ASSIST IN THE RECOVERY OF BYPASSED OIL FROM RESERVOIRS IN THE GULF OF MEXICO

Contract Number: DE-AC22-92BC14831

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Department of Petroleum Engineering
Baton Rouge, LA 70803-6417**

Contract Date: February 18, 1992

Anticipated Completion Date: March 18, 1994

Total Government Award: \$2,025,755

OCT 28 1993

OCT 1

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Quarterly Status Report (Final): Covering Apr. 1, 1993 - June 30, 1993

Report Date: July 30, 1993

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MASTER

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Executive Summary

Data collection from MMS continued and is 90% complete. Mobil Exploration and Producing U.S., Inc. (Mobil) provided data on one of their fields, Field 2, which LSU and subcontractors have agreed to blind code. Amoco Production Company, a partner with Mobil in the same field, also contributed data. Detailed studies will be performed on two reservoirs, Reservoir 3 and Reservoir 4.

The history match of the production performance of the B-35-K Sand reservoir in South Marsh Island 73 Field was refined through modification of the water-oil relative permeability, the down-dip location of the estimated oil-water contact, and the estimated attic volume of the reservoir. Using the final values for these variables in the model, the primary performance of the reservoir was accurately matched, as was the performance of the reservoir as a result of five attic gas injection cycles. The gas production, oil production, and pressure data were relatively easy to match. However, to obtain a match of the water production history, it was necessary to include an attic volume of approximately 846 acre-feet (1.3 million BO) and to assume that the oil-water contact was approximately 60 feet below the proven oil limit of the reservoir.

Using the final history match assumptions, various model sensitivities were conducted to examine the results of additional gas injection into the reservoir. These sensitivities were conducted to evaluate the impact of gas injection rate, post-injection shut-in period, gas injection volume, and gas injection cycle staging. The results of this study have offered a set of technically feasible solutions to help improve the oil recovery from the reservoir through additional attic gas injection cycles as follows:

1. The injection rate sensitivities indicate that relatively low injection rates accelerate the production response from additional gas injection cycles due to improved segregation of the gas in the attic. The ultimate incremental recovery is improved only slightly at higher gas injection rates. An injection rate of about 500 mcf/d appears to be reasonable for this reservoir.
2. The injection volume sensitivities show that production is slightly accelerated at higher injection volumes and that incremental oil recovery tends to be higher, but there is a point of diminishing returns. The optimum gas injection volume appears to be between 150 and 300 million cubic feet.
3. The post-injection shut-in time sensitivity indicates that a three month shut-in time yields an optimum incremental oil recovery.
4. The incremental volume staging sensitivity indicates that higher incremental recovery can be achieved by dividing the total injection cycle into two stages, with a short production stage between the two. This improved recovery is most likely due to better segregation of the injected gas in the attic.

Material balance and computer simulations studies of the B-65-G Sand reservoir, also in South Marsh 73 Field, continued.

Modifications to BOAST for modelling steeply dipping reservoirs were successfully implemented into the PC based BOAST II program. The modified PC program, BOAST III, was and is being used to model the Taylor reservoirs.

Separate modifications to the mainframe BOAST II code consisting of implementation of a radial grid system and inclusion of a gravity term continue. Accurate laboratory data for coning was obtained. An accurate simulation for this problem was developed and the solution is currently being tested. This will be a 3-D, two phase model that includes capillary and gravity forces. This model will then be scaled up, added to BOAST II, and compared to some other known field results.

INTRODUCTION

Much of the remaining oil offshore is trapped in formations that are extremely complex due to intrusions of salt domes. Conventional seismic processing techniques cannot clearly image either these traps or the full extent of oil-bearing segments near the salt domes; therefore, substantial volumes of oil may have remained uncontacted by previous drilling.

Recently, however, significant innovations have been made in seismic processing and mathematical migration of seismic signal. In addition, significant advances have been made in deviated and horizontal drilling technologies and applications. These technology advances make it possible to reprocess existing seismic data to identify non-contacted portions of the reservoirs, which can then be contacted using advanced drilling technologies to kick out new wells from existing wells. Effective application of these technologies, along with improved recovery methods, offers opportunities to significantly increase Gulf of Mexico production, delay platform abandonments, and preserve access to a substantial remaining oil target for enhanced recovery and other advanced recovery processes.

