CHAPTER IV

RESERVOIR MODEL DESCRIPTION

In this work, two types of reservoir model which are black oil and compositional models were synthetically constructed and used for reservoir simulation runs because the miscibility occurs during the injection of gas slug coupled to the fact that black oil simulation cannot model the miscibility of component. As mentioned earlier, the composition of the hydrocarbon together with an equation of state has to be identified in the compositional reservoir model.

The study was conducted as follows:

1. Compare the recovery factor obtained from waterflood with that from WAG process.
2. Investigate the effect of horizontal permeability, ratio of vertical to horizontal permeability, and distance between producer and injector on the optimum water-gas ratio and slug sizes for the WAG process.
3. Investigate the effect of compositional change probably occurring during gas injection.
4. Investigate the effect of relative permeability hysteresis models used in black oil and compositional reservoir model on the WAG process.

In this study, both black oil and compositional reservoir models use the same geometry and properties. The base case reservoir model is a Cartesian system containing a total number of grid blocks of $30\times21\times10$ in the x, y and z direction, respectively. The dimension of each grid block is 100 ft in the x and y direction and 5 ft in the z direction. Thus, the size of entire reservoir is 3,000 ft in length, 2100 ft in width, and 50 ft in thickness. The top of the reservoir is located at 8,000 ft below the surface level. The initial reservoir pressure is 3,745 psia. The configuration of reservoir model is shown in Figure 4.1

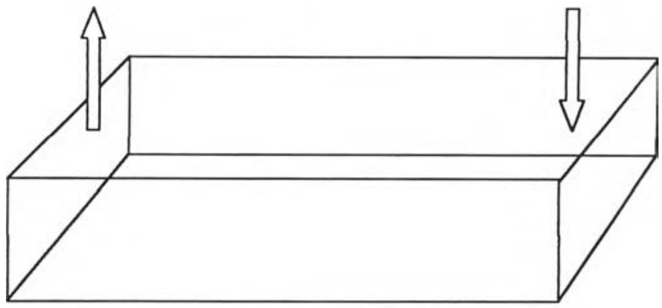

Figure 4.1: Reservoir model configuration.

For the base case, the reservoir is single layered homogeneous, anisotropic and water-wet with the porosity of 0.2, horizontal permeability of 200 millidarcies, and vertical permeability of 2 millidarcies.

4.1 Black oil reservoir model

The black oil model in the study was created using Eclipse 100 version 2003A_1 commercial black oil simulator from Schlumberger Inc. Eclipse 100 has an option of fully implicit solution. It can handle reservoir simulation models in Cartesian, radial and complex geometry.

Since the hydrocarbon fluid properties used in the black oil model have to be the same as the properties used in the compositional model, the PVT have to be carefully generated. In this study, the PVT properties data from the work of Killough *et al.* (1987) were used. These PVT properties also include the compositional fluid description of reservoir hydrocarbon and injected gas which is necessary in the compositional model.

Table 4.1 shows the PVT properties of oil and injected gas used in the model. The bubble point pressure of oil is 2302.3 psia and its initial solution gas oil ratio is equal to 572.8 SCF/STB. The density of oil, gas, and water at standard condition is set to 38.53, 0.068, and 62.4 lb /ft^3. The water compressibility is 3.0×10^{-6} per psi. The water viscosity is 0.503 cp. The rock compressibility is equal to 5×10^{-6} per psi.

It should be noted that the PVT properties at a pressure not specified in the table can be computed using linear interpolation between the specified fluid PVT properties.

Table 4.1: PVT properties of oil and injected gas used in reservoir model.

Pressure (psia)	R_s (MSCF/STB)	B_o (RB/STB)	Oil viscosity (cp)	B_g (RB/MSCF) (injected gas)	Gas viscosity (cp) (injected gas)
14.7	0.00	1.00	0.414	211.412	0.0107
500	0.1176	1.1017	0.295	5.924	0.0127
1000	0.2226	1.1478	0.274	2.851	0.0134
1200	0.2677	1.1677	0.264	2.344	0.0138
1500	0.3414	1.1997	0.249	1.846	0.0145
1800	0.4215	1.2350	0.234	1.52	0.0153
2000	0.479	1.2600	0.224	1.36	0.0159
2302.3	0.5728	1.3010	0.208	1.1751	0.0170
2500	0.5728	1.2958	0.214	1.1025	0.0170
3000	0.5728	1.2839	0.227	0.985	0.0170
3500	0.5728	1.2734	0.240	0.9116	0.0170
4000	0.5728	1.2639	0.253	0.862	0.0170
4500	0.5728	1.2554	0.265	0.8223	0.0170
4800	0.5728	1.2506	0.272	0.80321	0.0170

As mentioned in Chapter 1 that we should consider the effect of relative permeability hysteresis in the WAG process, two sets of three phase relative permeability functions of oil, water, and gas system (one for drainage and one for imbibition) have to be included in the reservoir model. With the availability of reservoir simulation keywords, each set of relative permeability data for the drainage and imbibition processes shown in Tables 4.2 and 4.3, resepectively, was included in the simulation model. This relative permeability data comes from the work of Kossack (2000).

Table 4.2: Relative permeability to oil, water, and gas used in the drainage process.

