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Water Flood Demonstration Project

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By
John Lomax

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Edith Allison, Project Manager
Bartlesville Project Office
P.O. Box 1398
Bartlesville, OK 74005

Prepared by
Lomax Exploration Company
475 17th St., Suite 1500
Denver, CO 80202

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Abstract

The successful water flood of the Green River Formation in the Monument Butte unit was analyzed in detail in the last yearly report. It was shown that primary recovery and the water flood in the unit were typical of oil production from an undersaturated oil reservoir close to its bubble point. The reservoir performance of the smaller Travis unit was also analyzed.

The Monument Butte unit is currently producing at around 300 barrels per day of oil. Two of the new wells drilled in the unit had zones pressurized by the water flood. The third well produced from pressurized as well as from zones which were unaffected by the water flood. The water flood response of the Travis unit is slow possibly due to problems of reservoir continuity. Water injection continues in the unit and the reservoir pressure is increasing steadily. The new well that was drilled in Travis, did not intersect the Lower Douglas Creek Sand into which most of the water has been injected. Plans for water flooding the Boundary unit were drawn.

Core description and Formation Micro Imaging log of well 14a-28 provided insight about the important Lower Douglas Creek sandstone. It was determined that this sandstone was extensively fractured and detailed fracture characteristics were obtained through comprehensive interpretation of the FMI log. Reservoir modeling and simulation studies of all the three units were also continued. A larger, more detailed model of the Monument Butte unit was built in order to study the performance of the new development wells being drilled. Three alternate models developed to explain the performance of the Travis flood revealed that intersecting hydraulic fractures may have also provided paths for water channeling observed in this unit. A comprehensive 28-layer model of the Boundary unit explained both the oil and gas production from the unit reasonably well. The model also revealed that the oil production from well 13-21, the largest producer in the unit was aided by water influx. The hydraulic fracture in well 13-21 may have provided a conduit to an underlying aquifer. The thermodynamic models of wax precipitation revealed that wax precipitation in the vicinity of the wellbore during injection operations was a distinct possibility. A method of characteristics model developed to analyze the effect of wax precipitation on oil recovery clearly showed that wax precipitation reduces oil recoveries during injection operations and this effect is felt late in the life of the water flood.

The reservoir characterization activities identified new reservoirs in the Travis unit. Reservoir simulations helped design an injection program in Travis, unit expansion plans on the west and north sides of the Monument Butte unit and to evaluate the infill drilling. The reservoir simulations are being used to examine the role of the aquifer underlying the oil bearing D2 sandstone in Boundary on water flood strategies and injection patterns.

Executive Summary

The primary objective of this project was to analyze the success of the water flood in the Monument Butte unit and transfer this technology to the Travis and the Boundary units and to other units in the region. The technology transfer aspect of this project has been an overwhelming success and several new water floods were begun during the last project year and efforts were made to expand the ongoing water floods.

Lomax Exploration Company (currently, Inland Resources, Inc./Lomax Exploration Company, after a merger with Inland Resources, Inc.) along with its project partners, the University of Utah Department of Chemical and Fuels Engineering and University of Utah Research Institute continued its efforts in the three project units; Monument Butte, Travis and Boundary. Once again, the project activities could be classified into three major categories:

1. Drilling new wells
2. Geologic and reservoir characterization
3. Reservoir modeling and performance analysis

All of the new wells drilled in the Monument Butte unit (10-34, 9-34 and 7-34) were reasonably successful. That in itself demonstrated the viability of water flood and pressure maintenance in fluvial reservoirs which were barely undersaturated (whose initial bubble point pressure was close to the initial reservoir pressure). By December 31, 1994, the water flood had already produced 142% of the primary production and 34% of the primary gas production. Reservoir simulation had identified the west-side of the field as pressurized and initial production data from these new wells appeared to corroborate that prediction. Reservoir simulation has also shown that water injection in that portion of the field is not sufficient to sustain production from these wells. Predictions from reservoir simulation are being used to identify water injection wells and develop water injection strategies for this portion of the field.

Continued water injection in the Lower Douglas Creek (LDC) sand pressurized this reservoir in the Travis unit. Surface pressures of nearly 2000 psia were reached in the two injectors, 15-28 and 3-33, indicating bottom hole pressures of about 4600 psia. Communication problems between the injectors and producers (2-33 and 10-28) appeared to have caused the slow response to the water flood being observed in this unit. The well 5-33 drilled in the unit did not intersect the LDC sandstone. However, the well was completed in other sands and is currently producing. Based on the reservoir characterization information provided by the FMI log, zones which would not normally have been completed, were completed and produced. Reservoir simulation predictions were used to slow the rate of water injection in the LDC sand. Simulations are once again being used to make field decisions regarding LDC.

New production and injection wells were planned for the Boundary unit. There was no field activity in the unit in 1994.

Detailed geologic and reservoir characterization of all the three units was continued. The FMI logs showed the fine structures in the sand bodies. Careful analysis and interpretation of these logs revealed detailed fracture information. Analysis of the core from 14a-28 showed the LDC to have turbidic structure.

The reservoir simulation and modeling of all the three units was also continued. The Travis unit was modeled using three alternative models and all the three models predicted that a response to the water flood should have been observed in well 2-33 had the sands been in good communication.

From the experience gained in modeling the Monument Butte and the Travis units, a comprehensive 28-layer reservoir model of the Boundary unit was constructed. The model matched primary production performance well and showed that the production from well 13-21 was aided by water influx. A water-oil contact had been observed in D2 sands in Well 7-20, which is downdip of well 13-21. The water production from 13-21 could be matched only by assuming that the hydraulic fracture in the well intersected the underlying aquifer. Thus, reservoir simulation provided an insight into the interaction of the aquifer with the D2 sand layer. The aquifer considerations are being carefully looked into in the design of a water flood in Boundary.

It was shown in the last yearly report that the crude oils from these reservoirs are extremely waxy with cloud points of about 120°F. It was also shown that the injected water reaches the perforations at temperatures much lower than the formation temperatures. The thermodynamic aspects of these oils and wax formation at these temperatures were analyzed

in this report and it was shown that thermodynamically, wax precipitation is very likely. A new model developed to account for the effect of wax precipitation on oil recovery showed that reductions of as much as 5% of the oil in place are possible due to wax precipitation and this effect is felt late in the life of a water flood when several pore volumes of water have already been injected.

The technology transfer aspect of the project was continued actively with presentation in the SPE-DOE Improved Oil Recovery Symposium in Tulsa, poster sessions at the AAPG meeting in Denver at the SPE Annual Fall Meeting in New Orleans and a presentation at the International Oilfield Chemistry Symposium in San Antonio.

Chapter 1

Introduction

Production of oil from fluvial deltaic reservoirs is challenging due to the geologic complexity of these reservoirs. The success of the Monument Butte water flood prompted a detailed examination of its performance with the goal of applying relevant aspects of the technology to other units and reservoirs.

This project essentially consisted of application of the water flood technology to three units in the Green River Formation:

1. The Monument Butte unit
2. The Travis unit
3. The Boundary unit

When the project was initiated, the Monument Butte unit was the most developed of all the three units with 22 wells. The unit had produced about 4.5% of the oil in place and would have clearly been uneconomical had a water flood been not initiated. The water flood initiated in 1987, when the production rate was about 40 bbl/d completely transformed the unit economics. Peak productions of about 350 bbl/d were observed and the unit has been producing in the vicinity of 300 bbl/d consistently. The latest unit map is shown in Figure 1.1. Wells 9-34 and 7-34 were drilled in late 1993 and late 1994 respectively. These new wells are doing reasonably well. The production rates from wells have declined steadily. Reservoir internal analysis (using reservoir simulation) has shown that there is movable oil in the vicinity of these wells, but the pressure in these wells is not adequate to sustain higher production rates. Thus, the production from the unit appeared limited more due to water injection limitations. The reservoir modeling also showed that about a third of the injected water was migrating beyond unit limits. The response to the water flood was also affected

by injection into sands which did not have direct communication with other wells. Finally, hydraulic fracturing also appeared to have played a role in determining the response of some of the wells. A cumulative gas oil ratio of about 940 scf/stb in comparison to the initial GOR of about 500 scf/stb shows that oil is still being produced from zones which are above the current bubble point and from zones which have free gas.

