ACCURACY OF MATERIAL BALANCE APPLIED TO TWO-LAYERED COMMINGLED GAS RESERVOIRS

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ความแม่นยำของสมการสมดุลมวลสารที่ประยุกต์ใช้กับแหล่งกักเก็บก๊าซสองชั้นที่ผลิตร่วมกัน

นางสาว ปิยะนันท์ จิตต์ชัยวิสุทธิ์

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ปิยะนันท์ จิตต์ชัยวิสุทธิ์ : ความแม่นยำของสมการสมดุลมวลสารที่ประยุกต์ใช้กับแหล่งกักเก็บก๊าซสองชั้นที่ผลิตร่วมกัน (ACCURACY OF MATERIAL BALANCE APPLIED TO TWO-LAYERED COMMINGLED GAS RESERVOIRS) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: ผศ. ดร. สุวัฒน์ อธิชนากร, 86 หน้า.

วิธีการสมดุลมวลสารหรือวิธีการหาค่าก๊าซเริ่มแรกของแหล่งกักเก็บก่อนการผลิตโดยการลากกราฟความสัมพันธ์ระหว่างความดันในแหล่งกักเก็บกับปริมาตรของการผลิตได้ถูกใช้กันอย่างอย่างแพร่หลายในการคำนวณหาค่าก๊าซเริ่มแรกของแหล่งกักเก็บ วิธีการที่ใช้กับแหล่งกักเก็บเดี่ยวนี้สามารถนำไปประยุกต์ใช้กับแหล่งกักเก็บก๊าซสองชั้นได้เช่นกัน

การประยุกต์ใช้วิธีการสมดุลมวลสารในแหล่งกักเก็บเดี่ยวกับแหล่งกักเก็บก๊าซสองชั้น เราควรจะมีความเข้าใจถึงปัจจัยที่มีผลต่อค่าความดันและมวลรวมสะสมของผลผลิตก๊าซในแหล่งกักเก็บร่วม ในการศึกษานี้เราใช้แบบจำลองแหล่งกักเก็บก๊าซในการจำลองกรณีศึกษาจากแหล่งกักเก็บก๊าซสองชั้นเพื่อแสดงให้เห็นถึงการนำวิธีการสมดุลมวลสารไปประยุกต์ใช้งาน กรณีศึกษาที่แต่งต่างกันของความตรงกันข้ามในคุณสมบัติของแหล่งกักเก็บของความหนา พื้นที่ ความพรุน ความสามารถซึมผ่านแนวระนาบ และค่าความถ่วงจำเพาะของก๊าซได้ถูกจำลองขึ้นเพื่ออธิบายถึงผลกะทบที่ได้จากการลากกราฟ

ผลการศึกษาพบว่าค่ารวมของก๊าซเริ่มแรกของแหล่งกักเก็บที่ประเมินได้จากวิธีการสมดุลมวลสารมีความแม่นยำทั้งๆแหล่งกักเก็บก๊าซทั้งสองชั้นนั้นมีความแตกต่างกันของค่าความหนา พื้นที่ ความพรุน ความสามารถซึมผ่านแนวระนาบ และค่าความถ่วงจำเพาะของก๊าซ เมื่อมีระดับค่าความแตกต่างระหว่างชั้นใดๆของความหนาและค่าแรงโน้มถ่วงของก๊าซ หรือมีค่าความแตกต่างน้อยๆในค่าการแทรกซึม เราจะเห็นกราฟเป็นเส้นตรง ซึ่งสามารถประเมินค่าเริ่มแรกของแหล่งกักเก็บรวมได้เท่านั้น ในทางกลับกันเมื่อมีระดับค่าความแตกต่างใดๆในค่าความพรุน หรือมีค่าความแตกต่างของความสามารถซึมผ่านแนวระนาบระหว่างชั้นในระดับปานกลางถึงมาก เราจะเริ่มเห็นเส้นตรงอีกเส้นที่มีความชันต่างกันบนกราฟ และค่าเริ่มแรกของแหล่งกักเก็บแต่ละชั้นได้ก็จะสามารถประเมินได้ อย่างไรก็ตามค่าความคลาดเคลื่อนที่ได้จากการประเมินจะอยู่ในช่วงที่ยอมรับได้ก็ต่อมีเมื่อค่าความแตกต่างระหว่างชั้นความพรุนอยู่ในช่วงปานกลางถึงมาก หรือค่าความแตกต่างระหว่างชั้นของความสามารถซึมผ่านแนวระนาบมากเท่านั้น

ภาควิชา วิศวกรรมเหมืองแร่และปิโตรเลียม ลายมือชื่อนิสิต ________________

สาขาวิชา วิศวกรรมปิโตรเลียม ลายมือชื่อ อ.ที่ปรึกษาวิทยานิพนธ์หลัก ________

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Material balance equation or the *p/Z* plot method is the well-known application for original gas in place estimation. This single tank model can be applied to commingled two-layered gas reservoirs as well.

To apply the single tank material balance model to estimate the OGIP of commingled two-layered gas reservoirs, we should understand the factors that affect the pressure and cumulative gas production in a commingled system. In this study, we use a reservoir simulator to simulate cases with two gas sands in order to demonstrate the application of the method. Different scenarios of reservoirs properties contrast on thickness, area, porosity, horizontal permeability, and gas specific gravity were run to determine their effect on *p/Z* plot.

Results from this study show that OGIP for the total system can be accurately determined via material balance despite there is contrast in thickness, area, porosity, horizontal permeability, or specific gas gravity. When there is any level of contrast in thickness or gas specific gravity or small contrast in area or permeability, only a single straight line is observed on the p/Z plot. In these cases, only total OGIP of the system can be estimated. On the other hand, when there is any level of contrast in porosity or medium to high contrast in area or permeability, two straight lines appear on the p/Z plot. Thus, OGIP can be estimated for each layer. However, only estimates for cases that have medium to large contrast in porosity or large contrast in permeability have acceptable error for layer OGIP estimate.

Department: Mining and Petroleum Engineering Student's Signature: ______________
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LIST OF ABBREVIATIONS

MMCFD	million standard cubic feet per day
GIP	gas in place
IPR	inflow performance relationship
OGIP	original gas in place
PPM	part per million
PVT	pressure volume temperature
S.G.	specific gravity of gas
STB	stock tank barrel
SCF	standard cubic foot
TVD	true vertical depth
VLP	vertical lift performance
THP	tubing head pressure
BHP	bottom hole pressure

NOMENCLATURES

A	reservoir drainage area, ft^2
k	permeability, mD
h	formation thickness, ft
P	pressure, psia
Z	gas deviation factor
P_i	initial formation pressure, psia
Z_i	initial gas deviation factor
G	original gas in place, MMscf
$OGIP$	original gas in place, MMscf
G_p	cumulative gas produced, MMscf

GREEK LETTERS

ϕ	porosity
Δ	difference operator
$\sum$	summation

CHAPTER I
INTRODUCTION

Reservoirs in the Gulf of Thailand are generally highly compartmentalized, stacked, thin, and deposited over an extensive pay window. Gas-prone organic-rich coals and carbonaceous shale source rocks which are inter-bedded within the reservoir sands are the main source for the gas and condensate. The area of individual reservoir varies from 20 acres up to several hundred acres. The main reservoirs are generally located above 8,500’ TVDSS and exhibit good productivity.

In order to determine the original gas in place in a reservoir, the material balance method [1] based on the principle of the conservation of mass that does not take reservoir geometry and flow in porous media into account. A tank model concept may be used. Therefore, to apply classic material balance equation to determine the original gas in place of multi-layered gas reservoirs, we should understand limitation and factors that affect the accuracy of original gas in place estimate. The purpose of this research is to investigate the parameters which influence the accuracy of single tank model material balance application in reserve estimation for multi-layered gas reservoirs. By analyzing results generated by numerical reservoir simulation, applicability of material balance equation in multi-layered commingled reserve estimation can be determined.

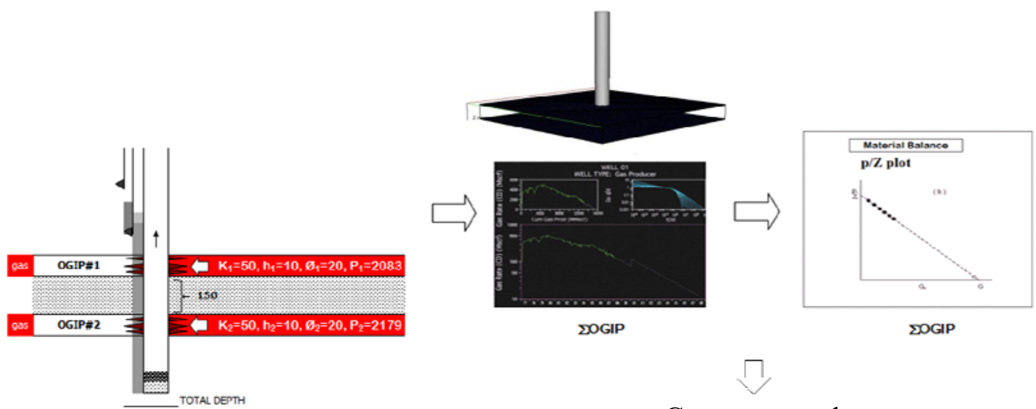
1.1 Methodology

The objective of the multi-layered, commingled material balance introduced in this work is to study effect of horizontal permeability, thickness, porosity, and area which influence the accuracy of gas in place estimation in multi-layered commingled gas reservoirs.

Numerical simulation is conducted in hypothetical reservoirs using ECLIPSE 100 reservoir simulator. The hypothetical reservoirs are based on the median statistical values of dry gas reservoir conditions from a field in the Gulf of Thailand. Two-layer commingled gas reservoirs are selected for the study and divided into three groups based on the degree of variance between the layers (zero variance between two layers, small variance between two layers, and large variance between two layers) in order to investigate the effect of contrast between two layers. Gas gravity also included in this study to determine its impact on commingled system OGIP estimation.

In material balance calculation, *p/Z* plot, which is the reservoir pressure divided by *Z* factor versus cumulative production, is used to estimate commingle OGIP.

Process diagram shown in Figure 1.1 describes the procedure for study which is outlined below:



Compare result:

$$\% \text{ Error} = \left(\frac{OGIP_{Estimate} - OGIP_{Actual}}{OGIP_{Actual}} \right) \times 100\ \%$$

Analyze result and make conclusion

Figure 1.1: Process diagram.

1. Determine reservoir properties and define the range of parameters to study. By evaluating the sand sedimentary and reservoir condition for a gas field, reservoir properties, fluid PVT behavior, and rock compressibility can be determined. Combinations of permeability, thickness, porosity, and area of each layer can be set.
2. Construct simulation model and generate production prediction. The simulation model will be constructed under homogeneous reservoir conditions, using a dry

gas type, based on the assumption that a single well penetrates into two layers, that the two layers are open to production at the same time, that there is natural depletion drive (no water influx), a constant bottom hole pressure, and zero skin in order to simplify the problem.

3. Perform material balance calculation. *p/Z* will be plotted versus cumulative gas production generated from numerical simulation to estimate OGIP of commingled reservoirs.
4. Compare result obtain from material balance and actual OGIP.
5. Analyze results and make conclusions. Investigate the impact of horizontal permeability, thickness, porosity, and area, and gas specific gravity.

1.2 Thesis Outline

Outline of thesis paper is as follows;

Chapter II	reviews related literatures of the gas in place estimation by *p/Z* method.
Chapter III	gives explanation and concepts related to this study.
Chapter IV	explains the methodology for this study.
Chapter V	discusses the result from of this study.
Chapter VI	provides conclusion and recommendation of the study.

1.3 Expected Usefulness

The result of this study will determine if certain reservoir properties make material balance applicable or not applicable in multi-layered commingled reserves estimation.

CHAPTER II

LITERATURE REVIEW

The effect of permeability on OGIP estimate in multi-layered heterogeneous reservoirs and multi-layered connectivity reservoirs were studied by Hedong et al. [2]. The result shows that if there is no connectivity between layers, then the permeability contrast is the main influence in reserves estimation. The study shows that the estimated reserve decreases when permeability contrasts between layers increase. However, if there is connectivity in between layers, then the vertical permeability is the main influence. The study suggests that the reserves estimation from material Balance method is more accurate when the vertical permeability is more than 0.0001 mD. When the vertical permeability is less than 0.0001 mD, material balance method still provides accurate reserve if the permeability ratio between the two zones is above 1/4. Furthermore result from this study also shows that a reservoir with high permeability (100, 200, and 300 mD) having the same permeability contrast gives larger reserve estimates when the permeability value is higher.

The study of the pitfalls of *p/Z* plots by Payne [3] develops a more accurate technique for material balance on tight-gas reservoirs by using field examples to evaluate potentially large errors associated with use of straight-line *p/Z* decline (tank). The study suggests the communicating reservoir (CR) model as a method for performing material balance calculation. The CR model is a technique that divides the reservoirs into several communicating tanks. The tanks can be depleted directly by wells or indirectly through other tanks. Flow rate between tanks is set proportionally in terms of pressure squared where there is communication factor and flow rate between the two tanks. At each time step, the pressures in various tanks are calculated. The pressure decline from the CR model is compared with actual pressures as a function of time to account for the reservoir performance that is missing in a typical *p/Z* plot. The study shows that the CR model is able to estimate OGIP more accurately than simply plotting *p/Z*. Consequently, the use of CR model can lead to expanded opportunities that would be missed from the underestimated OGIP in tight gas reservoirs.

Kuppe and Chugh [4] developed a simple spreadsheet model to estimate OGIP, layer productivity, and recoverable reserve for wells with commingled production. All high permeability layers are grouped into one model layers, and all low permeability layers are grouped into the tighter model layer. Then, the representing model was matched with production data from a productivity index weighted *p/Z* curve. The result shows that the model has been successfully applied to match and predict the productivity for various wells in Cooper Basin field with permeability ranges from 0.1 to 10 mD under no cross-flow condition and no extensive shut-in periods. This model also accounts for any changes in the productivity index.

Well performance in commingled reservoirs is investigated by Lefkovis et. al.[5] in terms of production response, pressure drawdown/build up, and skin effect. The results show that the pressure drawdown response of a producing well from a commingled reservoir is similar to that of a single layer reservoir. However, the transient period of commingled reservoirs rate is much longer than that of a single layer reservoir. At a constant production, depleted rate of each layer is different depending on the layer diffusivity or differential depletion. The magnitude of pressure rise during pressure build up depends on the contrast of the properties of the layers. The higher the contrast, the higher the pressure rise. In the same way for shut-in period, commingled reservoirs need longer time of pressure build up to reach pseudo-steady state. Therefore, when applying the *p/Z* plot to estimate OGIP for commingled reservoirs, the effect of pressure and the transient period should not be disregarded.

Ojo et al. [6] revisits the material balance equation and examines in the issues of average reservoir pressure. A new method for analyzing the material balance called the dynamic material balance equation “DMBE” is presented. This method is able to solve the combination of the original material balance equation and its time derivative by introducing a time factor to static tank model equation. This approach allows simultaneous determination of original oil in place (OOIP), original gas in place OGIP) and average pressure decline history. Instead of using pressure data, this approach suggests the use of production history and PVT data in the estimation of reserves.

CHAPTER III
THEORY AND CONCEPT

3.1 Assumptions

Building a reservoir model to represent a complex geological structure generally requires numerous subsurface information such as reservoir structure, fluid properties, and geological data. However, material balance is a simple type of reservoir model in which calculations are based on the average reservoir properties of a tank model which gives coarser resolution of results.

Since systems consisting of multiple sands are difficult to understand and to model analytically due to differences in reservoir parameters, this study will investigate two-layer systems.

Two-layer system is known to exhibit non straight line behavier in the *p/Z* plot due to different reservoir pressures and depletion behaviors between the two reservoirs [3]. In order to come up with a simple model to represent commingled gas sands, the following assumptions are made:

3.1.1 Assumption for reservoir simulation model

- We approximate the multiple sands by a system that consists of two reservoirs. The approximation is based on the idea that layers with similar reservoir pressure and depletion behavior can be combined into one.
- Rock compressibility is negligible.
- Only depletion drive from gas expansion is considered.

3.1.2 Assumption for material balance

- The reservoir is assumed to be in stabilized flow under pseudo-steady state condition with no aquifer influx.

- Assume relatively low production rate so we can neglect non-Darcy component on inflow performance.

3.2 Theory and concept

3.2.1 General definition of commingled reservoirs

Commingled reservoirs are composed of a number of layers whose characteristics can be very different from adjacent horizons. Wells in such reservoirs are produced from multiple layers as shown in Figure 3.1. There is no communication across layer boundaries, and hence the only communication occurs through the wellbore after perforation.

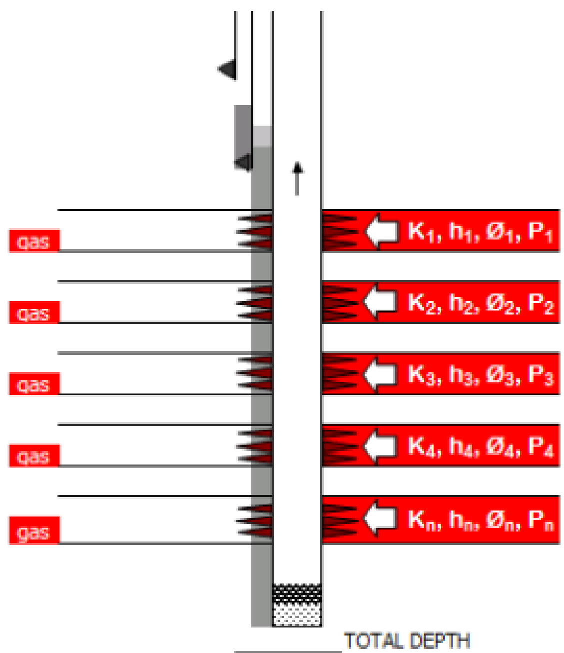


Figure 3.1: Commingled reservoirs

3.2.2 Material Balance Equations

Material balance is a simple but effective technique widely used for estimating OGIP. This technique is based on the principle of mass conservation.

Diagnostic plots (*p/Z* plot) are widely used to quantify the OGIP when volumetric reservoirs are completely enclosed under natural depletion and receive no external energy from other sources such as an aquifer.

$$\frac{p}{Z} = \frac{pi}{Zi}\left(1 - \frac{Gp}{G}\right) \tag{3-1}$$

where

P	is the average reservoir pressure, psia
P_i	is an initial reservoir pressure, psia
Z	is the gas deviation factor, unitless
Z_i	is an initial gas deviation factor, unitless
G_p	is cumulative gas production, scf
G	is original gas in-placce (OGIP), scf
$\frac{Gp}{G}$	is the gas recovery factor

If the rock and connate water expansions are negligible, the dominant mechanism is the gas expansion. A common diagnostic plot for volumetric reservoir consists of plotting *p/Z*, reservoir pressure divided by *Z* factor of gas, vs. *Gp*, cumulative gas production. For a volumetric gas reservoir, a plot of *p/Z* vs. *Gp* should give a straight line, from which we can estimate the original gas in place by extrapolating to atmospheric pressure. The graphical representation of the material balance for a volumetric depletion gas reservoir is shown in Figure 3.2.

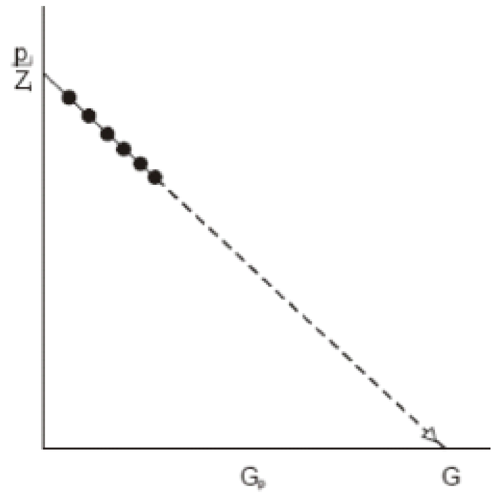


Figure 3.2: Graphical representation of the material balance
for a volumetric depletion gas reservoir.

The relative error in gas in place is expressed as

$$\% \text{ error} = \left(\frac{OGIP_{Estimate} - OGIP_{Actual}}{OGIP_{Actual}} \right) \times 100\,\% \tag{3-2}$$

3.3.3 Numerical simulation concept

Reservoir simulation is a computer models used as a standard tool in an oil industry to predict the flow of fluid (typically, oil, water, and gas) through porous media by applying numerical simulation concept or mathematic model to petroleum reservoirs.

The simulator can be used to obtain performance predictions for a hydrocarbon reservoir under different operation conditions by discretizing the reservoir into grids with each individual block corresponding to a volume in the reservoir that contains representative rock and fluids. The rock is assigned a value for compressibility, capillary pressure and a relative permeability relationship, and the fluids are assigned a value for viscosity, compressibility, solution gas/oil ratio and density. A three dimensional grid block arrangement for an anticline is shown in Figure 3.3.

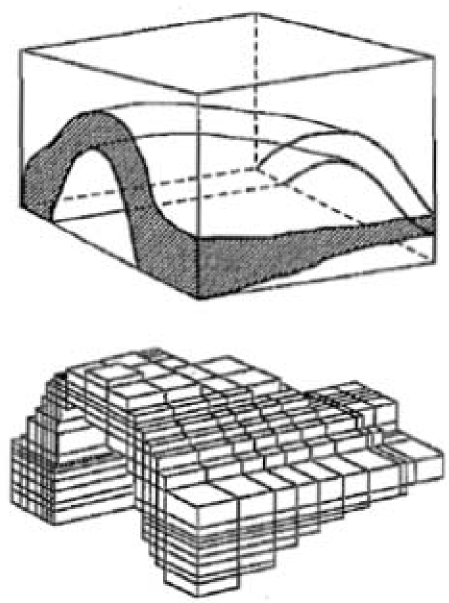


Figure 3.3: Three dimensional grid block arrangement for an anticline [7]

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To solve the fluid flow equation at each block face requires permeability, layer thickness, porosity, rock and fluid properties, elevation, and pressure. A reservoir system can be modeled using small grid-blocks to define the reservoir and increasingly larger grid blocks to define the whole system including aquifer by extending the finite difference grid covering the reservoir to include the aquifer.

CHAPTER IV
METHODOLOGY

4.1 Reservoir model

A homogeneous two layers reservoir model with a single well was constructed as illustrated in Figure 4.1. Both layers, containing dry gas, have the same rock and fluid properties. However, the initial pressures of the two layers are different due to difference in depth. These layers are separated by 150 ft of shale. The only possible communication between the sand layers is through the wellbore.

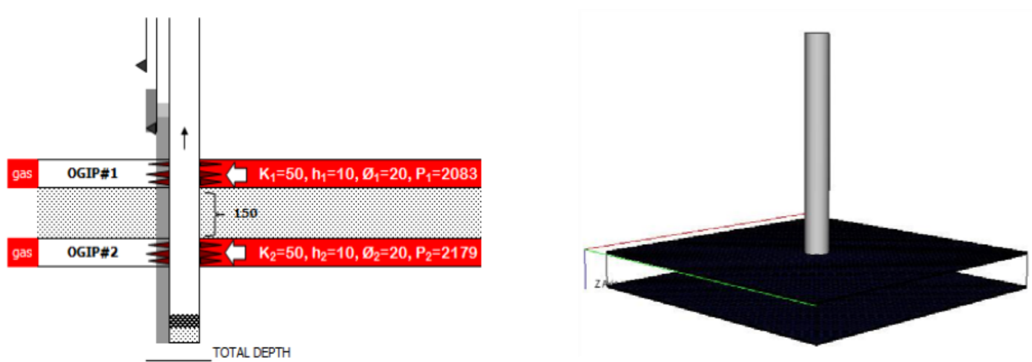


Figure 4.1 : Base case two layers model.

The general configuration of the model consists of uniformly sized grid blocks. The number of grid block in the x-, y-, and z- direction is 51 x 51 x 21 with the size of 30.40 x 30.40 x 1 ft^3. Each reservoir has a thickness of 10 ft. Shale is located at grid block layer 11^{th} with the size of 30.40 x 30.40 x 150 ft^3. The upper reservoir is located at 5030 ft. One vertical production well is located in the middle to drain the two reservoirs. The characteristics of well are shown in Table 4.1. A well was assumed to produce with a maximum rate of 5,000 Mscf/D.

Table 4.1 : Well characteristics

Wellbore radius	0.40 ft
Tubing inside diameter	2.441 in
Pipe roughness	0.0006 in

Table 4.2: Reservoir properties

Gas gravity	0.8
Reservoir temperature	203 °F
Top depth	5030 ft
Reservoir size	1550 x 1550 ft^2
Porosity	0.2
Water saturation	0.2
Horizontal permeability	50 mD
Vertical permeability	5 mD
Tubing head pressure	414.7 psia
Maximum gas production	5 MMscf/Day
Minimum gas rate	0.1 MMscf/Day

Table 4.3 : PVT data

Pressure (psia)	FVF (rb/Mscf)	Visc (cp)
429.39	7.46903	0.01324
615.11	5.12797	0.01353
800.82	3.87714	0.01386
986.54	3.10145	0.01425
1172.25	2.57558	0.01469
1357.96	2.19744	0.01517
1543.68	1.91403	0.01571
1729.39	1.69504	0.01629
1915.11	1.52186	0.01691
2100.82	1.38235	0.01757
2286.54	1.26827	0.01827
2472.25	1.17378	0.01900
2657.97	1.09465	0.01976
2843.68	1.02772	0.02054
3029.40	0.9706	0.02133

Reservoir properties are shown in Table 4.2. These properties are based on common values of dry gas reservoirs from an actual field in the Gulf of Thailand. The permeability was obtained from permeability - porosity correlation. The permeability in the x- and y- directions are 50 mD while the permeability in the z- direction is equal to 5 mD. The initial reservoir pressure of 2,605 psi is computed from the pressure gradient based on RFT data from the field.

PVT data in this model were generated by applying reservoir gas properties in PROSPER using Lee et al. correlation [8]. The same PVT properties for both layers shown in Table 4.3 are used. Temperature and pressure gradients are based on the RFT data from the actual field.

The simulation runs were made under a constant rate and were terminated when the tubing head pressure reached a level of 414.7 psia (or 400 psig + 14.7 atm). This is the minimum pressure required for unassisted flow from the well.

Vertical lift performance in the reservoir simulation is generated from PROSPER. The single phase gas flow in the tubing from top of the perforation to surface is generally calculated by using pressure and temperature gradient from the chosen field in the Gulf of Thailand.

4.2 Sensitivity analysis

The sensitivity runs were made to study the effect of many variables on the OGIP estimation. These variables are thickness, area, porosity, horizontal permeability, and gas specific gravity. The summary of variables are shown in Table 4.4.

Table 4.4 : Parameters for sensitivity analysis

Parameter	Value of property					
	Zero variances between 2 layers		Small variances between 2 layers		Large variances between 2 layers	
	1st	**2nd**	**1st**	**2nd**	**1st**	**2nd**
Thickness (ft)	10	10	10	30	10	120
			10	60	10	500
Area (acre)	55	55	55	70	55	500
			55	90	55	750
			55	120	55	1000
			55	180		
Porosity (%)	20	20	20	22	10	25
			20	25	10	30
			20	30	20	40
Permeability (mD)	50	50	50	57	50	100
			50	65	50	278
			50	80	14	80
			14	38	14	278
Gas specific gravity	0.7	0.7	0.8	0.9	0.7	0.9
	0.8	0.8				
	0.9	0.9				

This study addresses the effect of property contrast between two-layer that influence the original gas in place calculation. The use of porosity and permeability in this study comes from a correlation of a producing field in the Gulf of Thailand which can be generalized by Eq. 4.1 and is illustrated in Figure 4.2.

$$k = 0.0314 \text{ x Exp} (36.237 \text{ x } \phi) \tag{4.1}$$

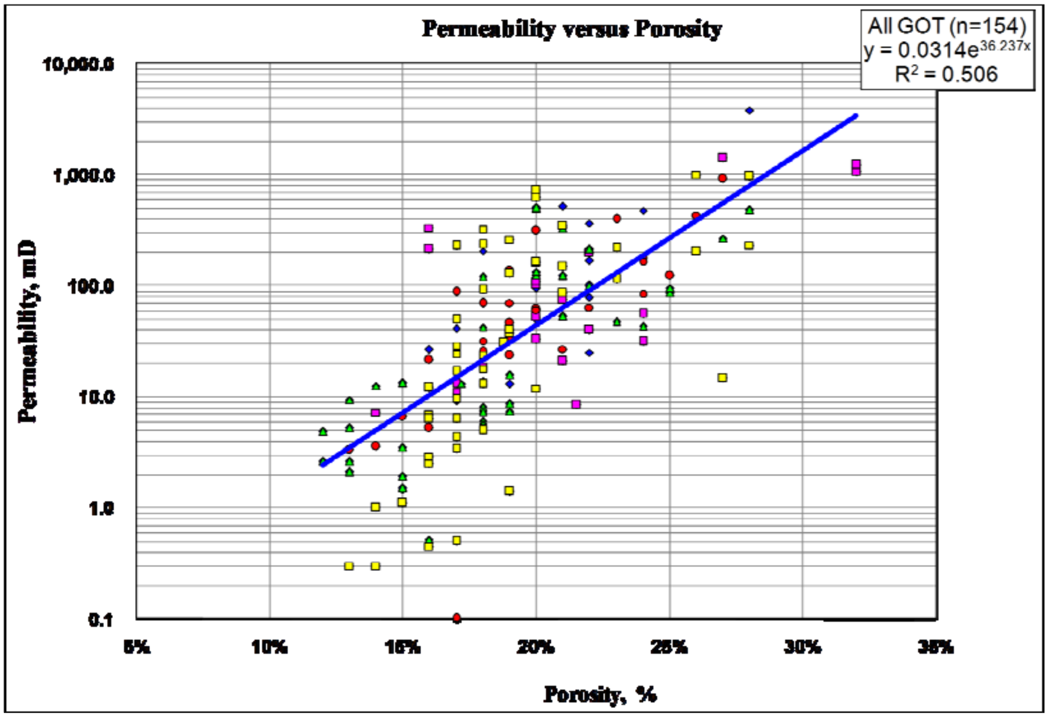


Figure 4.2 : Porosity and permeability correlation.

