An Advanced Fracture Characterization and Well Path Navigation System for Effective Re-Development and Enhancement of Ultimate Recovery from the Complex Monterey Reservoir of South Ellwood Field, Offshore California

Quarterly Technical Progress Report

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Abstract

Venoco Inc, intends to re-develop the Monterey Formation, a Class III basin reservoir, at South Ellwood Field, Offshore Santa Barbara, California.

Well productivity in this field varies significantly. Cumulative Monterey production for individual wells has ranged from 260 STB to 8,700,000 STB. Productivity is primarily affected by how well the well path connects with the local fracture system and the degree of aquifer support. Cumulative oil recovery to date is a small percentage of the original oil in place. To embark upon successful re-development and to optimize reservoir management, Venoco intends to investigate, map and characterize field fracture patterns and the reservoir conduit system. State of the art borehole imaging technologies including FMI, dipole sonic and cross-well seismic, interference tests and production logs will be employed to characterize fractures and micro faults. These data along with the existing database will be used for construction of a novel geologic model of the fracture network. Development of an innovative fracture network reservoir simulator is proposed to monitor and manage the aquifer's role in pressure maintenance and water production. The new fracture simulation model will be used for both planning optimal paths for new wells and improving ultimate recovery.

In the second phase of this project, the model will be used for the design of a pilot program for downhole water re-injection into the aquifer simultaneously with oil production. Downhole water separation units attached to electric submersible pumps will be used to minimize surface fluid handling thereby improving recoveries per well and field economics while maintaining aquifer support.

In cooperation with the DOE, results of the field studies as well as the new models developed and the fracture database will be shared with other operators. Numerous fields producing from the Monterey and analogous fractured reservoirs both onshore and offshore will benefit from the methodologies developed in this project.

This report presents a summary of all technical work conducted during the tenth quarter of Budget Period I.

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Introduction

The Field Demonstration site for this Class III (basin clastic) Program Proposal is the South Ellwood Field located offshore California. The Monterey Formation is the main producing unit in the South Ellwood Field and consists of fractured chert, porcelanite, dolomite, and siliceous limestone interbedded with organic mudstone. This reservoir has an average thickness of 1,000 feet, and lies at subsea depths of approximately -3,500' to -5,000'.

Venoco and USC jointly submitted an application to conduct a DOE co-operative investigation of the Monterey formation at South Ellwood in June 2000. The DOE granted this application in July 2000.

Executive Summary

Venoco and USC prepared a proposal for a DOE sponsored joint investigation of the fractured Monterey formation. It was agreed that Venoco would construct the geologic model for the field and gather new reservoir data as appropriate. USC would then develop a simulation model that would be used to optimize future hydrocarbon recovery. Joint Venoco-USC teams were established to manage the flow of data and insure that Venoco and USC activities remained synchronized. A co-operative agreement was signed with the DOE on July 31, 2000.

This cooperative work between the research team at USC and the operational engineers and geoscientist at Venoco has generated new insight into the evaluation methods for the Monterey Formation and has resulted in the formulation of new approaches to describe reservoir dynamics and to simulate reservoir performance for forecasting purposes. The project has made several contributions to the tech transfer goal of the U.S. Department of Energy. The most prominent of these are; the development of an interactive database on the Monterey Formation, a conceptual model for the description of fracture-controlled Monterey Reservoirs, a pattern recognition method for analysis of well log data and methods for subsurface control of high water production. The first well drilled as part of this study continues to be production tested. Additional perforations have been selected based on the image logs and the fracture study conducted earlier. The well will be re-completed during February 2003 to reduce the water production from the Lower Monterey.

Perhaps the most significant achievement of this project is the completion of a new reservoir simulation algorithm developed specifically for the Monterey. A fully three phase, 3D Pipeline Network model is undergoing final testing against a conventional commercial simulator model from CMG.

