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Reservoir Simulation Study of a Thermal Horizontal Well Pilot in the Cold Lake Oil Sands

K.O. Adegbesan, SPE, Imperial Oil Resources Ltd.

Summary. A reliable model was developed for evaluating and guiding the performance of horizontal wells in thermal operations to recover heavy oil in Cold Lake, Alta., Canada. The horizontal well model was developed with measured field data from the first thermal horizontal well pilot (HWPI) of Imperial Oil Resources Ltd.

Introduction

Excellent history matches of the pilot's bitumen and water production rates and bottomhole pressures (BHP's) and acceptable history matches of the observation-well temperatures and of the thermal energy of the produced fluid were achieved with a thermal reservoir simulator developed by Exxon Production Research Co. The 3D horizontal well model applied in the simulator had three phases and three components. It was interfaced with a 3D geological reservoir description model of the pilot area. The history-match study was valuable in understanding measured field data and the important physics affecting thermal horizontal well performance. Obtaining a reliable history match of the HWPI and developing simulator models to assess and guide horizontal well operations in Cold Lake was significantly facilitated by (1) the availability and use of a large number of diverse measured field data, (2) the incorporation of a detailed reservoir description model, and (3) strong emphasis on ensuring that measured field data supported major assumptions applied to history match the HWPI simulator model.

Background

The Imperial Oil Resources Cold Lake oil sands property is located 256 km [160 miles] northeast of Edmonton. It is the largest steam-injection project in Canada, and current bitumen production is 14 300 m^3/d [90,000 B/D] from nearly 2,000 wells. The vast majority of the production comes from the use of cyclic steam stimulation (CSS).

Currently, three horizontal well pilots are in operation at the site. The pioneering work[1-3] of the horizontal well application to produce heavy oil (bitumen) led to drilling the first pilot in 1979. Gallant and Dawson[4] described the objectives of the first two pilots. The third pilot will test the technical and economic feasibility of a horizontal well follow-up to CSS.[5]

The major thrust of this study was to develop simulator models to predict the performance of horizontal wells as a follow-up and as an alternative to CSS and to guide future operating strategies. This paper summarizes the history-match study of the first HWPI to develop a thermal horizontal well simulator model for heavy-oil operation in Cold Lake.

The first HWPI in Cold Lake had a 245-m [804-ft] slotted liner positioned about 30 m [98 ft] below the top of the Clearwater formation. A vertical well steam injector was located almost directly above the horizontal well 45 m [148 ft] from its reservoir end (see **Fig. 1**). An operating strategy[6] was applied to test gravity-drainage concepts.[7] It consisted of a preheating phase followed by high-pressure steam injection into the vertical well (i.e., above the reservoir failure pressure) and continuous production from the horizontal well. A bottomhole pump was installed in the horizontal well during July 1982.

The present study was performed with Exxon's fully implicit thermal version of the MARS simulator.[8] The 3D reservoir simulator model ($11 \times 5 \times 12$) handles three phases and allows more than three components to be studied. It was interfaced with a 3D reservoir description model of HWPI. The reservoir description model was a computerized geologic model describing formation thickness, bitumen saturation, permeability, and the location of vertical flow barriers or "tight streaks."

Reservoir Description

Steam injection operations in Cold Lake occur in the Clearwater formation.[9,10] The formation is an unconsolidated, clean, well-sorted, fine- to medium-grained sand. Initial average reservoir properties[6] of the pilot are 33% porosity, 47-m [154-ft] net pay thickness, 1.3-darcy permeability, and 60% bitumen saturation. Initial bitumen viscosity was approximately 0.1 MPa·s [100,000 cp] at the ambient reservoir temperature of 13°C [55°F].

The ratio of vertical to horizontal permeability, k_V/k_H, was varied as a history-matching parameter. A k_V/k_H of 0.2 resulted in acceptable history matches of thermal energy production, breakthrough time, and total fluid production.

Four major tight zones are present in the geological model: two in the top third and two in the bottom third of the Clearwater formation. Tight streaks with thicknesses greater than or equal to 1 m [3.3 ft] were included in the geologic model.

An initial reservoir datum pressure of 3 MPa [435 psi] was applied at the horizontal well layer. Bitumen viscosities and reservoir fluid and rock properties used in the model were the same as those used in prior CSS studies.[11,12]

Simulation Model Description and Treatment of Field Data

Simulation Grid Model. Fig. 2 shows the location of the HWPI in the Cold Lake Leming area and the boundaries of the reservoir area represented in the HWPI simulation model. **Fig. 3** is the full-size areal grid system of the model with the locations of fracture blocks indicated.

