CHAPTER IV
MODEL SET UP

This thesis is to study the some predetermined variables that affect the oil recovery using the in-situ gas lift technique in the commingled reservoirs in slim monobore completion. The results from using in-situ gas lift techniques in different scenarios will be compared to the base case which is a monobore well producing with the conventional gas lift.

Thus, this thesis study requires a very systematic approach in order to incorporate some key variables with minimum error possible. The base case is discussed in this chapter to provide the basic understanding for further discussion on the results from the other scenarios. Moreover, the basic understanding of the reservoir simulator used in this study is also discussed in this chapter.

4.1 Introduction to Integrated Production Model (IPM) Toolkit

The tool used for this study is known as Integrated Production Model (by Petroleum Experts). The tool itself has three main parts being GAP, PROSPER and MBAL which can be linked together to form an Integrated Production System. Some of the features of this software are briefly mentioned in the following sections.

General Allocation Package (GAP)

GAP is an extremely powerful and useful tool offered to the petroleum engineering community. Some of the tasks GAP can achieve are complete Surface Production and Injection Network Modeling. It also has a powerful optimizer that is capable of handling a variety of wells in the same network such as naturally flowing oil wells, gas-lifted wells, ESP operated wells, etc. The optimizer controls production rates using wellhead chokes to maximize the hydrocarbon production while honoring constraints at the gathering system at well and reservoirs levels. GAP models both production and injection system simultaneously, containing oil, gas, condensate and/or water wells to generate production and/or injection profiles.

GAP's powerful optimization engine can, for example, allocate gas for gas lift wells, sets wellhead chokes for naturally flowing wells to maximize revenue or oil production while honoring constraints at any level. GAP can also model and optimize injection networks associated with the production systems (both together).

GAP is used as the master controller to access instances of PROSPER and MBAL. Integration of the well and reservoir elements provides the ability to understand the dynamic interactions of the complete petroleum engineering system. The value of well re-design and well stimulation efforts can easily be evaluated in context of the complete petroleum engineering system.

During a prediction, MBAL passes the evolving reservoir fluids to GAP well elements. GAP uses the evolving reservoir fluids to capture well stability phenomena during a prediction enabling well contingency planning strategies to be developed.

GAP's scheduling power provides the ability to automatically develop well completion and drilling schedules that are required to meet a given overall flow objective. Drilling queues, workover, etc., can automatically be activated based on an objective function being set at any level in a given system.

Predicting measured reality is the ultimate goal of integrated studies and GAP offers a Model Validation utility to interrogate the system response. The model validation utility enables well model performance to be updated based on latest test data ensuring consistent model prediction ability.

Production Forecasting

GAP calculates full field production forecast including gas or water injection volumes required to meet reservoir unit pressure constraints. Reservoir pressures are obtained from decline curves, material balance or simulation models. The associated injection systems can be modeled and optimized so as to achieve injection targets for pressure maintenance programs. Apart from that, GAP also can be linked to MBAL and PROSPER for integrated calculations. GAP uses PROSPER to generate well IPR's and lift curve tables which are used to characterize the performance of the wells. GAP can be run in forecasting mode. At each time step, it transfers data to and receives data from MBAL. One well in GAP are connected to multiple MBAL tanks (or oil layers). Separate IPR can be defined for each tank. MBAL has strong aquifer modeling features.

Relative permeability curves can be defined to match the historical WGRs and to use in predictive mode.

Fully Compositional or Compositional Tracking Mode

GAP can calculate PVT properties fully compositionally and track compositions from the well/source level through to the separators. In a prediction, GAP can take compositions calculated by MBAL and record the evolution of compositions throughout the system with time.

MBAL

MBAL is in a package made up of various tools designed to gain a better understanding of the reservoir and perform prediction run. Some of the tools are material balance, reservoir allocation, decline curve analysis, Monte Carlo volumetrics and multilayer.

This incorporates the classical use of material balance calculations for history matching through graphical methods (like Havlena-Odeh, Cambell, Cole, etc.). Detailed PVT models can be constructed for oils, gases and condensates. Furthermore, predictions can be made with or without well models and using relative permeabilities to predict the amount of associated phase productions.

MBAL can also be tied into GAP for integrated production modeling studies, providing an accurate and fast reservoir model as long as the assumptions of material balance are valid for the real situation to be modeled.

PROSPER

PROSPER is functional element in the IPM mainly used for all the calculations in the pipeline and tubing section including various artificial lift designing capabilities. Its PVT section can generate fluid properties using standard correlations and allows them to be modified to better fit the measured lab data. It allows detailed PVT data in the form of tables to be imported for use in the calculations.

Apart from that, the tool can also be used to model reservoir inflow performance (IPR) for single layer, multilayer, or multilateral wells with complex and highly deviated completions, optimizing all aspects of a completion design including perforation details and gravel packing. It can be used to accurately predict both pressure and temperature profiles in producing wells and along surface flow lines. There are also sensitivity calculation capabilities to model and optimize tubing as well as surface flow line pressure. The multiphase flow correlations implemented can be adjusted to match measured field data to generate vertical lift performance curves (VLP) for use in simulators and net work models.

