CHAPTER IV

RESERVOIR MODEL CONSTRUCTION

Reservoirs models are constructed to better understand reservoir behavior and to better predict reservoir response. As mentioned earlier in Chapter I that the objectives of this study is to investigate the injection capacity and performance of M field and therefore, to perform this investigation using 3D reservoir simulator requires the assembly of a geo-cellular model to represent its geometry and petrophysical properties. This chapter discusses the details of the disposal reservoir and workflow of reservoir model construction. The data required for model construction are structural map, well log data and special core analysis, etc. The structural model was constructed by picking up the depth of top surfaces from the structural map. Girdding and layering were performed to choose an appropriate grid block size. The areal petrophysical properties were assumed to be the same. Finally, the basic reservoir properties were entered into the model to complete the model.

4.1 Reservoir Description

As mentioned in Chapter I, PW is producing as a byproduct with the production of gas and condensate in the M field. The M field in this study is located in North Malay Basin and covers approximately 1310 m^2 in the GOT as shown in the Figure 4.1. The field structural trend consists of a series of large east-dipping normal faults and smaller west-dipping antithetic normal faults forming relatively continuous north-south structural trend.

The stratigraphic succession in the field area is comprised of up to 32,808 ft of Tertiary sandstones, shales, and coals. These rocks were primarily deposited during Oligocene to Upper Miocene time in depositional environments ranging from fluvio-lacustrine to lower delta plain-marginal marine. Stratigraphy in the M field area is currently divided into four major formations.

Among those four formations, the interested formation is further subdivided into 5 units A and B are two of them. This formation is the period for a series of transgressive and regressive cycles influenced by a local marine setting. In middle early Miocene time a marine influence came to play in the northern Malay Basin. The five sub-unit cycles of major transgressive and regressive depositional sequences were recognized by well data. The total thickness of the formation ranges from 2132.5 – 4265 ft from starting blocks through end blocks. This study covers only A and B sand units at M field and details description of both A and B sand units are discussed in the following section.

4.1.1 Unit A

Unit A is characterized generally as a very sand-rich regressive sequence. This unit is inferred to be Upper Miocene in age deposited in more regressive sequence related to prior unit. It seems to be related with local uplifted event taken place after deposition of the formation in the northern Malay Basin. The predominant environment of deposition was fluvio-delta to restricted marine. Amalgamated distributary channels were deposited in the northern portion of the field area in relatively low-gradient topography. These sands are incised in places, and often stacked forming thick vertical sand-rich sections. They are fine to very fine grained, primarily composed of quartz. Glauconite may also be present in some sands. Distributary channel and bar sands were deposited in the southern portion of the project area in near shore to shallow marine settings. This sand prone unit indicates very good reservoir properties, both porosity and permeability. However, only in some specific block area encountered gas sand in the formation.

4.1.2 Unit B

Unit B is characterized generally as a regressive sequence. This unit is inferred to be Mid Miocene in age. The predominant environment of deposition was flood plain and upper to lower delta plain. High-sinuosity meandering stream sediments were deposited in the northern portion of the field area in relatively low-gradient topography. These sands are expected to be fine to medium grained, primarily composed of quartz. Distributary channel and bar sands were deposited in the southern portion of the field area in delta front and prodelta settings. Abundant medium to thick coal beds were significant in this unit forming numerous regional seismic markers, especially in the southern portion of the field Concession area. Coastal processes may have reworked these coals. Wells in some specific blocks encountered gas and light oil in bar and channel sand in this unit at M field area. Sweet gas with high condensate yields are significant from the formation reservoirs for petroleum exploration in some specific blocks due to good gas and condensate source rocks and high quality reservoir sands.

The A sand consists of mainly thick Sandstone interbedded with Claystone and Coal where as the B sand consists mainly of Claystone and Sandstone interbedded with Coal. There are 21 reservoirs located in the modeled area shown in Table 4.1 and two wells, MN-1 and MN-2, penetrating through the reservoirs. Reservoir 10-15 is the uppermost reservoir, located in the top formation A whereas reservoir 13-60 is the lowermost reservoir, located in the formation B. These formations are categorized by sediment characteristics that can be defined from seismic data correlating with sonic log.

MN-1 and MN-2 were drilled to the direction of west and south-west of the wellhead platform. These wells are water disposal wells drilled outside the main gas producing area, up thrown fault block next to the west, and penetrated stratigraphic section from sand unit A to upper part of upper sand unit. The objective is to inject PW into the water bearing reservoirs in sand unit A and sand unit B.

MN-1 and MN-2 were drilled as open hole water injectors completed with tubing, packer and un-cemented slotted liner covering the A, B and upper sand formations containing wet sands. In well MN-1, 3 ½″ slotted liner was run and set bull nose at 8120 ft MD (5196.5 ft TVD-MSL). The 3 ½″ OD (2.991″ ID) tubing completion was run and set packer at 3886.5 ft MD (2710.6 ft TVD-MSL). In well MN-2, 3 ½″ slotted liner was run and set at 7808.4 ft MD (5489.8 ft TVD-MSL). The 3 ½″ OD (2.991″ ID) tubing completion was run and set packer at 3808 ft MD (2493.4 ft TVD-MSL).

Table 4.1: Different Reservoirs Modeled in this Study.

Sand	**Reservoir Name**	**Net Pay TVT (ft)**	**Reservoir Top ft (TVD-MSL)**
A	10-15	85.5	3576
A	10-50	149	3671
A	10-80	48.3	3930
A	10-90	81	4049
B	11-20	6.2	4278
B	11-50	7.4	4308
B	11-75	5.1	4350
B	12-05	3.3	4416
B	12-20	11.2	4469
B	12-30	4.3	4498
B	12-35	1.4	4524
B	12-40	12.2	4537
B	12-55	4.5	4613
B	12-80	1.8	4672
B	12-95	7.1	4692
B	13-10	7.4	4724
B	13-15	1.4	4744
B	13-20	7.8	4751
B	13-30	2.6	4787
B	13-50	1.4	4882
B	13-60	5.5	4944