The Clearwater formation was gridded into 12 vertical layers. **Fig. 4** shows the average thicknesses of the blocks in each layer of the geological model. The vertical gridding was designed to allow accurate representation of the geological description and true locations of the vertical well perforations. Layer 6 in Zone 2 represents the vertical injector fracture layer, which results from steam injection into the reservoir. The horizontal well is located in Layer 10 of Zone 3.

The model included a representation of Wells T-14 and T-15 in the neighboring T pad to allow investigation of interwell communication effects on the HWPI history match.

The wellbore index formation applied to model the horizontal wellbore is consistent with that presented in Ref. 13.

Pressure Drop in the Horizontal Well. In the model, pressure-drop effects were neglected in the horizontal wellbore because calculated pressure drops are small compared with expected pressure drawdowns in the reservoir. The calculated maximum pressure drop in the horizontal well was <3.45 kPa [<0.50 psi]. Calculations were based on the following data, which are consistent with field measurements: a maximum bitumen production rate of 50 m^3/d [315 B/D] through the 193.6-mm [7.62-in.] -diameter slotted liner and a minimum bitumen temperature of 100°C [212°F] in the liner.

Boundary Conditions and General Well Constraints. Field data and experience suggested that negligible fluid and pressure communication existed between the wells in the model (Fig. 2) and those external to it. Consequently, a no-flow boundary condition was spec-

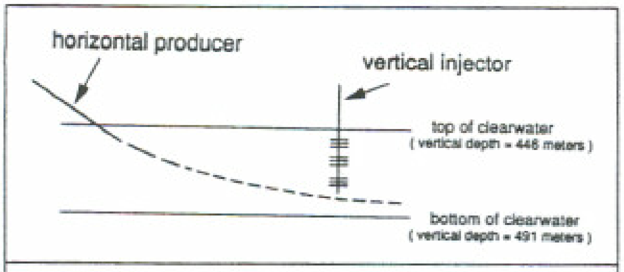

Fig. 1—HWPI configuration.

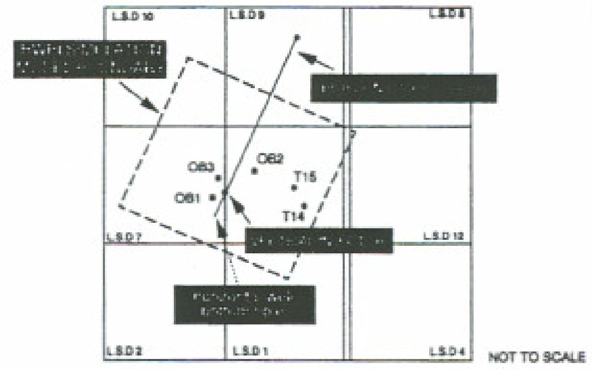

Fig. 2—Map showing location of HWPI and Wells T14 and T15 in the neighboring CSS T pad in the Cold Lake Leming pilot area.

ified for the model boundaries. A coupled implicit well option was specified for the horizontal well producer in which the production well was subjected to both minimum flowing BHP and maximum liquid rate constraints. The injection wells were subjected to a steam-injection rate constraint. The minimum BHP of the horizontal well during pumping was specified as 0.35 MPa [50 psi]. During the free-flowing phase of the horizontal well (Feb. 1980 to Aug. 1982), a minimum wellbore potential of 2.8 MPa [406 psi] was specified for the horizontal well. This value closely matches the minimum producing bottomhole potential recorded in the field during the early nonpumping regime.

Treatment of Field Data. Input parameters of reservoir description and reservoir physics were assigned confidence levels at the start of the history-match study. Input values for those parameters identified in the high-confidence category were not varied. Most of the greatest changes were made for the values at the low confidence levels. Monthly averages of the measured field data usually were used in the simulation unless wide variability within the month dictated that a greater frequency was appropriate.

Thermal energy production of the horizontal well was estimated as outlined in Ref. 6.

Reservoir Physics

Details of the fracture, deformation, and relative permeability hysteresis models applied in this study were presented elsewhere.[11,12] The following is a brief summary of the reservoir physics models applied in the HWPI history-match study.

