Water Flood Forecast between Injectors and Producers Pattern for Maximum Hydrocarbon Recovery in Depleted Reservoirs

Zorasi, C.B., Adooh, L.S.K., & Damabel, B. C.
School of Applied Science, (SLT/MATH/STAT.).
Ken SaroWiwa Polytechnic,
Rivers State.

Tanen, R. & Al Abbadd, A.
Department of Petroleum Engineering System
Regina University,
Canada.
collinzi4u@yahoo.com, ruti_allstars@yahoo.com

ABSTRACT
There are remarkable quantity of well-known resources of heavy oil, extra-heavy oil, and bitumen in Canada, Venezuela, Russia, the USA and many other countries. While these resources in North America only provide a small percentage of current oil production (approximately 2%), existing commercial technologies could allow for significantly increased production. Reservoir simulation models are used by oil and gas companies in the development of new fields as well as in developed fields where production forecasts are needed to help make investment decisions. In recent times, reservoir simulators have been used extensively to aid in planning, execution, evaluation and optimization of heavy oil operations. In this paper we considered heavy oil pool whose pressure has declined to less than 50% of initial reservoir pressure, resulting in large decline in oil production rates. To re-pressurize this pool and increase oil production, we used water injection. In an effort to understand the effect of the proposed water flood on the pool, a reservoir simulation study was carried out using software and a numerical model. The project is divided into 2 phases with water flood recently commenced in Phase 1. Using the results from Phase 1, production and injection rates are forecasted for Phase 1. Based on the results from Phase 1, the water flood scheme is expanded to Phase 2 and optimum injection and production rates are forecasted. No new wells are drilled for the injectors, rather, using the numerical model, optimum well pattern placements are studied and the water flood expansion plan is recommendation for phase 2 based on the best recovery scenario.

Keywords: *Water flood; heavy oil; reservoir simulation; decline pressure; hydrocarbon production.*

Introduction

Tunio et al.(2011) opined that we live in a dispensation of human existence which marks the gradual end of the era of readily available hydrocarbon discovery. This coupled with high energy demand worldwide, necessitated oil companies to look inward for oil and gas production from marginal fields as well as Heavy oil and bitumen deposits. Heavy oil is highly viscous crude that has API gravity between 10^{O} API and 20^{o} API with a viscosity greater than 100cp (Mayer, Attanasi and Freeman, 2007; Suncor Energy, 2014).This high viscous crude cannot easily flow to production wells under normal reservoir condition, that is, may be immobile in the reservoir. Therefore, because of its density or specific gravity quality relative to conventional oil it has low price in market. There are huge well known resources of heavy oil, extra –heavy oil, and bitumen in Canada, Venezuela, Russia, China, the USA and many other countries (Tanen and AlAbbad, 2014). Also, there are 192 basins containing these heavy oil resources distributions worldwide and Canada is taking the lead in production (Meyer et al,2007; Mai, Bryan, Goodarzi, and Kantas 2006). These Heavy oil and bitumen serve as an alteration product of conventional oil. (Meyeret al.2007).Tunio et al (2011) cited USA Department of energy which state that the amount of oil produced worldwide is only one third of the total oil available; this implies that the oil or gas produced by primary recovery from most reservoirs accounts for only 20 to 30% of the total amount available (CEC, 1999). Vast quantities of this hydrocarbon never got out of the source rock; that is, more oil is left behind in the reservoirs than will be recovered from them by the end of their life cycle (Shepherd, 2009). It has been estimated that there are 6 x 10^{12} tons of hydrocarbons in the reservoir rocks of the continents and continental shelves of the world and at least 100 times of this amount of hydrocarbons still remain in the source beds. To keep pace with consumption rate, heavy oil fields set apart by their high viscosity need to be properly re-evaluated for hydrocarbon production as they can contribute to the high energy demand that has exceed the supply by conventional oil (Zitha et al, 2011, Meyer et al.,2007).The study location in Northern hemisphere Canada has an estimated heavy oil of 80 billion barrel (Suncor Energy, 2014) and has only contributes a small percentage of current oil production which is approximately 2%.This field lacks efficient production due to the depletion of the reservoir pressure by 50%, but with the aid of current existing technologies significant increase in production of this heavy oil can be achieved (Tunio et tal., 2011; Tanen and AlAbbad, 2014). The aim of this project is to repressurize these reservoirs for effective oil and gas production. Glover (2001) recognized and highlighted recovery of hydrocarbon from an oil reservoir in several stages. These are primary (natural), secondary (water or gas injection) and tertiary (EOR).Related studies show that the amount of oil that can be produced with water flooding can reach up to 40% (Tunio et at., 2011) while using enhanced oil recovery (EOR) techniques, recovery can reach up to 60-65%. However, it is not feasible to recover all of the hydrocarbons from the reservoir (Shepherd, 2009).At initial production stage of a field, oil and gas flow naturally to the surface due to the existing reservoir pressure in the primary production stage till the reservoir pressure drops (Alagorm, Yaacob, and Nour, 2015).The reservoirs need to be re-pressurized to keep the production of hydrocarbon; and water is typically injected to boost the pressure to displace the oil into production wells. Reservoir simulation forecast using water flood pilot between injector and producer wells pattern was carried out for maximum hydrocarbon recovery from pressure depleted wells. Water flood study aid in forecasting, planning, and optimization of heavy oil operations for investment decisions. The results of this study lead to the increase in daily oil production to meet the energy demand and contribute its quota to the Nation’s economic development.

Regional Geology of the Study Area

The study area in western Alberta and Saskatchewan Canada has been the focal point of heavy oil development for many years and geographically it is the largest prospective area (Gingras and Rokosh, 2004). Heavy oil production is from the Manville formation group sediments with the entire suite of Mannville formation’s being prospective targets. According to Heyes et al (1994) Mannville group and equivalent strata comprise the oldest Cretaceous rocks over most of the western Canada sedimentary Basin and represent a major episode of subsidence and sedimentation following a long period of uplift, exposure and erosion of older strata are extremely widespread and heterogeneous, few comprehensive syntheses of the entire group exist. The sediment of the study area is sandstone, derived from sedimentary, metamorphic and igneous rocks terrain located in the South, East and West (Putnam, 1982).

The formations containing this heavy oil have three separate genetic intervals known as Upper Manville, Middle Manville and lower Mannville group in their descending order. The Upper Manville has thickness of about 35m. It has lenticular, ribbon-shaped deposits of cross-bedded sandstone which laterally grade into interbedded deposits of current rippled sheet sandstones, siltstones, shales and coals (Putnam, 1982). The middle Manville consists mainly of upward coarsening, very fine to fine grained, quartzose sheet sandstones. It has unit thickness generally between 6 to 9m and contains a restricted marine micro flora and micro fauna (Putnam,1982). The lower Manville consists of dominantly quartzose, fine to coarse grained sandstones of paleozoic carbonates (Putnam, 1982). In summary, the study area, both the lower and middle Mannville strata are dominantly quartzose whereas the upper Mannville contains both quartzose and lithofeldspathic sandstones. Hydrocarbon traps are created by differential compaction over thick intra Mannville sandstone, up dip margins of shale filled channels; sandstones pinch outs and sandstone on lap against Paleozoic ridges. These structural traps are commonly found in areas that have undergone salt dissolution.(Putnam,1982)

Origin of Heavy Oil

Heavy oil and bitumen are formed within Mannville group by several processes. First, it is oil expelled from its source rock as immature oil. Larter et al (2006) cited in Meyer et al (2007) stated that it can be thought of as been expelled from source rocks as light and medium oil and subsequently migrated to a trap. If the trap is later elevated into an oxidizing zone, several processes can convert the oil to heavy oil. These processes include water washing, bacterial degradation and evaporation (Meyer et al, 2007).

Field Development History

Development in this field started in early 1980s with three vertical wells. It came on production with about 2m^3 to 3m^{3}oil per day (OPD) and had cumulative production capacity of about 12,000m^3. The initial reservoir pressure when these wells came intoproduction was 5300 KPa. After a decade, the first horizontal well was drilled after the abandonment of thefirstthree vertical wells which resulted in production of 15m^3 (OPD) with cumulative oil production of 18,000m^3 in 12 years. The reservoir pressure when this well came on production was 4000 KPa. After 18years, 36 horizontal wells were drilled with 80m spacing and they came on production with a total of 200m^3 (OPD). The current cumulative oil production from these wells is about 120,000m$^{3.}$ Initial gas oil ratio (GOR) was 9sm^3 /m^3 and the current GOR is about 170sm^3 /m^3 indicating pressure loss. This field has been produced on primary recovery since early 1980s till the implementation of Phase 1 water flooding in 2013. Currently, there is no production in phase 1 as the producers are currently shut in for re-pressurization. The map of the study location is shown in figures 1-2 belowas compiled by Tanen and Al Abbad (2014) and Permeability curves in figure 3.

