJW 582.3
QUAL 0.8
INCOMP WATER  1.0 0.0 0.0 **Steam
OPERATE MAX STW  300
OPERATE MAX BHP  1350.

GEOMETRY K 0.292 0.377 0.25 0.
PERF GEO   'injector1'
```

```
** i  j  k ff
          1 15 1  1.
          1 15 2  1.
          1 15 3  1.
          1 15 4  1.
          1 15 5  1.


WELL  4 'producer3'     **Smart Horizontal Well - 9-spot pattern
PRODUCER 'producer3'

OPERATE MIN BHP  145. CONT

GEOMETRY J 0.292 0.363 0.5 0.
PERF GEO   'producer3'
** i  j  k ff
          15  1 20  1.
          15  2 20  1.
          15  3 20  1.
          15  4 20  1.
          15  5 20  1.

OPEN 'producer1'
SHUTIN 'producer2'
SHUTIN 'producer3'
SHUTIN 'injector1'

TIME    365
*OUTSRF *GRID *TEMP *SW *SO
TIME    730
TIME    1095
TIME    1460
TIME    1825
TIME    2190
TIME    2555
TIME    2920
TIME    3285
TIME    3650
TIME    4015
TIME    4380
TIME    4745
TIME    5110
TIME    5475
TIME    5840
TIME    6205

SHUTIN  'producer1'     **end primary depletion
OPEN  'injector1'
OPEN  'producer2'

TIME    6570

TIME    6935
```

```
TIME    6977     **BT 6703

SHUTIN  'producer2'
OPEN  'producer3'

TIME    7300
TIME    7665
TIME    8030
TIME    8395
TIME    8760

TIME    9125
TIME    9490
TIME    9855
TIME    10037.5

STOP
***************************** TERMINATE SIMULATION *****************************
```

APPENDIX C

THERMAL RESERVOIR SIMULATION FILES: STEAM-PROPANE INJECTION USING VERTICAL WELL SYSTEM

```
RESULTS SIMULATOR STARS
RESULTS SECTION INOUT
*TITLE1  'San Ardo Field - Lombardi Reservoir'
*TITLE2  'Vertical Well System'
*TITLE3  'Continuous Steam-Propane Injection'
*CASEID  '150 BPDCWE'
*INUNIT *FIELD

*INTERRUPT *INTERACTIVE
*RANGECHECK
*WPRN *GRID  *TIME
*WPRN *SECTOR  0
*WSRF *GRID 1
*WSRF *SECTOR  0
*WPRN *ITER *TIME
*OUTPRN *WELL *ALL
*OUTPRN *GRID *ALL
*OUTPRN *RES *ALL
*OUTPRN *ITER *BRIEF
*OUTSRF *WELL *COMPONENT *ALL *LAYER *ALL
*OUTSRF *GRID *PRES *SO *SW *SG *TEMP *VISO

*XDR *ON
*PRINT_REF *ON
*OUTSOLVR *OFF
*MAXERROR  20
*SR2PREC *DOUBLE


RESULTS XOFFSET 0.
RESULTS YOFFSET 0.
RESULTS ROTATION 0

GRID VARI 16 16 20

KDIR DOWN

DI CON 20.625

DJ CON 20.625

DK CON 5.75

DTOP
```

```
        256*1900.


**$ RESULTS PROP NULL  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 1  Maximum Value: 1
**$ 0 = NULL block, 1 = Active block
NULL CON 1.

**$ RESULTS PROP PINCHOUTARRAY  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 1  Maximum Value: 1
**$ 0 = PINCHED block, 1 = Active block
PINCHOUTARRAY CON 1.
RESULTS SECTION GRID

RESULTS SPEC 'Grid Thickness'
RESULTS SPEC SPECNOTCALCVAL 0
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 0
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 5
RESULTS SPEC STOP

RESULTS SPEC 'Grid Top'
RESULTS SPEC SPECNOTCALCVAL 0
RESULTS SPEC REGION 'Layer 1 - Whole layer'
RESULTS SPEC REGIONTYPE 1
RESULTS SPEC LAYERNUMB 1
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 1400
RESULTS SPEC STOP
RESULTS PINCHOUT-VAL       0.0002 'ft'
RESULTS SECTION NETPAY
RESULTS SECTION NETGROSS
RESULTS SECTION POR

**$ RESULTS PROP POR  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 0.345  Maximum Value: 0.345
POR CON 0.345
RESULTS SECTION PERMS

