2008

# Numerical Modeling of CO2 Non-Dracy Flow in a Petroleum Reservoir

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# Numerical Modeling of $CO_2$ Non-Darcy Flow in a Petroleum Reservoir

Senior Design Project (Phase II)

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January 2008

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# Acknowledgments

I would like to thank Professor Zhengwen Zeng of the University of North Dakota for his help with this Senior Design Project.  I would also like to thank Charlie Gorecki and Matt Belobraydic for their help in reference to ECLIPSE.

## Executive Summary

This engineering design is to provide a more accurate description of non-Darcy flow at the near wellbore region. Objectives of the research will be to characterize properties of non-Darcy flow and develop accurate descriptions of carbon dioxide ($CO_2$) flow during injection scenarios and oil flow during production. Other objectives will be to define non-Darcy flow criteria from Forchheimer's number and analyze the amount of energy used by enhanced flow rates through injection and production wells. Methodology used to obtain results will reflect geology, reservoir engineering, and injection and production flow rates. Reservoir simulations will be conducted using Schlumberger's ECLIPSE software.

Accurate descriptions of $CO_2$ flow in porous media are essential to $CO_2$ enhanced oil recovery and $CO_2$ sequestration. Non-Darcy flow near wellbore areas can influence description of $CO_2$ flow at injection wells and oil flows at production wells. Using ECLIPSE software a model of a three-dimensional black-oil reservoir will simulate patterns of flow at injection and production wells. Considering the non-Darcy effect multiple flow velocities will be analyzed to find optimum efficiency for production of oil and injection of $CO_2$ for sequestration.

Due to inconsistency of the non-Darcy coefficient during injection and production scenarios, whether or not to include the non-Darcy effect in simulation modeling depends upon the amount it contributes to Darcy's Law. When the non-Darcy effect is greater than 10% it should be considered during simulation.

## Introduction and Objectives

Darcy's law is used to define flow through a porous media; it is a proportional relationship between discharge rate, fluid velocity and pressure gradient. Darcy's Law describes a linear relationship between pressure gradient and velocity:

$$-dp/dx = (\mu/k)*v \quad \text{.....................................} \quad (1)$$

where $-dp/dx$ is the pressure gradient, $\mu$ is viscosity, k is permeability, and v is the velocity. Sometimes in near wellbore scenarios flow velocity is very high and cannot be described by Darcy's law. A non-linear relationship occurs due to high velocity fluid flows. A non-Darcy term is needed to account for the non-linearity of flow. Forchheimer (1901) added a non-Darcy term to Darcy's law to account for the non-linear pattern observed:

$$-dp/dx = (\mu/k)*v + \beta\rho v^2 \text{.....................................................} (2)$$

where $\rho$ is fluid density, $\beta$ is the non-Darcy coefficient. From Eq. (2), non-Darcy term is a multiple of the second power of velocity, fluid density and non-Darcy coefficient (Li and Engler, 2001). Due to non-Darcy effect, flow behaviors are altered at near wellbore areas. Data of non-Darcy coefficient is not always available, so correlations were made based on available properties of the reservoir (Li and Engler, 2001). Theoretical equations and empirical correlations have been developed to determine non-Darcy coefficient. No theoretical equations have been made available for multi-phase flow (Li and Engler, 2001).

A criteria for non-Darcy flow in porous media needs to be defined in order to account for the non-linearity of flow patterns in Darcy's Law. Zeng and Grigg (2006) derived criteria for numerical modeling of non-Darcy flow in porous media. Using the Forchheimer number, *Fo*, developed by Ma and Ruth (1993):

$$Fo = k_o\beta\rho v/\mu \ldots \quad (3)$$

where $k_o$ is the permeability at "zero" velocity from Darcy's law (Zeng and Grigg, 2006), the non-Darcy effect can be calculated. Defining the non-Darcy effect, E, as the ratio of pressure gradient consumed in overcoming liquid-solid interactions to the total pressure gradient, an essential energy loss can be calculated (Zeng and Grigg, 2006):

$$E = Fo/ (1+ Fo) \ldots \quad (4).$$

By defining the non-Darcy effect one can determine whether to include it in their simulation models.

For simulation, a reservoir model developed from Odeh (1981) will be used for gas injection and oil production. A gas injection well and an oil production well are located at two separate grid points (Fig. 1). Well locations are located 14,142ft apart, in a 10,000ft x 10,000ft square grid.

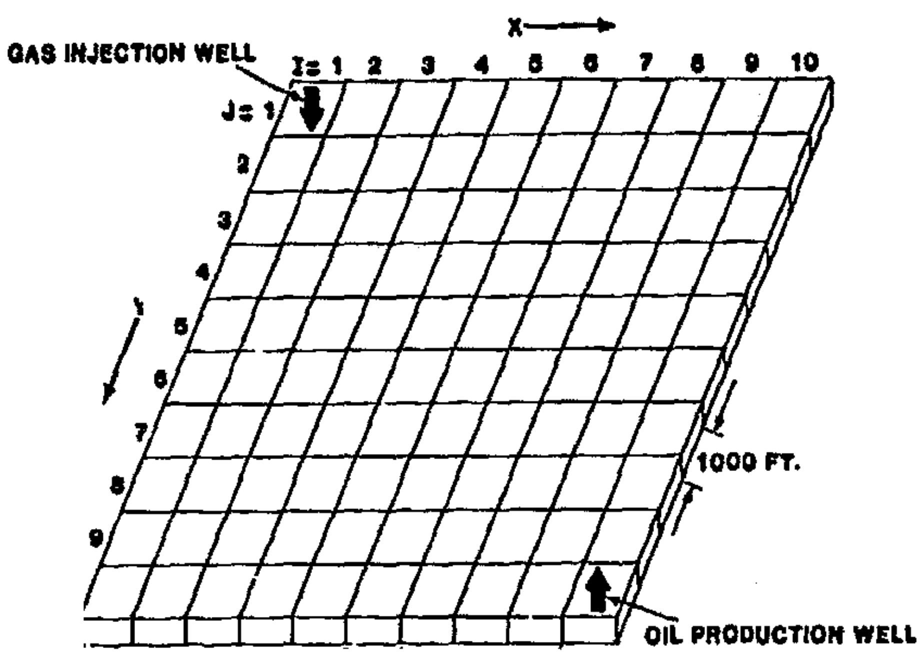


**Figure 1. Reservoir and grid system for gas injection well and oil production well (Odeh, 1981).**

PVT data are obtained from the paper by Odeh (1981), as shown in Table 1. Reservoir properties are given in Table 1 and Table 2 (Odeh, 1981). Calculation of the viscosity of $CO_2$ was obtained from depth and pressure of the wellbore Appendix A. Oil viscosity and density were obtained from Odeh (1981) Appendix B.

**Table 1. PVT data for reservoir simulations (Odeh, 1981) with addition of $CO_2$ viscosity and density at BHP and oil density**

| | |
|---|---|
| Initial reservoir pressure, psia at 8,400 ft | 4,800 |
| Gas Injection rate MMscf/D | 100 |
| Max. oil production rate, STB/D | 20,000 |
| Min. oil rate, STB/D | 1,000 |
| Min. oil flowing bottomhole press., psi | 1,000 |
| Max. saturation change during time step | 0 |
| Oil density at BHP, g/cm$^3$ | 0.583 |
| $CO_2$ density at BHP, g/cm$^3$ | 0.47 |
| Oil viscosity at BHP, cp | 0.449 |
| $CO_2$ viscosity at BHP, cp | 0.072 |
| Rock compressibility, 1/psi | 3 x 10^ -6 |
| Porosity at 14.7 psi | 0.3 |
| Wellbore radius, ft | 0 |
| Skin | 0 |
| Capillary press. | 0 |
| Reservoir Temperature, F | 200 |
| Gas specific gravity | 0.792 |

## Problem Definition

One issue in determining non-Darcy term is the non-Darcy coefficient. Non-Darcy coefficient in wells is usually determined by analysis of multi-rate core flow test results (Zeng and Grigg, 2006). A multi-rate core flow test is not always available, so correlations must be obtained to determine non-Darcy coefficient. Both theoretical equations and empirical correlations have been made to relate the non-Darcy coefficient to properties of the reservoir rocks (Li and Engler, 2001). Due to the unknown parameters of the non-Darcy coefficient, prediction of flow patterns becomes less accurate thus leading to less efficient injection and production.

Due to the high demand of natural resources, injection and production rates have increased to where a potential loss of energy may be presented due to the non-Darcy effect in flow rates. "Non-Darcy behavior has shown significant influence on well performance. Holditch and Morse (1976) numerically investigated the non-Darcy effect on effective fracture conductivity and gas well productivity. Their results show that at the near-wellbore region, non-Darcy flow could reduce the effective fracture conductivity by a factor of 20 or more, and gas production by 50%" (Zeng and Grigg, 2006).

Performance of $CO_2$-flooding in injection scenarios has been an important aspect of oil production enhancement. Proper interpretations of $CO_2$-flooding can have an impact on the amount of oil produced (Hsu et al., 1995). Pore pressure has a large influence on permeability in $CO_2$ flooding (Grigg et al., 2004). According to Grigg et al (2004), temperature influence is less significance in $CO_2$ flooding. Field-scale $CO_2$ flood simulations can help predict flooding properties of $CO_2$ for enhanced oil production.

