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INVESTIGATION ON CONTROLLING PARAMETERS ON
ZONAL GAS PRODUCTION OF MULTILAYER SYSTEM

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การศึกษานี้ได้ศึกษาพารามิเตอร์ที่ควบคุมการผลิตก๊าซจากระบบหลายชั้น โดยการศึกษามุ่งสนใจสภาวะที่อัตราการไหลในแต่ละชั้นเป็นสัดส่วนโดยตรงกับปริมาตรก๊าซของชั้นดังกล่าว มีการศึกษาผลกระทบจากคุณสมบัติของชั้นหินและอัตราการไหลของหลุมผลิตต่อความสัมพันธ์ระหว่างอัตราการไหลและปริมาตรก๊าซของชั้นนั้น การศึกษาใช้แบบจำลองแหล่งกักเก็บแบบระบบสองชั้น ประมวลผลสัดส่วนการไหลในหลายกรณี และใช้แบบจำลองระบบห้าชั้นในการทดสอบยืนยันข้อสรุปจากระบบสองชั้นเพื่อใช้กับระบบหลายชั้น

ผลการศึกษาพบว่าสัดส่วนการไหลของก๊าซในระบบหลายชั้นแปรผันตรงกับสัดส่วนของปริมาตรก๊าซในแต่ละชั้นในช่วงที่การไหลอยู่ในสภาวะเสถียรก็ต่อเมื่อ อัตราการไหลจากระบบน้อยกว่าความสามารถเต็มที่ของการไหล อีกทั้งสัดส่วนของการไหลของก๊าซในระบบหลายชั้นแปรผันตรงกับผลคูณของปริมาตรก๊าซ, อัตราการเปลี่ยนแปลงของแรงดันภายในแหล่งกักเก็บในระหว่างการผลิต, และส่วนกลับของความดันภายในแต่ละชั้นในช่วงเวลาที่ยาวกว่า (คือตลอดช่วงสภาวะคงตัวเทียม) อย่างไรก็ตามในช่วงที่การไหลอยู่ในสภาวะเสถียร (ส่วนหนึ่งของสภาวะคงตัวเทียม) อัตราส่วนของอัตราการเปลี่ยนแปลงของแรงดันภายในแหล่งกักเก็บในระหว่างการผลิตกับแรงดันภายในแหล่งกักเก็บของทุกชั้นจะมีค่าใกล้เคียงกันมากจนสามารถตัดกันทิ้งได้ นอกจากนี้สัดส่วนการไหลจะแปรผันตรงกับอัตราส่วนของความสามารถเต็มที่ของการไหล เฉพาะในช่วงต้นของการไหลเมื่อการไหลจากระบบเข้าใกล้ระดับความสามารถเต็มที่ของการไหล สำหรับพารามิเตอร์อื่นที่ควบคุมสัดส่วนการไหลของก๊าซจากระบบหลายชั้นยังได้แก่อัตราการไหลของหลุมและค่าความซึมผ่าน

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This study is intended to investigate controlling parameters of rate allocation from multi-layer system. The study is concentrated on the condition that rate allocation is proportional to gas volume in each layer. The effects from rock properties and flow rate to the gas volume allocation are investigated. The two-layered gas reservoir is used for investigation under various cases and the five-layered system is used for test of validity of this study to more layers reservoir.

From the study, rate allocation of multi-layered gas reservoir is proportional to gas volume ratio during the stabilized flow on the conditions that flow rate is less than flow capacity of reservoir. The rate allocation of multi-layered gas reservoir is also proportional to a product of gas volume, rate of change of reservoir pressure, and inverse of reservoir pressure of each layer for longer period (the whole pseudo-steady state period). However, during the stabilized flow (part of the pseudo-steady stage period) the ratio of rate of change of reservoir pressure and reservoir pressure of all layers are very close to each other and can be cancelled out. The rate allocation obey kh ratio during the early stage of flow when flow rate is close to flow capacity. The other controlling parameters are flow rate and permeability.

Department: Mining and Petroleum Engineering	Student's Signature..........
Field of Study: Petroleum Engineering	Advisor's Signature..........
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Contents

CHAPTER Page

List of Tables

Page

Page

List of Figures

Page

Page

List of Abbreviations

cp	centipoise
GIP	Gas-In-Place
mD	millidarcy
MMscf/d	million standard cubic feet per day
NTG	net-to-gross rock volume
OGIP	original Gas-In-Place
PLT	production logging tool
PVT	pressure-volume-temperature
RB or rb	reservoir barrel
RCF or rcf	reservoir cubic feet
SCAL	special core analysis
SCF or scf	standard cubic feet
STB or stb	stock-tank barrel

Nomenclatures

A	cross-section area
B_g	gas formation volume factor
c	fluid compressibility
d	differential operator
E	gas expansion factor
h	height or thickness
k	permeability
k_{rg}	gas relative permeability
k_{rw}	water relative permeability
p	pressure
q	volumetric flow rate
s	skin factor
S	saturation
t	time period
T	temperature
V	volume

GREEK LETTER

ϕ	porosity
Δ	difference operator
∂	partial differential operator

SUBSCRIPTS

g	gas
i	initial
w	water

CHAPTER I

INTRODUCTION

From reservoir management perspective, the ability to fully understand the reservoir is always considered as an advantage. Unfortunately, the resources to be spent in obtaining necessary data to achieve such aim are usually enormous. Therefore, the industry has been relied on the use of analytical procedure to compensate for the lack of direct measured data.

This is also the case for multi-layered gas reservoirs. In order to optimize production, the accurate determination of individual reservoir layer is necessary. The widely used methods of reservoir Gas In-Place determination are volumetric determination and material balance techniques.

Although both methods have found to be satisfactory in general, there are still limitations. The material balance cannot estimate GIP of individual layer, if the well production is commingled. The volumetric method relies on area extent of the reservoir which cannot be accurately acquired.

The relationship between production rate allocation and controlling parameters of multi-layered reservoirs has been discussed by Panichakul [1] and Wuttinansantikul [2] which will be covered in the next section. However, the correlation between rate allocation and the controlling parameters and the applicable range of rock properties have not been identified. The period required for the influence of controlling parameters to fully take place is also needed to be investigated. In summary, this study intends to propose such a correlation to estimate GIP of each layer which will be useful in terms of production optimization and reservoir management.

1.1 Outline of Methodology

To investigate the relationship of rate allocation and reservoir properties, it is necessary to have all reservoir data and performance. The reservoir simulation will be used in this study to generate all reservoir data, i.e. GIP or gas volume in the reservoir, reservoir pressure, flow rate from each layer and other related data. These data are considered to be actual data of a gas reservoir.

The hypothetical two-layered gas reservoir with depletion drive will be used for investigation in this study. The reservoir contains gas with no condensate dropping out in the reservoir during the production life. A homogeneous system is used in order to avoid obscurity due to heterogeneity that may exist when performing the investigation. Some rock and fluid properties and well characteristics will be fixed while the studied parameters are going to be changed to check their effects on the final results.

The study is carried out in following steps:

1) Set up of hypothetical reservoir model

In this step, a two-layered hypothetical reservoir model will be constructed. Various rock and fluid properties as well as reservoir characteristics of a typical reservoir in the Gulf of Thailand will be used to construct a reservoir model. The hypothetical model will be used for investigation of effects of all interesting parameters.

2) Study and identify relationship of rate allocation within various parameters range

Production rate of each sand layer will be observed when studied parameters are varied. The study will concentrate on the range of rock properties and flow rate that rate allocation has strong relationship with the controlling parameters. The period required for the influence of studied parameters to fully control the allocated rate will also be identified. In addition, the limitations of relationships of rate allocation and studied parameters will be investigated.

3) Propose GIP estimation method based on flow rate

After the correlation is obtained from the hypothetical model, it will be rearranged for estimating Gas In-Place based on flow rate data. This estimation method will be checked for validation by testing with flow data obtained from simulation run of a five-layered hypothetical model.

CHAPTER II

LITERATURE REVIEW

This chapter discussed previous works that are related to rate allocation of multi-layered reservoir and methodology to allocate flow rate of each layer.

2.1 Previous Works on Rate Allocation of Multi-layered reservoir

From his thesis, Panichakul [1] studied the reserve evaluation for multi-layered gas reservoir using material balance method. His study was carried out by comparing the OGIP obtained from p/z plots to the actual value from volumetric calculation of the simulator. His simulation run showed that flow rate for each layer was not constant though the total flow rate was constant and did not follow the kh allocation concept that was widely used. At the beginning of production period the rate allocation obeys the kh allocation concept, but after production pass into later period, the rate allocation does not obey the kh allocation concept and deviates to the trend that obeys the pore volume allocation concept. Actually, the pore volume mentioned in his study is gas volume.

Based on his findings, the relationship between allocation rate and pore volume can be concluded as follows:

- pore volume of each layer seems to have more influence on flow rate allocation than permeability.
- At high rate, the influence of pore volume on flow rate allocation seems to decrease and the influence of permeability seems to increase.
- At low flow rate, the influence of permeability can be negligible and rate allocation can be considered to be solely influence by pore volume of each layer.

Further detailed investigation on flow rate allocation for a two-layered system was recommended.

Wuttinansantikul [2] studied the condition that kh rule can be applied for flow contribution of multi-layered oil system. The controlling factor in case that flow contribution does not obey kh rule was investigated. From his study, rate allocation is controlled by kh rule and ϕAh rule and not controlled by individual parameters in these groups. The rate allocation obeys kh rule when the flow from the system is at fully flow capacity and only at starting period of production time. The rate allocation obeys ϕAh when the flow from the system is lower than flow capacity and is affected by ϕAh due to oil expansion. There are other controlling factors affecting rate allocation, i.e. presence of free gas, pressure depletion, and expandable fluid. Most controlling factors affecting flow contribution are related to energy in the reservoir except kh. It is found that OIP can be substituted for ϕAh in his study.

Fetkovich et al. [3] studied the depletion performance of a two-layered gas reservoir producing without crossflow using material balance and radial flow model. The study demonstrated that rate/time and pressure/cumulative-production responses can be correlated with ratio of flow rate from stabilized curve and initial gas-in-place (q_{max}/G_i) and layer volume ratio (V_1/V_2). The shut-in pressures obtained for layered reservoirs will track the pressure of the most permeable layer or layer with the highest value of q_{max}/G_i. Extrapolation of a shut-in p/z *vs.* G_p curve may possibly underestimate the GIP at early times and overestimate it at late times.

Kuppe *et al.* [4] studied the material balance for commingled production from multi-layered, tight gas reservoir. The material balance plots of multi-layered reservoir can lead to erroneous GIP, as depletion performance varies with respect to permeability and volume contrasts between layers. The plot can underestimate GIP at early times and overestimate GIP during the latter period of the wells productive life. The study introduced a method to determine total system GIP by introducing the Production Index (PI) weighted p/z curve from p/z plot of two layer groups, high kh layer and low kh layer. This technique can be successfully applied on conditions that the permeability contrast between the high and low layers does not exceed an order of magnitude, there is no crossflow occurring in the reservoir, and the well has not been shut-in for extended periods (which is allowing crossflow in the wellbore).

Prabowo and Rinadi [5] discussed a method to approximate the ratio of flow rate and the ratio of cumulative production for each reservoir in a commingled gas completion. They developed an analytic equation based on Darcy's law assuming pseudo-steady state gas conditions to calculate the production ratios of each layer of a multi-layered reservoir. Their approach imposed some limiting assumptions on reservoir and fluid properties i.e. equal drainage area for all layers which may not applicable in field operation.

McCracken and Chorneyko [6] proposed a method for back allocated rate using permanent downhole pressures. The allocation process involved building simple reservoir models based on pressure transient analysis. Then, using rate transient analysis to predict rates for each well or zone based on model and measured downhole pressures. The predicted rates were adjusted with an algorithm to match with cumulative production. Two field examples were implemented including one case where the wells producing from separate oil and gas reservoirs have commingled production at sub-sea template and another case where production from multi-layered reservoir was commingled in the wellbore. The results from field examples showed that the predicted rates were consistent with the downhole pressures. It may be able to reduce the number of required surface well tests for allocation purposes.

Rapach *et al.* [7] proposed the transient multi-layered test design of gas wells to provide individual layer parameters in commingled, layered reservoir. The Pressure Transient Multi-Layered Testing (TMLT) involves the sequential measurement of flowrate and pressure transients from an individual layer or group of layers after a rate change, starting with the bottom layer and working up layer by layer. This method can be performed without the need for zone isolation. With layer data obtained from the TMLT analysis, well performance can successfully history match for the example field. The major concerns of this analysis method are the accumulation of errors that can increase amount of uncertainty carried from one step to the next and it is required to obtain an analysis for any given layer before progressing to next TMLT.

Glordano *et al.* [8] used a simulator together with experiments to analyze the effects of permeability variations on flow in porous media. In unstable flow, the permeability variations within each layer can generate more and faster fingers than if no permeability variations were present.

From all the above studies, only a small amount of the review literatures has directly addressed the topic of rate allocation performance of multi-layered gas reservoir. Therefore, it is decided to investigate this topic in details.

CHAPTER III

ASSUMPTIONS, THEORY, AND CONCEPT

3.1 Assumptions

As mentioned previously, the main objective of this study is to investigate the controlling parameters on rate allocation of multi-layered gas reservoir or multi-layered gas system. In order to confine the investigation to a manageable condition, the following assumptions are made:

1. Gas reservoir with depletion drive which has no condensation of HC liquid in the reservoir during the production life.
2. Each layer is separated by impermeable shale. No communication between layers except at the production well.
3. Layer properties are homogeneous.

3.2 Theory

When it is assumed that porous media has no effect on flow from gas layers, the fluid compressibility can be used to investigate the controlling parameters on flow of gas from each layer.

Starting with fluid compressibility which is defined as,

$$c = -\frac{1}{V}\frac{\partial V}{\partial p} , \qquad (3.1)$$

where

c = fluid compressibility

V = volume of gas, (cu.ft)

p = pressure, (psia)

Rearranging and using difference concept,

$$\Delta V = -cV\Delta p \ . \quad (3.2)$$

Taking derivative with respect to time, we have

$$\frac{dV}{dt} = -cV\frac{dp}{dt} \ . \quad (3.3)$$

But $\frac{dV}{dt} = q$ and $c \approx \frac{1}{p}$ for gas, we obtain

$$q = -\frac{V}{p}\frac{dp}{dt} \ . \quad (3.4)$$

If $\frac{dp}{dt}$ can be treated as a constant, either during pseudo-steady state flow period or during the period that pressure changes when related to time can be treated as constant, we have

$$q = -\frac{V}{p} \cdot C \ , \quad (3.5)$$

where $C = \frac{dp}{dt}$

For layer 1, we have

$$q_1 = -\frac{V_1}{p_1} \cdot C_1 \ . \quad (3.6)$$

For layer 2, we have

$$q_2 = -\frac{V_2}{p_2} \cdot C_2 \ . \quad (3.7)$$

Combining Eqs. (3.6) and (3.7), we have

$$q_T = q_1 + q_2 = -\left(\frac{V_1}{p_1} \cdot C_1 + \frac{V_2}{p_2} \cdot C_2\right) , \quad (3.8)$$

where q_T = total flow rate

Therefore,

$$\frac{q_1}{q_T} = \frac{\frac{V_1}{p_1} \cdot C_1}{\left(\frac{V_1}{p_1} \cdot C_1 + \frac{V_2}{p_2} \cdot C_2\right)} \ . \quad (3.9)$$

and

$$\frac{q_2}{q_T} = \frac{\frac{V_2}{p_2} \cdot C_2}{\left(\frac{V_1}{p_1} \cdot C_1 + \frac{V_2}{p_2} \cdot C_2\right)} . \qquad (3.10)$$

It should be noticed that the results obtained in Eqs. (3.9) and (3.10) are with the assumption that expansion of connate water and rock is insignificant compared with expansion of gas.

If Eq. (3.6) is divided by Eq. (3.7), the following result is obtained,

$$\frac{q_1}{q_2} = \frac{\left(\frac{V_1}{p_1} \cdot C_1\right)}{\left(\frac{V_2}{p_2} \cdot C_2\right)} , \qquad (3.11)$$

When $\frac{C_1}{p_1}$ is approximately equal to $\frac{C_2}{p_2}$, Eqs (3.9), (3.10), and (3.11) become

$$\frac{q_1}{q_T} = \frac{V_1}{V_1 + V_2} , \qquad (3.12)$$

$$\frac{q_2}{q_T} = \frac{V_2}{V_1 + V_2} , \qquad (3.13)$$

and

$$\frac{q_1}{q_2} = \frac{V_1}{V_2} . \qquad (3.14)$$

This simplified version of rate allocation is applicable when gas flow in each layer is not controlled by flowing properties (mainly influenced by permeability).

3.3 Reservoir Simulation

The simulation technique is used in this study to generate all rock properties, fluid flowing performance, and interaction between each reservoir in multi-layered system. The hypothetical two-layered, gas reservoir with depletion drive was constructed in ECLIPSE software. Each layer is separated from one another by impermeable shale. Therefore, these layers can communicate at a common producing well only. Each layer has uniform thickness with close boundary and fluids in all layers have the same properties. The study concentrates on rate allocation during stabilized flow between two layers and gas volume in reservoir condition of each layer. The results from simulator are plotted to see rate allocation performance and behavior of flow in multi-layered system. After relationship between rate allocation and controlling parameters is proposed, a five-layered hypothetical model is used to confirm its validity on more layers system.

CHAPTER IV

MODEL FORMULATION

The hypothetical two-layered, gas reservoir and five-layered gas reservoir are used in this study. This chapter will describe construction of reservoir model in a reservoir simulator and assumptions used.

4.1 Reservoir Model for Two-Layered System

The hypothetical model is a two-layered rectangular reservoir with one producer at the center of reservoir as shown in Figure 4-1.

Figure 4-1: Hypothetical 2-layered reservoir model

The area of the 1st layer is 1,400x1,400 ft^2 and area of 2nd layer is 1,000x1,000 ft^2. The thickness of both layers is 50 ft with 200-ft shale lying between both layers. The homogeneous reservoir and fluid properties are used for establishing hypothetical model. General data for reservoir model are summarized below.

a) Case Definition

Simulator:	Black Oil	
Model Dimensions:	Layer 1	Layer 2
Number of cells in x direction	70	50
Number of cells in y direction	70	50
Number of cells in z direction	10	10
Grid type:	Cartesian	
Geometry type:	Block Centered	
Oil-Gas-Water options:	Water, Gas	

b) Grid

Grid size:

X Grid block sizes		=	20	ft
Y Grid block sizes		=	20	ft
Z Grid block sizes		=	5	ft
Depth of Top face:		=	6,000	ft
Properties:				
Porosity		=	0.2	
Permeability	k-x	=	100	mD
	k-y	=	100	mD
	k-z	=	10	mD
Net to Gross ratio		=	0.75	

c) Fluid, Rock, and SCAL Properties

Water PVT Properties:

Reference pressure (P_{ref})	=	2,600	psia
Water FVF at P_{ref}	=	1.0651	rb/stb
Water viscosity at P_{ref}	=	0.1878	cp

Fluid Densities at Surface Conditions:

Oil density	=	49.9991	lb/ft^3
Water density	=	62.4280	lb/ft^3
Gas density	=	0.0437	lb/ft^3

Rock Properties:

Reference pressure	=	2,600	psia
Rock compressibility	=	1.5299E-6	1/psi

Initial Fluid Properties:

Initial Water Saturation	=	0.38
Initial Gas Saturation	=	0.62

The water saturation and relative permeability relation is shown in Table 4.1 and Figure 4.2 below

Table 4-1: Water Saturation versus water and gas relative permeabilities.

Water Saturation (S_w)	k_{rw}	k_{rg}
0.38	0.0000	1.0000
0.42	0.0040	0.5549
0.47	0.0183	0.2846
0.51	0.0446	0.1317
0.55	0.0840	0.0529
0.60	0.1372	0.0173
0.64	0.2049	0.0041
0.68	0.2876	0.0005
0.73	0.3859	0.0000
0.77	0.5000	0.0000
1.00	1.0000	0.0000

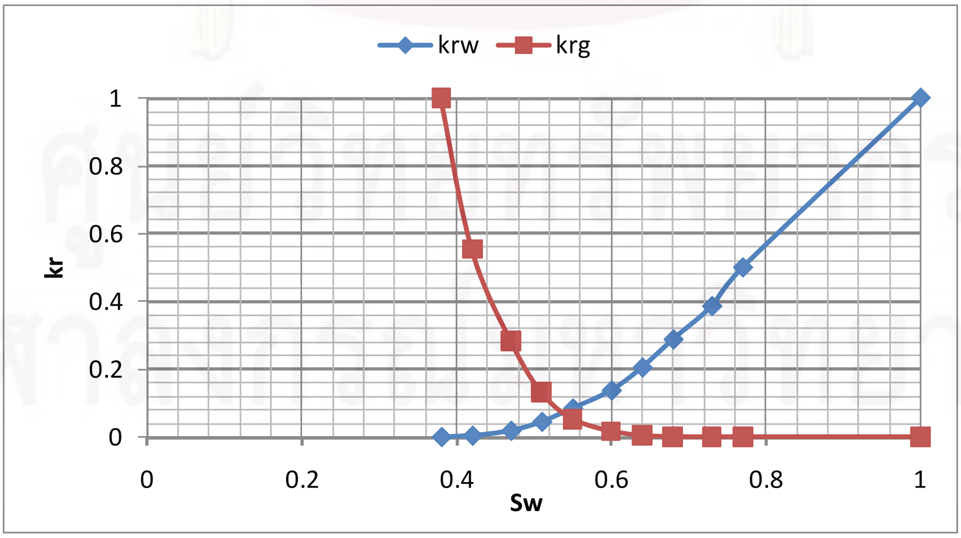


Figure 4-2: Relative permeability curve

The study aims to investigate controlling parameters to rate allocation of each layer. Therefore, various values of studied parameters are used. Table 4-2 shows the parameters that vary for various runs.

Table 4-2: Variable -value parameters to be studied

Rock properties and Conditions	**Values**
Reservoir size, Area (ft x ft)	500x500, 1,000x1,000, 1,400x1,400, 2,000x2,000, 3,300x3,300
Permeability, k (md)	10, 30, 50, 100, 500
Gas flow rate, q_g (MMscf/d)	1, 2, 3, 5, 10
Thickness, h (ft)	10, 50, 100
Porosity, ϕ (fraction)	0.1, 0.2, 0.3
Depth difference between layer 1 and 2 or shale thickness, (ft)	10, 100, 200, 1000
Skin factor, s (dimensionless)	0, 5, 10, 15, 20

4.2 Reservoir Model for Five-Layered System

The five-layered rectangular reservoir model is provided to confirm the validity of relationship between rate allocation and controlling parameters concluded from the two-layered system. There are five sand layers and four impermeable shales lie in between. The gas production comes from a common production well at the center of all layers. The area extent, thickness, and other rock properties are different in each layer. The shape of simplified five-layered reservoir model is shown in Figure 4-3.

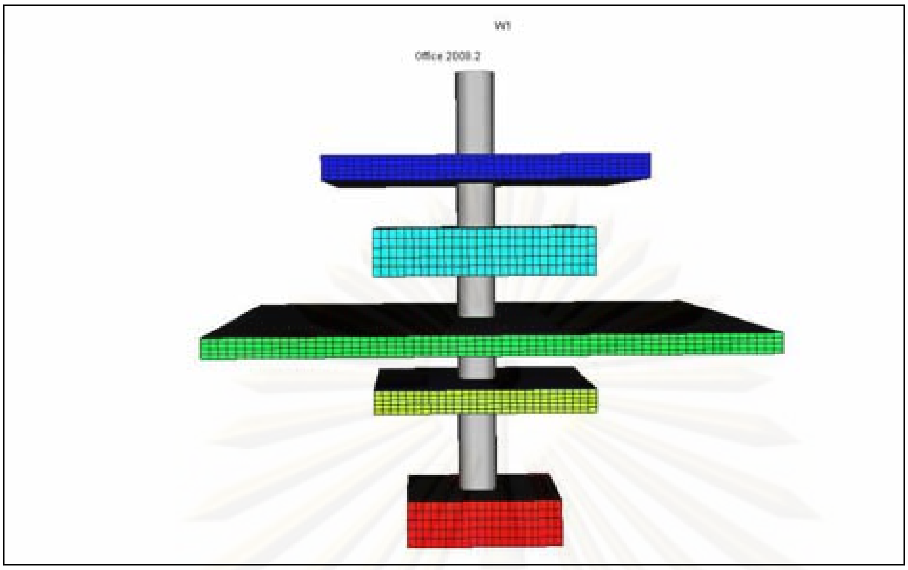


Figure 4-3: Hypothetical 5-layered reservoir model

The general reservoir data used in the two-layered system are also applicable for the five-layered system. In addition, there are other parameters used for this case as shown in Table 4-3.

Table 4-3: Rock properties of five-layered reservoir model

Rock properties	Layer 1	Layer 2	Layer 3	Layer 4	Layer 5
Area, (ft x ft)	2,000x2,000	1,400x1,400	3,300x3,300	1,400x1,400	1,000x1,000
k, (md)	80	100	200	200	80
h, (ft)	50	100	40	50	100
ϕ, (fraction)	0.3	0.2	0.12	0.2	0.3
Shale thickness between layer, (ft)	-	100	100	100	200
Depth of top face, (ft)	6,000	6,150	6,350	6,490	6,740

4.3 Well Model

The well model is constructed based on a monobored well design which is widely used in the Gulf of Thailand. The production casing is 3-1/2 inches with an inside diameter of 2.992 inches. The well is perforated from 6,000 ft to 7,100 ft, depending on each studied case. Figure 4-4 shows the well completion schematic using in this study.

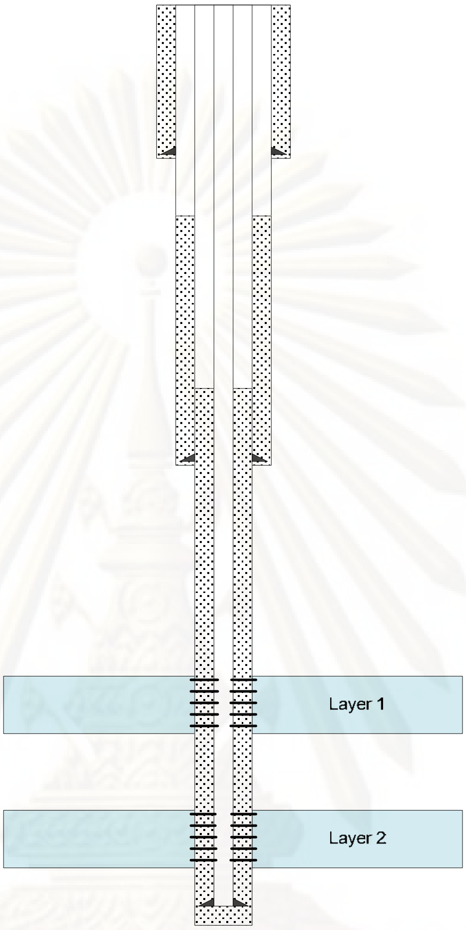


Figure 4-4: Well schematic

CHAPTER V

RESULTS AND DISCUSSION

In this chapter, an investigation of controlling parameters of rate allocation from multi-layered system is carried out. The objective is to study whether rate allocation is influenced by gas volume in each layer or not. In addition, it is planned to investigate the conditions that rate allocation is proportional to gas volume in each layer with acceptable deviation. The effects of rock properties and production rate on the relationship between rate allocation and gas volume in each layer are also investigated. The results are discussed in terms of deviation and time required to reach stabilized flow. Furthermore, an investigation on the effects of shutting well before running PLT is conducted. This will help us to select the suitable time and conditions to perform PLT. After that, a test on a five-layered system is carried out to check the application on more layers reservoir. Finally, detailed discussion of various controlling parameters on rate allocation of each layer will be undertaken.

5.1 Influencing factors on Production Rate Allocation

The reservoir simulation runs were conducted to investigate the characteristics of production rate allocation from a two-layered system. The results from simulation runs are plotted to see whether production rate allocation is proportional to kh as widely used or gas volume as previous studies mentioned before.

Figure 5-1 illustrates result of production rate allocation of a two-layered reservoir from simulation. Both layers have the same kh (k = 100 md, and h = 50 ft) but different area extent which is ratio as $Area_1$:$Area_2$ = 2:1. The figure shows that during constant well production rate, the production rate of each layer is not constant at the beginning and change until reaching a constant rate (for each layer) when entering a stabilized condition. The constant rate (for each layer) exists until the total well production come to the declining stage. Whereas the kh of both layers are equal, production rate of layer 1 is twice of production rate of layer 2. This result confirms that production rate allocation of multi-layered system does not follow the kh allocation concept as widely used based on Darcy's equation. But production rate allocation is clearly proportional to the ratio of gas volume at reservoir condition.

The deviation of calculated rate from actual rate (simulation result) during constant flow period is very small, less than 1.5% for this case. The calculated rate of the 1st layer is obtained by multiplication of total rate by the ratio of the gas volume at reservoir condition of the 1st layer and the total gas volume at reservoir condition of both layers. Discrepancy of the calculated rate from actual rate reflects the degree of relationship between rate allocation and gas volume at reservoir condition and also validity of estimation of gas volume at reservoir condition of multi-layered system using rate allocation. In this study, we consider the acceptable criteria that deviation should be less than 5%.

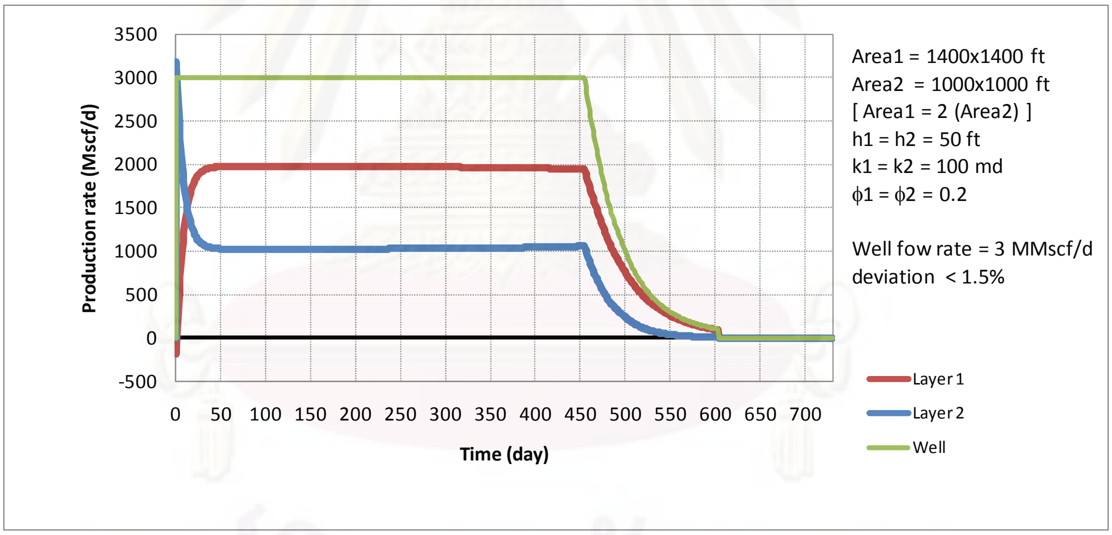


Figure 5-1: Production rate of two-layered reservoir where Vol_1:Vol_2 = 2:1, and $(kh)_1 = (kh)_2$

Figure 5-2 shows the production rate allocation of a two-layered reservoir where $(kh)_1$ is equal to 50% of $(kh)_2$ ($k_1 = k_2 = 100$ md, $h_1 = 50$ ft but $h_2 = 100$ ft) and V_{g1} is equal to V_{g2}. During stabilized flow period, defined as the period of which rate of each layer is approximately constant, the production rate of layer 1 is equal to production rate layer 2, hence their (rates) ratio is equal V_g ratio of the two layers.

The plot confirms again that production rate allocation at stabilized condition is proportional to gas volume at reservoir condition of each layer.

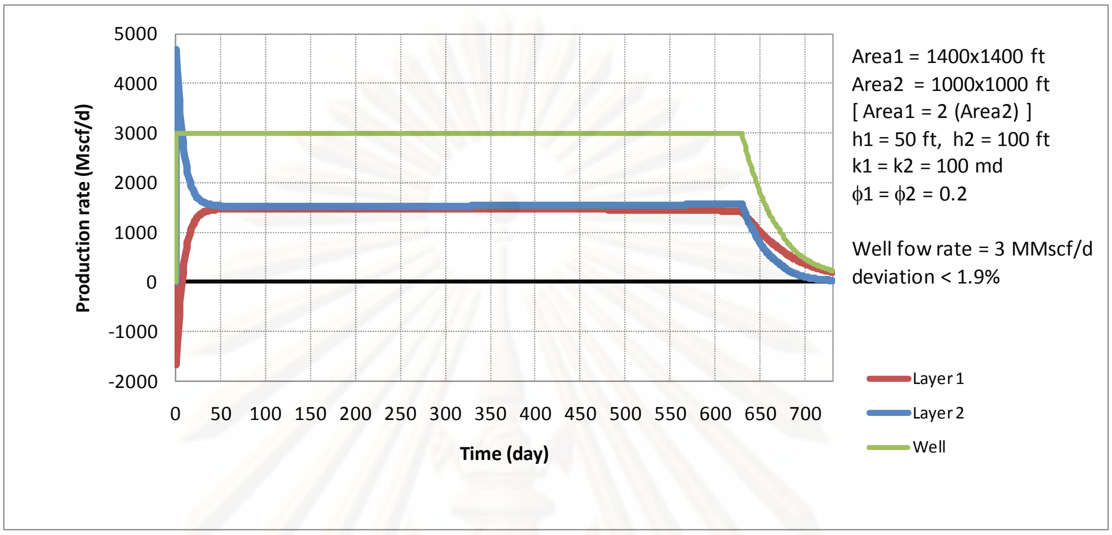


Figure 5-2: Production rates of two-layered reservoir where $V_{g1} = V_{g2}$, and $(kh)_1$:$(kh)_2$ = 1:2

From Figure 5-2, a cross flow can be observed during the first 6 production days. At the early stage, the flowing bottom hole pressure is controlled by pressure and flow from the higher initial pressure layer which is layer 2 in this case. The flowing bottom hole pressure in front of layer 1 is higher than pressure at sandface of layer 1, hence crossflow into layer 1. After 6 days, gas is starting to flow from layer 1 to well since the flowing bottom hole pressure is lower than pressure at sandface of layer 1. The plot in Figure 5-2 also shows that the crossflow at early production time do not affect the rate allocation during stabilized condition.

A plot under the conditions that rate allocation is not proportional to gas volume at reservoir condition is provided in Figure 5-3. For this case, permeability is low at 10 md and well flow rate is high as 20 MMscf/d. Other rock properties are duplicated from reservoir in Figure 5-1 where V_{g1} = 2 V_{g2} and $(kh)_1$ = $(kh)_2$. The production was conducted at full flow capacity of both layers since the beginning. This leads to non-existence of plateau period of flow rate. Figure 5-4 shows the production rate of this case during the first 20 days. The plot shows that rate allocation is approximately proportional to kh ratio at early stage of flow. There is no stabilized condition.