The Travis unit developed only over about 300 acres areally, produced about 245,000 barrels of oil in primary production predominantly from the thick (100 feet) Lower Douglas Creek Sand (LDC). The unit map is shown in Figure 1.2. Well 5-33 was drilled in 1994. FMI analyses of the core from 14a-28 showed the fine structure of the sand bodies and established that the fractures were oriented predominantly east-west. One of the project concepts was to apply some of the principles developed in the Monument Butte flood to Travis to recover secondary oil from LDC. Initially, based on the information provided by the FMI log in 14a-28, a dual-porosity, dual-permeability, fractured reservoir model was constructed for the Travis unit. This model showed that high injection rates that were being used (1000 stb/d) in 15a-28 might have caused the early water breakthrough in well 14a-28. Based on the predictions of this model the injection rates were reduced to around 300 stb/d. Eventually, well 3-33 was also converted to injection. This injection strategy has resulted in a gradual and steady pressurization of the LDC. Surface pressures of nearly 2000 psi have been reached, corresponding to bottom hole pressures of about 4600 psi. However, the production intervals open to LDC in wells 10-28 and 2-33 have not shown any response. In order to understand this reservoir behavior, three alternate reservoir models were constructed.

The three alternate models used to represent the Travis unit were a homogeneous model with locally adjusted permeabilities, a fractured model (dual-porosity, dual permeability) and a hydraulically fractured model. All of the three models were *tuned* to match the primary production data from the unit and were then used to predict the water flood response. The model predictions were slightly different in terms of production rates and water oil ratios.

The Boundary unit was the least developed of all the units. One of the sands in this unit was unusual in that a water oil contact was observed in the sand in one of the wells. The latest field map is shown in Figure 1.3. In the Boundary unit reservoir model, Data at 2 foot resolution was incorporated in the model. The model had 15 oil bearing layers separated by 13 non oil bearing layers for a total of 28 layers. The water-oil contact in one of the wells and the fact that the extent of the aquifer was not established, made this model the most complex of the three reservoir models. The model oil and gas predictions matched the field

results reasonably well. The logs for well 13-21, the largest producer in this unit did not show a water-oil contact. But the oil production from well 13-21 and the slow decline from that well could not be explained on the basis of sands present in that well. Hence it was determined that the production from 13-21 was aided by water influx from the same aquifer which was seen in the logs of well 7-20. It was also determined that 13-21 communicated with this aquifer through its hydraulic fracture.

Determining the conditions under which wax precipitation occurs and finding the effect of this precipitation on oil recovery were important tasks in this project. The thermal wellbore models were presented in the last report. In this report, it was demonstrated that wax precipitation models could be simplified to give equivalent results. It was also shown that wax appearance data as well as wax and oil composition data would be required to tune these models.

Currently, there are no models which account for the effect of wax precipitation on oil recovery. A first-generation model based on the generalized method of characteristics was developed. This model showed that wax precipitation causes lower oil recoveries and that the effect of precipitation is felt only in the later part of the water flood. For the parameters chosen in this study, the recovery reduction was nominal (4%), but for a certain combinations of parameters, the reduction in oil recovery could be as high as 10%.

During this project year, activities, both field and technical research, were continued in order to achieve the said objectives. Two new wells were drilled in Monument Butte and one in Travis during this project period. The field report is the subject of Chapter 2. The success of operating fluvial deltaic reservoirs successfully depends a great deal on geologic and reservoir characterization. A full-diameter core was obtained from well 14a-28 in Travis and was characterized. The core log has been presented in Chapter 3. The Formation Micro Imaging log (FMI) has been a excellent reservoir characterization tool. The FMI log of well 14a-28 has been analyzed in detail in Chapter 3 also. Reservoir simulations of the Travis unit are the subject of Chapter 4 followed by a 28-layer reservoir model of the boundary unit in chapter 5. Chapters 6 and 7 have been devoted to the analysis of wax (paraffin) formation and its effect on oil recovery.

Figure 1.1: A Unit map of the Monument Butte Unit.

Figure 1.2: A Unit map of the Travis Unit.

Figure 1.3: A Unit map of the Boundary Unit.

Chapter 2

Field Report

2.1 Monument Butte Unit:

2.1.1 Wells Drilled and Completed in 1994:

Federal #9-34: The well 9-34 was spud on 11/11/93 and put on production on 1/8/94. Initial oil production averaged 101 bbls per day for the month of January of 1994. Cumulative oil and gas production through December 31, 1994 has been 14,362 bbls and 10,930 mcf, respectively.

Federal #7-34: The well 7-34 was spud on 11/7/94 and put on production on 12/24/94. Initial oil production for 8 days of production in December of 1994 averaged 179.5 bbls per day. Cumulative oil and gas production through December 31, 1994 has been 1,436 bbls and 403 mcf, respectively.

2.1.2 Other Project wells:

Federal #10-34: The well 10-34 was spud in 10/92 and put on production on 11/26/94. Initial oil production averaged 65 bbls per day for the first 31 days of production. Cumulative oil and gas production through December 31, 1994 has been 13,164 bbls and 18,106 mcf, respectively.

2.1.3 Other Waterflood Activity:

The well 8-34 oil producer was converted into a water injector on 4/19/94. Cumulative water injection in the well 8-34 through December 31, 1994 was 15,907 bbls.

2.1.4 Summary of Monument Butte Unit Activity:

Cumulative oil and gas production for the entire unit through December 31, 1994 was 994,110 bbls and 2,171,382 mcf, respectively. Since the Monument Butte unit operations commenced in October of 1987, oil and gas production have increased 583,714 bbls or 142% and 548,291 mcf or 34%, respectively. Since the start of the cooperative agreement between the DOE and Lomax, oil and gas production has increased 223,278 bbls or 22% and 123,493 mcf 6%, respectively. Total water injection from inception through December 31, 1994 is 2,910,276 bbls.

2.2 Travis Unit

2.2.1 Wells Drilled and Completed in 1994:

Federal #5-33. The well 5-33 was spud on 10/25/94 and put on production on 12/12/94. Initial oil production averaged 62 bbls per day for the first 19 days of December of 1994. Cumulative oil and gas production through December 31, 1994 has been 1,181 bbls and 1,426 mcf, respectively.

2.2.2 Other Project wells:

Federal #14a-28: The well 14a-28 was converted into a water injector on 10/15/93 and has injected a total of 16,430 bbls of water through December 31, 1994.

2.2.3 Summary of Travis Unit Activity:

Cumulative oil and gas production for the entire unit through December 31, 1994 was 285,995 bbls and 1,344,077 mcf, respectively. Since the Travis unit operations commenced in December of 1991, oil and gas production have increased 32,259 bbls or 11% and 186,902 mcf or 14% respectively. Since the start of the cooperative agreement between the DOE and Lomax, oil and gas production has increased 29,012 bbls or 10% and 150,458 mcf or 11%, respectively. Total water injection from inception through December 31, 1994 is 616,075 bbls.

Chapter 3

Geologic Characterization: Travis Unit

3.1 The Lower Douglas Creek Sandstone

Correlation of well logs throughout the Uinta Basin has indicated the local occurrence of thick sandstones in the predominantly shaly interval between the Castle Peak marker and the B Limestone marker (Lomax terminology) in the lowest portion of the Eocene Green River Formation. The Lower Douglas Creek (LDC) sandstone is productive at the Duchesne Field, where it had been named the 'Extra Gold Sandstone' by Coors Energy geologists. In the Monument Butte area, the LDC is 100 ft thick in the Travis Unit (Figure 3.1). Based on detailed core description and facies associations in the Travis Unit, the LDC sandstone is interpreted to represent gravity flow deposits; predominantly, turbidites and debris or grain flows (Lutz and others, 1994). A log cross section through the Travis Unit is shown in Figure 3.2. The only other floodable sand in the Travis Unit was D-2. Isopach map of the D-2 sandstone is shown in Figure 3.3.