Task I- Database

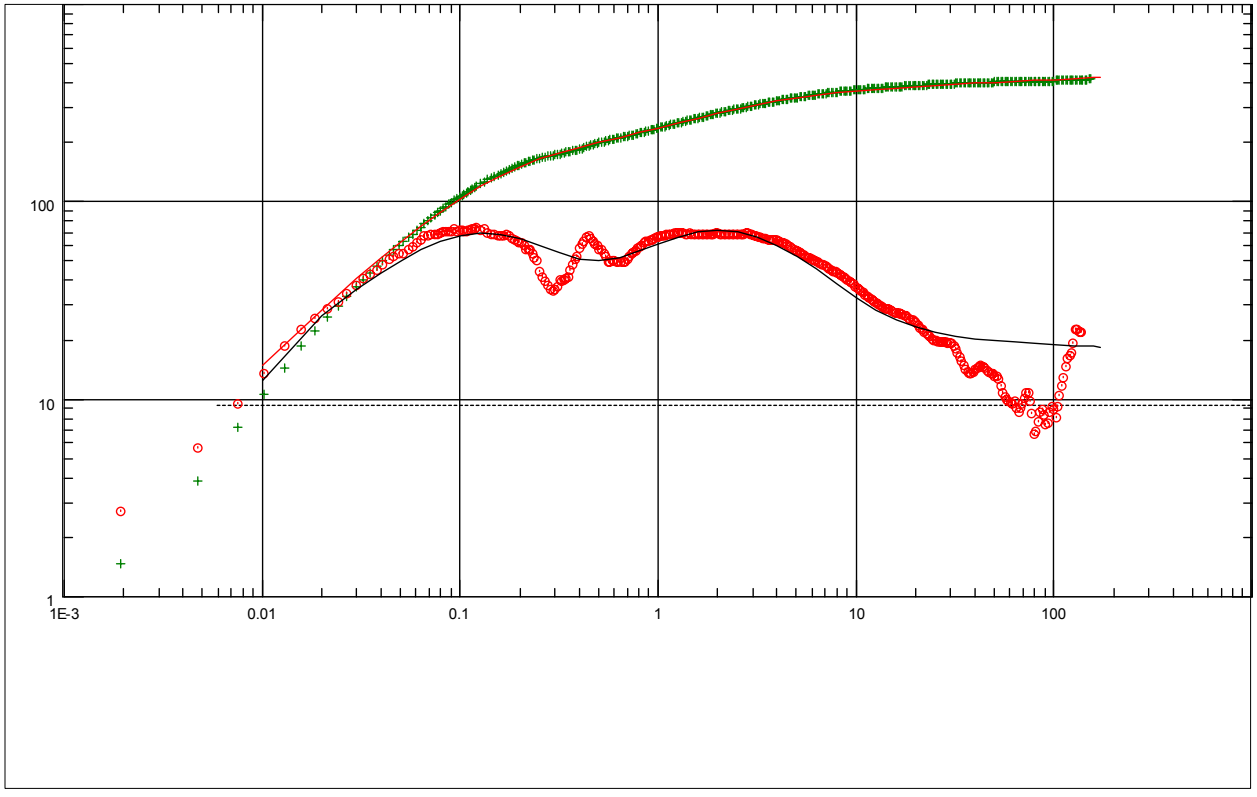
The paper on the database earlier presented at the 2002 Western Regional Meeting of SPE was updated for submission to SPE for the SPE library archives.

Task II- New Data

New Infill well 3242-7-2

As previously reported the first infill well at platform Holly, 3242-7-2, was production tested at disappointing water cuts from the lower M6-M7 zones. All but the top 80' of M6 perforations (8334-8414') were plugged back with a thru-tubing bridge plug. Additional perforations were shot through tubing in the M5 on October 26 and the M3-M4 on November 8, 2002. These perforations have not yet been acidized and do not appear to be producing. A second pressure build-up test, conducted in December 2002, shows that the productivity index of the well has dropped from 5.2 to 1.3 BFPD/psi since the well has been plugged back. Interestingly the build-up now exhibits the behavior of a radially composite system with a positive skin factor. However, the reservoir pressure and effective permeability have not appreciably changed from the pre-plugback values. This is interpreted to mean that the well is still connected to the same fracture system as before – simply that the connection factor has changed. During a workover that will take place in February 2003, additional perforations will be shot in the M2 repeat and the highly fractured section of hole that intersects the vertical beds. All the newly perforated zones will be acidized during this workover. All the perforations lie on the south side of a large thrust fault termed C3 that cuts 3242-7-2 just at the top of the vertical beds.

