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Producing Gas-Oil Ratio Performance of Conventional and Unconventional Reservoirs

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Abstract

This study presents a detailed analysis of producing gas-oil ratio performance characteristics from conventional reservoir to unconventional reservoir. Numerical simulations of various reservoir fluid systems are included for comparison.

In a wide sense of the word, the term of unconventional reservoir is including tight gas sand, coal bed methane, gas hydrate deposits, heavy oil gas shale and etc. In this study we specify the unconventional reservoir to only mean the low and ultra low permeability reservoir, which is including tight or shale reservoir. As an emerging research topic in the E&P industry, shale reservoir's long-term well performance characteristics are generally not well understood (Anderson et al. 2010). Research methods and techniques for conventional reservoir are usually directly used in this unconventional reservoir analysis. These methods, however, have proven to be too pessimistic (Anderson et al., 2010). Fit-for-purpose approaches or solutions should be introduced in this new topic. Recently, hydraulic fracturing treatment is commonly used in the low matrix permeability reservoir to attain an economic production rate. The difference of well production performance between conventional reservoir and unconventional reservoir is not well known. In this study, we are trying to give a quantitative analysis in order to answer this question.

In this study, a "generic" reservoir from field data with constant reserves and size were assumed. This reservoir model is homogeneous and of constant porosity, permeability and initial water saturation. In order to compare the production performance, fluid systems are varied from volatile oil to near critical oil, to gas condensate and to wet gas. The permeability of the reservoir model is also designed from high (conventional reservoir) to ultra low (unconventional), which ranges from 10^{1} to 10^{-5} mD. Influence from fracture is especially considered because fractures in the low permeability reservoir provide a high conductivity that connects the reservoir matrix to the horizontal well. Fractures in the model are designed with identical

geometrical characteristics (length, thickness) and of inner homogeneous properties (porosity, permeability).

A black-oil model is used for each reservoir, and its PVT properties are generated with a 31 components EOS model using Whitson-Torp procedure (Whitson et al., 1983). Reservoir fluid systems equilibrium calculation in the black-oil model is done using the initial gas-oil ratio. We have compared the well's production performance for each fluid system.

Based on the industry experience, two standards are used in reservoir simulation control: gas production rate and cumulative revenue. The gas production rate with 10 $\times 10^6$ ft^3/day in the first 10 days or the cumulative revenue equal to 5 $\times 10^5$ USD from the first 10 days is set as the standard for the commercial well rate. All of these simulations are run under the control of these two types which have just been mentioned.

A case of liquid rich gas reservoir is analyzed systematically, to compare its production performance when reservoir permeability is changed from high to low. We are interested in how much oil or gas condensate can be extracted from the "reservoir" if same initial fluids in the reservoir but of a different permeability. This study is useful and practical, particularly for the industry in the era of "high" oil price and "low" gas price in North America.

The simulation results show that we can extract more liquid from the reservoir if the matrix permeability is higher, particularly for the reservoir with initially large oil contents (volatile oil reservoir, near critical reservoir and gas condensate reservoir). Fracturing treatment in unconventional reservoir is required to attain an economic production rate. We also realize that for the required number of fractures and reservoir's matrix permeability, there exists linear correlation in log-log plot in the low-permeability reservoir.

In this study, the unique optimization software *Pipe-It* and reservoir simulator *SENSOR* are used. Optimal simulation results of permeability combination are obtained by the module *Optimizer* in *Pipe-It*.

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Δx_i	=	Grid size of i grid in x direction, Cartesian grid system
Δy_i	=	Grid size of i grid in y direction, Cartesian grid system
Δz_i	=	Grid size of i grid in z direction, Cartesian grid system
x_e	=	Model size in x direction, Cartesian grid system
y_e	=	Model size in y direction, Cartesian grid system
y_f	=	Half length or wing of hydraulic fracture, ft
ε_x	=	logarithmic spacing grids ratio in x direction
ε_{yf}	=	logarithmic spacing grids ratio in fracture perpendicular area, y direction
ε_{yb}	=	logarithmic spacing grids ratio in background area, y direction
N_x	=	Grids number in model's x direction, Cartesian grid system
N_{yf}	=	Grids number in model's y direction of fracture perpendicular part
N_{yb}	=	Grids number in model's y direction of background area
N_f	=	Fractures number along horizontal well
h	=	Thickness of simulation model, ft
w_f	=	Width of fracture, ft
k_m	=	Reservoir matrix permeability, mD
k_f	=	Fracture permeability, mD
GOR	=	Gas-oil-ratio, scf/STB
GOR_i	=	Initial gas-oil-ratio, scf/STB
q_o	=	Well oil production, STB
q_g	=	Well gas production, Mscf
P_o	=	Price of oil product, USD/STB
P_g	=	Price of gas product, USD/Mscf
G	=	Fracture geometry factor
Con	=	Simulation constraint, either gas rate or total revenue
R_p	=	Producing gas-oil ratio, scf/STB
r_p	=	Producing oil-gas ratio, STB/MMcf
r_s	=	Initial oil-gas ratio in reservoir, STB/MMcf
PVT	=	Pressure/Volume/Temperature
BHP	=	Bottom-hole flowing pressure
USD	=	United states dollar

Chapter 1
Introduction

Shale-gas reservoir has become an important part in North American gas supply and its development has opened a new era of oil and gas production worldwide (Fazlipour, 2010; Cipolla et al, 2009). The technology of hydraulic fracturing treatment is wildly used in the development of unconventional reservoir (extremely low permeability reservoir), particularly for tight gas and shale gas reservoir (Ghassemi et al, 2011). Hydraulic fracturing treatment stimulates the extremely low-permeability reservoir and connects the matrix to the wellbore, helping the well to attain a commercial production rate (Cipolla et al, 2009). As a new emerging type of reservoir, we still do not fully understand its performance characteristics compared to the performance characteristics of a conventional reservoir. This study is interested in the comparison of the production performance between these two, or the gradually variation trends from high-permeability reservoirs to ultra low-permeability reservoirs.

Numerical simulation is a versatile tool for this study, and all conclusions are based on the simulation results. A "Generic" reservoir of homogenous properties was designed, and an identical number of cells are applied in all simulation segments. In order to meet the constraint in the simulator, the fracture with high conductivity is designed in the low permeability reservoir as a positive factor. The fracture is also used in the high-permeability reservoir to limit well's production. The geometry of fracture is the same and with inner identical properties. Based on a uniform production rate or revenue of the first 10 days, production performance is compared among reservoirs with different permeability.

This study also shows that more fractures are required to obtain a commercial production rate if reservoir permeability is reduced. There is a linear correlation between the number of fractures and matrix permeability in the log-log plot. The equation can be generated for different reservoir fluid systems if the fracture geometry, fracture's conductivity and simulation controls have been specified before.

Section 1 outlines the description of the reservoir simulation model, including all parts of simulation input: grid system, rock and fluid properties, equilibrium initialization and simulation constraints. Only half of the entire fracture drainage space is used as simulation model in order to reduce the simulation CPU-time of computer. It also describes the various reservoir fluid systems which are used in this study.

Section 2 presents the simulation results under gas production control. The daily gas production: 10×10^6 ft^3 in the first 10 days is used to control the well production in all simulation cases. The comparison is based on each reservoir fluid system. Production performances of daily gas rate, ratio of gas-oil and oil-gas are compared for the reservoir with different permeability.

Section 3 shows the simulation results under revenue control. The revenue from the production of gas and oil is added to meet the limitation of 5×10^5 USD of the first 10 days. The comparison is based on different reservoir fluid system: from volatile oil to critical fluid, to gas condensate and to wet gas. Production performances of daily gas and oil rate are compared for the reservoir with different permeability. And the comparison of producing ratios of gas-oil and oil-gas is also addressed in this section.

Section 4 mainly introduces the relation between the number of fractures and the reservoir matrix permeability, which is under gas rate control or revenue control. A general equation was obtained, and can be used in the calculation of the number of fractures. But this equation is imperfect and relies on the simulation results. Furthermore, the required number of fractures in shale reservoir is calculated by using the generated equation. The calculated value depends on the standard of commercial well.

Section 5 presents the variation trends of producing oil-gas ratio for a liquid rich reservoir (GOR_i=4,587 scf/STB). Based on the assumption that the reservoir has the same initial fluids underground and geometry size, the reservoir is developed by pressure depletion. Cumulative revenue in the first 10 days equal to 5×10^5 USD is used to control the reservoir simulation. The producing oil-gas ratio is compared from conventional reservoir to unconventional reservoir. Simulation results indicate that production from the same ‘reservoir’ will vary with reservoir matrix permeability. High permeability reservoir will produce more liquid products (oil, condensate), while

low permeability reservoir will produce less. This is important when oil is more profitable compared to gas.

Chapter 2
Simulation Model Description

In this part, the simulation model is described and all simulation input sections are included: simulation area, grid system/structure, PVT model/Fluid model, rock properties and well constraint.

2.1 Simulation Area

First, the area of interest in the simulation or the definition of a proper reservoir model is described. A planar model, the simplest reservoir model for a horizontal well with fractures, is used in this study. The fracture system is assumed to be created solely by hydraulic fracturing, giving pure planar fractures (Knudsen, 2011). We also suppose that the reservoir is homogeneous and of constant matrix permeability, porosity and initial water saturation. The model is fixed to 1 mile × 1 mile (640 acres) in planar spacing area and 200 ft in thickness. One horizontal well with one or more than one fracture is designed as producer in the fixed area, and hydraulic fracturing treatment will be used if the reservoir permeability is low. Required numbers of fracture in the reservoir will vary if the reservoir's matrix permeability is changed. In geometry, the fracture is perpendicular to the horizontal wellbore and penetrates 200 ft to each side from the wellbore.

The simulation model is homogeneous and symmetrical, indicating that it is possible to simulate half of the indicated grid. In this study, simulation segment is half of the entire fracture's drainage area. The area of simulation segment is designed to decrease if more fractures go perpendicular on the horizontal well. For example, in single fracture model, only half of the spacing area is used in the simulation model, which is 320 acres. If fractures number increased to 2, the area of simulation segment reduces

to one quarter of the entire spacing area, which is 160 acres. The simulate segment and its relation with the number of fractures is shown in **Fig. 2.1**.

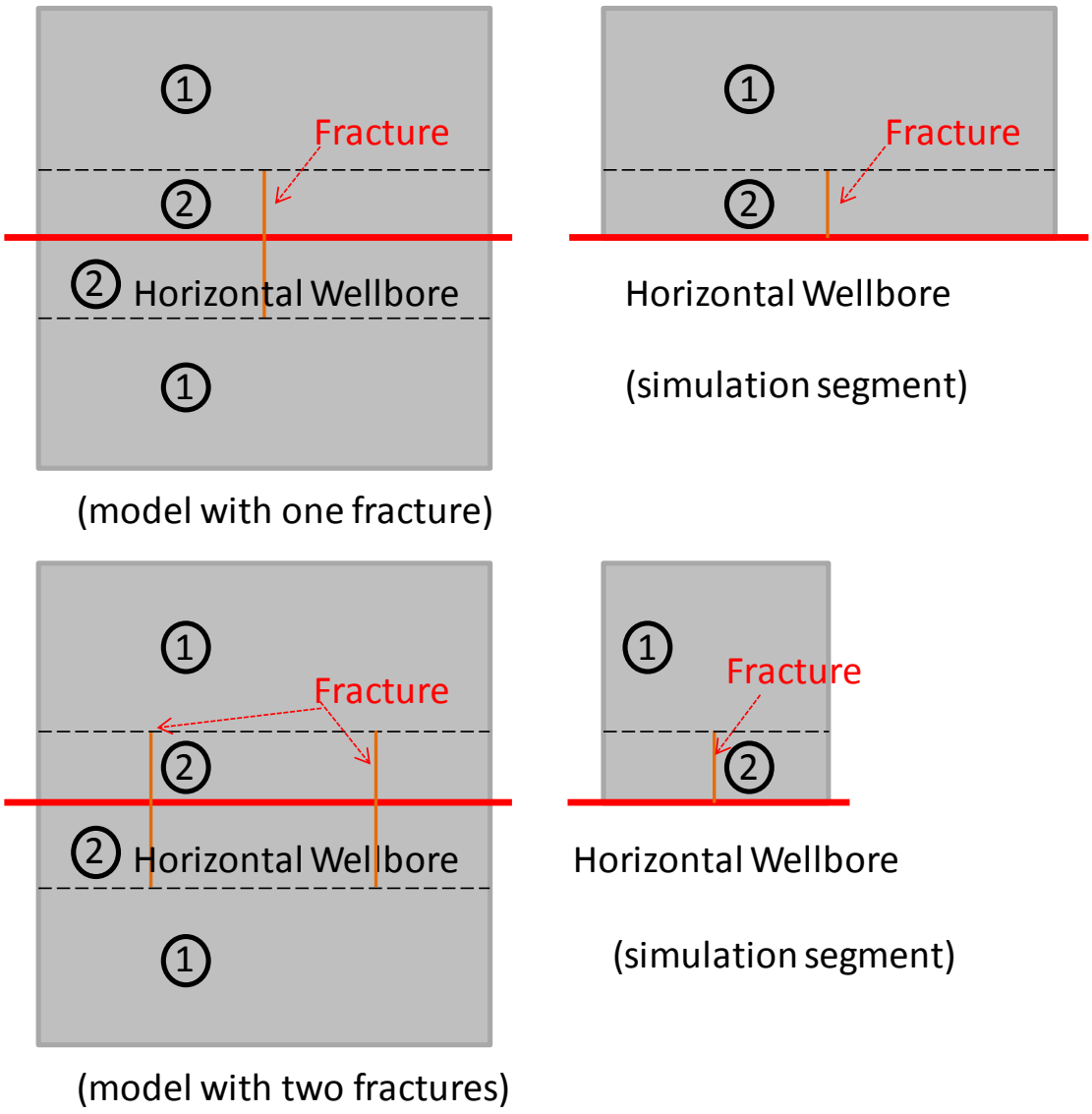


Fig. 2.1—Illustration of the planar model simulation segment and its relation to the number of fractures, 1: Background area; 2: Fracture perpendicular area

2.2 Simulation Gridding System

Cartesian grid geometry is used in this study. Multistage hydraulic-fracturing treatment creates a complex fracture grid structure. Unlike a common conventional gridding system of the same grid size in the whole simulation model, a fit-for-purpose grids geometry is introduced in this study. The new gridding structure is developed to reflect the shale gas reservoir production mechanism. Its typical feature is that the

sizes of the grids gradually grow as well as the model's length in x direction is increased at the same time.

The simulation grid system of one fracture reservoir model is shown in **Fig. 2.2**. In x direction, the smallest cell is close to the fracture and the sizes of grids increase as their distance from the fracture increases, too. In y direction, the smallest grids are the grids nearby fracture tip[1] and the sizes of grids increasing either toward or away from the well bore in y direction. The grids number is constant of 81×74×1 with one layer in vertical direction. The grids in y direction are fixed to 20 (N_{yf}) in the fracture perpendicular area and 54 (N_{yb}) in the background area. The number of grids in x direction is 81, including 1 grid representing the fracture. The total number of the grids in the simulation model is 5,994. The block size of both grids in x direction and in y direction follows the logarithm scale spacing rule (Eq. 2.1—2 .3):

$$\varepsilon_x = \frac{\Delta x_{i+1}}{\Delta x_i} = \left(\frac{x_e/2}{\Delta x_1}\right)^{\left(2/N_x\right)} \tag{2.1}$$

$$\varepsilon_{yf} = \frac{\Delta y_{f_{i+1}}}{\Delta y_{f_i}} = \left(\frac{y_f}{\Delta y_{f1}}\right)^{\left(1/Ny_f\right)} \tag{2.2}$$

$$\varepsilon_{yb} = \frac{\Delta y_{b_{i+1}}}{\Delta y_{b_i}} = \left(\frac{y_e - y_f}{\Delta y_{b1}}\right)^{\left(1/Ny_b\right)} \tag{2.3}$$

Where Δx_1, Δy_{fl} and Δy_{bl} represent the smallest grid and are close to the fracture in x direction, fracture perpendicular part and background area, respectively. x_e is the model length in x direction and will be changed if more fractures goes perpendicular to the horizontal well, y_f and y_e is the fracture's half length and total length in y direction respectively. Note that the block size of grids in x direction will change if different number of fractures exists in the horizontal well, however the grids block size in y direction remains unchanged in all cases.

[1] Fracture tip is the end/tail of fracture, the place of fracture end, 200 ft from the horizontal well bore

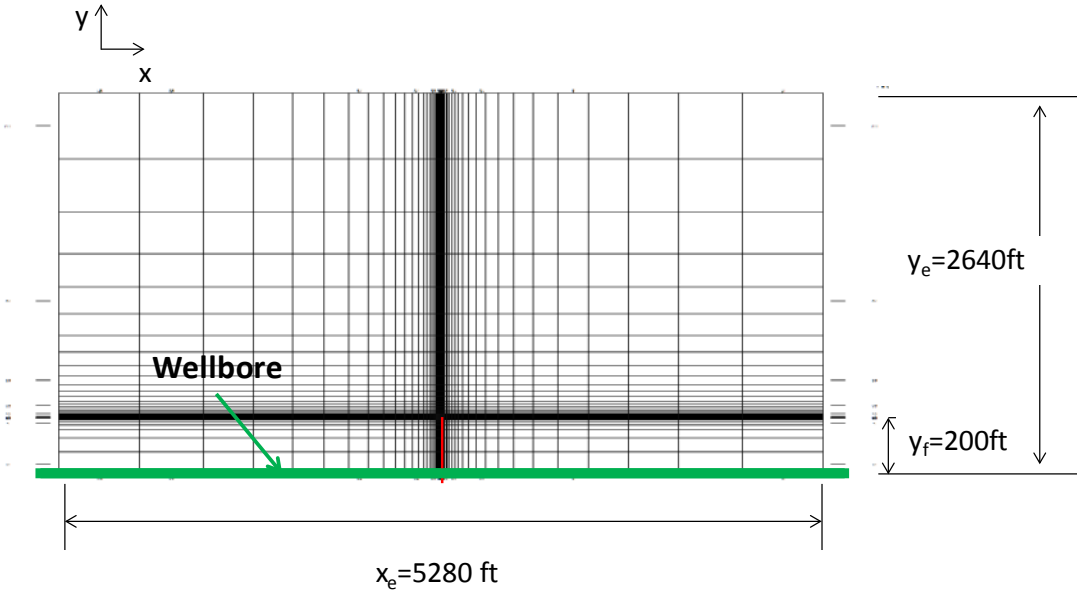


Fig. 2.2—Reservoir model grid system of one fracture shale reservoir, the area of simulation segment in model is 320 acres, 5,280 ft×2,640 ft, and half length of hydraulic fracture is 200 ft.

The grid geometry setting represents a reasonable grid for fluid flow character in the low permeability reservoir: refined grids nearby fracture capture the high pressure gradient. In low permeability reservoir and shale layer, rocks are impermeable without fracture. With the stimulate fracture, fluids which nearby fracture is able to flow from the matrix to the horizontal well. **Fig. 2.3** shows the pressure depletion in one fracture reservoir model after 10 days' production. The pressure depletion area is confined in a small space of the whole model.

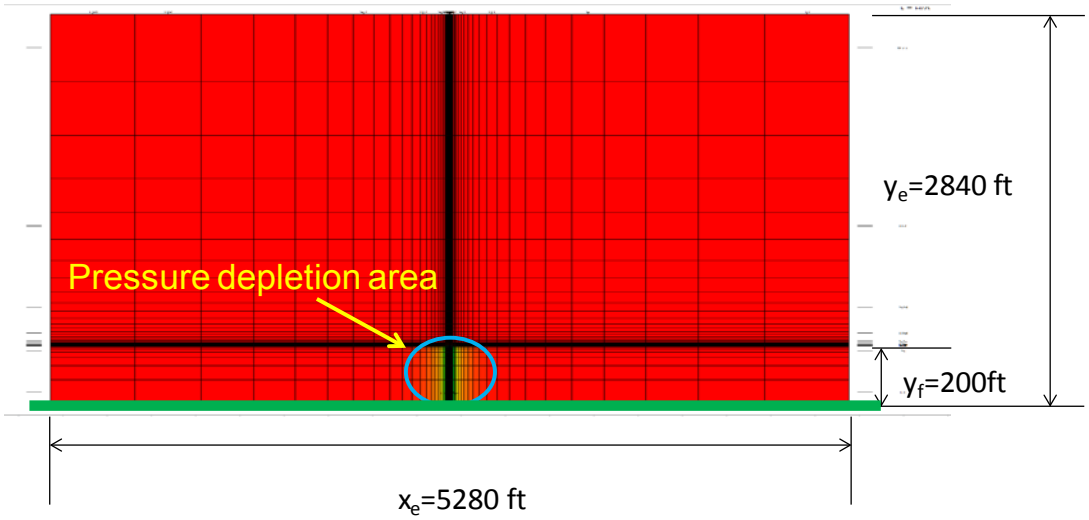


Fig. 2.3—The area of pressure depletion in one fracture reservoir model after 10 days of production, the red colour indicates the initial reservoir pressure: 4,800 psia.

2.3 Reservoir Properties

Reservoir properties such as reservoir porosity, thickness, well data etc, are from real field data of shale gas fields in North America. A 'generic' reservoir was assumed based on the real field data. The reservoir's parameter values which have been used in the simulation model are given in **Table 2.1**. The method of hydraulic-fracturing treatment creates fractures with high conductivity. A good fracture conductivity ($k_f.w_f$=100 mD-ft) and a constant fracture width of 0.01 ft are assumed in this study (Golan and Whitson, 1985). Fracture permeability is calculated to 100,000 mD and used as a regular value in low permeability reservoir. Because of the hydraulic fracturing treatment, the porosity in fracture increased from 5.9% to 30% as well.

Table 2.1—RESERVOIR PROPERTIES

Depth (ft):	10,000
Horizontal length (ft):	5,280
Spacing area, arce	640
Initial reservoir pressure (psia):	4,800
Reservoir temperature (°F):	250
Casing diameter OD (in):	4.5
Open hole (in):	5
h net (ft):	200
Reservoir porosity:	0.059
y_f,half length of fracture (ft):	200
k_f* (mD)	100,000
w_f,Fracture width (ft)	0.01
Fracture porosity:	0.30
Fracture conductivity (mD.ft)	1,000

2.4 Fluid Properties

The black-oil model is used in this study. Black-oil PVT properties have been generated by a 31-component SRK equation of state model (EOS) using the Whitson-Torp procedure (Whitson et al, 1983). The mole-fraction of each component is shown

in **Table 2.2**. **Table 2.3** provides the fluid characterization of the 31-component EOS. In order to compare production performances, different fluid systems are used for the given "reservoir". The type of reservoir fluids is varied if different initial gas oil ratio (GOR_i) is entered in the simulator. The fluid systems include:

- Volatile oil fluid system A, GOR_i= 1,000 scf/STB.
- Volatile oil fluid system B, GOR_i= 3,000 scf/STB.
- Near critical oil fluid system, GOR_i= 4,587 scf/STB.
- Gas condensate fluid system, GOR_i= 10,000 scf/STB
- Wet gas fluid system, GOR_i= 100,000 scf/STB

The relation between r_s, $1/R_s$ and saturation pressures is shown in **Fig. 2.4**. Reservoir fluid parameters were calculated with the help of the PVT analysis software *PhazeComp*. In simulation, the specified initial gas oil ratio (GOR_i) at depth 10,000 ft is used to define the type of the reservoir fluids. In this way, 5 different reservoir fluid systems were used out of the single compositional calculation.