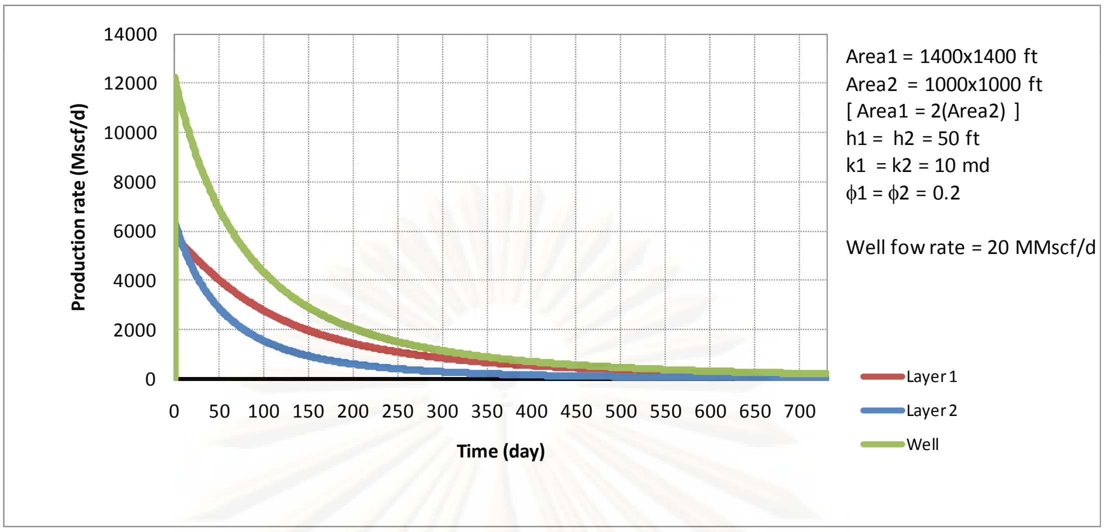


Figure 5-3: Production rate of two-layered reservoir at low k and high flow rate

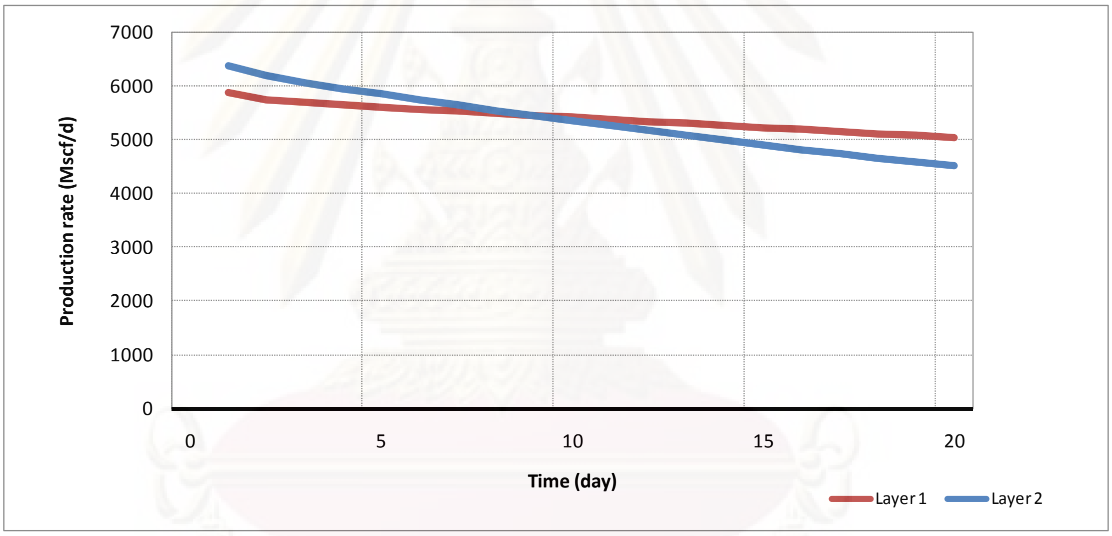


Figure 5-4: Rate allocation of a low k reservoir and high flow rate during early stage

Figure 5-5 shows production rate of a low permeability reservoir at low flow rate where $k_1 = k_2 = 10$ md and $q_T = 2$ MMscf/d. The stabilized condition can be achieved at the time close to the end of production plateau. At stabilized condition, rate allocation follow gas volume ratio at reservoir condition but with higher deviation (≈ 2.5%). This implies that even with poorer rock properties (k=10 md) the rate of each layer is proportional to gas volume (at reservoir condition) of each layer if rates are sufficiently low.

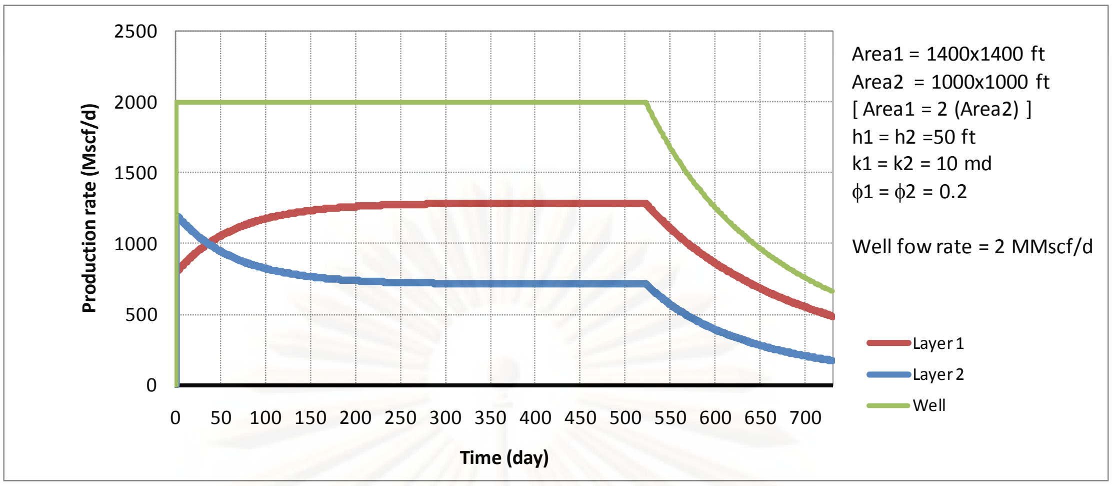


Figure 5-5: Production rate of two-layered reservoir at low k and low flow rate

Four different gas volume ratios between layer 1 and layer 2 are presented in Figure 5-6. The plot is provided to show whether rate allocation is still proportional to gas volume ratio or not when reservoir shape (in terms of area) is changed. In Figure 5-6, the stabilized condition can be achieved and rate allocation follows gas volume ratio in all cases. This implies that gas volume allocation concept is valid for various reservoir shapes.

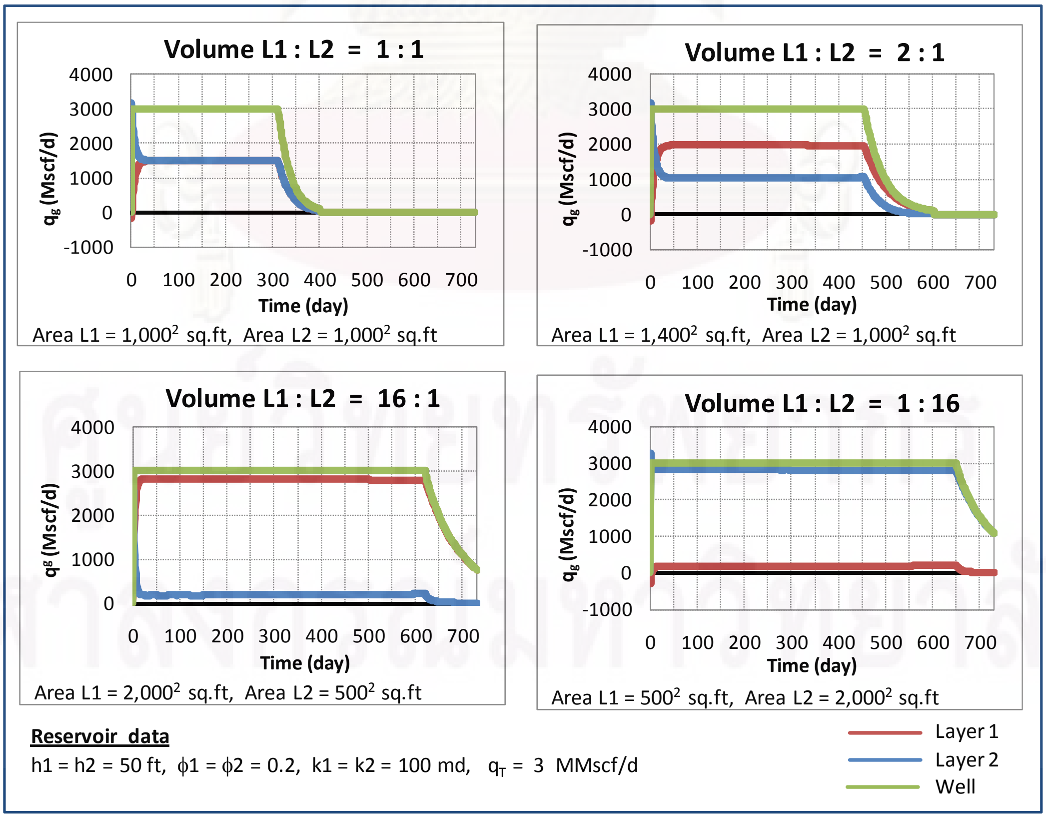


Figure 5-6: Rate allocation of two-layered reservoir under various gas volume ratios

From discussion above, it can be concluded that the production rate allocation is proportional to gas volume ratio at reservoir condition for the multi-layered gas reservoir on the conditions that flow rate is less than flow capacity of reservoir at certain level. With the mentioned conditions, the stabilized flow should be observed from well production profile. For well flow rate closed to flow capacity, layer flow rate of each layer will proportional to kh ratio during the early stage of flow.

To apply the gas volume allocation concept to GIP estimation, it is required an investigation of the threshold conditions that stabilized condition can be achieved and rate allocation is proportional to gas volume ratio at reservoir condition with low deviation, such as less than 5%. Before conducting such investigation, an analysis of the flow rate characteristics, to understand the relationship between production rate allocation and gas volume ratio at reservoir condition, is necessary.

Figure 5-7 shows a plot of well production rates of a two-layered gas reservoir where gas volume in layer 1 is twice of gas volume in of layer 2, both at reservoir condition. Well flow rate is controlled at 3 MMscf/d. In the early period, a crossflow between two layers can be noticed for 1.5 day. After that, flow rate of each layer still varies and becomes constant or stabilized and their ratio is proportional to the ratio of gas volume after some period of time. The crossflow phenomenon can be explained by the higher flowing bottom hole pressure than the pressure close to well location of layer 1. Figure 5-8 shows that at the initial condition pressure of layer 1 (2,660 psia) is lower than pressure of layer 2 (2,768 psia). During the early time period, 1.5 days for this case, with higher pressure of layer 2, the flowing bottom hole pressure is controlled by pressure and flow from layer 2. The flowing bottom hole pressure in front of layer 1 is still higher than pressure at sandface of layer 1, hence crossflow into layer 1 for 1.5 days. After 1.5 days, the flowing bottom hole pressure in front of layer 1 is lower than pressure at sandface of layer 1, hence no further crossflow and gas starting coming out of layer 1.

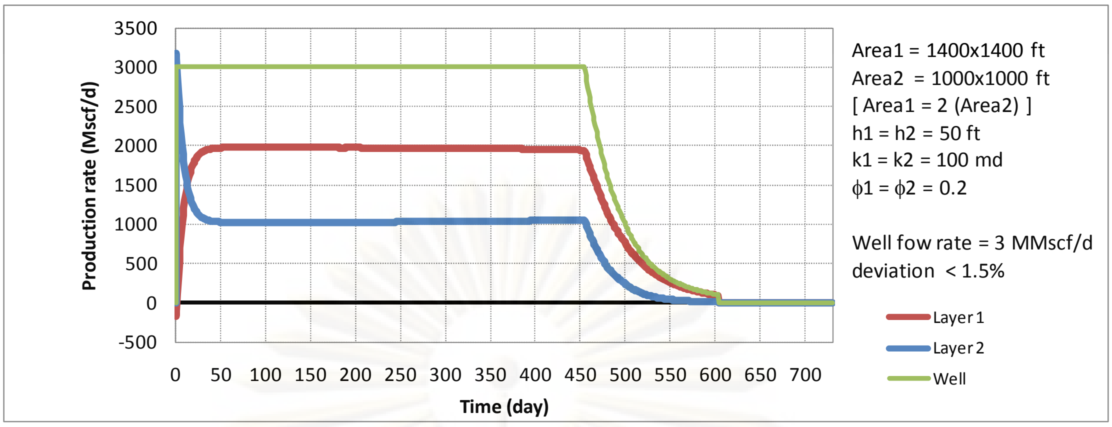


Figure 5-7: Production rate of two-layered reservoir where $Area_1$:$Area_2$ = 2:1, and q_T = 3 MMscf/d

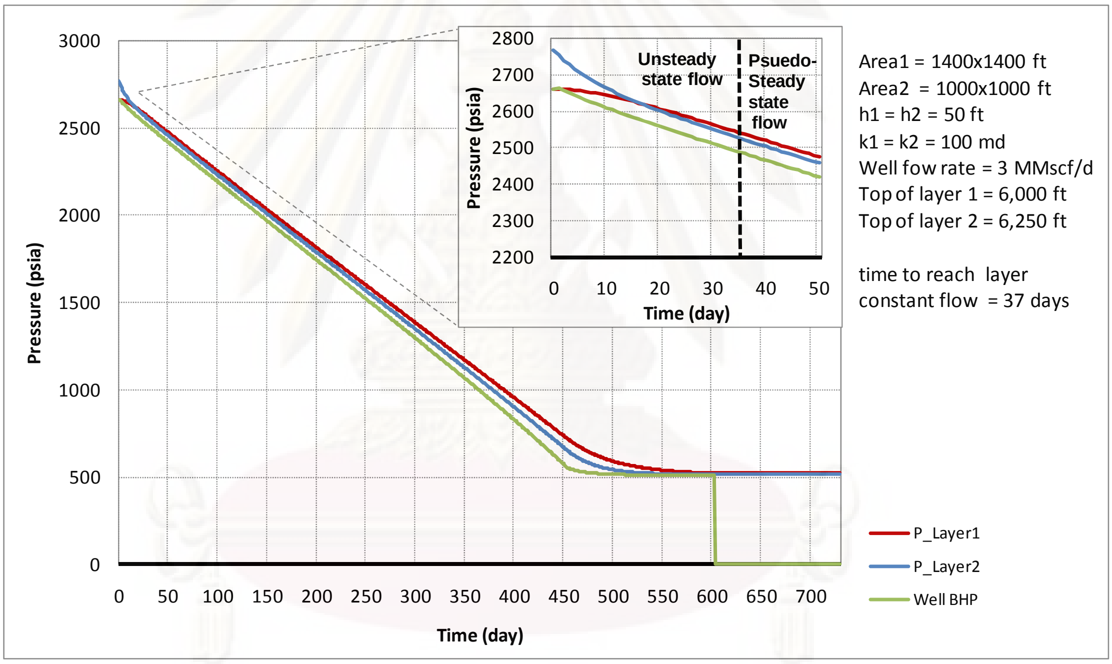


Figure 5-8: Reservoir pressure of two-layered reservoir

Figure 5-8 shows that at the beginning the reservoir pressure of layer 2 is highest and there is high pressure difference between bottom hole flowing pressure and reservoir pressure of layer 2. (It should be noted that the pressure shown in Figure 5-8 is average reservoir pressure of each layer, not pressure at the sandface.) The high difference in pressure causes flow rate of layer 2 to be high at the beginning (Figure 5-7). Later, flow rate of layer 2 declines rapidly (Figure 5-7) due to rapid decline of reservoir pressure of layer 2, hence less difference in pressure between layer 2 pressure and bottom hole flowing pressure. During the same period, flow rate of layer 1 increases rapidly due to rapid increase of pressure difference between layer 1 pressure and bottom hole flowing pressure. Then (for the period of 37-454 days), flow rates of layer 1 and layer 2 become constant and are proportional to gas volume at reservoir condition of each layer (Figure 5-7). During this period, rate of decline of reservoir pressure of each layer become approximately constant and it is believed to be controlled by the gas volume of each layer. Finally, flow rates of both layers decline (after 454 days) due to insufficient supply of gas from both layers. This reflects in low pressure of both layers (Figure 5-8, after 454 days), leading to less expansion of gas in each layer and not sufficient to maintain constant flow rates.

In light of using production rate allocation to determine gas volume and GIP of individual layer of multi-layered reservoir, we need to know the effects from each parameter and identify the threshold conditions that rate allocation is proportional to gas volume at reservoir condition with deviation less than 5% as showing in next section.

5.2 Effect of Production Rate

The production rate is the only parameter that can be controlled whereas other rock properties are given by nature. As discussed before, well production rate can affect the validity of estimation of gas volume of multi-layered reservoir by using rate allocation concept. Therefore, knowing effect from production rate and the applicable range is essential. Figure 5-9 shows the production rate allocation from a two-layered reservoir with k = 50 md under 5 well flow rates including 1, 2, 3, 5, and 10 MMscf/d cases. The deviation of rate allocation from gas volume ratio at reservoir condition and time required to reach stabilized flow are provided in Table 5-1.

Figure 5-9, shows similar trend of flow rates as those shown in Figure 5-7, especially for q_T = 1 MMscf/d. That is at sufficiently low total flow rate, there can be crossflow between layers because there is a period of time where flow contribution from one layer (layer 2 for this case) can still maintain bottom hole flowing pressure to be higher than the sandface pressure of the other layer (layer 1 for this case). However, higher total flow rate, bottom hole flowing pressure has to be lower than sandface pressure of both layers in order to achieve higher flow rate. This leads to no crossflow.

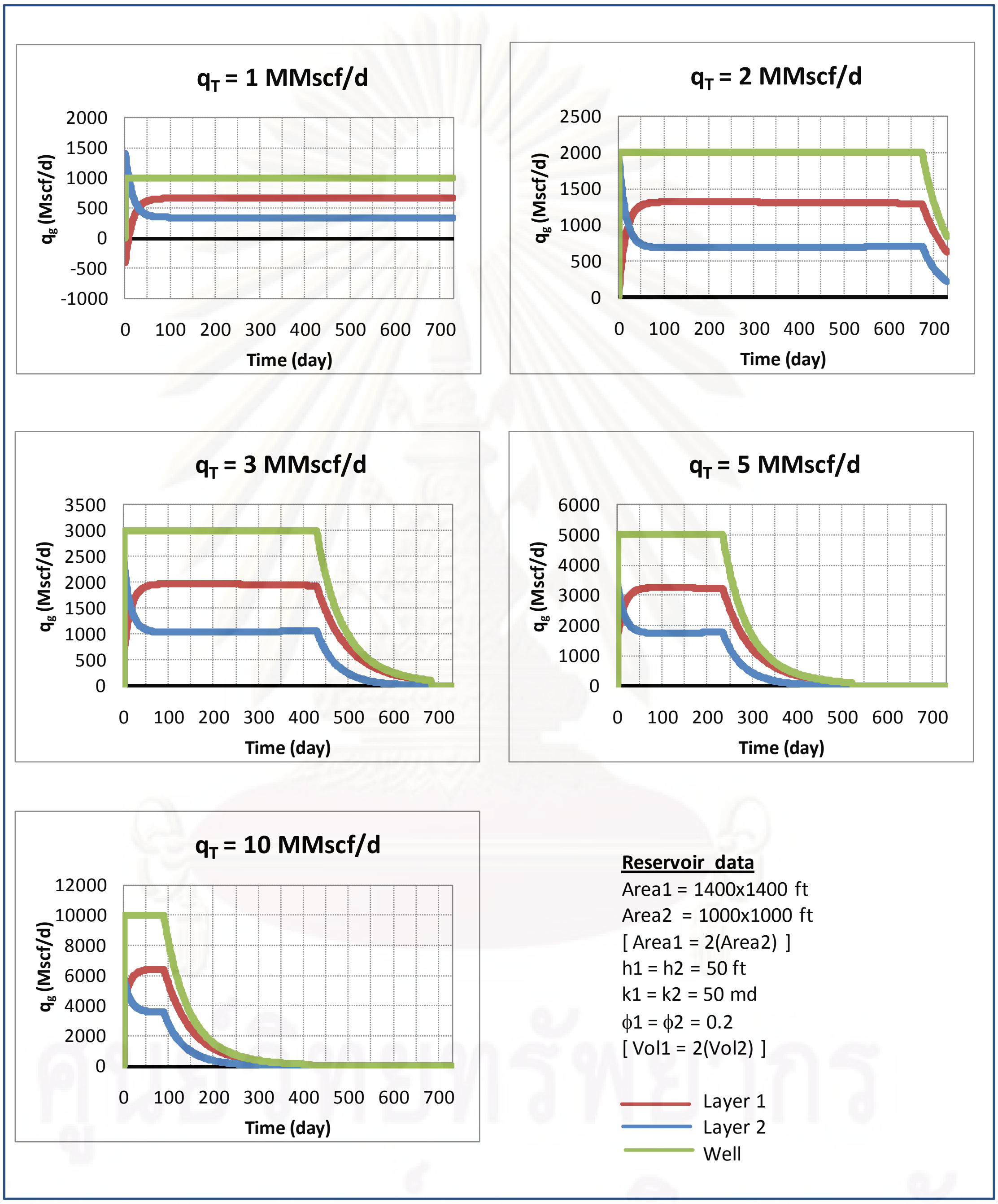


Figure 5-9: Rate allocation of two-layered reservoir under various well production rates at k = 50 md

In terms of stabilized flow period, Figure 5-9 clearly shows that lower total flow rate leads to longer stabilized flow period, and vice versa. It can also be concluded from Figure 5-9 and Table 5-1 that during the stabilized flow period, the flow rate allocation is proportional to the ratio of the gas volume. However, it can also be noticed that at higher flow rates, the discrepancy from this rule become larger. The case of 10 MMscf/d, total flow rate show high discrepancy. This leads to a conclusion that for any specific system, there is a threshold of rate that higher than this rate, the gas volume allocation concept will not be applicable. It will be shown later that this large discrepancy is due to effect of reservoir pressure and rate of change of reservoir pressure of each layer.

Table 5-1: Effect of well production rate on production rate allocation, the deviations, and time required to reach stabilized condition (V_{g1} = 2 V_{g2}, $h_1 = h_2$ = 50 ft, $k_1 = k_2$ = 50 md)

q_T (MMscf/d)	q_1 (MMscf/d)	q_2 (MMscf/d)	$\frac{q_1}{q_T}$	$\frac{V_{g1}}{V_{gT}}$	Deviation	Time required (days)
1	0.653 - 0.661	0.339 - 0.347	0.653 - 0.661	0.662	<1.0%	76
2	1.292 - 1.317	0.683 - 0.708	0.646 - 0.659	0.662	<1.6%	71
3	1.934 - 1.970	1.030 - 1.066	0.645 - 0.657	0.662	<1.7%	71
5	3.219 - 3.259	1.741 - 1.781	0.644 - 0.652	0.662	<1.8%	62
10	6.373 - 6.419	3.581 – 3.627	0.637 – 0.642	0.662	<2.5%	51

In addition, Table 5-1 shows that the time to reach the stabilized flow period is early for higher total flow rate though the differences in these starting times for each total flow rate case not significant.

It is, therefore, recommended to perform test runs for the multi-layered system under investigation in order to identify the most appropriate total flow rate for PLT run for the purpose of using flow rate of each layer to estimate GIP of each layer.

5.3 Effect of Permeability

Permeability is expected as one of highest impact parameters on the gas volume allocation concept. Five study cases on influence from permeability on the production rate allocation are selected at well flow rate of 3 MMscf/d and shown in Figure 5-10.

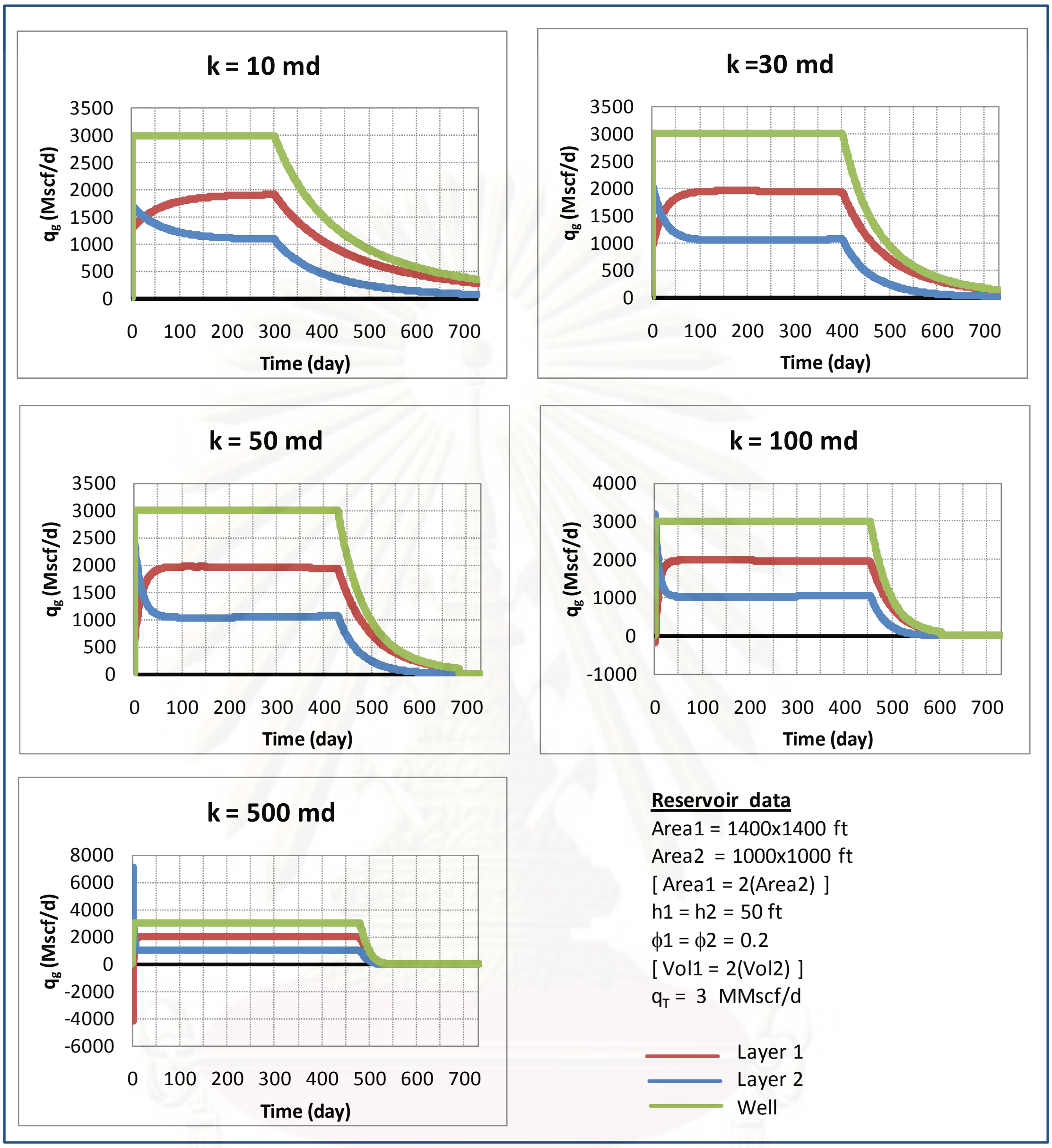


Figure 5-10: Rate allocation of two-layered reservoir under various permeabilities at q_T = 3 MMscf/d

At low permeability, 10-md case, the response of gas volume allocation is very slow and it cannot achieve the stabilized condition before the end of plateau. This leads to a conclusion that one has to be cautious in applying the gas volume allocation concept to the system with low permeability. On the other hand, gas volume allocation concept works very well with high permeability reservoirs as presented in 100-md and 500-md cases. Another interesting point is that there is crossflow only in 100-md and 500-md cases. It is because drawdown at well flow rate of 3 MMsf/d is considerably low for high permeability cases, hence the bottom hole flowing pressure is influenced by the higher pressure layer and it is still higher than pressure of the other layer, leading to crossflow.

Table 5-2: Effect of permeability on production rate allocation, the deviations, and time required to stabilized condition
(V_{g1} = 2 V_{g2}, $h_1 = h_2$ = 50 ft,, and q_T = 3 MMscf/d)

k (md)	q_1 (MMscf/d)	q_2 (MMscf/d)	$\frac{q_1}{q_T}$	$\frac{V_{g1}}{V_{gT}}$	Deviation	Time required (days)
10	1.885 - 1992	1.008 – 1.115	0.628 – 0.664	0.662	<3.4%	N/A
30	1.929 - 1.956	1.044 - 1.071	0.643 - 0.652	0.662	<1.9%	102
50	1.934 - 1.970	1.030 - 1.066	0.645 - 0.657	0.662	<1.7%	72
100	1.941 - 1.978	1.022 - 1.059	0.647 - 0.659	0.662	<1.5%	37
500	1.962 - 1.986	1.014 - 1.038	0.654 - 0.662	0.662	<1.0%	11

Table 5-2 shows the deviation of rate allocation and time required to reach stabilized condition for these study cases. It obviously demonstrates that permeability does have effect on rate allocation of multi-layered reservoir. The rate allocation shows strong relationship with gas volume at reservoir condition when permeability is high. The deviation and time to reach stabilized condition decrease as permeability becomes higher. This is because with high permeability, pressure drawdown will be very low and gas volume and reservoir pressure quickly control flow rate of each layer.

Another series of simulation runs were carried out for this study to see the effects of permeability when the two layers have different permeability. The permeability values were set as a fixed value layer 1 and five variable values for layer 2. The results are shown in Figure 5-11 and Table 5-3. It can be noticed that response of rate allocation to gas volume at reservoir condition is sharing between two layers. For the 10-md case, The stabilized flow cannot be reached before end of plateau period in the uniform permeability case as shown in Figure 5-10 but gas flow in the different permeability case, where k_1 = 100 md and k_2 = 10 md, can reach stabilized condition before the end of plateau period as shown in Figure 5-11. This can be considered as an advantage since we can practically apply rate allocation concept to estimate GIP of low permeability reservoir if there is high permeability reservoir connected to and produced within the same well. Another finding on different permeability in multi-layered reservoir is also shown in the last case where k_1 = 100 md and k_2 = 500 md. The deviation is escalated from <1.5% for the case with $k_1 = k_2$ = 100 md to <3.4% for the case with k_1 = 100 md and k_2 = 500 md even though one of permeability values of the different permeability case is higher.

Besides the observation mentioned above, the rate allocation obey the gas volume ratio concept for cases with different values of permeability for each layer.

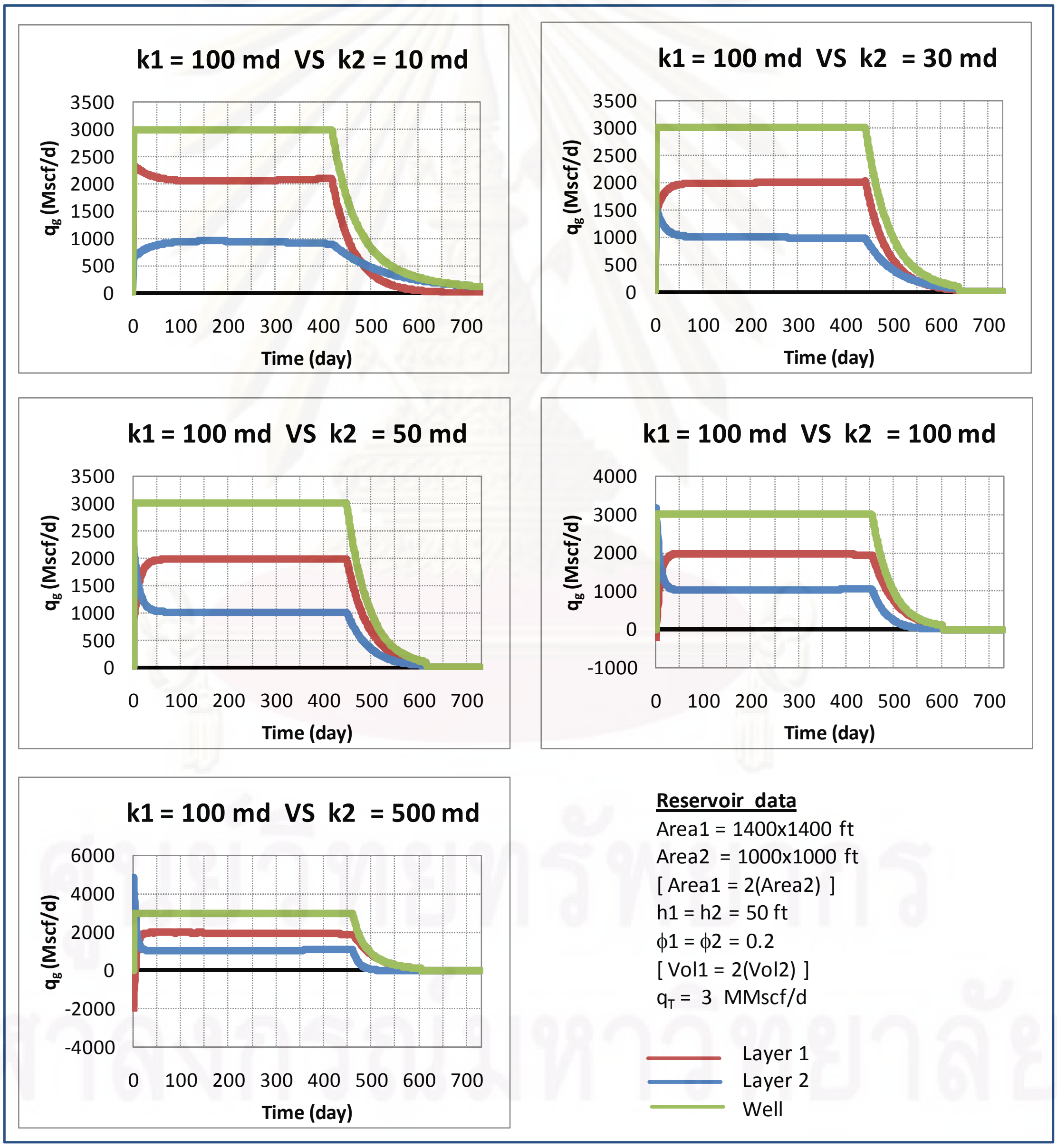


Figure 5-11: Rate allocation of two-layered reservoir under several unequal permeabilities at q_T = 3 MMscf/d

Table 5-3: Effect of unequal permeability on production rate allocation, the deviations, and time required to reach stabilized condition (V_{g1} = 2 V_{g2}, h_1 = h_2 = 50 ft,, and q_T = 3 MMscf/d)

k_1 (md)	k_2 (md)	q_1 (MMscf/d)	q_2 (MMscf/d)	$\frac{q_1}{q_T}$	$\frac{V_{g1}}{V_{gT}}$	Deviation	Time required (days)
100	10	2.048 - 2.098	0.902 - 0.952	0.683 - 0.699	0.662	<3.7%	101
100	30	1.959 - 2.021	0.979 - 1.041	0.653 - 0.674	0.662	<1.2%	46
100	50	1.958 - 1.985	1.015 - 1.042	0.653 - 0.662	0.662	<1.0%	45
100	100	1.941 - 1.978	1.022 - 1.059	0.647 - 0.659	0.662	<1.5%	37
100	500	1.884 - 1.974	1.026 - 1.116	0.628 - 0.658	0.662	<3.4%	29

5.4 Effect of Depth Difference between Layers

As shown in the theoretical part, gas flow from each layer of a multi-layered reservoir is also influenced by the pressure of each layer. Therefore, the effect of variation in initial pressure is now being investigated. In general, initial reservoir pressure depends on how much its depth from the ground level. The initial reservoir pressure is equal to the product of depth of the layer and water gradient for a normal pressure reservoir. In this study, four values of depth difference between layer 1 and layer 2 were used including 10, 100, 200, and 1,000 feet. Figure 5-12 showing the production rate allocation from a two-layered reservoir with k = 100 md and well flow at 3 MMscf/d. All cases follow gas volume allocation concept as our previous conclusion. All cases can reach the stabilized condition before the end of plateau period with slight difference in deviation and time required. For the 1,000 ft case, the crossflow between two layers can be observed during the first 12 days after production start. This can be expected since the pressure difference between both layers is considerably high.