During this reporting period, data collection continued from the Minerals Management Service (MMS) and several operators. Modifications to BOAST II and MASTER reservoir simulators for the integration of radial grid systems and for use in simulating miscible gas injection processes in steeply dipping reservoirs continued. The testing of the experimental apparatus designed for studying the recovery of attic oil began. Analysis of data obtained from Taylor Energy in South Marsh 73 field continued.

Project Description

The objective of this research is to assist the recovery of non contacted oil from known reservoirs on the Outer Continental Shelf in the Gulf of Mexico. Mature offshore reservoirs, declining oil reserves, declining production, and other natural forces are accelerating the abandonment of offshore oil resources and production platforms. As these offshore wells are plugged and the platforms are abandoned, an enormous volume of remaining oil will be permanently abandoned. Significant quantities of this oil could be recovered using advanced technologies now available if the resource can be identified.

This project will proceed under three broad phases:

Analysis -- TORIS level data will be collected on the major fields located in the piercement salt dome province of the Gulf of Mexico Outer Continental Shelf. Representative reservoirs will be studied in detail in order to evaluate undeveloped and attic oil reserve potential. These detailed investigations will be used to calibrate the TORIS level predictive models. The recovery potential of advanced secondary and enhanced oil recovery processes and the exploitation of undeveloped and attic oil zones for salt dome reservoirs in the Gulf of Mexico will be assessed.

Supporting Research -- Supporting research will focus on the modification of public domain reservoir simulation models to accurately simulate the conditions encountered in the piercement salt dome province of the Gulf of Mexico. Laboratory research will focus on the development of fluid relationships that will be used in the simulation of miscible and immiscible processes in the project area.

Technology Transfer -- A significant effort is planned to transfer the results of this project to potential users of the technology. Technology transfer activities will also provide feedback channels that will help keep the analysis and supporting research focused on the most important problems associated with this project.

Project Status and Planned Activities

Data Collection

ICF continued its data collection from MMS and is 90% complete. Mobil Exploration and Producing U.S., Inc. (Mobil) provided data on Field 2, which LSU and subcontractors have agreed to blind code. Amoco Production Company, a partner with Mobil in the same field, also contributed data. Detailed studies will be performed on Reservoir 3 and Reservoir 4. Amoco Production Company also provided data on one other field where no detailed studies are expected.

Data Analysis

LSU and BDM continued the analysis of data obtained from Taylor Energy on the South Marsh Island (SMI) Block 73 Field in the Gulf of Mexico.

B-35-K Sand Reservoir

The location of SMI 73 Field is offshore Vermilion and Iberia Parishes, Louisiana as Figure 1 shows. The field was originally discovered by Exxon in 1964 with peak production reaching 16,900 barrels of oil per day (BOPD) and 68 million cubic feet of gas per day (MMCFD) in 1971. It is currently producing 1800 BOPD and 4.6 MMCFD. Of the five offshore blocks which the field covers (69, 72, 73, 57, 58), Taylor Energy has purchased three (69, 72 and 73) while Shell retains ownership of the other two. These facts have been summarized in Table 1 and Figure 2. Structurally, the field consists of a piercement salt dome with its associated faults and shale-out trapping mechanisms. Figure 3 shows a structure map on top of the salt.

The B-35-K Sand Reservoir is located on the southeastern flanks of the salt dome and has produced from 4 wells. Figure 4 shows a structure map of the reservoir, Figure 5 shows daily production rates and Table 2 lists cumulative production by well.

Numerous simulation runs to refine the history match of the B-35-K Sand reservoir performance and to predict the incremental oil production which could result from future gas injection into the reservoir were performed. Figure 6

illustrates the grid layout of the simulation, while Figure 7 illustrates the layering, with average characteristics, used for the simulation. Initial assumptions for the simulation data set are summarized in Tables 3 and 4.

The history match of the production performance of the B-35-K Reservoir was refined through the modification of the water-oil relative permeability, the down-dip location of the estimated oil-water contact, and the estimated attic volume of the reservoir. Using the final values for these variables in the model, the primary performance of the reservoir was accurately matched, as was the performance of the reservoir as a result of the five attic gas injection cycles. The gas production, oil production, and pressure data were relatively easy to match. However, to obtain a match of the water production history, it was necessary to include an attic volume of approximately 846 acre-feet (1.3 million BO) and to assume that the oil-water contact was approximately 60 feet below the proven oil limit of the reservoir.