4.2 Base Case Well Model Discussion

Below is summary of general information and assumptions used for constructing the well model.

a) The completion design is the typical slim monobore type with 7" casing shoe (6.184" ID) set at approximately 4,000' TVD, and the production tubing is 2-7/8" tubing (2.441" ID).
b) The base case is a monobore oil well with conventional gas lift and no in-situ gas zone. In normal practice, the deepest gas lift valve in the monobore completion is set no lower than the 7" casing shoe which is, most of the time, set at approximate 4000' TVD (at 5825 ft MD in this case). It was assumed that only a single point injection (orifice valve) installed at 4,000 ft TVD and with the maximum injection pressure of 1,200 psi.
c) No booster compressor is installed. The separator pressure is fixed at 300 psia.
d) The total oil thickness from the referenced fields is between 20 ft up to 300 ft or an average mean of 160 ft per well while the number of oil zones per well can be as many as 20 to 40 zones. The hydrocarbon or pay window or reservoir depths where most of the oil and gas zones reside are between 5000 ft and 8000 ft TVD. The in-situ gas zones can be found in a variety of reservoir depths and thicknesses in the mentioned pay window. Therefore, in order to simplify the model and save simulation run time while maintaining representation of the multi-layered reservoir pattern, only four main layers will be modeled to represent the commingled oil reservoirs at 5000 ft, 6000 ft, 7000 ft and 8000 ft TVD. Thickness of each oil layer is 40 ft or a total of 160 ft per well.
e) The initial reservoir pressure are based on the reservoir pressure profile as shown in Figure A1 in Appendix A and all oil reservoirs are assumed to be undersaturated or above the bubble point. The original oil in place (OOIP) for

each oil layer is calculated using volumetric correlation in equation (4.1). The OOIP and parameters used for each oil layer is summarized in Table 4.1 and Table 4.2.

Table 4.1 OOIP for Oil Zones

Depth of Oil Layer (ft TVD)	h(ft)	A (acre)	Porosity	Swc	*B oi*** (rb/ stb)	OOIP (stb) = 7758 Ah (Porosity) (1-Swc)/Boi	OOIP (MMstb)
5000	40	61	0.24	0.25	1.00	3,406,119	**3.406**
6000	40	61	0.22	0.25	1.20	2,613,166	**2.613**
7000	40	61	0.2	0.25	1.43	1,988,245	**1.988**
8000	40	61	0.16	0.25	1.71	1,331,237	**1.331**
						Total	**9.339**

** *Boi* is from Figure A4 or a correlation: *Boi* = 0.4108 x e^(0.000178 x TVD)

Table 4.2 Tanks Parameters for Oil Layers

Name	Tank Parameters for Oil										
	Depth (ft TVD)	Reservoir Type	Reservoir Temp. (deg. F)	Initial Reservoir Pressure (psi)	Porosity (%)	Connate Sw (%)	Thickness, h (ft)	Area (acre)	Boi (rb/ stb)	Original Oil in Place (MMstb)	Permeability, k (mD)
Oil Layer #1	**5000**	Oil	240	2500	24%	15%	40	61.00	1.00	3.406	200
Oil Layer #2	**6000**	Oil	270	3000	22%	15%	40	61.00	1.20	2.613	150
Oil Layer #3	**7000**	Oil	290	3500	20%	15%	40	61.00	1.43	1.988	100
Oil Layer #4	**8000**	Oil	310	4000	16%	15%	40	61.00	1.71	1.331	50
						Total	**160**	**244**	**Total**	**9.339**	

f) One additional layer will be modeled as an in-situ gas zone at various depths or initial reservoir pressures, gas permeabilities, and thicknesses as shown in Table 4.5. The top depths of the in-situ gas zone are based on the distribution of the gas zone in the field data and in order to simplify the model each in-situ gas zone will be located in between the oil layers. The original gas in place (*OGIP*) for in-situ gas zone is calculated using volumetric correlation in equation (4.2) based on the average drainage area of 51 acres per layer. *OGIP* for each in-situ gas zone in each depth and thickness parameters used in in-situ gas layer are summarized in Table 4.3 and Table 4.4, respectively.

$$OOIP = \frac{Ah\phi(1-S_{wc})\ 7758}{B_{oi}} \tag{4.1}$$

$$OGIP = \frac{Ah\phi(1-S_{wc})\ 43560}{B_{gi}} \tag{4.2}$$

where

$OOIP$	=	original oil in place (stb)
$OGIP$	=	original gas in place (scf)
A	=	drainage area (acre)
h	=	thickness (ft)
ϕ	=	porosity (fraction)
S_{wc}	=	connate water saturation (fraction)
B_{oi}	=	initial oil formation volume factor (rb/stb)
B_{gi}	=	initial gas formation volume factor (rcf/scf)

Table 4.3 OGIP for In-situ Gas Zone

Depth of In-situ Gas Zone (ft TVD)	h (ft)	A (acre)	Porosity	Swc	B_{gi}* (rcf/ scf)	OGIP (scf) = 43560 Ah (Porosity) (1-S_{wc})/Bgi	OGIP (MMscf)
5500	15	51	0.17	0.15	0.0085	567,910,787	**568**
5500	45	51	0.17	0.15	0.0085	1,703,732,361	**1704**
5500	90	51	0.17	0.15	0.0085	3,407,464,723	**3407**
6500	15	51	0.17	0.15	0.0067	722,352,108	**722**
6500	45	51	0.17	0.15	0.0067	2,167,056,325	**2167**
6500	90	51	0.17	0.15	0.0067	4,334,112,649	**4334**
7500	15	51	0.17	0.15	0.0059	815,767,595	**816**
7500	45	51	0.17	0.15	0.0059	2,447,302,786	**2447**
7500	90	51	0.17	0.15	0.0059	4,894,605,573	**4895**

* B_{gi} is from correlations below:

If TVD > 6250 ft, B_{gi} = 1 / [(0.0194 x TVD) + 23.914]

If TVD <= 6250 ft, B_{gi} = 1 / [-0.000002598 x TVD^2 + 0.062 x TVD - 144.47)]