**$ RESULTS PROP PERMI  Units: md
**$ RESULTS PROP Minimum Value: 6922  Maximum Value: 6922
PERMI CON 6922.

**$ RESULTS PROP PERMJ  Units: md
**$ RESULTS PROP Minimum Value: 6922  Maximum Value: 6922
PERMJ CON 6922.

**$ RESULTS PROP PERMK  Units: md
**$ RESULTS PROP Minimum Value: 692.2  Maximum Value: 692.2
PERMK CON 692.2
```

```
RESULTS SECTION TRANS
RESULTS SECTION FRACS
RESULTS SECTION GRIDNONARRAYS

**AQUIFER  BOUNDARY
**    AQPROP 115 0.35 10000 10000 0.5
**    AQMETHOD CARTER-TRACY
**    AQGEOM RECTANG INFINITE
**    AQVISC 1
**    AQCOMP 9.00000000000001E-05
**    HFPROP 0.399999999971748 35.0000000000001

RESULTS SECTION VOLMOD
RESULTS SECTION VATYPE
RESULTS SECTION SECTORLEASE

RESULTS SECTION THTYPE
END-GRID

ROCKTYPE 1
  CPOR 9.E-05
  ROCKCP 35.02
  THCONR 1
  THCONW 0.36
  THCONO 1.2
  THCONG 0.0833
  HLOSSTDIFF 0.01
  HLOSSPROP +k 60. 60. -k 60. 60.


RESULTS SECTION GRIDOTHER
RESULTS SECTION MODEL

** PVT UNITS CONSISTENT WITH *INUNIT *FIELD

MODEL  8  8  8 **  8 components, with water (default) first
COMPNAME       'WATER'  'C1-C2'     'C3'    'IC4-C9'   'C10-C17'  'C18-C25'  'C26-C33'     'C34+'
**           --------  --------  --------  --------  --------  --------  --------  --------
   CMM        0.0000    16.1736    44.0970   110.5700   190.1146   288.6940   383.0189  1087.3628
   PCRIT        0.00     668.33     615.76     418.52     285.18     203.22     153.62     122.12
   TCRIT        0.00    -114.50     205.97     576.42     799.89     969.48    1098.28    1239.14
   KV1     0.000E+0  1.510E+5  3.002E+5  6.180E+5  1.554E+6  4.255E+6  9.934E+6  1.63E+07
   KV2     0.000E+0  0.000E+0  0.000E+0  0.000E+0  0.000E+0  0.000E+0  0.000E+0  0.000E+0
   KV3     0.000E+0  0.000E+0  0.000E+0  0.000E+0  0.000E+0  0.000E+0  0.000E+0  0.000E+0
   KV4          0.0    -1870.9    -4119.9    -7560.9   -10836.2   -14219.0   -17257.4   -20048.7
   KV5         0.00    -459.67    -459.67    -459.67    -459.67    -459.67    -459.67    -459.67
   MOLDEN   0.000E+00  1.101E+00  7.423E-01  4.056E-01  2.461E-01  1.602E-01  1.127E-01  8.270E-
02
   CP      0.000E+00  5.125E-05  3.024E-05  1.305E-05  6.607E-06  3.909E-06  3.101E-06  3.057E-06
   CT1     0.000E+00  1.921E-03  1.186E-03  5.566E-04  3.045E-04  1.874E-04  1.372E-04  1.124E-04
```

```
VISCTABLE
** T, deg F     'WATER'    'C1-C2'     'C3'      'IC4-C9'  'C10-C17'  'C18-C25'  'C26-C33'   'C34+'
**              --------   --------   --------   --------   --------   --------   --------   --------
    50.000   0.0000E+00  2.4745E+04  4.5218E+04  8.4794E+04  1.3550E+05  2.2275E+05  3.6093E+05
8.7963E+05
   100.000   0.0000E+00  1.4110E+03  2.4851E+03  4.3819E+03  6.5674E+03  1.0078E+04  1.5335E+04
3.5309E+04
   150.000   0.0000E+00  1.8568E+02  3.1710E+02  5.3109E+02  7.5443E+02  1.0929E+03  1.5779E+03
3.4648E+03
   200.000   0.0000E+00  4.2778E+01  7.1169E+01  1.1410E+02  1.5488E+02  2.1368E+02  2.9505E+02
6.2230E+02
   250.000   0.0000E+00  1.4495E+01  2.3580E+01  3.6413E+01  4.7533E+01  6.2884E+01  8.3567E+01
1.7026E+02
   300.000   0.0000E+00  6.4463E+00  1.0284E+01  1.5372E+01  1.9396E+01  2.4742E+01  3.1805E+01
6.2883E+01
   350.000   0.0000E+00  3.4835E+00  5.4630E+00  7.9361E+00  9.7206E+00  1.2010E+01  1.4995E+01
2.8877E+01
   400.000   0.0000E+00  2.1681E+00  3.3491E+00  4.7440E+00  5.6601E+00  6.7987E+00  8.2723E+00
1.5564E+01
   450.000   0.0000E+00  1.4955E+00  2.2793E+00  3.1569E+00  3.6794E+00  4.3100E+00  5.1254E+00
9.4456E+00
   500.000   0.0000E+00  1.1112E+00  1.6732E+00  2.2714E+00  2.5924E+00  2.9691E+00  3.4591E+00
6.2577E+00
   550.000   0.0000E+00  8.7017E-01  1.2962E+00  1.7280E+00  1.9353E+00  2.1720E+00  2.4841E+00
4.4193E+00
   600.000   0.0000E+00  7.0589E-01  1.0412E+00  1.3654E+00  1.5034E+00  1.6566E+00  1.8631E+00
3.2647E+00
   650.000   0.0000E+00  5.8582E-01  8.5639E-01  1.1064E+00  1.1994E+00  1.2997E+00  1.4396E+00
2.4882E+00
   700.000   0.0000E+00  5.0451E-01  7.3153E-01  9.3231E-01  9.9637E-01  1.0634E+00  1.1615E+00
1.9824E+00

