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

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Abstract

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. Thus far, research has consisted of data collection from Minerals Management Service (MMS), literature and operators; detailed studies of several screened reservoirs; modification of three public domain simulators; development of a predictive model; and design and construction of several laboratory experiments for studying attic oil recovery.

The methodology for data collection from MMS, literature and operators is keyed on 208 sands containing 1,289 reservoirs, representing 60% of the original oil in place (OOIP) in the Gulf of Mexico. This data collection has been completed after several delays concerning confidentiality agreements between MMS, DOE, and LSU and its subcontractors.

Secondary recovery by downdip gas injection in steeply dipping oil reservoirs has been widely used successfully since the 1950's. Methane and nitrogen have been the primary gases used. Reservoirs which had been subjected to this type of recovery or had the potential to be subjected to this type of recovery were screened for detailed studies. Three reservoirs were identified which possessed the proper criteria and which had data available for detailed studies, the B-35-K and B-65-G reservoirs of South Marsh Island Block 73 Field and Reservoir 3 of Field 2, which was blind-coded by operator request.

Detailed data sets for simulating these reservoirs were created. This included the review and analysis of the geology of the reservoirs to define reasonable grid configurations for use in the simulator and review of well histories, including production, gas injection, and pressure data.

History matching and prediction runs have been completed on the B-35-K reservoir, history matching has been completed on the B-65-G reservoir and history matching is almost completed on Reservoir 3. Prediction runs on the B-35-K reservoir indicated an economical amount of oil to be recovered by additional injection of gas. The most efficient gas cycles, injection amounts and injection rates were also identified by the prediction runs.

Modifications on three public domain computer reservoir simulators, BOAST II mainframe, BOAST II PC and MASTER, were underway. Modifications consisted of developing a code to handle steeply dipping oil reservoirs and a radial grid format for near wellbore studies. Modifications for steeply dipping reservoirs have been successfully implemented and tested against commercial simulators in the PC version of BOAST II, renamed BOAST III. At present, modifications to BOAST II for radial grid systems are producing acceptable results in a 2-D model. A paper was presented at the 1994 ACM Symposium on Applied Computing in Phoenix, Arizona, March 6-8, 1994 on these results. Modifications have also been successfully implemented in the MASTER simulator. It is presently undergoing industry testing for validity.

Laboratory investigations continued but were slowed by several unforeseen incidences involving broken apparatus and inability to receive parts due to the California earthquake.

Executive Summary

The objective of this research is to assist in 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 currently 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 is permanently abandoned. Significant quantities of this oil could be recovered using advanced technologies now available if the resource can be identified.

The methodology for data collection from Minerals Management Service (MMS), literature and operators is keyed on 208 sands containing 1,289 reservoirs. These sands contain 60% of the original oil in place (OOIP) in the Gulf of Mexico. This data collection has been completed after several delays concerning confidentiality agreements between MMS, DOE, and LSU and its subcontractors.

From these sources, a list of high-priority fields/reservoirs were compiled, and additional information were perused on these fields/reservoirs for detailed studies. Operators of these fields/reservoirs were contacted to determine their interest in providing data or other assistance.

Secondary recovery by downdip gas injection in steeply dipping oil reservoirs has been widely used successfully since the 1950's. Methane and nitrogen have been the primary gases used. Reservoirs which had been subjected to this type of recovery or had the potential to be subjected to this type of recovery were screened for detailed studies.

Taylor Energy Company provided data on South Marsh Island 73 Field. From further review of this field, two reservoirs were selected for detailed studies, the B-35 Sand Reservoir K and the B-65 sand Reservoir G. The production and pressure history for both of these reservoirs was matched. Several simulations were then run to refine the history match of the reservoir performance and to predict the incremental oil production which could result from future gas injection into the reservoirs. Prediction runs on the B-35-K reservoir indicated

an economical amount of oil to be recovered by additional injection of gas. The most efficient gas cycles, injection amounts and injection rates were also identified by the prediction runs.

ARCO, Amoco, Texaco and Chevron all responded and were very helpful. However, upon reviewing their reservoirs which had been screened, it was determined that they did not fit the anticipated criteria and further studies were not warranted.

During the second quarter, Mobil Exploration and Producing U.S., Inc. (Mobil) provided data on Field 2, which LSU and subcontractors agreed to blind code. Amoco, a partner with Mobil in the same field, also contributed data on this same field. From this data, a third reservoir was chosen for detailed studies, Reservoir 3.

Modifications on two public domain computer reservoir simulators, BOAST II and MASTER, continued. Modifications to develop a code to handle steeply dipping oil reservoirs in the PC version of BOAST II were completed. The new PC version was renamed BOAST III. Modifications to BOAST III also include post-processing programs. BDM began the process of verifying both the BOAST III and MASTER (which had been previously modified in the year prior) models through comparison of model output to published model results for an attic gas injection process in a steeply dipping reservoir.

Modifications for a radial grid for use on near wellbore studies continued with good results in 2-D. Attempts to reproduce the results of small-scale 2-D experiments produced in the Department of Petroleum Engineering were successful. A paper was presented at the 1994 ACM Symposium on Applied Computing in Phoenix, Arizona, March 6-8, 1994 on these results.

Laboratory investigations continued but were slowed by several unforeseen incidences involving broken apparatus and inability to receive parts due to the California earthquake.

Introduction

The objective of this research is to assist in 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 currently 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 is permanently abandoned. Significant quantities of this oil could be recovered using advanced technologies now available if the resource can be identified.

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 these traps or the full extent of oil-bearing segments near the salt domes; therefore, substantial volumes of oil may have remained un-contacted 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 technological advances make it possible to reprocess existing seismic data to identify non-contacted portions of the reservoirs, which can then be contacted using advanced technologies such as drilling to kick out new wells from existing wells. Effective application of these technologies, along with improved recovery methods, offers opportunities to increase significantly Gulf of Mexico production, delay platform abandonments, and preserve access to a substantial remaining oil target for enhanced recovery and other advanced recovery processes.

This project will proceed under three broad phases: analysis, supporting research, and technology transfer.

In the analysis phase, 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 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.

During the final phase of the project 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 Description and Objectives

The objective of the project is to estimate the potential reserve additions that could result from the application of advanced secondary and enhanced oil recovery technologies and the exploitation of undeveloped and attic oil zones in Gulf of Mexico oil fields that are related to piercement salt domes. A task list follows.

1. Develop a detailed work plan. This plan will include detailed task assignments, scheduled outlines of data collection and field assessment methodologies, and integration of the laboratory work into reservoir simulation as well as TORIS model development efforts. This task will include the selection and orientation of a peer review committee and planning for the integration of the data collection efforts with the work being performed by the Texas Bureau of Economic Geology to develop a Gulf of Mexico oil and gas atlas.

2. Collect TORIS-level data. TORIS level reservoir data will be collected on the major oil fields in the piercement salt dome province offshore of Louisiana. This

data will be generated or extracted from data available through the Department of Interior Minerals Management Service, Louisiana Geological Survey, published operator case studies, and other available sources. It will be necessary to negotiate an interagency agreement to protect the confidentiality of the MMS data.

3. Modify public reservoir models. Readily available public reservoir simulation models (BOAST II and/or MASTER) will be modified to simulate accurately the conditions encountered in steeply dipping high permeability reservoirs. The modifications will also involve the development and integration of radial grid systems suitable for the investigations proposed in the project. The existing models will be evaluated, modified, and validated against commercial reservoir models.

4. Perform laboratory research. A program of laboratory research will be undertaken to study and develop fluid relationships that will be utilized in the reservoir simulation of miscible and immiscible processes in steeply dipping reservoirs. The investigations will focus on developing three phase-relative permeability relationships, defining minimum miscibility pressures for various injectants, defining critical velocities of gas front movement in gravity stable miscible displacement processes, and determining the impact of the various injectant gases on miscible and immiscible processes.

5. Develop TORIS predictive models. TORIS-level predictive models for miscible and immiscible processes and for undeveloped and attic oil zones in steeply dipping reservoirs will be developed. These models will be calibrated using the modified reservoir simulation models developed in Task 3 and the results of the laboratory investigations of Task 4. The methodology used in the modeling will be subject to peer review.

6. Characterize representative reservoirs. Selected representative reservoirs will be studied in detail in order to evaluate undeveloped and attic reserve potential. A detailed geological and reservoir characterization of these reservoirs will be performed using available geological, geophysical, and reservoir data, some of which will be provided by operators.

7. Define production potential. The production potential for undeveloped and attic oil zones in representative fields will be determined using material balance and reservoir simulation studies. The modified reservoir simulation models from Task 3 will be utilized in the reservoir simulation efforts.

8. Integrate and complete regional assessment of production potential. The results of the detailed geological and reservoir engineering studies of Task 6 and 7 will be integrated with the TORIS models developed in Task 5 for calibration purposes. Cost and economic data will also be integrated in the models.

9. Install TORIS models at BPO. The TORIS models developed by this research program will be installed at the Bartlesville project office. Economic parameters developed in Task 8 will be utilized to assess the recovery potential for the application of advanced secondary recovery and enhanced oil recovery processes and the exploitation of undeveloped and attic oil zones for salt dome reservoirs in the Gulf of Mexico. Documentation of the database development task, laboratory and simulation tasks, the detailed field analysis tasks, and the TORIS models will be prepared and presented as a summary report of the project.

10. Conduct technology transfer. This technology will be transferred to the industry through publications and a workshop.

Project Status

Data Collection

During the first quarter, to collect data from Minerals Management Service (MMS) in the most efficient and accurate manner, efforts were shifted from the 118 reservoirs that had more than 2.5 MMBLS reserves and which had been more than 60% produced. These reservoirs were large and incorrectly mapped. Instead, focus was placed on 208 sands in 46 fields which contained 1,289 reservoirs. This represents 60% of the original oil in place (OOIP) for the entire offshore Gulf of Mexico. Figure 1 illustrates the distribution of the OOIP in piercement salt dome fields by sand horizon. It shows that the most efficient target for an accurate description of the bypassed oil in the Gulf of Mexico is in the 208 sands containing 60% OOIP.

ICF Resources, Inc., a subcontractor on the project, first concentrated on data pertinent to Bay Marchand 2 field because this is the largest and most prolific field in the offshore Gulf Coast. Upon completion of the data collection for the Bay Marchand 2 field, ICF personnel began collecting data on South Marsh 73 field and other pertinent fields. Taylor Energy Co., the main operator of South Marsh 73 field, agreed to provide a substantial amount of data for the project. Therefore, efforts at MMS were coordinated with the Taylor data collection efforts. Figure 2 shows the unit of analysis and scope of data collected for the sands. MMS will provide, through DOE, the content of FRRE Database for the 1,289 reservoirs. ICF's on-site personnel will compile measurements of fault blocks from maps, data elements from MER and other hard copy files, and key reservoir properties from hard copy files.

LSU collected the Taylor data. LSU also collected data from other operators. ARCO Oil and Gas Co. has provided some excellent data on the South Pass 60 and 61 field areas. Amoco provided an information package for sands in Eugene Island 208 after obtaining approval from its partner, Texaco.

During the second quarter, Mobil Exploration and Producing U.S., Inc. (Mobil) provided data on field 2, which LSU and subcontractors have agreed to blind code. Amoco, a partner with Mobil in the same field, also contributed data on this same field.

During the third and fourth quarters, ICF completed its data collection from MMS. This data is now being put into the TORIS model. Any remaining data will be collected from several operators on an "as need basis."

Data Validation and Map Measurements

During the fourth quarter, maps collected at the MMS office in New Orleans were measured in order to verify and cross-check data in the FRRE database and to obtain reservoir size, shape, dip and relative well position data for use in TORIS process models. At this time, measurements of estimated salt diameter and updip areas are also being derived. Production data was read from the tapes obtained in New Orleans and reformatted for use in TORIS. Any errors in these tapes are being corrected.

Model Development

Conceptual work is in progress on the development of the models required to assess unrecovered oil, to continue primary recovery of existing mapped oil, updip attic oil recovery, and miscible and immiscible CO₂ injection recovery. Also, preliminary model designs have been tested against subsets of the data and model refinements are underway.

Supporting Cost Data Collection

Efforts have begun to supplement existing TORIS data with drilling, workover, and facility costs related to past enhanced oil recovery efforts in the offshore Gulf of Mexico area. Data on CO₂ sources was collected and byproduct CO costs were estimated for use in the economic model.

Data Analysis

Secondary recovery by downdip gas injection in steeply dipping oil reservoirs has been widely used successfully since the 1950's¹. Methane and nitrogen have been the primary gases used^{2, 3}. Reservoirs which had been subjected to this type of recovery or which had the potential to be subjected to this type of recovery were screened for detailed studies. Three reservoirs were identified which possessed the proper criteria and which had data available for detailed studies.

SOUTH MARSH ISLAND BLOCK 73 FIELD

LSU and BDM Federal, Inc. (previously BDM International, Inc.) (BDM), a subcontractor for the project, began analysis of data obtained from Taylor Energy on the South Marsh Island (SMI) Block 73 field in the Gulf of Mexico during the first quarter of 1993. The location of SMI 73 field is offshore Vermilion and Iberia Parishes, Louisiana, as Figure 3 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. Table 1 and Figure 4 summarizes the production history of these blocks. Structurally, the field consists of a piercement salt dome with its associated faults and shale-out trapping mechanisms. Figure 5 shows a structure map on top of the salt.

Two reservoirs, the B-35-K and B-65-G reservoirs, were identified from this data as having the proper characteristics for detailed studies. The analysis of the geology of the reservoirs included the review of all well histories, production, gas injection, and pressure data. BDM concentrated on the B-35 K reservoir, and LSU concentrated on the B-65 reservoir.

B-35-K Sand Reservoir

Initial efforts were placed primarily on the B-35 K Sand reservoir for several reasons. The data was easily accessible because Taylor Energy was also

reviewing this reservoir for possible gas injection. All other data were still in boxes and unorganized because of Taylor's recent purchase of the field from Exxon. Also, production from the B-35 K reservoir had exceeded the mapped reserves as a result of poor definition of either the up-dip limit or the original oil/water contact, or both. To date, recovery from the B-35 K reservoir represents 86% of the initially defined original oil in place. Volumetric analysis of this additional potential was performed to define a reservoir volume that resulted in a reasonable percentage recovery.

This reservoir also provided an opportunity to simulate attic gas injection, because numerous gas injection cycles were conducted. As mentioned earlier, the operator intends to conduct additional cycles. Therefore, the simulation was used to help define the following: optimum injection rate and volume, an anticipated shut-in time necessary for optimum gas migration, and a more accurate estimate of the up-dip oil volumes.

The B-35-K Sand Reservoir is located on the southeastern flank of the salt dome and has produced from four wells. Figure 6 shows a structure map of the reservoir; Figure 7 shows daily production rates; and Table 2 lists cumulative production by well. Relative permeability data was modeled initially after Combs and Knezek and Strickland and Morse¹¹⁻¹³. PVT data were taken from several empirical correlations described by Glaso, Beggs, Robinson, Sutton and Farshad¹⁴⁻¹⁷.

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 8 illustrates the grid layout of the simulation, while Figure 9 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. 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 appeared 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 because 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 10 through 13 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 14 through 18 are discussed below.