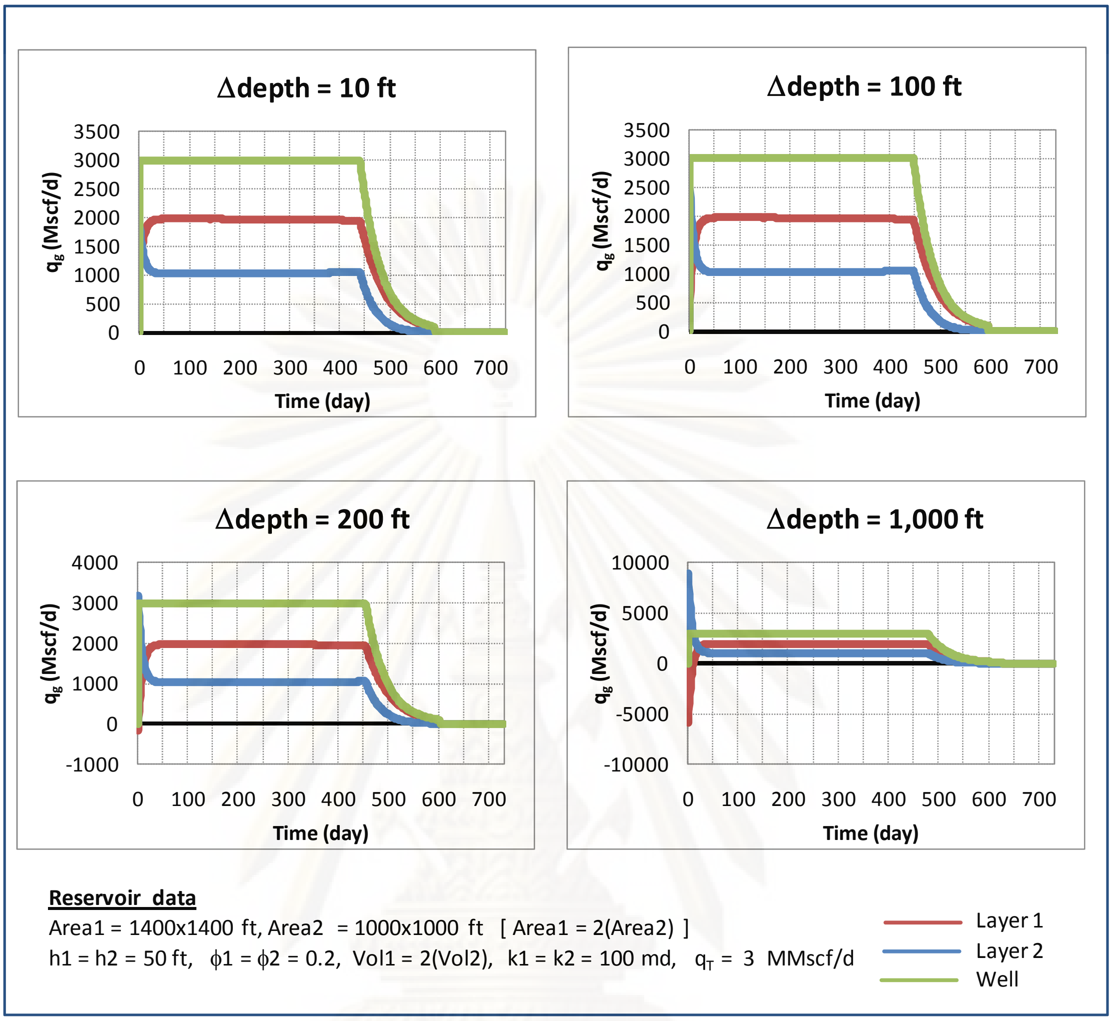


Figure 5-12: Rate allocation under various depth differences between two layers at k = 100 md and q_T = 3 MMscf/d

Table 5-4: Effect of depth difference on production rate allocation, the deviations, and time required to reach stabilized condition ($V_{g1} = 2\ V_{g2}$, $h_1 = h_2 = 50$ ft, $k_1 = k_2 = 100$ md, and $q_T = 3$ MMscf/d)

Depth Difference (ft)	Initial pressure (psia)			Deviation	Time required (days)
	Layer 1	Layer 2	Difference		
10	2,621	2,647	26	<1.4%	30
100	2,638	2,702	64	<1.5%	36
200	2,660	2,768	108	<1.5%	37
1,000	2,660	3,113	453	<1.7%	48

Table 5-4 shows the deviation of calculated rate allocation to the real rate allocation and time to reach stabilized flow for various depth difference cases. The deviation is higher for higher initial pressure difference cases. Similarly, the stabilized time is longer for the higher initial pressure difference cases. It can be concluded that difference of initial pressure between layers of a multi-layered reservoir does have effect on its rate allocation. However, it is found later that the effect is not so strong as for the cases of variation in permeability and total flow rate.

5.5 Effect of Area Extent

Because time to reach pseudo-steady state is dependent on the area extent and shape of each layer, it is, therefore, worth investigating the effect of area extent on the dependence of rate allocation on gas volume of each layer. An investigation on effects from area extent was then carried out for six cases of two-layered, square reservoir covering various ratios of gas volume between two layers. Figure 5-13 shows results of the runs at k = 100 md and well flow rate = 3 MMscf/d. The results confirm that rate allocation on gas volume concept can be applied for a good range of two layer combination i.e. up to ratio of layer 1 to layer 2 at 16:1. The time to reach the stabilized condition is dependent on the size of each layer and contrast of size between layers (Table 5-5). From results of this study, it can be concluded that the effects from area extent and area extent ratio are small. The deviation can be varied based on gas volume ratio between layers.

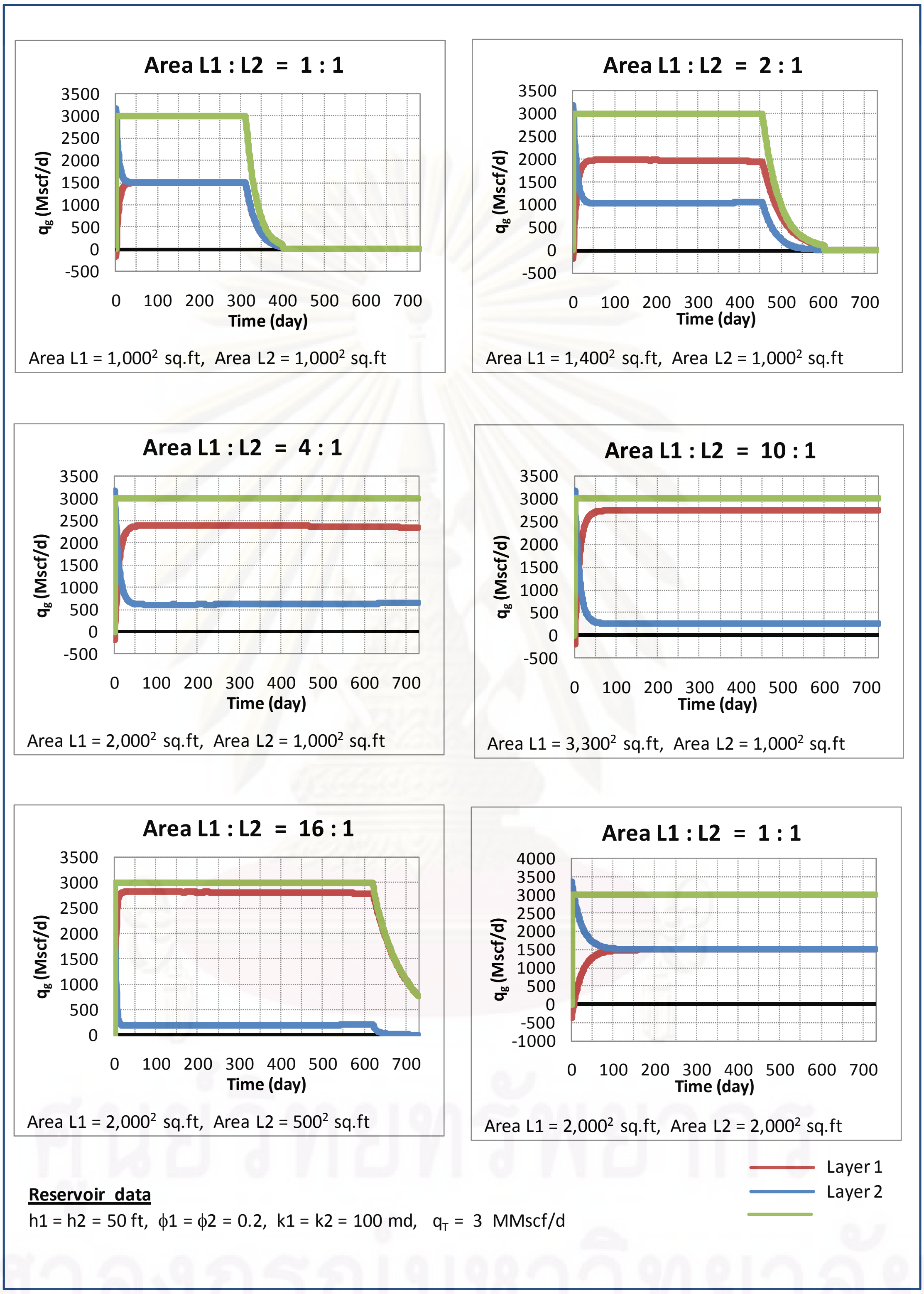


Figure 5-13: Rate allocation of two-layered reservoir under various Area cases at $k = 100$ md and $q_T = 3$ MMscf/d

Table 5-5: Effect of area extent and area extent ratio on production rate allocation, their deviations, and time required to reach stabilized condition ($h_1 = h_2 = 50$ ft, $k_1 = k_2 = 100$ md, and $Q_T = 3$ MMscf/d)

Area Layer 1 (sq.ft)	Area Layer 2 (sq.ft)	Area extent Ratio (L1 : L2)	Deviation	Time required (days)
1,000x1,000	1,000x1,000	1 : 1	<1.0%	26
1,400x1,400	1,000x1,000	2 : 1	<1.5%	37
2,000x2,000	1,000x1,000	4 : 1	<2.0%	48
3,300x3,300	1,000x1,000	10 : 1	<1.4%	56
2,000x2,000	500x500	16 : 1	<1.3%	16
2,000x2,000	2,000x2,000	1 : 1	<1.0%	99

5.6 The Combination Effects

The combination of flow rate, permeability, depth difference between layer, and area were studied to see the threshold values of these parameters for deviation less than 5%. The effects from these parameters are similar to above discussion which can be summarized as follows:

1) With higher flow rate, the calculated gas volume at reservoir condition using rate allocation will be more deviated from the actual gas volume at reservoir condition but time required to reach stabilized flow will decrease
2) With higher permeability, the calculated gas volume at reservoir condition using rate allocation will be less deviated from the actual gas volume at reservoir condition and time required to reach stabilized flow will decrease.

Table 5-6: Effect of flow rate, permeability, distance between layers, and area extent on production rate allocation, their deviations, and time required to reach stabilized condition.

	Flow rate	1 MMscf/d				2 MMscf/d				3 MMscf/d				5 MMscf/d				10 MMscf/d			
	Area L1 : L2	1 : 1	2 : 1	16 : 1	1 : 16	1 : 1	2 : 1	16 : 1	1 : 16	1 : 1	2 : 1	16 : 1	1 : 16	1 : 1	2 : 1	16 : 1	1 : 16	1 : 1	2 : 1	16 : 1	1 : 16
	Area Layer1 (ft^2)	$(1000)^2$	$(1400)^2$	$(2000)^2$	$(500)^2$	$(1000)^2$	$(1400)^2$	$(2000)^2$	$(500)^2$	$(1000)^2$	$(1400)^2$	$(2000)^2$	$(500)^2$	$(1000)^2$	$(1400)^2$	$(2000)^2$	$(500)^2$	$(1000)^2$	$(1400)^2$	$(2000)^2$	$(500)^2$
	Area Layer2 (ft^2)	$(1000)^2$	$(1000)^2$	$(500)^2$	$(2000)^2$	$(1000)^2$	$(1000)^2$	$(500)^2$	$(2000)^2$	$(1000)^2$	$(1000)^2$	$(500)^2$	$(2000)^2$	$(1000)^2$	$(1000)^2$	$(500)^2$	$(2000)^2$	$(1000)^2$	$(1000)^2$	$(500)^2$	$(2000)^2$
k (md)	Depth btw layer (ft)																				
	10	<1%/87d	<1.5%/257d	<1%/124d	<1%/128d	<1%/47d	<2.5%/257d	<2%/131d	<2%/144d	<1%/26d	2-3%/N.A.	<2.5%/111d	<2.5%/123d	<1%/3d	5-6%/N.A.	3-6%/N.A.	4-6%/N.A.	1%/N.A.	7-18%/N.A.	6-44%/N.A.	6-42%/N.A.
10	100	<1%/141d	<1.5%/282d	<1%/140d	<1%/119d	<1%/100d	<2.5%/213d	<2.1%/121d	<2.1%/108d	<1%/76d	2-3%/N.A.	<2.5%/129d	<2.5%/116d	<1%/48d	5-8%/N.A.	4-7%/N.A.	4-6%/N.A.	1-2%/N.A.	7-18%/N.A.	6-44%/N.A.	6-42%/N.A.
	200	<1%/171d	<1.5%/302d	<1%/141d	<1%/106d	<1%/130d	<2.5%/245d	<2.1%/121d	<2.1%/101d	<1%/105d	2-3%/N.A.	<2.5%/129d	<2.5%/109d	1-4%/N.A.	5-8%/N.A.	4-7%/N.A.	3-6%/N.A.	1-2%/N.A.	8-19%/N.A.	6-45%/N.A.	6-41%/N.A.
	1000	<1%/262d	<2.5%/308d	<1%/162d	<1%/86d	<1%/233d	<2.5%/348d	<2.2%/136d	<1.8%/2d	<1%/213d	3-4%/N.A.	<2.5%/143d	<2.5%/78d	2-5%/N.A.	6-9%/N.A.	4-8%/N.A.	2-4%/N.A.	7-10%/N.A.	8-26%/N.A.	6-53%/N.A.	6-33%/N.A.
	10	<1%/52d	<1%/96d	<1%/40d	<1%/35d	<1%/38d	<1.8%/81d	<1.3%/42d	<1%/40d	<1%/30d	<1.8%/86d	<1.8%/46d	<1.8%/45d	<1%/20d	<2%/84d	<2%/38d	<2%/38d	<1%/7d	3-6%/N.A.	2-4%/N.A.	2-4%/N.A.
30	100	<1%/70d	<1%/112d	<1%/44d	<1%/23d	<1%/57d	<1.8%/92d	<1.3%/45d	<1.2%/36d	<1%/48d	<1.8%/96d	<1.9%/48d	<1.9%/41d	<1%/38d	<2%/91d	<2%/46d	<2%/41d	<1%/24d	3-7%/N.A.	2-4%/N.A.	2-4%/N.A.
	200	<1%/79d	<1%/119d	<1%/46d	<1%/23d	<1%/66d	<1.8%/98d	<1.3%/46d	<1.1%/29d	<1%/58d	<1.9%/102d	<1.9%/49d	<1.9%/37d	<1%/48d	<2%/97d	<2%/47d	<2%/38d	1-6%/N.A.	3-8%/N.A.	2-4%/N.A.	2-4%/N.A.
	1000	<1%/109d	<1%/153d	<1%/56d	<1%/45d	<1%/96d	<2.1%/130d	<1.3%/54d	<1%/37d	<1%/89d	<2.2%/137d	<2%/56d	<1.8%/30d	<1%/82d	<2.5%/109d	<2.1%/53d	<1.9%/14d	1-11%/N.A.	4-13%/N.A.	2-5%/N.A.	<2%/21d
	10	<1%/38d	<1%/60d	<1%/25d	<1%/20d	<1%/29d	<1.6%/58d	<1%/25d	<1%/23d	<1%/25d	<1.7%/60d	<1.7%/26d	<1.7%/24d	<1%/18d	<1.8%/52d	<1.8%/28d	<1.8%/28d	<1%/10d	2.5%/44d	<1.8%/32d	<1.8%/31d
50	100	<1%/49d	<1%/71d	<1%/29d	<1%/15d	<1%/41d	<1.6%/67d	<1%/27d	<1%/18d	<1%/36d	<1.7%/68d	<1.7%/28d	<1.7%/22d	<1%/30d	<1.8%/58d	<1.8%/30d	<1.8%/26d	<1%/21d	2.5%/48d	<1.9%/33d	<1.8%/29d
	200	<1%/53d	<1%/76d	<1%/30d	<1%/23d	<1%/45d	<1.6%/71d	<1%/29d	<1%/7d	<1%/41d	<1.7%/71d	<1.7%/29d	<1.7%/17d	<1%/35d	<1.8%/62d	<1.8%/31d	<1.8%/23d	<1%/26d	2.5%/51d	<1.9%/33d	<1.8%/27d
	1000	<1%/69d	<1%/99d	<1%/37d	<1%/31d	<1%/63d	<1.9%/82d	<1%/35d	<1%/27d	<1%/59d	<2%/80d	<1.8%/34d	<1.6%/24d	<1%/55d	<2.1%/84d	<1.9%/35d	<1.7%/19d	<1.5%/41d	3.6%/50d	<1.9%/38d	<1.7%/2d
	10	<1%/24d	<1%/34d	<1%/14d	<1%/2d	<1%/20d	<1.2%/30d	<1%/13d	<1%/11d	<1%/17d	<1.4%/30d	<1.3%/13d	<1.3%/12d	<1%/14d	<1.5%/30d	<1.4%/13d	<1.4%/13d	<1%/10d	<1.6%/27d	<1.4%/15d	<1.4%/15d
100	100	<1%/30d	<1%/41d	<1%/17d	<1%/14d	<1%/26d	<1.2%/37d	<1%/16d	<1%/8d	<1%/23d	<1.5%/36d	<1.3%/16d	<1.2%/7d	<1%/20d	<1.5%/34d	<1.4%/16d	<1.4%/11d	<1%/16d	<1.6%/30d	<1.4%/16d	<1.4%/14d
	200	<1%/32d	<1%/43d	<1%/18d	<1%/16d	<1%/27d	<1.3%/39d	<1%/16d	<1%/13d	<1%/25d	<1.5%/37d	<1.3%/16d	<1.2%/9d	<1%/22d	<1.5%/36d	<1.4%/16d	<1.4%/7d	<1%/18d	<1.6%/31d	<1.4%/17d	<1.4%/13d
	1000	<1%/42d	<1%/54d	<1%/22d	<1%/19d	<1%/37d	<1.5%/51d	<1%/20d	<1%/17d	<1%/36d	<1.7%/48d	<1.3%/19d	<1%/16d	<1%/32d	<1.8%/49d	<1.5%/19d	<1.3%/14d	<1%/29d	<1.8%/44d	<1.5%/19d	<1.3%/10d
	10	<1%/9d	<1%/10d	<1%/5d	<1%/5d	<1%/8d	<1%/9d	<1%/4d	<1%/4d	<1%/7d	<1%/9d	<1%/4d	<1%/4d	<1%/7d	<1%/8d	<1%/4d	<1%/2d	<1%/6d	<1%/7d	<1%/4d	<1%/3d
500	100	<1%/11d	<1%/13d	<1%/7d	<1%/6d	<1%/9d	<1%/12d	<1%/6d	<1%/6d	<1%/9d	<1%/11d	<1%/6d	<1%/5d	<1%/8d	<1%/10d	<1%/5d	<1%/4d	<1%/7d	<1%/9d	<1%/5d	<1%/3d
	200	<1%/10d	<1%/13d	<1%/7d	<1%/7d	<1%/9d	<1%/12d	<1%/6d	<1%/6d	<1%/9d	<1%/11d	<1%/6d	<1%/6d	<1%/8d	<1%/10d	<1%/6d	<1%/5d	<1%/7d	<1%/9d	<1%/5d	<1%/4d
	1000	<1%/13d	<1%/17d	<1%/8d	<1%/8d	<1%/12d	<1%/15d	<1%/8d	<1%/7d	<1%/11d	<1%/14d	<1%/7d	<1%/7d	<1%/10d	<1%/14d	<1%/7d	<1%/6d	<1%/9d	<1%/13d	<1%/6d	<1%/6d

Note 1) results are show in format of 'error / time required to reach stabilized flow'

2) N.A. means the production rate from each layer cannot reach stabilized flow

35

3) With increasing depth difference between layers, the calculated gas volume at reservoir condition using rate allocation will be more deviated from the actual gas volume at reservoir condition and time required to reach stabilized flow will increase. Nevertheless, effects from depth difference between layers are small.
4) Area extent has less influence to deviation and time to reach stabilized flow.

The results showing in Table 5-6 do not cover all possible cases. Therefore, it can only be use as general guideline. Specific runs for the systems under investigation are recommended in order to specify appropriate threshold value of each influencing parameters.

5.7 Effects of Porosity

The effects from porosity are investigated by vary porosity of layer 1 and layer 2 from 0.1 to 0.3 when other parameters are fixed. The permeability of 100 md and flow rate of 3 MMscf/d are used for all cases. The results from simulation runs are shown in Figure 5-14 and Table 5-7. The rate allocation does depend on gas volume ratio with deviation less than 5% in every case. From Table 5-7, the case of $\phi_1 = \phi_2 = 0.3$ requires more time to reach stabilized condition. This is probably because it has more gas volume hence more pressure support. The deviation from the case of $\phi_1 = 0.2$, $\phi_2 = 0.1$ is less than 5% which is higher than base case of $\phi_1 = 0.2$, $\phi_2 = 0.2$. It can be noticed that the deviation from the case of $\phi_1 = 0.2$, $\phi_2 = 0.1$ is equal to the case of $area_1 = 2{,}000^2$ sq.ft and $area_2 = 1{,}000^2$ sq.ft from section 5.5 and both cases has the same gas volume ratio ($V_{g1}:V_{g2}$ = 4:1). The similar behavior can be observed from the case of $\phi_1 = 0.2$, $\phi_2 = 0.3$ which has $V_{g1}:V_{g2}$ ratio = 1.3:1 and its deviation is close to the case of $area_1 = area_2 = 1{,}000^2$ sq.ft. From this study, it can be concluded that effects from porosity are minor and the change of porosity impacts only on magnitude of gas volume. The deviation can be changed based on gas volume ratio between layers.

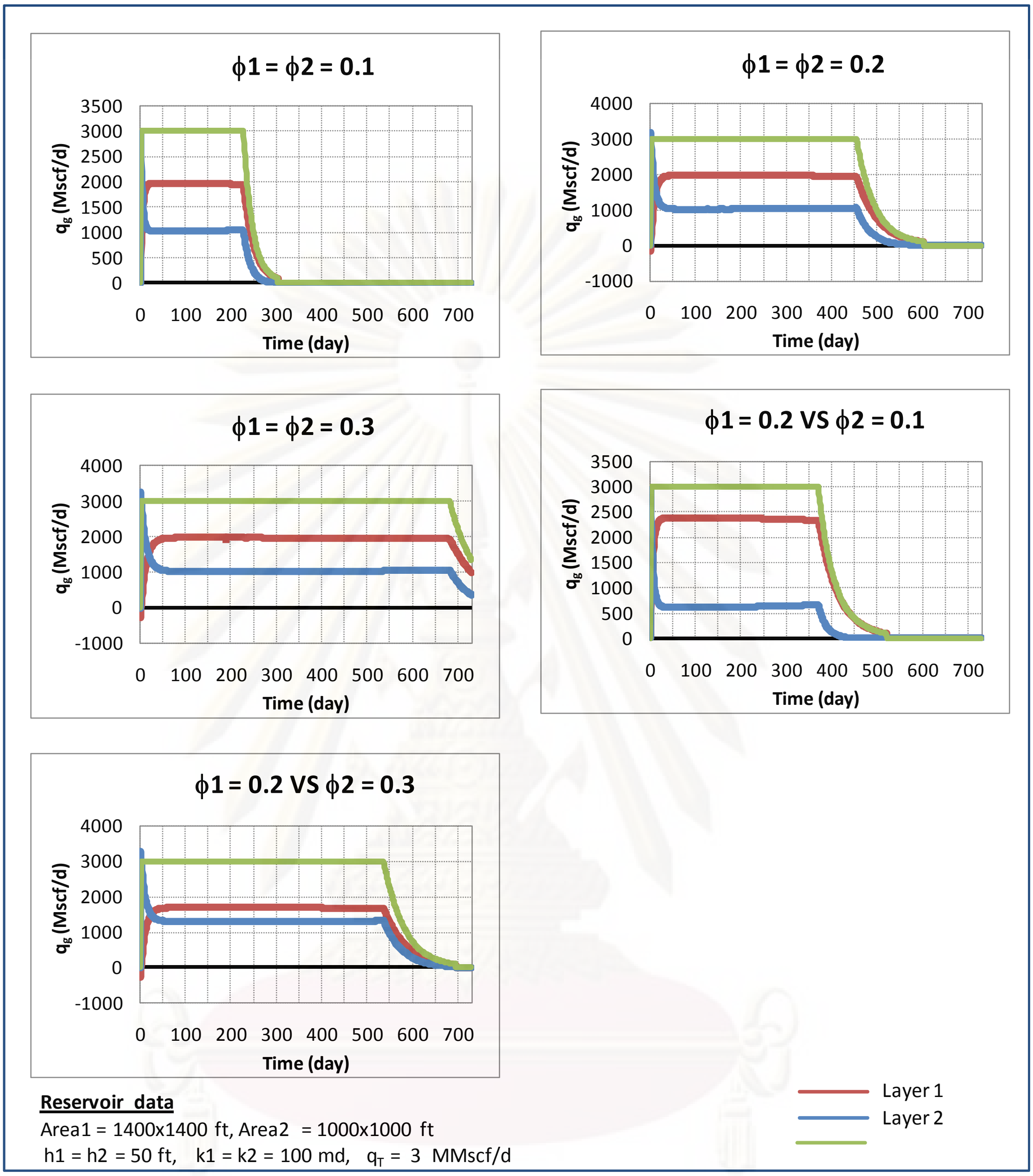


Figure 5-14: Rate allocation of two-layered reservoir under various porosity values

Table 5-7: Effect of porosity on production rate allocation
(reservoir size 1,400x1,400 ft and 1,000x1,000 ft , $h_1 = h_2 = 50$ ft,
$k_1 = k_2 = 100$ md, and $q_T = 3$ MMscf/d)

ϕ_1	ϕ_2	$V_{g1} : V_{g2}$	Deviation	Time required (days)
0.1	0.1	2 : 1	<1.5%	21
0.2	0.2	2 : 1	<1.5%	37
0.3	0.3	2 : 1	<1.5%	56
0.2	0.1	4 : 1	<2.0%	25
0.2	0.3	1.3 : 1	<1.0%	45

5.8 Effects of Thickness

Three cases of thickness values are investigated and shown in Table 5-8 and Figure 5-15. Other parameters are fixed in order to see the effects of thickness change. The results show that rate allocation is proportional to gas volume with deviation less than 5% for all cases. The deviation and time required to reach to the stabilized condition will increase when thickness increase. Considering small deviation, it can be concluded that the effects from thickness are small and insignificant.

Table 5-8: Effect of thickness on production rate allocation
(reservoir size 1,400x1,400 ft and 1,000x1,000 ft, $\phi_1 = \phi_2 = 0.2$,
$k_1 = k_2 = 100$ md, and $q_T = 3$ MMscf/d)

h_1 (ft)	h_2 (ft)	$V_{g1} : V_{g2}$	Deviation	Time required (days)
50	10	10 : 1	<1.1%	18
50	50	2 : 1	<1.5%	37
50	100	1 : 1	<1.9%	42

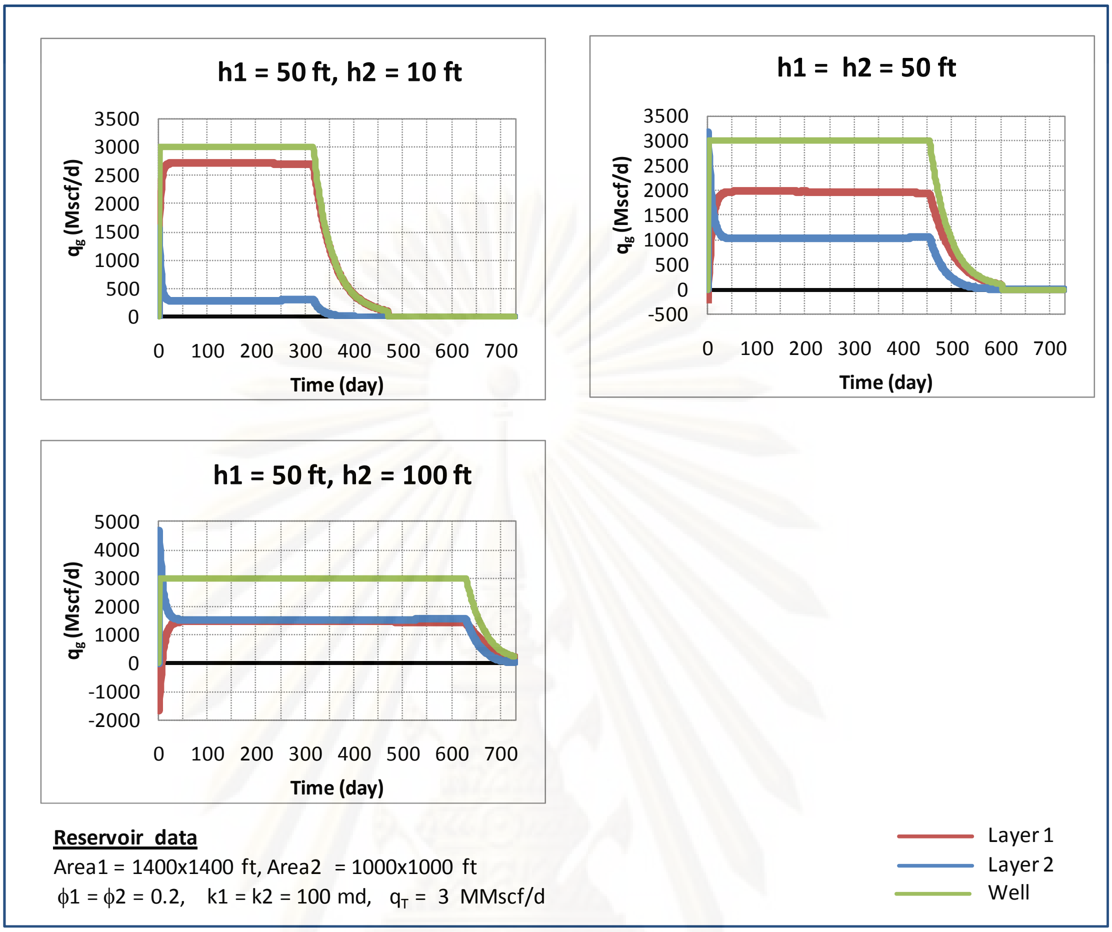


Figure 5-15: Rate allocation of two-layered reservoir under various thickness values

5.9 Effects of Skin Factor

The skin factor indicates difficulty of reservoir fluid flowing into a well and it may affect the rate allocation between layers. The effects from skin factor are investigated for 5 skin factor values including 0, +5, +10, +15, and +20. Figure 5-16 and Table 5-9 show results from simulation runs. It is shown that the rate allocation is proportional to gas volume for all cases. Considering the change of skin factor from 0 to +20, the deviation increases in a very small amount but time required to reach equilibrium increase twice from 24 days to 85 days. It can be concluded that the effects from skin factor is very small and major impact is on the time required to reach the stabilized condition.

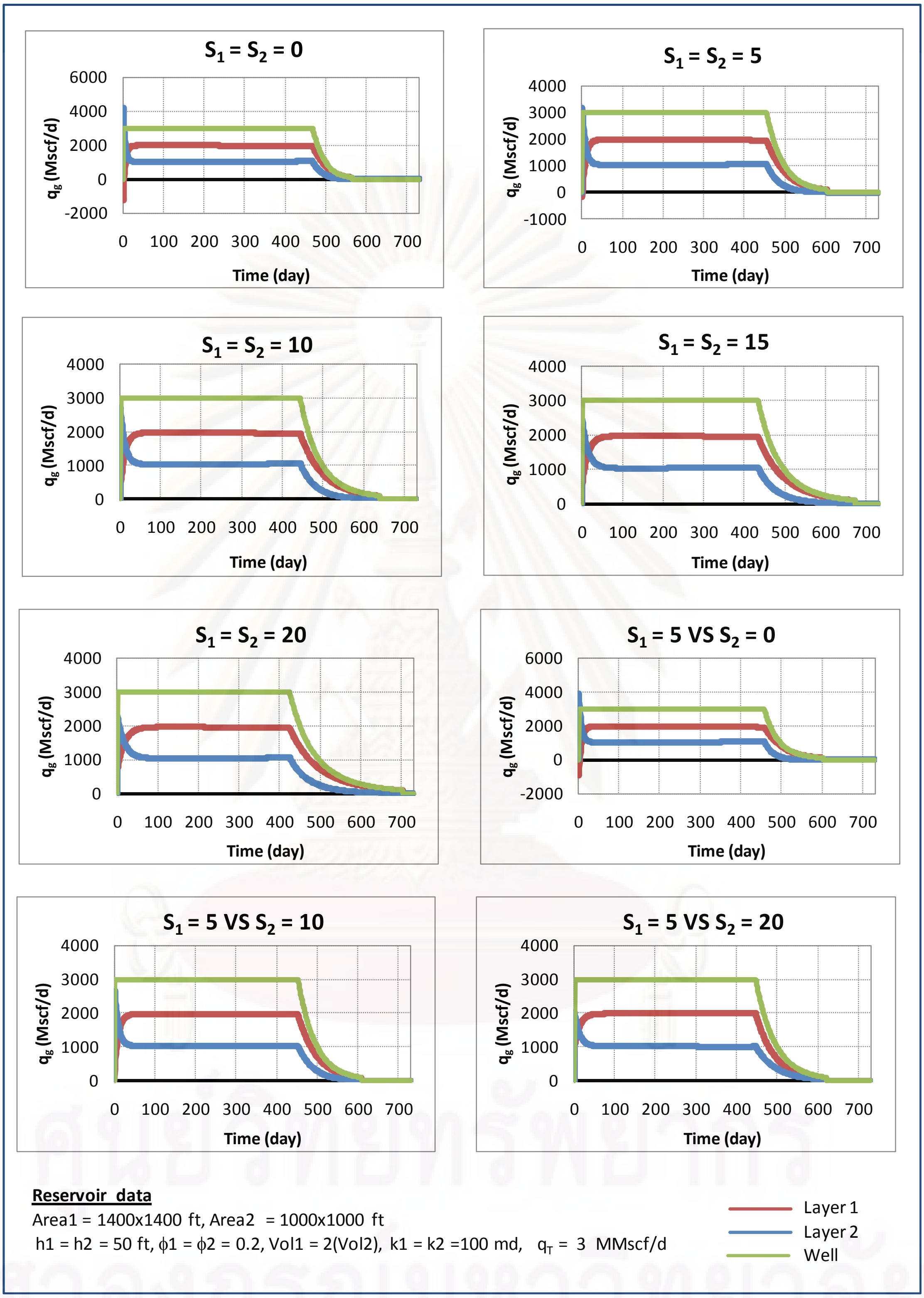


Figure 5-16: **Rate allocation of two-layered reservoir under various skin factor values**

Table 5-9: Effect of skin factor on production rate allocation
($V_{g1} = 2\ V_{g2}$, $h_1 = h_2 = 50$ ft, $k_1 = k_2 = 100$ md, and $q_T = 3$ MMscf/d)

Skin factor Layer 1	Skin factor Layer 2	Deviation	Time required (days)
0	0	<1.2%	24
+5	+5	<1.5%	37
+10	+10	<1.5%	52
+15	+15	<1.6%	67
+20	+20	<1.6%	85
+5	0	<2.3%	33
+5	+10	<1.0%	42
+5	+20	<1.0%	46

5.10 Application to GIP Estimation

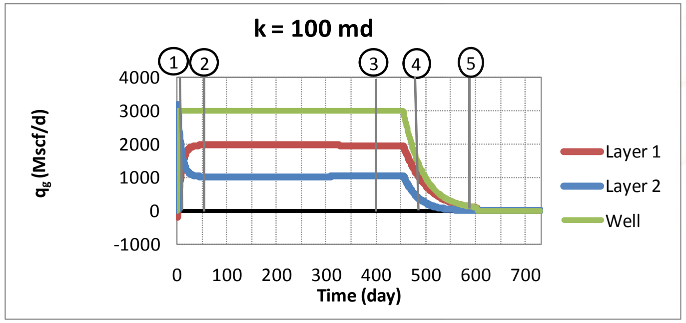
After analysis of results from simulation runs, it is found that flow rate is proportional to gas volume, reservoir pressure, and rate of change of reservoir pressure as already described in Chapter III. The relationship between flow rate and gas volume can be expressed as in Eq. (3.11), which is shown again below.