PRSR     64.700 ** reference pressure,     corresponding to the density
TEMR    122.000 ** reference temperature,  corresponding to the density
PSURF    14.696 ** pressure at surface,    for reporting well rates, etc.
TSURF    60.000 ** temperature at surface, for reporting well rates, etc.

SURFLASH KVALUE

K_SURF 'WATER   '  0.0000E+00
K_SURF 'C1-C2   '  1.9066E+02
K_SURF 'C3      '  8.6242E+00
K_SURF 'IC4-C9  '  1.8829E-02
K_SURF 'C10-C17 '  1.9937E-05
K_SURF 'C18-C25 '  6.7589E-09
K_SURF 'C26-C33 '  2.5840E-12
K_SURF 'C34+    '  9.5688E-16


RESULTS SECTION MODELARRAYS
RESULTS SECTION ROCKFLUID
```

```
** ============= ROCK-FLUID PROPERTIES =====================

*ROCKFLUID


*RPT 1 *WATWET *STONE2      **
*SWT               **WATER-OIL
**    Sw    Krw      Krow
**   ----   -------   -------
0.500000  0.000000  0.550000  0.000000
0.525000  0.010000  0.275000  0.000000
0.550000  0.020000  0.120000  0.000000
0.575000  0.030000  0.020000  0.000000
0.600000  0.050000  0.000000  0.000000
0.625000  0.080000  0.000000  0.000000
0.650000  0.115000  0.000000  0.000000
0.675000  0.150000  0.000000  0.000000
0.700000  0.195000  0.000000  0.000000
0.725000  0.245000  0.000000  0.000000
0.750000  0.295000  0.000000  0.000000
0.775000  0.360000  0.000000  0.000000
0.800000  0.420000  0.000000  0.000000
0.825000  0.495000  0.000000  0.000000
0.850000  0.570000  0.000000  0.000000
0.875000  0.650000  0.000000  0.000000
0.900000  0.740000  0.000000  0.000000
1.000000  1.000000  0.000000  0.000000

*SLT  *NOSWC
**    SL    KRG    KROG
**  ------  ------  --------
0.850000  0.460000  0.000000  0.000000
0.875000  0.290000  0.065000  0.000000
0.900000  0.160000  0.150000  0.000000
0.925000  0.080000  0.240000  0.000000
0.950000  0.030000  0.340000  0.000000
0.975000  0.005000  0.435000  0.000000
1.000000  0.000000  0.550000  0.000000

*KRTEMTAB   *SWR   *SWCRIT   *SORW    *SOIRW   *SORG   *SOIRG   *KRWIRO
*KROCW   *KRGCW
** Temp     Swr     Swcrit   Sorw      Soirw   Sorg    Soirg     Krwiro   Krocw    Krgcw
   110.     0.5     0.5      0.4      0.4      0.85    0.85     0.05     0.55     0.46
   255.     0.6     0.6      0.25     0.25     0.74    0.74     0.05     0.575    0.375
   400.     0.6125  0.6125   0.225    0.225    0.715   0.715    0.05     0.61     0.35


RESULTS SECTION ROCKARRAYS

**$ RESULTS PROP KRTYPE  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 1  Maximum Value: 1
KRTYPE CON 1.
RESULTS SECTION INIT
```