The location of the oil-water contact had a significant impact on the production performance of the simulator. Because the sand thickens in the down-dip direction, the original oil-in-place of the reservoir increases significantly as the oil-water contact is pushed down-dip. Downward movement of the oil-water contact also slows the water production rate because the water level is moved away from the production well take points. By moving the contact in the simulator to a level 60 feet below the proven oil limit, an optimum match of water production performance was achieved.

Because the sand appears to thin in the up-dip direction, the attic volume had less impact on the simulated performance. An attic volume is necessary to obtain the history match, but the exact volume is difficult to define since both the up-dip and down-dip limits are unknown. In other words, there are multiple combinations of oil-water contact and attic volume that will yield a reasonable history match.

Figures 8 through 11 show the excellent results of the final history match and illustrate actual reservoir pressure, oil production, gas production, and water production data versus the simulated values. The volumetric calculations

comparing the various history match cases considered are summarized in Table 5. Using the final history match assumptions, the volumetric original oil-in-place for the reservoir is calculated at 6.3 million barrels of oil, meaning that 48% recovery has been realized to date.

Using the final history match assumptions, various model sensitivity tests were conducted to examine the results of additional gas injection into the reservoir through the A-6 well. These sensitivities were conducted to evaluate the impact of gas injection rate, post-injection shut-in period, gas injection volume, and gas injection cycle staging. These incremental oil recovery results of these sensitivity cases are presented in Table 6 and Figures 12 through 16 and discussed below.

The first sensitivity was conducted to evaluate the impact of gas injection rate on the incremental oil recovery. Figure 12 compares the results of injecting 300 million cubic feet of gas in one stage at three different injection rates, 250, 500, and 1000 mcf/d, followed by a 3-month shut-in period. The data indicates that lower injection rates improve the performance of the gas injection cycle by accelerating the production response after the shut-in period. In addition, the incremental recovery is higher for the lower injection rates. These effects could be attributed to the efficiency of the process at lower gas injection rates due to reduced gas fingering and a higher segregation rate.

The impact of post injection shut-in time was also evaluated. The cases evaluated used a total injection volume of 150 million cubic feet of gas at 500 mcf/d in one stage, and the shut-in period varied between 0 and 6 months. Figure 13 shows the best predictive performance of the reservoir was achieved using the 3-month shut-in period. Although the results of the three cases are similar, the 3-month shut-in case has slightly accelerated oil production, and the 6-month shut-in case has slightly higher incremental recovery. Economic analysis of the results will probably indicate that the 3-month shut-in case is economically optimum.

Figure 14 illustrates the incremental recovery over time for gas injection volumes between 75 and 400 million cubic feet. Comparison of the four cases in

this figure shows that production is slightly accelerated at higher injection volumes and that incremental oil recovery tends to be higher for the larger injection volumes. However, there appears to be a point of diminishing returns, as there is very little difference for cases between 300 and 400 million cubic feet. The optimum gas injection volume is probably in the range of 150 to 300 million cubic feet of gas.

An additional sensitivity was conducted to investigate the results of gas injection cycle staging. The effects of two and three injection stages were compared to the 150 million cubic feet injection volume case where the injection rate was 500 mcf/d and the shut-in period after injection was 3 months. The first case assumes that injection occurs in two stages: (1) half of the gas is injected followed by a 3-month shut-in period and 6 months of production; (2) the remaining half of the gas is injected with production initiated after a 3-month shut-in period. The next case assumes that the gas volume is injected in three stages, with similar shut-in and production stages in between.

Figures 15 and 16 exhibit the results of injecting gas in stages, and compare a single stage case with 2-stage and 3-stage injection cases. Figure 15 indicates that the 2-stage injection case produces more oil than the 1-stage or 3-stage injection cases. Figure 16 illustrates that water production is held off by staging the gas injection. A 2-stage injection scenario is probably optimum because the production duration between the first and second stages was only 6 months, contributing to the gas segregation phenomena and, thereby, contributing to the oil recovery enhancement with lower associated water production rate than for one stage.

To help improve oil recovery from the reservoir through additional attic gas injection cycles the results of this study offer a set of technically feasible solutions:

1. The injection rate sensitivities indicate that relatively low injection rates accelerate the production response from additional gas injection cycles due to improved segregation of

the gas in the attic. The ultimate incremental recovery is improved only slightly at higher gas injection rates. An injection rate of about 500 mcf/d appears to be reasonable for this reservoir.