Due to the importance of non-Darcy effect, numerical simulations will be conducted to determine optimum efficiency rates of both $CO_2$ gas injection and oil production. Reservoir simulations will be conducted under properties given by Odeh (1981). According to Zeng and Grigg (2006) a 10% non-Darcy effect will be used for optimum flow rates.

The non-Darcy coefficient is determined from correlations obtained from literature (Li and Engler, 2001). Based on available data for non-Darcy coefficient, two methods of calculation were chosen. Comparing two coefficients, rather than one with experimentally measured results, will give a more reasonable expression of the Forchheimer equation. Equations (5) and (6), will be used to calculate non-Darcy coefficient (Li and Engler, 2001)

$$\beta_1 = (0.005)/(k^{0.5} * \Phi^{5.5}) \quad (5)$$

$$\beta_2 = (4.8*10^{12})/(k^{1.176}) \quad (6)$$

where k is the permeability of the reservoir and Φ is porosity of the rocks. Other guidelines for determining non-Darcy effect will be based on pore geometry, number of known parameters, and lithology. These non-Darcy coefficient correlations were selected due to the availability of the reservoir properties.

**Preliminary Analysis**

Using ECLIPSE software, modeling of fluid flow through porous media in a three-dimensional reservoir will be analyzed (Fig. 2). Available data of the reservoir is giving in Table 2 (Odeh, 1981).

**Table 2. Reservoir properties given by Odeh (1981)**

| | Thickness | Permeability | Porosity |
|---|---|---|---|
| | (ft) | (mD) | |
| Top Layer | 20 | 500 | 0.3 |
| Middle Layer | 30 | 50 | 0.3 |
| Bottom Layer | 50 | 200 | 0.3 |

Different injection scenarios will be introduced and compared to determine the most efficient flow rates and pressures to be utilized. Well production will also be given multiple flow velocity scenarios to determine the most efficient methods for extracting oil from the reservoir utilizing non-Darcy term and coefficient. The non-Darcy effect will be calculated using Eq. (4) to determine the percent of energy lost due to the high flow rates. Pore pressure and permeability will be analyzed and compared with injection and production rates for maximum efficiency.

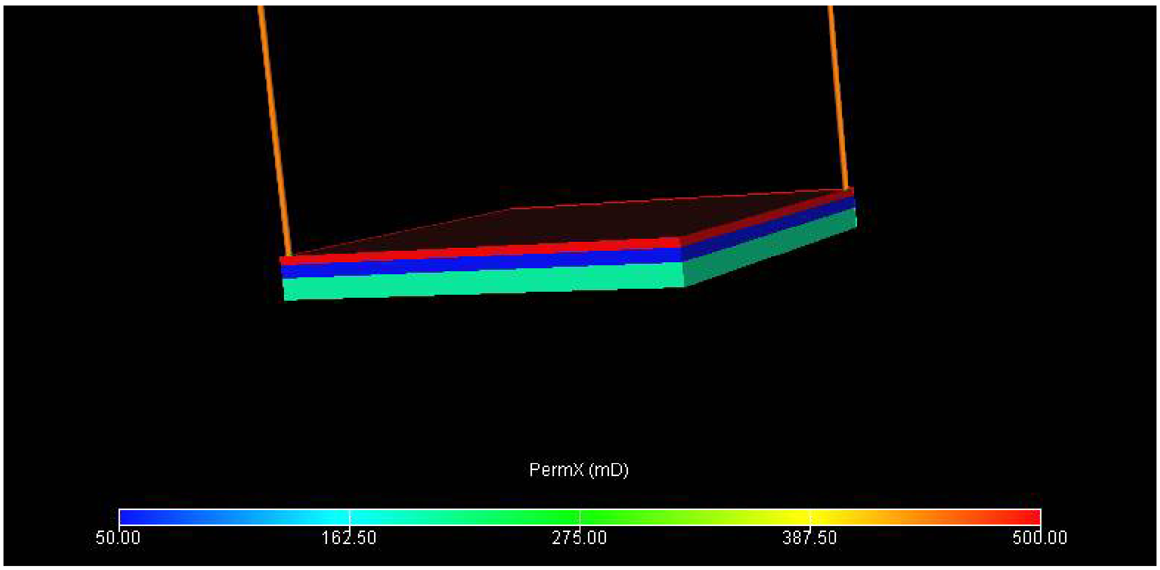


**Figure 2. Reservoir model with an injection well on the left and production well on the right.**

**Design**

Actual data collection for multiple simulations is impossible in an oil reservoir. Taking measurements at 8,000 ft below the surface provides many difficulties in monitoring and recording data. To provide multiple scenarios for changes of pressure and flow rates for both injection of $CO_2$ and production of oil, computer modeling is the most effective method.

ECLIPSE software will be used to model the many calculations required to provide the best possibilities of results for maximum efficiency. Reservoir data obtained by a simulation problem presented by Odeh (1981) will be used to test for maximum efficiency using different injections and production scenarios. Relative permeabilities are given in Table 3.

After all relevant data is programmed into ECLIPSE, multiple rate simulations will be analyzed to determine theoretical equations for non-Darcy flow at the near-wellbore region. Assessing high velocity flow and equivalent reservoir properties at near-wellbore regions including multiple pressure flows for injection of $CO_2$ and oil production, an optimum efficiency flow rate will be determined considering non-Darcy term.

**Design Constraints**

Measurements of permeability and the non-Darcy coefficient are important for proper quantification of non-Darcy effect (Grigg et al., 2004). Relative permeabilities are given in Table 3(Odeh, 1981).

**Table 3. Relative permeability data for reservoir simulation (Odeh, 1981).**

| $s_g$ | $k_{rg}$ | $k_{ro}$ |
|---|---|---|
| 0.000 | 0.000 | 1.000 |
| 0.001 | 0.000 | 1.000 |
| 0.020 | 0.000 | 0.997 |
| 0.050 | 0.005 | 0.980 |
| 0.120 | 0.025 | 0.700 |
| 0.200 | 0.075 | 0.350 |
| 0.250 | 0.125 | 0.200 |
| 0.300 | 0.190 | 0.090 |
| 0.400 | 0.410 | 0.021 |
| 0.450 | 0.600 | 0.010 |
| 0.500 | 0.720 | 0.001 |
| 0.600 | 0.870 | 0.000 |
| 0.700 | 0.940 | 0.000 |
| 0.850 | 0.980 | 0.000 |
| 1.000 | 1.000 | 0.000 |

Economic interest in testing non-Darcy term is limited to the number of scenarios that can be performed on an actual reservoir properties. Time and equipment is too valuable to be testing different pressures during operations. Computer simulations will help solve actual operations to achieve desired results.

## Alternative Designs

Alternative designs for determining the most efficient flow rates for both injection and production scenarios might be to use other reservoir simulators. One simulator that could be used is MASTER, recently upgraded by Grigg and Zeng (Grigg and Zeng, 2005).

An alternative to calculating the non-Darcy effect may be to run simulations with a different and more realistic reservoir. A different description of the non-Darcy coefficient may also be used depending on reservoir characteristics.

**Final Design Selection**

Initial conditions set by Odeh (1981) will be used as a reference simulation. Non-Darcy effect will be calculated based upon initial conditions and simulation properties. An Excel model was created to calculate different injection and production flow rates as well as permeability changes that will affect the non-Darcy effect.

After analyzing the non-Darcy effect, multiple injection and production rates will be used to generate the most efficient flow rates. In order to utilize ECLIPSE, a phase control of gas, oil, and water will be used with the top layer consisting of gas contact and bottom layer consisting of a water aquifer that will not come into contact with the oil reservoir.

For the calculation of the non-Darcy coefficient, $\beta_{m,}$ measured values obtained from Grigg et al., (2004) were used. Calculated values obtained from correlation Equations 5 and 6 did not give reasonable values for β.

**Table 4. Comparison of $\beta_1$, $\beta_{2,}$ and βm.**

| **Q** MMscf/day | **k** mD | **$\beta_1$** $10^8$/m | **$\beta_2$** $10^8$/m | **βm** $10^8$/m |
|---|---|---|---|---|
| 100 | 2.5 | 7.563 | 16340.4 | 287 |
| 100 | 5 | 5.348 | 7231.9 | 210 |
| 100 | 25 | 2.392 | 1089.59 | 33.44 |
| 100 | 50 | 1.691 | 482.228 | 31 |
| 100 | 100 | 1.196 | 213.423 | 43 |
| 100 | 200 | 0.846 | 94.456 | 2.86 |
| 100 | 500 | 0.534 | 32.155 | 2.73 |

**Plans and Specifications**

The following is a basic overview of the tasks required to build and run the reservoir simulation models.

(1) Data collection

a. Non-Darcy conditions

b. Non-Darcy properties

c. Reservoir properties

d. PVT data

e. Geological data

(2) Geological model development

a. Structural model

b. Geometry of reservoir

(3) Reservoir model

a. Initial reservoir pressure

b. Initial reservoir temperature

c. Reservoir porosity

d. Reservoir permeability

e. PVT tables and data for gas injection and oil production

f. Injection design and production design

(4) Simulations

a. Reservoir simulations will be conducted using Schlumberger's ECLIPSE software

b. Three different cases for injection and production rates

(5) Analysis and Report

**Budget, Cost, and Timeline**

The following budget is created to provide an estimate of cost for the designed project. Labor costs are based on the mean hourly wages for a petroleum engineer (U.S. DOL, 2006).