4.3 Base case OGIP estimation

For the base case, two layered reservoirs having the same properties as shown in Table 4.5 were simulated. In the simulation run, the well was scheduled to be shut-in for 24 hours from time to time in order to calculate static bottom-hole pressure at the top depth of the upper layer (5030 ft). Then, the static bottom-hole pressures were used to represent the reservoir pressures at different stages of depletion. These measured pressures were then used to plot *p/Z* versus cumulative gas production.

Table 4.5: Parameters for base case analysis

Porosity (ϕ)	**Thickness (ft)**	**Permeability (mD)**	**Area (ft^2)**	**Contrast**
20	10	50	2.40E+06	**1.00**
20	10	50	2.40E+06	

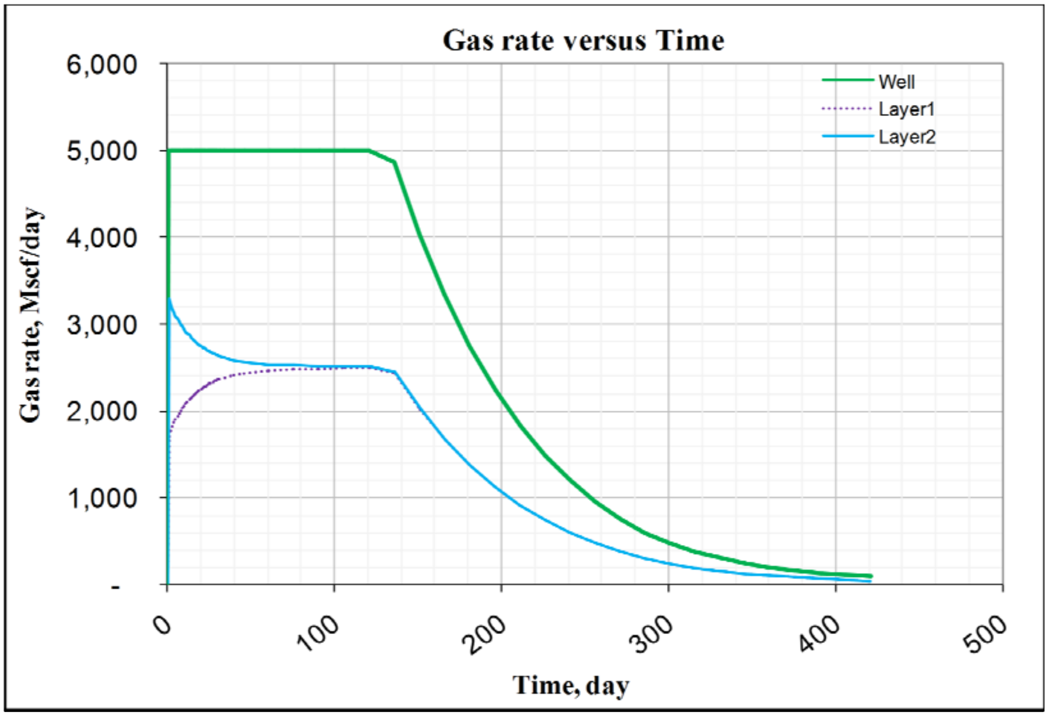


Figure 4.3 : Gas rate versus time from simulated basecase.

The gas rate over time from Figure 4.3 illustrates behavior of two layers having different initial pressures due to difference in depths. The green line represents gas rate of the entire system; the blue line represents gas rate of the upper layer, while the light blue represents gas rate of the lower layer.

Figures 4.4 and 4.5 illustrate pressures versus time. The figures demonstrate that the reservoir pressure, bottom hole pressure, and tubing head pressure drop quickly, in the early stage because of high gas production rate. Later on, bottom hole pressure, and tubing head pressure decrease gradually until they become constant at 483, 473, and 414.7 psia, respectively. (It should be noted that the pressure shown in Figure 4.4 is average reservoir pressure, not pressure at the sandface.)

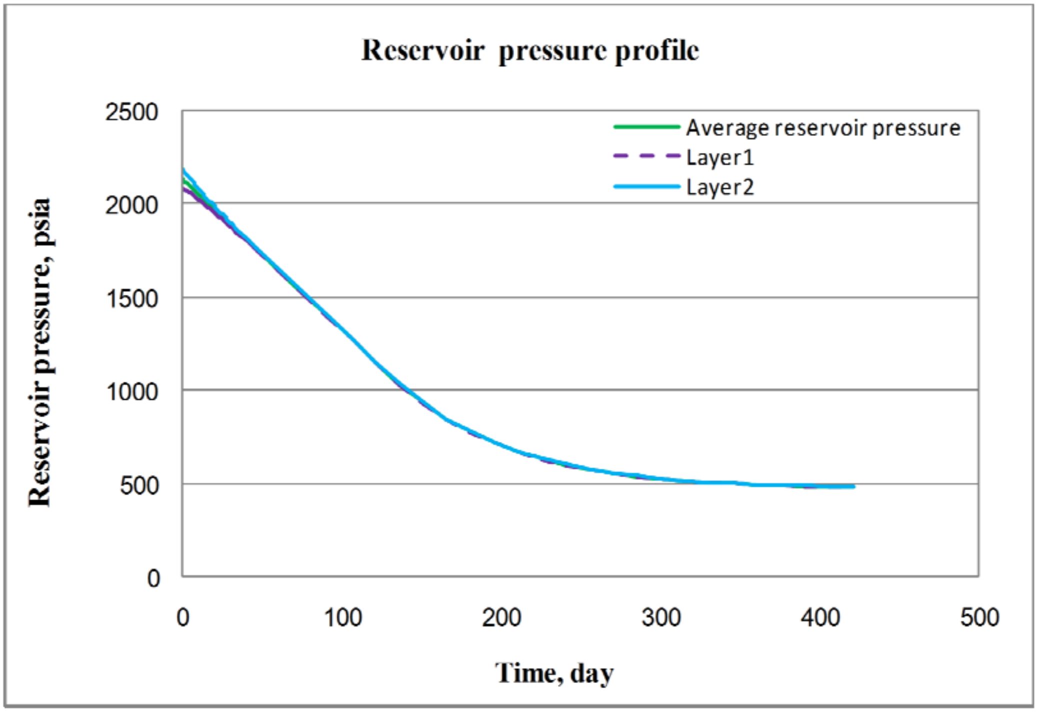


Figure 4.4: Reservoir pressure versus production time.

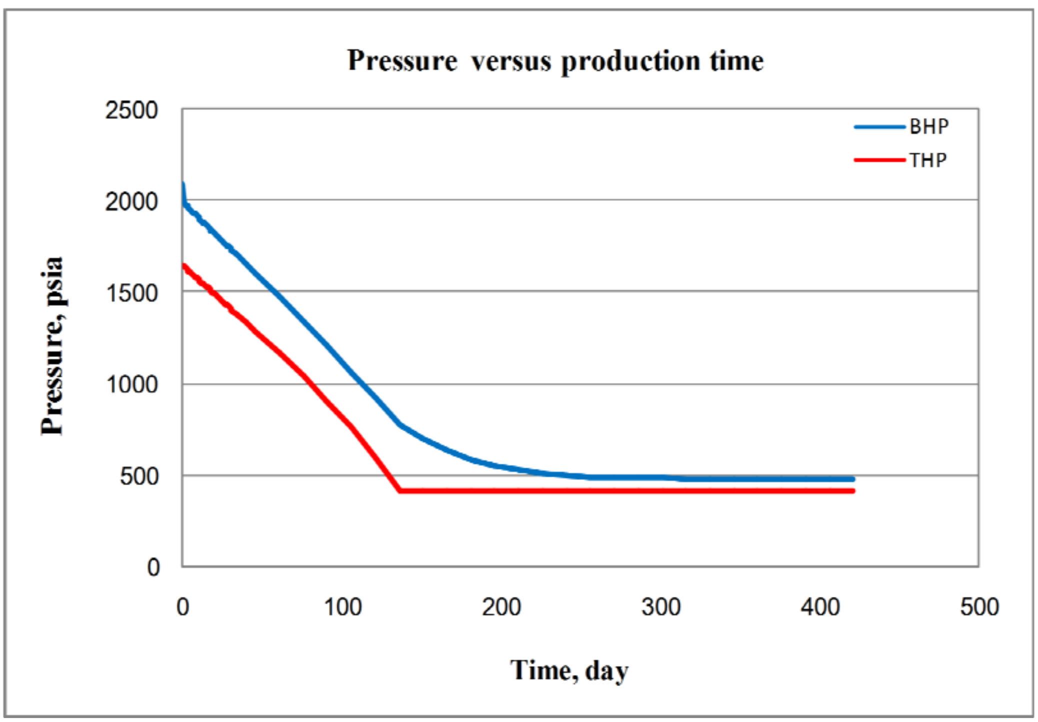


Figure 4.5: Bottom hole and tubing head pressures versus production time.

In the early stage, the bottom layer has higher initial pressure than the upper layer. Thus the flowing bottom hole pressure is dominated by the lower layer. High difference in pressure between bottom hole flowing pressure and reservoir pressure of the deeper sand causes the deeper sand to produce with high initial flow rate. After a while, the reservoir pressure of the lower layer starts to decline, causing the gas rate from the lower layer to drop. As the reservoir pressure of the lower layer drops, gas rate from the upper layer increases due to less difference in pressure between the deeper sand and bottom hole flowing pressure. At 27 days, the pressures of the two layers are in equilibrium hydrostatically. After this point, both layers produce at the same gas rate and deplete together.

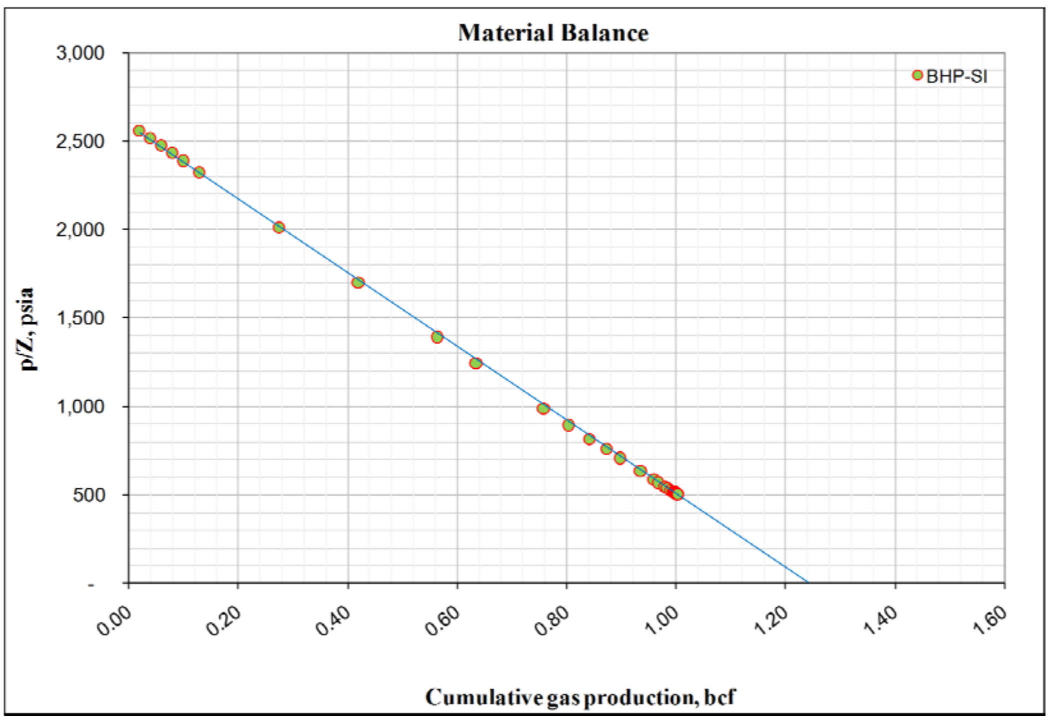


Figure 4.6 : *p/Z* versus cumulative production from simulated base case.

In order to determine the original gas in place, *p/Z* was plotted versus cumulative gas production as shown in Figure 4.6. Note that *P* in the y-axis is the shut-in bottom hole pressure. The *p/Z* plot in Figure 4.6 exhibits a single straight line when there is no contrast in fluid and reservoir properties between the two layers. This indicates that the two-layered system behaves like a single layer although the flow contributions from the two layers are different at the beginning.

The original gas in place for the two layers is estimated to be 1.245 Bcf. The actual original gas in place is 1.250 Bcf. There is a 0.42% difference between the estimated and the actual values. This error may be caused by inconsistence in the calculation of the *Z*-factor in the reservoir simulation and the excel spread sheet used to determine *p/Z*. In any case, this small difference helps verify the accuracy of the model set up.

Table 4.6 : Estimation of original gas in place based on different pressures

Basecase	**Actual**	$\mathbf{P_{BHP/Z}}$	$\mathbf{P_{layer1}/Z}$	$\mathbf{P_{layer2}/Z}$	$\mathbf{P_{Avg}/Z}$
OGIP (Bcf)	1.250	1.245	1.243	1.240	1.243
% Error	-	(0.42)	(0.58)	(0.83)	(0.58)

With the intention to study the effect of pressure on OGIP estimate, four different pressures were used to represent the reservoir pressure in the *p/Z* plot: shut-in bottom hole pressure, reservoir pressure of the upper layer, reservoir pressure of the lower layer, and average reservoir pressure computed from the two layers. Results from Table 4.6 show that the errors caused by different pressures are comparable. However, the error obtained when using the reservoir pressure of the lower layer is slightly higher than other cases. In any case, the results from the table show that the shut-in bottom hole pressure can be used to represent the reservoir pressure in material balance calculation.

CHAPTER V

RESULTS AND DISCUSSION

This chapter examines the effect of various thicknesses, areas, porosities, permeabilities, and gas specific gravities on the original gas in-place estimation.

5.1 Influence of thickness contrast on OGIP estimate

Ranges of thickness contrast from low to high were selected for studying effects of thickness on the estimation of original gas in place. Table 5.1 illustrates thickness contrast between two layers in a commingled system used in this study.

Table 5.1 : Contrast between reservoir thickness

	Thickness (ft)	**Contrast**
Case1:		
Layer1	10	3
Layer2	30	
Case2:		
Layer1	10	6
Layer2	60	
Case3:		
Layer1	10	12
Layer2	120	
Case4:		
Layer1	10	50
Layer2	500	

Figure 5.1 illustrates gas rate versus time for different thicknesses of the lower layer. The increased thickness leads to a higher original gas in place, resulting in a longer plateau and slower depletion during the decline period.

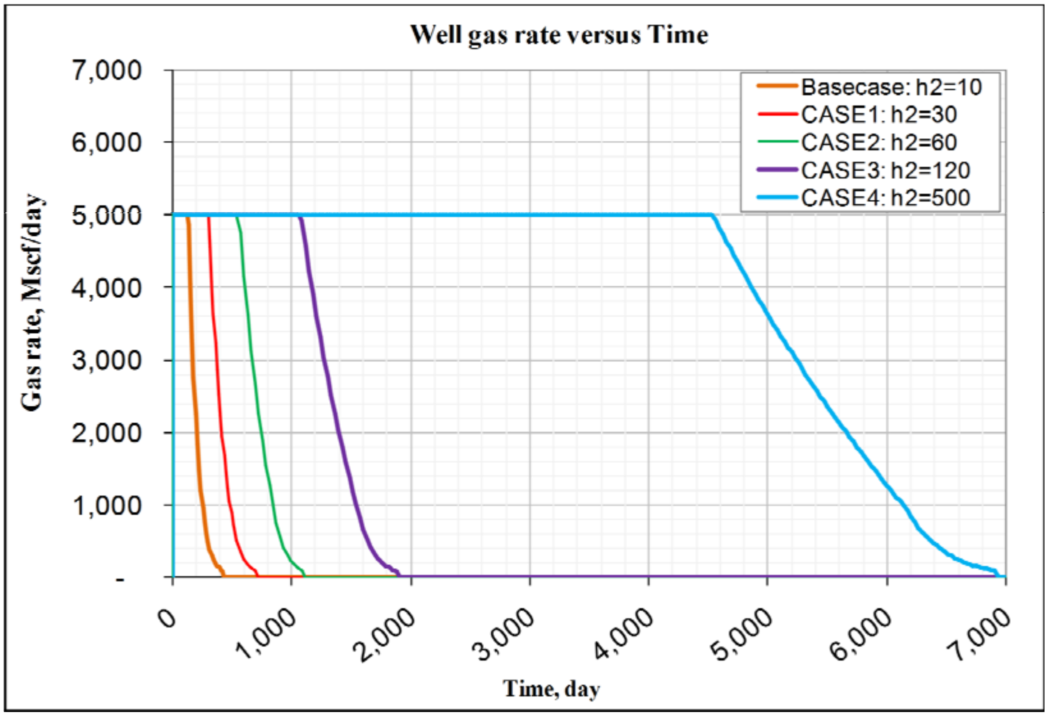


Figure 5.1 : Well gas rate versus time – effect of thickness contrast on OGIP.

Figures 5.2 and 5.3 show the gas rate for the upper and lower layers, respectively. For the cases with thickness contrast, the main contributor of the commingled system comes from the lower layer due to its larger thickness. Gas from the lower layer initially flows at a high rate while there is a small rate from the upper layer since the lower reservoir has a higher pressure than the upper layer. After a couple of months, the gas rate of the lower layer drops sharply due to the reduction of reservoir pressure. At this point, the pressure of the lower layer is in dynamic equilibrium with that of the upper layer. Then, the upper layer starts to have a higher flow rate. Later on, both layers supply gas to the wellbore at some constant production rates until gas rates from both layers decline as the reservoirs are depleted. Note that the rate contribution of each layer to the total flow rate is proportional to the thickness of the layer.

For the case with thickness contrast is approximately equal or higher than 6 (cases 2, 3, and 4), crossflow occurs during the initial period of production can be observed for 13 days, 26 days, and 61 days, respectively. Part of the gas from the lower layer flows into the upper layer which has a lower reservoir pressure, causing the flow rate of the upper layer to be negative at the very early period.

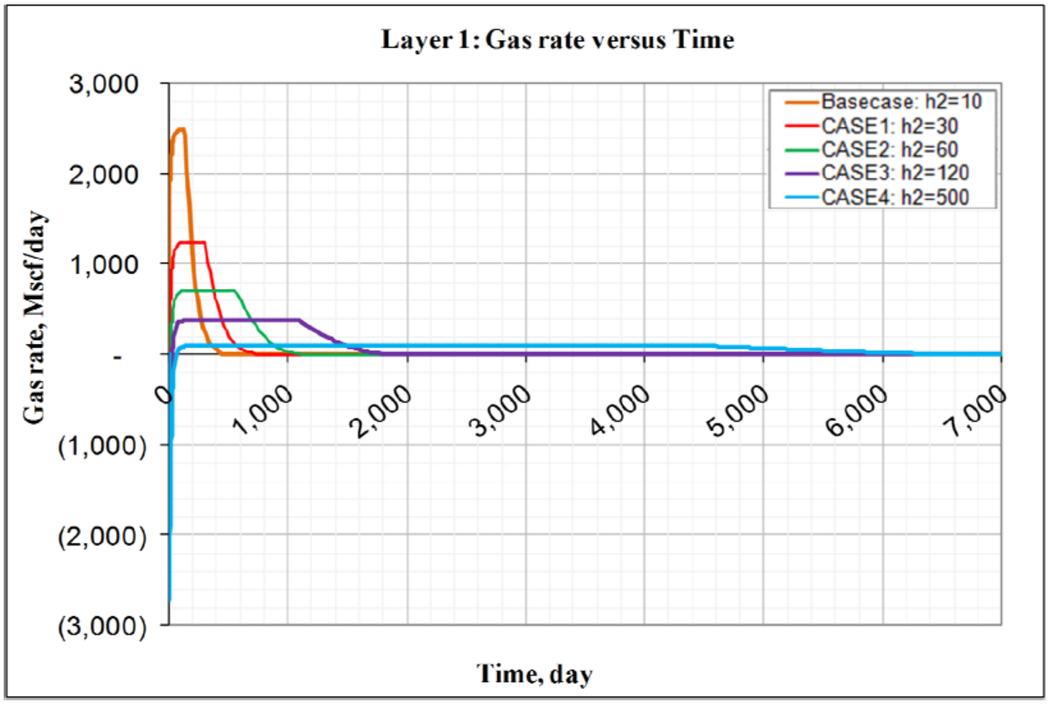


Figure 5.2 : Gas rate versus time for the upper layer – effect of thickness contrast on OGIP.

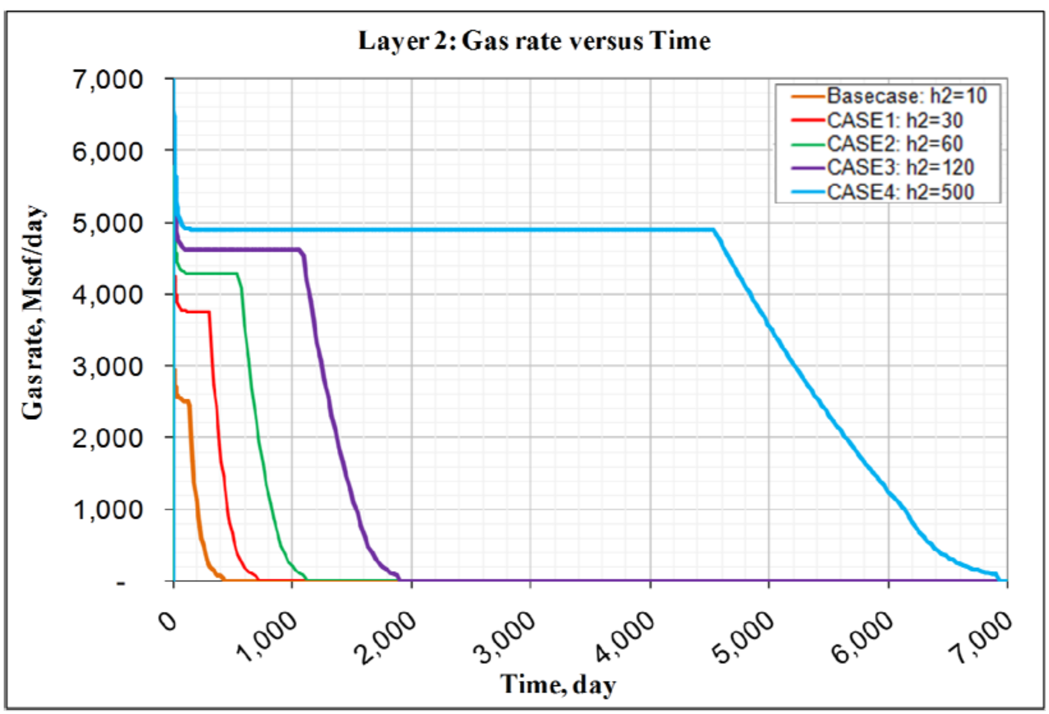


Figure 5.3 : Gas rate versus time for the lower layer – effect of thickness contrast on OGIP.

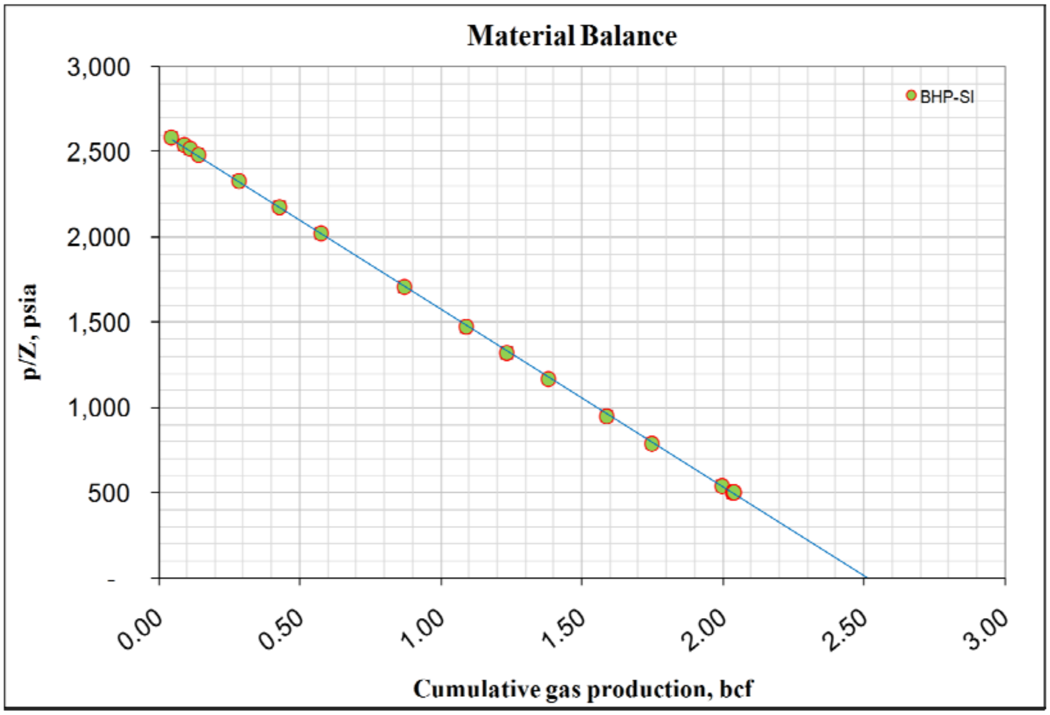


Figure 5.4 : *p/Z* versus cumulative production - Case1: Layer thickness of 10 and 30 ft.

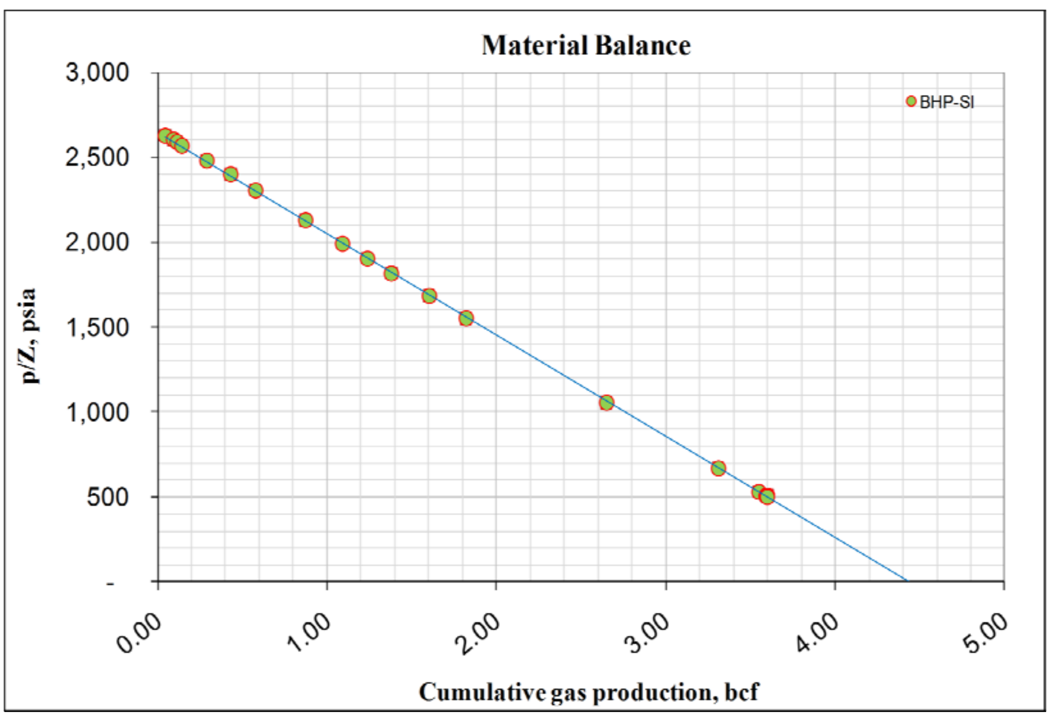


Figure 5.5 : *p/Z* versus cumulative production -Case2: Layer thickness of 10 and 60 ft.