Figure 1 3242-7-2 December 2002 Pressure Buildup Horner Plot



Log-Log plot: dp and dp' [psi] vs dt [hr]

Table 1 3242-7-2 PBU Analysis

Company	Venoco	Formation interval	Monterey
Field	South Ellwood	Perforated interval	7796-8414
Well	3242-7-2	Final BU Pressure	974 psia
Test	BU Dec02		
Date	12/1/02		
Gauge	Quartz E2042		
Depth	6111' MD, 3054' TVD		

TEST TYPE	Standard	FLUID TYPE	Oil
Porosity Phi (%)	1	Volume factor B	1.131 B/STB
Well Radius rw	0.255417 ft	Total Compr. Ct	6.67611E-5 psi-1
Pay Zone h	618 ft	Viscosity	4.15395 cp

Group	build-up #9	RESERVOIR	Radial Composite
Rate	0 STB/D	BOUNDARY	Infinite
Rate Change	650 STB/D	WELL	Storage + Skin
P at dt=0	555.913 psia	Storage C	0.0195 STB/psi
Pi	1051.38 psia	Skin factor	5.53
		Delta P Skin	102.563 psi
Time Match	84.6 [hr]**-1		
Pressure Match	0.054 [psia]**-1	kh	23300 md.ft
		K	37.7 md
		Mobility k/mu	9.06 md/cp

Reservoir Pressure Data

During December 2002, platform Holly was shutdown for equipment maintenance. Long term pressure build-up surveys were run in three wells during the five day shutdown. These wells were 3120-12, 3242-9 and 3242-7-2. Wells 3242-9 and 3120-12 gave approximately the same reservoir pressure of 1300 psia at the datum of 3881' SS. Well 3242-7-2 gives a reservoir pressure of 1400 psia at this same datum. It would appear that the C3 thrust fault noted in well 3242-7-2 may be isolating this well from the main field area.

All the pressure build-up data that is available for the Monterey formation since initial production in 1971 has been reanalyzed in a consistent manner using the Kappa Saphir pressure transient analysis package. It became evident during this analysis that it could take many weeks for the bottom hole pressure in a given well to build up to a true reservoir pressure particularly if it had been on production for a long time prior to the test. Therefore previous reservoir studies that had used instantaneous static bottom hole pressures could be misleading. The most representative data is obtained from initial build-up tests on recently completed wells or from long build-ups where the entire field had been shut-in. The following Table summarizes the interpretation of these tests:

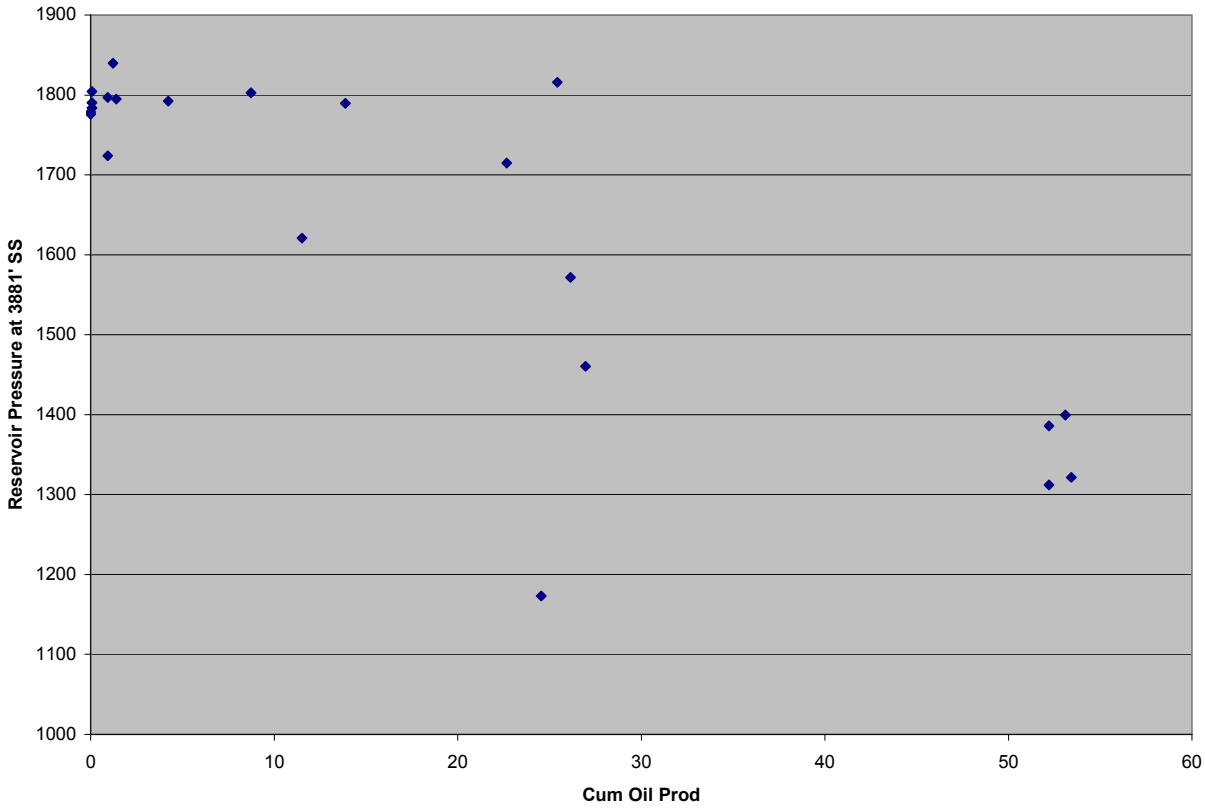
Table 2 South Ellwood Monterey Pressure History from build-up tests