2. The injection volume sensitivities show that production is slightly accelerated at higher injection volumes and that incremental oil recovery tends to be higher, but there is a point of diminishing returns. The optimum gas injection volume appears to be between 150 and 300 million cubic feet.
3. The post-injection shut-in time sensitivity indicates that a 3-month shut-in time yields an optimum incremental oil recovery.
4. The incremental volume staging sensitivity indicates that higher incremental recovery can be achieved by dividing the total injection cycle into two stages, with a short production stage between the two. This improved recovery is most likely due to better segregation of the injected gas in the attic.

B-65-G Sand Reservoir

Material balance and computer simulation studies of the B-65 reservoir continued. Values for pressure-volume-temperature (PVT) properties were obtained using methods outlined by Oistein Glaso¹ and further analyzed by R. P. Sutton² since actual field values were not available. An initial history matching attempt indicated that the reservoir was more limited by faulting than originally believed. Therefore, major modifications to the data set were necessary. Material balance and simulation studies continue based on these new reservoir characterizations.

Critical Process Parameter Laboratory Experiments

The apparatus for experiments for the study of attic oil recovery techniques was tested. Problems arose with sand plugging in various ports and are currently being solved.

BOAST II Modification

Modifications to BOAST for modelling steeply dipping reservoirs were successfully implemented into the PC based BOAST II program. The modified PC program, BOAST III, was and is being used to model the Taylor reservoirs.

Separate modifications to the mainframe BOAST II code consisting of implementation of a radial grid system and inclusion of a gravity term continue. Accurate laboratory data for coning was obtained. An accurate simulation for this problem was developed, and the solution is currently being tested. This will be a 3-D, two-phase model that includes capillary and gravity forces. This model will then be scaled up, added to BOAST II, and compared to some other known field results.

The near wellbore region simulation models must properly represent the near wellbore reservoir properties, the completion interval, and the multiphase flow into the well, especially coning and stratified flow. Modelling this region requires an extremely fine grid in the neighborhood of the well, and this rapidly became a large scale computer problem. An accurate near wellbore regional simulator can be used for better well management. Well management can include setting of well rates or pressures, operating policies, production levels, etc. An accurate simulation can influence the decision to work over or recompleat a well, to install artificial lifts, and/or to control water and gas production rates.

The need for an accurate and feasible way to model the simulation of flow near the well led to the development of a hybrid approach to reservoir simulation. In this technique, a Cartesian grid is used for the entire reservoir with arbitrary fine meshes in the near wellbore regions that can include one or more blocks of the Cartesian grid.

Multiphase flow near the well can be more accurately modelled with finite element methods coupled with adaptive, dynamic grid refinements in the region of high activity (maximum change). Timed portions of the current finite element program on large-scale problems, have shown that the mesh refinement algorithms require an extremely small amount of time while the solution of the systems of equations consume approximately 90% of the total computation time. To use dynamic grid refinement techniques in three dimensions, it was necessary to construct a unique finite element which, apparently, has not been used before.

The number of elements required for the near well portion of the reservoir using this approach can be very large. However, this approach is intended to improve the treatment of wells by use of this fine mesh in the well region and a normal (large) rectangular grid elsewhere in the reservoir. This will substantially improve the treatment of wells in BOAST II. The rectangular grid that is currently used in BOAST II will remain. The flow equations for the two regions are to be solved with different levels of implicitness; the simultaneous solution (implicit) method is to be applied to the well regions and the explicit saturation (IMPES) technique that is currently used in BOAST II will remain in the reservoir region.

The use of a hybrid grid scheme in reservoir simulation was introduced by Pedrosa and Aziz¹; however, their scheme was also to improve the treatment of wells. LSU's scheme is different because it will use

- * BOAST,
- * Finite element methods in the well region,
- * Adaptive grid refinements in the region of high activity, and
- * Modern PDE solvers for the well region.

Finite element methods (FEM) are very useful in solving problems in which the unknown function varies sharply in a localized region. FEM meshes are constructed so that smaller elements are placed in regions of high activity while larger elements are placed in regions where there is little activity. An adaptive

refinement technique has been developed that automates the process of refining the mesh where it is needed most and, in transient problems, allows mesh refinement to occur in different regions near the well as the solution evolve. The use of FEM with adaptive refinement techniques should permit radial flow results near the well because of the fineness of the grid.