Two weeks will be spent gathering data and obtaining numerical and theoretical information. After significant data is collected and analyzed, three weeks will be used to conduct simulations and prepare for analytical interpretation. Two weeks will be spent analyzing the results generated by multiple simulations. A final report will be prepared from the data collected. Results for optimum injection and oil production for $CO_2$ sequestration and production flow rates will be obtained in the report.

Data collection will require a petroleum engineer working 40 hours per week at $50.00 per hour. Computer modeling and analyzing data for increased flow efficiency will be performed by a single petroleum engineer working 40 hours per week. In total seven weeks will be required to assess the problem. A petroleum engineer working 40 hours per week at $50.00 per hour will charge $14,000. An extra fee of $6,000 will be assessed for miscellaneous expenses, such as computer use and program usage fee. Total cost is $20,000.

**Table 5. Proposed budget and timeline**

| | | | |
|---|---|---|---|
| Budget and Timeline for Enhanced Oil Production | | | |
| Petroleum Engineer | | | |
| | $50.00 per hour | | |
| | 40 hour work week | | |
| Weeks | Task | | Cost $ |
| 2 | Data analysis | | $4,000 |
| 3 | model simulations | | $6,000 |
| 2 | model analysis report | | $4,000 |
| | Misc. | | $6,000 |
| Timeline: 7 weeks | | Total Cost | $20,000 |

## Simulation Parameters

Reservoir parameters are provided by Odeh (1981) and given in Tables 1-3. Several initial assumptions needed to be made in order to conduct the simulation exercises. First, the simulation assumes a homogeneous and isotropic reservoir. Next, it is assumed that $CO_2$ does not go into solution with the formation water and exists only in the gas phase. The simulation also assumes that the overlying formation has zero vertical permeability and rock strength characteristics adequate for $CO_2$ injection. An injection well is positioned at local grid point (1,1) with a control injection rate of 100 MMscf/day. The injection well provides an injection gas of $CO_2$ for a time span of forty years. Gas is injected into the top layer of the reservoir having a permeability of 500mD and a porosity of 0.3 (Fig 3). An oil production well is located at grid point (10,10) that is operated at a rate of 20,000 STB/day for forty years.  The oil production well is perforated in the bottom layer of the reservoir having a permeability of 200mD and a porosity of 0.3 (Fig 4).

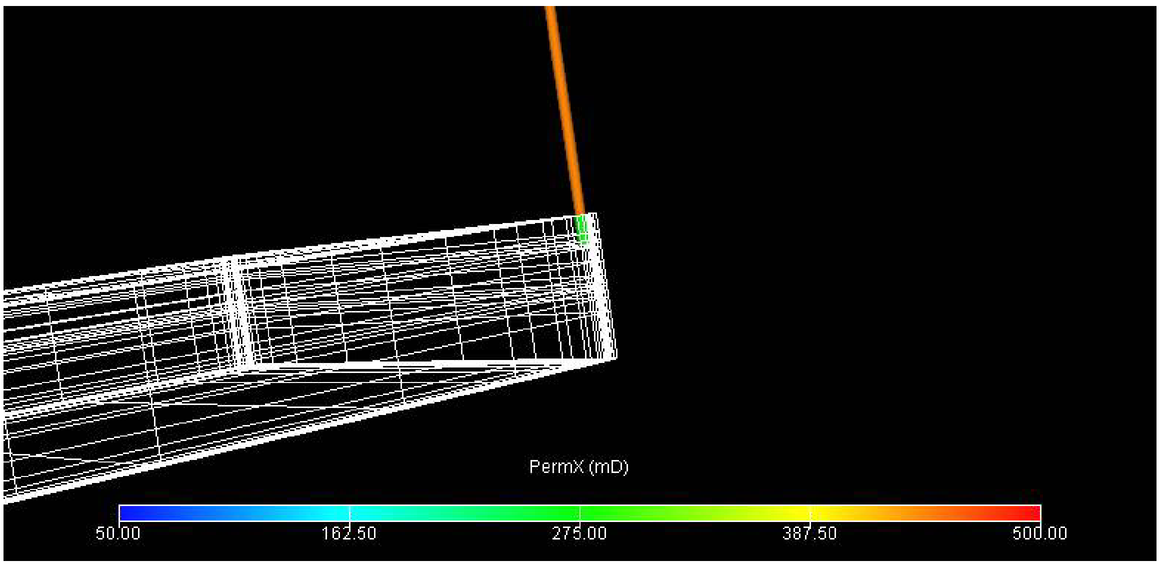


**Figure 3.  Location of the injection well in the reservoir.**

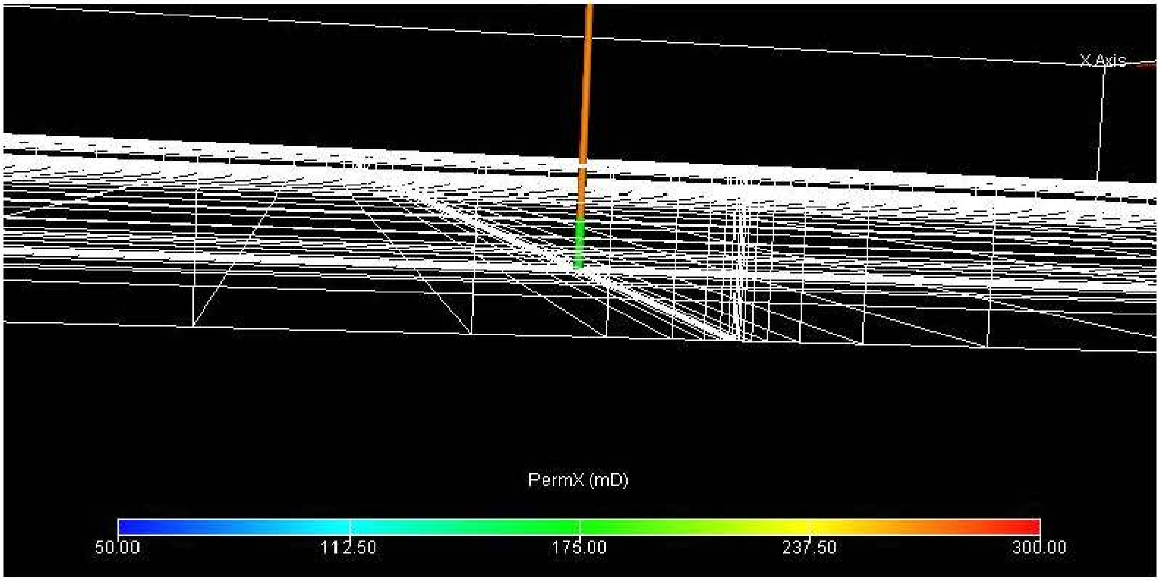


**Figure 4. Location of the production well in the reservoir.**

## Results

Main focus of this design project was to obtain a critical Forchheimer number that corresponds to a reasonable non-Darcy effect, E. Three different injection flow rates for $CO_2$ and three different production flow rates for oil yielded non-Darcy effect percentages to match the flow rates assigned. Injection rates and non-Darcy effect percentages are given in Table 6. Oil production flow rates and non-Darcy effect rates are given in Table 7. Viscosities and densities were obtained from PVT tables for given pressures (Appendixes A and B).

To calculate $Q_{BH}$ (flow rate at bottom hole) mass flow rate was found from Equations 7 and 8:

$$m = Q_{STD} * \rho_{STD} \qquad (7)$$

$$Q_{BH} = m/\rho_{BH} \qquad (8)$$

where m is mass flow rate, $Q_{STD}$ is flow rate at the surface, $Q_{BH}$ is flow rate at the bottom hole region, $\rho_{STD}$ is the density at surface pressure, and $\rho_{BH}$ is the density at the bottom hole pressure. Velocity is calculated from bottom hole conditions Eq. 9:

$$v = Q_{BH}/A \qquad (9)$$

where v is velocity at the wellbore and A is the area of the wellbore. $F_o$ and E were calculated using Eqs. 3 and 4. Results are shown in Tables 6 and 7.

**Table 6. Non-Darcy effect results due to injection flow rates at a pressure of 4,800 psia**

| Q MMscf/day | v cm/s | k mD | ρ $g/cm^3$ | βm $10^8$/m | μ cp | Fo | E % |
|---|---|---|---|---|---|---|---|
| 100 | 4.63 | 2.5 | 0.48 | 287 | 0.0722 | 22.09 | 95.67 |
| 100 | 4.63 | 5 | 0.48 | 210 | 0.0722 | 32.32 | 97.00 |
| 100 | 4.63 | 25 | 0.48 | 33.44 | 0.0722 | 25.73 | 96.26 |
| 100 | 4.63 | 50 | 0.48 | 31 | 0.0722 | 47.71 | 97.95 |
| 100 | 4.63 | 100 | 0.48 | 18 | 0.0722 | 55.41 | 98.23 |
| 100 | 4.63 | 200 | 0.48 | 2.86 | 0.0722 | 17.61 | 94.63 |
| 100 | 4.63 | 500 | 0.48 | 2.73 | 0.0722 | 42.02 | 97.68 |
| 10 | 0.46 | 2.5 | 0.48 | 287 | 0.0722 | 2.19 | 68.69 |
| 10 | 0.46 | 5 | 0.48 | 210 | 0.0722 | 3.21 | 76.25 |
| 10 | 0.46 | 25 | 0.48 | 33.44 | 0.0722 | 2.56 | 71.88 |
| 10 | 0.46 | 50 | 0.48 | 31 | 0.0722 | 4.74 | 82.58 |
| 10 | 0.46 | 100 | 0.48 | 18 | 0.0722 | 5.50 | 84.63 |
| 10 | 0.46 | 200 | 0.48 | 2.86 | 0.0722 | 1.75 | 63.63 |
| 10 | 0.46 | 500 | 0.48 | 2.73 | 0.0722 | 4.17 | 80.67 |
| 0.3 | 0.014 | 2.5 | 0.48 | 287 | 0.0722 | 0.07 | 6.26 |
| 0.3 | 0.014 | 5 | 0.48 | 210 | 0.0722 | 0.10 | 8.90 |
| 0.3 | 0.014 | 25 | 0.48 | 33.44 | 0.0722 | 0.08 | 7.22 |
| 0.3 | 0.014 | 50 | 0.48 | 31 | 0.0722 | 0.14 | 12.61 |
| 0.3 | 0.014 | 100 | 0.48 | 18 | 0.0722 | 0.17 | 14.35 |
| 0.3 | 0.014 | 200 | 0.48 | 2.86 | 0.0722 | 0.05 | 5.05 |
| 0.3 | 0.014 | 500 | 0.48 | 2.73 | 0.0722 | 0.13 | 11.27 |