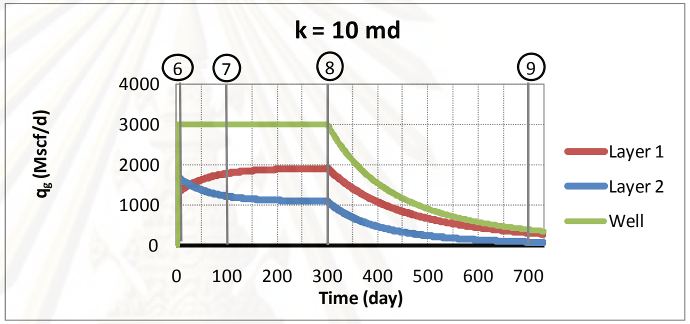
$$\frac{q_1}{q_2} = \frac{\left(\frac{V_1}{p_1} \cdot C_1\right)}{\left(\frac{V_2}{p_2} \cdot C_2\right)}, \qquad (3.11)$$

where $C_1 = \frac{dp_1}{dt}$ and $C_2 = \frac{dp_2}{dt}$

Table 5.10 shows the calculated rate of layer 1 based on Eq. (3.11) obtained from the gas volume and pressure in simulation runs and comparing with actual rate. The deviation of calculated rate from actual rate is small for every time period of production life (less than 10%). This can confirm the validity of the relationship of flow rate of each layer and gas volume, reservoir pressure, and rate of change of reservoir pressure as shown in Eq. (3.11) for quite large ranges of various influencing parameters, such as permeability, reservoir pressure, and flow rate.

Table 5-10: Calculation of gas flow rate of layer 1 based on relationship $q_{g1} = q_{gT} \times \left(\dfrac{\dfrac{V_{g1}}{p_1} C_1}{\dfrac{V_{g1}}{p_1} C_1 + \dfrac{V_{g2}}{p_2} C_2} \right)$





Test no.	Day	V_{g1} (rcf)	V_{g2} (rcf)	p_1 (psia)	p_2 (psia)	C_1 (psia/day)	C_2 (psia/day)	$\dfrac{C_1/p_1}{C_2/p_2}$	Actual q_{g1} (Mscf/d)	q_T (Mscf/d)	Calculated q_{g1} (Mscf/d)	Deviation
1	1	9.11×10^6	4.65×10^6	2,660	2,753	0.409	-14.515	-0.03	-177	3,000	-182	-2.8%
2	50	9.11×10^6	4.65×10^6	2,474	2,457	-4.462	-4.555	0.97	1,973	3,000	1,968	-0.3%
3	400	9.11×10^6	4.65×10^6	956	903	-4.319	-4.532	0.90	1,955	3,000	1,915	-2.0%
4	480	9.11×10^6	4.65×10^6	634	573	-2.581	-2.005	1.16	1,143	1,595	1,109	-3.0%
5	590	9.11×10^6	4.65×10^6	526	516	-0.264	-0.054	4.82	117	129	117	0.0%
6	1	9.11×10^6	4.65×10^6	2,657	2,760	-2.993	-7.814	0.4	1,296	3,000	1,314	1.4%
7	100	9.11×10^6	4.65×10^6	2,296	2,146	-3.966	-5.317	0.7	1,783	3,000	1,732	-2.9%
8	300	9.11×10^6	4.65×10^6	1,473	1,179	-4.167	-4.672	0.71	1,912	3,000	1,750	-8.5%
9	700	9.11×10^6	4.65×10^6	772	599	-0.686	-0.361	1.48	308	389	289	-6.2%

42

In Table 5-10, it is noticed that the value of rate of change of reservoir pressure divided by reservoir pressure itself of layer1 is almost equal to that of layer 2 $\left(\frac{C_1}{p_1} \approx \frac{C_2}{p_2}\right)$ during stabilized flow (test no. 2 and 3). Therefore, during stabilized flow, Eq.(3.11) can be reduced to Eq. (3.12) as follows:

$$\frac{q_1}{q_T} = \frac{V_1}{V_1 + V_2} . \tag{3.12}$$

The relationship as per Eq. (3.12) coincides with the results from simulation runs as already mentioned. Therefore, it can be concluded that rate allocation is proportional to gas volume ratio at reservoir condition for the multi-layered gas reservoir during stabilized flow.

From the relationship of rate allocation and gas volume in each layer, it can be used to estimate GIP as follows:

Starting from volumetric estimation, we have

$$GIP = Ah\phi(1 - S_w)(E_i) = V_g E_i , \tag{5.1}$$

where

A = area extent of a layer

h = thickness of that layer

ϕ = porosity, or volume fraction of that layer

S_w = connate or irreducible water saturation

E_i = gas expansion factor, (scf/rcf)

For layer 1, we have

$$GIP_1 = V_{g1} E_{i1} . \tag{5.2}$$

For layer 2, we have

$$GIP_2 = V_{g2} E_{i2} . \tag{5.3}$$

For total reservoir, we have

$$GIP_T = V_{gT} E_{iT} + V_{g2} E_{i2} . \tag{5.4}$$

If Eqs. (5.2) and (5.3) are divided Eq. (5.4), we will obtain

$$\frac{GIP_1}{GIP_T} = \frac{V_{g1} \cdot E_{i1}}{V_{g1} \cdot E_{i1} + V_{g2} \cdot E_{i2}} \quad , \qquad (5.5)$$

and

$$\frac{GIP_2}{GIP_T} = \frac{V_{g2} \cdot E_{i2}}{V_{g1} \cdot E_{i1} + V_{g2} \cdot E_{i2}} \quad . \qquad (5.6)$$

During stabilized flow, $\frac{q_1}{q_T} = \frac{V_{g1}}{V_{gT}}$ and $\frac{q_2}{q_T} = \frac{V_{g2}}{V_{gT}}$, we obtain

$$\frac{GIP_1}{GIP_T} = \frac{q_1 \cdot E_{i1}}{q_1 \cdot E_{i1} + q_2 \cdot E_{i2}} \quad , \qquad (5.7)$$

and

$$\frac{GIP_2}{GIP_T} = \frac{q_2 \cdot E_{i2}}{q_1 \cdot E_{i1} + q_2 \cdot E_{i2}} \quad . \qquad (5.8)$$

From Eqs. (3.12), (5.7), and (5.8), it can be seen that the production rate of a two-layered, gas reservoir under preferable conditions can be used for determining gas volume at reservoir condition and GIP of each layer when total GIP is known. This can help increase our understanding of multi-layered reservoirs and support further production optimization which require accurate determination of individual layer.

5.11 Five-Layered System

A study case on a hypothetical model of five-layered rectangular reservoir is carried out to investigate validity of relationship between rate allocation and gas volume ratio at reservoir condition for a system of more than two layers. Well flow rate is set at 5 MMscf/d. Different area, thickness, and rock properties were assigned to each layer as showing in Table 5-11.

Table 5-11: Rock properties for a hypothetical model of five-layered reservoirs

Properties	Layer 1	Layer 2	Layer 3	Layer 4	Layer 5
Area (ft^2)	$2{,}000^2$	$1{,}400^2$	$3{,}300^2$	$1{,}400^2$	$1{,}000^2$
h (ft)	50	100	40	50	100
k (md)	80	100	200	200	80
ϕ	0.3	0.2	0.12	0.2	0.3
S_w	0.38	0.38	0.38	0.38	0.38
NTG	0.75	0.75	0.75	0.75	0.75
Depth of Top Face (ft)	6,000	6,150	6,350	6,490	6,740
p_i (psia)	2,638	2,724	2,786	2,870	2,879
Gas Volume (rcf)	$2.790x10^7$	$1.823x10^7$	$2.431x10^7$	$9.114x10^7$	$1.395x10^7$
GIP (Bcf)	3.613	2.434	3.317	1.279	2.027
Fraction of Gas volume at reservoir condition	0.298	0.195	0.260	0.098	0.149

Figure 5-17 shows the production rate from simulation runs. It can be observed that production rate from each layer becomes approximately constant after a period of production time. At the initial stage, gas from layer 2-5 which have high initial pressure are flowing into layer 1 during the first 38 days and gas flow rates from all layers become approximately constant within 127 days.

Figure 5-18 presents the fraction of flow contribution from each layer during 150 to 300 days. The fraction of flow contribution can be directly compared with fraction of gas volume at reservoir condition of each layer (Table 5-11). It can be clearly seen that rate allocation during stabilized flow is proportional to gas volume ratio.

Table 5-12 shows the calculation of GIP from rate allocation. As discussed before, GIP of each layer is calculated from total GIP, rate allocation, and gas expansion factor. The discrepancy of the calculated GIP from the actual GIP is less than 1% from every layer which is considerably acceptable. This confirms that the relationship of rate allocation and gas volume ratio can be applied for multi-layered reservoir if well flow rate is lower than flow capacity of each layer.

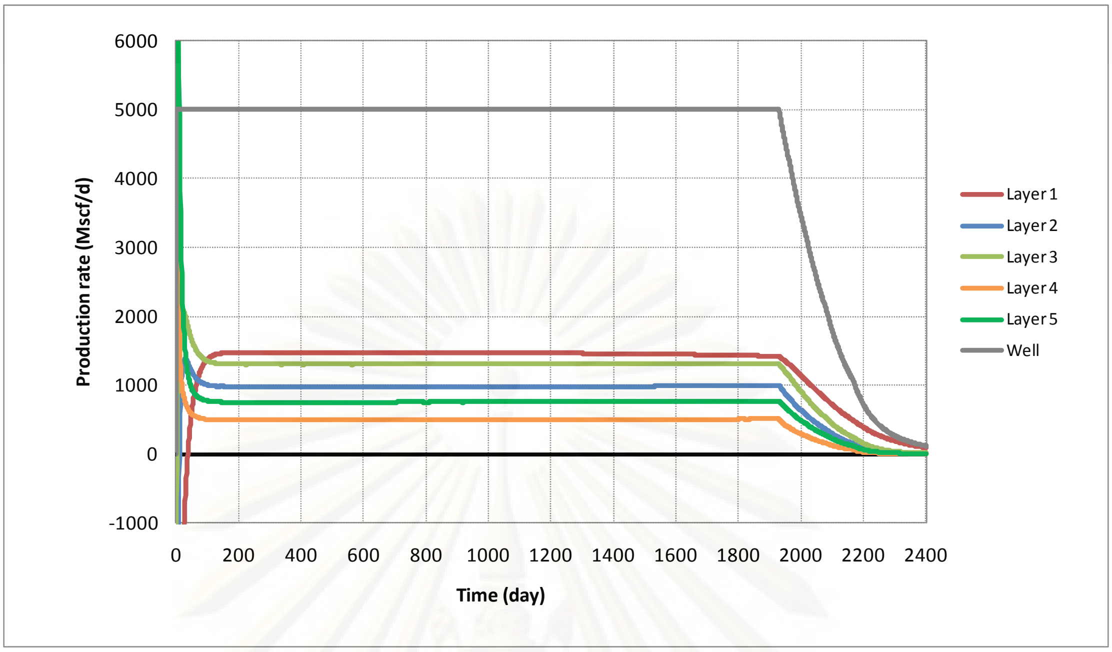


Figure 5-17: Production rate of a five-layered reservoir

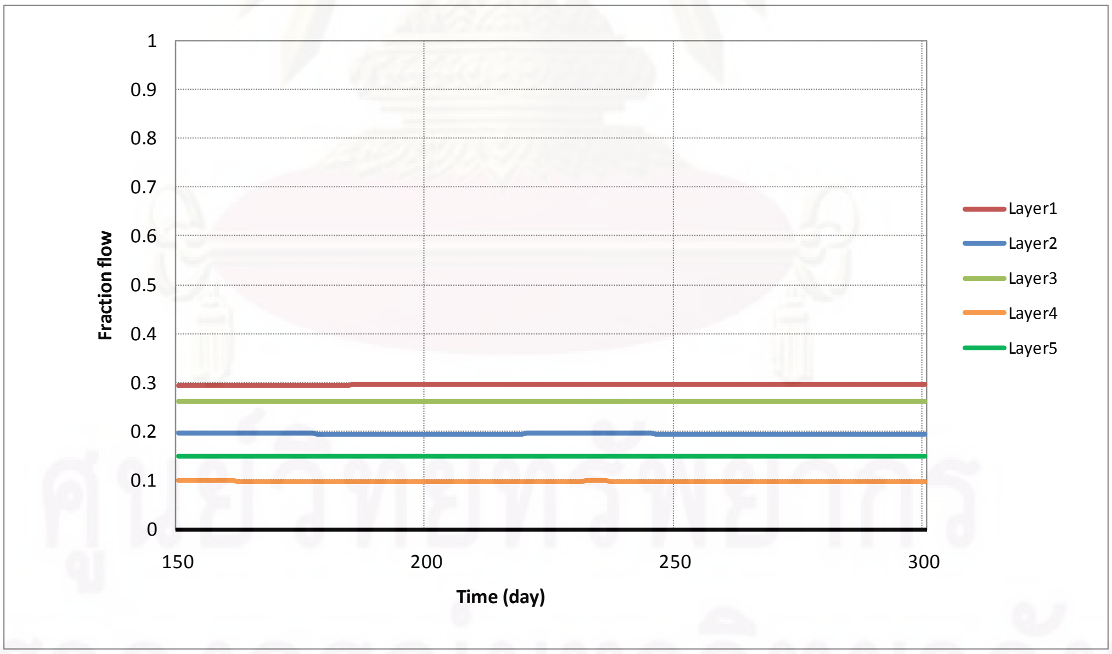


Figure 5-18: Fraction of flow contribution during stabilized condition

Table 5-12: Calculation of GIP for five-layered reservoir

Layer	q (MMscf/d)	q_i/q_T	V_{gi}/V_{gT}	Deviation	Time required (days)	Ei (scf/rcf)	Calculated GIP (Bcf)	Actual GIP (Bcf)	Deviation
1	1.443 – 1.478	0.289 – 0.296	0.298	<0.9%	127	129.49	3.522 – 3.514	3.613	<0.8%
2	0.975 – 0.997	0.195 – 0.199	0.195	<0.4%	89	133.53	2.454 – 2.445	2.434	<0.2%
3	1.301 – 1.332	0.260 – 0.266	0.260	<0.6%	103	136.44	3.346 – 3.337	3.317	<0.2%
4	0.490 – 0.511	0.098 – 0.102	0.098	<0.4%	67	140.31	1.296 – 1.317	1.279	<0.3%
5	0.749 – 0.771	0.150 – 0.154	0.149	<0.5%	84	145.29	2.051 – 2.057	2.027	<0.2%

5.12 Effects of Shutting-in Well

To obtain flow rate contribution from each layer, we are required to conduct a PLT run. In normal operation, the well will be shut-in for approximately 1 hour to put logging tool into position. During well shut-in, it is expected that new disturbance starts moving into the reservoir for each layer. A study is carried out to investigate the rate allocation after well shut-in. Four shut-in period cases were selected for this study including well shut-in for 1 hour, 1 day, 6 months, and 1 year cases. Figure 5-19 shows plots from all studied cases at well flow rate of 3 MMscf/d.

From Figure 5-19, it can be observed that there is a crossflow from layer 1 to layer 2 after well shut-in. For case of 6-months and 1-year well shut-in period, a crossflow has occurred until pressure from two layers is balancing. Flow after well re-open again is not stabilized and it requires 26 production days to reach a stabilized condition. For the 1-day and 1-hr well shut-in case, it requires 2 days and 1 hour, respectively, to reach a stabilized condition. It can be said that increasing of well shut-in period will disturb pressure to be further away from its equilibrium.

From this study, it should be recommended that well shut for PLT activity should be minimized at around one hour or less and it is required to have well flow for a period of time before the measured value can be applicable.

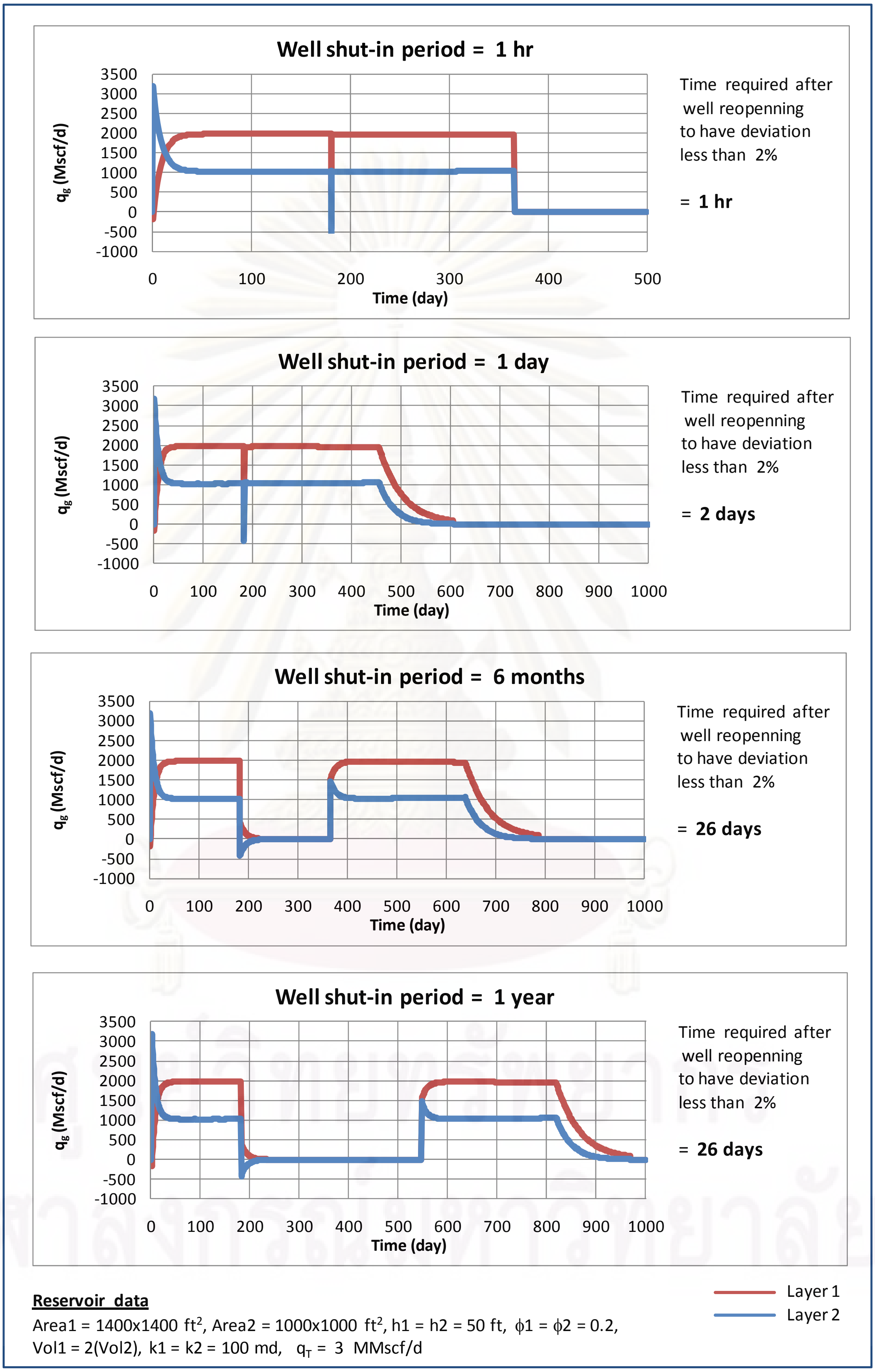


Figure 5-19: Rate allocation of two-layered reservoir with well shut-in

CHAPTER VI

CONCLUSIONS

This study is intended to investigate the controlling parameters of rate allocation from a multi-layered system. The condition that rate allocation is proportional to gas volume in each layer is identified. The effects from rock properties and flow rate on the gas volume allocation are investigated. In addition, the methodology to estimate GIP of each layer is also proposed. The two-layered, gas reservoir is used for investigation for various cases and the five-layered system is used for test of validity of applying the gas volume allocation concept to more layers reservoir. The results from this study can be summarized as follows:

1. The rate allocation of multi-layered gas reservoir is proportional to gas volume ratio during the stabilized flow on the conditions that flow rate is less than flow capacity of each layer.
2. The rate allocation of multi-layered gas reservoir is proportional to kh ratio during the early stage of flow when flow rate is close to flow capacity.
3. The rate allocation of multi-layered gas reservoir is proved to be proportional to the product of gas volume ratio, rate of change of reservoir pressure, and inverse of reservoir pressure. However, during the stabilized flow period, the ratio of rate of change of reservoir pressure and reservoir pressure of all layers are very close to each other. Therefore, it can be approximated that rate allocation is proportional to gas volume ratio during the stabilized flow period.
4. The rate allocation of multi-layered gas reservoir can be used for determining GIP of each layer when total GIP is known.
5. Flow rate and permeability can affect the deviation of calculated gas volume from actual gas volume and time required to reach stabilized flow. It has tendency that deviation will be higher for low permeability and high flow rate case. It is also required more time to reach stabilized flow for low permeability case.
6. The effects of area extent and depth different between layers are small.

7. Porosity, thickness, and skin factor have minor and insignificant effects to the relationship between flow rate and gas volume of each layer.
8. During well shut-in period, it is likely that there is a cross-flow between layers. Therefore, it is recommended that the well shut-in for PLT run should be minimized at approx. one hour or less and it is required to let the well flowing for a period of time before collecting the flow rate data from PLT run.

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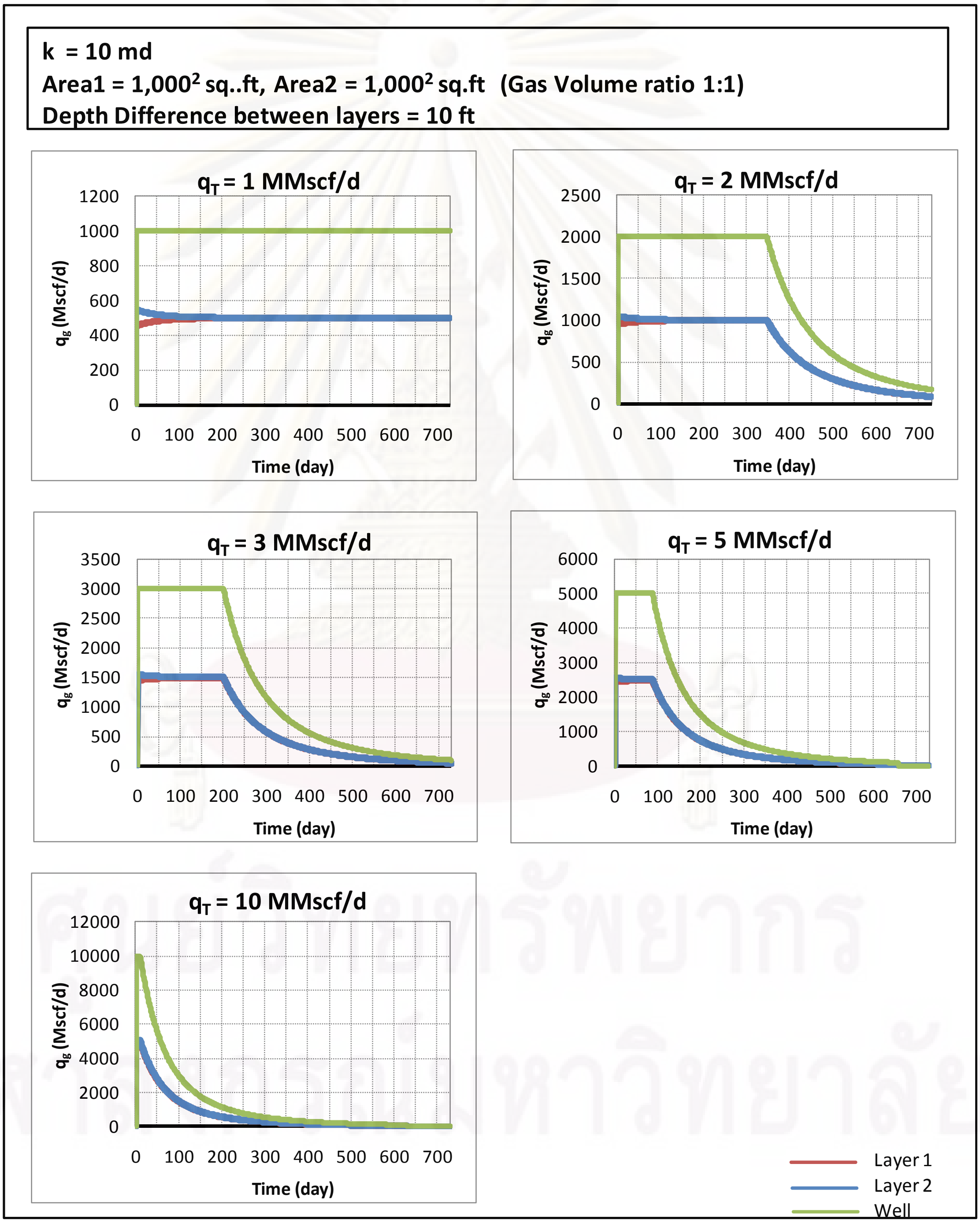
APPENDIX

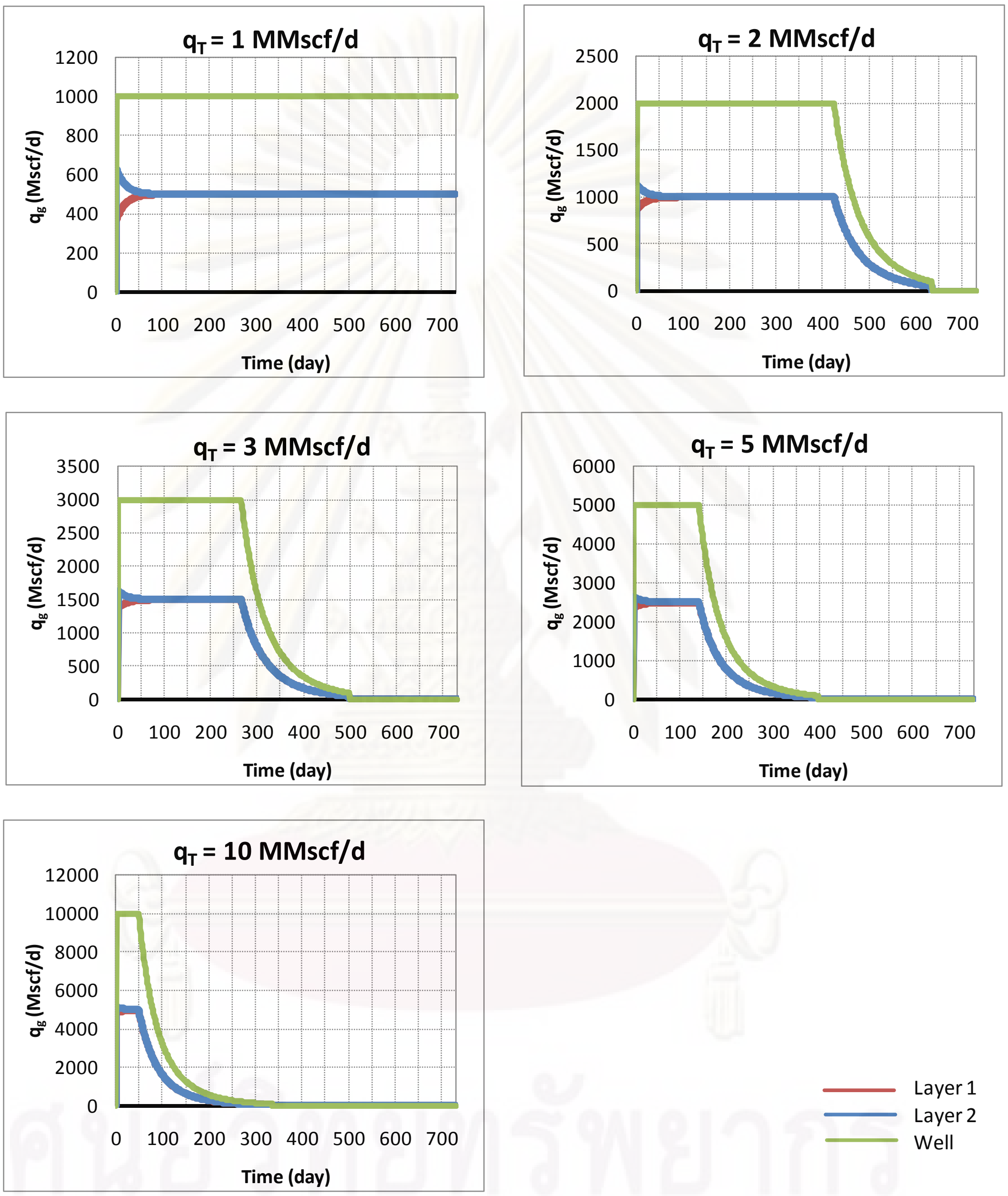
Selected results of the combination effects of flow rate, permeability, and area extent at depth between layers = 10 and 1,000 ft (Table 5-6)

A-1) Rate Allocation of two-layer reservoir with depth difference between layers = 10 ft and

- flow rate = 1, 2, 3, 5, and 10 MMscf/d,
- permeability = 10, 30, 50, 100, and 500 md,
- Area extent ratio = 1:1, 2:1, 16:1, and 1:16.



k = 30 md
Area1 = 1,000^2 sq..ft, Area2 = 1,000^2 sq.ft (Gas Volume ratio 1:1)
Depth Difference between layers = 10 ft



