GAS DRAW WATERFLOOD

FEASIBILITY STUDY

By

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## CONTENTS

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>ABSTRACT</td>
<td>v</td>
</tr>
<tr>
<td>ACKNOWLEDGMENTS</td>
<td>vi</td>
</tr>
<tr>
<td>INTRODUCTION</td>
<td>1</td>
</tr>
<tr>
<td>GEOLOGY AND HISTORY</td>
<td>3</td>
</tr>
<tr>
<td>Geology of Field</td>
<td>3</td>
</tr>
<tr>
<td>Well Designation of Field</td>
<td>4</td>
</tr>
<tr>
<td>History of Field</td>
<td>5</td>
</tr>
<tr>
<td>RESERVOIR PARAMETERS</td>
<td>7</td>
</tr>
<tr>
<td>Effective Pay Thickness</td>
<td>7</td>
</tr>
<tr>
<td>Porosity</td>
<td>8</td>
</tr>
<tr>
<td>Permeability</td>
<td>8</td>
</tr>
<tr>
<td>Water Saturation</td>
<td>9</td>
</tr>
<tr>
<td>RESERVOIR FLUID STUDIES</td>
<td>11</td>
</tr>
<tr>
<td>RELATIVE PERMEABILITY DATA</td>
<td>13</td>
</tr>
<tr>
<td>Gas-Oil Relative Permeability</td>
<td>13</td>
</tr>
<tr>
<td>Water-Oil Relative Permeability</td>
<td>14</td>
</tr>
<tr>
<td>DETERMINATION OF OIL-IN-PLACE</td>
<td>16</td>
</tr>
<tr>
<td>PRIMARY PERFORMANCE</td>
<td>17</td>
</tr>
</tbody>
</table>
CONTENTS

SECONDARY PERFORMANCE .................................................. 21
Laboratory Waterflood Tests ............................................. 21
Sweep Efficiency ................................................................. 22
Displacement Efficiency ..................................................... 23
Vertical Sweep Efficiency ................................................... 24
Areal Sweep Efficiency ....................................................... 25
Injection and Production Rates ............................................ 26
  Injection Rate ................................................................. 26
  Production Rate .............................................................. 27
WATER SOURCE ...................................................................... 29
ECONOMICS OF SECONDARY RECOVERY ................................ 31
CONCLUSIONS ....................................................................... 33
BIBLIOGRAPHY ..................................................................... 34
APPENDIX ............................................................................. 36
ABSTRACT

A reservoir engineering study was made to determine the feasibility of waterflooding the Gas Draw Field. The oil-in-place was calculated volumetrically and primary performance calculations were made to determine the oil recovery by natural depletion. Secondary recovery performance calculations were made to determine additional oil recovery by waterflooding.

Comparison of the primary and secondary performance calculations indicated 4,146,500 STB of additional oil would be recovered by waterflooding the reservoir. A waterflood would be feasible because an undiscounted profit of $5,948,200 would be realized by the initiation of a waterflood.
ACKNOWLEDGMENTS

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INTRODUCTION

Secondary recovery is a method for increasing oil recovery from a new or a depleted reservoir. This increased recovery is important because the cost of a barrel of secondary recovery oil is less than the cost of finding a new barrel of oil.

A reservoir engineering study was made to determine the feasibility of waterflooding the main Muddy pay in the Gas Draw Field. Necessary data for the reservoir study was obtained from fluid analysis and special core analysis made by commercial laboratories, well logs from each well, and the production from each well. No pressure history for the field was available except for an initial pressure.

An oil-effective isopach was prepared from the individual well logs and the reservoir volume was calculated volumetrically from the reservoir volume and other reservoir parameters such as water saturation and porosity. Primary oil recovery above the bubble-point pressure was obtained by considering the fluid and rock expansion that occurred during a pressure drop from the initial pressure to the bubble-point pressure. Oil recovery below the bubble-point was calculated from a material balance which forecasts the
reservoir performance by relating pressure decline to oil recovery.

Secondary oil recovery by waterflooding was obtained by multiplying a reservoir recovery efficiency by the oil-in-place. The reservoir recovery efficiency considered a displacement efficiency, an areal sweep efficiency, and a vertical sweep efficiency.

Cash flows were calculated for the primary and secondary performances. Undiscounted and discounted profit, payout, and rate of return on the investment were obtained by comparing the two cash flows and considering an investment for the waterflood.
The Gas Draw Field is located in northeast Campbell County, Wyoming, some 20 miles north of Gillette, Wyoming. A county-maintained road provides all weather access to the field (Figure 1). The following is a discussion of the geology, well designation, and history of the Gas Draw Field.

**Geology of Field**

The reservoir, a stratigraphic trap of sand-bar origin, is located on the gentle dipping east flank of the Powder River Basin. The oil accumulation is trapped by an updip sand pinchout with a well-defined oil-water contact downdip. Production is from three sands in the Muddy formation (regional name, sometimes referred to as Newcastle formation) of lower Cretaceous Age at a depth of approximately 7400 ft (Figure 2).