The first sensitivity test was conducted to evaluate the impact of gas injection rate on the incremental oil recovery. Figure 14 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 15 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 16 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 17 and 18 exhibit the results of injecting gas in stages and compare a 1-stage case with 2-stage and 3-stage injection cases. Figure 17 indicates that the 2-stage injection case produces more oil than the 1-stage or 3-stage injection cases. Figure 18 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. This duration contributed to the gas segregation phenomena, thereby contributing to the enhanced oil recovery with a lower associated water production rate than the 1-stage injection scenario had.

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. However, 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.

The draft of the final report on the B-35-K reservoir has been included at the back of this report. The draft is presently being circulated for review.

B-65-G Sand Reservoir

The B-65-G Sand reservoir in South Marsh 73 field, was chosen to be modeled for calibration studies because of its numerous gas injection cycles from different locales and its production longevity, also data for this reservoir is accessible.

Four wells were produced from the reservoir; three wells injected some quantity of gas, while one did not. A fifth down-dip well served as a primary gas injector with no production from this reservoir.

Material balance studies of this reservoir closely followed the techniques described by Havlena and Odeh^{18,19}, who described the material balance as an equation of a straight line. Table 7 tabulates the results of the material balance study. The material balance studies support the theory that the reservoir has a small gas cap and a moderate water drive. Figure 19 further supports these findings as a straight line with a y-intercept at 12 to 13 MMSTB of oil.

The reservoir model was developed by integrating geologic and engineering data. As Figure 20 shows, the reservoir is a long, north-south trending, steeply dipping sandstone that pinches out just before encountering a piercement salt dome. Structure and trapping are all results of the piercement salt dome. The sandstone produces in several reservoirs within the field, including two which are adjacent to the B-65-G reservoir. Because of differences observed in the bottomhole pressure histories of producing wells, it was believed that these two adjacent reservoirs are isolated from the B-65-G reservoir by faulting. This belief was later confirmed by computer simulation.

Furthermore, it was originally believed that the reservoir was subject to a fairly strong water drive. However, upon performing material balance studies, the reservoir was found to have a very weak and limited water drive. Also initially, the computer simulation of this reservoir was performed using a data set which did not contain a gas cap. While attempting to arrive at a history match, it was necessary to include a small gas cap. This was in agreement with material balance studies. Also, the up-dip volume of the reservoir had to be reduced substantially from the initial volume in order to obtain a history match. Overall, the simulation matched superbly with the results of the material balance work.

Reservoir characteristics are summarized in Table 8. The reservoir consists of approximately 7,000 acre-feet with an average net thickness of 27 feet. Porosity averages 28.5% and the original oil saturation was estimated at 75%. Material balance calculations and simulation work indicates that the reservoir was originally at its bubble point with a small gas cap and contained about 12 MMSTB of oil. Its original reservoir pressure was 3457 psi at -7351 feet subsea. Simulation work assumed that this original reservoir pressure was the bubble point.

The reservoir produced 6.2 MMSTB of oil, 3.4 BCF of gas (this accounts for all gas injected back into reservoir also) and 820 MBBLs of water over a period of 27 years. Table 9 illustrates the cumulative production and cumulative gas injection for the reservoir and each well.

As Figure 21 shows, the model consisted of 12 rows and 12 columns, oriented northeast-southwest over the reservoir. Grid block lengths averaged 425 feet and grid block widths averaged 224 feet. Grid block dimensions around the well bores were approximately 150 feet by 150 feet.

The sand was subdivided into three flow-unit layers. These flow-unit layers were defined by alternating layers of low and high permeability (alternating sand-shale sequences) as observed on electric logs. Initially, constant average values for porosity and permeability were assigned to each layer. Vertical permeability was taken to be 10% of the horizontal permeability. While attempting to obtain a history match, detailed modifications were made to these values. On average, the layers were 22 feet in gross thickness and 10 feet in net thickness. Figure 22 shows further.

PVT data and initial relative permeability curves used at the beginning of the simulation were based on values calculated using empirical methods as described earlier. These relative permeability curves were later slightly modified to obtain a history match.

Through history matching and predictive simulation runs, it has been shown that the gas injection cycles were very successful in moving attic oil down to be produced by the down-dip wells in the B-65-G reservoir in South Marsh Island Block 73 Field. No additional oil reserves are anticipated because of the conclusion that the reservoir initially had a gas cap and also, the performance of the wells. Only the remaining gas cap remains to be blowdown.

The study of this reservoir also indicates that BOAST III is able to accurately describe the history of a steeply dipping reservoir with a past gas injection project.

FIELD 2

Reservoir 3, Field 2

Evaluation included well log analysis, pressure and production data analysis, evaluation of PVT data, and development of preliminary model grid schemes. Well logs and log analysis were used to define the optimum layering for

the simulation. Subsequently, net sand isopach maps were prepared for each of these layers. 3-D geophysical data was used to define the structural interpretation for the geologic model. Proprietary material balance programs served in evaluating the production and pressure history of the reservoir. Through an iterative process, the optimum PVT properties were defined for the simulation. The material balance programs defined the aquifer size and strength and established the original oil in place value that was in agreement with the material balance work. A history match of this reservoir is almost completed. LSU and its subcontractors are working closely and simultaneously with Mobil in modeling this reservoir. All groups are presently reviewing results.

Predictive Modeling Phase

The determination of the methodology for the predictive modeling phase of the project is about 50% complete. The design of the blueprint began in February 1993, and the computer coding began in March 1993.

Modifications of BOAST II

BOAST III

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

Mainframe BOAST II

Separate modifications to the mainframe BOAST II code consisting of implementation of a radial grid system and inclusion of a gravity term also continue. 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. Modeling 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 recomplete 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 modeled 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 consumes 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 evolves. The use of FEM with adaptive refinement techniques should permit radial flow results near the well because of the fineness of the grid.

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 by Lance Hebert in the LSU Department of Petroleum Engineering for coning and sweep efficiency problems¹. When an agreement exists between the program and experimental results, the near well model will be added to BOAST II, and real field test simulations will be executed.

Figures 23 and 24 document the present calculated test results. Figure 23 shows oil (black) being produced and being replaced by water (white). Figure 24 shows oil (black) being pushed by water (white). Both Figures 23 and 24 present results that are reasonable. Although coning traces were produced similar to those in the Lance Hebert thesis, oscillations are still a problem. Testing on much simpler hypothetical problems produces oscillation-free results, but at the expense of heavy mesh refinement along the oil-water interface.

It is believed that extensive mesh refinement in the Hebert problem would also produce oscillation-free results, but calculations need to be quicker and memory requirements need to be reduced. Distribution of the workload and memory across a cluster of RS6000's has been accomplished, utilizing PVM for interprocess communication. On an 'unloaded' system, the speed-ups have been excellent. However, it is currently limited to four nodes on the cluster at a

time, usually sharing the nodes with other users, so it is difficult to achieve any speed-up under these conditions. It is anticipated that the code will be ported to a 128-node Cray T3D later in the spring for testing in an MPP environment. The parallel version of the code is suitable for 1, 2, and 3D problems using static meshes.

Currently, the implementation of our dynamic mesh routines on the parallel architectures is being studied, recognizing the fact that efficient load-balancing will become a major issue. Much of the work from the past few years is being compiled as a doctoral dissertation. Parts of the dissertation, particularly parallel implementation, are intended for publication. A paper was presented at the 1994 ACM Symposium on Applied Computing in Phoenix, Arizona, March 6-8, 1994 on these results²². A copy of this paper has been included in the Appendix. Testing of this method on areal sweep efficiencies is continuing and should be completed soon.

MASTER Modification

LSU and BDM have modified the MASTER reservoir simulation model for use in simulating miscible gas injection processes in steeply dipping reservoirs. The simulation code has been modified to include the dip feature, and the program has been successfully installed and operated on in-house PCs. BDM began the process of verifying the model by comparing the model output to published model results for an attic gas injection process in a steeply dipping reservoir. The model is also being tested within the industry. Results of this test have not been completed.

Attic Oil Critical Parameters

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. A delay arose with the delivery of a valve from a company in California due to an earthquake.

Planned Activities

Planned activities include completing TORIS database and modeling work; finishing write-ups on detailed reservoir studies; completing laboratory work and implementation into TORIS model; and completing all remaining deliverables of the project.

Summary

During March 1993, ICF continued data collection with Minerals Management Service (MMS). LSU also continued collecting data from several operators and modifying BOAST II for both the integration of radial grid systems and the building of the experimental apparatus designed for studying the recovery of attic oil. BDM continued modifying the MASTER reservoir simulation model for use in simulating miscible gas injection processes in steeply dipping reservoirs. In addition, a meeting was held between LSU, BDM, and ICF to discuss progress.

During April and May 1993, ICF continued data collection with MMS. LSU and BDM began the analysis of data obtained from Taylor Energy in South Marsh 73 field. A meeting was also held with representatives from Mobil Exploration and Producing U.S., Inc. (Mobil), BDM, ICF, and LSU to discuss obtaining data from Mobil. In addition, Amoco Production Company agreed to provide data to the project.

During June 1994, the production and pressure history for Taylor Energy's B-35K reservoir in South Marsh Island 73 field was matched. Several simulations were then run to refine the history match of the reservoir performance and to predict the incremental oil production which could result from future gas injection into the reservoir. Mobil Exploration and Producing U.S., Inc. (Mobil) agreed to provide data from one of their fields. Amoco Production Company provided data on their Eugene Island 208 field.

During July 1993, data collection from MMS continued and was 90% complete. Mobil provided data on one of their fields, Field 2, which LSU and subcontractors have agreed to blind code. Amoco, a partner with Mobil in the same field, also

contributed data. Material balance and computer simulations studies of the B-65-G Sand reservoir in South Marsh 73 field continued. Modifications to BOAST for modeling steeply dipping reservoirs were successfully implemented into the PC-based BOAST II program. The modified PC program, BOAST III, was then and still is being used to model the Taylor reservoirs. Separate modifications to the mainframe BOAST II code also continued. 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.

During August 1993, data collection from MMS continued and was 95% complete. Work continued on Field 2 and South Marsh Island 73 Field. Reservoir 3 of Field 2 was selected from Mobil's data for detailed study.

During September, 1993, data collection from MMS was completed. Data collection from operators was 95% complete. Remaining collection concerned general trend input and statistical data. Data analysis continued on Reservoir 3 in Field 2. Material balance and computer simulations studies of the B-65-G Sand reservoir in South Marsh 73 field continued. A rough history match was obtained on the reservoir. Work continued on refining the match for use in predictive runs. Modifications to BOAST continued with no unforeseen problems or delays. An abstract was submitted and accepted by the SPE/DOE EOR Conference to present some of the research findings. The apparatus for experiments for the study of attic oil recovery techniques was being tested. Modifications to MASTER continued with no unforeseen problems or delays.

During October 1993, analysis continued on Reservoir 3 in Field 2. The input dataset continued to be generated. All data was input and initial history match runs were conducted. Material balance and computer simulations studies of the B-65-G Sand reservoir in South Marsh 73 field also continued.

During November 1993, statistical data concerning successes, failures, and observations with 3-D seismic was obtained from several industry companies, including Amoco, Chevron, Mobil, and Texaco. Analysis continued on Reservoir 3 in Field 2. Attempts to history match continued. A history match was obtained for the B-65-G Sand reservoir in South Marsh 73 field.

During December 1993 and January 1994, a reasonably close match of the historical oil, water, gas, and pressure was achieved for Reservoir 3 of Field 2, but additional simulation runs need to be conducted. Material balance and computer simulations studies of the B-65-G Sand reservoir in South Marsh 73 field also continued. A copy of a modified copy of the PC version of BOAST II, BOAST III, was being validated against a proprietary industry simulator at this time. Modifications to MASTER have been completed and are currently undergoing testing.

During February 1994, a draft of documentation of the match results for Reservoir 3 in Field 2 were circulated to the operator and others for review. Documentation for the simulation of the B-65-G Sand reservoir in South Marsh 73 Field was also being prepared. A paper was presented at the 1994 ACM Symposium on Applied Computing in Phoenix, Arizona, March 6-8, 1994, on the results of some of the BOAST modifications. Experiments for the study of attic oil recovery techniques began. A delay arose with the delivery of a valve from a company in California due to an earthquake.

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FIGURES

Selection of Fields/Sands/Reservoirs

Figure 1

Unit of Analysis and Scope of Data Collection

Figure 2

LOCATION OF SMI BLOCK 73 FIELD IN THE GULF OF MEXICO

FIGURE 3

SMI 73 FIELD PRODUCTION HISTORY

FIGURE 4

STRUCTURE MAP ON TOP OF SALT FOR SMI 73 FIELD

FIGURE 5

SMI BLOCK 73 FIELD: B-25 SAND STRUCTURE MAP

FIGURE 6

DAILY PRODUCTION RATES FOR B-35K RESERVOIR

FIGURE 7

RESERVOIR SIMULATION GRID SCHEME

FIGURE 8

RESERVOIR SIMULATION LAYERS AND DATA

Well A-3ST		Layer	Average Thickness (ft)	Porosity (%)	Water Saturation (%)	Permeability (md)	
Gamma Ray	SP	Resistivity					
B-35 Sand	6300						
	6332						
	(5846ss)						
	Layer 1	1	11	33	18.5	1440	
		Layer 2	2	5	29	24.7	570
		Layer 3	3	6	32	20.5	1125
	6100						

FIGURE 9

FINAL HISTORY MATCH OF RESERVOIR PRESS.

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

FIGURE 10

FINAL HISTORY MATCH OF CUM OIL PROD.

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

--- SIMULATION — ACTUAL

FIGURE 11

FINAL HISTORY MATCH OF CUM GAS PROD.

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

--- SIMULATION — ACTUAL

FIGURE 12

FINAL HISTORY MATCH OF CUM WATER PROD.

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

FIGURE 13

GAS INJECTION RATE SENSITIVITY ANALYSIS

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

FIGURE 14

POST-INJECTION SHUT-IN TIME SENSITIVITY

(150 MMCF @ 500 MCFD, 1 STAGE)

FIGURE 15

INCREMENTAL OIL PROD DUE TO GAS INJECT

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

FIGURE 16

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

FIGURE 17

INJ. VOLUME STAGING SENSITIVITY ON H2O

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

FIGURE 18

SOUTH MARSH 73 FIELD
B65G SAND—assuming water drive

FIGURE 19

FIGURE 21

B-10 WELL

FIGURE 22

FIGURE 24

TABLES

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:	67 276 46	million Bbl Oil billion scf Gas million Bbl Water
Taylor Blocks:	45 36	million Bbl Oil 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 INFLUX 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:

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

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
Zero			213				
Three							
1 Stage	203	212	219	236	227	226	229
2 Stage			225	238			
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, produce for 6 months; inject the remaining volume, shut-in for 3 months then produce to a WOR of 1.5.