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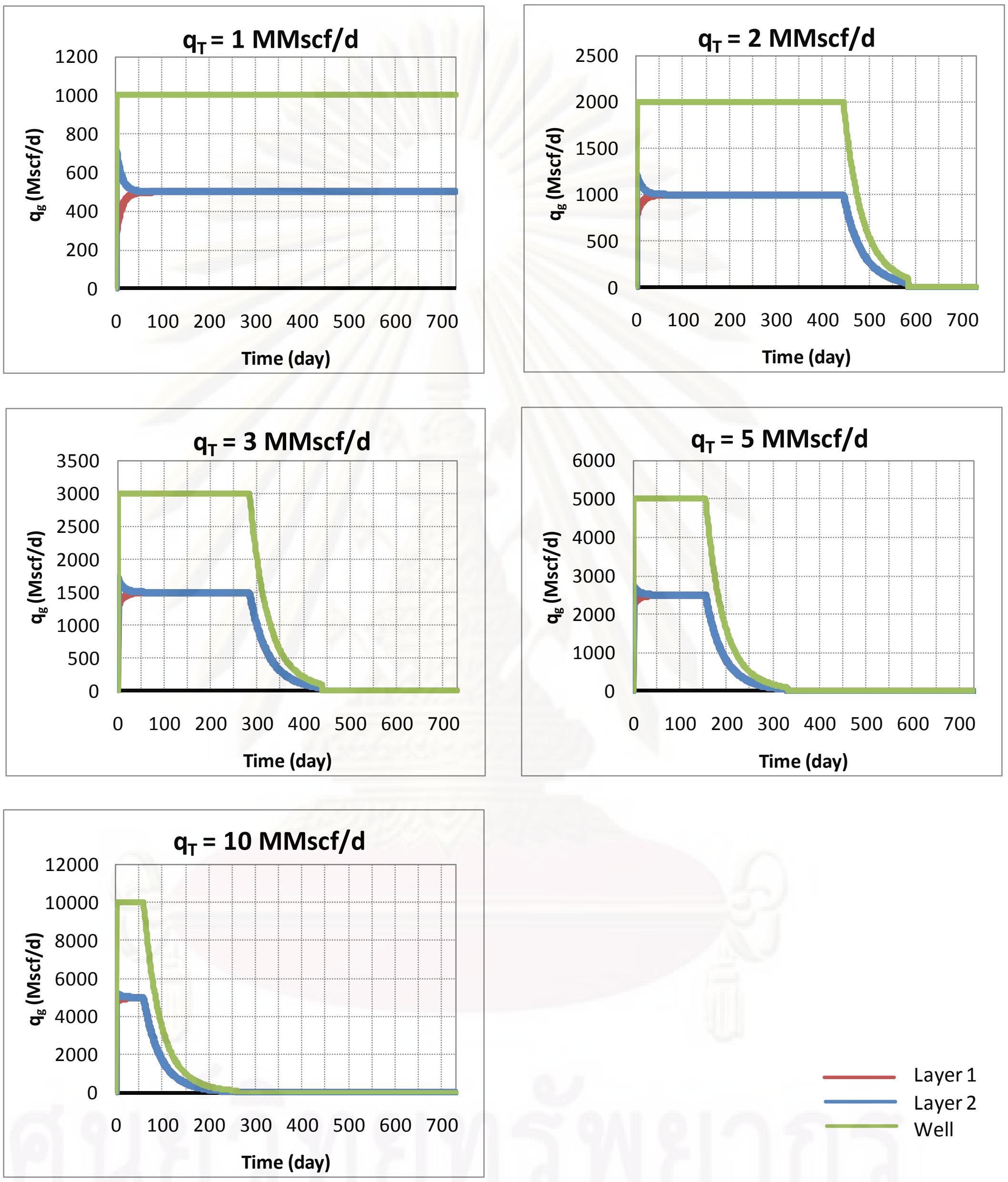
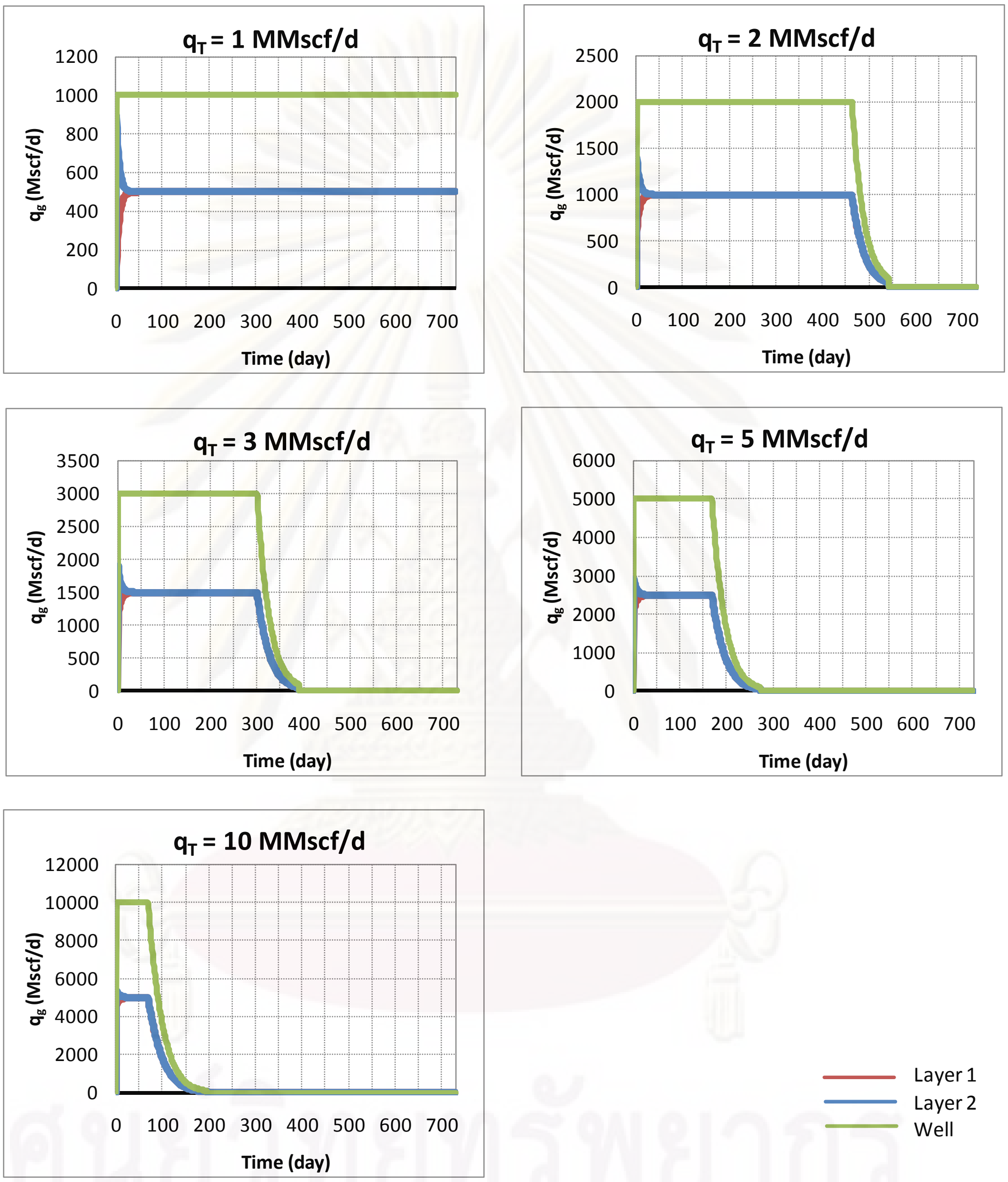
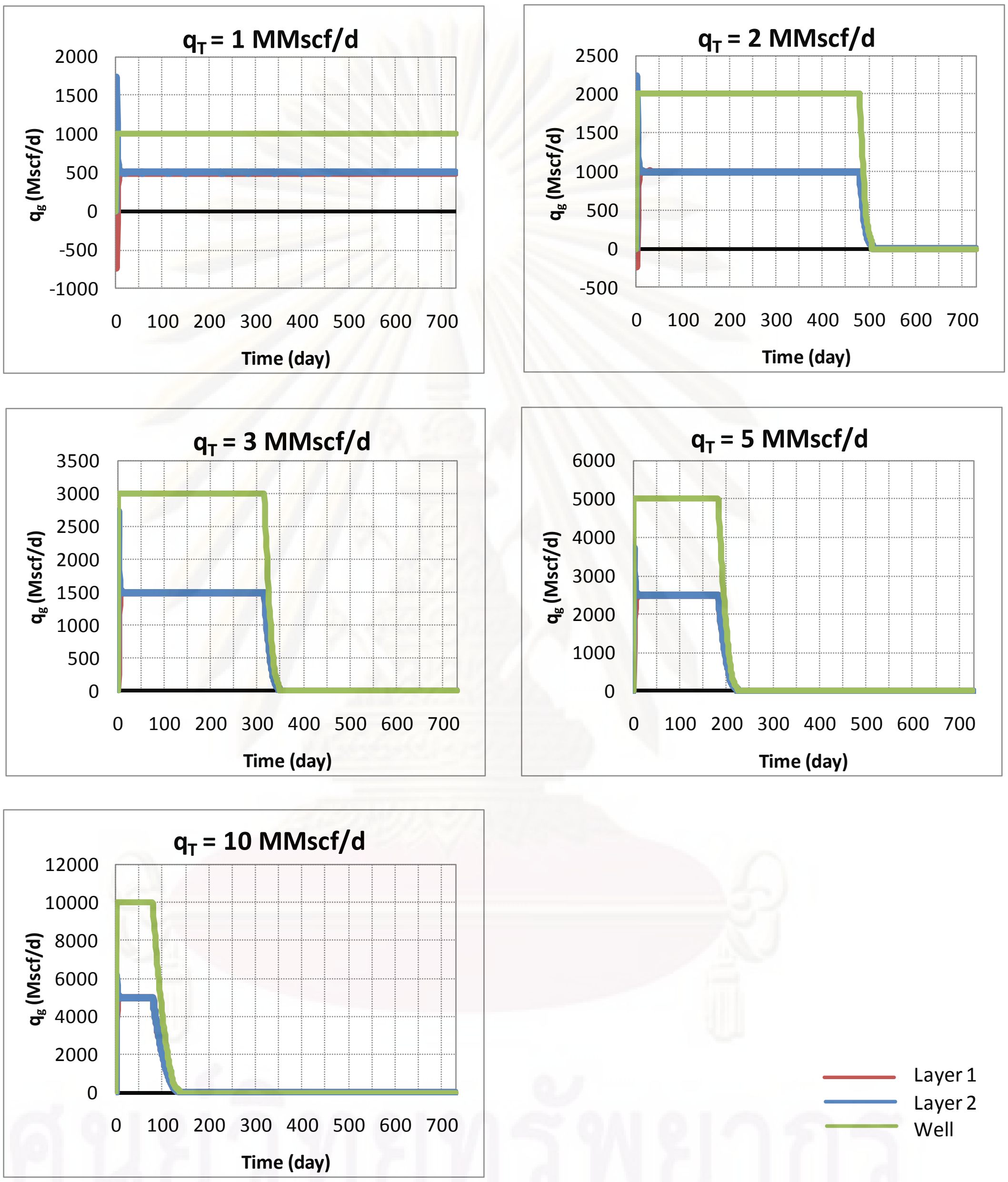
Area1 = $1,000^2$ sq..ft, Area2 = $1,000^2$ sq.ft (Gas Volume ratio 1:1)
Depth Difference between layers = 10 ft



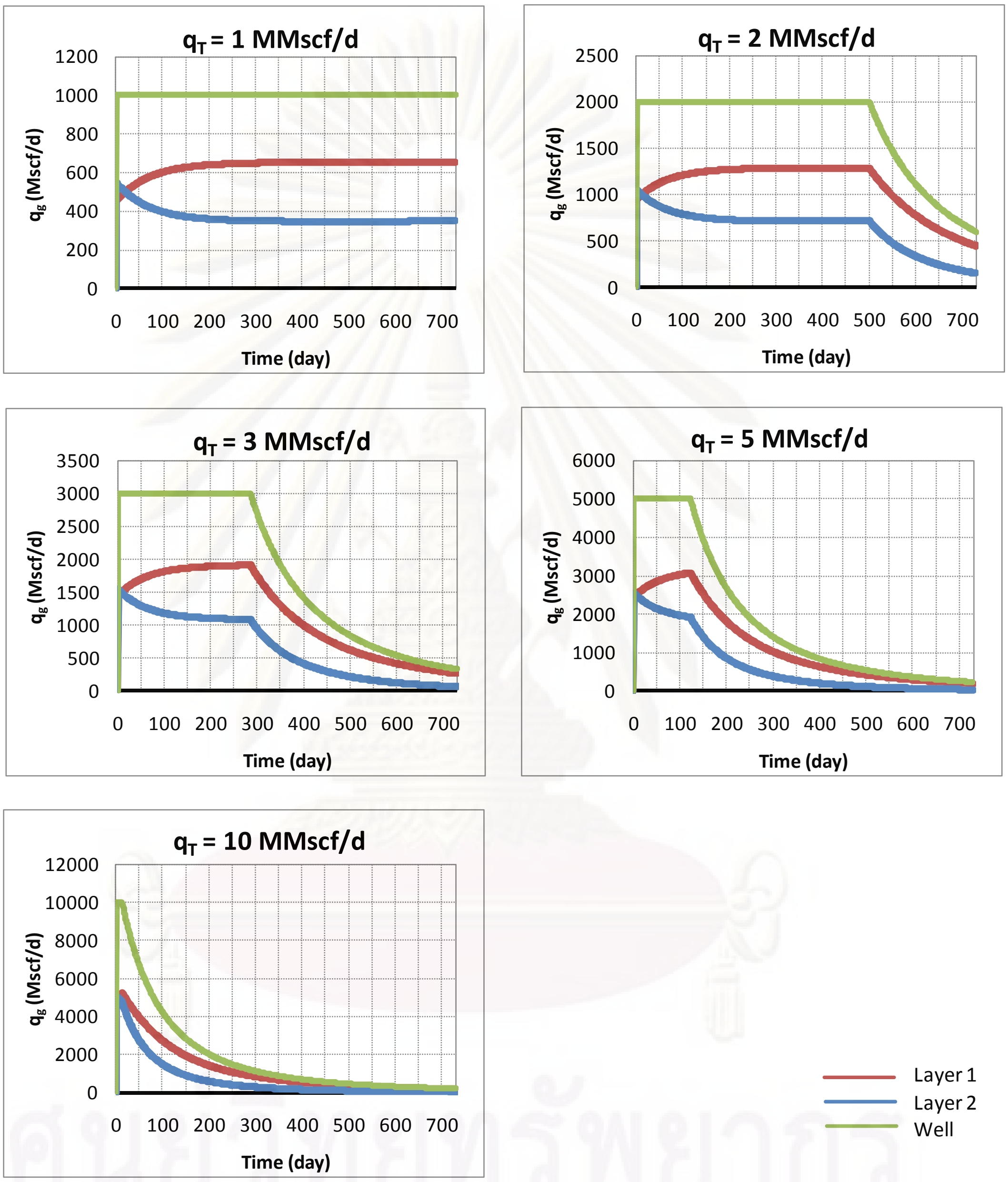
k = 100 md
Area1 = 1,000^2 sq..ft, Area2 = 1,000^2 sq.ft (Gas Volume ratio 1:1)
Depth Difference between layers = 10 ft



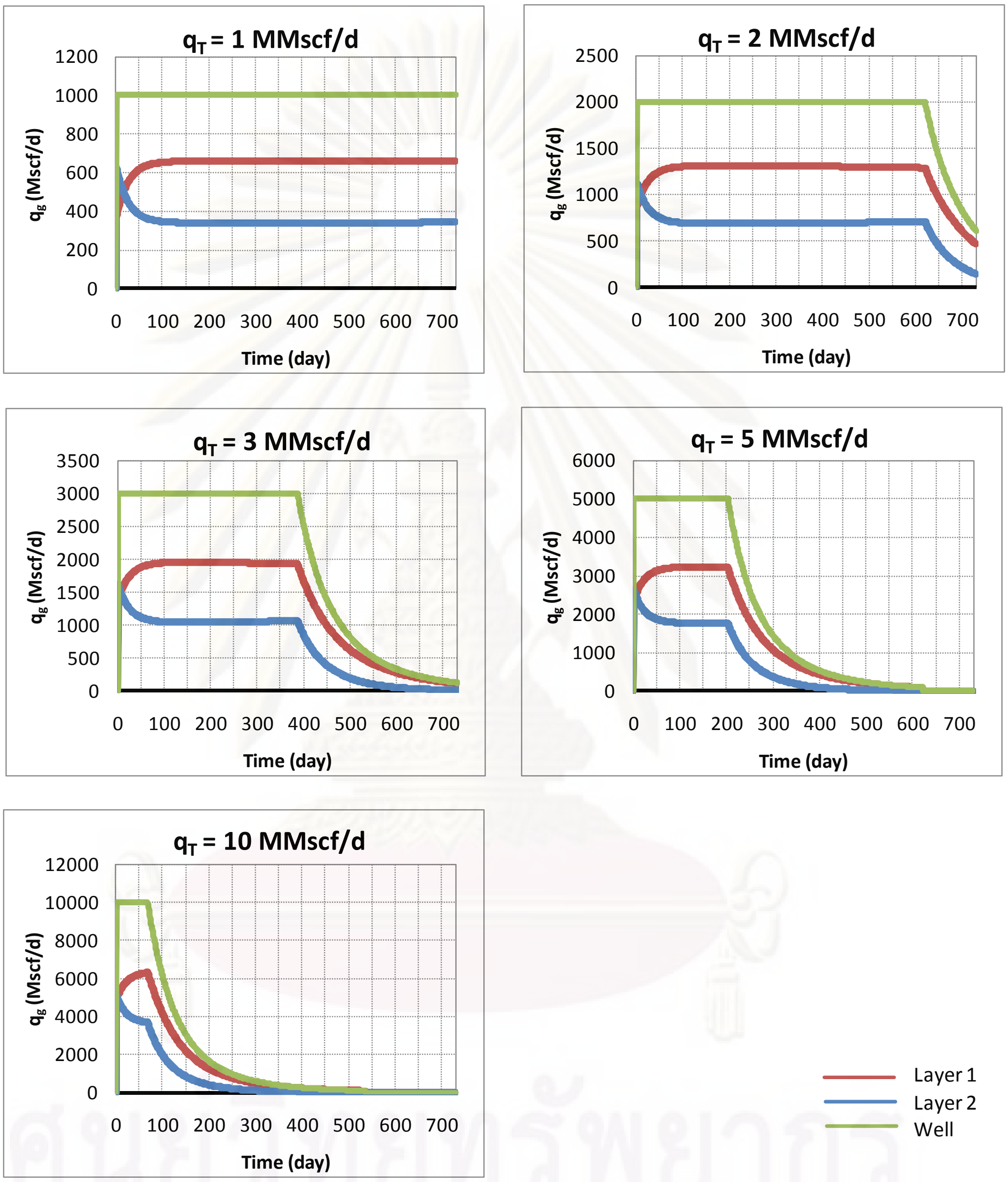
k = 500 md
Area1 = $1{,}000^2$ sq..ft, Area2 = $1{,}000^2$ sq.ft (Gas Volume ratio 1:1)
Depth Difference between layers = 10 ft

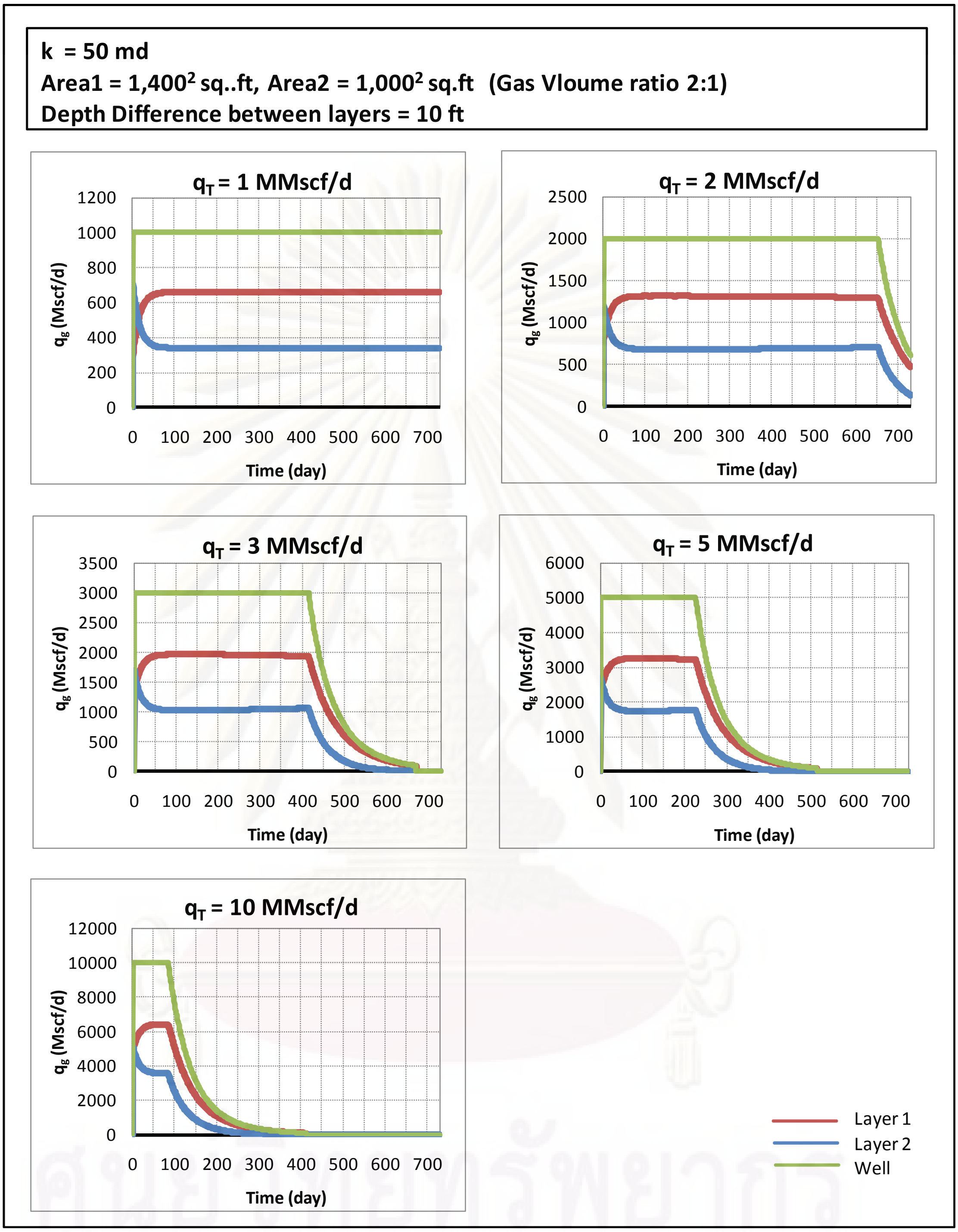


k = 10 md
Area1 = 1,400^2 sq..ft, Area2 = 1,000^2 sq.ft (Gas Volume ratio 2:1)
Depth Difference between layers = 10 ft

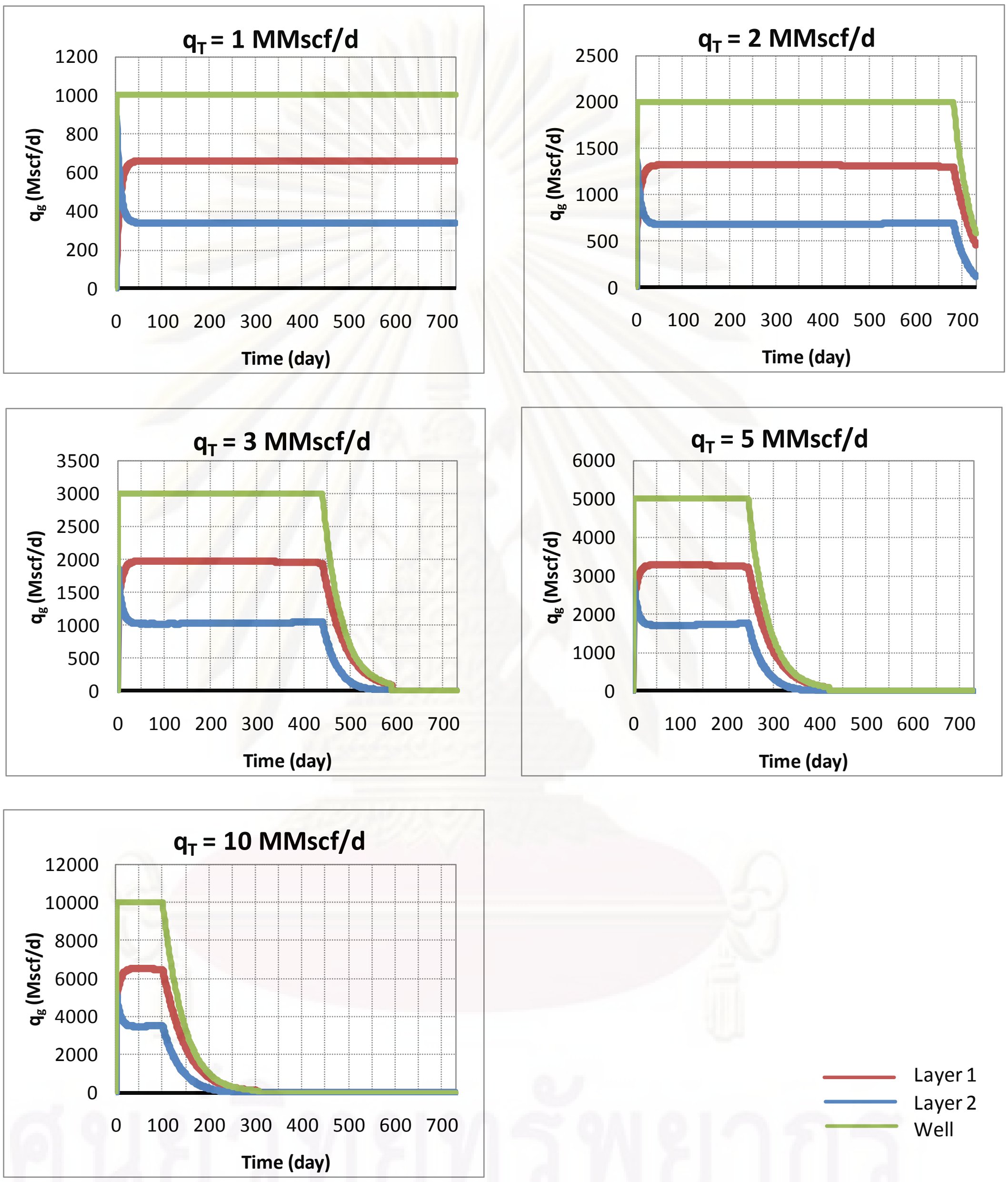


k = 30 md
Area1 = $1{,}400^2$ sq..ft, Area2 = $1{,}000^2$ sq.ft (Gas Volume ratio 2:1)
Depth Difference between layers = 10 ft

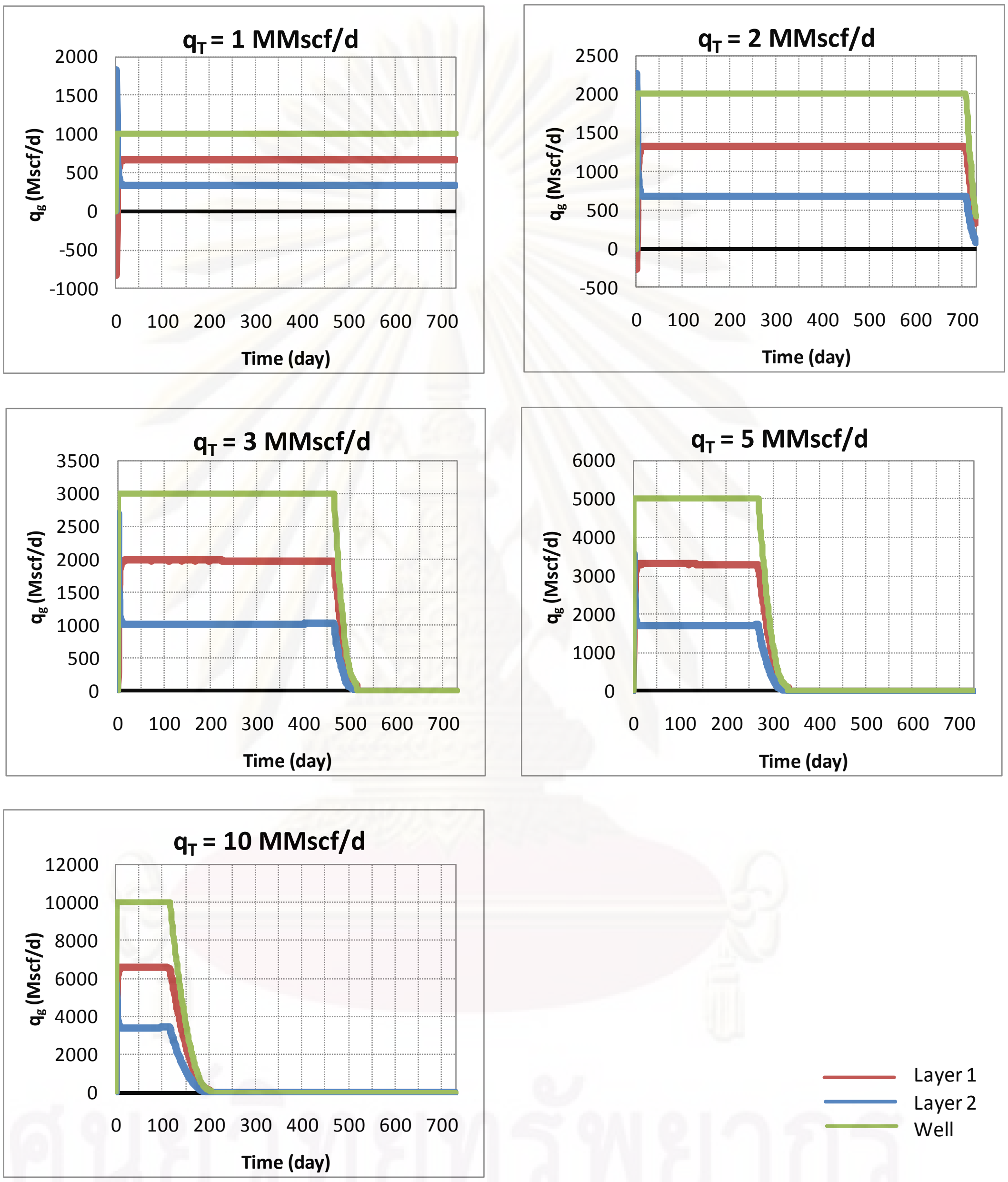



k = 50 md
Area1 = $1,400^2$ sq..ft, Area2 = $1,000^2$ sq.ft (Gas Vloume ratio 2:1)
Depth Difference between layers = 10 ft
q_T = 1 MMscf/d
q_T = 2 MMscf/d
q_T = 3 MMscf/d
q_T = 5 MMscf/d
q_T = 10 MMscf/d
q_g (Mscf/d)
Time (day)
Layer 1
Layer 2
Well

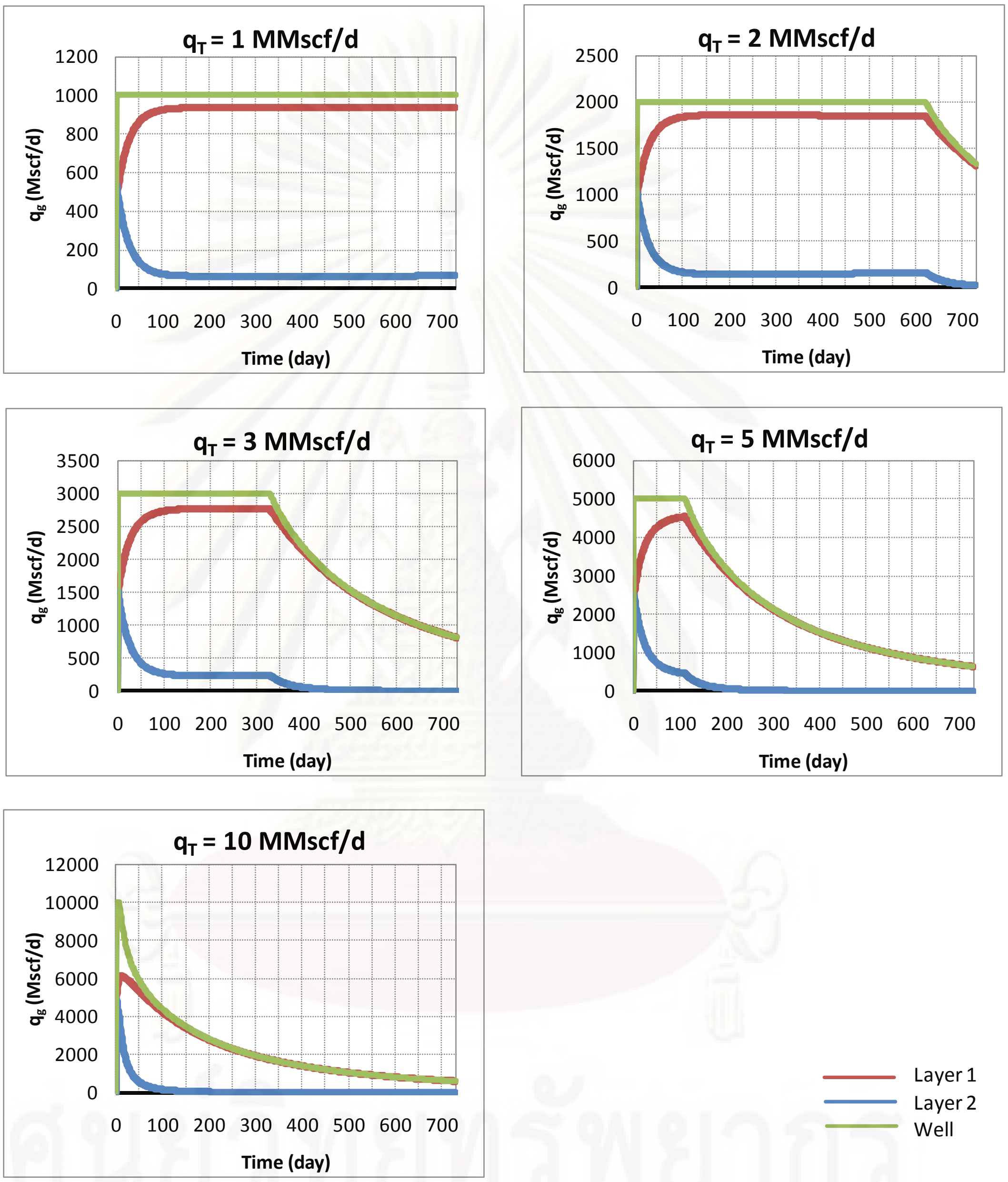
k = 100 md
Area1 = 1,400^2 sq..ft, Area2 = 1,000^2 sq.ft (Gas Volume ratio 2:1)
Depth Difference between layers = 10 ft

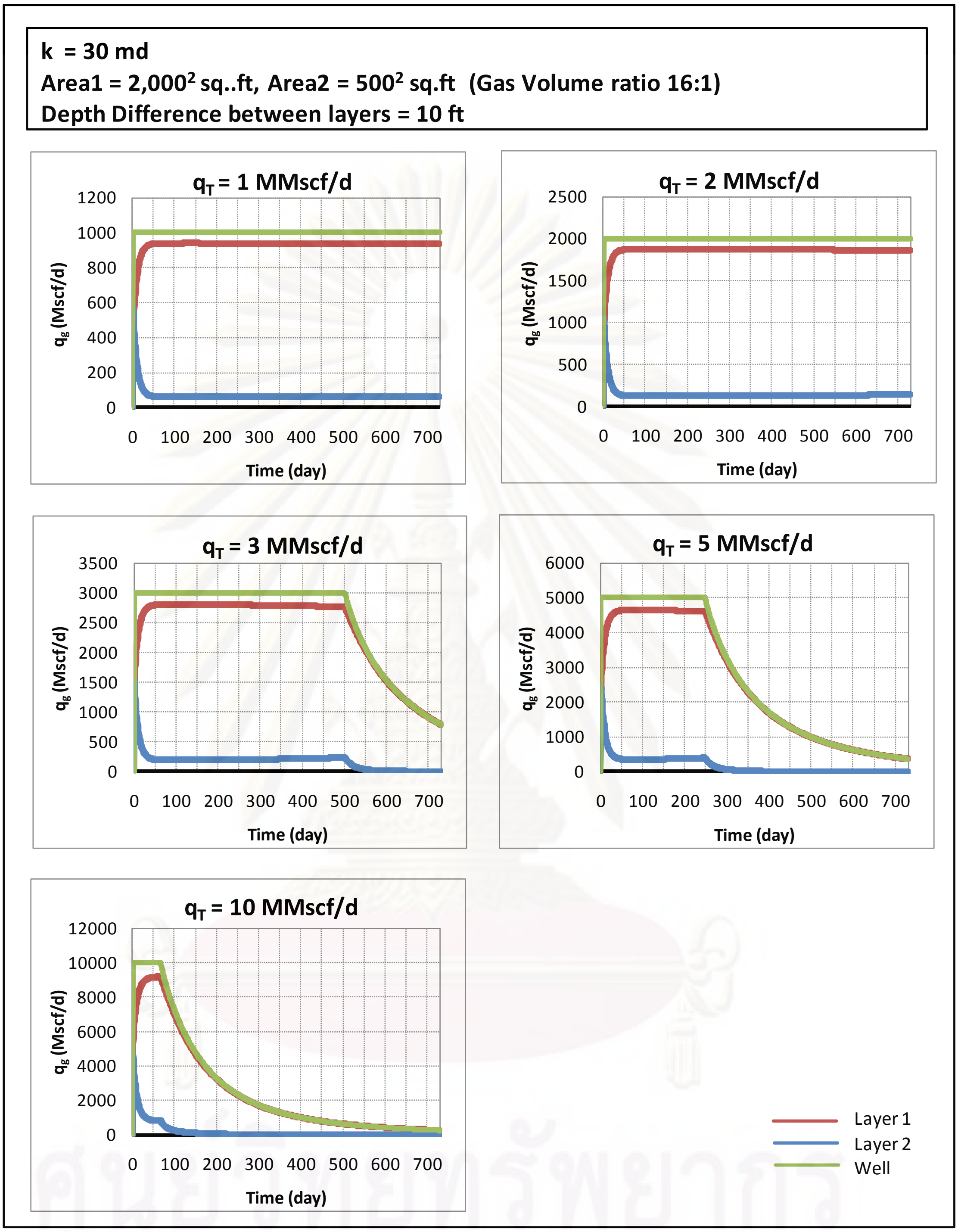


k = 500 md
Area1 = $1,400^2$ sq..ft, Area2 = $1,000^2$ sq.ft (Gas Volume ratio 2:1)
Depth Difference between layers = 10 ft