The main Muddy pay is productive in all the wells and is the uppermost sand in the Muddy formation. This sand is light brown, carbonaceous, fine to very fine grained, well sorted, subangular to subrounded, and friable.

The remaining two sands are small in area. One sand is located in the south part of the field, and the other
sand is located in the north part of the field. These sands are light brown, very argillaceous and clay filled, fine grained, well sorted, and subangular. They are perforated in five different wells, but have proven to be non-productive on swab and drill-stem tests.

**Well Designation of Field**

Each well is fully described through use of a legal subdivision number, a section number, a township number, and a range number. This USGS well designation is used because most of the wells are on Federal leases and because the well designation makes each well location unique. Reference is always made to the meridian from which the location is immediately west and the latitude from which the location is north or south. The descriptions at Gas Draw are all made in reference to the 6th prime meridian and the 40°N latitude.

Between meridians the land is subdivided into six mile strips. Each of these lines, which run north and south, is called a range line. Numbering of the range lines begins at 1W when a meridian is crossed. Starting at the 40th latitude the land is again divided into six mile strips. Each of these lines is called a township, and numbering begins with 1N when the 40°N latitude is crossed.

With range and township lines the land is divided into six mile squares which are called townships. Each
ER-1305
township is divided into 36 sections with the numbering begin­ning with one in the upper right-hand corner and pro­gressing to the left and back to the right and so on until 36 is reached in the lower right-hand corner.

Each section is divided into 16 legal subdivisions with the numbering beginning with 1 in the upper left corner and progressing to number 41 in the right hand corner. The second row begins on the left with number 12 and progresses to the right to number 42. The numbering is repeated until number 44 is reached in the lower right-hand corner (Figure 3).

History of Field

The field was discovered in August, 1968, with the drilling of the 11-19-54N-72W well. Development followed rapidly, and development drilling was essentially completed by June, 1969. A total of 86 wells were drilled of which 65 wells were productive (two presently shut in). Development was on uniform 80-acre spacing, except for three 40-acre infill wells.

The common completion practice was to drill to the Skull Creek formation (approximately 120 ft below the Muddy formation top) and set 5-1/2-in. casing to total depth. Wells were perforated by using two casing jets per foot. Approximately 1/3 of the wells were fractured on completion using 20,000-40,000 gallons gelled water. Almost all the
ER-1305

wells not fractured on completion have subsequently been
fractured using gelled water.

Gas Draw Field was an under-saturated reservoir
with the primary reservoir energy being fluid and rock
expansion above the bubble-point pressure. The primary
reservoir energy below the bubble-point pressure was
solution gas. It is not apparent if the downdip water
is contributing any reservoir energy.

Initial production rates of the wells varied from
a minimum of 20 BOPD (barrels oil per day) to a maximum of
1000 BOPD with no production restrictions. A maximum field
production rate of 13,000 BOPD was achieved with the
completion of field development. The field exhibited a
rapid production decline and was producing 9700 BOPD in
December, 1969. Engineering, geological, and commercial
laboratory studies are presently being made to determine
pressure maintenance feasibility. Pressure maintenance is
necessary to increase the production rate and increase
cumulative oil recovery.
RESERVOIR PARAMETERS

Reservoir parameters such as effective pay thickness, porosity, permeability, and water saturation must be known for reliable reservoir engineering calculations. The following is a discussion of the determination of effective pay thickness, porosity, permeability, and water saturation for Gas Draw Field.

Effective Pay Thickness

One of the most important parameters to be resolved was the size of the reservoir, the largest single variable being effective pay thickness. Determination of the reservoir size by volumetric methods was necessary as there was insufficient pressure history to obtain the reservoir size by material balance calculations.

It was necessary to use electric logs to calculate the effective pay thickness since only 12 of the 65 productive wells were cored. A 12% porosity cut-off on the density log and 14% porosity cut-off on the sonic log were used to determine net pay thickness. These cut-offs appear valid, as 99.5% of the samples from core analysis had 12% porosity or greater. This 12% core porosity cut-off was found to correspond to a 30 md. permeability cut-off
ER-1305
(Figure 4). Log and core porosities were compared. However, since few wells were cored and few wells had both sonic and density logs, core and log porosity correlations were unreliable.

The top and bottom of the main pay were easily obtained by using the gamma ray log (Figure 5). Using this information, structure contour maps of the top and bottom of the main pay were drawn (Figures 6 and 7). Using the values obtained for the effective pay thickness and the structure contour maps of the top and bottom of the main pay, and oil-effective isopach was drawn (Figure 8). The productive acreage, by planimetering, was 5284 acres with an average net thickness of 8.93 ft, resulting in a reservoir volume of 47,196 acre ft.