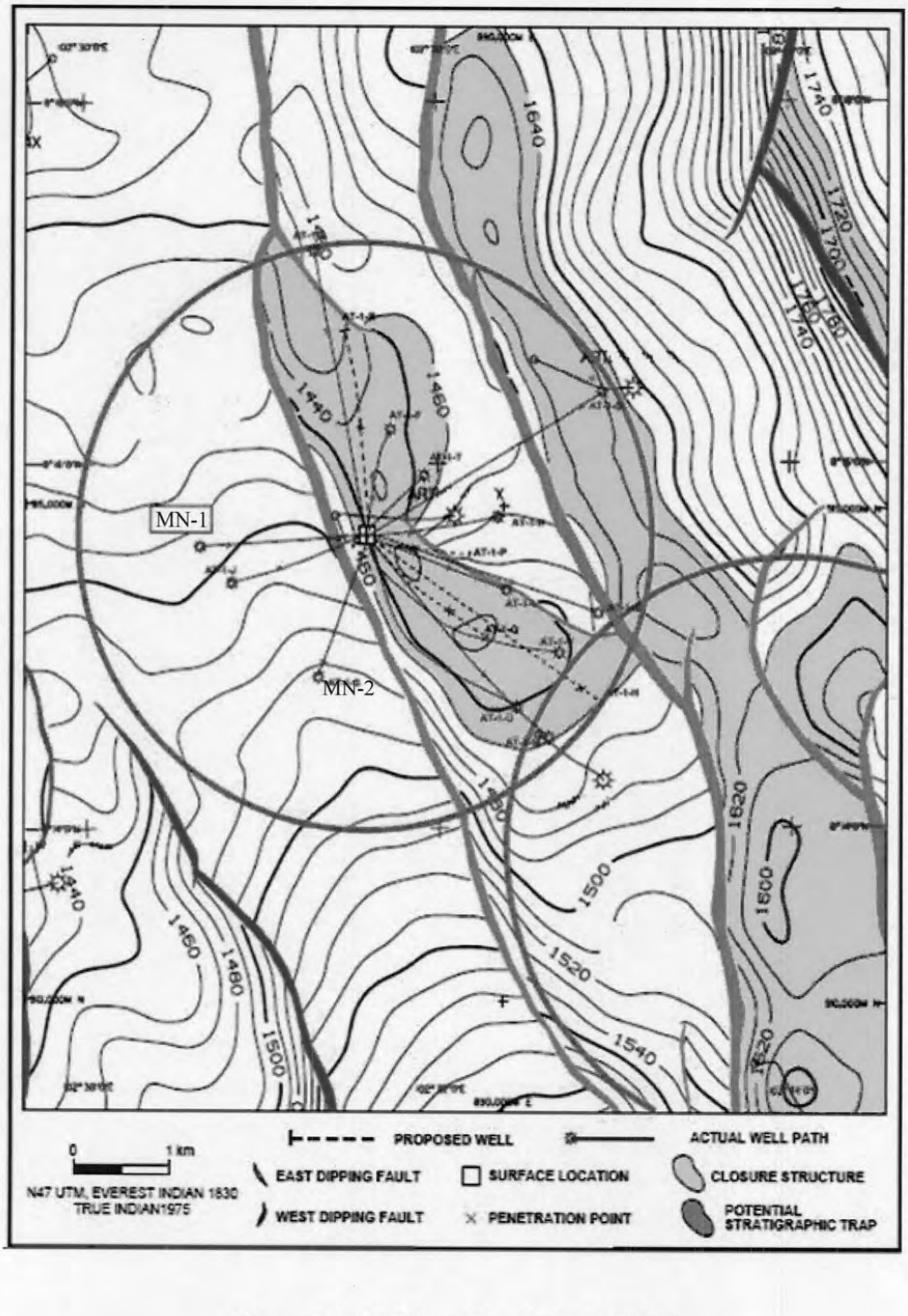

Figure 4.1: Well Location Map of M Field.

4.2 Model Area

Figure 4.2 shows the representative reservoir sector selected. Areal dimensions were 15912 ft x 9022 ft. As shown in Figure 4.2, three wells had been drilled in the area at the time of the study; MN-1 and MN-2 are water injector and the rest is producer and that is not concern with this study. Both the water injector wells are located outside from the main gas producing area, up thrown fault block next to the west.

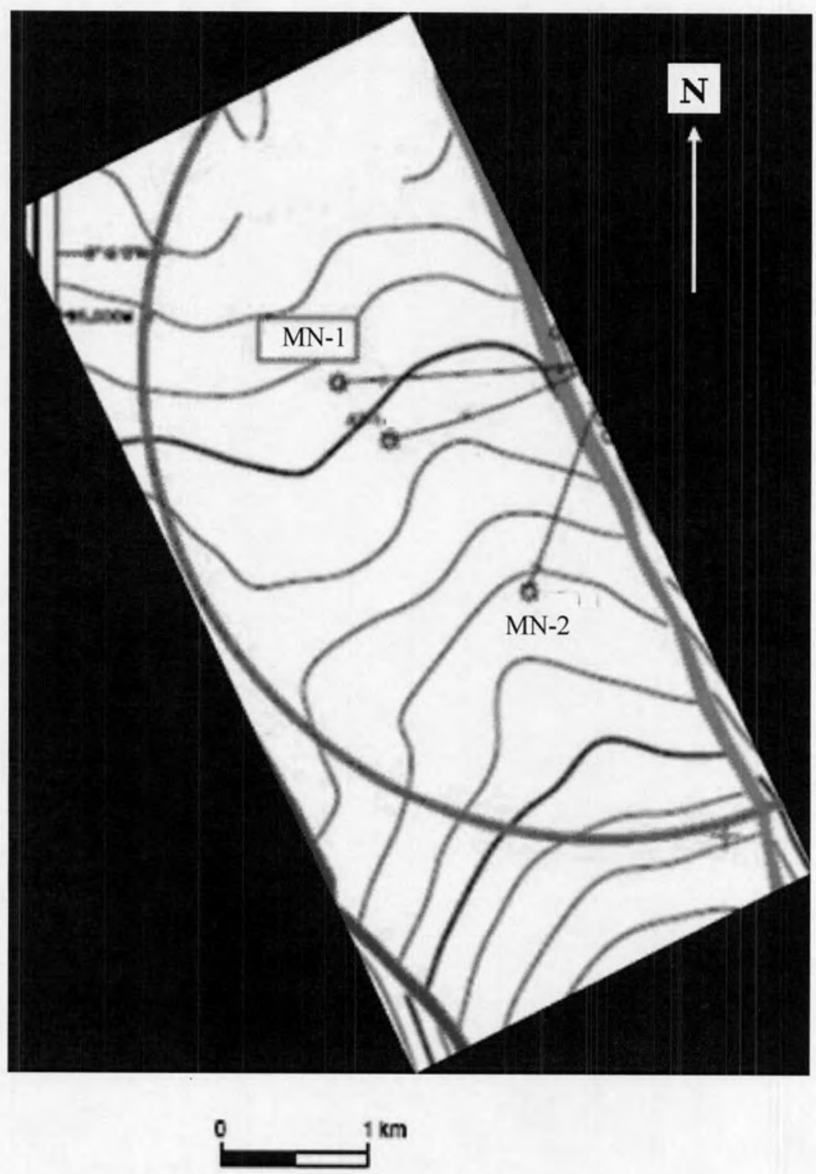

Figure 4.2: Area of M field modeled in this study.

4.3 Reservoir Model Construction

As mentioned earlier, the reservoir model of M field was constructed by using a 3-D reservoir simulator called ECILPSE 100. The model was constructed based on structural map, well log data and special core analysis data.

4.3.1 Input Data for Model Construction

The data required for initial model construction are structural map, well log data such as porosity and water saturation data, and special core analysis data such as relative permeability to water and gas and capillary pressure.

i. Structural map

Structural map HM, corresponds to a particular reservoir located in sand unit B, was used to create the main surfaces. Depth of top of surfaces was picked up from the structural map HM for each grid to create the surfaces.

ii. Well Log Data

The required data from well log are porosity and water saturation were assigned from wet sand distribution expected in the area west of wellhead platform, as analogized from nearby well MN-3 LWD log interpretation. The net sand estimation using net to gross ratios over the 20 reservoirs interval as derived from gamma ray (GR) and mud log result of MN-1 and MN-2.

iii. Special Core Analysis Data

Special core analysis has never been carried out for MN-1 and MN-2. Therefore all the SCAL data are borrowed from other available data from the nearby field. The SCAL data includes relative permeability to water and gas, and capillary pressure.