Table 2.2—REFERENCE FLUID SAMPLE CONTAINS

Nc	Composition mole-fraction
H2S	0.00000000
N2	0.00009032
CO2	0.00028785
C1	0.72443534
C2	0.09995367
C3	0.04329560
I-C4	0.01200208
N-C4	0.01612318
I-C5	0.00799159
N-C5	0.00604448
C6	0.01486822
C7	0.01338211
C8	0.01085318
C9	0.00878513
C10	0.00723370
C11	0.00595599
C12	0.00490595
C13	0.00404363
C14	0.00333555
C15	0.00275400
C16	0.00227619
C17	0.00188340
C18	0.00156027
C19	0.00129424
C20	0.00107500
C21	0.00089414
C22	0.00074477
C23	0.00062126
C24	0.00051899
C25	0.00043420
C26+	0.00235598
Depth,TVD,ft	10,000
Pressure,psia	4,800
Saturation pressure, psia	4,800
Temperature,°F	250

Table 2.3—PARAMETERS OF THE 31-COMPONENT SRK EOS MODEL

PSAT psia	BO rb/STB	RS scf/STB	VISO cp	rs STB/MMcf	BG rb/scf	VISG cp	IFT dyne/cm
100	1.0976	11.4	0.347	57.8224	0.037307	0.0127	12.7740
500	1.1867	125.0	0.223	27.2592	0.007022	0.0134	8.8271
1000	1.3063	305.7	0.172	21.2774	0.003383	0.0142	5.8335
1200	1.3557	384.2	0.158	21.1350	0.002790	0.0146	4.9039
1400	1.4070	467.3	0.146	21.6758	0.002372	0.0150	4.0930
1600	1.4604	555.2	0.136	22.7574	0.002062	0.0156	3.3877
1800	1.5164	648.3	0.127	24.3051	0.001824	0.0162	2.7776
2000	1.5752	747.2	0.119	26.2822	0.001637	0.0168	2.2532
2200	1.6374	852.6	0.112	28.6755	0.001487	0.0176	1.8059
2400	1.7035	965.4	0.105	31.4883	0.001364	0.0184	1.4280
2600	1.7743	1086.6	0.099	34.7371	0.001262	0.0193	1.1118
2800	1.8506	1217.8	0.094	38.4510	0.001177	0.0204	0.8501
2900	1.8912	1287.6	0.091	40.4952	0.001140	0.0209	0.7377
3000	1.9336	1360.5	0.089	42.6730	0.001106	0.0214	0.6364
3100	1.9780	1436.9	0.087	44.9926	0.001074	0.0220	0.5456
3200	2.0246	1517.1	0.084	47.4634	0.001045	0.0226	0.4644
3300	2.0737	1601.5	0.082	50.0967	0.001018	0.0233	0.3923
3400	2.1256	1690.6	0.080	52.9060	0.000993	0.0239	0.3284
3600	2.2392	1884.9	0.076	59.1189	0.000949	0.0253	0.2231
3800	2.3690	2105.9	0.072	66.2752	0.000911	0.0269	0.1436
4000	2.5210	2362.4	0.068	74.6424	0.000880	0.0286	0.0858
4200	2.7049	2669.4	0.064	84.6738	0.000853	0.0305	0.0457
4400	2.9399	3055.3	0.060	97.2489	0.000832	0.0327	0.0200
4600	3.2733	3589.2	0.055	114.5335	0.000817	0.0356	0.0056
4800	3.9266	4587.7	0.049	146.5819	0.000814	0.0402	0.0002
4821	4.0742	4804.7	0.048	153.5214	0.000816	0.0412	0.0001

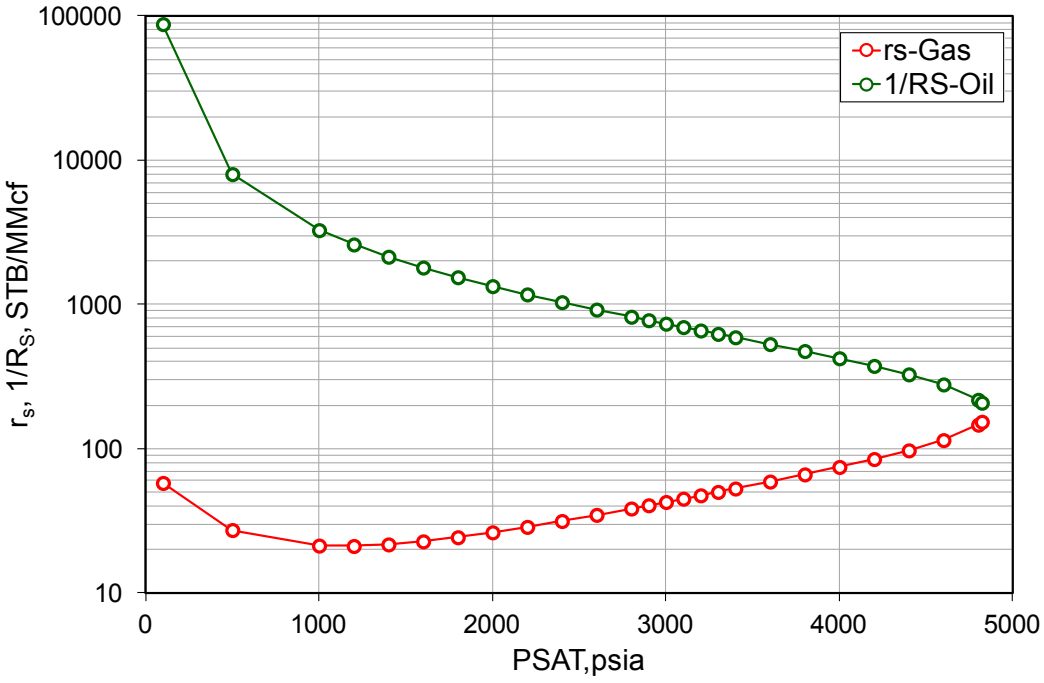


Fig. 2.4—Solution oil/gas ratios for reservoir oils, $1/R_S$ and inverse solution gas/oil ratio for reservoir gases, r_s as a function of pressure.

2.5 Relative Permeability Model

The relative permeability curve used in this simulation study is shown in **Fig. 2.5**. The initial water saturation (S_{wc}) is setting to 0.2, the residual oil saturation to water (S_{orw}) is 0.2, residual oil saturation to gas (S_{org}) is 0.2, and the critical gas saturation is setting to 0.1.

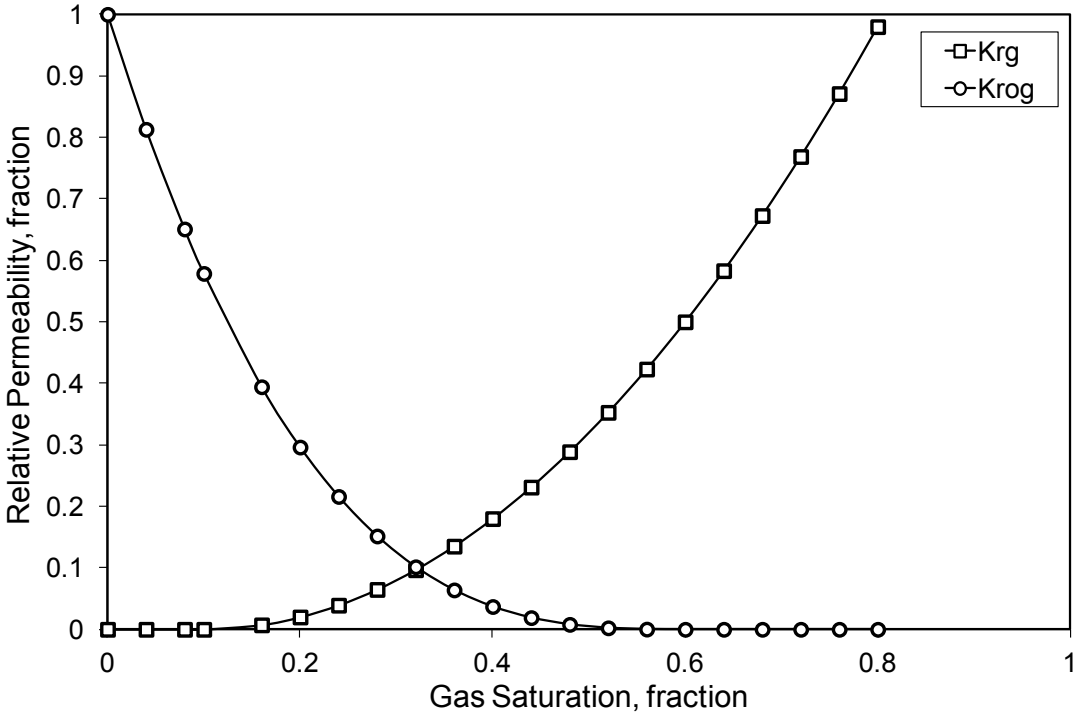


Fig. 2.5—Gas-Oil relative permeability curves used in simulations.

2.6 Simulation Constraints

A horizontal well is placed in the centre of the reservoir model as a producer, and the grid at the joint of horizontal wellbore and fracture (X=41, Y=1, Z=1) is perforated. The well is always run to 500 psia bottom-hole flowing pressure (BHP) or a specified model rate, which ever occurred first. The two types of production constraint used in this study is the daily gas rate or total revenue of the first 10 days.

Concerning gas rate control, daily well production of 10×10^6 ft^3/day is assigned as the simulation constraint of the first 10 days. Note that the gas rate constraint in the simulation model will change if more fractures were designed in the reservoir. For

example, if the number of fractures (N_f) is 10, the gas constraint in the simulator is reduce to 500 Mscf/day because only 1/20 of the entire reservoir is simulated in the model.

Concerning the revenue control, total revenues of 50,000 USD from the first 10 days production is used in the simulation control. The revenues of simulation segment will also change if different amounts of fractures are set in the reservoir.

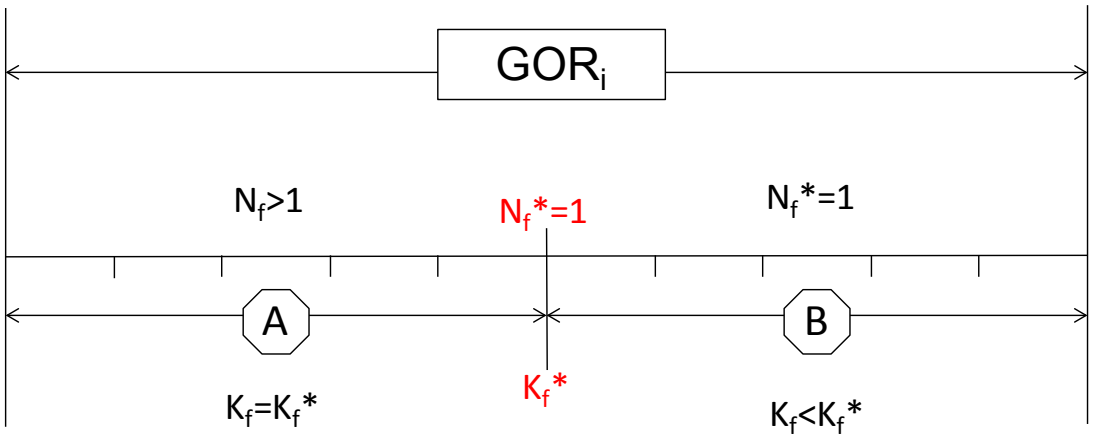
2.7 Simulation Cases Definition

This section presents the definition of simulation cases in this study. The simulation cases were designed with different reservoir fluid systems, which range from volatile oil, near critical oil, gas condensate to wet gas. The reservoir fluid systems are specified by setting the initial gas oil ratio (GOR_i) in simulator.

With the purpose of studying the performance trends of well production from conventional reservoir (high permeability) to unconventional reservoir (low permeability), reservoir permeability is designed in the range from 10^1 mD to 10^{-5} mD. In order to obtain the objective production rate/revenue in the early stage, the number of fractures in the horizontal well will increase if the reservoirs vary from conventional reservoir to unconventional reservoir. Since it is based on an identical fracture geometry and conductivity, production from single fracture segment will decrease in the low permeability reservoir. Finally, the optimal results of the combination of reservoir permeability and fracture numbers are given and their comparisons of well performance among different cases are shown. The relation between the number of fractures and reservoir permeability are established based on the numerical simulation results. Generated equations are used in the fracture design.

Fig. 2.6 shows the running simulation cases definition. Reservoirs with different fluid systems (GOR_i) and permeability were designed to run reservoir simulation. In low permeability case, more fractures (N_f>1) are designed to meet the target of gas rate or cumulative revenue of the first 10 days. The fracture permeability is fixed to 100,000 mD when fracture play as a positive factor to stimulate fluids flow from reservoir to well. On the condition of fracture permeability (k_f) equal to reservoir matrix

permeability (k_m), no fracture will be required for stimulation or restriction. The case with identical reservoir permeability ($k_m=k_f$) is named as 'critical case' in this study. On the condition where matrix permeability is higher than the permeability in 'critical case', the permeability of fracture is limited ($k_f < k_m$) to reach either the objective production rate or total revenue. All simulation cases are list in **Table. 2.4**.



K_f*: 100,000 mD
N^f*: 1

Fig. 2.6—Simulation cases definition with different reservoir permeability combinations in specified initial gas-oil ratio (GOR_i) in simulator.

Table 2.4—SIMULATION CASES LIST

Simulation Constraint	GOR_i		Fluid System
Well daliy gas rate of : 10×10^6 ft^3/day	1,000	scf/STB	Volatile Oil
	3,000	scf/STB	Volatile Oil
	4,587	scf/STB	Near Critical Oil
	10,000	scf/STB	Gas Condensate
Cumulative revenue of: 50,000 USD/first10 days	1,000	scf/STB	Volatile Oil
	3,000	scf/STB	Volatile Oil
	4,587	scf/STB	Near Critical Oil
	10,000	scf/STB	Gas Condensate
	100,000	scf/STB	Wet Gas

In all cases, reservoir is developed by pressure depletion, which means there is no gas injection or alternative treatment to modify the production schedule. The production from reservoir is driven by its natural energy.

Chapter 3
Gas Production Control

This section presents the simulation results under the gas production control. Simulation is controlled by the specified well gas production. The gas production rate, 10×10^6 ft^3/day, is assumed to be the objective gas rate in simulation of the first 10 days. In other word, gas production of well is in plateau of 10×10^6 ft^3/day in the first 10 days. From the industry experience, one well with this amount of gas production is considered to be a commercial production rate which can create profit.

As introduced in the simulation area part, simulation segment is only half of the entire fracture drainage area. The cut of simulation area can save the CPU-time, and lead to faster simulator running. The constraint gas rate in simulation will change if different amount of fractures was designed in the entire reservoir area (1 mile × 1 mile). **Table 3.1** shows the size of the simulation model with different number of fractures when the fracture play as a positive factor. The size includes the value in x, y, z direction and its spacing area. The model's length in x direction, along the horizontal wellbore, will decrease if more fractures were designed in the well. The model's length in y direction, along the fracture penetration direction, was however fixed to 2,640 ft. The thickness of the model is fixed to 200 ft as well.

Table 3.1—SIMULATION MODEL SIZE OF DIFFERENT FRACTURE'S NUMBER

Fracture-Number	xe-model ft	ye-model ft	ze-model ft	Spacing-model acre
1	5280	2640	200	320
2	2640	2640	200	160
10	528	2640	200	32
20	264	2640	200	16

* xe-model: length perpendicular fracture of simulation model
ye-model: length along fracture direction of simulation model
ze-model: thickness of model in vertical direction

In addition to these four cases, two cases with high reservoir matrix permeability (5 mD and 10 mD) were designed, and their corresponding fracture permeability was optimized to match the gas rate constraint in simulation. Fracture in these cases, with low conductivity, is implemented as a damage factor in well production.

In addition, 'critical case' with identical reservoir permeability is designed. The fracture is not required to stimulate or restrict the production on this condition. However, maintaining the fracture in the model is for the purpose of having same gridding structure as other cases and to make it easy to compare. The fracture in this model plays as neither positive nor negative factor for well's production.

The simulated production performance is systematic analyzed for a variety of reservoir fluid systems which range from volatile oil to near critical oil, and to gas condensate.

3.1 Cases of GOR_i=1,000 scf/STB

Gas-oil ratio equal to 1,000 scf/STB indicates the reservoir fluid type of volatile oil. 7 simulation cases of volatile oil reservoir were designed, and run to a 20-years-production period. **Table 3.2** shows the simulation optimal results that matched the gas production constraint, daily production of 10×10^6 ft^3/day in the first ten days. The reservoir matrix permeability is ranging from 10 mD to 0.0043 mD. On the case of $k_f=k_m$=2.2158 mD, critical condition, no fracture was required to reach this production target. When the matrix permeability is higher than 2.2158 mD, the permeability in fracture is limited to meet the gas rate control. In such case, fracture plays as a damage factor.

All daily gas production profiles are shown in **Fig. 3.1**. Daily gas production in the first 10 days is the same, 10×10^6 ft^3/day. However, there is significant difference after the first 10 days. In low reservoir permeability cases, the gas production dropped rapidly. While in high permeability cases, production will carry on a long period of high rate.

The producing gas-oil ratio (GOR) and oil-gas ratio (OGR) are shown in **Figs. 3.2 – 3.3**. The greatest difference in yield is their variation range over the duration of 20 years' production, ratio in low permeability case is keeping stable from the beginning to the end.

Table 3.2—SIMULATION OPTIMAL RESULTS BY GAS RATE CONTROL, GOR_i=1,000 scf/STB

Case No.	Fracture-Number	k_m mD	k_f mD
1	1	0.9245	100000
2	2	0.3000	100000
3	10	0.0165	100000
4	20	0.0043	100000
5*	1	2.2158	2.2158
6	1	5.0000	0.8965
7	1	10.0000	0.8080

*k_m=k_f, fractures are not required to get 10 MMcf/day for the first 10 days

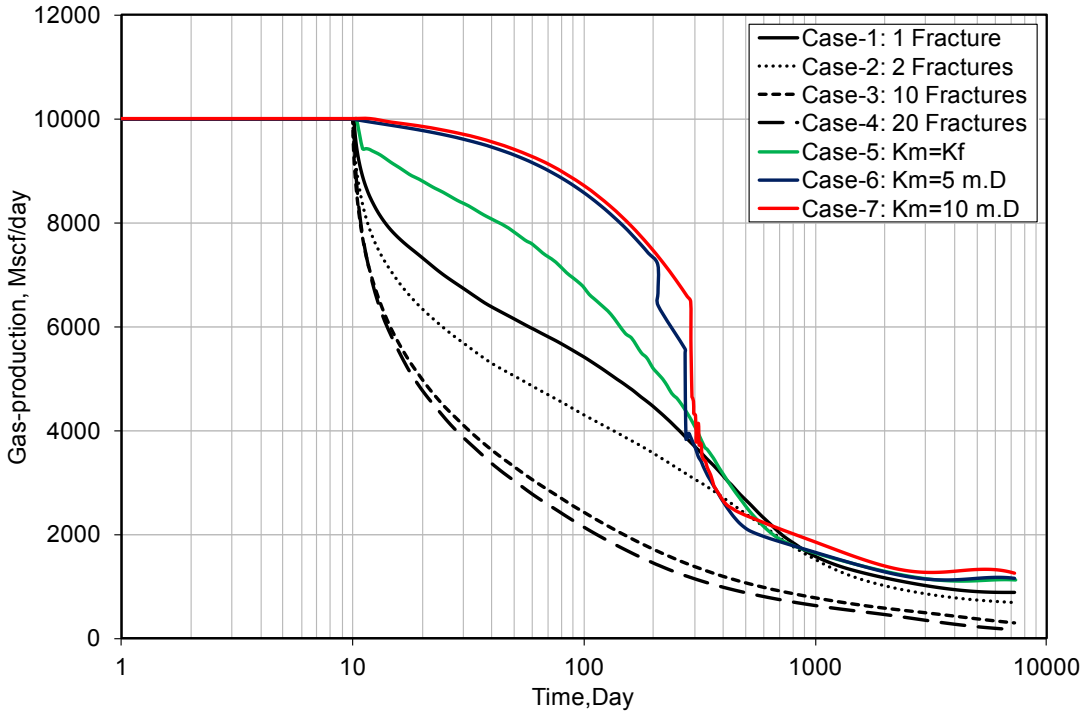


Fig. 3.1—Simulation well gas production profile of 7 cases, GOR_i=1,000 scf/STB.

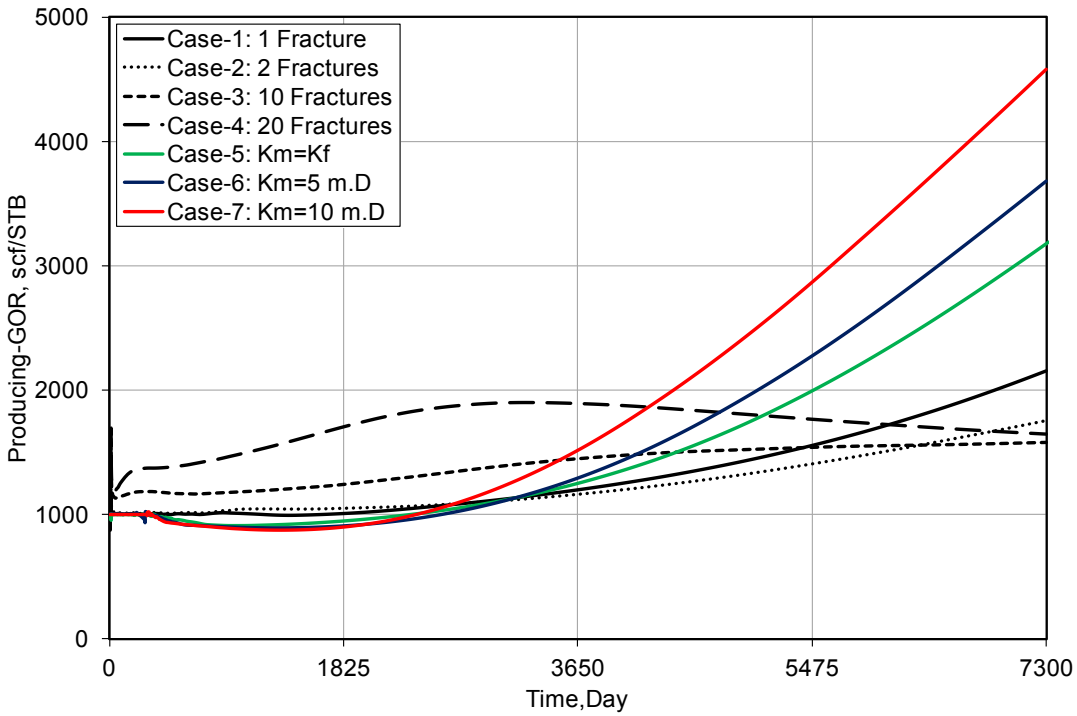


Fig. 3.2—Reservoir model producing gas-oil ratio profile of 7 cases, GOR_i=1,000 scf/STB.

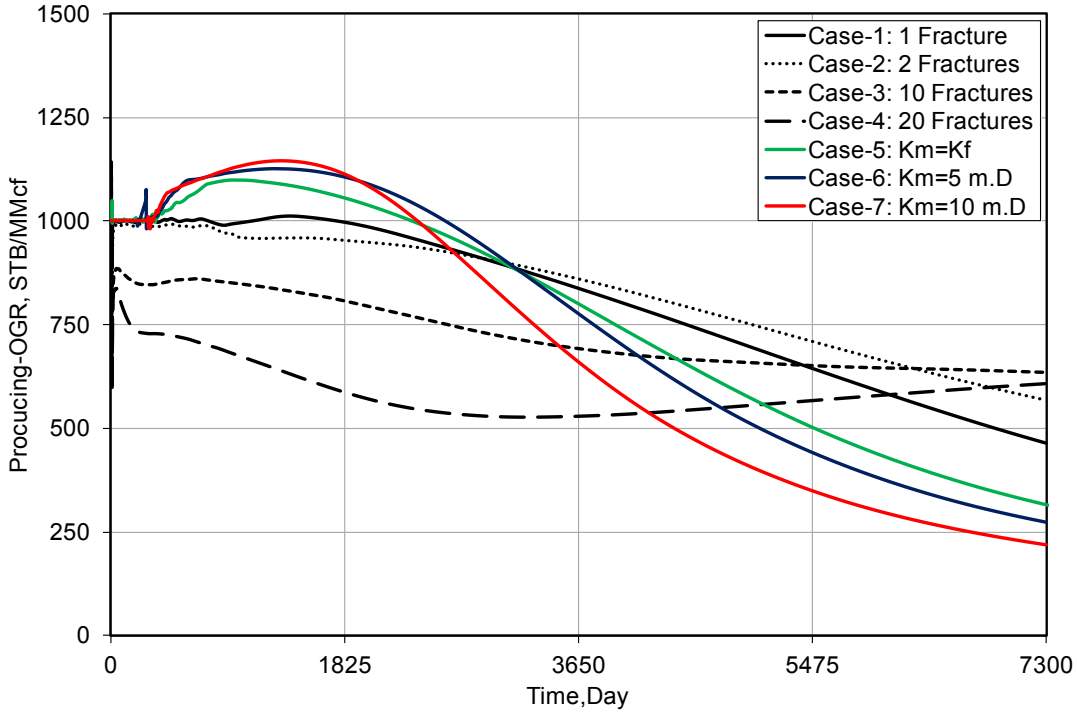


Fig. 3.3—Reservoir model producing oil-gas ratio profile of 7 cases, r_s=1000 STB/MMcf(GOR_i=1,000 scf/STB).

3.2 Cases of GOR_i=3,000 scf/STB

Gas-oil ratio of 3,000 scf/STB indicates a reservoir fluid type of lean volatile oil. 7 cases of lean volatile oil are set up and run to 20 years production duration. **Table 3.3** shows the optimal results of each model which is under the gas production control: daily gas rate with 10×10^6 ft^3/day of the first 10 days. The reservoir matrix permeability ranges from 10 mD to 0.0008 mD. If the lowest matrix permeability of reservoir is reduced to 0.0008 mD, 20 fractures in reservoir are required to attain the plateau rate of 10 days.

Table 3.3—SIMULATION OPTIMAL RESULTS BY GAS RATE CONTROL, GOR_i=3,000 scf/STB

Case No.	Fracture-Number	k_m mD	k_f mD
1	1	0.2690	100000
2	2	0.0710	100000
3	10	0.0030	100000
4	20	0.0008	100000
5*	1	1.5412	1.5412
6	1	5.0000	0.1972
7	1	10.0000	0.1923

*k_m=k_f, fractures are not required to get 10 MMcf/day for the first 10 days

Fig. 3.4 shows the well gas rate profile of these 7 simulation cases. All cases have the same gas production rate in the first 10 days, but present different performance after this period. The gas rate in the ultra low matrix permeability (k_m=0.0008 mD) case drops to 2×10^6 ft^3/day after 100 days, while the gas rate in high matrix permeability is around 9.5×10^6 ft^3/day at the same time. The oscillation problem in simulation appears in the cases with high permeability (k_m=5mD and 10 mD), particularly in the case of k_m=5 mD. A detailed analysis is shown in **Appendix B**.

The producing gas-oil ratio and oil-gas ratio profile of 7 cases are shown in **Figs. 3.5 –3.6**. Ratio profiles will change with different permeability, and the ratio in low permeability case was remaining relative stable over the 20-year simulation period.