Porosity

The porosity of the main pay was obtained from a statistical analysis of all the core samples. Results of this statistical analysis were found to be as follows:

- Arithmetic average porosity: 20.21%
- Arithmetic mean porosity: 20.18%
- Median porosity: 19.75%
- Standard deviation: 3.6%

Permeability

The vertical and horizontal permeability of the main pay was also determined by statistical analysis of all the core samples. Results of this statistical analysis were
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found to be as follows:

- Arithmetic average horizontal permeability: 188 md.
- Geometric mean horizontal permeability: 135 md.
- Horizontal permeability variation: 55.87%
- Arithmetic average vertical permeability: 230 md.
- Geometric mean vertical permeability: 141 md.
- Vertical permeability variation: 61.5%

**Water Saturation**

The average initial water saturation, an important parameter in calculating the oil-in-place by the volumetric method, was obtained from capillary pressure tests and cumulative sand volume versus sub-sea elevation as follows:

1. Four core samples were obtained from wells in different portions of the field with different permeability ranges. These wells all produce from the same sub-sea datum. A complete oil-brine capillary pressure curve was obtained on each sample by a commercial laboratory.

2. The laboratory water saturations were plotted against the corresponding air permeabilities for each sample on semi-log paper. The log of permeability exhibits a straight-line relationship to water saturation for a constant capillary pressure. A best-fit straight-line was drawn through these points using the method of least squares. A relationship between permeability and water saturation was then known.

3. Knowing the geometric mean permeability and the relationship between permeability and water saturation, a field average capillary pressure was obtained. The capillary pressures were converted to height above the oil-water contact (Figure 9).

4. From the structure contour map on the top of the main Muddy pay and the net thickness of the wells, the cumulative sand
volume above the oil-water contact (-3197) was obtained (Figure 10). The sand volume in 10-foot increments above the oil-water contact was determined from the cumulative sand volume versus sub-sea elevation tabulation. The summation of the product of the sand volume for the increments and the water saturations for the increment (obtained from capillary pressure curve) is the weighted field average initial water saturation. This average water saturation was found to be 32%.

Attempts to average capillary pressures by other methods, such as the J function, were made. Because such methods were found not to be representative, they were not used.
Representative reservoir fluid data is necessary to make reservoir engineering calculations. The following is a discussion of how the necessary reservoir fluid data were obtained.

Bottom-hole fluid samples were obtained from two wells producing from the same sub-sea datum in different parts of the field. Both samples were obtained early in the life of the field while the reservoir was still above the bubble-point pressure. Results of the two fluid studies were the same.

The saturation pressure was found to be 1231 psig at the reservoir temperature of 178°F. The solution gas-oil ratio was 346 standard cubic feet of gas per barrel of residual oil. The formation volume factor at the bubble-point pressure was 1.256 bbls per barrel of residual oil. The oil viscosity was 0.95 centipoise at the bubble-point pressure and increased to a maximum of 1.96 centipoises at atmosphere pressure (Figures 11, 12, and 13). The gravity of the residual oil was 35.7° API at standard conditions of 60°F and 14.7 psig.

The gas deviation factor was determined from analysis
ER-1305

of the liberated gas (Figure 14). Using the gas deviation factor, reservoir temperature, and reservoir pressure, the gas volume factor was calculated by the following formula (Figure 15):

\[ B_g = \frac{0.00504 Z T_R}{P} \]

where \( B_g \) = gas volume factor, Bbl/SCF,
\( Z_g \) = gas deviation factor, fractional,
\( T_R \) = reservoir temperature, \( ^\circ R \),
\( P \) = reservoir pressure, psig.

The gas viscosity was obtained by the use of Carr's (1954) gas viscosity correlations (Figure 16).
Relative permeability tests, both gas-oil and water-oil, were run on four core samples. The following is a discussion of how these relative permeability tests were averaged to obtain representative relative permeability curves for the reservoir.

**Gas-Oil Relative Permeability**

The equations for $K_{rg}/K_{ro}$ (gas-oil relative permeability) as developed by Corey (1954, p. 38ff) were used to obtain a gas-oil relative permeability relationship which is representative of the reservoir. Corey's equations are as follows:

$$K_{rg} = \left[1 - \frac{S_L - S_{Lr}}{S_m - S_{Lr}}\right]^2 \left[1 - \left(\frac{S_L - S_{Lr}}{1 - S_{Lr}}\right)^2\right]$$

$$K_{ro} = \left[\frac{S_L - S_{Lr}}{1 - S_{Lr}}\right]^4$$

$$\frac{K_{rg}}{K_{ro}} = \left[1 - \frac{S_L - S_{Lr}}{S_m - S_{Lr}}\right]^2 \left[1 - \left(\frac{S_L - S_{Lr}}{1 - S_{Lr}}\right)^2\right]$$

$$\left[\frac{S_L - S_{Lr}}{1 - S_{Lr}}\right]^4$$

where $S_L$ = total liquid saturation, fractional.