```
*INITIAL
*VERTICAL *ON
*REFPRES 845
*REFDEPTH 1957.5


RESULTS SECTION INITARRAYS

RESULTS SECTION INITARRAYS

**$ RESULTS PROP SW  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 0.267  Maximum Value: 0.267
SW CON 0.267

**PRES CON 845

**$ RESULTS PROP SO  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 0.733  Maximum Value: 0.733
SO CON 0.733

**$ RESULTS PROP TEMP  Units: F
**$ RESULTS PROP Minimum Value: 127  Maximum Value: 127
TEMP CON 127.


 MFRAC_OIL 'C1-C2   ' CON  2.0441E-01
 MFRAC_OIL 'C3      ' CON  8.5692E-04
 MFRAC_OIL 'IC4-C9  ' CON  1.6684E-02
 MFRAC_OIL 'C10-C17 ' CON  2.6887E-01
 MFRAC_OIL 'C18-C25 ' CON  2.1255E-01
 MFRAC_OIL 'C26-C33 ' CON  1.2611E-01
 MFRAC_OIL 'C34+    ' CON  1.7052E-01


RESULTS SECTION NUMERICAL
**PRES CON 845.
**DWOC  4000.

*NUMERICAL
**MAXSTEPS 6000
*DTMAX 90.      **140.

*CONVERGE *TOTRES *TIGHTER

**UNRELAX -0.9
*AIM *STAB

*ITERMAX 200
*NCUTS 400
*NORM *PRESS 290.
      *SATUR  0.4
      *TEMP 270.
**MAXPRES 1.450377E+05
```

```
RUN


TIME 0

DTWELL 0.0005


WELL  1 'producer1'          **Primary Depletion
PRODUCER 'producer1'
**OPERATE MAX STO  1000. CONT
OPERATE MIN BHP  420 CONT

GEOMETRY J 0.292 0.249 1.0 0.
PERF GEO   'producer1'
** i  j  k   ff
        9 8  1  1.
        9 8  2  1.
        9 8  3  1.
        9 8  4  1.
        9 8  5  1.
        9 8  6  1.
        9 8  7  1.
        9 8  8  1.
        9 8  9  1.
        9 8 10  1.
        9 8 11  1.
        9 8 12  1.
        9 8 13  1.
        9 8 14  1.
        9 8 15  1.
        9 8 16  1.
        9 8 17  1.
        9 8 18  1.
        9 8 19  1.
        9 8 20  1.


WELL  2 'producer2'    **9-spot pattern
PRODUCER 'producer2'
**OPERATE MAX STO  1000. CONT
OPERATE MIN BHP  145. CONT

GEOMETRY J 0.292 0.377 0.25 0.
PERF GEO   'producer2'
** i  j  k ff
        1 1 11  1.
        1 1 12  1.
        1 1 13  1.
        1 1 14  1.
        1 1 15  1.
```

```
          1 1 16  1.
          1 1 17  1.
          1 1 18  1.
          1 1 19  1.
          1 1 20  1.


WELL  3 'producer3'     **9-spot pattern
PRODUCER 'producer3'
**OPERATE MAX STO  1000. CONT
OPERATE MIN BHP  145. CONT

GEOMETRY J 0.292 0.377 0.25 0.
PERF GEO   'producer3'
** i  j  k ff
          16 1 11  1.
          16 1 12  1.
          16 1 13  1.
          16 1 14  1.
          16 1 15  1.
          16 1 16  1.
          16 1 17  1.
          16 1 18  1.
          16 1 19  1.
          16 1 20  1.


WELL  4 'producer4'     **9-spot pattern
PRODUCER 'producer4'
**OPERATE MAX STO  1000. CONT
OPERATE MIN BHP  145. CONT

GEOMETRY J 0.292 0.377 0.25 0.
PERF GEO   'producer4'
** i  j  k ff
          16 16 11  1.
          16 16 12  1.
          16 16 13  1.
          16 16 14  1.
          16 16 15  1.
          16 16 16  1.
          16 16 17  1.
          16 16 18  1.
          16 16 19  1.
          16 16 20  1.


WELL  5 'injector1' **FRAC 0.25  **Steam Injection
INJECTOR MOBWEIGHT 'injector1'
TINJW 582
QUAL 0.8
INCOMP WATER  1.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 **Steam
OPERATE MAX STW  150. *CONT
```

```
OPERATE MAX BHP  1350

GEOMETRY J 0.292 0.377 0.25 0.
PERF GEO   'injector1'
** i  j  k ff
          1 16 1  1.
          1 16 2  1.
          1 16 3  1.
          1 16 4  1.
          1 16 5  1.


WELL  6 'injector2'  **FRAC 0.25  **Propane Injection
INJECTOR MOBWEIGHT 'injector2'
TINJOV 582
INCOMP GAS  0.0 0.0 1.0 0.0 0.0 0.0 0.0 0.0  **Propane
OPERATE MAX STG 22642 *CONT  **Inj. Rate SCF/D
OPERATE MAX BHP  1350

GEOMETRY J 0.292 0.377 0.25 0.
PERF GEO   'injector2'
** i  j  k ff
          1 16 1  1.
          1 16 2  1.
          1 16 3  1.
          1 16 4  1.
          1 16 5  1.