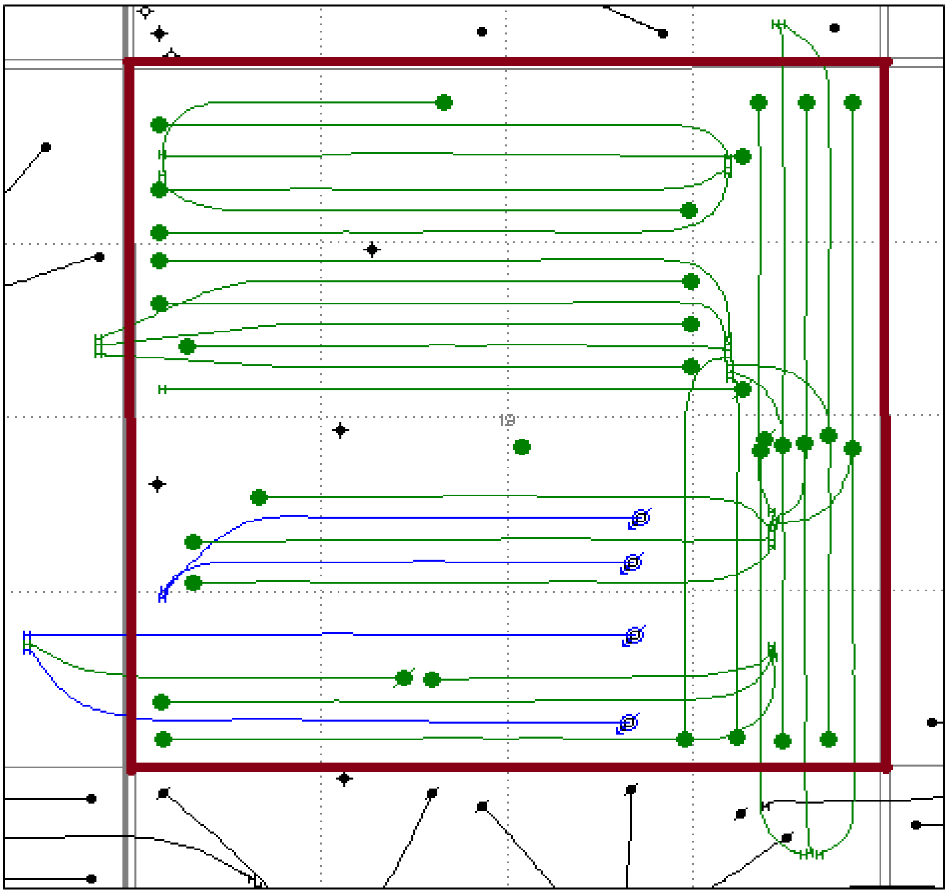

Figure 1: Study Area Map.The area outlined in brown is the study area location. The green wells are the producers and the blue wells are the current injectors.

Material and Methods

The field of study has high viscosity oil reservoir located in part XYZ formation in Alberta with viscosity of 4300cp and specific gravity of 11.9^{o}API. The pressure in this reservoir has declined by 50% over the years resulting in low oil production. To maintain the reservoir pressure, large volumes of water will need to be circulated through the reservoir in order to obtain economic oil recovery this is called water flooding (secondary recovery). The first step in this research is implementing a water flood pilot in phase 1 to study its effect on the high viscosity oil with the idea to pressurize this area for 6-8 months using four injectors and 6six producers with only the injectors being active during the period of pressurization. By this the pressure of the reservoir of interest is expected to increase to 4500KPa which is very close to the initial reservoir pressure, according to the water flooding injected. Production is then expected to commence once this pressure is achieved and the wells will produce while maintaining the pressure. The second step follows the observation of the water flood effect on Phase 1 and if the result achieved is positive, then initiate further expansion to Phase 2. Prior to the initiation of water flood to phase 2, the pool will be studied and the best water flood pattern placement for maximum recovery will be implemented after running two sensitivities as follows: These patterns are:

- One producer alternating one injector alternating one producer (P-I-P)
- Two producers alternating one injector alternating two producers (PP-I- PP)

No infill wells are drilled for the injectors in this project rather existing producers were converted to injectors. With the aid of MGSTARS simulation softwares, we then study the sensitivities (P-I-P and PP-I-PP) using the result gotten from the ongoing water injection in phase 1. Also sensitivities test will also be run to determine the optimum injection rates. Our recommendations will be based on a 15 year forecast for the water flood scheme to be expanded to the whole section.

Data Collection

Geological data comprising of structural map, pay map, sand thickness, net-to-gross ratio, porosity, permeability and water saturation profiles were collected from XYZ Company Canada. Also well data information were gotten from Accumap and they comprised of well name, well type, surface easting and northing, kelly bushing elevation, on production date, measured depth (MD) inclination, Azimuth, true vertical depth (TVD), perforation date and perforation interval (depth). Core lab reports provided a pressure viscosity table taken at a constant temperature that was used to generate the Black Oil PVT tables from Builder.

Reservoir Simulation Model

We divide the input parameters required to build this model into two categories. **Geology:** comprising of maps, rock data, well trajectories and coordinates. **Engineering**: comprising of fluid data, pressure data, production data and injection data. We imported the well trajectories and field production history to create an appropriate file needed for analyzing the results. The pressure and production history data were gotten from Accumap. A lot of the pressure data was inaccurately collected so we performed further analysis to come up with a suitable pressure trend.

CMG Builder

We used the CMG Builder (version 2013, 11) to build the model, utilizing 53 by 53 by 12 grid blocks in the x, y, z direction, each being 50m in width and length, to accommodate the structure per map. We built the model initially with layers in the vertical direction as recommended based on the porosity, permeability and water saturation, variations profiles and the model to cover extra-legal subdivision (LSDS) on each side of our focus area to account for drainage from the wells outside our focus area. We imported the pay map and rock data to create the geologist model, splitting them evenly into 12 layers in the vertical direction. Fig 8-9. After building the model and importing all the required data, we validated the file and compared the original oil in place OOIP with that provided by the XYZ company geologist.

Result Presentation

Results of the findings within the study area, after careful analyses are presented below:

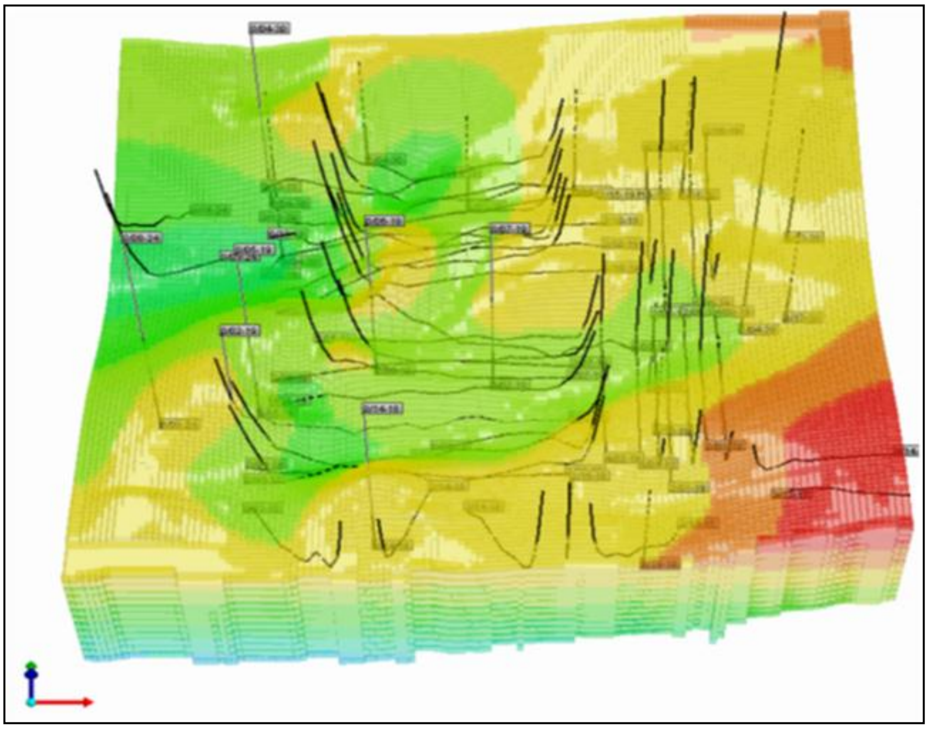

Figure2: Horizontal Wells Layout of the study Area

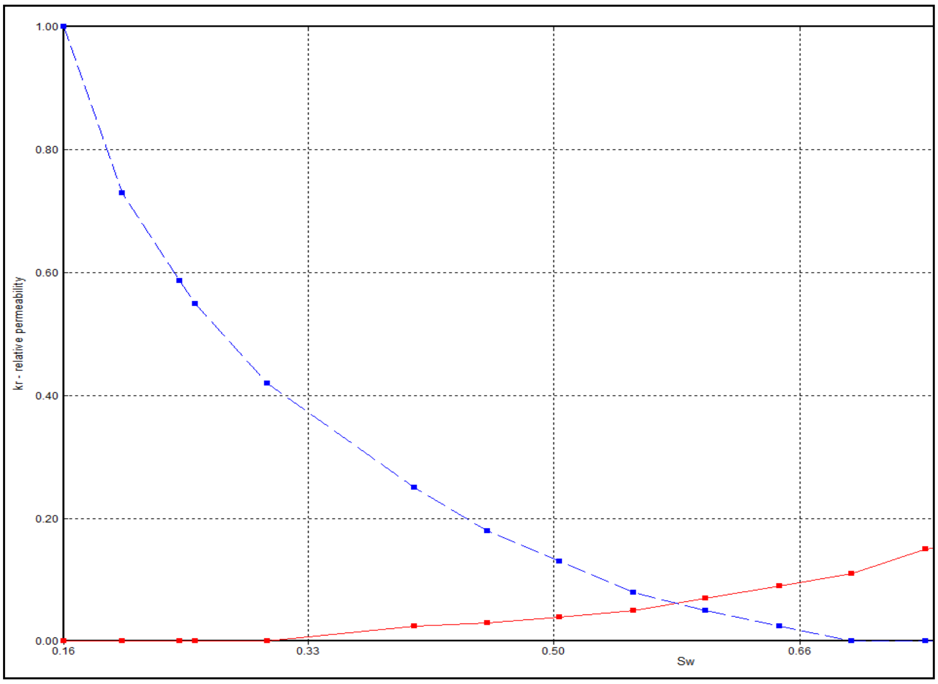

Figure 3: Relative Permeability Curves of the studyArea.

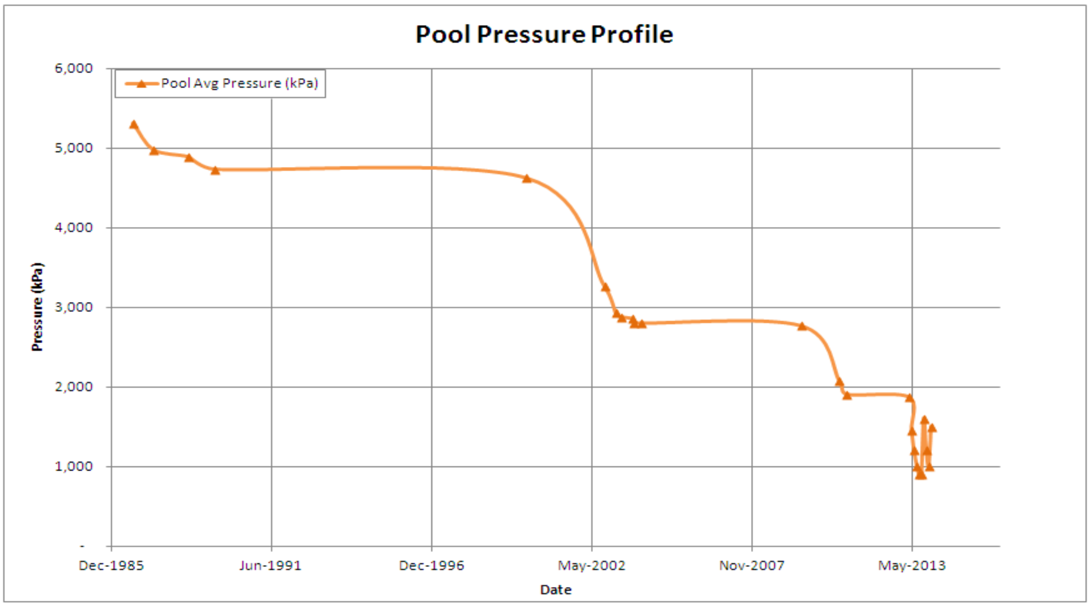

Figure 4: Reservoir Pressure Trend FromInitial Stages Till Beginning Of Water Injection

