Geological software, PETRA (HIS Inc.) was used to construct the geological model with all the reservoir properties collected through the aforementioned methods. The spatial distribution of the Ogallah reservoir properties such as porosity, permeability, water saturation and net-pay gridded surfaces were subsequently exported to Builder, a pre-processing application of commercial simulator, IMEX (Computer Modeling Group, Inc.) for further construction of a reservoir model.

3.2 Reservoir Model and Simulation

Black oil simulator, IMEX was used to perform history match of primary production in Ogallah unit. The geological model was exported to Builder to construct a reservoir model along with PVT data, relative permeability data and recurrent data such as well location, perforation depth and production history. The model was discretized with 127 blocks in east-west direction, 70 blocks in north-south direction and 8 layers in vertical direction. The grid block size was 110 feet in length and 110 feet in width. The thickness of each grid varied. Figure 33 presents the structure top of the oil field and the location of 103 wells. Figure 34 shows an example of the cross-section view of the layers consisting of Arbuckle dolomite and Reagan sandstone. The Granite wash was not included in the model as it is assumed to be part of the aquifer underling the reservoir. The aquifer was modeled with Carter-Tracery method to simulate the aquifer as a bottom water drive aquifer.
Figure 34 Example of cross section view of Ogallah Unit

Figure 35 presents the permeability and porosity distribution in the Arbuckle and Reagan layer of the model. High permeability and porosity are generally observed in the central-southwest part of the field which includes part of Lease 1, (G. Bittle), Lease 3, (E.A. Scott), and Lease 13, (U.S. Government).

Figure 35 Permeability and porosity of Arbuckle dolomite and Reagan sandstone
3.2.1 History Match of Primary Production

Primary production of the Ogallah started in 1951. Well production history shows that no water was produced before 1960. Water breakthrough in producers started after 1960. At the peak of production in 1969, the Ogallah field had 85 producing wells. The field was producing 1.07 MMBO/year with cumulative production of 11.37 MMBO by 1969. After 1969, the field commenced commingle-production from LKC formation and approximately half number of these wells were shut in at 1989 due to economic decline. The Ogallah field was unitized in 1991 and the number of active producers since then was reduced to 18.

![Graph showing production history of Lease 3, E. A. Scott]

Figure 36 Production history of Lease 3, E. A. Scott

Individual well production history in Ogallah unit was not recorded in the early years of production. Most recent record for individual active producer was from 1991 onwards. Nevertheless, Kansas Geological Survey database has production record of each lease in the unit. Figure 36 shows the production history of Lease 3, E. A. Scott. Production in Lease 3 started in 1952 when well 3-1 and 3-2 were first drilled and produced from Arbuckle formation. Well 3-3 started production from Arbuckle in 1955. The total production rate from all three wells stabilized at around 2700 BO/month. The production rate started to decline from 1963. In 1965, well 3-4 was drilled and produced from Arbuckle and Lasing-Kansas City (LKC). At the late of
1965, LKC-F was perforated in well 3-1 to have a comingle production with Arbuckle. The production rate started decline significantly after water breakthrough. Another apparent rate increase occurred in 1977 when well 3-1 was perforated at upper formations, LKC-A and Topeka.

It is challenging to history match the primary production performance of the whole unit as there is insufficient field data for each individual producer, and in most cases, the production is commingled with other formations on top of the Arbuckle group. Because of the limitation of data, the effort to history match was directed toward wells with detailed production record from the Arbuckle group only. Two wells, well 3-2 and 3-3 in Lease 3 (E.A Scott), and two wells, 4-12 and 4-13 in Lease 4 (Schoenthaler), are produced from Arbuckle formation. The history match on these four wells is discussed in the following sections.