OPEN 'producer1'
SHUTIN 'producer2'
SHUTIN 'producer3'
SHUTIN 'producer4'
SHUTIN 'injector1'
SHUTIN 'injector2'


TIME    365
*OUTSRF *GRID *TEMP *SW *SO
TIME    730
TIME    1095
TIME    1460
TIME    1825
TIME    2190
TIME    2555
TIME    2920
TIME    3285
TIME    3650
TIME    4015
TIME    4380
TIME    4745
TIME    5110
TIME    5475
```

```
TIME    5840
TIME    6205
TIME    6326.667

SHUTIN  'producer1'
OPEN  'injector1'
OPEN  'injector2'
OPEN  'producer2'
OPEN  'producer3'
OPEN  'producer4'

TIME    6570
TIME    6935
TIME    7300
TIME    7665
TIME    8030
TIME    8395
TIME    8760
TIME    9125
TIME    9490
TIME    9855
TIME    10098.33333

STOP
*************************** TERMINATE SIMULATION ****************************
```

APPENDIX D

THERMAL RESERVOIR SIMULATION FILES: STEAM-PROPANE INJECTION USING VERTICAL-SMART HORIZONTAL WELL SYSTEM

```
RESULTS SIMULATOR STARS
RESULTS SECTION INOUT
*TITLE1  'San Ardo Field - Lombardi Reservoir'
*TITLE2  'Vertical-Smart Horizontal Well System'
*TITLE3  'Continuous Propane-Steam Injection'
*CASEID  '150 BPDCWE'
*INUNIT *FIELD

*INTERRUPT *INTERACTIVE
*RANGECHECK
*WPRN *GRID  *TIME
*WPRN *SECTOR  0
*WSRF *GRID 1
*WSRF *SECTOR  0
*WPRN *ITER *TIME
*OUTPRN *WELL *ALL
*OUTPRN *GRID *ALL
*OUTPRN *RES *ALL
*OUTPRN *ITER *BRIEF
*OUTSRF *WELL *COMPONENT *ALL *LAYER *ALL
*OUTSRF *GRID *PRES *SO *SW *SG *TEMP *VISO

*XDR *ON
*PRINT_REF *ON
*OUTSOLVR *OFF
*MAXERROR  20
*SR2PREC *DOUBLE


RESULTS XOFFSET 0.
RESULTS YOFFSET 0.
RESULTS ROTATION 0

GRID VARI 16 16 20

KDIR DOWN

DI CON 20.625

DJ CON 20.625

DK CON 5.75

DTOP
```

```
          256*1900.

**$ RESULTS PROP NULL  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 1  Maximum Value: 1
**$ 0 = NULL block, 1 = Active block
NULL CON 1.

**$ RESULTS PROP PINCHOUTARRAY  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 1  Maximum Value: 1
**$ 0 = PINCHED block, 1 = Active block
PINCHOUTARRAY CON 1.
RESULTS SECTION GRID

RESULTS SPEC 'Grid Thickness'
RESULTS SPEC SPECNOTCALCVAL 0
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 0
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 5
RESULTS SPEC STOP

RESULTS SPEC 'Grid Top'
RESULTS SPEC SPECNOTCALCVAL 0
RESULTS SPEC REGION 'Layer 1 - Whole layer'
RESULTS SPEC REGIONTYPE 1
RESULTS SPEC LAYERNUMB 1
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 1400
RESULTS SPEC STOP
RESULTS PINCHOUT-VAL       0.0002 'ft'
RESULTS SECTION NETPAY
RESULTS SECTION NETGROSS
RESULTS SECTION POR

**$ RESULTS PROP POR  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 0.345  Maximum Value: 0.345
POR CON 0.345
RESULTS SECTION PERMS

**$ RESULTS PROP PERMI  Units: md
**$ RESULTS PROP Minimum Value: 6922  Maximum Value: 6922
PERMI CON 6922.

**$ RESULTS PROP PERMJ  Units: md
**$ RESULTS PROP Minimum Value: 6922  Maximum Value: 6922
PERMJ CON 6922.

**$ RESULTS PROP PERMK  Units: md
**$ RESULTS PROP Minimum Value: 692.2  Maximum Value: 692.2
PERMK CON 692.2
```

```
RESULTS SECTION TRANS
RESULTS SECTION FRACS
RESULTS SECTION GRIDNONARRAYS

**AQUIFER  BOUNDARY
**   AQPROP 115 0.35 10000 10000 0.5
**   AQMETHOD CARTER-TRACY
**   AQGEOM RECTANG INFINITE
**   AQVISC 1
**   AQCOMP 9.00000000000001E-05
**   HFPROP 0.399999999971748 35.0000000000001

RESULTS SECTION VOLMOD
RESULTS SECTION VATYPE
RESULTS SECTION SECTORLEASE

RESULTS SECTION THTYPE
END-GRID

ROCKTYPE 1
  CPOR 9.E-05
  ROCKCP 35.02
  THCONR 1
  THCONW 0.36
  THCONO 1.2
  THCONG 0.0833
  HLOSSTDIFF 0.01
  HLOSSPROP +k 60. 60. -k 60. 60.