Well	Date	Gauge Depth MD	FSIBHP psia	P* psia	Kh md-ft	Skin	P* at Datum psia
3120-8	4/1/1971	3500	1615	1615	NA	NA	1776
3120-8	1/31/1972	3593	1634	1649	44600	-6.5	1779
3120-8	4/25/1972	3580	1634	1654	21300	-1.9	1784
3242-5	6/6/1972	3593	1516	1525	6580	-5	1804
3120-3	5/29/1972	3132	1498	1504	5500	-4.2	1790
3120-3	2/7/1974	3203	1325	1611	2260	-6.8	1797
3242-2	2/7/1974	3315	1354	1481	4020	-1.3	1724
3120-6-2	7/6/1974	4042	1677	1764	6320	6.8	1840
3120-6-2	9/8/1974	4055	1529	1726	2500	-4.4	1795
3120-7-3	11/18/1977	3615	1394	1482	4610	-5.3	1792
3120-15-1	10/1/1980	4508	1556	1664	274	-2.6	1803
3120-10	9/27/1981	3657	1398	1570	6700	-6.2	1621
309-8	6/21/1982	3898	1760	1781	56900	-0.4	1790
208-102	2/26/1985	4058	1681	1708	853	-3.7	1715
3242-19	11/6/1985	4278	1153	1281	24200	37.4	1173
3242-19	3/1/1986	3850	1237	1753	57100	10.7	1816
3120-16	5/16/1986	7959	1642	1654	8350	-5.5	1572
3242-13	9/27/1986	3538	1147	1252	4450	-4.2	1460
3242-18	11/29/2001	6630	1143	1199	104000	3.3	1386
3120-12	12/2/2001	5652	1113	1134	88700	30	1312
3242-7-2	9/2/2002	6111	970	1060	16300	-4.6	1399
3242-7-2	12/2/2002	6111	974	1051	23300	5.5	1436
3120-12	12/2/2002	5652	1093	1127	52600	11.1	1298
3242-9	12/2/2002	6040	1078	1098	87200	13.2	1322

Plotting this pressure data against cumulative oil production, we see reservoir pressure has decreased just 400 psi for a cumulative production of 51 MMBO. The shape of this graph would

seem to indicate early pressure support from a gas cap while later in the life of the field aquifer and/or microfracture support is more important. The large amount of scatter in the data indicates that reservoir compartmentalization is a significant factor. This data is presently being used as the basis for a material balance study.

Figure 2 South Ellwood Monterey Reservoir Pressure History



Task III- Basic Reservoir Studies

For naturally fractured reservoirs producing from the Monterey Formation, Offshore California, evidence from cores and outcrops suggest the important role of micro fractures in providing storage support to the major fracture system. From the theoretical work earlier published by AlGhamdi and Ershaghi (SPEJ March 1996) on dual fracture systems, we have developed and tested a process where performance data from individual wells can be analyzed to quantify the extent of micro fracture support. We continued our work on the algorithms for estimation of micro porosity support system from performance data. Significant amounts of reservoir characterization information are embedded in performance data of producing wells. Developing analytical methods to extract such signals contributes to a better understanding of complex reservoirs.