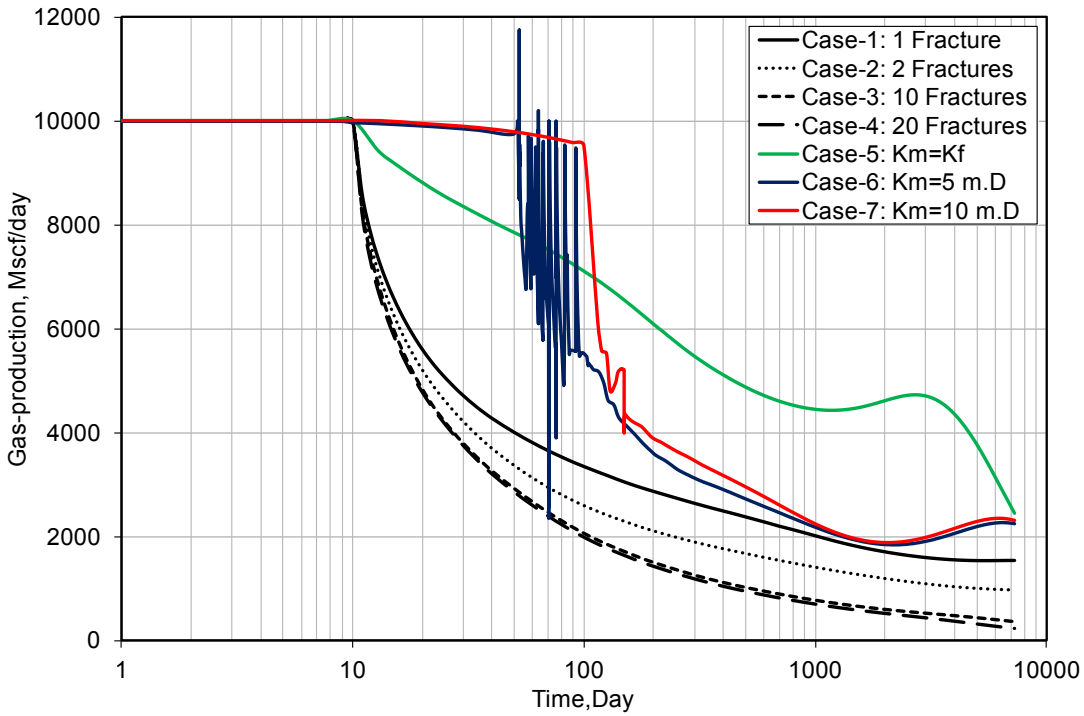


Fig. 3.4—Simulation well gas production profile of 7 cases, GOR_i=3,000 scf/STB.

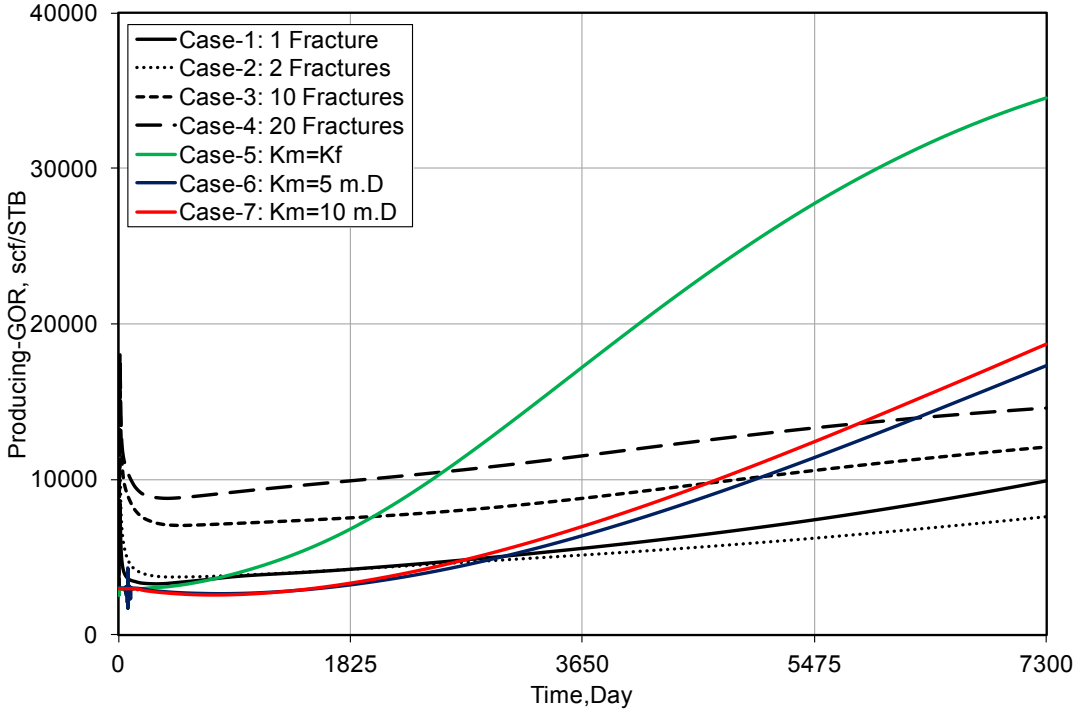


Fig. 3.5—Reservoir model producing gas-oil ratio profile of 7 cases, GOR_i=3,000 scf/STB.

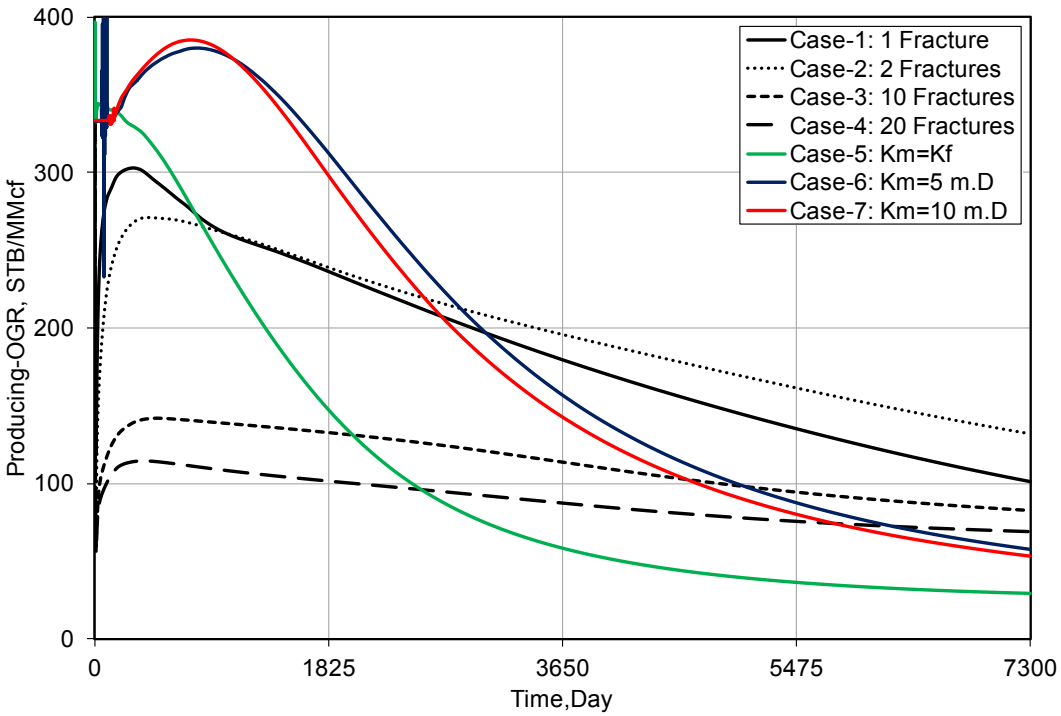


Fig. 3.6—Reservoir model producing oil-gas ratio profile of 7 cases, r_s=333 STB/MMcf(GOR_i=3,000 scf/STB).

3.3 Cases of GOR_i=4,587 scf/STB

The gas-oil ratio of 4,587 scf/STB suggests the fluids type of near critical oil. 7 cases with GOR_i of 4,587 scf/STB are designed to study. **Table 3.4** shows the optimal results that reach the gas rate control: daily production of 10×10^6 ft^3/day in the first 10 days. The optimal results of matrix permeability range from 10 mD to 0.0003 mD.

Fig. 3.7 shows the well gas rate profile over the duration of 50 years production. The gas rate is same in all cases of the first 10 days. However, it becomes different after this period. The gas production in the model of low matrix permeability reduces rapidly after the first 10 days. While, the gas production in high matrix permeability cases (k_m=5 mD and 10 mD) is remaining in a high rate level to 7 years. **Figs. 3.8 –3.9** show the producing gas-oil ratio (R_p) and oil-gas ratio (r_p) of each case. In the low permeability cases (km=0.02 mD, 0.0011 mD and 0.0003 mD), these two ratios keep in a stable level over 50 years of production.

Table 3.4—SIMULATION OPTIMAL RESULTS BY GAS RATE CONTROL: GOR_i=4,587 scf/STB

Case No.	Fracture-Number	k_m mD	k_f mD
1	1	0.1100	100000
2	2	0.0298	100000
3	10	0.0011	100000
4	20	0.0003	100000
5*	1	1.0088	1.0088
6	1	5.0000	0.7100
7	1	10.0000	0.6720

*k_m=k_f, fractures are not required to get 10 MMcf/day for the first 10 days

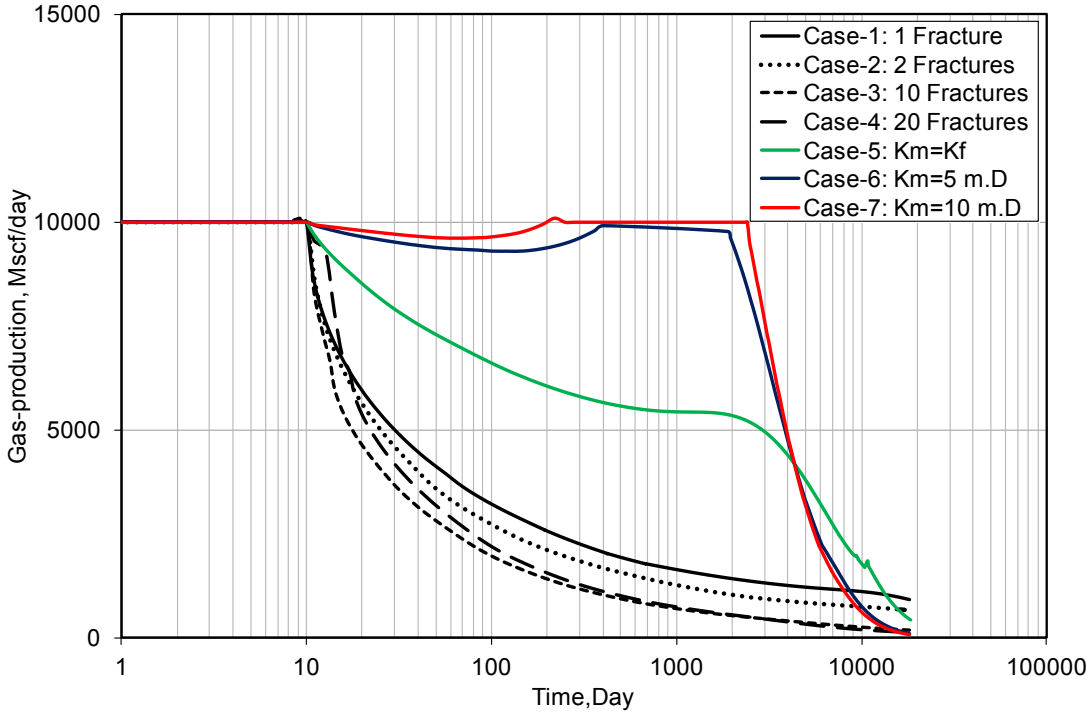


Fig. 3.7—Simulation well gas production profile of 7 cases, GOR_i=4,587 scf/STB.

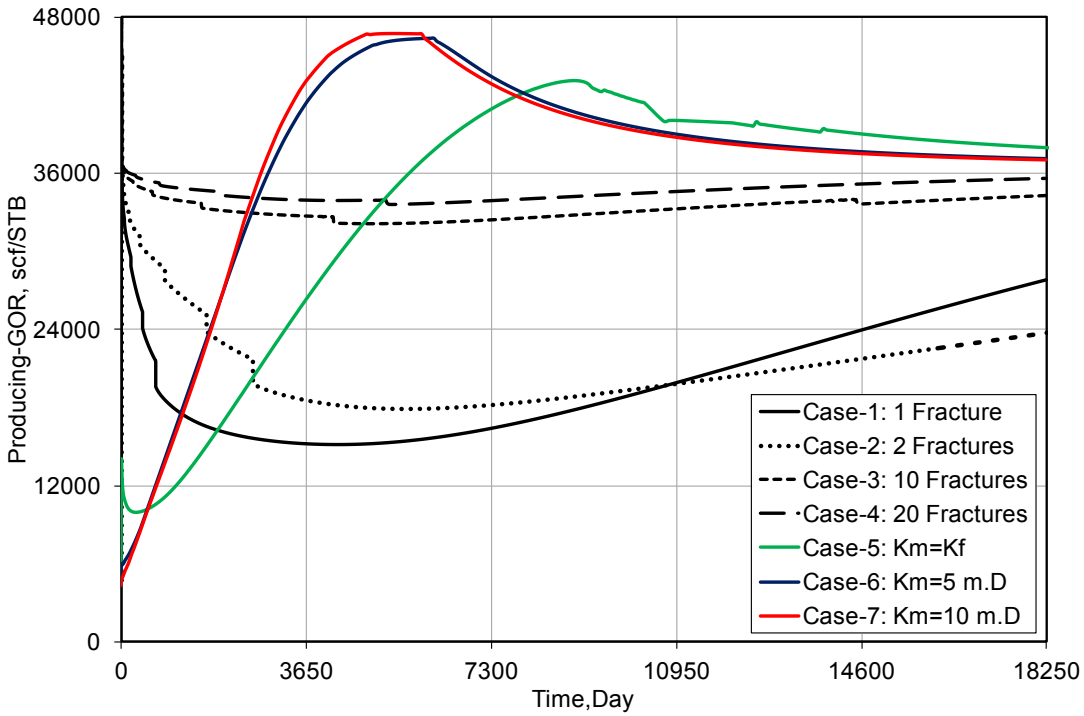


Fig. 3.8—Reservoir model producing gas-oil ratio profile of 7 cases, GOR_i=4,587 scf/STB.

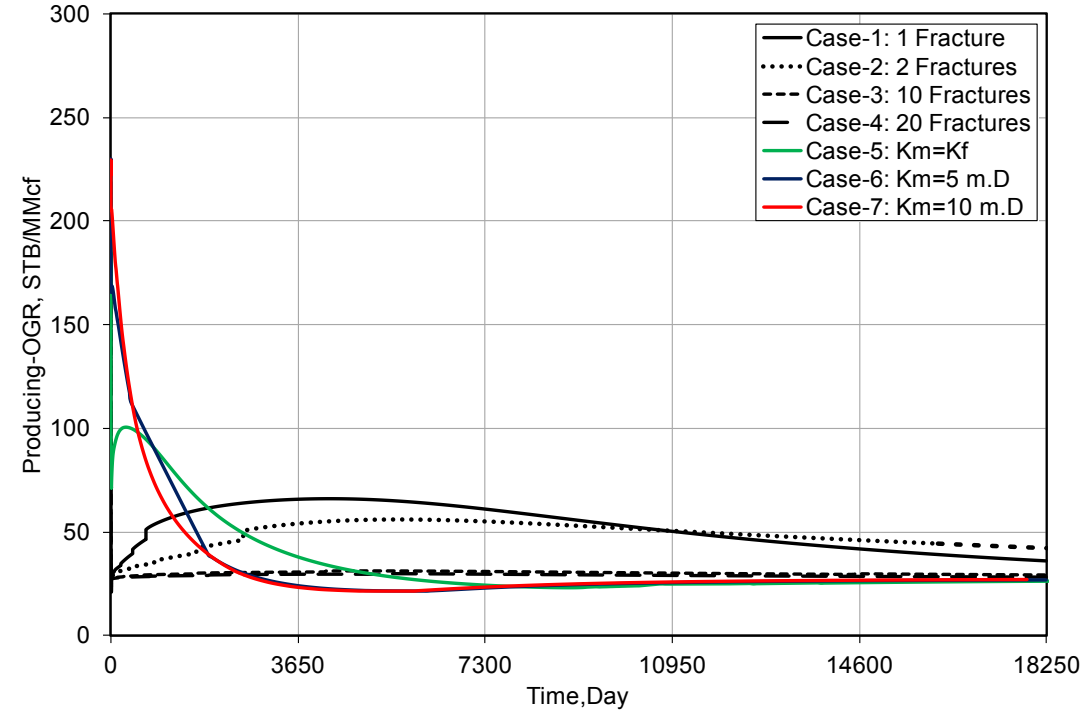


Fig. 3.9—Reservoir model producing oil-gas ratio profile of 7 cases, r_s=218 STB/MMcf (GOR_i=4,587 scf/STB).

3.4 Cases of GOR_i=10,000 scf/STB

A reservoir with initial gas-oil ratio of 10,000 scf/STB represents a gas condensate reservoir with 100 STB/MMcf liquid contents. The optimal results are shown in **Table 3.5**, which summarize the combination of fractures number and reservoir permeability. Each model with the combination is run to reach the gas production constraint of the first 10 days. **Fig. 3.10** shows the gas production profile over the duration of production period (50 years), the daily gas rate is equal to 10 MMcf/day in the first 10 days. Their corresponding plots of producing gas-oil ratio and oil-gas ratio are shown in **Figs. 3.11 –3.12.** The ratio in low permeability cases performs rather stable, which almost no changes over the 50 years production.

Table 3.5—SIMULATION OPTIMAL RESULTS BY GAS RATE CONTROL: GOR_i=10,000 scf/STB

Case No.	Fracture-Number	k_m mD	k_f mD
1	1	0.04400	100000
2	2	0.01200	100000
3	10	0.00051	100000
4	20	0.00013	100000
5*	1	0.4820	0.4820
6	1	5.0000	0.0907
7	1	10.0000	0.0893

*k_m=k_f, fractures are not required to get 10 MMcf/day for the first 10 days

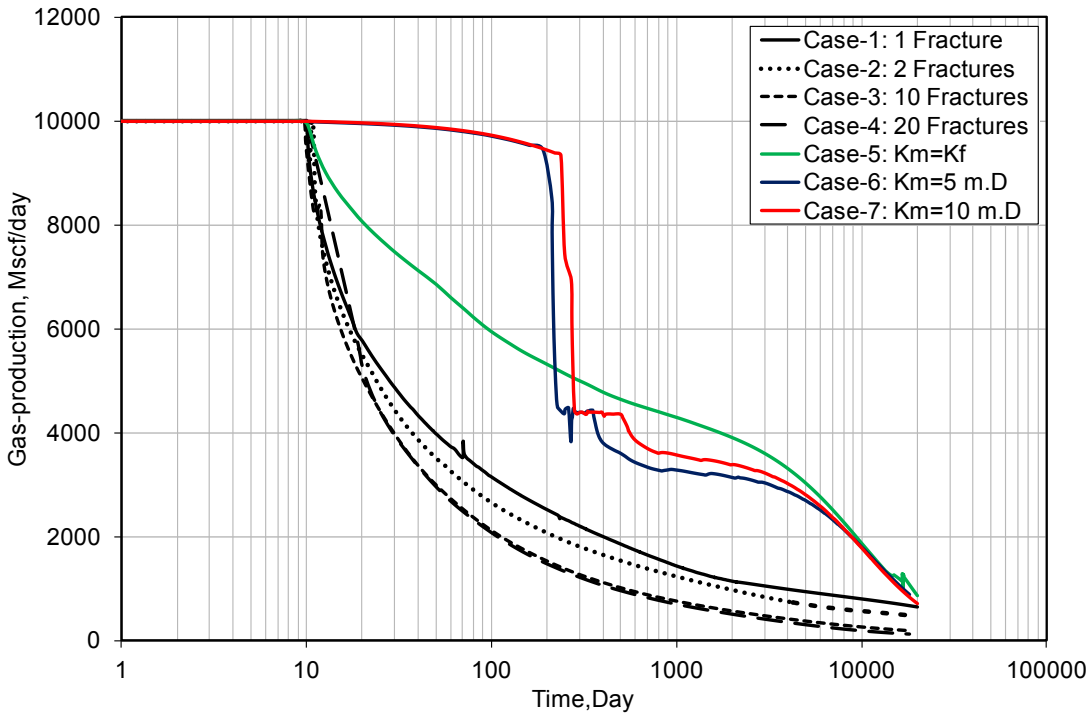


Fig. 3.10—Simulation well gas production profile of 7 cases, GOR_i=10,000 scf/STB.

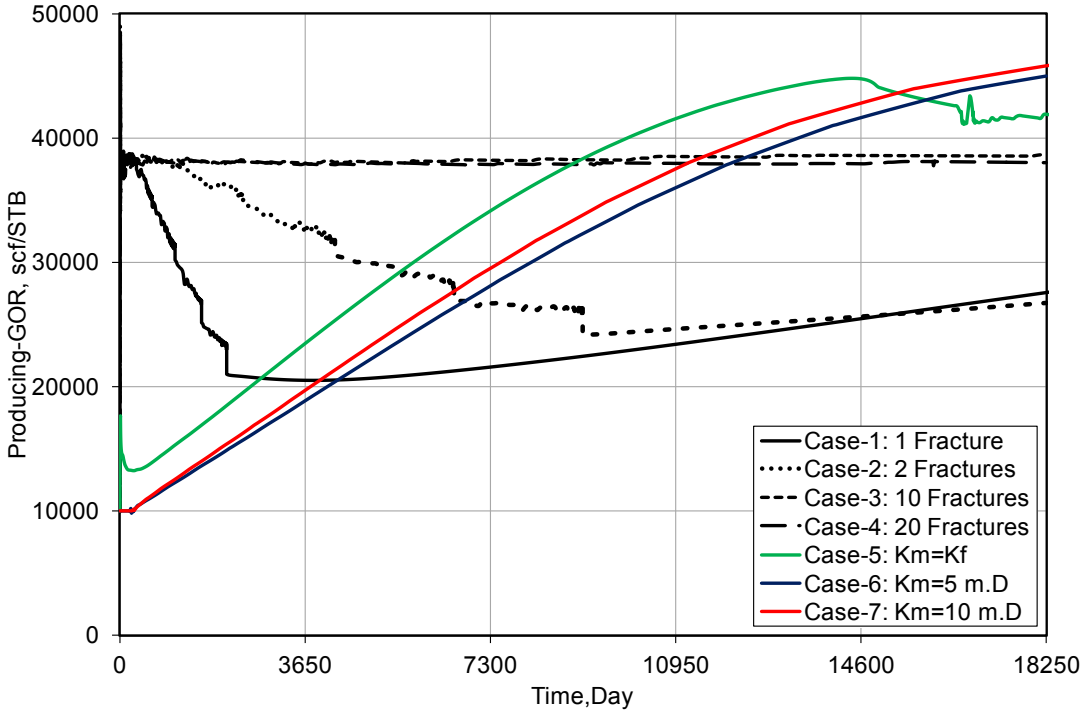


Fig. 3.11—Reservoir model producing gas-oil ratio profile of 7 cases, GOR_i=10,000 scf/STB

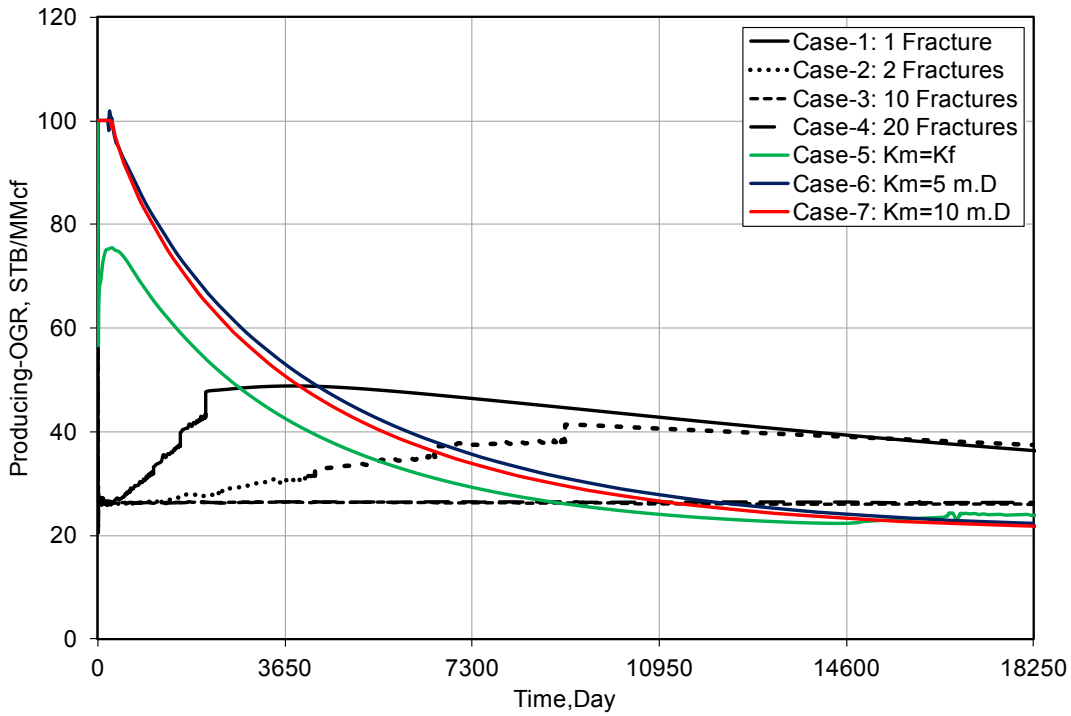


Fig. 3.12—Reservoir model producing oil-gas ratio profile of 7 cases, r_s=100 STB/MMcf (GOR_i=10,000 scf/STB).

3.5 Gas Production Control Summary

This section summarizes the most important conclusion from the simulation controlled by gas rate. With numerical simulation studies, some significant phenomenon of well's production performance are obtained.

To obtain a same gas rate of the first 10 days, more fractures are needed if the matrix permeability is decreased. In addition, gas production in the low permeability model drops rapidly after the first 10 days. On the condition of high matrix permeability, the fracture conductivity is limited to obtain the objective gas rate. The fracture plays as a positive factor in the low permeability reservoir, while performs as a negative factor in the high permeability reservoir.

Fig. 3.13 shows the relation between the reservoir permeability and the initial gas-oil ratio of critical cases. In the critical case, the fracture is not required to limit or increase the conductivity from reservoir matrix to horizontal wellbore. Inverse correlation exists between the initial gas-oil ratio (GOR_i) and the reservoir matrix

permeability (k_m). This means more gas will produce if the initial gas-oil ratio is in a large value.

