การประเมินค่าความน่าจะเป็นของปริมาตรน้ำที่อัดลงไปในแหล่งกักเก็บหลายชั้น ที่ไม่สามารถผลิตได้แล้ว

นายธีรศักดิ์ เลื่อมใส

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
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PROBABILISTIC ESTIMATION OF WATER INJECTION VOLUME INTO MULTILAYER DEPLETED RESERVOIRS

Mr. Teerasak Luamsai

A Thesis Submitted in Partial Fulfillment of the Requirements
for the Degree of Master of Engineering Program in Petroleum Engineering
Department of Mining and Petroleum Engineering
Faculty of Engineering
Chulalongkorn University
Academic Year 2009

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By	Mr.Teerasak Luamsai
Field of Study	Petroleum Engineering
Thesis Advisor	Assistant Professor Suwat Athichanagorn, Ph.D.

Accepted by the Faculty of Engineering, Chulalongkorn University in Partial Fulfillment of the Requirements for the Master's Degree

.... Dean of the Faculty of Engineering
(Associate Professor Boonsom Lerdhirunwong, Dr.Ing.)

THESIS COMMITTEE

.... Chairman
(Assistant Professor Jirawat Chewaroungroaj, Ph.D)

.... Thesis Advisor
(Assistant Professor Suwat Athichanagorn, Ph.D.)

.... External Examiner
(Siree Nasakul, Ph.D)

ธีรศักดิ์ เลื่อมใส : การประเมินค่าความน่าจะเป็นของปริมาตรน้ำที่อัดลงไปในแหล่งกักเก็บหลายชั้นที่ไม่สามารถผลิตได้แล้ว (PROBABILISTIC ESTIMATION OF WATER INJECTION VOLUME INTO MULTILAYER DEPLETED RESERVOIRS) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: ผศ. ดร. สุวัฒน์ อธิชนากร, 123 หน้า.

การศึกษานี้ได้ศึกษาการประเมินค่าความน่าจะเป็นของปริมาตรน้ำที่อัดลงไปในแหล่งกักเก็บหลายชั้นที่ไม่สามารถผลิตได้แล้วกับความไม่แน่นอนของการแบ่งสัดส่วนของอัตราการผลิต, ปริมาตรแหล่งกับเก็บและสกินของการอัดน้ำ ความถูกต้องของการประมาณปริมาตรน้ำที่สามารถอัดลงไปในแหล่งกับเก็บขึ้นอยู่กับข้อมูลของความดันเริ่มแรกของแหล่งกับเก็บก่อนการผลิต, ความดันในแหล่งกับเก็บหลังผลิตหรือขณะผลิต, ปริมาตรแหล่งกับเก็บและปริมาตรของการผลิตของแต่ละแหล่งกักเก็บ ข้อมูลดังกล่าวไม่สะดวกในการวัดสำหรับหลุมผลิตที่ผลิตจากแหล่งกักเก็บหลายชั้น ดังนั้นวิธีการทั่วไปที่ใช้ในการประเมินค่าของปริมาตรน้ำที่อัดลงไปในแหล่งกักเก็บหลายชั้นจึงไม่สามารถใช้ได้เนื่องจากข้อมูลไม่เพียงพอ

การประเมินค่าความน่าจะเป็นของปริมาตรน้ำในการศึกษานี้สามารถประเมินค่าได้โดยใช้โปรแกรมแบบจำลอง ผลของการประเมินค่าได้ถูกพิสูจน์ความแม่นยำโดยการเปรียบเทียบกับค่ามาตรฐานซึ่งสร้างขึ้นมาโดยการใส่ค่าของปริมาตรแหล่งกับเก็บที่แน่นอนในโปรแกรม โอเพนเซอร์เวอร์ของตัวโปรแกรมถูกใช้ในการควบคุมการทำงานของโปรแกรมเพื่อสะดวกในการสร้างฟังก์ชั่นการกระจายตัวของปริมาตรน้ำที่สามารถอัดลงไปในแหล่งกักเก็บที่โปรแกรมประเมินออกมาได้

จากผลการศึกษาวิธีการประเมินค่าความน่าจะเป็นของปริมาตรน้ำที่อัดลงไปในแหล่งกักเก็บหลายชั้นในการศึกษานี้สามารถประเมินค่าปริมาตรน้ำที่สามารถอัดลงไปในแหล่งกักเก็บ, ปริมาตรแหล่งกักเก็บและวันที่หยุดการอัดน้ำได้อย่างใกล้เคียงกับค่าจริง ผลของสกินต่อการอัดน้ำมีผลไม่มากต่อประมาตรน้ำที่อัดลงไปได้ แต่มีผลมากต่อระยะเวลาที่ใช้ในการอัดน้ำเพื่อที่จะทำให้ความดันของแหล่งกับเก็บเท่ากับความดันเริ่มแรกก่อนการผลิต

ภาควิชา วิศวกรรมเหมืองแร่และปิโตรเลียม ลายมือชื่อนิสิต..............................

สาขาวิชา วิศวกรรมปิโตรเลียม ลายมือชื่อ อ.ที่ปรึกษาวิทยานิพนธ์หลัก..............................

ปีการศึกษา 2552

4971612721 : MAJOR PETROLEUM ENGINEERING
KEYWORDS: ESTIMATION / WATER INJECTION / MULTILAYER / DEPLETED / RESERVOIRS

TEERASAK LUAMSAI: PROBABILISTIC ESTIMATION OF WATER INJECTION VOLUME INTO MULTILAYER DEPLETED RESERVOIRS. THESIS ADVISOR: ASST. PROF. SUWAT ATHICHANAGORN, Ph.D., 123 pp.

This study is intended to investigate a probabilistic approach to estimate possible water injection volume into multilayer depleted reservoirs by accounting for uncertainties in OGIP, rate allocation and injection skin. The estimation of injection volume depends on the knowledge of the original and current reservoir pressures and cumulative production; given that the final injection pressure should not be higher than the original undepleted reservoir pressure. Since the well has commingled completion, the data for the original and current reservoir pressures, cumulative production and injection skin for each individual reservoir are not available. Therefore, a conventional method of estimating water injection volume based on history matching and material balance is not practical for multilayer reservoirs. The probabilistic estimation introduced in this study uses integrated production modeling (IPM) to forecast production and injection profiles. This estimation is validated by comparing water injection history vs. simulated water injection volume where simulated water injection volume is generated from applying probabilistic estimation. Openserver is used to generate a large number of realizations to create a cumulative distribution function for cumulative water injection volume. From this study, the probabilistic estimation can provide a reliable estimate for water injection volume, total OGIP and the end of injection period. Injection skin has little effect on cumulative water injection but has important effect on the amount of time needed to inject water until a reservoir pressure reaches its original reservoir pressure.

Department: Mining and Petroleum Engineering Student's Signature: ....
Field of Study: Petroleum Engineering Advisor's Signature: Suwat Athichanagorn
Academic Year: 2009

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LIST OF ABBREVIATIONS

BWPD	barrel of water per day
GIP	gas in place
IPR	inflow performance relationship
OGIP	original gas in place
PPM	part per million
PVT	pressure volume temperature
STB	stock tank barrel
SCF	standard cubic foot
TVD	true vertical depth
VLP	vertical lift performance

NOMENCLATURES

G	original gas in place (OGIP)
G_p	cumulative gas production
h	formation thickness
k	formation permeability
k_s	damaged formation permeability
M	thousand
P	pressure
P_i	initial reservoir pressure
P_{wf}	well flowing pressure
q	flow rate
r_s	radius of invasion
r_w	wellbore radius
s	skin factor
S_w	water saturation
t	time
Z	Gas deviation factor

GREEK LETTERS

Φ	porosity
Δ	difference operator
$\sum$	summation

CHAPTER I

INTRODUCTION

Currently, one field in the gulf of Thailand produces about 140,000 bbl/day of water and additional water will be produced from new projects. The field is in the Pattani basin. The Pattani basin is located near the geographic center of the Gulf of Thailand and contains non-marine fluvial-delta plain sediments. Some hydrocarbon productions in the Pattani basin field have matured. Management associated with produced water has become a focus of attention because produced water is the main waste from oil and gas production process. Therefore, produced water has to be disposed. In addition, petroleum industry has been proactive in dealing with the environment impact of oil and gas production, particularly in offshore fields.

Three main alternatives are used to handle produced water. The first method is injecting produced water to drive oil in water flooding project. The second alternative is to inject produced water into wet sands (aquifer) which may not be connected to hydrocarbon. Lastly, but most importantly, produced water can be stored by injecting it into depleted reservoirs. All these three methods are known as “Produced Water Re-Injection (PWRI)”.

To manage produced water, the estimation of cumulative water injection is very important because accurate estimation allows the produced water to be better handled and can avoid production becoming constrained by produced water handling.

Therefore, this study would like to investigate a probabilistic approach to estimate reliable water injection volume into multilayer reservoirs by accounting for uncertainties in OGIP, rate allocation and injection skin.

1.1 Methodology

1. Gather and prepare data for simulation model.
2. Create OpenServer to create and control simulation model.
3. Use Integrated Production Modeling (IPM) to create test model with given required parameters in order to create the production and injection profiles. These

profiles are considered as actual profiles and used as base case to verify the methodology.

4. Run prediction in test model with difference verification period to verify the methodology
5. Comparing and analyzing the results obtained from two verification periods that apply the proposed methodology and uncertainties with the water injection history.
6. Study injection skin effects
7. Create realistic model from actual well information
8. Apply the proposed method with actual well model
9. Analyze the results and conclude

1.2 Thesis Outline

This thesis paper consists of six chapters and the outlines of each chapter are listed below.

Chapter II reviews literatures that mentioned the management of produced water.

Chapter III describes concepts related to this study.

Chapter IV describes the methodology for this study.

Chapter V verifies the methodology by using test and actual models.

Chapter VI provides conclusion and recommendation of the study.

1.3 Expected Usefulness

The probabilistic estimation of water injection volume can be used to estimate water injection volume into multilayer depleted reservoirs that can handle produced water in the future. Predicted produced water injection volume will help engineers to design and prepare facilities to handle produced water in the future.

CHAPTER II
LITERATURE REVIEW

Water injection is a method that is widely used to handle produced water in petroleum industry because it can handle one hundred percent of produced water with low environment impact after being injected into reservoirs. This chapter will demonstrate the management of produced water and the application of water injection.

Sahni *et al.* [1] provided insights into the subsurface alternative of produced water management. Their paper focuses on injecting produced water (1) to drive oil, (2) into aquifer and (3) into depleted oil and gas reservoirs. The advantage of injecting produced water into depleted oil and gas reservoir is the reservoir volume can be estimated from historical production. Another advantage is that an existing produced well can be converted to injection well. The result from a pilot test indicates that depleted oil and gas sand can be used to store produced water.

Sirilumpen *et al.* [2] present how Erawan field in the Gulf of Thailand handle produced water from oil and gas operation to minimize an environment impact. Water treatment and water re-injection are considered. For re-injection option, the injection wells have all been converted from pressured and depleted gas wells by injecting approximately 20,000 BWPD of produced water in 30 wells located on 12 platforms. To estimate produced water disposal capacity, surface volumes of cumulative production are converted to reservoir volumes.

Ahmet *et al.* [3] present produced water management strategy and water injection, including decision tree for evaluating various options. For produced water management, the authors discuss the physical phenomena, namely matrix and fractured injection. Matrix injection is a process whereby contaminants are deposited in the pore spaces of the rock matrix without actually fracturing the formation. The main factor that affects well injectivity during injection of produced water is the rate of formation plugging around the well bore. The rate of formation plugging is influenced by produced water quality. Therefore, long-term injection requires high quality of produced water. Treatment facilities are required to treat produced water.

The requirement of treatment facilities causes higher operating cost. The fractured injection is used to restore injectivity, and has the ability to stimulate itself and to generate new surface area for contaminant injection. The operating cost of fractured injection is lower than matrix injection because it helps reduce surface water treatment facility requirements.

Evans [4] presents produced water management strategy with the aid of decision analysis. Decision analysis can be regarded as a framework for making decisions in an environment of risk and uncertainty. For produced water management, decision analysis is used to evaluate available strategies. The main objective of produced water management strategy are to minimize produced water handling costs, avoid produced water handling becoming a bottleneck to production, maximize asset net present value and minimize environmental impact. For produced water injection, the main alternative strategies are high-pressure water injection above the original fracture pressure, injection under thermal fracturing condition and radial flow injection below the fracture pressure.

Furtado *et al.* [5] present an overview of the produced water injection in Petrobras fields. Produced water injection becomes a solution for produced water disposal because of low environmental impact and low costs. Injectivity decline during a produced water injection is the main problem, mainly if quality of water is poor. To solve this problem, workover with solvents and acid are used to remove the formation damage. When workover efficiency is not enough to maintain injection performance or its cost is too high, injection with pressure above fracture propagation is used.

Bachman *et al.* [6] present produced water injection at high rate. Oil production operations produce large volumes of produced water. The produced water injection is the method of water disposal. The main problem of produced water injection at high rate is large reduction of injectivity. The injectivity is reduced by plugging of solid and oil in water. Contaminants with produced water can cause skin around 200. Consequently, injection pressure increases with time and induced fracturing may take place. Therefore, the authors created a simulation to predict permeability change, fracture propagation pressure to minimize disposal costs. The application of simulation in Masila Block in Yemen shows that it is feasible to sustain over 100,000 BWPD in a single disposal well.

Rubiandni *et al.* [7] present an injection program of produced water injection in mature fields. The reservoir simulation is used to find the most suitable reservoir based on production and pressure history. OGIP and pressure build-up due to injection water for each reservoir can be estimated by reservoir simulation. For operation design, the authors estimated maximum allowable injection volume by plotting the reservoir pressure versus cumulative water injection. Injectivity index and maximum discharge pressure without fracturing the formation can be estimated from the simulation. The maximum discharge pressure can be estimated by using the plot of discharge pressure versus the bottom hole injection pressure for each well.

Khatib *et al.* [8] present produced water management. Produced water is no longer a byproduct of gas and oil production because it can be used for pressure support, for water flood, for enhanced oil recovery and for reuse in other operation. To manage produced water, their paper discusses produced water management principles. These principles included (1) minimizing the volume of produced water to surface during oil and gas production by reservoir and well management, (2) maximizing the re-use of produced water by injecting it to support depleted reservoir pressures or for waterflood, (3) ensuring low impact on the receiving environment.

Rangponsumrit [9] presents well and reservoir management for mercury contaminated waste disposal. Mercury contaminated waste is one of the byproducts from hydrocarbon production in many gas fields. One method to dispose the waste is to inject mercury contaminated waste into confined depleted reservoirs through a depleted well. Mercury contaminated slurry injection was optimized by performing sensitivity simulation on slurry density, injection rate and slurry viscosity. The optimal injection criterion is minimum injection time under a condition that the injection pressure is not high enough to create any fracture in the reservoirs.

CHAPTER III

CONCEPTS AND HYPOTHESIS

To handle produced water, this thesis focuses on injecting produced water into multilayer depleted reservoirs. The advantage of this approach is the existing production well can be converted to injection well, avoiding the costs of drilling new injection well. The production well will be converted to injection well when reservoirs are depleted. The depleted reservoirs are selected to handle produced water, and then the injection program will be executed.

One of the most important aspects of water injection is the calculation of injection water volume. As the water is injected into a reservoir, the reservoir pressure will increase. To avoid interfering production from nearby wells, the final reservoir pressure after injecting water should not be higher than the original undepleted reservoir pressure.

The estimation of water injection volume depends on the knowledge of original pressure, current reservoir pressure, production rate and original hydrocarbon in place. The wells in the production areas of interest have commingled completion penetrating multiple reservoirs, separated by shale. These reservoirs may be produced simultaneously or open/closed in any patterns due to designed schedule. Figure 3-1 illustrates a simple completion design for commingled well that connects to three reservoirs by one tubing.

For comingled well, only production rate of the well is measured, but the current reservoir pressure and production rate and original gas in place (OGIP) of each individual reservoir are not available. Therefore, the estimation of water injection volume based on material balance cannot be performed.

Produced water usually contains contaminants and can cause skins that influence water injection rate and water injection volume. Because injection is not executed at the present time and the skin for each reservoir occurs when the water injection starts, the injection skin is still unknown.

As mentioned above, allocated production rate, original gas in place (OGIP) and injection skin for each individual reservoir are main parameters that affect the estimation of water injection volume. These parameters are considered as uncertainties and will be described in the next section.

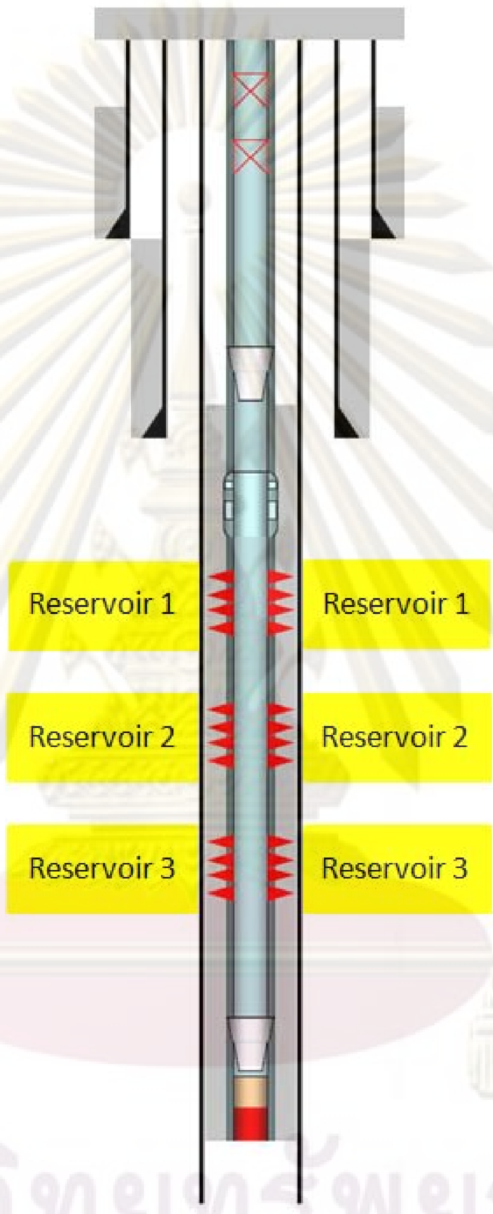

Figure 3-1 : Example of completion design for commingled well

3.1 Uncertainties

3.1.1 Allocation of Production Rate for Each Reservoir

Production rate is one of the most important parameters that affect reservoir pressure. Figure 3-2 illustrates a reservoir produced at different production rates. Higher production rate causes more pressure decline in the reservoir. Lower remaining reservoir pressure can accept more water volume. This figure also shows reservoir pressures when injecting at the same water injection rates. In this case, it takes longer time for the reservoir pressure to get back to the original undepleted reservoir pressure. Since multilayer reservoirs are produced by commingled well, only well production rate can be measured. Production rate and reservoir pressure of each individual reservoir after producing are not available. Furthermore, reservoirs are not produced simultaneously for all periods. Some reservoirs may be closed while others are still produced and these may be changed due to the well schedule. Therefore, allocated production rate for each individual reservoir is an uncertainty.

3.1.2 Original Gas In Place (OGIP)

Original gas in place (OGIP) indicates the capacity of the fluid that can be stored in a reservoir. This can be implied that when OGIP is high, a reservoir can produce more fluid (for the same recovery factor) and it has high pore volume after the reservoir produces hydrocarbon. Thus, a large amount of produced water can be injected back into the reservoir. Figure 3-3 shows the cumulative production, and cumulative water injection for two reservoirs having different OGIPs. If two reservoirs operate at the same separator and injection manifold pressures during the production and injection periods, the reservoir with a higher OGIP can be produced and injected more than the reservoir with a lower OGIP. Furthermore, OGIP also affects the reservoir pressure. The reservoir pressure declines slowly when OGIP is high. Figure 3-4 shows the difference in pressure declines for reservoirs with high and low OGIP that are produced and injected at the same rate.

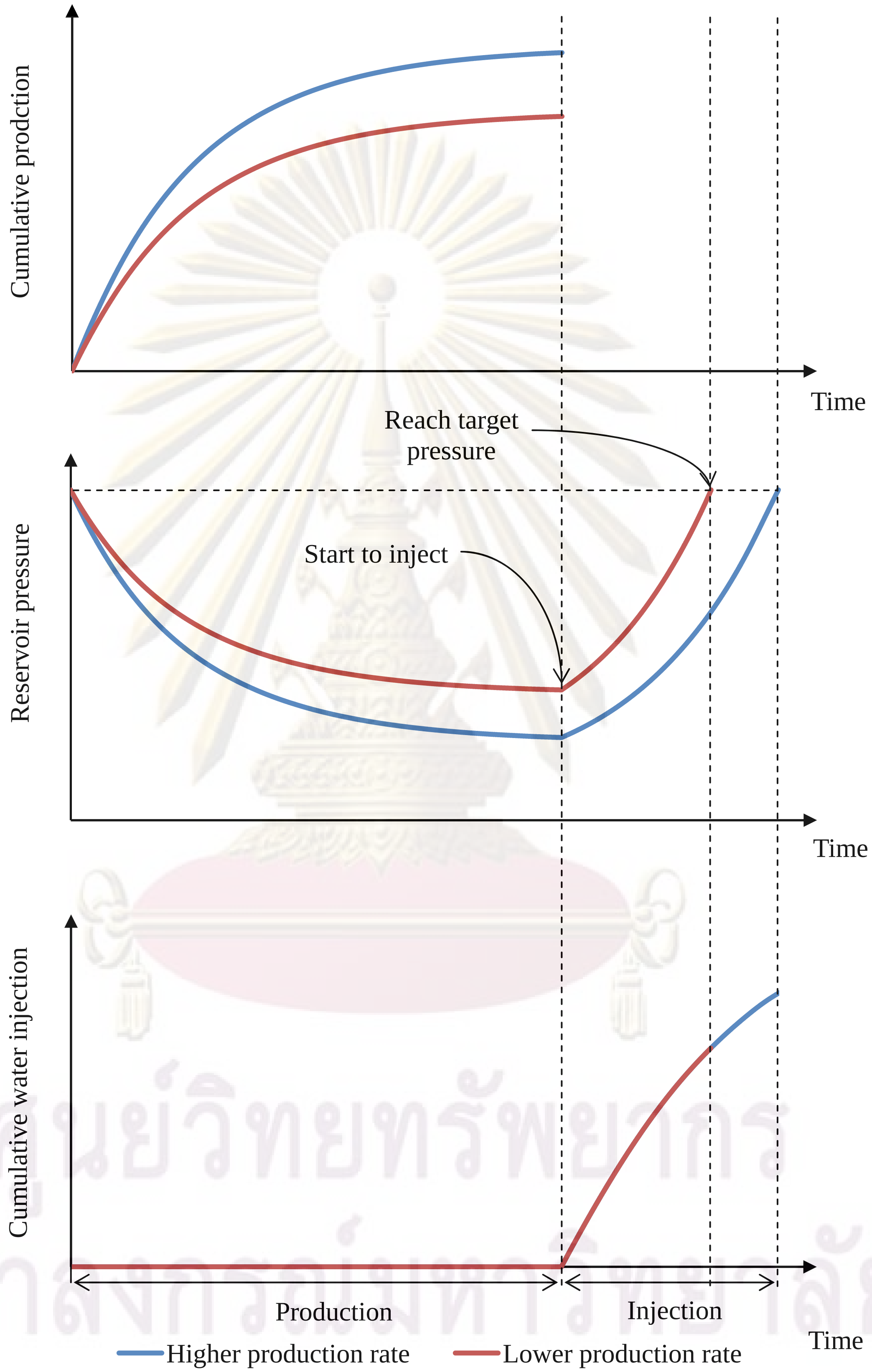

Figure 3-2 : A reservoir produced at different production rates

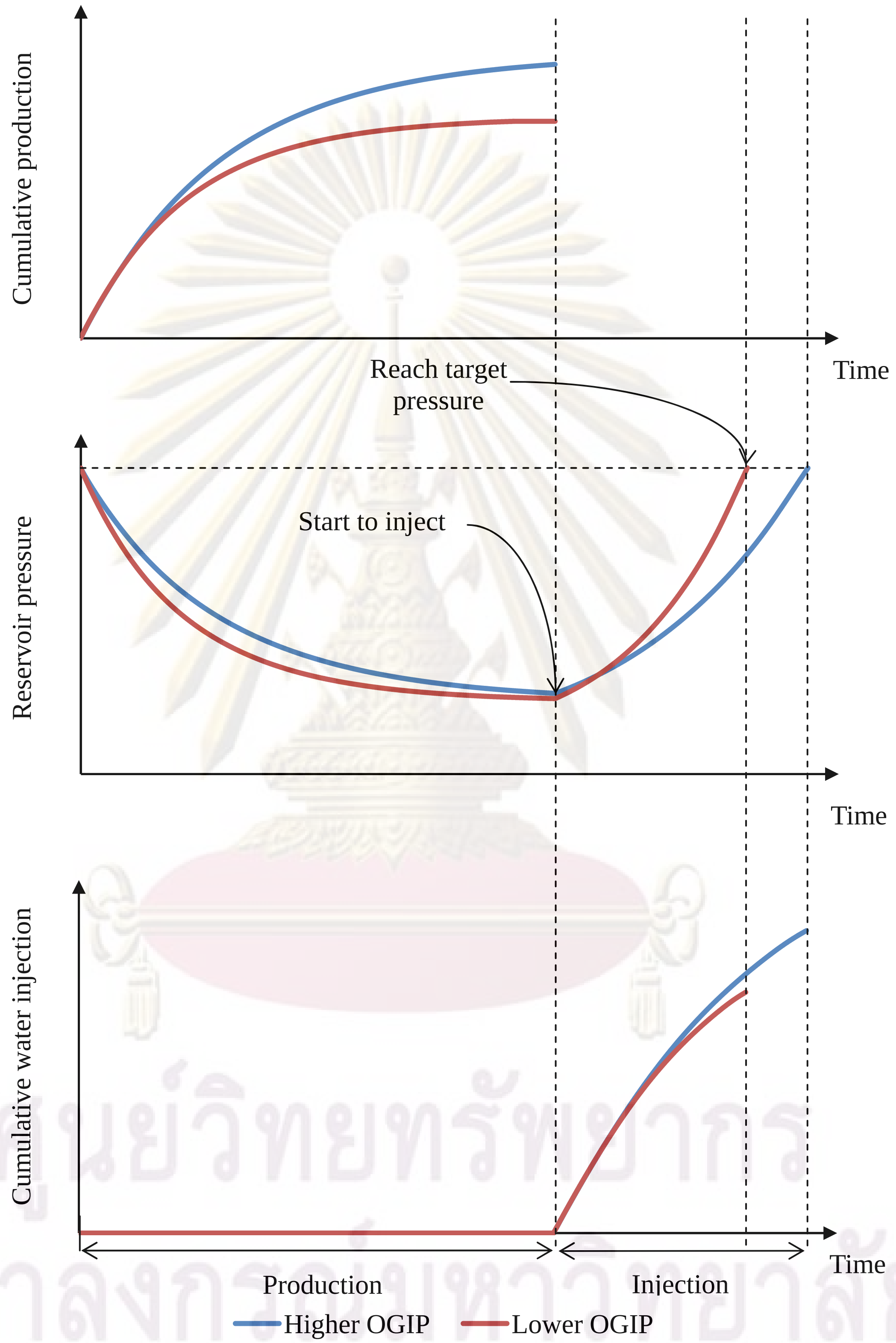

Figure 3-3 : Difference cumulative production and injection of higher and lower OGIP reservoirs at the same separator and injection manifold pressures.

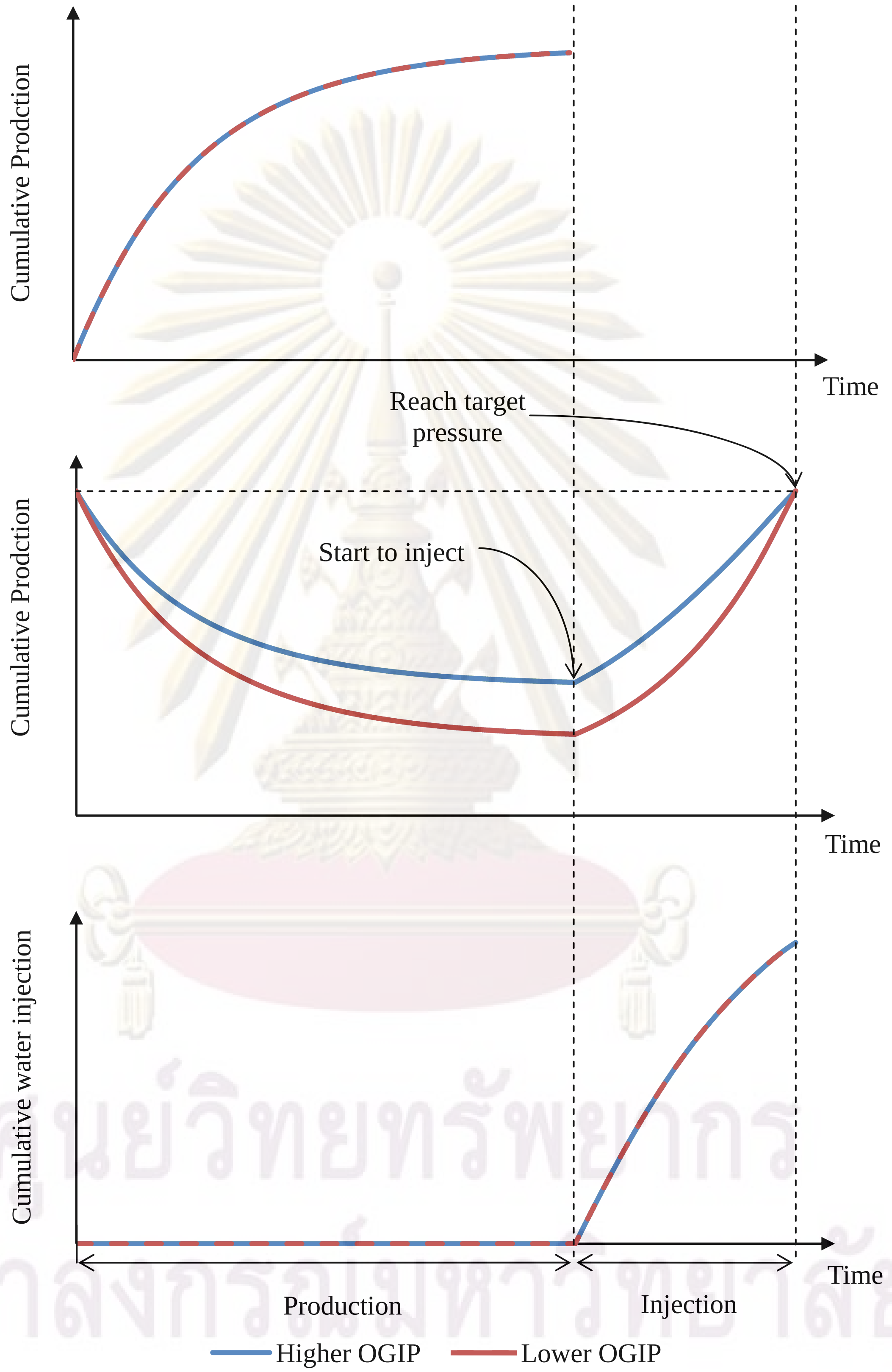

Figure 3-4 : Difference pressure of difference OGIP reservoir when producing and injecting at the same rate.

3.1.3 Injection Skin

Skin causes an excessive pressure difference that occurs around the wellbore and reduces permeability. If existing surface facilities such as injection pump can provide high enough pressure, the well can inject produced water until the reservoir is full. In this situation, a skin reduces only the injection rate. A lower injection rate takes a longer time to inject water for the same volume. A Higher skin requires a higher injection pressure to make the final reservoir pressure equal to the original reservoir pressure. If existing facilities do not have the capability to inject at high pressure to meet high-pressure requirements, a water injection volume is lower than a reservoir capacity. Figure 3-5 illustrates additional pressure difference between wellbore and reservoir due to skin.

To dispose produced water into depleted reservoirs, a method to estimate water injection volume for multilayer commingled reservoirs is required. The conventional method of estimating disposal capacity based on history matching the oil/gas well production performance is not practical given uncertainties in original gas in place (OGIP), production allocation for each individual reservoir and injection skin. The method to estimate produced water disposal capacity that converts production history to water injection volume cannot forecast disposal capacity in the future because we have to know how much a well can produce before converting volume.

Due to lack of information, we cannot estimate water disposal capacity into multilayered reservoirs with accuracy. This research will investigate a probabilistic approach to forecast water injection volume into multilayer depleted reservoirs.

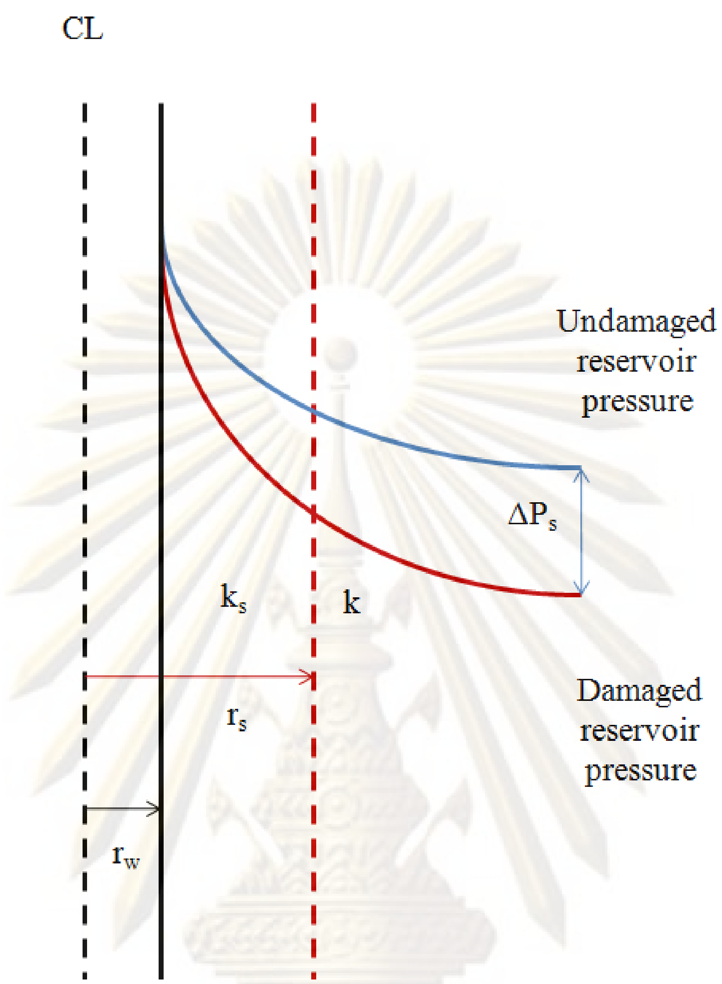

Figure 3-5 : Positive skin causing additional pressure difference while injection

CHAPTER IV
METHODOLOGY

The methodology for this study consists of two main parts. The first part describes how to create models from available information, including reservoir, fluid and well properties. The second part describes the methodology that is used to estimate production and injection profiles.