4.3.2 Reservoir Model Construction Workflow

The following processes were performed to construct the reservoir model:

- Gridding
- Surface and Zone Making
- Grid Block Layering
- Petrophysical Modeling
- Reservoir Model Initialization

i. Gridding

The grid orientation is on the direction of the main fault that is on the North-West to South-East direction. There are three different sizes of grids such as 328.1 ft, 82 ft and 41 ft, are used in areal gridding resulting 87 x 100 grids. For both wells, around the wellbore grid size is 41 ft, i.e. 4 grids, then grid size is 82 ft, i.e. 6 grids, and finally grid size is 328 grid size is used. The orientations of grids are shown later in this chapter from Table 4.6 to Table 4.8 under Base Case. A sample of grids around the wellbore is also shown in Figure 4.15 under Base Case.

ii. Surface and Zone Making

To construct the new surface maps the structural map, HM, was selected as the reference surface. New surfaces were then constructed using the thickness from well log data. The process was performed until the top and bottom reservoir maps were generated. Finally, the zones were defined from each pair of nearby surfaces.

iii. Grid Block Layering

The M field is a multi layer reservoir with alternate sand and shale sequences. The A and B sands appear in different reservoirs (i.e. 10-15, 10-50, 10-80, and so on) with alternate sand and shale sequences. The thickness of shale layers ranges from 6.6 ft to 94.5 ft. Shale layers are not what we are interested, therefore one grid block for each shale zone. Shale layers those are appeared within sand layer and are less than 6.6 ft thick that are grouped with the sand layers and the respective NTG ratio expresses the exact sand proportion. After a consolidation session with senior reservoir engineer, it's gained that maximum thickness 16 ft is worth to use for each sand grid. Therefore, the number of vertical grids became 93. Thus, 87 x 100 x 93 grids results 532,890 active simulation cells. There are 55 layers, from reservoir 10-15 to 10-90, in sand unit A and 38 layers, from reservoir 11-20 to 13-60, in sand unit B. Total simulation layers are 43 and 19 in A and B unit respectively.

iv. Petrophysical Modeling

Petrophysical modeling consists of Porosity and Permeability modeling and is described as following:

- **Porosity Modeling**

The formation that is considered to be the reservoir should has Vsh $\leq$ 40% and porosity $\geq$ 10%. No core analysis has never been carried out for MN-1 and MN-2. On the other hand, only GR and mud logs were performed for both wells. Therefore, the formation porosity is estimated from wet sand distribution expected in the area west of AA producing platform, as analogized from MN-3 LWD log interpretation and applied for the area selected.

- **Permeability Modeling**

Both horizontal (k_H) and vertical permeability (k_V) are generated in the model. First horizontal permeability is generated from porosity-permeability correlations for both A and B sands. The horizontal permeability is generated using data converted from porosity log from a nearby well.

From A correlation shown in the following Figure 4.4, it is seen that there are some layers having substantial difference of permeability value and surely those will dominate the injection result. After a consolidation session with senior reservoir engineer, its gained that maximum permeability 337.71 mD corresponding to 28% porosity is worth to use. Similarly, maximum permeability 74.35 mD corresponding to 28% porosity is used for B sand.

For vertical permeability generation, the core analysis result of another nearby well is reviewed. After a careful look of the core analysis result, the horizontal and vertical permeability ratio (k_V/k_H) 10% is decided to be used. The following Figure 4.3 and Figure 4.4 show the horizontal permeability of A and B.

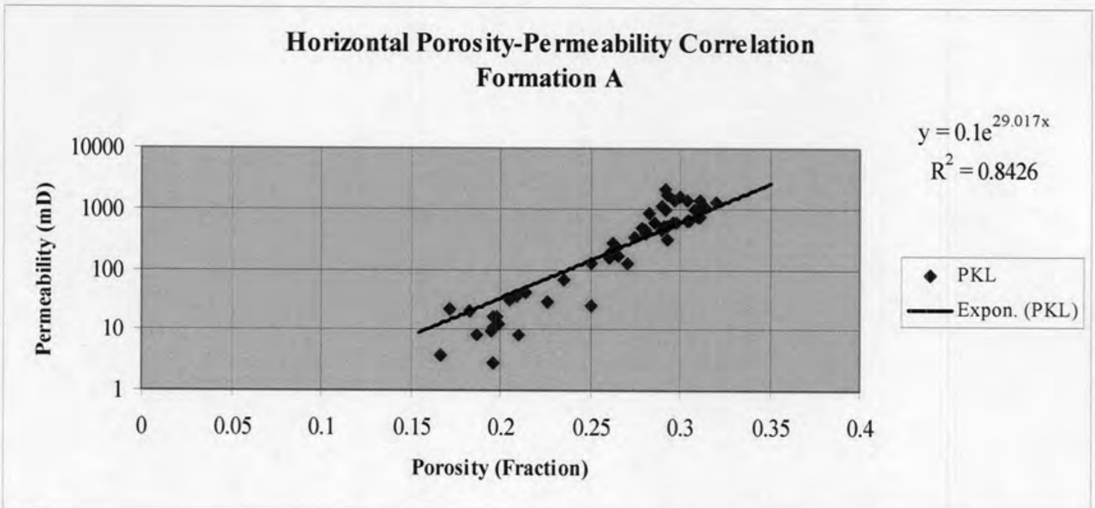

Figure 4.3: Horizontal Permeability of A Sand.

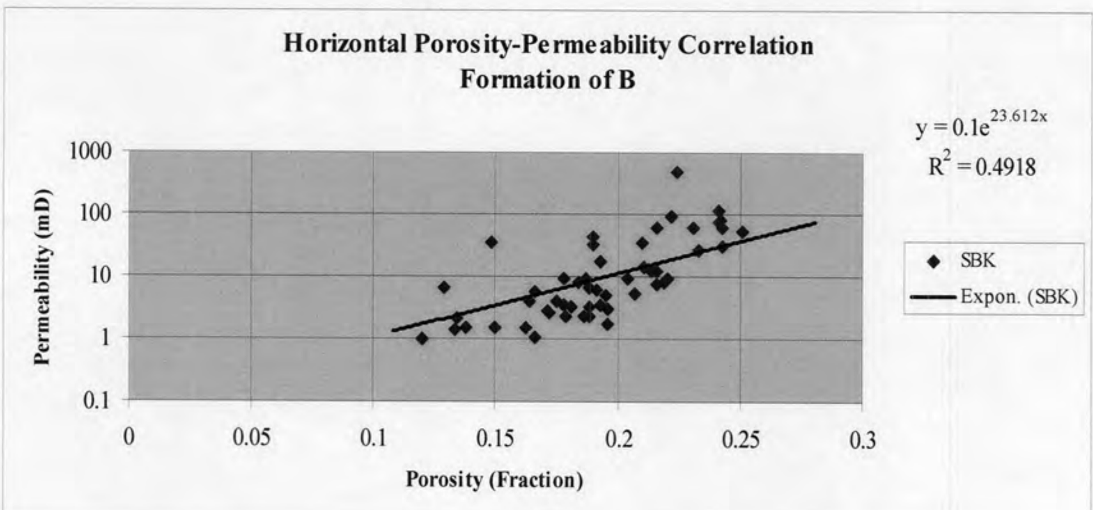

Figure 4.4: Horizontal Permeability of B Sand.

v. Reservoir Model Initialization

Model Initialization is an initial run in which the model calculates the correct amount and distribution of the original reservoir fluids. In this stage primary calculations are made for running the simulator. The fluid pressure at the initial conditions is calculated based on the fluid density and formation pressure that is provided in initialization section. After that, the capillary pressure can be calculated as follows:

$$P_{cwg} = P_g - P_w \tag{4.1}$$

where, P_{cwg} = gas-water capillary pressure

and then grid block water saturations are calculated based on the capillary pressure data.

Before test run of the model, the following data are needed to input to complete the model:

- **Initial Water Saturation**

Only GR and mud logs were performed for both wells. Therefore, initial water saturation is estimated from wet sand distribution expected in the area west of wellhead platform, as analogized from MN-3 LWD log interpretation and applied for the area selected.

- **Capillary Pressure vs. Water Saturation**

Special core analysis was not conducted for MN-1 and MN-2 wells. Therefore, the capillary pressure data was borrowed form available core analysis data from a nearby well for A formation and applied for this model. Figure 4.5 shows the capillary pressure vs water saturation model. The model was constructed from averaging of the available data.