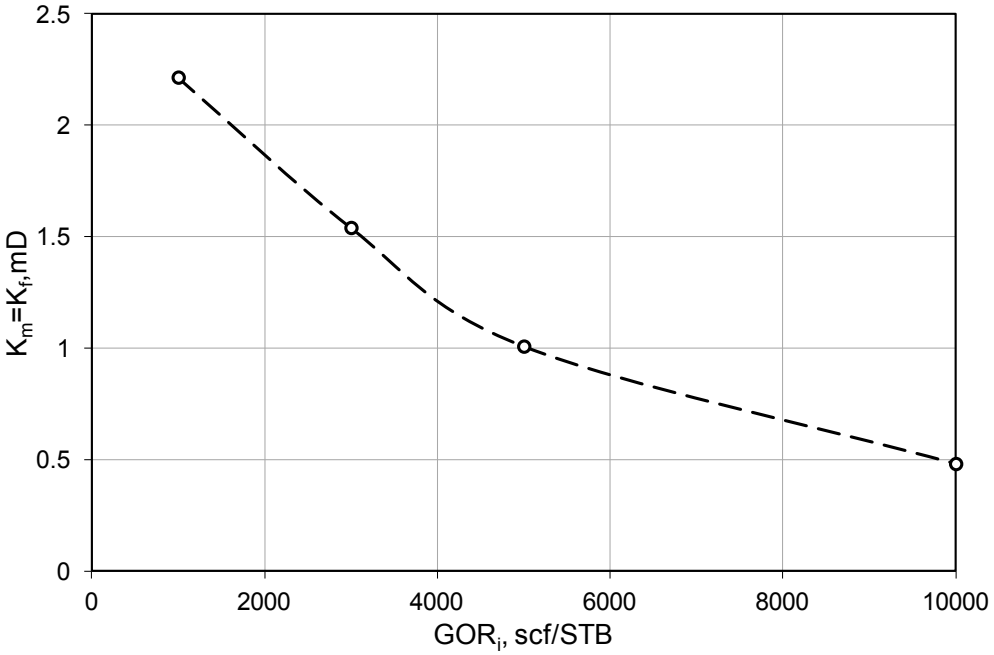


Fig. 3.13—Relation between GOR_i and reservoir permeability of critical case, no fracture is required and uniform permeability in reservoir

The simulation oscillation problem is shown in some model of high matrix permeability, including these cases of k_m=5mD or 10 mD When GOR_i=3,000 scf/STB and the case of k_m=5 mD when GOR_i=10,000 scf/STB. The simulation oscillation problem is caused by the model's gridding geometry. A detailed analysis is described in **Appendix B.**

Chapter 4
Revenue Control

In the gas production control, reservoir simulation only considers the well production from gas. This is true for the dry gas or wet gas reservoir, which contain a small amount of liquid. However, concerning the reservoir of low initial gas-oil ratio, such as volatile oil reservoir, near critical oil reservoir and gas condensate reservoir, large amounts of revenue is come from liquid part. At a time when oil price is keeping in high level and gas prices is cheap, it is more reasonable and appropriates to use well's total revenue as the constrain in simulation. Revenue both from gas production and oil production will be considered if the simulation is controlled by the total revenue.

The revenue calculation of well's production is based on both of the production rate and the price of the products. **Table 4.1** shows the assumption of products price, and the total revenue of the well's production is calculated by equation **(4.1)**:

$$Revenue_{total}=q_o \times P_o+q_g \times P_g \tag{4.1}$$

Table 4.1—REVENUE CALCULATION ASSUMPTION

Oil-price	P_o	100	\$/STB
Gas-price	P_g	4	\$/Mscf

Based on the E&P industry experience, cumulative revenue of 500,000 USD in the first 10 days is set as the criterion of a commercial well. All simulation cases in this section will be optimized to match this standard.

In order to compare the well performance between the conventional reservoir and the unconventional reservoir, reservoir's matrix permeability is set in the range from 10 mD to 10^{-5} mD. The comparisons are analyzed of each fluid system. In all simulation cases, two of them are conventional reservoirs with a high matrix permeability (k_m=1

mD, 10 mD), one of them is critical case of an identical permeability and the others are low permeability reservoirs with a high fracture conductivity (k_f=100,000 mD).

The fracture conductivity is high in the low permeability reservoir, while it will be reduced to restrict the fluid flow from reservoir matrix to fracture in high permeability reservoirs. Neither the fracture plays as a positive or a negative factor in the critical case, which has identical permeability.

4.1 Cases of GOR_i=1,000 scf/STB

7 cases with initial gas-oil ratio of 1,000 scf/STB are set to run, and their optimal results are listed in the **Table 4.2**. The matrix permeability ranges from 10 mD to 1.2×10^{-5} mD. Comparing the optimal results of simulation controlled by gas rate, the matrix permeability is lower in the reservoir with same fracture conductivity.

Table 4.2—SIMULATION OPTIMAL RESULTS BY REVENUE CONTROL, GOR_i=1,000 scf/STB

Case No.	Fracture-Number	k_m mD	k_f mD
1	1	0.004440	100000
2	2	0.001166	100000
3	10	0.000048	100000
4	20	0.000012	100000
5*	1	0.051518	0.051518
6	1	1	0.035916
7	1	10	0.034990

*k_m=k_f, fractures are not required to get 10 MMcf/day for the first 10 days cummulative production

Fig. 4.1 shows the total revenue of 7 different cases over the duration of a 50 years simulation. All of these cases have the same cumulative revenue of the first 10 days. However, the reservoir with high matrix permeability yields more revenue after 50 years of production. The producing total revenue is 10 times as much between the highest permeability reservoir (k_m=10 mD) and the lowest permeability reservoir (k_m=1.2×10^{-5} mD) after 50 years.

Figs. 4.2 – 4.3 show the 50-year profile of gas production and oil production. As seen in these two figures, the greatest difference is the production variation range over the 50 years production period. The production form low permeability model is high in the early stage and starts to decline after a short time. However, the production from the high permeability model stays at a stable level for the first 30 years. There is large difference in rate between the early stage and the late stage of the low permeability reservoir.

Figs. 4.4 –4.5 show the plot of gas-oil ratio and oil-gas ratio respectively. The simulation oscillation problem occurs in the critical cases with identical permeability (k_m=k_f=0.051518 mD). This problem is caused by the gridding structure in the simulation model, and a detailed analysis is shown in **Appendix B**.

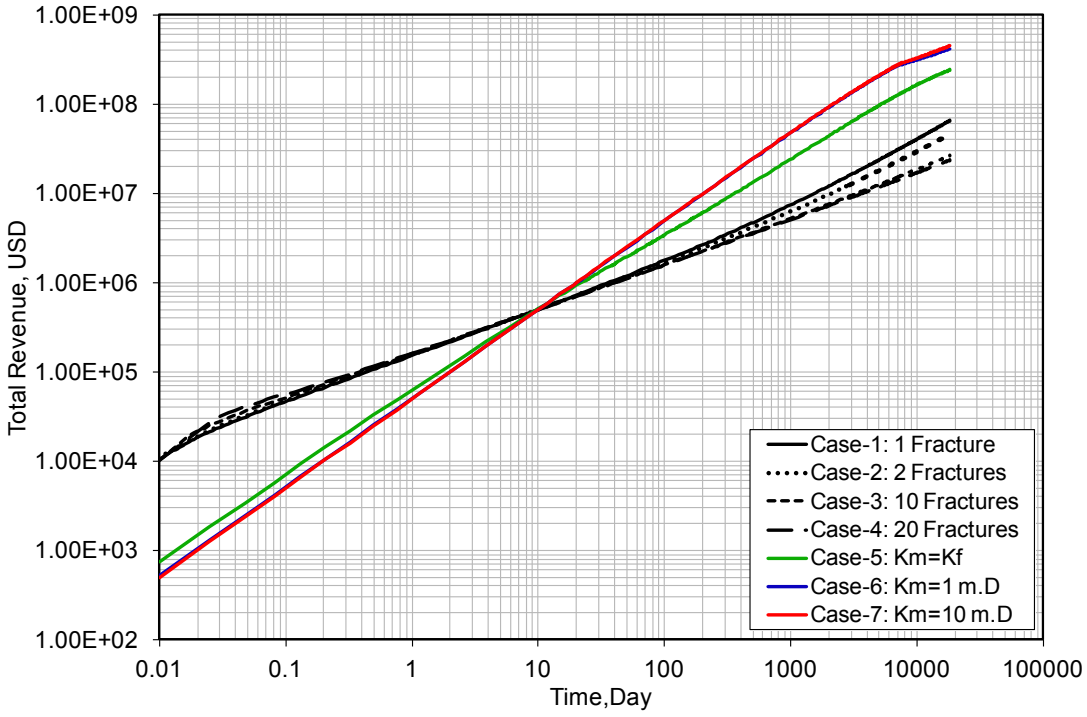


Fig. 4.1—Simulation well cumulative revenue of 50 years production of 7 cases, GOR_i=1,000 scf/STB.

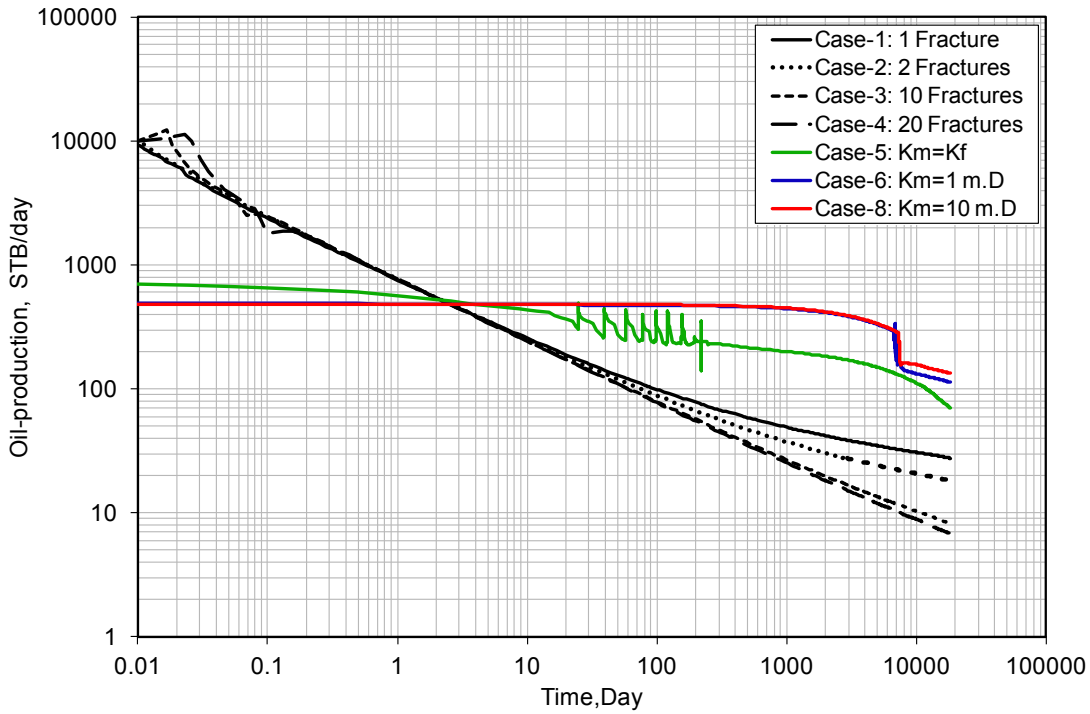


Fig. 4.2—Simulation well oil production profile of 7 cases by total revenue control, GOR_i=1,000 scf/STB.

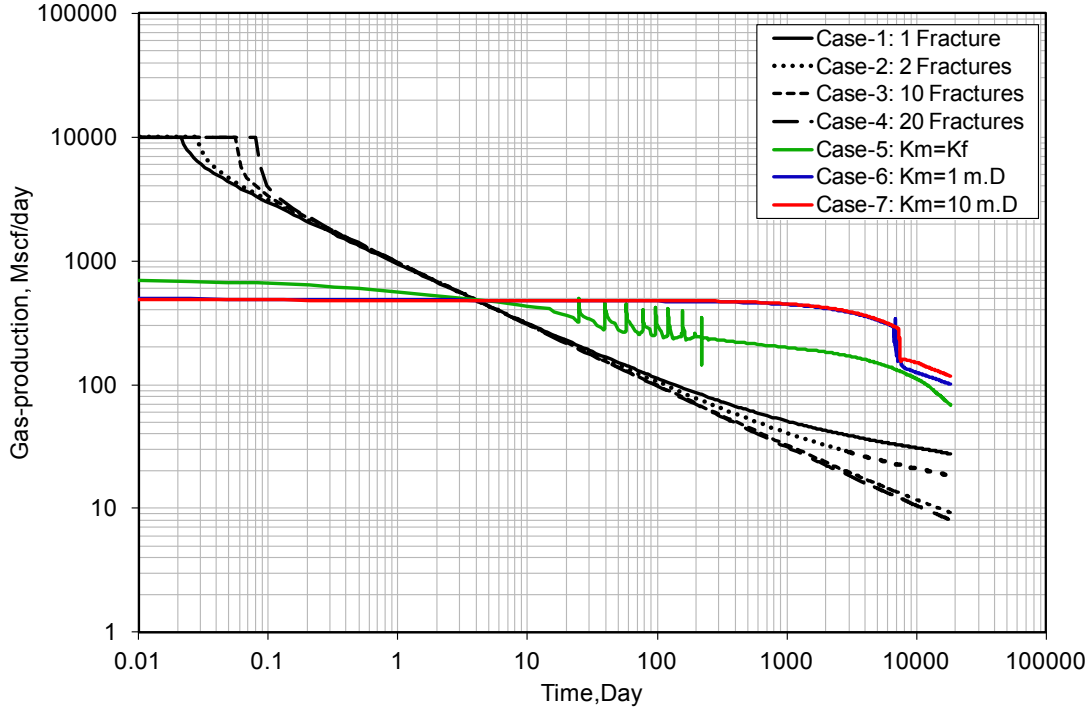


Fig. 4.3—Simulation well gas production profile of 7 cases by total revenue control, GOR_i=1,000 scf/STB.

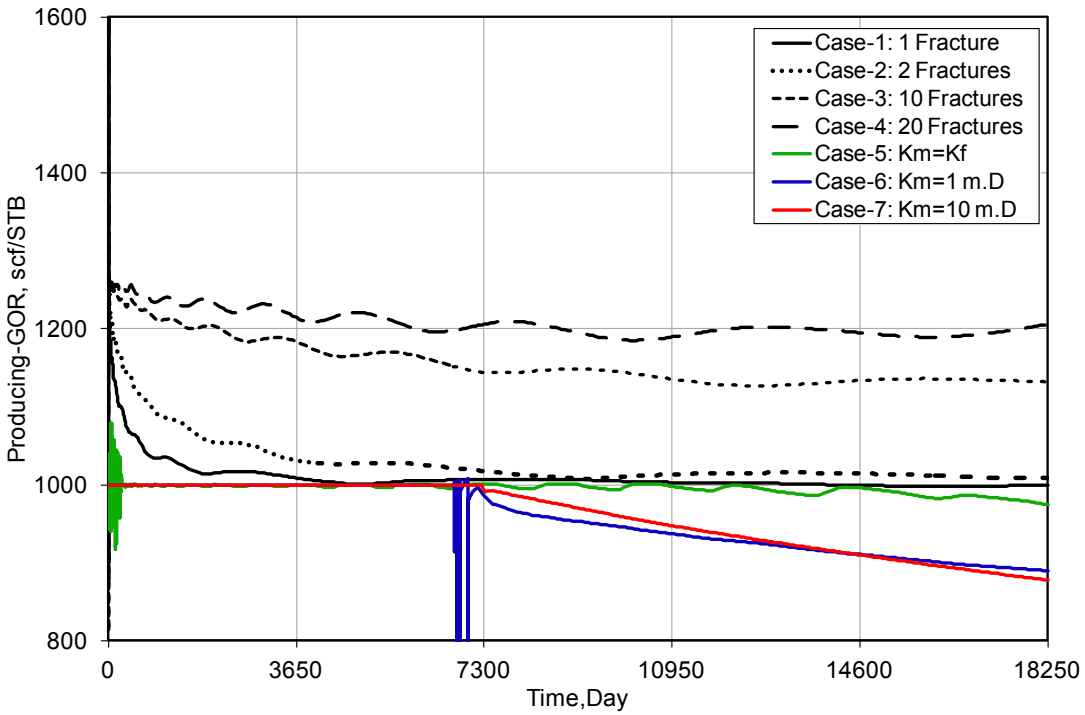


Fig. 4.4—Reservoir model producing gas-oil ratio profile of 7 cases by total revenue control, GOR_i=1,000 scf/STB.

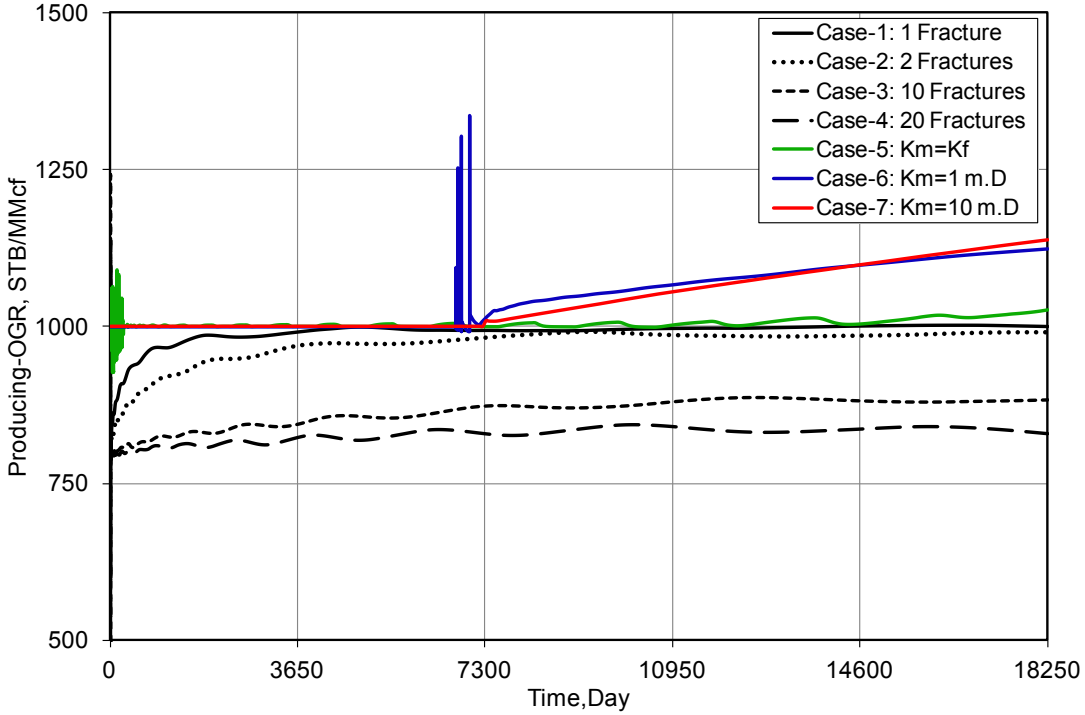


Fig. 4.5—Reservoir model producing oil-gas ratio profile of 7 cases by total revenue control, r_s=1000 STB/MMcf (GOR_i=1,000 scf/STB).

4.2 Cases of GOR_i=3,000 scf/STB

Initial gas-oil ratio of 3,000 scf/STB represents the fluid type of volatile oil. 7 cases are designed to compare their production performance under the total revenue control. **Table 4.3** lists the simulation optimal results of reservoir matrix permeability (k_m) and fracture permeability (k_f) combination. In the cases of 1, 2, 3 and 4, the fracture performs as a positive factor which improved the reservoir permeated capacity. However, the fracture in the cases 6 and 7 plays as a negative factor to limit the conductivity between reservoir matrix and horizontal well.

Table 4.3—SIMULATION OPTIMAL RESULTS BY REVENUE CONTROL,GOR_i=3,000 scf/STB

Case No.	Fracture-Number	k_m mD	k_f mD
1	1	0.025120	100000
2	2	0.007236	100000
3	10	0.000341	100000
4	20	0.000087	100000
5*	1	0.125237	0.125237
6	1	1	0.025621
7	1	10	0.025010

*k_m=k_f, fractures are not required to get 10 MMcf/day for the first 10 days cummulative production

Fig. 4.6 shows the 50-year cumulative revenue of each case. The cumulative revenue in all cases is same after the first 10 days' production. These profiles also indicate that high-permeability reservoir will yield larger revenue compared with low-permeability reservoir after a long time production (50 years).

The 50-years production profiles of gas and oil rate are shown in **Figs. 4.7 – 4.8**. In the high-permeability models (k_m=1 mD and k_m=10 mD), production keeps steady for the first 3 years. However, the production plateau in the low-permeability model is much shorter, less than one day. **Figs. 4.9 – 4.10** show the plot of producing gas-oil ratio and oil-gas ratio respectively. As seen in the ratio plot, the ratio stays at a stable level over the duration of 50 years of production.

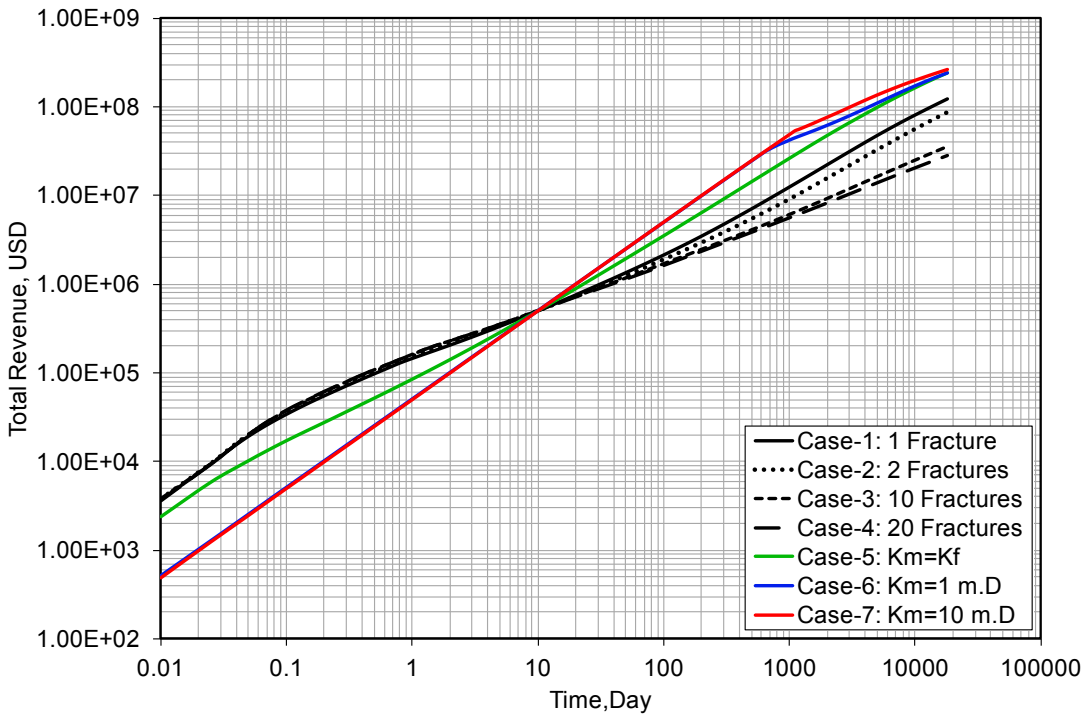


Fig. 4.6—Simulation well cumulative revenue of 50 years production of 7 cases, GOR_i=3,000 scf/STB.

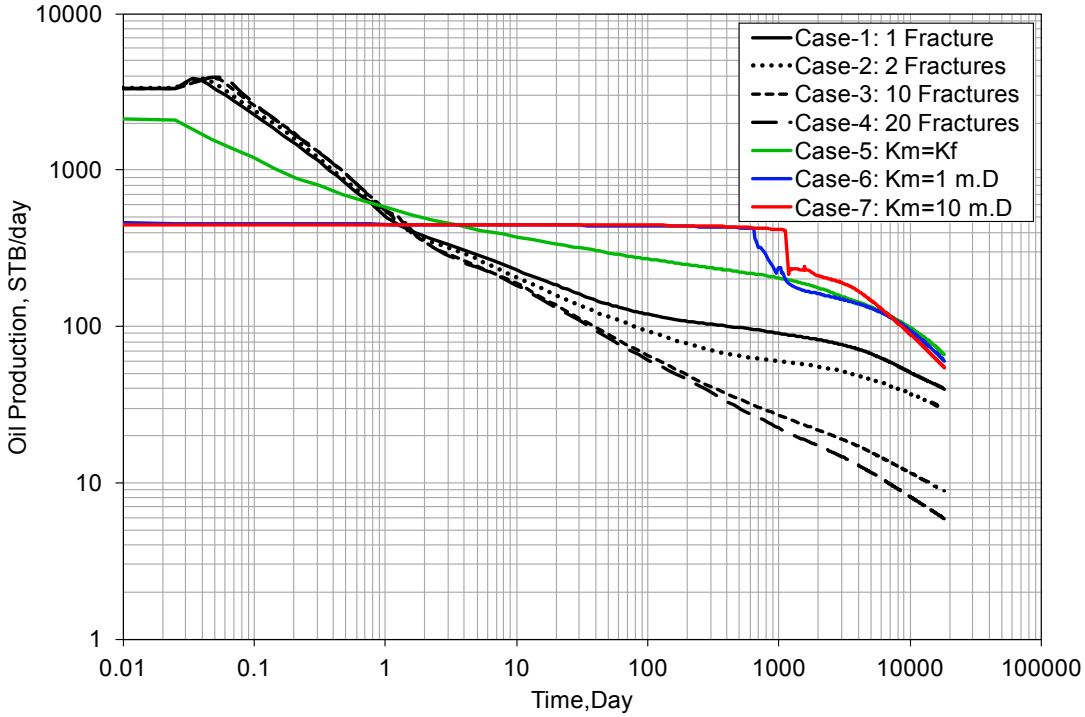


Fig. 4.7—Simulation well oil production profile of 7 cases by total revenue control, GOR_i=3,000 scf/STB.