The production of the Ogallah unit is primarily attributed to natural water drive as the reservoir pressure has been maintained at above 1150 psi for more than 50 years. To simulate the primary production by the bottom water drive, black oil simulator, IMEX was used to history match the production performance. The volumetric performance of reservoir fluids at various pressure levels are tabulated in Table 14. These data are derived from the laboratory studies of PVT of reservoir fluid in a companion technical report (Tsau, et al. 2010)

Table 14 PVT data used in simulator

<table>
<thead>
<tr>
<th>P (psia)</th>
<th>Rs (scf/stb)</th>
<th>Bo (rb/stb)</th>
<th>z</th>
<th>viso (cp)</th>
<th>visg (cp)</th>
</tr>
</thead>
<tbody>
<tr>
<td>15</td>
<td>3.5</td>
<td>1.021</td>
<td>0.999</td>
<td>4.124</td>
<td>0.0124</td>
</tr>
<tr>
<td>412</td>
<td>62.8</td>
<td>1.039</td>
<td>0.964</td>
<td>2.906</td>
<td>0.0127</td>
</tr>
<tr>
<td>809</td>
<td>136.7</td>
<td>1.063</td>
<td>0.933</td>
<td>2.176</td>
<td>0.0133</td>
</tr>
<tr>
<td>1206</td>
<td>218.6</td>
<td>1.091</td>
<td>0.908</td>
<td>1.735</td>
<td>0.0140</td>
</tr>
<tr>
<td>1603</td>
<td>306.1</td>
<td>1.122</td>
<td>0.889</td>
<td>1.445</td>
<td>0.0148</td>
</tr>
<tr>
<td>2000</td>
<td>398.1</td>
<td>1.157</td>
<td>0.878</td>
<td>1.241</td>
<td>0.0157</td>
</tr>
</tbody>
</table>

Relative permeability curves for two flow units (Arbuckle and Reagan) were modeled using modified Corey-type equations (Corey, 1954) where \( S_{wc} \) was obtained from the laboratory measurement. The modified Corey relative permeability equations used were:

\[
k_{ro} = k_{ro_{wi}} (1-S_{WD})^m \\
k_{rw} = k_{rw_{ORW}} (S_{WD})^n \\
S_{WD} = (S_{w}-S_{WC})/(1-S_{ORW}-S_{WC})
\]
where m is the exponent of the oil relative permeability and n is the exponent of water relative permeability. Figure 37 shows the oil-water relative permeability curves used in the simulation. The m- and n-exponent used are 5 and 2 respectively. The end-points residual oil and water saturation are both 0.25. For Arbuckle formation parameters used were: $k_{ro}S_{Wi} = 1.0$, $k_{rw}S_{ORW} = 0.18$; for Reagan formation parameters used were: $k_{ro}S_{Wi} = 1.0$, $k_{rw}S_{ORW} = 0.07$.

The initial reservoir pressure was assumed to be 1200 psia based on DSTs conducted in the early years of production. The rate constraint was applied to the wells when prorate production was imposed. Otherwise, the pressure constraint was applied to the producers at a given bottomhole pressure when the record was available or pumped off when it was not available. During the process of history match, properties being adjusted include horizontal permeability, end point of relative permeability and initial water saturation.

Some of the production history match results are presented in Figure 38 to Figure 45 where the symbols represent the field data while the curves represent the simulation results. In most of these plots, the production rate of each individual well is not available prior to 1991. At the early time of simulation, the oil production was controlled at a given rate in the model to represent the prorate production stipulated by the government at the early stage of the development. In general, the production history is reasonably well matched.
Figure 38 History match of oil production in well 3-2

Figure 39 History match of water production in well 3-2
Figure 40 History match of oil production in well 3-3

Figure 41 History match of water production in well 3-3
Figure 42 History match of oil production in well 4-12

Figure 43 History match of water production in well 4-12
Figure 44 History match of oil production in well 4-13

Figure 45 History match of water production in well 4-13
Although the Ogallah unit has been in production since 1951, the average reservoir pressure was not changed significantly. Figure 46 shows the average reservoir pressure based on the model calculation which decreases from 1200 psi to 1180 psi in 50 years of production. This confirms the assertion that the reservoir is underlain by an aquifer and the Carter-Tracery method is adequate to simulate the pressure support needed by the reservoir performance. As shown in the same figure, the average reservoir pressure in Lease 3, E. A. Scott varies between 1200 psi and 1150 psi.

Figure 46 Average reservoir pressures of Ogallah unit and Lease E. A. Scott