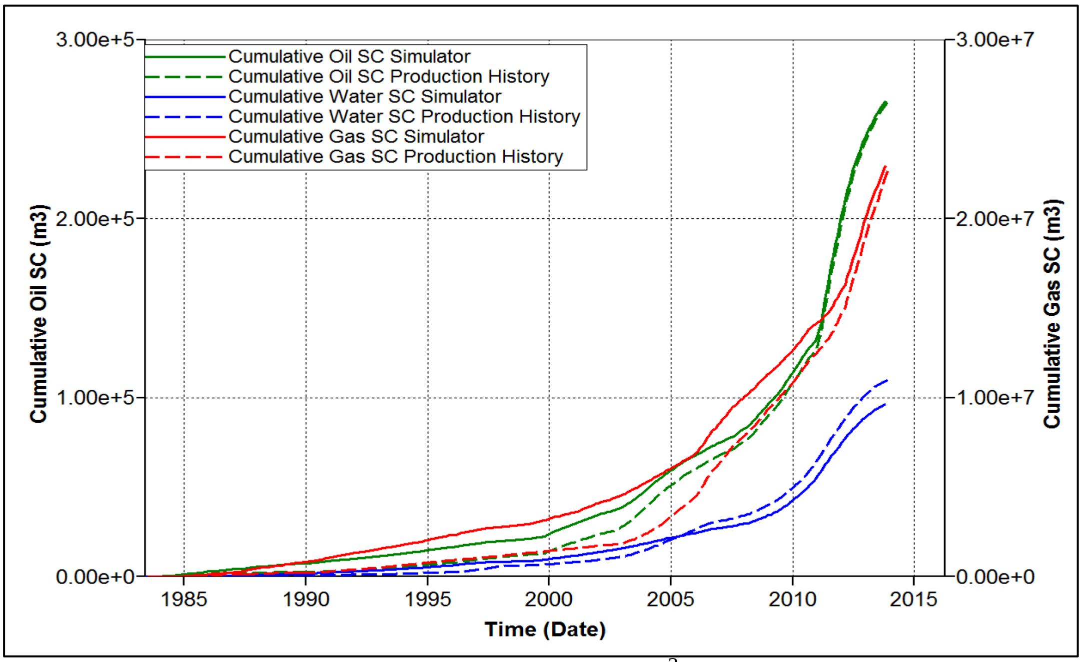

Figure 5: Cumulative Production History Match (m^3) – Well combination

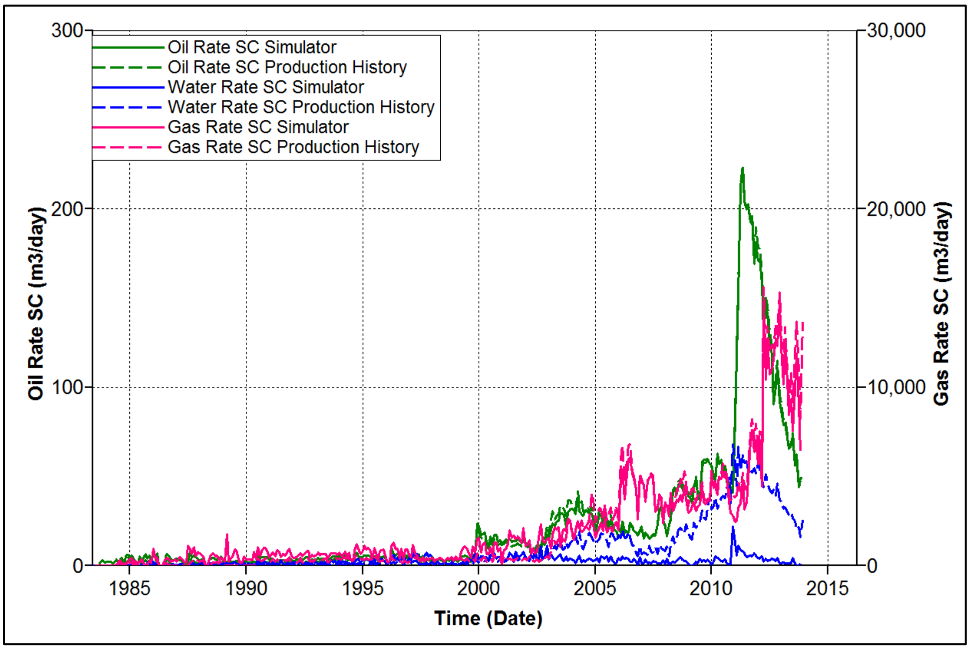

Figure 6: Daily Production Rates History Match (m3/day) – Well combination

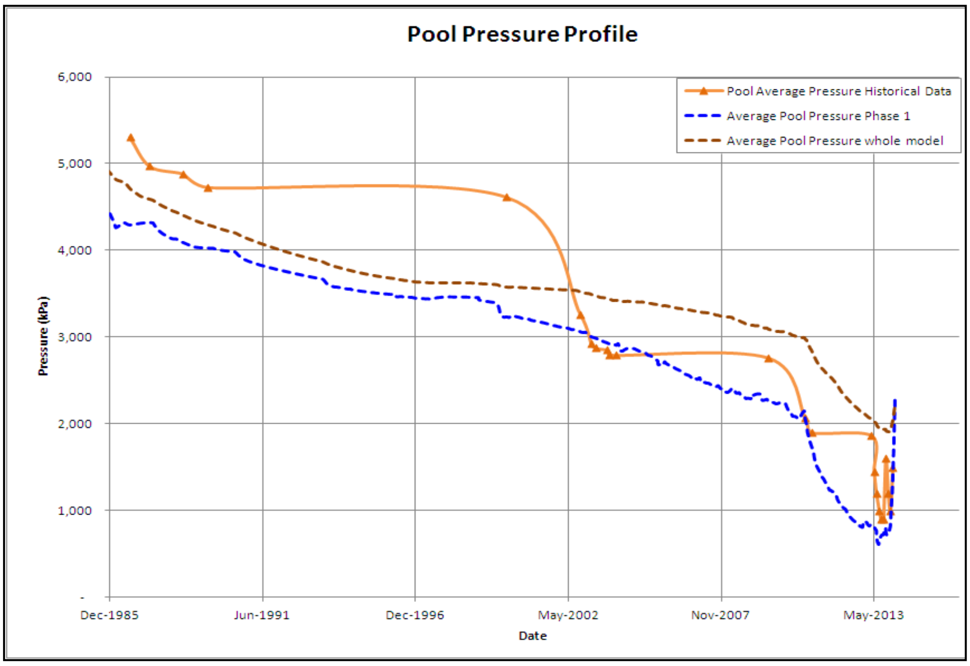

Figure 7: Pool Pressure History Match – Well combination

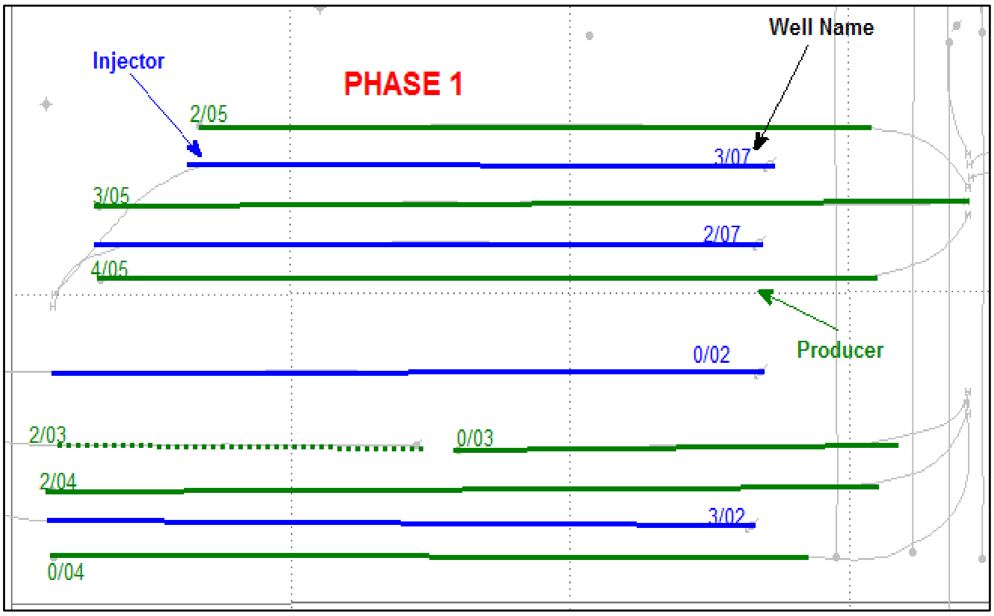

Figure 8: Phase 1 Pilot Well Pattern

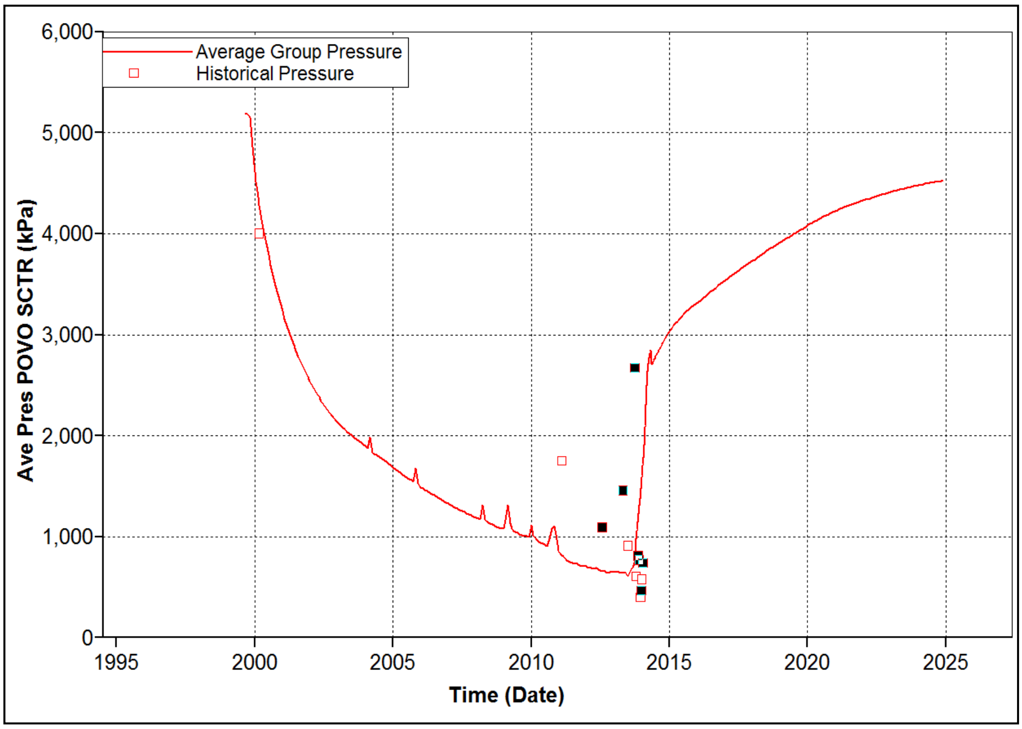