The probabilistic estimation of water injection volume into multilayer depleted reservoirs investigation is achieved via Integrated Production Modeling (IPM) software program. GAP, MBAL and PROSPER are main modules of Integrated Production Modeling (IPM) tool kit. These modules are used to create models and estimate production and injection profiles.

GAP (General Allocation Package) is a multiphase optimizer of the surface network which links with PROSPER and MBAL to model entire reservoir and production systems. GAP can model production systems containing oil, gas and condensate, in addition to gas or water injection systems. GAP allows the user to build complete system models, including the reservoirs, well and surface system. Its powerful calculation engines allow to model and optimize very complex networks, composed by thousands of elements: wells, pipelines, compressors, pumps, heat exchangers, etc, connected in any possible way. The GAP optimizer allows optimizing the system to maximize a certain objective function for example oil production or both oil and gas production. The applications of GAP can be listed in the following below.

- Full field surface network design
- Field optimization studied with mixed systems (ESP, Gas lift and natural flowing)
- Models full field injection system performance, using MBAL reservoir tank models
- Compressor and Pump system modeling
- Production forecasting

- links to PROSPER (well model) and MBAL (tank model) to allow entire production system to be modeled and optimized over the life of the field

The MBAL package contains the classical reservoir engineering tool, which is part of the Integrated Production Modeling Toolkit (IPM) of Petroleum Experts. MBAL has redefined the use of Material Balance in modern reservoir engineering and helps the engineer define reservoir drive mechanisms and hydrocarbon volumes. For existing reservoirs, MBAL provides extensive matching facilities. Realistic production profiles can be run for reservoirs, with or without history matching. MBAL is commonly used for modeling the dynamic reservoir effects prior to building a numerical simulator model. The applications of MBAL can be listed by following below.

- History matching reservoir performance to identify hydrocarbons in place and aquifer drive mechanisms
- Building Multi-Tank reservoir model
- Generate production profiles
- Model performance of retrograde condensate reservoirs for depletion and re-cycling
- Decline curve analysis
- Monte Carlo simulations
- Reservoir allocation

PROSPER is a well performance, design and optimization program which is part of the Integrated Production Modeling Toolkit (IPM). PROSPER is designed to allow the building of reliable and consistent well model, with the ability to address each aspect of well bore modeling VIZ, PVT (fluid characterization), VLP correlations (for calculation of flow-line and tubing pressure loss) and IPR (reservoir inflow). PROSPER enables detailed surface pipeline performance and design: Flow Regimes, pipeline stability, Slug Size and Frequency. The capabilities of PROSPER can be divided in the following disciplines:

- Fluid modeling (PVT)
- Reservoir model (IPR)
- Well bore and pipeline hydraulics (VLP)
- Artificial lift options
- Flow assurance and advanced thermal options

- Design and optimize well completions including multi-lateral, multilayer and horizontal wells
- Design, diagnose and optimize Gas Lifted, Hydraulic pumps and ESP wells
- Generate life curve for use in simulators
- Calculate pressure losses in wells, flow lines
- Predict flowing temperature in wells and pipelines

OpenSever is a utility of IPM that is designed to provide an open architecture for all Petroleum Experts IPM products. It allows other programs (such as Excel or programs written in Visual Basic) to access public functions in Petroleum Experts programs to automate data transfer, automate procedure and model calculation. Microsoft Excel with Visual Basic is used as the OpenServer to create models, automate transfer parameters, calculation of IPR, procedure, model calculation and record results for this study.

Because this study relates to commingled well, the model has many reservoirs that connect to the tubing of the well. Moreover, the objective of this study is to estimate water injection volume. Injection well is converted from production well after the reservoirs are depleted. Therefore, the model includes both production and injection wells. The tubings of both wells connect to all reservoirs that are shown in Figure 4-1. The reason for having the production and injection wells connects to the reservoir because GAP does not allow the user to convert the well from production well to injection well while the simulation is running. The Production and injection well in the model have the same well properties. These wells are controlled by setting opening/closing with each individual well’s schedule. In the production period, the production well is opened and the injection well is closed. In the injection period, the production well is closed and the injection well is opened.

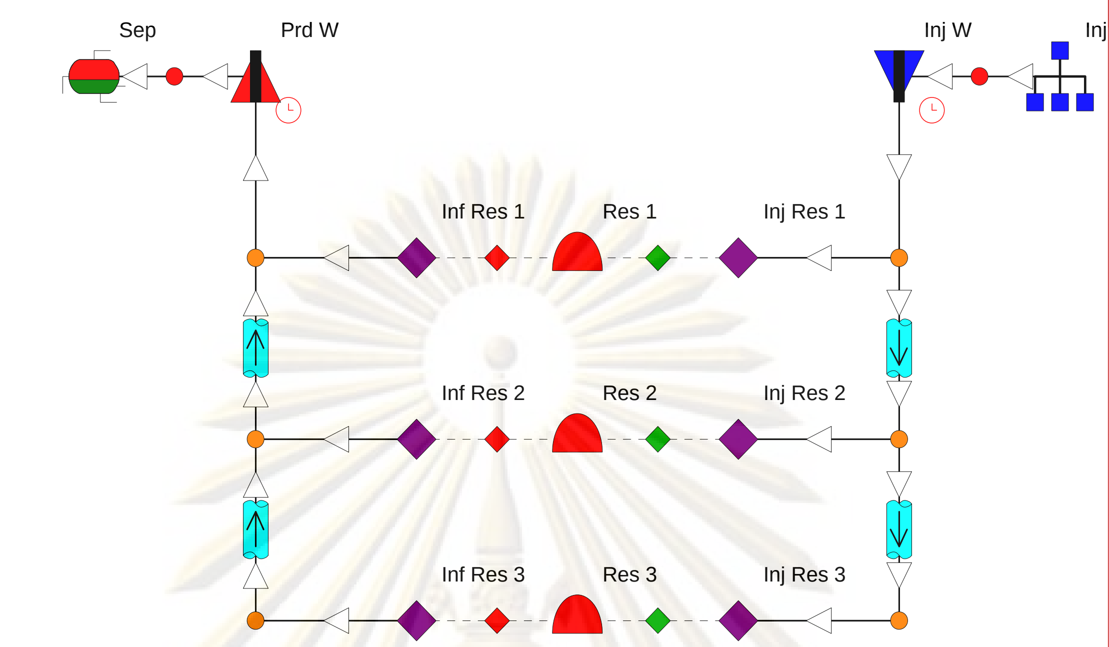

Figure 4-1 : Production and injection wells in the model

The overview of methodology is illustrated in Figure 4-2. The methodology starts from creating model to record prediction results. The details of each step will be described.

To create models, OpenServer creates model by inputting and connecting items automatically in IPM. Separator (Sep) and injection manifold (Inj) in models are considered as wellhead that are used to input production and injection wellhead pressures. Production well (Prd W) and injection well (Inj W) are used to calculate vertical lift performance (VLP). Production inflow (Inf Res) and injection inflow (Inj Res) are used to input injection skin for injection well and calculate inflow performance relationship (IPR) for each individual reservoir.

Since models are created, the next step is to run prediction to evaluate the water injection volume that can be injected into the reservoirs. The prediction process consists of seven steps. The overview of these steps and time line is shown in Figure 4-3.

Figure 4-3 shows the sequences of steps and simulation results as the procedure progresses (the numbers in blue circles indicate the step order that will be described in the next section). Three main sequences of simulation process to estimate water injection volumes are also shown in this figure. In the first sequence, MBAL simulation period, the well production rate from the production history is allocated to each individual reservoir (step 1). Then, Monte Carlo Simulation is applied by varying allocated production rate and original gas in place (OGIP) for each individual reservoir since production rates and OGIPs are considered as uncertainties for multilayer reservoirs (step 2, 3). The new production rate and OGIP are used to calculate the remaining reservoir pressure and gas in place (GIP) by using MBAL (step 4). The objective of Monte Carlo Simulation is to estimate the values of these uncertainties that can make prediction results match with the production history. In the second sequence, the results from MBAL simulation are used to run prediction in the verification period. GAP calculates predicted production during the verification period. The predicted productions are used to calculate percent error at the end of verification period to verify new production rate and OGIP (step 5). In the third sequence, if the percent error is less than acceptable error, the prediction continues to forecast production and cumulative water injection (step 6). If not, repeat in step number 2. Finally, all results are recorded (step 7).

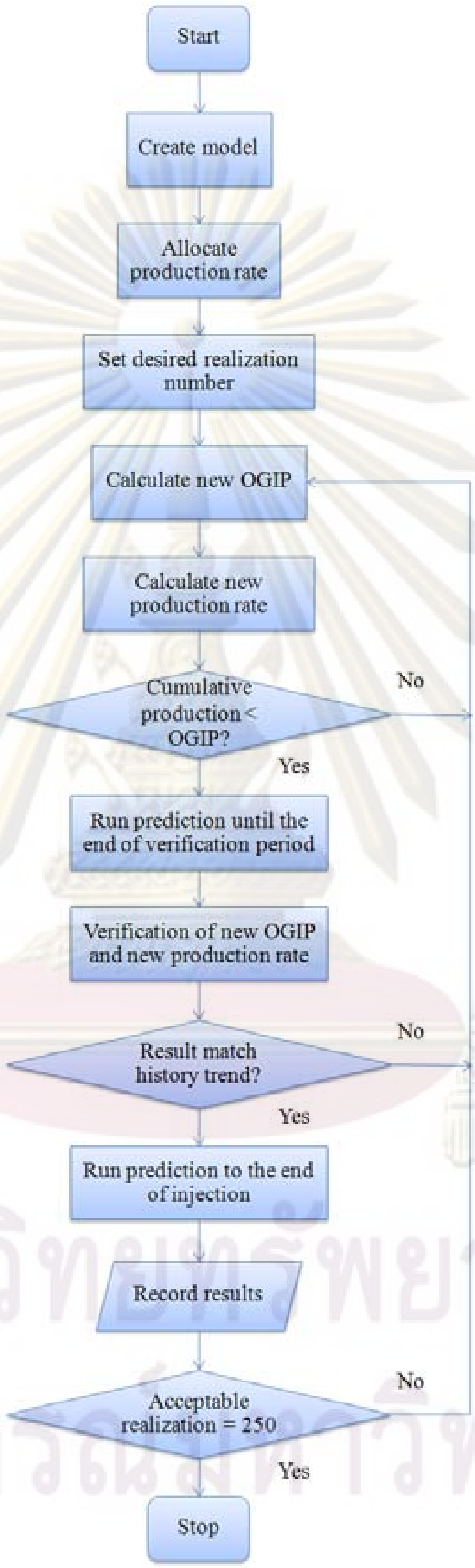

Figure 4-2 : Overview of methodology

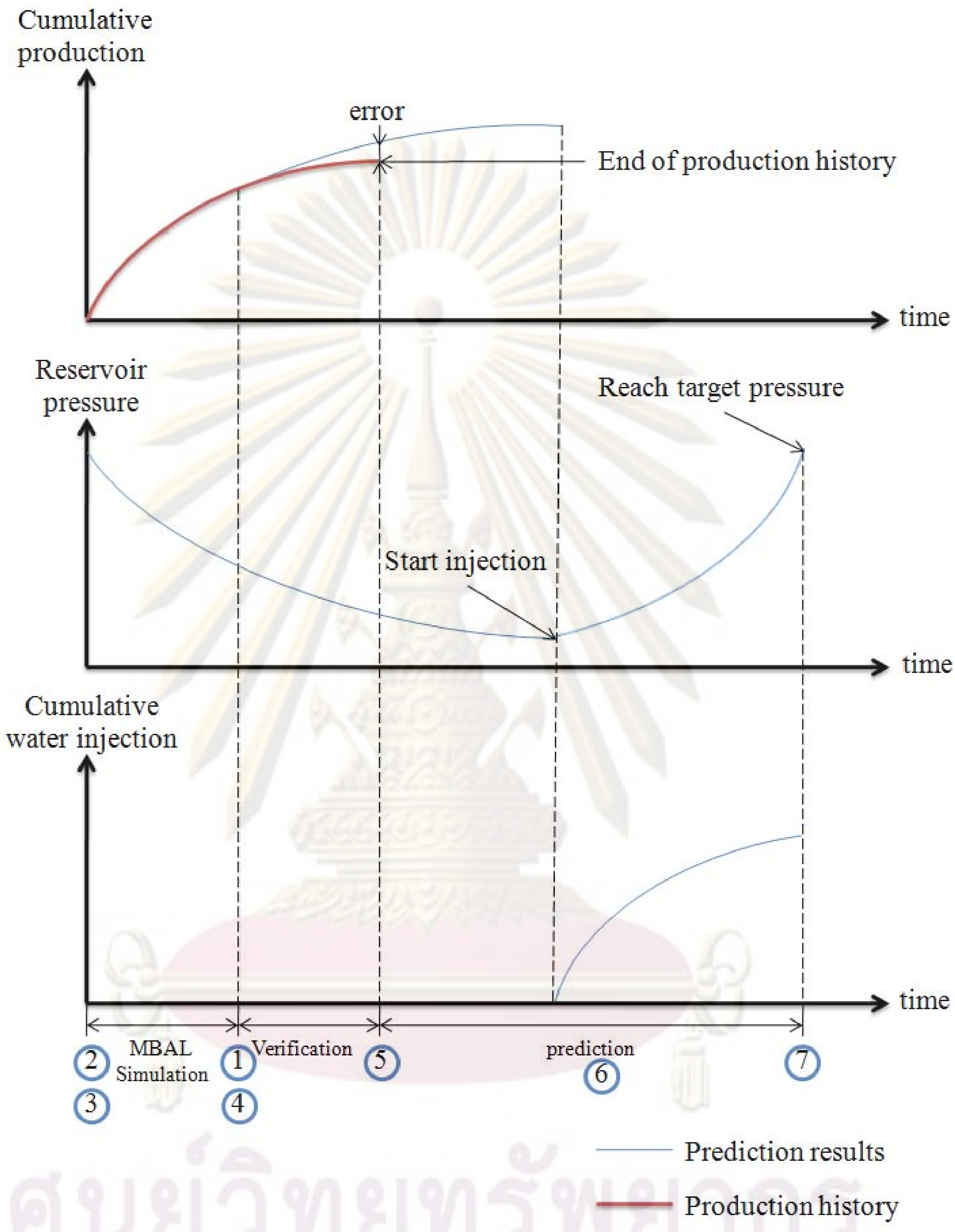

Figure 4-3 : Overview of simulation process (for 1 realization)

4.1 Production Rate Allocation

In this step, well production rate from wellhead is allocated into production rate for each individual sand or reservoir. The production rate is allocated from the start of production history until the date that specify as the start of verification period or the end of production history. In order to allocate production to each reservoir, porosity, water saturation, reservoir thickness and pressure difference between reservoir and estimated well flowing pressure at reservoir depth are required to create the product term, $\phi h(1\text{-}S_w)\Delta P$, used to calculate allocation ratio.

The calculation of allocation ratio can be expressed as Equation 4-1 and 4-2. At a specific time,

$$R_{ij} = \frac{\phi_i h_i (1 - S_{wi}) \Delta p_i}{\sum_{i=1}^{n} \left[\phi_i h_i (1 - S_{wi}) \Delta p_i \right]} \tag{4-1}$$

and

$$\Delta p_i = p_i - p_{wfi,est} \tag{4-2}$$

where

i	=	producing reservoir index
j	=	date
n	=	the number of producing reservoirs at the j^{th} date
R_{ij}	=	allocation ratio for the i^{th} reservoir at the j^{th} date
ϕ_i	=	porosity for the i^{th} reservoir (fraction)
h_i	=	reservoir thickness for the i^{th} reservoir (ft)
S_{wi}	=	water saturation for the i^{th} reservoir (fraction)
ΔP_i	=	the difference between the reservoir pressure and well flowing pressure at the i^{th} reservoir's depth (psi)
P_i	=	reservoir pressure for the i^{th} reservoir (psig)
$P_{wfi,est}$	=	estimated well flowing pressure at the i^{th} reservoir's depth (psig)

Equation 4-1 shows the calculation of allocation ratio for one day only. When allocation ratios of produced reservoirs are created, these ratios are multiplied with well production rates to calculate allocated production rate for each individual reservoir. Allocated production rates are calculated from start of production to the end of production history.

For example,

One well connects to three reservoirs. In January, the well produces from reservoirs number 1 and 2. In February, the well produces from reservoirs number 1, 2 and 3.

In January,

$$R_{1January} = \frac{\phi_1 h_1 (1 - S_{w1}) \Delta p_1}{\phi_1 h_1 (1 - S_{w1}) \Delta p_1 + \phi_2 h_2 (1 - S_{w2}) \Delta p_2}$$

$$R_{2January} = \frac{\phi_2 h_2 (1 - S_{w2}) \Delta p_2}{\phi_1 h_1 (1 - S_{w1}) \Delta p_1 + \phi_2 h_2 (1 - S_{w2}) \Delta p_2}$$

$$R_{3January} = 0$$

In February

$$R_{1February} = \frac{\phi_1 h_1 (1 - S_{w1}) \Delta p_1}{\phi_1 h_1 (1 - S_{w1}) \Delta p_1 + \phi_2 h_2 (1 - S_{w2}) \Delta p_2 + \phi_3 h_3 (1 - S_{w3}) \Delta p_3}$$

$$R_{2February} = \frac{\phi_2 h_2 (1 - S_{w2}) \Delta p_2}{\phi_1 h_1 (1 - S_{w1}) \Delta p_1 + \phi_2 h_2 (1 - S_{w2}) \Delta p_2 + \phi_3 h_3 (1 - S_{w3}) \Delta p_3}$$

$$R_{3February} = \frac{\phi_3 h_3 (1 - S_{w3}) \Delta p_3}{\phi_1 h_1 (1 - S_{w1}) \Delta p_1 + \phi_2 h_2 (1 - S_{w2}) \Delta p_2 + \phi_3 h_3 (1 - S_{w3}) \Delta p_3}$$

In January, reservoir number 3 does not produce; therefore, allocation ratio equals zero. Allocation ratios are calculated for reservoirs number 1 and 2 only.

The calculation of allocated production rate can be expressed as

$$q_{ij} = R_{ij} \times q_{wj} \tag{4-3}$$

where

q_{ij} = allocated production rate for the ith reservoir at the jth date

R_{ij} = allocation ratio for the ith reservoir at the jth date

q_{wi} = well production rate at the jth date

4.2 Calculation of New OGIP

OGIP for multilayer commingled reservoirs are considered as uncertainties. Therefore, Monte Carlo Simulation is applied to OGIP for each individual reservoir. New OGIP for each reservoir is calculated by multiplying OGIP correction factor. The OGIP correction factor is generated by randomly drawing from uniform distribution with the minimum and maximum value for every reservoir. A OGIP correction factor is needed for each reservoir.

4.3 Calculation of New Production Rate

In this step, Monte Carlo Simulation is applied to allocate production rates for all reservoirs that are derived from the first step. Similar to the second step, the rate correction factors are generated by randomization using uniform distribution.

The calculation of new production rate is shown in Equation 4-4 to Equation 4-7.

At a specific time,

$$q'_{ij} = q_{ij} \times X_i \tag{4-4}$$

if

$$\sum_{i=1}^{n} q'_{ij} \neq q_{wj} \tag{4-5}$$

Then

$$N_j = \frac{q_{wj}}{\sum_{i=1}^{n} q'_{ij}} = \frac{\sum_{i=1}^{n} q_{ij}}{\sum_{i=1}^{n} q'_{ij}} \tag{4-6}$$

$$q_{nij} = q'_{ij} \times N_j \tag{4-7}$$

where

i = reservoir index

j = time index

q_{ij} = allocated production rate for the ith reservoir at the jth date

q_{wj} = well production rate at the jth date

q'_{ij} = corrected production rate for the ith reservoir at the jth date

q_{nij} = new production rate for the ith reservoir at the jth date

X_i = rate correction factor for the ith sand

N_j = normalization ratio at the jth date

The rate correction factors are multiplied with allocated production rate to calculate corrected production rate for each individual reservoir (Equation 4-4). The sum of corrected production rate after applying rate correction factor may not be equal to well production rate (Equation 4-5). Therefore, the corrected production rates have to be normalized, by using the well production rate as a constraint.

For normalization method, the sum of corrected production rates from all reservoirs is calculated. It is compared with well production rate to make a normalization ratio. This ratio multiplies with corrected production rates for all reservoirs, so that sum of new production rates is equal to well production rate (Equation 4-7). However, the new cumulative production should not be higher than the new OGIP. If the new cumulative production is higher than new OGIP, repeat the second step to calculate new OGIP.

4.4 Determination of Remaining Reservoir Pressure and GIP

To calculate the remaining reservoir pressure and GIP, the undepleted reservoir pressure or original reservoir pressure, new OGIP and new production rate for each reservoir have to be input into MBAL. New production rates are used as production history. Remaining GIP and the reservoir pressure after producing are calculated by running simulation in MBAL. The calculation of the remaining reservoir pressure and GIP can be described using a plot of P/Z against cumulative production (Gp). This is shown in Figure 4-4.

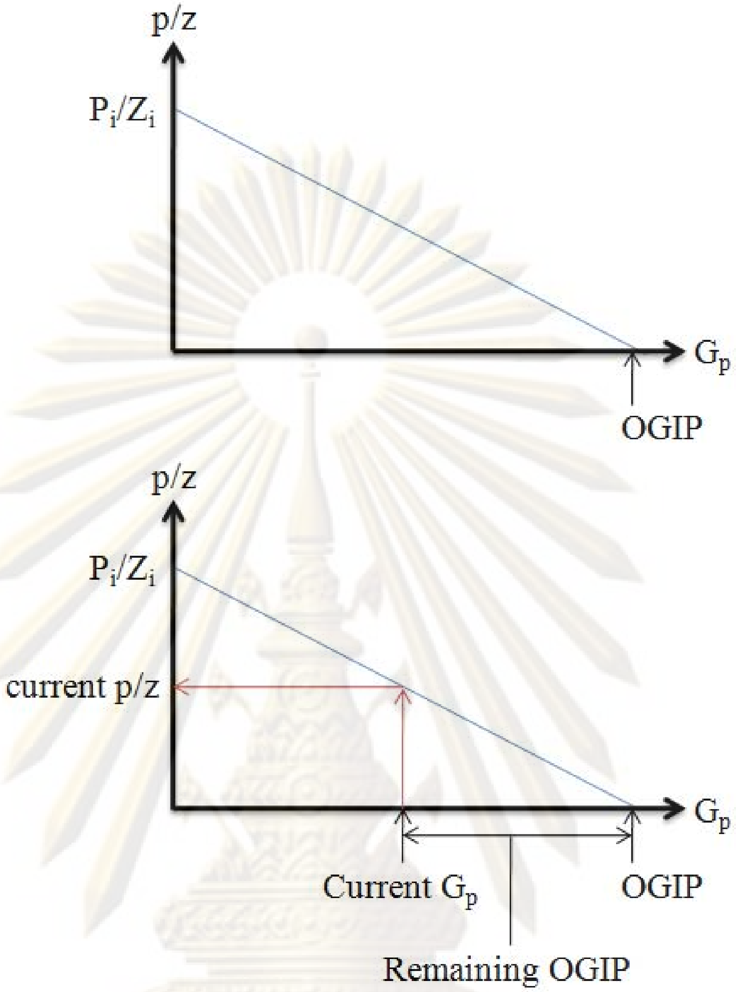

Figure 4-4 : P/Z vs. Gp

MBAL uses the general material balance equation to calculate the remaining reservoir pressure and GIP as Equation 4-8.

$$\frac{P}{Z} = \frac{Pi}{Zi}\left(1 - \frac{Gp}{G}\right) \qquad (4\text{-}8)$$

where

P	=	average reservoir pressure, psia
P_i	=	initial reservoir pressure, psia
Z	=	gas deviation factor, unitless
Z_i	=	initial gas deviation factor, unitless
G_p	=	cumulative gas production, scf
G	=	original gas in place (OGIP), scf

The assumptions for this equation are no aquifer influx and the rock compressibility is negligible. Only depletion drive due to gas expansion is considered. A plot of P/Z versus cumulative gas production (Gp) is a straight line. The intercept in the y-axis represents the initial pressure divided by the initial gas deviation factor. The intercept in the x-axis represents OGIP. When OGIP, initial pressure and cumulative production are known, the remaining reservoir pressure can be calculated by reading P/Z value from the y-axis as shown in Figure 4-4. The pressure can then determined by iterating on the value of pressure and gas deviation factor until the value of iterated P/Z equals the value read from the y-axis.

4.5 Verification of Rate Allocation and OGIP

The remaining reservoir pressure and GIP after producing gas have to be input as initial pressure and OGIP in new MBAL file. GAP runs prediction from the start of verification period to the end of production history. The start of verification period can be specified from the start of production date to the date that all reservoirs finish production. The shortest verification period should be specified for all reservoirs being produced at the same time.

At the end of verification period, prediction results are compared with production history. Percent errors between actual production rate and prediction results have to be calculated. The percent error value implies how appropriate the values of new OGIP and new production rate are. Thus, if the percent error is higher than the acceptable error, this prediction run will be marked as “unacceptable” realization (the values of new OGIP and new production rate are not good enough to make the prediction results to match the trend of production history). For unacceptable realization, prediction run has to stop and the second step needs to be repeated (drawing new random OGIP value). On the other hand, if the prediction run is marked as “acceptable” realization, the prediction run will continue to the next step.

In order to determine the error, cumulative production is used to compare the difference between production history and prediction results. The criterion, which is error in cumulative production, is used in this study.

4.5.1 Error in cumulative production

In this method, the prediction is run until the end of production history. Then, percent error is calculated by comparing the predicted production profile with actual production profile during a period chosen as verification period.

The cumulative productions from production history and prediction results in the verification period are used to calculate the average historical and predicted production rates in this period as shown in Figure 4-5.

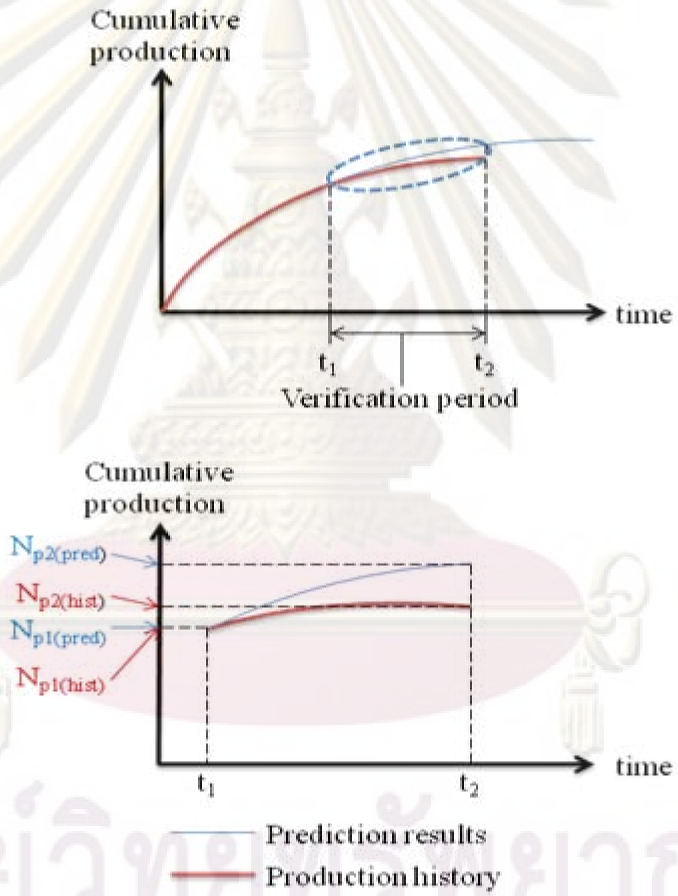

Figure 4-5 : Cumulative production

The percent error of prediction results is calculated by using the equation 4-9. The difference between the prediction cumulative production and historical cumulative production is divided by the difference historical cumulative production within verification period.

$$\varepsilon = \left[\frac{\left(N_{p2} - N_{p1}\right)_{pred} - \left(N_{p2} - N_{p1}\right)_{hist}}{\left(N_{p2} - N_{p1}\right)_{hist}} \right] \times 100 \qquad (4\text{-}9)$$

where

ε	=	the (error) between production history and prediction results (in percent)
$N_{p1\ (hist)}$	=	cumulative production at the start of verification period from production history
$N_{p2\ (hist)}$	=	cumulative production at the end of verification period from production history
$N_{p1\ (pred)}$	=	cumulative production at the start of verification period from prediction results
$N_{p2\ (pred)}$	=	cumulative production at the end of verification period from prediction results

4.6 Forecast of Future Production and Water Injection Volume

After the values of new OGIP and new production rate are verified or the percent error less than acceptable error, the prediction will be continued. GAP runs prediction to predict future production until the well is converted from production well to injection well. At this moment, Monte Carlo Simulation is applied to another uncertainty variable; injection skin. The injection skin for each individual reservoir is generated by randomizing within the minimum and maximum range without correction factor. The generated injection skins are used directly in the prediction period. After the generated values of injection skin are applied to all layers, PROSPER calculates IPR for each individual reservoir. The prediction continues to forecast cumulative water injection, constrained by surface equipment and the original reservoir pressure.

Finally, OpenServer records prediction results. The cumulative water injection including correction factors and injection skin for all reservoirs are recorded. New prediction run (realization) will start from the second step until it reaches the maximum number of realization or until there are enough acceptable realizations to create the distribution of uncertainties and cumulative water injection.

4.7 Creating Distribution for Prediction Results

Several plots will be made in order to study the distribution of uncertainties and the relationship among themselves. These include cumulative distribution functions (CDF) of total cumulative water injection, total OGIP from all reservoirs, end of injection period and the relationship between error and uncertainty variables.

CHAPTER V
VERIFICATION OF METHODOLOGY

There are two main cases used in this study: test case and actual case. The test case is used to verify the methodology and the actual case is used to apply the proposed method with actual information of the well. The details of test and actual cases will be described.

5.1 Test Case

The test case is used to verify the methodology by assuming all parameters are known. This section describes details of the test model, how to generate production and injection profiles, how to use test model to verify the methodology and study effect of injection skins.

5.1.1 Generation of Production and Injection Profiles

The test model is the model with all parameters that are required for generating production and injection profiles are known. Both production and injection profiles are considered as actual production and injection history that are used as the base case to calculate percent error of prediction results. The methodology proposed in this study is applied to the test model to verify the methodology.

Figure 5-1 shows the detail of the test model that consists of production and injection wells. There is actually one well but we need to construct two wells in the software in order to use one as producer and the other as injector. The inside diameter of the well is 3.5 inch. The separator and injection manifold pressure is set at 750 psig and 1,500 psig, respectively. Perforation interval for each individual reservoir is equal to the reservoir thickness. The two wells connect to three gas reservoirs. These reservoirs do not connect to one another. Only the tubing connects to each reservoir. The three reservoirs in the model are reservoir A, reservoir B and reservoir C. Fluid and reservoir properties are shown in Table 5-1 and Table 5-2, respectively. All these data are set to be constant throughout the simulation model. In Figure 5-1, “Sep” represents separator, “Inj” represents injection manifold, “Prd W” and “Inj W” represent production and injection wells, Res A, B and C represent reservoir names.

In this study, the OpenServer creates the model by inputting and connecting items (such as well, separator, inflow and reservoir) in GAP. Necessary parameters can also be transferred from Microsoft Excel to GAP, PROSPER and MBAL.

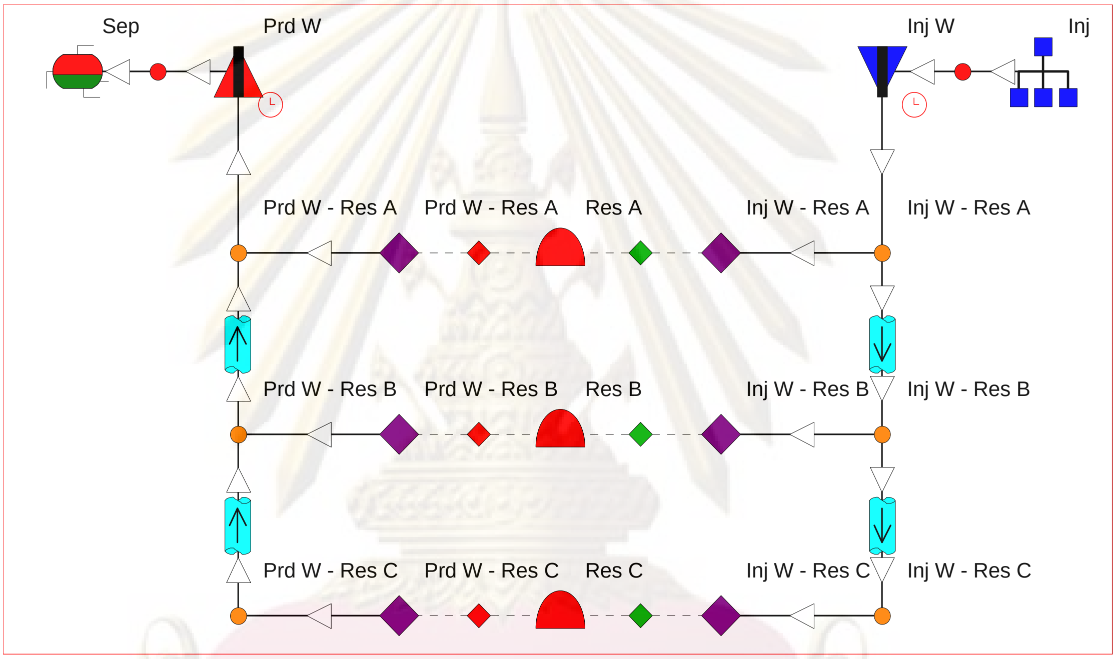

Figure 5-1 : Test model

Table 5-1 : Fluid properties of test model

Fluid Properties			
Reservoir name	A	B	C
Gas gravity (sp. gravity)	0.774	0.728	0.8
Condensate to gas ratio (STB/MMscf)	4.35	6.19	4.35
Condensate gravity (API)	59.5	63	58
Water to gas ratio (STB/MMscf)	6.4	6.19	7.5
Water Salinity (ppm)	100,000	100,000	100,000
Mole percent of H2S (percent)	0	0	0
Mole percent of CO2 (percent)	17.2	14.95	23.86
Mole percent of N2 (percent)	0.93	1.38	0.34

Table 5-2 : Reservoir properties of test model

Reservoir Properties			
Reservoir Name	A	B	C
Temperature (deg F)	350	355	360
Initial pressure (psig)	3,500	3,550	3,600
Porosity (fraction)	0.05	0.05	0.05
Connate Water Saturation (fraction)	0.1	0.1	0.1
Original Gas In Place (MMscf)	25,000	30,000	35,000
Reservoir Permeability (md)	80	80	80
Reservoir Thickness (feet)	100	125	150
Drainage Area (acre)	150	150	150
Bottom Depth of Reservoir (TVD, feet)	7,000	7,500	8,000
Injection Skin	0	0	0
Start of Production (m/d/y)	1/1/2000	1/1/2000	1/1/2000

5.1.1.1 Generation of production profile

After defining reservoir and fluid properties, production profile is generated using data in the test model. To generate production profile, the injection well is closed. GAP is used to simulate production profile from 1st January 2000 to 1st January 2025. The generated production profile is used to observe the time that all reservoirs are almost depleted, i.e, the production rates for the well become lower than 1 MMscfd. This time is then chosen as the start of injection period.