Cores and imaging logs of the LDC in well 14A-28 at the Travis Unit indicate the presence of thick (15 ft) packages of oil-stained, planar-laminated, fine-grained sandstone exhibiting various degrees of dewatering and soft-sediment deformation. The sandstones commonly contain complete Bouma sequences and are interpreted as moderate to low-density turbidite channel deposits. The core description is shown in Figure 3.4.

The LDC sandstones occur in isolated pods in a predominantly shale interval. In the Travis Unit, the sandstone has a funnel-shaped geometry with a localized, channelized base and a broad, flat top. Isopach thicks correspond with the location of syndepositional faults that offset older strata by as much as 50 ft. Our interpretation is that offset along these faults

created a slope in the generally shallow sublacustrine environment, caused the shelf margin to become unstable, and created accommodation space for the deposition of the turbidites.

3.2 Borehole Imaging

3.2.1 Introduction

Borehole imaging logs have proven to be very useful in the evaluation and characterization of the different sandstone reservoirs in the Monument Butte area. In this work the Formation Microimager (FMITM)¹ log, which is an improved version of the older dipmeter log, has been used. The following provides a brief outline of this type of log and its interpretation.

The dipmeter or fracture log is the oldest of the borehole imaging techniques (Schlumberger, 1986; Atlas Wireline Services, 1987). This type of log is essentially an oriented 4-arm caliper that maps the resistivity of lithologic units and fractures. The output are resistivity traces that have to be interpreted either manually or on a workstation. The earlier versions of this log utilized one resistivity sensor on each caliper arm (HDT) while a later version developed for stratigraphic work (SHDT) utilized two resistivity sensors per arm. Since fractures are normally filled with mud during the drilling process, they are often detected as more electrically conductive than the surrounding rock. However, if the fractures have been mineralized with quartz or calcite, they may appear as more resistive than the host rock.

The output from a dipmeter log is a series of resistivity traces that must be correlated, by an interpreter, to define the sinusoidal curve that represents its strike and dip. The difficulty in interpretation lies in the correct correlation of anomalies on the four traces of a microresistivity log.

Subsequent improvements in the dipmeter tool have been made by increasing the number of microresistivity sensors on each arm (Ekstrom et al., 1987; Bourke et al., 1989). The data display has also been improved by color coding to reflect the resistivity measured by these sensors. More conductive units are colored black to resemble shale while more resistive units are lightly colored to resemble sandstone. The greater density of resistivity sensors removes much of the uncertainty of correlation of the anomalies that existed with the older dipmeter tool. Interpretation is done using a workstation that quickly calculates strike and dip of zones identified by the operator.

Determining the orientation of planar features intersecting the borehole is generally de-

¹FMI is a trademark of Schlumberger Well Services

scribed in Figure 3.5. Here a planar feature, that dips to the south, is intersected by a cylinder representing the borehole. The imaging log maps the inside circumference of the borehole. If this map is unrolled and displayed flat, the intersection of the planar feature with the borehole wall appears as a sinusoidal curve. The dip azimuth of the feature is the direction of the trough of the sinusoid, while the dip angle is calculated as $\tan^{-1} h/d$. Thus a flat planar feature, such as horizontal bedding, intersected by a vertical well, will appear as a line across the image. The amplitude of the sinusoid will increase as the dip of the planar element increases.

3.2.2 Well Federal #14A-28

One of the initial activities in the Class I project in the Greater Monument Butte area was the coring of the Lower Douglas Creek section in well Federal #14A-28 drilled in the Travis Unit. Figure 3.6 shows the location of the well and gamma-ray and density logs for the section between the B limestone marker and the Castle Peak marker. A continuous core was collected between 5550 and 5646 feet. The FMI log was run between 5480 and 5770 feet and provided an invaluable comparison between lithology and imaging log response.

One of the initial realizations upon logging the core was that the Lower Douglas Creek reservoir was, in large part, formed as a turbidite. The core allowed the calibration of the sedimentary structures shown on the imaging logs. Analysis of bedding orientation from the FMI log, using FRACVIEW software on a SUN workstation, demonstrated the deformed nature of the bedding. Figure 3.7 shows plots of dip angle and dip azimuth as a function of depth for the portion of the Lower Douglas Creek Sandstone logged with the FMI tool. The dip data have all been corrected for a regional dip of 1° with a dip azimuth of 30° . Although this is a small correction, it is necessary to restore the dip data to its original orientation in order to make accurate determinations of sedimentary transport directions. The portions of the Lower Douglas Creek sandstone that have slumped can be easily identified by their relatively high dip angles. Note that the log has not reached the bottom of the turbidic sediments although it is largely in a shale section. The top of the slumped section is located at about 5535 feet. The high-angle portions of the slumped sections appear to have azimuths with a 300° orientation indicating that these sediments were emplaced by flow from the southeast toward the northwest. However, the long axis of the thickest portion of the net sandstone is oriented to the north and northeast (Figure 3.6). This would suggest that the sands filled a previously-formed channel or trough by transport at a high angle to the trough

axis.

Another way of plotting this data is shown on Figure 3.8. This is a plot of dip angle versus dip azimuth for the slumped section between 5535 and 5775 feet. Plotting in this manner shows the general high angle of the dips and again suggests a northwest trend to the depositional processes.

The core from the Lower Douglas Creek interval is moderately fractured. In general, fractures are developed in cemented sandstone beds rather than in more ductile, finer-grained lithologies. In the upper portion of the core, fractures are present in carbonate-cemented sandstone beds at 5570-5572', 5582' and at 5589-5590'. All of these fractures are identifiable on the FMI log. The fractures are open, subvertical and planar. Fractures in the upper and lower turbidite sandstone units are more irregular. At 5608-5611' and 5625-5627', open fractures are subvertical but tend to mimic the orientation and geometry of dewatering pipes in the laminated sandstones and are non-planar. The dewatering pipes appear to be oil-stained; the pipes may be filled with migrated fines (clay) that preferentially absorb oil.

Figure 3.9 is a rose diagram of the orientations of the highest quality fractures measured throughout the imaged portion of the #14A-28 well. These are oriented to the west-northwest, parallel to the Duchesne fault zone. It was clear from these early imaging logs that permeability in the Travis area is strongly influenced by fractures. In fact, the D2 reservoir interval, the only other candidate for water flood in this well, is also strongly fractured. It would seem likely that the common practice of hydrofracturing wells in this area will tend to enhance the natural west-northwest fracture permeability and could eventually lead to short circuiting. Interestingly, short circuiting did occur between the #14A-28 and #15-28 wells during the drilling of the #14A-28 and prior to hydrofracturing. The previous discussion of depositional trends of the LDC interval would tend to suggest that this short circuiting could be related to stratigraphic rather than fracture heterogeneity.

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Greater Monument Butte Area

Figure 3.1: Isopachs of Lower Douglas Creek sandstone in the Greater Monument Butte area

Figure 3.2: Correlated well-logs of Lower Douglas Creek sandstone in the Travis Unit at Monument Butte. Note occurrence of thick sandstone in downdropped fault blocks (see offset Castle Peak marker)

Figure 3.3: Isopachs of D-2 sandstone in the Vicinity of the Travis Unit

Figure 3.4: Summary lithologic log of Lower Douglas Creek core, well 14A-28, Travis Unit at Monument Butte. Note oil-stained turbiditic facies

Dip direction is trough of sinusoid
 Angle = $\tan^{-1} h/d$

Figure 3.5: Planar feature intersecting a wellbore and borehole imaging log of the feature.
 (modified from Zemanek et al. 1970)

B Limestone Marker

Travis Unit
Sections 28 and 33, T8S, R16E.