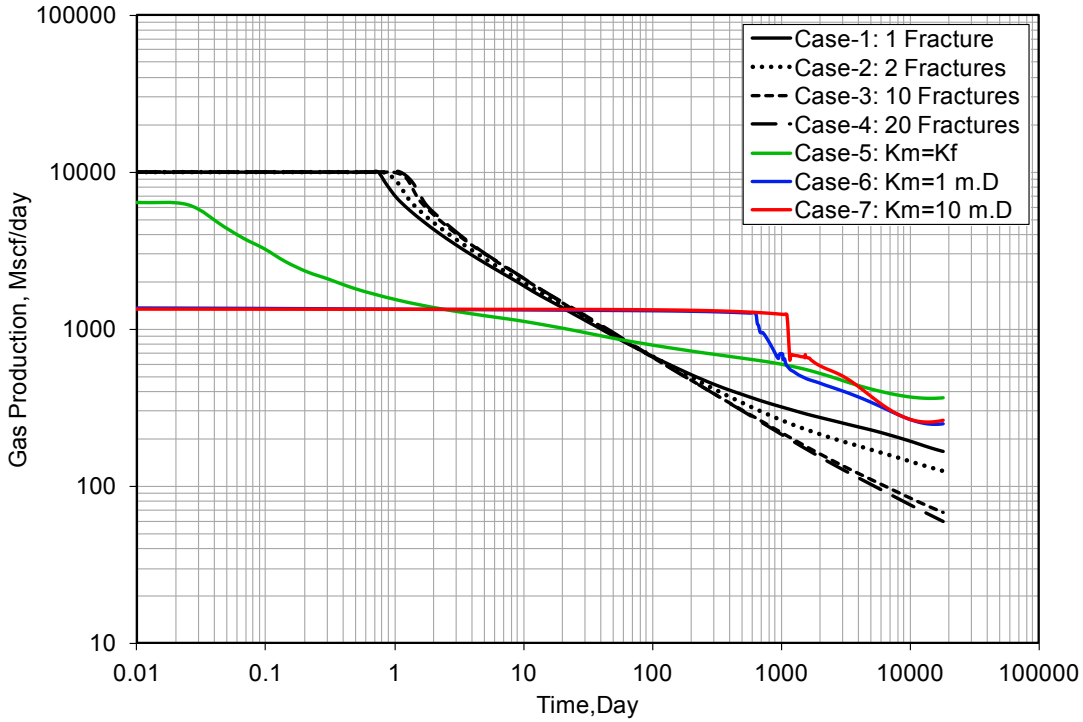


Fig. 4.8—Simulation well gas production profile of 7 cases by total revenue control, GOR_i=3,000 scf/STB

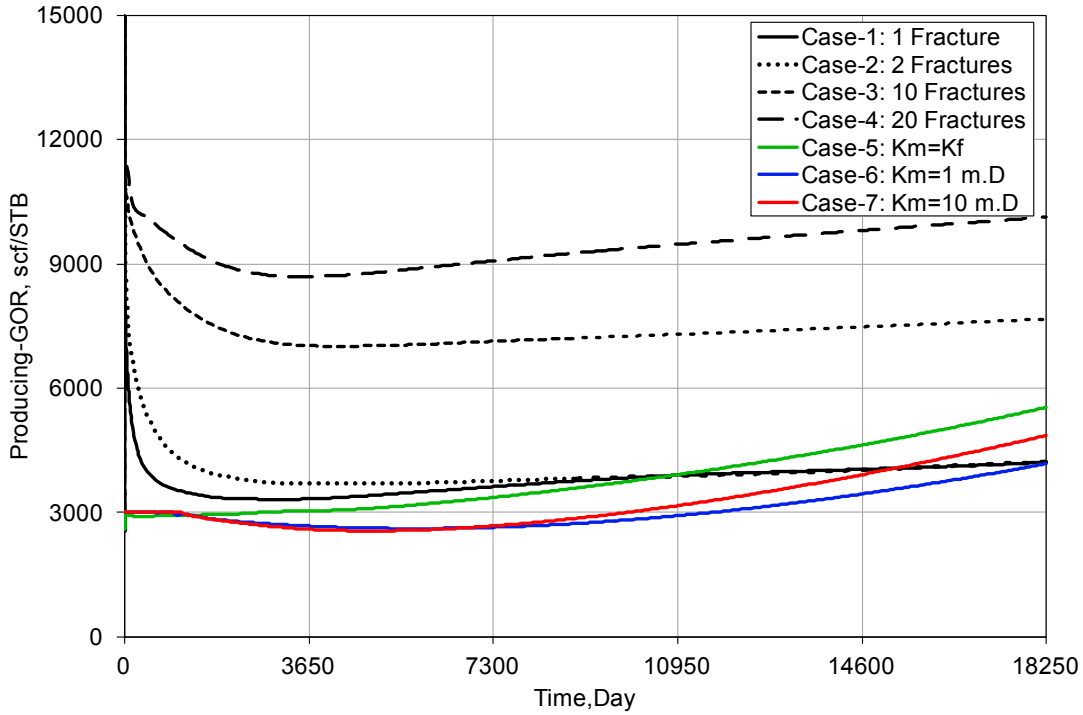


Fig. 4.9—Reservoir model producing gas-oil ratio profile of 7 cases by total revenue control, GOR_i=3,000 scf/STB.

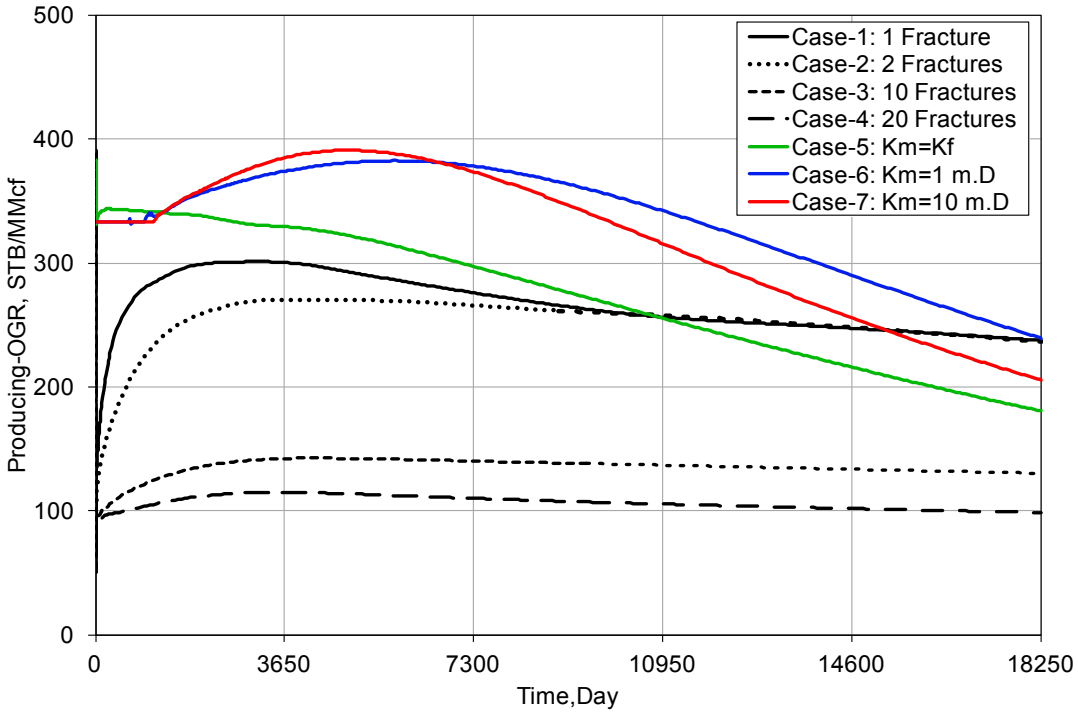


Fig. 4.10—Reservoir model producing oil-gas ratio profile of 7 cases by total revenue control, r_s=333 STB/MMcf (GOR_i=3,000 scf/STB).

4.3 Cases of GOR_i=4,587 scf/STB

Initial gas-oil ratio of 4,587 scf/STB represents the fluid type of near critical oil. 7 cases with specified reservoir permeability combination are simulated to obtain their optimal value under the total revenue constraint. The optimal results are shown in **Table 4.4**. These 7 cases include 4 cases of low-matrix-permeability reservoir and 2 cases of high-matrix-permeability reservoir, which represent the unconventional reservoir and conventional reservoir respectively. The critical case with identical permeability in matrix and fracture is also included in this study.

Fig. 4.11 shows the plot of 50-year production cumulative revenue. In general, high permeability reservoir will result large revenue after 50 years production. The production daily profile of oil and gas are shown in **Figs. 4.12 – 4.13**. Unlike the production profile of high permeability cases in GOR_i=1,000 scf/STB and GOR_i=3,000 scf/STB, there is no production plateau existing in these cases with GORi=4,587 scf/STB. The producing ratio of gas-oil and oil-gas were shown in the

Figs. 4.14 – 4.15. The ratio profile of GOR_i=4,587 scf/STB presents a typical trends for a near critical oil reservoir.

Table 4.4—SIMULATION OPTIMAL RESULTS BY REVENUE CONTROL, GOR_i=4,587 scf/STB

Case No.	Fracture-Number	k_m mD	k_f mD
1	1	0.043193	100000
2	2	0.011423	100000
3	10	0.000497	100000
4	20	0.000130	100000
5*	1	0.348033	0.348033
6	1	1	0.163945
7	1	10	0.053445

*k_m=k_f, fractures are not required to get 10 MMcf/day for the first 10 days cummulative production

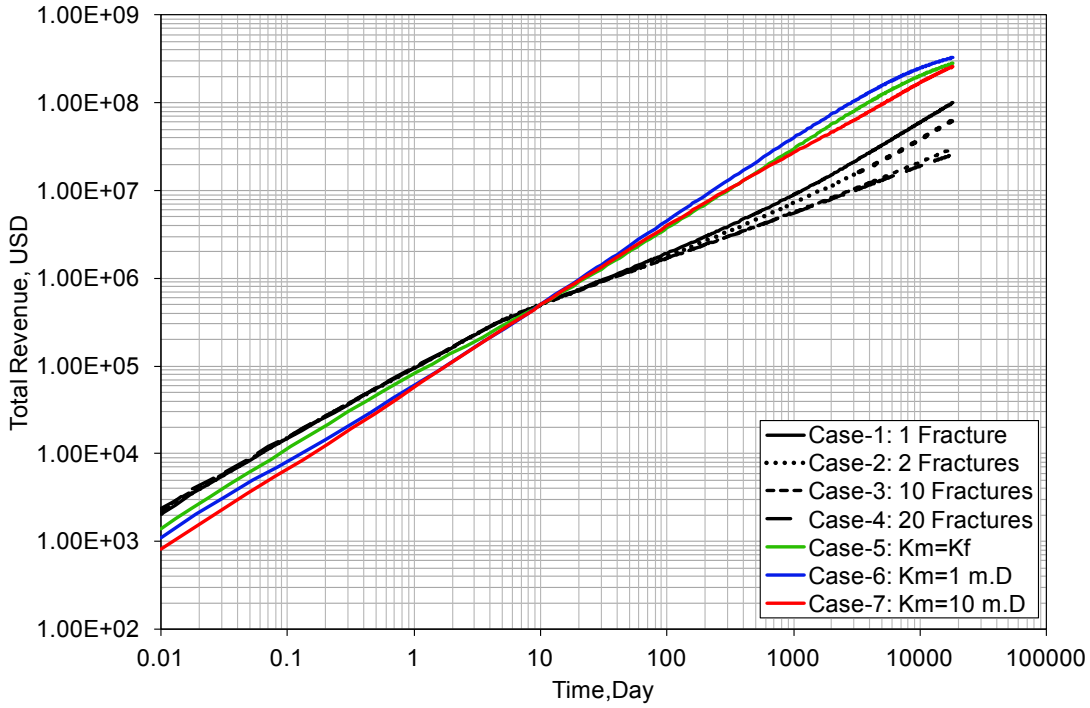


Fig. 4.11—Simulation well cumulative revenue of 50 years production of 7 cases, GOR_i=4,587 scf/STB.

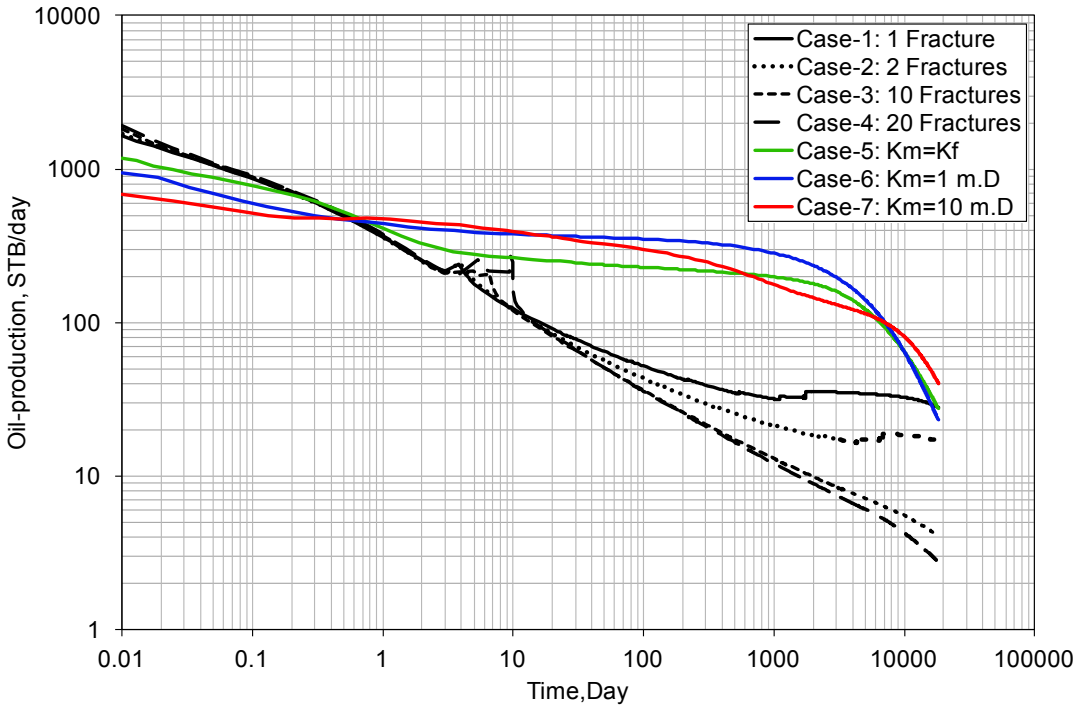


Fig. 4.12—Simulation well oil production profile of 7 cases by total revenue control, GOR_i=4,587 scf/STB.

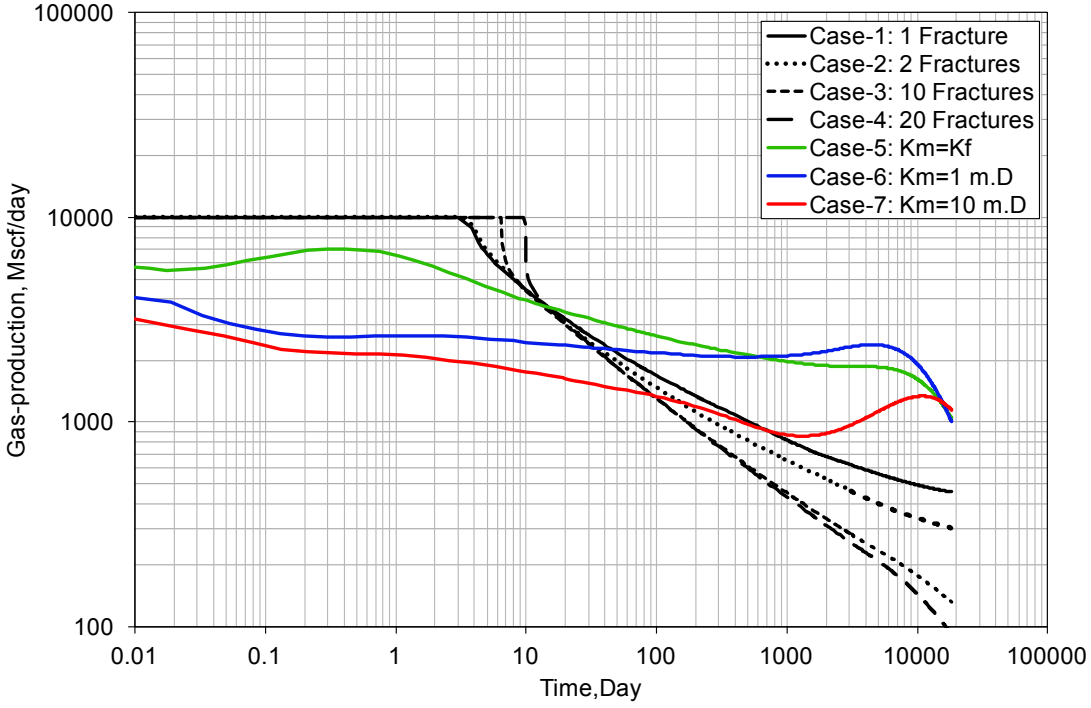


Fig. 4.13—Simulation well gas production profile of 7 cases by total revenue control, GOR_i=4,587 scf/STB.

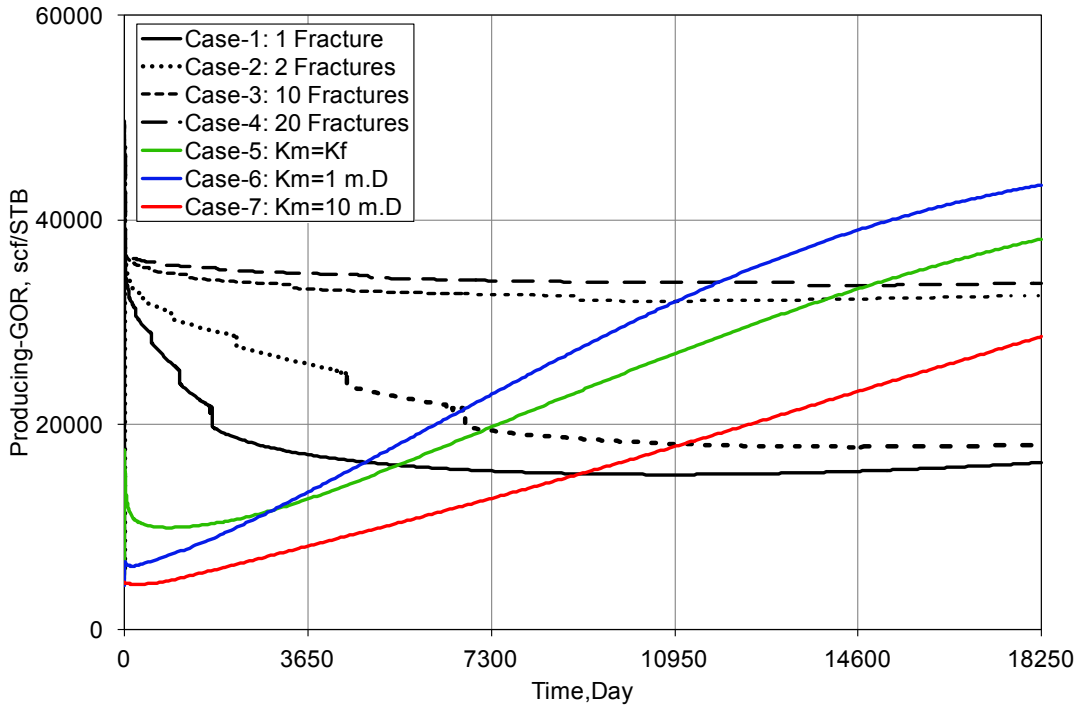


Fig. 4.14—Reservoir model producing gas-oil ratio profile of 7 cases by total revenue control, GOR_i=4,587 scf/STB.

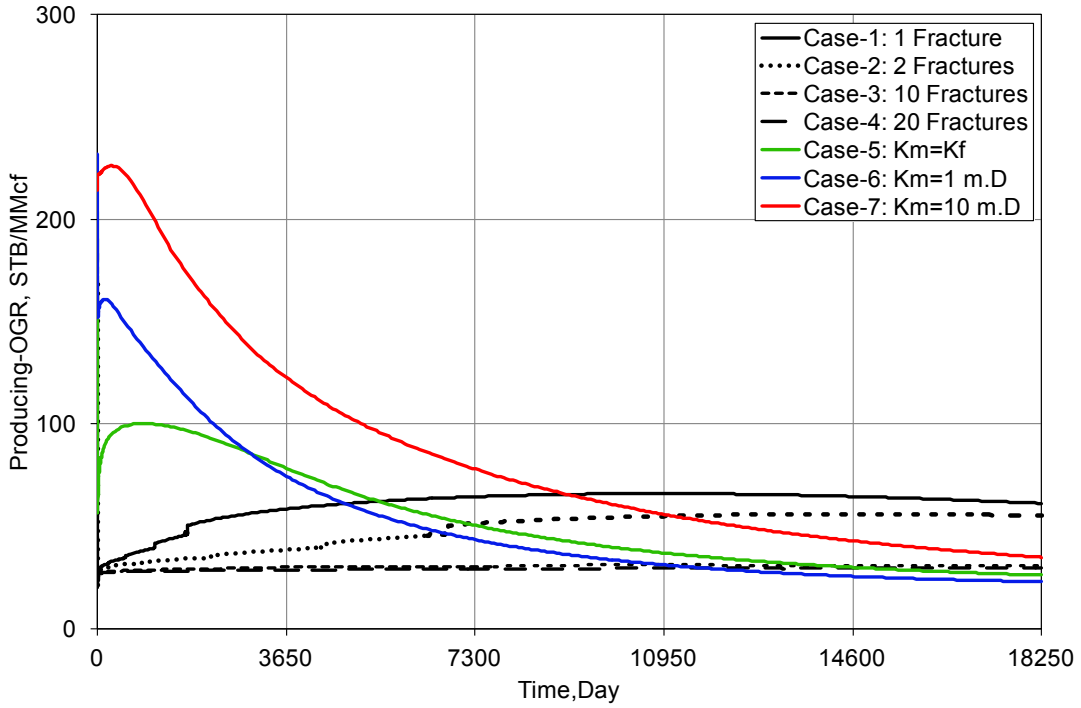


Fig. 4.15—Reservoir model producing oil-gas ratio profile of 7 cases by total revenue control, r_s=218 STB/MMcf(GOR_i=4,587 scf/STB).

4.4 Cases of GOR_i=10,000 scf/STB

The reservoir with an initial gas-oil ratio of 10,000 scf/STB represents the gas condensate reservoir. 7 cases with different permeability combination are run to obtain the revenue target. The optimal results of reservoir's parameters combination are shown in **Table 4.5**.

In all cases, the cumulative revenue of the first 10 days is same, 5×10^5 USD. And in general, the total revenue after 50 years production is high in the reservoir with high matrix permeability. The cumulative revenue profile of each case is shown in **Fig. 4.16**.

Figs. 4.17—4.18 show the well production profile of oil rate and gas rate. There is a 2—3 years production plateau existing in the cases of high matrix permeability (k_m=1 mD, 10 mD). However, the production's plateau in these cases of low matrix permeability lasted less than 10 days. The plots of producing gas-oil ratio and oil-gas ratio are given in **Figs. 4.19 – 4.20**. Simulation oscillation problem occurs in the case of k_m=1 mD, and more detailed analysis is included in **Appendix B**.

Table 4.5—SIMULATION OPTIMAL RESULTS BY REVENUE CONTROL: GOR_i=10,000 scf/STB

Case No.	Fracture-Number	k_m mD	k_f mD
1	1	0.017500	100000
2	2	0.004595	100000
3	10	0.000197	100000
4	20	0.000050	100000
5*	1	0.159000	0.159000
6	1	1	0.032707
7	1	10	0.031466

*k_m=k_f, fractures are not required to get 10 MMcf/day for the first 10 days cummulative production

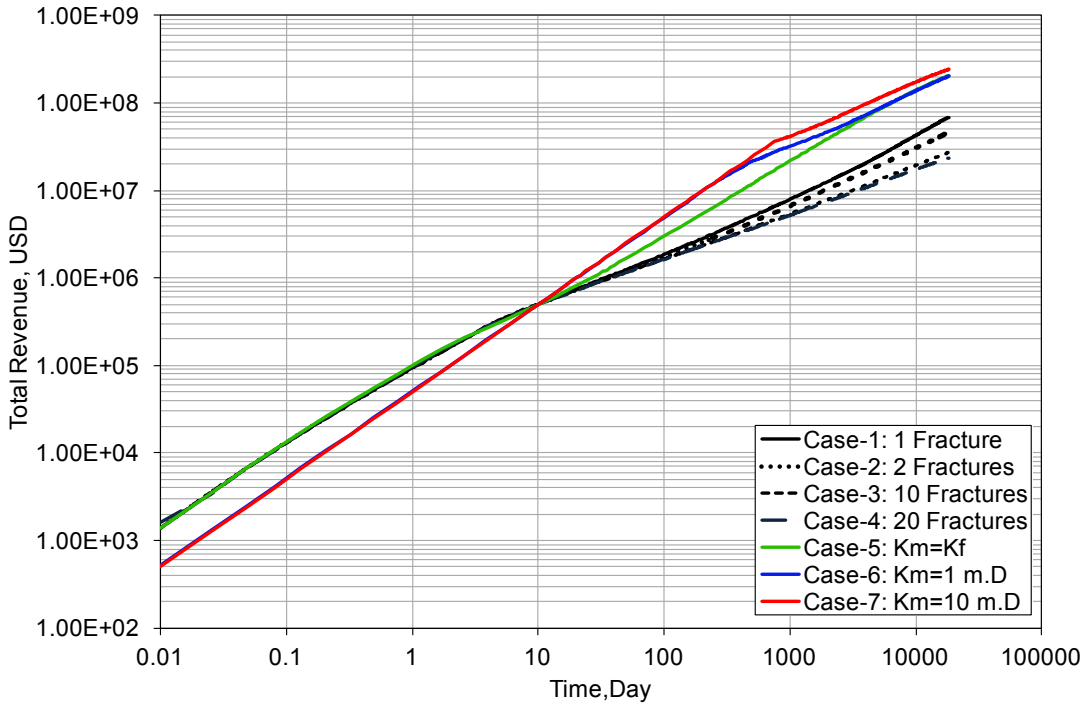


Fig. 4.16—Simulation well cumulative revenue of 50 years production of 7 cases, GOR_i=10,000 scf/STB.