Figure 9: Phase 1 Pressure History and Forecast

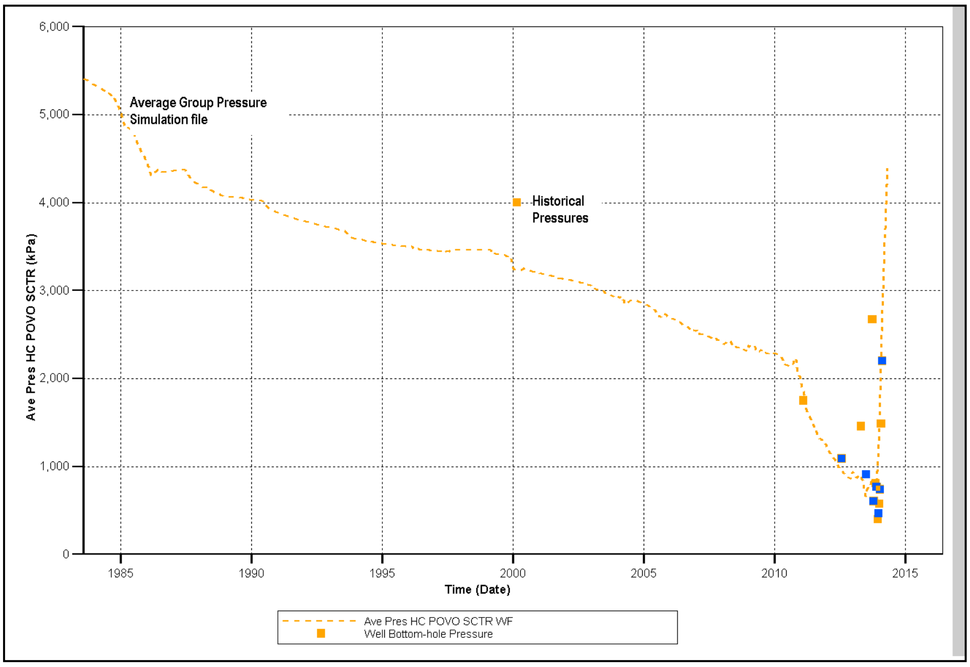

Figure 10: Current Reservoir Pressure Trend

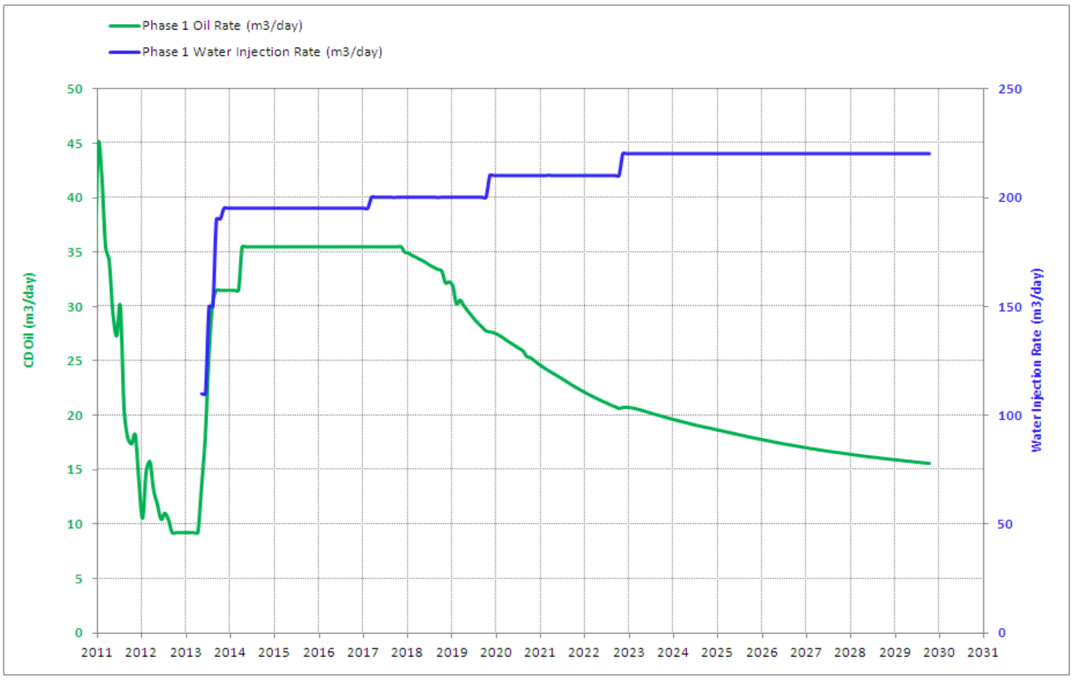

Figure 11: Phase 1 Oil Production and Water Injection Rates

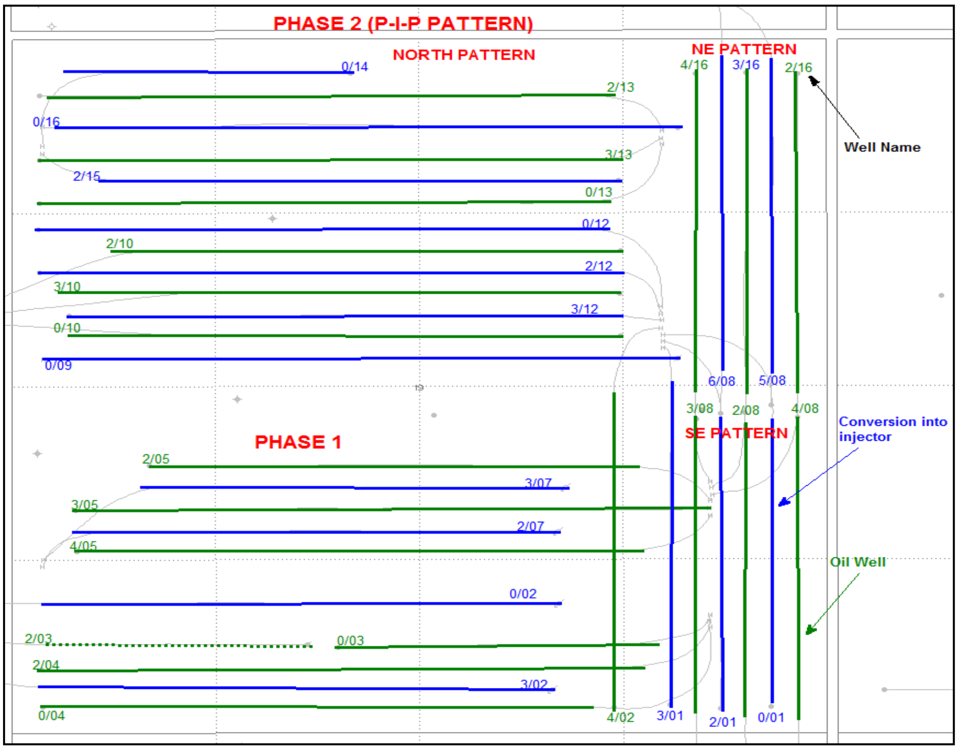

Figure 12: Pattern: Producer-Injector-Producer (P-I-P)

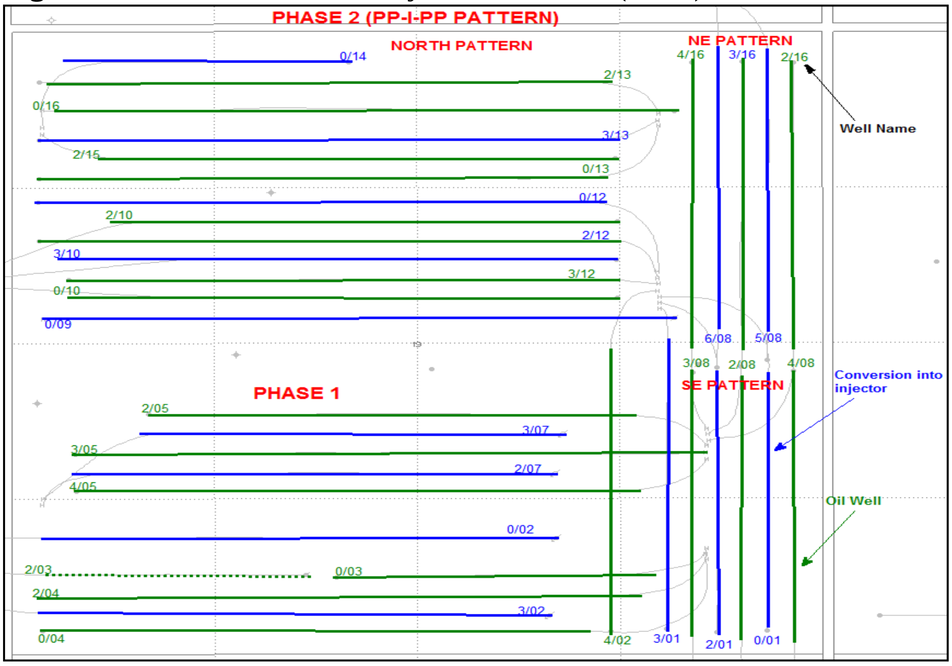

Figure 13: Pattern: Producer-Producer-Injector-Producer-Producer (PP-I-PP)