Table 4.4 Tanks Parameters for In-situ Gas Zones

Name	Tank Parameters for In-situ Gas Zone									
	Depth (ft TVD)	Reservoir Type	Reservoir Temp. (deg. F)	Initial Reservoir Pressure (psi)	Porosity (%)	Connate Sw (%)	Thickness, h (ft)	Area (acre)	Bgi (rf/ scf)	Original Gas in Place (MMscf)
In-Situ Gas	5500	Gas	255	2750	0.17	0.15	15	51	0.00848	568
In-Situ Gas	5500	Gas	255	2750	0.17	0.15	45	51	0.00848	1,704
In-Situ Gas	5500	Gas	255	2750	0.17	0.15	90	51	0.00848	3,407
In-Situ Gas	6500	Gas	280	3250	0.17	0.15	15	51	0.00667	722
In-Situ Gas	6500	Gas	280	3250	0.17	0.15	45	51	0.00667	2,167
In-Situ Gas	6500	Gas	280	3250	0.17	0.15	90	51	0.00667	4,334
In-Situ Gas	7500	Gas	300	3750	0.17	0.15	15	51	0.00590	816
In-Situ Gas	7500	Gas	300	3750	0.17	0.15	45	51	0.00590	2,447
In-Situ Gas	7500	Gas	300	3750	0.17	0.15	90	51	0.00590	4,895

g) Fluid properties of oil and gas layers are based on field data and some of them are assumed constant or calculated according to correlations.

h) The initial reservoir pressure (Figures A1 in Appendix A), reservoir temperature (Figure A2 in Appendix A) and permeability of each oil layer are estimated from field data mentioned-above.

i) Other parameters that may affect inflow and tubing performance are assumed constant or calculated according to correlations.

Figure 4.1 represents the completion schematic of the base case well model that is based on the information above whereas Figure 4.2 illustrates the completion schematic for different scenarios and also indicates reservoir depth of each in-situ gas zone at 5500', 6500' and 7500' TVD.

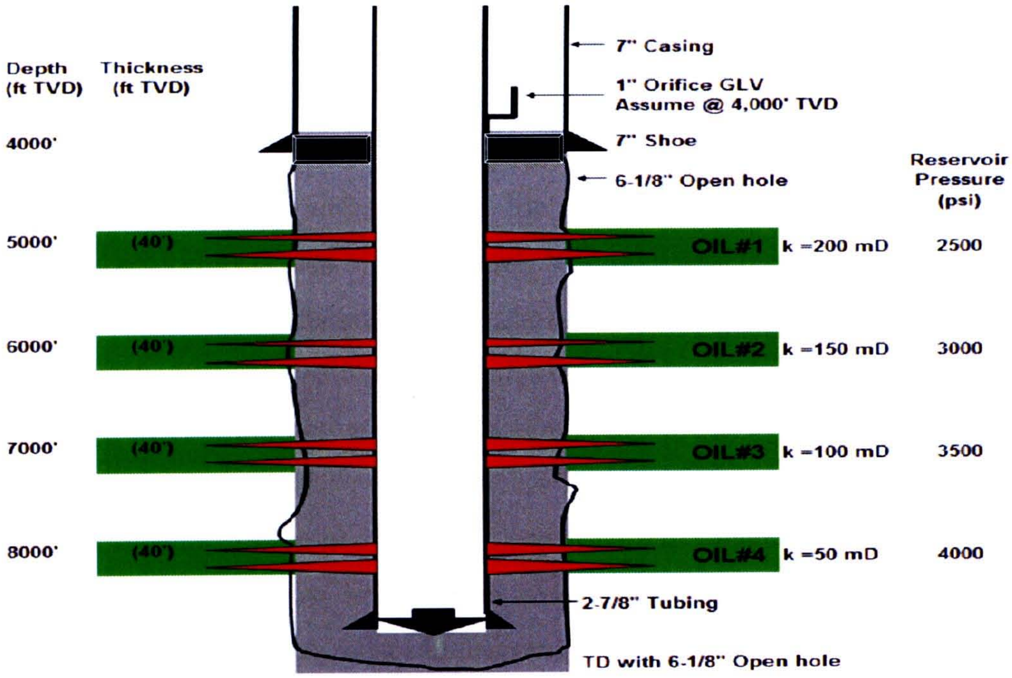


Figure 4.1 Completion Schematic for Base Case Scenario with an Orifice Gas Lift Valve

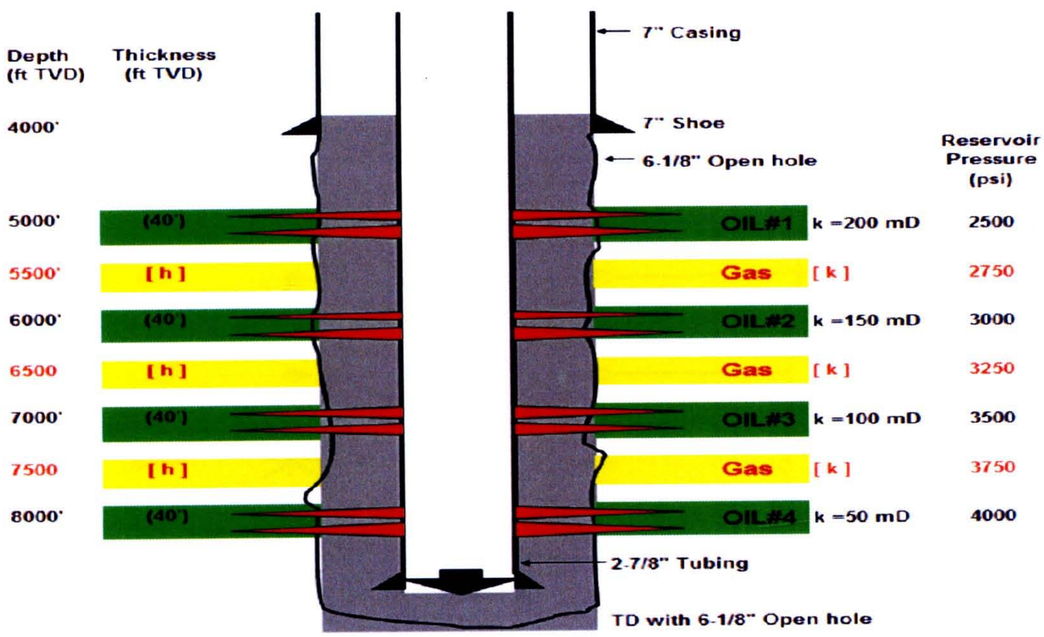


Figure 4.2 Completion Schematic for Different Scenarios by Varying Depth, k and h of an In-situ Gas Zone