S_o	k_{row}	k_{rowg}	S_w	k_{rw}	p_{cow}	S_g	k_{rg}	p_{cog}
0	0	0	0.2	0	6	0	0	0
0.2	0.05	0	0.25	0.005	5	0.05	0.005	0.1
0.25	0.08	0.01	0.3	0.01	4	0.1	0.02	0.2
0.3	0.1	0.02	0.35	0.012	3	0.15	0.06	0.4
0.35	0.15	0.035	0.4	0.035	2.4	0.2	0.1	0.6
0.4	0.2	0.05	0.45	0.05	1.98	0.25	0.15	0.83
0.45	0.25	0.1	0.5	0.065	1.5	0.3	0.2	1.1
0.5	0.3	0.15	0.6	0.1	0.75	0.35	0.25	1.4
0.55	0.4	0.25	0.65	0.2	0.4	0.4	0.3	1.62
0.6	0.45	0.35	0.7	0.25	0.25	0.5	0.45	2.4
0.7	0.7	0.55	0.8	0.36	0.001	0.55	0.6	2.7
0.8	0.9	0.9	1.0	1	0	0.6	0.75	3

Table 4.3: Relative permeability to oil, water, and gas used in the imbibition process.

S_o	k_{row}	k_{rowg}	S_w	k_{rw}	p_{cow}	S_g	k_{rg}	p_{cog}
0.2	0	0	0.2	0	6	0	0	0
0.25	0	0.05	0.25	0.04	3	0.2	0	0
0.3	0.0001	0.15	0.3	0.1	2	0.3	0.005	0
0.35	0.0005	0.4	0.35	0.18	1	0.4	0.001	0.01
0.4	0.005	0.9	0.4	0.25	0.6	0.5	0.18	1.6
0.45	0.02	0.9	0.5	0.4	0.08	0.55	0.4	2.2
0.5	0.04	0.9	0.6	0.5	0.01	0.6	0.75	3
0.55	0.1	0.9	0.7	0.63	0.005			
0.6	0.2	0.9	0.8	0.75	0.003			
0.65	0.3	0.9	0.9	0.9	0.001			
0.7	0.45	0.9	1.0	1.0	0			
0.75	0.65	0.9						
0.8	0.9	0.9						

As shown in Tables 4.2 and 4.3, it can be noticed that the connate water saturation is 0.2 and that the residual oil saturation is 0.2. The end point saturation of drainage and imbibition for the relative permeability to oil coincides at $S_o = 0.8$. For water and gas, the end point saturations are at $S_w = 1.0$ and $S_g = 0.6$, respectively.

The relative permeability hysteresis used in the base case model is Killough hysteresis model. The modification parameter for trapped non-wetting phase saturation in the Killough model is set to default (0.1).

4.2 Compositional reservoir model

For the case of compositional reservoir model, we used Eclipse 300 version 2003A_1. It can handle reservoir model with complicated configuration as well as Eclipse 100. In this model, the compositions of reservoir fluid and injected gas were specified as shown in Table 4.4. A set of parameters for the equation of state are also needed in compositional simulation. Table 4.5 and Table 4.6 show the parameters associated each hydrocarbon component. In this study, Peng-Robinson equation of state was used because of availability of data. This set of data for compositional model also comes from the work of Killough *et al.* (1987). The relative permeability data and hysteresis model used in this simulator are the same as those in the black oil simulator.

Table 4.4: Compositional reservoir fluid and injected gas .

Component	Mole fraction of reservoir fluid	Mole fraction of injected gas
C_1	0.50	0.77
C_3	0.03	0.2
C_6	0.07	0.03
C_{10}	0.20	0
C_{15}	0.15	0
C_{20}	0.05	0

Table 4.5: Fluid properties needed in Peng-Robinson equation of state.

Component	p_c (psia)	T_c (°R)	*MW*	Accentric factor	Critical z
C_1	667.8	343.0	16.040	0.0130	0.200
C_3	616.3	665.7	44.100	0.1524	0.277
C_6	436.9	913.4	86.180	0.3007	0.264
C_{10}	304.0	1111.8	142.290	0.4885	0.257
C_{15}	200.0	1270.0	206.00	0.6500	0.245
C_{20}	162.0	1380.0	262.00	0.8500	0.235

Table 4.6: Binary interaction coefficients (δ).

	C_1	C_3	C_6	C_{10}	C_{15}	C_{20}
C_1	0					
C_3	0	0				
C_6	0	0	0			
C_{10}	0	0	0	0		
C_{15}	0.05	0.005	0	0	0	
C_{20}	0.05	0.005	0	0	0	0

4.3 Production and injection strategy for base case model

In the base case model, the production and injection wells are located at (6,11) and (25,11) on Cartesian grid, respectively. The well bore diameter is set at 0.583 ft for both producer and injector. These two wells are perforated for the entire 50 ft. of reservoir thickness.

For the production well, the maximum allowable oil rate is set to 2,000 STB/day. In order to prevent the reservoir pressure from dropping below the bubble point pressure (2302.3 psia) during the production period, the minimum bottom hole pressure of the production well is set to 2,400 psia. There are two economic limits to be specified for the production well. The first criteria is 200 STB/day minimum oil rate. This is because the producing time is too long if the oil rate economic limit is set lower than 200 STB/day. Another criteria is 70% water cut. When one or both economic limits is reached, the well will be shut in.

For the injection well, water and gas is injected at the same fluid rate alternately. Injection starts when production well starts producing. Since the reservoir pressure is not constant during the WAG process and formation volume factor of oil and gas is a strong function of reservoir pressure, controlling the injection rate by surface rate is impossible. Hence, the injection well is controlled by the down hole rate instead. The down hole rate is set to 2,000 RB/day for both water and gas in this study. In the base case model in which the cycle size is 2 years and the water-gas ratio is 1, the injection well started injecting water for one year and then injected gas for another year alternately until achieving the economic limit. For different water-gas ratios, the volume of injected water and gas can be controled by adjusting the injection period of each phase for that particular cycle size. For example, in case of water-gas ratio of 2 and 1-year cycle, water is injected for 8 months and gas is injected for the subsequent 4 months.