Table 8

South Marsh Island Block 73 Field

B-65-G Reservoir Characteristics

Original Reservoir Pressure -----	3457 psi
Datum -----	7351 feet subsea
Average Porosity -----	29.5%
Original Water Saturation -----	23%
Average Thickness -----	27 feet
Areal Extent -----	260 acres
Average Horizontal Permeability -----	620 md
Average Horizontal/Vertical Permeability Ratio -----	0.1
Initial Gas-Oil Ratio -----	867 SCF/STB

Table 9

South Marsh Island Block 73 Field

B-65-G Reservoir Production Summary

<u>Well</u>	<u>Oil-MSTB</u>	<u>Gas-MMCF</u>	<u>Water-MBbls</u>	<u>Gas Inj.-MMCF</u>
B-1	1825	2086	259	654
B-7	1020	1576	0.9	0
B-10-D	1325	792	220	11
B-12	2037	3980	341	1,348
B-15	0.0	0.0	0.0	732
<hr/>				
Total	6,207	8,434	821	2,745

APPENDIX

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**SOUTH MARSH ISLAND BLOCK 73 FIELD
RESERVOIR SIMULATION STUDY
B-35 SAND, RESERVOIR K
Assist in the Recovery of Bypassed Oil
From Reservoirs in the Gulf of Mexico
October 31, 1993**

**Contract Number: DE-AC22-92BC14831
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BDM FEDERAL, INC.

**South Marsh Island Block 73 Field
Reservoir Simulation Study
B-35K Sand, Reservoir K**

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1.0 ABSTRACT

This report documents the results of a detailed study of a Gulf of Mexico salt dome-related reservoir and the application of a publicly available PC-based black oil simulator to model the performance of a gas injection process to recover attic oil. This work was performed by BDM Federal, Inc. in support of the Louisiana State University Bypassed Oil Study, which is funded by the U.S. Department of Energy (DOE contract number DE-AC22-92BC831). The overall objective of the LSU research project is to assess the oil reserve potential that could result from the application of proven technologies to recover bypassed oil from reservoirs surrounding piercement salt domes in the Gulf of Mexico.

The objective of this reservoir simulation study was to develop a detailed calibration case for use by the project team in the assessment of the oil recovery potential for Gulf of Mexico salt dome reservoirs. The specific study objective was to simulate the primary recovery and attic gas injection performance of the subject reservoir to: 1) Validate the BOAST Model, 2) quantify the attic volume, and 3) predict the attic oil recovery potential that could result from additional updip gas injection.

The simulation study was performed on the B-35K Reservoir in the South Marsh Island Block 73 Field utilizing data provided by one of the field operators, Taylor Energy, a New Orleans based independent operator. A detailed reservoir study was conducted on this reservoir

to define the parameters required to simulate the reservoir performance. A modified PC-version of the BOAST II model was utilized to match the production and injection performance of this reservoir in which numerous gas injection cycles had been conducted to recover attic oil. The historical performance of the five gas injection cycles was accurately matched and numerous predictive runs were made to define additional potential for attic oil recovery using gas injection. Predictive sensitivities were conducted to examine the impact of gas injection rate, injection volume, post-injection shut-in time, and gas injection cycle staging on oil recovery.

1.1 Introduction

This report presents the results of the simulation study of the Taylor Energy B-35K Reservoir in the Gulf of Mexico South Marsh Island Block 73 Field. Section 2.0 is an overview of the field and reservoir history and includes discussions of the field and reservoir geology, the reservoir production history, reservoir and geologic data, and original oil-in-place calculations. Section 3.0 is an overview of the BOAST model and includes discussions of the model capabilities and enhancements which have been made. Section 4.0 addresses the development of the simulation input data and includes discussions of the simulation grid, specific reservoir parameters, aquifer influx and productivity index calculations, production constraints used in the model, the treatment of recurrent data, and other simulation assumptions. The history match process is presented in Section 5.0 and the results

of the predictive analysis is presented in Section 6.0.

2.0 FIELD AND RESERVOIR HISTORY

2.1 Field Development History

The South Marsh Island (SMI) Block 73 Field is located approximately 77 miles south of Intercoastal City, LA in 135 feet of water in the Gulf of Mexico (see Figure 1). The field was discovered in 1963 by Exxon with the drilling of the #1 Well on SMI 69. Several other exploratory wells were drilled by Exxon and Shell on this block and the surrounding blocks (see Figure 2). The field was subsequently developed by Shell (SMI 57 and 58) and Exxon (SMI

69, 72, and 73). Production from the field was initiated in 1964, and over time, a total of eight platforms were set and over 100 development wells were drilled. Taylor Energy purchased the Exxon interest in SMI Blocks 69, 72, and 73 in 1993 and assumed operatorship. (See Figure 3.)

The field is predominantly oil productive and production peaked in 1971 at a rate of 16,900 BOPD and 68 MMCFD. The field is currently producing almost 2,000 BOPD, 5 MMCFD and 2,600 BWPD (see Figure 4). Cumulative production from the field as of 1/1/92 totaled 67 million barrels of oil (MMBO), 276 billion cubic feet of gas (BCF), and 46 million barrels of water (MMBW). The gas from the field has not been sold, rather the gas has been

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Figure 1. Location of South Marsh Island Block 737 Filled in the Gulf of Mexico

Figure 2. Structure Map on the Top of Salt for South Marsh Island 73 Field

Discovery:	1963 (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

5276-02

Figure 3. South Marsh 73 Field Production Statistics

5276-06

Figure 4. South Marsh Island 73 Field Production History

used for fuel or reinjected to improve oil recovery. The cumulative production from the Taylor blocks totals 45 MMBO and 36 BCF.

2.2 Field and Reservoir Geology

The SMI 73 Field is established by the simple piercement salt dome structure, as shown in Figure 2. The dome is relatively circular in shape, with a small area of overhang at the southeast corner. The present-day top-of-salt is approximately 364 feet below mean sea level. This dome formed in relatively shallow water, with salt movement having been initiated prior to the deposition of many of the key reservoir units. Sedimentation continued during the movement of the salt. The source for the main reservoir sands was apparently predominantly from the north and east. Drilling has been concentrated on the northern, eastern and southeastern portions of the structure, with twenty-five Miocene- and Pliocene-age sands being productive from more than sixty reservoirs around those sides of the dome. Exploratory drilling on the western side of the structure indicates that that area was on the lee side during deposition, and was sheltered from most of the sand-laden currents. Production has been established at depths between 5,000 and 11,500 feet. The rate of sediment influx appears to have been low and the material very fine-grained during the deposition of most of the key reservoirs, with sands having been limited to deeper-water areas around the growing dome, and shale having been deposited atop the structure in a more-or-less starved environment. This

helps to account for the facts that many of the reservoirs pinch out updip, toward the salt, and that most of the dome is wrapped in a shale sheath.

The key reservoir in this study is the B-35 K Sand, shown in Figure 5. This is a typical sand for the SMI 74 Field. The sand is relatively widespread around the southeastern flank of the dome, with a thickness, downdip, of 40 feet or more. Toward the salt, the sand begins to steepen, eventually pinching out to shale near the salt. Numerous faults radiate out from the salt, cutting the sands into discreet reservoirs. The study area is isolated on the east and west ends by two sealing faults, each with 150 to 200 feet of throw. Exxon had initially identified and interpreted the geology of this block using a series of older, 2-D, seismic lines. The B-35 K Reservoir was originally developed with a series of five wells. This gave limited control for a geologic interpretation. Four wells from the A platform cut the sand and provided isopach data. The C-6 well, however, penetrated the projected sand updip from the other wells and encountered shale at the position of the B-35 zone.

Based on the seismic data and a conservative interpretation of the shale-out position, Exxon developed a reservoir model for the B-35 reservoir. To determine the downdip oil limit, they used an arbitrary 100-feet-below-the-lowest-proven-oil standard to set a hypothetical oil-water contact. Exxon also mapped a small fault that seem to show up on the 2-D seismic data, thus compartmentalizing the B-35 K into

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Figure 5. South Marsh Island 73 Field B-35 Sand Structure Map

two separate reservoirs. The fault was assumed to be sealing.

Figure 6a shows the B-35K Reservoir net sand isopach contours, the internal fault, and the shale-out line, as mapped by Exxon. BDM conducted a detailed analysis of the production histories of the wells and of the reservoir pressure over time. The data and analyses did not support the concept of an internal fault in the center of block. No direct evidence for the fault could be found. The original seismic data were not available and the well logs did not show the sort of missing or duplicated geologic sections that would be expected in wells which penetrate fault zones.

Based on the actual reservoir performance, the geologic model was reinterpreted (Figure 6b). The internal fault was removed. If such a fault exists, offsets appear to be minor, and the fault is apparently not sealing, making it irrelevant, in model terms. The updip limit of the sand was extremely conservative, originally, and required an unnatural pinching together of the contours in the updip area. This left a large potential attack reservoir volume above the original shale-out line, which could help to explain the overproduction from this reservoir. Moving the pinchout line updip, closer to the C-6 control point made the thinning-rate of the sand appear much more normal, and fit the production model quite well. In the downdip direction, the oil-

a) Original Interpretation

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b) Revised Interpretation with Attic volume addition

Figure 6. B-35K Reservoir Net Sand Isopachous Map

water contact was analyzed, and adjusted slightly, to better fit the actual well production histories.

The geologic interpretation and reservoir engineering analysis were used synergistically by BDM engineers and geologists in this project to identify a model which much better fit the evidence and data available, and which provided a much closer fit to the actual production information for the B-35K Reservoir.

2.3 B-35K Reservoir Production History

Production from the B-35K Reservoir was initiated in October of 1966 from the A-1 Well and the short string completion of the dually-completed A-3 Well (Well A-3D). Well A-3D produced until July of 1971 when the well was reworked and put on production as a single completion in the B-35K Reservoir. Well A-3 produced from March 1972 through November 1982, when the well was shut-in due to sanding problems. In June 1983 the B-35K completion in the A-3 Well was abandoned and the well was side-tracked and completed as a producer in the deeper D-5 Sand. The cumulative Well A-3D/A-3 production from the B-35K Reservoir totaled 1.2 MMBO, 530 MMCF, and 69,000 BW. Well A-1, which is located downdip of Well A-3 in the B-35K Reservoir, watered-out in October of 1971, with cumulative production of 394,000 BO, 193 MMCF, and 43,000 BW. Well A-6D produced from the B-35K Reservoir from October 1966 through May 1976 when the well watered-out

and was recompleted as a single producer in the deeper D-5 Sand. Cumulative production from Well A-6D totaled 1.4 MMBO, 739 MMCF, and 86,000 BW. The cumulative production for the B-35K Reservoir totals 3.0 MMBO, 1.5 BCF, and 198,000 BW. The B-35K Reservoir production history is displayed in Figure 7 and the production history for the individual wells are displayed in Figures 8 through 10. The cumulative production data are shown in Table 1.

In 1992, the A-6 well was recompleted and tested in the B-35K zone, which came on initially with 100% oil and immediately went to water. This well is the only active well in the B-25K Reservoir. Taylor is planning to inject gas into this well and then produce additional attic oil from this well.

2.4 B-35K Reservoir Gas Injection History

During the productive life of the B-35K Reservoir, five attic gas injection cycles were conducted on the A-3D/A-3 Well to improve the oil recovery from the reservoir. The injection of gas into the attic of the reservoir resulted in the recovery of additional oil by causing the oil-water contact to move downdip, away from the producing wellbores. Water free production was realized until the oil-water contact moved back up to the producing wells. The success of these gas injection cycles is readily apparent from the data, although wellbore mechanical problems influenced the results of some of the gas cycles. A total of 452 MMCF of gas

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Figure 7. Daily Production Rates for B-35K Reservoir

DAILY PRODUCTION RATES FOR WELL A-1
B-35 SAND

5276-06

Figure 8. Production History for SMI 73 Well A-1

DAILY PROD. RATES FOR WELL A-3D/A-3
B-35 SAND

Figure 9. Production History for SMI 73 Well A-3D/A-3

DAILY PRODCUTION RATES FOR WELL A-6D
B-35 SAND

Figure 10. Production History for SMI Well A-6D

TABLE 1. CUMULATIVE PRODUCTION FOR THE 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	452
A-6D	1,446	739	86	—
Total	3,024	1,462	198	452

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was reinjected into the reservoir, which resulted in the incremental recovery of 1.2 MMBO, or 2,191 BO/MMCF. The results of the gas injection cycles are indicated in Figure 7 and are summarized in Table 2. The results of the attic gas injection cycles were generally favorable and additional cycles would undoubtedly be beneficial.

2.5 B-35K Reservoir Parameters and Geologic Data

The SMI 73 B-35K Reservoir is located on the southeast flank of the piercement salt dome feature at a depth of about 5,800 feet subsea. The average net thickness of the oil column is approximately 22 feet, and the sand shales-out in the updip direction and thickens in

the down-dip direction. The average porosity in the reservoir is 29.5%, the water saturation is 16.5%, and the permeability is 1,150 millidarcies. The reservoir exhibits an active natural water drive and it is believed that the reservoir was initially at saturated conditions with no initial gas cap. The initial reservoir pressure was estimated at 2,712 psia and the pressure history is shown in Figure 11. This pressure performance indicates the presence of a strong water drive in the reservoir.

None of the development wells which penetrated the B-35K Reservoir encountered an oil-water contact, so the exact location of the contact is unknown. The A-1 Well encountered oil at the lowest structural point in the reservoir, and the down-dip A-6 (#2 Sidetrack)

TABLE 2. B-35K RESERVOIR GAS INJECTION HISTORY SUMMARY

GAS INJECTION DATES	INJECTION VOLUME (MMCF)	INCREMENTAL OIL RECOVERY (1,000 BO)	RECOVERY PER MMCF (BO/MMCF)
12/69 - 05/70	32	59	1,845
04/71 - 07/71	239	866	3,264
08/76 - 11/76	106	38	353
09/80 - 11/80	46	11	241
09/81 - 11/81	29	17	580
TOTAL	452	1,184	2,191

Pressure History For B-35K Reservoir
Pressure Versus Time

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Figure 11. Pressure History for the B-35K Reservoir

was wet in this zone, as shown in Figure 5. So, the location of the oil-water contact is somewhere between these two structural levels. Likewise, the exact updip limit of the reservoir is unknown. The A-3 (Sidetrack) encountered oil at the highest structural position in the reservoir, but at the updip location of Well C-6, the sand is completely shaled-out. Thus, the updip limit of the reservoir lies somewhere between these two structural points (see Figure 6).

2.6 Original Oil-In-Place Calculations

The average reservoir properties were utilized along with the net pay isopachous maps to calculate three volumetric original oil-

in-place (OOIP) values for the B-35K Reservoir, as summarized in Table 3. The first OOIP calculation is the "Proven Oil Limit" case, which assumes that the shale-out is above the highest take point in the reservoir and that the oil-water contact is just below the lowest take point. This conservative case yields an OOIP of 3.5 MMBO, which means that recovery to date equals 86% of the OOIP. This recovery value is unreasonably large, meaning that the OOIP must be higher. If it is assumed that the oil-water contact is 100 feet below the low proven point, then the OOIP increases to 7.3 MMBO, and the percent recovery decreases to 41% of the OOIP. If it is assumed that the sand gradually thins in the updip direction to a zero value at the C-6 well, then the OOIP increases by 1.3 MMBO to 8.6 MMBO,

TABLE 3. SUMMARY OF ORIGINATE OIL-IN-PLACE CALCULATIONS

CASE	Acre-Feet	OOIP Million BO	Percent Recovery
Proven Oil Limit	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 of 6137 Feet and Updip Potential	4,247	6.3	48%
Assumptions: Porosity = 29.5% Water Saturation = 16.5% 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			

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reducing the recovery value to 35% of the OOIP. Also shown in this table is the original oil-in-place for the final model history match case, where the original oil-water contact was assumed to be at -6,176 feet subsea. The OOIP for this case is 6.3 MMBO and the recovery value is 48% of the OOIP.

