CHAPTER IV

RESERVOIR MODEL CONSTRUCTION

This work aims at an application of process control concept to petroleum production process in order to obtain the optimum ultimate oil recovery from a close system reservoir having solution gas drive mechanism. In this study, a reservoir model is created and used for reservoir simulation runs. All the studies in this work then are performed by using this reservoir model.

The studies are performed as follows:

1. Investigate the effect of maximum allowable oil production rate on ultimate recovery of oil producing from a closed solution gas drive reservoir under natural depletion.
2. Investigate the effect of PVT properties of oil and gas on the relationship between maximum allowable oil rate and ultimate recovery of oil produced.
3. Investigate the effect of reservoir heterogeneity in term of porosity and effective permeability on the relationship between maximum allowable oil rate and ultimate recovery of oil produced.
4. Determine the surface information that can possibly be used as an indicator for improving ultimate recovery of oil or reduce time to reach ultimate oil recovery.

As it can be seen that the study does not cover the effect of other parameters and variables such as relative permeability, capillary pressure, etc., those parameters and variables are left constant for the entire study program. A commercial black oil reservoir simulator is used in this work.

The simulator used in this work is the Black Oil Simulation module of Petroleum WorkBench release 1.6 from Scientific Software-Intercomp, Inc. This simulator is capable of handling simulation problems in both cartesian and radial systems.

The numerical reservoir model is a radial system having total number of grid blocks of 19*12*6 in r, θ, and z directions, respectively. The top of the reservoir is located at 5,000 ft below mean sea level. The radii of the inner grid block to the outer grid block are as follows (in feet):

.500	1.000	2.000	3.000	4.000	5.000	6.000
7.000	8.000	9.000	10.000	20.000	40.000	80.000
160.000	240.000	320.000	400.000	480.000		

Each segment is 30 degree thus there are 12 segments per layer. This model consists of six layers. Each layer has constant gross and net thickness of 10 feet thus the reservoir has total thickness of 60 feet. The datum depth for reporting average reservoir pressure is set to mid point of the reservoir thickness which is at 5,030 feet. For the studies that involve homogeneous reservoir, porosity values of the entire model are set constant at 0.200 and effective permeability values of a block are identical in three directions with a constant value of 100 md.

As there is one studying category concerning the effect of hydrocarbon fluid properties on the ultimate recovery, a set of PVT properties of oil and gas are computed by using correlations. The major properties used for determining other properties include solution gas oil ratio and bubble point pressure of oil. Correlations which are used for determining solution gas oil ratio and formation volume factor of oil as a function of pressure are of Standing.[17] Correlation for determining viscosity of oil is a correlation of Beggs and Robinson.[17] For gas, the correlation proposed by Lee *et al.*[18] is used for determining gas viscosity. Details of each correlation used in this work is included in the appendix. Bubble point pressure of this oil sample is 2,500 psia and its initial solution gas oil ratio, R_{si}, is equal to 500 SCF/STB. API gravity of oil is set to 35 and specific gravity of gas is 0.60 where specific gravity of air equals 1.0. Table 4.1 shows PVT properties of oil and gas which are used in the base case.

Note that given property values are up to pressure of 2,500 psia. At the pressure of 6,000 psia which is the upper limit of pressure, the simulator calculates all properties according to undersaturated oil compressibility above initial bubble point pressure. It uses linear interpolation for the fluid property values of the other pressures between oil bubble point pressure and this upper limit. This approach is applied to all cases of studying the effects of PVT properties of oil and gas.

The standard condition used for reporting purpose is set to 14.65 psia and 60 degree Fahrenheit. Reservoir temperature is set to 160 degree Fahrenheit. Density of water at standard condition is set to 0.99955 g/cm^3. Water compressibility of 3.0×10^{-6} per psi is used for every study. Water formation volume factor at initial reservoir pressure and initial temperature is 1.0010 RB/STB and is kept constant for every pressure point. Water viscosity is constant at 0.50 cp. Rock compressibility is 6.0×10^{-6} per psi.

Two-phase relative permeability of oil-water system and gas-liquid system are used in the model. Table 4.2 and 4.3 include relative permeability of the oil-water system and the gas-liquid system, respectively.