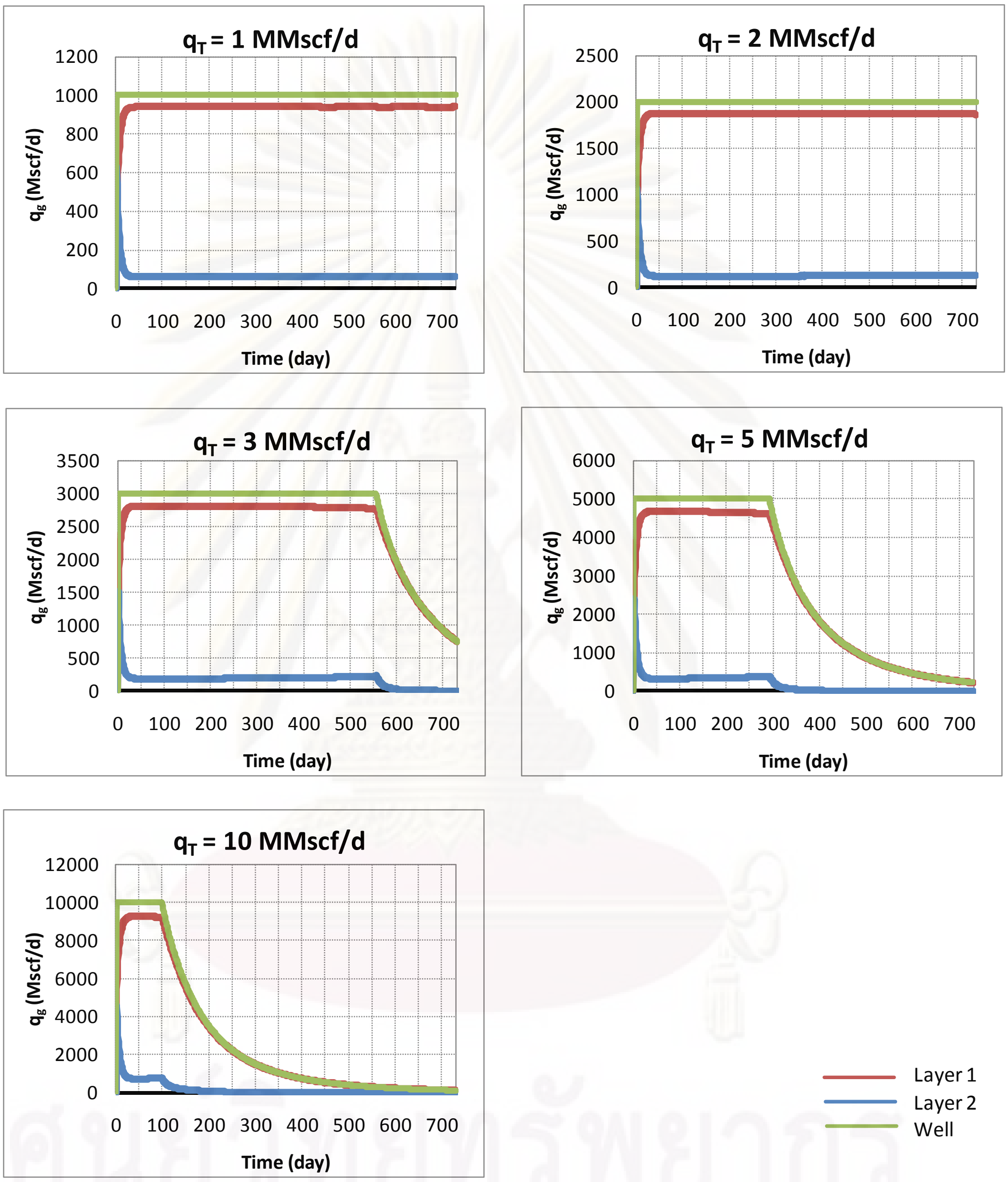


k = 10 md
Area1 = 2,000^2 sq..ft, Area2 = 500^2 sq.ft (Gas Volume ratio 16:1)
Depth Difference between layers = 10 ft

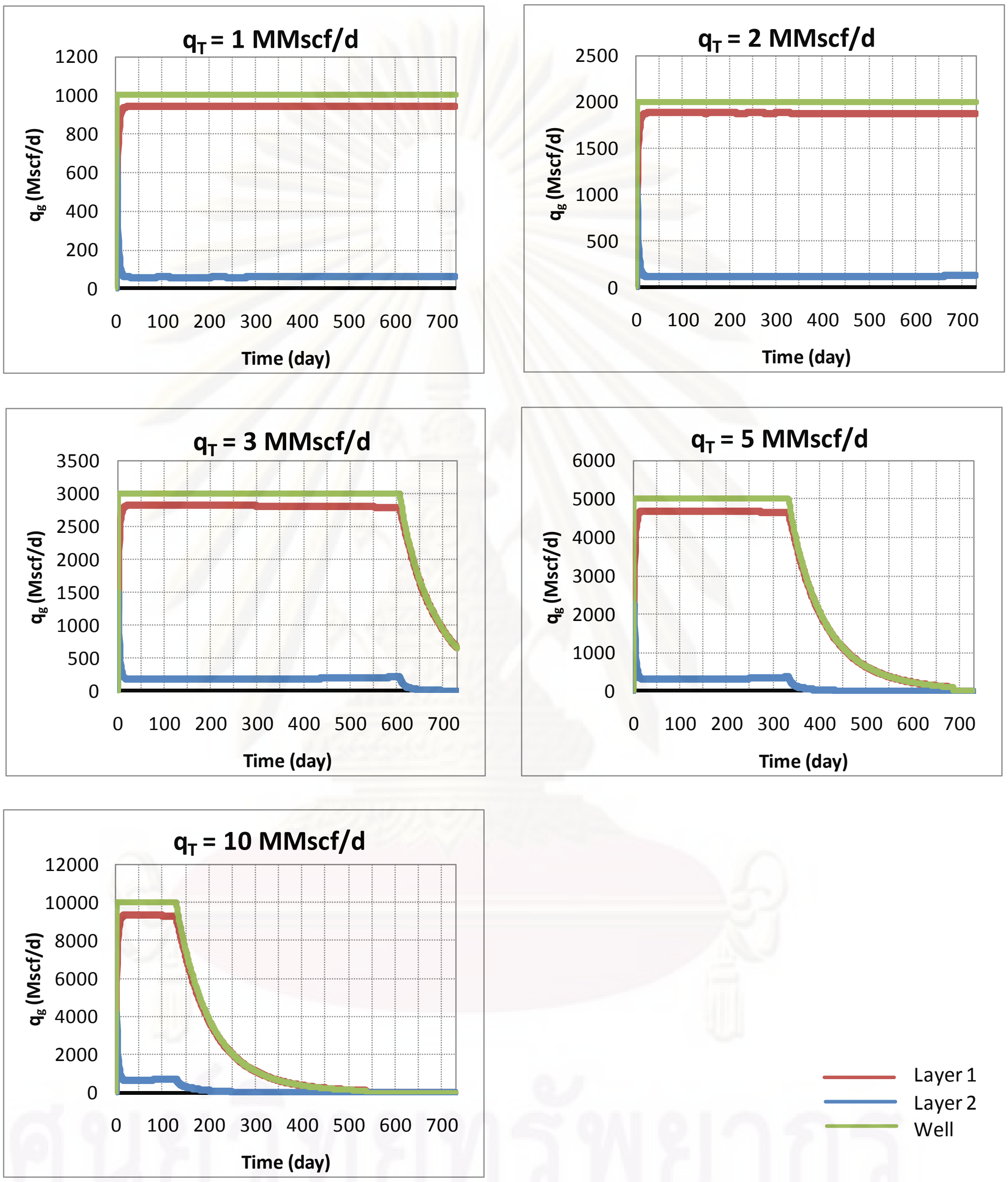



k = 30 md
Area1 = 2,000² sq..ft, Area2 = 500² sq.ft (Gas Volume ratio 16:1)
Depth Difference between layers = 10 ft
qT = 1 MMscf/d
qT = 2 MMscf/d
qT = 3 MMscf/d
qT = 5 MMscf/d
qT = 10 MMscf/d
qg (Mscf/d)
Time (day)
Layer 1
Layer 2
Well

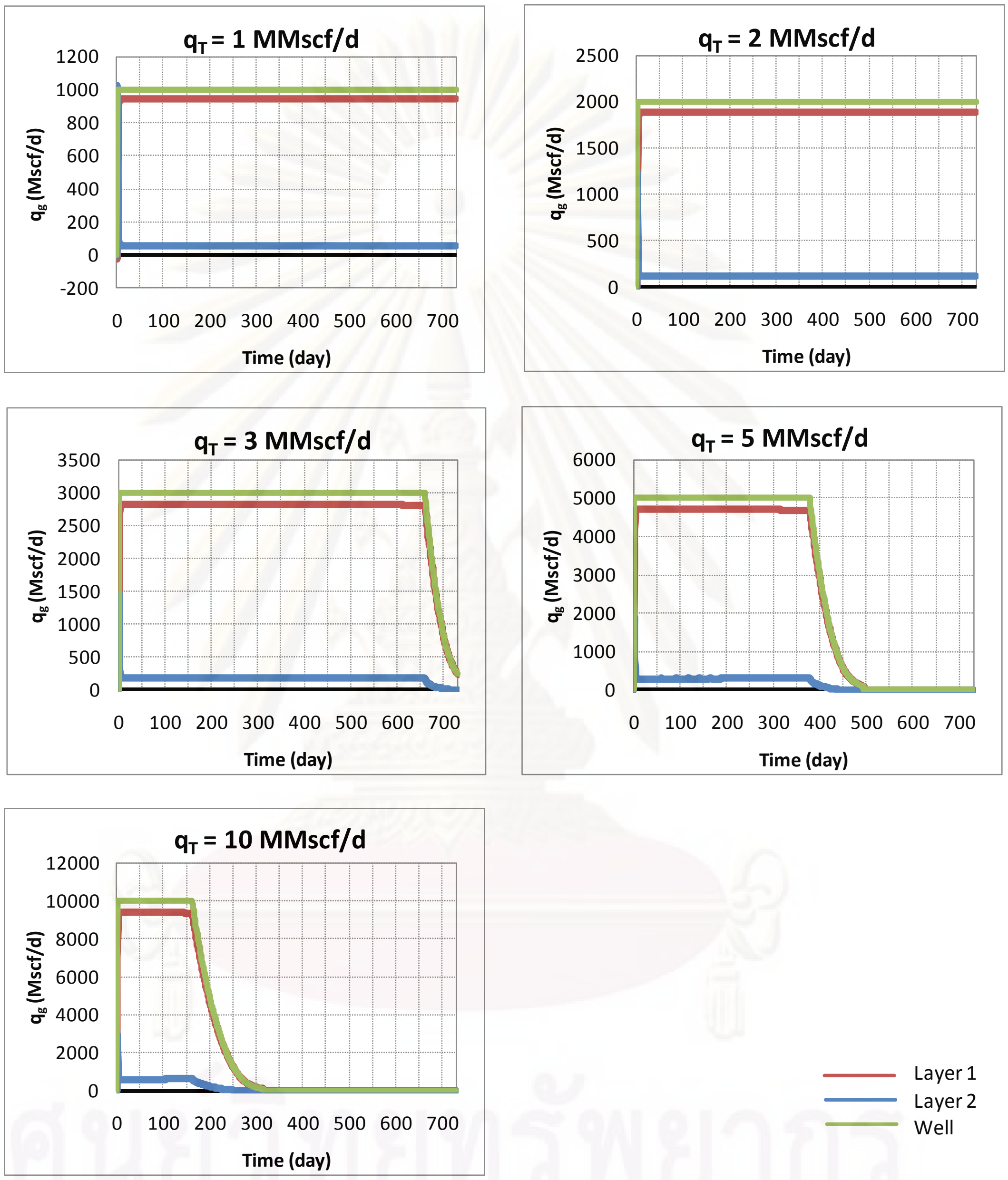
k = 50 md
Area1 = $2{,}000^2$ sq..ft, Area2 = 500^2 sq.ft (Gas Volume ratio 16:1)
Depth Difference between layers = 10 ft



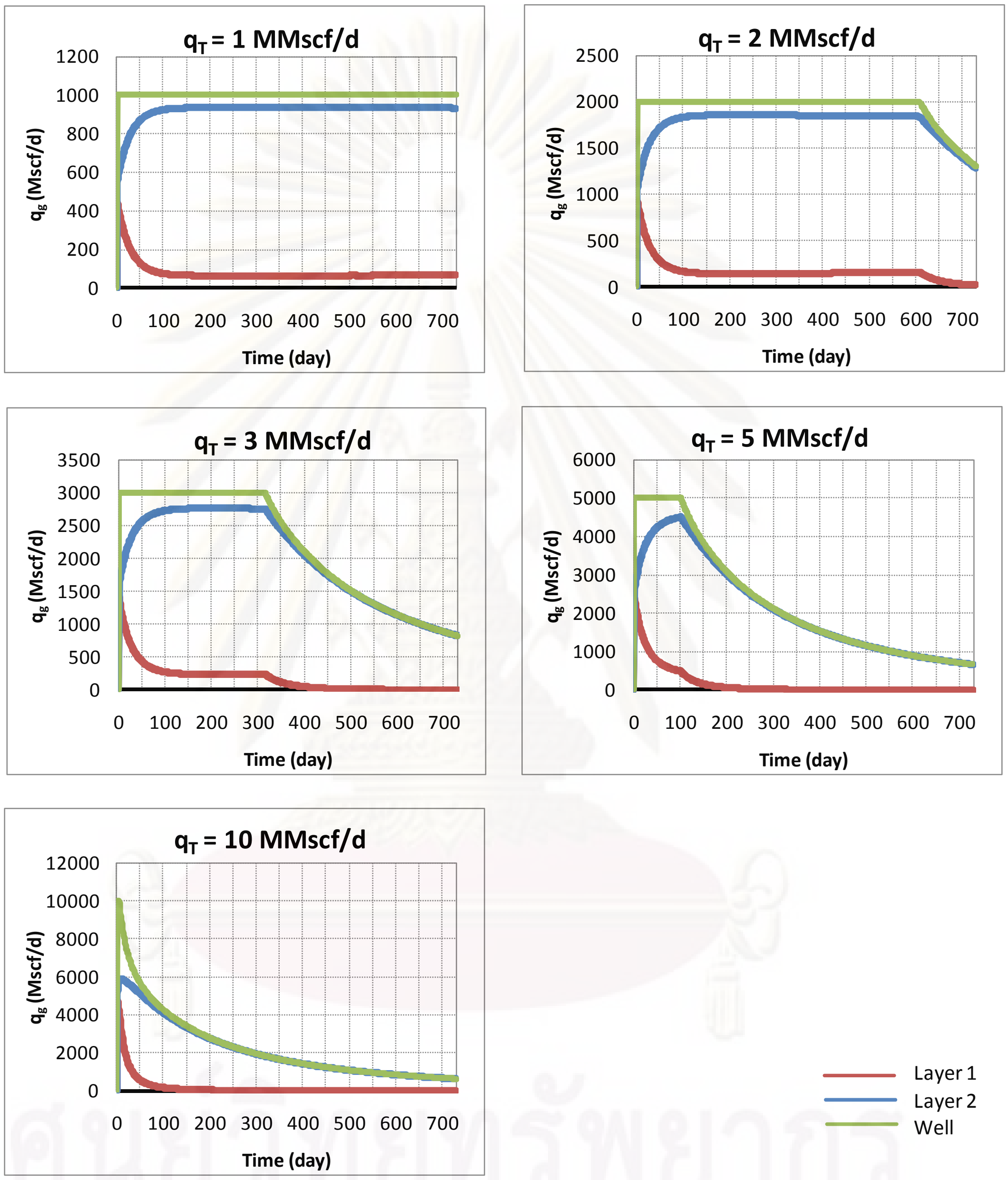
k = 100 md
Area1 = $2{,}000^2$ sq..ft, Area2 = 500^2 sq.ft (Gas Volume ratio 16:1)
Depth Difference between layers = 10 ft

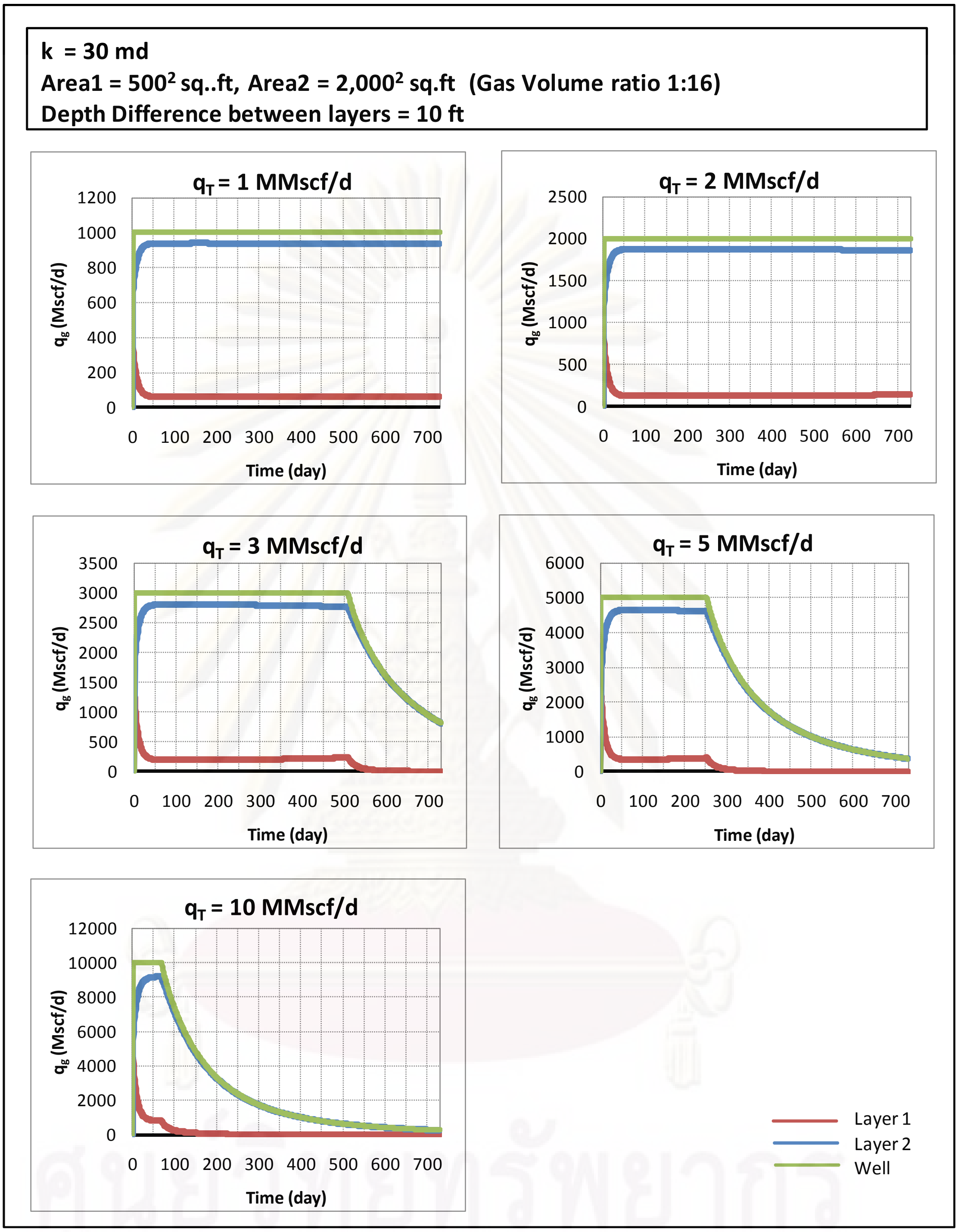


k = 500 md
Area1 = 2,000^2 sq..ft, Area2 = 500^2 sq.ft (Gas Volume ratio 16:1)
Depth Difference between layers = 10 ft

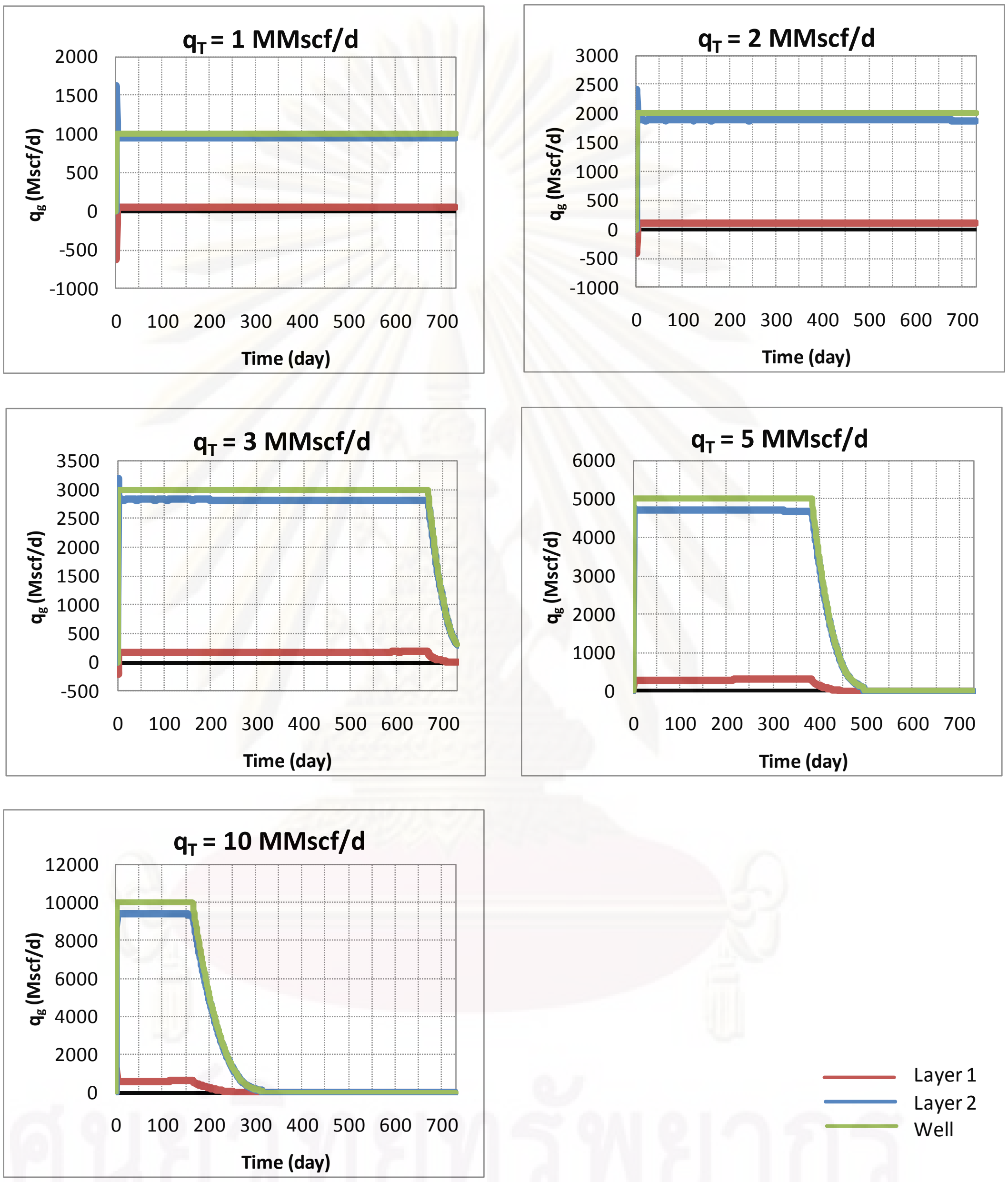


k = 10 md
Area1 = 500^2 sq..ft, Area2 = $2,000^2$ sq.ft (Gas Volume ratio 1:16)
Depth Difference between layers = 10 ft

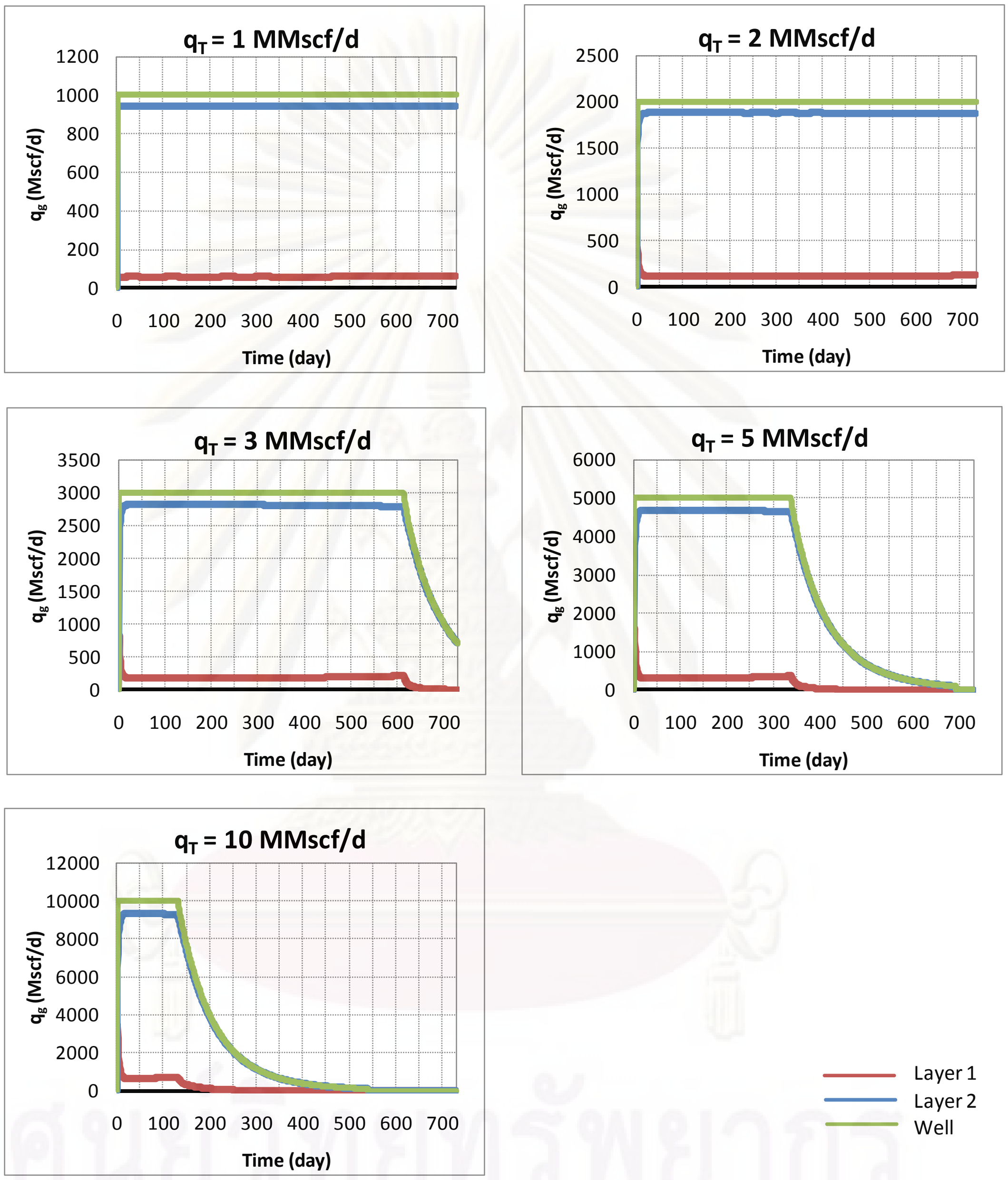



k = 30 md
Area1 = 500² sq..ft, Area2 = 2,000² sq.ft (Gas Volume ratio 1:16)
Depth Difference between layers = 10 ft
qT = 1 MMscf/d
qT = 2 MMscf/d
qT = 3 MMscf/d
qT = 5 MMscf/d
qT = 10 MMscf/d
qg (Mscf/d)
Time (day)
Layer 1
Layer 2
Well

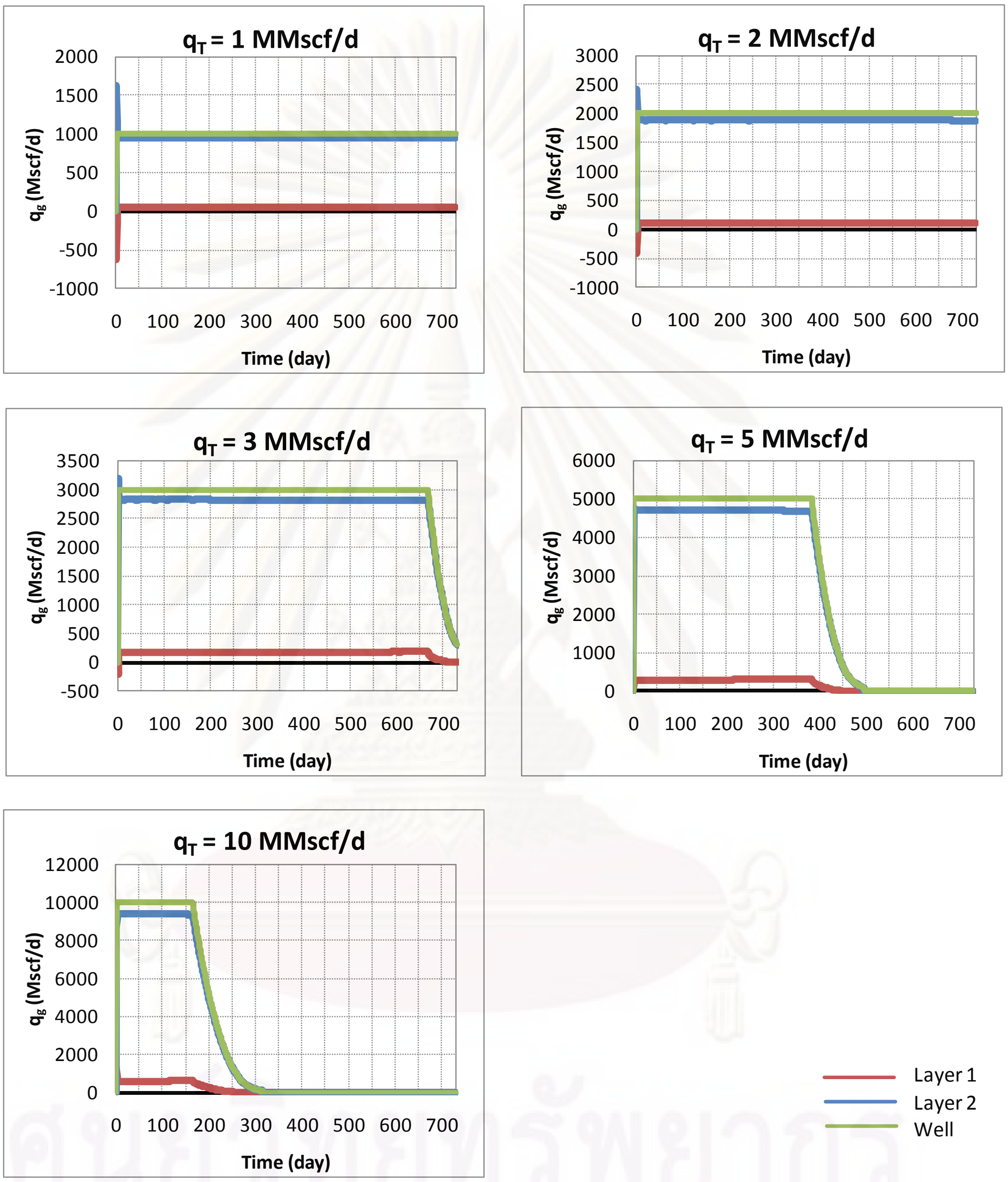
k = 500 md
Area1 = 500^2 sq..ft, Area2 = $2{,}000^2$ sq.ft (Gas Volume ratio 1:16)
Depth Difference between layers = 10 ft



k = 100 md
Area1 = 2,000^2 sq..ft, Area2 = 500^2 sq.ft (Gas Volume ratio 1:16)
Depth Difference between layers = 10 ft



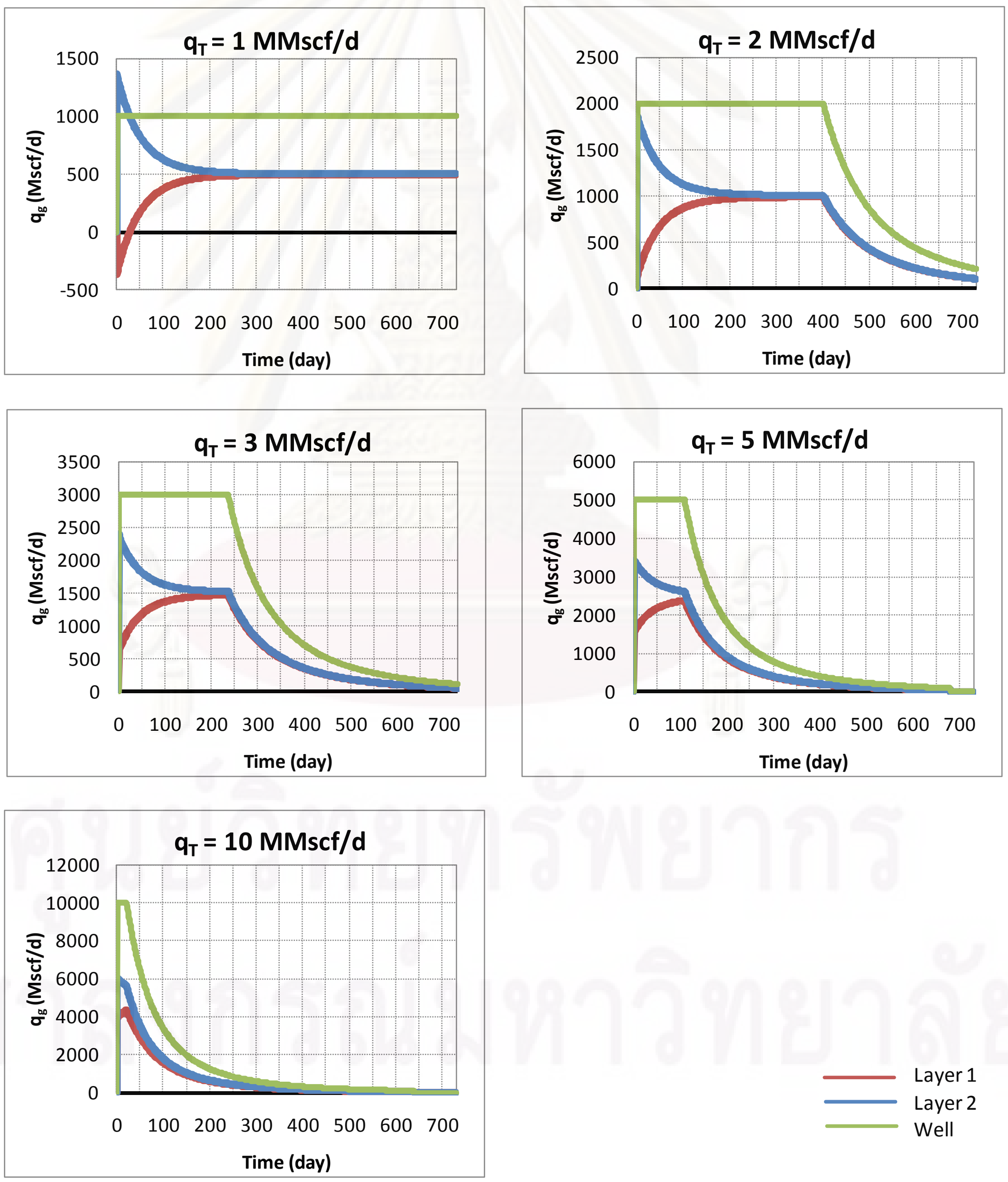
k = 500 md
Area1 = $2{,}000^2$ sq..ft, Area2 = 500^2 sq.ft (Gas Volume ratio 1:16)
Depth Difference between layers = 10 ft



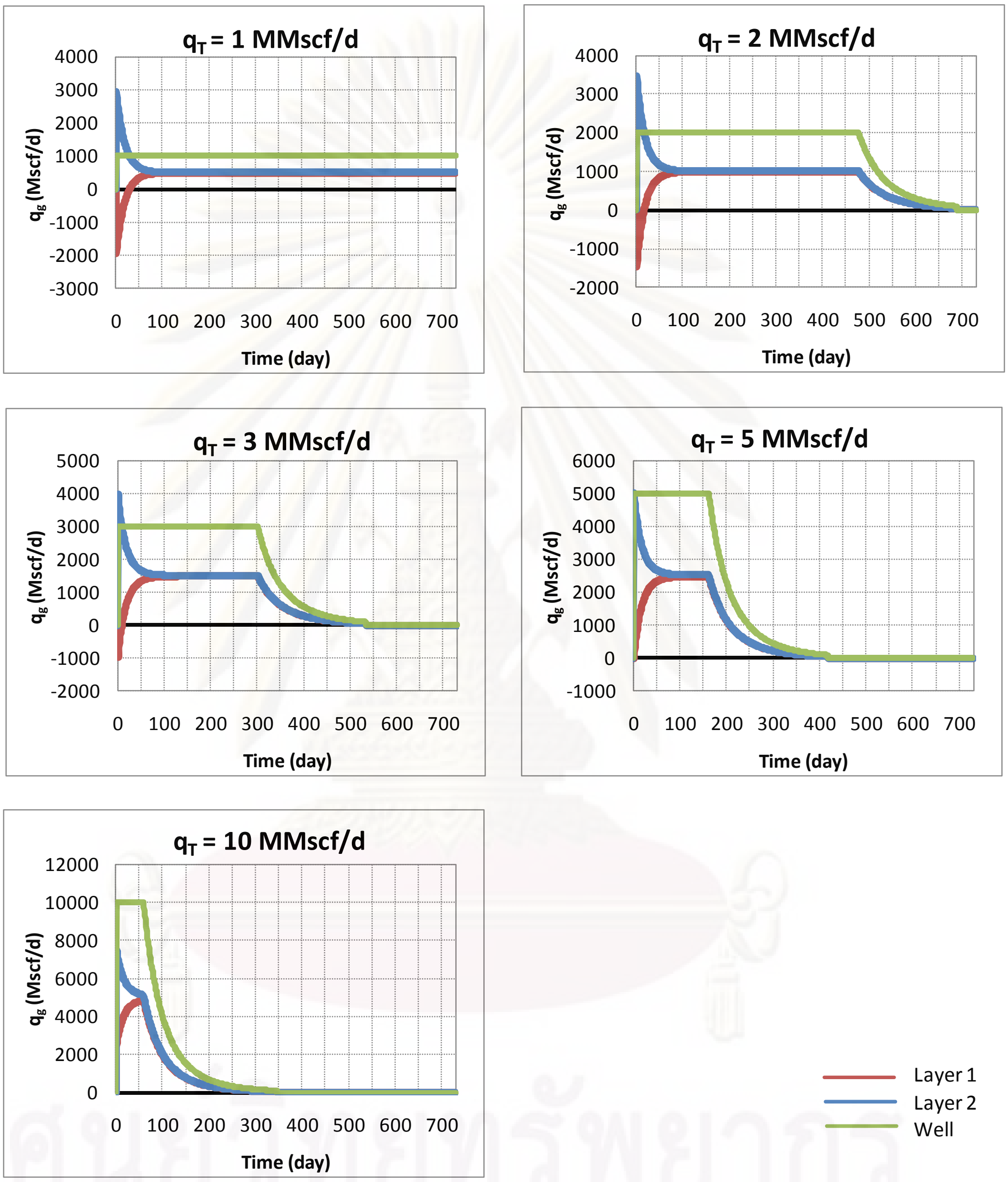
A-2) Rate Allocation of two-layer reservoir with depth difference between layers = 1,000 ft and

- flow rate = 1, 2, 3, 5, and 10 MMscf/d,
- permeability = 10, 30, 50, 100, and 500 md,
- Area extent ratio = 1:1, 2:1, 16:1, and 1:16.