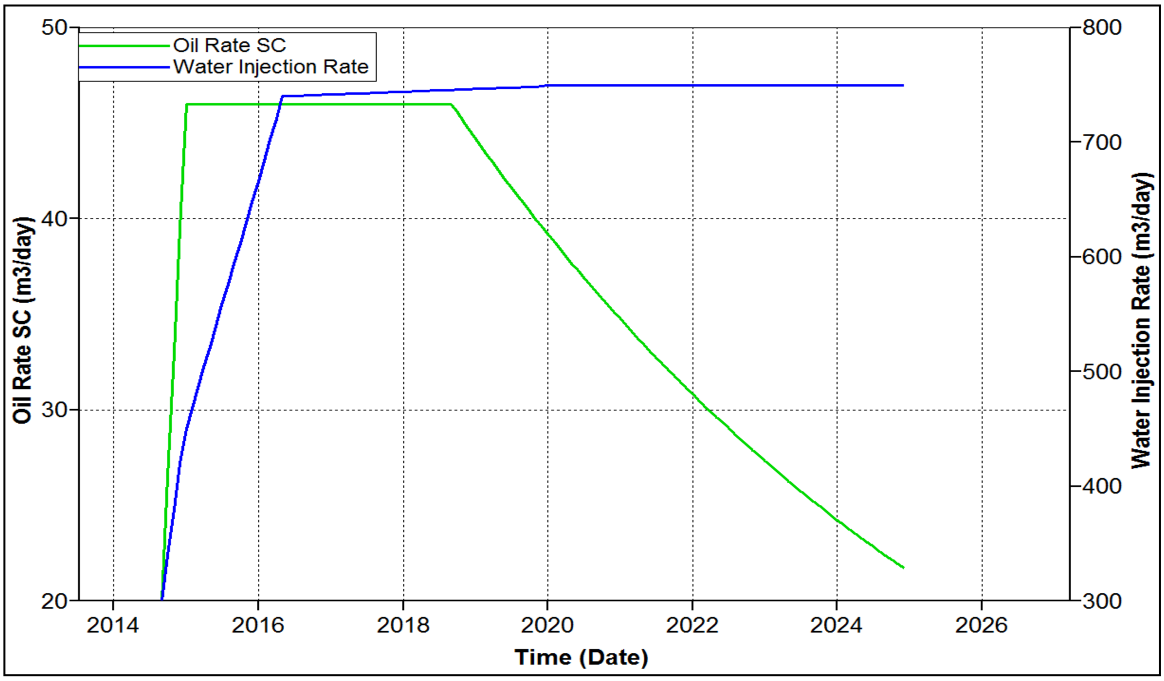

Figure 14: Oil Production and Water Injection Rates - P-I-P Case

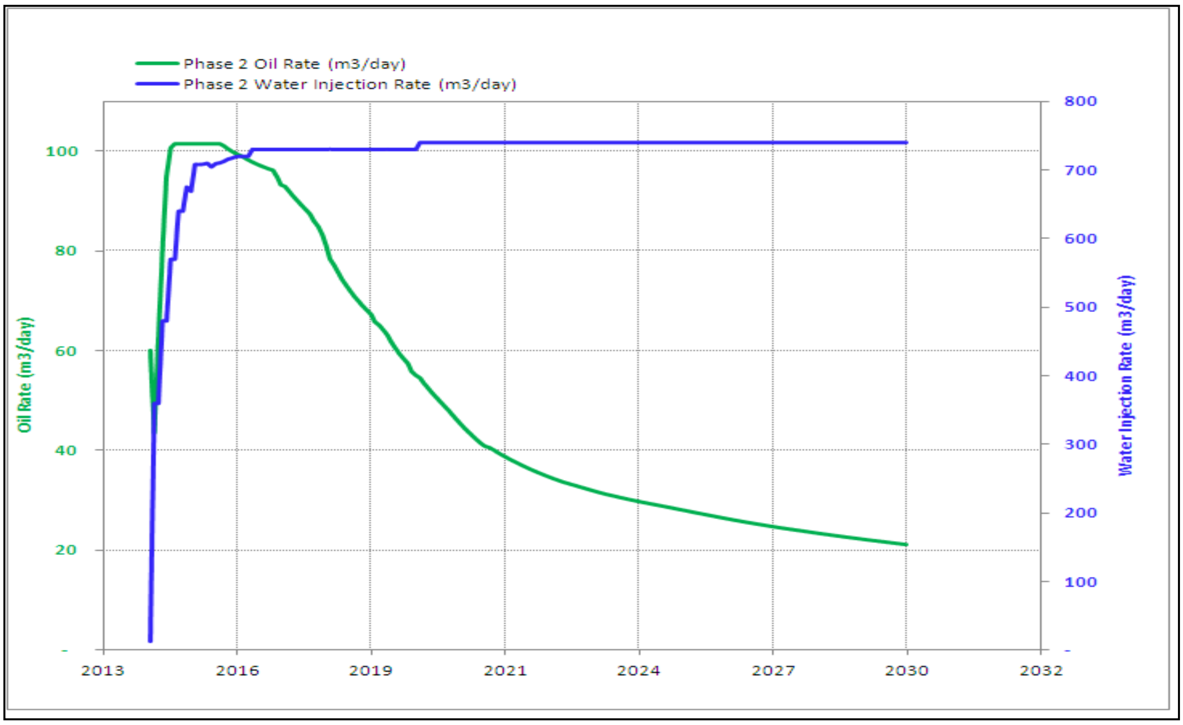

Figure 15: Oil Production and Water Injection Rates - PP-I-PP Case

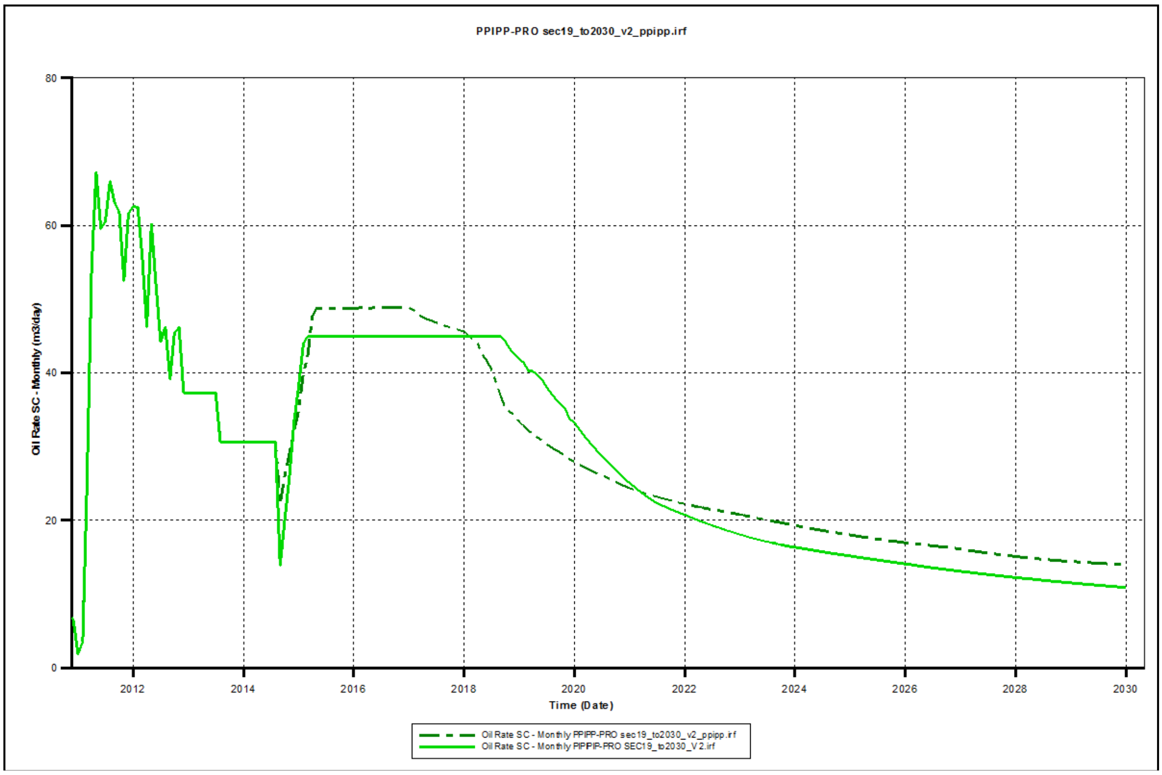

Figure 16: Pattern Comparison – Rates

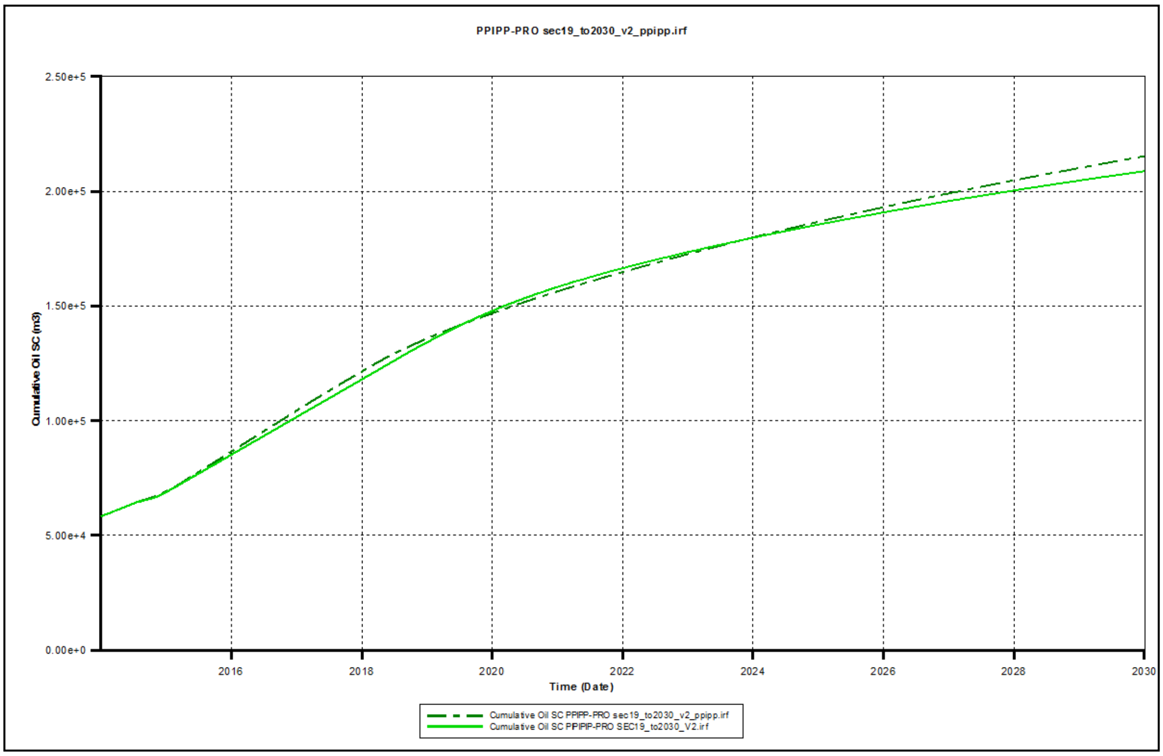

Figure 17: Pattern Comparison - Cumulative Oil Production

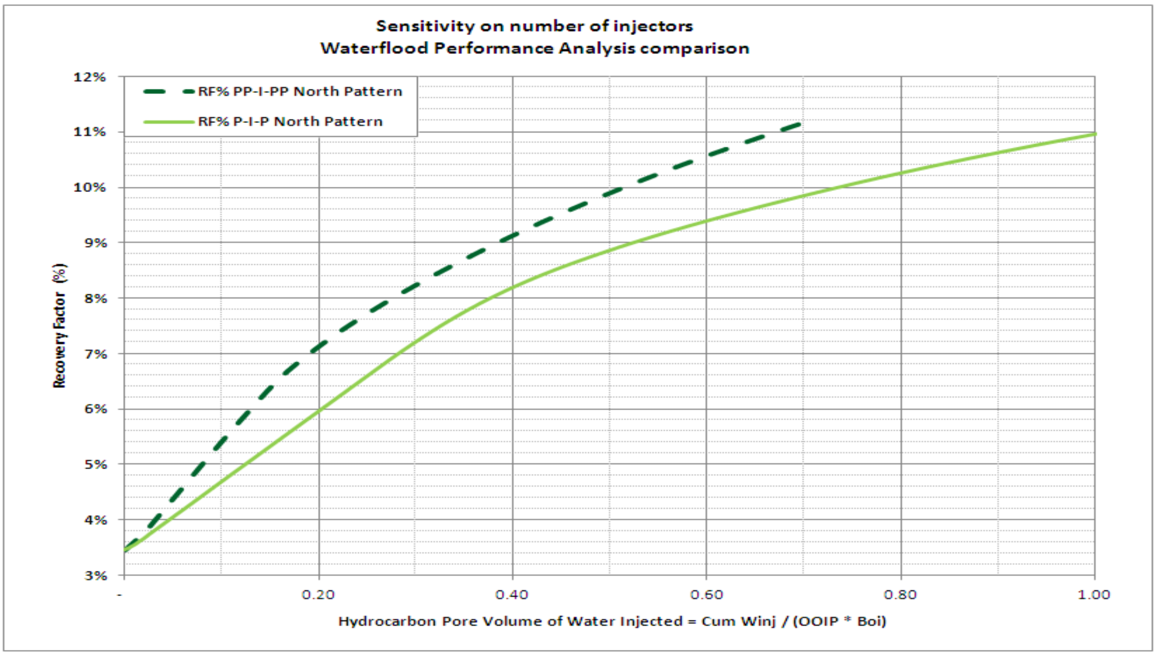

Figure 18: Waterflood Performance Analysis Comparison

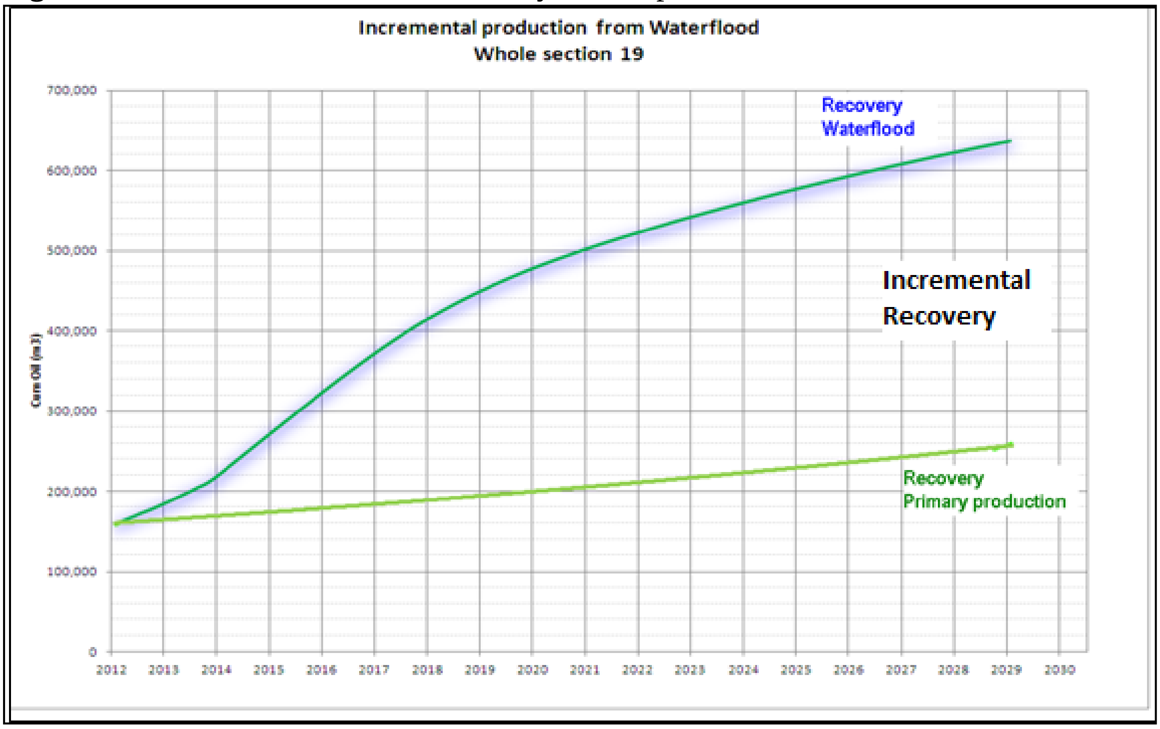

Figure 19: Incremental Oil Recovery

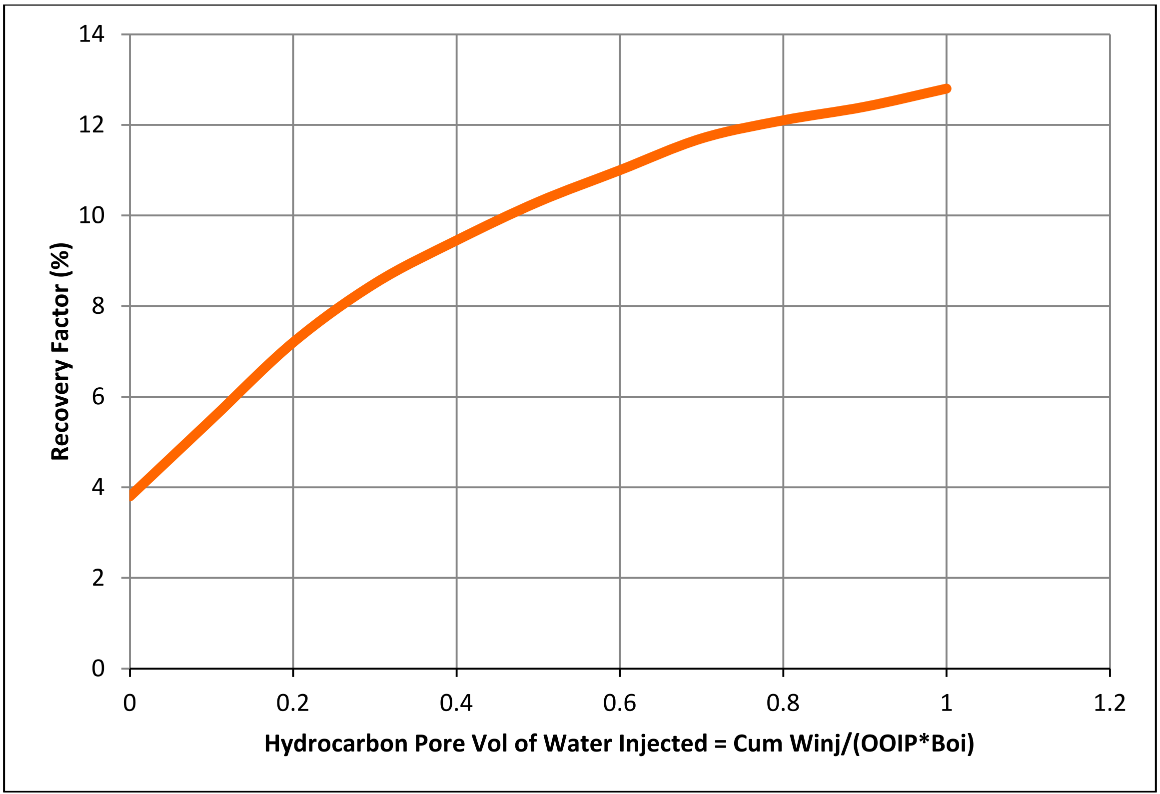

Figure 20: Water flood Performance Analysis

DISCUSSION

In all solution gas drive reservoirs, including the foamy oil reservoirs, gas is released from solution as the reservoir pressure declines. With continued decline in pressure, the bubbles created at different locations become large enough to touch each other and combine into a continuous gas phase. One outcome of this description is that in heavy oil reservoirs, the producing gas-oil ratio increases rapidly after the critical gas saturation has been exceeded. The observed behavior in some heavy oil reservoirs does not fit this solution gas drive model in the sense that the gas-oil ratio remains relatively low down to low reservoir pressures. The recovery factors in such reservoirs are also unexpectedly high. A simplistic explanation of the observed behavior would be that the critical gas saturation, for some unknown reason, is very high. The observed GOR in the field is low, but becomes higher than the solution GOR soon after the pressure becomes lower than the bubble point pressure. Therefore, the gas becomes mobile at low saturation but its mobility remains very low and does not increase rapidly with increasing gas saturation. An alternate explanation of the observed GOR behavior is that the gas phase, instead of flowing only as a continuous phase, also flows in the form of a gas-in-oil dispersion.