$S_m$ = constant for reservoir, fractional.

$S_{Lr}$ = constant dependent on initial water saturation, fractional.
The constants $S_{LR}$ and $S_m$ were determined graphically. $S_m$ is a constant for all samples and $S_{LR}$ is a constant dependent on the initial water saturation of the sample. From the linear relationship between $S_{LR}$ and the water saturation of the samples, $S_{LR}$ for the reservoir was calculated for the average water saturation of the reservoir. Using the constants $S_m$ and $S_{LR}$ for the average water saturation, Corey's equations were solved for $K_{rg}/K_{ro}$ to determine a field average gas-oil relative permeability curve (Figure 17).

**Water-Oil Relative Permeability**

The Dykstra-Parson's method (method is not published) was used to obtain a water-oil relative permeability relationship which is representative of the reservoir. Only two laboratory samples were used to average the relative permeability data as two samples were damaged in the laboratory.

To obtain representative water-oil relative permeability data by the Dykstra-Parson's method, the water saturation of each laboratory sample is plotted against the initial water saturation of the sample. For a constant $K_{rw}/K_{ro}$ value (water-oil relative permeability), a straight line was drawn through the points using the method of least squares and forcing the line to fit through the water saturation at the residual oil saturation. From the family
of lines drawn for different $K_{rw}/K_{ro}$ values and knowing the average initial water saturation of the reservoir, values of water saturation and $K_{rw}/K_{ro}$ are obtained for the initial water saturation of the reservoir. The values for the average initial water saturation were used to draw a relative permeability curve representative of the reservoir (Figure 18).
DETERMINATION OF OIL-IN-PLACE

The oil-in-place was calculated volumetrically using the known reservoir parameters. The oil-in-place was obtained using the following formula:

\[ N = 7758 \theta A h (1 - S_{wi}) / B_o \]

where
- \( \theta \) = average arithmetic mean porosity, fractional.
- \( A \) = surface area, acres.
- \( h \) = effective pay thickness, feet.
- \( S_{wi} \) = average initial water saturation, fractional.
- \( B_o \) = oil formation volume factor, res bbl/STB.

Based on the reservoir volume of 47,196 acre ft the oil-in-place was determined to be 39,650,300 STB or 840 STB per acre ft.

Oil-in-place could not be calculated by material balances because there is no pressure history at Gas Draw.
To determine how much of the oil-in-place will be recovered, primary performance calculations must be made. The following is a discussion of how the primary performance calculations were made.

The Gas Draw Field was initially an undersaturated reservoir with solution gas the primary recovery energy below the bubble-point pressure. Fluid and rock expansion was the primary reservoir mechanism above the bubble-point.

The oil recovery due to fluid and rock expansion that occurred during a pressure drop from the discovery pressure of 2205 psig to the bubble-point pressure of 1231 psig, was calculated by the following formula:

\[ N_p = \Delta P \left( C_f + (1-S_{wi}) C_o + S_{wi} C_w \right) \]

where \( \Delta P \) = pressure drop from initial pressure to bubble-point pressure, psig.
\( S_{wi} \) = average initial water saturation, fractional.
\( C_o \) = oil compressibility, vol/vol/psi.
\( C_w \) = water compressibility, vol/vol/psi.
\( C_r \) = rock compressibility, vol/vol/psi.

Recovery from fluid and rock expansion was calculated to be 1.10% of the oil-in-place or 436,000 STB. The oil compressibility was obtained from reservoir fluid analysis and the rock and water compressibilities were obtained...
from published literature.

The recovery due to solution gas drive below the bubble-point pressure was obtained by using Schilthuis (1936, p. 18ff) solution of Tarner's material balance. The material balance forecasts the reservoir performance by relating pressure decline to the oil recovery and the gas-oil ratio. Time is not a factor in the material balance using the assumptions of no water influx and no gravity segregation.

The material balance is a trial and error solution based on an assumed incremental oil production for an assumed decrease in reservoir pressure. Three equations must be satisfied to an accuracy of 0.5% by trial and error to obtain sufficiently accurate performance predictions. These three equations are:

\[
N = \frac{N_p (B_t + B_g (R_p - R_{si}))}{B_t - B_{ti}}
\]

\[
R = R_s + \frac{B_o \mu_o}{B_g \mu_g} \left( \frac{K_g}{K_{ro}} \right)
\]

\[
S_o = \frac{N - N_p}{N} \left( \frac{B_o}{B_{oi}} \right)
\]

where

- \(N\) = cumulative oil production, fractional.
- \(N_p\) = oil-in-place, for this material balance \(N = 1 \text{ bbl.}\).
- \(B_t\) = total formation volume factor, res bbl/STB.
- \(B_g\) = gas volume factor, res bbl/SCF.
- \(B_{oi}\) = oil volume factor, res bbl/STB.
- \(\mu_o\) = oil viscosity, centipoise.
R = cumulative GOR, SCF/STB.
μg = gas viscosity, centipoise.
RG = solution gas-oil ratio, SCF/STB.
Kg/Ko = gas-oil relative permeability, fractional.
Rsi = initial solution gas-oil ratio, SCF/STB.