The results generated by the test model are shown in Figure 5-2 to Figure 5-7. Figure 5-2 shows cumulative gas production. Figure 5-3 shows gas production rate of the production well. Figure 5-4 shows the cumulative gas production for each individual reservoir. Reservoir C has the highest cumulative gas production while reservoir A has the lowest. Reservoir C has the highest cumulative production because it has the highest OGIP (35,000 MMscf) in the test model. Figure 5-5 shows gas production rates for each reservoir. Reservoir C also has the highest gas production rate while reservoir A has the lowest gas production rate. Figure 5-6 shows the reservoir pressure for each reservoir that responds to gas production. Figure 5-7 shows recovery factor of each reservoir. On 1st July 2012, cumulative production of the well is 66,660.532 MMscf. More information of the production profile is shown in Appendix A, and the procedure to set up reservoir model is shown in Appendix B. The production rate of production well is 0.977 MMscfd. Gas recovery factor for each reservoir is around 74 percent. The start of injection date for test model is set on 1st July 2012.

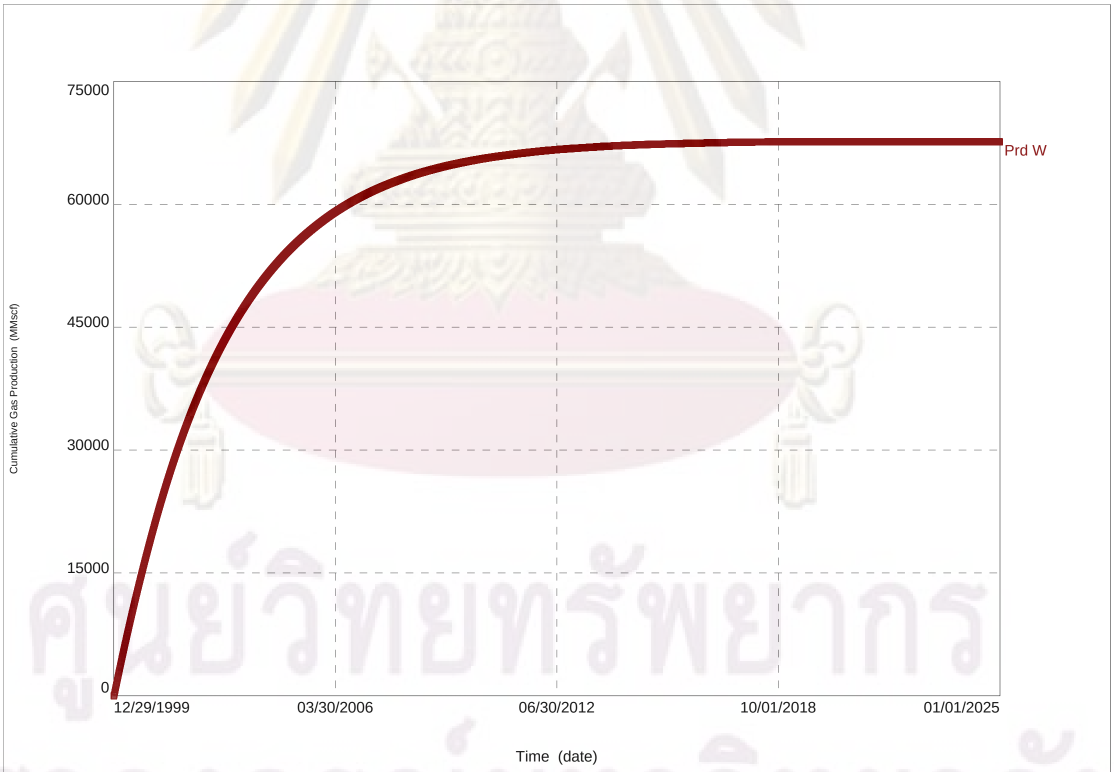

Figure 5-2 : Cumulative gas production (MMscf) for production well

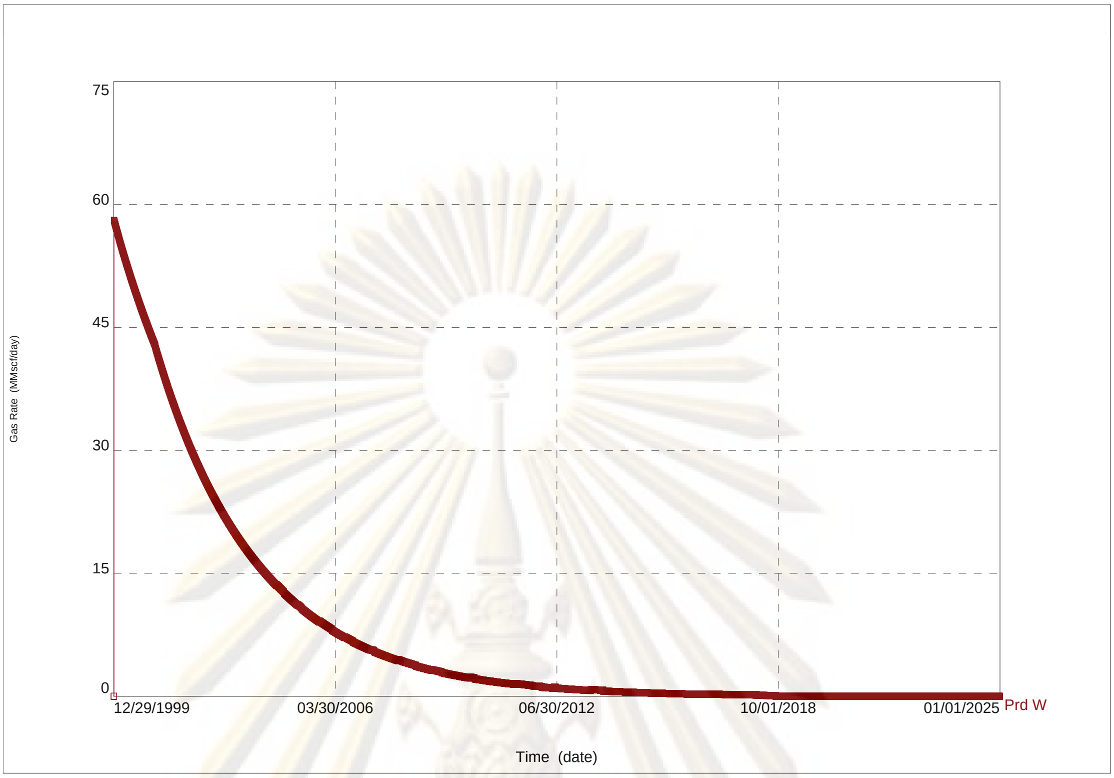

Figure 5-3 : Gas production rate for production well

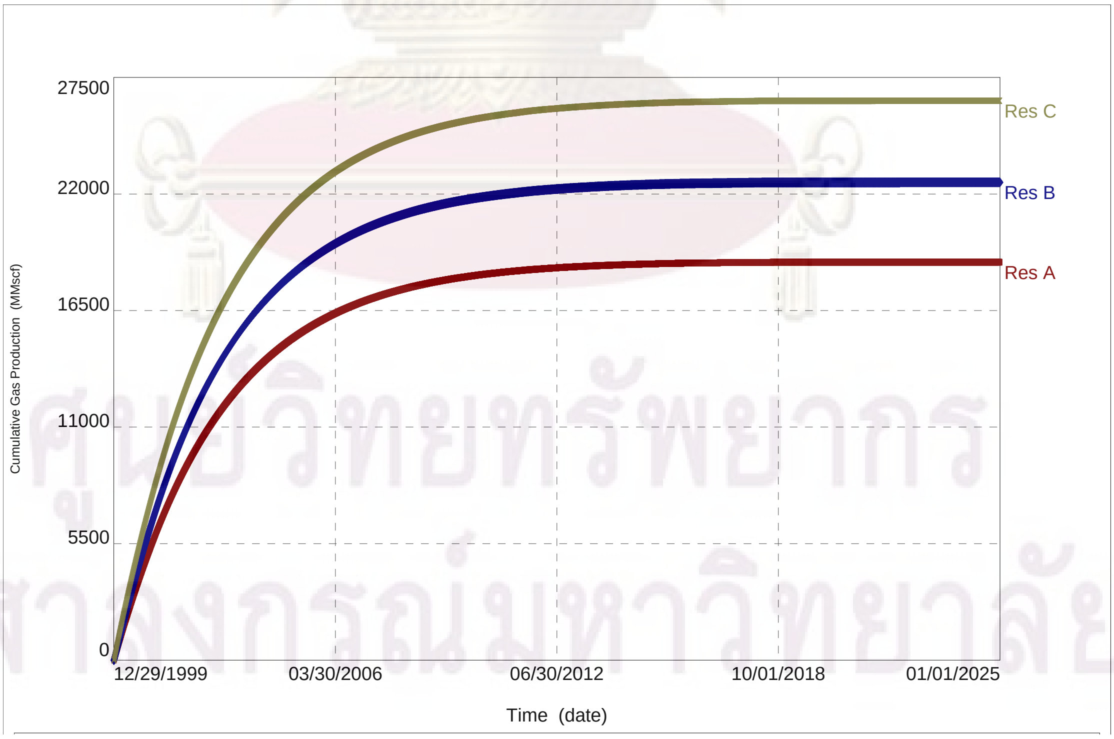

Figure 5-4 : Cumulative gas production for each reservoir

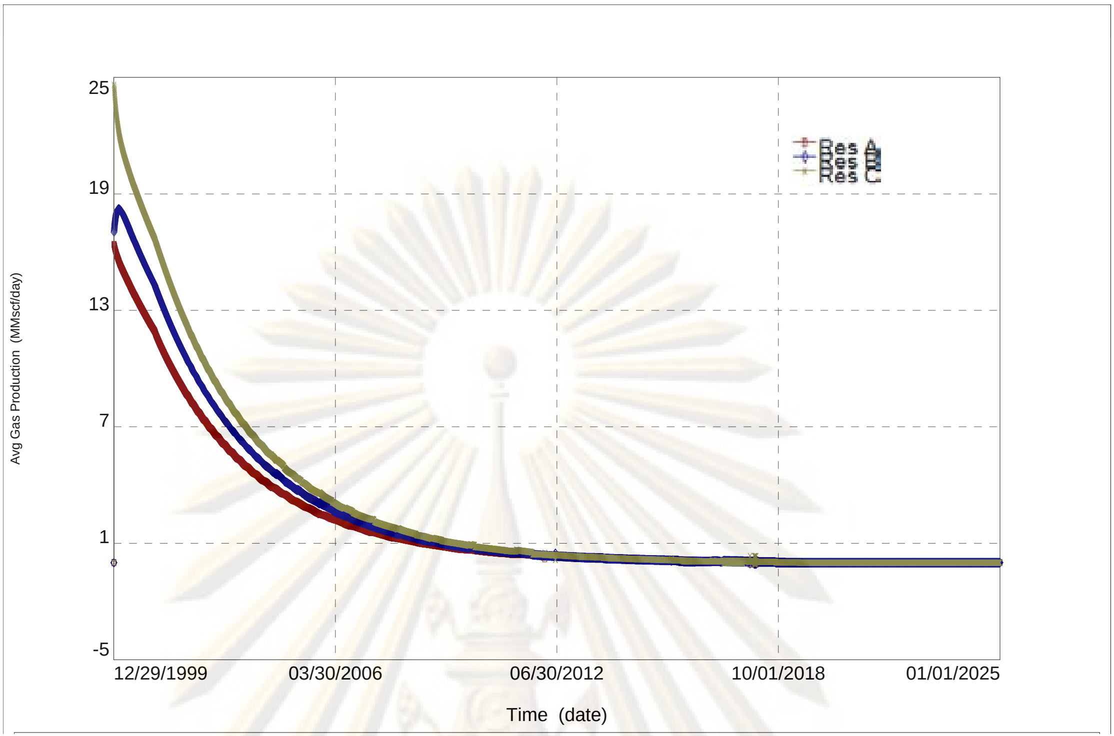

Figure 5-5 : Gas production rate for each reservoir

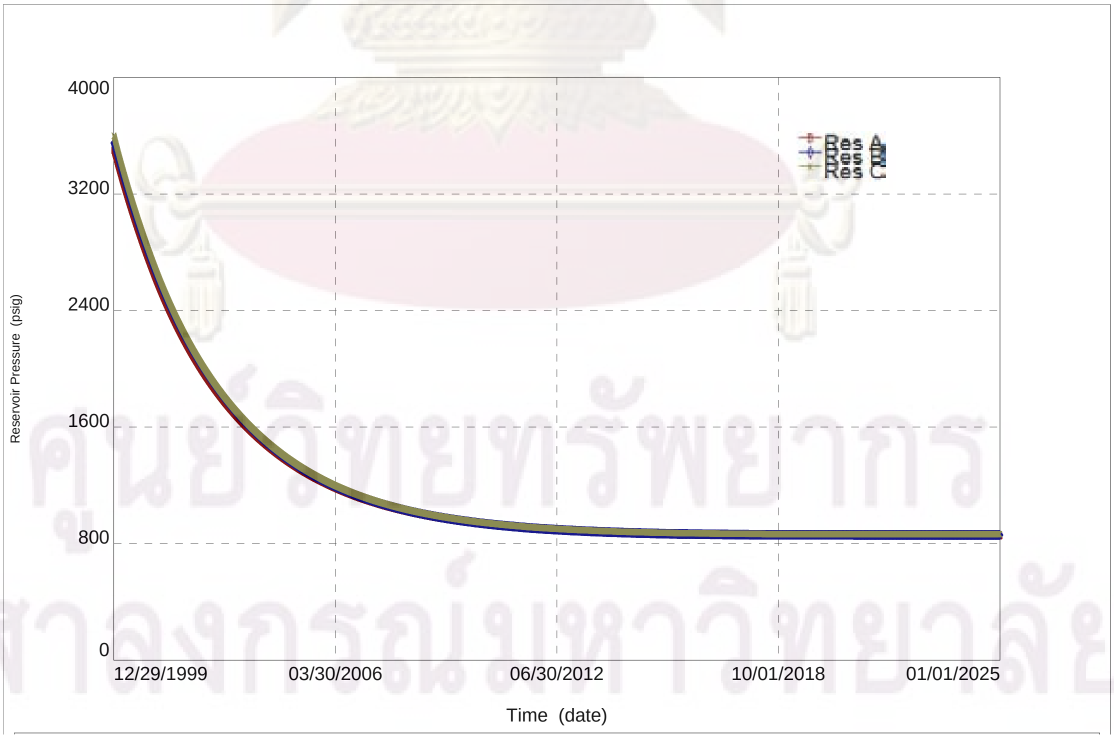

Figure 5-6 : Reservoir pressure after producing for each reservoir

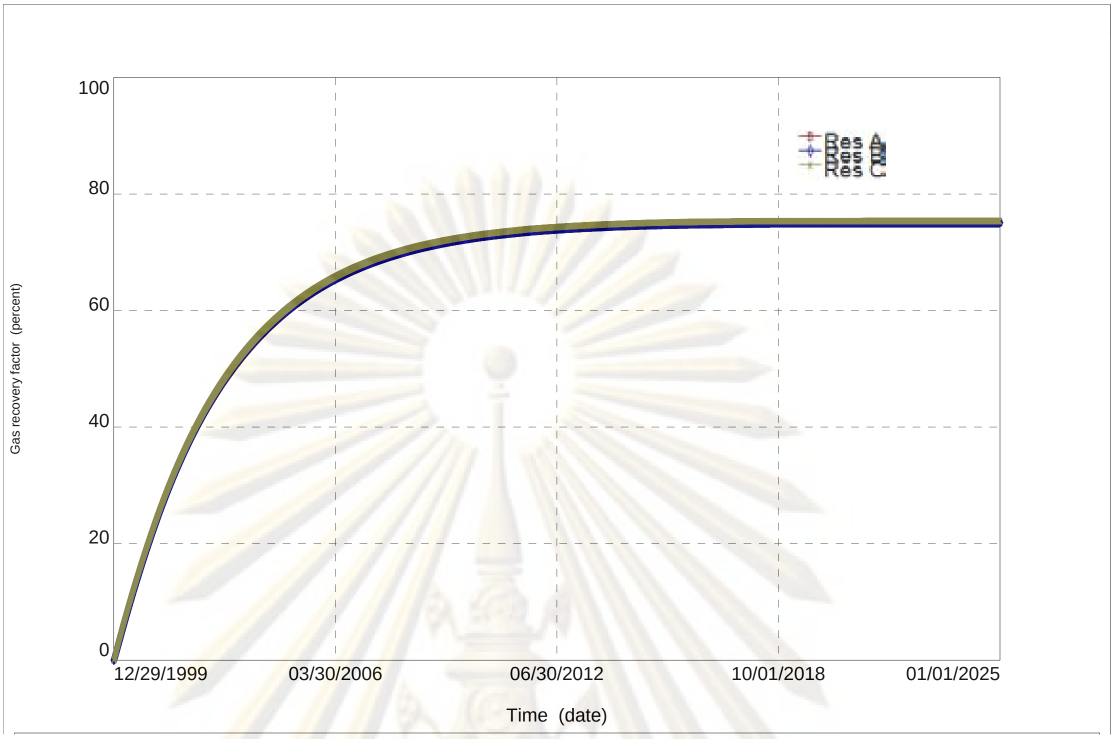

Figure 5-7 : Gas recovery factor for each reservoir

5.1.1.2 Generation of injection profile

The objective of this section is to estimate the cumulative water injection and the time to stop water injection, i.e., the time when the reservoir pressure reaches the original pressure.

The injection profile is generated after the production period has ended. GAP is used to generate the injection profile. On 1st July 2012, the production well is closed, and the injection well is opened in order to change the model from production mode to injection mode. Injection skin for all reservoirs are set to 0 (no skin) to eliminate the skin effect on the injection profile.

The results are shown in Figure 5-8 to Figure 5-13. Figure 5-8 shows the well cumulative water injection that can be injected into the reservoirs. The maximum water injection volume is around 77 MMstb. Figure 5-9 shows the water injection rate for the injection well. Figure 5-10 shows cumulative water injection for each reservoir. Reservoir A has the lowest cumulative water injection and reservoir C has the highest cumulative water injection because this reservoir produces the highest volume of gas and it has the highest OGIP. Figure 5-11 shows water injection rate for each reservoir. Reservoir A has the lowest water injection rate, and reservoir C has the highest water injection rate. Figure 5-12 shows the predicted reservoir pressure for each reservoir. Corresponding to cumulative water injection as seen in Figure 5-12, reservoir C is the first reservoir that the pressure reaches the original pressure after injecting water into the reservoir because reservoir C has the highest perforation interval and the highest well flowing pressure that is shown in Figure 5-13. Therefore, reservoir C has the highest injection rate when compared with other reservoirs. The pressure of reservoir C reaches the original pressure on 7th January 2018. On this date, the cumulative water injection of the injection well is 69.282 MMstb, and the cumulative water injection for reservoir A, B and C is 19.622 MMstb, 23.562 MMstb and 27.144 MMstb, respectively. Therefore, 69.282 MMstb of cumulative water injection is considered as the actual cumulative water injection and used as a water injection history to verify the methodology.

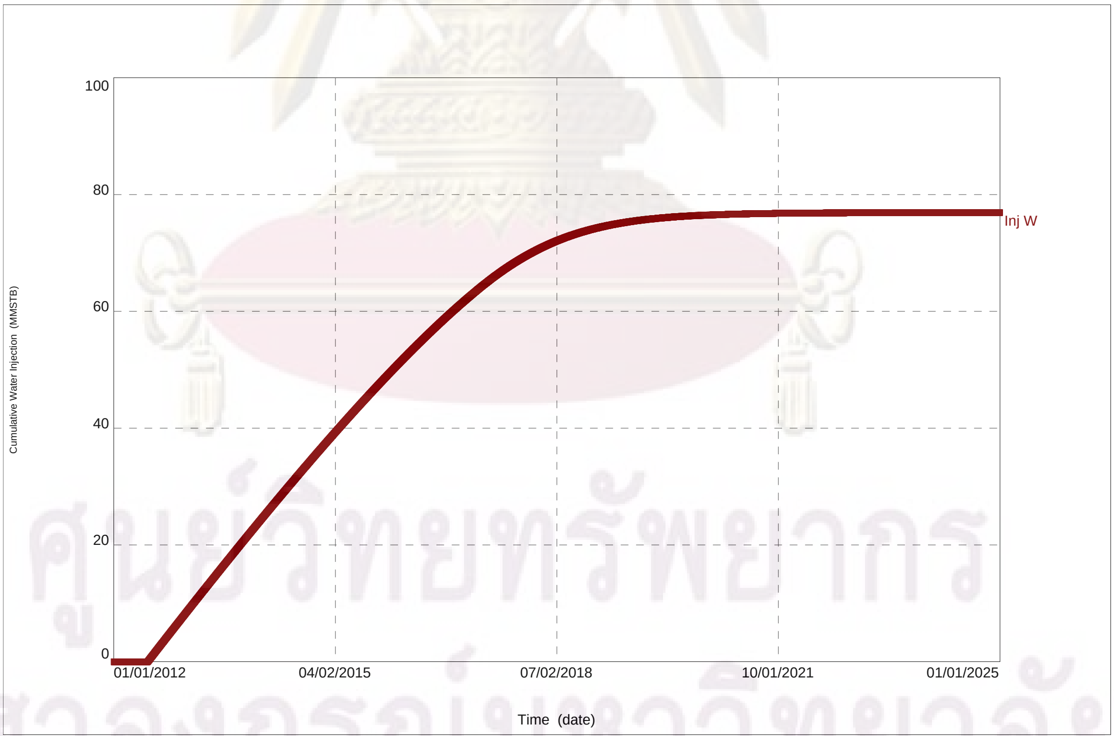

Figure 5-8 : Cumulative water injection as a function of time

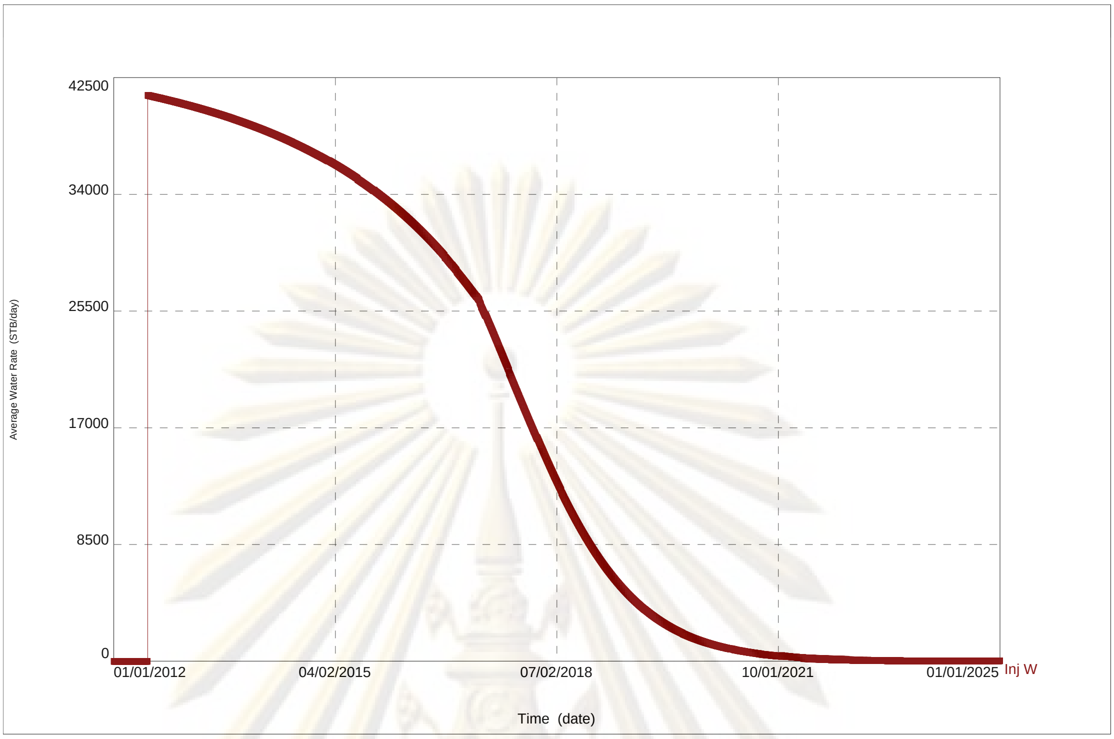

Figure 5-9 : Water injection rate as a function of time

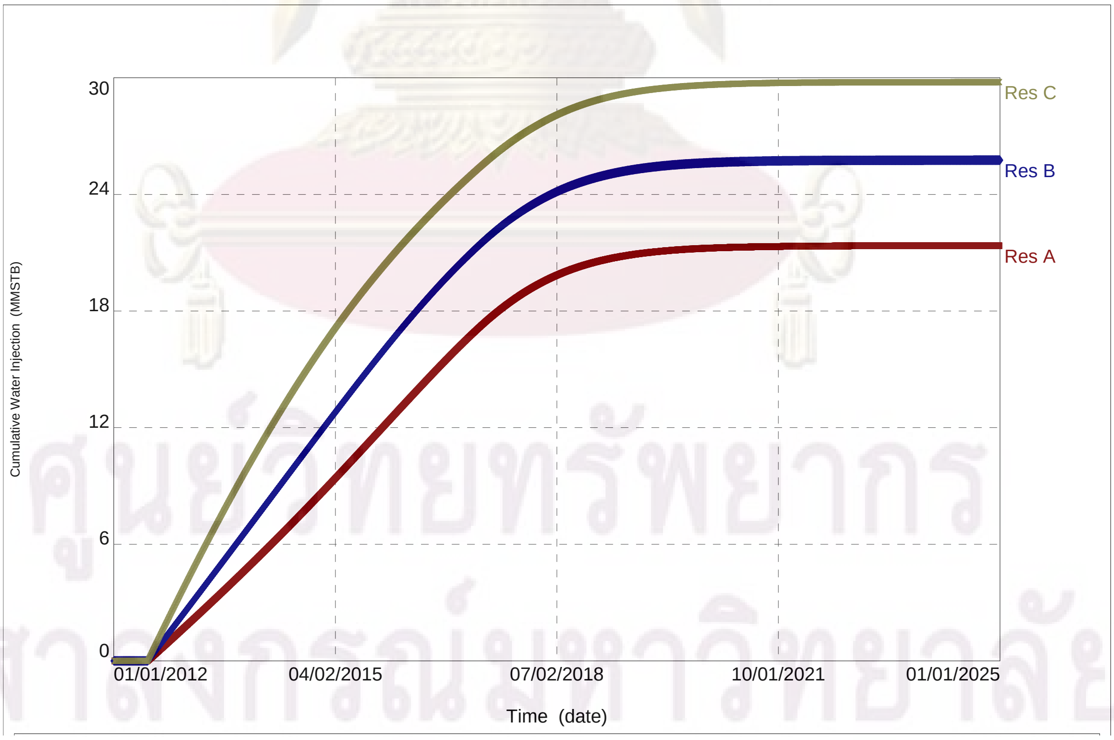

Figure 5-10 : Cumulative water injection for each reservoir

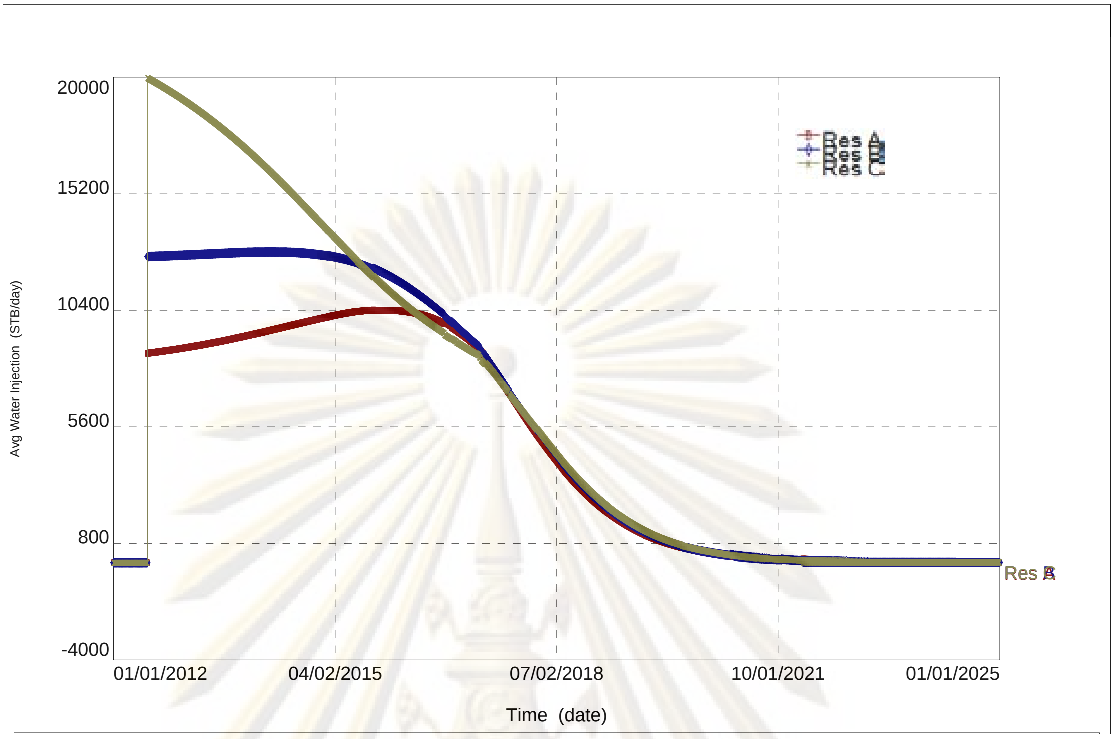

Figure 5-11 : Water injection rate for each reservoir

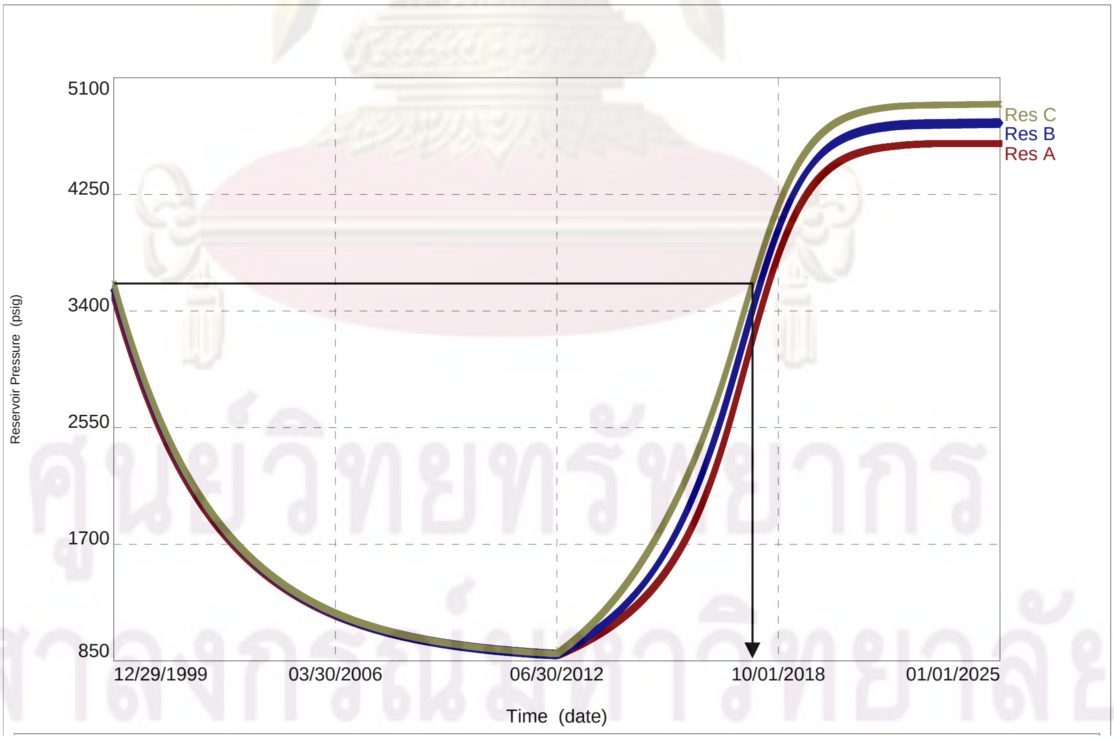

Figure 5-12 : Predicted reservoir pressure for each reservoir

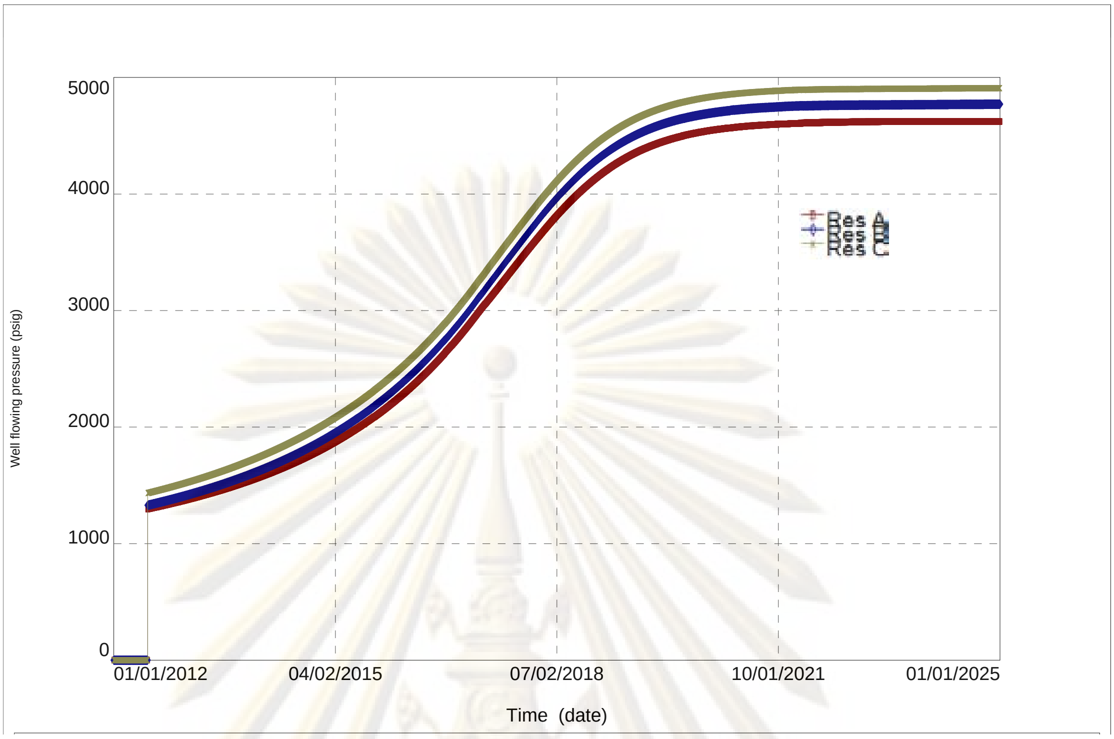

Figure 5-13 : Well flowing pressure for each reservoir

5.1.2 Determination of OGIP

After generating production and injection data, the next step is to use the data to estimate OGIP. This OGIP will be compared with actual OGIP in order to validate the methodology. Production rate allocation correction factor is set to 1 (no variation). After allocating production rate, gas cumulative production for reservoir A, B and C on 1st July 2012 is 19,369.43, 22,454.49 and 24,836.61MMscf, respectively.