RESULTS SECTION GRIDOTHER
RESULTS SECTION MODEL

** PVT UNITS CONSISTENT WITH *INUNIT *FIELD

MODEL  8  8  8 **  8 components, with water (default) first
COMPNAME       'WATER'  'C1-C2'     'C3'    'IC4-C9'  'C10-C17'  'C18-C25'  'C26-C33'    'C34+'
**          --------  --------  --------  --------  --------  --------  --------  --------
    CMM       0.0000   16.1736   44.0970   110.5700   190.1146   288.6940   383.0189  1087.3628
    PCRIT       0.00    668.33    615.76    418.52    285.18    203.22    153.62    122.12
    TCRIT       0.00   -114.50    205.97    576.42    799.89    969.48   1098.28   1239.14
    KV1     0.000E+0  1.510E+5  3.002E+5  6.180E+5  1.554E+6  4.255E+6  9.934E+6  1.63E+07
    KV2     0.000E+0  0.000E+0  0.000E+0  0.000E+0  0.000E+0  0.000E+0  0.000E+0  0.000E+0
    KV3     0.000E+0  0.000E+0  0.000E+0  0.000E+0  0.000E+0  0.000E+0  0.000E+0  0.000E+0
    KV4          0.0   -1870.9   -4119.9   -7560.9  -10836.2  -14219.0  -17257.4  -20048.7
    KV5         0.00   -459.67   -459.67   -459.67   -459.67   -459.67   -459.67   -459.67
    MOLDEN   0.000E+00  1.101E+00  7.423E-01  4.056E-01  2.461E-01  1.602E-01  1.127E-01  8.270E-
02
    CP      0.000E+00  5.125E-05  3.024E-05  1.305E-05  6.607E-06  3.909E-06  3.101E-06  3.057E-06
    CT1     0.000E+00  1.921E-03  1.186E-03  5.566E-04  3.045E-04  1.874E-04  1.372E-04  1.124E-04


VISCTABLE
```

```
** T, deg F     'WATER'    'C1-C2'     'C3'      'IC4-C9'   'C10-C17'   'C18-C25'   'C26-C33'    'C34+'
**              --------   --------    --------   --------   --------    --------    --------    --------
    50.000   0.0000E+00  2.4745E+04  4.5218E+04  8.4794E+04  1.3550E+05  2.2275E+05  3.6093E+05
8.7963E+05
   100.000   0.0000E+00  1.4110E+03  2.4851E+03  4.3819E+03  6.5674E+03  1.0078E+04  1.5335E+04
3.5309E+04
   150.000   0.0000E+00  1.8568E+02  3.1710E+02  5.3109E+02  7.5443E+02  1.0929E+03  1.5779E+03
3.4648E+03
   200.000   0.0000E+00  4.2778E+01  7.1169E+01  1.1410E+02  1.5488E+02  2.1368E+02  2.9505E+02
6.2230E+02
   250.000   0.0000E+00  1.4495E+01  2.3580E+01  3.6413E+01  4.7533E+01  6.2884E+01  8.3567E+01
1.7026E+02
   300.000   0.0000E+00  6.4463E+00  1.0284E+01  1.5372E+01  1.9396E+01  2.4742E+01  3.1805E+01
6.2883E+01
   350.000   0.0000E+00  3.4835E+00  5.4630E+00  7.9361E+00  9.7206E+00  1.2010E+01  1.4995E+01
2.8877E+01
   400.000   0.0000E+00  2.1681E+00  3.3491E+00  4.7440E+00  5.6601E+00  6.7987E+00  8.2723E+00
1.5564E+01
   450.000   0.0000E+00  1.4955E+00  2.2793E+00  3.1569E+00  3.6794E+00  4.3100E+00  5.1254E+00
9.4456E+00
   500.000   0.0000E+00  1.1112E+00  1.6732E+00  2.2714E+00  2.5924E+00  2.9691E+00  3.4591E+00
6.2577E+00
   550.000   0.0000E+00  8.7017E-01  1.2962E+00  1.7280E+00  1.9353E+00  2.1720E+00  2.4841E+00
4.4193E+00
   600.000   0.0000E+00  7.0589E-01  1.0412E+00  1.3654E+00  1.5034E+00  1.6566E+00  1.8631E+00
3.2647E+00
   650.000   0.0000E+00  5.8582E-01  8.5639E-01  1.1064E+00  1.1994E+00  1.2997E+00  1.4396E+00
2.4882E+00
   700.000   0.0000E+00  5.0451E-01  7.3153E-01  9.3231E-01  9.9637E-01  1.0634E+00  1.1615E+00
1.9824E+00

PRSR     64.700 ** reference pressure,      corresponding to the density
TEMR    122.000 ** reference temperature,  corresponding to the density
PSURF    14.696 ** pressure at surface,     for reporting well rates, etc.
TSURF    60.000 ** temperature at surface, for reporting well rates, etc.