Results of the material balance calculations indicate 16.53% of the oil-in-place or 6,554,200 STB will be recovered by solution gas drive at a reservoir abandonment pressure of 100 psig (Figures 19 and 20). The total primary recovery by fluid and rock expansion and solution gas would be 17.63% of the oil-in-place or 6,990,200 STB.

The reservoir could have water influx as the west flank of the reservoir has an oil-water contact. No water influx was assumed as wells on the west flank do not produce water and these wells have experienced production declines similar to the remainder of the field. No pressures are available for material balances to confirm or disprove the assumption of no water influx.

To confirm the estimated primary recovery, a field decline curve of the oil production rate was plotted against time on semi-log paper (Figure 21). Extrapolation of this decline curve indicates primary production to be 7,000,000 STB at a field economic limit of 100 BOPD. Even though the extrapolation confirms the primary performance, extrapolation of this curve is questionable because of the short period of production history.
Extrapolation of individual well-decline curves is of little value because of the short period of production history. Additionally, the individual decline curves are difficult to extrapolate because of frequent stimulation workovers and wells being placed on pump after they stopped flowing.
SECONDARY PERFORMANCE

In order to increase the production rate and ultimate recovery, the available means of secondary recovery were examined. The methods of secondary recovery investigated were waterflooding, gas flooding, and miscible flooding. Because there is not a cheap supply of either gas or LPG nearby, waterflooding is the only applicable method of secondary recovery. The following is a discussion of how the secondary recovery performance calculations were made.

Laboratory Waterflood Tests

To provide sufficient information to make secondary recovery predictions, waterflood susceptibility tests were run on four core samples which were selected to be representative of the reservoir. All the tests indicated good oil recovery could be obtained by waterflooding. The pertinent results of the waterflood susceptibility tests are shown below:

<table>
<thead>
<tr>
<th>Description</th>
<th>Percentage</th>
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<tr>
<td>Oil-in-place, per cent of pore space</td>
<td>79.4%</td>
</tr>
<tr>
<td>Residual oil saturation, per cent of pore space</td>
<td>19.3%</td>
</tr>
<tr>
<td>Oil recovered, per cent of pore space</td>
<td>60.1%</td>
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The water-oil relative permeability data was obtained from the same core samples. Averaging of the water-oil relative permeabilities has been previously discussed.

Sweep Efficiencies

The oil recovery by waterflooding the Gas Draw Field was determined by obtaining the product of applicable sweep efficiencies and the oil-in-place. The sweep efficiencies were obtained as follows:

1. The displacement efficiency was obtained using Buckley-Leverett's (1942, p. 107-110) fractional flow and rate-of-frontal-advance equations.
2. The vertical sweep efficiency was obtained using Dykstra-Parson's (1950, p. 160-173) concept of permeability variation.
3. The areal sweep efficiency was obtained by advancing a water front along streamlines drawn on an isopotential map.

Oil recovery from waterflooding was obtained by using the sweep efficiencies in the following equation.

\[ N_p = N E_A E_D E_I \]

where
- \( N \) = oil-in-place, barrels.
- \( E_D \) = displacement efficiency, fractional.
- \( E_V \) = vertical sweep efficiency, fractional.
- \( E_A \) = areal sweep efficiency, fractional.

A producing water-oil ratio of 10:1 was used in determining the sweep efficiencies. This 10:1 cut-off on the water-oil ratio is reasonable because the waterflood susceptibility tests showed that very little additional oil would be recovered after water break through.
ER-1305

**Displacement Efficiency:** Buckley-Leverett's fractional flow equation and rate-of-frontal-advance formula were used to determine the amount of oil which would be displaced by the water. The fractional flow equation (assuming no gravity and capillary effects) is as follows:

\[
f_w = \frac{1}{1 + \frac{K_{ro}}{K_{rw}} \frac{\mu_w}{\mu_o}}
\]

where \( K_{ro} \) = oil relative permeability, fractional.
\( K_{rw} \) = water relative permeability, fractional.
\( \mu_o \) = oil viscosity, centipoise.
\( \mu_w \) = water viscosity, centipoise.

Using the above equation and the previously determined water-oil relative permeability relationships, a fractional flow curve versus water saturation was drawn (Figure 22).

Graphically solving Buckley-Leverett's rate-of-frontal-advance formula, the water saturation behind the front at water break through was calculated to be 59%. The water saturation at a producing WOR of 10:1 \( (f_w = 0.8) \) was 62%.