In order to find OGIP, we need to assume a recovery factor. In this study, the recovery factor for each reservoir is set at 70 percent. Therefore, the estimated OGIPs can be calculated by dividing cumulative allocated production by the recovery factor. The estimated OGIP for reservoir A, B and C is 27,670.614, 32,077.843 and 35480.871 MMscf, respectively. Cumulative allocated productions and estimated OGIPs are shown in Table 5-3.

Table 5-3 : Estimated OGIP

Reservoir name	Res A	Res B	Res C
Cumulative allocated production	19,369.43	22,454.49	24,836.61
Recovery factor	0.70	0.70	0.70
Estimated OGIP	27,670.61	32,077.84	35,480.87

5.1.3 Determination Range of OGIP Correction Factor

After estimating OGIPs, the next step is to use the estimated OGIPs to estimate the range of OGIP correction factor. The prediction schedule is set to run the prediction in the production period only. GAP is run with estimated OGIP for reservoir A, B and C. At the end of run (1st July 2012), predicted cumulative gas production is 70,230.86 MMscf and generated cumulative gas production (production history) is 66,660.53 MMscf. The difference in cumulative gas production between the two values is 3,570.33 MMscf. The ratio between the cumulative gas production of production history and prediction results is 0.95. The range of OGIP correction factor is calculated from plus and minus 50 percent of the ratio between cumulative gas productions. For the test model, the ratio is close to 1. Therefore, the range of OGIP correction factor is 0.5 and 1.5. Figure 5-14 and Figure 5-15 show the prediction results compared with the production history.

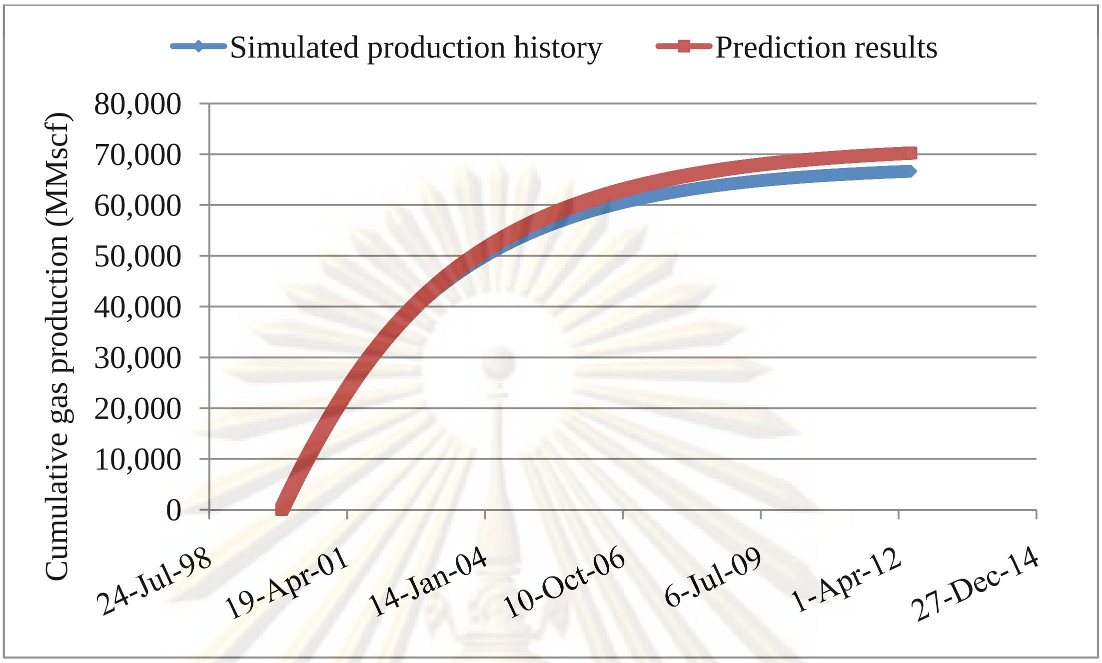

Figure 5-14 : Computed cumulative gas production based on estimated OGIP in comparison with cumulative gas production from simulated production history.

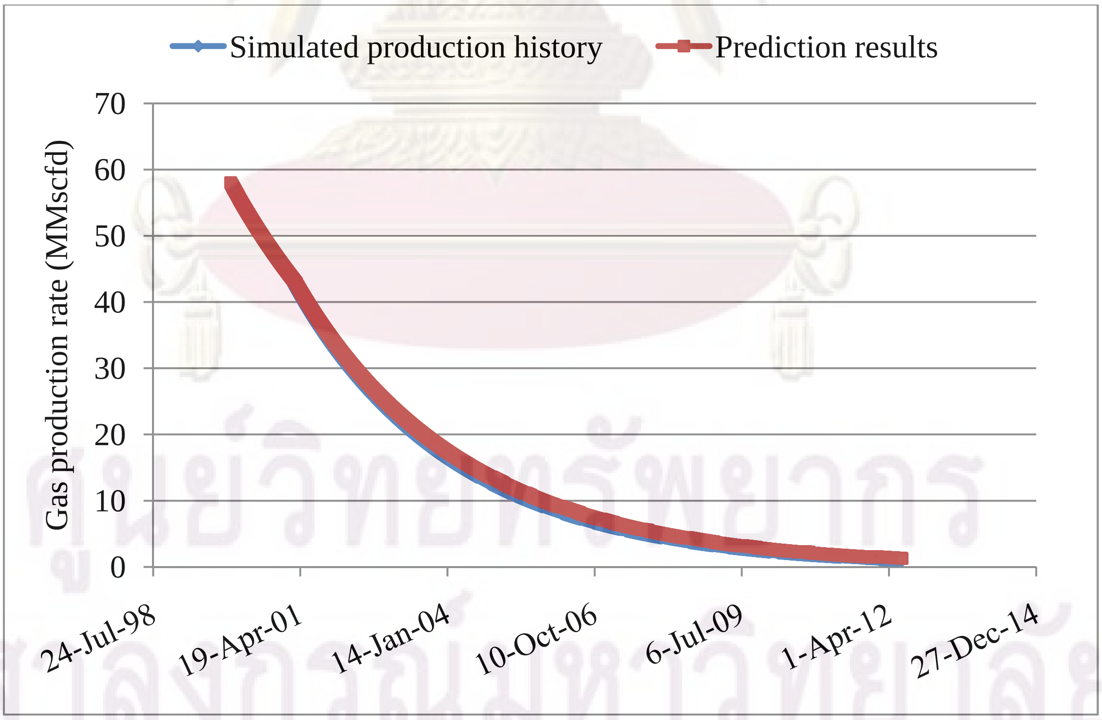

Figure 5-15 : Gas production rate based on estimated OGIP in comparison with simulated production history

5.1.4 Verification the Methodology Using Test Model

In this section, two cases of prediction are run with different verification periods in order to verify the methodology. In the first case, the verification period starts from the beginning of the production history. In the second case, the verification period starts after the reservoirs are produced for two-third of the production period. Again, test model is used to run prediction in this section. The range of production rate allocation is 0.75 to 1.25. This range is used to calculate new production rate or vary production rate. The range of OGIP correction factor is used to calculate new OGIP, and the range of injection skin is -4 to 20. These correction factors are used for both cases. The run starts from 1st January 2000 to 1st January 2025. After the end of the run, the prediction results from both cases are compared and analyzed. Table 5-4 shows correction factors for production rate allocation, OGIP and skin.

Table 5-4 : Range of correction factor

Correction Factor	Minimum	Maximum
Production rate allocation	0.75	1.25
OGIP	0.5	1.5
Injection skin	-4	20

5.1.4.1 Verification Period Starts at the Beginning of Production History

This case verifies the methodology with the start of verification period at the beginning of production history. The schedule of this case is shown in Table 5-5, and verification period is illustrated in Figure 5-16. From Figure 5-16, the start of verification period for this case is 1st January 2000, and the end of verification period is 30th June 2012. This case requires 250 acceptable realizations to create distribution of results. The acceptable percent error for this study is 25%.

Figures 5-17 and 5-18 show the distribution of cumulative water injection and its cumulative distribution function, respectively. The 50th percentile of cumulative water injection is 66.70 MMstb. From the distribution, predicted cumulative water injection is around 67 MMstb. Figure 5-19 and Figure 5-20 show probability density function and cumulative distribution function of cumulative water injection, respectively. We can see from the figures that different acceptable error results in different probabilistic density functions and cumulative distribution functions of cumulative water injection. Lower acceptable percent error shows narrower distribution of cumulative water injection. Table 5-6 shows the 10^{th}, 50^{th}, 90^{th} percentile, mean and variance of cumulative water injection for different ranges of acceptable error. The 50^{th} percentile of cumulative water injection for 0-5% and 0-12% acceptable error is 67.28 and 66.70 MMstb, respectively. The simulated cumulative water injection at the end of injection period is 69.282 MMstb. The results from Table 5-6 show that narrower range of acceptable error has the 10^{th}, 50^{th} and 90^{th} percentile of cumulative water injection closer to simulated cumulative water injection when compared with wider range of acceptable error. The range of acceptable error from 0 to 5 percent has lower variance when compared with the range of acceptable error from 0 to 12 percent. Figure 5-21 shows percent error of cumulative gas production against cumulative water injection. The cumulative water injection is close to 69 MMstb at zero percent error. The actual cumulative water injection for the test model is 69.282 MMstb. The difference of the two values is around 0.282 MMstb. Figure 5-22 and 5-23 shows distribution of the end of injection period when the reservoir pressure reaches the original pressure. Figure 5-24 shows percent error of cumulative gas production against the end of injection period. From this figure, the 50^{th} percentile of the end of injection period is 16^{th} February 2018. The end of injection period from injection history is 7^{th} January 2018. The difference of end of injection period is around 40 days within five and a half years of injection period. Figure 5-25 shows percent error of cumulative gas production against total OGIP. At 0 percent error of cumulative gas production, the total OGIP from prediction result is close to 90,000 MMscf. The actual OGIP for reservoir A, B and C are 25,000, 30,000 and 35,000, respectively. The results from this case show the methodology for this study can be used to estimate cumulative water injection, end of injection period and total OGIP. Figure 5-26 shows the 50^{th} percentile of cumulative water injection against cumulative number of acceptable realizations. The 50^{th} percentile of cumulative water injection starts to stable when the cumulative number of realization is around 50.

Table 5-5 : Schedule of test model (The verification period starts at the beginning of production history)

Prediction schedule		
Start of production	1/1/2000	m/d/y
Start of verification period	1/1/2000	m/d/y
End of verification period	6/30/2012	m/d/y
Prediction time step	1	week

Table 5-6 : Cumulative water injection (The verification period starts at beginning of production history)

The verification starts at the beginning of production history		
Acceptable error	0 - 5%	0 - 12%
P10 of cumulative water injection (MMstb)	64.03	61.15
P50 of cumulative water injection (MMstb)	67.28	66.70
P90 of cumulative water injection (MMstb)	70.87	72.44
Mean of cumulative water injection (MMstb)	67.35	66.70
Variance	8.34	19.26

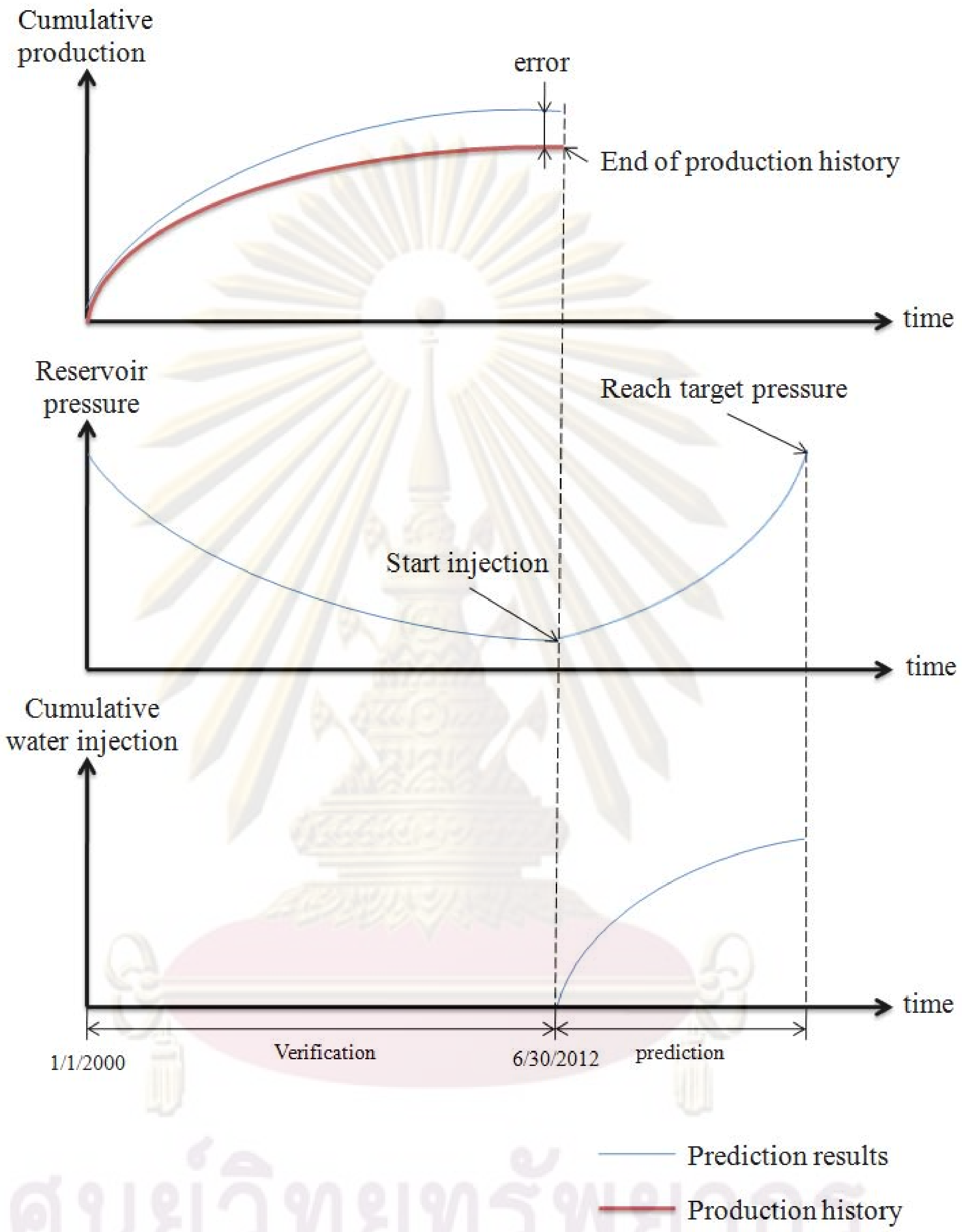

Figure 5-16 : Prediction timeline showing verification period starting at the beginning of production history

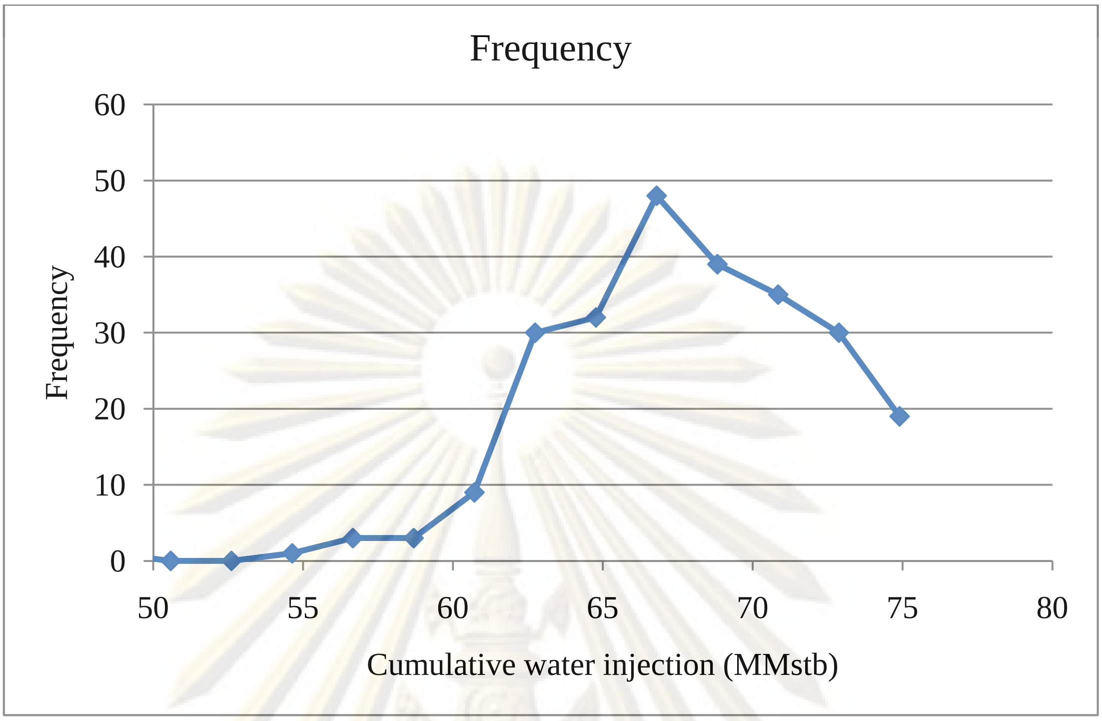

Figure 5-17 : Distribution of cumulative water injection
(Verification period starts at the beginning of production history)

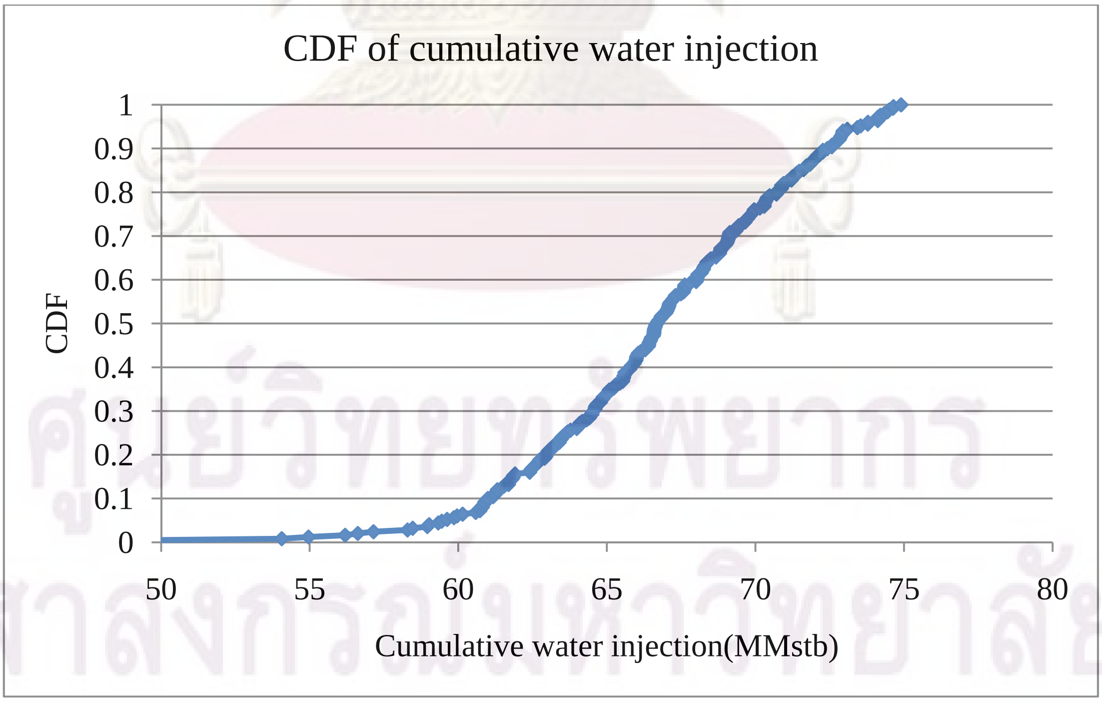

Figure 5-18 : CDF of cumulative water injection
(Verification starts at the beginning of production history)

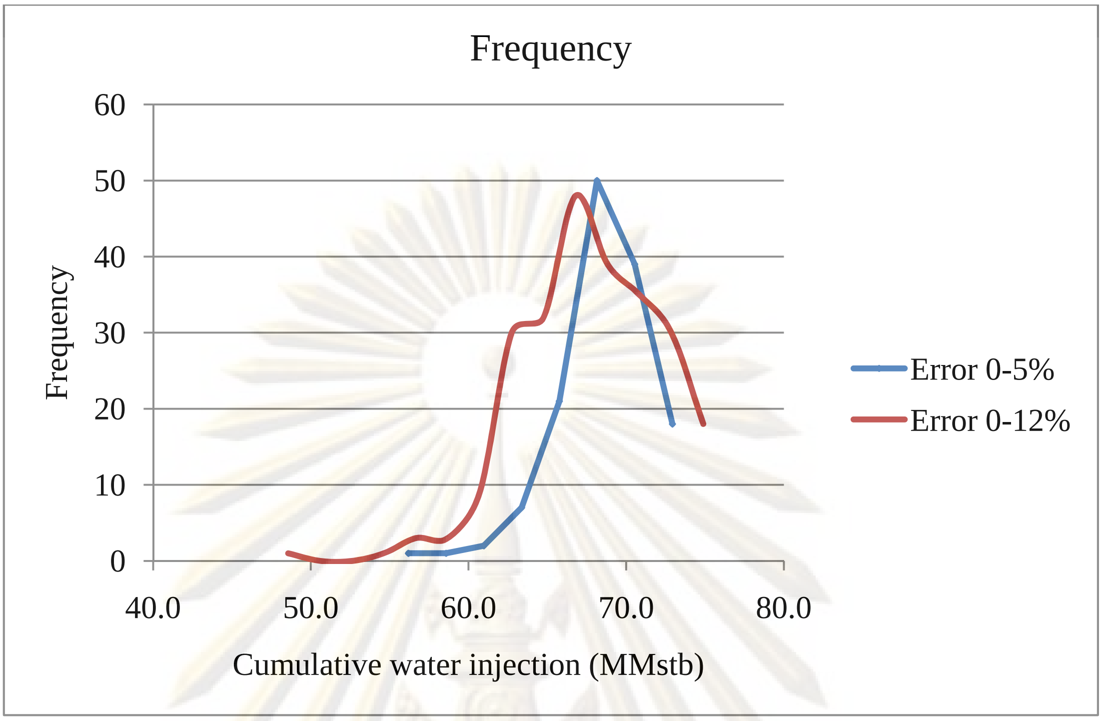

Figure 5-19 : Distribution of cumulative water injection for different ranges of acceptable error. (Verification period starts at the beginning of production history)

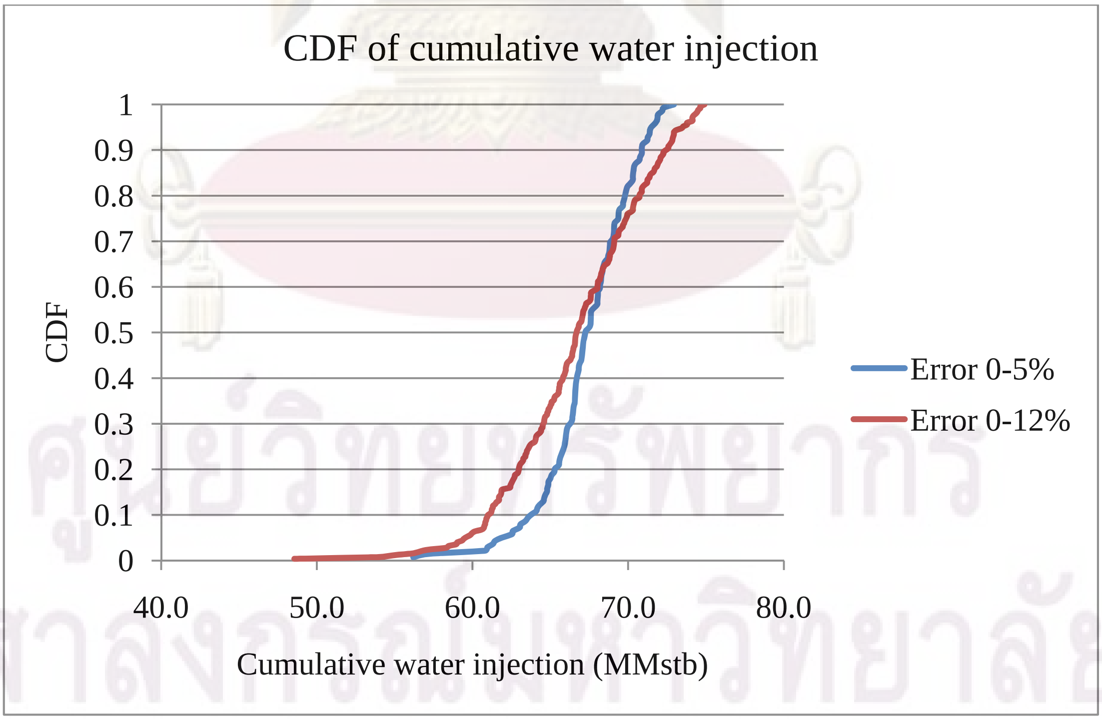

Figure 5-20 : CDF of cumulative water injection for different ranges of acceptable error (Verification period starts at the beginning of production history)

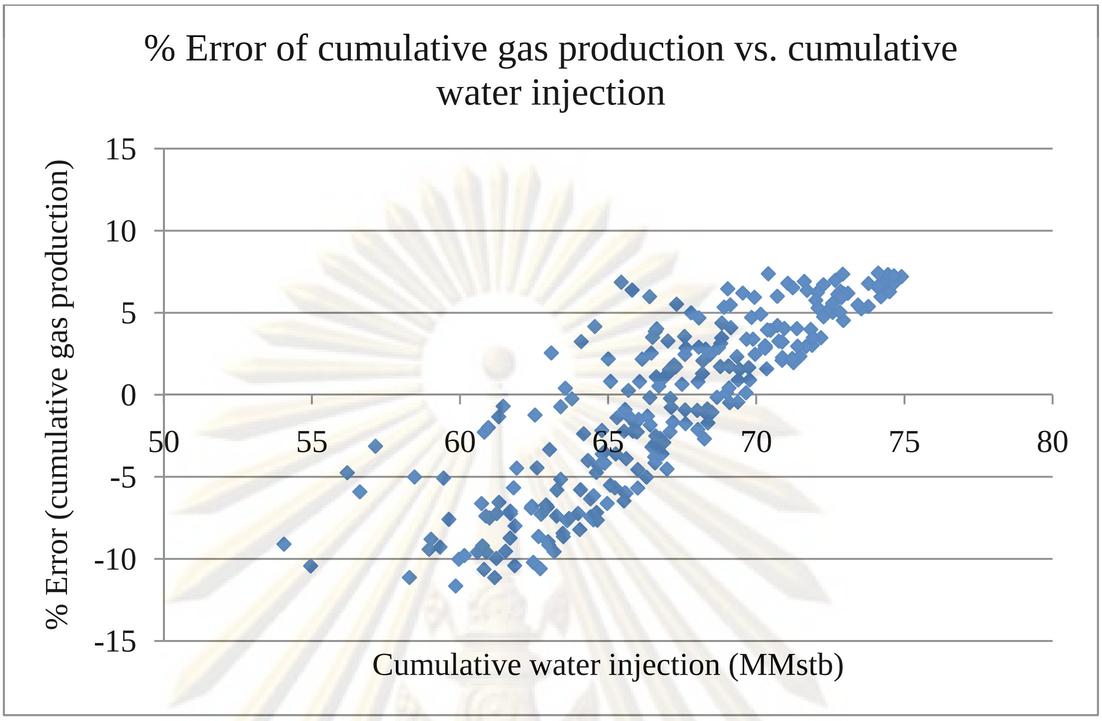

Figure 5-21 : % error of cumulative gas production against cumulative water injection
(Verification period starts at the beginning of production history)

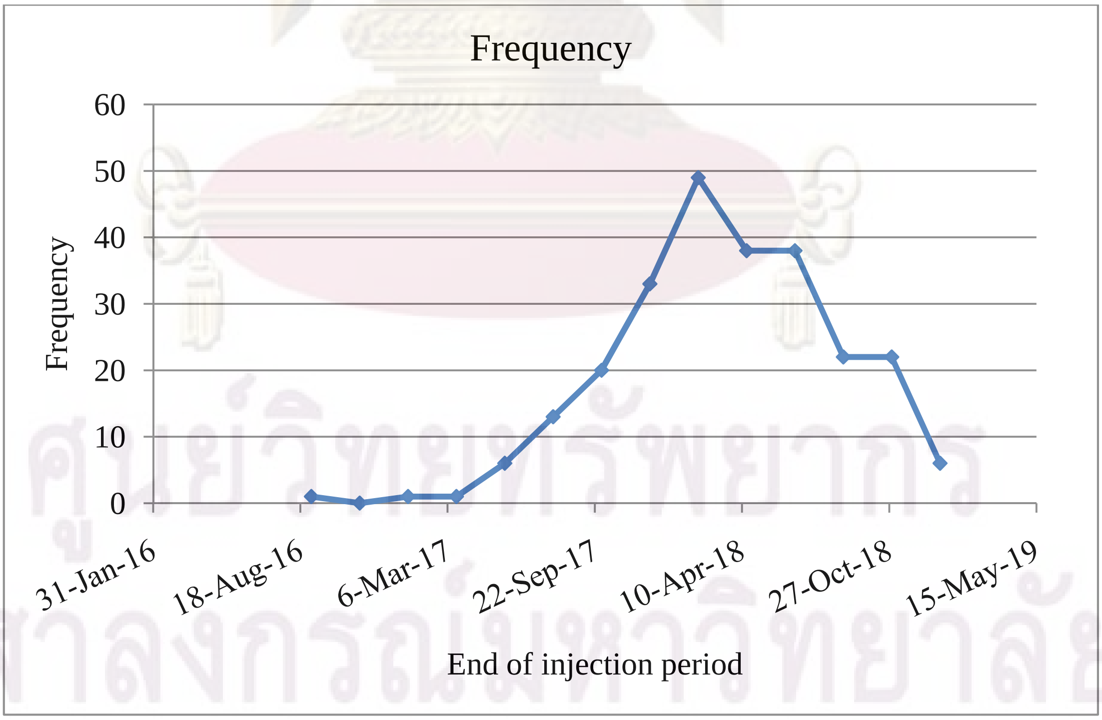

Figure 5-22 : Distribution of end of injection period
(Verification period starts at the beginning of production history)