Simulation Studies

Using various sources of data, we established the existence of compartmentalization in the fractured reservoir of dual porosity behavior of the South Ellwood Field. Recognition of such isolated blocks substantially improves the accuracy of history matching of the individual wells.

Deterministic information about reservoir compartmentalization was derived from the study of fluid recoveries and variations of fluid properties from individual wells. Had the blocks been in total communication, differences would have rapidly disappeared by density-driven convection. Their preservation indicates a barrier to fluid flow among the blocks.

The Projection of Field and Well Performances from the CMG Model
After successfully history matching the wells with the compartmentalized dual fracture CMG model, we conducted a number of case studies considering various scenarios. These cases were to examine productivity from potential new wells and the effect of water injection on ultimate recovery.

Several prediction runs were made for projection of field and well performances in South Elwood under various development scenarios:

- Projection of the existing wells only.
- All existing wells plus the new well 3242-7-2
- All existing wells including new wells 3242-7-2 and 3242-19RD1 (Eagle Canyon well).
- Converting wells 3120-11 and 3242-08RD4 to injection wells at the first quarter of 2004

It is estimated that at 12/01/2012, the projected cumulative production of existing wells will be 63 MMSTB. New wells 3242-7-2 and 3242-19RD1 will increase recovery to 66.6 MMSTB and converting wells 3120-11 and 3242-08RD4 into water injection will further increase the total field production to 68.6 MMSTB

Pipeline Network Model
We conducted a number of calibrations run with the Pipeline Network Model (PNM). The software interfaces are being improved. We are adding features such as plots for pressure, saturation to graphic displays for the model. The model is able to generate pressure, saturation and rate data for different producing faulted intervals represented by fracture chimneys.

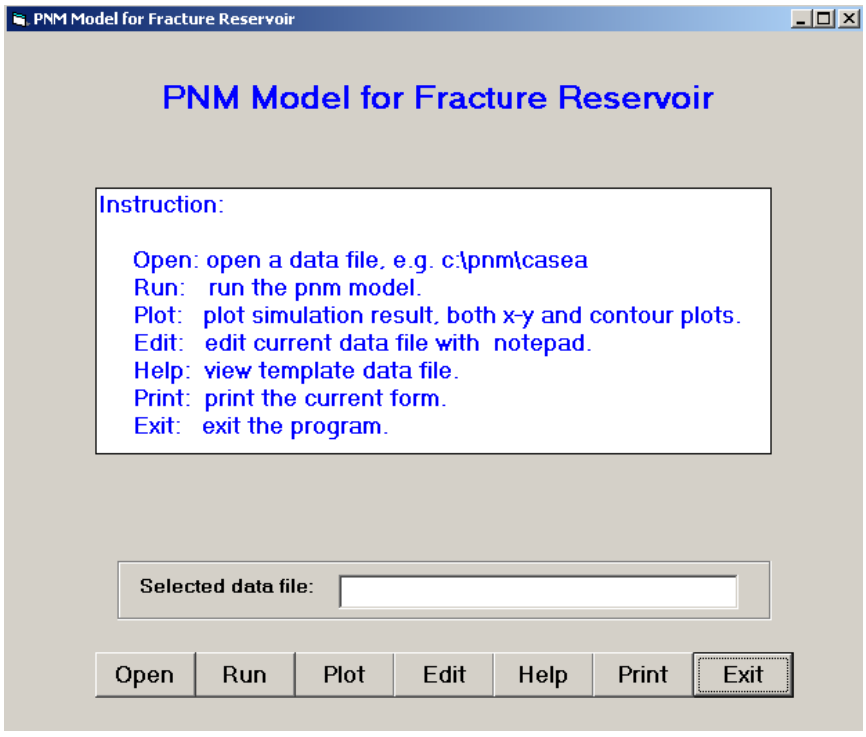
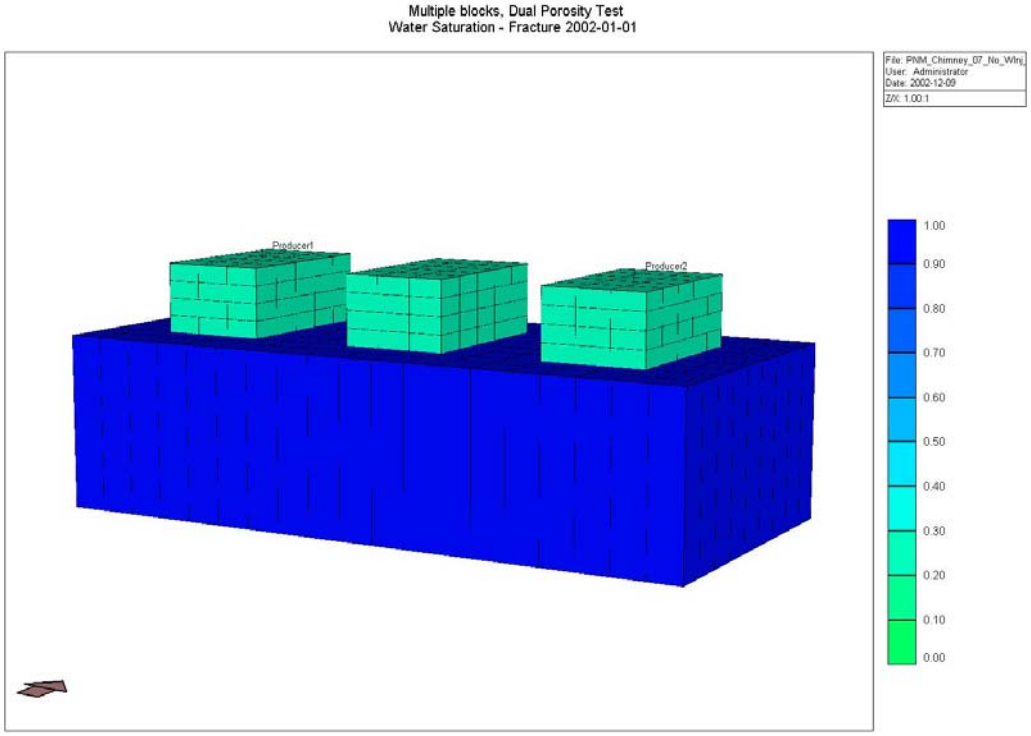