Model Setup

The completion schematic for base case in Figure 4.1 can be constructed as the IPM diagram as shown in Figure 4.3 which represents the base case well model with gas lift (WELL GL) and well without a gas lift (WELL NATURAL) connected to four simplified oil reservoirs (green oil tanks) with 40 ft thickness each and one gas zone (red in-situ gas tank) with 40 ft thickness to the choke and then to the separator but the in-situ gas zone is masked or disabled from the prediction runs for the base case.

This IPM diagram allows the prediction runs for the well with the natural flow (WELL NATURAL) until the oil rate reaches abandonment rate of 10 stb/d or ceases flowing then switched to the gas lift (WELL GL) with the abandonment rate of 20 stb/d due to higher operating cost or until the well stops flowing. This type of gas lift application is generally called "post-production gas lift".

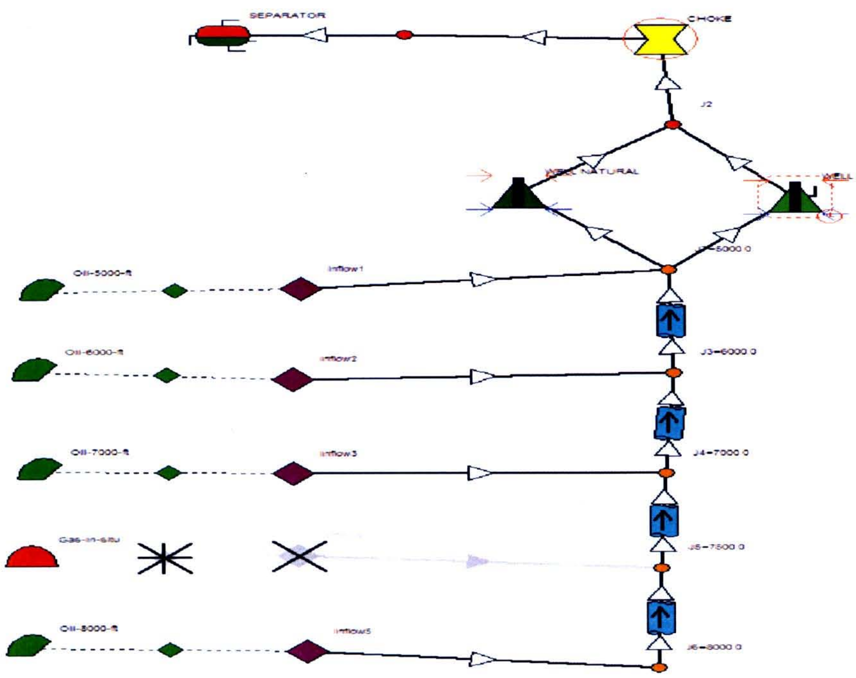


Figure 4.3 Base Case Well Model Diagram in IPM for Gas Lift

Figures 4.4, 4.5 and 4.6 represent the IPM well model with each in-situ gas zone which is located at 5500', 6500' and 7500' TVD, respectively.