**Table 7. Non-Darcy effect due to oil production flow rates at a pressure of 2,500 psia**

| Q STB/day | v cm/s | k mD | ρ $g/cm^3$ | βm $10^8$/m | μ cp | Fo | E % |
|---|---|---|---|---|---|---|---|
| 20,000 | 4.03 | 2.5 | 0.583 | 287 | 0.449 | 3.754 | 78.97 |
| 20,000 | 4.03 | 5 | 0.583 | 210 | 0.449 | 5.494 | 84.60 |
| 20,000 | 4.03 | 25 | 0.583 | 33.44 | 0.449 | 4.375 | 81.39 |
| 20,000 | 4.03 | 50 | 0.583 | 31 | 0.449 | 8.111 | 89.02 |
| 20,000 | 4.03 | 200 | 0.583 | 2.86 | 0.449 | 2.993 | 74.96 |
| 10,000 | 2.01 | 2.5 | 0.583 | 287 | 0.449 | 1.873 | 65.19 |
| 10,000 | 2.01 | 5 | 0.583 | 210 | 0.449 | 2.740 | 73.26 |
| 10,000 | 2.01 | 25 | 0.583 | 33.44 | 0.449 | 2.182 | 68.57 |
| 10,000 | 2.01 | 50 | 0.583 | 31 | 0.449 | 4.045 | 80.18 |
| 10,000 | 2.01 | 200 | 0.583 | 2.86 | 0.449 | 1.493 | 59.89 |
| 5,000 | 1.01 | 2.5 | 0.583 | 287 | 0.449 | 0.941 | 48.48 |
| 5,000 | 1.01 | 5 | 0.583 | 210 | 0.449 | 1.377 | 57.93 |
| 5,000 | 1.01 | 25 | 0.583 | 33.44 | 0.449 | 1.096 | 52.30 |
| 5,000 | 1.01 | 50 | 0.583 | 31 | 0.449 | 2.033 | 67.03 |
| 5,000 | 1.01 | 200 | 0.583 | 2.86 | 0.449 | 0.750 | 42.86 |

Analyzing results obtain from calculating the non-Darcy effect, a preferred injection rate of 0.3 MMscf/day or 300Mscf/day, E of 11.27%, would provide a more efficient flow rate for a reservoir with the given properties assigned by the Odeh (1981) simulation problem. Preferred oil production flow rates of 5,000 STB/day, E of 42.86% is suggested to minimize the non-Darcy effect. Zeng and Grigg (2006) suggested a 10% non-Darcy effect on flow rates would be an acceptable allowance. Tables 6 and 7 also show that as permeability increases the non-Darcy effect decreases, stating that permeability is a major contributor in the nonlinearity of pressure gradient and velocity.

Simulations of the initial conditions were made and results are shown in Appendix C. Reservoir characteristics of oil saturation are shown in Figures 5 and 6.