Figure 3
Current Software Interface for the PNM Model

PNM Calibration Work

This is an example of a three chimney model. The case study included examining the pressure profile with and without injection into the bottom aquifer.

Figure 4 Water Saturation profiles without Injection



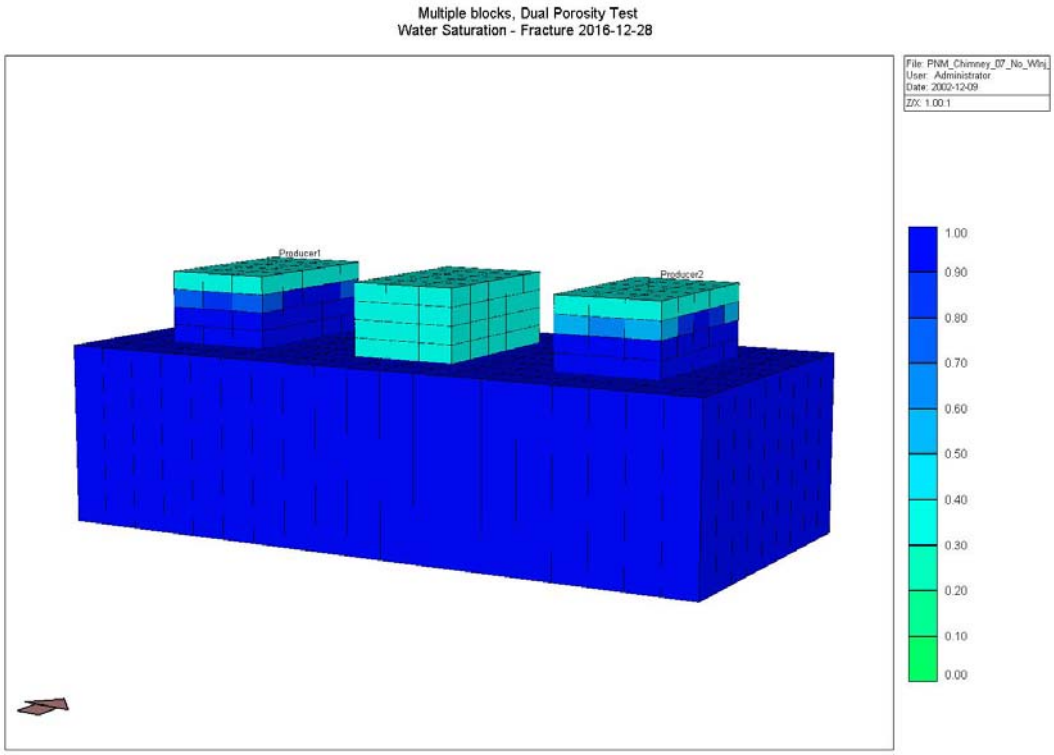
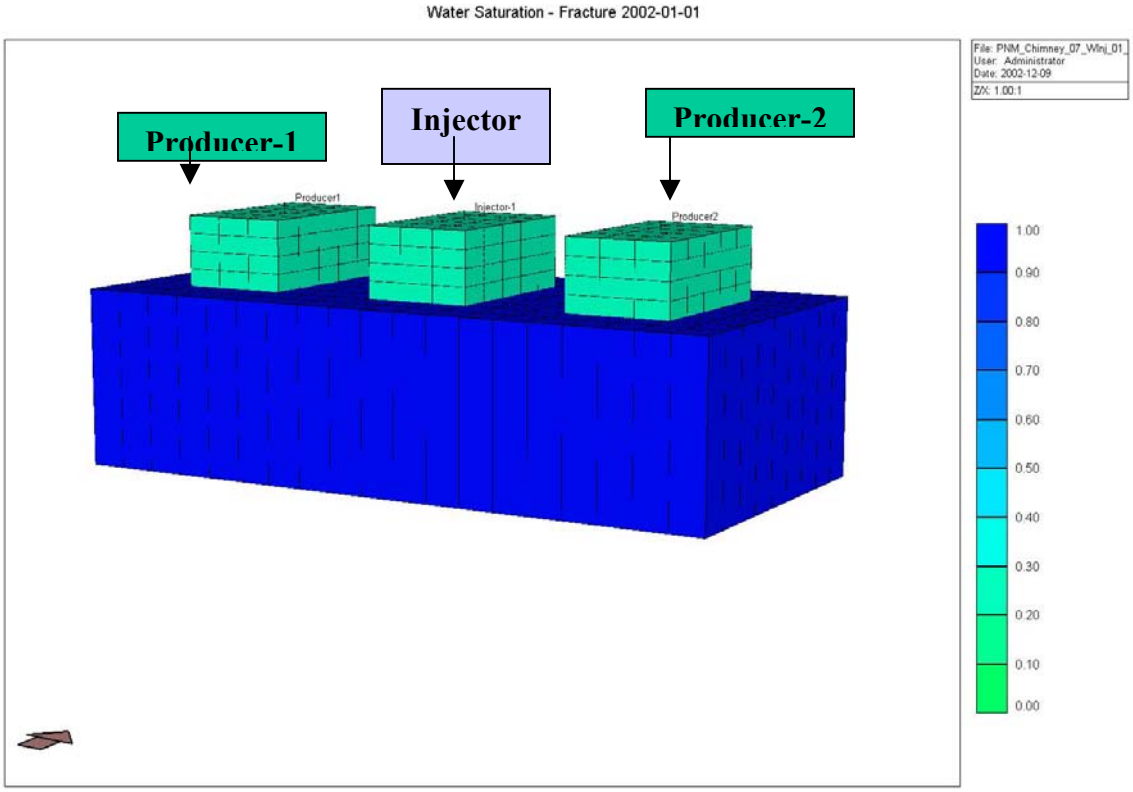


Figure 5 Water Saturation Profile for the Test Case of Three Fracture Chimneys with water injection.