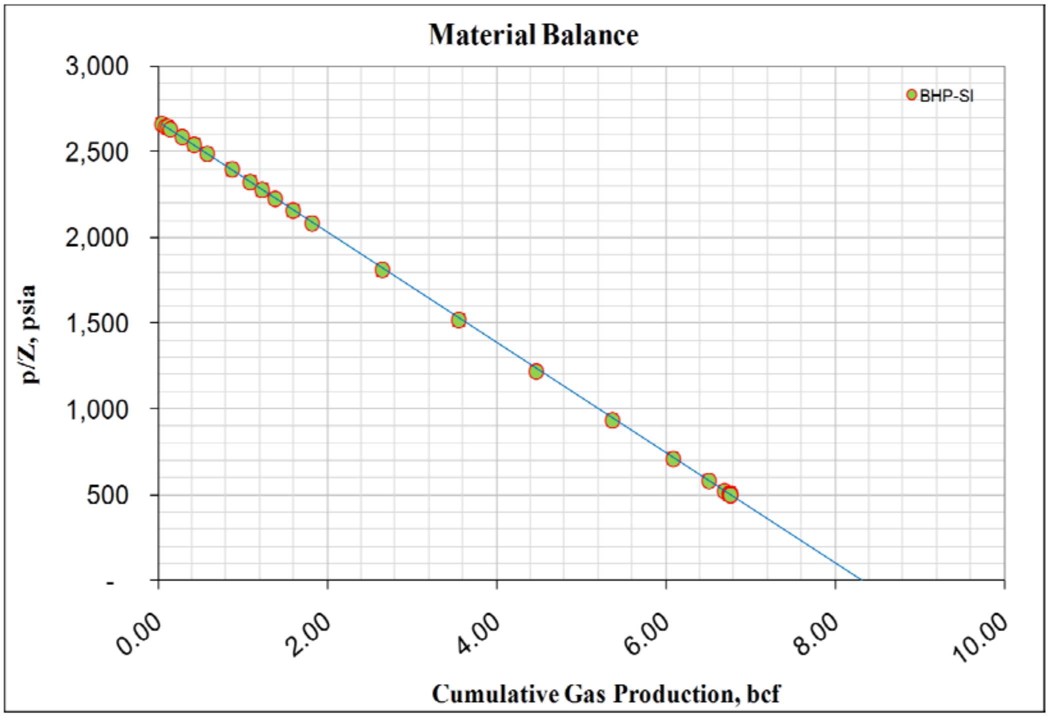


Figure 5.6 : *p/Z* versus cumulative production - Case3: Layer thickness of 10 and 120 ft.

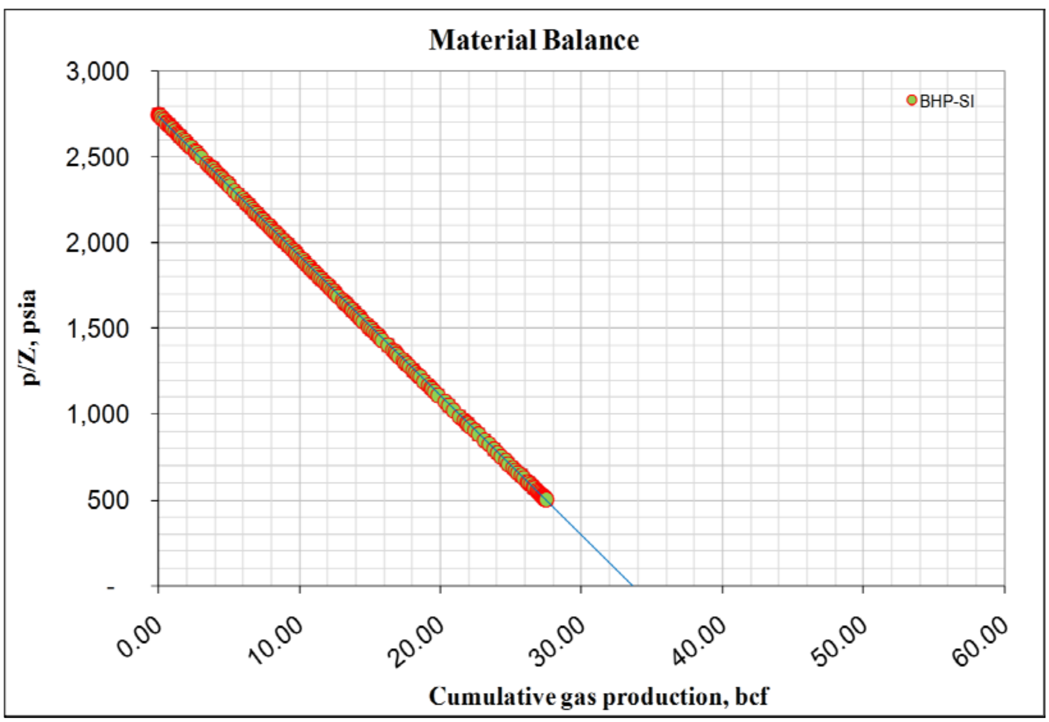


Figure 5.7 : *p/Z* versus cumulative production – Case4: Layer thickness of 10 and 500 ft.

Figures 5.4 to 5.7 illustrate the *p/Z* plot for cases 1, 2, 3, and 4, respectively. When varying the thickness of the lower layer from 10 to 30, 60, 120, and 500 ft, the *p/Z* plot exhibits a single straight line. Therefore, the OGIP of each layer cannot be obtained from these straight line *p/Z* plots.

Table 5.2 provides, in tabular form, the OGIP estimates for different contrasts of reservoir thickness. Table 5.3 summarizes the appearance of two straight lines on *p/Z* plot as a function of thickness contrast between the two layers. In all cases, only a single straight line can be seen.

Table 5.2 : Original gas in place for different contrasts of reservoir thicknesses

	Actual OGIP	***p/Z* OGIP**	**% Error**
Case1: Thickness contrast = 3	**2.543**	**2.526**	**-0.65**
Case2: Thickness contrast = 6	**4.483**	**4.449**	**-0.76**
Case3: Thickness contrast = 12	**8.399**	**8.333**	**-0.79**
Case4: Thickness contrast = 50	**33.913**	**33.629**	**-0.84**

Table 5.3 : Appearance of two straight lines on *p/Z* plot for various thickness contrasts

Thickness contrast	**Appearance of two straight lines**
3	None
6	None
12	None
50	None

5.2 Influence of area contrast on OGIP estimate

In order to study the influence of contrast between areas of the two layers on OGIP estimate, seven different areas which are 70, 90, 120, 180, 500, 750, and 1000 acres are considered for the lower layer. Table 5.4 illustrates contrast of reservoir areas between the upper and lower layers.

Table 5.4 : Contrast between reservoir areas

	Area (acre)	**Contrast**
Case1:		
Layer1	55	1.3
Layer2	70	
Case2:		
Layer1	55	1.6
Layer2	90	
Case3:		
Layer1	55	2.2
Layer2	120	
Case4:		
Layer1	55	3.3
Layer2	180	
Case5:		
Layer1	55	9.1
Layer2	500	
Case6:		
Layer1	55	13.6
Layer2	750	
Case7:		
Layer1	55	18.2
Layer2	1000	

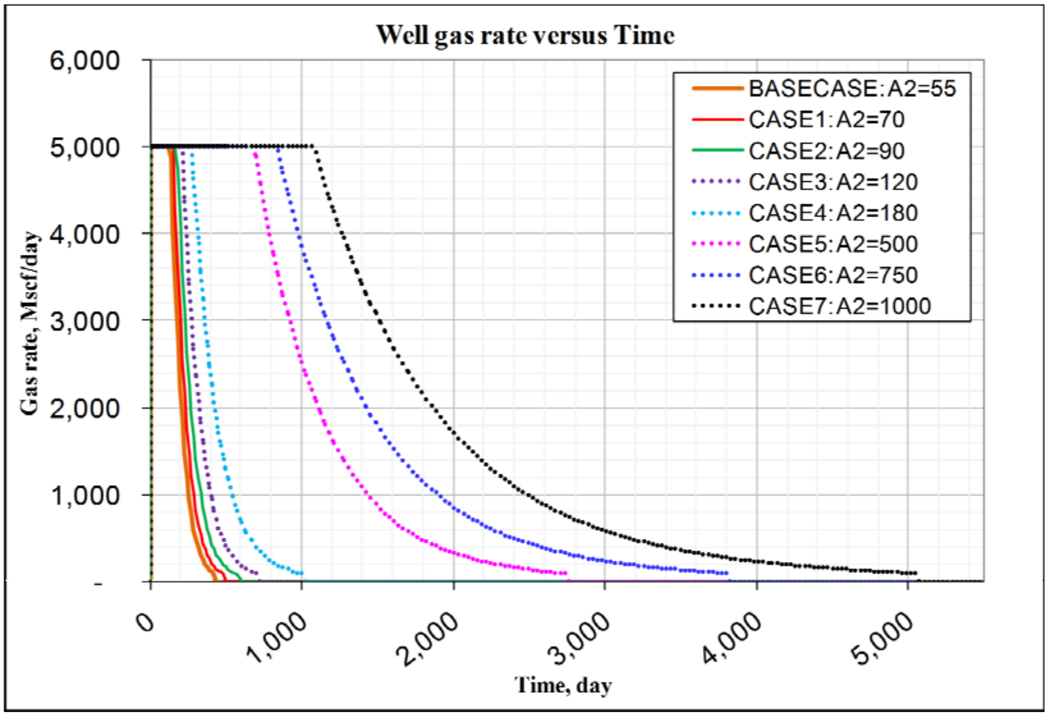


Figure 5.8 : Well gas rate versus time – effect of area on OGIP.

Figure 5.8 shows the gas production profile of the well for different contrasts between areas of the two layers. We can observe that the increase in area causes the well to decline slower.

Figures 5.9 and 5.10 illustrate gas rate versus time for the upper layer and lower layer, respectively. When area contrast is lower than or equal to 1.6, the lower layer initially produces with a high initial rate. Then the gas rate from the lower layer drops sharply within a month while the upper layer gas production increases rapidly, compensating for the drop in the rate from the upper layer to maintain a constant well rate of 5,000 Mscf/D. After that, gas rates from both layers decline.

For large area contrast cases, the gas rate from this layer increases while the gas rate from the upper layer drops quickly during the early time. After that gas rates of both layers are more or less constant at longer plateau period before the well decline.

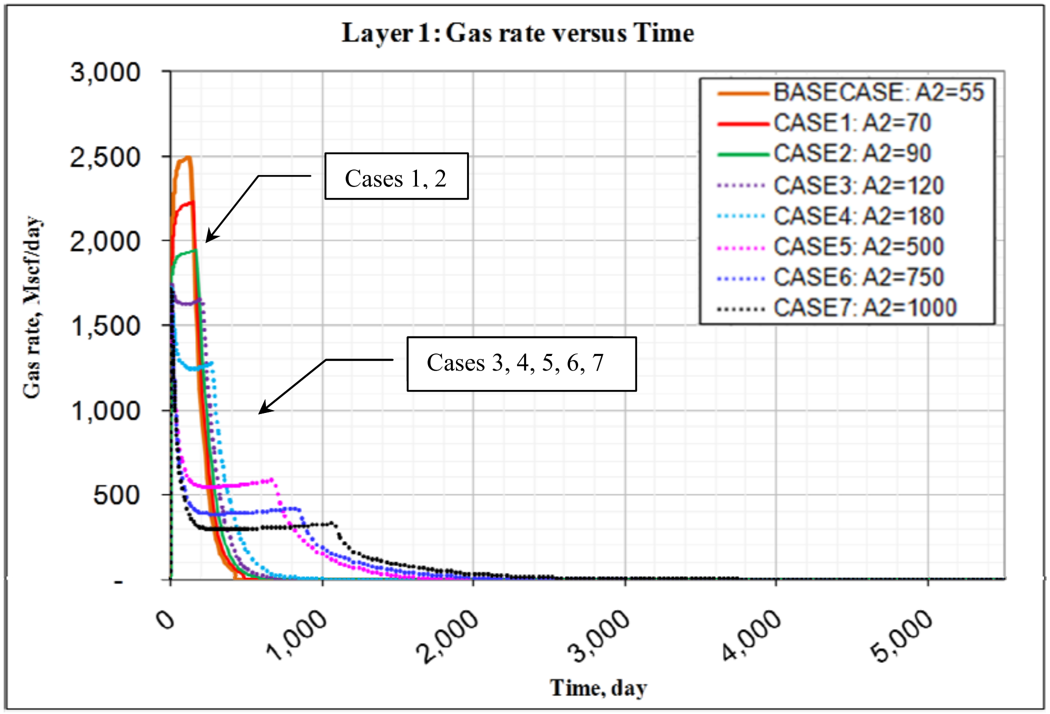


Figure 5.9 : Gas rate versus time for the upper layer – effect of area on OGIP.

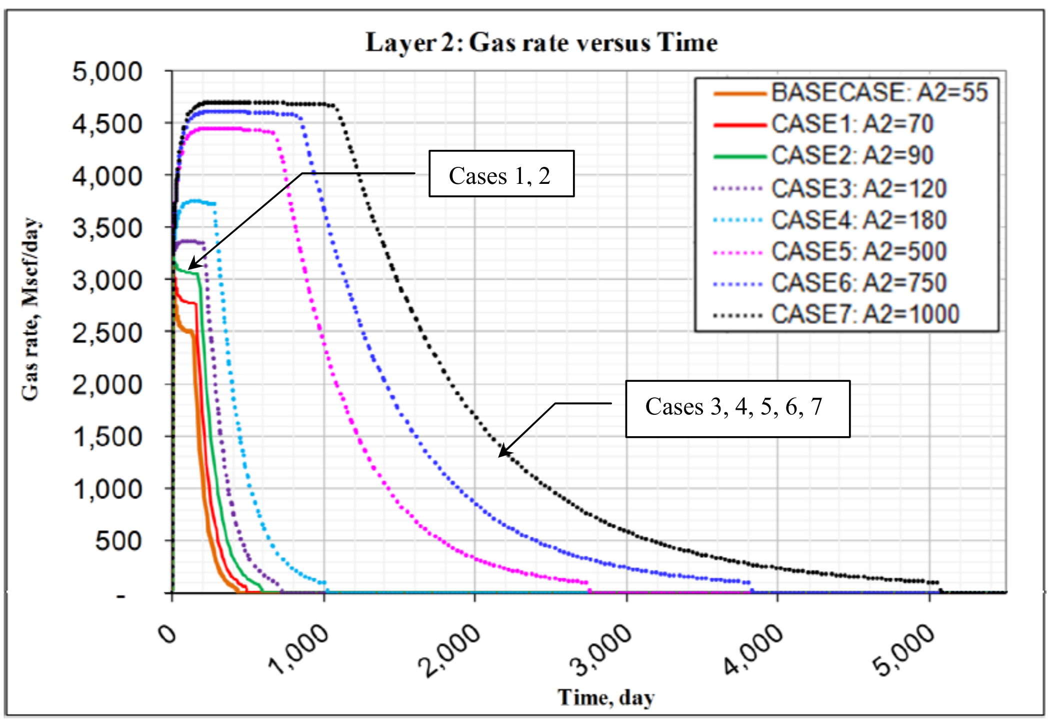


Figure 5.10 : Gas rate versus time for the lower layer – effect of area on OGIP.

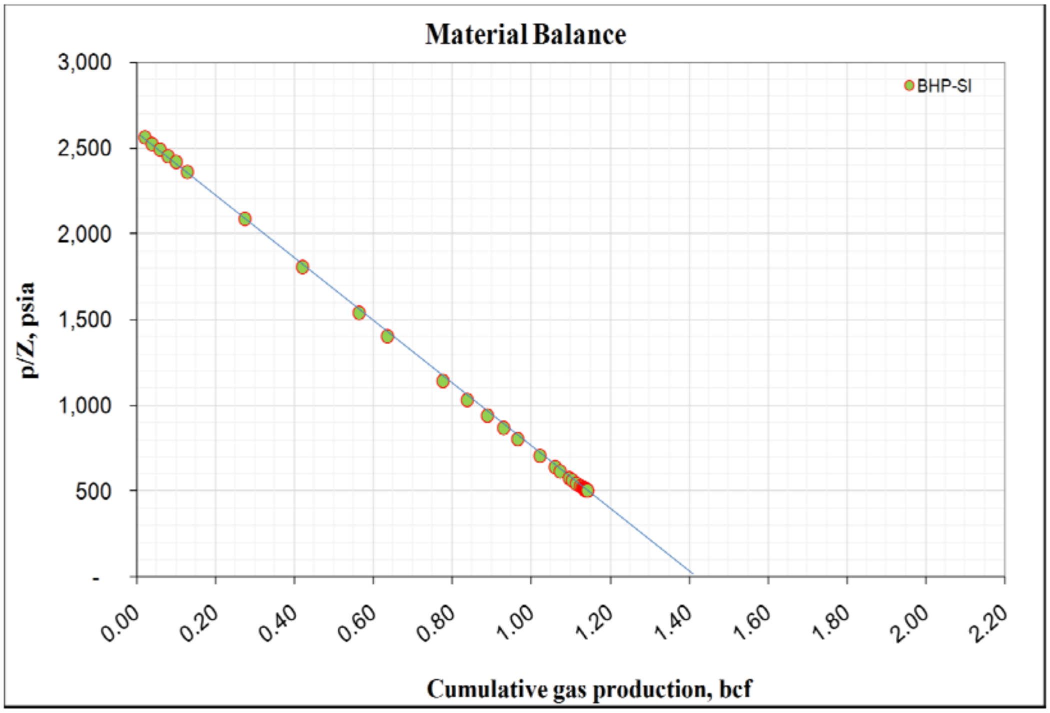


Figure 5.11 : *p/Z* versus cumulative production – Case1: Layer area of 55 and 70 acre.

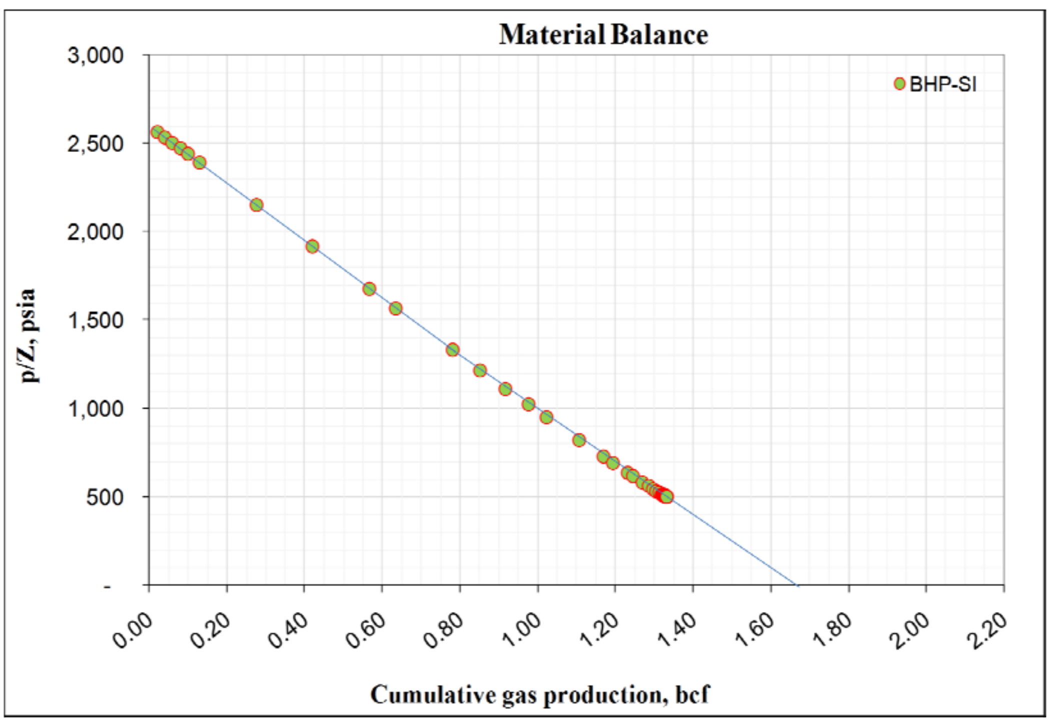


Figure 5.12 : *p/Z* versus cumulative production – Case2: Layer area of 55 and 90 acre.

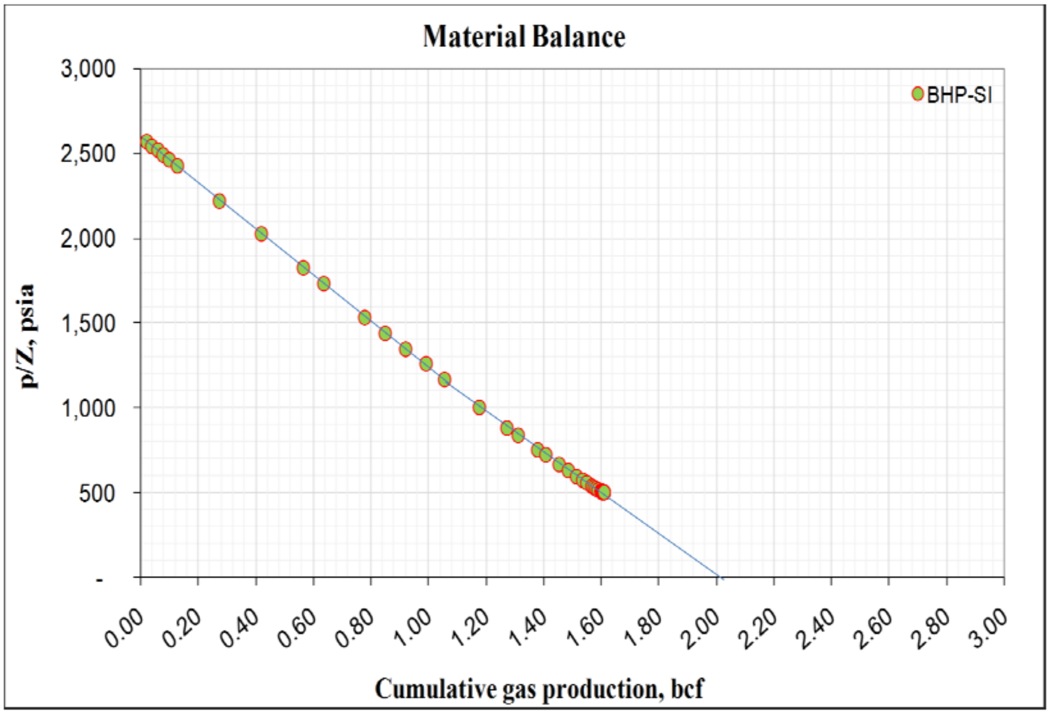
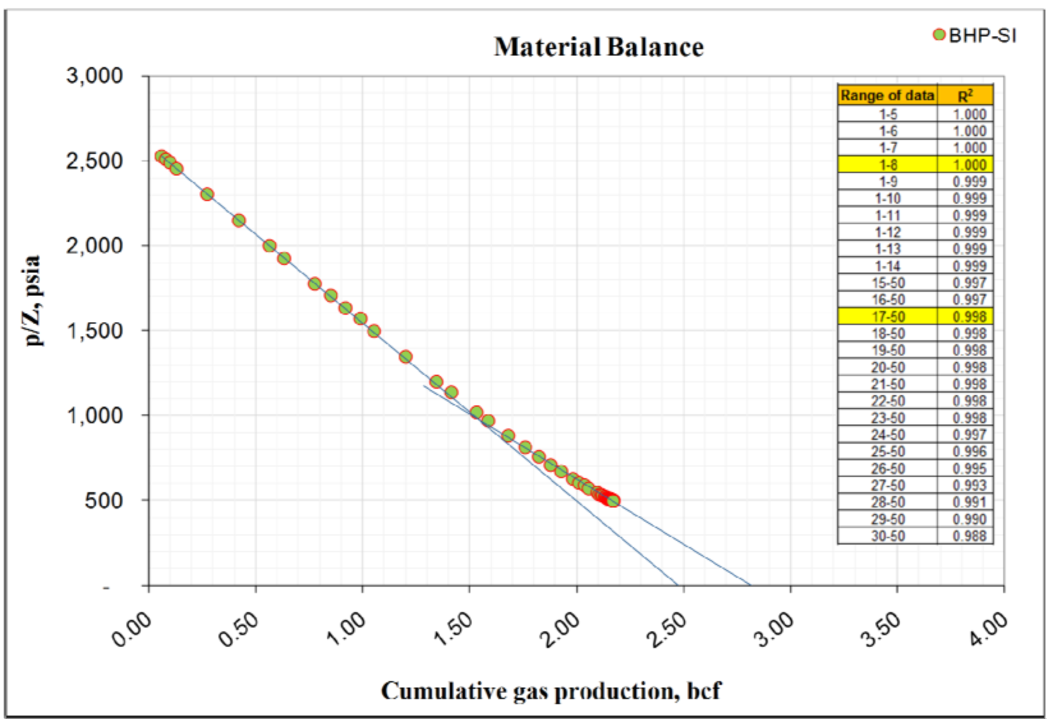


Figure 5.13 : *p/Z* versus cumulative production – Case3: Layer area of 55 and 120 acre.



Range of data	R^2
1-5	1.000
1-6	1.000
1-7	1.000
1-8	1.000
1-9	0.999
1-10	0.999
1-11	0.999
1-12	0.999
1-13	0.999
1-14	0.999
15-50	0.997
16-50	0.997
17-50	0.998
18-50	0.998
19-50	0.998
20-50	0.998
21-50	0.998
22-50	0.998
23-50	0.998
24-50	0.997
25-50	0.996
26-50	0.995
27-50	0.993
28-50	0.991
29-50	0.990
30-50	0.988

Figure 5.14 : *p/Z* versus cumulative production – Case4: Layer area of 55 and 180 acre.

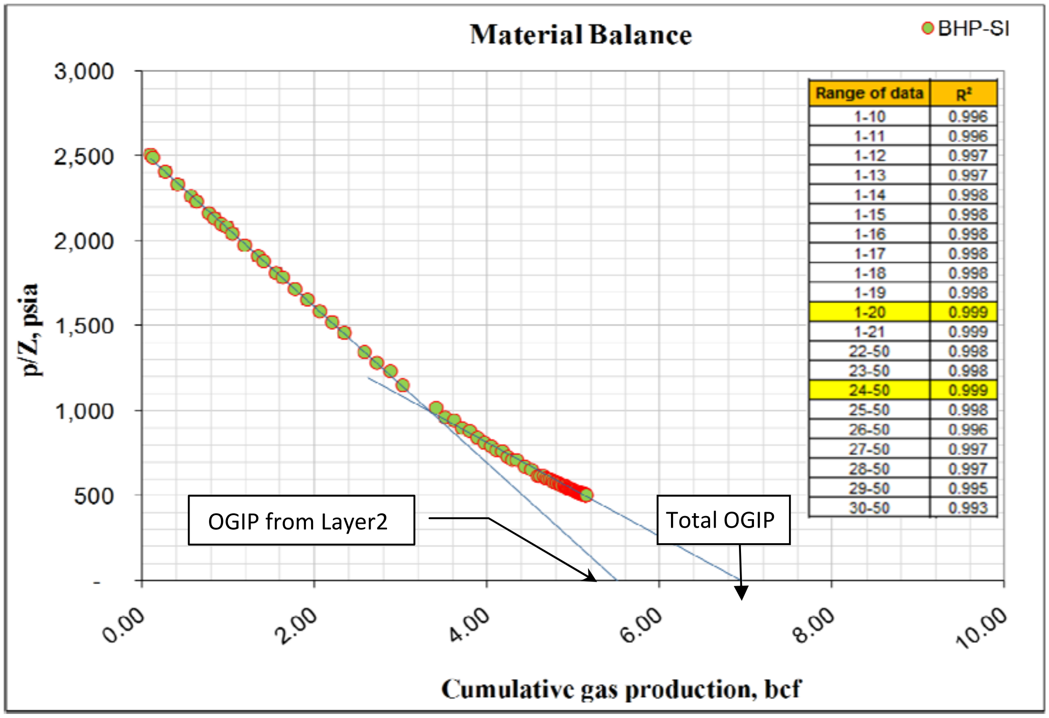


Figure 5.15 : *p/Z* versus cumulative production – Case5: Layer area of 55 and 500 acre.

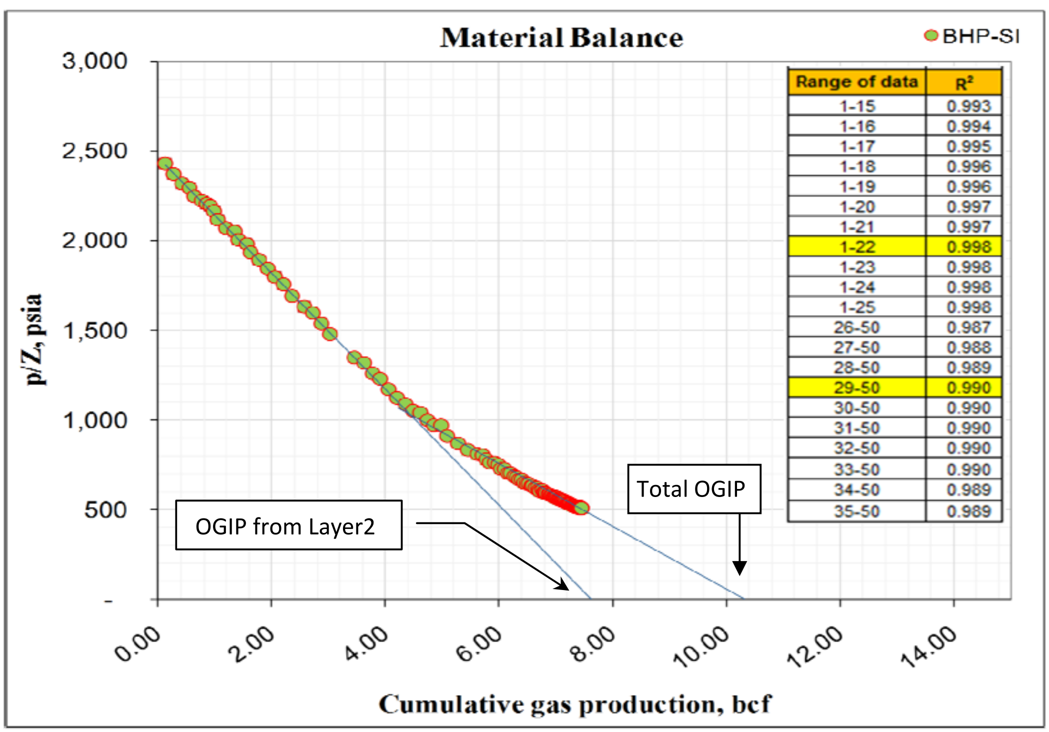


Figure 5.16 : *p/Z* versus cumulative production – Case6: Layer area of 55 and 750 acre.