SURFLASH KVALUE

K_SURF 'WATER   '  0.0000E+00
K_SURF 'C1-C2   '  1.9066E+02
K_SURF 'C3      '  8.6242E+00
K_SURF 'IC4-C9  '  1.8829E-02
K_SURF 'C10-C17 '  1.9937E-05
K_SURF 'C18-C25 '  6.7589E-09
K_SURF 'C26-C33 '  2.5840E-12
K_SURF 'C34+    '  9.5688E-16


RESULTS SECTION MODELARRAYS
RESULTS SECTION ROCKFLUID

** =============  ROCK-FLUID PROPERTIES  =====================
```

```
*ROCKFLUID

*RPT 1 *WATWET *STONE2      **
*SWT                **WATER-OIL
**    Sw     Krw      Krow
**   ----   -------   -------
0.500000  0.000000  0.550000  0.000000
0.525000  0.010000  0.275000  0.000000
0.550000  0.020000  0.120000  0.000000
0.575000  0.030000  0.020000  0.000000
0.600000  0.050000  0.000000  0.000000
0.625000  0.080000  0.000000  0.000000
0.650000  0.115000  0.000000  0.000000
0.675000  0.150000  0.000000  0.000000
0.700000  0.195000  0.000000  0.000000
0.725000  0.245000  0.000000  0.000000
0.750000  0.295000  0.000000  0.000000
0.775000  0.360000  0.000000  0.000000
0.800000  0.420000  0.000000  0.000000
0.825000  0.495000  0.000000  0.000000
0.850000  0.570000  0.000000  0.000000
0.875000  0.650000  0.000000  0.000000
0.900000  0.740000  0.000000  0.000000
1.000000  1.000000  0.000000  0.000000

*SLT  *NOSWC
**    SL    KRG    KROG
**  ------  ------  --------
0.850000  0.460000  0.000000  0.000000
0.875000  0.290000  0.065000  0.000000
0.900000  0.160000  0.150000  0.000000
0.925000  0.080000  0.240000  0.000000
0.950000  0.030000  0.340000  0.000000
0.975000  0.005000  0.435000  0.000000
1.000000  0.000000  0.550000  0.000000

*KRTEMTAB    *SWR    *SWCRIT    *SORW     *SOIRW    *SORG    *SOIRG    *KRWIRO
*KROCW    *KRGCW
**  Temp     Swr      Swcrit   Sorw       Soirw    Sorg     Soirg     Krwiro    Krocw     Krgcw
   110.     0.5       0.5       0.4       0.4       0.85      0.85      0.05      0.55      0.46
   255.     0.6       0.6       0.25      0.25      0.74      0.74      0.05      0.575     0.375
   400.     0.6125    0.6125    0.225     0.225     0.715     0.715     0.05      0.61      0.35

RESULTS SECTION ROCKARRAYS

**$ RESULTS PROP KRTYPE  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 1  Maximum Value: 1
KRTYPE CON 1.
RESULTS SECTION INIT
*INITIAL
*VERTICAL *ON
*REFPRES 845
```

```
*REFDEPTH 1957.5

RESULTS SECTION INITARRAYS

RESULTS SECTION INITARRAYS

**$ RESULTS PROP SW  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 0.267  Maximum Value: 0.267
SW CON 0.267

**PRES CON 845

**$ RESULTS PROP SO  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 0.733  Maximum Value: 0.733
SO CON 0.733

**$ RESULTS PROP TEMP  Units: F
**$ RESULTS PROP Minimum Value: 127  Maximum Value: 127
TEMP CON 127.

 MFRAC_OIL 'C1-C2   ' CON  2.0441E-01
 MFRAC_OIL 'C3      ' CON  8.5692E-04
 MFRAC_OIL 'IC4-C9  ' CON  1.6684E-02
 MFRAC_OIL 'C10-C17 ' CON  2.6887E-01
 MFRAC_OIL 'C18-C25 ' CON  2.1255E-01
 MFRAC_OIL 'C26-C33 ' CON  1.2611E-01
 MFRAC_OIL 'C34+    ' CON  1.7052E-01


RESULTS SECTION NUMERICAL
**PRES CON 845.
**DWOC  4000.