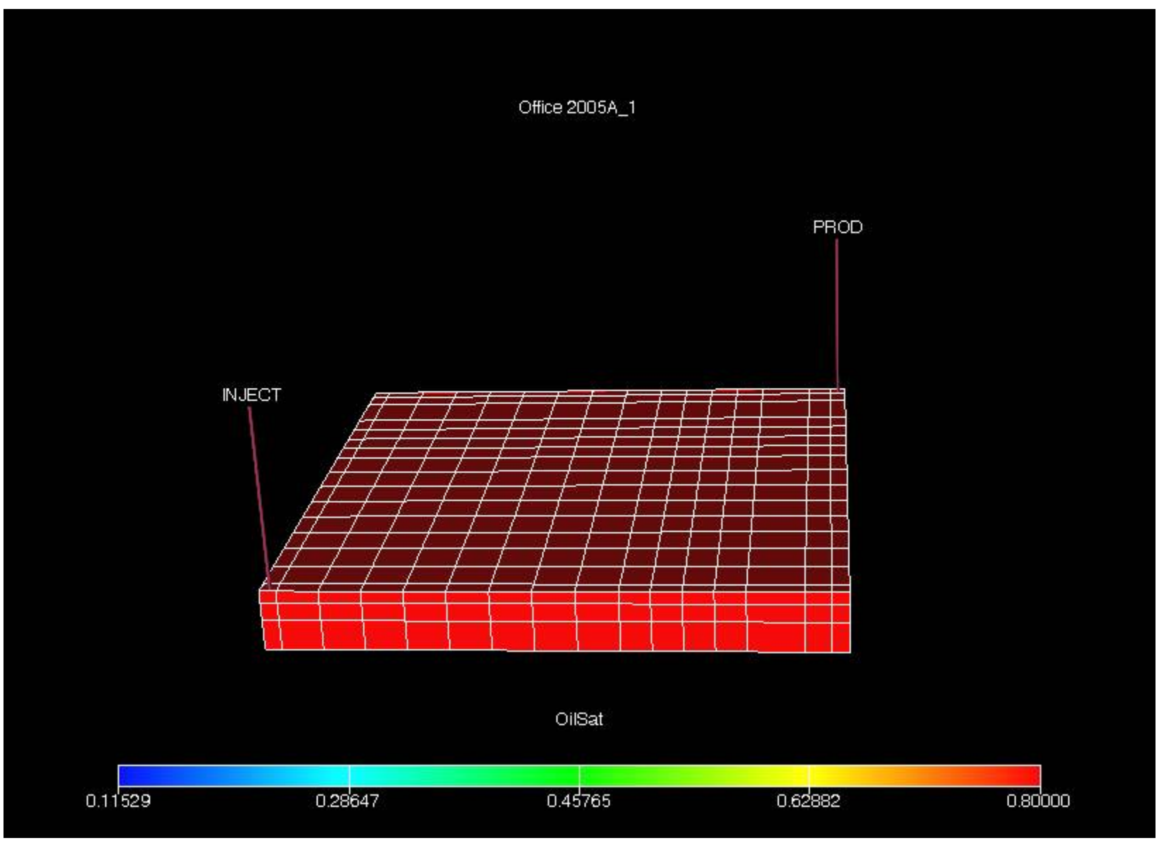


**Figure 5. Reservoir oil saturation at beginning of simulation for the reference simulation.**

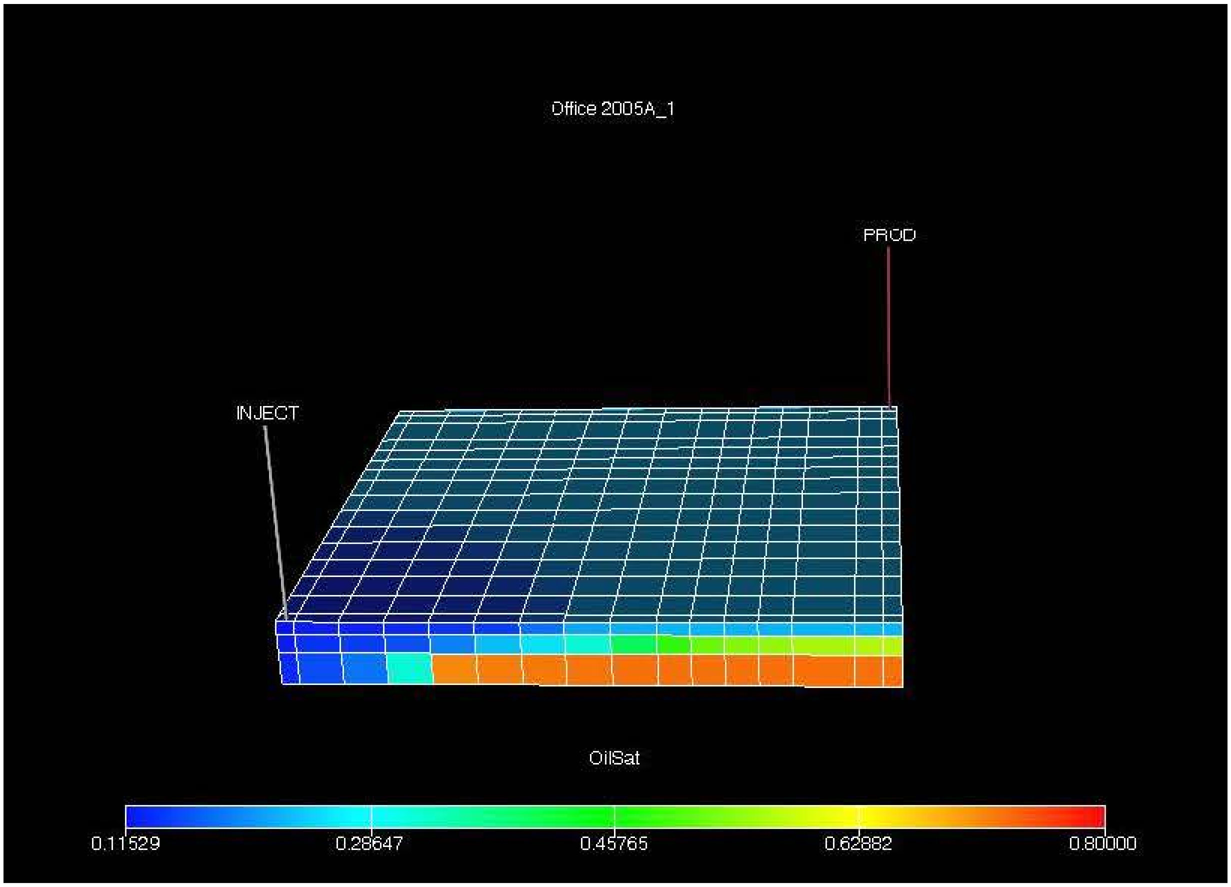


**Figure 6. Reservoir oil saturation after 40 years at a flow rate of 20,000 STB/day for the reference simulation.**

By calculating the non-Darcy effect and analyzing the percentage to be greater than 10% a non-Darcy effect was added to the control simulation (Fig. 7).

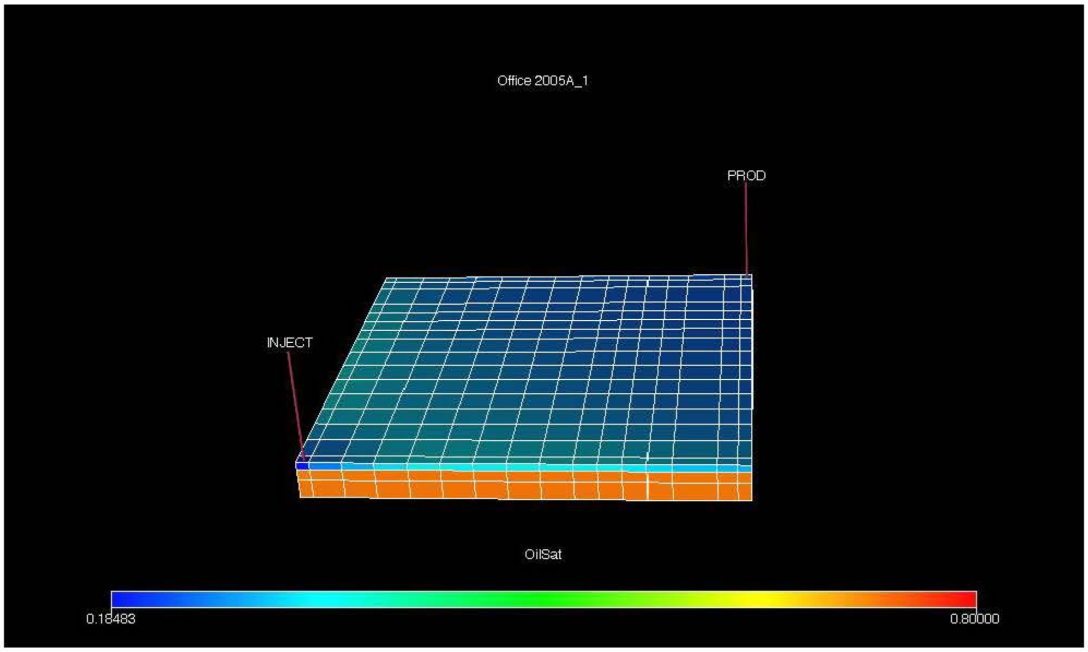


**Figure 7. Reservoir oil saturations including the non-Darcy effect of the reference model after 40 yrs for the reference simulation.**

As seen in Figure 7, there is now a gain of oil saturation in the non-Darcy reference model which resulted in a loss of actual production of oil. Analyzing gas saturation for the same method resulted in similar results with a loss in efficiency in gas saturation (Figs. 8-10).