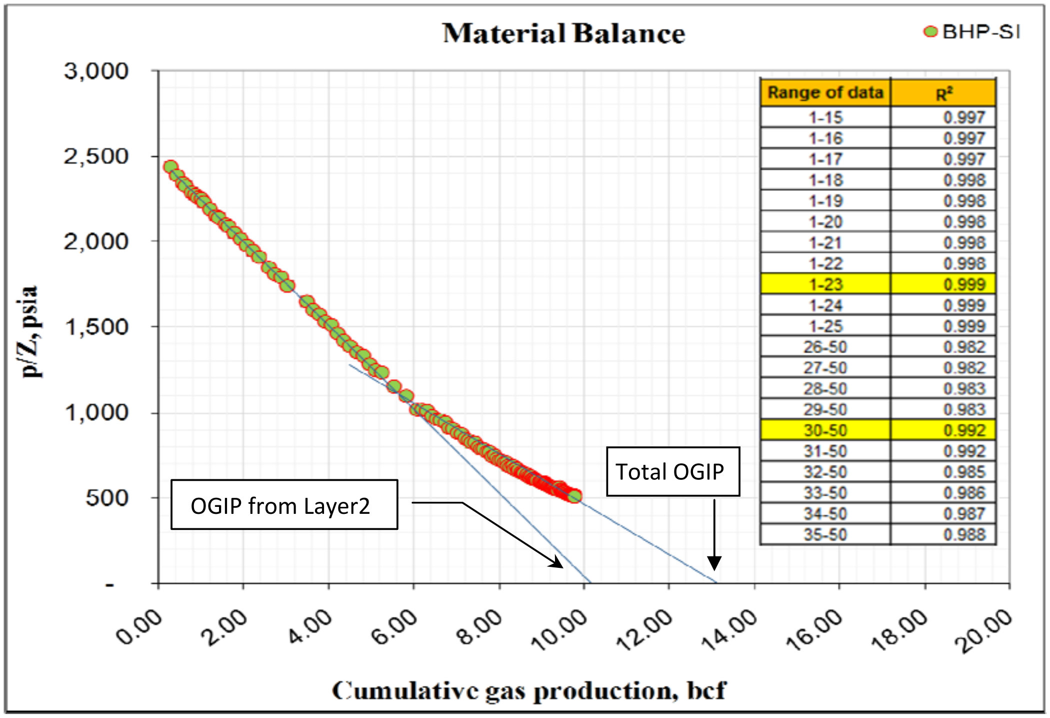


Figure 5.17 : *p/Z* versus cumulative production – Case7: Layer area of 55 and 1000 acre.

Results on Figures 5.14 to 5.17 illustrate that there are two different straight lines on *p/Z* plot while there is only a single straight line in Figures 5.11 to 5.13. The angle between the two lines is wider when the contrast of areas between the two layers is larger. We can detect two different straight lines when the contrast of area between two layers is approximately six or larger. OGIP obtained from the first trend corresponds to OGIP of the reservoir with a larger area which delivers more gas to the wellbore while OGIP of the second trend represents OGIP of entire system. For cases in which only one straight line is observed, only total OGIP can be estimated.

To obtain two different straight lines on *p/Z* plot as shown in Figure 5.14 to 5.17, different ranges of data set were used to evaluate the coefficient of determination (R-square) in order to find two best fitted straight lines. To establish a linear trend of the first straight line, one new data point is added to a group of data points starting from the first point, one at a time to determine R^2. The range of data set that gives R-square closer to 1 is chosen to represent the first curve part on the *p/Z* plot. To establish a linear trend of the second straight line, one new data point is added to a group of data points starting from the last point, one at a time to determine R^2. The range of data set that gives the best R-square is chosen to represent the second straight line. It should be noted that the ranges of data set contain more than 15 points of data.

Table 5.5 : Original gas in place for different contrasts between reservoir areas

Tank	Area (Acre)	Contrast	Actual OGIP	*P/Z* OGIP	% Error
Case1:			**1.427**	**1.416**	**-0.79**
Layer1	55	1.3			
Layer2	70				
Case2:			**1.662**	**1.672**	**0.58**
Layer1	55	1.6			
Layer2	90				
Case3:			**2.009**	**2.027**	**0.91**
Layer1	55	2.2			
Layer2	120				
Case4:			**2.707**	**2.822**	**4.28**
Layer1	55	3.3	0.613	0.345	-43.74
Layer2	180		2.093	2.478	18.35
Case5:			**6.429**	**6.971**	**8.42**
Layer1	55	9.1	0.613	1.450	136.56
Layer2	500		5.816	5.521	-5.08
Case6:			**9.337**	**10.374**	**11.11**
Layer1	55	13.6	0.613	2.730	345.22
Layer2	750		8.723	7.644	-12.37
Case7:			**12.245**	**13.218**	**7.94**
Layer1	55	18.2	0.613	3.033	394.75
Layer2	1000		11.632	10.184	-12.44

Table 5.5 show the estimates of OGIP for different contrasts in areas of two layers, and Table 5.6 summarizes the appearance of two straight lines on *p/Z* plot for various area contrasts. Note that OGIP for each individual layer cannot be estimated in cases with low area contrasts (cases 1, 2, and 3) because only a single straight line can be seen on the *p/Z* plot. For cases with high area contrasts (cases 4, 5, 6, and 7), there are two straight lines on the *p/Z* plot. Thus, OGIP corresponding to each straight

line is determined. The OGIP estimated from the first straight line corresponds to the layer that has a larger OGIP which is the bottom layer. The OGIP estimated from the second straight line is for the system. From Table 5.5, the maximum error for OGIP estimate for the larger reservoir (bottom layer) is 18.35%. However, OGIP estimate for the upper layer which has less area generally contains a large amount of error. This is because the layer with less area contributes less to total production and its original OGIP is much smaller. For the system, the error in total OGIP estimate becomes more significant when there is higher contrast in area between layers (higher than 3.3). However, the maximum error is 11.11%.

Table 5.6 : Appearance of two straight lines on *p/Z* plot for various area contrasts

Area contrast	**Appearance of two straight lines**
1.3	None
1.6	None
2.2	None
3.3	Yes
9.1	Yes
13.6	Yes
18.2	Yes

5.3 Influence of porosity contrast on OGIP estimate

In this section, six cases of porosity contrast as tabulated in Table 5.7 were used to study the impact of porosity on OGIP estimate.

Table 5.7 : Contrast between reservoir porosity

	Porosity (ϕ)	**Porosity Contrast**
Case1:		
Layer1	20	1.1
Layer2	22	
Case2:		
Layer1	20	1.3
Layer2	25	
Case3:		
Layer1	20	1.5
Layer2	30	
Case4:		
Layer1	20	1.8
Layer2	36	
Case5:		
Layer1	10	2.5
Layer2	25	
Case6:		
Layer1	10	3.0
Layer2	30	

The well gas rate versus time for different porosity contrasts are demonstrated in Figure 5.18. We can observe that the cases where the upper zone has low porosity (cases 5 and 6), the well can maintain shorter plateau but depletes slowly afterward because gas from the upper tight reservoir gradually comes out after the pressure of the lower layer is depleted. For cases 1, 2, 3, and 4, the well can maintain a longer plateau when porosity of the lower layer is higher.

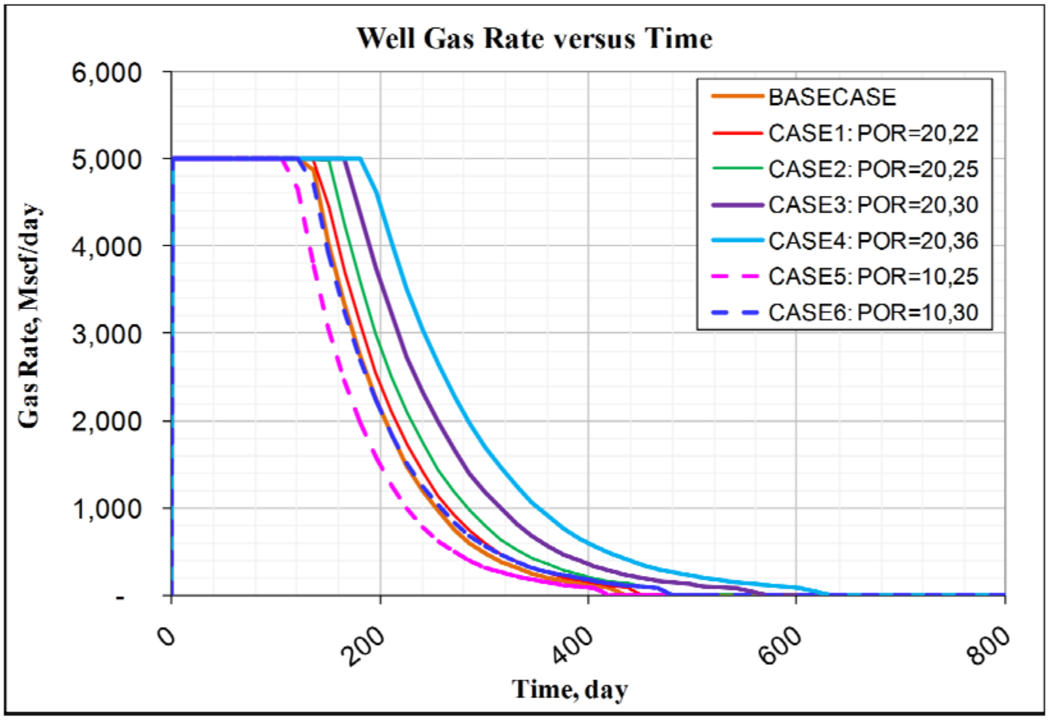


Figure 5.18 : Well gas rate versus time – effect of porosity on OGIP

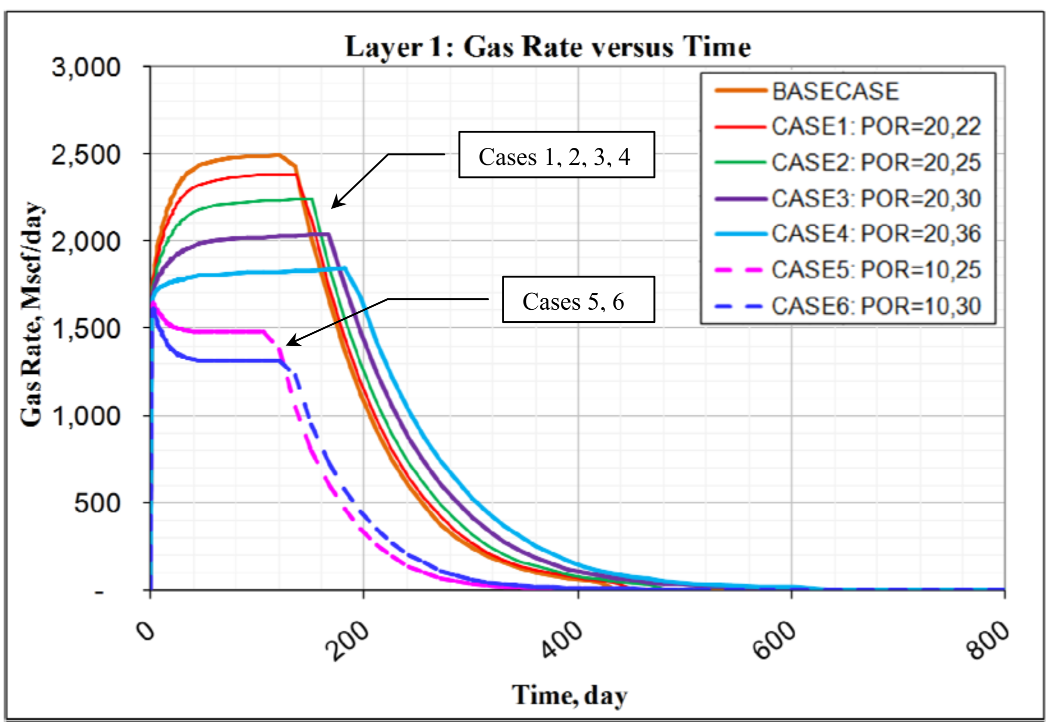


Figure 5.19 : Gas rate versus time for the upper layer – effect of porosity on OGIP

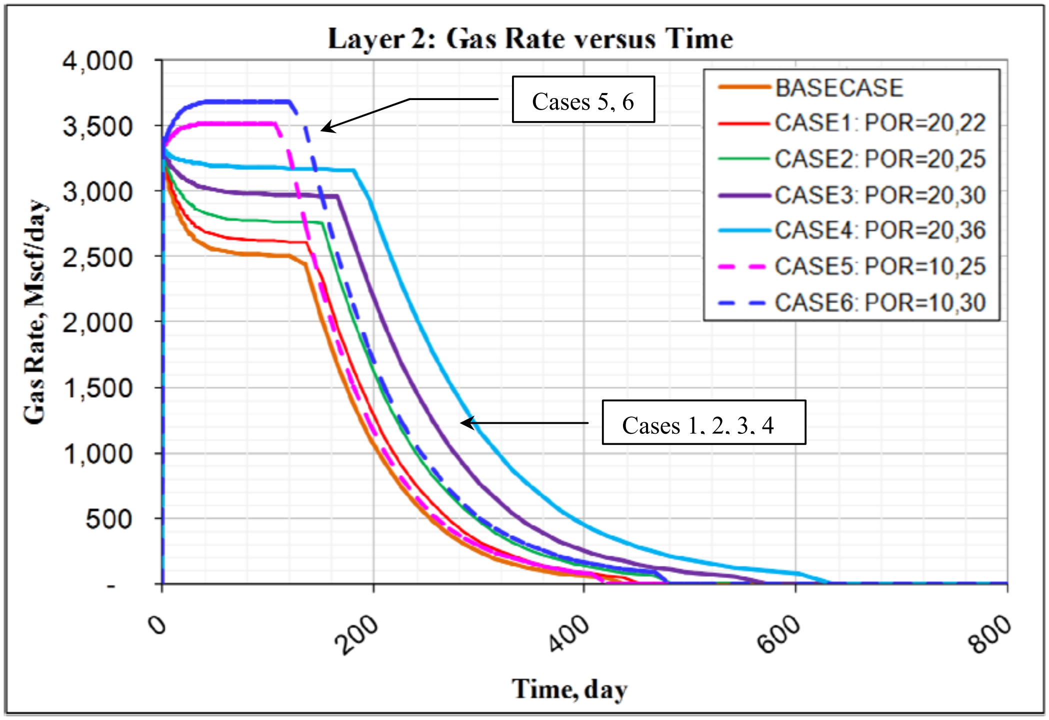


Figure 5.20 : Gas rate versus time for the lower layer – effect of porosity on OGIP

Figures 5.19 to 5.20 illustrate that in the early stage of the well life, the gas rate from the lower layer which has higher porosity is initially higher than that from the upper layer. Then, the gas rate from the lower layer for cases 1, 2, 3, and 4 slightly goes down while gas rate from the upper layer slightly increases until both layers produces at some constant rates. This continues for a while until gas production from both layers decline due to depletion.

In cases 5 and 6, gas rate from the lower layer initially increases while gas rate from the upper layer drops until flow rates from both layer reach plateau values. This happens because the lower layer has much higher permeability than the upper layer. Therefore, it contributes more towards the total production rate. Later on, the flow rates for both layers decline due to depletion.

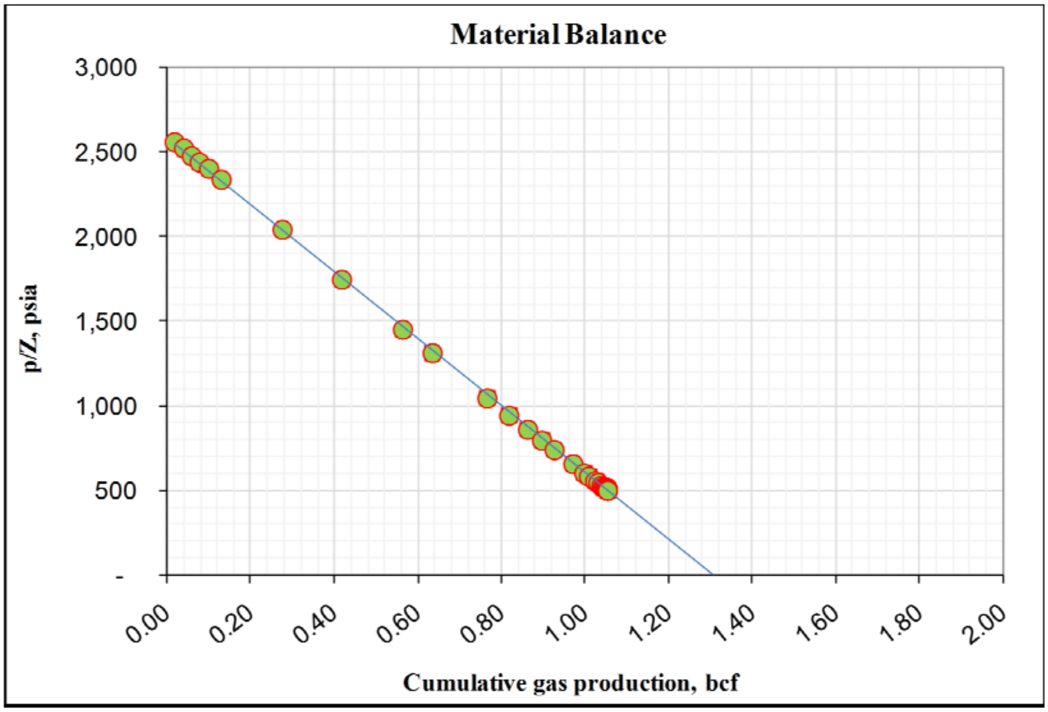


Figure 5.21 : *p/Z* versus cumulative production – Case1: Layer porosity of 20 and 22.

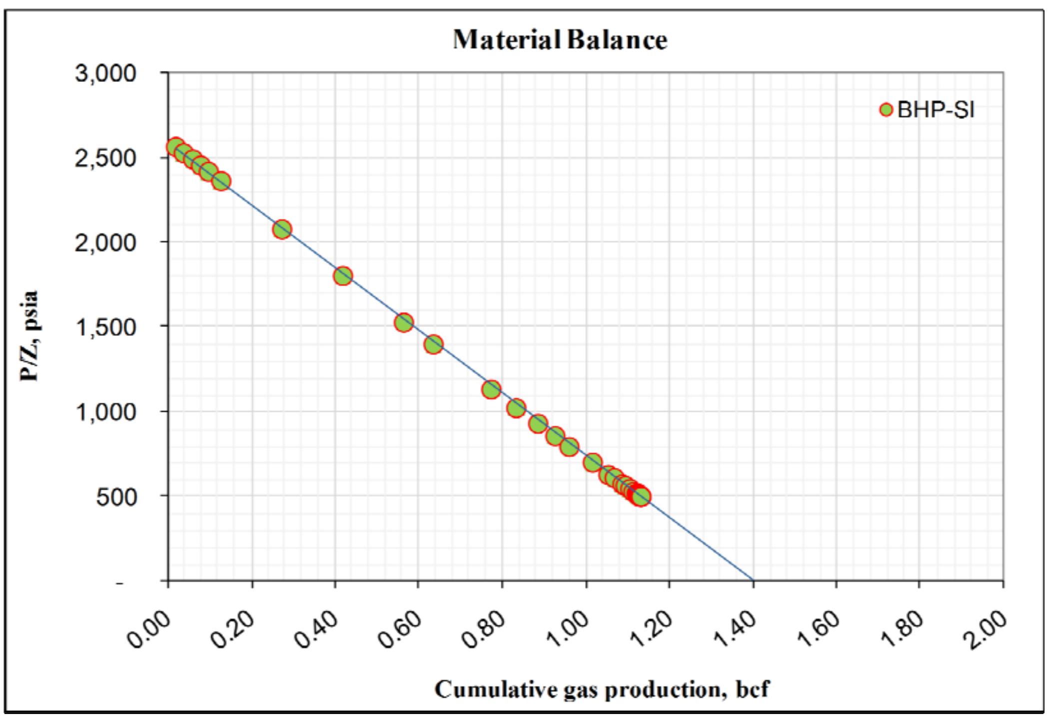


Figure 5.22 : *p/Z* versus cumulative production – Case2: Layer porosity of 20 and 25.

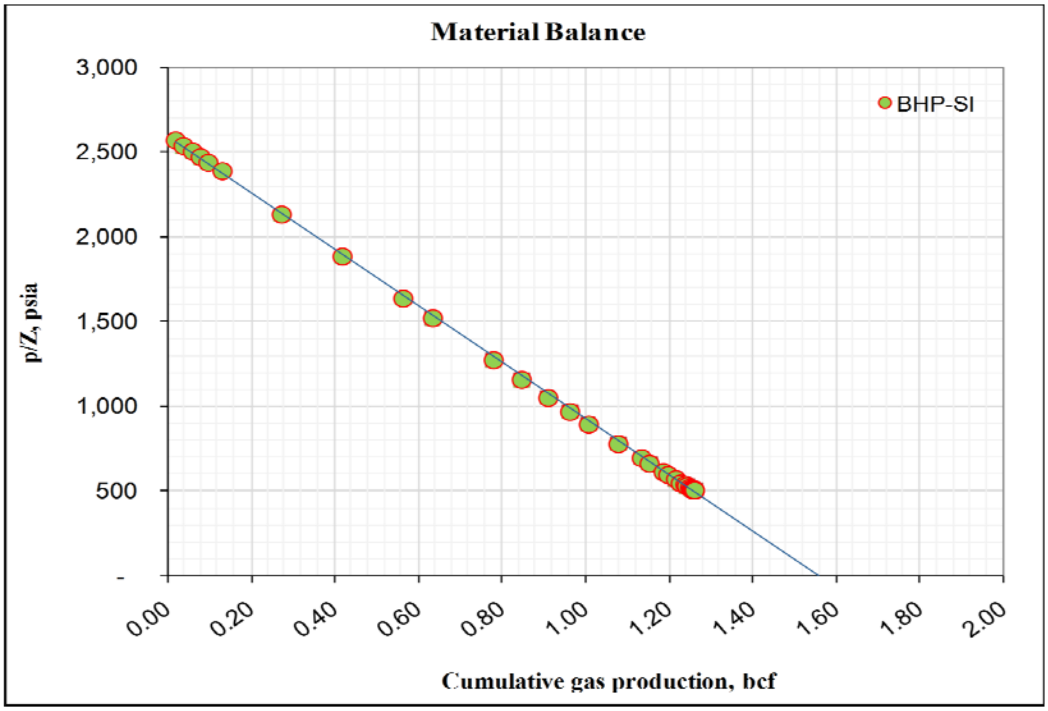


Figure 5.23 : *p/Z* versus cumulative production – Case3: Layer porosity of 20 and 30.

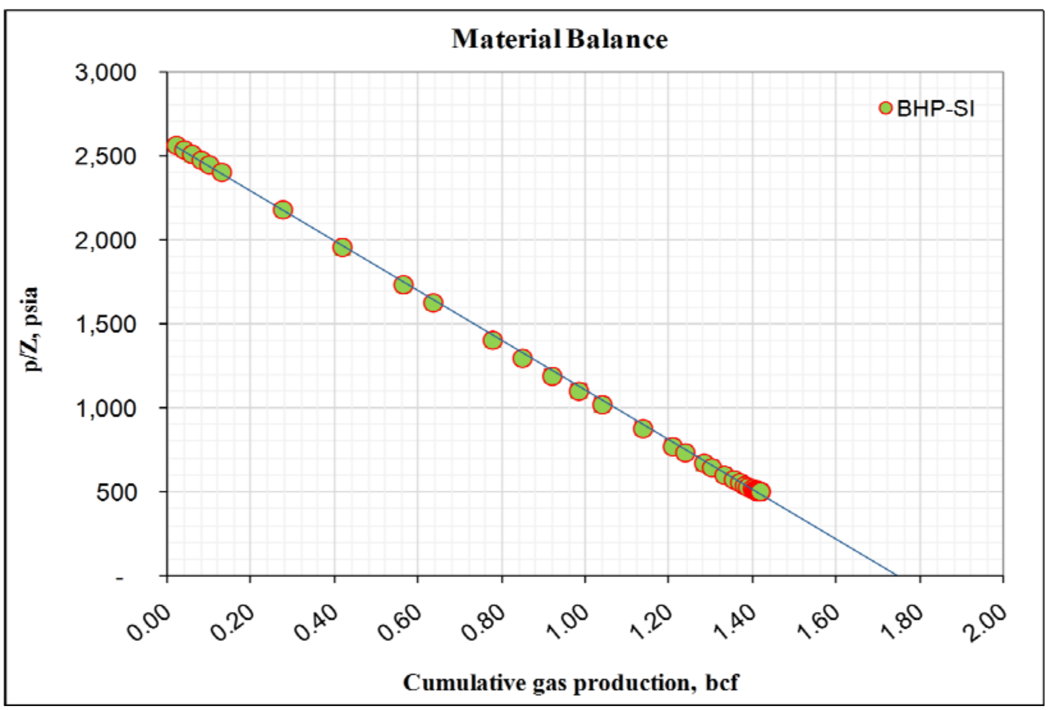


Figure 5.24 : *p/Z* versus cumulative production – Case4: Layer porosity of 20 and 36.

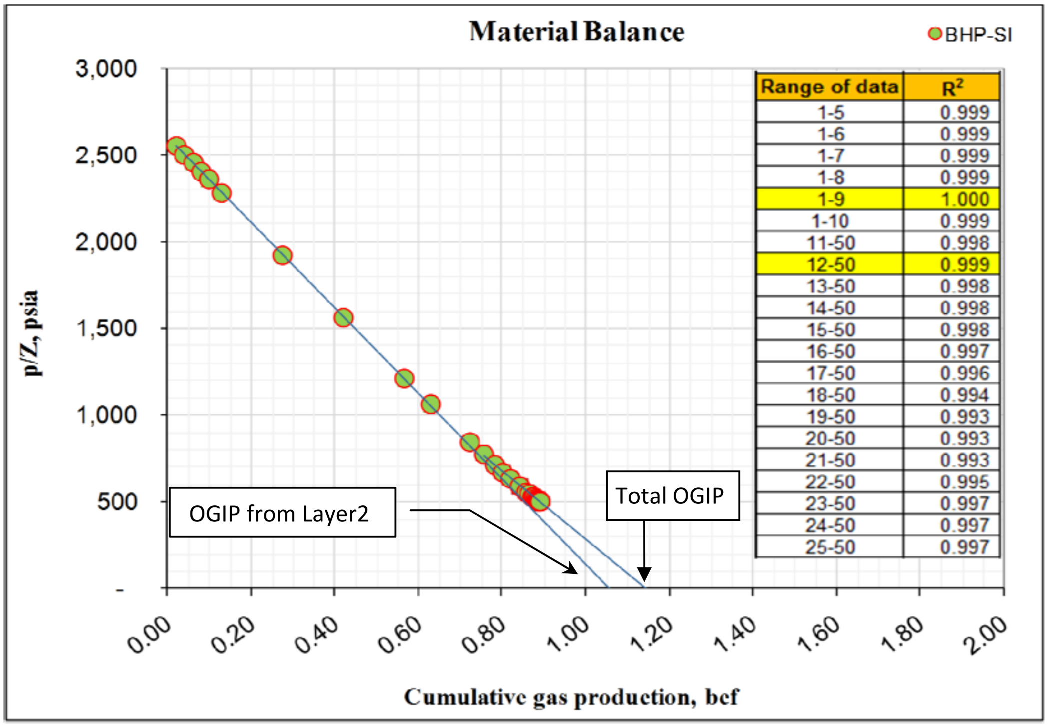


Figure 5.25 : *p/Z* versus cumulative production – Case5: Layer porosity of 10 and 25.