Table 4.1. PVT properties of oil and gas used in the base case model

Pressure (psia)	Rs (SCF/STB)	Oil Viscosity (cp)	Bo (RB/STB)	Bg (RB/MSCF)	Gas viscosity (cp)
0	0.00	2.7741	1.0463	15.3210	0.0108
300	39.88	2.1584	1.0611	10.0933	0.0113
600	91.86	1.7034	1.0810	4.8656	0.0117
900	149.68	1.3997	1.1038	3.1338	0.0124
1200	211.63	1.1882	1.1289	2.2790	0.0132
1500	276.86	1.0338	1.1560	1.7779	0.0143
1800	344.83	0.9166	1.1848	1.4559	0.0155
2100	415.15	0.8248	1.2153	1.2377	0.0169
2400	487.56	0.7510	1.2473	1.0845	0.0185
2500	500.00	0.7399	1.2583	1.0476	0.0190
6000	507.00	0.7920	1.2701	0.4365	0.0366

Table 4.2. Relative permeability to oil and water used in the model

S_w	K_{rw}	K_{row}	P_{cow} (psia)
0.1000	0.00E+00	1.0000	113.2
0.1379	2.72E-08	0.8975	52.43
0.1758	1.23E-06	0.8004	22.04
0.2137	1.14E-05	0.7086	13.28
0.2516	5.56E-05	0.6220	9.268
0.2895	0.0002	0.5406	7.012
0.3274	0.0005	0.4644	5.583
0.3653	0.0012	0.3933	4.605
0.4032	0.0025	0.3277	3.897
0.4411	0.0048	0.2677	3.363
0.4789	0.0086	0.2135	2.948
0.5168	0.0145	0.1653	2.617
0.5547	0.0234	0.1233	2.347
0.5926	0.0364	0.0876	2.124
0.6305	0.0546	0.0584	1.936
0.6684	0.0799	0.0354	1.776
0.7063	0.1139	0.0187	1.638
0.7442	0.1590	0.0076	1.519
0.7821	0.2177	0.0017	1.414
0.8200	0.2931	0.0000	1.322
1.0000	1.0000	0.0000	1.000

Table 4-3 Relative permeability to gas and liquid used in the model

S_l	K_{rog}	K_{rg}	P_{cgo} (psia)
0.2800	0.00E+00	1.0000	93.710
0.3153	6.24E-08	0.8975	43.400
0.3505	2.82E-06	0.8003	18.250
0.3858	2.62E-05	0.7083	10.990
0.4211	0.0001	0.6212	7.673
0.4563	0.0004	0.5390	5.805
0.4916	0.0012	0.4617	4.622
0.5268	0.0028	0.3895	3.812
0.5621	0.0058	0.3226	3.226
0.5974	0.0110	0.2613	2.784
0.6326	0.0197	0.2059	2.441
0.6679	0.0333	0.1569	2.167
0.7032	0.0538	0.1146	1.943
0.7384	0.0835	0.0792	1.758
0.7737	0.1255	0.0508	1.603
0.8089	0.1834	0.0293	1.470
0.8442	0.2616	0.0143	1.356
0.8795	0.3651	0.0052	1.257
0.9147	0.5000	0.0010	1.171
0.9500	0.6731	0.0000	1.094
1.0000	1.0000	0.0000	1.000

In the tables, the relative permeability is defined as a ratio of effective permeability to effective permeability of oil at irreducible water saturation. This could be noticed from relative permeability value of oil which is 1.000 at irreducible water saturation, S_{wirr}, of 10% in table 4.2. Residual oil saturation is 18% and critical gas saturation is 5%.

The reservoir includes one vertical producer located at the center of the model. The completion is made through the entire thickness. This theoretically ensures fully radial flow thus excluding the effect of non-radial flow behavior from the study. One primary purpose of this work is to investigate ultimate oil recovery of a solution gas drive reservoir producing under natural depletion process. Therefore, there is no pressure support means attached to the model.

Since reservoir drive mechanism which will be used in this work is solution gas drive mechanism, initial reservoir pressure is then set to 500 psi above initial oil bubble point pressure. This condition is applied for all study cases. Initial reservoir pressure is 3,000 psia for the base case.