Presently, a program for water and oil FEM with adaptive refinement techniques for the well region has been developed, and this program is being tested against experimental results obtained for coning and sweep efficiency problems. When an agreement exists between the program results and the experimental results, the near well model will be added to BOAST II and real field test simulations will be executed.

Figures 17 and 18 document the present calculated test results. Figure 17 show oil (black) being produced and being replaced by water (white). Figure 18 shows oil (black) being pushed by water (white). Both Figures 17 and 18 present results that are reasonable.

MASTER Modification

Modifications to MASTER continue with no unforeseen problems or delays.

Summary of Progress

ICF Resources Incorporated (ICF), a subcontractor for the project, continued data collection with Minerals Management Service (MMS). LSU continued collecting data from operators.

LSU and BDM Federal. Inc., a subcontractor on the project, continued the analysis of data obtained from Taylor Energy in South Marsh 73 Field. The production and pressure history for the B-35-K Sand reservoir was matched. Also, several simulations were run to refine the history match of the reservoir performance and predict the incremental oil production. This resulted in several conclusions and recommendations for the operator, Taylor Energy, who is planning a gas injection program for the reservoir, as well as providing an excellent calibration reservoir for the TORIS modelling efforts.

Material balance and computer simulation studies continued on the B-65-G Sand reservoir in South Marsh Island 73 Field.

LSU and BDM personnel began analyzing two reservoirs within a blind coded field for which Mobil Exploration and Producing Co., Inc and Amoco Production Company provided data. Two reservoirs will be studied in detail within the field, which will henceforth be referred to as Field 2. The two reservoirs will henceforth be regarded as Reservoir 3 and Reservoir 4.

LSU continued modifying BOAST II for the integration of radial grid systems and testing experimental apparatus designed for studying the recovery of attic oil.

Report Distribution List

Document Control Center
U.S. Department of Energy
Pittsburgh Energy Technology Center
P.O. Box 10940, MS 921-118
Pittsburgh, PA 15236-0940

References

Glaser, Oistein: "Generalized Pressure-Volume-Temperature Correlations," Journal of Petroleum Technology. (May, 1980) 785-795.

Sutton, R. P. and Farshad, F.: "Evaluation of Empirically Derived PVT Properties for Gulf of Mexico Crude Oils," SPE Reservoir Engineering. (February, 1990) 79-86.

Pedrosa, Oswaldo A. and Aziz, Khalid: "Use of a Hybrid Grid in Reservoir Simulation," SPE Reservoir Engineering. (November, 1986) 611-621.

Publications

There were no publications during this reporting period.

APPENDIX

LOCATION OF SMI BLOCK 73 FIELD IN THE GULF OF MEXICO

FIGURE 1

SMI 73 FIELD PRODUCTION HISTORY

FIGURE 2

STRUCTURE MAP ON TOP OF SALT FOR SMI 73 FIELD

New Orleans Geological Society

FIGURE 3

SMI BLOCK 73 FIELD: B-35 SAND STRUCTURE MAP

FIGURE 4

DAILY PRODUCTION RATES FOR B-35K RESERVOIR

FIGURE 5

RESERVOIR SIMULATION GRID SCHEME

FIGURE 6

RESERVOIR SIMULATION LAYERS AND DATA

FIGURE 7

FINAL HISTORY MATCH OF RESERVOIR PRESS.

(ATTIC VOLUME, WOC @ 6137', MOD Krw)

FIGURE 8

FINAL HISTORY MATCH OF CUM OIL PROD.

(ATTIC VOLUME, WOC @ 6137', MOD Krw)

FIGURE 9

FINAL HISTORY MATCH OF CUM GAS PROD.

(ATTIC VOLUME, WOC @ 6137', MOD Krw)

FIGURE 10

FINAL HISTORY MATCH OF CUM WATER PROD.

(ATTIC VOLUME, WOC @ 6137', MOD K_{rw})

FIGURE 11

GAS INJECTION RATE SENSITIVITY ANALYSIS

(300 MMCF, 3 MO SHUT-IN, 1 STAGE)

FIGURE 12

POST-INJECTION SHUT-IN TIME SENSITIVITY

(150 MMCF @ 500 MCFD, 1 STAGE)

FIGURE 13

INCREMENTAL OIL PROD DUE TO GAS INJECT

(500 MCFD, 3 MOS SHUT-IN, 1 STAGE)

FIGURE 14

INJ. VOLUME STAGING SENSITIVITY ON OIL (150 MMCF @ 500 MCFD, 3 MO SHUT-IN)