Lower Douglas Creek Sandstone

Castle Peak Marker

Figure 3.6: Type log for Lower Douglas Creek sandstone in Travis Unit, Greater Monument Butte Area. Log is from well Monument Federal # 14A-28. Inset map shows net thickness of the LDC sandstone in each well. The net sandstone portion of the LDC is shaded

Figure 3.7: Azimuth vs. depth and dip vs. depth plots for a portion of the Lower Douglas Creek sandstone in well 14A-28. Structural dip of 1° at 30° azimuth removed

Figure 3.8: Dip angle - Dip azimuth (DVA) cross plot of the turbidic portion of the Lower Douglas Creek sandstone between 5535 and 5775 feet from the analysis of FMI log. Structural dip of 1° at 30° azimuth removed

Figure 3.9: Rose diagram of the orientation of fractures in 14A-28 well

Chapter 4

Travis Unit Reservoir Simulations

4.1 Simulations

Detailed reservoir simulations for the Travis unit were continued. The response to the water flood in Travis has been slower than expected. Hence, three different reservoir models were constructed in order to analyze the ongoing water flood in Travis.

1. A homogeneous reservoir model with locally adjusted permeabilities.
2. Fractured dual-porosity, dual-permeability model.
3. A model with hydraulically fractured wells.

4.2 The homogeneous model

A variable thickness, variable depth model was employed. The reservoir parameters are summarized in Table 4.1¹.

The D-sands, the Lower Douglas Creek (LDC) sands and the Castle Peak sands were represented by two benches of sand bodies each. The injection and production field operations were duplicated in the simulations. The primary production match was satisfactory. If water injection in Travis is continued at a rate of 300 stb/day, the model predicts production rates of 67 stb/day of oil from the unit at the end of 1995 and peak production rates of 104 stb/day.

¹Tables and Illustrations are at the end of the Chapter

4.3 Fractured reservoir model

A description of this model was included in previous quarterly reports and in the first annual report. The dual-porosity, dual-permeability option was employed. These models do not permit inclusion of limited fracturing. With continued injection of 300 stb/day, this model predicts peak production rates of 51 stb/day at very high water cuts ($> 80\%$).

4.4 Hydraulically fractured model

This model was constructed specifically to see if hydraulic fractures were responsible for the water flood behavior being observed in Travis. The hydraulic fractures were represented by thin, essentially vertical blocks around wells. The widths of the smallest grid blocks were either 0.5 or 1 ft. The block widths were then progressively increased. Permeability of the hydraulically fractured zone was of the order of 100 Darcies in contrast to permeabilities of 5-10 mD in the surrounding blocks. The reservoir parameters employed are given in Table 4.2

In this particular model, the sands (D, LDC and Castle Peak) were lumped into single sections (to reduce computation time). The peak production rates predicted by this model were only half the rates predicted by the homogeneous model and the water cuts were higher. This model essentially illustrates that hydraulic fractures could have provided conduits for water channeling in the Travis unit.

4.5 Model comparison

Cumulative oil production results from the three models are compared with the field data in Figure 4.1. It is observed that the oil production history-match is reasonable for all the models. The cumulative gas production from the field is compared with the model predictions in Figure 4.2. Even though the ultimate gas production is well matched by all the models, the rates of gas production over the entire production interval are not well represented. We believe that matching gas production in all intervals will require incorporation of limited fracturing along with more accurate representations of hydraulic fractures. The oil production results from the homogeneous model for well 15-28 (which accounted for about 40% of the total field production) are compared with the field results in Figure 4.3. Once again, the model performance is reasonable, given its limitations.

Table 4.1: Reservoir Description of the Travis Unit employed in the Homogeneous Model

Reservoir extent	5,300-6300 ft
Grid	$5 \times 7 \times 8$
Grid size (x and y)	660 ft
Porosity (constant)	0.132
Initial reservoir pressure	2700 psia
Initial bubble point pressure	2350 psia
Oil gravity	33 API
Gas gravity	0.77
Initial oil saturation	0.76-0.78
Bottom-hole pressure	900 psi
Permeabilities	10 - 40 mD

Table 4.2: Reservoir Parameters employed in the Hydraulic Fracture Model

Grid	$7 \times 53 \times 5$
Grid size (x and y)	Varying from 660 ft to 0.5 ft
Porosity (constant)	0.132
Initial reservoir pressure	2700 psia
Initial bubble point pressure	2350 psia
Oil gravity	33 API
Gas gravity	0.77
Initial oil saturation	0.76
Bottom-hole pressure	900 psi
Reservoir Permeabilities	5-10 mD
Hydraulic Fracture Permeabilities	100-150 D

Figure 4.1: Cumulative oil production from the Travis Unit; Comparison of the three models.

Figure 4.2: Cumulative gas production from the Travis Unit; Comparison of the three models.

Figure 4.3: Oil Production in well 15-28 from the Travis Unit; Comparison of the three models.

Chapter 5

Boundary Unit Case Study

5.1 Synopsis

A reservoir model for the Boundary Unit has been presented. This was by far the most complicated reservoir model developed during the project. An effort is made to represent reservoir geology (porosity, thickness) at 2 feet resolution. Two types of reservoir models were developed; one without hydraulic fractures and with hydraulic fractures. The simpler of the two models, without hydraulic fractures is described in this report. This model had a total of 28 layers and about 6000 grid blocks.

5.2 Reservoir Description

The Boundary unit has six wells which have been completed in different regions. They are 7-20, 9-20, 15-20, 5-21, 11-21 and 13-21. Out of these, the well 5-21 has been shutdown and has never been operational. The remaining five wells encompass different regions of essentially six types of sands i.e. D_1 , D_2 , C, Castle Peak (CP), Lower Douglas Creek (LDC) and A_3 . General descriptions of each of these sandstones are presented below.

5.2.1 D_1 Sandstone

This is the uppermost sand layer and is present at an average depth of 5235 feet. D_1 sandstone is located only in well 13-21 with 11 feet of gross and 6 feet net thickness. This sandstone is quite compact with an average porosity of 11.3%. Since D_1 sandstone is located only in 13-21 it is limited to a narrow region in the unit. Because of its discontinuous nature in the Boundary Unit, the D_1 sandstone is not considered floodable and its isopachs are not shown.

5.2.2 D₂ Sandstone

The D₂ sandstone is present in the maximum number of wells covering four out of the five productive wells i.e 7-20, 9-20, 5-21 and 13-21. Log analyses have shown this sandstone to be divided into lobes; the lobes being separated layers of shale. Well 7-20 has 30 feet of net D₂ (36 feet gross) which is divided into two lobes of 8 feet and 22 feet. The upper lobe of 8 feet has an average porosity of 16.0% while the lower 22 feet lobe has an average porosity of 16.2%. The lower lobe of 7-20 has been found to have a water-oil contact at a depth of about 10 feet from the top. This complicates its modeling and representation in the simulator.

Well 9-20 has 9 feet of net D₂ sandstone which is also divided into two lobes of 5 feet and 4 feet each. The log analysis shows the sand to be highly porous with an average porosity of 18.67% in the upper lobe and 18.0% in the bottom lobe.

Well 5-21 has 14 feet of net D₂ (20 feet gross) which again is present in two lobes of 6 feet and 8 feet. The average porosities are 14.67% in the upper lobe and 13.71% in the lower lobe.

Well 13-21 also has D₂ in two lobes with net thicknesses of 4 feet and 12 feet, with average porosities of 15.0% and 17.0% for the upper and lower lobe respectively.

There also exists a structural gradient in the Boundary Unit. Well 7-20 is downdip of 9-20 which is completed in zones structurally below 13-21. The fact that oil-water contact was observed in 7-20 is consistent with the reservoir structure.

Thus the D-2 sandstone is fairly continuous through the Boundary Unit and the net sand isopach map is shown in Figure 5.1.

5.2.3 C Sandstone

C sandstone is present in two wells i.e. 7-20 and 11-21. In 7-20, there is net 5 feet of C with an average porosity of 15.28%. In 11-21 C sandstone is present in two lobes of thickness 9 feet and 6 feet each. The upper 9 feet has an average porosity of 14.22% and the lower 6 feet has an average porosity of 15.0%. C-sandstone appears regionally better developed around 11-21, outside the Unit boundaries. The net isopach map of the C-sandstone is shown in Figure 5.2.