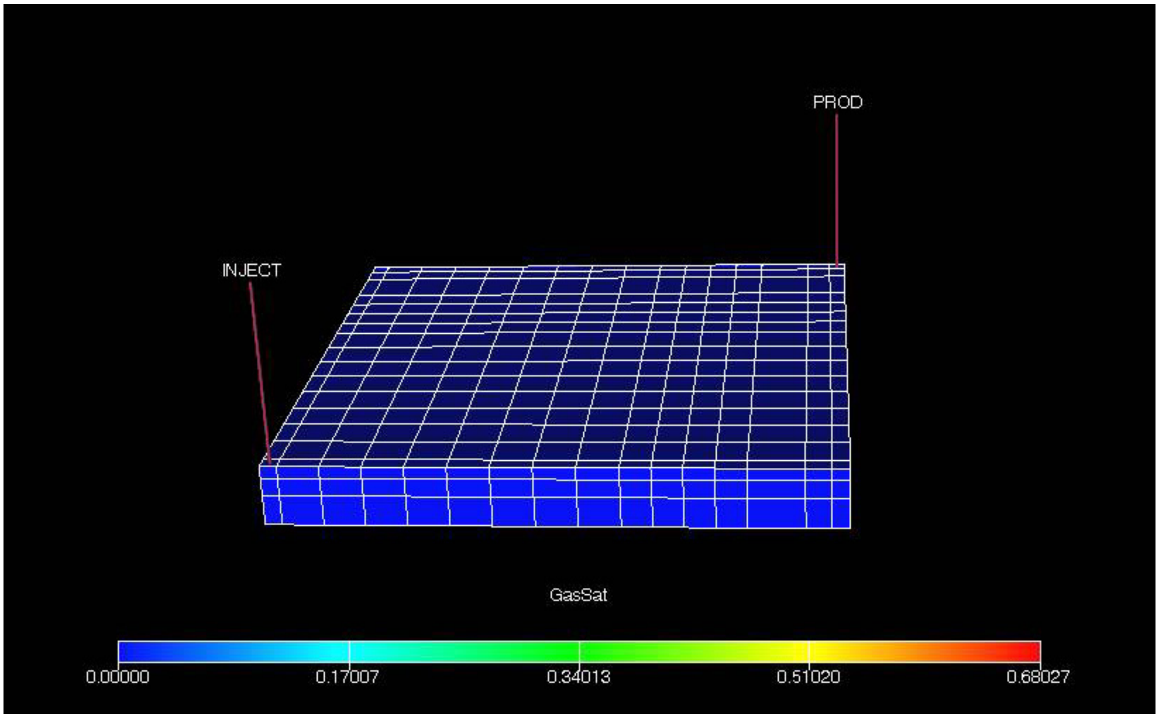


**Figure 8. Initial gas saturation in the reservoir for the reference simulation.**

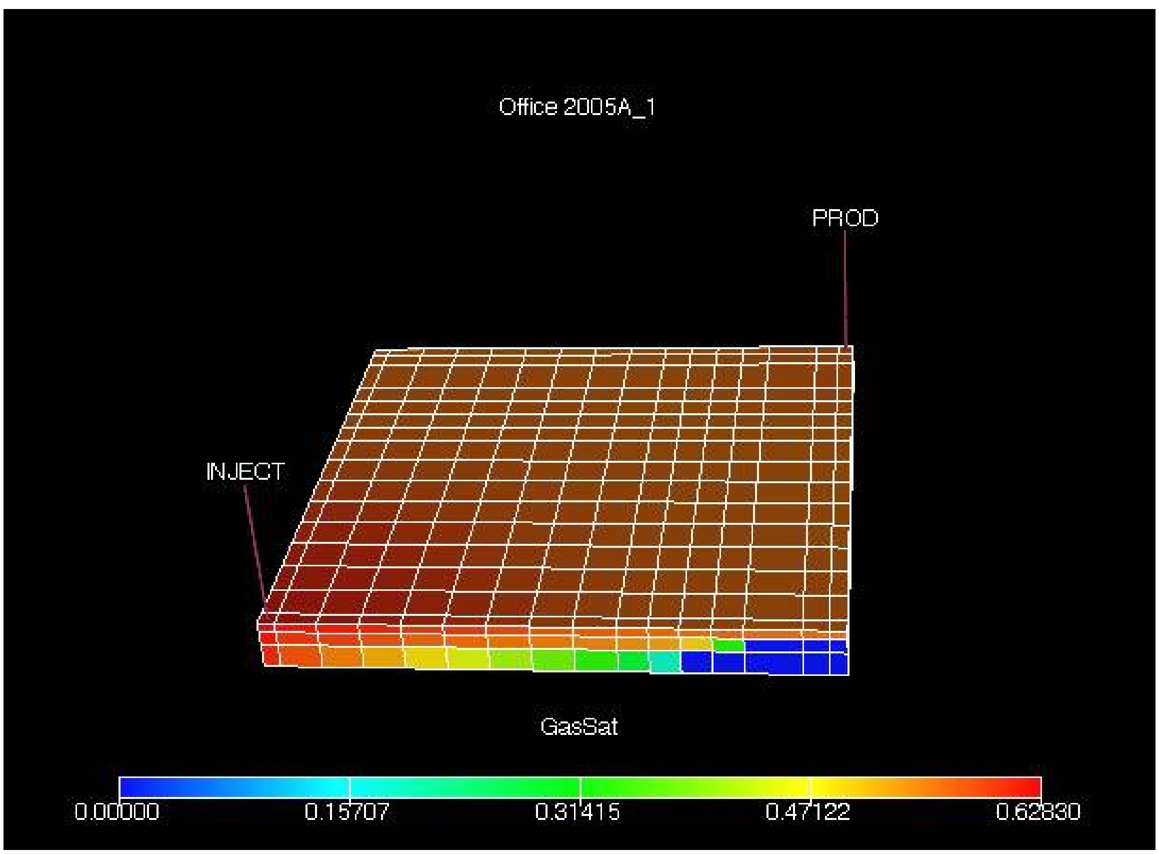


**Figure 9. Gas saturation after 40 years at an injection rate of 100 MMscf/day.**

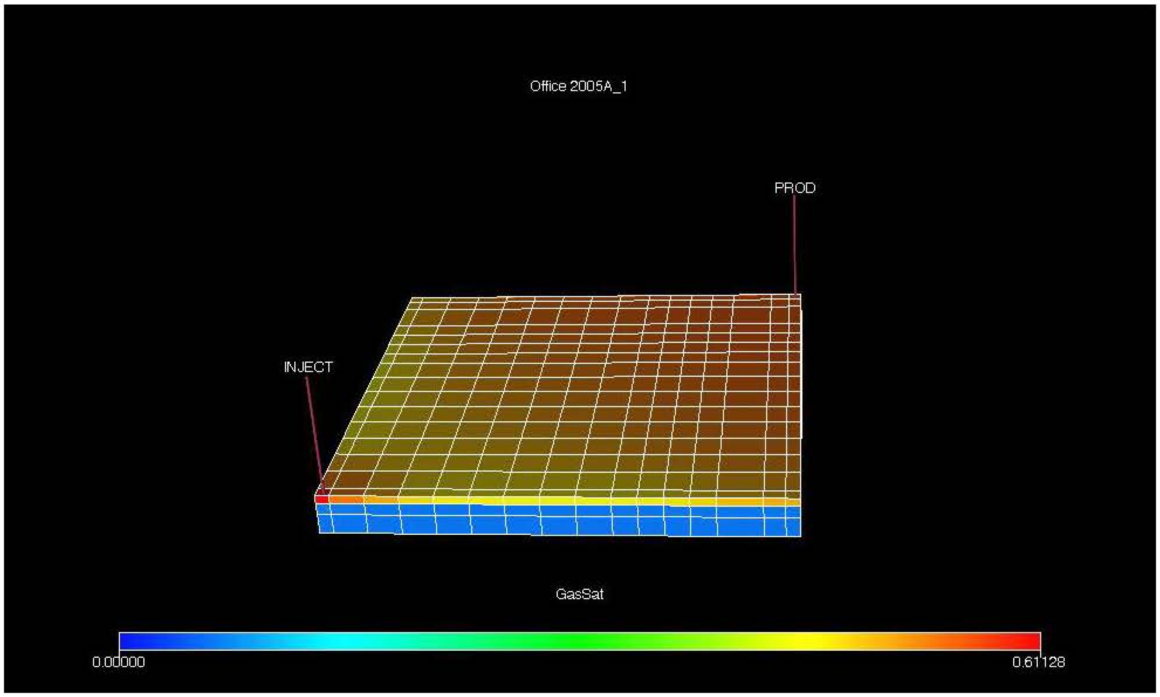


**Figure 10. Gas saturation of the reservoir including non-Darcy effect after 40 years for the reference simulation.**

As seen in Figure 10, the reservoir does not hold as much $CO_2$ gas due to the non-Darcy effect applied to the simulation.

Using results obtained from the calculation of non-Darcy effect and simulating injection flow rates with a tolerable non-Darcy effect of 11.27% (Table 6) and a production flow rate of a preferred non-Darcy effect of 42.86% and a corresponding flow rate of 5,000 STB/day (Table 7) shows minimal changes in both gas saturation and oil saturation within the reservoir (Figs. 11-14). The non-Darcy effect value, E, of 42.86% is used in simulation modeling based on the production rate of 5,000 STB/day. Lowering this value will not produce a reasonable rate of oil based on the economics of less oil per time period. Although E is high, other factors may be involved with production scenarios. The calculation of β may not be as accurate considering the flow of oil and not a gas.