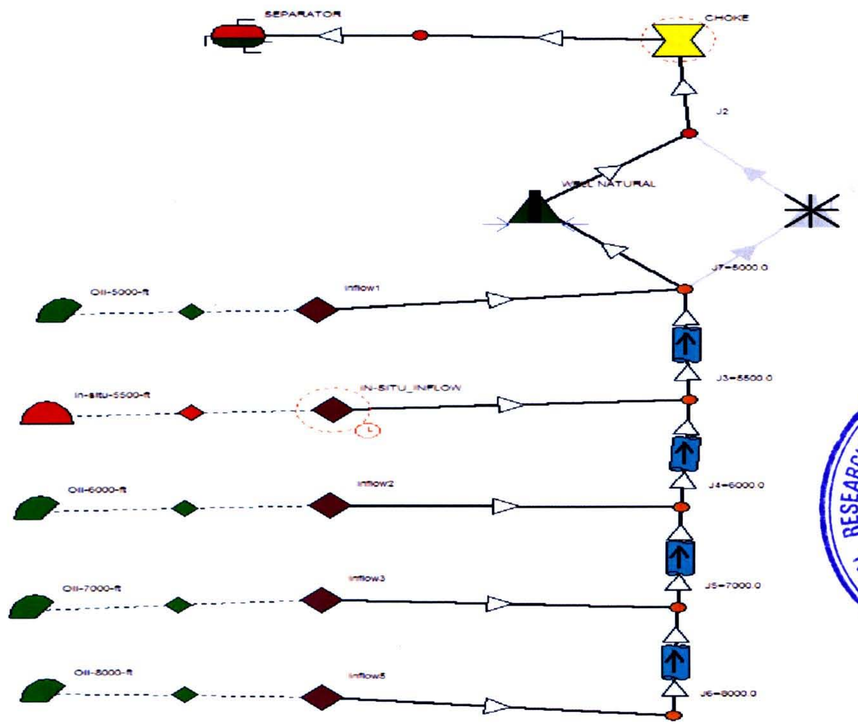


Figure 4.4 Well Model Diagram in IPM for In-situ Gas Zone @ 5500’ TVD

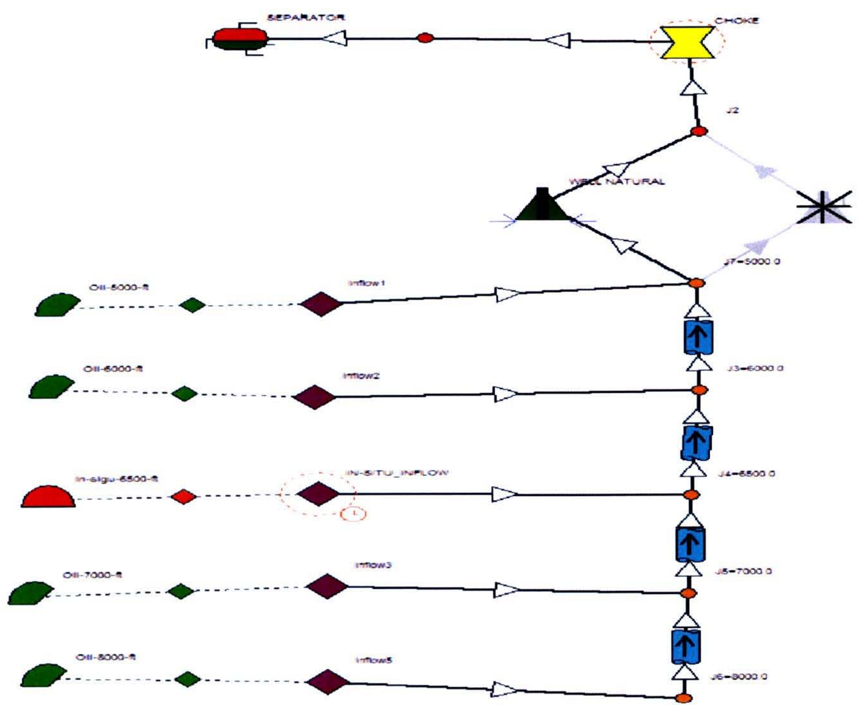


Figure 4.5 Well Model Diagram in IPM for In-situ Gas Zone @ 6500’ TVD

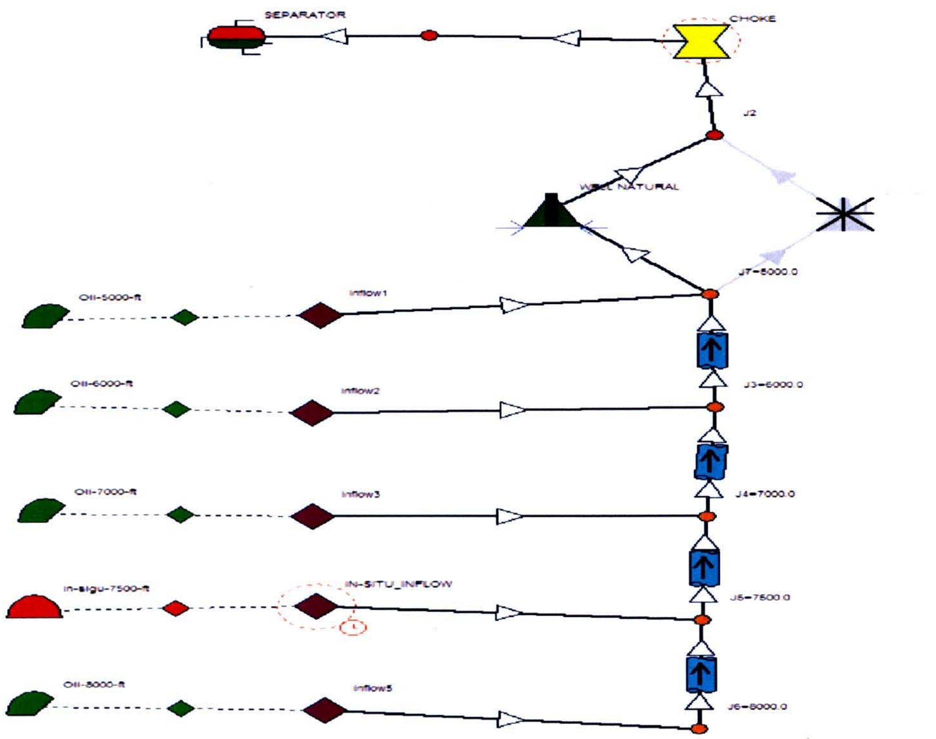
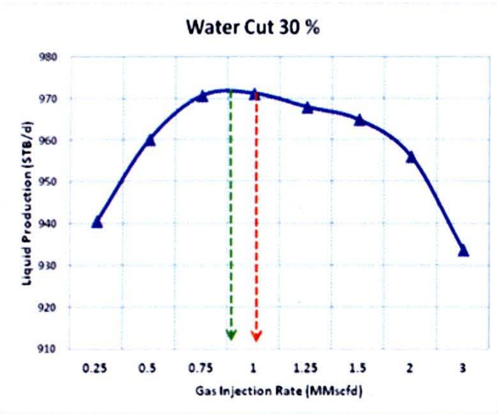


Figure 4.6 Well Model Diagram in IPM for In-situ Gas Zone @ 7500' TVD

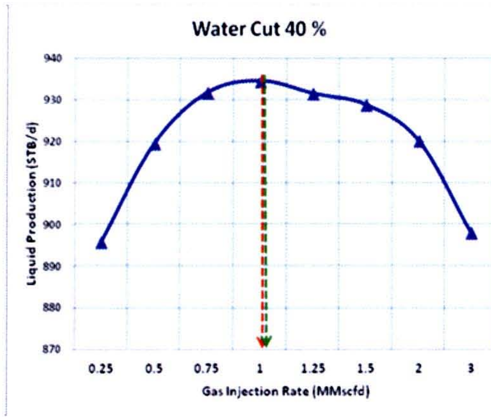
4.3 Conventional Gas Lift Operation Practice

The control of the gas lift in the base case model is based on the normal practice in the offshore environment in the studied fields, i.e., the gas injection rate, most of the time, is set at constant or fixed injection rate or at maximum injection gas available when the well is producing at high water cut or loaded up. Practically, the gas lift injection rate is available between 0.5 – 1.0 MMscfd per well with 1,200 – 1,500 psi injection pressure which is the normal capacity of the gas lift compressor currently installed in the studied offshore fields.