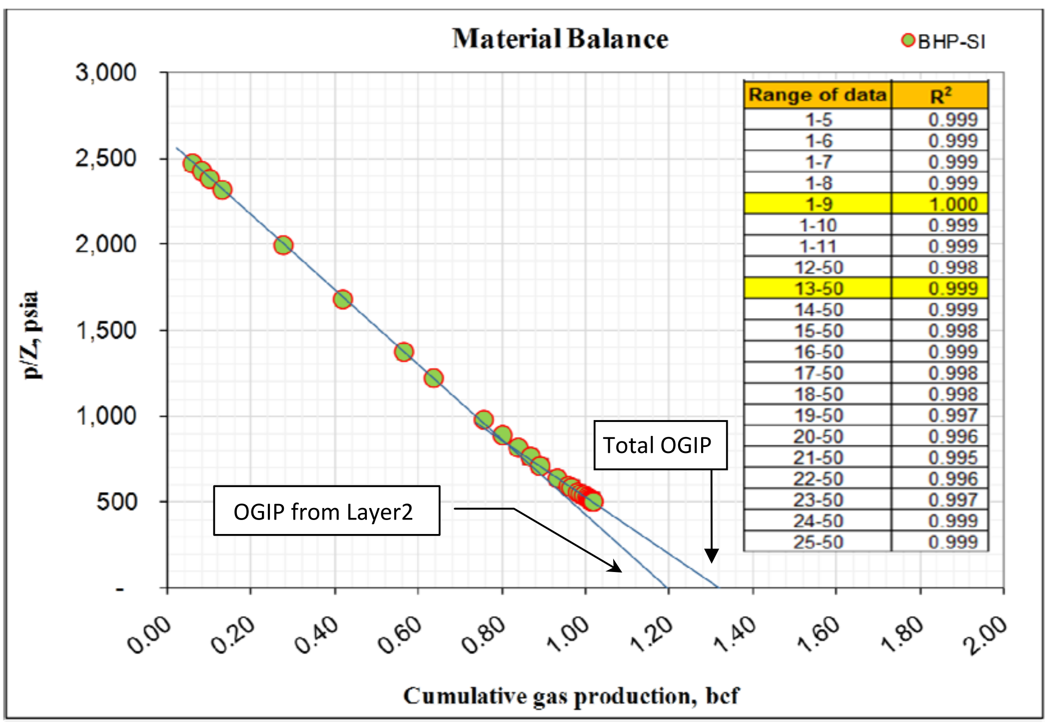


Figure 5.26 : *p/Z* versus cumulative production – Case6: Layer porosity of 10 and 30.

The contrast between the tight reservoir porosity of the upper layer with the porosity of the lower layer displays two straight lines of *p/Z* plot as shown in Figures 5.25 and 5.26 while there is only a single straight line in the other cases as shown in Figures 5.21 to 5.24. We can detect two different straight lines when the contrast of porosity between two layers is approximately 2.5 or larger.

Table 5.8 : Original gas in place for different contrasts between reservoir porosity

	Porosity (ϕ)	**Permeability (mD)**	**Porosity Contrast**	**Actual OGIP**	***P/Z* OGIP**	**% Error**
Case1:				**1.319**	**1.308**	**-0.87**
Layer1	20	50	1.1			
Layer2	22	50				
Case2:				**1.415**	**1.404**	**-0.79**
Layer1	20	50	1.3			
Layer2	25	50				
Case3:				**1.576**	**1.564**	**-0.77**
Layer1	20	50	1.5			
Layer2	30	50				
Case4:				**1.768**	**1.757**	**-0.66**
Layer1	20	50	1.8			
Layer2	36	50				
Case5:				**1.109**	**1.147**	**3.41**
Layer1	10	50	2.5	0.307	0.092	-70.12
Layer2	25	50		0.802	1.055	31.51
Case6:				**1.269**	**1.320**	**4.02**
Layer1	10	50	3.0	0.307	0.128	-58.35
Layer2	30	50		0.963	1.193	23.88

For all cases of porosity contrast, the OGIP estimate for the entire system has small errors. For the cases of tight upper sand (Cases 5 and 6), two values of OGIP can be estimated from the two straight lines on *p/Z* plot. However, there is a large amount of error for OGIP estimate for each individual layer.

Table 5.9 : Appearance of two straight lines on *p/Z* plot for various porosity contrasts

Porosity contrast	Appearance of two straight lines
1.1	No
1.3	No
1.5	No
1.8	No
2.5	Yes
3.0	Yes

5.4 Influence of porosity and permeability contrast on OGIP estimate

By varying porosity, the magnitude of permeability varies correspondingly based on the permeability - porosity correlation. Six cases of porosity contrast as tabulated in Table 5.10 were used to study the impact of porosity on OGIP estimate. Other reservoir properties and operating conditions were kept the same as in previous cases.

Table 5.10 : Contrast between reservoir porosity and corresponding permeability

	Porosity (ϕ)	Permeability (mD)	Porosity x Permeability Contrast
Case1:			
Layer1	20	50	2.0
Layer2	22	91	
Case2:			
Layer1	20	50	6.7
Layer2	25	270	
Case3:			
Layer1	20	50	49.6
Layer2	30	1653	
Case4:			
Layer1	20	50	523.3
Layer2	36	14536	
Case5:			
Layer1	10	10	67.5
Layer2	25	280	
Case6:			
Layer1	10	10	495.8
Layer2	30	1653	

The well gas rate versus time for different porosity contrasts are presented in Figure 5.27. We can observe that when porosity and permeability of the lower layer is higher, the well can maintain a longer plateau but depletes rapidly afterward due to the fact that gas from reservoir with high porosity and permeability can move easier, causing the reservoir pressure to drop faster.

On the other hand, when the upper zone is a tight gas reservoir (cases 5 and 6), the well produces gas with a shorter plateau because of smaller porosity and permeability.

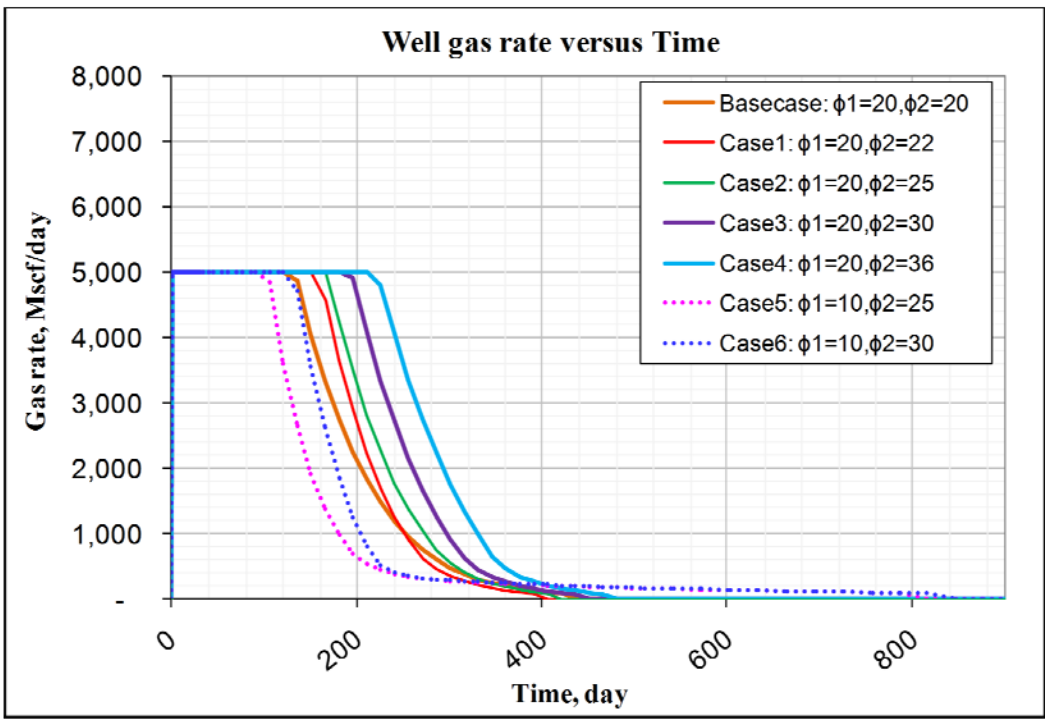


Figure 5.27 : Well gas rate versus time – effect of porosity and permeability on OGIP

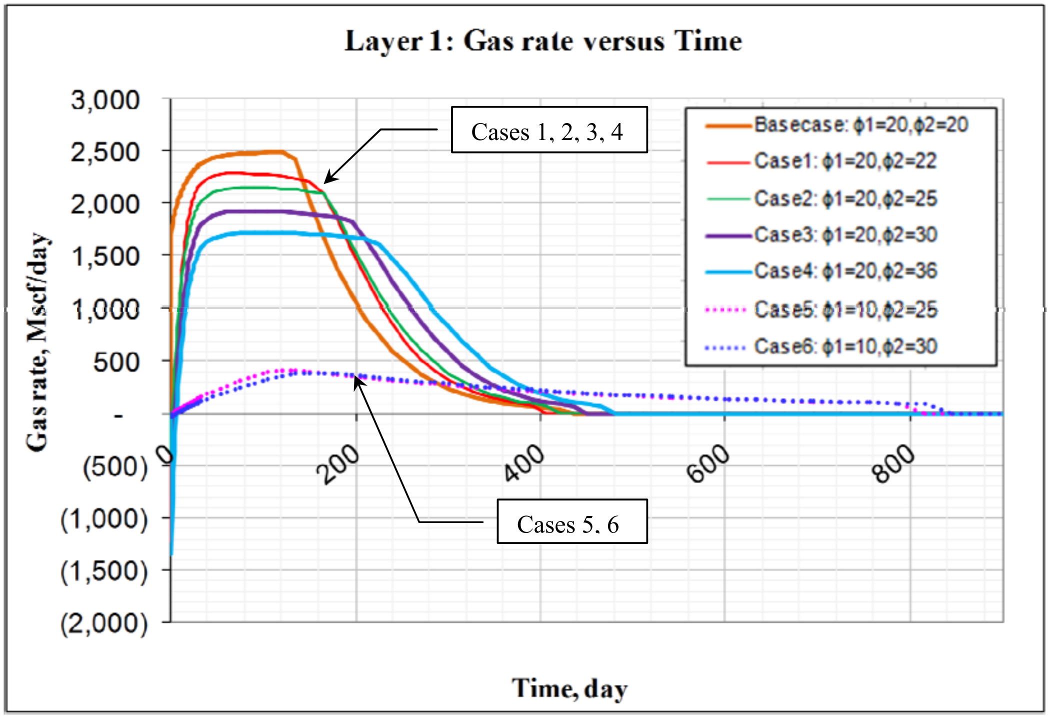


Figure 5.28 : Gas rate versus time for the upper layer – effect of porosity and permeability on OGIP

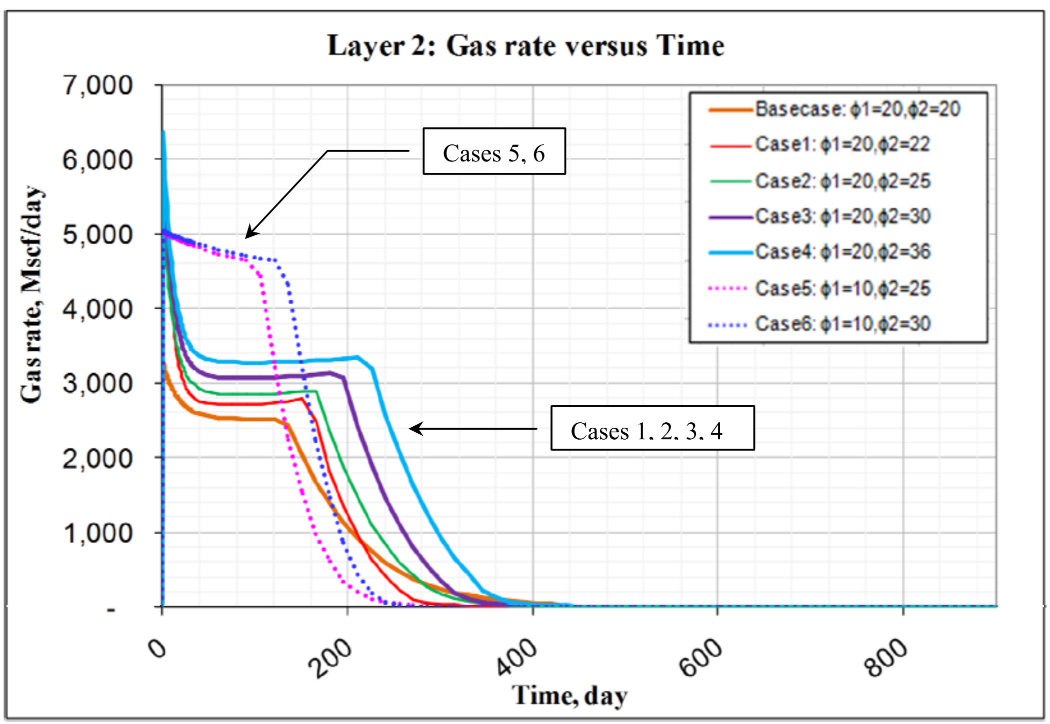
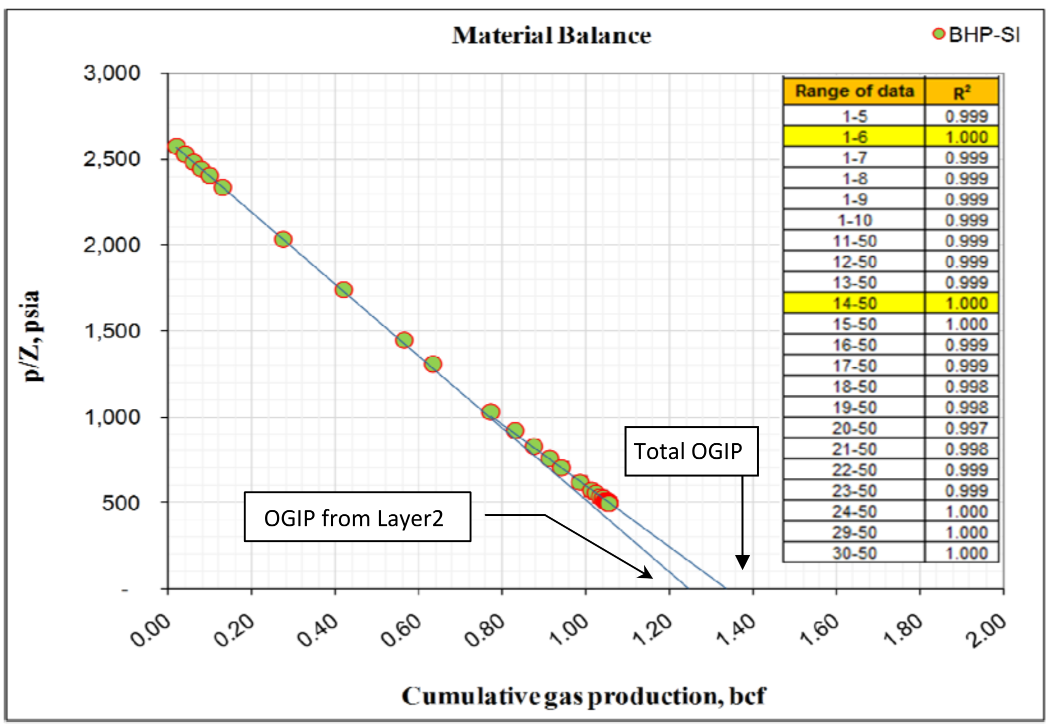


Figure 5.29 : Gas rate versus time for the lower layer – effect of porosity and permeability on OGIP

Figures 5.28 to 5.29 illustrate that in the early stage of the well life, gas from the lower layer which has higher porosity and permeability crossflows into the upper layer which has lower porosity and permeability layer, causing the pressure of the lower layer to drop sharply. Then, the gas rate from the lower layer falls. After that, the upper layer starts to contribute more until both layers produces at some constant rates. In cases where the lower layer has higher porosity and permeability, the lower layer has higher plateau rate than the upper one.

For the tight gas reservoir in case 5 and 6, gas rate from the upper layer which is tight is very small. In these cases, the lower layer is the main contributor to gas production until some late time when the lower layer is depleted. After that, production comes from the upper layer.



Range of data	R^2
1-5	0.999
1-6	1.000
1-7	0.999
1-8	0.999
1-9	0.999
1-10	0.999
11-50	0.999
12-50	0.999
13-50	0.999
14-50	1.000
15-50	1.000
16-50	0.999
17-50	0.999
18-50	0.998
19-50	0.998
20-50	0.997
21-50	0.998
22-50	0.999
23-50	0.999
24-50	1.000
29-50	1.000
30-50	1.000

Figure 5.30 : *p/Z* versus cumulative production – Case1: Layer porosity of 20 and 22, and Layer permeability of 50 and 91.

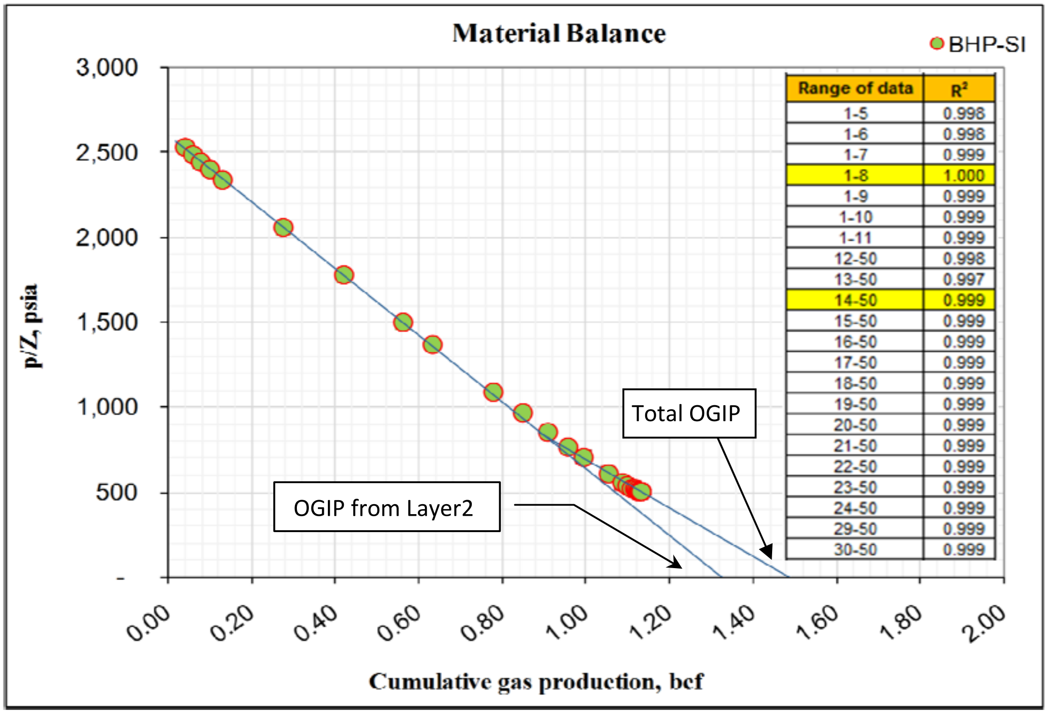


Figure 5.31 : *p/Z* versus cumulative production – Case2: Layer porosity of 20 and 25 and Layer permeability of 50 and 270.

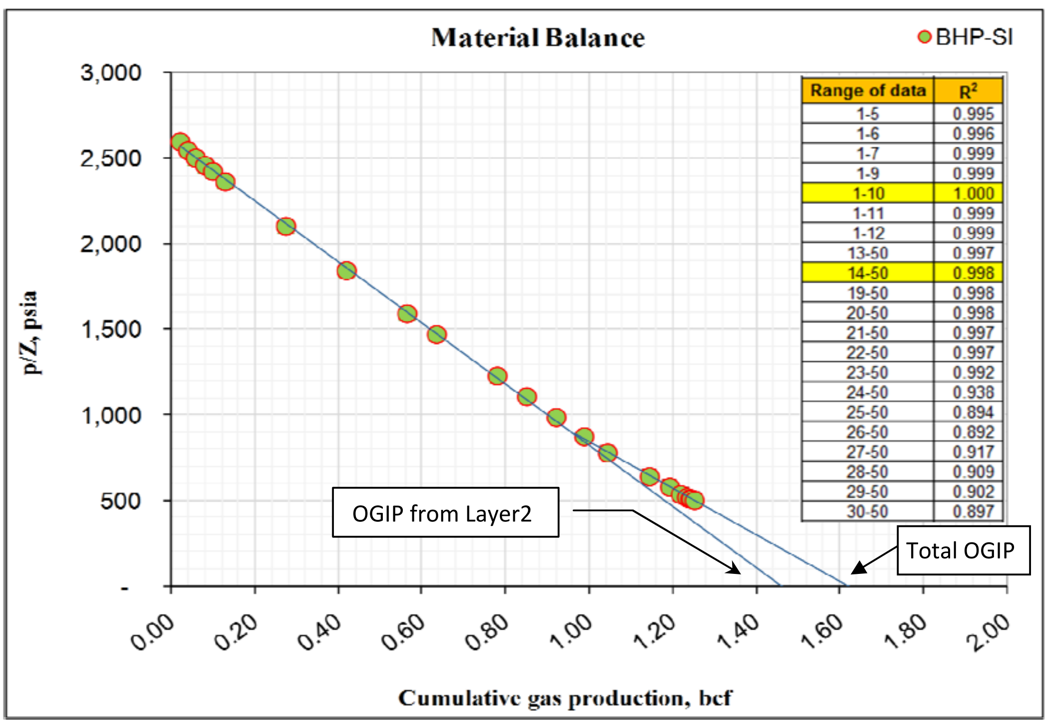


Figure 5.32 : *p/Z* versus cumulative production – Case3: Layer porosity of 20 and 30 and Layer permeability of 50 and 1653.

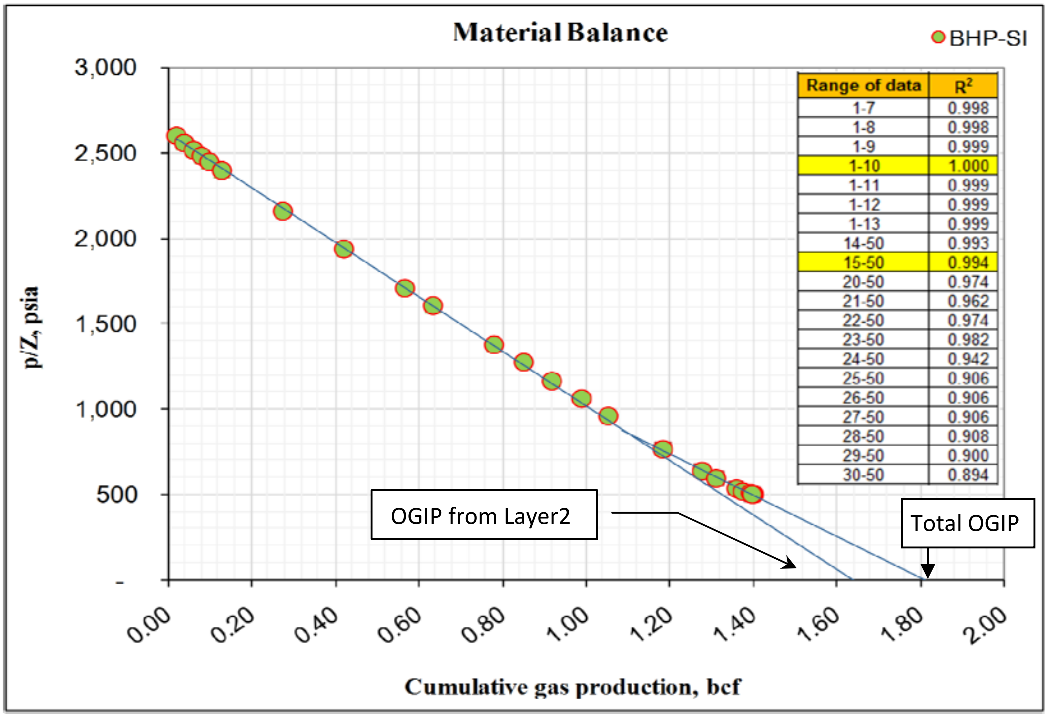


Figure 5.33 : *p/Z* versus cumulative production – Case4: Layer porosity of 20 and 36 and Layer permeability of 50 and 14536.

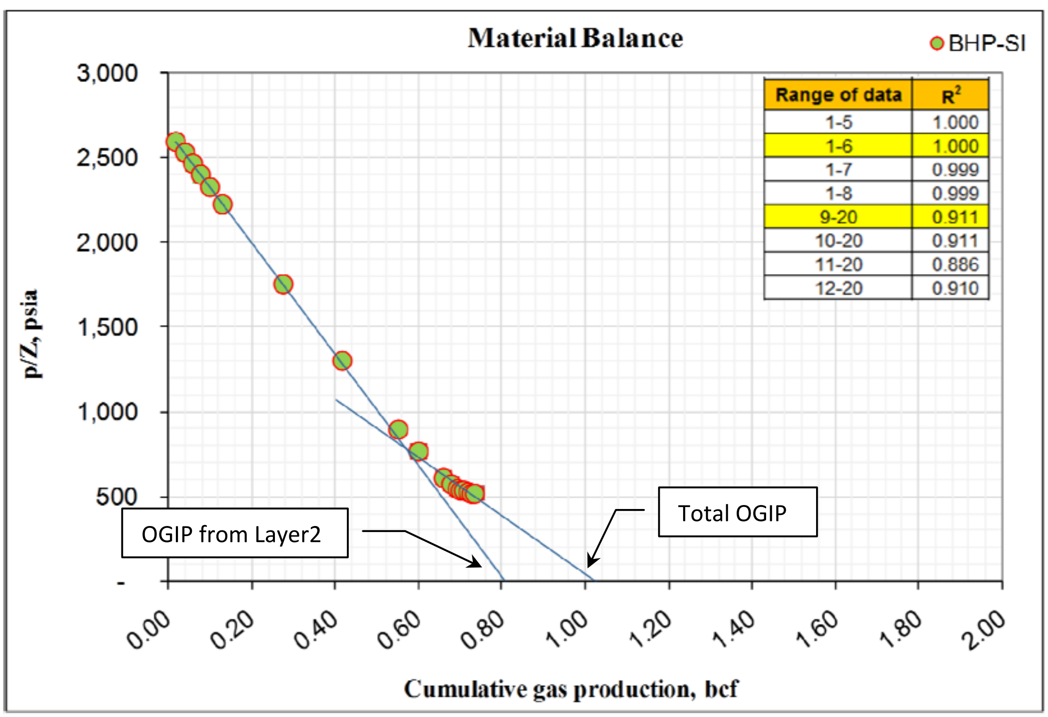


Figure 5.34 : *p/Z* versus cumulative production – Case5: Layer porosity of 10 and 25 and Layer permeability of 10 and 280.

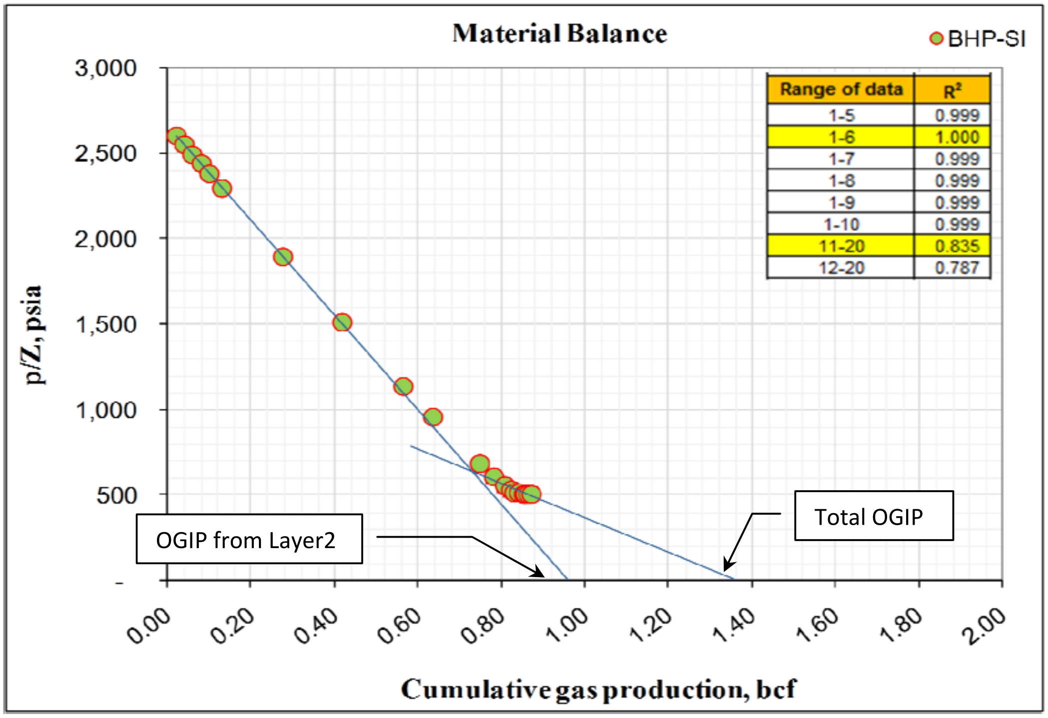


Figure 5.35 : *p/Z* versus cumulative production – Case6: Layer porosity of 10 and 30 and Layer permeability of 10 and 1653.

The contrast of reservoir porosity and corresponding permeability clearly demonstrates two straight lines of *p/Z* plot as shown in Figures 5.30 to 5.35. The difference between the two straight lines becomes larger when there is a larger contrast between reservoir porosity and corresponding permeability as shown in Tables 5.11 and 5.12.