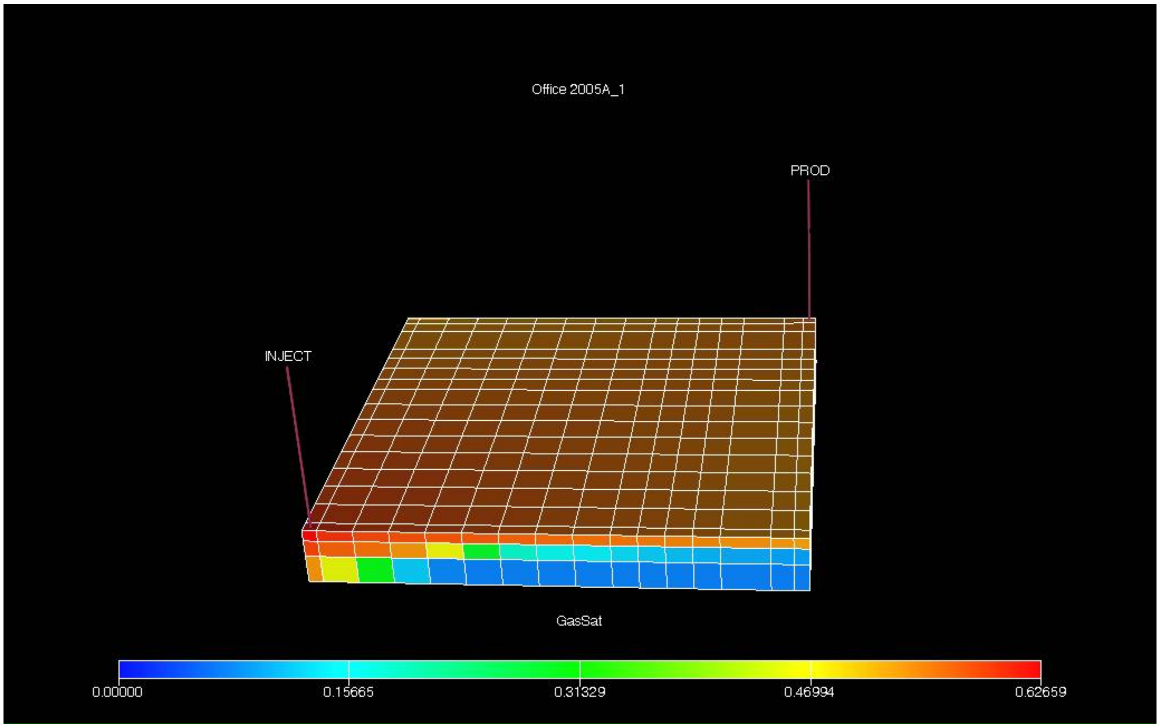


**Figure 11. Gas saturation in reservoir at preferred flow rates after 40 years.**

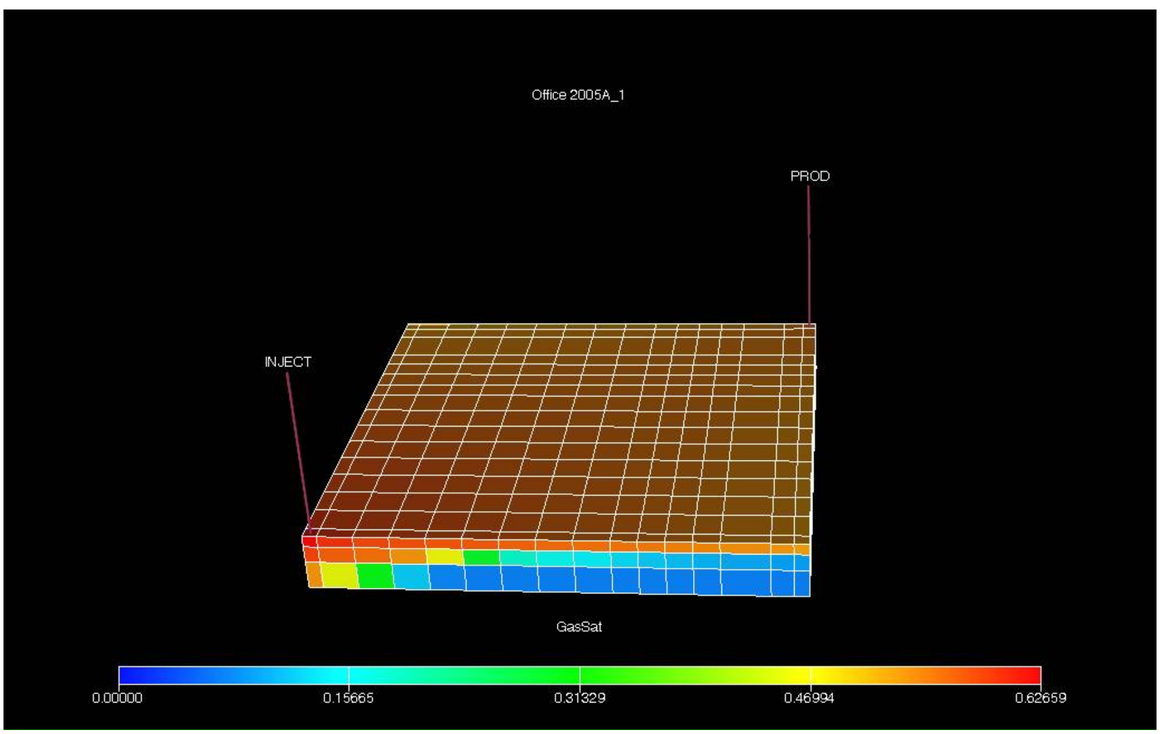


**Figure 12. Gas saturation of reservoir including non-Darcy effect after 40 years.**

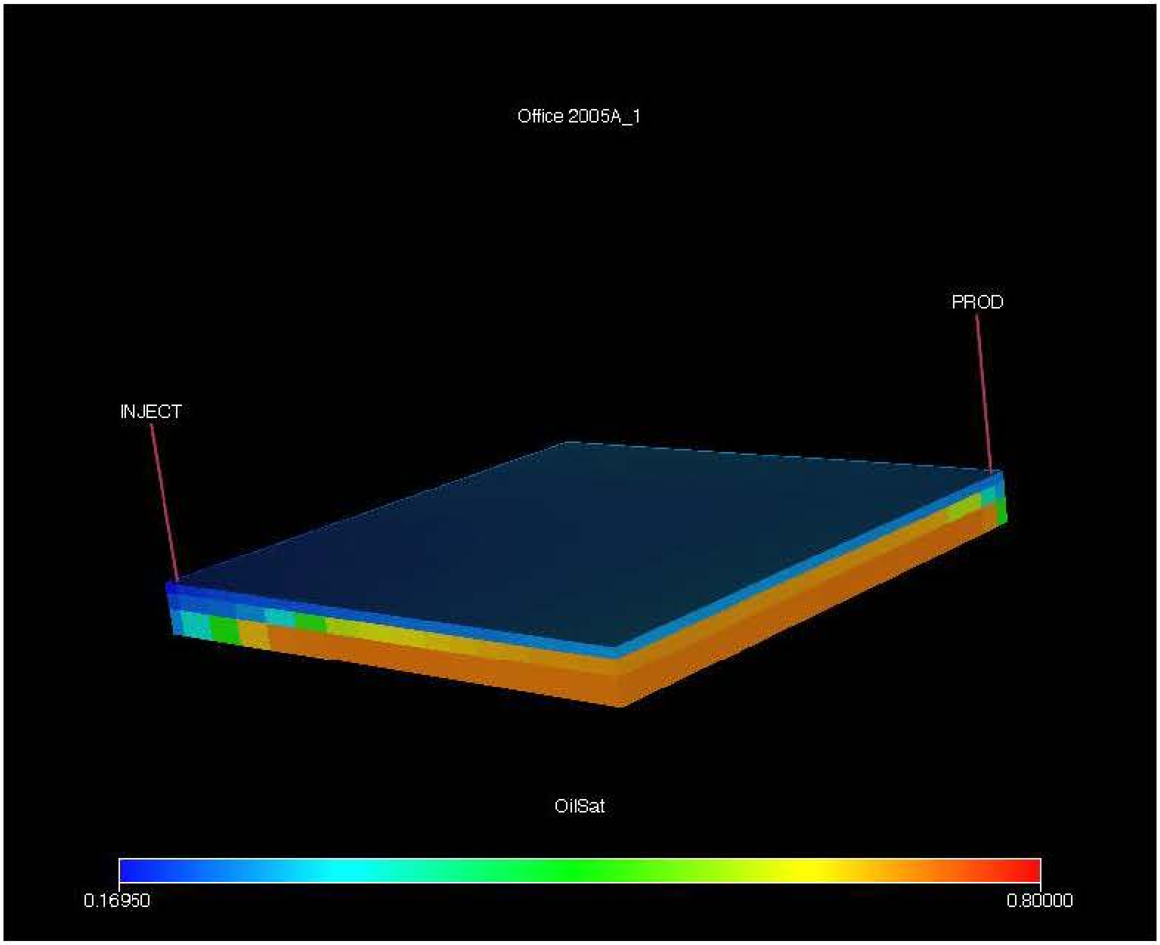


**Figure 13. Oil saturation in the reservoir at preferred injection and production flow rates after 40 years.**

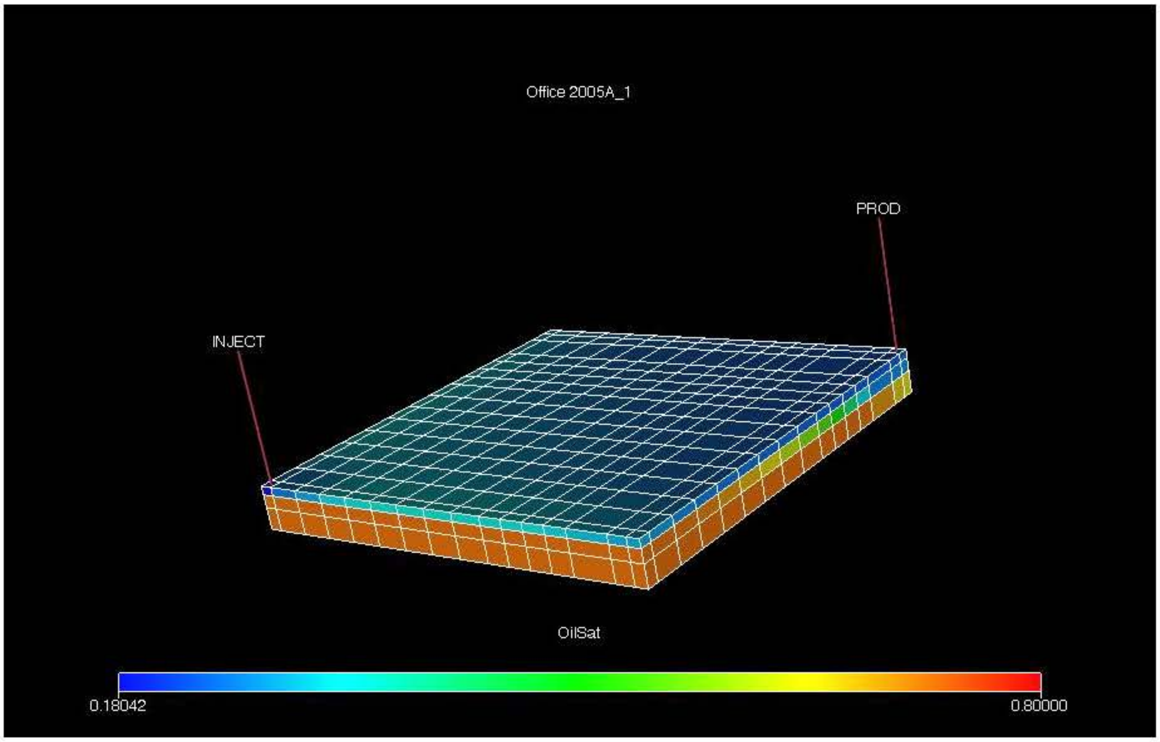


**Figure 14. Oil saturation in the reservoir at preferred injection and production flow rates with the non-Darcy effect after 40 years.**

## Conclusions

Accurate description of $CO_2$ flow in rocks is important because it is related to both $CO_2$ enhanced oil recovery for producing more oil from mature reservoirs and to $CO_2$ sequestration for reducing greenhouse gas emission. Ability to calculate non-Darcy flow near wellbore regions will increase efficiency of $CO_2$ flow for sequestration and oil flow during production. From results shown, adding the non-Darcy effect, E, when the percentage is greater than 10%, results in different reservoir results. Table 6 and Table 7 show changes in flow rates along with corresponding non-Darcy percents. From the tables and simulation runs high flow rates reduce the efficiency of injection and production in the reservoir. Tables 6 and 7 also provide permeability changes, k, that may result in different non-Darcy effects. Table 6 and Table 7 show that an increase in k will result in higher non-Darcy effect, E, percentages. By calculating the non-Darcy effect, E, one can determine whether or not to apply E to their simulation runs. By calculating E into simulation runs an increase in efficiency of both $CO_2$ injection and oil production will be projected.