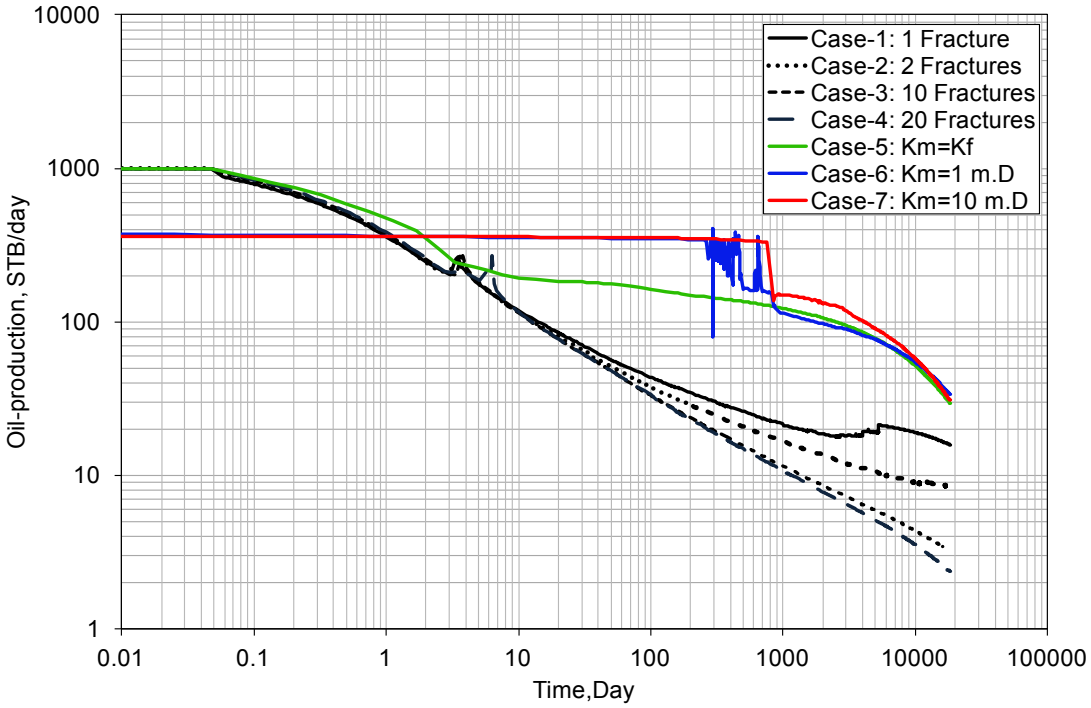


Fig. 4.17—Simulation well oil production profile of 7 cases by total revenue control, GOR_i=10,000 scf/STB.

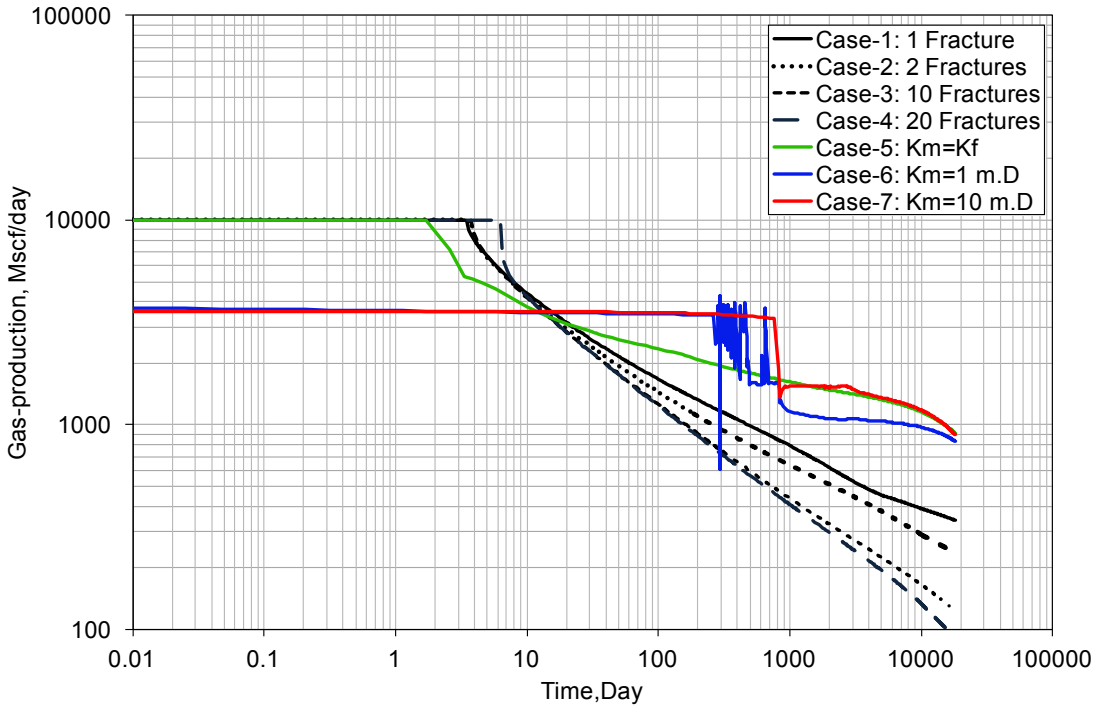


Fig. 4.18—Simulation well gas production profile of 7 case by total revenue control, GOR_i=10,000 scf/STB.

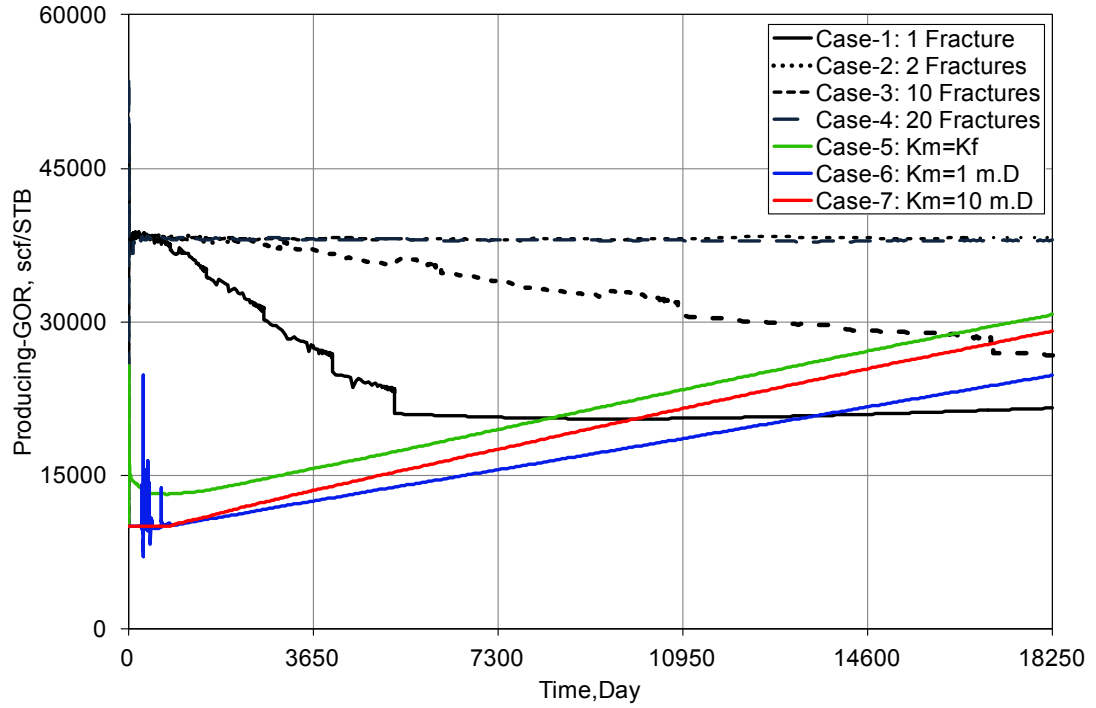


Fig. 4.19—Reservoir model producing oil-gas ratio profile of 7 cases by total revenue control, GOR_i=10,000 scf/STB.

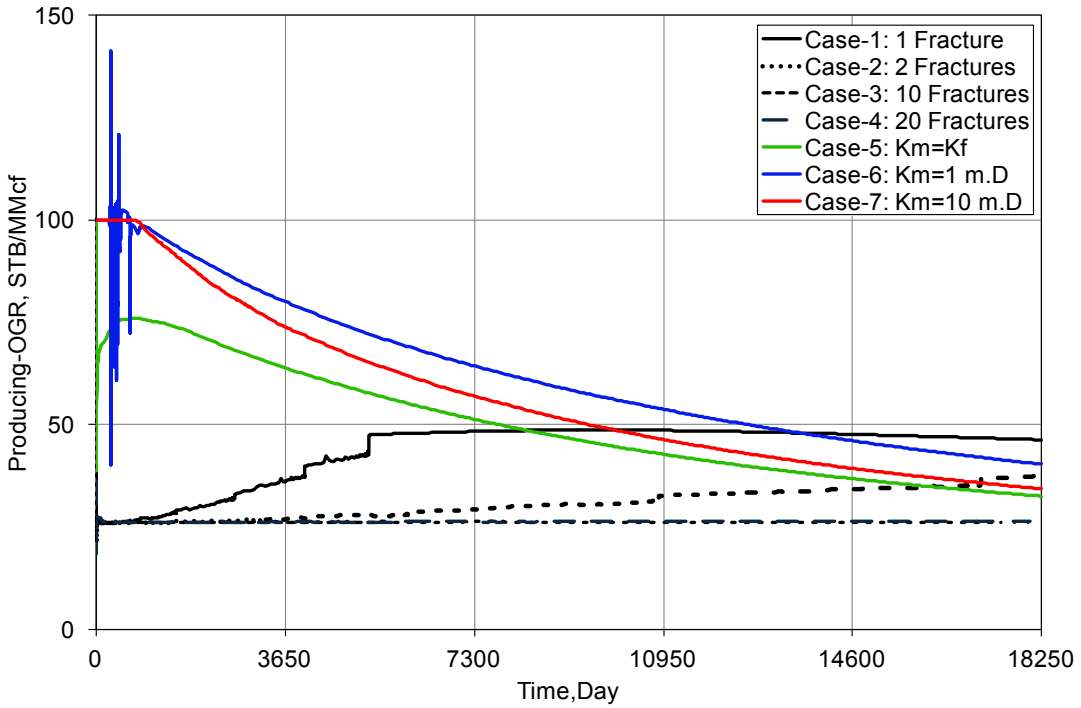


Fig. 4.20—Reservoir model producing oil-gas ratio profile of 7 cases by total revenue control, r_s=100 STB/MMcf(GOR_i=10,000 scf/STB).

4.5 Cases of GOR_i=100,000 scf/STB

The gas-oil ratio of 100,000 scf/STB represents the fluid type of wet gas, which well production is gas with a small amount of liquid. 7 simulation cases with different permeability combination are run to present their production performances. **Table 4.6** lists the optimal results that reached the revenue standard of the first 10 days.

Fig. 4.21 shows the total revenue plot as a function of time. In the first 10 days, the total revenue of each case is similar, but the permeability has a significant impact on the revenue after this period. In general, high permeability in reservoir will result great total revenue after a 50-years production.

The shape of gas production profiles is similar with plot of oil production, which is shown in **Figs. 4.22 – 4.23**. The similar shape is result out of the fixed R_p and r_p over 50 years of production. The initial gas-oil ratio in simulator is higher than the maximum value of gas-oil ratio in the fluid model: 47,315 scf/STB. Under the influence of this limitation, the producing ratios of gas-oil and oil-gas is fixed to

47,315 scf/STB and 21.135 STB/MMscf respectively, which is shown in **Figs. 4.24 – 4.25**. This value of r_p is the minimum value of the r_s in the fluid model.

Table 4.6—SIMULATION OPTIMAL RESULTS BY REVENUE CONTROL: GOR_i=100,000 scf/STB

Case No.	Fracture-Number	k_m mD	k_f mD
1	1	0.014468	100000
2	2	0.004011	100000
3	10	0.000176	100000
4	20	0.000044	100000
5*	1	0.116188	0.116188
6	1	1	0.060323
7	1	10	0.055708

*k_m=k_f, fractures are not required to get 10 MMcf/day for the first 10 days cummulative production

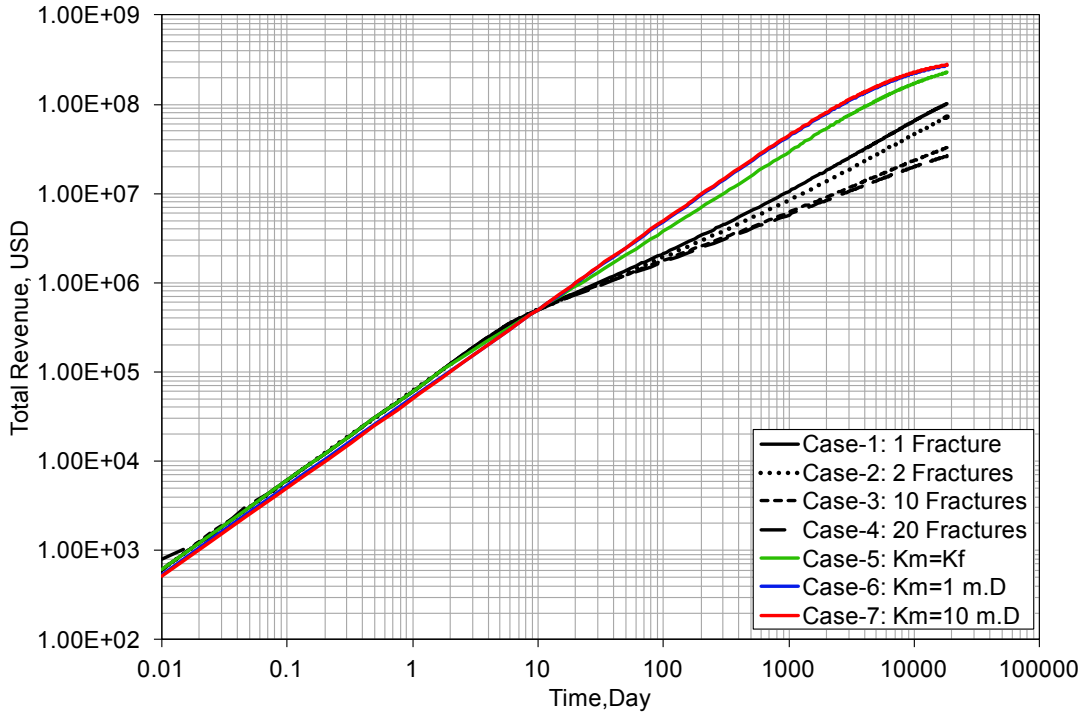


Fig. 4.21—Simulation well cumulative revenue of 50 years production of 7 cases, GOR_i=100,000 scf/STB.

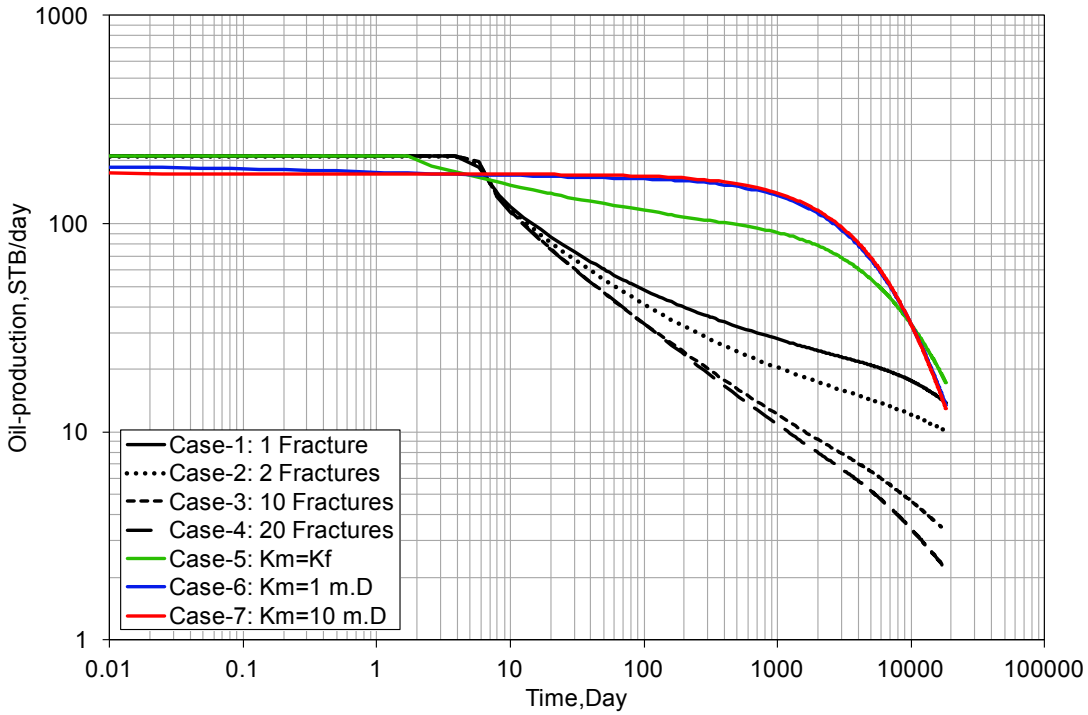


Fig. 4.22—Simulation well oil production profile of 7 cases by total revenue control, GOR_i=100,000 scf/STB.

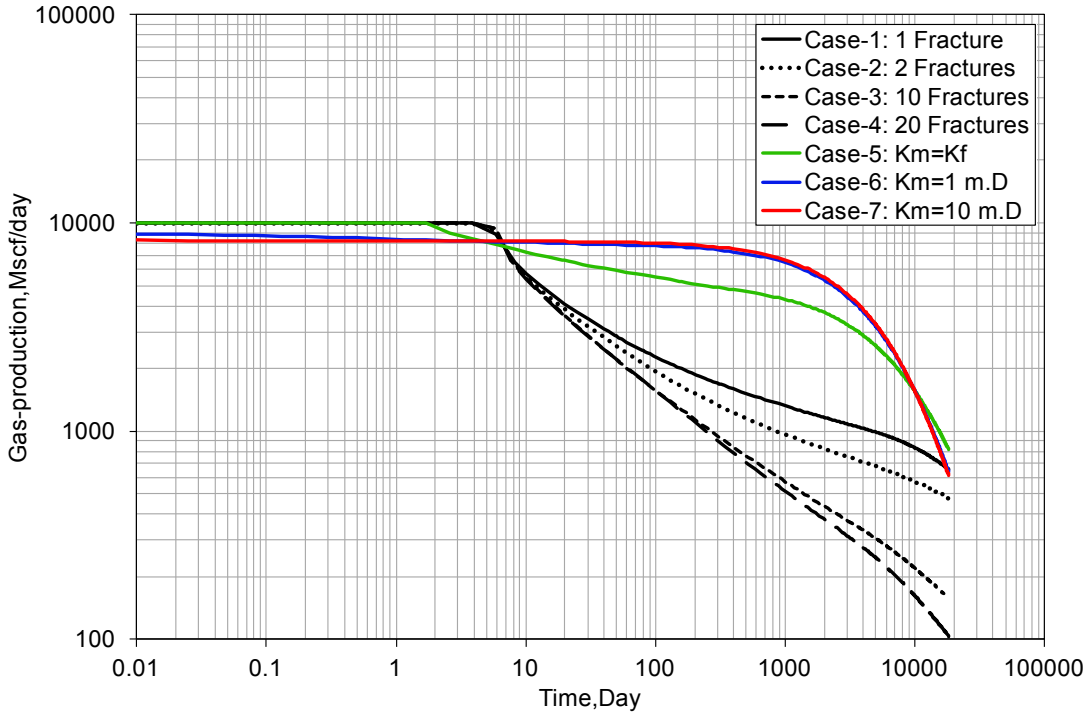


Fig. 4.23—Simulation well gas production profile of 7 cases by total revenue control, GOR_i=100,000 scf/STB.

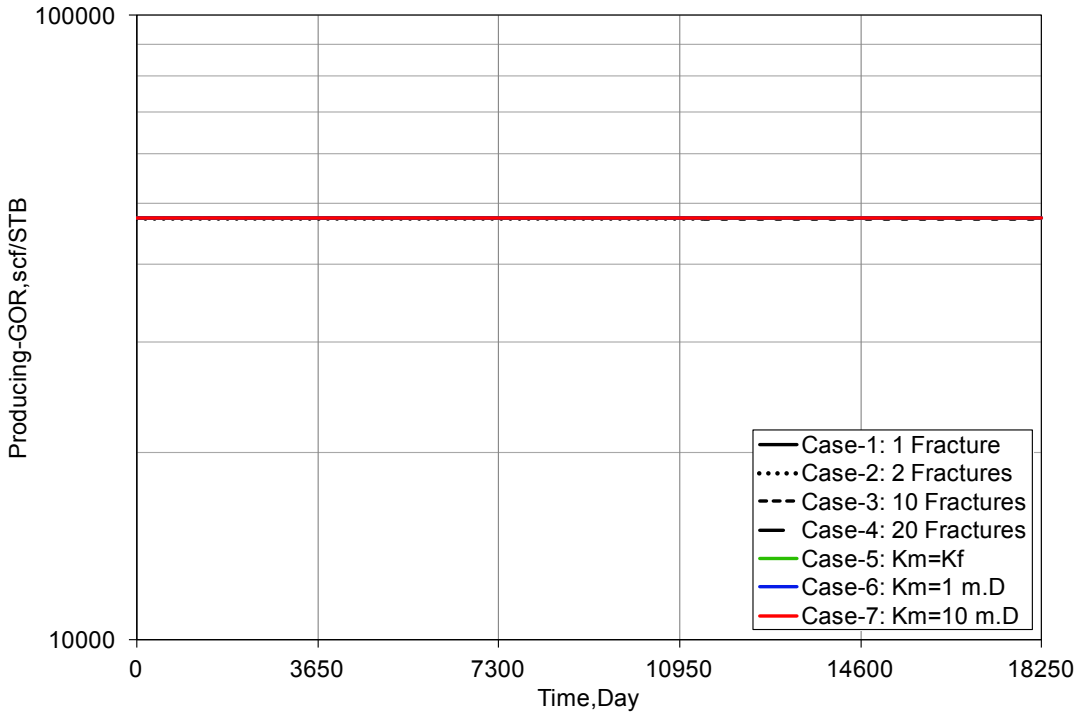


Fig. 4.24—Reservoir model producing gas-oil ratio profile of 7 cases by total revenue control, GOR_i=100,000 scf/STB.

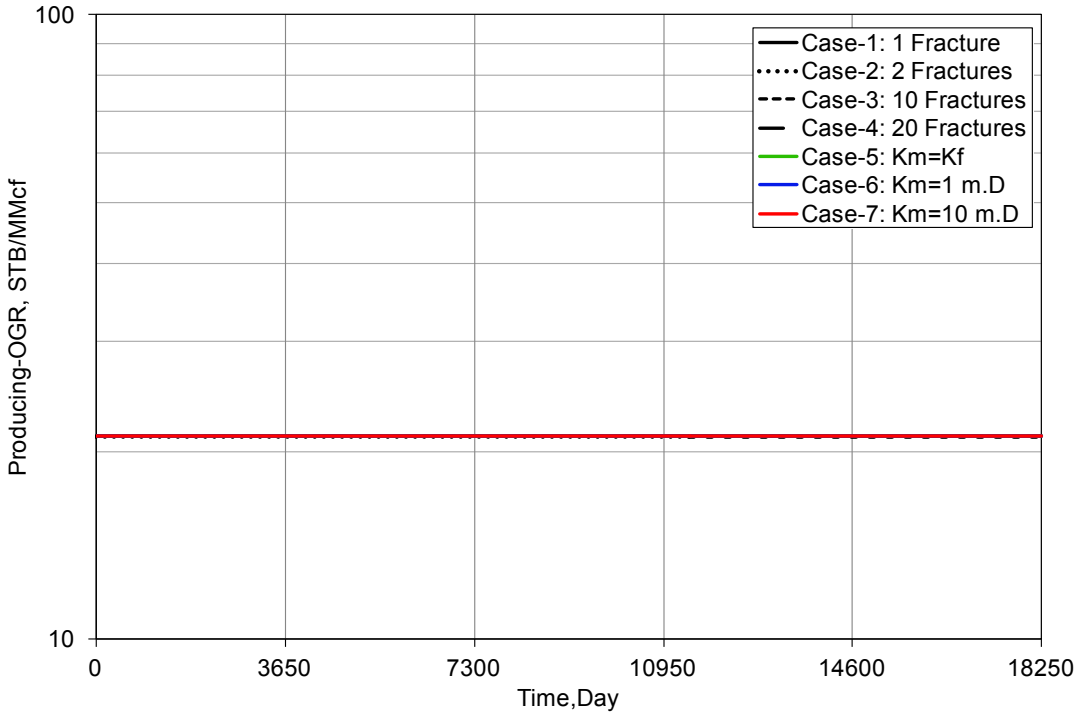


Fig. 4.25—Reservoir model producing oil-gas ratio profile of 7 cases by total revenue control, r_s=21,135 STB/MMcf(GOR_i=100,000 scf/STB).