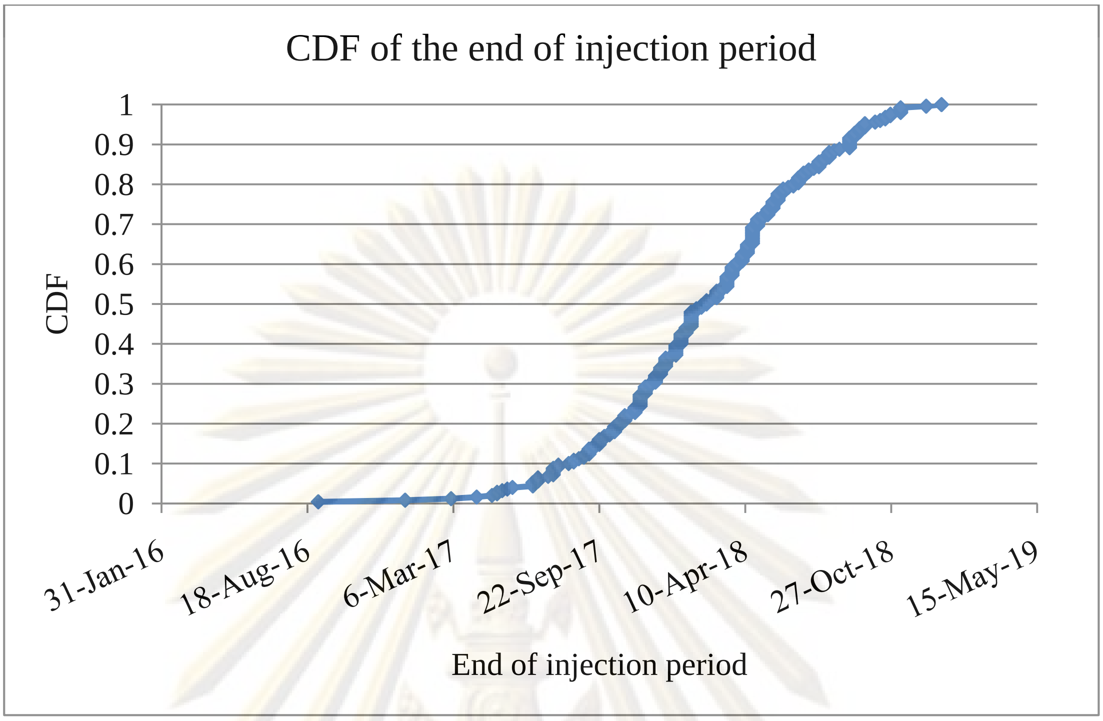

Figure 5-23 : CDF of end of injection period
(Verification period starts at the beginning of production history)

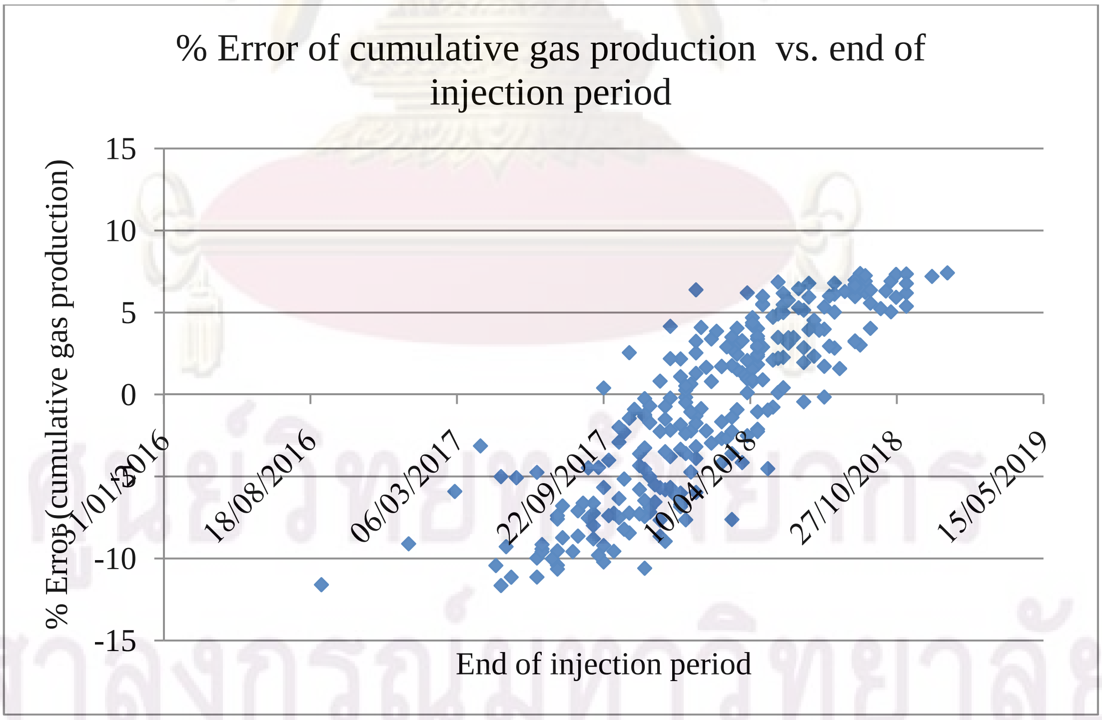

Figure 5-24 : % Error of cumulative gas production against end of injection period
(Verification period starts at the beginning of production history)

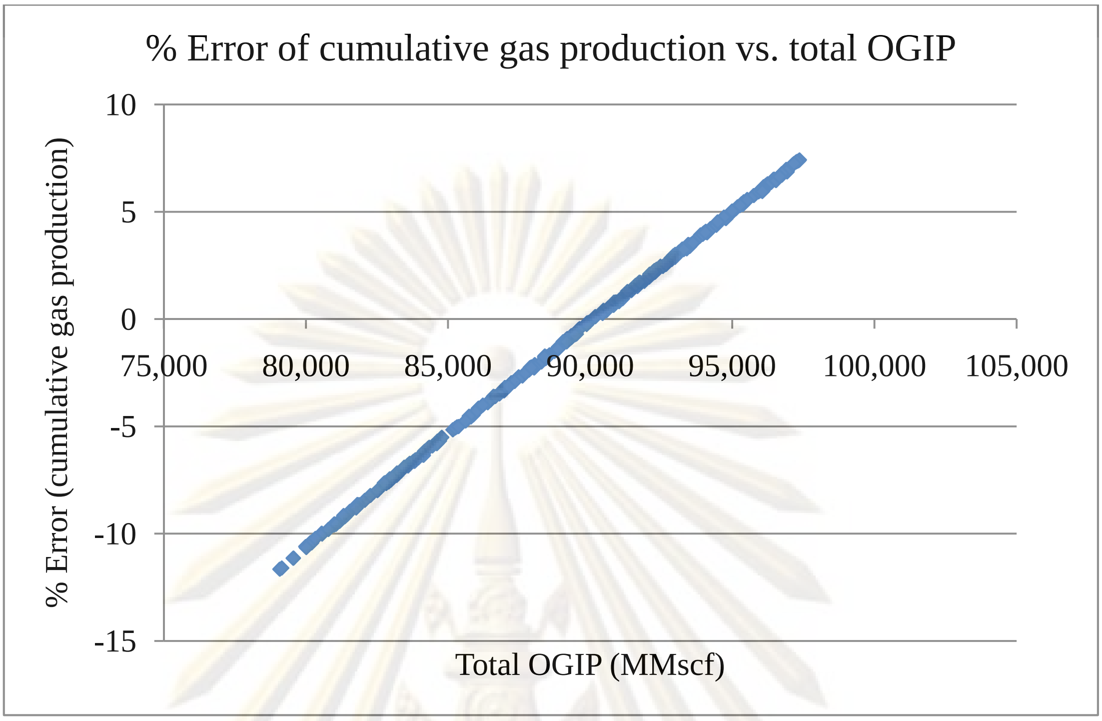

Figure 5-25 : % Error of cumulative gas production against total OGIP
(Verification starts at the beginning of production history)

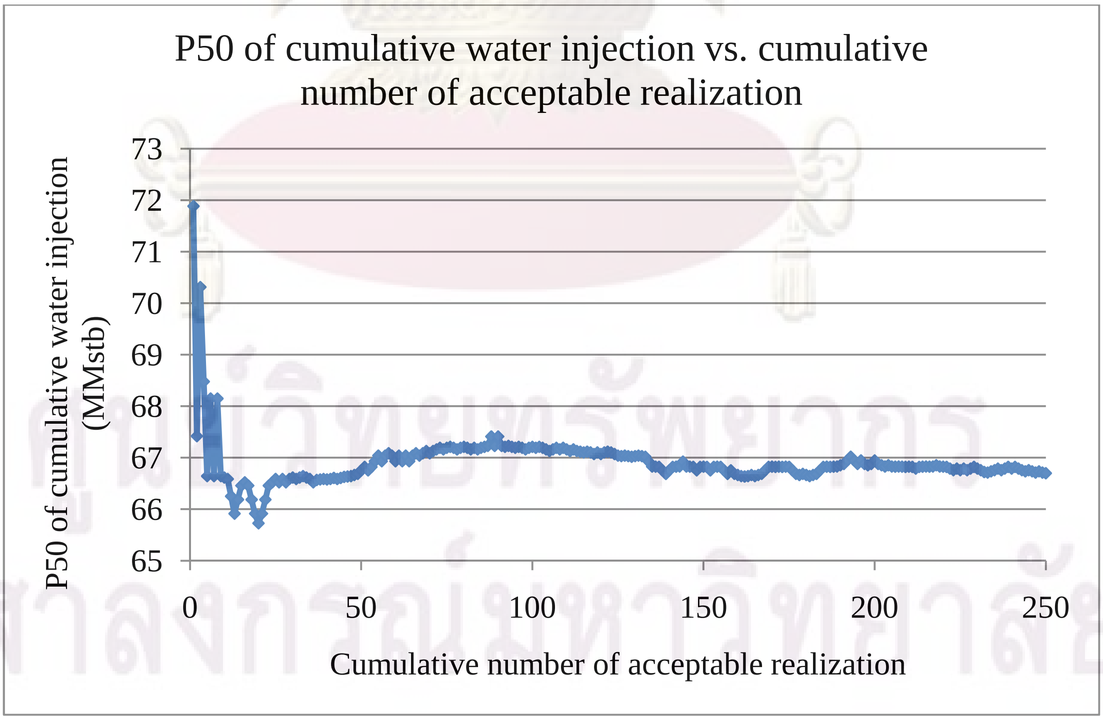

Figure 5-26 : P50 of cumulative water injection against cumulative number of acceptable realization

5.1.4.2 Verification Period Starts at Two-Third of Production History

This case verifies the methodology with the start of verification period at two-third of production history. The schedule of this case is shown in Table 5-7, and verification period is illustrated in Figure 5-27. From Figure 5-27, the start of verification period for this case is 31st March 2008, and the end of verification period is 30th June 2012. This case requires 250 acceptable realizations to create distribution of results. The acceptable percent error for this study is 25%.

Figures 5-28 and 5-29 show the distribution of cumulative water injection and its cumulative distribution function, respectively. The 50th percentile of cumulative water injection is 68.07 MMstb. From the distribution, predicted cumulative water injection is around 69 MMstb. Figure 5-30 and Figure 5-31 show probability density function and cumulative distribution function of cumulative water injection, respectively. Lower acceptable percent error shows narrower distribution. Table 5-8 shows the 10th, 50th, 90th percentile, mean and variance of cumulative water injection for different ranges of acceptable error. The simulated cumulative water injection at the end of injection period is 69.282 MMstb. The results from Table 5-8 shows that narrower range of acceptable error has the 50th percentile of cumulative water injection closer to simulated cumulative water injection. Higher acceptable percent error shows wider distribution especially on the lower side of cumulative water injection. Figure 5-32 shows percent error of cumulative gas production against cumulative water injection. The trend of cumulative water injection is not clear. The maximum cumulative water injection is close to 70 MMstb at zero percent error. Figure 5-33 and 5-34 show distribution of the end of injection period when the reservoir pressure reaches the original pressure. Figure 5-35 shows percent error of cumulative gas production against the end of injection period. From this figure, the 50th percentile of the end of injection period is 25th March 2018. The end of injection period from injection history is 7th January 2018. The difference of end of injection period is around 77 days within five and a half years of injection period. Figure 5-36 shows percent error of cumulative gas production against total OGIP. At 0 percent error of cumulative gas production, the total OGIP from prediction results is close to 90,000 MMscf. Figure 5-37 shows the 50th percentile of cumulative water injection against cumulative number of acceptable realizations. The 50th percentile of cumulative water injection starts to stable when the cumulative number of realization is around 55. Therefore, the number of acceptable realization for test case can be reduced from 250 realizations to 50 realizations to estimate reliable cumulative water injection.

The prediction results for both cases are shown in Table 5-9. The estimated cumulative water injections for the two cases are close to the generated injection history. The end of injection period for the verification starts at the beginning of production history case is closer to the actual date than other case. However, it takes a longer time to run prediction. Estimated total OGIPs for both cases are 90,000 MMscf. Prediction results for verification starting at two-third production of history are narrower than those for verification starting at the beginning of production history. Finally, the results from both cases show that the methodology can be used to estimate cumulative water injection, end of injection period and total OGIP. Predicted results for each realization are shown in Appendix C.

Table 5-7 : Schedule of test model (Verification period starts at two-third of production history)

Prediction schedule		
Start of production	1/1/2000	m/d/y
Start of verification period	3/31/2008	m/d/y
End of verification period	6/30/2012	m/d/y
Prediction time step	1	week

Table 5-8 : Cumulative water injection (The verification period starts at two-third of production history)

The verification starts at two-third of production history					
Acceptable error	0-25%	0-25%	0-25%	0-25%	0-25%
P10 of cumulative water injection (MMstb)	65.48	65.35	65.16	65.17	65.25
P50 of cumulative water injection (MMstb)	68.34	68.23	68.09	68.04	68.07
P90 of cumulative water injection (MMstb)	69.81	69.78	69.72	69.72	69.72
Mean	68.12	67.86	67.65	67.64	67.69
Variance	2.42	3.29	4.13	4.11	3.90

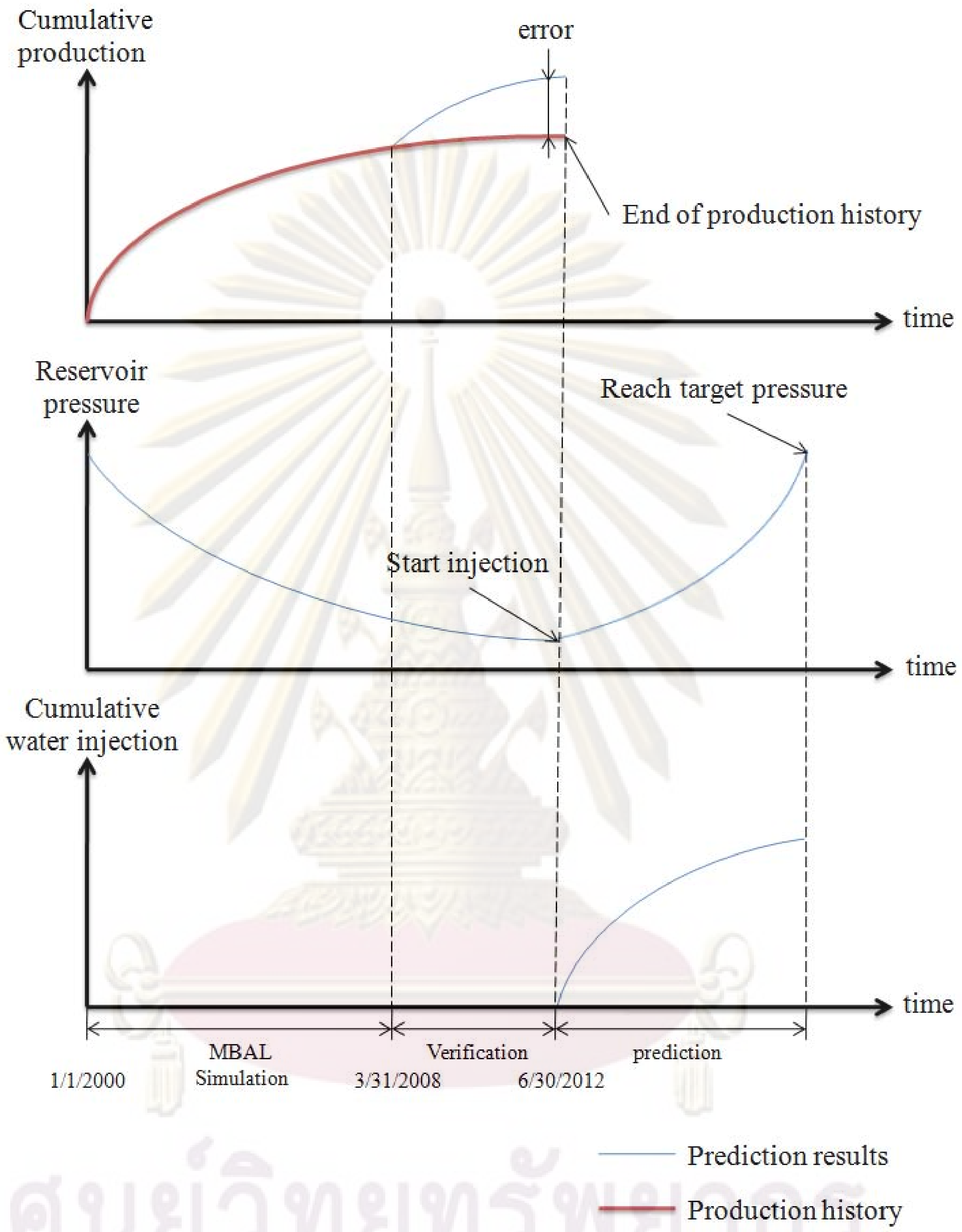

Figure 5-27 : Prediction timeline showing verification period starting at two-third of production history

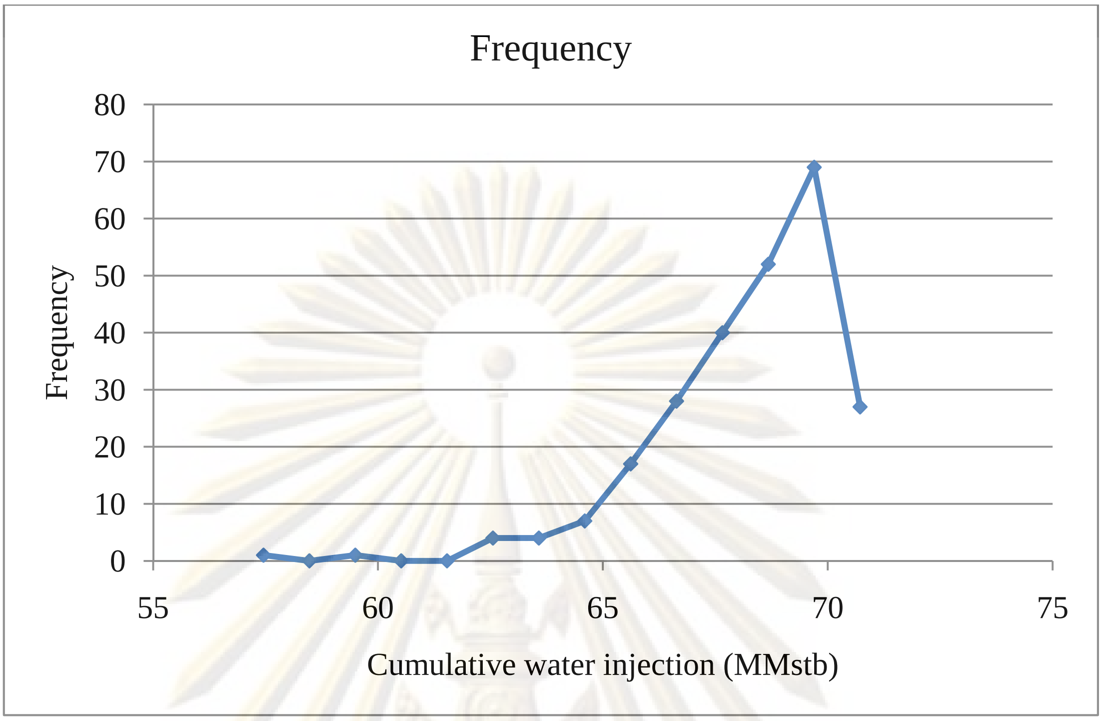

Figure 5-28 : Distribution of cumulative water injection
(Verification period starts at two-third of production history)

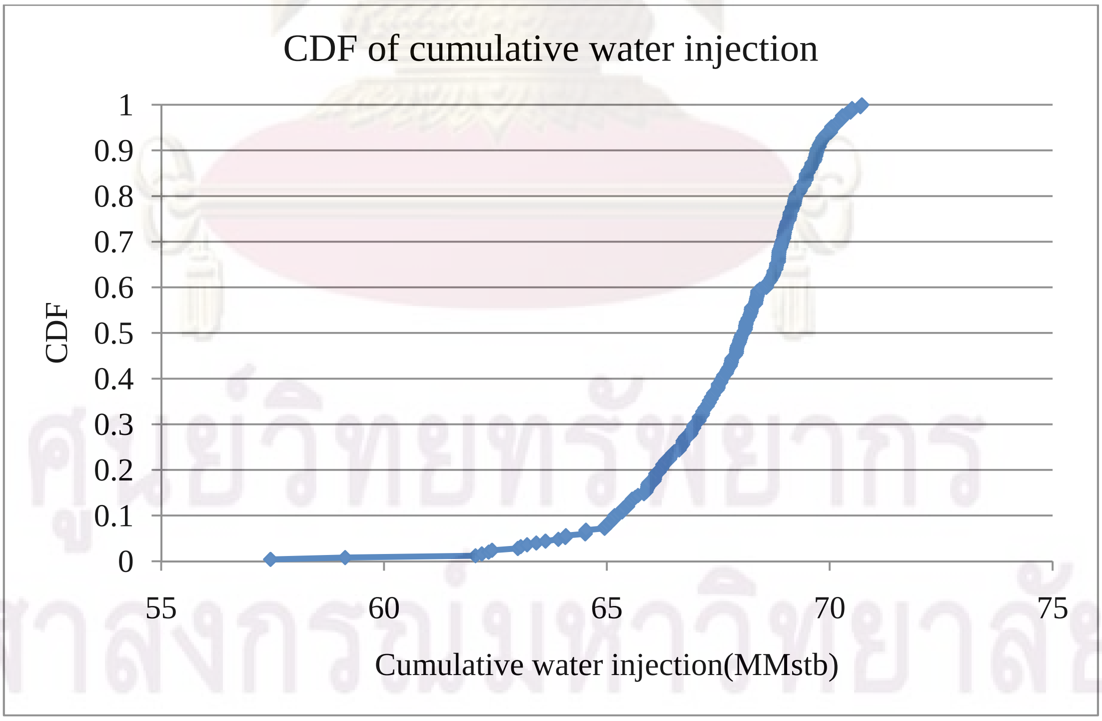

Figure 5-29 : CDF of cumulative water injection
(Verification period starts at two-third of production history)

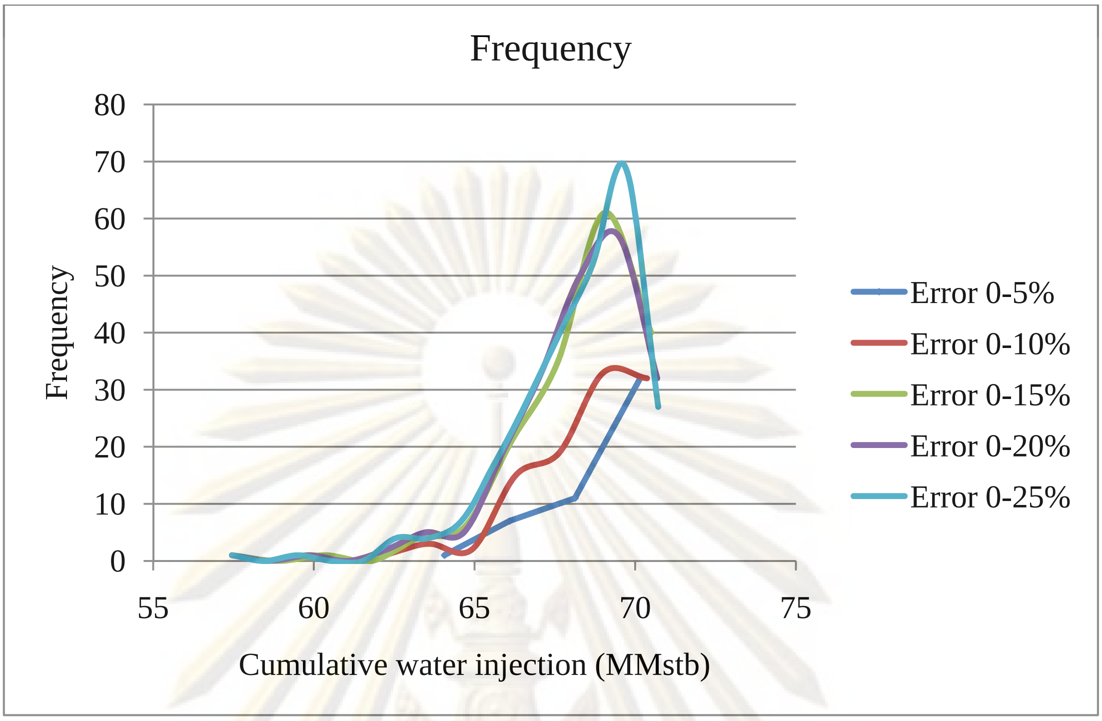

Figure 5-30 : Distribution of cumulative water injection for different ranges of acceptable error (Verification starts at two-third of production history)

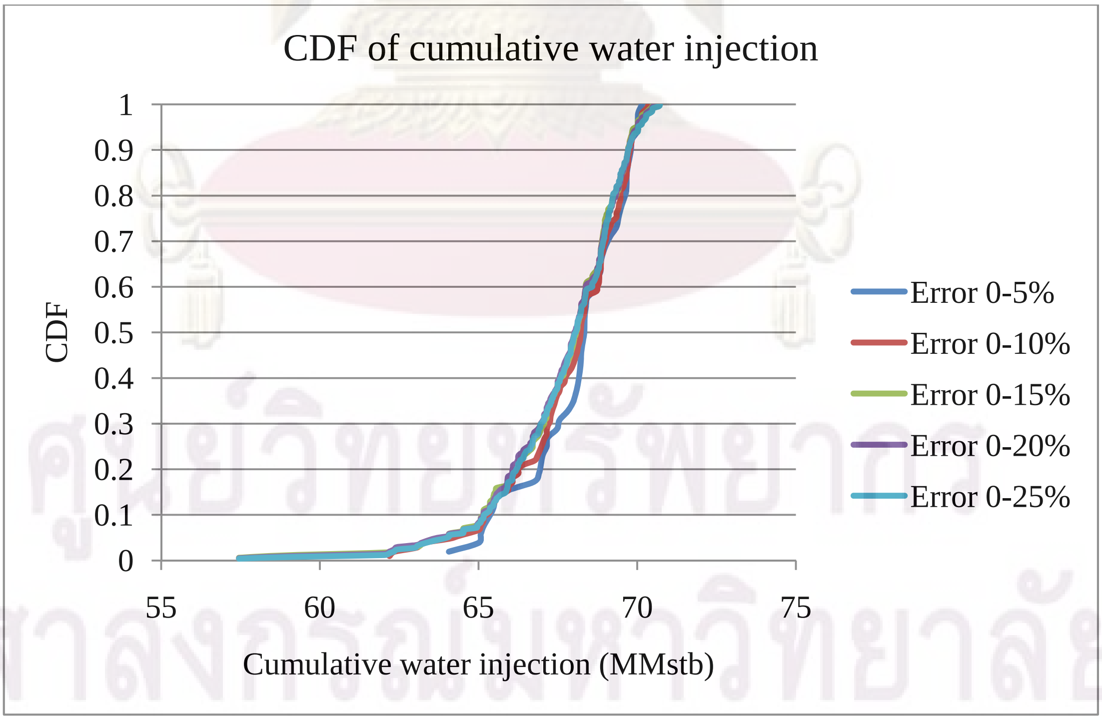

Figure 5-31 : CDF of cumulative water injection for different ranges of acceptable error (Verification period starts at beginning of production history)

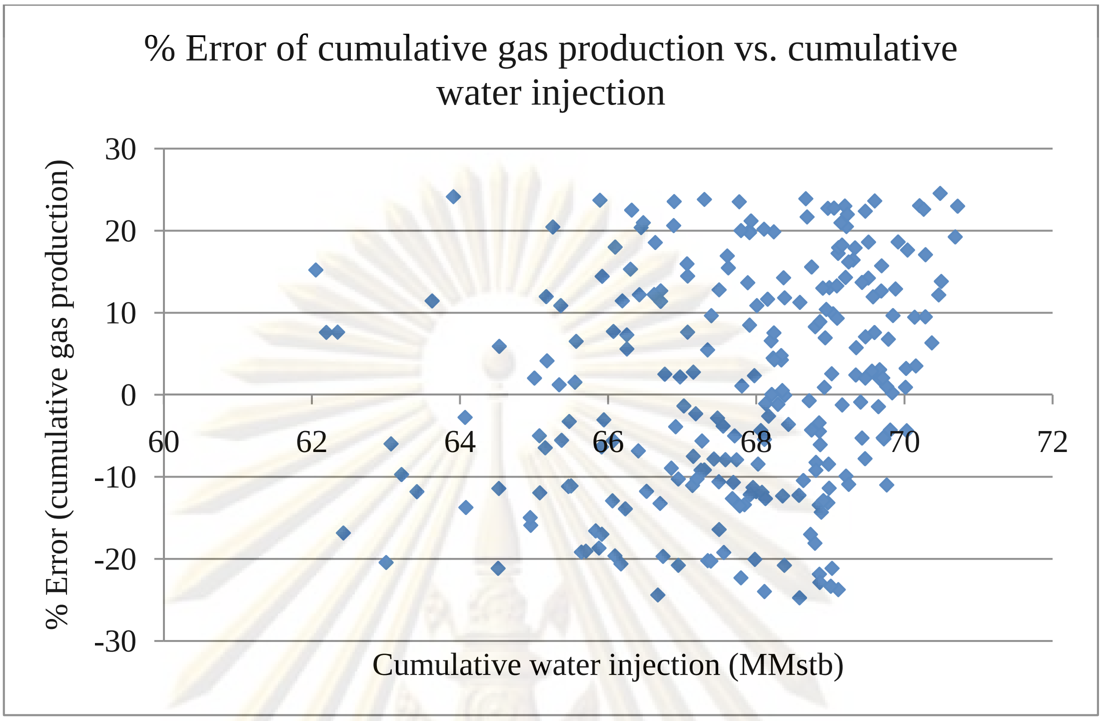

Figure 5-32 : % Error of cumulative gas production against cumulative water injection (Verification period starts at two-third of production history)

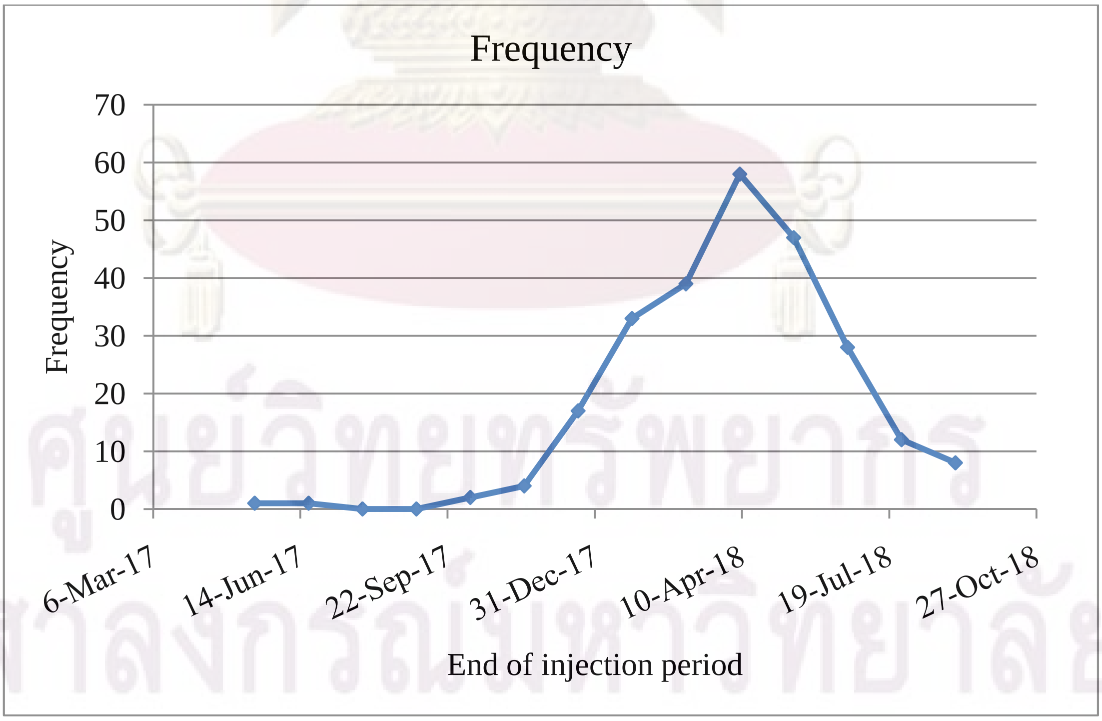

Figure 5-33 : Distribution of end of injection period (Verification period starts at two-third of production history)

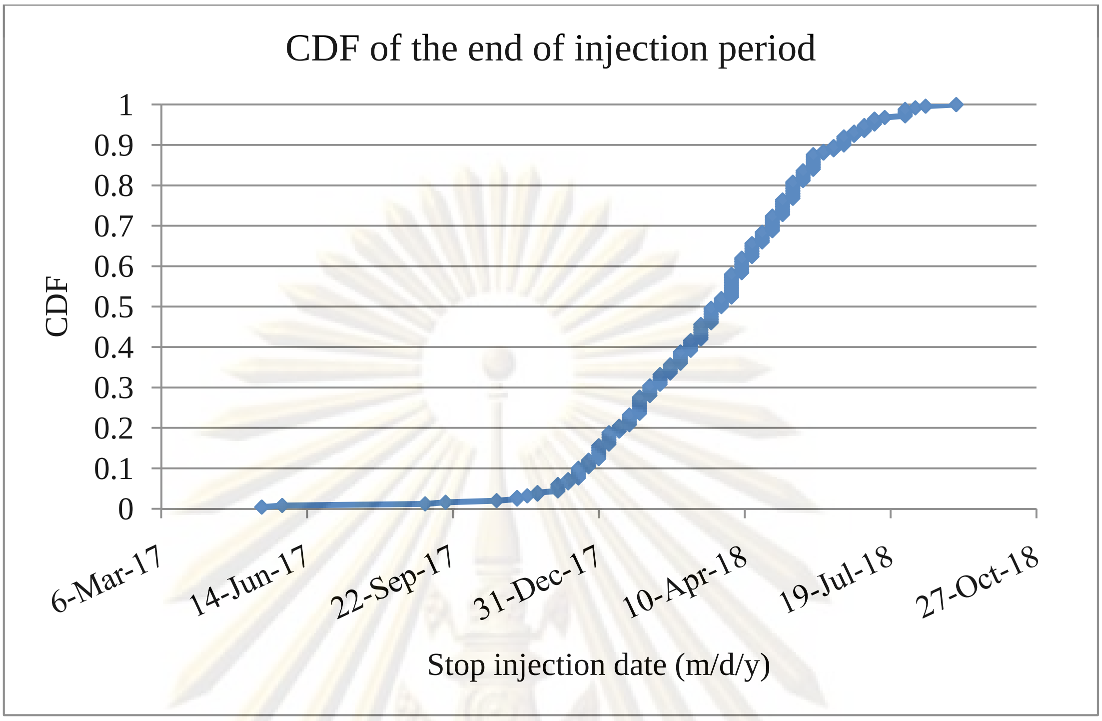

Figure 5-34 : CDF of end of injection period
(Verification period starts at two-third of production history)