2.7 Summary

The South Marsh Island B-35K Reservoir appears to be a candidate for additional gas injection cycles to recover attic oil that could not otherwise be recovered. The highest structural well has watered out due to the active water drive. The updip or attic oil volume, the volume above the highest well, is unknown as is the location of the original oil/water contact. Previous gas injection cycles have successfully recovered attic oil. The remaining question is whether additional attic oil can be recovered through gas injection. The development of a numerical simulation that accurately matches the historical performance of the B-35K Reservoir should provide reasonable predictions of the performance which could be achieved through additional gas injection cycles.

3.0 OVERVIEW OF BOAST3-PC

BOAST3-PC is a Black Oil Applied Simulation Tool used routinely for performing evaluation and design work in modern petroleum reservoir engineering. In 1982 the U.S. Department of Energy released the original black oil model called BOAST.

BOAST II, released in 1987, was designed to provide more flexibility and to overcome some of the limitations of the original BOAST. Many features were added to improve the versatility of the model.

BOAST3 is a modified, PC-version of BOAST II. It is more efficient and is designed to run in a 386/486 PC-based environment. As a result of streamlining the code and using a 32-bit Fortran compiler, BOAST3 is 3.7 times faster than BOAST II.

BOAST3 simulates isothermal, darcy flow in three dimensions. It assumes reservoir fluids can be described by three fluid phases (oil, gas, and water) of constant composition with physical properties that depend on pressure only. This PC version of BOAST is limited by a maximum grid dimension of 20x20x21 in the X, Y, and Z- directions.

BOAST3 has a wide range of applicability. It can simulate oil and/or gas recovery by fluid expansion, displacement, gravity drainage, and capillary imbibition mechanisms. Some of the typical field production problems which can be handled by BOAST3 include but not limited to:

- Primary depletion studies.
- Pressure maintenance by water and/or gas injection.
- Evaluation of waterflooding operations.

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BOAST3 is a finite-difference, implicit pressure/explicit saturation (IMPES) numerical simulator. It has the option for both direct and iterative solution techniques for solving systems of algebraic equations. The main features of BOAST3 are exhibited in Figure 12. The following outlines the various features/options of BOAST3 model:

- Option for simulating steeply dipping reservoirs
- Multiple rock and PVT regions
- Bubble point tracking scheme
- Automatic time step control method
- Material balance check on solution stability
- Multiple wells per grid block

- Option for rate or pressure constraints on well performance

In addition, BOAST3 includes two post processors: B3PLOT and COLORGRID.

B3PLOT is a line graphics package used to plot production, pressure, saturation and other data vs time. It has two basic modes: (1) plotting simulated data, and (2) history matching. In mode (1), results from five different simulation runs may be compared. In mode (2), historical data may be history matched using oil, water, or gas production, GOR, or WOR. Also, average reservoir pressure or bottomhole well pressure may be matched.

- Designed to run in a 386/486 PC-based environment (3.7 times faster than BOAST II)
- Three dimensional, three phase flow model with a wide range of applicability to simulate oil and/or gas recovery by:
 - Fluid expansion
 - Displacement
 - Gravity drainage/dipping reservoir option
 - Capillary imbibition
- BOAST3 is a finite-difference, implicit pressure/explicit saturation (IMPES) numerical simulator
- Multiple rock and PVT regions can be defined
- Three different aquifer models are available as options
- Maximum grid dimension limits: 20x20x21
- Plotting package— two post processors B3 PLOT and Colorgrid

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Figure 12. Overview of BOAST3 Model Features

COLORGRID is used to view the finite-difference grid on the screen in plan or elevation view. The grid is colored based on the range of the parameter selected. Various arrays (maps) of input or output data may be represented by a 12-band color legend. An annotation option is provided which displays the numerical values of the parameter selected within each grid block. Any portion of the grid may be expanded to fill the entire screen.

4.0 MODEL INPUT DATA ANALYSIS

The data required to perform the modeling study using BOAST3-PC were very extensive. Most of the data were provided by Taylor Energy (as discussed earlier) which included reservoir pressure data and a production history (oil, gas, and water production) over the life of the reservoir.

Geophysical well logs were provided and analyzed for porosity and water saturation values and were used as input values for the model. In addition, core data were analyzed to predict the permeability of the different zones/layers within the B-35 sand reservoir as interpreted by BDM's geologists.

The following sections will analyze the different reservoir input parameters and will discuss the basis for the assumptions made in order to perform the simulation study. It is important to mention that Taylor Energy's field data set was incomplete in terms of the requirements/ needs

for modeling the reservoir. Therefore, to meet the model requirements, several assumptions were made based on similar producing reservoirs, field histories, and published data.

4.1 Reservoir Model Grid Dimensions and Geometry

A 14 X 11 X 3 grid was generated and superimposed on the structural map for elevation readings and the isopach map to read thickness values for each of the grid blocks. The elevation values were read at the midpoint of each grid block. Using the elevation values, an angle of inclination (Alpha) greater than zero for downward dip in the x-direction was computed by the simulator. Figure 13 exhibits the grid used for simulating the B-35 sand reservoir. The option of reading a depth value for each grid block in layer one (part of the input data set) was exercised. The elevations to the midpoints of the grid blocks in layers two and three were computed by the simulator using the elevations of the grid blocks in layer one and the thickness values for layers two and three.

4.2 Porosity, Water Saturation, and Permeability Distribution

BDM was supplied with geophysical well logs and sidewall core data to assist in evaluating the reservoir parameters in terms of porosity, water saturation, and permeability.

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Figure 13. Reservoir Simulation Grid Scheme

After reviewing the geology and core data, it was determined that a three layer model can describe the B-35 sand reservoir. The top and bottom layers had high permeability values and were separated by a shaley streak with a much lower permeability. The geophysical well logs when evaluated revealed porosity and water saturation values that are comparable to Gulf of Mexico reservoirs. Figure 14 summarizes the results of the log analysis and lists the estimated thickness, porosity and water saturation for each layer.

The core analysis performed on well A-3D/A-3/A-3ST generated a list of permeability versus porosity values at different depths. A plot of these data was generated with a best-fit

curve as exhibited in Figure 15. Values of average permeability per layer were read from Figure 15 for each porosity value determined from the geophysical well log interpretations. As exhibited in Figure 14, both layer one and layer three were separated by a thin lower permeability layer. Using this geological interpretation, BDM assumed a constant thickness per block of five and six feet for layers two and three respectively. The thickness of each grid block in layer one was calculated by subtracting the sum of the thicknesses of layers two and three from the value of total net thickness values obtained from the modified isopach.

Figure 14. Reservoir Simulation Layers and Data

Figure 15. Correlation of Porosity Versus Permeability

4.3 Relative Permeability Curves

BOAST3-PC requires relative permeability curves as part of the input data set to simulate the three-phase flow of oil, gas, and water in the reservoir. The nonavailability of measured relative permeability data from the Taylor field dictated the need to use available published data representing similar reservoirs. Published relative permeability data derived from the "Gas Injection For Upstructure Drainage", JPT, October 1979 publication, were used for simulating the reservoir. Figure 16 exhibits the relative permeability curves derived from this publication. Early history match simulation runs indicated the need to modify the relative permeability data. Figure 17 illustrates the modified relative permeability curves used to arrive at a final history match of the actual pressure and production data.

The results of the early simulation runs, illustrated that the relative permeability curves are critical data elements in terms of impact on simulation performance. Unfortunately, relative permeability curves are often among the missing or poorer quality data. Relative permeability data are affected significantly by alterations in wettability conditions in the core. In principle, three-phase relative permeabilities should be used when oil, water, and gas are flowing simultaneously. As a practical matter, the difficulty of accurately measuring three-phase relative permeabilities often makes their use meaningless. It is often sufficient to work with

two-phase relative permeability curves only. For this study, BOAST3-PC exercised the option for computing a three-phase oil relative permeability curve using water-oil and gas-oil relative permeability curves.

4.4 PVT Data Analysis

Part of the input data set required to run BOAST3 and simulate oil recovery is a set of PVT data representative of the fluid properties that reflects the inter-relationship among the various reservoir/fluid properties.

In the case of the Taylor field study, PVT data were not available for modeling, history matching, and predicting the reservoir performance. On the other hand certain initial reservoir and fluid properties were recorded in the early life of the reservoir.

The need to derive a set of PVT data using the initial reservoir conditions required the evaluation of several empirical PVT correlations for application in the Gulf of Mexico (Evaluation of Empirically Derived PVT Properties for Gulf of Mexico Crude Oils, R.P. Sutton, SPE#13172). These correlations were used to determine values for bubble point pressure, solution gas-oil ratio, formation volume factor, and viscosity. The various correlation techniques were reviewed and tested. The appropriate equations used to develop the results are exhibited in the appendix of SPE paper #13172.

Figure 16. Relative Permeability Curves

Figure 17. Modified Relative Permeability Curves

The bubble point pressure was estimated by constructing a plot of reservoir voidage versus reservoir pressure, as shown in Figure 18. From this plot, the bubble point pressure was estimated to be 2,723 psig.

Glaso's method was used for bubble point pressure, oil formation volume factor, and solution gas-oil ratio and dead oil viscosity correlations. Furthermore, it was determined that the Calhoun correlation can best explain the oil compressibility which is dependent on the bubble point pressure estimate. The Vasquez and Beggs correlation was used to derive the viscosity of the undersaturated oil. Table 4 tabulates the results of the empirically derived PVT data using the different correlation methods.

4.5 Aquifer Model

In order to model the actual reservoir behavior, it was very critical to simulate the aquifer which was contributing to the production performance of each of the producing wells in the reservoir.

To simplify the solution methods and to account for the aquifer strength in terms of the water influx, a steady-state aquifer option was exercised to essentially maintain a constant reservoir pressure.

A spreadsheet was developed to compute the water influx (W_e) for an undersaturated oil reservoir with a water drive using initial

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Figure 18. Reservoir Voidage Versus Pressure for B-35K Reservoir

TABLE 4. PVT DATA SUMMARY TABLE

SOLUTION GOR & BUBBLE POINT

PRESSURE CORRELATION (GLASO'S)

Pb, psig	Pb*	Rs
3000.00	17.85	546.08
2900.00	17.25	523.70
2800.00	16.65	501.69

2700.00	16.07	480.06
2600.00	15.48	458.79
2500.00	14.91	437.89
2400.00	14.33	417.34
2300.00	13.76	397.14
2200.00	13.20	377.28
2100.00	12.64	357.76

2000.00	12.08	338.57
1900.00	11.53	319.72

COMPRESSIBILITY CORRELATION(CALHOUN)

Gob	Pb	COMPRES
0.71	2723.00	1.20E-05

DEAD OIL VISCOSITY CORRELATION(GLASO'S)

TEMP, oF	API	VISC, cp
146.00	34.30	2.588

GAS SATURATED OIL VISCOSITY(BEGGS& ROBINSON)

Rs	Mod	a	b	Mob
480.00	2.588	0.404	0.616	0.726

OIL FORMATION VOLUME FACTOR(GLASO'S)

Rs	Bob*	Bob
480.00	540.23	1.20

PRESS, PSI	Bo
2808.00	1.2035
2800.00	1.2024
2700.00	1.2038
2600.00	1.2053
2500.00	1.2067
2400.00	1.2082
2300.00	1.2096
2200.00	1.2111
2100.00	1.2125
2000.00	1.2140

UNDER SATURATED OIL VISCOSITY

(VASQUEZ & BEGGS)

Mob =	0.726
Pob =	2723.00

PRESS	m	Mo
3000.00	0.27	0.745
2900.00	0.26	0.738
2800.00	0.25	0.731
2700.00	0.24	0.725
2600.00	0.23	0.718
2500.00	0.22	0.712
2400.00	0.22	0.707
2300.00	0.21	0.701
2200.00	0.20	0.696
2100.00	0.19	0.691
2000.00	0.18	0.687

Reference SPE Paper # 13172

Key: Pb = Bubble Point Pressure (psig)
 Pb* = correlating Number for Pb Calculation
 Rs = Solution Gas-Oil Ratio (scf/STB)
 Bob = Oil Formation Volume Factor at Pb (Bbl/STB)
 Bob* = Correlating Number for Bob Calculation
 Bo = Oil Formation Volume Factor
 Gob = Correlation of Isothermal Oil Compressibility (g/cc)
 COMPRESS = Oil Compressibility
 Mod = Viscosity of Dead Oil (cp)
 a,b,m = correlation constants
 Mob = Viscosity of Gas Saturated Oil (cp)
 Mo = Viscosity of Undersaturated Oil (cp)

reservoir conditions and parameters. The spreadsheet was generated using Slider's method for computing the water influx. Figure 19 lists the required input data and exhibits the results of Slider's method for calculating the water influx.

Using the model's steady-state aquifer option, the following model equation was used to simulate the rate of influx:

$$q_{wss} = SSAQ (P_0 - P_n - 1) \quad (1)$$

Where, q_{wss} = Water influx rate for steady state flow, scf/d

SSAQ = Model constant, scf/day/psi

P_0 = Initial grid block pressure, psi

P_{n+1} = grid block pressure at a future time, psi

From the above generated spreadsheet (Figure 19):

$$W_e = \frac{BQ_w(P_0 - P_n + 1)}{2.0} \quad (2)$$

simplifying equation 2 and dividing by time value t:

$$\frac{W_e}{t} = \frac{BQ_w(P_0 - P_n + 1)}{2.0 t}$$

$$q_{wss} = \frac{BQ_w(P_0 - P_n + 1)}{2.0 t} \quad (3)$$

Where, q_{wss} = Water influx rate for steady state flow, bpd (Slider)

to convert q_{wss} to scf/day, in order to satisfy the model requirements, the modified equation (3) is:

$$q_{wss} = \frac{BQ_w(P_0 - P_n + 1)}{11.23 t} \quad (4)$$

$$\text{by assuming } SSAQ = \frac{BQ_w}{11.23 t} \quad (5)$$

equation (4) is equal to equation (1) and therefore the SSAQ value can be calculated.

To calculate SSAQ for the model, use the generated data from the spreadsheet at $t = 1027$ days.

$$SSAQ = \frac{1146.68 * 76.23}{11.23 * 1027} = 7.58$$

The above SSAQ value was used as an initial value to history match the reservoir pressure and production and quantify/model the aquifer.