5.2.4 LDC Sandstone

The LDC sandstone is present only in 15-20 with a net thickness of 41 feet (54 feet gross). It is divided into three lobes. The upper lobe has a net thickness of 5 feet and an average

porosity of 12.6%, middle lobe has 13 feet net and an average porosity of 14.0% while the bottom lobe has a net thickness of 23 feet and an average porosity of 13.6%. Since LDC is present only in 15-20, this well does not communicate with any other well.

5.2.5 A₃ Sandstone

This sandstone is found only in two wells i.e. 7-20 and 9-20. The net 25 feet of A₃ in 7-20 is divided into three lobes with net thicknesses of 9 feet, 6 feet, and 10 feet and average porosities of 15.56%, 12.33% and 14.6% in the upper, middle and lower lobes respectively. The well 9-20 has two lobes of A₃ sandstone. The upper lobe has a net thickness of 5 feet and an average porosity of 13.2% while the lower lobe has a net thickness of 3 feet with an average porosity of 11.67%.

5.2.6 CP Sandstone

The CP sandstone is present in wells 9-20 and 5-21. This is the deepest sand in the reservoir. The wells 13-21 and 11-21 were not drilled deep enough to verify the presence or absence of this sandstone in other areas of the reservoir. In 5-21, CP sandstone is present as two beds with net sands of 2 feet and 8 feet and average porosities of 11.0% each. In the well 9-20, the sandstone has three components of 5 feet, 8 feet, and 6 feet net and average porosities of 11.8%, 12.5% and 13.67% in the upper, middle and lower lobes respectively. The beds are at the same stratigraphic horizons in both wells. The two lobes in 5-21 are thus assumed to be communicating with the upper and the middle lobe in 9-20 while the bottom lobe in 9-21 is independent.

5.3 Simulation Analysis

Reservoir simulation of the Boundary unit was performed using a 28 layer, 16 × 13 grid model. The 28 layers consist of 14 oil bearing sandstone layers, 1 aqueous layer, and the rest impermeable shale barriers separating the sandstones. Every attempt was made to incorporate the geologic information available as accurately as possible in the simulation data. A general description of the Boundary Unit is presented in Table 5.1. Computed average value of porosities were assigned to different layers although the data was available at 2 foot intervals. This is because representing separate 2 feet layers individually would have greatly increased the number of grid blocks making a single simulator run impossible

in a reasonable amount of CPU time, even on fast SPARC10 machines. In the order of increasing depths the 14 oil-bearing layers were: D₁ (1 layer), D₂ (2 layers), C (2 layers), LDC (3 layers), A₃ (3 layers) and CP (3 layers). The parameters employed in Boundary Unit simulation are given in Table 5.2. The water-oil contact in well 7-20 was modeled as a separate aqueous layer directly beneath the lowest D₂ sandstone layer in 7-20. Assumptions were made as to the extent of the aquifer, since enough data is not available to establish its extent. A comparison of the actual and simulated cumulative oil and cumulative gas produced in the Boundary Unit is shown in Figures 5.3 and 5.4 respectively.

Table 5.1: Reservoir Description of the Boundary Unit

Reservoir extent	7,920 × 6,600 ft
Grid	16 × 13 × 28
Grid size (x and y)	Varying from 760 ft to 200 ft
Oil gravity	33 API
Gas gravity	0.77
Initial oil saturation	0.78
Bottom-hole pressure	1000 psi

Figure 5.1: The Net Sand Isopach Map of the D-2 sandstone in the Boundary Unit.

Figure 5.2: The Net Sand Isopach Map of the C sandstone in the Boundary Unit.

Table 5.2: Reservoir Parameters employed in Simulation of Boundary Unit

Layer # in the model	Sand Identification	Porosity	Initial Reservoir Pressure (psi)	Bubble Point Pressure (psi)	OIP (MSTB)
1	D1	0.1133	2356	2300	253.6
3	D2	0.161	2388	2350	1370.0
5	D2	0.1623	2395	2360	1945.1
8	C	0.15	2440	2400	679.2
10	C	0.15	2444	2405	315.9
12	LDC	0.126	2605	2550	50.3
14	LDC	0.14	2614	2550	460.9
16	LDC	0.136	2626	2550	739.5
18	A3	0.144	2609	2550	841.8
20	A3	0.12	2615	2575	376.1
22	A3	0.146	2636	2600	304.1
24	CP	0.114	2760	2600	116.7
26	CP	0.1175	2764	2650	340.4
28	CP	0.1367	2768	2700	125.9

Figure 5.3: Cumulative Oil production from the Boundary Unit: Comparison of actual and simulated values

Figure 5.4: Cumulative Gas production from the Boundary Unit: Comparison of actual and simulated values

Chapter 6

Thermodynamics of Wax

6.1 Synopsis

In most nonthermal injection processes, fluids are injected at temperatures much lower than reservoir temperatures. Even though injected fluids are heated due to the prevailing geothermal gradient, in most applications, they reach the formation at temperatures far lower than the reservoir temperatures and cool the formation in the vicinity of the wellbore. The temperature lowering could cause solids precipitation particularly for paraffinic crudes and for oils susceptible to asphaltene precipitation. In this chapter, the effect of cold-water injection in paraffinic crude reservoirs has been studied.

Temperatures of water reaching the formation were calculated using an analytical wellbore model modified to include realistic wellbore resistances. These temperatures were observed to be below the cloud points of paraffinic crudes. These results have been reported in the first annual report. Solid-liquid equilibrium calculations showed that there was a strong possibility of paraffin precipitation under certain injection conditions.

6.2 Introduction

Injection of fluids into oil reservoirs for improving oil recovery is a common practice. Most of the oil reservoirs around the world are water flooded. Gas injections (light petroleum gas, carbon dioxide, etc.) are also fairly common. The fluids are usually injected at surface-ambient temperatures. These fluids get heated due to the geothermal gradient and injected fluid temperature at the perforations is governed by the actual value of the geothermal gradient, the nature of the injected fluid and the injection rate. Moss and White (1959) developed an analytical model for calculating temperature profiles for injected fluids. Ramey

(1962) modified the model to include other resistances to heat transfer. Sample calculations by Ramey showed water injected at 288 K (58°F) into a well which had a bottom-hole temperature of 322 K (120°F) was heated only to 292 K (65°F) as it entered the reservoir. In case of gas injections, the effect is less pronounced. Ramey commented that this reservoir cooling would reduce oil recoveries due to adverse fractional flow effects. A number of other wellbore heat transfer models have since been published (Pratt, 1982). The essential conclusions regarding fluid heating in wellbores have remained the same. The temperature profiles predicted by models have been substantiated by temperature logs (Ramey, 1962). Thus, there is sufficient evidence to believe that the fluids injected into reservoirs reach the target zones at temperatures substantially lower than reservoir temperatures.

The cooler temperatures, at the least, increase oil viscosities and adversely affect the water-oil fractional flow behavior (in case of a water flood), thus lowering oil recoveries. If the crude oil contains significant fractions of high-molecular weight hydrocarbons, precipitation of solids is possible. Solids deposition in oil reservoirs has been studied under two mutually exclusive subjects; wax precipitation and asphaltene deposition. Wax precipitation has been studied to understand deposition in oil transportation pipelines. Little attention has been paid to deposition within the reservoir, particularly on fluid injection, despite the fact that simple fluid cooling can bring about wax precipitation. Asphaltene precipitation has been studied in conjunction with gas injection processes, where depletion of lighter components may bring about precipitation.

There has been a great deal of work on the thermodynamic models for predicting paraffin (or wax) precipitation from oils (Weingarten and Euchner, 1988; Won, 1985, 1986, 1989; Hansen, 1988; Pedersen, 1991; Brown, 1994). Ring and Wattenbarger (1992) developed a computer simulator for predicting oil recovery in paraffinic crude reservoirs. Their model did not consider injection options and they used a simple thermodynamic representation for the hydrocarbon mixture. In analyzing the displacement of paraffinic crudes by cold water, Bedrikovetski and Klyakhandler (1991) assumed that the paraffin deposition changed the relative permeability of oil while leaving the water relative permeability unaffected.