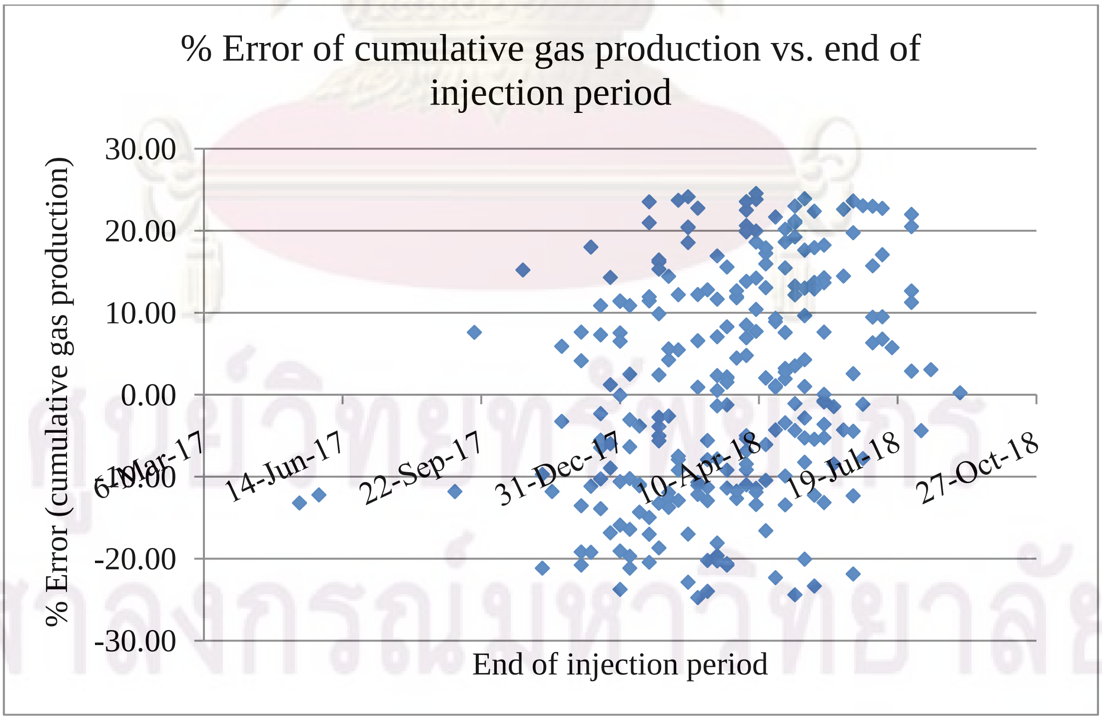

Figure 5-35 : % Error of cumulative gas production against end of injection period
(Verification period starts at two-third of production history)

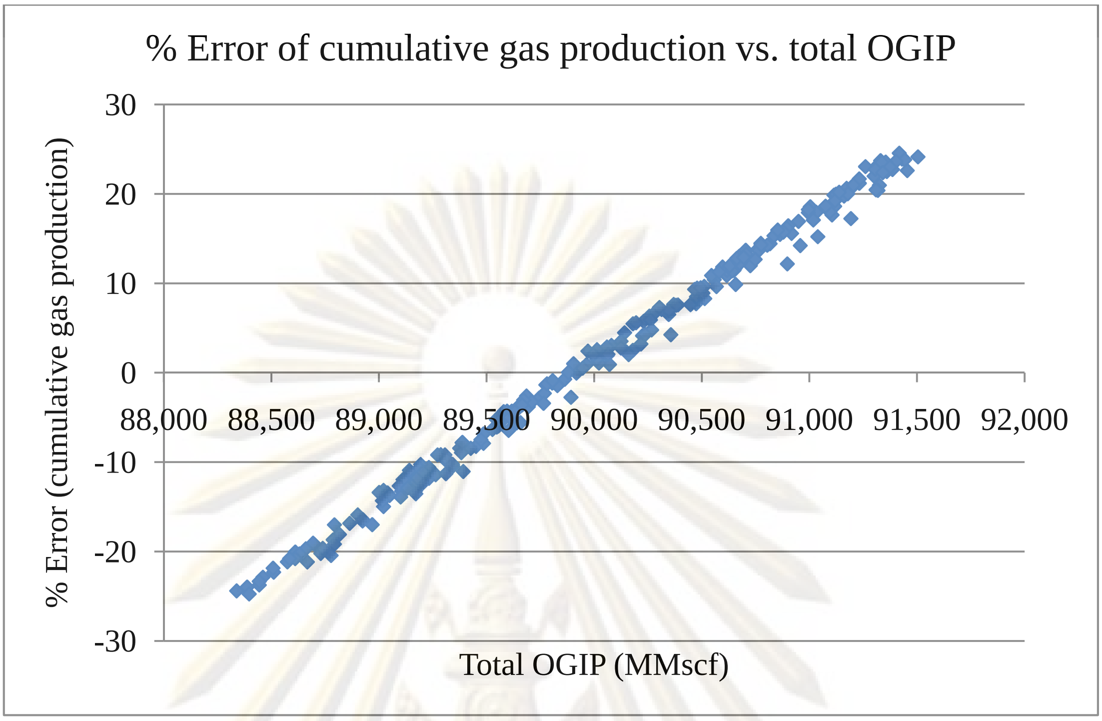

Figure 5-36 : % Error of cumulative gas production against total OGIP
(Verification starts at two-third of production history)

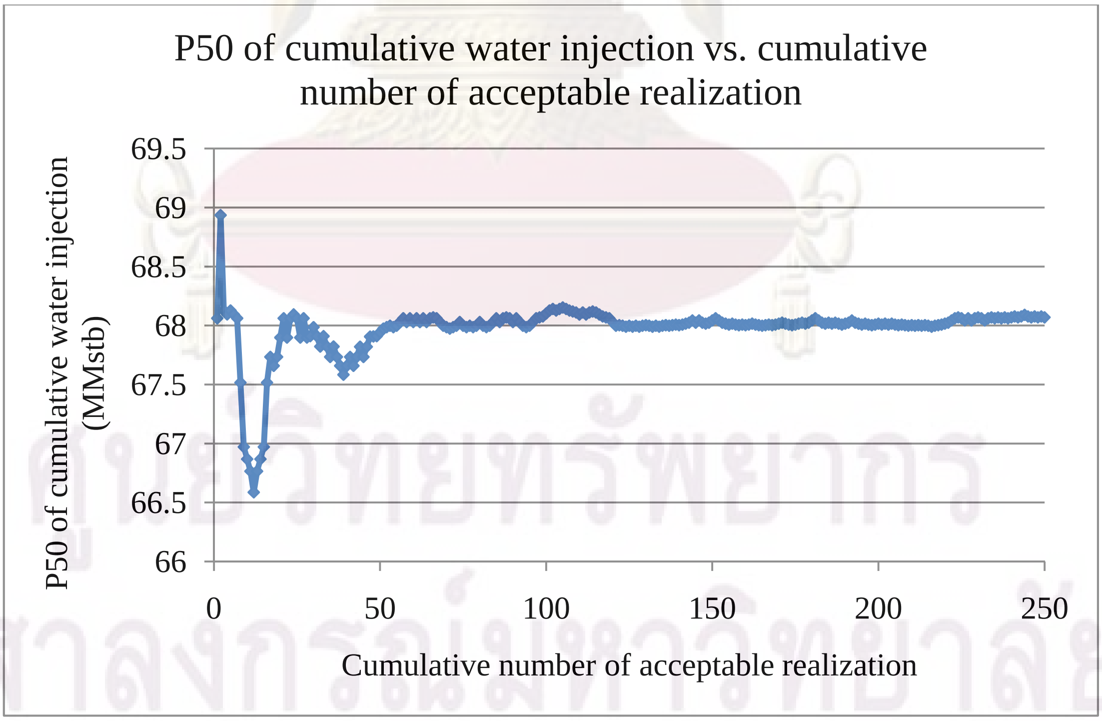

Figure 5-37 : P50 of cumulative water injection against cumulative number of acceptable realization

Table 5-9 : Prediction results

Prediction Results	Generated history	Verification starts at beginning of production history	Verification starts at 2/3 production history
Cumulative water injection (MMstb)	69.29	66.70	68.07
End of injection period	7th Jan 18	16th Feb 18	25th Mar 18
Total OGIP (MMscf)	90,000	90,000	90,000
Acceptable realization		250	250
Total realization		653	11,106
Prediction time		14 Hr 15 Min	12 Hr 35 Min

5.1.6 Effect of Injection Skin

In this section, injection skins are varied in order to observe their effect to cumulative water injection that can be injected into the reservoirs. The injection skins are varied from 0 to 100 for all reservoirs to predict the total amount of water that can be injected and the time to stop injection. Figure 5-38 shows that the cumulative water injection declines as injection skin increases. Figure 5-39 shows that the reservoirs take longer times to inject until the reservoir pressure reaches the original reservoir pressure when the injection skin increases.

The skins are varied from 0 to 100, which is very wide in range. Around 69.28 MMstb of water can be injected when the skin is 0 (no skin) and 67.45 MMstb of water can be injected when skin is 100 (very high skin).

Figures 5-40 to 5-42 show the reservoir pressure of reservoir A, B and C for different injection skins, respectively. These figure show that reservoir C is the first reservoir that the pressure after water injection reaches the original reservoir pressure for all different injection skins. Figures 5-43 to 5-45 show cumulative water injection of reservoir A, B and C for different injection skins, respectively. These figures show reservoir C has the same cumulative water injection because reservoir C reaches the original reservoir pressure for all different injection skins but other reservoirs have lower cumulative water injection when the injection skin increases at the last date of injection. Therefore, well cumulative water injection decreases when injection skin increases. Figures 5-46 to 5-48 show water injection rate for reservoir A, B and C, respectively. The water injection rate decreases when the injection skin increases. Therefore, a higher skin takes a longer time to make a reservoir reache the original reservoir pressure. Well flowing pressure for reservoir A, B and C are shown in Figures 5-49 to 5-51, respectively.

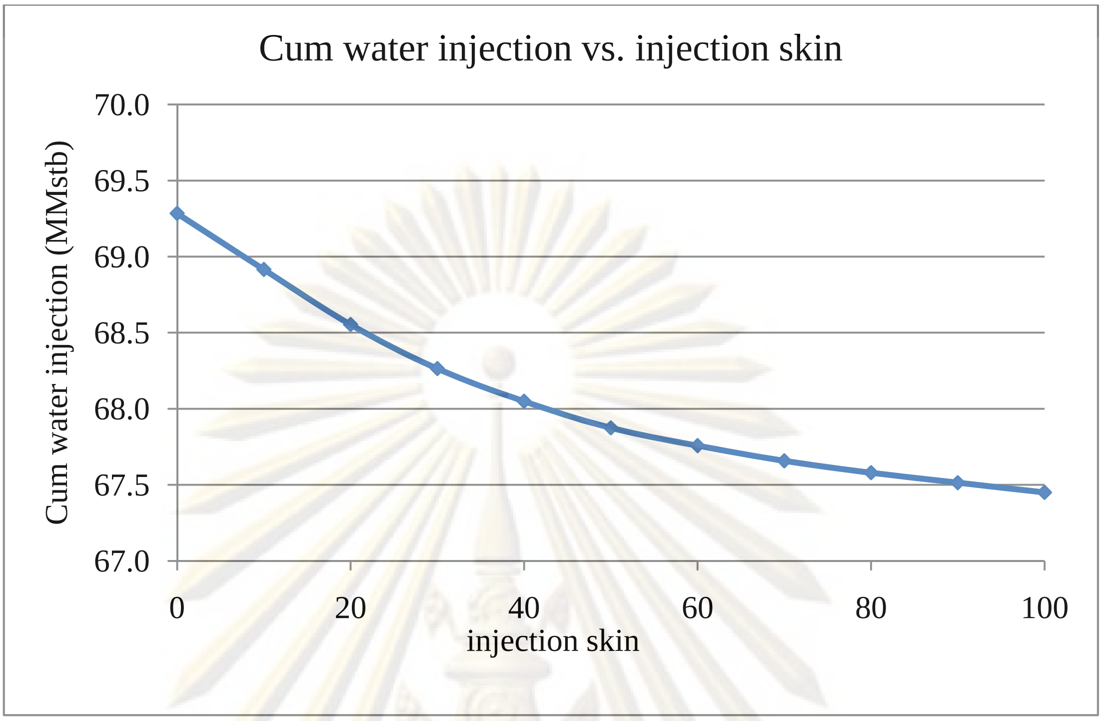

Figure 5-38 : Cumulative water injection against injection skin

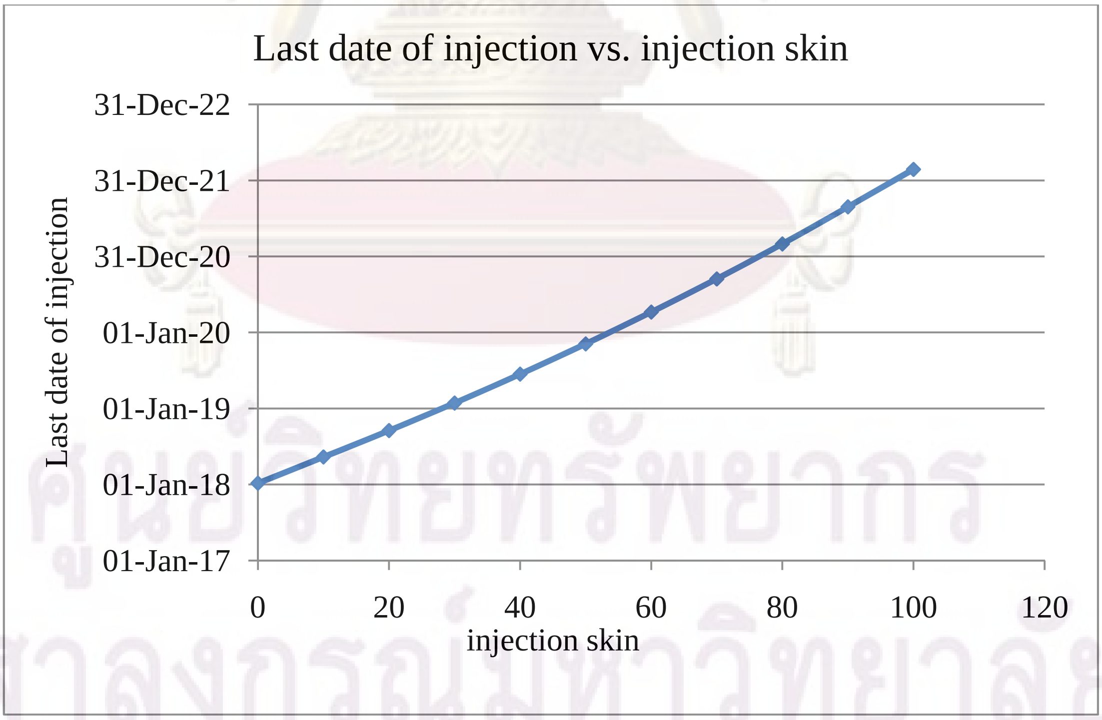

Figure 5-39 : Last date of injection

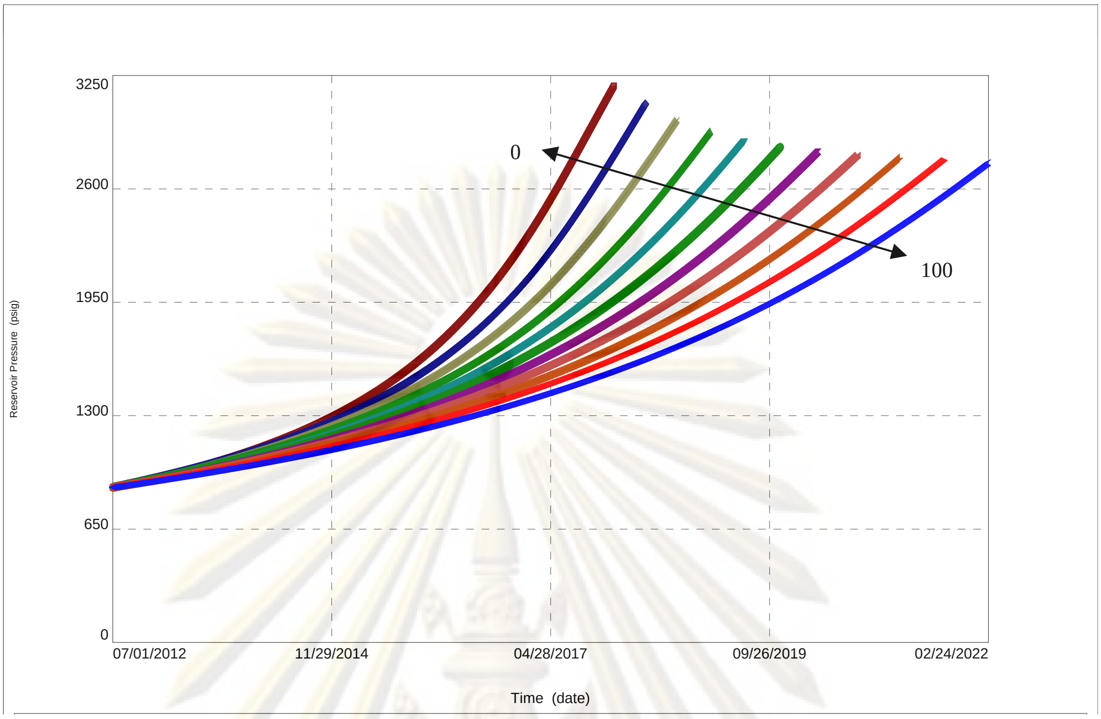

Figure 5-40 : Reservoir pressure for different injection skins (Reservoir A)

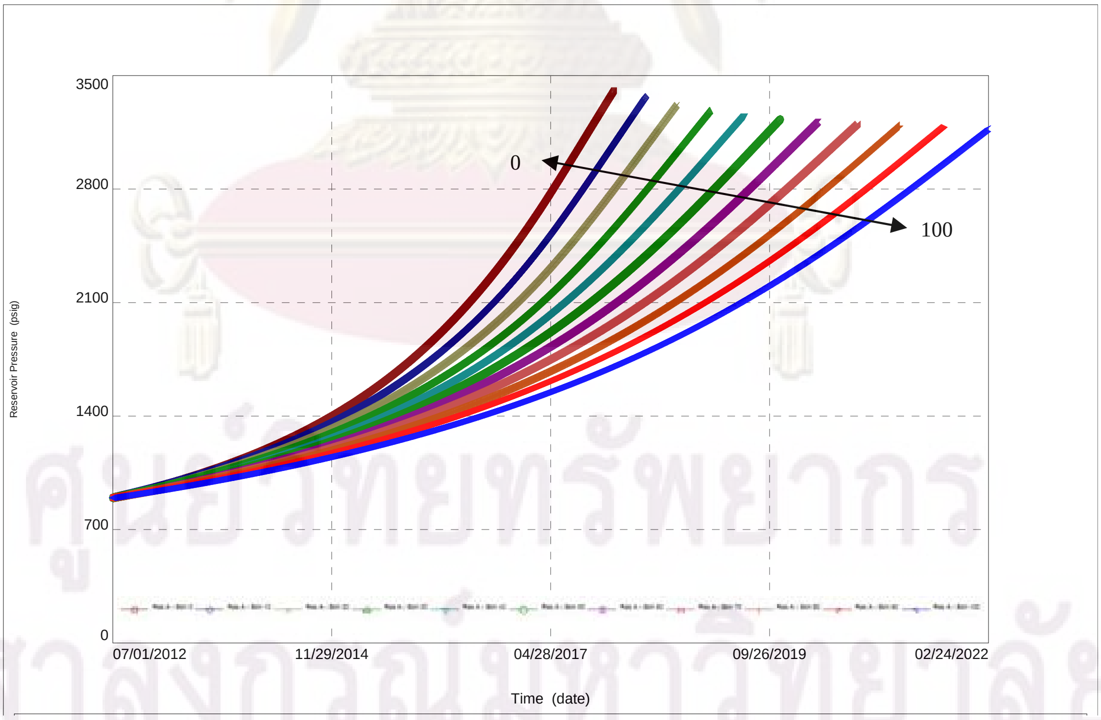

Figure 5-41 : Reservoir pressure for different injection skins (Reservoir B)

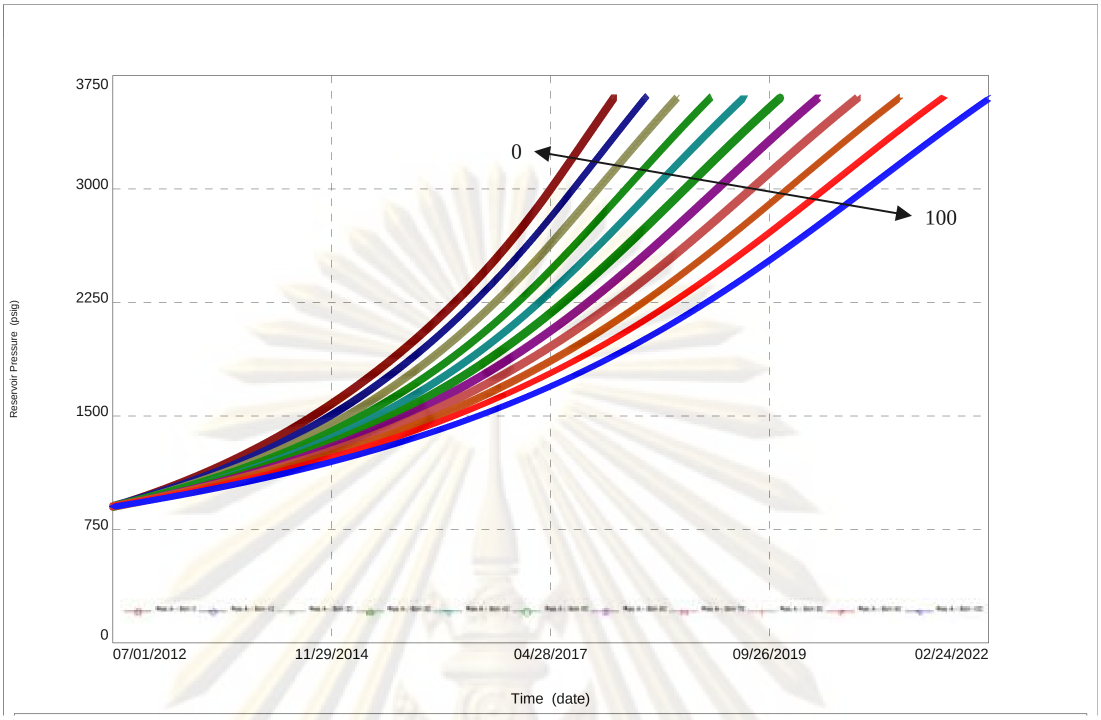

Figure 5-42 : Reservoir pressure for different injection skins (Reservoir C)

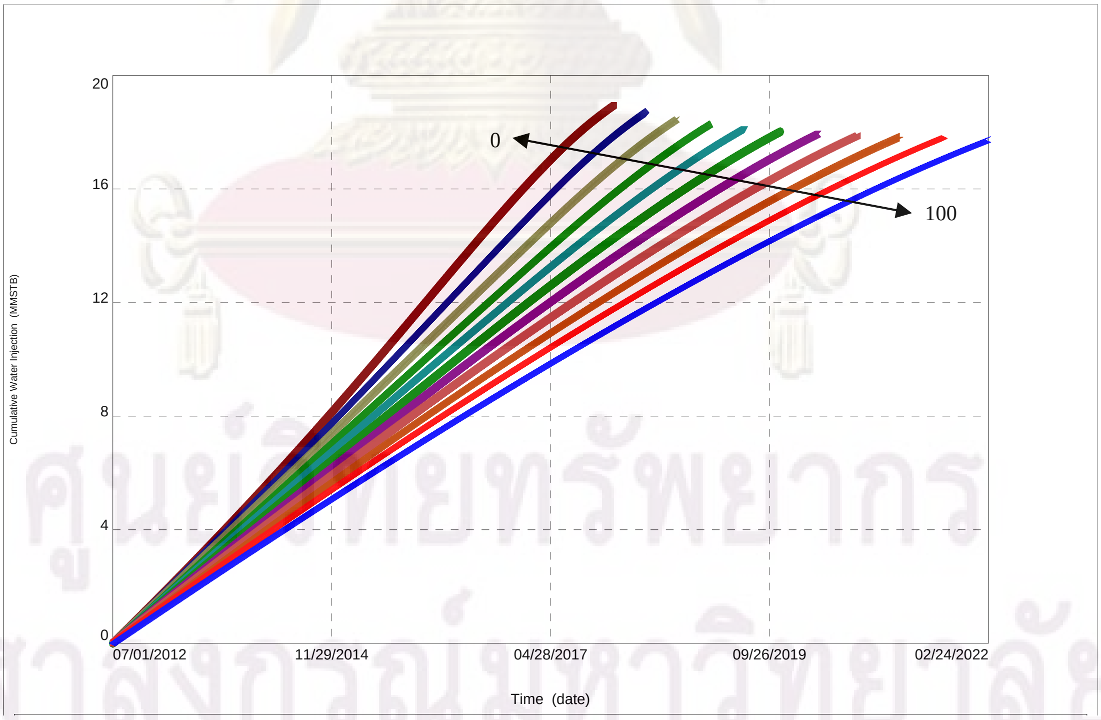

Figure 5-43 : Cumulative water injection for different injection skins (Reservoir A)

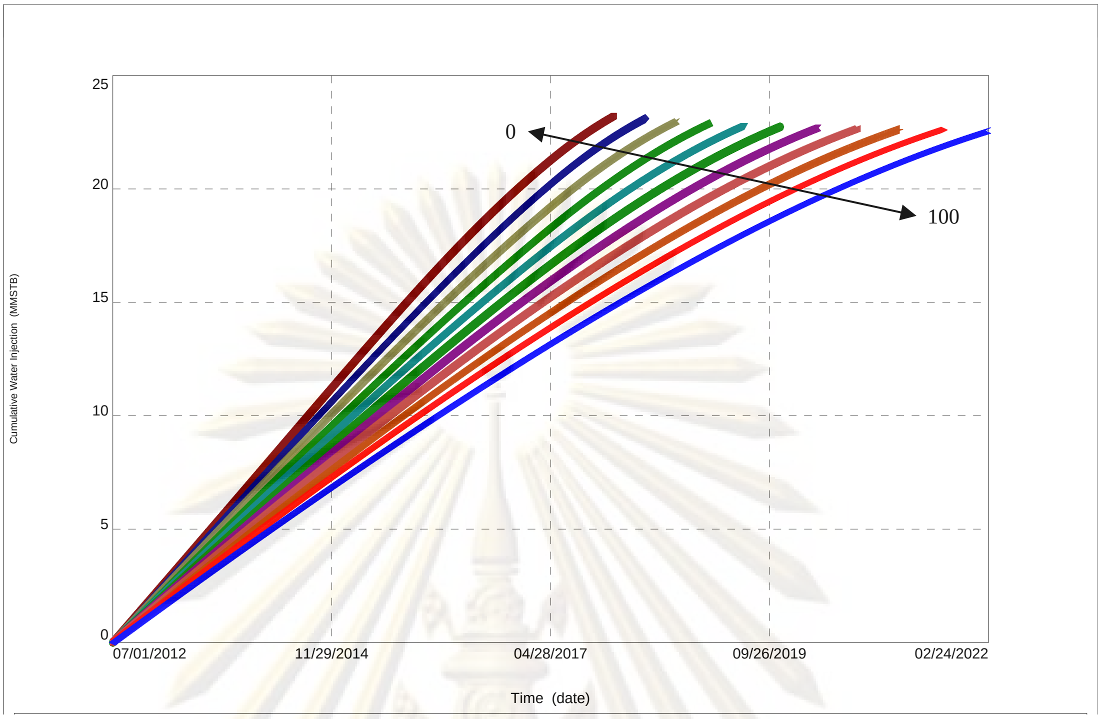

Figure 5-44 : Cumulative water injection for different injection skins (Reservoir B)

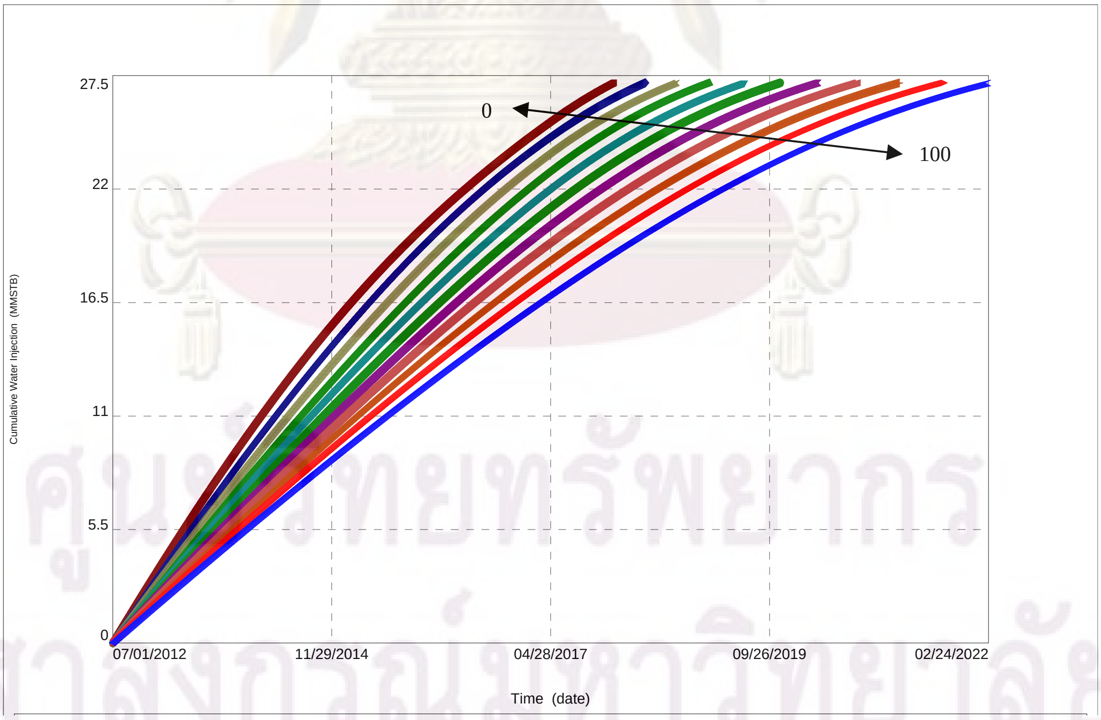

Figure 5-45 : Cumulative water injection for different injection skins (Reservoir C)

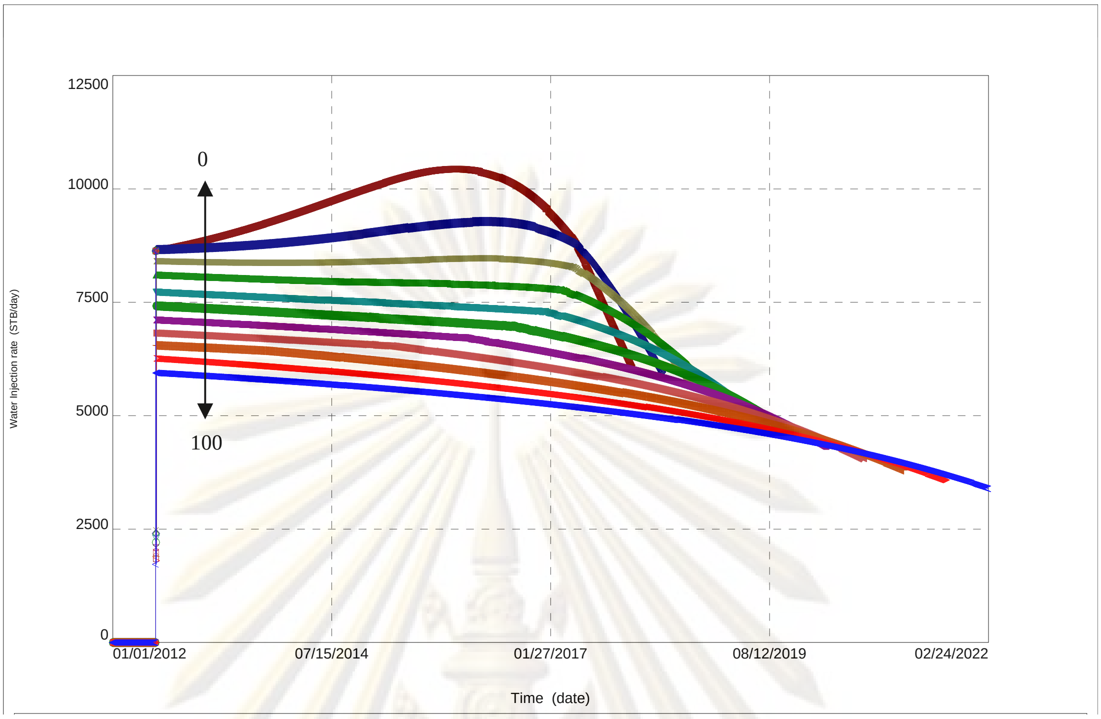

Figure 5-46 : Water injection rate for different injection skins (Res A)