4.6 Productivity Index Calculations (PID)

A value of the layer flow index, PID, can be estimated as follows:

$$PID = \frac{0.00708 kh}{\ln\left(\frac{0.121 \sqrt{d_x d_y}}{r_w}\right) + S} \quad (6)$$

Where, k = Layer absolute permeability,

h = Layer thickness, ft

d_x = X-direction grid block thickness, ft

Initial Data

Initial Reservoir Pressure	2712 psi	Porosity, ϕ	29.5 %
Saturation Pressure	2712 psi	Permeability, k	1.275 Darcy
Reservoir External Radius	1224 ft	Water compressibility	3E-6 psi ⁻¹
Aquifer External Radius	20000 ft	Oil compressibility	7.7E-6 psi ⁻¹
Reservoir Thickness, h	22 ft	Formation Compressibility	4E-6 psi ⁻¹
Water Viscosity, μ_w	0.56 cp	Init. Oil Form. Vol. Factor	1/29 bbl/stb
Connate Water Sat., S_w	16.5 %	Production Rate, q_o	250 bbl/day

Water Influx Calculations at Time = 1027 days

$$B = 1.12\phi hcr^2 = 76.23$$

$$\text{diffusivity, } \eta = \frac{6.33k}{\phi\mu c} = 6,979,202.70$$

$$t_{D(1027 \text{ days})} = \frac{\eta t}{r^2} = 4,784.25$$

$$r_{Dc} = \frac{r_{\text{aquifer}}}{r_{\text{reservoir}}} = 16.34$$

$$Q_{w(4.784)} \text{ from Table 3.2 (Slider, p. 110)} = 1,146.68$$

$$B_{op} = B_{oi} + C_o(p_i - p)B_{oi} = 1.31699$$

$$N = \frac{\pi r^2 h \phi (1 - S_w)}{5.615B} = 3,500,000 \text{ bbls}$$

$$B \left(\frac{p_n - 1 - p_{1027 \text{ days}}}{2} \right) Q_w = N_p B_o + W_p - N(B_o - B_{oi}) + (C_r + C_w S_w) \left[\frac{\Delta p B_{oi} N}{(1 - S_w)} \right]$$

$$p_{1027 \text{ days}} = 2705 \text{ psi}$$

$$W_{e(1027 \text{ days})} = \left[\frac{B Q_{w(1027 \text{ days})} (p_i - p_{1027 \text{ days}})}{2} \right] = 271,318.75 \text{ bbls}$$

Figure 19. Summary of Water Influx Calculations

d_y = Y-direction grid block thickness, ft

r_w = Wellbore radius, ft

S = Layer skin factor

In principle, the layer flow index could be related to measured values. In practice, however, the terms r_o , S , and $k_{xy}/\mu_o B_o$ are seldom well known, especially for a multiphase flowing well. As a matter of expediency, therefore an estimate of the equivalent radius (r_o) and productivity index (PI) are often used for an initial estimate to model the fluid flow from the reservoir to the wellbore.

The equivalent radius, r_o , depends upon the block geometry and permeability anisotropy. The following equations were used to estimate r_o and PI for non-fractured wells in the study area:

$$PI = \frac{0.00708 k_{avg} ds}{\ln\left(\frac{r_o}{r_w}\right) + S} \quad (7)$$

For vertical wells:

$$ds = dz = h$$

$$S = 0 \text{ (assumed for this case)}$$

$$k_{avg} = \sqrt{k_x k_y}$$

$$r_o = \frac{0.28(R^{1/2}d1^2 + R^{-1/2}d2^2)^{1/2}}{R^{1/4} + R^{-1/4}} \quad (8)$$

Where, $R = k_y/k_x$

$$d1 = dx$$

$$d2 = dy$$

The following table summarizes the results of the PI calculations per well required for simulating the B-35 sand reservoir.

4.7 Water-Oil Ratio and Gas-Oil Ratio Constraints

Maximum gas/oil (GOR) and water/oil (WOR) are input by the user and apply to every oil production well. The ratio WOR is defined as total water production divided by total oil production for all active well completion intervals. If WOR for the well exceeds WORMAX, then the completion interval (layer)

TABLE 5. SUMMARY OF CALCULATED PI VALUES BY LAYER FOR EACH WELL

WELL #	PI VALUES		
	LAYER 1	LAYER 2	LAYER 3
A-1	29.60	4.50	10.67
A-3D/A-3	28.18	4.85	11.49
A-6	20.40	4.76	11.27

with the highest WOR will be shut-in. If more than one layer has the same maximum WOR, the deepest layer will be shut-in first. Similarly, the same concept applies to the GOR where the maximum GOR controls the performance of the reservoir.

In this study the WOR was the controlling factor in terms of the wells shut-in schedule. Using the available field data, the pressure and production histories were matched using a WORMAX of 2.0 as the cut-off point. If WOR exceeds the WORMAX of 2.0, then the well is shut-in.

When simulating and predicting the reservoir performance due to future gas injections a WORMAX of 1.5 was used as the cut-off point. Based on this assumption, the results of these predictions were conservative in nature.

4.8 Simulation of Well Histories - Recurrent Data

In an attempt to simulate the actual production and pressure history of the reservoir, several solution methods were reviewed and tested to determine the optimum setup of the data leading to accurate results.

After reviewing the data, it was determined that using oil production rates with an implicit rate calculation option should result in accurate predictions of the reservoir performance when simulating the actual history. Since the oil rate per well was specified, the reservoir's

pressure, gas production, and water production were simulated and compared to actual reservoir pressure and production values. Average oil rates were computed over specified time periods with each average oil rate represented by a recurrent data set. Small initial time steps and time increments were used to control any computational errors associated with the time step size.

When simulating/projecting the reservoir performance due to future gas injection cycles, pressure and productivity index constraints were used to simulate the additional oil, gas, and water production using the implicit pressure calculation option.

Appendix A provides a listing of the input data set used for history matching the actual pressure and production data, and for simulating the performance of the reservoir due to future injection cycles. It is worth noting that in the history matching stage, the four injection cycles that were performed during the life of the reservoir were simulated using gas injection rate specified option using implicit rate calculation.

In terms of the model's solution method, the Line Successive Over-Relaxation (LSOR) option with z-direction tridiagonal algorithm was recommended and used as the optimum solution method for solving two or three-dimensional problems. The LSOR solution method in the z-direction will account for the flow between the different layers and thereby model the actual performance of the reservoir. Certain parameters associated with the LSOR-Z

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Centimeter

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2 of 2

solution method are listed in the BOAST3-PC manual (page 45) and their values are exhibited in the input data set (Appendix A).

4.9 Additional Reservoir Simulation Assumptions

In addition to the available model input parameters discussed above and used in simulating the Taylor reservoir (SMI 73 Block), additional parameters were assumed/estimated based on geologic and engineering data provided to BDM. (See Figure 20.)

An initial reservoir pressure of 2,712 psig measured at a datum point of 5,846 feet was used as a model input parameter. This pressure value was measured in the early life of

the reservoir. Additional reservoir shut-in measurements were not available to provide the basis for a pressure build-up analysis in order to estimate the initial reservoir pressure.

Permeability anisotropy was another input parameter required by the model. Based on the provided geologic data, the permeability values in the X and Y- directions were assumed equal, whereas the permeability in the Z- direction was different ($K_x = K_y \neq K_z$).

Based on the available and assumed reservoir parameters a model representing the reservoir under study was developed to simulate the actual reservoir performance as detailed in the following sections.

- 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

m93-5276-38

Figure 20. Additional Reservoir Simulation Assumption

5.0 HISTORY MATCH

The history match of the production performance of the B-35K Reservoir was refined through the modification of the water-oil relative permeability curve, 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 modify the water-oil relative permeability curves, the oil-water contact location, and the attic oil volume. The details of five of the most significant history match cases are presented in detail in Appendix B. The results of the history match effort are discussed below.

The location of the oil-water contact had a significant impact on the production performance of the simulator. Since the sand thickens in the down-dip direction (see Figure 6), the original oil-in-place of the reservoir increases significantly as the oil-water contact is pushed down-dip. If the water-oil contact is assumed to be at the proven oil limit of -6,076 feet subsea, as defined by Well A-1, the original oil-in-place is estimated at 3.5 Million barrels of oil. By moving the water-oil contact 100 feet down-dip to -6,176 feet subsea, the original oil-in-place more than doubles to 7.3 million barrels of oil. (This case is Run 2 as included in Appendix B.) The downward movement of the oil-water contact in the simulator significantly impacts the water production rate since the water level is moved away from the production well take points. Comparison of the simulated cumulative water production from these two cases illustrates the impact of the water-oil contact movement, as shown in Figure 21. The producing well waters out

Figure 21. Comparison of Cumulative Water Production for History Match Runs 1 and 2

much too soon in Run 1 and too late in Run 2, as compared to the actual data. The optimum match of water production performance was achieved in the final history match by assuming that the water-oil contact was approximately 60 feet below the proven oil limit (Run 5).

The addition of an attic oil volume also impacts the simulated reservoir performance. The original oil-in-place is not significantly impacted since the sand appears to thin in the up-dip direction (see Figure 6), but the production performance is significantly impacted. By moving the sand limit updip approximately 200 feet structurally, the original oil-in-place in the reservoir increases from 7.3 to 8.6 million barrels of oil, so the assumed attic volume is approximately 1.3 million barrels of oil. The impact of the addition of the attic oil volume is illustrated in Figure 22

by comparing the cumulative water production values from Run 3 and Run 4. The results of Run 3 matches the actual water data fairly well, but in the later time frame there is not enough water production. When the attic oil volume is added, Run 4, the water production falls below the actual data. This problem was solved in Run 5, the final history match case, by assuming that the oil-water contact was at an elevation of -6,137 feet subsea, or approximately 60 feet below the proven oil limit. The history match work indicates that an attic volume is probably necessary to obtain the best 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.

Figure 22. Comparison of Cumulative Water Production for History Match Runs 3, 4, and 5

The excellent results of the final history match are displayed in Figures 23 through 26, which illustrate the actual reservoir pressure, oil production, gas production, and water production data versus the simulation results. These results are also included in Appendix B, Run 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.

6.0 GAS INJECTION SENSITIVITIES

Using the final history match assumptions, various model sensitivities were conducted to examine the results of additional gas injection into the reservoir through the Well A-6. 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 incremental oil recovery results of these sensitivity cases are presented in Table 6 and Figures 27 through 31, as discussed below. Detailed results of the sensitivity cases are presented in Appendix C.

6.1 Injection Rate Sensitivity

The first sensitivity was conducted to evaluate the impact of gas injection rate on the incremental oil recovery. Figure 27 compares the results of injecting 300 million cubic feet of gas in one stage at three different injection rates, 250, 500, and 1,000 MCFD, followed by a three 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.

6.2 Post-Injection Shut-In Time Sensitivity

The impact of post injection shut-in time was also evaluated. The cases evaluated utilized a total injection volume of 150 million cubic feet of gas at 500 MCFD in one stage, and the shut-in period varied between zero and six months. As shown in Figure 28, the best predictive performance of the reservoir was achieved using the three month shut-in period. Although the results of the three cases are similar, the three month shut-in case yields slightly accelerated oil production, and the six month shut-in case has slightly higher incremental recovery. Economic analysis of the results will probably indicate that the three month shut-in case is economically optimum.

6.3 Injection Volume Sensitivity

Figure 29 illustrates the incremental recovery over time for gas injection volumes between 75 and 400 million cubic feet. Comparison of the four cases shown on this figure shows that production is slightly accelerated at higher injection volumes and that incre-

Cumulative Oil Production Versus Time

Figure 23. Final History Match Results - Cumulative Oil Production Versus Time

Pressure Versus Time

Figure 24. Final History Match Results - Pressure Versus Time

Figure 25. Final History Match Results - Cumulative Gas Production Versus Time

Figure 26. Final History Match Results - Cumulative Water Production Versus Time

TABLE 6. SUMMARY OF OIL PRODUCTION FOR VARIOUS GAS INJECTION PREDICTION SENSITIVITIES

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	741
	Rate (mcf/d)		Rate (mcf/d)		Rate (mcf/d)		Rate (mcf/d)	Rate (mcf/d)
	250	500	250	500	250	500	1000	3000
Zero			213					
Three								
1 Stage	203	212		219	236	227	226	229
2 Stage			225	238				
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, produce for 6 months; inject the remaining volume, shut-in for 3 months then produce to a WOR of 1.5.

3276-76

GAS INJECTION RATE SENSITIVITY ANALYSIS
(300 MMCF, 3 MO SHUT-IN, 1 STAGE)

Figure 27. Gas Injection Rate Sensitivity Analysis Results

POST-INJECTION SHUT-IN TIME SENSITIVITY
(150 MMCF @ 500 MCFD, 1 STAGE)

5276-28

Figure 28. Post-Injection Shut-In Time Sensitivity Analysis Results

INCREMENTAL OIL PROD DUE TO GAS INJECT
(500 MCFD, 3 MOS SHUT-IN, 1 STAGE)

5276-29

Figure 29. Gas Injection Volume Sensitivity Analysis Results

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

Figure 30. Injection Volume Staging Sensitivity Analysis Results - Oil

INJ. VOLUME STAGING SENSITIVITY ON H2O
(150 MMCF @ 500 MCFD, 3 MONTH SHUT-IN)

Figure 31. Injection Volume Staging Sensitivity Analysis Results - Water

mental 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 between the 300 and 400 million cubic foot cases. The optimum gas injection volume is probably in the range of 150 to 300 million cubic feet of gas.

6.4 Injection Volume Staging Sensitivity

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 foot injection volume case where the injection rate was 500 MCFD and the shut-in period after injection was three months. The first case assumes that injection occurs in two stages, as follows: half of the gas is injected, then there is a three month shut-in period followed by six months of production, then the other half of the gas is injected with production initiated after a three month shut-in period. The third case assumes that the gas volume is injected in three stages, with similar shut-in and production stages in between.

Figures 30 and 31 exhibit the results of injecting gas in stages, and compare a single stage case with two stage and three stage injection cases. Figure 8 indicates that the two stage injection case produces more oil than the one stage or three stage injection cases. Figure 9 illustrates the water production is held off by staging the gas injection. A two stage injection

scenario is probably an optimum due to the fact that the production duration between the first and the second stage was only six months, which contributes to the gas segregation phenomena and thereby contributes to the oil recovery enhancement with lower associated water production rate than for one stage.

7.0 CONCLUSION

The reservoir simulation study which is documented in this report provides the LSU Bypassed Oil Study team with a calibration case for use in the evaluation of the oil recovery potential of Gulf of Mexico salt dome reservoirs. The BOAST model used in this study can accurately simulate the performance of gas injection projects for recovering attic oil and provide reasonable predictive results.

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:

- a. 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 lower gas injection rates. An injection rate of about 500 MCFD appears to be reasonable for this reservoir.

- b. 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.
- c. The post-injection shut-in time sensitivity indicates that a three month shut-in time yields an optimum incremental oil recovery.
- d. The injection 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. This improved recovery is most likely due to better segregation of the injected gas in the attic.

In addition to the technical solutions the results of the sensitivity cases could be analyzed from an economic point of view to determine the optimum injection volume, injection rate, and shut-in period, based on operating conditions and costs.

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APPENDIX A
MODEL INPUT DATA

SMI 73 Simulation Input Data

NOTE: See BOAST User's Manual for definitions of the keywords which are used in the input dataset.

ID1: LSU PROJECT- ACTUAL FIELD STUDY TAYLOR ENERGY-BOAST III 04/05/93]

ID2: ACTUAL RESERVOIR WITH 3-WELLS IREPRS:0—>1

ID3: A-1, A-3, AND A-6 (b) DIP = 27 degrees down!

ID4: modified Krw (mod #5N, USING CASE 13N), MODIFIED KRG (MOD#4), WOC @ 6137 FT AND ATTIC RESERVIOR.

ID5: SMI 73 BLOCK, 3-layer set up, thickness by grid block, well producing @ constant rate
RESTART AND POST-RUN CODES

-10

GRID DATA: NUMBER OF GRID BLOCKS X, Y, Z

14 11 3

GRID BLOCK LENGTHS: dimensions in feet, with thickness varied by grid block

0 0 1 1

375. 500. 500. 500. 125. 594. 500. 500. 125. 406. 500. 500. 125. 563.

250. 250. 125. 125. 62.5 31.25 125. 125. 204. 250. 500.

0. 0. 0. 0. 0. 0. 0. 0. 0. 0. 0. 0. 0. 0.