In this report, results of a modified heat transfer model presented last year which was developed to calculate the temperature of injected water as functions of depth and time have been reviewed. Solid-liquid equilibria models have been reviewed and capabilities and limitations of current models in predicting solid-liquid equilibria of highly paraffinic crudes have been presented.

6.3 Results and Discussion

6.3.1 The Wellbore Thermal Model

Temperature profile in a typical water injector using the previously described procedure is shown in Figure 6.1. The wellbore parameters used in the calculations are shown in Table 6.1. The sample calculation was performed for an injection well, 1525 m (5000 feet) deep, with an injection rate of 48 m³ per day (300 barrels per day). The temperature of injected water was 289 K (60°F), while the reservoir temperature was 333 K (140°F). Figure 6.1 shows that the temperature of the water entering the perforations after about 1 year of injection is 302 K (83.8°F) for the parameters employed in this calculation. For smaller injectors (16 m³/d or 100 barrels per day) the injected water reaches the perforations at 316 K (109°F), while for the larger injectors (80 m³/d or 500 barrels per day), the injected water reaches the formation at 298 K (76°F). Continued injection of cold water does not change the above results significantly. For example, after ten years of injection, the temperature of the injected water for the base case (48 m³/d or 300 stb/day) at the perforations was 301 K (82.3°F). These basic calculations illustrate the fact that water is entering the reservoir at temperatures much cooler than reservoir temperatures. The cloud points of the crudes from Monument Butte are known to be around 322 K (120°F). Thus, when cold water is injected into a reservoir containing equivalent crude oils, wax deposition (solids precipitation) is a distinct possibility.

6.4 Solid-liquid equilibria

Weingarten and Euchner (1988) developed a simple solubility model to calculate the solubility of 'paraffin' component in liquid oil.

$$\ln x_{ps} = \frac{-\Delta H_f}{R} \left(\frac{1}{T} - \frac{1}{T_f} \right)$$

With this simple representation, the solubility of the 'paraffin' fraction in the oil at any given temperature can be calculated by using the heat of fusion and the melting point of the pseudo-component. If the solubility of the fraction in oil exceeds the initial concentration of the paraffin component in oil, then all the paraffin will remain in solution. Paraffin precipitation will occur when the solubility is lower than the initial concentration of paraffin

in oil. Weingarten and Euchner extended the concept to predicting wax appearance points of live oils at high pressures. Ring and Wattenbarger (1992) adopted the concept in simulating oil production from paraffinic reservoirs susceptible to paraffin precipitation. The above approach does not consider detailed oil composition data.

Won developed a series of models for predicting solid-liquid and solid-liquid-vapor equilibria (Won, 1985,1986,1989). He essentially created the framework for using detailed oil compositions in solid-liquid equilibria predictions. Rigorous expression for the solid-liquid K-values, K_{iSL} was shown to be:

$$K_{iSL} = \frac{s_i}{x_i} = \frac{\gamma_i^L}{\gamma_i^S} \exp\left[\left(\frac{\Delta H_f}{RT}\left(1 - \frac{T}{T_f}\right)\right) + \frac{\Delta c_p}{R} \left(1 - \frac{T_f}{T} + \ln \frac{T_f}{T}\right) + \int_0^P \frac{\Delta V}{RT} dP\right]_i$$

Won (1985,1986,1989) neglected the last two terms within the exponential. In his earlier paper (1985), he assumed that the ratio of activity coefficients, γ_i^L/γ_i^S to be equal to 1.0, while in a later paper on solid-liquid-vapor equilibria (1986) he calculated the ratio using the regular solution theory. Pure-component solubility parameters were required in using this approach for solid-liquid equilibria calculations. Later (Won, 1989), he used a more sophisticated irregular solution theory for the calculation of activity coefficients. Hansen et al (1988) contended that the wax appearance points calculated by Won's models for about 17 crude oils were considerably higher than the experimental values. They proposed an alternate model for the calculation of activity coefficients. The model appeared to perform better than Won's model even though activity coefficients predicted by the model were of the order of 10^{-10} . Pederson et al (Pedersen, Skovborg and Ronningesen, 1991) concluded that Hansen's model did not provide any phenomenological advantage over Won's models and proceeded to use Won's model with modified expressions for heats of fusion, solubility parameters, and by considering the Δc_p term in the K-value expression. Won (1986) proposed the following expressions for solubility parameters using the regular solution theory.

$$\delta_{iL} = \left(\frac{\Delta H_v - RT}{v}\right)_{i,L}^{1/2}$$

$$\delta_{iS} = \left(\frac{\Delta H_v + \Delta H_f - RT}{v}\right)_{i,S}^{1/2}$$

Won (1986) listed the values of solubility parameters that he obtained, although he did not discuss computation of heats of vaporization. The following methodology can be used

for the calculation of heats of vaporization. Heat of vaporization at normal boiling point for a component is given by (Reid, Prausnitz and Poling, 1987):

$$\Delta H_{vb} = RT_c T_{br} \left[\frac{3.978 T_{br} - 3.958 + 1.555 \ln P_c}{1.07 - T_{br}} \right]$$

Heat of vaporization at 25°C, which is used for the calculation of the solubility parameters is determined using the following expression (Reid, Prausnitz and Poling, 1987).

$$\Delta H_v = \Delta H_{vb} \left(\frac{1 - T_{r25^\circ C}}{1 - T_{br}} \right)^n$$

where, n is given by:

$$n = (0.00264 \frac{\Delta H_{vb}}{RT_b} + 0.8794)^{10}$$

The boiling point T_b is calculated using standard correlations.

The heats of vaporization for normal paraffins calculated by the abovementioned approach were verified with experimental values (Perry, 1973). The solubility parameters calculated using the method described, are different from the solubility parameters listed by Won (1986) for components up to C_{45} . Pedersen et al (Pedersen, Skovborg and Ronningsen, 1991) developed independent correlations for solubility parameters. They also modified the expression for heat of fusion used by Won to reflect the presence of nonparaffins in the oil and considered the effect of heat capacity differences in the solid and the liquid phases. This modified Won's method has been the most successful model in the prediction of wax appearance points and wax amounts for 17 North Sea crude oils. The wax appearance points for Hansen's (1988) oils 1, 2, 10 and 12 and for a paraffinic crude from Green River Formation, Utah were calculated using the following methods:

1. Assuming the activity coefficients were equal to 1. This was Method 1.
2. Using the solubility parameters listed by Won (1986). This was Method 2.
3. Using the solubility parameters obtained via correlations presented in this paper. This was Method 3.
4. Using the solubility parameters listed by Pedersen and by modifying the expression for heat of fusion, also proposed by Pedersen et al (Pedersen, Skovborg and Ronningsen, 1991). In these calculations, the Δc_p term was not considered and the individual C_7+ fractions were *not* divided into paraffinic, naphthenic and aromatic sub-constituents.

Thus, this was a simplification of the procedure proposed by Pedersen et al (Pedersen, Skovborg and Ronningsen, 1991). This was method 4.

Oils 1 and 2 were chosen because detailed compositional information was provided by Hansen et al (1988). Oils 10 and 12 were selected since the wax appearance points predicted by Pedersen et al (Pedersen, Skovborg and Ronningsen, 1991) for these two oils differed from the experimental values by more than 20 K.