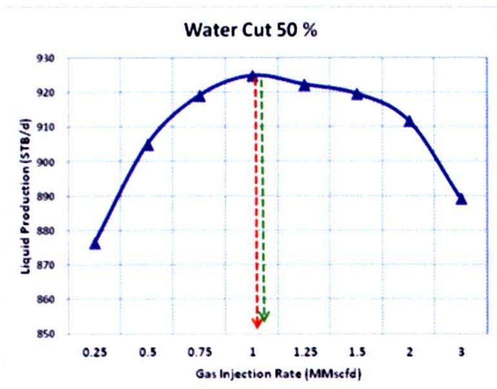
To verify which gas injection rate is suitable for such a base case, the initial liquid production rate (plateau) at 1,500 stb/d was assumed while the sensitivity run on gas lift injection rates of 0.25, 0.5, 0.75, 1.0, 1.25, 1.5, 2.0, and 3.0 MMscfd and various water cuts (30%, 40%, 50%, 60%, 70%, 80%, 90% and 95%) were run to identify the optimal GLR. According to the results shown in Figure 4.7 (a), (b), (c), (d), (e), (f), (g) and (h), it can be observed that at any given water cuts, the gas injection rate of 1.0 MMscfd could provide GLR that is close to the optimal GLR for wider range of water cuts with excessive GLR for one case only.


Water Cut 30 %
Liquid Production (STB/d)
980
970
960
950
940
930
920
910
0.25 0.5 0.75 1 1.25 1.5 2 3
Gas Injection Rate (MMscfd)

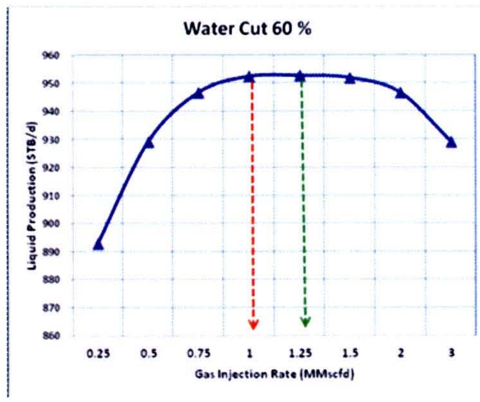
(a)


Water Cut 40 %
Liquid Production (STB/d)
940
930
920
910
900
890
880
870
0.25 0.5 0.75 1 1.25 1.5 2 3
Gas Injection Rate (MMscfd)

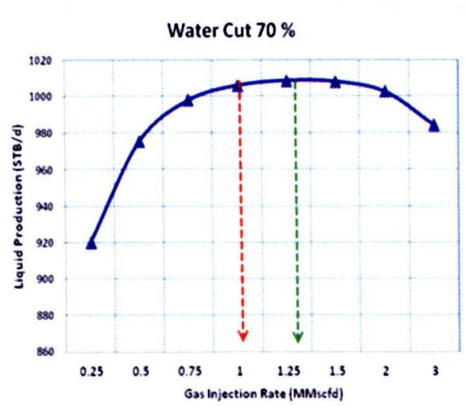
(b)


Water Cut 50 %
Liquid Production (STB/d)
930
920
910
900
890
880
870
860
850
0.25 0.5 0.75 1 1.25 1.5 2 3
Gas Injection Rate (MMscfd)

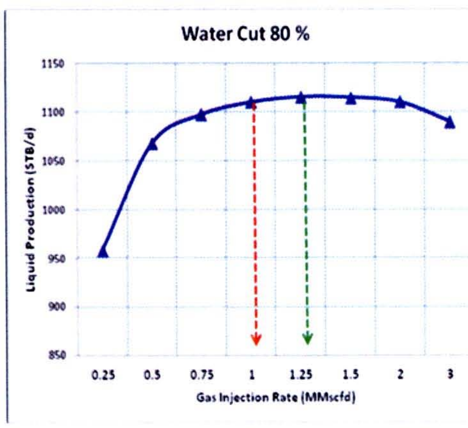
(c)


Water Cut 60 %
Liquid Production (STB/d)
960
950
940
930
920
910
900
890
880
870
860
0.25 0.5 0.75 1 1.25 1.5 2 3
Gas Injection Rate (MMscfd)

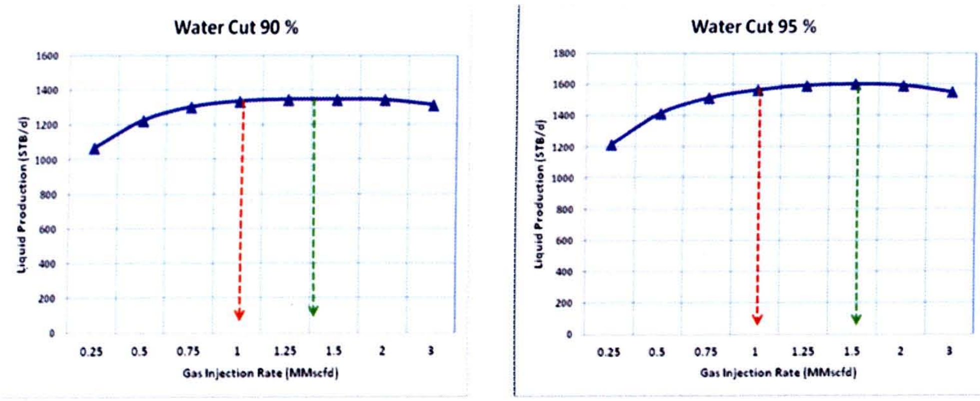
(d)