4.6 Revenue Control Summary

This section summarizes the main features of these simulation cases which controlled under total revenue of 5×10^5 USD in the first 10 days. 7 cases with different reservoir matrix permeability are studied, ranging from conventional reservoir to unconventional reservoir.

Comparing with the simulations which controlled by gas production rate, there are some similar features and also some differences in the simulation results. The phenomenon of oil-gas ratio keeping in stable level appears in all low permeability reservoir cases. However, the optimal results of permeability combination are significantly different. This is because simulation in this section is controlled by total revenue, which takes into account the production of gas and oil together. But the simulation in Chapter 3 is only considered the gas rate. The production rate relates to the fluid type, which is controlled by the initial gas-oil ratio (GOR_i).

On the condition of critical case, unlike the relation of permeability and GOR_i in the case of gas rate control, the relation under total revenue control is not unidirectional, which is shown in **Fig. 4.26**. This is influenced by the simulation is considered both oil and gas, and the price of products is different.

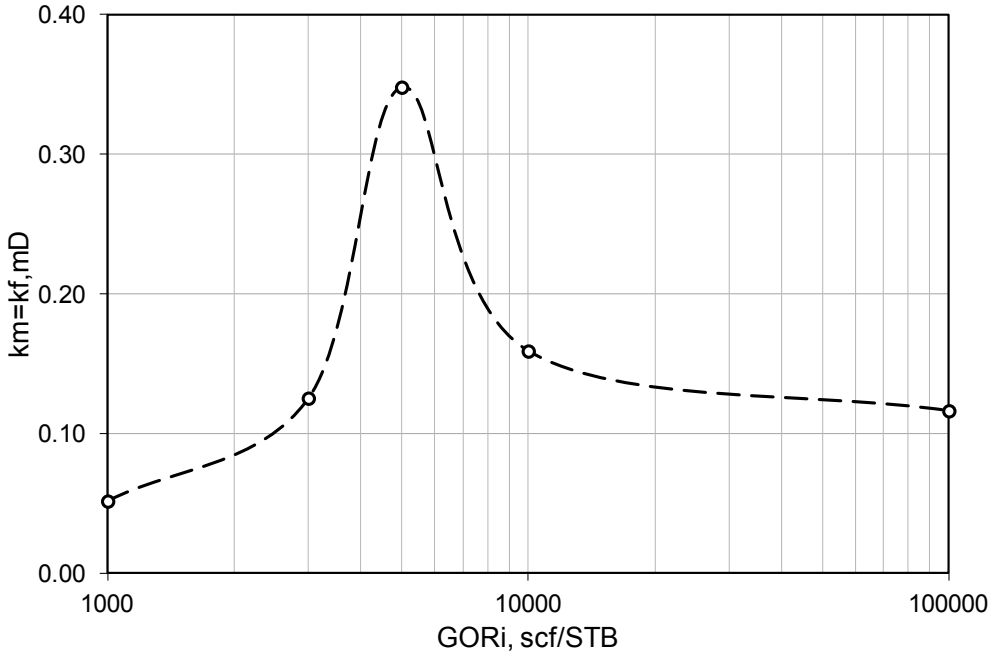


Fig. 4.26—Relation between reservoir permeability and initial gas-oil ratio, cases controlled by total revenue.

The optimal results of reservoir permeability are significantly affected by the initial gas-oil ratio. **Fig. 4.27** shows the revenue contribution from oil production in different fluids types. In the volatile oil reservoir (GOR_i=1,000 scf/STB), more than 90% of total revenue is from oil production. On the contrary, around 35% of total revenue is from oil production when reservoir fluid is wet gas (GOR_i= 100,000 scf/STB). The revenue contribution from oil production will vary in the near critical oil reservoir and gas condensate reservoir if reservoir permeability is changed.

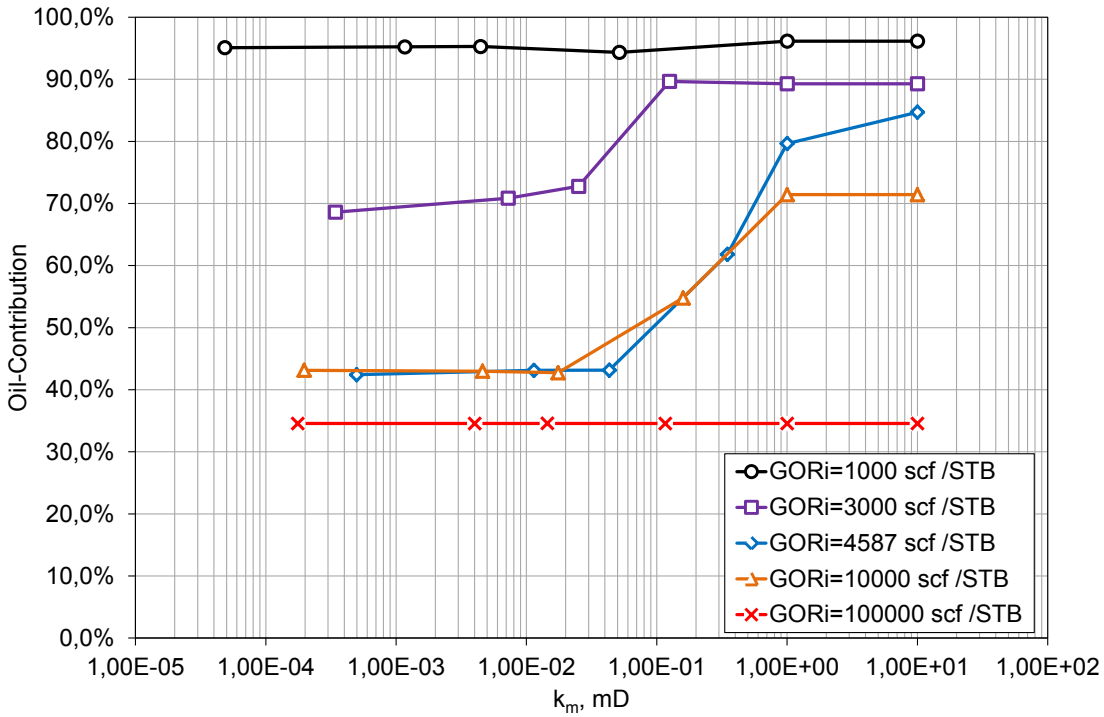


Fig. 4.27—Oil contribution to total revenue of the first 10 days in different initial gas-oil ratio

Chapter 5

Fractures Number and Reservoir Permeability Relation

This section presents the relation between the number of fractures and reservoir permeability when hydraulic fractures are used to stimulate the reservoir. The required number of fractures in the shale reservoir is calculated based on the analysis results.

5.1 Gas Rate Control

Table 5.1 lists the optimal results of the fractures number and reservoir permeability when the fracture permeability is fixed to 100,000 mD.

In low permeability reservoir, such as tight gas reservoir or shale reservoir, hydraulic fracturing treatment is required to obtain an economic production rate. The number of fractures is increased as matrix permeability reduced. **Fig. 5.1** shows the relation between the number of fractures and the reservoir matrix permeability when fixed the fracture permeability to 100,000 mD. There is a good agreement of linear correlation between fractures number and matrix permeability in log-log scale.

Table 5.1—RELATION BETWEEN FRACTURES NUMBER AND RESERVOIR PERMEABILITY BY GAS RATE CONTROL, k_f=100,000 mD

Fractures Number	Segment Spacing acre	GORi=1000 scf/STB k_m*,mD	GORi=3000 scf/STB k_m*,mD	GORi=4587 scf/STB k_m*,mD	GORi=10000 scf/STB k_m*,mD
1	320	0.9245	0.2690	0.1100	0.0440
2	160	0.3000	0.0710	0.0298	0.0120
10	32	0.0165	0.0030	0.0013	0.0005
20	16	0.0043	0.0008	0.0003	0.0001

k_m*: optimal result of matrix permeability when the fractures number and fluids type is fixed

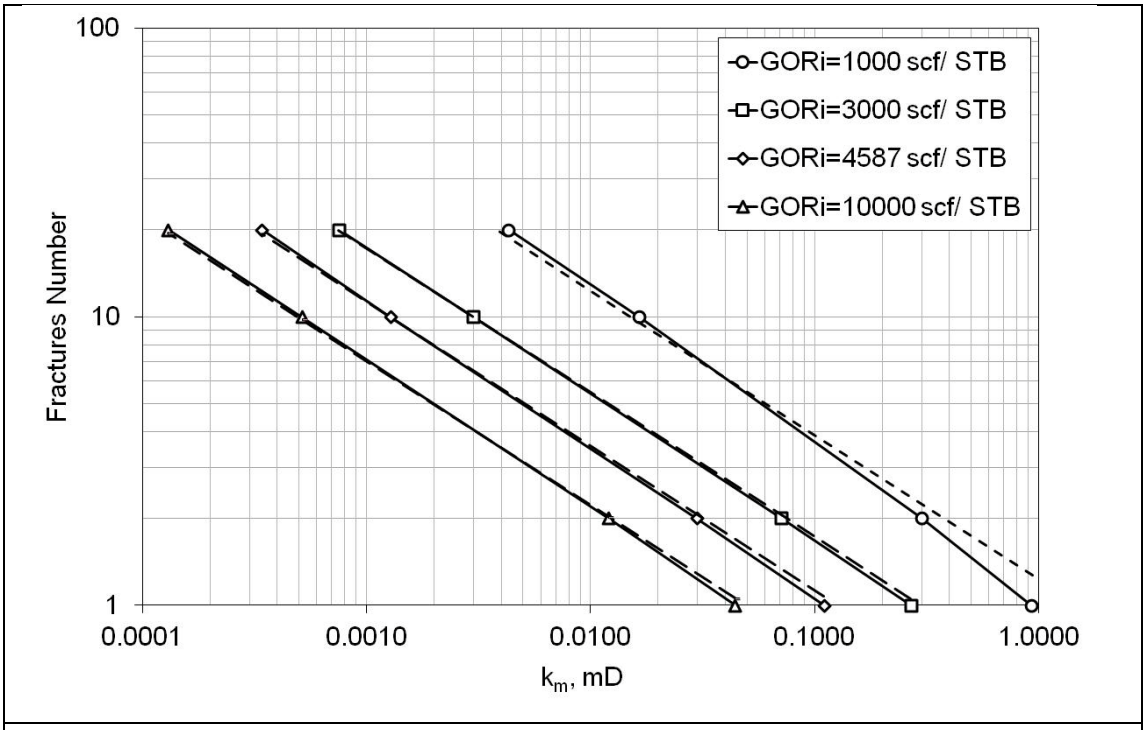


Fig. 5.1—Plot of fractures number in the function of reservoir matrix permeability, gas production control.

Equations between fractures number and matrix permeability are established for different reservoir fluids. The reservoir fluid system is defined by the initial gas-oil ratio (GOR_i). Dashed lines in **Fig. 5.1** show equation's plots of each fluid type:

GOR_i=1,000 scf/STB: $$N_f = \frac{1.2301}{\sqrt{k_m}} \quad (5.1)$$

GOR_i=3,000 scf/STB: $$N_f = \frac{0.5465}{\sqrt{k_m}} \quad (5.2)$$

GOR_i=4,587 scf/STB: $$N_f = \frac{0.3566}{\sqrt{k_m}} \quad (5.3)$$

GOR_i=10,000 scf/STB: $$N_f = \frac{0.2217}{\sqrt{k_m}} \quad (5.4)$$

In general, the relation between the fractures number and the reservoir matrix permeability is:

$$N_f = \frac{f(G,k_f,GOR_i,Con,\cdots)}{\sqrt{k_m}} \quad (5.5)$$

Where:

$f(G, k_f, GOR_i, Con, \cdots)$ is a function of fracture geometry, fracture permeability or conductivity, initial gas-oil ratio/reservoir fluids type, and simulation constraint, etc.

These equations can be used in the economic fractures number calculation when reservoir fluid type is specified. **Table 5.2** lists the calculation results in the shale reservoir range: 10^{-5} mD – 10^{-3} mD. Ignoring the revenue from oil production will lead to a big fractures number request in the oil type. This is unreasonable in times of high oil price.

Table 5.2—CALCULATION RESULTS OF FRACTURES NUMBER REQUEST BY GENERATED EQUATION, GAS RATE CONTROL

Fluid type	GOR_i	Fractures number(Integer Number)		
Gas Condensate	10000	70	22	7
Near Critical Oil	4587	113	36	11
Volatile Oil B	3000	173	55	17
Volatile Oil A	1000	389	123	39
		1,00E-05	1,00E-04	1,00E-03
		Shale Reservoir, k_m, mD		

5.2 Revenue Control

In the simulations under total revenue control, production both from gas and oil were calculated to the total revenue. Total revenue of 5×10^5 USD was set as the economic standard of the simulation constraint. **Table 5.3** summarizes the optimal results of matrix permeability in terms of fractures number when the fracture permeability is fixed to 100,000 mD. The relation between the number of fractures and matrix permeability is shown in **Fig. 5.2**. There is a linear correlation in the log-log plot.

Table 5.3—RELATION BETWEEN FRACTURES NUMBER AND RESERVOIR PERMEABILITY BY REVENUE CONTROL, k_f=100,000 mD

Fractures Number	Segment Spacing acre	GORi=1000 scf/STB k_m*,mD	GORi=3000 scf/STB k_m*,mD	GORi=4587 scf/STB k_m*,mD	GORi=10000 scf/STB k_m*,mD	GORi=100000 scf/STB k_m*,mD
1	320	0.00444	0.02512	0.04319	0.01750	0.01447
2	160	0.00117	0.00724	0.01142	0.00460	0.00401
10	32	0.00005	0.00034	0.00050	0.00020	0.00018
20	16	0.00001	0.00009	0.00013	0.00005	0.00004

k_m*: optimal result of matrix permeability when the fractures number and fluids type is fixed

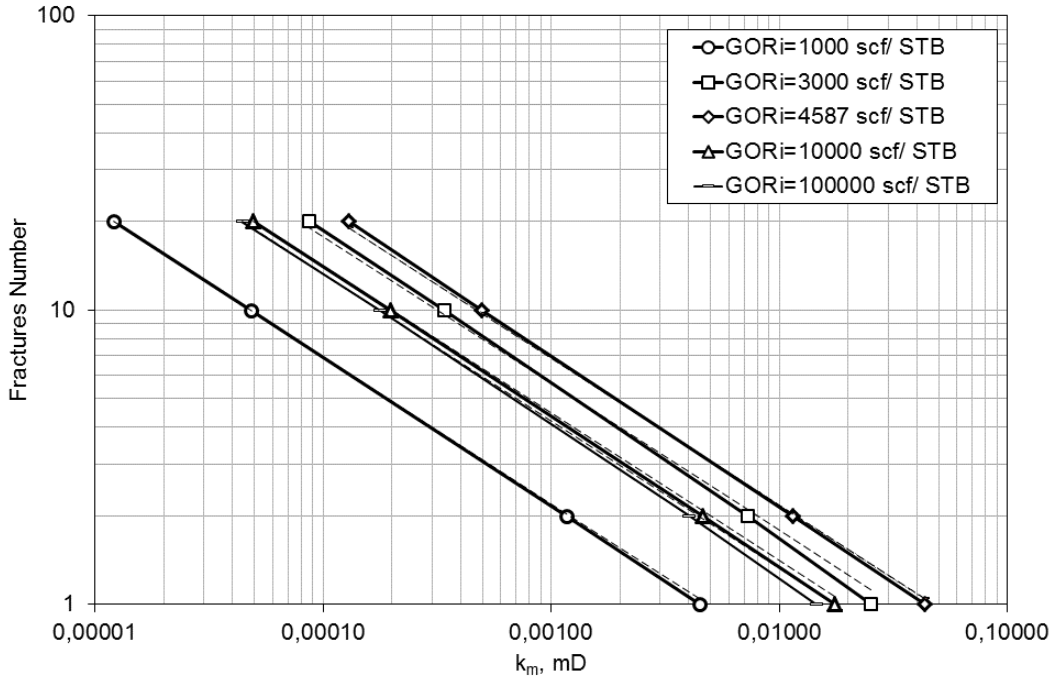


Fig. 5.2—Plot of fractures number in the function of reservoir matrix permeability, total revenue control.

Equations for each fluid system was generated based on the simulation results,

GOR_i=1,000 scf/STB: $$N_f = \frac{0.06936}{\sqrt{k_m}} \quad (5.6)$$

GOR_i=3,000 scf/STB: $$N_f = \frac{0.178}{\sqrt{k_m}} \quad (5.7)$$

GOR_i=4,587 scf/STB: $$N_f = \frac{0.217}{\sqrt{k_m}} \quad (5.8)$$

GOR_i=10,000 scf/STB: $$N_f = \frac{0.1407}{\sqrt{k_m}} \quad (5.9)$$

GOR_i=100,000 scf/STB: $$N_f = \frac{0.1326}{\sqrt{k_m}} \quad (5.10)$$

In general, same as the equation of (5.5), the relation between fractures number and matrix permeability is:

$$N_f = \frac{f(G,k_f,GOR_i,Con,\cdots)}{\sqrt{k_m}} \quad (5.11)$$

Where:

$f(G, k_f, GOR_i, Con, \cdots)$ is a function of fracture geometry, fracture permeability or conductivity, initial gas-oil ratio/reservoir fluids type, and simulation constraint, etc.

Table 5.4 gives the calculation results of required fractures number for shale reservoir which based on the generated equation. Numerically, the number of fractures in shale reservoir is much less than the results from gas rate control, particularly in the case of liquid rich reservoir, such as volatile oil and near critical oil. In the range of shale reservoir, the plot between fractures number and reservoir permeability reservoir is shown in **Fig. 5.3**. This plot can be used to fractures number evaluation if the reservoir's permeability and fluids type are known. Note that, all of this evaluation is based on the assumption of 5×10^5 USD total revenue in the first 10 days.

Table 5.4—CALCULATION RESULTS OF FRACTURES NUMBER REQUEST BY GENERATED EQUATION, REVENUE CONTROL

Fluid type	GOR_i	Fractures number(Integer Number)		
Wet Gas	100000	42	13	4
Gas Condensate	10000	44	14	4
Near Critical Oil	4587	69	22	7
Volatile Oil B	3000	56	18	6
Volatile Oil A	1000	22	7	2
		1,00E-05	1,00E-04	1,00E-03
		Shale Reservoir, k_m, mD		

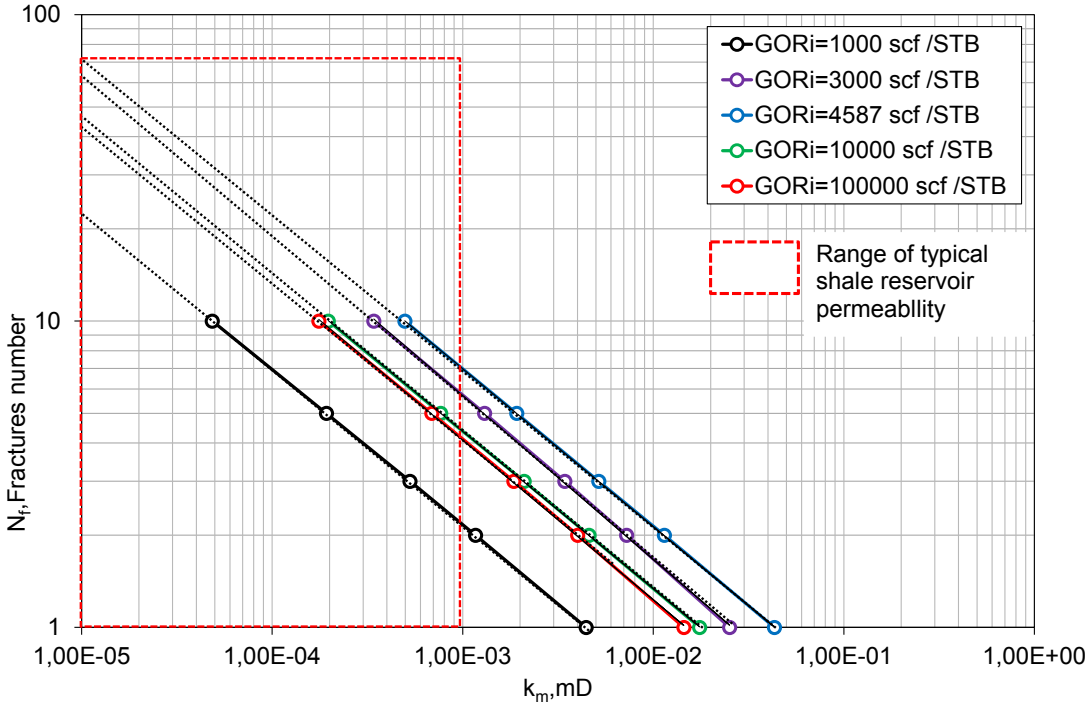


Fig. 5.3—Plot of fractures number and reservoir permeability when the fracture permeability fix to 100,000 mD and cumulative revenue of 5×10^5 USD.

Chapter 6

Production Performance Trends Study

This section presents the production performance variation trends from conventional reservoir to unconventional reservoir. The production from reservoir is not only the gas, but also petroleum liquid. Producing oil-gas ratio (r_p) is a precise parameter that is used to analyze the production performance of a liquid rich reservoir. A reservoir with initial gas-oil ratio of 4,587 scf/STB represents the near critical oil. In this part, the trends of producing oil-gas ratio are systematically studied, and the reservoir permeability ranges from high to ultra low. All of the results are based on numerical simulations.

Simulation models are designed with matrix permeability ranging from 10 mD to 10^{-5} mD. There are three combinations of matrix permeability and fracture permeability in the reservoir:

- High matrix permeability with low fracture permeability, fracture implemented as a damage factor which restricts the fluid flow from reservoir matrix to the well.
- Matrix permeability equal to fracture permeability, fracture on this condition is not contributing to the well's production.
- The fracture permeability is fixed to 100,000 mD together with low matrix permeability.

The optimal results from simulation are listed on **Table 6.1**. The value of fractures number is using an integer number, except the case when matrix permeability is closes to 0.1 mD.

The models are run to 50 years to compare their production performance of producing oil-gas ratio. Two concerns were expressed.

1, in the cases with high matrix permeability (k_m=10 mD, 5 mD and 1 mD), oil-gas ratio is high in the early stage and then decline during production period if the reservoir is developed by pressure depletion.

2, in the cases with low matrix permeability (k_m=0.001mD, 0.0001mD and 0.00001mD), oil-gas ratio drops immediately and stays in a low level over the duration of 50-years-production period.

Table 6.1—SIMULATION OPTIMAL RESULTS of CASE: GOR_i=4,587 scf/STB

k_m,mD		k_f, mD	N_f
10		0.0534	1
5		0.0769	1
1		0.1639	1
0.5		0.2363	1
0.348		0.348	0
0.12	≈0.1	100000	0.5*
0.0114	≈0.01	100000	2
0.000988	≈0.001	100000	7
0.000092	≈0.0001	100000	23
0.0000094	≈0.00001	100000	75

* half length of standard fracture length, 100 ft

The variation tendency of oil-gas ratio from high permeability to low permeability is shown in **Fig. 6.1**. It indicates that more liquids can be extracted from the conventional reservoir (high permeability) by pressure depletion. The producing oil-gas ratios (r_p) in conventional reservoir will decline as the production continues. Liquids production out of gas in unconventional reservoir is low and keeps steady, particularly for the reservoir of permeability less than 0.001 mD.

As the reservoir is developed by pressure depletion, the average pressure of reservoir determines the quantity of energy stored in the reservoir. In low permeability reservoir, pressure depletion only occurs in the area that nearby the fracture, the reservoir average pressure keeps in a high level even after decades of production. That means the fluids in the area which is far away from the fracture are hard to flow to the wellbore. In contrast, the fluids in the high-permeability reservoir are much easier to flow from reservoir matrix to the fracture and to the wellbore. The average pressure of reservoir will drop a lot if the reservoir has been developed for some decades. **Fig. 6.2** presents a 10 years producing oil-gas ratio profile in terms of reservoir average

pressure. The plots in the cases of k_m=5 mD and 10 mD are close to each other, indicating a constant volume depletion (CVD) process. The ratios of oil-gas in the cases with matrix permeability less than 0.001 md (k_m=0.001 mD, 0.0001 mD and 0.00001 mD) remain in a low level. As introduced in Chapter 2, the initial reservoir pressure is 4,800 psia. After 10 years of production, the average pressure is reduced to 3,850 psia in the reservoir with matrix permeability of 1 mD. However, a constant pressure of 4,650 psia occurs in the reservoir with ultra low permeability (k_m= 0.00001 mD). This is because the pressure drop is only happened in the area where around the fracture, or the drainage takes a long time to reach the segment's boundary.