*NUMERICAL
**MAXSTEPS 6000
*DTMAX 90.      **140.

*CONVERGE *TOTRES *TIGHTER

**UNRELAX -0.9
*AIM *STAB

*ITERMAX 200
*NCUTS 400
*NORM *PRESS 290.
      *SATUR  0.4
      *TEMP 270.
**MAXPRES 1.450377E+05

RUN


TIME 0
```

```
DTWELL 0.0005

WELL  1 'producer1'          **Primary Depletion
PRODUCER 'producer1'
**OPERATE MAX STO  1000. CONT
OPERATE MIN BHP  420 CONT

GEOMETRY J 0.292 0.249 1.0 0.
PERF GEO   'producer1'
** i  j  k   ff
          9 8  1  1.
          9 8  2  1.
          9 8  3  1.
          9 8  4  1.
          9 8  5  1.
          9 8  6  1.
          9 8  7  1.
          9 8  8  1.
          9 8  9  1.
          9 8 10  1.
          9 8 11  1.
          9 8 12  1.
          9 8 13  1.
          9 8 14  1.
          9 8 15  1.
          9 8 16  1.
          9 8 17  1.
          9 8 18  1.
          9 8 19  1.
          9 8 20  1.


WELL  2 'producer2'            **Horizontal Well
PRODUCER 'producer2'
**OPERATE MAX STO  1000. CONT
OPERATE MIN BHP  145. CONT

GEOMETRY J 0.292 0.363 0.5 0.
PERF GEO   'producer2'
** i  j  k ff
          16  1 20  1.
          16  2 20  1.
          16  3 20  1.
          16  4 20  1.
          16  5 20  1.
          16  6 20  1.
          16  7 20  1.
          16  8 20  1.
          16  9 20  1.
          16 10 20  1.
          16 11 20  1.
          16 12 20  1.
```

```
            16 13 20  1.
            16 14 20  1.
            16 15 20  1.
            16 16 20  1.


WELL  3 'injector1' **FRAC 0.25     **Steam Injection
INJECTOR MOBWEIGHT 'injector1'
TINJW 582
QUAL 0.8
INCOMP WATER  1.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 **Steam
OPERATE MAX STW  150. *CONT
OPERATE MAX BHP  1350

GEOMETRY J 0.292 0.377 0.25 0.
PERF GEO   'injector1'
** i  j  k ff
            1 16 1  1.
            1 16 2  1.
            1 16 3  1.
            1 16 4  1.
            1 16 5  1.

WELL  4 'injector2'  **FRAC 0.25    **Propane Injection
INJECTOR MOBWEIGHT 'injector2'
TINJOV 582
INCOMP GAS  0.0 0.0 1.0 0.0 0.0 0.0 0.0 0.0  **Propane
OPERATE MAX STG 22642 *CONT           **Inj. Rate SCF/D
OPERATE MAX BHP  1350

GEOMETRY J 0.292 0.377 0.25 0.
PERF GEO   'injector2'
** i  j  k ff
            1 16 1  1.
            1 16 2  1.
            1 16 3  1.
            1 16 4  1.
            1 16 5  1.


WELL  5 'producer3'              **Smart Horizontal Well
PRODUCER 'producer3'
**OPERATE MAX STO  1000. CONT
OPERATE MIN BHP  145. CONT

GEOMETRY J 0.292 0.363 0.5 0.
PERF GEO   'producer3'
** i  j  k ff
            16  1 20  1.
            16  2 20  1.
            16  3 20  1.
            16  4 20  1.
            16  5 20  1.
```

```
OPEN 'producer1'
SHUTIN 'producer2'
SHUTIN 'producer3'
SHUTIN 'injector1'
SHUTIN 'injector2'

TIME    365
*OUTSRF *GRID *TEMP *SW *SO
TIME    730
TIME    1095
TIME    1460
TIME    1825
TIME    2190
TIME    2555
TIME    2920
TIME    3285
TIME    3650
TIME    4015
TIME    4380
TIME    4745
TIME    5110
TIME    5475
TIME    5840
TIME    6205
TIME    6326.667

SHUTIN  'producer1'
OPEN  'injector1'
OPEN  'injector2'
OPEN  'producer2'

TIME    6570
TIME    6935
TIME    7300

TIME  7316   **BT 7042

SHUTIN  'producer2'
OPEN  'producer3'

TIME    7665
TIME    8030
TIME    8395
TIME    8760
TIME    9125
TIME    9490
TIME    9855
TIME    10098.33333

STOP
**************************** TERMINATE SIMULATION ****************************
```

VITA

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