Water Cut 70 %
Liquid Production (STB/d)
1020
1000
980
960
940
920
900
880
860
0.25 0.5 0.75 1 1.25 1.5 2 3
Gas Injection Rate (MMscfd)

(e)


Water Cut 80 %
Liquid Production (STB/d)
1150
1100
1050
1000
950
900
850
0.25 0.5 0.75 1 1.25 1.5 2 3
Gas Injection Rate (MMscfd)

(f)



(g) (h)

Figure 4.7 Gas Lift Performance Curve for Various Water Cuts at (a) 30%, (b) 40%, (c) 50%, (d) 60%, (e) 70%, (f) 80%, (g) 90%, and (h) 95%

4.4 Favorable Gas to Liquid Ratio (GLR)

In this study, the initial reservoir pressures of all oil reservoirs are assumed undersaturated or above the bubble point. As a result, at the beginning of the production with natural depletion of the oil reservoirs (without an in-situ gas zone), the producing GLR is consequently low and constant (see also Section 3.3.1 Solution Gas Drive).

After the oil production falls, the gas lift system is then instituted. It is necessary to determine the amount of gas injection rate required to achieve the favorable or optimal GLR to obtain the maximum oil production rate possible. However, this favorable GLR may not be achieved mainly due to limited amount of injection gas or high cost of the gas compression and separation equipment needed to separate large gas quantities.

As a result, the maximum oil rate is not necessarily the most economic one. However, for solution gas drive reservoirs (Section 3.3.1), the needed gas-injection GLR increases at early stages but drops rapidly as reservoir GLR increases when reservoir pressure drops below the bubble point.

At a given rate where the formation GLR is higher than the favorable GLR needed as shown in Figure 4.8, there is no gain in production by injecting more gas. Injecting a constant gas lift rate of 1.0 MMscfd may not give the favorable or optimal GLR; however, it will not cause excessive GLR in most cases as discussed in Figure 4.7 previously and is in line with the current gas lift operation practice in the studied fields.

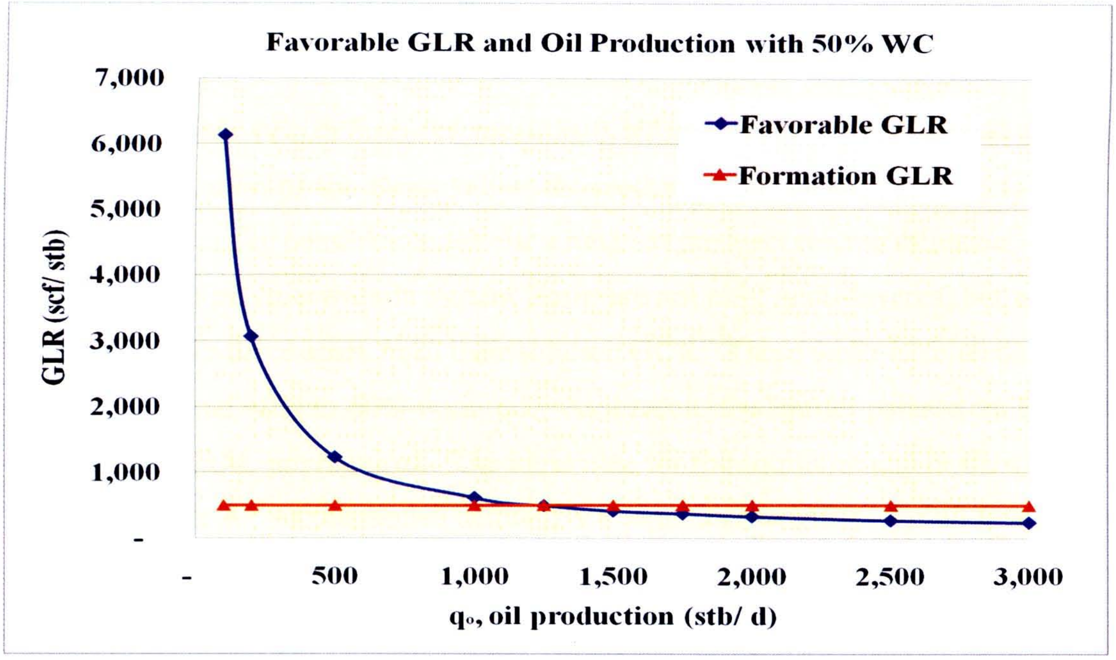


Figure 4.8 Favorable GLR Curve for the Base Case with Injection Gas Rate of 1.0 MMscfd, 50% WC and Formation GLR of 500 scf/stb

4.5 Tank Model (MBAL)

Each of oil and gas reservoir or layer is simplified with the reservoir properties shown in the Table 4.2 and Table 4.4 to represent multi-layered reservoirs in monobore completions. All of reservoir parameters are based on the typical fluid properties obtained from the actual field data of two major oil fields in one of the concession blocks in Pattani Basin in the Gulf of Thailand. This block is approximately 2,891 square kilometers in size and lies on the north-western edge of Pattani Basin with production from fluvial sands of Miocene and Oligocene age. Two different petroleum systems are identified in this block primarily inferred from analyses of produced hydrocarbons.