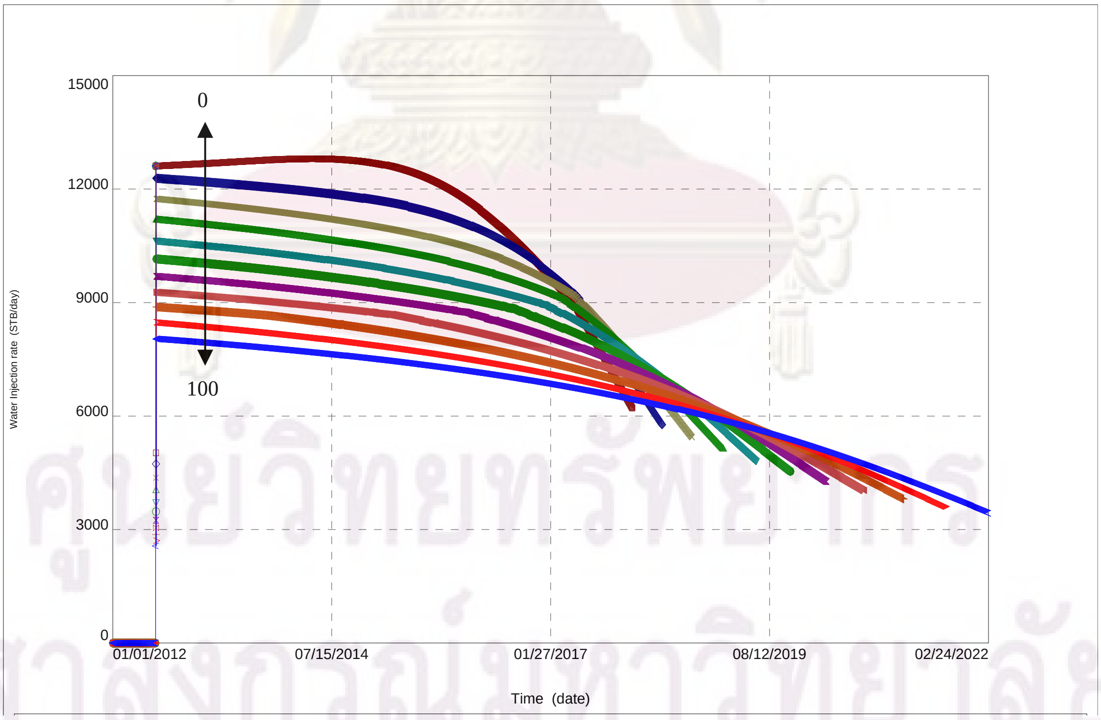

Figure 5-47 : Water injection rate for different injection skins (Res B)

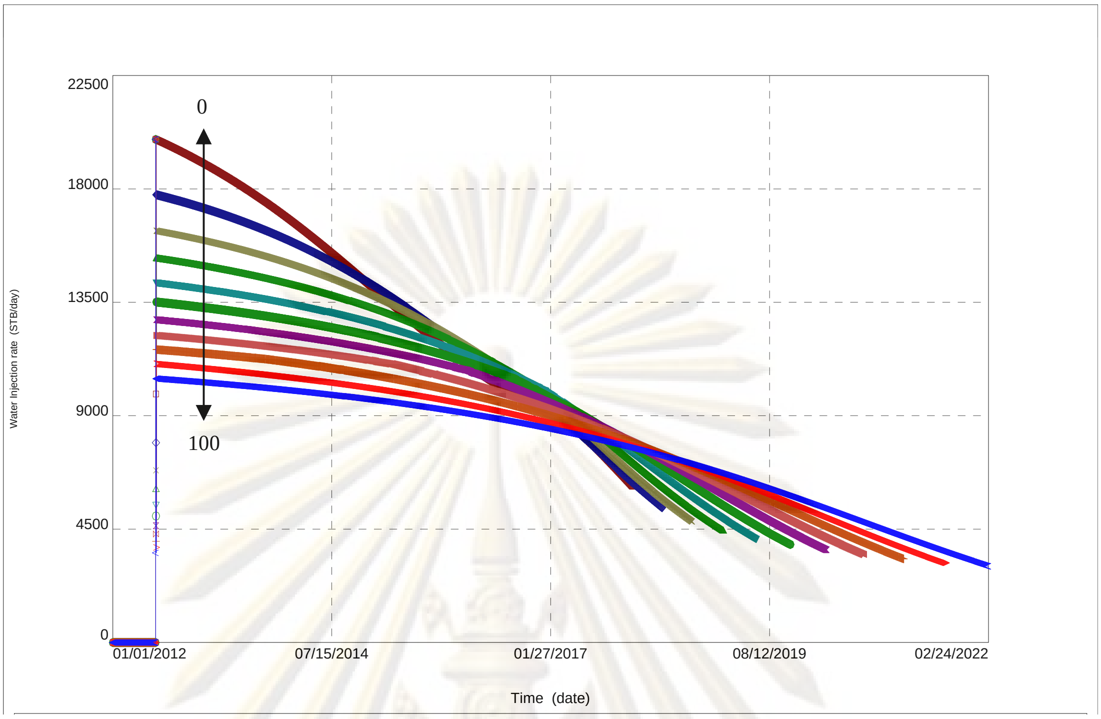

Figure 5-48 : Water injection rate for different injection skins (Res C)

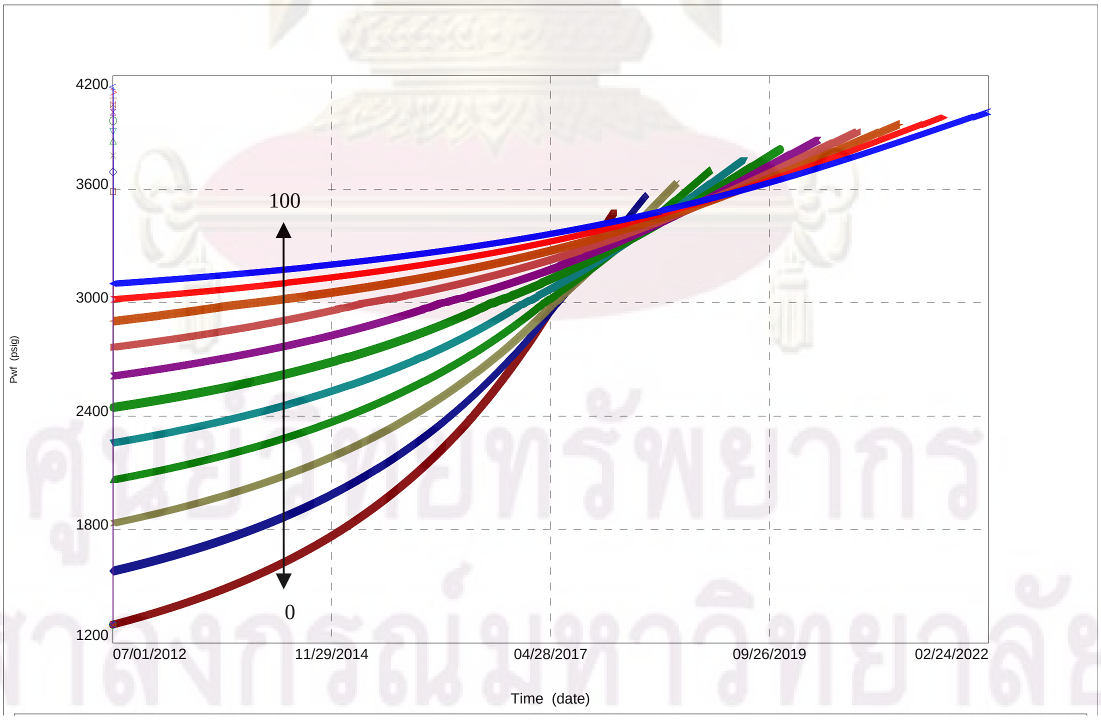

Figure 5-49 : Well flowing pressure for different injection skins (Reservoir A)

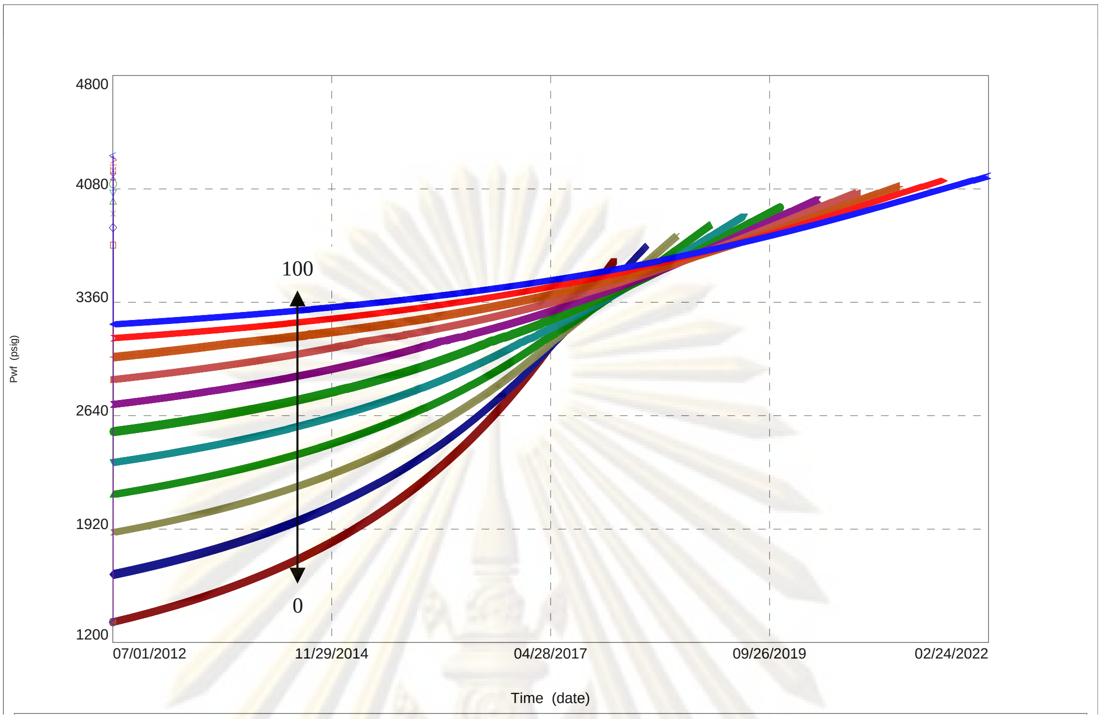

Figure 5-50 : Well flowing pressure for different injection skins (Reservoir B)

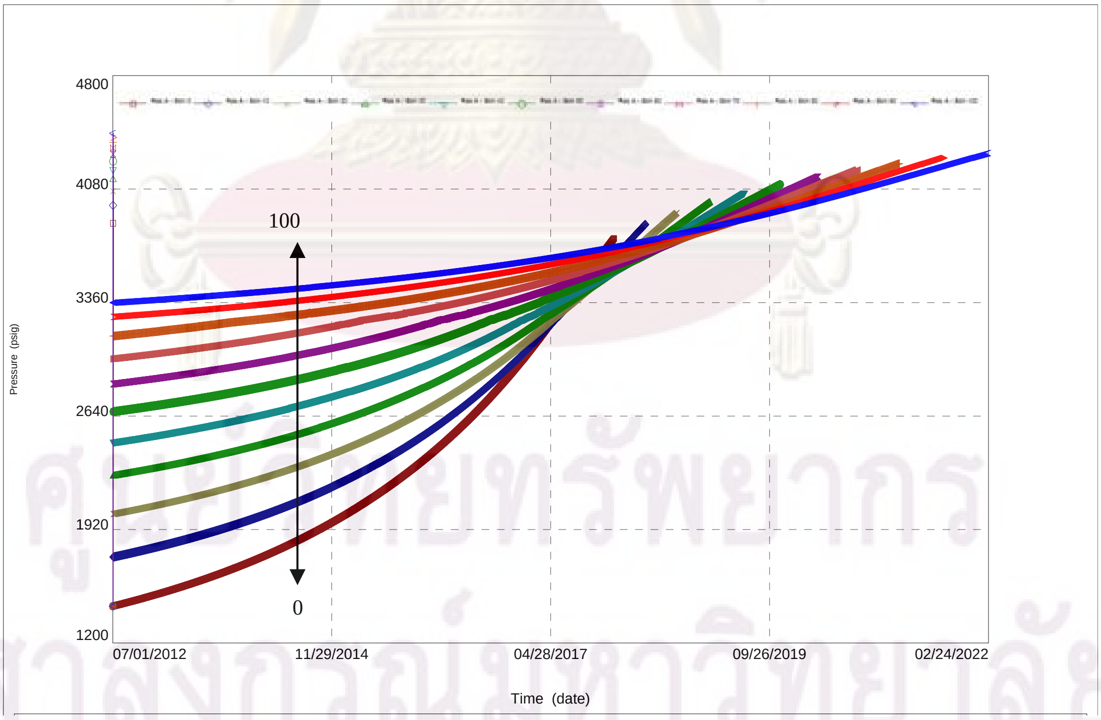

Figure 5-51 : Well flowing pressure for different injection skins (Reservoir C)

5.2 Actual Case

In this section, the methodology is applied to an actual well. The well for this study is a former gas production well that will be converted well to an injection well.

5.2.1 Actual Model

The actual model consists of production and injection wells. The inside diameter of these wells are 2.441 inch. Both wells are connected to 14 gas reservoirs. These reservoirs are separated into two groups. The first group started to produce on 20th June 2002, and the second group started to produce on 17th October 2003. The well is converted to injection well on 16th November 2006. On 18th October 2009, the cumulative of water injection for this well is 1.21 MMstb. Separator and injection manifold in the model are used to set the actual wellhead pressure of production and injection well, respectively. Fluid properties are shown in Table 5-10. Table 5-11 shows deviation survey of the well. Table 5-12 shows the reservoir properties. Figure 5-52 illustrates the actual model. The cumulative gas productions at the start of verification period and the end of verification period are used to calculate percent error to verify new OGIP and production rate allocation. The acceptable percent error for this model is set at 25 percent.

Table 5-10 : Fluid properties

Fluid Properties	
Gas gravity (sp. gravity)	0.85
Condensate to gas ratio (STB/MMscf)	35.69
Condensate gravity (API)	60
Water to gas ratio (STB/MMscf)	161.60
Water salinity (ppm)	100,000
Mole percent of H2S (percent)	0
Mole percent of CO2 (percent)	10
Mole percent of N2 (percent)	5

Table 5-11 : Deviation survey

Deviation Survey					
No.	MD (feet)	TVD (feet)	No.	MD (feet)	TVD (feet)
1	0	0	9	9,839	6854.50
2	7,107	5003.50	10	10,013	6969.91
3	9,121	6365.48	11	10,125	7044.38
4	9,144	6381.41	12	10,387	7216.28
5	9,166	6396.58	13	10,401	7225.23
6	9,270	6467.87	14	10,594	7348.58
7	9,541	6652.60	15	10,666	7394.74
8	9,658	6732.12	16	10,680	7403.70

Table 5-12 : Reservoir properties

Reservoir Properties														
Reservoir name	49-0	62-6	62-7	62-9	63-6	65-5	66-3	67-5	68-6	69-4	71-1	71-2	72-4	72-9
Temperature (deg F)	268.38	288.20	288.40	289.84	290.40	292.10	292.50	295.20	298.94	300.30	304.72	304.93	308.26	309.68
Initial pressure (psig)	2168	2861	2866	2876	2912	3009	3049	3110	3167	3207	3294	3299	3360	3386
Porosity (fraction)	0.21	0.18	0.17	0.16	0.18	0.19	0.14	0.19	0.16	0.2	0.16	0.13	0.14	0.14
Connate Water Saturation (fraction)	0.61	0.47	0.56	0.76	0.43	0.28	0.56	0.48	0.78	0.4	0.55	0.64	0.76	0.62
Original Gas In Place (MMscf)	97	421	450	264	388	804	388	513	174	464	70	64	27	257
Reservoir Permeability (md)	57.27	21.36	14.87	10.35	21.36	30.69	5.01	30.69	10.35	44.10	10.35	3.49	5.01	5.01
Reservoir Thickness (feet)	5	15	12	10	31	30	35	12	42	12	2	2	2	8
Perforation Interval (feet)	5	9	9	4	21	26	25	12	10	9	2	2	2	4
Bottom depth of reservoir (TVD)	5008.4	6377.9	6391.7	6404.8	6494.5	6677.6	6756.0	6864.4	7003.7	7054.3	7218.8	7226.5	7350.5	7403.7
Drainage Area (acre)	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Start of Production (date m/d/y)	10/17/03	6/20/02	6/20/02	10/17/03	6/20/02	6/20/02	6/20/02	6/20/02	10/17/03	6/20/02	10/17/03	10/17/03	10/17/03	10/17/03

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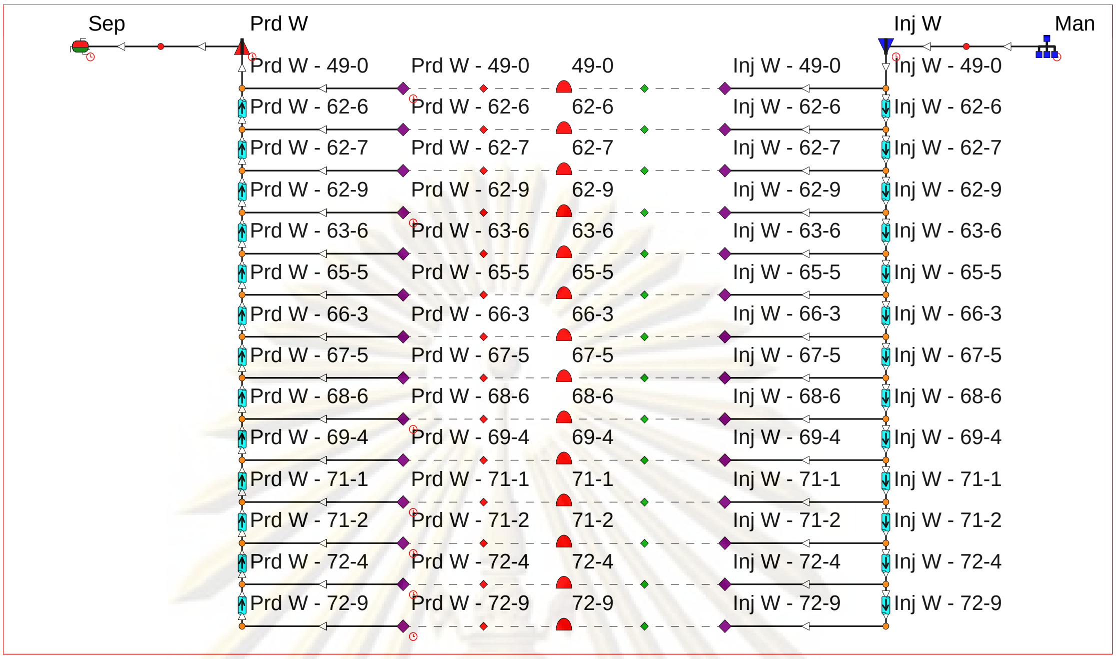

Figure 5-52 : Actual model

5.2.2 Determination of OGIP Correction Factor

This section determines the range of OGIP correction factor for the actual model. The prediction schedule is set to run the prediction in the production period only. The model is first run with constant OGIP correction factor of 1 to predict cumulative gas production. At the end of the run (11th November 2006), the predicted cumulative gas production is 2,278.33 MMscf, and the actual cumulative production is 1,213.29 MMscf. Figure 5-53 shows the predicted cumulative gas production results compared with the production history. The ratio between the cumulative gas production on production history and prediction results is 0.53. The range of OGIP correction factor is calculated from plus and minus 50 percent of the ratio between the predicted cumulative gas productions and the production history. For the actual model, the ratio is close to 0.5. Therefore, the range of OGIP correction factor is 0.25 and 0.75. Table 5-13 shows the ranges of correction factor that are used for the actual model.

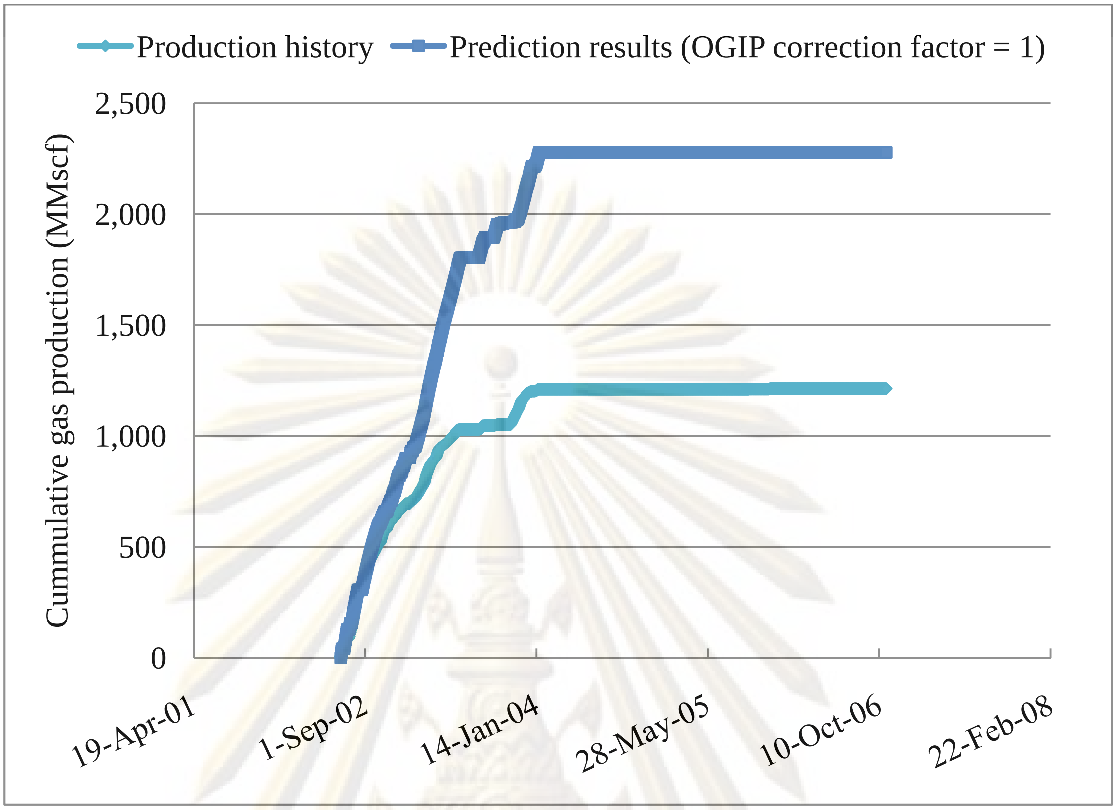

Figure 5-53 : Predicted cumulative gas production and actual cumulative production

Table 5-13 : Ranges of correction factor

Correction Factor	Minimum	Maximum
Allocation	0.75	1.25
OGIP	0.25	0.75
Injection skin	80	100

5.2.3 With Actual Well

This section shows the prediction results of the actual model after applying the proposed methodology. There are two cases to estimate cumulative water injection for the actual well. These cases have different verification periods, i.e., the verification start at the beginning and two-third of the production history.

5.2.3.1 The Verification Period Starts at the Beginning of Production History

In this case, the verification period is set to starts at the beginning of the production history. The prediction schedule of this case is shown in Table 5-14. The prediction timeline is illustrated in Figure 5-54. From Figures 5-55 to 5-59, the predicted cumulative water injection is around 783,243.4 stb. Table 5-15 shows the 10^{th}, 50^{th}, 90^{th} percentile, mean and variance of cumulative water injection for different range of acceptable error. The narrower range of acceptable has narrower range between the 10^{th} and 90^{th} percentile of cumulative water injection. The range of acceptable error for 0 to 5 percent has lowest variance when compared with other ranges of acceptable error. The predicted end of injection period is around 13^{th} November 2007, which is illustrated in Figures 5-60 to 5-62. The predicted total OGIP is around 1,800 MMscf at percent error equals zero as illustrated in Figure 5-63. Figure 5-64 shows the 50^{th} percentile of cumulative water injection against cumulative number of acceptable realizations. The 50^{th} percentile of cumulative water injection starts to stable when the cumulative number of realization is around 75.

Table 5-14 : Prediction schedule of actual model

Prediction schedule		
Start of production	6/20/2002	m/d/y
Start of verification period	6/20/2002	m/d/y
End of verification period	10/31/2006	m/d/y
End of injection period	10/18/2009	m/d/y
Prediction time step	1	week

Table 5-15 : Cumulative water injection (Verification period starts at the beginning of production history)

The verification starts at the beginning of production history					
Acceptable error	0-25%	0-25%	0-25%	0-25%	0-25%
P10 of cumulative water injection (MMstb)	0.51	0.50	0.50	0.50	0.52
P50 of cumulative water injection (MMstb)	0.79	0.74	0.76	0.78	0.78
P90 of cumulative water injection (MMstb)	0.93	0.94	0.97	0.97	0.97
Mean	0.76	0.74	0.75	0.77	0.77
Variance	0.02	0.03	0.03	0.03	0.03

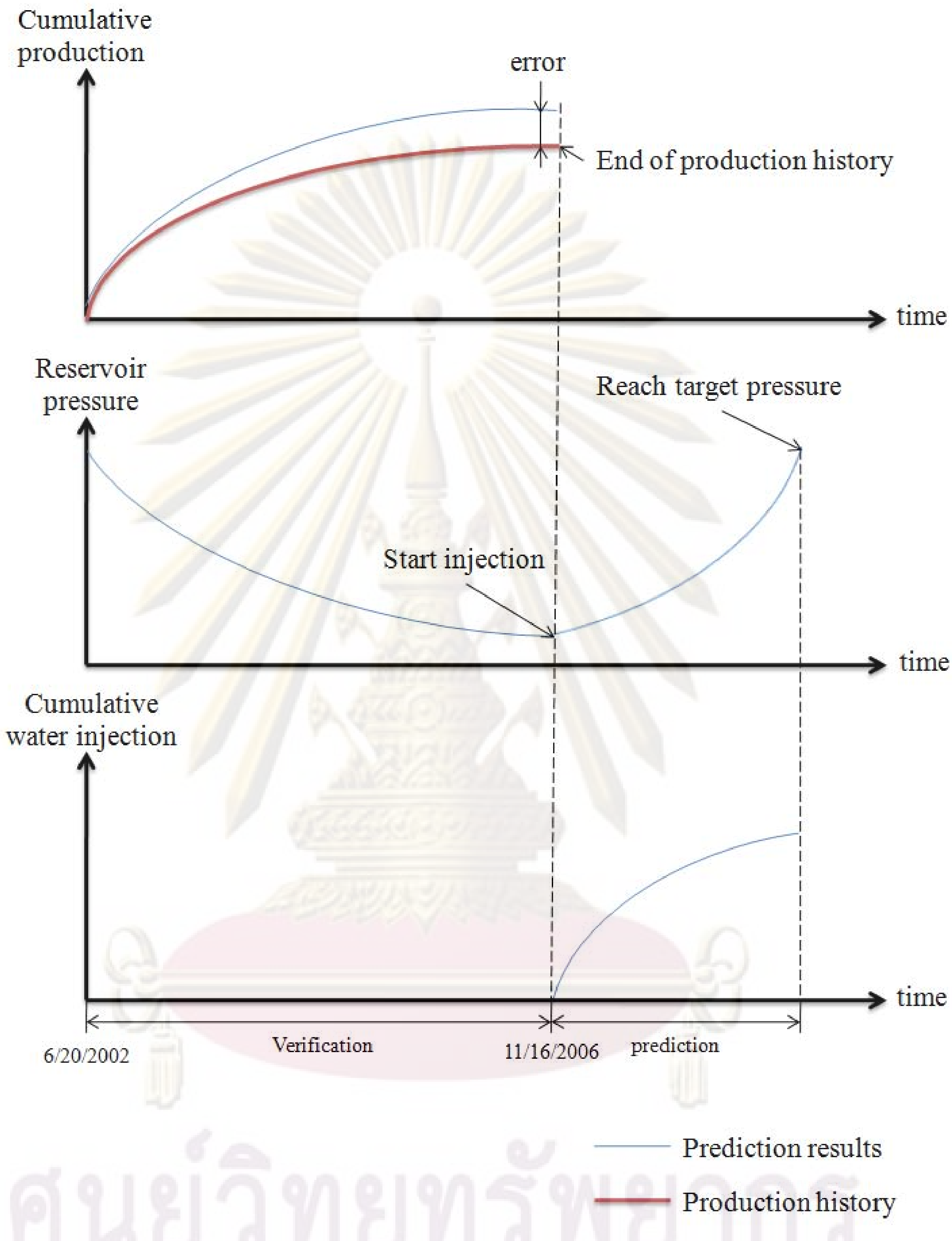

Figure 5-54 : Prediction timeline showing verification period starts at the beginning of production history

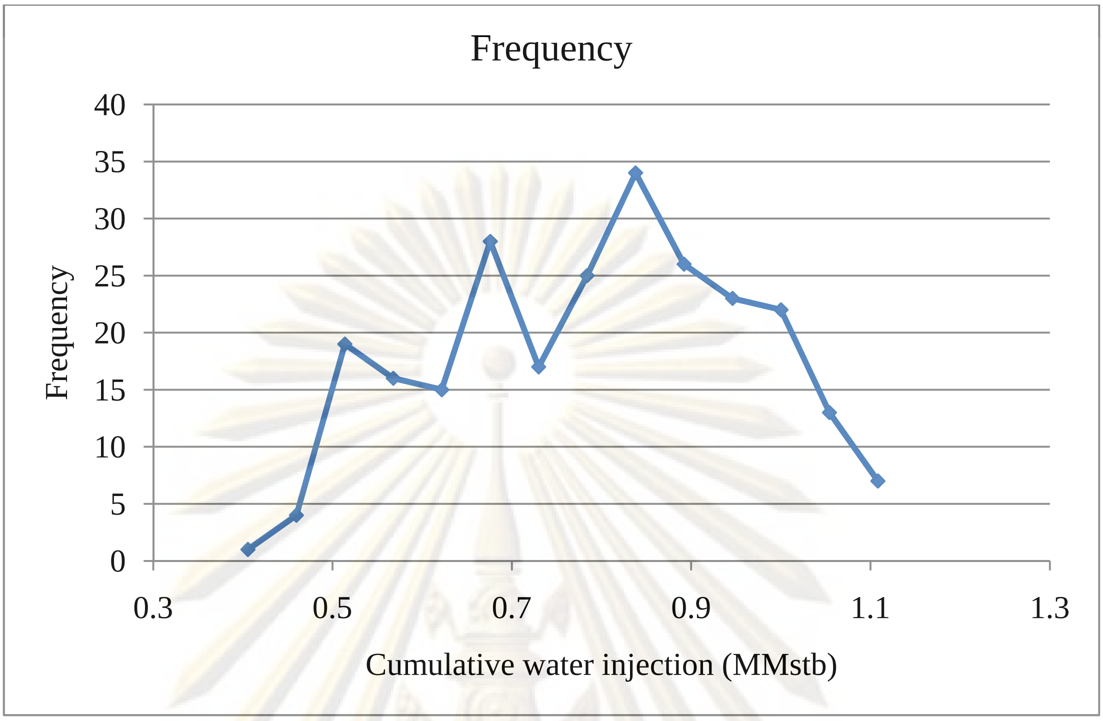

Figure 5-55 : Distribution of cumulative water injection
(Verification period starts at the beginning of production history)

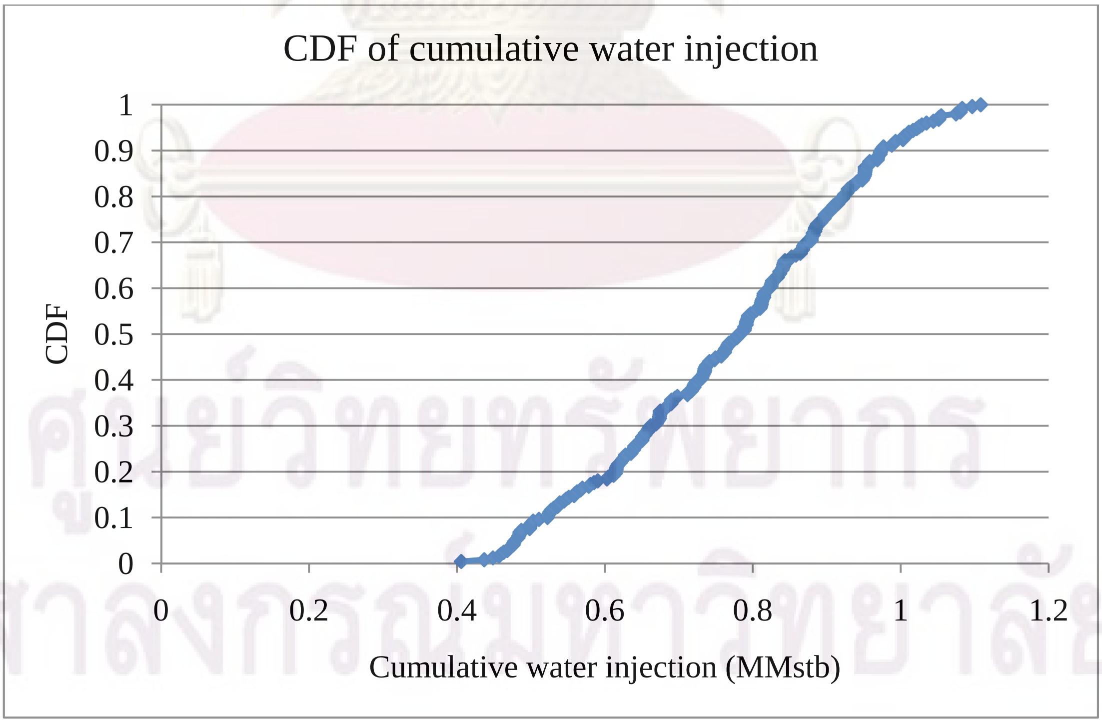

Figure 5-56 : CDF of cumulative water injection
(Verification period starts at the beginning of production history)