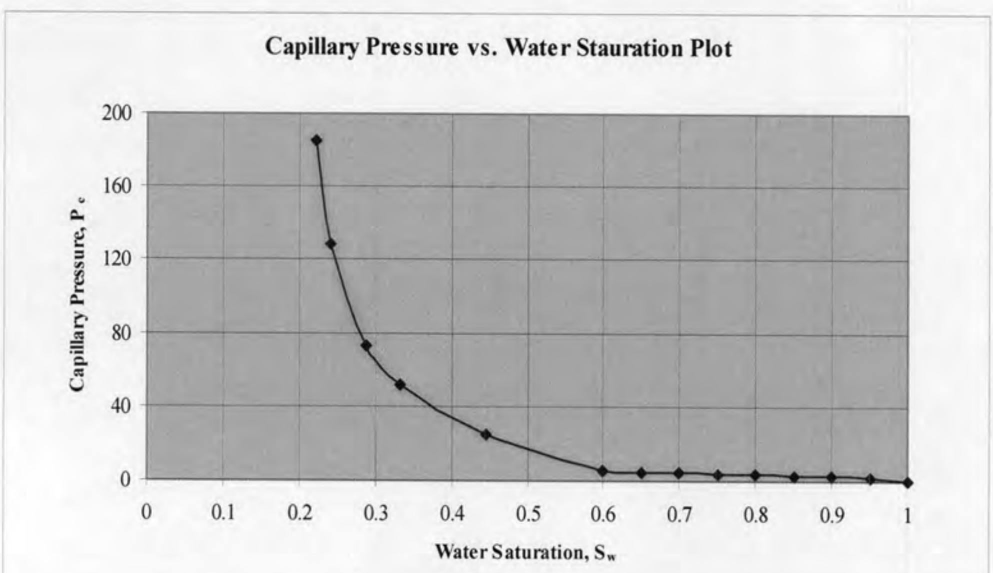

Figure 4.5: Capillary Pressure Model

- **Relative Permeability Curves**

As mentioned earlier, no core analysis was performed for both MN-1 and MN-2 wells, therefore, relative permeability to water was borrowed from representative core analysis from a nearby well and relative permeability to gas was borrowed from another nearby well A formation as well. Relative permeability to water and relative permeability to gas are shown in Figure 4.6 and Figure 4.7.

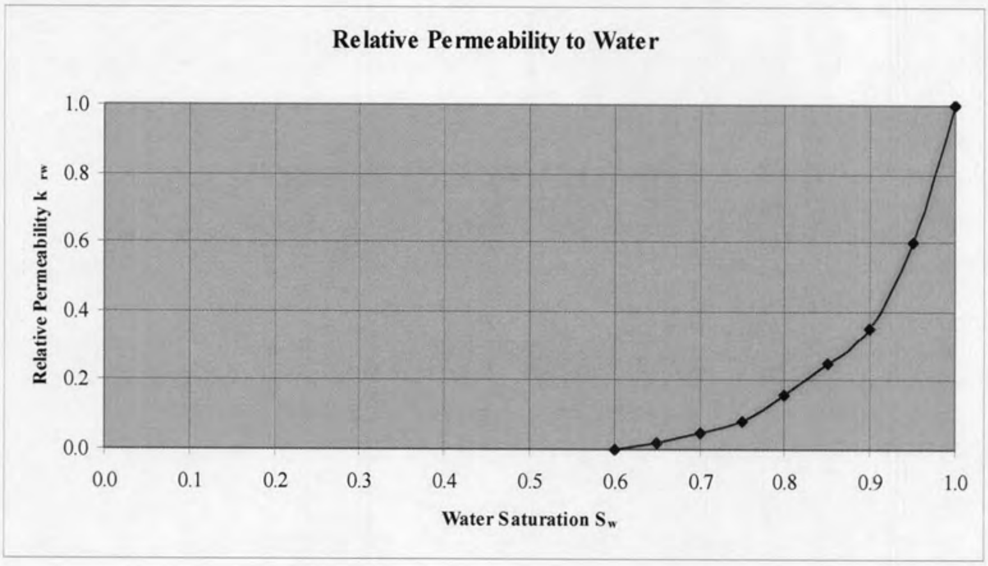

Figure 4.6: Relative Permeability to Water

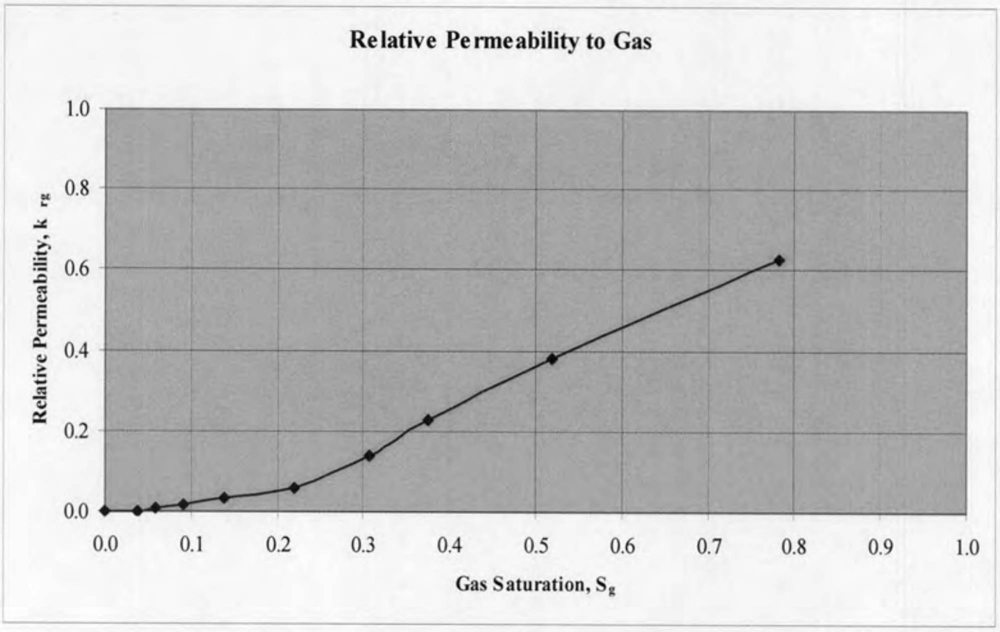

Figure 4.7: Relative Permeability to Gas

From Figure 4.6 and Figure 4.7, the end point saturations are measured as follows:

Minimum Water Saturations	=	0.60
Maximum Water Saturations	=	0.99
Minimum Gas Saturations	=	0.01
Maximum Gas Saturations	=	0.30
Critical Water Saturations	=	0.65
Critical Gas Saturations	=	0.07

- **Initial Reservoir Pressure**

The initial pressure gradient of the reservoir was taken from the nearby well MN-3 in the area west of wellhead platform and applied for this model area. The following Figure 4.8 shows the initial reservoir pressure.