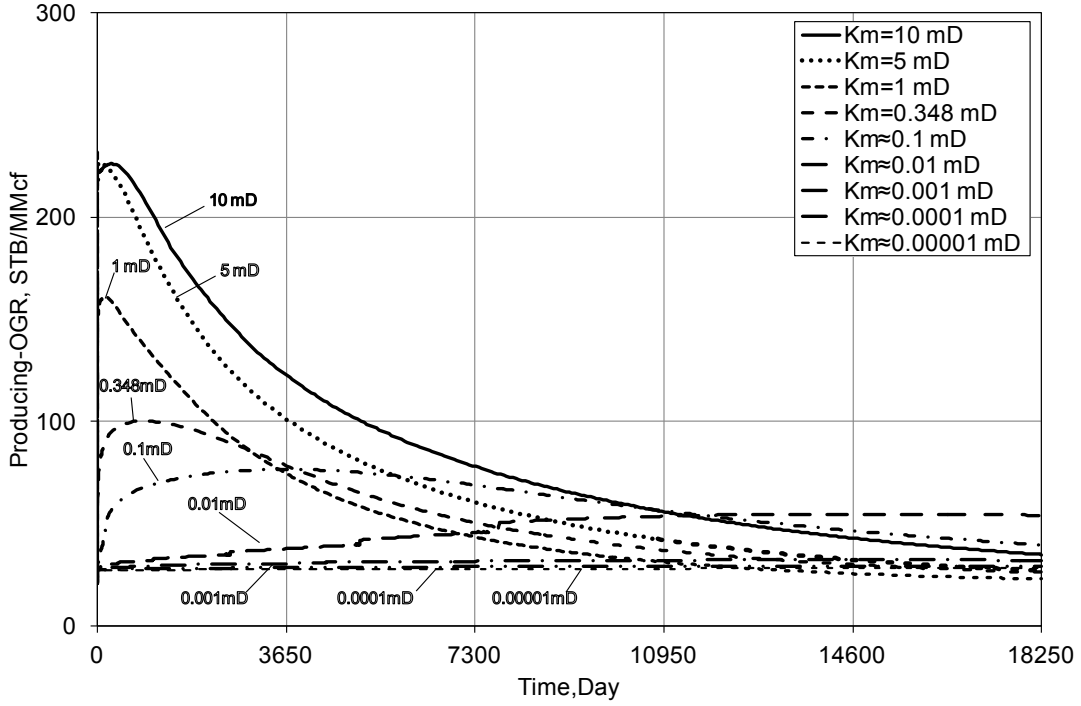


Fig. 6.1—Producing oil-gas ratio versus time, r_s= 218 STB/MMcf (GOR_i=4,587 scf/STB).

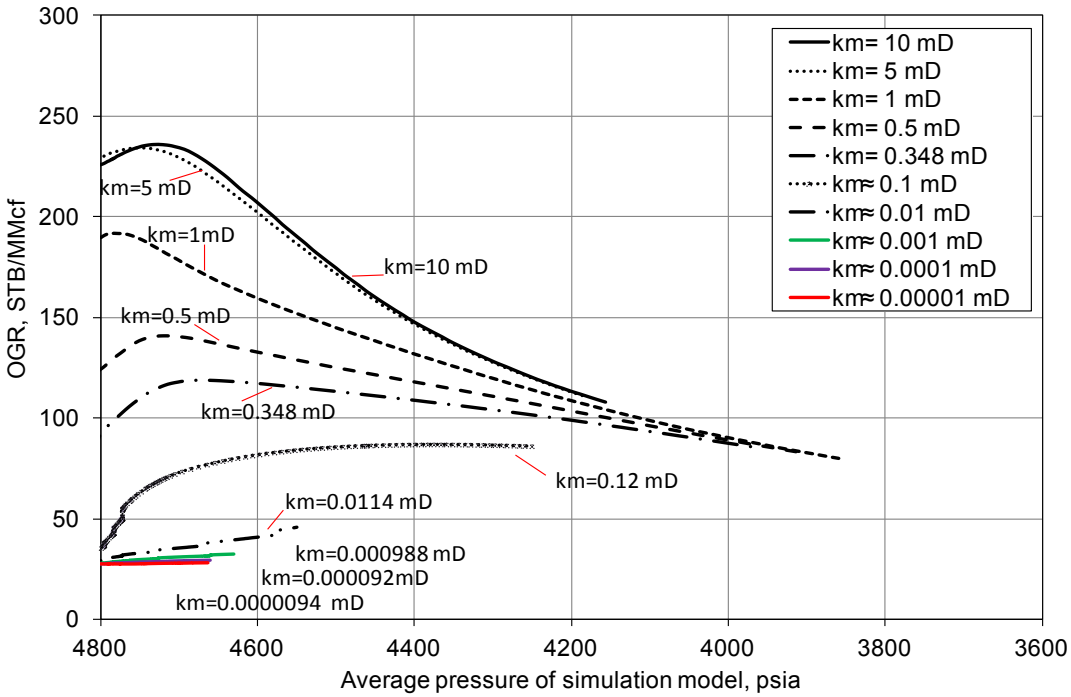


Fig. 6.2—Producing oil-gas ratio versus reservoir average pressure, r_s= 218 STB/MMcf (GOR$_i$=4,587 scf/STB).

After a 10-year production, the gas recovery factor is 2.7% in the lowest permeability case. We find a good way/method to classify the conventional reservoir and unconventional reservoir based on the producing oil-gas ratio. The processes are:

1. Selecting the gas recovery factor of 2.7% as the standard.
2. All cases with different reservoir matrix permeability are run to meet this standard.
3. Plot r_s/r_p versus k_m (reservoir matrix permeability) when gas recovery factor reached 2.7% of each case.

The plot of r_s/r_p versus reservoir matrix permeability is shown in **Fig. 6.3**. The value of r_s/r_p represents the percentage of liquids production from the reservoir. In the high-permeability reservoir, the value of r_s/r_p is close or equal to 1, while in the low-permeability reservoir, the value of r_s/r_p is much higher. In this plot, three zones can be classified: conventional, transition, and unconventional. This classification is based on the well production performance and is related to reservoir fluid types. In this near critical oil system, reservoir permeability higher than 1 mD can be defined as the conventional reservoir, and reservoir with permeability less than 0.0001 mD is classified to unconventional reservoir, the reservoir with permeability between these two values is a transition zone. This method of classification is useful and practical in the industry. Note that, the standard of unconventional is significantly different

between dry gas reservoir and volatile oil reservoir. In the dry gas reservoir, the gas is easier to extract from the reservoir of 0.1 mD permeability, while in the volatile oil reservoir it becomes difficult of the same permeability value.

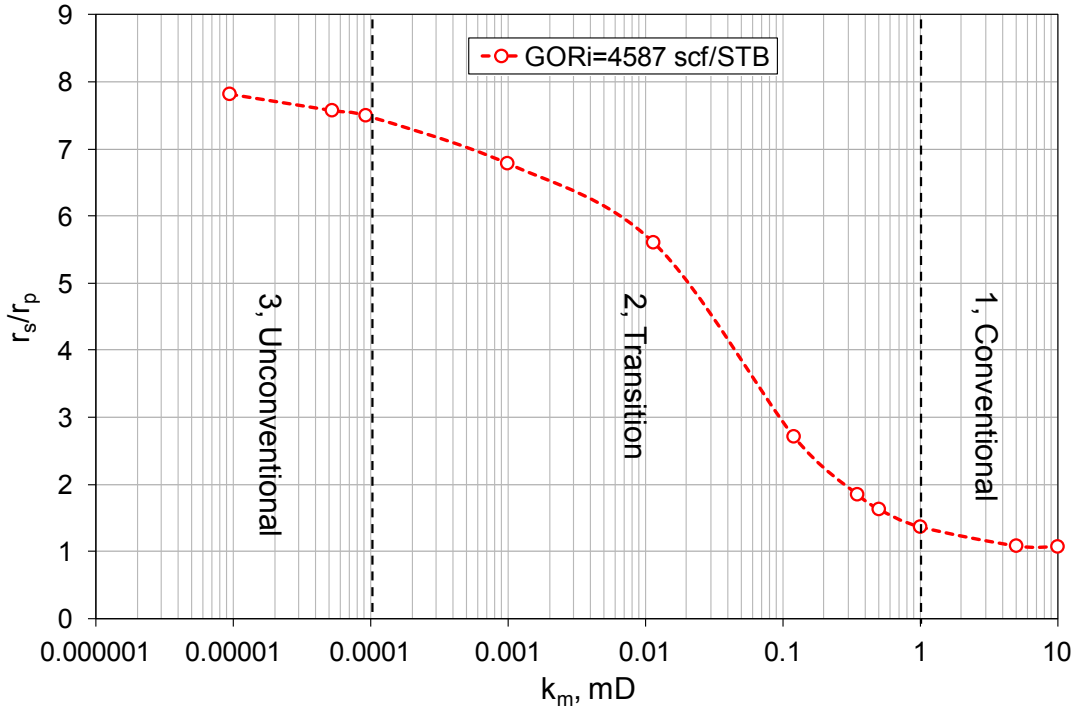


Fig. 6.3—r_s/r_p versus reservoir matrix permeability, and reservoir classification.

Chapter 7
Conclusion

Based on the ideal reservoir model, with a homogeneous layer and of constant parameters, numerical simulations were run in this study. Finally, the relation between fractures number and reservoir permeability are established. The trends of Production performance from conventional reservoir to unconventional reservoir were displayed as well.

1. With assumption of economic standards of either gas rate or total revenue, the required number of fractures will increase as the reservoir permeability decreases.

2. The reservoir with low permeability is developed economically with the help of hydraulic fracturing technology/treatment.

3. The relation between the number of fractures and reservoir permeability shows a linear correlation in the logarithm-logarithm coordinate system.

4. Less hydraulic fractures is required if the revenue of oil production is considered, particularly for the high liquid contents reservoir, such as volatile oil reservoir, near critical oil reservoir and liquid rich gas condensate reservoir.

5. The production performance ranging from the conventional reservoir to the unconventional reservoir is significantly affected by the reservoir permeability. In the conventional reservoir (high permeability), more liquid will be extracted from the reservoir and the producing ratio of oil-gas is declined as production. In the unconventional reservoir, the oil-gas ratio drops immediately and stays at a low level during the whole period of production.

6. Simulation oscillation problem only occurs in some cases of high permeability reservoir. This problem is caused by the model's gridding geometry and can be removed by changing the perforation location to the fracture's tip. A detailed analysis is included in **Appendix B**.

7. The plot of r_s/r_p versus reservoir permeability can be used to classify the zones of conventional, transition, and unconventional.

References

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Appendix A

SENSOR Input Deck

```
TITLE
 Simulate gas/oil flow in shale reservoir.
 Treat horizontal multi-frac well using vertical cartersian model
 - 1 mile × 1 mile area, with different farctures based on different
reservoir matrix permeability.
 - ignore gravity.
 - initial GOR=4587 scf/STB
 - reservoir thickness h=200 ft, half-fracture length yf=200 ft.
ENDTITLE

GRID 81 74 1
RUN
CPU
IMPLICIT
D4

MAPSFILE P SG SO SW KX
MAPSPRINT P SG SO SW KX

C    Bwi cw     denw visw cr     pref
MISC 1   3.0E-6 62.4 0.5  4.0E-6 6000

C ---------------------------------
C I_CELLS          81
C J_CELLS          74
C K_CELLS          1
C DEPTH            10000
C SYM_ELEMENTS     2
C ---------------------------------

C ---------------------------------------------------------------------
C Cell width along wellbore
C ---------------------------------------------------------------------
DELX XVAR
27.8751  21.9888  17.3455  13.6827  10.7934  8.51416  6.71626  5.29801  4.17924
3.29673  2.60057  2.05141  1.61822  1.27651  1.00695  0.79432  0.62658  0.49427
0.3899   0.30756  0.24262  0.19138  0.15097  0.11909  0.09394  0.0741   0.05846
0.04611  0.03638  0.02869  0.02263  0.01785  0.01408  0.01111  0.00876  0.00691
0.00545  0.0043   0.00339  0.00268  0.01     0.00268  0.00339  0.0043   0.00545
0.00691  0.00876  0.01111  0.01408  0.01785  0.02263  0.02869  0.03638  0.04611
0.05846  0.0741   0.09394  0.11909  0.15097  0.19138  0.24262  0.30756  0.3899
0.49427  0.62658  0.79432  1.00695  1.27651  1.61822  2.05141  2.60057  3.29673
4.17924  5.29801  6.71626  8.51416  10.7934  13.6827  17.3455  21.9888  27.8751

C ---------------------------------------------------------------------
C Cell width away from wellbore
C ---------------------------------------------------------------------
DELY YVAR
164.52  96.855  57.0189  33.5672  19.7611  11.6334  6.8487   4.0318   2.3736
1.3973  0.8226  0.4843   0.2851   0.1678   0.0988   0.0582   0.0342   0.0202
```

```
0.0119  0.0070  0.0026   0.0032   0.0040   0.0051   0.0064   0.0080   0.0101
0.0127  0.0159  0.0200   0.0251   0.0315   0.0396   0.0497   0.0625   0.0785
0.0986  0.1239  0.1556   0.1955   0.2456   0.3086   0.3876   0.4870   0.6117
0.7685  0.9654  1.2128   1.5236   1.9141   2.4046   3.0208   3.7949   4.7673
5.9890  7.5237  9.4517   11.8738  14.9165  18.7390  23.5410  29.5736  37.152
46.672  58.633  73.6577  92.5331  116.245  146.034  183.457  230.469  289.53
363.72  456.93

C -----------------------------------------------------------------------
C Porosity
C -----------------------------------------------------------------------
POROS CON
    0.059

MOD
41 41 1 20 1 1 = 0.3

C -----------------------------------------------------------------------
C Permeability
C -----------------------------------------------------------------------
KX CON
 8.953e-05

MOD
41 41 1 20 1 1 = 100000

KY EQUALS KX
KZ EQUALS KX

C -----------------------------------------------------------------------
C Depth
C -----------------------------------------------------------------------
DEPTH CON
 10000

C -----------------------------------------------------------------------
C Thickness
C -----------------------------------------------------------------------
THICKNESS CON
 200

C -----------------------------------------------------------------------
C Relperm
C -----------------------------------------------------------------------
KRANALYTICAL 1
  0.2 0.2 0.2 0.1      ! Swc Sorw Sorg Sgc
  1 0.5 1                   ! krw(Sorw) krg(Swc) kro(Swc)
  2.5 2.5 2 3 1 0.2   ! nw now ng nog (nwg Swcg)

C -----------------------------------------------------------------------
C Black oil table
C -----------------------------------------------------------------------

BLACKOIL    1     26    30   SRK
PRESSURES 100   500 1000 1200 1400 1600 1800 2000 2200 2400 2600 2800
2900 3000 3100 3200 3300 3400 3600 3800 4000 4200 4400 4600 4800 4825
5500 6000 6500 7000

RESERVOIR FLUID
0.00000000
0.00009032
0.00028785
0.72443534
0.09995367
0.04329560
```

```
0.01200208
0.01612318
0.00799159
0.00604448
0.01486822
0.01338211
0.01085318
0.00878513
0.00723370
0.00595599
0.00490595
0.00404363
0.00333555
0.00275400
0.00227619
0.00188340
0.00156027
0.00129424
0.00107500
0.00089414
0.00074477
0.00062126
0.00051899
0.00043420
0.00235598

SEPARATOR
440   104
14.70 60.0

ENDBLACKOIL

C ------------------------------------------------------------------------
C Fluid Properties
C ------------------------------------------------------------------------
PVTEOS SRK
250  ! Reservoir temperature (deg F)
```

CPT	MW	TC	PC	ZCRIT	SHIFT	AC	PCHOR
H2S	34.082	672.12	1299.97	0.28292	0.10153	0.09	80.1
N2	28.014	227.16	492.84	0.29178	-0.0009	0.037	59.1
CO2	44.01	547.42	1069.51	0.27433	0.21749	0.225	80
C1	16.043	343.01	667.03	0.2862	-0.0025	0.011	71
C2	30.07	549.58	706.62	0.27924	0.05894	0.099	111
C3	44.097	665.69	616.12	0.2763	0.09075	0.152	151
I-C4	58.123	734.13	527.94	0.28199	0.10952	0.186	188.8
N-C4	58.123	765.22	550.56	0.27385	0.11028	0.2	191
I-C5	72.15	828.7	490.37	0.27231	0.09773	0.229	227.4
N-C5	72.15	845.46	488.78	0.26837	0.11947	0.252	231
C6	83.676	921.53	473.57	0.244	0.13422	0.252	235.82
C7	96.986	984.11	437.78	0.24284	0.14547	0.28777	267.77
C8	110.671	1038.77	402.88	0.2409	0.15739	0.32768	300.61
C9	124.134	1087.82	370.65	0.23727	0.17497	0.36975	332.92
C10	137.435	1131.48	342.84	0.23464	0.19184	0.41118	364.84
C11	150.672	1171.07	318.6	0.2317	0.20799	0.45208	396.61
C12	163.837	1207.22	297.38	0.22867	0.2233	0.49235	428.21
C13	176.92	1240.4	278.73	0.22619	0.23772	0.53195	459.61
C14	189.918	1271.03	262.24	0.22366	0.25121	0.57085	490.8
C15	202.824	1299.42	247.61	0.22116	0.26379	0.60905	521.78
C16	215.636	1325.84	234.57	0.21908	0.27547	0.64654	552.53

```
C17   228.35   1350.51  222.89   0.21732  0.28628  0.68333  583.04
C18   240.964  1373.64  212.41   0.21557  0.29626  0.71942  613.31
C19   253.475  1395.37  202.95   0.21387  0.30547  0.75483  643.34
C20   265.883  1415.85  194.39   0.21244  0.31394  0.78956  673.12
C21   278.188  1435.21  186.63   0.21124  0.32173  0.82362  702.65
C22   290.389  1453.54  179.56   0.21007  0.32889  0.85704  731.93
C23   302.486  1470.94  173.1    0.20909  0.33545  0.88981  760.97
C24   314.481  1487.49  167.18   0.20827  0.34148  0.92197  789.75
C25   326.374  1503.27  161.75   0.20748  0.34699  0.95351  818.3
C26+  422.424  1612.22  129.42   0.20385  0.37814  1.19607  1048.82

BIN

        H2S     N2    CO2 C1  C2  C3 I-C4 N-C4 I-C5 N-C5 C6  C7  C8  C9 C10 C11 C12 C13 C14 C15 C16 C17 C18 C19 C20 C21 C22 C23 C24 C25 C26+
H2S      0
N2       0    0
CO2   0.08 0.02    0
C1    0.07 0.06 0.12 0
C2    0.07 0.08 0.12 0  0
C3    0.06 0.08 0.12 0  0  0
I-C4  0.06 0.08 0.12 0  0  0  0
N-C4  0.06 0.08 0.12 0  0  0  0  0
I-C5  0.06 0.08 0.12 0  0  0  0  0  0
N-C5  0.05 0.08 0.12 0  0  0  0  0  0  0
C6    0.03 0.08 0.12 0  0  0  0  0  0  0  0
C7    0.03 0.08  0.1 0  0  0  0  0  0  0  0  0
C8    0.03 0.08  0.1 0  0  0  0  0  0  0  0  0  0
C9    0.03 0.08  0.1 0  0  0  0  0  0  0  0  0  0  0
C10   0.03 0.08  0.1 0  0  0  0  0  0  0  0  0  0  0  0
C11   0.03 0.08  0.1 0  0  0  0  0  0  0  0  0  0  0  0  0
C12   0.03 0.08  0.1 0  0  0  0  0  0  0  0  0  0  0  0  0  0
C13   0.03 0.08  0.1 0  0  0  0  0  0  0  0  0  0  0  0  0  0  0
C14   0.03 0.08  0.1 0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0
C15   0.03 0.08  0.1 0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0
C16   0.03 0.08  0.1 0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0
C17   0.03 0.08  0.1 0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0
C18   0.03 0.08  0.1 0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0
C19   0.03 0.08  0.1 0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0
C20   0.03 0.08  0.1 0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0
C21   0.03 0.08  0.1 0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0
C22   0.03 0.08  0.1 0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0
C23   0.03 0.08  0.1 0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0
C24   0.03 0.08  0.1 0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0
C25   0.03 0.08  0.1 0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0
C26+  0.03 0.08  0.1 0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0

SEP 1
500    150
14.70  60.0

C  ------------------------------------------------------------------
C Initialize
C ------------------------------------------------------------------
INITIAL

DEPTH  GOR
10000  4587

  PINIT 4800
  ZINIT 10000

ENDINIT

C ------------------------------------------------------------------
C Trans. modification to fractures
C ------------------------------------------------------------------
MODIFY TX 1.0
 40 40 20 20 1 1 * 1
 41 41 20 20 1 1 * 1
```

```
C ------------------------------------------------------------------------
C Define Wells
C ------------------------------------------------------------------------
WELL
       I   J   K
PROD   41  1   1

BHP
PROD 500

WELLTYPE
 PROD MCF

PSM
C ------------------------------------------------------------------------
C Define rate schedules.
C ------------------------------------------------------------------------
RATE
 PROD 10000

MAPSFREQ 1
MAPSFILEFREQ 1

DT 0.01

TIME 10

TIME 365 30

TIME 2000 100

TIME 3650 365

TIME 7300 3650 ! Simulation time table can be edited as required.

END
```

Appendix B

Simulation Oscillation Problem Analysis

The simulation oscillation problem only occurs in the cases with high matrix permeability, which list on **Table Appendix B-1**. However, not all cases with high matrix permeability exists the simulation oscillation problem. Under the control either by gas rate or total revenue, fracture permeability is restricted to meet the constraint of gas rate or total revenue if its matrix permeability is higher than the reservoir permeability of critical case. In that cases, low-conductivity fracture play as a reservoir damage role which blocks the fluids flow from the reservoir's matrix to the horizontal wellbore.

Table Appendix B-1—LIST OF CASES WITH OSCILLATION PROBLEM

Case No.	Simulation Controling type	GOR_i scf/STB	k_m mD	k_f mD
1	Gas rate	3,000	5	0.1972
2	Gas rate	3,000	10	0.1923
3	Gas rate	10,000	5	0.0907
4	Revenue	1,000	0.051518	0.051518
5	Revenue	10,000	1	0.032707

The problem of oscillation is caused by model's gridding structure, which finest grids system nearby the fracture tip (41, 20, 1). But the producer is locates at the joint of wellbore and fracture (41, 1, 1), the grids size around producer is not gradual grow in y direction. In high matrix permeability cases, the fracture permeability is reduced to limit the well's production, and the fracture works as a damage factor for production.

In order to remove the simulation oscillation problem, well perforation location is relocated to the fracture tip (41, 20, 1), which is show in **Fig. Appendix B-1**. This relocation of perforation makes the grids nearby producer changed gradually and all of the smallest grids are close to the perforation grids. Take the case of GOR_i=3,000 scf/STB and with 5 mD reservoir matrix permeability as the example, the simulation

oscillation problem exists in the early 200 days if the producer is perforated at the joint. As seen in **Fig. Appendix B-2**, the oscillation problem in the early 200 days is omitted after we move the perforation location to the fracture tip. Two parameters are changed to meet the gas rate constraint: productivity index of well and the fracture permeability. In the case with matrix permeability is 5 mD, well's production index is changing from 0.07389 RB-CP/D-PSI to 200 RB-CP/D-PSI, and the fracture permeability is changed from 0.1792 mD to 0.242 mD.

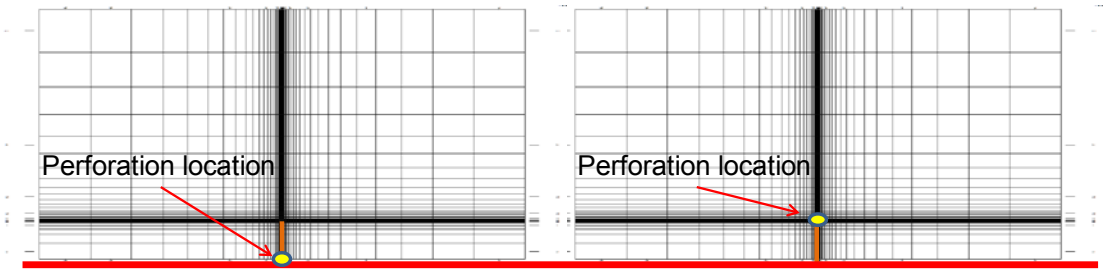

Fig. Appendix B-1—Relocation the well's perforation location from wellbore to fracture tip.

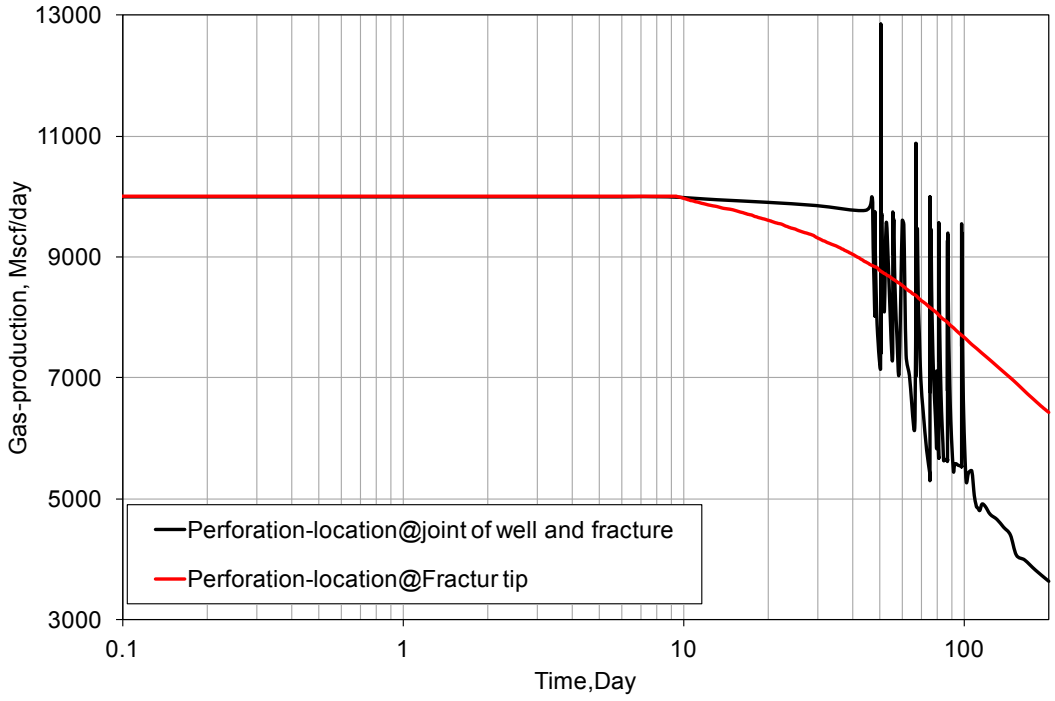

Fig. Appendix B-2—Comparison of simulation results between two cases with different perforation location.

In summary, the simulation oscillation problem only exists in some cases with high matrix permeability and can be resolved by changing the perforation position. However, the productivity index and fracture permeability need to be changed as well.