1. 1.5 3. 1.5 0. 0. 0. 0. 0. 0. 0. 1. 1.5 2.5

3. 4.5 6. 6. 5.5 4.5 5. 5. 4.5 4.5 5. 5. 5.5 5.5

5. 6.5 8. 7. 7. 6. 7. 7.5 7.5 6.5 6.5 6.5 6.5 7.5

6.5 8. 10. 9. 8.5 8.0 8.5 8.5 8.5 8.5 8.0 8.0 8.0 9.0

7.0 9.0 11.5 11.5 9.5 8.5 10. 11. 11.5 9.0 9.0 11.5 8.5 9.5

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16.5 19. 21. 21.5 21. 21. 21.5 21.5 21.5 21.5 21. 19. 16.5 17.

21. 22. 23. 24. 24. 23. 23. 23. 23. 23. 22.5 21.5 20.5 20.

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SMI 73 Simulation Input Data (Continued)

6022. 6058. 6093. 6140.

6113. 6108. 6104. 6087. 6082. 6083. 6065. 6060. 6068. 6078. 6093. 6132. 6160. 6200.

6207. 6192. 6175. 6160. 6158. 6154. 6160. 6167. 6175. 6187. 6215. 6244. 6274. 6308.

POROSITY AND PERMEABILITY DISTRIBUTIONS

1 0 0 0

0.066 0.314 0.165 0.033 0.0 0.0 0.0 0.0 0.0 0.0 0.132 0.297 0.33 0.165
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 0.198 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.297
 0.198 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.314
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 0.33 0.264 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.281 0.33 0.33
 0.33 0.33 0.33 0.33 0.33 0.264 0.297 0.314 0.297 0.264 0.33 0.33 0.33 0.330
 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.330 0.33 0.330 0.33 0.33 0.33 0.33
 0.058 0.276 0.145 0.029 0.00 0.00 0.00 0.00 0.00 0.00 0.116 0.261 0.29 0.145
 0.058 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.032
 0.116 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.261
 0.116 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.261
 0.174 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.276
 0.203 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.290
 0.232 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29
 0.261 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.203
 0.290 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29
 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.290 0.290 0.29 0.29
 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29
 0.064 0.304 0.16 0.032 0.00 0.00 0.00 0.00 0.00 0.00 0.128 0.288 0.320 0.16
 0.064 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.256
 0.128 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.288
 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.288
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 0.224 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.320
 0.256 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.320
 0.288 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.224
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 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.320
 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32

1440. 570. 1125.

1440. 570. 1125.

14.4 5.7 11.25

POROSITY AND PERMEABILITY MODIFICATIONS

0 0 0 0 0 0

TRANSMISSIBILITY MODIFICATIONS

0 0 0 1

ROCK PVT : number of rock regions and PVT data sets.

1 1

SMI 73 Simulation Input Data (Continued)

SAT	KROW	KRW	KRG	KROG	PCOW	PCGO	
0.00	0.00	0.00	0.00	0.00	0.00	0.00	relative perm data
0.165	0.00	0.000	0.00	0.00	0.00	0.00	and capillary pressure
0.30	0.00	0.0035	0.035	0.00	0.00	0.00	values.
0.40	0.02	0.0055	0.09	0.00	0.00	0.00	
0.50	0.13	0.01	0.18	0.01	0.00	0.00	
0.60	0.38	0.05	0.32	0.04	0.00	0.00	
0.70	0.65	0.090	0.42	0.12	0.00	0.00	
0.80	1.00	0.48	0.64	0.26	0.00	0.00	
0.90	1.00	0.65	0.85	0.60	0.00	0.00	
1.00	1.00	1.00	1.00	1.00	0.00	0.00	

ITTHREE SWR

1 .165

PBO PBODAT PBGRAD: bubble point pressure and datum at which that value was measured
2870.0 6324. 0.000

VSLOPE BSLOPE RSLOPE PMAX REPRS

.000046 -.0000232 0. 3000.0 0 <---- "ON"

P MUO BO RSO

2000.	0.6869	1.215	338.75	PVT data for the three phases oil
gas, and water. It includes viscosity,
solution GOR, formation volume
factors, and density values.
2100.	0.6914	1.213	357.76	
2200.	0.6962	1.212	377.28	
2300.	0.7013	1.211	397.14	
2400.	0.7067	1.209	417.34	
2500.	0.7124	1.208	437.89	
2600.	0.7184	1.206	458.79	
2700.	0.7247	1.205	480.06	
2800.	0.7313	1.204	501.69	
2900.	0.7381	1.203	523.69	
3000.	0.7452	1.202	546.08	

P MUW BW RSW

100.	0.56	1.000	0.00
3000.	0.56	0.9928	0.00

GAS AND ROCK PROP

0

P MUG BG PSI CR

100.	.0163	.13729	0.0	.000003
200.	.0164	.06381	0.0	.000003
300.	.0165	.04014	0.0	.000003
400.	.0168	.02884	0.0	.000003
500.	.0171	.02222	0.0	.000003
800.	.0183	.01273	0.0	.000003
1200.	.0238	.00785	0.0	.000003
1600.	.0497	.00573	0.0	.000003
2000.	.0604	.00480	0.0	.000003
3000.	.0700	.00300	0.0	.000003

RHOSCO RHOSCW RHOSCG

53.415 62.238 0.047

Initialization Option Codes

0 1 6137. 0.00 [KPI KSI PDATUM GRAD]

NR Pwoc WOC Pgoc GOC Soi Swi Sgi [Initialization by Rock Region]

SMI 73 Simulation
Input Data (Continued)

1 2804. 6137. 0.0 5100. 0.835 0.165 0.0

Initialization by Layer (NZ Records)

1 2816 0.815 0.185 0.0 [Pi Soi Swi Sgi]

2 2816 0.753 0.247 0.0 [Pi Soi Swi Sgi]

3 2816 0.795 0.205 0.0 [Pi Soi Swi Sgi]

INITIAL OIL SATURATION FOR GRID(oil saturation per grid block for each layer)

0.815 0.815 0.815 0.815 0.00 0.00 0.00 0.00 0.00 0.00 0.815 0.815 0.815 0.815
0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815
0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815
0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815
0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815
0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815
0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815
0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.693
0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.734 0.408 0.082
0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000
0.753 0.753 0.753 0.753 0.000 0.00 0.00 0.00 0.00 0.00 0.753 0.753 0.753 0.753
0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753
0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753
0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753
0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753
0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753
0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.640
0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.677 0.376 0.075
0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000
0.795 0.795 0.795 0.795 0.00 0.00 0.00 0.00 0.00 0.00 0.795 0.795 0.795 0.795
0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795
0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795
0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795
0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795
0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795
0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795
0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.675
0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.715 0.397 0.079
0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000
INITIALIZE WATER SATURATION (water saturation per grid block for each layer)
0.185 0.185 0.185 0.185 0.00 0.00 0.00 0.00 0.00 0.00 0.185 0.185 0.185 0.185
0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185
0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185
0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185
0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185
0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185
0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185
0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.307
0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.266 0.592 0.918

Input Data (Continued)

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SMI 73 Simulation Input Data (Continued)

3 5 5 1 1
3 5 5 2 1
3 5 5 3 1

RECURRENT DATA: control the production performance of each well with time.

C===== DATA SET 1 =====

0 2 1 [ICHANG IOMETH IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
1.0 30.42 [Times for output - IOMETH values]
1 1 1 0 0 0 [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
0 0 0 0 0 0 [KROMP, KRWMP, KRGMP,IRSOMP,PCOWMAP,PCOGMAP,PHIMAP]
0.01 0.01 15.0 [DT,DTMIN,DTMAX]

HEADER ----> Beginning of data read by NODES - if IWLCNG=1]

3 0 [NWELLN=No. of new wells, NWELLO=No. of old wells]

--NEW WELLS--

PROD 1 13 8 1 3 [FORMATTED: A5,I3 - WELLID, IDWELL, I, J, PERF1, NLAYER]

29.6 4.50 10.67

0.00 0.00 0.000

PROD 1 1 109.6 0. 0000. 000. [FORMATTED: A5,2I3,4F10.0]

PROD 3 9 6 1 3 [FORMATTED: A5,I3 - WELLID, IDWELL, I, J, PERF1, NLAYER]

28.18 4.85 11.49

0.00 0.00 0.000

PROD 3 1 12.03 0. 0000. 000. [FORMATTED: A5,2I3,4F10.0]

PROD 6 5 5 1 3 [FORMATTED: A5,I3 - WELLID, IDWELL, I, J, PERF1, NLAYER]

20.5 4.76 11.27

0.00 0.00 0.000

PROD 6 1 93.6 0. 0000. 000. [FORMATTED: A5,2I3,4F10.0]

C===== DATA SET 2

=====

0 7 1 [ICHANG IOMETH IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
30.5 31.0 35.0 60.0 90.0 182. 213.0 [Times for output - IOMETH values]
1 1 1 0 0 0 [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
0 0 0 0 0 0 [KROMP, KRWMP, KRGMP,IRSOMP]
0.01 0.01 15.0 [DT,DTMIN,DTMAX]

HEADER ----> Beginning of data read by NODES - if IWLCNG=1]

3 0 [NWELLN=No. of new wells, NWELLO=No. of old wells]

--NEW WELLS--

PROD 1 13 8 1 3 [FORMATTED: A5,I3 - WELLID, IDWELL, I, J, PERF1, NLAYER]

29.60 4.50 10.67

0.00 0.00 0.000

PROD 1 1 109.6 0. 0000. 000. [FORMATTED: A5,2I3,4F10.0]

PROD 3 9 6 1 3 [FORMATTED: A5,I3 - WELLID, IDWELL, I, J, PERF1, NLAYER]

28.18 4.85 11.49

0.00 0.00 0.000

PROD 3 1 133.33 0. 0000. 000. [FORMATTED: A5,2I3,4F10.0]

PROD 6 5 5 1 3 [FORMATTED: A5,I3 - WELLID, IDWELL, I, J, PERF1, NLAYER]

20.5 4.76 11.27

0.00 0.00 0.000

PRGD 6 1 139.72 0. 0000. 000. [FORMATTED: A5,2I3,4F10.0]

C===== DATA SET 3

=====

0 8 1 [ICHANG IOMETH IWLCNG -> NOTE: ICHANG not used if IOMETH>0]

SMI 73 Simulation
Input Data (Continued)

214.0 215. 220. 240. 300. 365. 426. 517. [Times for output - IOMETH values]
1 1 1 0 0 0 [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
0 0 0 0 0 0 [KROMP, KRWMP, KRGMP,IRSOMP]
0.01 0.01 30.0 [DT,DTMIN,DTMAX]
HEADER —> Beginning of data read by NODES - if IWLCNG=1]
3 0 [NWELLN=No. of new wells, NWELLO=No. of old wells]
—NEW WELLS—
PROD 1 13 8 1 3 [FORMATTED: A5,I3 - WELLID, IDWELL, I, J, PERF1, NLAYER]
29.6 4.50 10.67
0.00 0.00 0.000
PROD 1 1 138.7 0. 0000. 000. [FORMATTED: A5,2I3,4F10.0]
PROD 3 9 6 1 3 [FORMATTED: A5,I3 - WELLID, IDWELL, I, J, PERF1, NLAYER]
28.18 4.85 11.49
0.00 0.00 0.000
PROD 3 1 133.33 0. 0000. 000. [FORMATTED: A5,2I3,4F10.0]
PROD 6 5 5 1 3 [FORMATTED: A5,I3 - WELLID, IDWELL, I, J, PERF1, NLAYER]
20.5 4.76 11.27
0.00 0.00 0.000
PROD 6 1 139.72 0. 0000. 000. [FORMATTED: A5,2I3,4F10.0]

BDM FEDERAL, INC.

APPENDIX B
HISTORY MATCH RESULTS

SMI 73 Simulation Results
Summary of History Match Cases

RUN	CASE NAME	CASE DESCRIPTION
Run 1	Proven Oil Case	Assumes that the original oil-water contact is at -6,076 feet subsea as defined by Well A-1
Run 2	Estimated O/W Contact Case	Assumes that the original oil-water contact is at -6,176 feet subsea, or 100 feet below the proven limit.
Run 3	Modified K _{rw} Case	This is the same case as Run 2, with a modified water-oil relative permeability curve.
Run 4	Attic Oil Volume Case	This is the same case as Run 3, with an additional attic oil volume of 1.3 MMBO.
Run 5	Final History Match Case	This is the same case as Run 4 with the original oil-water contact at -6,137 feet subsea.

SMI 73 Field, B-35K Reservoir Simulation Cumulative Oil Production Versus Time

SMI 73 Field, B-35K Reservoir Simulation Pressure Versus Time

**SMI 73 Field, B-35K Reservoir Simulation
Cumulative Gas Production Versus Time**

SMI 73 Field, B-35K Reservoir Simulation
Cumulative Water Production Versus Time

**B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
PROVEN OIL LIMIT CASE - RUN 1**

| Time
(Days)	HISTORY MATCH DATA			ACTUAL FIELD DATA		
	Cum Oil
(MBO)	Cum Gas
(MMSCF)	Cum Water
(MSTB)	Cum Oil
(MBO)	Cum Gas
(MMSCF)	Cum Water
(MSTB)
0	0	0	0	0	0	0
365	139	74	0	131	83	0
730	307	164	12	296	175	0
1,095	589	315	100	587	359	8
1,460	870	463	419	863	516	9
1,825	1,226	653	796	1,257	698	42
2,190	1,646	973	838	1,656	902	45
2,555	2,140	1,279	1,164	2,266	1,120	46
2,920	2,231	1,335	1,262	2,616	1,281	53
3,285	2,231	1,335	1,262	2,875	1,400	94
3,650	2,231	1,335	1,262	2,960	1,443	198

| Time
(Days)	Model		Actual	
	Pressure
(psi)	Cum Oil
(MBO)	Pressure
(psi)	Cum Oil
(MBO)
0	2,755	0		
1,003	2,650	791	2,747	863
1,428	2,608	1,226	2,825	863
1,460	2,808	1,240	2,805	897
1,551	2,598	1,301	2,526	1,015
1,673	2,791	1,470	2,746	1,171
1,825	2,667	1,692	2,793	1,279
2,038	2,582	2,036	2,723	1,496
2,464	2,545	2,231	2,708	2,170
2,920	2,742			
3,285	2,742			
3,650	2,783			

**B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
PROVEN OIL LIMIT CASE - RUN 1**

BDM FEDERAL, INC.

1-3276-1
10/23/79

B-7

**B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
PROVEN OIL LIMIT CASE - RUN 1**

BDM FEDERAL, INC.

GA/EZ/01
06-07-05-1

B-8

**B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
ESTIMATED OIL/WATER CONTACT CASE - RUN 2**

| Time
(Days)	HISTORY MATCH DATA			ACTUAL FIELD DATA		
	Cum Oil
(MBO)	Cum Gas
(MMSCF)	Cum Water
(MSTB)	Cum Oil
(MBO)	Cum Gas
(MMSCF)	Cum Water
(MSTB)
0	0	0	0	0	0	0
365	139	74	0	131	83	0
730	301	161	0	296	175	0
1,095	589	315	0	587	359	8
1,460	859	459	1	863	516	9
1,825	1,220	650	20	1,257	698	42
2,190	1,662	950	21	1,656	902	45
2,555	2,245	1,274	21	2,266	1,120	46
2,920	2,587	1,455	31	2,616	1,281	53
3,285	2,822	1,579	50	2,875	1,400	94
3,650	2,905	1,623	60	2,960	1,443	198

| Time
(Days)	Model		Actual	
	Pressure
(psi)	Cum Oil
(MBO)	Pressure
(psi)	Cum Oil
(MBO)
0	2,755	0		
1,003	2,719	791	2,747	863
1,428	2,720	1,226	2,825	863
1,460	2,683	1,240	2,805	897
1,551	2,676	1,301	2,526	1,015
1,673	2,820	1,470	2,746	1,171
1,825	2,719	1,692	2,793	1,279
2,038	2,632	2,036	2,723	1,496
2,464	2,614	2,231	2,708	2,170
2,920	2,700			
3,285	2,719			
3,650	2,725			

**B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
ESTIMATED OIL/WATER CONTACT CASE - RUN 2**

BDM FEDERAL, INC.