A nomograph prepared by Dardaganian (1958, p. 122-132) indicated the residual gas saturation would be 7%. The displacement efficiency was then determined by the following equation.

\[
E_D = S_w - S_{wi} - S_{gi} + S_{gr}
\]
where $S_w =$ water saturation at end of flood, fractional.
$S_{wi} =$ water saturation at commencement of flood, fractional.

Using known values, the displacement efficiency was calculated to be 0.24. This displacement efficiency indicated an additional 24% of the oil-in-place would be recovered by waterflooding.

**Vertical Sweep Efficiency:** The Buckley-Leverett fluid displacement equations assume a piston-like linear displacement. Because all the reservoir is not contacted by the water, the displacement efficiency must be reduced by a vertical sweep efficiency by considering permeability variations in the reservoir rock. To obtain the vertical sweep efficiency, the horizontal permeability variation, the mobility ratio between the displacing and displaced fluids, and the limiting WOR must be known. The horizontal permeability and limiting WOR have previously been discussed.

The equation to calculate the mobility ratio is as follows:

$$M = \frac{K_{rw} \mu_o}{K_{ro} \mu_w}$$

where $K_{rw} =$ relative permeability to water behind the flood front, fractional.
$K_{ro} =$ relative permeability to oil at the initial water saturation, fractional.
$\mu_w =$ viscosity of water, centipoises.
$\mu_o =$ viscosity of oil, centipoises.

Using the above equation, the mobility ratio of the displacing and the displaced fluids was calculated to be 1.035. From the published curves of Johnson (1956, p. 395-
the vertical sweep efficiency at a WOR of 10:1 is 0.90. This vertical sweep efficiency indicates 90% of the reservoir rock would be contacted vertically by the water.

*Areal Sweep Efficiency:* Gas Draw is a long "skinny" reservoir, and a normal flood pattern (such as a 5-spot) can not be used as a large part of the reservoir would not be swept by water. The areal sweep efficiency was calculated concurrently with the selection of the water injection wells because the areal sweep efficiency depends directly on which wells are selected for injection (Figure 23). The areal sweep efficiency was determined as follows:

1. A number of wells were selected for water injection.
2. Water was injected into the wells at a rate of 93 BWPD per foot of effective pay.
3. The production rate of the oil wells was the same as their production rate in July, 1969 (date of maximum field production).
4. A potential distribution was calculated for the reservoir using the production and injection rates assumed. The potentials were calculated at the intersection of lines on a square grid using a density of 16 grid intersections per well.
5. An isopotential map was prepared using the calculated potentials.
6. Streamlines were drawn on the isopotential map.
7. The waterfront was advanced along the streamlines. A volumetric weighted areal sweep efficiency was obtained by planimetering the area swept by water and considering the net thickness of the area swept by the water.

The volumetric weighted areal sweep efficiency was 0.65 for the particular flood pattern selected. Additional work can be done to optimize the areal sweep efficiency to
obtain more oil recovery.

The product of the three sweep efficiencies and the oil-in-place indicate an additional 5,138,700 STB of oil will be recovered by waterflooding.

**Injection and Production Rates**

The anticipated injection rate must be known to design the water-injection facilities, and the anticipated production rate must be known to calculate the economics of the waterflood. The following is a discussion of the estimated injection and production rates.

**Injection Rate:** The water injection rate \((i)\) was calculated using Deppe's (1960) equation. The equation assumes radial flow. The assumption of radial flow is valid because most of the pressure drop occurs immediately around the well bore where the flow is radial. The equation is as follows:

\[
i = \frac{7.07 \times K \times K_{rw} \times (P_{wi} - P_{wp})}{\mu_w \times (\ln \frac{d}{r_w} - 0.249)}
\]

where:
- \(i\) = water injection rate, bbls per day.
- \(K\) = absolute permeability, darcies.
- \(K_{rw}\) = water relative permeability, fractional.
- \(P_{wi}\) = bottom hole injection pressure, psig.
- \(P_{wp}\) = bottom hole producing pressure, psig.
- \(\mu_w\) = water viscosity, centipoises.
- \(d\) = distance between wells, feet.
- \(r_w\) = well bore radius, feet.

Results of the above equation indicate water can be injected at 93 BPD (bbls per day) per foot of effective pay at 1000 psig wellhead pressure (bottom hole producing
pressure of 2200 psig). A total of 17,400 BWPD (bbls water per day) can be injected into the 19 water injection wells. This injection rate is reasonable because wells were pumped into at 2 BPM (bbls per minute) at 1000 psig when the reservoir was at initial pressure. The injection pressure should not exceed 2500 psig because the breakdown pressure on fracturing treatments was 2500 psig. Experience has shown many of the fracture treatments went out of zone.