Table 5.11 : Original gas in place for different contrasts between reservoir porosity and corresponding permeability

	Porosity (ϕ)	Permeability (mD)	Porosity & permeability contrast	Actual OGIP	*P/Z* OGIP	% Error
Case1:				**1.319**	**1.318**	**-0.12**
Layer1	20	50	2.0	0.613	0.130	-78.77
Layer2	22	91		0.706	1.187	68.18
Case2:				**1.415**	**1.433**	**1.21**
Layer1	20	50	6.7	0.613	0.106	-82.67
Layer2	25	270		0.802	1.326	65.31
Case3:				**1.576**	**1.650**	**4.67**
Layer1	20	50	49.6	0.613	0.199	-67.53
Layer2	30	1653		0.963	1.450	50.64
Case4:				**1.768**	**1.885**	**6.60**
Layer1	20	50	523.3	0.613	0.257	-58.05
Layer2	36	14536		1.155	1.628	40.91
Case5:				**1.109**	**1.159**	**4.48**
Layer1	10	10	67.5	0.307	0.350	14.12
Layer2	25	280		0.802	0.809	0.80
Case6:				**1.269**	**1.362**	**7.28**
Layer1	10	10	495.8	0.307	0.403	31.33
Layer2	30	1653		0.963	0.959	-0.37

Table 5.12 : Appearance of two straight lines on *p/Z* plot for various porosity contrasts

Porosity contrast	Appearance of two straight lines
1.1	Yes
1.3	Yes
1.5	Yes
1.8	Yes
2.5	Yes
3.0	Yes

For all cases of porosity contrast with corresponding variation in permeability, two straight lines on *p/Z* plot can be observed. The OGIP estimate for the lower layer which has higher porosity is more accurate when there is a larger contrast between reservoir porosity (Cases 5 and 6). This is because the layer with high porosity and corresponding permeability drains out faster with more contribution to total production and its original gas in place is much greater. For cases with low contrast in porosity (cases 1, 2, 3, and 4), the OGIP estimate for each individual layer contains a large amount of error. In any case, the OGIP estimate for the entire system contains a small amount of error. The maximum one is 7.28%.

5.4 Influence of permeability on OGIP estimate

In this section, the effect of different permeabilities with the same porosity was brought into sight. Five cases of high permeability and three cases of low permeability as illustrated in Table 5.13 were used to demonstrate the impact of permeability on OGIP estimate.

Table 5.13 : Contrast between reservoir permeability

	Permeability (mD)	**Contrast**
Case1:		
Layer1	50	1.1
Layer2	57	
Case2:		
Layer1	50	1.3
Layer2	65	
Case3:		
Layer1	50	1.6
Layer2	80	
Case4:		
Layer1	50	2.0
Layer2	100	
Case5:		
Layer1	50	5.6
Layer2	278	
Case6:		
Layer1	14	2.7
Layer2	38	
Case7:		
Layer1	14	5.7
Layer2	80	
Case8:		
Layer1	14	19.9
Layer2	278	

The well gas rate versus time is presented in Figure 5.36 to demonstrate the effect of permeability on gas production profile. For high permeability cases (cases 1, 2, 3, 4, and 5), the increase in permeability of the lower layer yields a longer plateau period but more rapid decline in the production rate during the decline period. From cases 1 to 5, we can see that case 5 gives the longest plateau but depletes faster than any other cases that have high permeability. Oppositely, for low permeability cases (cases 6, 7, and 8), the plateau is quick short and the flow rate gradually declines over a longer period of time.

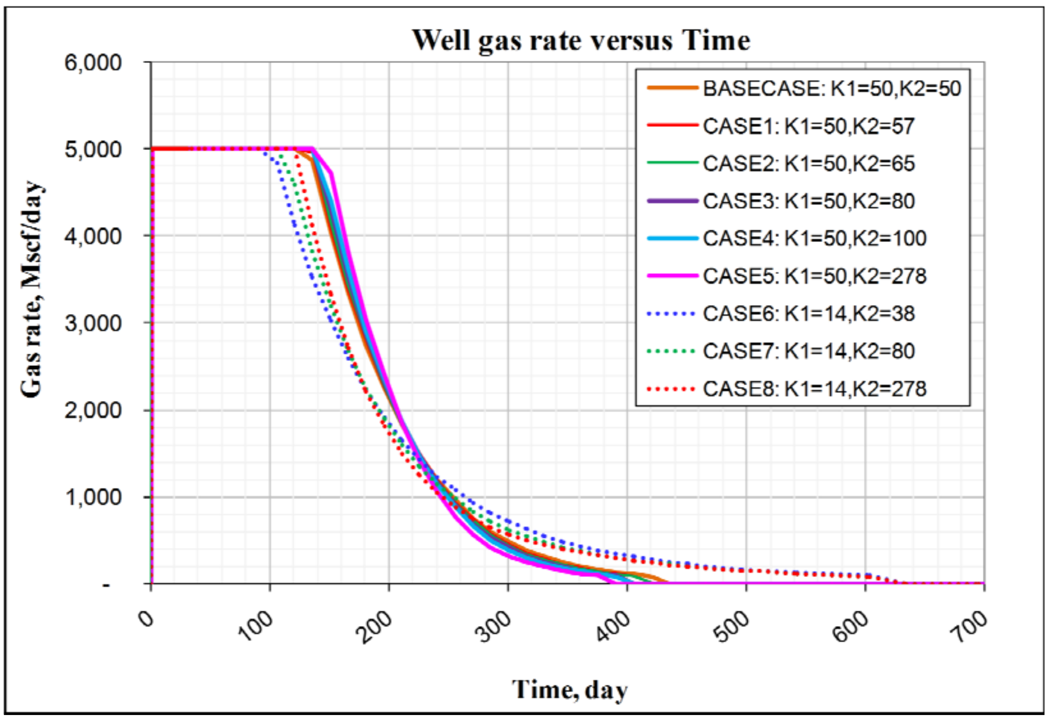


Figure 5.36 : Well gas rate versus time – effect of permeability on OGIP.

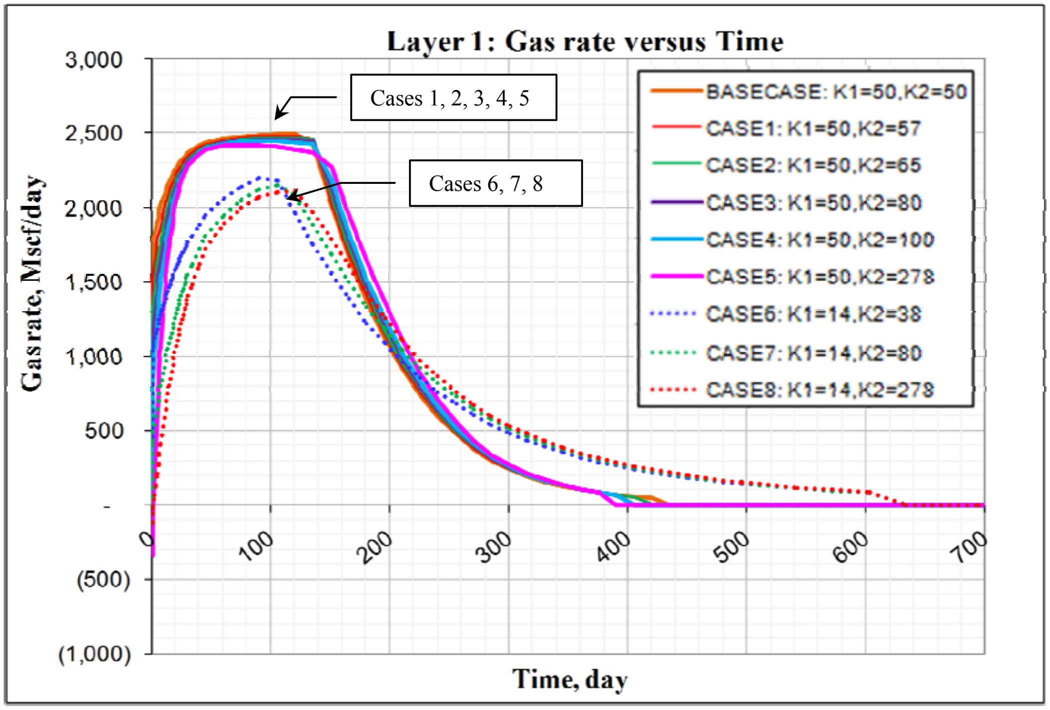


Figure 5.37 : Gas rate versus time for the upper layer – effect of permeability on OGIP.

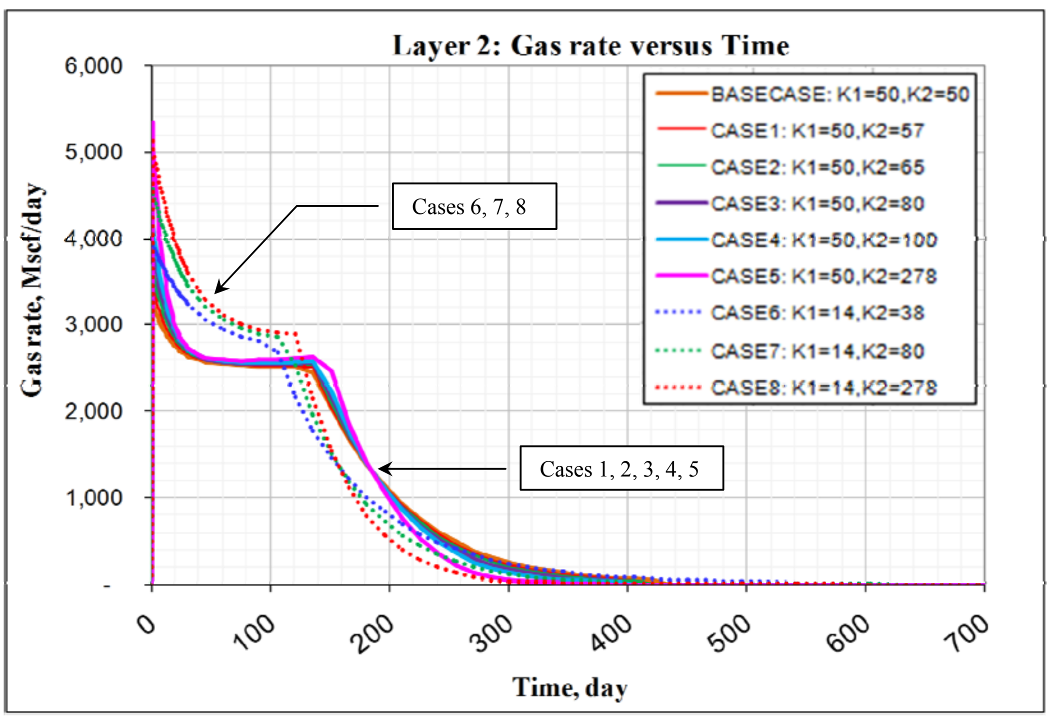


Figure 5.38 : Gas rate versus time for the lower layer – effect of permeability on OGIP.

Figures 5.37 to 5.38 illustrate gas rate versus time of the upper and lower layers. Crossflow occurs for cases with high permeability contrast (cases 5 and 8) for a short period of time (2 days). In these cases, the high permeability layer produces gas at a high rate initially for a couple of weeks. Then, the gas rate from the high-permeability layer becomes smaller and reaches more or less a plateau production while the gas rate from the upper layer gets larger and reaches plateau production as well. Afterward, the gas rates from the upper and lower layers both decline.

For cases where the upper layer has low permeability, gas rate from the lower layer decreases more slowly than those for cases where the upper layer has high permeability. Afterward, the gas rate from the upper layer is more or less stable at a value smaller than that from the lower layer. The plateau period in these cases does not last long. Later, both layers decline together with a longer decline period in the upper layer.

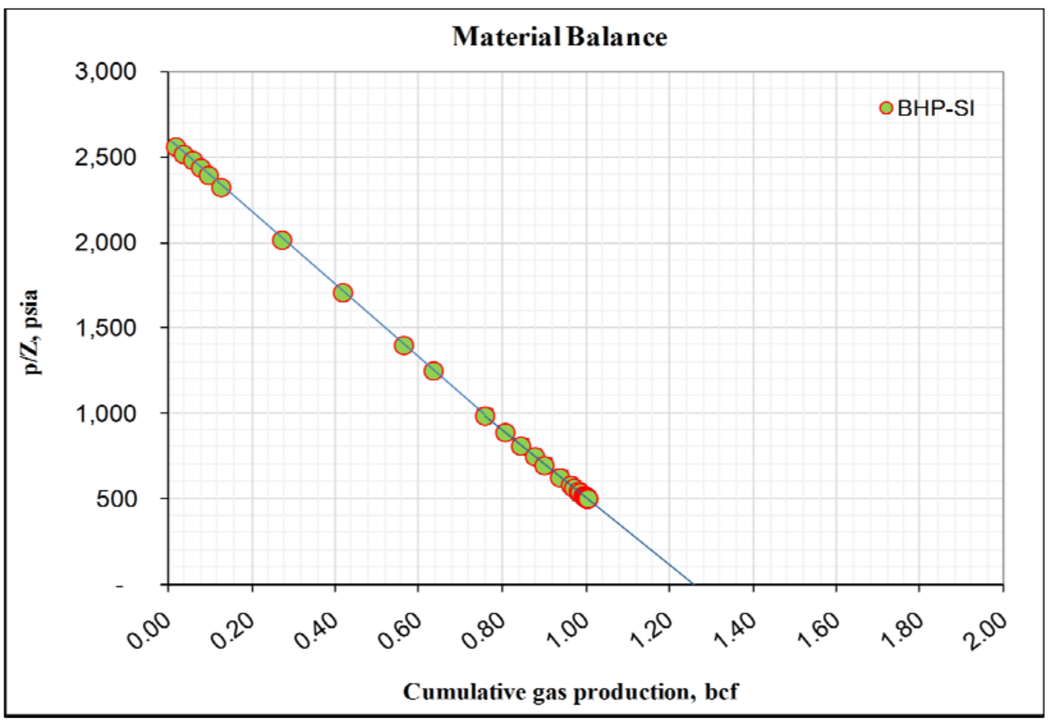


Figure 5.39 : *p/Z* versus cumulative production – Case1: Layer permeability of 50 and 57 mD.

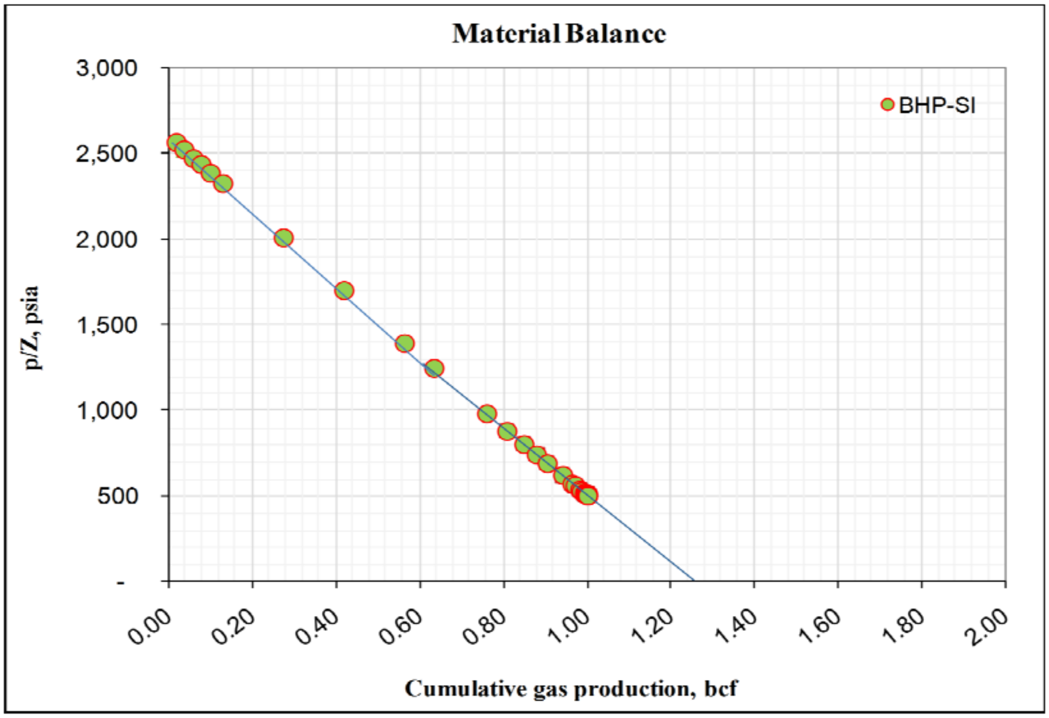
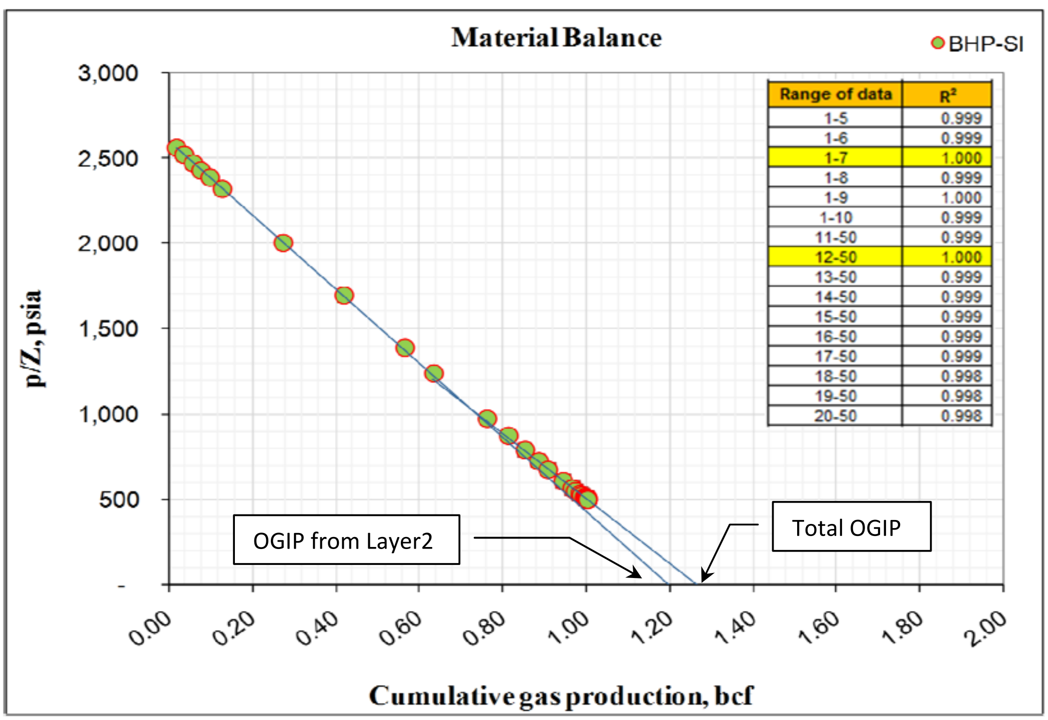


Figure 5.40 : *p/Z* versus cumulative production – Case2: Layer permeability of 50 and 65 mD.



Range of data	R^2
1-5	0.999
1-6	0.999
1-7	1.000
1-8	0.999
1-9	1.000
1-10	0.999
11-50	0.999
12-50	1.000
13-50	0.999
14-50	0.999
15-50	0.999
16-50	0.999
17-50	0.999
18-50	0.998
19-50	0.998
20-50	0.998

Figure 5.41 : *p/Z* versus cumulative production – Case3: Layer permeability of 50 and 80 mD.

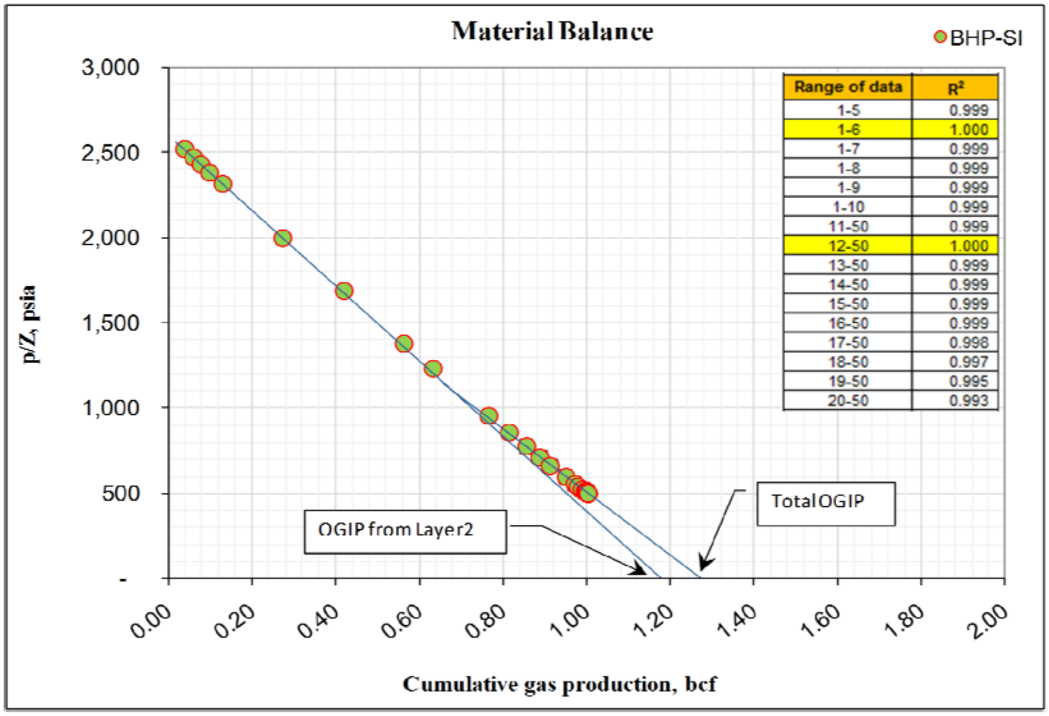


Figure 5.42 : *p/Z* versus cumulative production – Case4: Layer permeability of 50 and 100 mD.

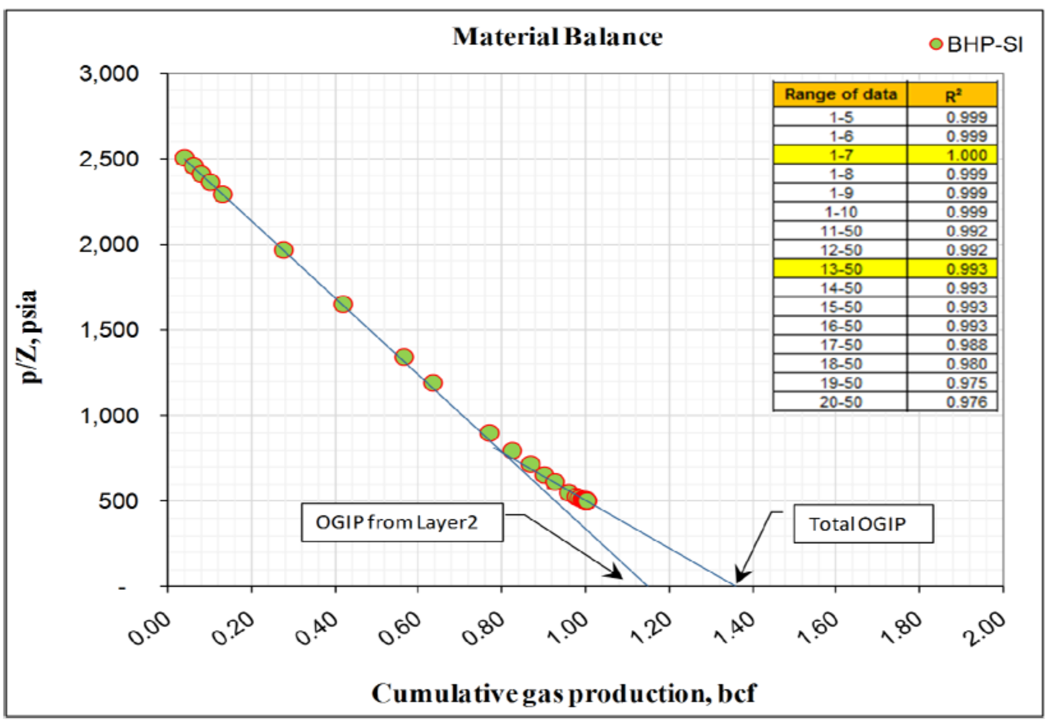


Figure 5.43 : *p/Z* versus cumulative production – Case5: Layer permeability of 50 and 278 mD.

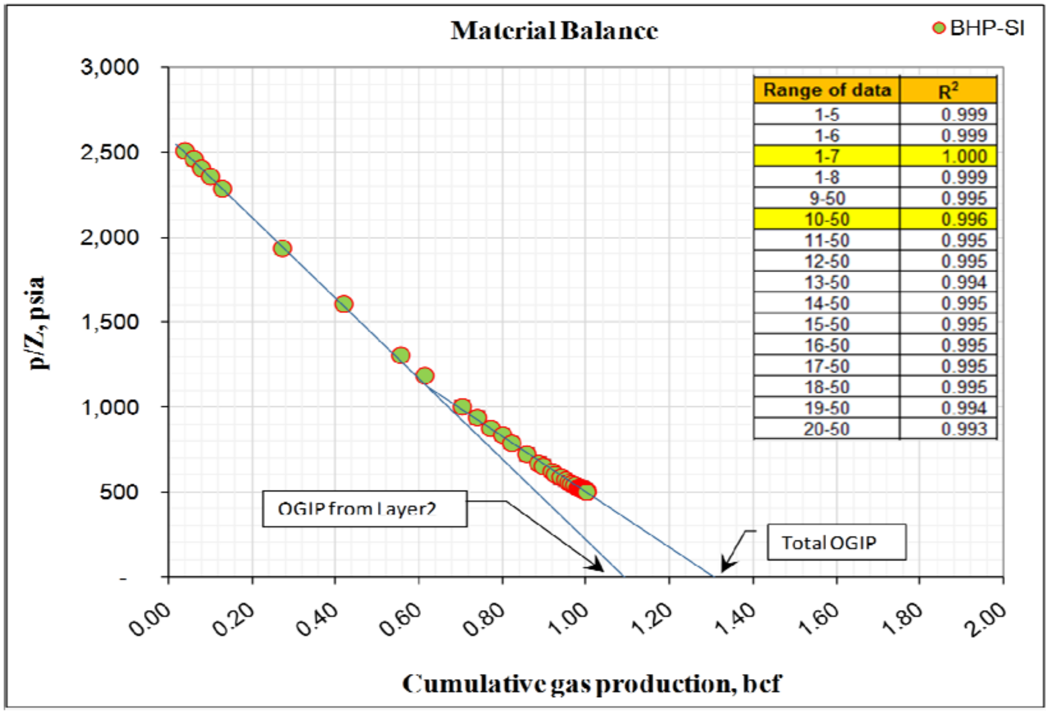


Figure 5.44 : *p/Z* versus cumulative production – Case6: Layer permeability of 14 and 38 mD.

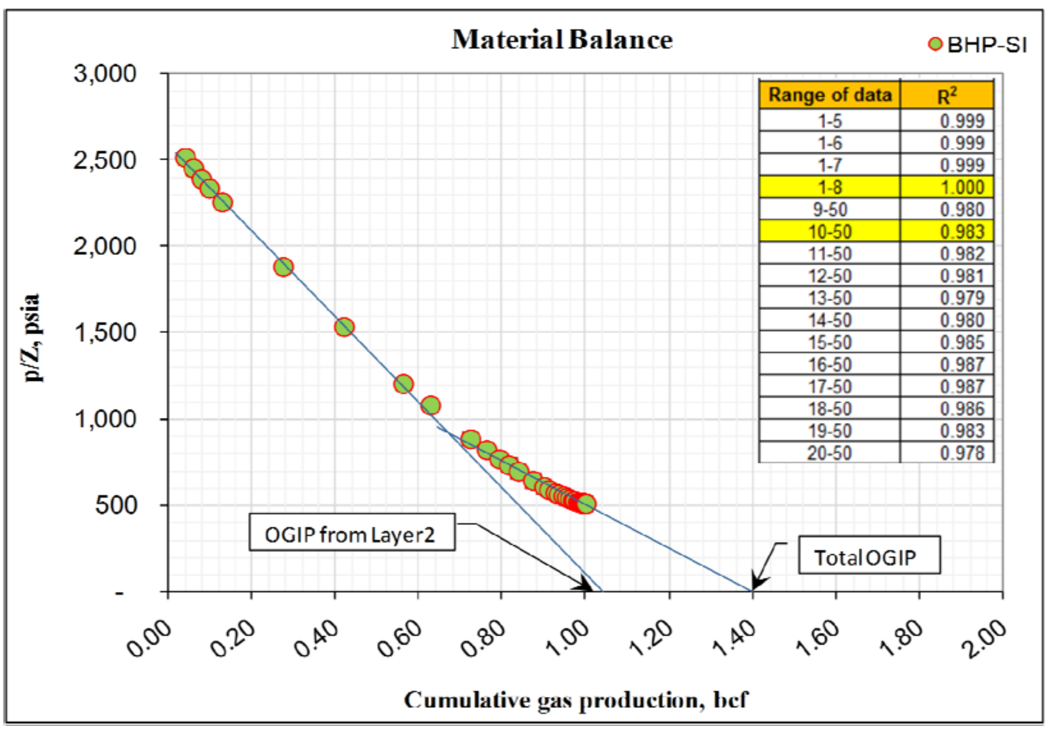


Figure 5.45 : *p/Z* versus cumulative production – Case7: Layer permeability of 14 and 80 mD.