After building the model and importing all the required data, we validated the file and compared the OOIP with that given to us by the XYZ Company's geologist interpretation.
Figure 4-7 shows history matching to ensure that the model is an accurate representation of the reservoir and matching the production from the model with the field production history does this. The goal is to match the reservoir pressures, oil, water and gas production rates, and cumulative oil, water and gas production. We began in August 1983 and ran the model to generate production till December 2013. We constrained the wells on oil production rates and a minimum bottom hole pressure of 200 KPa to ensure they would produce at the proper rates. Using results graphs, we plotted the simulator results beside the field production history

data to determine if we had an appropriate match.In Figure 7,we could not get a perfect match for this reservoir due to the following reasons:

- The foamy oil model was based on an assumed model
- The relative permeability tables were assumed to be the same as from an analogue pool
- The grid blocks used in building the model were larger than recommended to accommodate available licenses
- Permeability were estimated from log data and not from well test data

Water flood and Forecast

According to the water flood approval clause by the regulatory agency of the study prospect, the reservoir must be pressurized to a minimum of 4,500 KPa, so we constrained the model at group level on pressure maintenance.

Phase 1

Since Phase 1 is already ongoing, we used the current injectors and injection rates in the model to come up with the pressures and using those pressures we forecasted injection rates for the 4 injectors and production rates for the 6 producers in Phase 1 Figure 8, up to December 2028. We did not need to run any sensitivity here since the injector conversions already occurred. From the current available pressure profile, we see that the pool is being pressurized and has currently reached its target but not in all the wells. From the forecast, it is expected to reach the target of 4500 KPa in all the wells by 6months interval. In figure 9-12, we forecasted the rates for the producers using the current bottom hole pressures measured from the field and the maximum fluid rates based on the actual pump capacity. No sensitivity was run here since the injector conversions already occurred.

Phase 2

We carried out two sensitivities to determine the best water flood pattern placement for maximum recovery. The first pattern is the producer-injector-producer (P-I-P) pattern and the second is the producer-producer-injector-producer-producer (PP-I-PP) Figure 12 and 13. The wells at the north east and south east corners were not changed for the sensitivity runs. We forecasted injection rates for Phase 2, beginning in September 2014, using the waterflood approval of 4500 KPa, based on the current bottom hole pressures shown in figures 14 and 15.

Pattern Comparison for P-I-P and PP-I-PP

In order to determine which pattern placement was the best to implement; we compared the results from the oil rates, cumulative oil production and economic analysis. Figures 16, 17, and 18.From the above plots, the darker green represents the PP-I-PP Case and the lighter green shows the P-I-P Case. The comparison shows that the PP-I-PP Case produces more oil than the P-I-P Case. A water flood analysis comparison was performed and plotted recovery factor RF versus hydrocarbon pore volume of water injected (HCPV Winj). The plot showed that at a specific HCPV Winj, the PP-I-PP Case gave a higher RF than the P-I-P Case as shown in Table 1.1.Using Schlumberger's Merak Peep Economics, we performed an economic analysis and it showed that the PP-I-PP case was the better well pattern placement to implement for maximum oil recovery.Table1.2.

Table 1.1 :*Results from sensitivity for Optimum Injection Rates*

	40 m^3/day/inj	60 m^3/day/inj	80 m^3/day/inj	100 m^3/day/inj
HCPV Winj	**RF (%)**	**RF (%)**	**RF (%)**	**RF (%)**
0	3.8	3.8	3.8	3.8
0.1	5.8	5.5	5.5	5.5
0.2	7.5	7.3	6.7	6.6
0.3	8.4	8.2	7.7	7.5
0.4	9	9.1	8.5	8
0.5	9.6	9.9	9	8.6
0.6	9.8	10.6	9.4	9.2
0.7	10.2	11.2	9.6	9.4
0.8	10.5	11.9	9.8	9.6
0.9	10.55	12.3	10	9.7
1	10.6	12.8	10.1	9.8

Table 1.2: *Economics Analysis Comparison*

Economics	P-I-P	PP-I-PP
Capital (MM)	$ 8.33	8.31
NPV@15% (MM)	$7.8	$9
PayoutPeriod (yr)	3	2.5

Optimum Injection Volume for Phase 2

After running some sensitivities, we found that 60 m^3/day/injector was the best optimum injection rate to use for maximum recovery in phase 2.

Simulation Results for the study area

From the simulation results of the study area, we found that there was incremental oil recovery after implementing water flood and the recovery factor increased to 12.8% after a 15-year forecast as shown in Figures 19 and 20.

Conclusions

The average depth of this reservoir is 650 m with a net pay thickness of 6-8 m. Initial pool pressure as stated earlier is 5300 kPa and reservoir temperature is 25^0C. The porosity of this pool is 27-31%, initial water saturation is 17-40% and permeability is 800-2500 mD. The oil formation volume factor (Boi) is 1.02 and as stated above, specific gravity of the oil is 11.9 ^{0}API. The initial solution GOR is 9sm^3/m^3 and viscosity is 4300 cP as stated above. The original oil in place (OOIP) is 5,000,000 m^3 according to geological estimations. Cumulative oil produced from this pool up to 2013 is about 170,000 $m^3$with recovery factor (RF) of 3.2%

based on primary recovery. After a careful simulation studies and analysis of the data collected, the researchers make the following conclusions:

- The reservoir pressure increased to almost initial reservoir pressure from implementing water flood.
- The well placement pattern for maximum recovery for Phase 2 is the Producer-Producer-Injector-Producer-Producer (PP-I-PP) pattern.
- The optimum injection rate for maximum recovery is 60 m^3/day/injector.
- A recovery Factor of 12.8% is achieved after implementing water flood for a 15-year period.

REFERENCES

Alberta Energy and Utilities Board (2004). Alberta's reserves 2003 and supply/demand Outlook 2004-2013: Bitumen, crude oil and natural gas basic reserve data tables:

Alaogorni, A. H, Yaacob, Z.B, and Nour, A.H. (2013).An overview of oil production. stages: Enhanced oil recovery techniques and nitrogen injection.*Internal Journal of Environmental Science and Development* 6, 9.

CEC (Canadian Energy Commission,1999).Enhanced oil recovery coping study.*Retrieve from:www.energy.ca.gov*.

El Adawy, Z. M. (2011) Comparison of different enhanced oil recovery techniques for Better oil Productivity.*International Journal of Applied Science and Technology*. I. 5

Glover, P. (2011). Formation evaluation MSc course, Aberdeen University, pp. 19-26.

Gingrace, M. and Rokosh, D. (2004) A brief overview of the geology of heavy oil, bitumen and oil sand deposits. *Canadian Society of Exploration Geophysicists*.

Hayes, B.J.R, Christopher, J.E, Rosential, L. Los, G., Mckerncher, B., Nimken, D. Tremblay, Y.M and Fennell, J (1994).Cretaciousmannville group of the Western Canada Sedimentary Basin: In atlas of western Canada sedimentary basin.cspg.317-318.

Larter, S., Huang, H., Adams, J., Bennett, B., Jokanola, O., Oldenburg, T., Jones, M., Head, I., Riediger, C. and Fowler, M., (2006). The controls in the composition of biodegraded oils in the deep subsurface: part II. Geological controls on subsurface biodegradation fluxes and constraints on reservoir-fluid property prediction: *American Association of Petroleum Geologists Bulletin*, v. 90, no. 6, p. 921-938.

Mai, A , Bryan, J., Goodarzi, N. and Kantas, A (2006). *Insights into non-thermal recovery of heavy oil*. World heavy oil conference (WHOC). Calgary, Alberta.

Meyer, R.F., Attanasi, E.D. and Freeman, P.A (2007).Heavy oil and natural bitument resources in geological basins of the world. *U.S.GeologicalSurvey* available online at http://pubs.usga.gov/ of 2007/10841.

Putman, P.E.(1982) Aspects of the petroleum geology of the Lloyd minster heavy oil fields Alberta and Saskatchawan. *Bulletin of Canadian Petroleum Geology*.

Shepherd, M., (2009) Factors influencing recovery from oil and gas fields. In M. Shepherd oil field production Geology. *AAPG Memoir* 91, 37-46.

Suncor Energy (2014) Heavy oil 101*Geology of Canadian heavy oil association. Retrieve from www.choa.ab.ca*.

Statistical Series 2004-98 (CD-ROM). Map of Designated Fields (Oil and Gas) and Oil Sands Areas included separately. [Available from website www.eub.gov.ab.ca]

Tanen, R, Albbad, A.(2014). *Reservoirs simulation study waterflood pilot in a high viscosity oil pool*. BSc project Regina University Saskatchawan, Canada.

U.S. Department of Energy, National Energy Technology Laboratory (2005). *Heavy oil Database 2004 [updated 2005]:* U.S. Department of Energy, National Energy. Technology Laboratory.[Available as CD-ROM or at website www.netl.doe.gov]

Zitha, P. Felder, R. Zornes, D. Brown, K and Mohanty, K. (2011) Increasing hydrocarbon Recovery factors. *Society of Petroleum Engineering*.