Production Rate: Calculations indicate response from the waterflood will be seen in six months, which is the time necessary to inject 0.05 pore volumes of water (difference between initial and residual gas saturation). The production rate will increase to 6900 BOPD after the free gas saturation is displaced. This production rate is 0.50 the water injection rate of 17,400 BWPD after considering the difference between water and oil formation volume factors. Water will break through in three years after injection is started (results from the isopotential map). The oil production will then exhibit a rapid production decline at water-break through, and the field will reach an economic limit of 100 BOPD in three years (Figure 24).

Oil recovery from the waterflood will be less than the calculated 5,138,700 STB of waterflood oil because some of the oil from primary depletion will not be recovered at the time the waterflood is initiated. The remaining oil
ER-1305

from the primary depletion will never be recovered.
WATER SOURCE

To provide water for the waterflood, a water source of sufficient quantity and quality must be developed. The following is a discussion of the water source selected.

A "rule of thumb" suggests the quantity of water needed over the life of the waterflood is 1.5 times the pore volume and 0.5 of the pore volumes required will be produced water. This "rule of thumb" indicates 90 million barrels of water will be required over the life of the flood. Of this 90 million barrels required, 30 million barrels will be produced water, hence a water supply of 60 million barrels must be developed. The water must have a quality sufficient to economically perform the flood.

Investigation of the potential water sources indicate the only water source of sufficient quantity is the many fresh water sands in the Ft. Union formation. The Ft. Union is a massive formation in the Powder River Basin and is found at a depth of 3500 feet at Gas Draw. Because the quality of the water is excellent (the water contains only 4-5 ppm total dissolved salts and contains no dissolved gases), no water treatment will be required.

The Ft. Union water has been used as a water source
for other waterfloods in the Powder River Basin. The quantity and quality of the water have always been sufficient, and there has been no sand problem with the production of the water.
A waterflood project is not feasible if the project will not make a profit. The following is a discussion of the economic evaluation of the Gas Draw Waterflood.

The waterflood economics were calculated as follows:

1. The undiscounted and discounted cash flows for the remaining primary oil production after January 1, 1971 were obtained (primary cash flow).
2. The undiscounted and discounted cash flows were obtained for the secondary oil production (secondary cash flow).
3. Difference between the discounted secondary cash flow and the discounted primary cash flows is the discounted income from the waterflood. The difference between the undiscounted cash flows is the undiscounted income.
4. The necessary investment to perform the waterflood was determined. The net investment was calculated. The net investment considers federal income tax credits for the intangible investment.
5. The payout of the project was obtained. The payout is the time necessary to receive enough income from the waterflood to retire the net investment. No consideration is given to discounted monies.
6. The rate of return on the investment was calculated. Rate of return on the investment is the applicable discount rate which must be applied to the undiscounted income to retire the undiscounted net investment over the life of the project.
7. The undiscounted profit of the project was determined. Undiscounted profit is the difference between the undiscounted income and the undiscounted net investment.
8. The discounted profit was obtained. Discounted profit is the difference between the discounted income and the discounted net investment.

The undiscounted primary cash flow is $1,741,000 and the discounted primary cash flow is $1,598,700 (all monies discounted at 10%). The secondary cash flow is $8,365,400 undiscounted and $6,849,800 discounted (Figure 25).

The initial investment for the waterflood is $300,000 ($200,000 tangibles). An investment of $100,000 will be required for each additional year of the waterflood. This additional investment will be needed for high volume pumping equipment and water injection facilities. The total investment would be $800,000 resulting in an undiscounted net investment of $676,200 or a discounted net investment of $556,700.

Differences of the cash flows and the net investments indicate an undiscounted profit of $5,948,200 and a discounted profit of $4,694,400 would be realized by a waterflood. The project would pay out in 1.33 years and would yield a 188% rate of return on the investment.
The purpose of this engineering study was to determine the feasibility of waterflooding the main Muddy pay in the Gas Draw Field. Conclusions from the study indicate a waterflood at Gas Draw would be feasible. Specific conclusions from the study are as follows:

1. Ultimate oil recovery by primary depletion would be 6,880,200 STB.
2. Ultimate recovery by primary depletion and waterflooding would be 11,136,700 STB if the waterflood was initiated January 1, 1971.
3. The waterflood project would pay out in 1.33 years with a rate of return of 188% on a $800,000 investment. An undiscounted profit of $5,948,200 would be realized by the waterflood.
BIBLIOGRAPHY