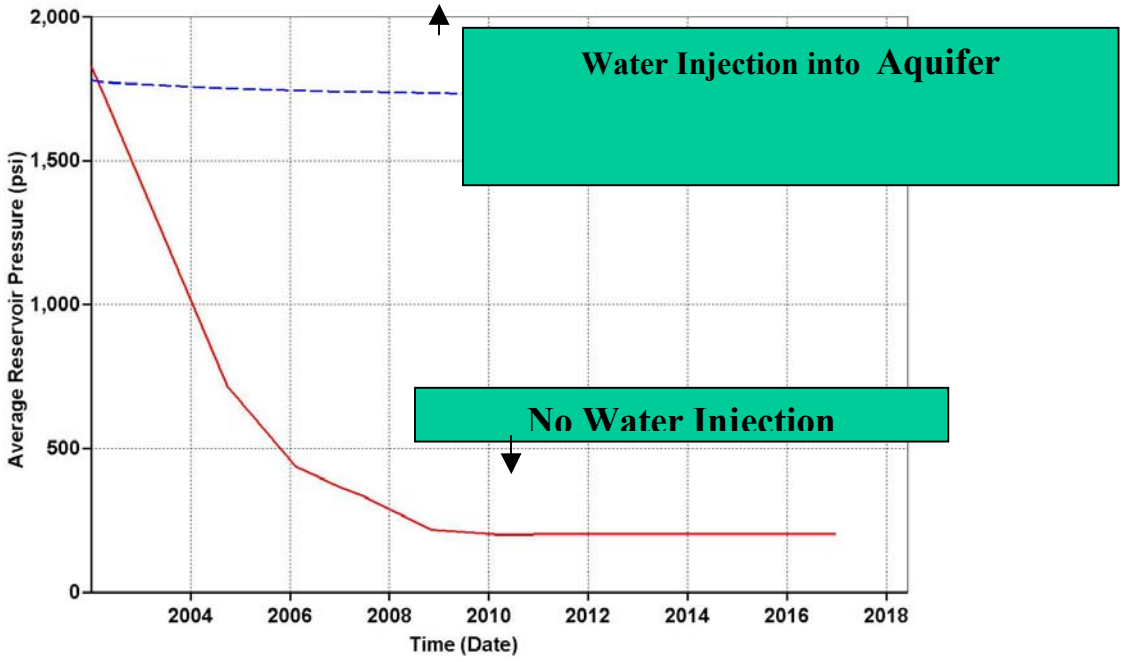


Figure 6 Comparison of Pressure Profiles with and without water Injection

Pipeline Network Model Coding

The model has been tested against CMG STARS on 3D, 2-phase (Oil and Water) with dual-porosity (matrix and fracture) problems. The results are reliable.

The coding for 3D, 3-Phase (oil, water, gas) and dual porosity (matrix and fracture) has been finished. The preliminary testing on 3D three phase black-oil model shows promising results for the gas phase performance. Currently, we are working on debugging the problem of small time steps due to large material balance errors near the bubble point. After this is finished, the history-match feature will be added to the user-interface to make the model easier to use. When the model is stable, a few more realistic three-phase test cases will be designed.

Work Schedule for the Next Quarter

The tentative work schedule for next quarter will be as follows:

Continuing on further development and testing of the PNM Model for 3D and 3 Phase.

- Preparing the final report on the CMG simulation study.
- Preparing final report and documentation on the PNM Model.
- Preparing the manuscript for an SPE paper due March 2003
- Preparing Final Report on the Database
- Finalizing the work on Expert System for Detection of Producing Intervals from Well Logs for presentation at the AAPG annual meeting.

Task IV--Stimulation

No activity

Task V- Project Management

Project review meetings were held on a monthly basis in Carpinteria. Individuals working on the project during this quarter included:

Database:
I. Ershaghi (USC), H. Patel (USC), Tim Rathmann (Venoco) and Kim Halbert (Venoco).

Reservoir Studies:
I. Ershaghi (USC), Doddy Abdassah (USC), Zhengming Yang (USC), Steve Horner (Venoco), M. Heidari (USC), M. Kashfi (USC).

Geological Modeling
Marc Kamerling (Venoco), Karen Christensen (Venoco)

Geophysical Modeling
Karen Christensen (Venoco)

Project Management:
Steve Horner (Venoco) and I. Ershaghi (USC)

Task VI-Technology Transfer

We revised the SPE 77739 earlier presented at the SPE Fall meeting in San Antonio for the editorial review committee of SPE for potential publication in one of the SPE Journals.
We submitted three abstracts for the Western Regional Meeting of SPE scheduled for May 2003 in Long Beach.

Conclusions:

A careful analysis of the individual well pressure histories supports the concept of compartmentalization in the reservoir. This concept has been fully developed in the CMG simulation model.

We made substantial progress in reservoir simulation work in terms of investigating several development scenarios. The CMG simulator now is becoming a tool for reservoir management. We upgraded the PNM model to from 2D to 3D two-phase. The full 3D 3 phase model is close to completion.