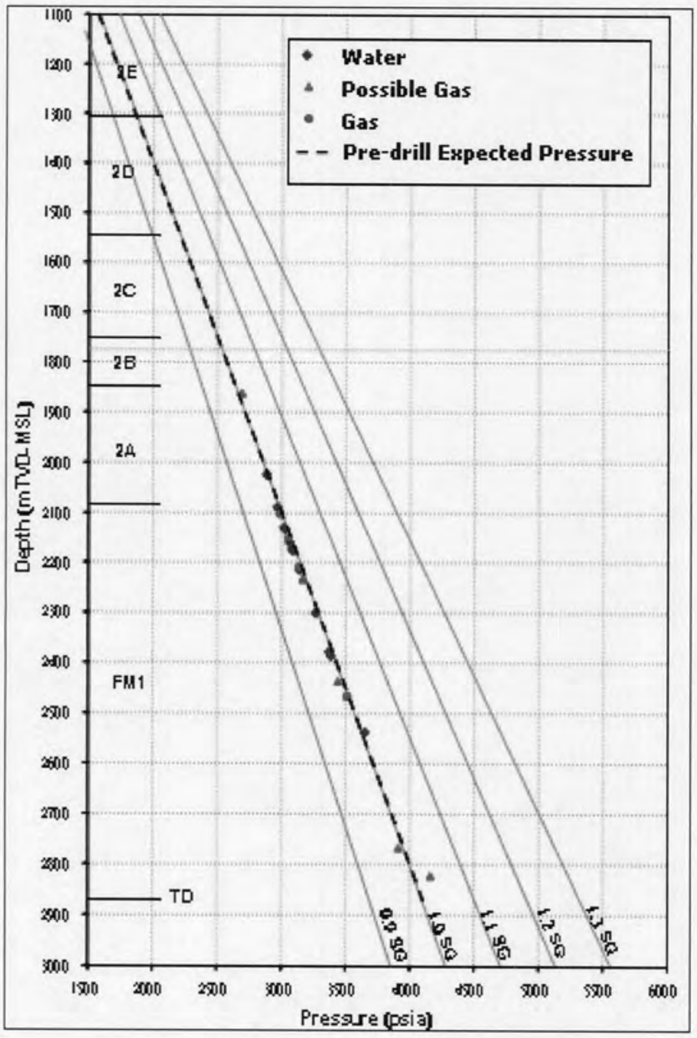

Figure 4.8: Pressure Gradient of MN-3.

- **Initial Reservoir Temperature**

The initial temperature measurements of the reservoir were taken by MWD for both the wells MN-1 and MN-2. As sample temperature gradients of well MN-1 is shown in the following Figure 4.9.

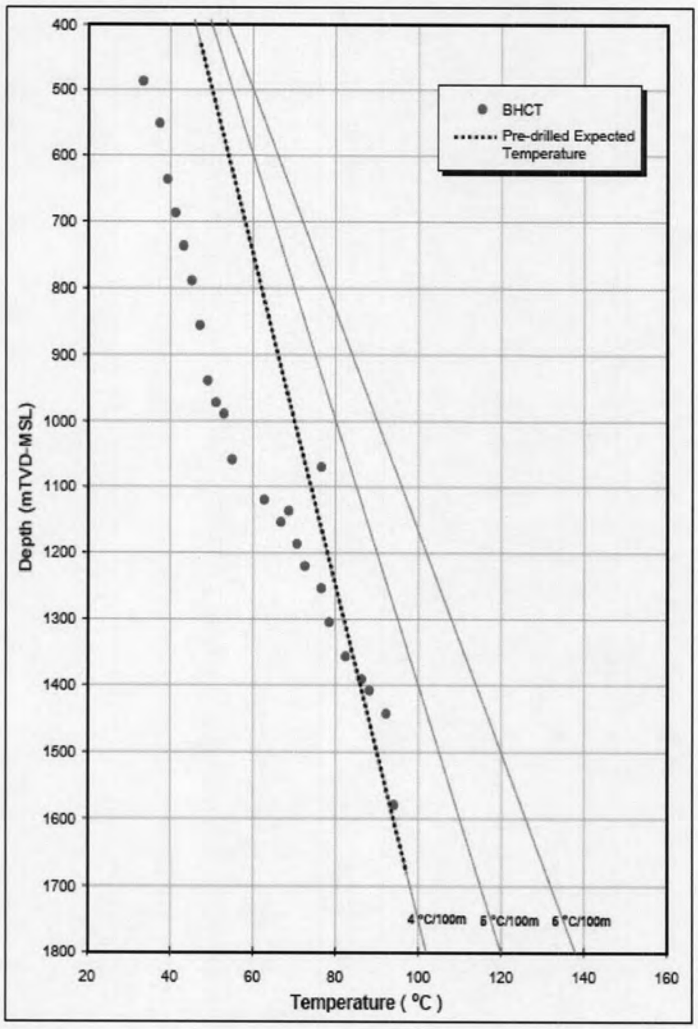

Figure 4.9: Temperature gradient of well MN-1

- **PVT Data**

The reservoir model consists of wet sands A and B. To complete the simulation model, the following PVT properties are needed to be entered into the simulation model:

- **Water Properties**

No PVT analysis was performed for this reservoir. Therefore, the following correlations and 30000 ppm water salinity data are used to determine the fluid properties:

Table 4.2: Correlations and data used for water properties determination.

Properties	**Correlations**
Water Compressibility	Meehan correlation
Water Formation Volume Factor	Meehan correlation
Water Viscosity	Meehan correlation
Data	
Water Salinity	30000 ppm

Water density at surface conditions (14.7 psia and 60 ^{0}F) is 62.33 lb/ft^3. The water properties at a reference pressure of 2400 psia and temperature 200 ^{0}F calculated from Meehan correlations are given as follows:

Table 4.3: Water properties determination at reference pressure and temperature.

Meehan Correlations	
Water Formation Volume Factor, rb/STB	1.0289811
Water Compressibility, psi^{-1}	3.135×10^{-6}
Water Viscosity, cp	0.3003537
Water Density, lb/ft^3	60.561

- **Gas Properties**

Gas density at surface conditions (14.7 psia and 60 ^{0}F) is 0.04852526 lb/ft^3. The gas properties are calculated from Katz, Lee et. al. correlations and are shown in the following Table 4.4 and Table 4.5 and Figure 4.10.

Table 4.4: Correlations and Data used for gas properties determination.

Properties	Correlations
Gas Formation Volume Factor	Katz correlation
Gas Viscosity	Lee, *et. al*
Data	
Gas specific gravity	0.70

Table 4.5: Gas properties at different pressures.

Pressure (psia)	FVF (rb /Mscf)	Visc (cp)
14.7	221.08079	0.012617471
224.45	14.092499	0.012783939
434.21	7.0919503	0.01304884
643.96	4.6579764	0.013391549
853.71	3.4258189	0.013810006
1063.46	2.6854563	0.014305765
1273.22	2.194832	0.014880817
1482.97	1.8488529	0.0155358
1692.72	1.5944577	0.016268641
2000	1.327994	0.017470039
2112.23	1.2529013	0.017941432
2321.98	1.1358039	0.018859435
2531.74	1.0424876	0.019813513
2775.87	0.95627738	0.020950676
2951.24	0.90575403	0.021774616
3160.99	0.85501346	0.022758306
3370.74	0.81263906	0.023732491
3580.50	0.77685875	0.024691419
3790.25	0.74632459	0.025631292
4000	0.72000467	0.026549833