Results of these calculations are shown in Table 6.2. Wax appearance points calculated by neglecting the effect of activity coefficients and by using the solubility parameters listed by Won (1986) are almost identical. Methods 1 and 2 overpredict wax appearance points. However, predictions from the model are still considerably lower than the values attributed to these models by Hansen et al (1988). Use of solubility parameters determined by established correlations makes the predictions worse. Pedersen's modifications of the Won's model do improve predictions for oils 1 and 2. Our calculations indicate that simplifying the calculations (considering single, lumped carbon number components and neglecting the Δc_p term) actually improves predictions for some of the oils. The heats of fusion adjustment makes a much bigger difference in wax appearance points predictions (compared to Won's models) than adjustments in solubility parameters. The comparison also illustrates that wax appearance points should be used with caution for tuning models. The wax appearance point of 314 K for oil 10, which contains only 33 wt% C_{20+} , definitely appears to be an anomaly. Oil 1 which contains about 61 wt% C_{20+} has a wax appearance point of 304 K. The chemical compositional division into paraffinic, naphthenic and aromatic constituents which has been built into the models is not sufficient to explain these differences. The calculations illustrate that reasonable predictions could be obtained by using the simplest of the Won's models (neglecting the effect of activity coefficients) with heats of fusion modification proposed by Pedersen et al (Pedersen, Skovborg and Ronningsen, 1991). Won's most recent model (1989) and some of the more recent models (Brown, et al., 1994) were not compared in this study.

A brief review of solid-liquid equilibria calculations for the prediction of wax precipitation and calculations performed as part of this study underscore the following points. Tuning models to predict wax appearance points or wax amounts may not yield adequate models. Considering phase compositions will improve model predictions. In this regard, data on phase compositions are necessary, particularly for oils containing substantial fractions of heavy components. The calculations shown in Table 6.2 indicate that even after a 10-20 K

adjustment (for presence of gas, pressure, etc.), at temperatures predicted by the wellbore model, paraffin precipitation is certain in reservoirs containing the Green River crude. The effect of this precipitation on oil recovery is analyzed in the next chapter.

6.5 Nomenclature

K_{iSL} Solid -Liquid equilibrium coefficient, dimensionless

P_c Critical pressure, bar

R Universal gas constant, J/mole-K

s_i Mole fraction of component i in solid phase, dimensionless

T_{br} Reduced temperature at normal boiling point, dimensionless

T_c Critical temperature, K

T_f Fusion temperature, K

x_i Mole fraction of component i in liquid phase, dimensionless

x_{ps} Solubility of solid paraffin (that can be dissolved) in oil, dimensionless

ΔC_p Heat capacity change of fusion, cal/mole-K

ΔH_f Latent heat of fusion, cal/mole

ΔH_v Latent heat of vaporization, cal/mole

ΔV Volume change on fusion, cm^3

δ_i^L Solubility parameter of component i in liquid phase, $(\text{cal/cc})^{0.5}$

δ_i^S Solubility parameter of component i in solid phase, $(\text{cal/cc})^{0.5}$

γ_i^L Activity coefficient of component i in liquid phase, dimensionless

γ_i^S Activity coefficient of component i in solid phase, dimensionless

6.6 References

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Table 6.1: Parameters used in Calculating the Temperature Profiles in Injection Wells

Surface Temperature	289 K
Geothermal Gradient	0.029 K/m
Reservoir Temperature at 1525 m	333 K
Water Injection Temperature	289 K
Tubing, Outside Diameter	0.073 m
Tubing, Inside Diameter	0.062 m
Casing, Outside Diameter	0.14 m
Casing, Inside Diameter	0.124 m
Cement, thickness	0.013 m
Thermal Conductivity, Steel	43.27 J/s-m-K
Thermal Conductivity, Earth	2.45 J/s-m-K
Thermal Conductivity, Cement	0.87 J/s-m-K
Thermal Diffusivity, Earth	$3.87 \times 10^{-3} \text{ m}^2/\text{hr}$

Table 6.2: Comparison of wax appearance points (K) calculated by different methods

	Method 1	Method 2	Method 3	Method 4	Experimental
Oil 1	339	340	349	326	304
Oil 2	332	333	339	321	312
Oil 10	316	317	328	301	314
Oil 12	324	325	333	311	305
Utah Oil	342	343	—	330	322

Notes:

1. Oils 1, 2, 10 and 12 are North Sea Crudes. Compositional data on these oils has been provided by Hansen et al⁸.
2. Utah oil is from the Green River formation in the Monument Butte field.
3. Experimental values for the North Sea crudes were reported by Pedersen et al⁹.

Figure 6.1: Temperature profile in a typical water injection well after one year of injection.

Chapter 7

Effect of Precipitation on Recovery

7.1 Synopsis

Strong possibilities of reservoir cooling and wax precipitation due to the cooler temperatures were established in the last chapter. The effect of precipitation on oil recovery was analyzed using the method of characteristics approach and has been presented in this chapter. This amounts to the solution of the partial differential equations for the flow of oil and water, with and without paraffin deposition.

7.2 Problem Description and Formulation

Bedrikovetski and Klyakhandler (1991) performed oil recovery calculations on water flooding paraffinic oil reservoirs. The calculations described in this paper provide theoretical bases and formal explanations for some of the solutions presented by them.

The following physical situation is considered. A reservoir at its initial reservoir temperature is being water flooded. The temperature of water entering the reservoir can be determined using the wellbore thermal model described earlier. If the oil is assumed to contain a single, lumped paraffin component and paraffin precipitation is taken into account, the problem of calculating oil recovery is reduced to the solution of the following three quasi-linear hyperbolic equations. The formulation is in one dimension and volume change on mixing is neglected.

$$\frac{\partial S_w}{\partial \tau} + \frac{\partial f_w}{\partial \xi} = 0$$

$$\frac{\partial}{\partial \tau}(S_p + C_s(1 - S_p - S_w)) + \frac{\partial}{\partial \xi}(C_s(1 - f_w)) = 0$$

$$\begin{aligned}
& \frac{\partial}{\partial \tau} ([c_{pw}S_w + (C_s(1 - S_w - S_p) + S_p)c_{pp} \\
& + (1 - C_s)(1 - S_w - S_p)c_{po}] + [\frac{1 - \phi}{\phi}c_{pr}])T \\
& + \frac{\partial}{\partial \xi} [c_{pw}f_w + (1 - f_w)(C_sc_{pp} + (1 - c_s)c_{po})]T = 0
\end{aligned}$$

The first two differential equations are material balances on water and paraffin components respectively, while the third equation is the overall energy balance. Heat transfer to and from the surrounding media is neglected in the development of the energy balance.

7.3 Solution Technique

The simplest physical situation which can be solved using the above formulation is cold-water injection without paraffin deposition. The solution to such a problem would require consideration of only two differential equations, the water material balance and the energy balance. Just like in hot-water injections, this problem is characterized by two fractional flow curves (one at reservoir temperature and the other at the cold-water injection temperature; Figure 7.1). The only differences between the two fractional flow curves were fluid viscosities. The fractional flow curves were generated by using normalized Corey equations. The Corey exponents and other relevant parameters are shown in Table 7.1. The solution to the cold-water injection problem is more complicated than the solutions which have been developed for hot-water injections to enhance oil recoveries (Fayers, 1962). In the cold-water injection problem, two shocks are formed in water saturation profiles, one which coincides with the Buckley-Leverett shock and the other due to the temperature shock. A schematic of this profile is shown in Figure 7.2. In a general situation (with paraffin deposition), the velocity of the temperature front is given by:

$$v_T = \frac{f_w + \left(\frac{c_{po}(1 - C_s) + C_sc_{pp}}{c_{pw} - (1 - C_s)c_{po} - C_sc_{pp}} \right)}{S_w + \frac{c_{po}(1 - S_p)(1 - C_s) + [C_s(1 - S_p) + S_p]c_{pp} + \frac{1 - \phi}{\phi}c_{pr}}{c_{pw} - (1 - C_s)c_{po} - C_sc_{pp}}}$$

In the cold-water injection problem without paraffin deposition, S_p and C_s are set equal to zero. Coherence (Helfferich, 1981) requires that the temperature shock coincide with the second saturation shock. Velocity constraints require the downstream value of the second

saturation shock (point 2 in Figure 7.2) to be on the lower, reservoir-temperature fractional flow curve. Thus, the condition for determining the downstream (-) value of water saturation, associated with the second water saturation shock is given by:

$$v_T = \left(\frac{df_w}{dS_w} \right)_{\text{reservoir-temp}}$$

The above condition lends itself to a straightforward graphical construction, very similar to the graphical construction for hot-water injection (Lake, 1989). The coordinates from which tangent is drawn to the reservoir-temperature fractional flow curve are easily deduced from the temperature velocity expression.