Relative Permeability Model. The hysteretic water/oil relative permeability model used in this study is similar to that used in a CSS history-match study[11] of Cold Lake bitumen. The model was based on laboratory experiments. The gas/oil relative permeability model assumed "stick curves." This is consistent with the concept of segregated flow in gravity drainage, which was a dominant mechanism in HWPI.[14]

In 1985, a cased-hole neutron log of Observation Well OB3 confirmed the presence of gas across the top 5 m [16.4 ft] of the Clearwater. Results of cased-hole neutron logs run in the same well in 1988 showed that the gas saturation had increased from 15% to 55%. Analysis of field data showed that the production mechanism was dominated by gravity drainage, particularly during the later period of the pumping phase.[14] The increase in gas saturation probably was influenced by downward drainage of bitumen toward the horizontal well and gravity segregation between the fluid phases. It is likely that the gravity drainage mechanism was augmented by pressure support of gas in the reservoir. Using a high critical gas saturation (20%) was found necessary to retain gas in the reservoir and to obtain a reasonable match of the bitumen production, particularly during the pumping phase. Critical gas saturations of less than 20% in the model resulted in lowered bitumen production and much higher thermal energy of produced fluids than observed in the field. This confirmed the gas retention or accumulation in the reservoir as suggested by field observations. Although a critical gas saturation of 20% was used successfully in the model to obtain a better match of the field pilot history, no attempts were made to distinguish between critical-gas-saturation and trapped-gas-saturation effects actually occurring in the reservoir. Hysteretic gas/oil relative permeabilities with trapped-gas modeling capabilities were not used in this study. Therefore, it is possible that any pressure maintenance effects attributable to high critical-gas-saturation effects may in fact result largely from trapped-gas-saturation effects.

Three-phase relative permeability was determined according to Stone's[15] first method. Incorporating the effects of temperature was not necessary to obtain a reasonable match.

Fracture Placement. Horizontal fractures for the vertical and horizontal wells were located as shown in Fig. 3 to allow modeling

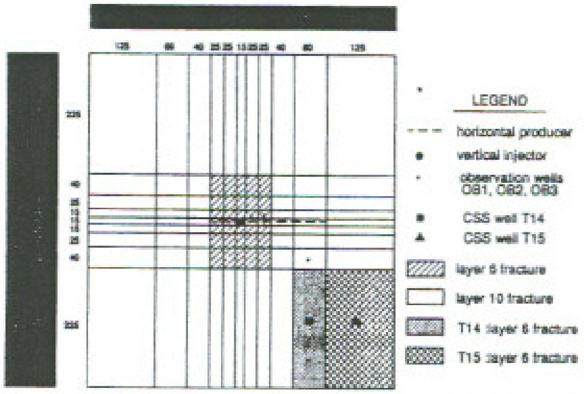

Fig. 3—HWPI simulation grid model (areal view—grid dimensions in meters).

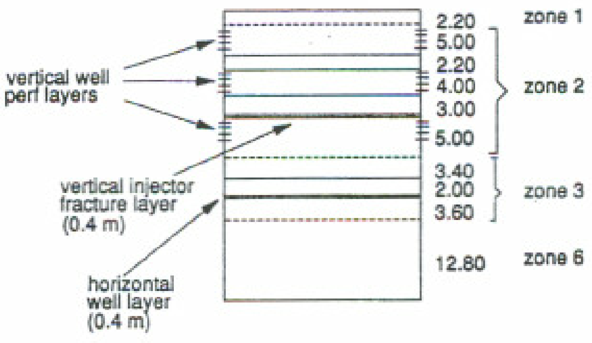

Fig. 4—HWPI grid model; average thickness of layers in the model (distances in meters).

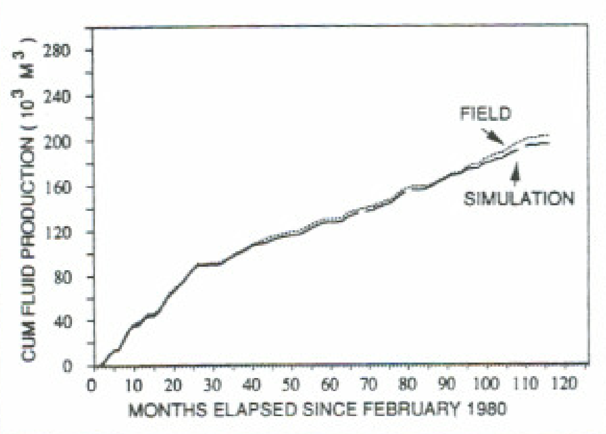

Fig. 5—History match of HWPI total fluid production.