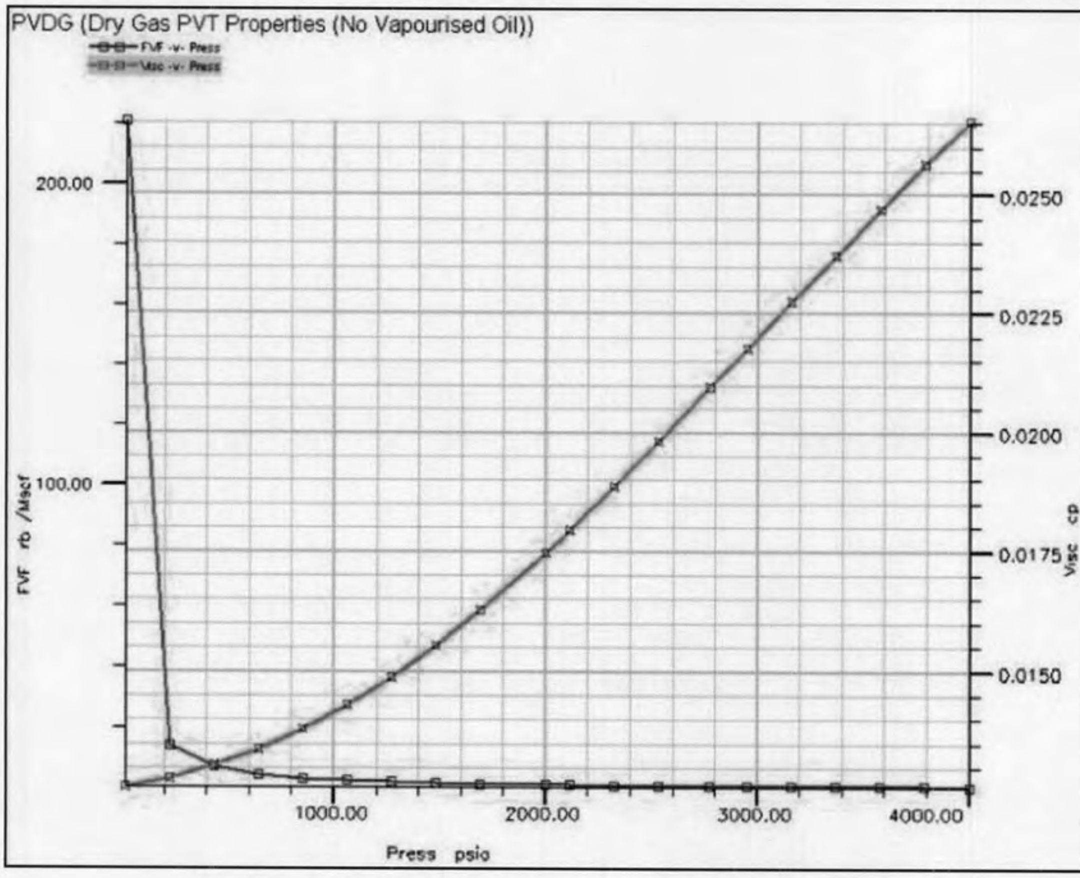

Figure 4.10: Gas properties at different pressure.

- **Rock Properties**

Rock compressibility was defined using Newman Correlation. In this study, the rock compressibility value $C_r = 1.66138 \times 10^{-5}$ psi^{-1} was used.

- **Well Completions**

The trajectories of wells MN-1 and MN-2 were created by importing wells deviation surveys with grid sizes and properties (.EGRID and .INIT files) in SCHEDULE program. Then those Selected SCHEDULE for both wells were exported to WELSPECS and COMPDAT in ECLIPSE to locate the well and block intersection. Figure 4.11 and Figure 4.12 show the well trajectories of both wells.

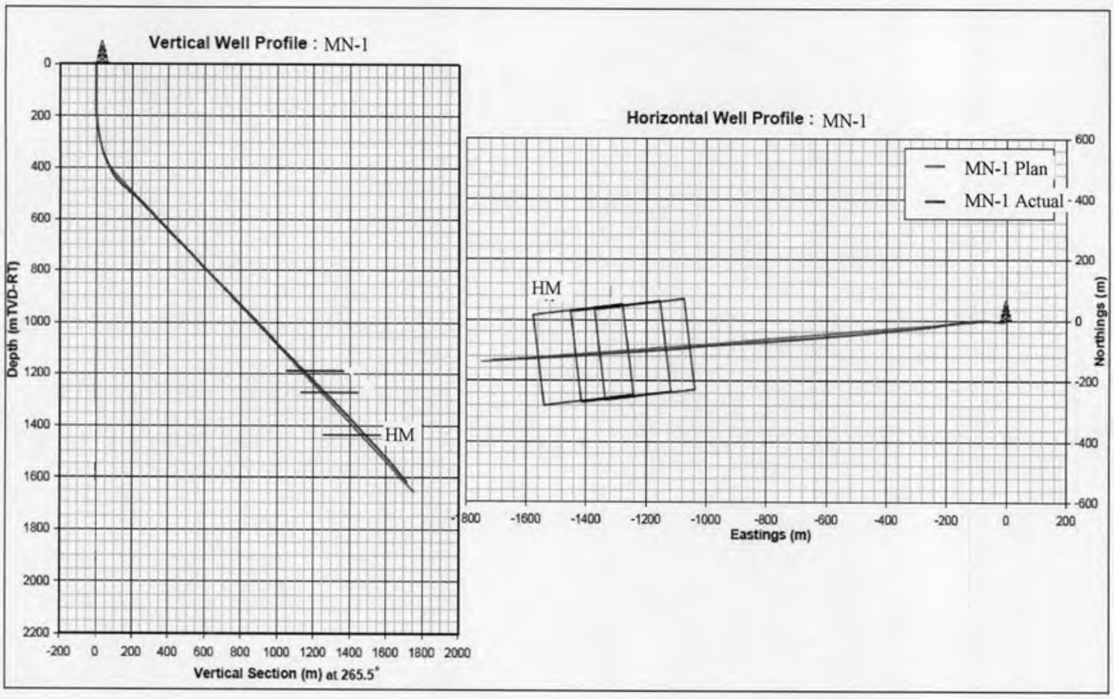

Figure 4.11: MN-1 well trajectory.

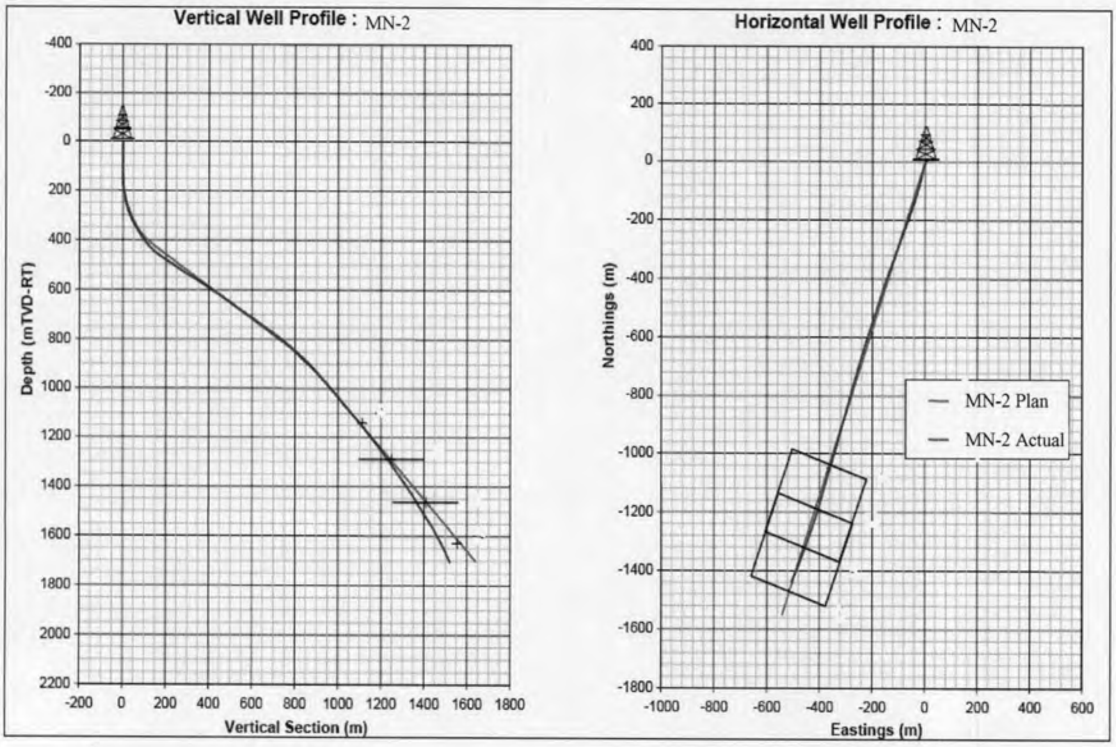

Figure 4.12: MN-2 well trajectory.