FIGURE 15

INJ. VOLUME STAGING SENSITIVITY ON H2O

(150 MMCF @ 500 MCFD, 3 MO SHUT-IN)

FIGURE 16

1 x 1,00000 -02

1 x 7,00000 -02

1 x 8,00000 -02

FIGURE 17

1. 1.0000E+00

1. 1.0000E+00

1. 1.0000E+00

1. 1.0000E+00

1. 1.0000E+00

1. 1.0000E+00

FIGURE 18

SMI BLOCK 73 FIELD

PRODUCTION STATISTICS

Discovery:	1964	(Exxon SMI 69 #1)
Ownership:	Taylor Shell	(SMI 69, 72, 73) (SMI 57, 58)
Initial Production:	1964	
Peak Production (1971):	16,900 BOPD,	68 million scfd
Current (1/92):	1800 BOPD	4.6 million scfd
Cumulative Production (1/92) Field:	67	million Bbl Oil
	276	billion scf Gas
	46	million Bbl Water
Taylor Blocks:	45	million Bbl Oil
	36	billion scf Gas

TABLE 1

CUMULATIVE PRODUCTION FOR B-35K RESERVOIR

Well	Oil (1000 Bbl)	Gas (million scf)	Water (1000 Bbl)	Gas Injection (million scf)
A-1	394	193	43	—
A-3D, A-3	1,184	530	69	446
A-6D	1,446	739	86	—
Total	3,024	1,462	198	446

TABLE 2

AQUIFER INFUX

CALCULATIONS AND ASSUMPTIONS

- Assume infinite aquifer with steady-state water influx rate
- Calculated the water influx rate as a function of time using material balance equations
- The calculated water influx rate was utilized as a starting point in the BOAST3 simulator

TABLE 3

ADDITIONAL RESERVOIR SIMULATION ASSUMPTIONS

- Initial reservoir pressure = 2,712 psig
Reservoir datum = 5,846 ft
- Estimated PVT data based on values at initial conditions
- Estimated/modified relative permeability curves taken from "Gas Injection for Upstructure Oil Drainage," Strickland and Morse, JPT October 1979, pp 1323-1331
- $K_x - K_y \neq K_z$
- Wells producing from three different layers with variable formation properties
- Initially, used proven oil limit with "water-oil contact" at 6,076 ft
- Wells producing at historical average oil production rates

TABLE 5
ORIGINAL OIL IN PLACE CALCULATIONS

	Acre-Feet	OOIP Million BO	Percent Recovery
Proven Oil Limit With Estimated O/W Contact at 6076 Feet	2,396	3.5	86%
With Estimated O/W Contact at 6176 Feet	4,961	7.3	41%
With Estimated O/W Contact at 6176 Feet and Updip Potential	5,807	8.6	35%
With Estimated O/W Contact at 6137 Feet and Updip Potential	4,247	6.3	48%

Assumptions:

Porosity	= 29.50%
Water Saturation	= 16.50%
Oil Formation Volume Factor	= 1.29 STB/BBL
Initial Pressure	= 2,712 psia
Oil in Place per AF	= 1,481 B/AF
Cum Oil Production	= 3.0 MMBO

TABLE 6
Simulation Results of Additional Oil Recovery Due to Injecting Different
Gas Volumes at Different Rates With Different Shut-in Periods (WOR = 1.5)
(MSTB OF OIL)

Shut-in Time (Months)	Injection Volumes (mmcf)							
	75		150		300		400	
	Rate (mcf/d)		Rate (mcf/d)		Rate (mcf/d)		Rate (mcf/d)	
	250	500	250	500	250	500	1000	Rate (mcf/d)
Zero				213				741
Three								
1 Stage	203	212		219	236	227	226	229
2 Stage			225	238				260
3 Stage				230				
Six				220				

One Stage: Inject total volume at a specified rate, shut-in for 3 months then produced to a WOR = 1.5.

Two Stage: Inject half the volume at a specified rate, shut-in for 3 months, produced for 6 months, then inject the remaining volume at the same rate, shut-in for 3 months then produced to a WOR = 1.5.

Three Stage: Inject a third of the volume at a specified rate, shut-in for 3 months, produced for 6 months; inject another third, shut-in for 3 months, produces for 6 months; inject the remaining volume, shut-in for 3 months then produce to a WOR of 1.5.

END

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