ER-1305


**APPENDIX**

<table>
<thead>
<tr>
<th>Figures</th>
<th>Description</th>
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<tbody>
<tr>
<td>1</td>
<td>Location Map of Gas Draw Field</td>
<td>38</td>
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<tr>
<td>2</td>
<td>Portion of Stratigraphic Section of the Powder River Basin</td>
<td>39</td>
</tr>
<tr>
<td>3</td>
<td>Gas Draw Section and Legal Subdivision Numbering</td>
<td>40</td>
</tr>
<tr>
<td>4</td>
<td>Gas Draw Main Muddy Pay, Horizontal Permeability - Porosity Distribution</td>
<td>41</td>
</tr>
<tr>
<td>5</td>
<td>Typical Gas Draw Gamma Ray - Sonic Log</td>
<td>42</td>
</tr>
<tr>
<td>6</td>
<td>Gas Draw Structure Map, Top Main Muddy Pay</td>
<td>43</td>
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<td>44</td>
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<tr>
<td>8</td>
<td>Gas Draw Oil Effective Isopach, Main Muddy Pay</td>
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<tr>
<td>9</td>
<td>Gas Draw Average Capillary Pressure</td>
<td>46</td>
</tr>
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<td>10</td>
<td>Gas Draw Cumulative Sand Volume Above Subsea Datum</td>
<td>47</td>
</tr>
<tr>
<td>11</td>
<td>Gas Draw Differential Gas Liberation</td>
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<tr>
<td>12</td>
<td>Gas Draw Reservoir Oil Pressure - Volume Relationship</td>
<td>49</td>
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<tr>
<td>13</td>
<td>Gas Draw Reservoir Oil Pressure - Viscosity Relationship</td>
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<td>Gas Draw Reservoir Gas Deviation Factor</td>
<td>51</td>
</tr>
</tbody>
</table>
ER-1305

Figures

15 Gas Draw Reservoir Gas Pressure - Volume Relationship .......................... 52
16 Gas Draw Reservoir Gas Pressure - Viscosity Relationship ....................... 53
17 Gas Draw Gas - Oil Relative Permeability .............................................. 54
18 Gas Draw Water - Oil Relative Permeability ............................................. 55
19 Schilthuis Material Balance, Solution Gas Drive, Gas Draw ..................... 56
20 Gas Draw Reservoir, Schilthuis Material Balance ....................................... 57
21 Gas Draw Production Decline Curve .......................................................... 58
22 Gas Draw Reservoir - Water Fractional Flow Relationship ......................... 59
23 Gas Draw Water Injection Wells ...... 60
24 Gas Draw Production Decline Curve .. 61
25 Gas Draw - Primary and Secondary Cash Flows ........................................... 62
Figure 1: Location Map of Gas Draw Field
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<thead>
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Figure 2: Portion of Stratigraphic Section of the Powder River Basin
Figure 3: Gas Draw Section and Legal Subdivision Numbering
Figure 4: Gas Draw Main Muddy Pay, Horizontal Permeability - Porosity Distribution
Figure 5: Typical Gas Draw
Gamma Ray - Sonic Log
Figure 6: Gas Draw Structure Map, Top Main Muddy Pay
Figure 7: Gas Draw Structure Map, Bottom Main Muddy Pay
Figure 8: Gas Draw Oil Effective Isopach, Main Muddy Pay
Figure 9: Gas Draw Average Capillary Pressure
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Figure 10: Gas Draw Cumulative Sand Volume Above Subsea Datum
Figure 11: Gas Draw Differential
Gas Liberation
Figure 12: Gas Draw Reservoir
Oil Pressure - Volume Relationship
Figure 13: Gas Draw Reservoir
Oil Pressure - Viscosity Relationship
Figure 14: Gas Draw Reservoir
Gas Deviation Factor
Figure 15: Gas Draw Reservoir
Gas Pressure - Volume Relationship
Figure 16: Gas Draw Reservoir
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Figure 17: Gas Draw Gas - Oil Relative Permeability
Figure 18: Gas Draw Water-Oil Relative Permeability
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**Figure 19:** Schilthuis Material Balance, Solution Gas Drive, Gas Draw
Figure 20: Gas Draw Reservoir Schilthuis Material Balance

PRODUCING GOR, SCF/STB x 10^{-2}
Figure 21: Gas Draw Production Decline Curve

TIME, YEARS

OIL PRODUCTION, BOPD x 10\(^{-3}\)

NATURAL DEPLETION
Figure 22: Gas Draw Water
Fractional Flow Relationship

WATER SATURATION, PER CENT PORE SPACE
Figure 23: Gas Draw Water Injection Wells
Figure 24: Gas Draw Production Decline Curve
## Primary Oil Production

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## Secondary Oil Production

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### Financials

- **Total Investment**: $800,000  
- **Working Interest**: 100%  
- **Net Investment**: $676,200  
- **Royalty**: 12.5%  
- **Net Discounted Investment**: $556,700  
- **Crude Value**: $3.18/bbl  
- **Payout**: 1.33 years  
- **Lifting Cost**: $.40/bbl  
- **ROR**: 188%  
- **Severance Tax**: $.03/bbl  
- **Discounted Profit**: $4,694,400  
- **Depreciation**: $.46/bbl  
- **Undiscounted Profit**: $5,988,200  
- **Federal Income Tax**: 55%  

**Figure 25: Gas Draw - Primary and Secondary Cash Flows**