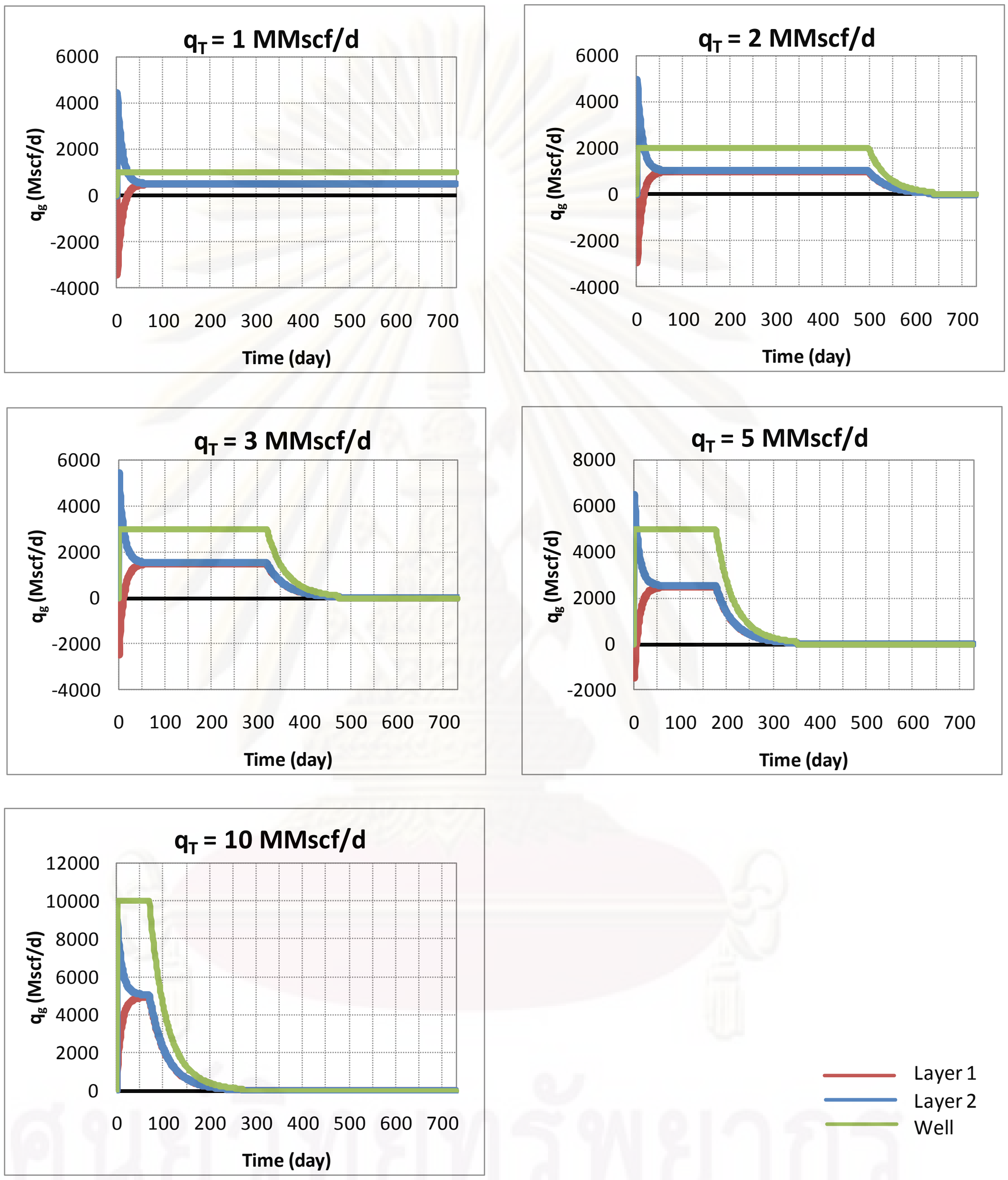
k = 10 md
Area1 = 1,000^2 sq..ft, Area2 = 1,000^2 sq.ft (Gas Volume ratio 1:1)
Depth Difference between layers = 1,000 ft



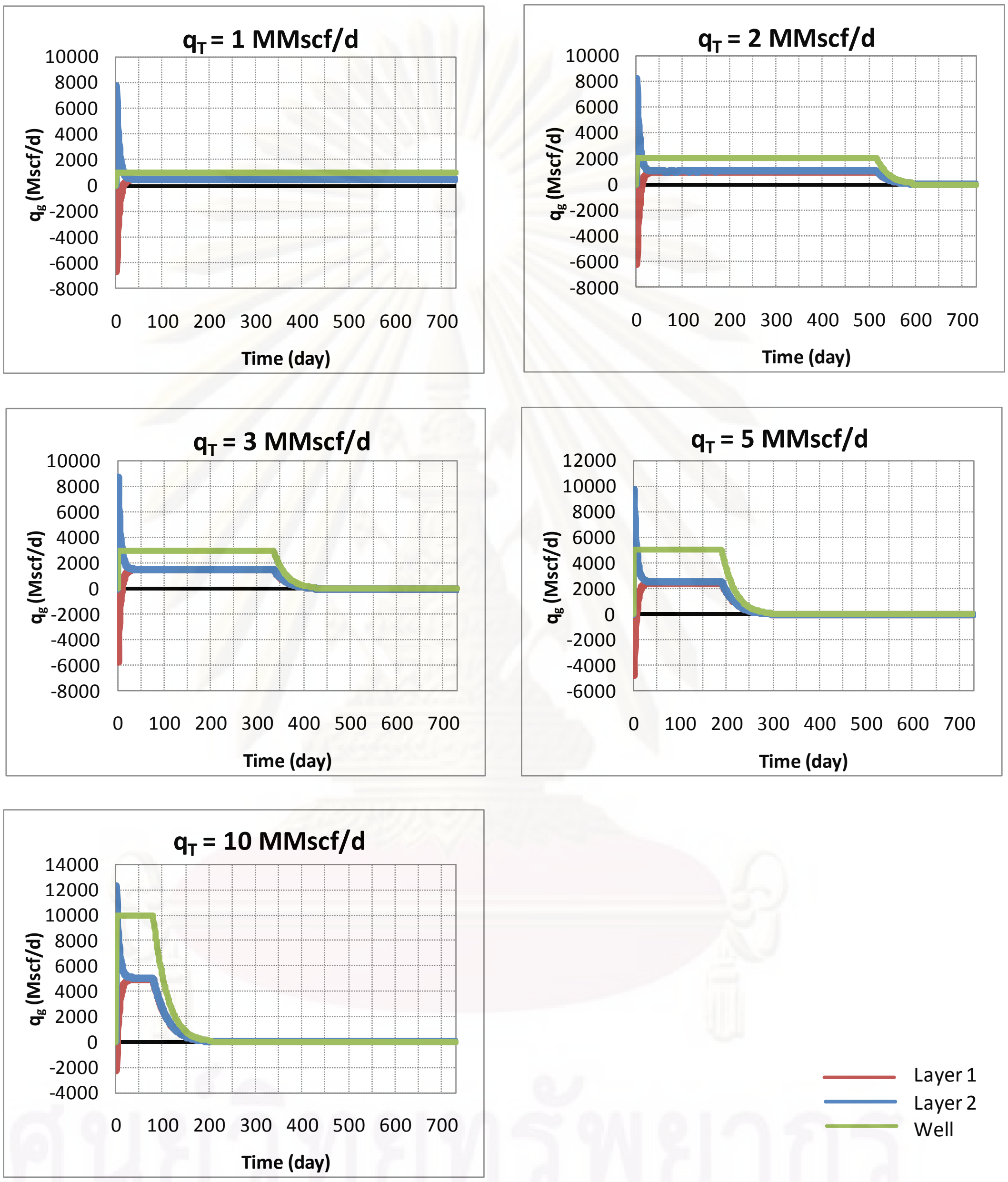
k = 30 md
Area1 = $1{,}000^2$ sq..ft, Area2 = $1{,}000^2$ sq.ft (Gas Volume ratio 1:1)
Depth Difference between layers = 1,000 ft



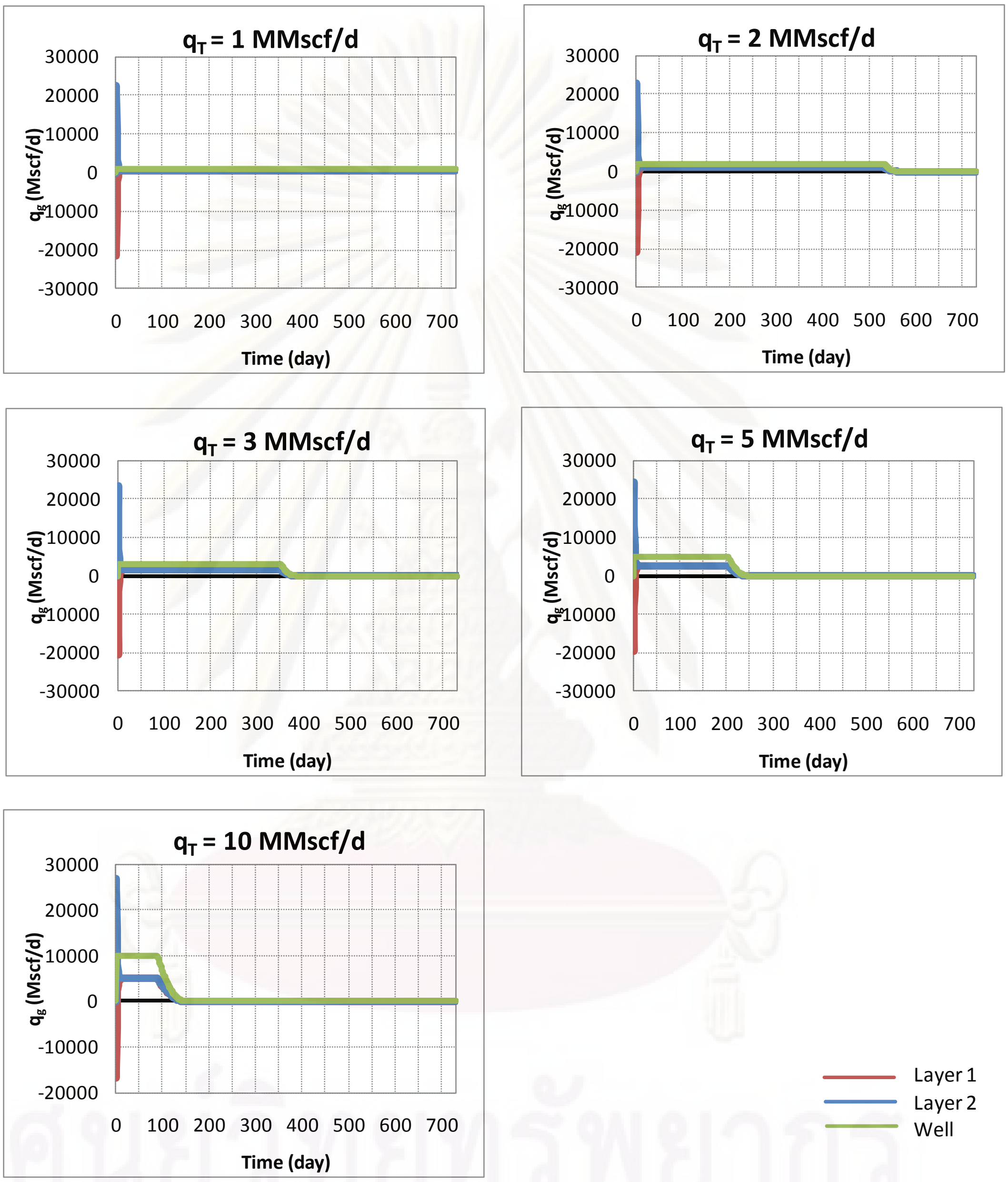
k = 50 md
Area1 = 1,000^2 sq..ft, Area2 = 1,000^2 sq.ft (Gas Volme ratio 1:1)
Depth Difference between layers = 1,000 ft



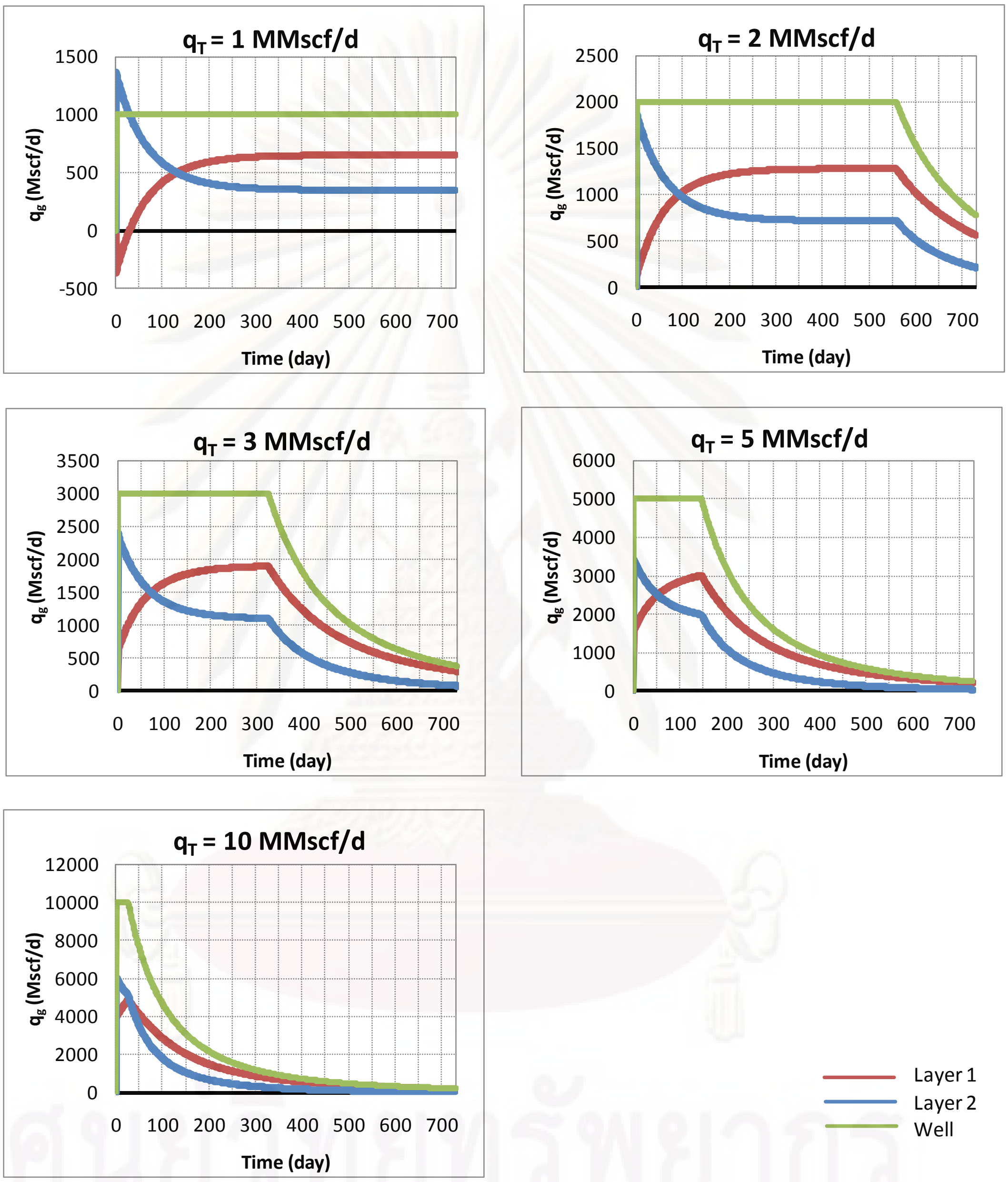
k = 100 md
Area1 = $1,000^2$ sq..ft, Area2 = $1,000^2$ sq.ft (Gas Volume ratio 1:1)
Depth Difference between layers = 1,000 ft

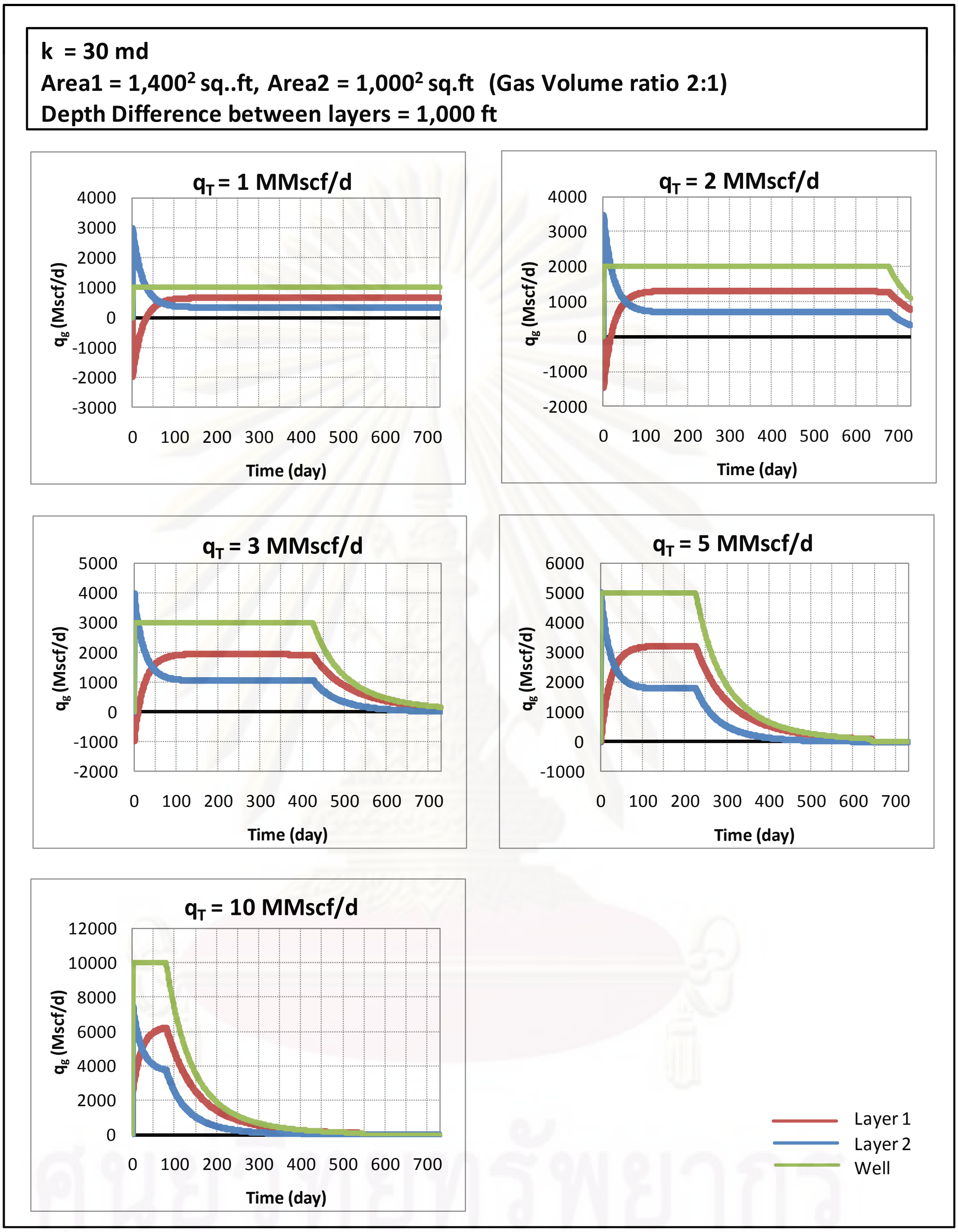


k = 500 md
Area1 = 1,000^2 sq..ft, Area2 = 1,000^2 sq.ft (Gas Volume ratio 1:1)
Depth Difference between layers = 1,000 ft

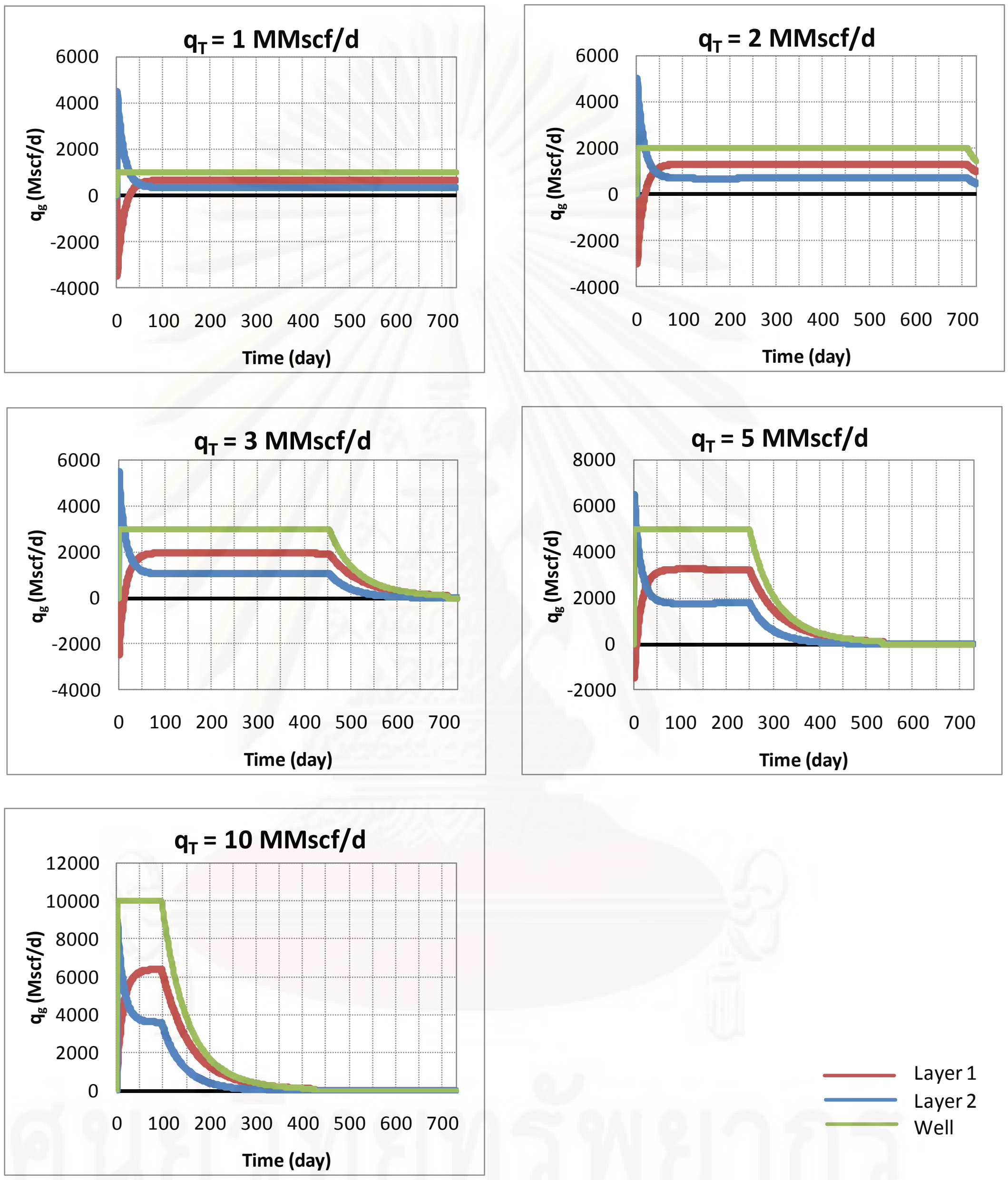


k = 10 md
Area1 = $1{,}400^2$ sq..ft, Area2 = $1{,}000^2$ sq.ft (Gas Volume ratio 2:1)
Depth Difference between layers = 1,000 ft

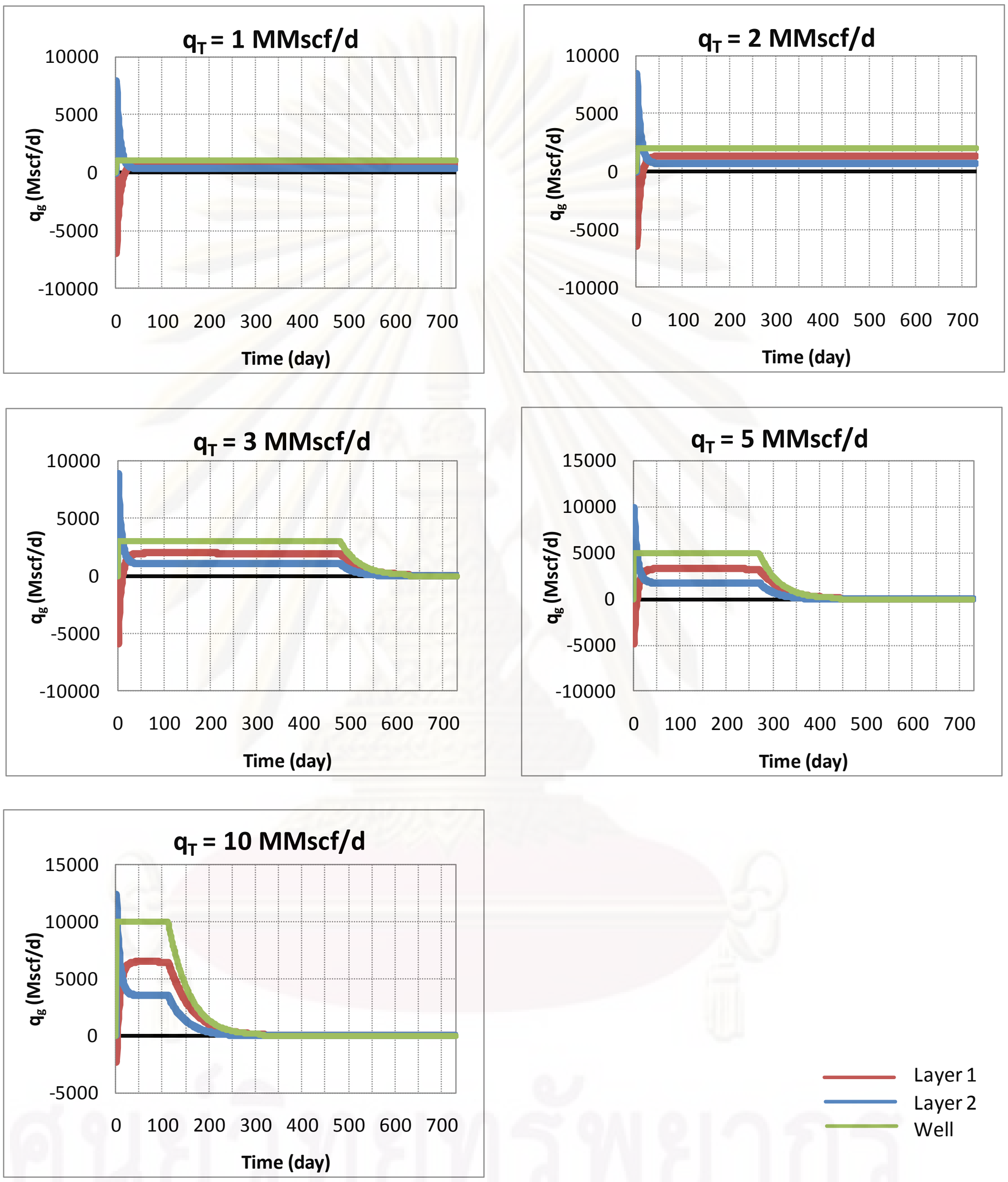


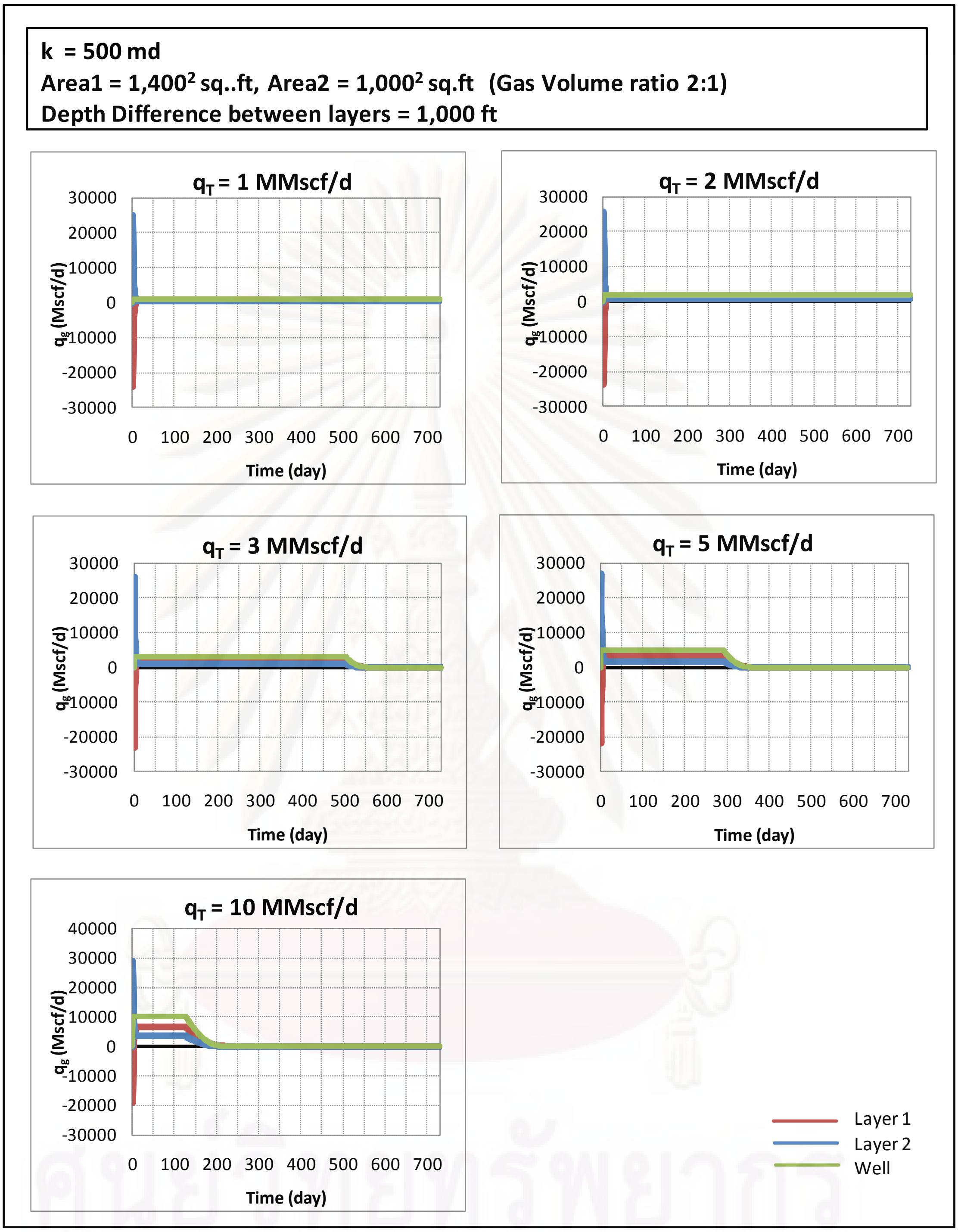

k = 30 md
Area1 = 1,400² sq..ft, Area2 = 1,000² sq.ft (Gas Volume ratio 2:1)
Depth Difference between layers = 1,000 ft
qT = 1 MMscf/d
qT = 2 MMscf/d
qT = 3 MMscf/d
qT = 5 MMscf/d
qT = 10 MMscf/d
qg (Mscf/d)
Time (day)
Layer 1
Layer 2
Well

k = 50 md
Area1 = 1,400² sq..ft, Area2 = 1,000² sq.ft (Gas Volume ratio 2:1)
Depth Difference between layers = 1,000 ft