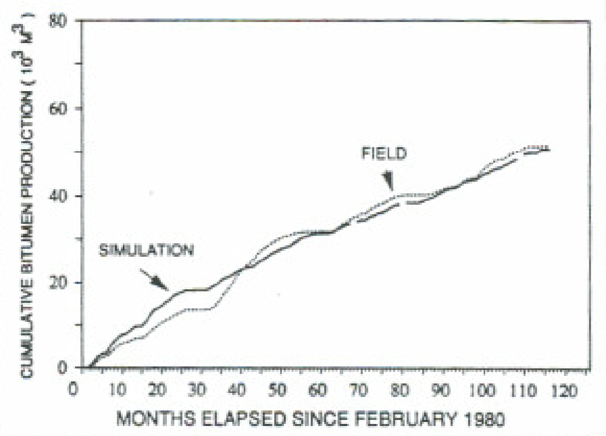

Fig. 6—History match of HWPI bitumen production.

of the steam-injection process in the reservoir. A fracture for the horizontal well was included to allow modeling of steam injection into the horizontal well during preheating.

The vertical well fracture was assumed to be horizontal and was placed orthogonal to the horizontal well (Fig. 3). Its orientation was determined from analyses of observation-well temperature data. This placement gave the best history matches of the bitumen and water breakthrough times and the thermal energy of the produced fluid. The relatively large areal coverage of the fracture zones ensured that injected energy spread outward from the inner blocks, enclosing the vertical steam injector and hence tending to minimize thermal energy production.

Vertical fracture geometries also were tested to determine the sensitivity of the history match to fracture types. Thermal energy production of the model with vertical fractures was unacceptably high.

Deformation Model. A deformation model used successfully in CSS history-match studies[11,12] was applied. Equations used in the model relate changes in gridblock porosity to changes in gridblock pressure. The gridblock absolute permeability was allowed to vary as a function of the gridblock porosity for all blocks in the model. Maximum permeability multipliers of 1,000 and 1.5, determined at a maximum vertical injector BHP of 10.4 MPa [1,508 psia], were applied in the fracture and matrix blocks, respectively. The fracture permeability multiplier proved adequate for rapidly spreading injected thermal energy areally over large distances from the vertical injection well. However, further increases in the multiplier values over 1,000 did not result in proportionately improved energy distribution in the model. The values of parameters of the deformation model applied in the final HWPI history-match trials were identical to those used in the CSS history match.

Communication of HWPI With T Pad

A radioactive tracer test was conducted in 1983. It involved the injection of 750 MBq [20 curies] of tritium into Wells T14 and T15 followed by production of the horizontal well. Measured production response of the horizontal well indicated fluid and pressure communication between it and the T pad. A good history match of the measured HWPI field data was achieved when communication from the T pad to the HWPI was accounted for in the model. An important objective in constructing a model to include the influence of the T pad was to keep the model as simple as possible to minimize costs. Layer 6 fractures for Wells T14 and T15 were approximated as shown in Fig. 3. Field data of only the first four CSS cycles of Wells T14 and T15 were included in the history-match process. Measured field potentials of Wells T14 and T15 were included as input data into the simulation model.

History-Match Results

A reasonable history match was achieved for (1) cumulative total fluid production, (2) cumulative bitumen production, (3) bitumen and water production rates, (4) BHP of the vertical and horizontal wells, and (5) injected steam volumes during cycles 1 through 4 of Wells T14 and T15. **Fig. 5** shows the excellent match to the cumulative total fluid production. After Month 90, the model results began to diverge from the field data, probably because only the

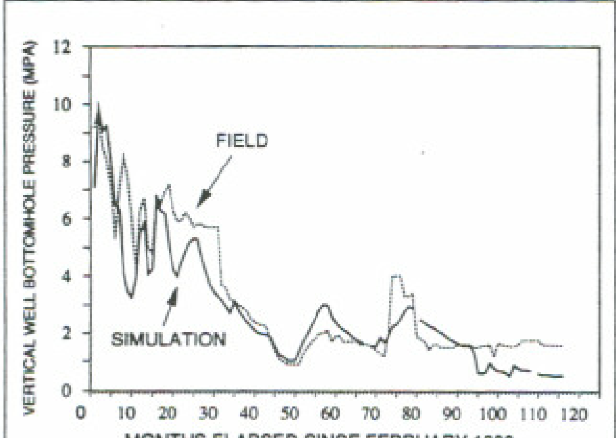

Fig. 7—History match of HWPI BHP's.