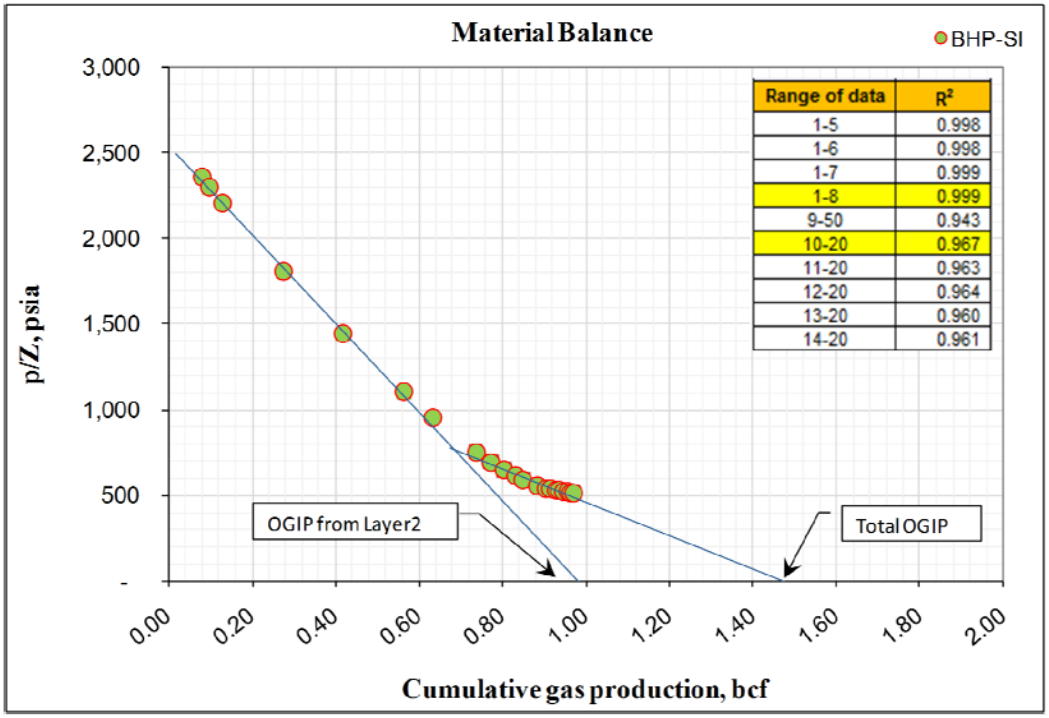


Figure 5.46 : *p/Z* versus cumulative production – Case8: Layer permeability of 14 and 278 mD.

Figures 5.39 to 5.46 show *p/Z* plots for different contrasts of permeability between two layers. In cases 1 and 2, we can observe a single trend in the curve. However, when the contrast becomes higher than 1.6, the data exhibit two different trends for straight lines. The first trend characterizes the original gas in place of the higher permeability layer, and the second trend illustrates the original gas in place of the commingled system. The errors of original gas in place estimates are higher in the low permeability cases

Table 5.14 : Original gas in place for different contrasts in reservoir permeability

	Permeability (mD)	Contrast	Actual OGIP	*P/Z* OGIP	% Error
Case1:			**1.255**	**1.255**	**0.00**
Layer1	50	1.1	-	-	
Layer2	57		-	-	
Case2:			**1.255**	**1.257**	**0.16**
Layer1	50	1.3	-	-	
Layer2	65		-	-	
Case3:			**1.255**	**1.269**	**1.12**
Layer1	50	1.6	0.613	0.071	-88.45
Layer2	80		0.642	1.198	86.66
Case4:			**1.255**	**1.273**	**1.46**
Layer1	50	2.0	0.613	0.099	-83.83
Layer2	100		0.642	1.174	82.94
Case5:			**1.255**	**1.359**	**8.29**
Layer1	50	5.6	0.613	0.208	-66.09
Layer2	278		0.642	1.151	79.33
Case6:			**1.255**	**1.309**	**4.30**
Layer1	14	2.7	0.613	0.220	-64.12
Layer2	38		0.642	1.089	69.66
Case7:			**1.255**	**1.395**	**11.16**
Layer1	14	5.7	0.613	0.358	-41.62
Layer2	80		0.642	1.037	61.58
Case8:			**1.255**	**1.476**	**17.60**
Layer1	14	19.9	0.613	0.513	-16.36
Layer2	278		0.642	0.963	50.04

Tables 5.14 and 5.15 depicts that when permeability contrast is 1.6 or higher (cases 3, 4, 5, 6, 7, and 8), two-slope behavior can be observed, and then layer OGIP can be estimated. However, in all cases, the estimate for each individual layer has a large amount of error.

From the results shown in Table 5.14, OGIP for the system can be accurately determined even though the layers have different permeabilties. The amount of error for most cases is quite small except for the cases in which there is a large contrast in permeability (Cases 5, 7, and 8). The highest error is 17.60% in case 8. For a system where the upper layer has low permeability (cases 6, 7, and 8), the increase in permeability contrast causes the OGIP estimate of the system to contain more error due to contrast between low and medium to high permeability and a longer decline period in the upper layer.

Table 5.15 : Appearance of two straight lines on *p/Z* plot for various permeability contrasts

Permeability contrast	**Appearance of two straight lines**
1.1	None
1.3	None
1.6	Yes
2.0	Yes
2.7	Yes
5.6	Yes
5.7	Yes
19.9	Yes

5.5 Influence of gas gravity contrast on OGIP estimate

In this section, the effect of gas gravity is addressed to illustrate the influence of the gas gravity on original gas in place calculation. PVT data shown in Table 5.13 were generated from PROSPER using Lee et al. correlation.

Table 5.16 : PVT data of gas gravity of 0.7, 0.8, and 0.9

Pressure (psia)	S.G. = 0.7		S.G. = 0.8		S.G. = 0.9	
	FVF (rb/Mscf)	Visc (cp)	FVF (rb/Mscf)	Visc (cp)	FVF (rb/Mscf)	Visc (cp)
429.39	7.5498	0.01365	7.4690	0.01324	7.3733	0.01288
615.11	5.2088	0.01388	5.1280	0.01353	5.0313	0.01322
800.82	3.9577	0.01415	3.8771	0.01386	3.7800	0.01364
986.54	3.1812	0.01446	3.1015	0.01425	3.0046	0.01413
1172.25	2.6542	0.01480	2.5756	0.01469	2.4797	0.01469
1357.97	2.2743	0.01517	2.1974	0.01517	2.1034	0.01532
1543.68	1.9888	0.01557	1.9140	0.01571	1.8228	0.01604
1729.40	1.7671	0.01601	1.6950	0.01629	1.6074	0.01682
1915.11	1.5909	0.01647	1.5219	0.01691	1.4386	0.01768
2100.83	1.4480	0.01696	1.3823	0.01757	1.3040	0.01859
2286.54	1.3304	0.01747	1.2683	0.01827	1.1952	0.01956
2472.26	1.2321	0.01800	1.1738	0.01900	1.1062	0.02057
2657.97	1.1492	0.01855	1.0946	0.01976	1.0325	0.02162
2843.69	1.0785	0.01911	1.0277	0.02054	0.9709	0.02269
3029.40	1.0176	0.01969	0.9706	0.02133	0.9189	0.02377

Table 5.17 : Parameters for base case analysis

	Porosity (ϕ)	Thickness (ft)	Permeability (mD)	Area (ft^2)	Contrast
Layer1	20	10	50	2.40E+06	1.00
Layer2	20	10	50	2.40E+06	

Variables which are not function of gas specific gravity were kept the same as in the previous cases. Summary of various gas gravities for sensitivity analysis are shown in Table 5.15.

Table 5.18 : Parameters for sensitivity analysis

	Gas gravity				
Layer1	0.7	0.7	0.8	0.8	0.9
Layer2	0.7	0.9	0.8	0.9	0.9

The Standing-Katz correlation has been used to obtain Z-factor. The Z-factor is determined as a function of the shut-in bottom hole pressure at constant reservoir temperature (203 °F), with various gas gravity (0.7, 0.8, 0.85, and 0.9).

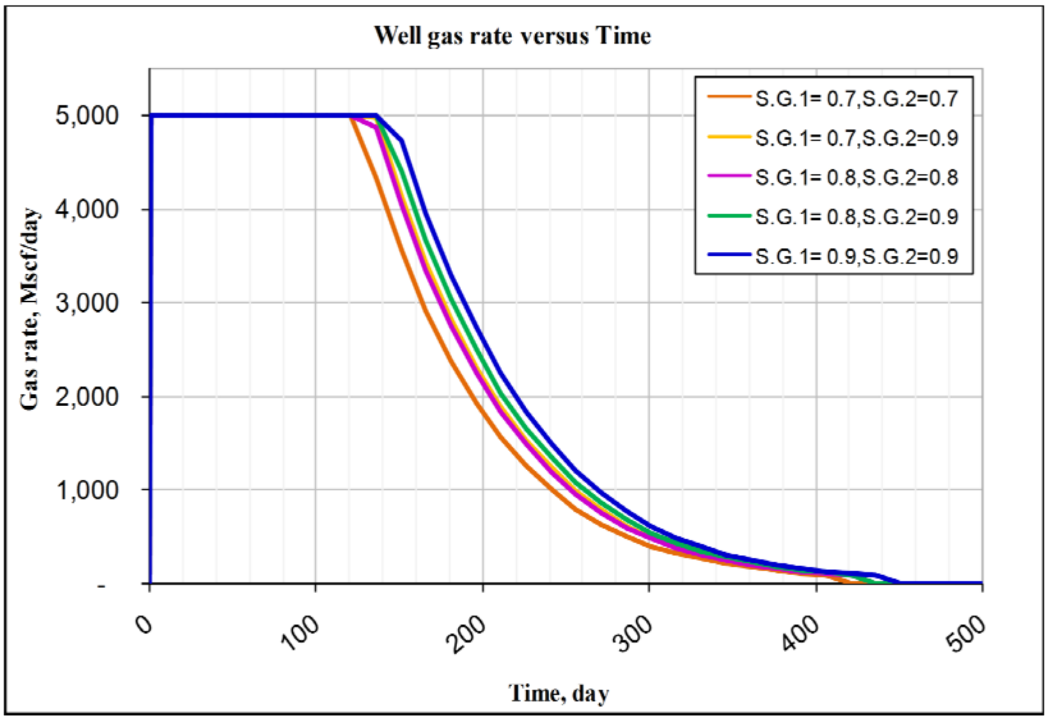


Figure 5.47 : Well gas rate versus time – effect of gas gravity on OGIP.

Results generated from the simulations are illustrated in Figures 5.47 to 5.49. The gas rates versus time in these figures illustrate behaviors of two layered system having different gas gravities.

In Figure 5.47, during the early production life, gas is produced at maximum rate of 5,000 Mscf/D for a certain period. Then gas rate drops as reservoir pressure falls. The gas rate from the lowest gas gravity of 0.7 starts to decline first, followed by the cases with higher gas gravity (0.8 and 0.9, respectively).

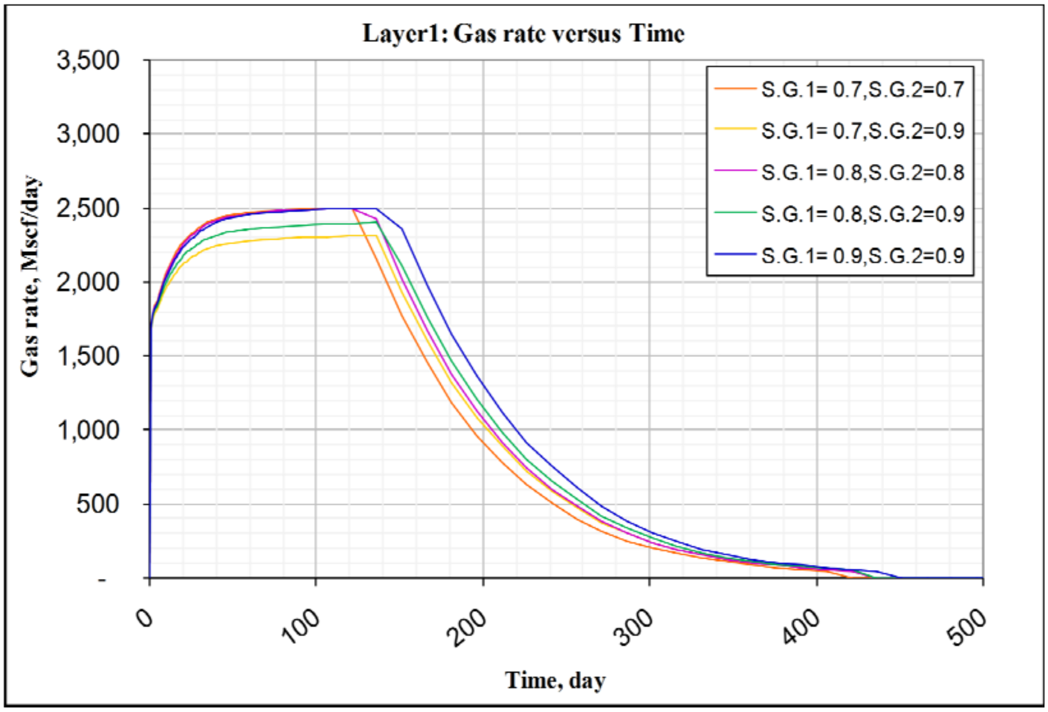


Figure 5.48 : Gas rate versus time for the upper layer – effect of gas gravity on OGIP.

Figures 5.48 and 5.49 show the amount of gas produced from the top and bottom layers. At the beginning, gas production from the bottom layer is quite high drops when gas production from the top layer slightly increases. This indicates that the initial gas produced mainly comes from the bottom layer. The decrease in gas rate from the bottom layer occurs after the pressure of the bottom layer decreases. As time progresses, gas from the bottom layer gradually decreases until it becomes steady. About four months after production has been initialized, the gas production of the well sharply declines.

Figure 5.48 and 5.49 also show that contrast in gas gravity between two layers causes the plateau rate of the two layers to be different. The layer with higher gas gravity contributes slightly more than the layer with lower gas gravity.

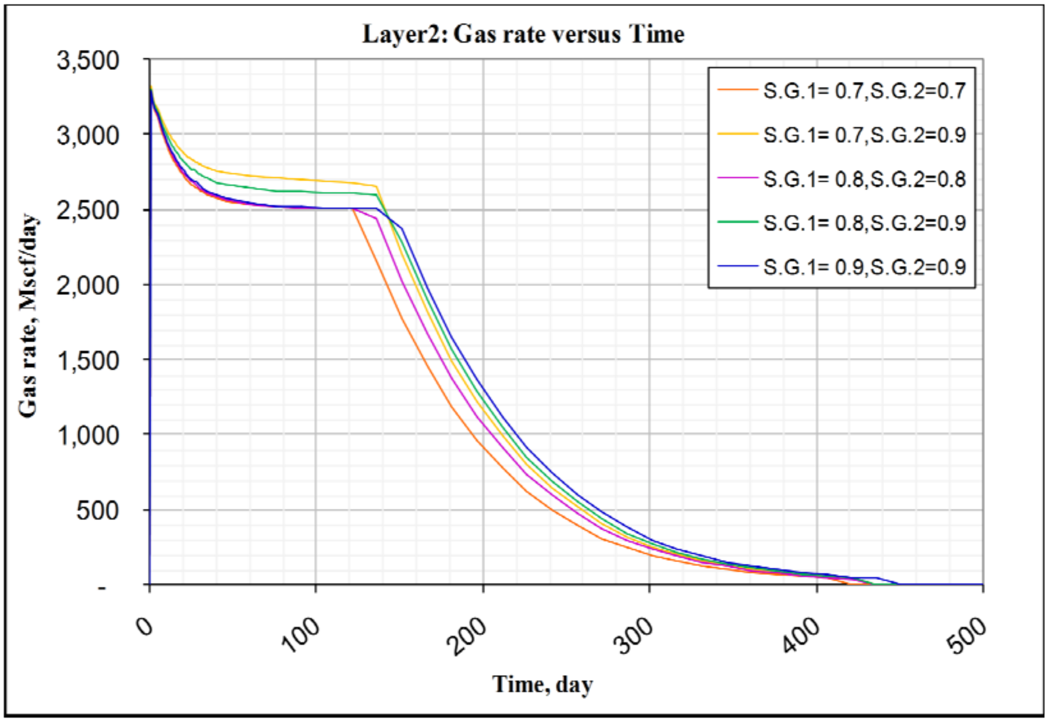


Figure 5.49 : Gas rate versus time for the lower layer – effect of gas gravity on OGIP.

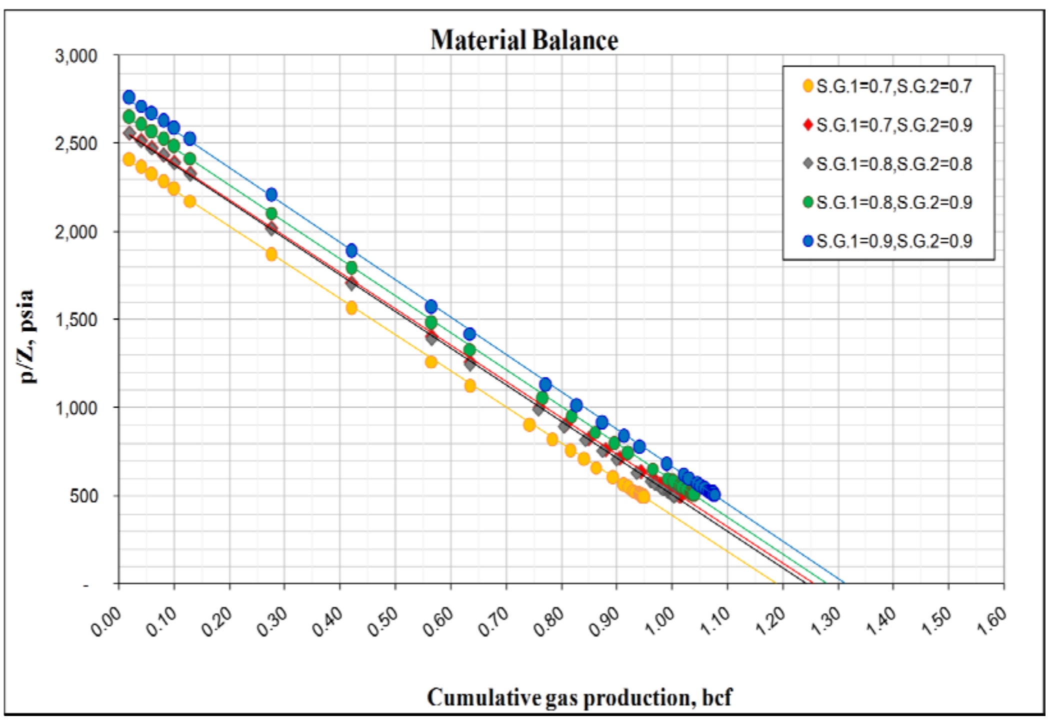


Figure 5.50 : *p/Z* versus cumulative production – effect of gas gravity on OGIP.

The *p/Z* plot in Figure 5.50 indicates that the change of gas gravity has influence on the original gas in place. Higher gas gravity results in higher original gas in place. However, the difference in gas specific gravity between the two layers does not cause the *p/Z* plot to exhibit two straight lines.

Tables 5.19 to 5.20 illustrate that the difference between actual gas in place and estimated gas in place derived from material balance for four cases of various gas gravities is only within 1% of error. This means that contrast in specific gas gravity of two layers has a slight impact on OGIP estimate.

Table 5.19 : Original gas in place for zero contrast between reservoir gas gravity

S.G. = 0.7, 0.7			S.G. = 0.8, 0.8			S.G. = 0.9, 0.9		
Actual OGIP	*P/Z* OGIP	% Error	Actual OGIP	*P/Z* OGIP	% Error	Actual OGIP	*P/Z* OGIP	% Error
1.198	1.193	-0.41	1.250	1.245	-0.42	1.331	1.319	-0.86

Table 5.20 : Original gas in place for different contrasts between reservoir gas gravity

S.G. = 0.7, 0.9			S.G. = 0.8, 0.9		
Actual OGIP	*P/Z* OGIP	% Error	Actual OGIP	*P/Z* OGIP	% Error
1.266	1.257	-0.70	1.294	1.283	-0.82

In order to see effect of Z-factor in the p/*Z* plot on various cases of S.G., three different Z-factors were used to represent the gas deviation factor in the p/*Z* plot: Z-factor from upper layer reservoir pressure, Z-factor from lower layer reservoir pressure, and Z-factor from shut-in bottom hole pressure.

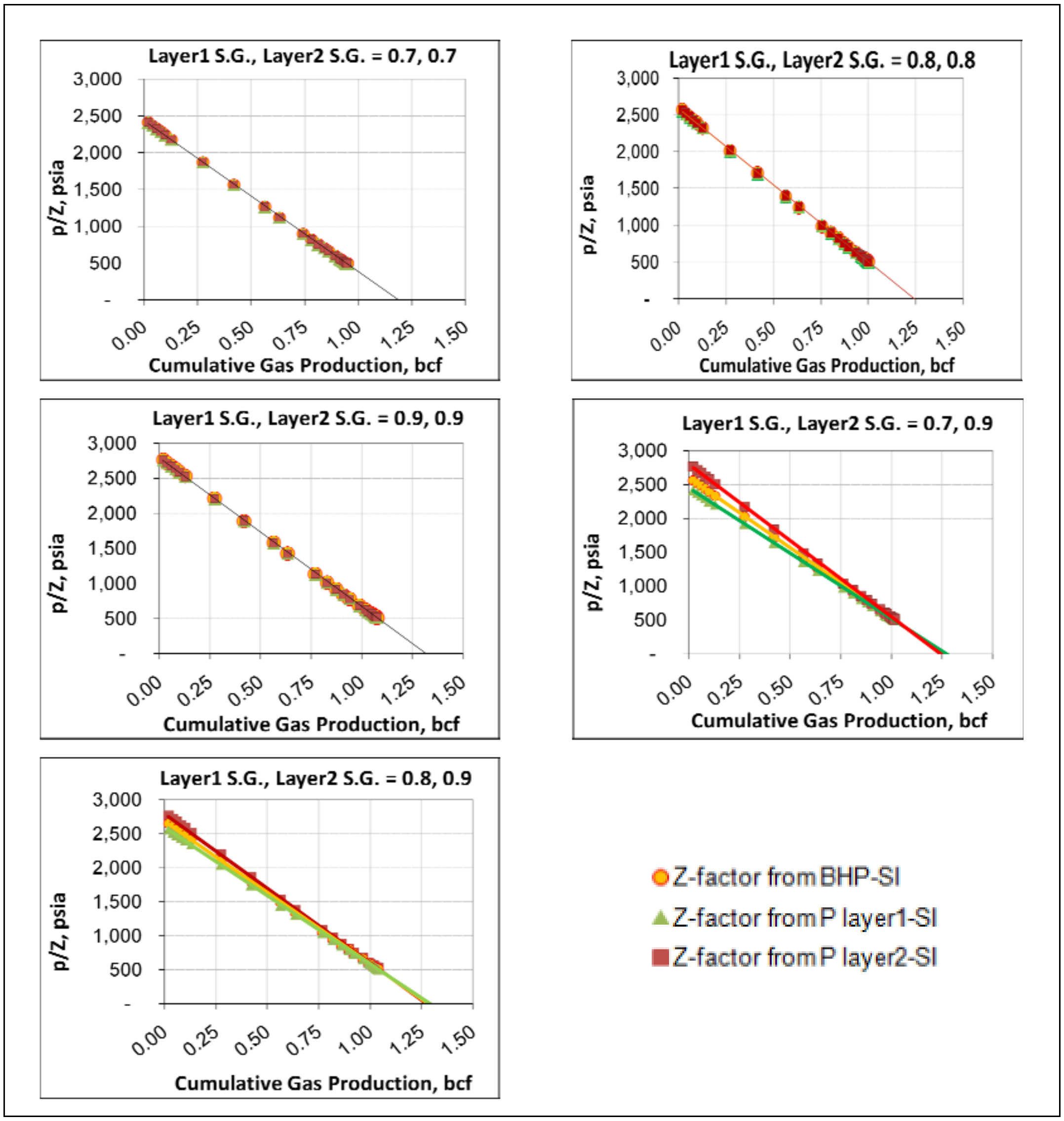


Figure 5.51 : *p/Z* versus cumulative production – Z-factor in the p/*Z* plot for various specific gas gravities

Figure 5.51 illustrate that there are small difference in OGIP estimate from using different pressure to determine Z-factor when the contrast of gas gravity between the two layers is zero. However, for cases that have gas gravity contrast, OGIP estimate from the Z-factor calculated from shut-in bottom hole pressure is not much different from OGIP estimate from the Z-factor base on the pressures of the upper and lower reservoirs. In any case, difference in OGIP estimate is quite small; therefore, difference in Z-factor has only a minor impact on OGIP estimate.

Table 5.21 : Original gas in place using different pressures used to determine Z-factor in the p/Z plot.

S.G. (Layer1,Layer2)	Actual		P_{BHP}/Z Z-factor from BHP		P_{BHP}/Z Z-factor from P layer1		P_{BHP}/Z Z-factor from P layer2	
	OGIP	%Error	OGIP	%Error	OGIP	%Error	OGIP	%Error
0.7, 0.7	1.198	-	1.190	-0.66	1.190	-0.68	1.189	-0.70
0.8, 0.8	1.250	-	1.244	-0.48	1.244	-0.50	1.244	-0.50
0.9, 0.9	1.331	-	1.316	-1.11	1.316	-1.11	1.316	-1.11
0.7, 0.9	1.266	-	1.260	-0.51	1.273	0.53	1.241	-1.97
0.8, 0.9	1.294	-	1.284	-0.73	1.290	-0.31	1.273	-1.63

By comparing OGIP estimates based on Z-factor determined at different pressures, results in Table 5.21 show that the Z-factor determined from the shut-in bottom hole pressure can be used to represent the gas deviation factor in material balance calculation because it provides the smallest error in most cases. The error obtained when using the Z-factor from the lower layer is relatively higher than other cases.

5.5.1 Influence of gas gravity contrast on OGIP estimate in various thickness contrast

In this section, we further investigate the effect of contrast in gas gravity between the two layers when the thicknesses of the layers are different.

Figure 5.52 illustrates straight line *p/Z* plot of different combinations of gas gravity and thickness of the two layers. The higher the gas gravity, the higher the original gas in place. In all cases, there is only a single trend of the straight line. Thus, only OGIP for the system can be estimated.

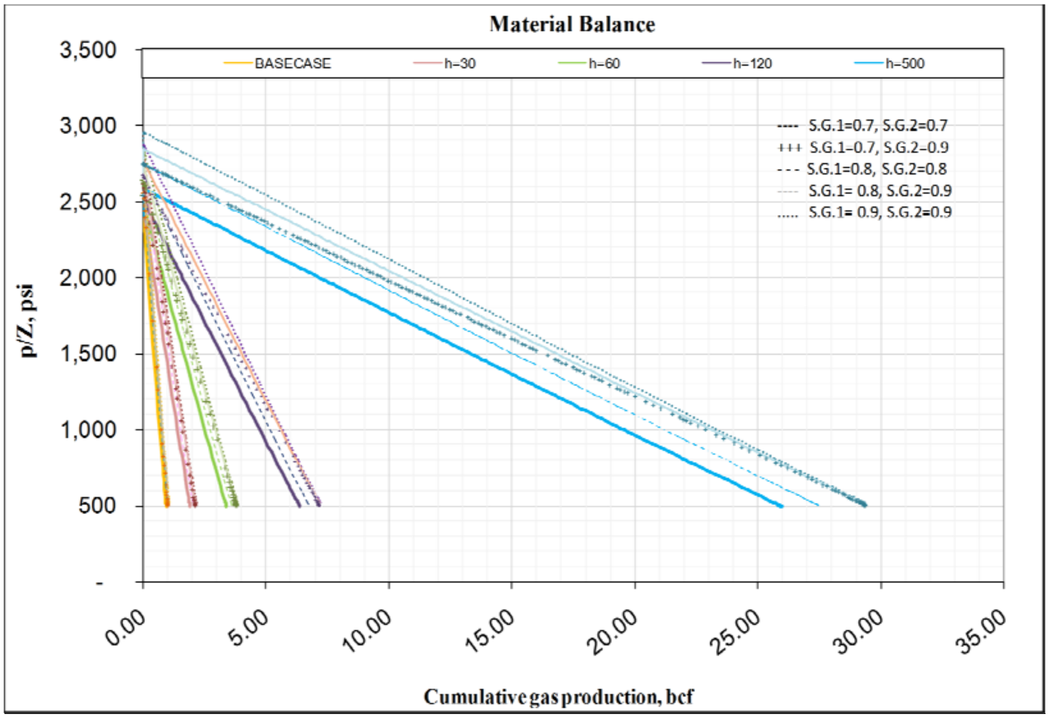


Figure 5.52 : *p/Z* plot – Effect of gas gravity and thickness on OGIP.