1-5276-93
10/25/93

B-10

Cumulative Oil Production Versus Time

Pressure Versus Time

**B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
ESTIMATED OIL/WATER CONTACT CASE - RUN 2**

BDM FEDERAL, INC.

1-5276-93
10/25/93

B-11

**B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
MODIFIED Krw CASE - RUN 3**

| Time
(Days)	HISTORY MATCH DATA			ACTUAL FIELD DATA		
	Cum Oil
(MBO)	Cum Gas
(MMSCF)	Cum Water
(MSTB)	Cum Oil
(MBO)	Cum Gas
(MMSCF)	Cum Water
(MSTB)
0	0	0	0	0	0	0
365	139	74	1	131	83	0
730	310	165	1	296	175	0
1,095	590	315	3	587	359	8
1,460	860	460	16	863	516	9
1,825	1,227	654	50	1,257	698	42
2,190	1,646	954	51	1,656	902	45
2,555	2,236	1,279	53	2,266	1,120	46
2,920	2,580	1,463	71	2,616	1,281	53
3,285	2,822	1,589	94	2,875	1,400	94
3,650	2,910	1,637	103	2,960	1,443	198

| Time
(Days)	Model		Actual	
	Pressure
(psl)	Cum Oil
(MBO)	Pressure
(psl)	Cum Oil
(MBO)
0	2,755	0		
1,003	2,738	791	2,747	863
1,428	2,730	1,226	2,825	863
1,460	2,711	1,240	2,805	897
1,551	2,709	1,301	2,526	1,015
1,673	2,810	1,470	2,746	1,171
1,825	2,740	1,692	2,793	1,279
2,038	2,684	2,036	2,723	1,496
2,464	2,676	2,231	2,708	2,170
2,920	2,690			
3,285	2,719			
3,650	2,755			

**B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
MODIFIED K_{rw} CASE - RUN 3**

BDM FEDERAL, INC.

Cumulative Oil Production Versus Time

Pressure Versus Time

1-5276-3
10/25/88

B-13

**B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
MODIFIED K_{rw} CASE - RUN 3**

BDM FEDERAL, INC.

Cumulative Gas Production Versus Time

Cumulative Water Production Versus Time

1-5276-93
10/29/93

B-14

B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS

ATTIC VOLUME CASE - RUN 4

| Time
(Days)	HISTORY MATCH DATA			ACTUAL FIELD DATA		
	Cum Oil
(MBO)	Cum Gas
(MMSCF)	Cum Water
(MSTB)	Cum Oil
(MBO)	Cum Gas
(MMSCF)	Cum Water
(MSTB)
0	0	0	0	0	0	0
365	139	74	0	131	83	0
730	310	165	0	296	176	0
1,095	587	314	0	587	359	8
1,460	863	463	6	863	516	9
1,825	1,229	656	27	1,257	698	42
2,190	1,646	880	27	1,656	902	45
2,555	2,232	1,191	28	2,266	1,120	46
2,920	2,580	1,375	28	2,616	1,281	53
3,285	2,821	1,503	29	2,875	1,400	94
3,650	2,910	1,550	30	2,960	1,443	198

| Time
(Days)	Model		Actual	
	Pressure
(psi)	Cum Oil
(MBO)	Pressure
(psi)	Cum Oil
(MBO)
0	2,755	0		
974	2,746	791	2,747	863
1,428	2,727	1,226	2,825	863
1,460	2,722	1,240	2,805	897
1,551	2,721	1,301	2,526	1,015
1,673	2,800	1,470	2,746	1,171
1,825	2,750	1,692	2,793	1,279
2,038	2,707	2,036	2,723	1,496
2,464	2,688	2,231	2,708	2,170
2,920	2,719			
3,285	2,751			
3,650	2,797			

**B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
ATTIC VOLUME CASE - RUN 4**

1-5274-1
10/75

B-16

BDM FEDERAL, INC.

**B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
ATTIC VOLUME CASE - RUN 4**

BDM FEDERAL, INC.

1-374-73
04/25/79

B-17

B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS FINAL HISTORY MATCH - RUN 5

| Time
(Days)	HISTORY MATCH DATA			ACTUAL FIELD DATA		
	Cum Oil
(MBO)	Cum Gas
(MMSCF)	Cum Water
(MSTB)	Cum Oil
(MBO)	Cum Gas
(MMSCF)	Cum Water
(MSTB)
0	0	0	0	0	0	0
365	138	75	0	131	83	0
730	310	166	0	296	175	0
1,095	598	320	0	587	359	8
1,460	877	469	21	863	516	9
1,825	1,226	655	47	1,257	698	42
2,190	1,652	883	48	1,656	902	45
2,555	2,242	1,198	48	2,266	1,120	46
2,920	2,584	1,390	81	2,616	1,281	53
3,285	2,823	1,518	149	2,875	1,400	94
3,650	2,910	1,584	195	2,980	1,443	198

| Time
(Days)	Model		Actual	
	Pressure
(psl)	Cum Oil
(MBO)	Pressure
(psl)	Cum Oil
(MBO)
0	2,755	0		
974	2,755	791	2,747	863
1,428	2,751	1,226	2,825	863
1,460	2,733	1,240	2,805	897
1,551	2,732	1,301	2,526	1,015
1,673	2,828	1,470	2,746	1,171
1,825	2,756	1,692	2,793	1,279
2,038	2,723	2,036	2,723	1,496
2,484	2,706	2,231	2,708	2,170
2,920	2,722			
3,285	2,752			
3,650	2,800			

B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
FINAL HISTORY MATCH - RUN 5

BDM FEDERAL, INC.

1-327-6-95
04-9-225-1

B-19

B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
FINAL HISTORY MATCH - RUN 5

BDM FEDERAL, INC.

1-327-6-93
10/25/93

B-20

APPENDIX C
PREDICTION RESULTS

SMI 73 Simulation Results Summary of Prediction Sensitivity Cases

Text Reference	Sensitivity Name	Case Name	Case Description
Figure 27	Injection Rate	500 MMCFD Rate	Inject 300 MMCF @ 500 MCFD, Shut-In For 3 Months
		1000 MMCFD Rate	Inject 300 MMCF @ 500 MCFD, Shut-In For 3 Months
		250 MMCFD Rate	Inject 300 MMCF @ 250 MCFD, Shut-In For 3 Months
Figure 28	Post-Injection Shut-In Period	3 Month Shut-In Period	Inject 150 MMCF @ 500 MCFD, Shut-In For 3 Months
		No Shut-In Period	Inject 150 MMCF @ 500 MCFD, No Shut-In Period
		6 Month Shut-In Period	Inject 150 MMCF @ 500 MCFD, Shut-In For 3 Months
Figure 29	Injection Volume	150 MMCF Injection	Inject 150 MMCF @ 500 MCFD, Shut-In For 3 Months
		300 MMCF Injection	Inject 300 MMCF @ 500 MCFD, Shut-In For 3 Months
		75 MMCF Injection	Inject 75 MMCF @ 500 MCFD, Shut-In For 3 Months
		400 MMCF Injection	Inject 400 MMCF @ 500 MCFD, Shut-In For 3 Months
Figure 30,31	Injection Volume Staging	Single Stage	Inject 150 MMCF @ 500 MCFD, Shut-In For 3 Months
		Two Stage	Stage 1: Inject 75 MMCF @ 500 MCFD, Shut-In For 3 Months,
Produce for 6 Months
Stage 2: Inject 75 MMCF @ 500 MCFD, Shut-In For 3 Months.
		Three Stage	Stage 1: Inject 75 MMCF @ 500 MCFD, Shut-In For 3 Months,
Produce for 6 Months
Stage 2: Inject 75 MMCF @ 500 MCFD, Shut-In For 3 Months,
Produce for 6 Months
Stage 3: Inject 75 MMCF @ 500 MCFD, Shut-In For 3 Months.

SMI 73 SIMULATION RESULTS INJECTION RATE SENSITIVITY ANALYSIS RESULTS

500 MMCFD CASE INJECT 300 MMCF @ 500 MCFD, SHUT-IN FOR 3 MOS
 1000 MMCFD CASE INJECT 300 MMCF @ 1000 MCFD, SHUT-IN FOR 3 MOS
 250 MMCFD CASE INJECT 300 MMCF @ 250 MCFD, SHUT-IN FOR 3 MOS

500 MMCFD Case					1000 MMCFD Case					250 MMCFD Case				
Time Step (Days)	Cumulative Production			Time Step (Days)	Cumulative Production			Time Step (Days)	Cumulative Production					
	Oil (MMB)	Gas (MMCF)	Water (MMBL)		Oil (MMB)	Gas (MMCF)	Water (MMBL)		Oil (MMB)	Gas (MMCF)	Water (MMBL)			
13	8	10	0	0	3	7	0	0	15	0	0			
45	23	31	1	32	16	33	1	31	29	15	1			
73	33	44	1	61	25	47	1	60	41	31	1			
104	42	53	2	92	34	57	1	90	50	42	1			
134	50	60	3	122	42	65	3	121	58	49	2			
164	57	66	4	154	49	72	4	151	66	55	3			
195	65	72	6	184	56	78	5	182	73	60	3			
225	71	78	7	214	62	83	7	213	80	66	5			
255	77	83	9	244	69	89	8	243	88	70	6			
287	84	88	11	275	75	94	10	273	95	75	8			
317	89	92	12	306	81	99	11	304	103	79	10			
347	95	96	14	336	86	103	13	334	108	83	11			
377	100	100	16	366	92	108	15	365	111	86	13			
407	105	104	18	396	97	111	17	395	116	90	15			
439	110	108	21	427	102	116	19	425	119	93	17			
468	115	111	23	457	107	119	20	456	123	97	20			
498	120	115	25	486	111	123	22	485	127	100	22			
520	124	119	28	519	116	131	24	517	131	103	24			
530	128	122	30	546	120	135	27	548	136	107	27			
560	133	126	33	579	125	139	29	577	142	110	29			
592	137	129	35	610	129	142	31	608	146	114	32			
621	141	133	38	640	133	146	33	638	150	117	34			
651	145	136	40	672	137	150	35	669	154	121	37			
681	149	140	43	700	141	154	38	699	158	125	40			
712	153	143	46	732	145	157	41	730	162	128	43			
742	157	147	49	761	148	161	43	761	166	132	45			
773	160	150	52	793	152	165	46	790	170	135	48			
803	164	154	55	823	156	168	49	822	173	139	51			
834	167	157	58	853	159	172	51	851	177	143	55			
864	171	161	61	883	163	175	54	883	180	146	57			
894	175	164	64	913	166	179	57	913	184	150	61			
925	178	168	68	944	170	182	59	942	187	154	64			
956	182	171	71	974	173	186	62	973	191	157	67			
987	185	174	74	1005	176	189	65	1004	194	161	70			
1016	188	177	77	1037	180	193	68	1035	197	164	74			
1047	191	181	81	1067	183	196	71	1064	200	168	77			
1078	194	184	84	1097	186	199	74	1095	203	171	80			
1107	198	187	87	1127	189	203	77	1125	206	174	84			
1139	199	190	91	1158	192	206	80	1156	209	178	87			
1168	201	194	94	1187	195	209	83	1186	212	181	91			
1200	204	197	98	1218	198	213	86	1216	215	184	94			
1230	207	200	101	1249	201	216	89	1248	218	188	97			
1260	209	204	105	1279	204	219	92	1278	221	190	101			
1290	212	207	108	1310	207	223	95	1310	224	193	105			
1320	215	210	112	1340	210	226	98	1340	227	194	107			
1353	218	213	115	1370	212	229	101	1370	230	196	109			
1382	220	215	116	1401	215	232	105	1400	232	197	110			
1413	221	214	118	1431	216	236	108	1430	236	198	112			
1442	223	215	120	1463	220	239	111	1460	241	199	114			
1474	224	215	122	1493	223	241	115	1490	242	200	116			
1505	226	216	124	1523	225	242	118	1521	242	201	118			
1535	227	216	124	1554	226	242	119	1554	242	202	120			
1568	227	216	124	1584	226	242	120	1583	242	202	122			
1598	227	216	124	1616	226	242	120	1613	242	202	124			
1629	227	216	124		226	242	120		242	202	124			

SMI 73 SIMULATION RESULTS
INJECTION RATE SENSITIVITY ANALYSIS RESULTS
(CONTINUED)

500 MMCFD Case				1000 MMCFD Case				250 MMCFD Case			
Time Step (Days)	Cumulative Production			Time Step (Days)	Cumulative Production			Time Step (Days)	Cumulative Production		
	Oil (MBO)	Gas (MMCF)	Water (MBBL)		Oil (MBO)	Gas (MMCF)	Water (MBBL)		Oil (MBO)	Gas (MMCF)	Water (MBBL)
1659	227	216	124	1653	226	242	120	1643	236	199	126
1689	227	216	124	1683	226	242	120	1676	236	199	126
1729	227	216	124	1713	226	242	120	1711	236	199	126
1749	227	216	124	1753	226	242	120	1748	236	199	126
1789	227	216	124	1773	226	242	120	1788	236	199	126
1809	227	216	124	1813	226	242	120	1808	236	199	126
1849	227	216	124	1833	226	242	120	1828	236	199	126
1869	227	216	124	1873	226	242	120	1868	236	199	126
1909	227	216	124	1893	226	242	120	1888	236	199	126
1929	227	216	124	1933	226	242	120	1928	236	199	126
1969	227	216	124	1953	226	242	120	1948	236	199	126
2009	227	216	124	1993	226	242	120	1988	236	199	126
2029	227	216	124	2013	226	242	120	2008	236	199	126
2069	227	216	124	2053	226	242	120	2048	236	199	126
2089	227	216	124	2073	226	242	120	2068	236	199	126
2129	227	216	124	2113	226	242	120	2108	236	199	126
2149	227	216	124	2133	226	242	120	2148	236	199	126
2189	227	216	124	2173	226	242	120	2168	236	199	126
2209	227	216	124	2193	226	242	120	2208	236	199	126
2249	227	216	124	2233	226	242	120	2228	236	199	126
2269	227	216	124	2253	226	242	120	2268	236	199	126

BDM FEDERAL, INC.