Upper Oligocene lacustrine intervals in the block represent the primary source for liquid hydrocarbons. Most of the reservoir section was deposited in a fluvial or coastal plain environment, with linear, discontinuous sands through laterally extensive amalgamated sand sequences. Hydrocarbon accumulations are generally associated with three-way dip closures formed along normal faults. Stratigraphic closure in the strike direction, at the depositional edge of fluvial sand, is also common. Wells are usually directionally drilled parallel to the trapping fault and encounter multiple stacked pay sands. The individual sands are generally thin, averaging about 10 to 40 feet; however, some sands are as thick as 90 up to 150 feet.

The average drainage areas for oil and gas reservoirs are 61 and 51 acres per layer, respectively. These drainage areas are estimated from the field data using Swanson's rule. Swanson's rule defines the mean as $0.3(P_{10})+0.4(P_{50})+ 0.3(P_{90})$, and provides a good approximation to the mean values for modestly skewed distributions to present a range of geologically possible models for a range of prospect reserve estimates.

Most of oil reservoirs in Pattani Basin are not only multi-layered, but also driven by radial aquifer drive apart from their solution GOR. These wells have tendency to die or load up around 40% to 60% water cut. As a result, the aquifer parameters for all four oil layers in MBAL are required. The input data for the aquifer model is shown in Table A1 in Appendix A. As mentioned before, PVT input data in MBAL for all four oil layers as shown in Table A2 in Appendix A are based on the typical fluid properties of the two major fields in Pattani Basin. The example input data for relative permeability for oil and gas layers are also shown in Table A3 in Appendix A, while Table A4 in Appendix A contains input data for residual saturation and Corey exponents for oil and gas layers to match the core data analysis. Figure A8 in Appendix A is water-oil relative permeability calculated in MBAL to match the data from core analysis shown in Figure A9 in Appendix A. Similarly, Figure A11 in Appendix A is the gas-oil relative permeability calculated in MBAL to match the data from core analysis shown in Figure A12 in Appendix A.

Inflow Performance Relation (IPR)

The IPR describes reservoir fluid inflow into the wellbore and constitutes a major component of the nodal analysis technique for well performance optimization. For the base case, the nodal analysis model for each oil and gas layer was constructed in PROSPER based on the input data in Tables A5 and A6 in Appendix A.

Geothermal gradient is also estimated from average field data per Table A8 in Appendix A while the deviation of the well is picked up from one of the existing oil wells in Pattani Basin as shown in Table A9 in Appendix A.

Vertical Lift Performance (VLP)

Fluid Flow Correlation

For oil wells, Hagedorn & Brown correlation has remained the most widely used and most reliable even though it is one of the very first multiphase flow correlations developed. However, since OLGA flow correlation which is the best correlation available in the industry is available in the current software used, OLGAS 3P (Steady State Offshoot of OLGA) is selected in all the tubing in the base case well model. The OLGAS 3P is the mechanistic model in which all flow equations are solved by a numerical method and suitable for all the flow conditions.

In order to allow GAP to produce the VLP, the well model is constructed in PROSPER using the input data in Tables A7, A8 and A9 in Appendix A.

The sensitivity variables for VLP are as follows:

1. Liquid rate ranges from 20 to 5,000 stb/d for 20 values using geometric spacing.
2. Manifold pressure ranges from 50 to 2,000 psi for 10 values using geometric spacing.
3. GOR ranges from 250 to 20,000 scf/stb for 10 values using geometric spacing.
4. Water cut ranges from 0 to 99% for 10 values by manual spacing.
5. Gas injection rate ranges from 0.25 to 1.25 MMscfd for 6 values using linear spacing.

The in-situ gas lift scenarios are generated for the prediction runs to record the oil recovery factors with various values of variables as shown in Table 4.5. Each variable in the sensitivity runs has three values, being low, medium and high. The combination of variables is varied and simulation runs are made based on these different combinations.

Table 4.5: Variables for Thesis Study

Variable	Value #1	Value #2	Value #3
Estimated initial reservoir pressure for in-situ gas zone (psia) or Reservoir depth (ft TVD)	2750 psia or 5500' TVD	3250 psia or 6500' TVD	3750 psia or 7500' TVD
Permeability of in-situ gas zone (mD)	10 mD	100 mD	1000 mD
Total gas pay thickness (ft)	15 ft	45 ft	90 ft
Perforation schedule of in-situ gas zone	Concurrent vs. Time-lapsed		

In this thesis, the concurrent and time-lapsed perforation schedules of in-situ gas zone are studied. The concurrent perforation schedule for the in-situ gas zone is the case that the in-situ gas zone is perforated at the same time as the oil zones and produced commingledly while the time-lapsed perforation schedule will let the well produce naturally for a certain duration or until the well reaches the abandonment rate of 10 stb/d, and require the in-situ gas zone to be perforated later on. In this study, approximate 50% water cut is used as a trigger for the time-lapsed perforation schedule of the in-situ gas zone. For both cases, the gas zone is perforated with 1-ft interval and the mechanical straddle pack-off with check-valve is assumed to be installed across the perforation to prevent cross-flow into the in-situ gas zone.

Moreover, after a few scenarios for in-situ gas zone were simulated, a problem with crossflow into the in-situ gas zone occurred, resulting in well instability phenomena during a prediction run. To prevent the crossflow problem, there has been proven technology and equipment and is viable practice in the studied fields which is to set a mechanical straddle pack-off with a check valve across the perforation interval of the in-situ gas zone. This mechanical pack-off will prevent the crossflow into the in-situ gas zone. As a result, this equipment is assumed to be set across the perforation interval on the in-situ gas zone in every scenario. This can be achieved in the simulation by making the positive differential pressure. The pressure drop due to its restriction of the pack-off is assumed negligible.