Table 5.22 : Original gas in place for zero contrast between reservoir gas gravity and different contrasts between thicknesses

S.G. = 0.7, 0.7			**S.G. = 0.8, 0.8**			**S.G. = 0.9, 0.9**		
Actual OGIP	***P/Z* OGIP**	**% Error**	**Actual OGIP**	***P/Z* OGIP**	**% Error**	**Actual OGIP**	***P/Z* OGIP**	**% Error**
Case1: h = 10, 30 ft								
2.426	**2.416**	**-0.42**	**2.543**	**2.532**	**-0.43**	**2.696**	**2.672**	**-0.89**
Case2: h = 10, 60 ft								
4.277	**4.252**	**-0.59**	**4.483**	**4.455**	**-0.63**	**4.755**	**4.711**	**-0.91**
Case3: h = 10, 120 ft								
8.012	**7.959**	**-0.66**	**8.399**	**8.332**	**-0.79**	**8.908**	**8.807**	**-1.14**
Case4: h = 10, 500 ft								
32.336	**32.080**	**-0.79**	**33.913**	**33.641**	**-0.80**	**35.980**	**35.554**	**-1.18**

Table 5.23 : Original gas in place for different contrasts between reservoir gas gravity and thickness

S.G. = 0.7, 0.9			**S.G. = 0.8, 0.9**		
Actual OGIP	***P/Z* OGIP**	**% Error**	**Actual OGIP**	***P/Z* OGIP**	**% Error**
Case1: h = 10, 30 ft					
2.632	**2.625**	**-0.25**	**2.659**	**2.644**	**-0.56**
Case2: h = 10, 60 ft					
4.690	**4.671**	**-0.40**	**4.718**	**4.690**	**-0.58**
Case3: h = 10, 120 ft					
8.844	**8.792**	**-0.58**	**8.871**	**8.817**	**-0.62**
Case4: h = 10, 500 ft					
35.915	**35.670**	**-0.68**	**35.943**	**35.648**	**-0.82**

Tables 5.22 to 5.23 illustrate an error of gas in place calculation for various gas gravities. The error for OGIP estimate of the system for all cases is very low. Note that OGIP estimate for each layer cannot be obtained when the two layers have different gas specific gravities and thicknesses.

CHAPTER VI
CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

The objective of this study is to investigate an approach to estimate original gas in place in two-layer reservoirs through the application of material balance (*p/Z* method). The results of the original gas in place estimate as shown in Table 6.1 can be summarized as follows:

1. When there is no contrast in fluid and reservoir properties between two layers, the two-layered system behaves like a single layer. A simple form of material balance calculation, i.e., straight line *p/Z* plot is an appropriate tool for OGIP estimate of the commingled system.
2. Contrast in area, thickness, porosity, and permeability of the layers has small effect on OGIP estimate of the system. When there is a large contrast between layer properties, the error becomes larger in general. However, the magnitude of the error is still in an acceptable range.
3. Even with a thickness contrast between two layers, *p/Z* plot exhibits a single straight line. Therefore, only total OGIP can be estimated. The thickness contrast does not have any effect on the error of total OGIP. The error is generally less than 1%.
4. When the contrast in layer areas is high, two straight lines can be observed on *p/Z* plot. In these cases, OGIP of individual layer can be estimated. OGIP estimate for the layer contains a large unacceptable error, however the OGIP estimate for larger layer is more accurate than smaller area. In all cases, error of OGIP estimate for the total system is less than 8% even though the error increases when there is higher contrast in areas.
5. When there is difference in porosity between two layers, two straight lines can be seen in the p/Z plot where the upper layer has low porosity. However, layer OGIP estimate contain a large amount of error (more than 20%) which is unacceptable. In most cases, only a single straight line can be seen. The entire system OGIP in

all cases can be determined with an amount of error less than 5%. The error is high in cases of low porosity (error between 3% to 5%).

6. When there is contrast in layer porosity and corresponding permeability, two straight lines can be seen on *p/Z* plots. Large amount of error in layer OGIP occurs when the porosity contrast is low and the range of error is narrower when the porosity contrast is high. In all cases, error for OGIP for the system has error less than 8% even though the error slightly increases when the contrast becomes larger.
7. When there is permeability medium to high permeability contrast, the *p/Z* plot exhibits two straight lines. In these cases, layer OGIP can be estimated. But the error in layer OGIP estimates are very large and considered not acceptable. In most cases, the OGIP for total system can be accurately estimated with error less than 9%. However, the cases where the upper layer has low permeability have an error in the range 11% to 18%. In general the magnitude of the error increases as the contrast in permeability increases.
8. When there is difference in gas gravity between two layers, only a single straight line can be seen in the p/Z plot. Thus, only total OGIP can be determined. The difference in gas specific gravity and also the difference in Z-factor calculated from different pressures do not have an impact on error of OGIP estimate.

Table 6.1 : Original gas in place for different contrasts between reservoir thickness, area, porosity, permeability, and gas specific gravity

<table>
<tr><th rowspan="2">Parameter</th><th rowspan="2">Contrast</th><th rowspan="2">Total OGIP estimate</th><th colspan="2">Layer OGIP estimate</th></tr>
<tr><th>1^{st} Layer</th><th>2^{nd} Layer</th></tr>
<tr><td rowspan="3">Thickness (ft)</td><td>Low: 1-5</td><td rowspan="3">Error < 1%</td><td colspan="2" rowspan="3">Not Applicable</td></tr>
<tr><td>Mid: 6-10</td></tr>
<tr><td>High: > 10</td></tr>
<tr><td rowspan="3">Area (Acre)</td><td>Low: 1-5</td><td rowspan="2">Error < 9%</td><td colspan="2">Not Applicable</td></tr>
<tr><td>Mid: 6-10</td><td rowspan="2">Error > 50%</td><td>Error < 6%</td></tr>
<tr><td>High: > 10</td><td>Error > 10%</td><td>Error > 10%</td></tr>
<tr><td rowspan="3">Porosity (%)</td><td>Low: 1-1.5</td><td rowspan="3">Error < 5%</td><td colspan="2" rowspan="2">Not Applicable</td></tr>
<tr><td>Mid: 1.5-2</td></tr>
<tr><td>High: > 2</td><td colspan="2">Error > 20%</td></tr>
<tr><td rowspan="3">Porosity (%) & Permeability (mD)</td><td>Low: 1-5</td><td rowspan="3">Error < 8%</td><td rowspan="3">Error > 10%</td><td rowspan="3">Error < 1%</td></tr>
<tr><td>Mid: 6-10</td></tr>
<tr><td>High: > 10</td></tr>
<tr><td rowspan="3">Permeability (mD)</td><td>Low: 1-5</td><td>Error < 5%</td><td colspan="2">Not Applicable</td></tr>
<tr><td>Mid: 6-10</td><td rowspan="2">Error > 10%</td><td colspan="2" rowspan="2">Error > 20%</td></tr>
<tr><td>High: > 10</td></tr>
<tr><td rowspan="2">Gas specific gravity</td><td>Zero</td><td rowspan="2">Error < 1%</td><td colspan="2" rowspan="2">Not Applicable</td></tr>
<tr><td>Low: 1-5</td></tr>
</table>

6.2 Recommendations for further study

It is recommended that further study of three-layered and multiple-layered reservoirs should be commenced. In addition, retrograde gas reservoirs should also be studied. The number of dry gas reservoirs in the Gulf of Thailand is relatively small when compared with the amount of retrograde gas reservoirs. Therefore, retrograde gas should be brought into sight.

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APPENDICES

APPENDIX A

ECLIPSE 100 Reservoir Model

Initial model for validation

1. Case Definition

Simulator	: Black oil
Model dimensions	: Number of grid in x direction = 51
	: Number of grid in y direction = 51
	: Number of grid in z direction = 21
Simulation start date	: 1 Jan 2000
Grid type	: Cartesian
Geometry type	: Block centred
Oil-Gas-Water properties	: Gas
Solution type	: Fully implicit

2. Grid

2.1 Initial model for validation

1) Properties

Active grid block	: 1 for box X, Y, Z (1:51, 1:51, 1:21)
	: 0 for box X, Y, Z (1:51, 1:51, 11:11)
X permeability	: 50 mD
Y permeability	: 50 mD
Z permeability	: 5 mD
Porosity	: 0.20

2) Geometry

Grid block size for basecase model

X grid block sizes	: 30.4 ft for box X, Y, Z (1:51, 1:51, 1:21)
Y grid block sizes	: 30.4 ft for box X, Y, Z (1:51, 1:51, 1:21)
Z grid block sizes	: 1 ft for box X, Y, Z (1:51, 1:51, 12:21)
	: 150 ft for box X, Y, Z (1:51, 1:51, 11:11)
Depth of top face	: 5030 ft
Regions	: 1 for box X, Y, Z (1:51, 1:51, 1:11)
	: 2 for box X, Y, Z (1:51, 1:51, 12:21)

3. PVT

Dry gas PVT properties (No vaporized oil)

Fluid densities at surface conditions

: Oil density 49.99 lb/ft3

: Water density 62.43 lb/ft3

: Gas density 0.043 lb/ft3

4. SCAL

no SCAL data input

5. Initialization

Table A.1: Initial pressure versus depth

Depth (ft)	Pressure (psia)
4839	1962
5030	2083
5170	2171
5316	2232
5655	2318
5807	2459
5960	2520
6010	2544
6062	2550
6101	2579
6739	2941

6. Schedule

Well : WELL1
I location : 26
J location : 26
K location : 1-10, 12-21
Datum depth : 5030 ft
Preferred phase : GAS
Crossflow : YES
Maximum gas rate : 5000 Mscf/d
Minimum gas rate : 100 Mscf/d
THP target : 414.7 psia
Well is schedule for shut-in from time to time

APPENDIX B

PROSPER Input Data for Reservoir Model

1. System summary

Fluid Option

Fluid : Dry and wet gas

Well

Flow type : Tubing

Well type : Producer

Well completion : Cased Hole

2. PVT data

Gas gravity	: Varied 0.7,0.8,0.9
Condensate to gas ratio	: 0 STB/MMscf
Water to gas ratio	: 0 STB/MMscf
Mole percent of H_2S	: 0 %
Mole percent of CO_2	: 10 %
Mole percent of N_2	: 0.07 %
Correlation	: Lee et al

3. Deviation survey

Measure depth(ft)	: 0, 10000
True vertical depth (ft)	: 0, 10000
Angle	: 0 degree

4. Downhole equipment

Table B.1: Downhole equipment

Type	Measured depth (ft)	Tubing ID (inch)	Tubing roughness (inch)
Xmas tree	0		
Tubing	5030	2.441	0.0006

5. Geothermal gradient

Table B.2: Geothermal gradient

Formation Measured Depth (ft)	Formation Temperature (°F)
0	60
5030	203

Overheat transfer coefficient 5 BTU/h/ft^2/°F

6. VLP input data

Top node pressure : 414.7 psia

Table B.3: Downhole equipment

Gas rate (MMscf/D)	Bottom hole pressure (psia)
0.1	414.7
1.0	464.7
1.5	514.7
2.0	564.7
2.5	614.7
3.0	714.7
3.5	814.7
4.0	1014.7
4.5	2014.7
5.0	2514.7
5.5	
7.0	
7.5	
9.0	
10.0	
11.0	
14.0	
15.0	
18.0	
20.0	

APPENDIX C

Fundamentals for Inflow and Material Balance during Pseudo-steady Flow of Depletion Systems

The dimensionless pressure at the well for the liquid solution during pseudo-steady state flow of a depletion system can be written as

$$p_{wD} = 2\pi t_{AD} + \frac{1}{2}\ln\left(\frac{4A}{e^{\gamma} C_A r_{w2}}\right) + skin \tag{C-1}$$

where:

$$p_{wD} = \frac{kH(p_i - p_{wf})}{141.2qB\mu} \tag{C-2}$$

$$t_{AD} = \frac{0.00633kt}{\phi\mu C_t A} \tag{C-3}$$

and A = area; γ = Euler constant = 1.781; C_A = shape factor

Examining Equation C-1, one recognizes that it combines both the material balance (first term on the RHS) and the inflow performance (combining the second and third term on the RHS); or

$$p_{wD} = \text{Material balance} + \text{Inflow Performance}$$

Also, expanding the LHS term of Equation C-1, one can write

$$p_{wD} = \frac{kH(p_i - p_{wf})}{141.2qB\mu} = \frac{kH\{(p_i - p_{ave}) + (p_{ave} - p_{wf})\}}{141.2qB\mu} = 2\pi t_{AD} + \frac{1}{2}\ln\left(\frac{4A}{e^{\gamma} C_A r_{w2}}\right) + skin \tag{C-4}$$

or

$$\text{Materialbalance} \equiv \frac{kH\{(p_i - p_{ave})\}}{141.2qB\mu} = 2\pi t_{AD} \tag{C-5}$$

$$\text{Inflow performance} \equiv \frac{kH\{(p_{ave} - p_{wf})\}}{141.2qB\mu} = \frac{1}{2}\ln\left(\frac{4A}{e^{\gamma} C_A r_{w2}}\right) + skin \tag{C-6}$$

Equation C-1 is the most fundamental expression to relate well-bore pressures and rates for transient analysis. It also serves as the basis for the rate forecast associated with decline curve analyses by its inversion or reciprocity. For compressible gas systems, the general form of Equation C-1 or C-2 can still be used by replacing the pressure and time terms with appropriate pseudo-pressures and pseudo-times.

APPENDIX D

Mean Statistical Data of Reservoir Properties

Data from the typical field in the Gulf of Thailand

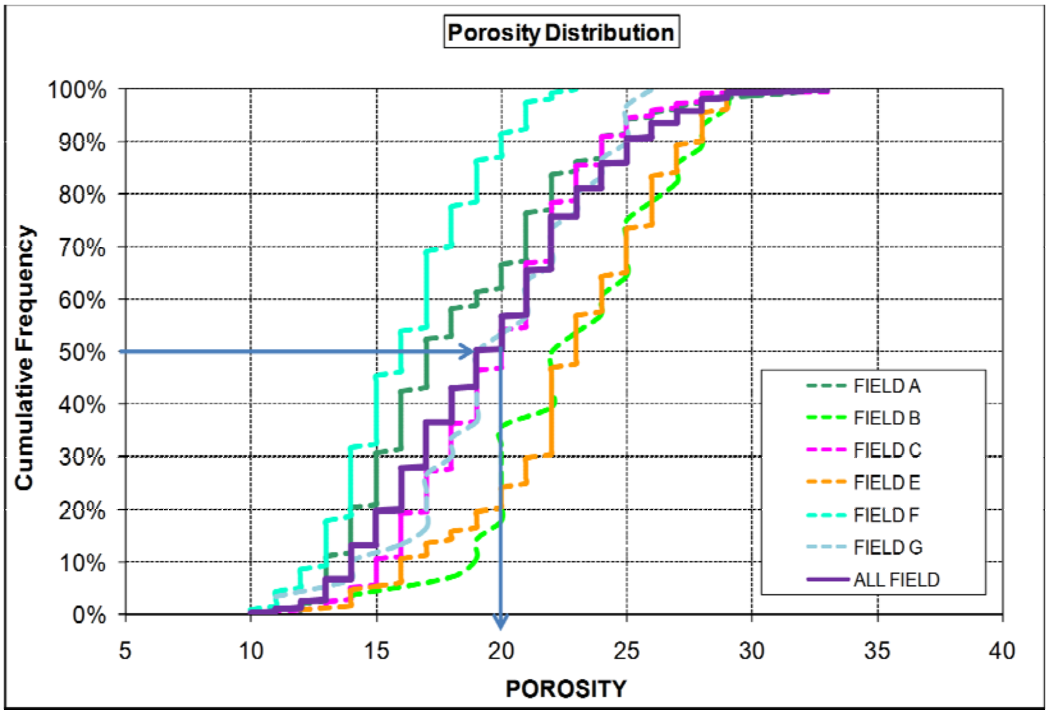

Figure D.1 : Porosity distribution

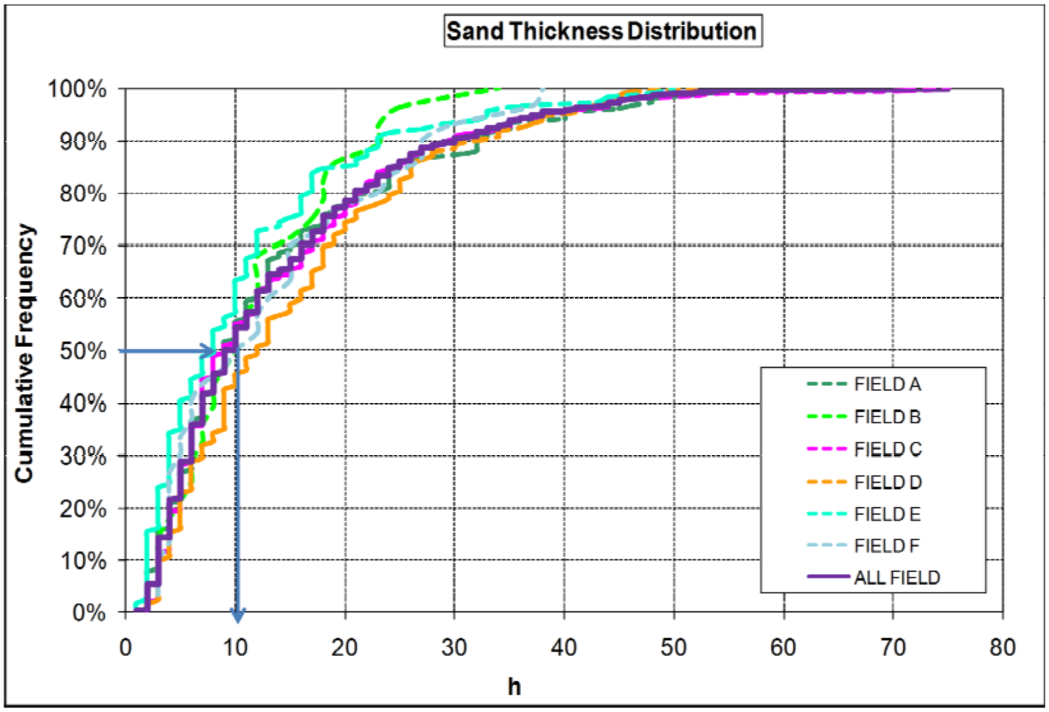

Figure D.2: Sand thickness distribution

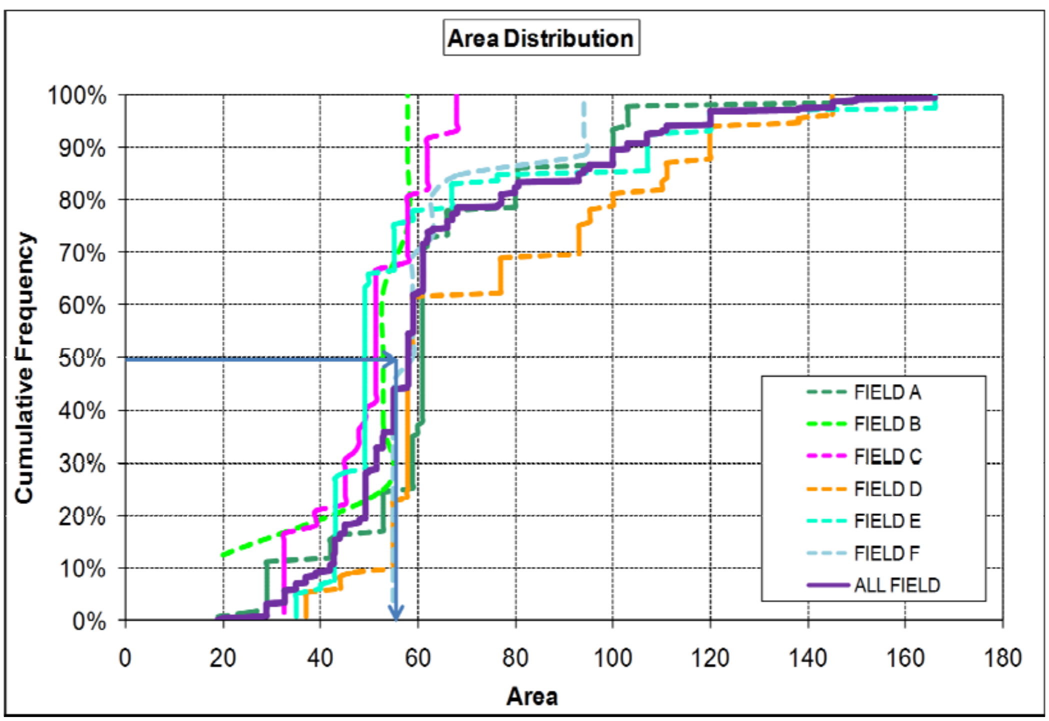

Figure D.3: Area distribution

Table D.1: P-10-50-90 of area of each typical field

1 Acre = 43560 sq.ft

OA	Area (Acre)		
	P10	**P50**	**P90**
FIELD A	29	61	100
FIELD B	20	53	58
FIELD C	33	51	62
FIELD D	55	58	120
FIELD E	43	49	107
FIELD F	55	59	94

Average (Acre)	39	55	90
Average (Sq.ft)	1,706,100	2,403,060	3,927,660

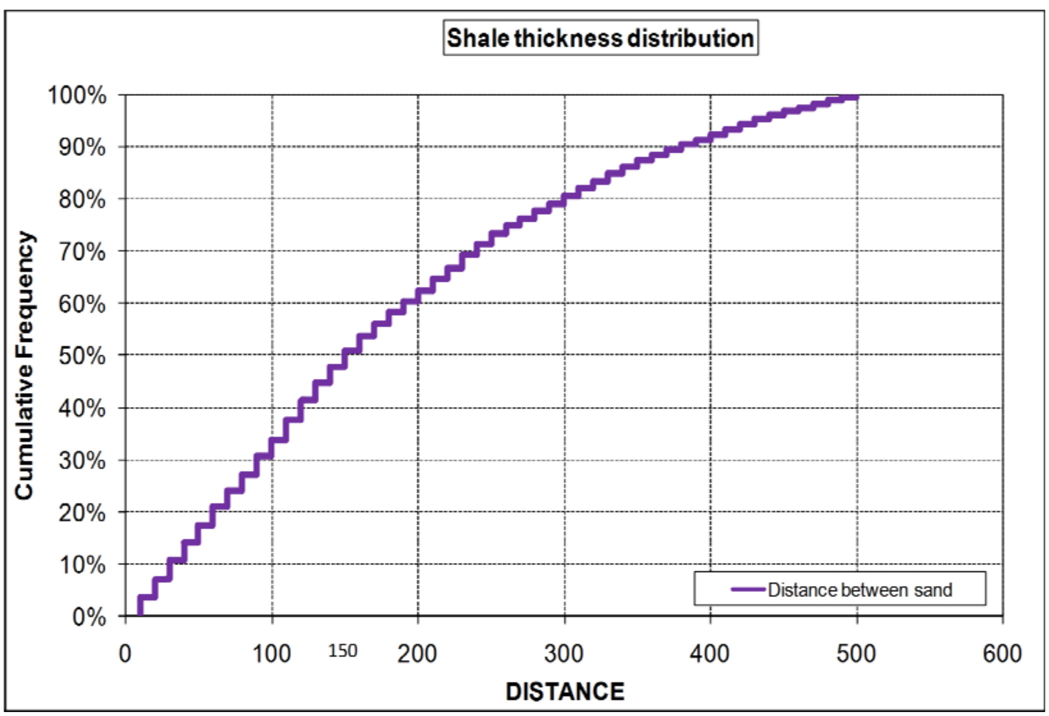

Figure D.4: Shale thickness distribution

APPENDIX E

Well Stabilization Times

From 28 sampling data of the wells in typical field in the Gulf of Thailand that have done production logging in year 2001, For the stability for shut-in normally appears to be with-in 1 hour. With some exceptions for the wells those have big connectivity reservoir that wellhead pressure increases by more than 1000 psi after 1 hour, an additional ½ hours should be allowed.

Table E.1: Well stabilization times

Well	Choke	Gas	Condy	Water	Time	Comments
Well#1	40	3.5	120	220	0:20	RIH condition unknown
Well#1	20	2.5	145	200	0:10	Seems flowing while RIH. Wait only 10min ±1.5psi
Well#1	15	1.7	100	0	1:00	Choke Change, although Δp is almost 500 psi
Well#1	Shut-in	0	0	0	0:00	Sequence ambiguous, PBU not plotted
Well#2	32	no	test	0:05	0:00	well flowing while RIH
Well#2	Shut-in	0	0	0	0:00	Well SI 4 hrs before RIH. No wait before passes
Well#3	32	7	300	0	0:15	Flowing while RIH
Well#3	24	4.5	215	0	1:00	Choke change. Pressure drop after ≈45 min
Well#3	18	3.25	100	0	0:15	Choke change
Well#3	Shut-in	0	0	0	0:45	PBU Strange BU initial Δp of 20 then 20 more
Well#4	30	0.15	5	700	2:00	Flowing while RIH. Pressure dropped 30psi
Well#4	Shut-in	0	0	0	1:30	PBU. Odd BU to 1660 then 1620, 50 above flowing
Well#5	30	9.6	120	230	0:00	Plot does not match Sequence
Well#5	18	5.7	90	250	0:00	Plot does not match Sequence
Well#6	32	10	220	250	1:10	SI while RIH. Pressure still dropping 3 psi/hr
Well#6	20	6.4	230	400	1:00	SI while RIH. Pressure still dropping 2 psi/hr
Well#6	10	4.5	290	300	1:20	SI while RIH. Pressure still dropping 1.3 psi/hr
Well#6	Shut-in	0	0	0	0:00	Well SI overnight. No SI Plot

Table E.1: Well stabilization times (continued)

Well	Choke	Gas	Condy	Water	Time	Comments
Well#7	32	2.7	140	420	2:00	SI while RIH. Increasing 10 psi/hr from 2 to 4 hrs
Well#7	22	2.1	575	600	0:45	SI while RIH
Well#7	10	1.1	200	450	1:15	SI while RIH
Well#7	Shut-in	0	0	0	0:00	Well SI 3 hrs before RIH. No SI Plot
Well#8	35	2.7	120	90	1:30	SI while RIH
Well#8	20	2.2	90	90	0:05	Flowing while RIH
Well#8	10	1.5	80	60	0:30	SI while RIH. As good at 0:30 as 4:00
Well#8	Shut-in	0	0	0	0:00	SI while RIH
Well#9	20	1.85	60	340	1:00	SI while RIH
Well#9	Shut-in	0	0	0	0:00	SI 6 hrs before RIH
Well#10	25	2.7	68	100	1:40	SI while RIH
Well#10	10	1.6	70	60	1:30	SI while RIH
Well#11	25	1	25	1450	1:50	RIH condition unknown
Well#11	Shut-in	0	0	0	0:00	SI 6 hrs before RIH
Well#12	35	4	100	100	0:30	SI while RIH
Well#12	20	2.5	50	70	1:00	SI while RIH
Well#12	10	1.4	33	35	0:45	SI while RIH
Well#12	Shut-in	0	0	0	0:00	SI while RIH
Well#13	35	2.25	25	2500	2:00	Maybe less, choke changes
Well#13	Shut-in	0	0	0	0:00	Well shut-in while RIH, increased 10 psi in 2 hrs
Well#14	55	3.4	45	470	0:00	Open well while RIH
Well#14	Shut-in	0	0	0	0:00	Well SI overnight
Well#15	35	1.1	40	100	1:45	Open well while RIH
Well#15	Shut-in	0	0	0	0:00	Well SI overnight
Well#16	35	2.7	700	475	1:15	SI while RIH
Well#16	20	1.7	150	190	0:45	Flowing while RIH
Well#16	10	1.5	100	75	0:00	SI while RIH Time scale appears incorrect
Well#16	Shut-in	0	0	0	0:00	SI 9 hrs before RIH

Table E.1: Well stabilization times (continued)

Well	Choke	Gas	Condy	Water	Time	Comments
Well#17	35	test	not	stable	1:40	RIH condition unknown. Still dropping 11 psi/hr
Well#17	Shut-in	0	0	0	0:00	SI 2 weeks before
Well#18	60	2.2	30	64	1:00	Seems SI while RIH. ΔP <12psi/hr after 1 hr
Well#18	Shut-in	0	0	0	0:00	Well SI 17 hrs before RIH
Well#19	45	1.5	36	140	0:45	Open well while RIH
Well#19	Shut-in	0	0	0	0:30	Well SI 4 days. ≈15 psi anomaly at start
Well#20	55	2	35	560	0:30	SI while RIH
Well#20	Shut-in	0	0	0	0:00	SI 48 hrs before RIH
Well#21	64	0.27	0	400	1:10	1 st day RIH condition unknown
Well#21	64	0.27	0	400	1:10	2 nd day RIH condition unknown
Well#21	Shut-in	0	0	0	0:00	SI overnight
Well#22	40	0	0	0	0:00	No Test pressure dropping 100 psi/hr after 1:40
Well#22	Shut-in	0	0	0	1:30	PBU [Δp 1660] After 2 hrs steady increase of 24 psi/hr
Well#23	20	0.34	0	200	0:05	Well flowing while RIH
Well#23	Shut-in	0	0	0	0:00	SI day before. No wait before passes
Well#24	64	2.5	10	225	1:30	RIH cond unknown. As good at 1½ hrs as 4
Well#24	Shut-in	0	0	0	0:30	PBU
Well#25	32	0.4	25	250	1:45	RIH condition unknown
Well#25	Shut-in	0	0	0	1:00	PBU After 30 min a Δp of –45psi over the next hr
Well#26	25	2.49	400	630	0:15	Seems flowing while RIH then choke reduction
Well#26	Shut-in	0	0	0	0:00	SI while RIH
Well#27	30	5.4	200	100	0:45	Maybe less, appears to be choke changes
Well#27	Shut-in	0	0	0	0:30	PBU As good at 0.5 hr as 1.5
Well#28	BD	NA	NA	NA	Never	Well noflow while RIH, Blow Down
Well#28	Shut-in	0	0	0	0:00	Well SI overnight before RIH

VITAE

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