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# Appendix A

Table A-1. $CO_2$ Properties at 200˚F.

| D (ft) | P (psia) | z | $\rho_g$ (g/cm3) | $B_g$ (RB/Mscf) | $c_g$ (/psi) | $\mu_g$ (cp) |
|---|---|---|---|---|---|---|
| | 100 | 1.020019925 | 0.009597427 | 34.50768808 | | 0.009664622 |
| | 300 | 0.96016021 | 0.03058729 | 10.82753654 | 3.4691E-03 | 0.010086012 |
| | 500 | 0.907572027 | 0.053932724 | 6.140706007 | 2.6431E-03 | 0.010716291 |
| | 700 | 0.862212915 | 0.079478008 | 4.167001842 | 1.9823E-03 | 0.011571906 |
| | 900 | 0.823962013 | 0.106929805 | 3.097218814 | 1.6519E-03 | 0.012685448 |
| | 1100 | 0.792627828 | 0.135858503 | 2.437720105 | 1.2224E-03 | 0.014094723 |
| | 1300 | 0.76795597 | 0.165718307 | 1.998481706 | 1.0242E-03 | 0.015836647 |
| | 1500 | 0.749636814 | 0.195886185 | 1.690701179 | 8.4249E-04 | 0.017940713 |
| | 1700 | 0.737313122 | 0.225714996 | 1.467270717 | 6.7730E-04 | 0.020421816 |
| | 1900 | 0.730587609 | 0.254592001 | 1.30084607 | 4.2951E-04 | 0.023273669 |
| | 2100 | 0.729030452 | 0.281992191 | 1.174447434 | 3.1057E-04 | 0.026464774 |
| | 2300 | 0.732186755 | 0.307517208 | 1.076964136 | 3.0396E-04 | 0.029938802 |
| | 2500 | 0.739583951 | 0.330914644 | 1.00081701 | 2.9735E-04 | 0.0336201 |
| | 2700 | 0.750739156 | 0.352077404 | 0.940659643 | 2.6101E-04 | 0.037423385 |
| | 2900 | 0.765166473 | 0.371027006 | 0.892616978 | 2.2466E-04 | 0.04126523 |
| 5666 | 3100 | 0.78238424 | 0.38788685 | 0.853818594 | 1.7098E-04 | 0.045074501 |
| 6032 | 3300 | 0.801922223 | 0.40285165 | 0.822101645 | 1.6685E-04 | 0.048799534 |
| 6397 | 3500 | 0.823328759 | 0.416157968 | 0.795815603 | 1.4372E-04 | 0.052411141 |
| 6763 | 3700 | 0.846177848 | 0.428058897 | 0.773690272 | 1.3050E-04 | 0.055901771 |
| 7128 | 3900 | 0.870076188 | 0.438804204 | 0.754744375 | 1.1564E-04 | 0.059281947 |
| 7494 | 4100 | 0.894670159 | 0.448625919 | 0.738220845 | 1.0407E-04 | 0.062575235 |
| 7860 | 4300 | 0.919652755 | 0.457728586 | 0.723540139 | 9.4161E-05 | 0.065812781 |
| 8225 | 4500 | 0.944770462 | 0.466283087 | 0.71026596 | 8.5901E-05 | 0.069028046 |
| 8311 | 4547 | 0.950670506 | 0.468229088 | 0.707314033 | 8.4249E-05 | 0.069783856 |
| 8591 | 4700 | 0.969830084 | 0.47442292 | 0.698079689 | 7.8467E-05 | 0.072251933 |
| 8956 | 4900 | 0.994705513 | 0.482241977 | 0.686761046 | 7.2686E-05 | 0.075508251 |
| 9322 | 5100 | 1.019344454 | 0.489793106 | 0.676173267 | 6.7730E-05 | 0.078809287 |
| 9687 | 5300 | 1.043775088 | 0.497086992 | 0.666251602 | 6.4426E-05 | 0.082151246 |
| 10053 | 5500 | 1.068112686 | 0.504091149 | 0.656994286 | 5.9470E-05 | 0.085509419 |
| 10418 | 5700 | 1.092566174 | 0.51072905 | 0.648455388 | 5.7818E-05 | 0.088833161 |
| 10784 | 5900 | 1.117444636 | 0.516879672 | 0.640739078 | 5.2862E-05 | 0.092041111 |
| 11150 | 6100 | 1.143163775 | 0.522377951 | 0.633994992 | 5.1210E-05 | 0.095017598 |

# Appendix B

Table B-1. Oil PVT functions for reservoir simulation (Odeh 1981)

| **Reservoir Pressure** (psia) | **Viscosity** (cp) | **Density** lmb/ft$^3$ |
|---|---|---|
| 14.7 | 1.040 | 46.244 |
| 264.7 | 0.975 | 43.544 |
| 514.7 | 0.910 | 42.287 |
| 1014.7 | 0.830 | 41.004 |
| 2014.7 | 0.695 | 38.995 |
| 2514.7 | 0.641 | 38.304 |
| 3014.7 | 0.594 | 37.781 |
| 4014.7 | 0.510 | 37.046 |
| 5014.7 | 0.449 | 36.424 |
| 9014.7 | 0.203 | 34.482 |

# Appendix C

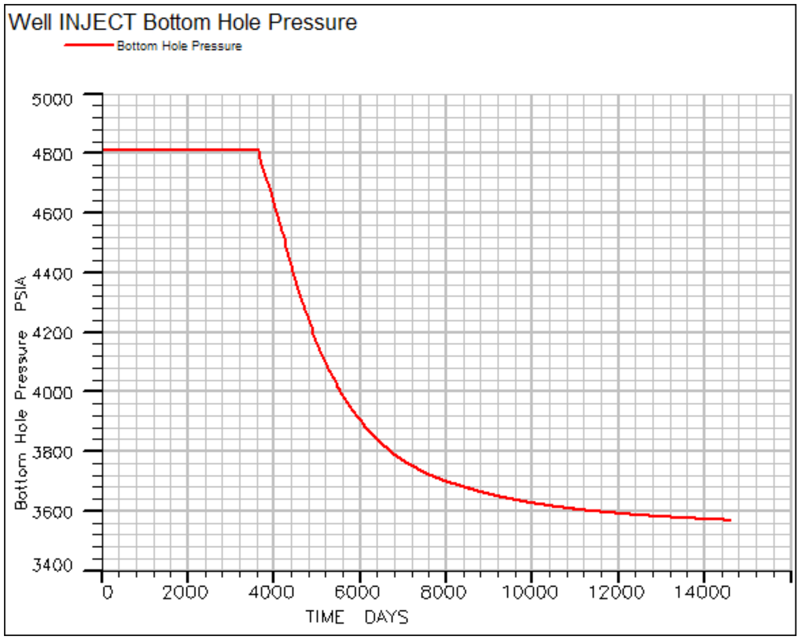


**Figure C-1. Bottom hole pressure of injection well.**

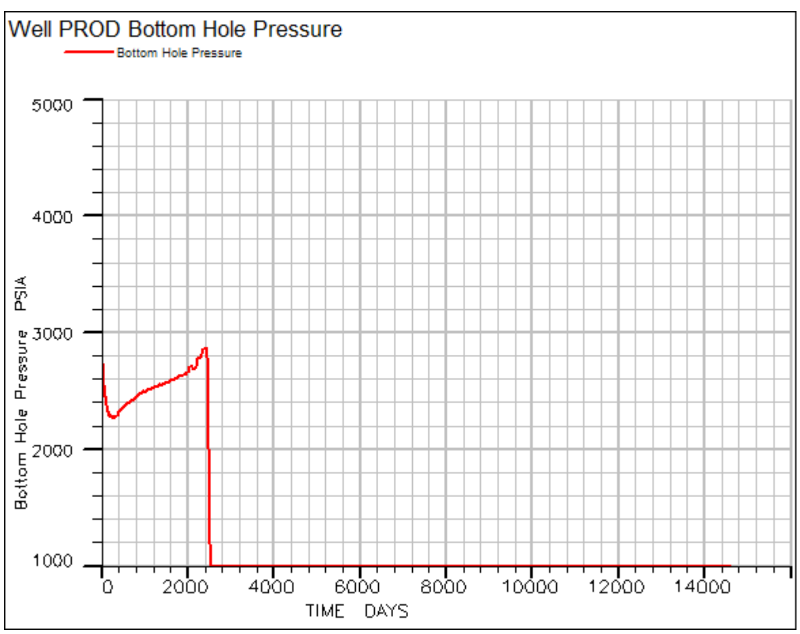


**Figure C-2. Bottom hole pressure of production well.**

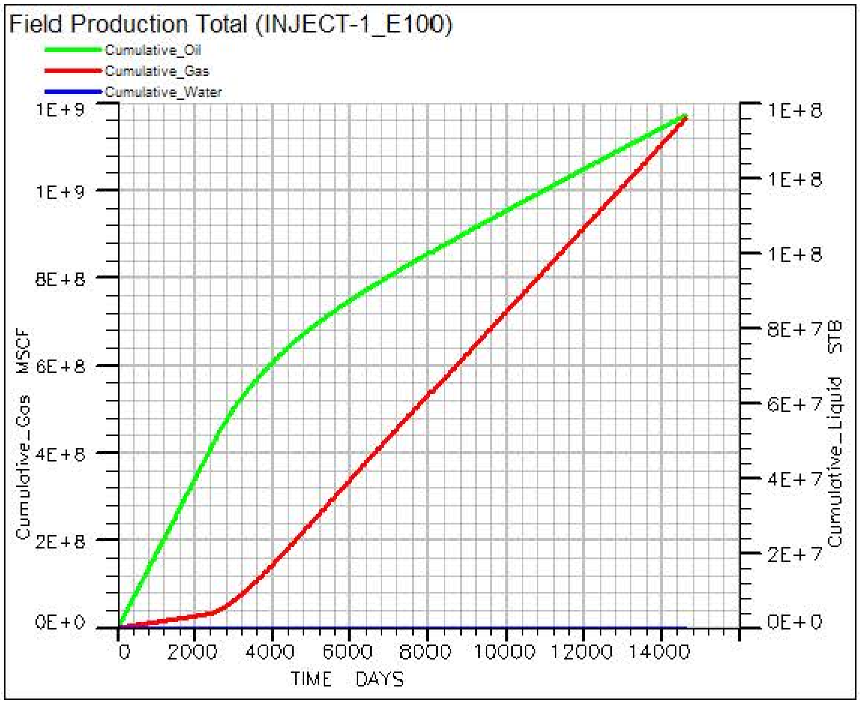

**Figure C-3. Total field production of control simulation.**