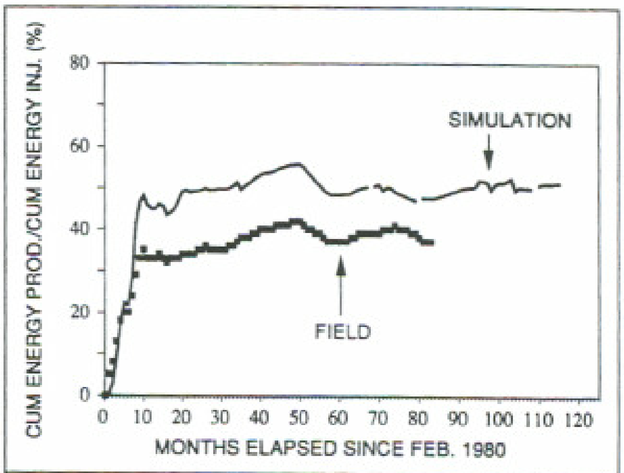

Fig. 8—History match of HWPI thermal energy of produced fluid.

Author

Kenny O. Adegbesan is a senior engineer reservoir simulation and horizontal well expert in the Research and Technology Div. of Imperial Oil Resources Ltd. in Calgary. He is chairman of the Horizontal Well Special Interest Group of the Petroleum Soc. of CIM. He holds a BS degree from the U. of New Brunswick, an MS degree from McMaster U., and a PhD degree from the U. of Calgary, all in chemical engineering.

first four CSS cycles of Wells T14 and T15 were included in the model. Consequently, pressure support of the HWPI provided because of operation of the T pad after four CSS cycles (Month 65) was absent in the model. In the model, this resulted in a gradual decline of total fluid production of the horizontal well at later times. No attempt was made to represent further cycles of the T pad in the model because we found the current history match of field data to be adequate.

Fig. 6 shows good agreement of cumulative bitumen production between the field and the model. Cumulative bitumen production was overestimated by the model during the free-flowing regime (Months 0 through 30) and underestimated during the pumping regime.

Fig. 7 shows the good match to the HWPI vertical well BHP's. The vertical well BHP from the field and the model data diverged after Month 90, probably because only four CSS cycles of Wells T14 and T15 were used to model the pressure support of the T pad.

Measured potentials of Wells T14 and T15 were provided as input data to the model, and the wells' steam injection and total fluid production were history matched. Good agreement was achieved between calculated and measured field volumes.[6]

Fig. 8 shows a match of the thermal energy of the produced fluid. The field energy production data were not estimated past Month 82 because no bottomhole temperature log data were available from the horizontal well after this date. An excellent match of the field data exists during the early periods until Month 10; then the model overpredicts the field data. The maximum thermal energy production ratio (cumulative thermal energy of the produced fluid to cumulative thermal energy of the injected steam) determined from field data is 40%, compared with 56% predicted by the model. This discrepancy probably results because secondary heat-transfer mechanisms were not fully accounted for in the simulator model. In the field, the secondary heat-transfer mechanisms[16] promote upward heat loss to the overburden owing to convective cells rolling upward in the steam zone. This rolling action results in rapid heat transfer upward toward the overburden, thus minimizing thermal energy production from the horizontal well positioned directly below the steam injector. Consequently, inadequate description of these mechanisms in the simulator may result in more thermal energy production in the simulator than actually measured in the field, as demonstrated in Fig. 8.

Conclusions

1. An excellent history match of measured field data was obtained by use of a simplified approach to modeling interwell communication and ensuring that measured field data supported the major assumptions used in the simulator model of the HWPI. The successful history-match study provided valuable support in understanding measured field data and important physics affecting thermal horizontal well performance in Cold Lake.

2. Two important mechanisms augmenting gravity drainage in the HWPI appear to be pressure support from the T pad and pressure support from gas in the reservoir.

3. The availability and use of a large number of diverse measured field data and the incorporation of a detailed reservoir description model significantly facilitated obtaining a reliable history match of the HWPI and development of a thermal horizontal well model to assess horizontal wells in Cold Lake.

4. A horizontal fracture geometry was used successfully to model the fracture or zone of high-PV expansion created from the startup of steam injection into the HWPI. Vertical fractures were not successful.

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SI Metric Conversion Factors

bbl × 1.589 873 E−01 = m^3
ft × 3.048* E−01 = m
md × 9.869 233 E−04 = μm^2
psi × 6.894 757 E+00 = kPa

*Conversion factor is exact.

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