4.4 Base Case

Following tasks are performed for the base case model construction:

1. Define the area and coordinate from structural map.
2. Design the grids and pick up depth for each grid from the structural map. Pick up the coordinate from the depth map.
3. Define the sand thickness from log data.
4. Net to Gross (NTG) ratio from log data.
5. Define porosity from log data and permeability from porosity-permeability correlation.
6. PVT data from correlation.
7. SCAL data from core analysis.
8. Initialize the model.
9. MN-1 and MN-2 both wells are deviated, therefore the well paths are constructed by another program namely SCHEDULE and exported into Schedule Section in the model.
10. Vertical Flow Performance (VFP) Curves are also prepared by using PROSPER program and then exported into the Schedule Section in the model.
11. Testing the model.

The reservoir is a multi-layer reservoir with alternate sand and shale sequences. The reservoir geometry was set to be a Cartesian model consisting of 87 and 100 grid blocks in X and Y direction respectively, and 93 grid blocks in Z direction.

As mentioned in Gridding section under Reservoir Model Construction Workflow, the areal grid sizes around the wellbore is 41 ft, then the grid size is 82 ft and the rest are 328.1 ft. As the wells are deviated wells, therefore from top to bottom layer around the wellbore grid blocks are designed as 41 ft to honor the wellbore effect. In vertical direction, Z direction, maximum grid sizes upto 15.9 ft and the details of every grid sizes are shown in the following Table 4.6, Table4.7 and Table 4.8.

Table 4.6: Orientation of Grids in X-direction.

Grids in X-direction	**87**
Grid Nos.	Dimensions, ft
1-15	328.1
16-22	82
23-78	41
79-85	82
86-87	328.1

Table 4.7: Orientation of Grids in Y-direction.

Grids in Y-direction	**100**
Grid Nos.	Dimensions, ft
1-15	328.1
16-23	82
24-45	41
46-51	82
52-60	328.1
61-63	82
64-81	41
82-86	82
87-100	328.1

Table 4.8.: Grid sizes in the Z-direction.

Z-direction	
Grid	**Grid Size (ft)**
1	10.9
2	9.8
3	7.7
4	3.0
5	9.8
6	8.8
7	9.8
8	9.8
9	9.8
10	6.6
11	10.1
12	10
13	9.6
14	15.3
15	13
16	9.2
17	8.2
18	9.6
19	12.1
20	10.5
21	10.5
22	3.8
23	5.7
24	6.6
25	7.6
26	20.4
27	13
28	5.4
29	7.5
30	9.4
31	7.3

Z-direction	
Grid	**Grid Size (ft)**
32	48.5
33	11.6
34	10.8
35	10.5
36	9.8
37	11.8
38	13.1
39	51
40	11.3
41	13.6
42	15.9
43	14.4
44	9.2
45	13.3
46	11
47	9.8
48	7.2
49	13.7
50	14.3
51	2.1
52	43.2
53	3.3
54	12.4
55	6
56	29.5
57	7.6
58	21.3
59	11.3
60	31.6
61	5.1
62	61.5

Z-direction	
Grid	**Grid Size (ft)**
63	3.3
64	48.2
65	11.2
66	19.6
67	4.3
68	21.4
69	1.4
70	10.2
71	10.8
72	11.2
73	4.9
74	50.9
75	4.5
76	52.2
77	1.8
78	18.4
79	2
80	10.5
81	6.8
82	14.3
83	7.4
84	13.4
85	10
86	13.6
87	4.4
88	13.4
89	2.6
90	94.5
91	1.41
92	58.5
93	5.5

The wellbore radius of the reservoir model was set to be 0.256 ft. Figure 4.13 shows the 3-D perspective of the multilayer Cartesian model.

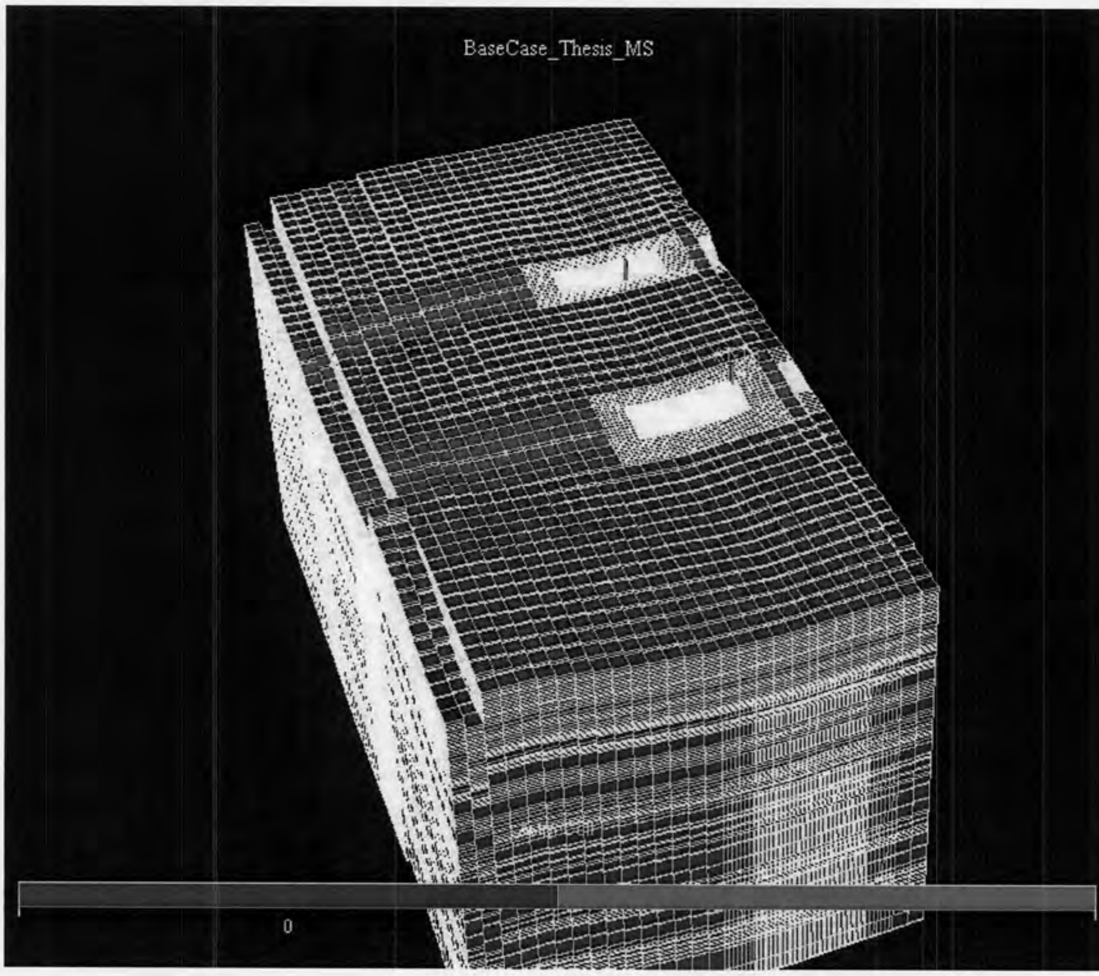

Figure 4.13: 3-D view of Base Case Model.

The top depth of the reservoir is 3782.6 ft TVD SS. The reservoir thickness of the reservoir model is 1372.5 ft. The wells are connected to the whole depth of the model. The thickness of sand unit A and B are 672.2 and 700.3 ft respectively. The cross section of sand unit A and B is shown in Figure 4.14. The well connection transmissibility was calculated by using SCHEDULE program and import in simulation.