SMI 73 SIMULATION RESULTS POST-INJECTION SHUT-IN PERIOD SENSITIVITY ANALYSIS RESULTS

3 MONTH SHUT-IN PERIOD CASE INJECT 150 MAMCF @ 500 MCFD, SHUT-IN FOR 3 MOS
 NO SHUT-IN PERIOD CASE INJECT 150 MAMCF @500 MCFD, NO SHUT-IN PERIOD
 6 MONTH SHUT-IN PERIOD CASE INJECT 150 MAMCF @ 500 MCFD, SHUT-IN FOR 6 MOS

3 MONTH SHUT-IN CASE					NO SHUT-IN PERIOD CASE					6 MONTH SHUT-IN PERIOD CASE				
Time
Step
(Days)	Cumulative Production				Time
Step
(Days)	Cumulative Production				Time
Step
(Days)	Cumulative Production			
	Oil
(MBO)	Gas
(MMCF)	Water
(MBSL)			Oil
(MBO)	Gas
(MMCF)	Water
(MBSL)			Oil
(MBO)	Gas
(MMCF)	Water
(MBSL)	
0	0	0	0		0	0	0	0		0	0	0	0	
31	19	18	1		31	17	30	1		28	5	4	0	
61	29	25	1		61	28	37	1		58	20	15	0	
83	37	30	3		90	33	41	3		89	30	22	1	
122	44	33	4		122	40	45	4		118	38	28	3	
153	51	37	6		151	47	49	6		149	45	30	4	
183	57	41	8		182	54	53	8		179	52	34	6	
214	64	44	9		212	60	56	10		209	59	37	8	
245	70	47	11		243	66	59	11		240	65	41	9	
274	75	47	13		273	71	62	13		270	71	44	11	
305	81	50	15		305	77	65	16		301	76	47	13	
335	86	53	17		334	82	68	18		331	82	50	15	
365	91	55	20		365	87	70	20		362	87	53	18	
398	96	61	22		395	92	73	22		393	92	55	20	
427	101	64	24		425	97	75	24		423	97	58	22	
457	105	66	27		456	102	78	27		453	102	60	24	
486	110	69	29		487	106	81	30		484	106	63	27	
518	114	71	32		518	111	83	32		514	111	65	30	
548	118	73	35		548	115	85	35		544	115	68	32	
579	123	76	38		577	120	88	37		575	119	70	35	
610	127	78	41		608	124	90	40		606	124	73	38	
641	131	81	43		639	128	92	43		635	128	75	40	
670	135	83	46		670	132	94	46		666	132	78	43	
700	139	86	49		699	136	96	49		696	136	80	46	
731	143	88	52		730	140	99	52		728	140	83	49	
761	146	90	55		760	144	101	55		757	143	85	52	
792	150	93	59		791	148	103	58		788	147	87	55	
822	154	96	62		821	151	106	61		818	151	90	58	
853	157	98	65		851	155	108	64		848	155	92	62	
883	161	101	68		882	159	110	66		879	158	95	65	
913	164	103	71		912	162	113	71		909	162	97	68	
945	168	106	75		943	166	115	74		940	165	100	71	
975	171	108	78		973	169	117	77		971	169	102	75	
1005	175	111	81		1005	173	120	81		1002	172	105	78	
1036	178	113	85		1034	176	122	84		1031	175	107	81	
1066	181	116	88		1064	179	124	87		1062	179	110	85	
1096	184	118	92		1097	183	127	91		1093	182	113	88	
1127	188	121	95		1125	186	129	94		1122	185	115	91	
1158	191	123	99		1156	189	132	98		1153	188	117	95	
1187	194	126	102		1189	192	134	102		1184	191	120	98	
1218	197	129	106		1217	195	136	105		1214	194	122	102	
1248	199	131	109		1249	198	139	109		1244	197	125	105	
1279	202	134	113		1277	200	141	112		1275	200	128	108	
1310	205	136	117		1308	203	144	116		1306	203	130	113	
1341	207	138	119		1339	206	146	119		1336	206	133	116	
1370	209	139	122		1370	208	147	122		1366	208	135	120	
1400	211	140	124		1399	210	149	124		1397	210	136	122	
1431	213	142	126		1430	212	150	127		1428	212	138	125	
1461	215	144	128		1460	213	151	129		1457	214	139	127	
1492	217	144	131		1501	213	151	129		1490	216	140	129	
1523	219	144	133		1533	213	151	129		1519	218	141	131	
1556	219	145	133		1565	213	151	129		1548	220	142	133	
1594	219	145	133		1595	213	151	129		1582	220	142	134	
1614	219	145	133		1615	213	151	129		1619	220	142	134	

SMI 73 SIMULATION RESULTS
POST-INJECTION SHUT-IN PERIOD SENSITIVITY ANALYSIS RESULTS
(CONTINUED)

3 MONTH SHUT-IN CASE				NO SHUT-IN PERIOD CASE				6 MONTH SHUT-IN CASE			
Time
Step
(Days)	Cumulative Production			Time
Step
(Days)	Cumulative Production			Time
Step
(Days)	Cumulative Production		
	Oil
(MBO)	Gas
(MMCF)	Water
(MBBL)		Oil
(MBO)	Gas
(MMCF)	Water
(MBBL)		Oil
(MBO)	Gas
(MMCF)	Water
(MBBL)
1654	219	145	133	1655	213	151	129	1653	220	142	134
1674	219	145	133	1675	213	151	129	1673	220	142	134
1714	219	145	133	1715	213	151	129	1713	220	142	134
1754	219	145	133	1735	213	151	129	1733	220	142	134
1774	219	145	133	1775	213	151	129	1773	220	142	134
1814	219	145	133	1795	213	151	129	1793	220	142	134
1834	219	145	133	1835	213	151	129	1833	220	142	134
1874	219	145	133	1875	213	151	129	1853	220	142	134
1894	219	145	133	1895	213	151	129	1893	220	142	134
1934	219	145	133	1935	213	151	129	1933	220	142	134
1954	219	145	133	1955	213	151	129	1953	220	142	134
1994	219	145	133	1995	213	151	129	1973	220	142	134
2014	219	145	133	2015	213	151	129	2013	220	142	134
2054	219	145	133	2055	213	151	129	2053	220	142	134

BDM FEDERAL, INC.

SMI 73 SIMULATION RESULTS INJECTION VOLUME SENSITIVITY ANALYSIS RESULTS

180 MMCF INJECTION CASE INJECT 180 MMCF @ 800 MCFD, SHUT-IN FOR 3 MOS
 300 MMCF INJECTION CASE INJECT 300 MMCF @ 800 MCFD, SHUT-IN FOR 3 MOS
 75 MMCF INJECTION CASE INJECT 75 MMCF @ 800 MCFD, SHUT-IN FOR 3 MOS
 400 MMCF INJECTION CASE INJECT 400 MMCF @ 800 MCFD, SHUT-IN FOR 3 MOS

180 MMCF INJECTION CASE						300 MMCF INJECTION CASE						75 MMCF INJECTION CASE						400 MMCF INJECTION CASE					
Time	Cumulative Production			Time	Cumulative Production			Time	Cumulative Production			Time	Cumulative Production			Time	Cumulative Production			Time	Cumulative Production		
Shut (Days)	Oil (MMBBL)	Gas (MMCF)	Water (MMBBL)	Shut (Days)	Oil (MMBBL)	Gas (MMCF)	Water (MMBBL)	Shut (Days)	Oil (MMBBL)	Gas (MMCF)	Water (MMBBL)	Shut (Days)	Oil (MMBBL)	Gas (MMCF)	Water (MMBBL)	Shut (Days)	Oil (MMBBL)	Gas (MMCF)	Water (MMBBL)	Shut (Days)	Oil (MMBBL)	Gas (MMCF)	Water (MMBBL)
0	4	3	0	13	8	10	0	30	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0
31	19	18	1	45	23	31	1	61	17	12	1	31	14	25	1	31	14	25	1	31	14	25	1
61	29	25	1	73	33	44	1	91	25	17	2	60	27	49	2	60	27	49	2	60	27	49	2
93	37	30	3	104	42	53	2	122	32	21	4	92	38	68	4	92	38	68	4	92	38	68	4
122	44	33	4	134	50	60	3	153	39	24	5	121	47	80	5	121	47	80	5	121	47	80	5
153	51	37	6	164	57	68	4	182	45	29	7	152	55	89	7	152	55	89	7	152	55	89	7
183	57	41	8	196	65	72	6	213	52	31	9	182	62	97	9	182	62	97	9	182	62	97	9
214	64	44	9	225	71	78	7	243	57	34	11	212	68	105	11	212	68	105	11	212	68	105	11
245	70	47	11	255	77	83	9	274	63	37	13	243	74	112	13	243	74	112	13	243	74	112	13
274	75	50	13	287	84	88	11	305	69	40	15	273	80	118	15	273	80	118	15	273	80	118	15
305	81	53	15	317	89	92	12	336	74	43	17	304	85	124	17	304	85	124	17	304	85	124	17
336	86	56	17	347	95	98	14	365	79	45	19	334	90	130	19	334	90	130	19	334	90	130	19
366	91	59	20	377	100	104	16	395	84	48	22	365	95	136	22	365	95	136	22	365	95	136	22
396	96	61	22	407	105	108	18	427	89	51	24	395	101	141	24	395	101	141	24	395	101	141	24
427	101	64	24	439	110	110	21	456	93	53	27	425	106	145	27	425	106	145	27	425	106	145	27
457	105	66	27	468	115	111	23	485	98	55	29	457	111	150	29	457	111	150	29	457	111	150	29
486	110	69	29	500	120	115	25	517	102	56	32	486	116	155	32	486	116	155	32	486	116	155	32
518	114	71	32	530	124	119	28	548	107	58	35	517	122	159	35	517	122	159	35	517	122	159	35
548	118	73	35	560	128	122	30	578	111	60	38	548	125	164	38	548	125	164	38	548	125	164	38
579	123	76	38	592	133	126	33	608	116	63	40	578	130	168	40	578	130	168	40	578	130	168	40
610	127	78	41	621	137	129	35	638	120	65	43	608	134	172	43	608	134	172	43	608	134	172	43
641	131	81	43	651	141	133	38	669	124	67	46	638	138	176	46	638	138	176	46	638	138	176	46
670	135	83	46	681	145	136	40	701	129	70	49	669	143	180	49	669	143	180	49	669	143	180	49
700	139	86	49	712	149	140	43	730	133	72	52	699	147	184	52	699	147	184	52	699	147	184	52
731	143	88	52	742	153	143	46	761	137	74	55	730	151	188	55	730	151	188	55	730	151	188	55
761	146	90	55	773	157	147	49	791	141	76	58	760	155	192	58	760	155	192	58	760	155	192	58
792	150	93	59	803	160	150	52	823	145	80	61	791	159	196	61	791	159	196	61	791	159	196	61
822	154	96	62	834	164	154	55	853	149	82	64	823	163	200	64	823	163	200	64	823	163	200	64
853	157	98	65	864	167	157	58	883	153	85	67	853	167	204	67	853	167	204	67	853	167	204	67
883	161	101	68	894	171	161	61	913	156	87	70	883	170	207	70	883	170	207	70	883	170	207	70
913	164	103	71	925	175	164	64	943	160	89	73	913	174	211	73	913	174	211	73	913	174	211	73
945	168	106	75	956	178	168	68	974	164	91	77	943	177	215	77	943	177	215	77	943	177	215	77
975	171	108	78	987	182	171	71	1004	167	94	80	974	180	219	80	974	180	219	80	974	180	219	80
1006	175	111	81	1016	185	174	74	1035	171	96	84	1005	184	222	84	1005	184	222	84	1005	184	222	84
1036	178	113	85	1047	188	177	77	1065	174	98	87	1034	187	226	87	1034	187	226	87	1034	187	226	87
1066	181	116	88	1078	191	181	81	1095	177	100	90	1065	190	230	90	1065	190	230	90	1065	190	230	90
1096	184	118	92	1107	194	184	84	1125	180	102	94	1095	193	233	94	1095	193	233	94	1095	193	233	94
1127	188	121	95	1139	198	187	87	1157	183	104	98	1125	197	237	98	1125	197	237	98	1125	197	237	98
1158	191	123	99	1168	201	190	91	1188	186	106	101	1156	200	240	101	1156	200	240	101	1156	200	240	101
1187	194	125	102	1200	204	194	94	1217	189	108	105	1186	203	244	105	1186	203	244	105	1186	203	244	105
1216	197	129	106	1230	207	197	96	1249	192	109	112	1218	206	247	109	1218	206	247	109	1218	206	247	109
1246	199	131	109	1260	209	200	98	1278	195	110	112	1247	210	251	110	1247	210	251	110	1247	210	251	110
1279	202	134	113	1290	212	204	105	1309	198	112	116	1279	212	254	112	1279	212	254	112	1279	212	254	112
1310	205	136	117	1320	215	207	108	1339	200	113	118	1308	215	258	113	1308	215	258	113	1308	215	258	113
1341	207	138	119	1353	216	210	112	1369	202	114	121	1338	218	261	114	1338	218	261	114	1338	218	261	114
1370	209	139	122	1382	220	212	115	1400	204	117	124	1368	220	264	117	1368	220	264	117	1368	220	264	117
1400	211	140	124	1413	221	213	117	1430	205	118	125	1398	223	265	118	1398	223	265	118	1398	223	265	118
1431	213	142	126	1442	223	214	118	1465	208	119	126	1424	225	266	119	1424	225	266	119	1424	225	266	119
1461	215	142	128	1474	224	215	120	1491	210	118	130	1454	227	266	114	1454	227	266	114	1454	227	266	114

SMI 73 SIMULATION RESULTS
INJECTION VOLUME SENSITIVITY ANALYSIS RESULTS
(CONTINUED)

150 MMCF INJECTION CASE				300 MMCF INJECTION CASE				75 MMCF INJECTION CASE				400 MMCF INJECTION CASE			
Time Step
(Days)	Oil
(MBO)	Gas
(MMCF)	Water
(MBBL)	Time Step
(Days)	Oil
(MBO)	Gas
(MMCF)	Water
(MBBL)	Time Step
(Days)	Oil
(MBO)	Gas
(MMCF)	Water
(MBBL)	Time Step
(Days)	Oil
(MBO)	Gas
(MMCF)	Water
(MBBL)
1482	217	144	131	1506	226	215	122	1522	211	119	133	1492	228	257	115
1523	219	144	133	1535	227	216	124	1553	212	120	134	1523	229	257	116
1556	219	145	133	1566	227	216	124	1582	212	120	134	1556	229	257	116
1594	219	145	133	1596	227	216	124	1615	212	120	134	1588	229	257	116
1614	219	145	133	1629	227	216	124	1655	212	120	134	1626	229	257	116
1654	219	145	133	1669	227	216	124	1675	212	120	134	1645	229	257	116
1674	219	145	133	1699	227	216	124	1715	212	120	134	1685	229	257	116
1714	219	145	133	1729	227	216	124	1735	212	120	134	1705	229	257	116
1734	219	145	133	1749	227	216	124	1775	212	120	134	1745	229	257	116
1774	219	145	133	1789	227	216	124	1795	212	120	134	1785	229	257	116
1814	219	145	133	1809	227	216	124	1835	212	120	134	1805	229	257	116
1834	219	145	133	1849	227	216	124	1875	212	120	134	1825	229	257	116
1874	219	145	133	1869	227	216	124	1895	212	120	134	1865	229	257	116
1894	219	145	133	1909	227	216	124	1935	212	120	134	1905	229	257	116
1934	219	145	133	1929	227	216	124	1955	212	120	134	1925	229	257	116
1954	219	145	133	1969	227	216	124	1995	212	120	134	1965	229	257	116
1994	219	145	133	2009	227	216	124	2015	212	120	134	1985	229	257	116
2014	219	145	133	2029	227	216	124	2055	212	120	134	2025	229	257	116
2054	219	145	133	2069	227	216	124	2075	212	120	134	2045	229	257	116

DATE

FILMED

7/25/94

END