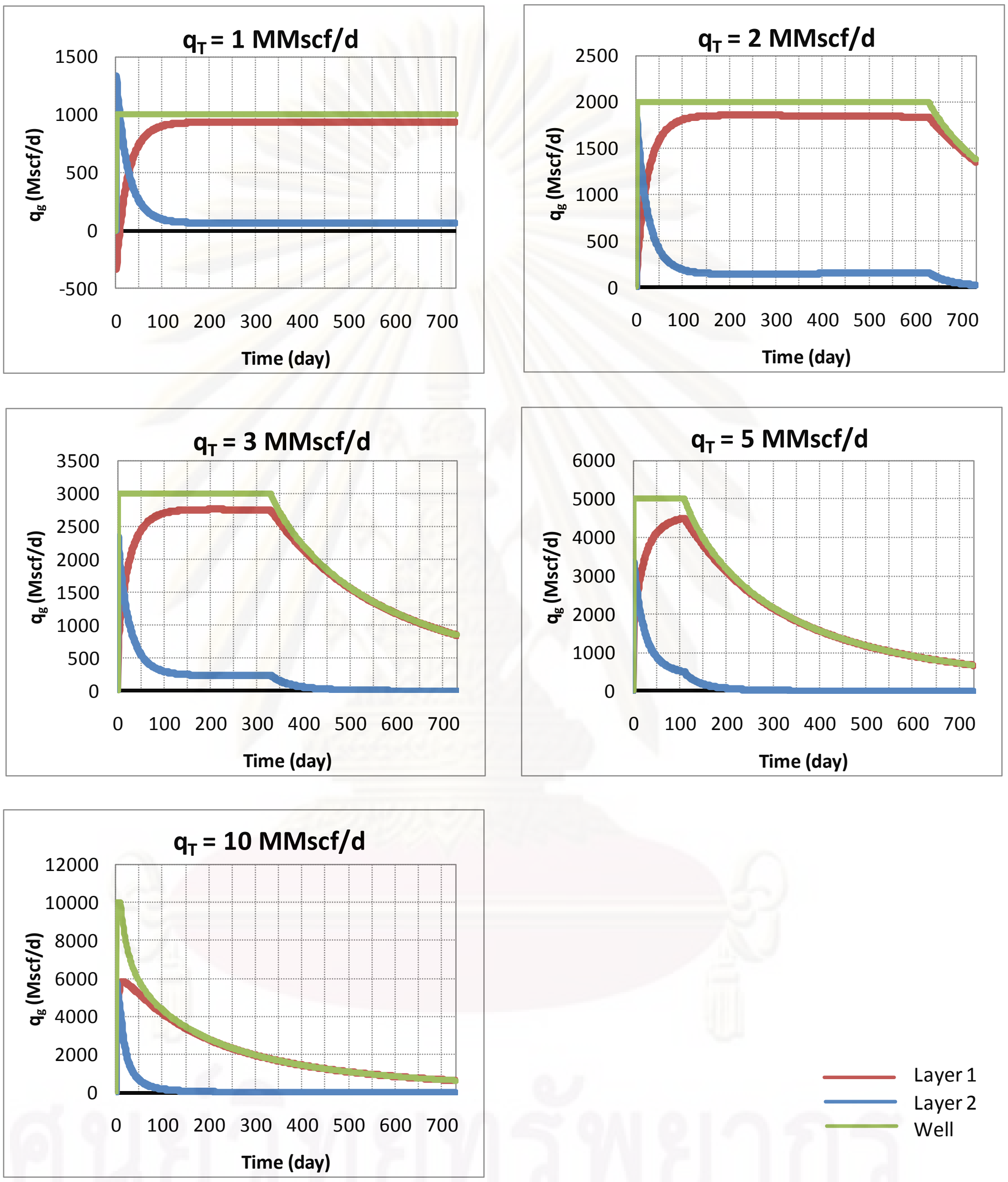


k = 100 md
Area1 = 1,400^2 sq..ft, Area2 = 1,000^2 sq.ft (Gas Volume ratio 2:1)
Depth Difference between layers = 1,000 ft

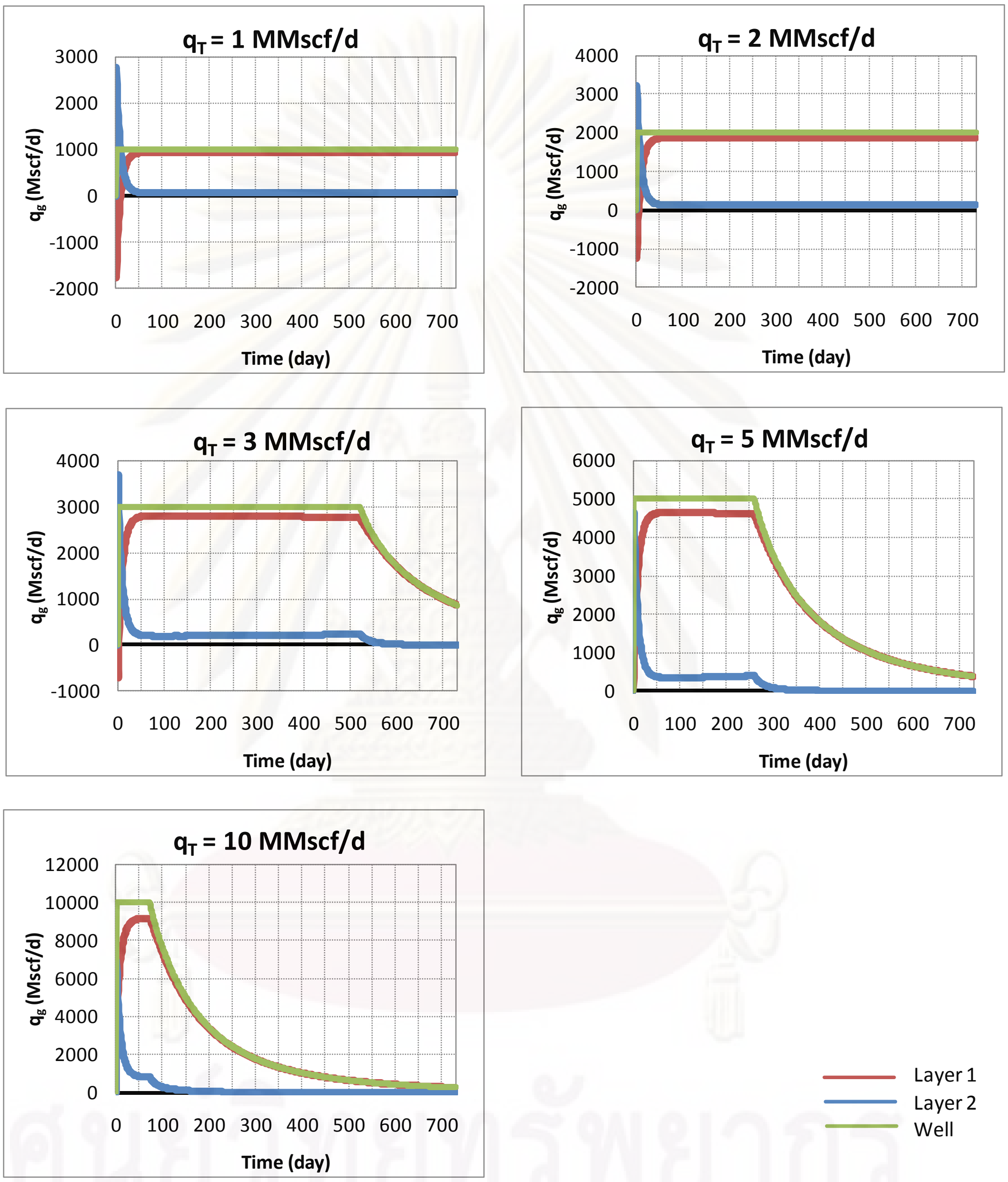



k = 500 md
Area1 = 1,400^2 sq..ft, Area2 = 1,000^2 sq.ft (Gas Volume ratio 2:1)
Depth Difference between layers = 1,000 ft
q_T = 1 MMscf/d
q_T = 2 MMscf/d
q_T = 3 MMscf/d
q_T = 5 MMscf/d
q_T = 10 MMscf/d
q_g (Mscf/d)
Time (day)
Layer 1
Layer 2
Well

k = 10 md
Area1 = $2{,}000^2$ sq..ft, Area2 = 500^2 sq.ft (Gas Volume ratio 16:1)
Depth Difference between layers = 1,000 ft

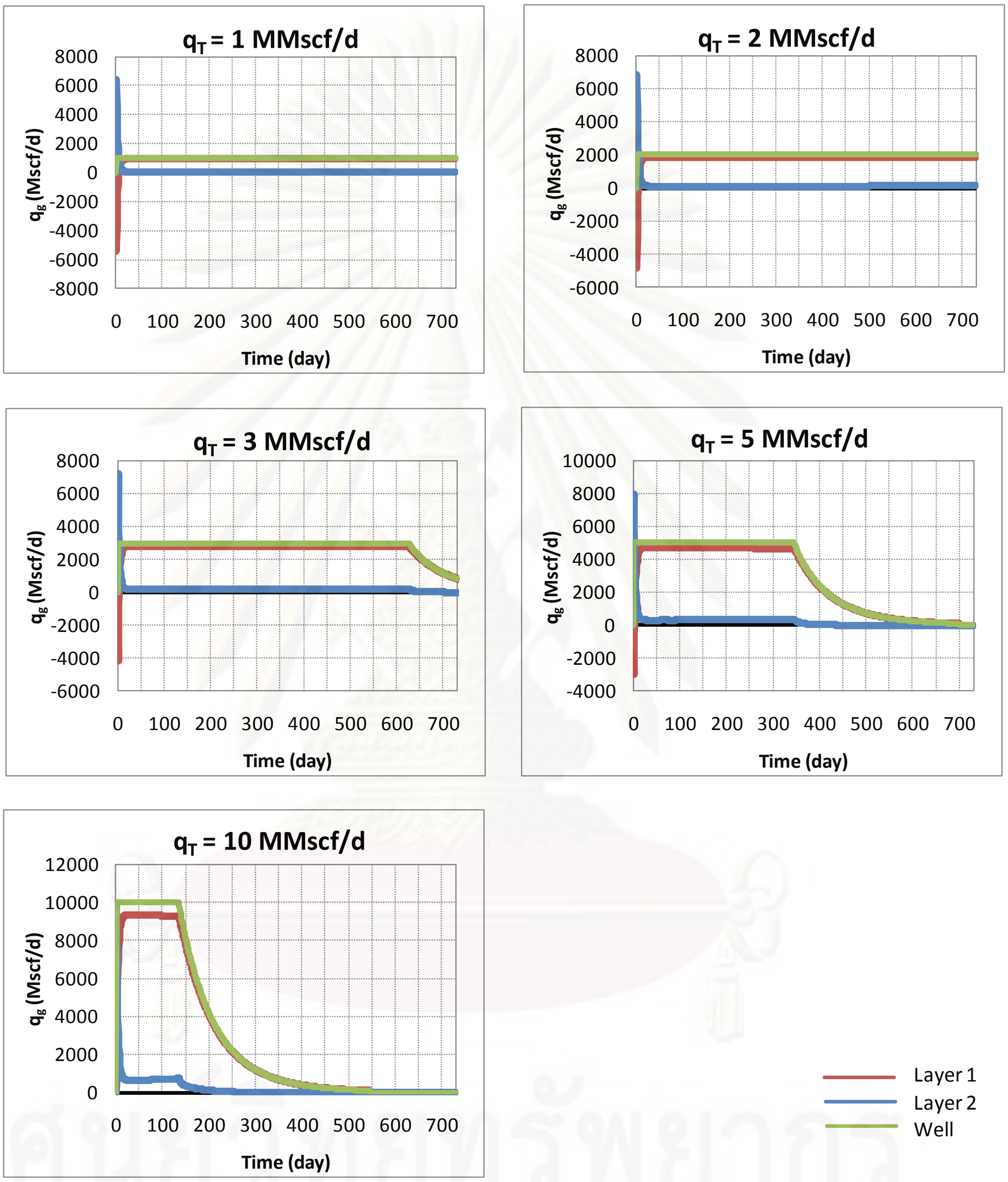


k = 30 md
Area1 = $2{,}000^2$ sq..ft, Area2 = 500^2 sq.ft (Gas Volume ratio 16:1)
Depth Difference between layers = 1,000 ft

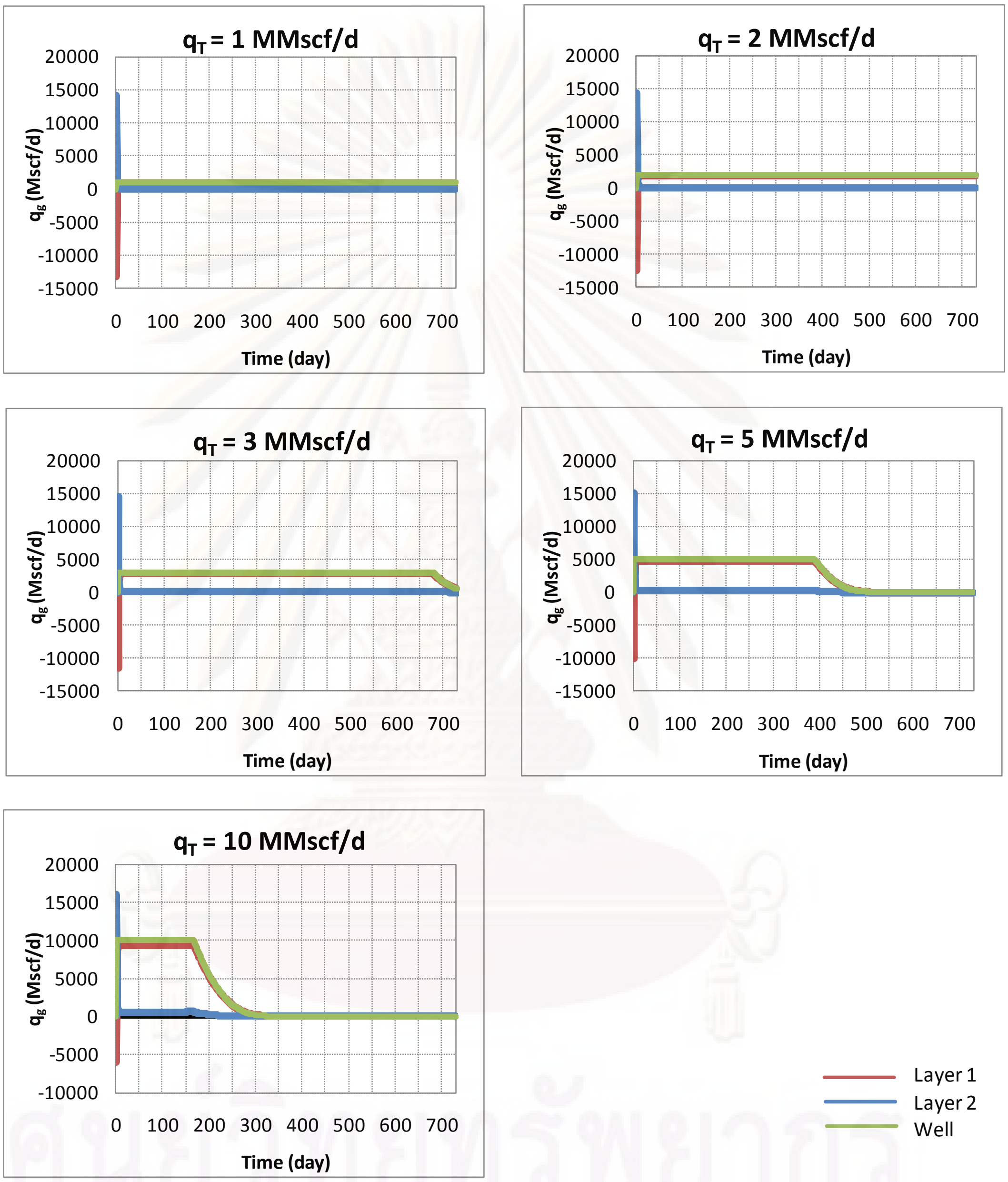


k = 50 md
Area1 = 2,000^2 sq..ft, Area2 = 500^2 sq.ft (Gas Volume ratio 16:1)
Depth Difference between layers = 1,000 ft

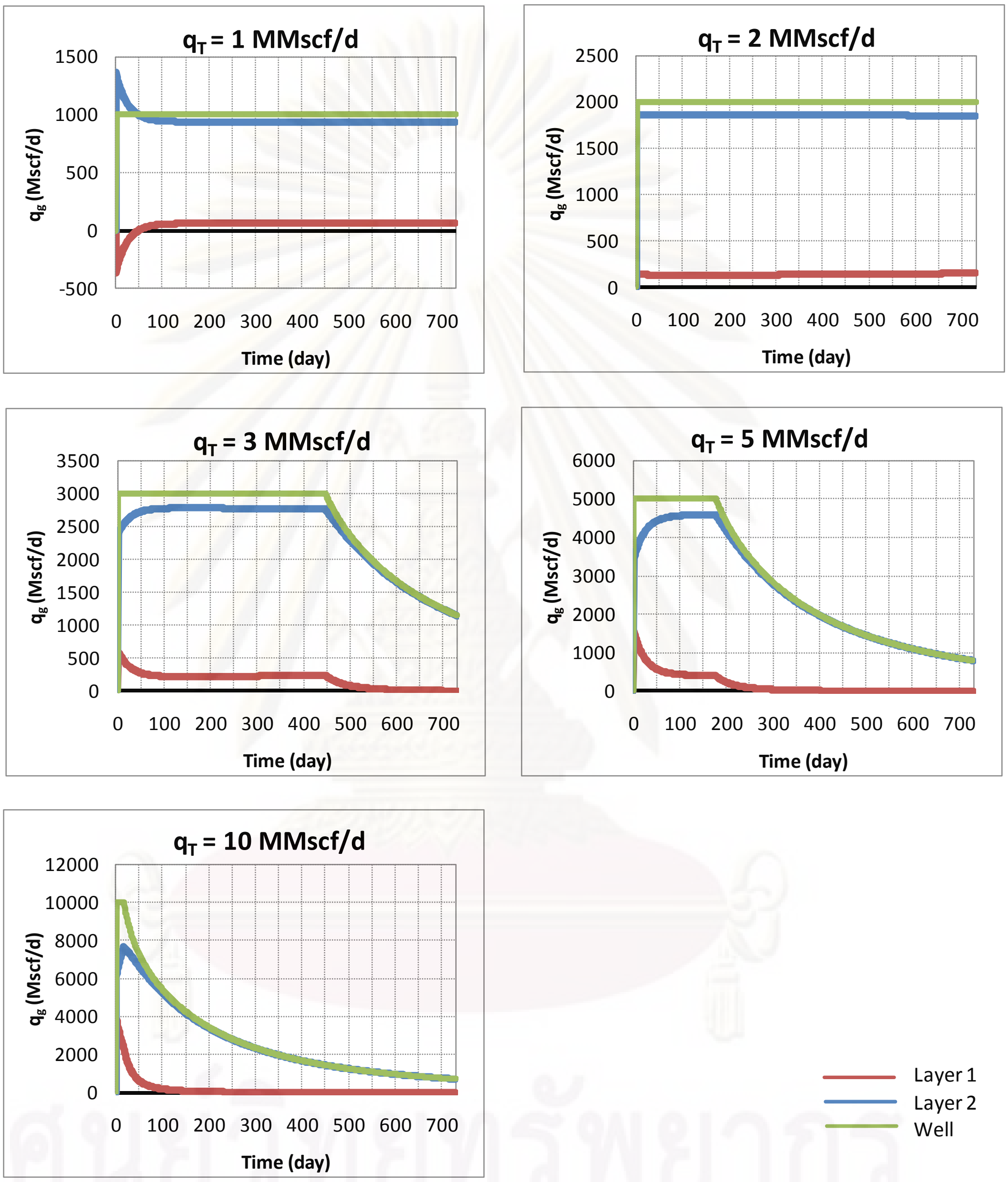
k = 100 md
Area1 = $2{,}000^2$ sq..ft, Area2 = 500^2 sq.ft (Gas Volume ratio 16:1)
Depth Difference between layers = 1,000 ft



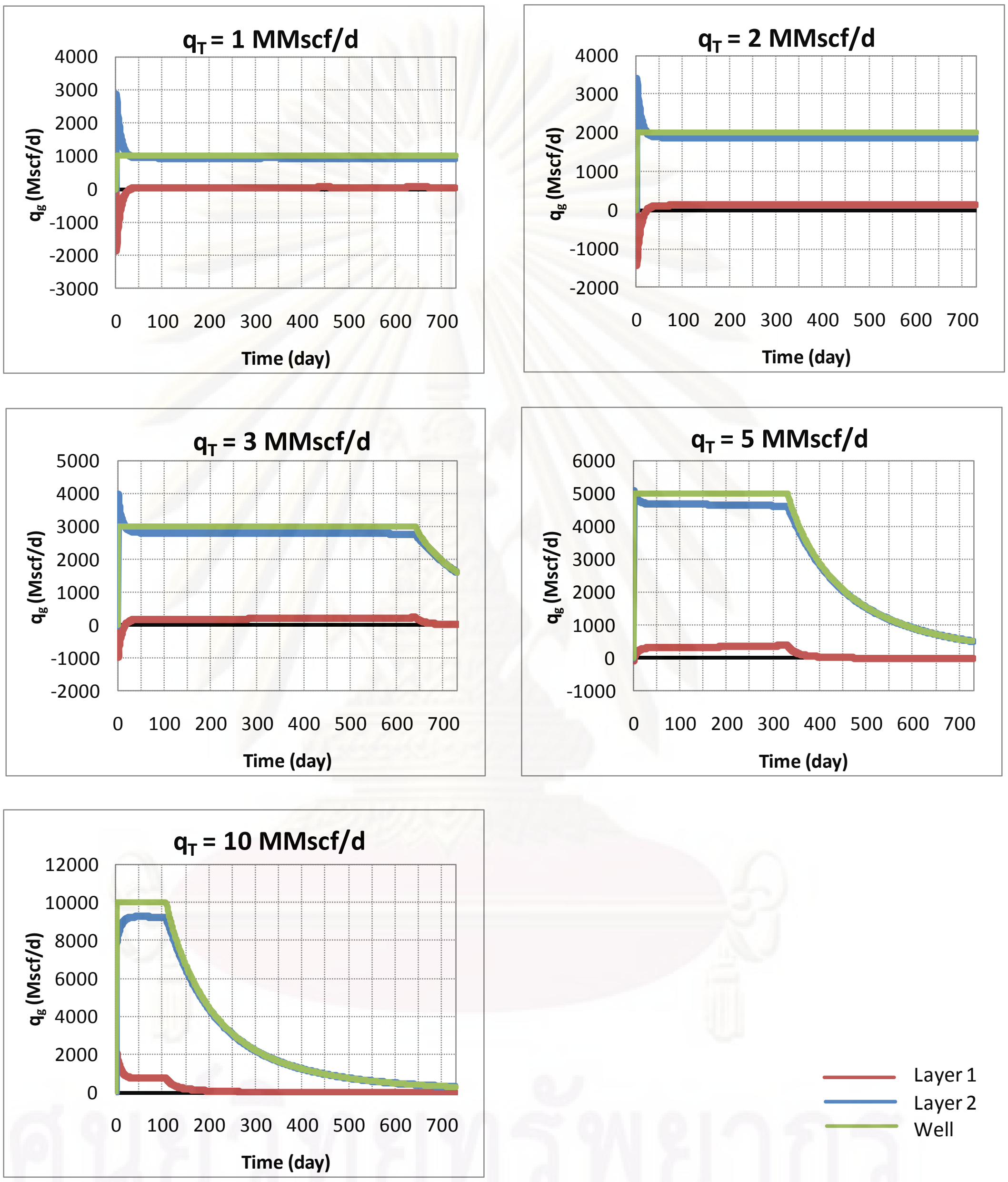
k = 500 md
Area1 = $2{,}000^2$ sq..ft, Area2 = 500^2 sq.ft (Gas Volume ratio 16:1)
Depth Difference between layers = 1,000 ft



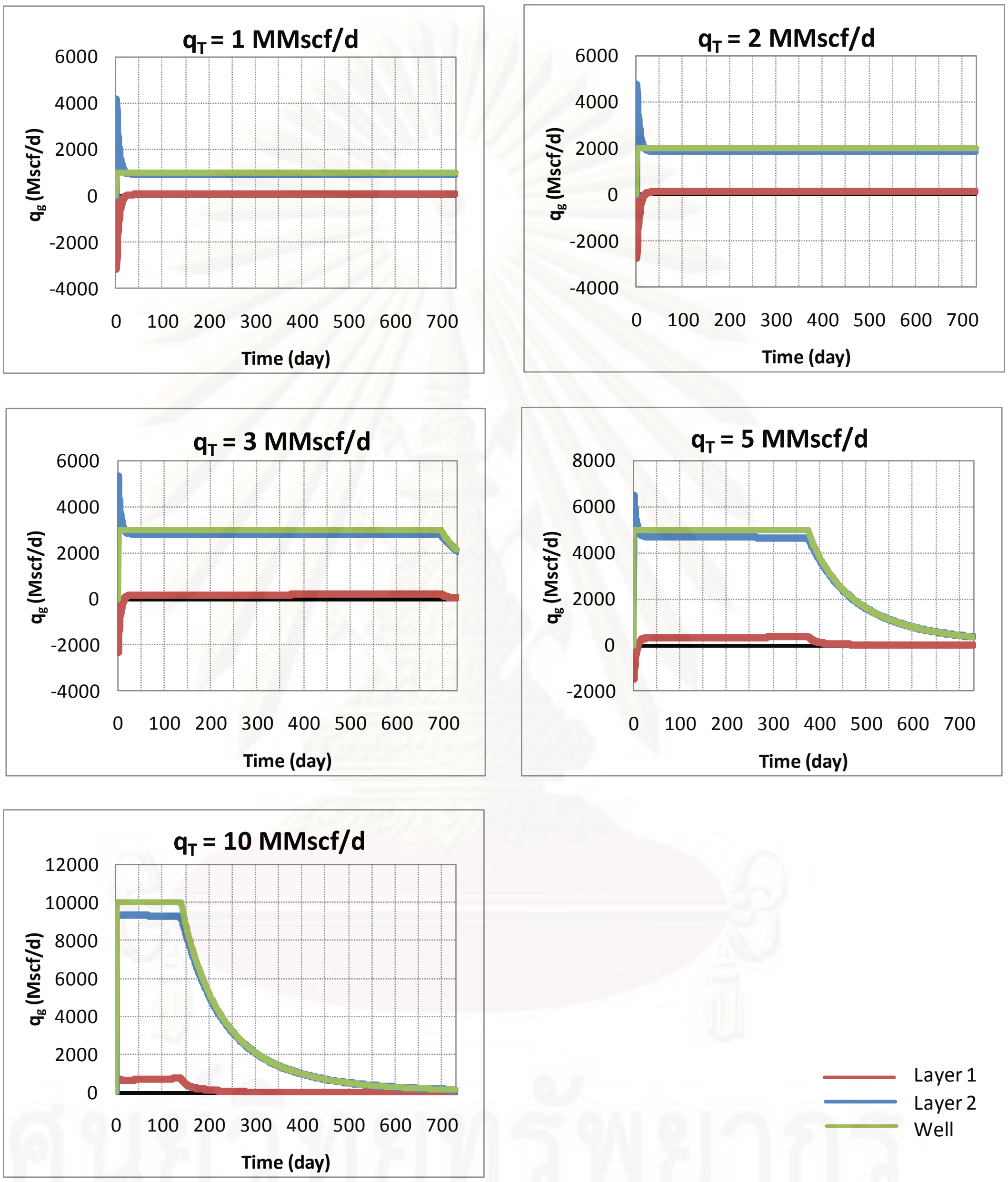
k = 10 md
Area1 = 500^2 sq..ft, Area2 = $2{,}000^2$ sq.ft (Gas Volume ratio 1:16)
Depth Difference between layers = 1,000 ft

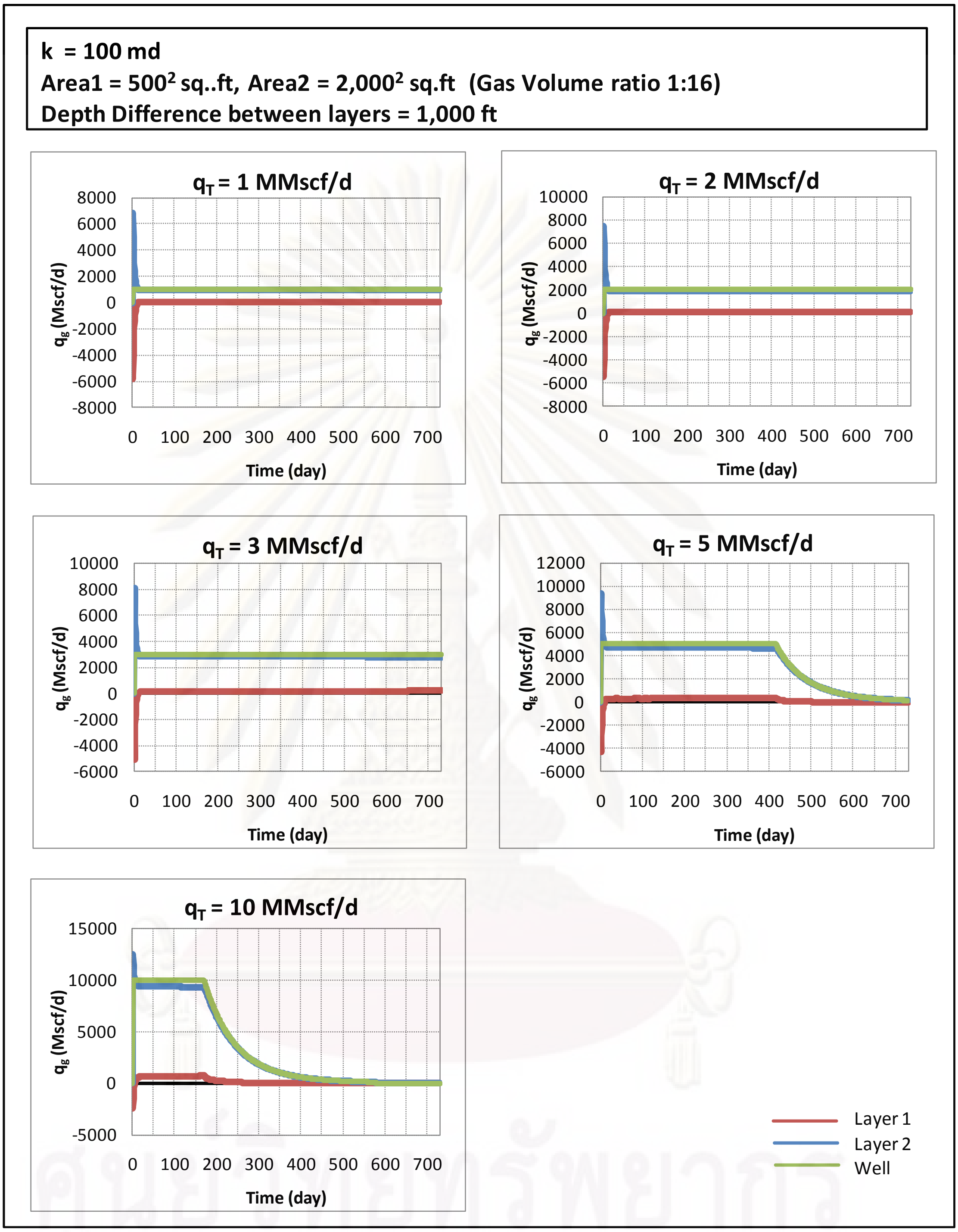


k = 30 md
Area1 = 500^2 sq..ft, Area2 = $2{,}000^2$ sq.ft (Gas Volume ratio 1:16)
Depth Difference between layers = 1,000 ft

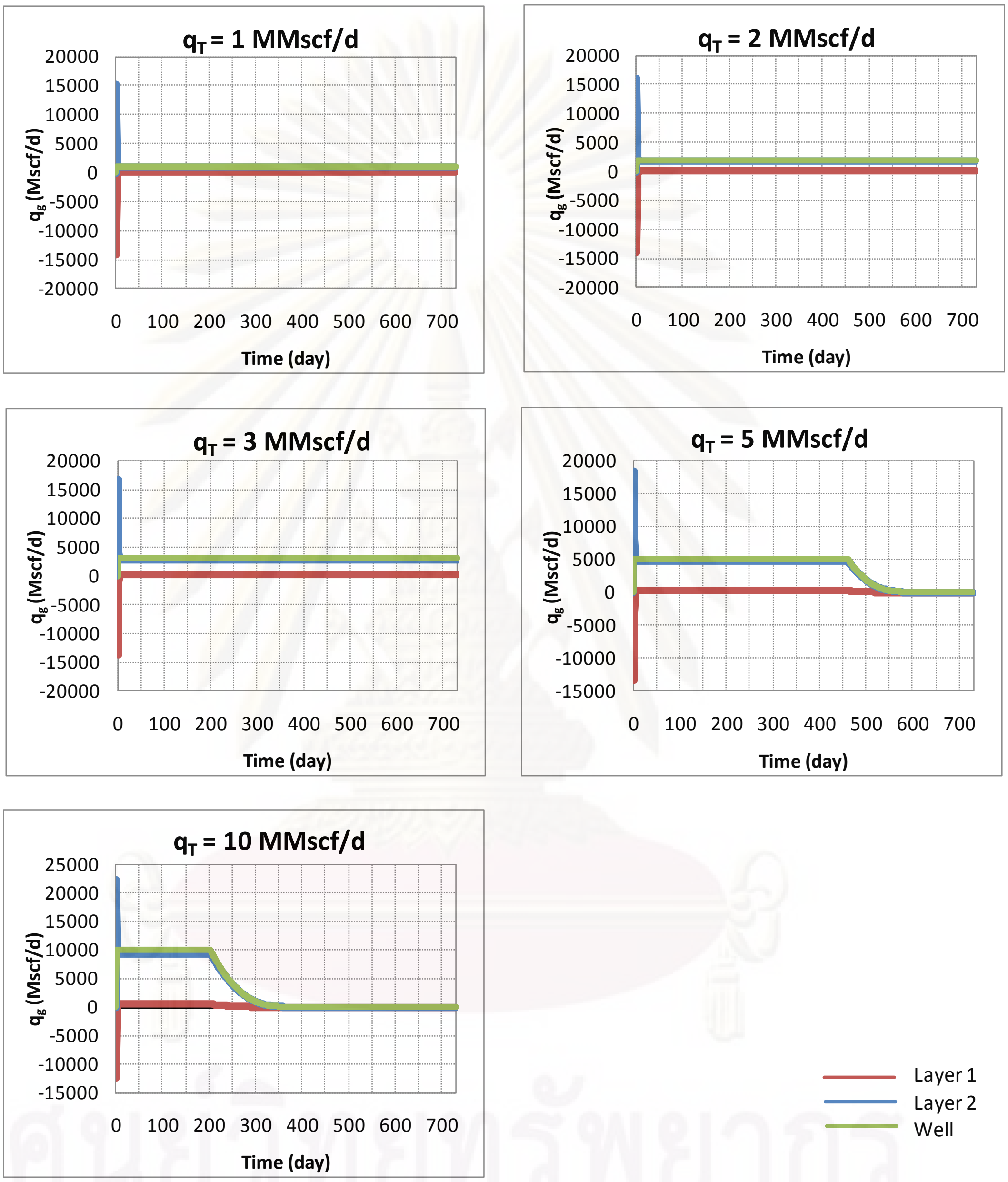


k = 50 md
Area1 = 500^2 sq..ft, Area2 = $2{,}000^2$ sq.ft (Gas Volume ratio 1:16)
Depth Difference between layers = 1,000 ft




k = 100 md
Area1 = 500² sq..ft, Area2 = 2,000² sq.ft (Gas Volume ratio 1:16)
Depth Difference between layers = 1,000 ft
qT = 1 MMscf/d
qT = 2 MMscf/d
qT = 3 MMscf/d
qT = 5 MMscf/d
qT = 10 MMscf/d
qg (Mscf/d)
Time (day)
Layer 1
Layer 2
Well

k = 500 md
Area1 = 500^2 sq..ft, Area2 = $2,000^2$ sq.ft (Gas Volume ratio 1:16)
Depth Difference between layers = 1,000 ft



Vitae

Praphakorn Sojisunsanee was born on February 20th, 1971 in Bangkok, Thailand. He received his Bachelor of Engineering in Mechanical Engineering from the Faculty of Engineering, Chulalongkorn University in 1992. He has been a graduate student in the Master's Degree Program in Petroleum Engineering of the Department of Mining and Petroleum Engineering, Chulalongkorn University since 2006.