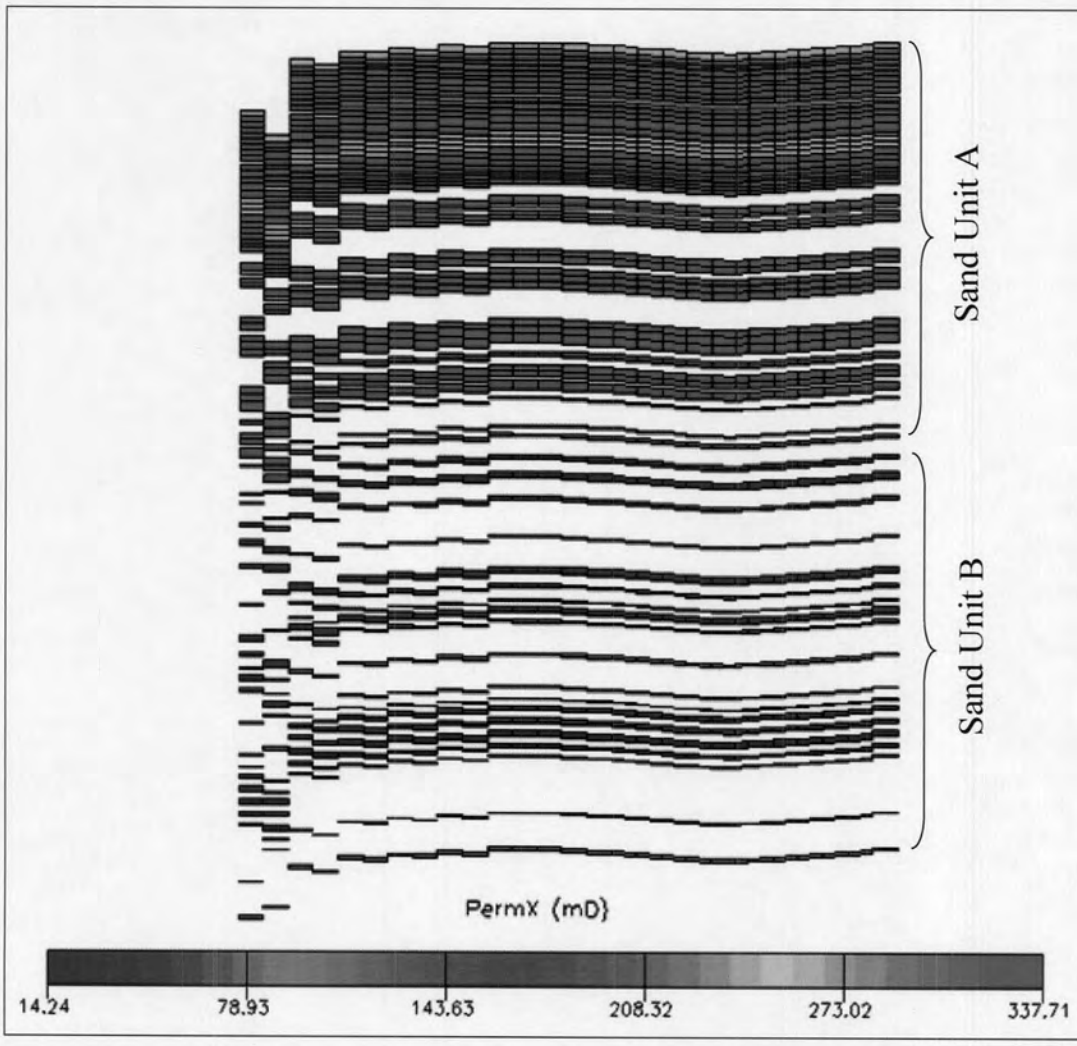

Figure 4.14: Cross section showing sand unit A and B permeability.

As from the Figure 4.14, the grids around the well are not clear enough, therefore, as a sample the grids around the wellbore of well MN-1 is shown in the following Figure 4.15 to show the grids clearly around well.

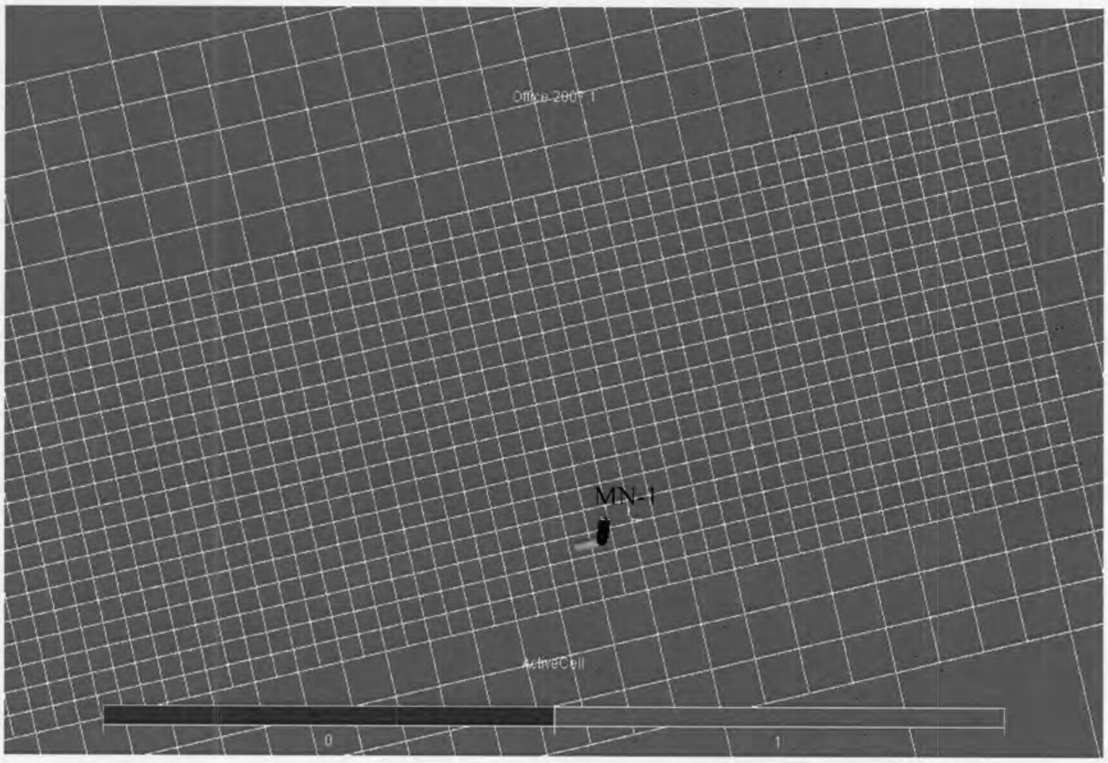

Figure 4.15: Showing grid sizes and orientation around well MN-1.

The reservoir model porosity ranges from 0.22 to 0.32 and 0.21 to 0.32 for A and B sands respectively. The reservoir is assumed to be homogeneous. For horizontal permeability estimation, the cut off porosity is 0.28 for both A and B sands. Thus, horizontal permeability ranges from 105.79 mD to 337.71 mD and 14.24 mD to 74.7 mD for A and B sands respectively. The vertical to horizontal permeability ratio (k_v/k_H) was set to 0.1. Water and gas are present in the reservoir. Initial water saturation ranges from 0.70 to 0.99.

Table 4.9 summarizes some other conditions that used in this simulation. The datum was set at 3782.6 ft, top of the reservoir. Used water and gas properties are in Table 4.3 and Table 4.5.

Table 4.9: Reservoir conditions in simulation model.

Parameter	Value
Top of Sand Unit A Depth, ft TVD SS	3782.6
Datum Depth, , ft TVD SS	3782.6
Pressure at Datum, psia	1658.7
Pressure at Standard Condition, psia	14.7
Temperature at Standard Condition, ^{0}F	60

In summary, to determine the injection capacity and performance, a reservoir simulation model for the M field was constructed. The workflow of reservoir model construction was gridding, surface and zone making, grid block layering, petrophysical modeling and finally, reservoir model initialization. The data required for model construction are structural map, well log data and special core analysis data. To complete the model for simulation run, initial reservoir pressure and temperature, reservoir rock and fluid properties, well trajectories are entered into the reservoir simulation model. Reservoir model initialization is then preformed to determine the initial pressure and saturation for each grid block.