Since the water-saturation velocities increase monotonically from the Buckley-Leverett shock saturation to the downstream side of the second shock, there is a zone of continuous variation between these two points. The upstream (+) value of water saturation (point 3 in Figure 7.2) lies on the upper, lower-temperature fractional flow curve. This point is characterized by a faster shock velocity and a slower saturation velocity (point 4 in Figure 7.2). As a result, a zone of constant state develops at this saturation. A zone of continuous variation from this saturation to the residual oil saturation on the lower-temperature fractional flow curve completes the solution. Saturation profile for a specific cold-water injection problem is shown in Figure 7.3. Corresponding temperature profile and paraffin saturation profile (when paraffin precipitation does occur) are also shown on the same figure. All the calculation parameters used for constructing this profile are given in Table 7.1. The corresponding recovery curve is shown in Figure 7.4 along with the equivalent Buckley-Leverett curve (for an isothermal water flood at the reservoir temperature). It is seen that reduction in oil recovery is realized, late in the life of the flood.

When paraffin precipitation is considered, the precipitation shock coincides with the temperature shock. The paraffin saturation on the upstream side of the shock is obtained by the coherence requirement.

$$v_T = \frac{C_s^+(1 - f_w^+) - C_s^-(1 - f_w^-)}{[S_p + C_s^+(1 - S_w^+ - S_p)] - C_s^-(1 - S_w^-)}$$

Limited data is available on the effect of paraffin precipitation on absolute permeabilities of porous media (Sutton, et al., 1974). There is no data on the effect of paraffin precipitation on relative permeabilities. Bedrikovetski and Klyakhandler (1991) assumed that the paraffin precipitation affects only oil relative permeabilities apart from absolute permeabilities. There is also no data on the effect of paraffin deposition on residual oil saturation. In order

to illustrate the solution, it was assumed that paraffin deposition does not alter relative permeability curves and thus, fractional flow behavior. It was also assumed that the residual oil saturation without paraffin deposition was equal to residual oil saturation plus solid paraffin saturation when the paraffin precipitation did occur. These assumptions were made without justification and simply to illustrate the solution procedure. The solution procedure easily accommodates other situations (varying relative permeabilities, varying end-points, etc.) without loss of generality. The sensitivity of these parameters and their effect on the overall solution is being published as part of a companion paper.

With the assumptions listed above, the fractional flow curves for the lower temperature with and without paraffin precipitation remain identical. As a result, the water saturation profiles remain more or less the same. Water saturation profile along with temperature and paraffin saturation profiles are illustrated in Figure 7.3. With about 12 wt% paraffin in the original oil (very highly paraffinic crudes), the paraffin solid saturation was determined to be about 3%. In most fine-grained rocks, a 3% solid saturation would have a catastrophic effect on reservoir absolute permeabilities. When the original paraffin weight content was reduced to 8 wt%, the solid saturation in the cold zone decreased to 1.43. Since the water saturation profile remains more or less the same as in the cold-water injection case, the oil recovery curve is also more or less the same as shown in Figure 7.4. Since the water saturation profiles are not very different from the cold-water injection case, the oil recovery curves with and without paraffin precipitation do not change much. However, this will not be the case when effects of relative permeabilities, etc. are considered. In heterogeneous systems, paraffin deposition may plug the most productive zones, affecting oil recoveries to a greater extent. As expected in injection operations, the temperature shock significantly lags the first saturation shock and the effect of cold water injection are felt late in the life of the water flood.

7.4 Summary of Near Wellbore Effects

Wellbore thermal model analysis indicates that in normal water injection operations, reservoir cooling is likely. A review of current solid-liquid equilibria models reveals that the models are not adequate in predicting wax appearance temperatures for highly paraffinic crudes. This is as much a result of wax appearance point temperature measurements as the model phenomenology. Model validation should be based on complete thermodynamic information including phase compositions. The models do indicate that at near wellbore

temperatures in injection operations, paraffin precipitation is a distinct possibility. The effect of paraffin deposition on oil recovery was studied using a no-dispersion, one-dimensional method of characteristics model. Example calculations indicated that there is reduction in oil recovery and it is felt late in the life of the water flood.

7.5 Field Activities to Address the Wax Problem

7.5.1 The Microbial Program

In the Monument Butte Unit, wells 6-35, 10-35, 12-35, 14-35 and 12-36 were subjected to microbial treatment. The wells were treated with a known volume of an aqueous solution containing the microbes and the nutrients and were shutin for 24 hours (except for 10-35, which was shutin for six hours due to its larger flow capacity). The results of the microbial treatment have been inconclusive with respect to production enhancement. However, the number of hot-oiling treatments to maintain production rates have been reduced by about half and the oil gravity has increased 1° API on the average. Injection wells were not subjected to treatment. The techniques as well as results and analysis will be provided in the final report, when more data will be available.

7.5.2 Hot Water Injection

Based on the results of wellbore heat transfer presented in the first Yearly Report, heated water was injected into well 3-35 in order to increase the injection rate. The injection rate at the time of hot water injection was around 55 stb/d. The injection of hot water did not significantly affect the injection rate, which has remained at around 55 stb/d over about 2 years of hot water injection. The water was heated to about 155°F at the surface prior to injection.

The heat-transfer model which was presented in the previous Yearly Report did show that the effect of wellbore cooling was minimal for small injectors. The model shows that for the 55 stb/d injector, when water is injected at 60°F at the surface, it heats up to about 125°F at 5300 ft. When injected at 155°F, the water reaches the same depth at 126.5°F, a marginal improvement. Furthermore, the temperatures, 125°F and 126.5°F are slightly above the cloud point of this oil, which is around 120°F. The hot water injection is expected to make a more significant difference in larger injectors (around 300 stb/d).

7.6 Nomenclature

c_{pw} Volumetric heat capacity of water, Joules/cc-°C

c_{po} Volumetric heat capacity of oil, Joules/cc-°C

c_{pp} Volumetric heat capacity of solid paraffin, Joules/cc-°C

c_{pr} Volumetric heat capacity of rock, Joules/cc-°C

C_s^+ Volume fraction of dissolved paraffin in oil at injection temperature, dimensionless

C_s^- Volume fraction of dissolved paraffin in oil at reservoir temperature, dimensionless

f_w Water fractional flow, dimensionless

S_p Paraffin solid saturation, dimensionless

S_w Water saturation, dimensionless

t_D Dimensionless time defined in the text

ϕ porosity of the formation, dimensionless

τ Dimensionless time

ξ Dimensionless distance

7.7 References

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Table 7.1: Parameters used in constructing the saturation profiles and oil recovery curves

Connate water saturation	0.15
Residual oil saturation	0.25
Corey exponent on normalized oil relative permeability	3
Corey exponent on normalized water relative permeability	4
End-point oil relative permeability	0.8
End-point water relative permeability	0.15
Porous medium porosity	0.15
Water viscosity at reservoir temperature	5.0×10^{-4} Pa-s
Oil viscosity at reservoir temperature	1.0×10^{-2} Pa-s
Water viscosity at injection temperature	7.5×10^{-4} Pa-s
Oil viscosity at injection temperature	4.0×10^{-2} Pa-s
Volumetric heat capacity of water	4.2 J/cc-K
Volumetric heat capacity of oil	1.9 J/cc-K
Volumetric heat capacity of rock	1.9 J/cc-K
Initial paraffin solubility	8 wt%
Initial paraffin concentration (volume fraction)	0.06
Final paraffin concentration (volume fraction)	0.015

Figure 7.1: Fractional flow curves employed in calculations to assess the impact of low-temperature water flood and of paraffin deposition on oil recoveries.

Figure 7.2: A schematic illustrating the method of characteristics solution developed to analyze the effect of paraffin precipitation in reservoirs on oil recovery.

Figure 7.3: Water saturation, temperature and paraffin saturation profiles for calculation parameters shown in Table 7.1.

Figure 7.4: Comparison of oil recovery in the cold-water injection case with oil recoveries for isothermal, Buckley-Leverett displacement.