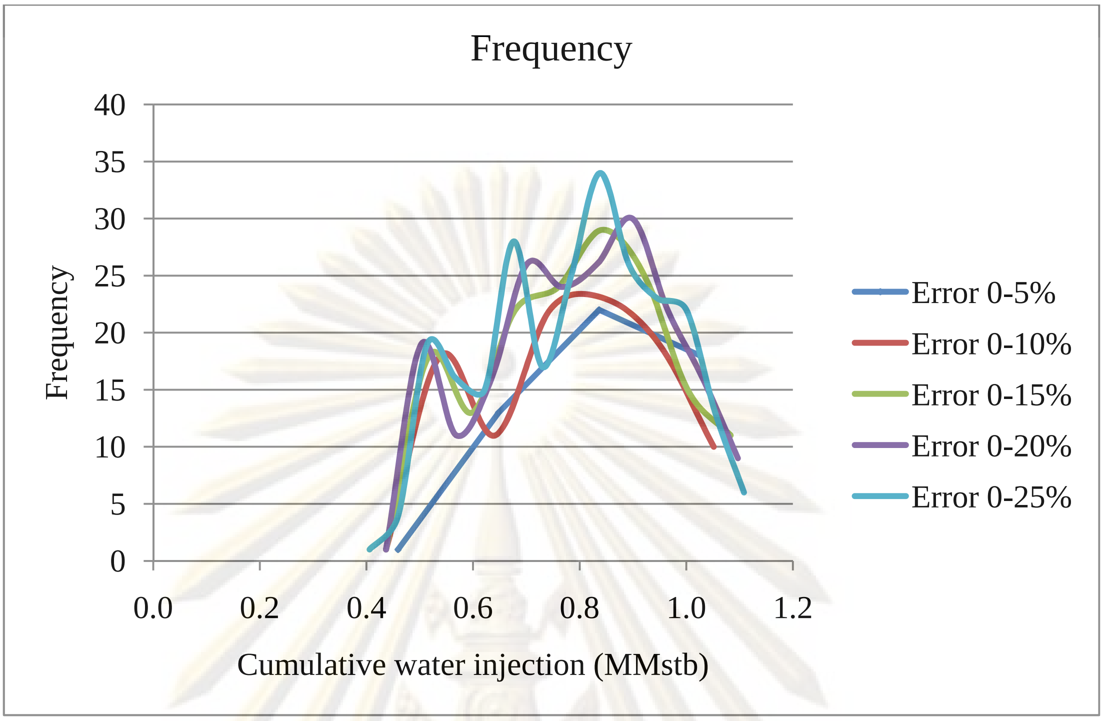

Figure 5-57 : CDF of cumulative water injection for different ranges of acceptable error (Verification period starts at the beginning of production history)

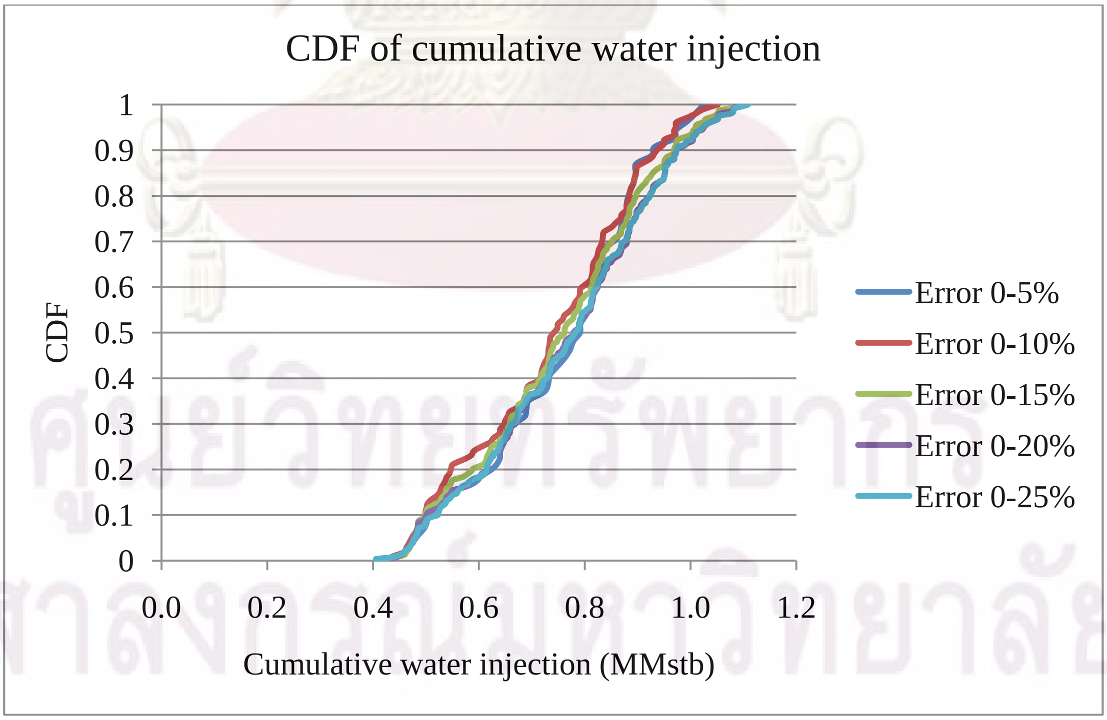

Figure 5-58 : CDF of cumulative water injection for different ranges of acceptable error (Verification period starts at the beginning of production history)

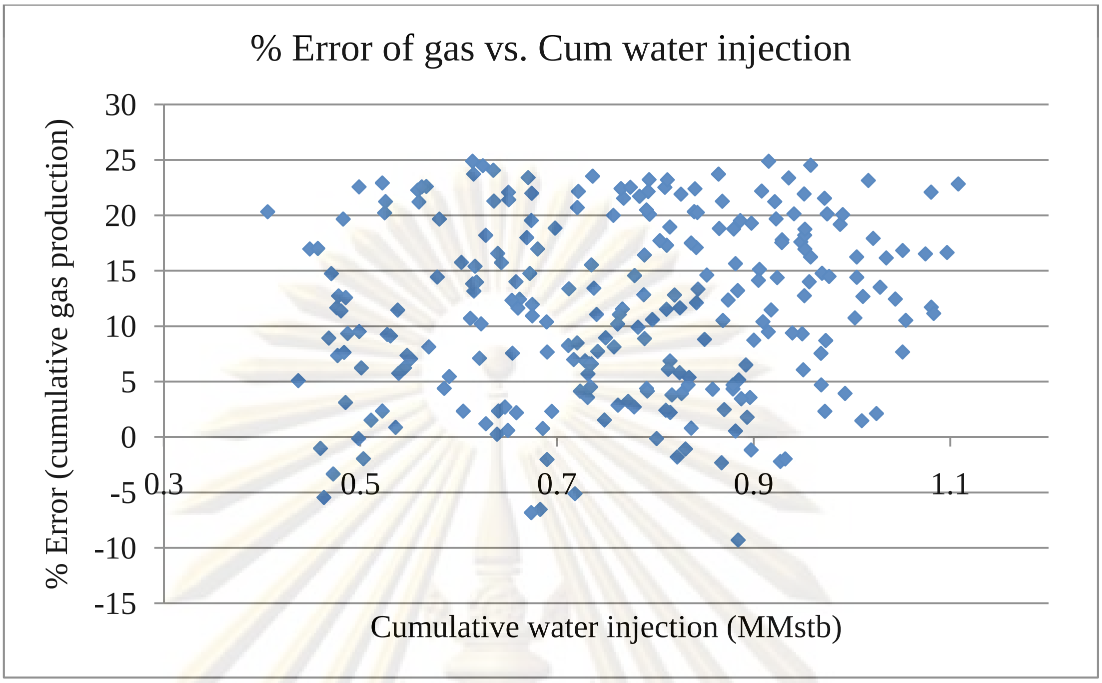

Figure 5-59 : % Error of cumulative gas production against cumulative water injection (Verification period starts at the beginning of production history)

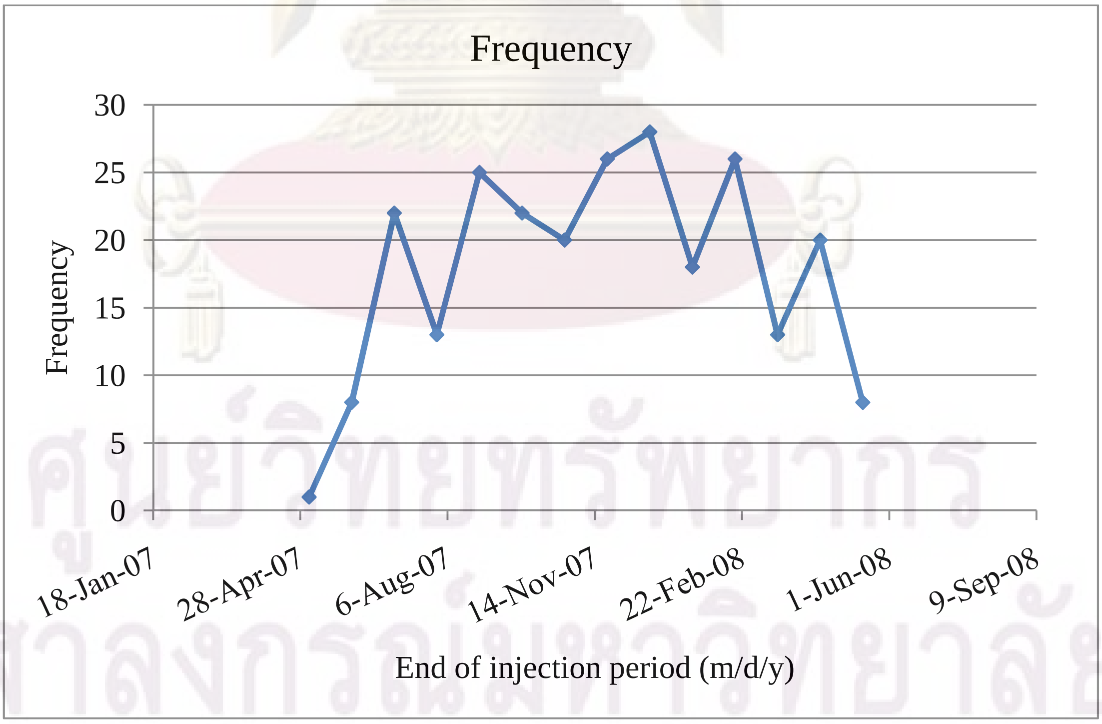

Figure 5-60 : Distribution of end of injection period (Verification period starts at the beginning of production history)

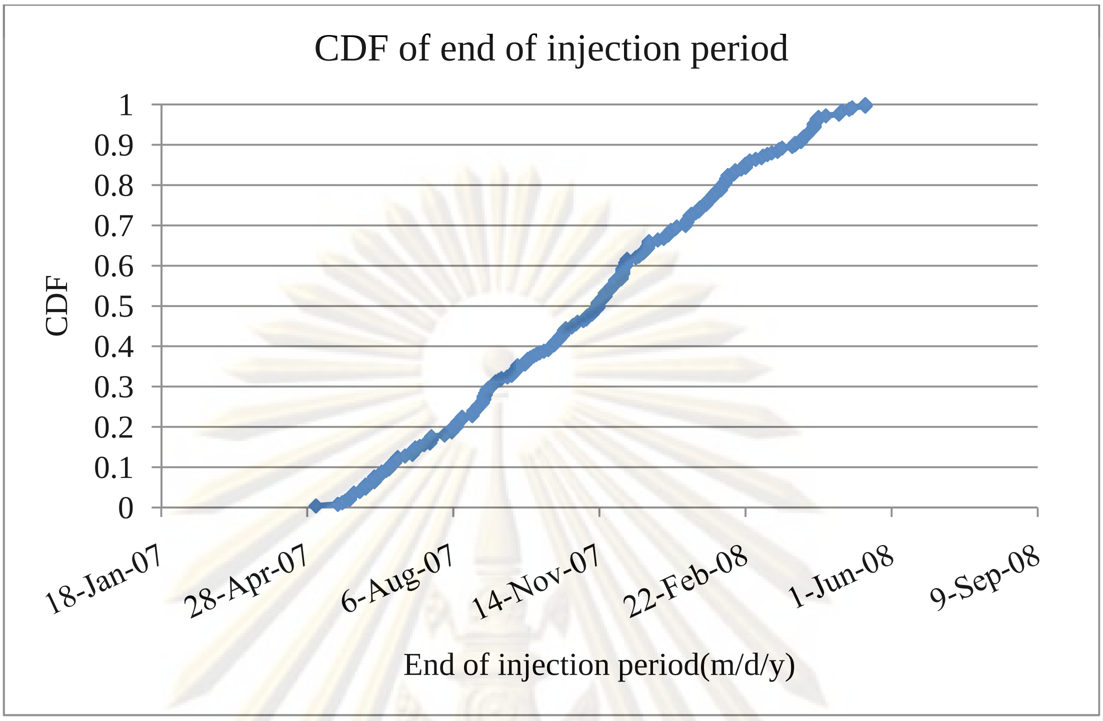

Figure 5-61 : CDF of end of injection period
(Verification period starts at the beginning of production history)

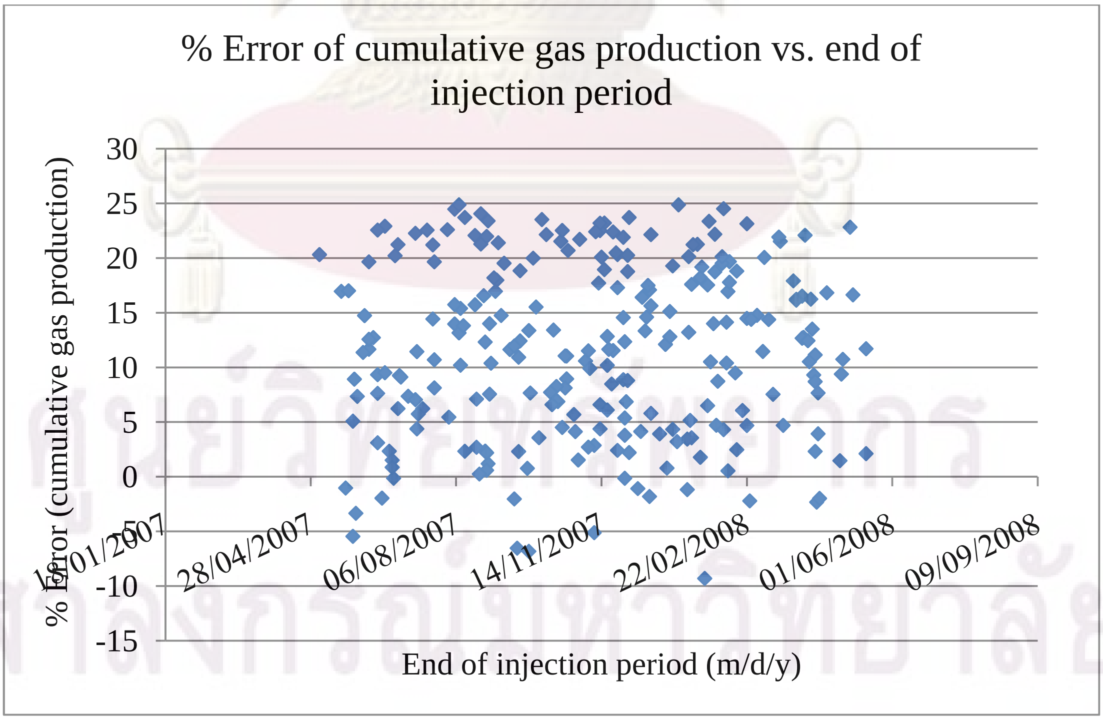

Figure 5-62 : % Error of cumulative gas production against end of injection period
(Verification period starts at the beginning of production history)

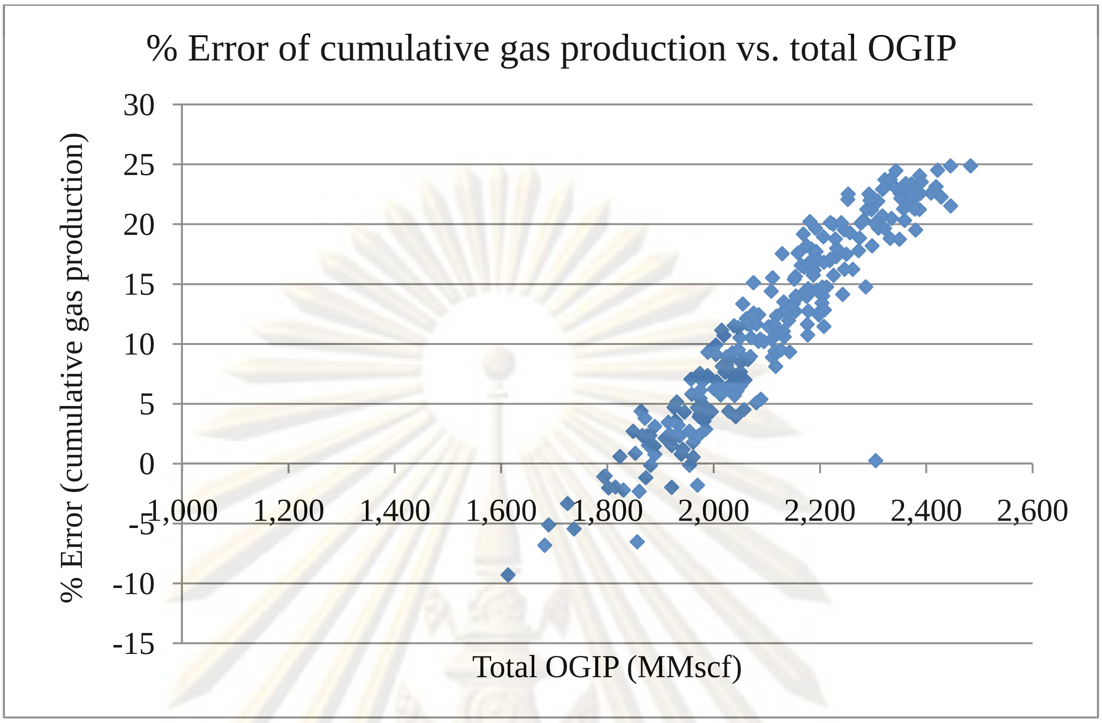

Figure 5-63 : % Error of cumulative gas production against total OGIP
(Verification period starts at the beginning of production history)

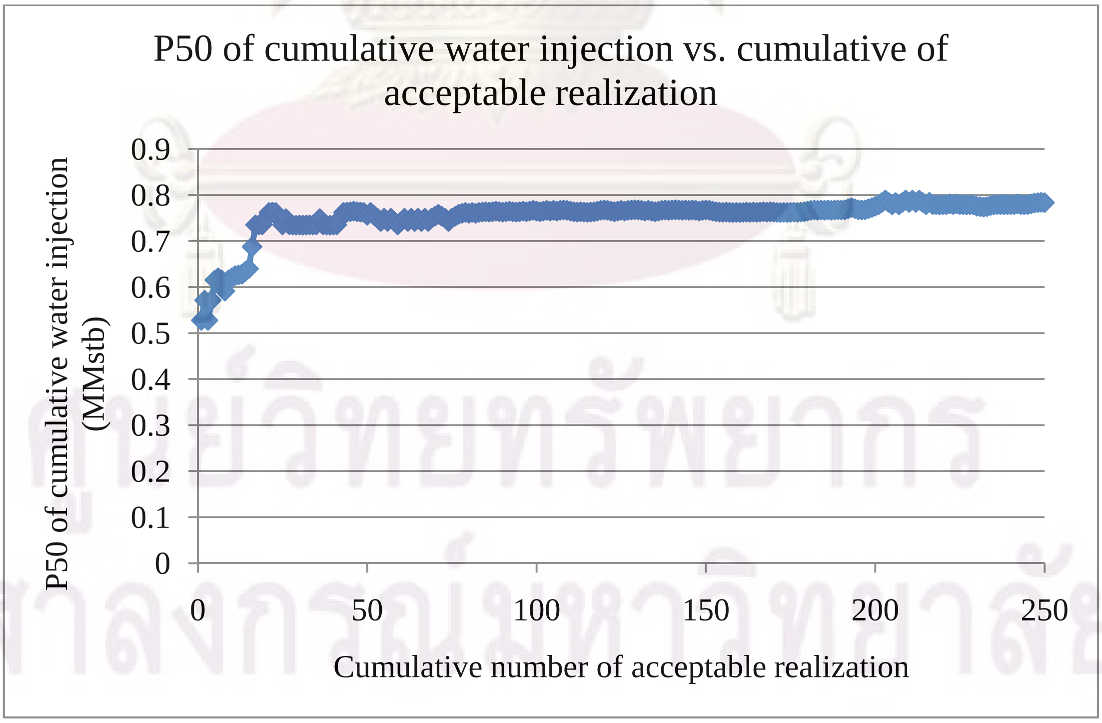

Figure 5-64 : P50 of cumulative water injection against cumulative number of
acceptable realization

5.2.3.2 The Verification Period Starts at Two-Third of Production History

In this case, the verification period starts at two-third of the production history. The prediction schedule of this case is shown in Table 5-16. Prediction timeline is illustrated in Figure 5-65. From Figures 5-66 to 5-70, the predicted cumulative water injection is around 690,887.8 stb. Table 5-17 shows the 10th, 50th, 90th percentile, mean and variance of cumulative water injection of different range of acceptable error. The range of acceptable error for 0 to 5 percent has lowest variance when compared with other ranges of acceptable error. The predicted end of injection period is around 13th September 2007, which is illustrated in Figures 5-71 to 5-73. The predicted total OGIP is around 1,750 MMscf at percent error equals zero as illustrated in Figure 5-74. Figure 5-75 shows the 50th percentile of cumulative water injection against cumulative number of acceptable realizations. The 50th percentile of cumulative water injection starts to stable when the cumulative number of realization is around 50. Therefore, the number of acceptable realization for actual case can be reduced from 250 realizations to 50 realizations to estimate reliable cumulative water injection. The prediction results of two cases are shown in Table 5-18.

The predicted cumulative water injection is lower than the actual cumulative water injection because the model stops injecting water when the reservoir pressure reaches the original reservoir pressure. However, the actual well stopped injecting water when the well cannot inject any more water under operating conditions. In this case, the reservoir pressure may be higher than the original reservoir pressure. The results from this model are regarded as an estimation for a safe water injection volume.

Table 5-16 : Prediction schedule for the verification starts at two-third of production history

Prediction schedule		
Start of production	6/20/2002	m/d/y
Start of verification period	2/28/2003	m/d/y
End of verification period	10/31/2006	m/d/y
End of injection period	10/18/2009	m/d/y
Prediction time step	1	week

Table 5-17 : Cumulative water injection (Verification period starts at two-third of production history)

The verification starts at two-third of production history					
Acceptable error	0-25%	0-25%	0-25%	0-25%	0-25%
P10 of cumulative water injection (MMstb)	0.43	0.42	0.43	0.44	0.44
P50 of cumulative water injection (MMstb)	0.68	0.66	0.67	0.69	0.69
P90 of cumulative water injection (MMstb)	0.85	0.87	0.88	0.89	0.89
Mean	0.67	0.65	0.67	0.68	0.68
Variance	0.02	0.03	0.03	0.03	0.03

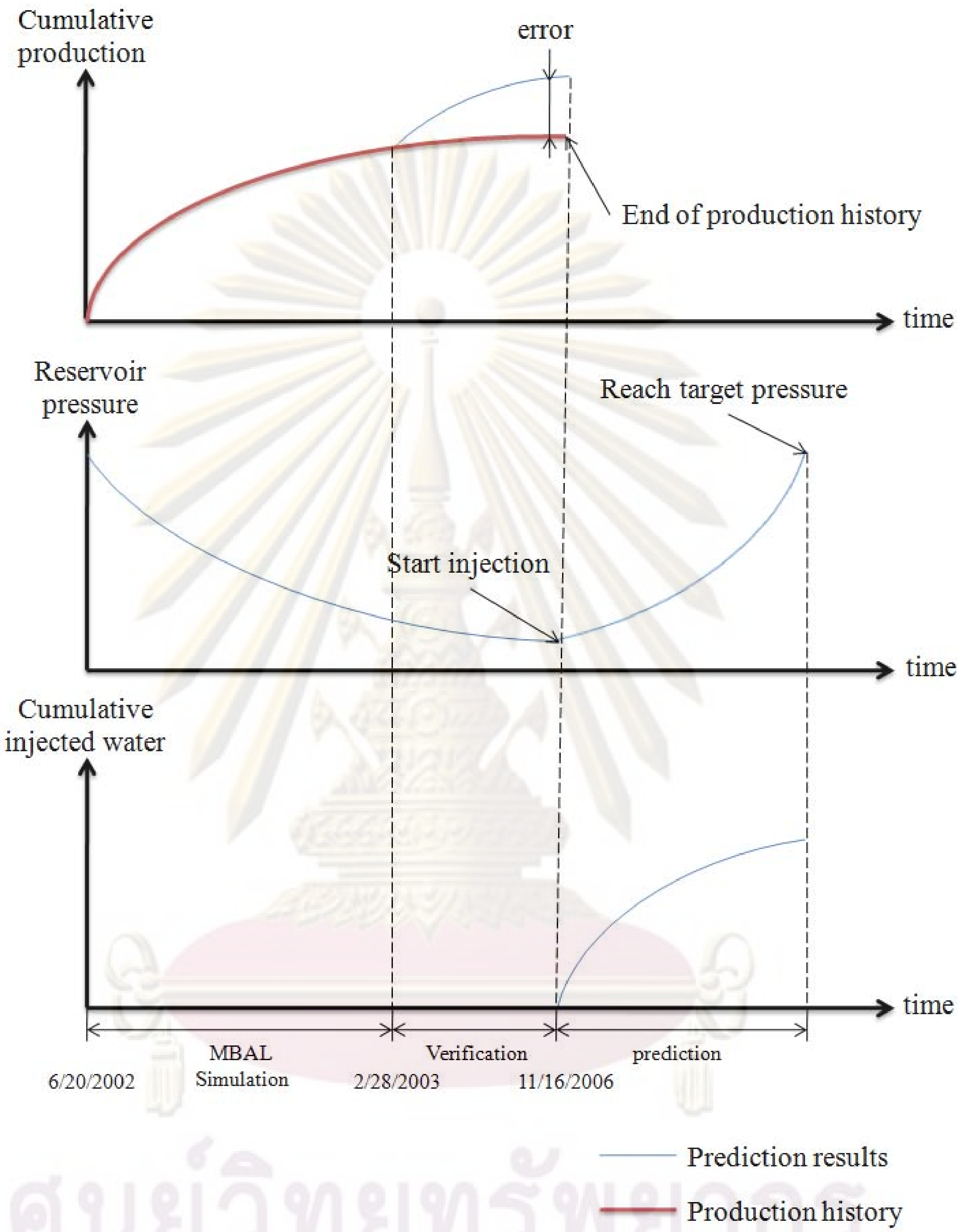

Figure 5-65 : Prediction timeline showing verification period starts at two-third of production history

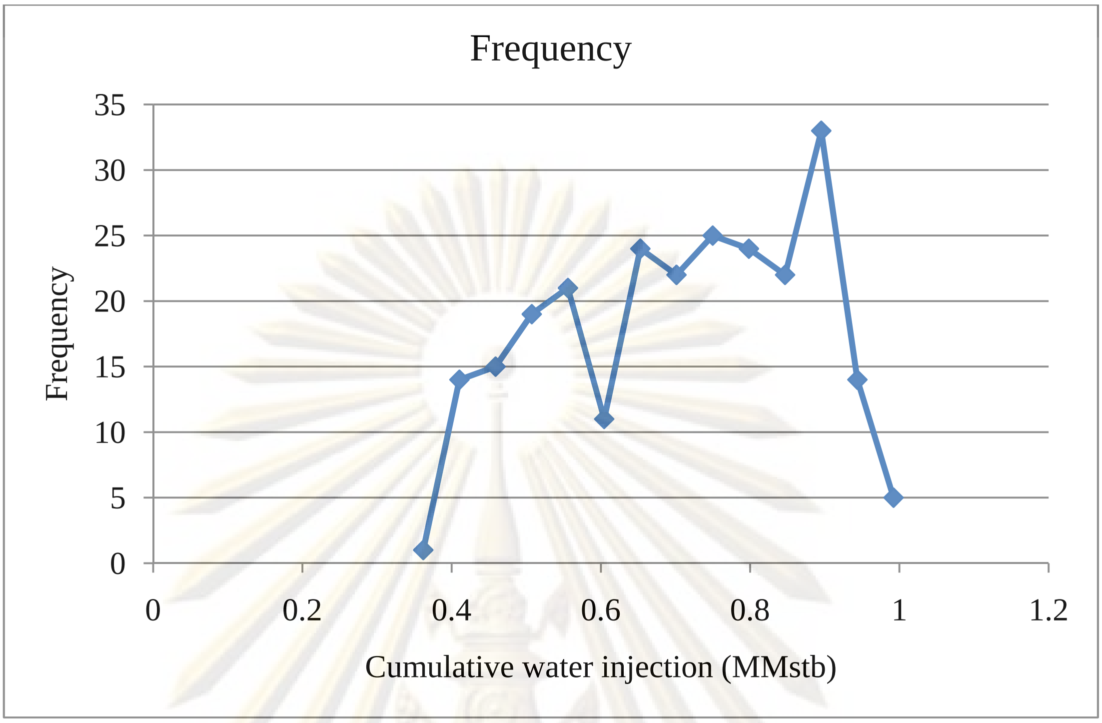

Figure 5-66 : Distribution of cumulative water injection
(Verification period starts at two-third of production history)

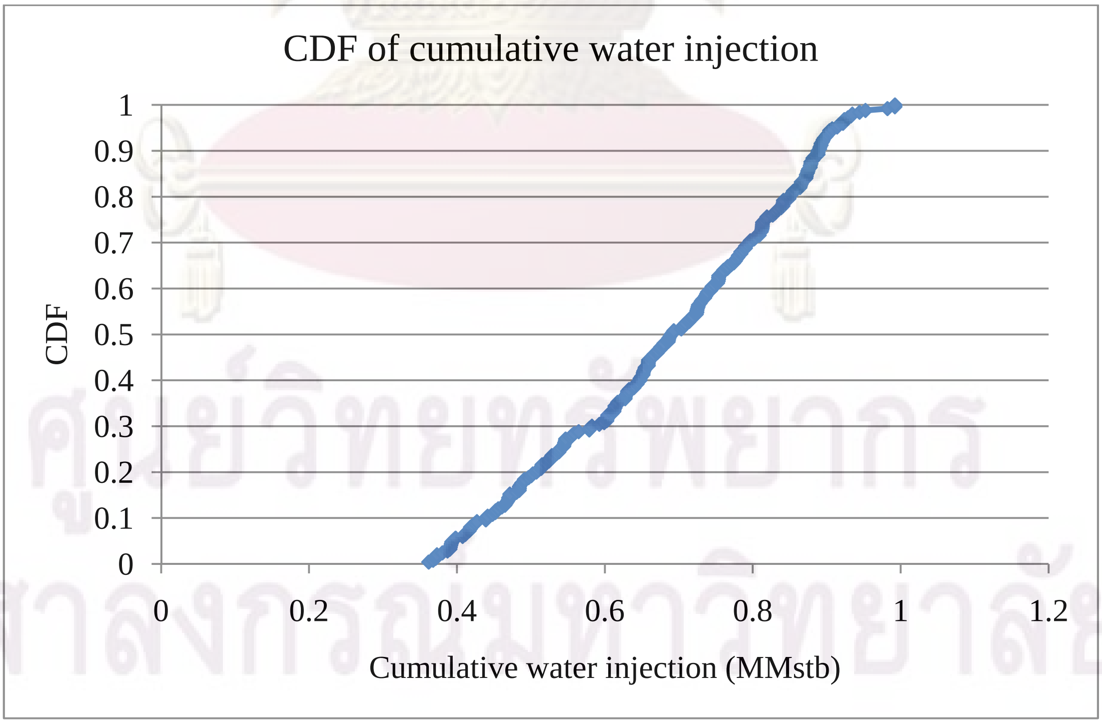

Figure 5-67 : CDF of cumulative water injection
(Verification period starts at two-third of production history)

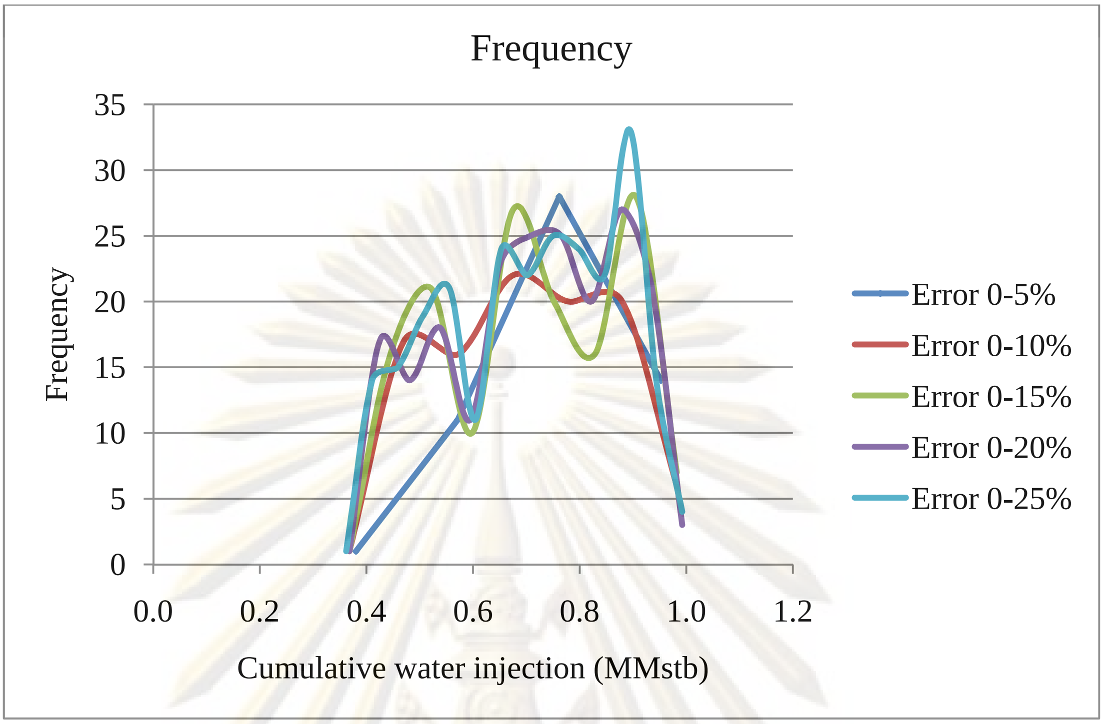

Figure 5-68 : CDF of cumulative water injection for different ranges of acceptable error (Verification period starts at two-third of production history)

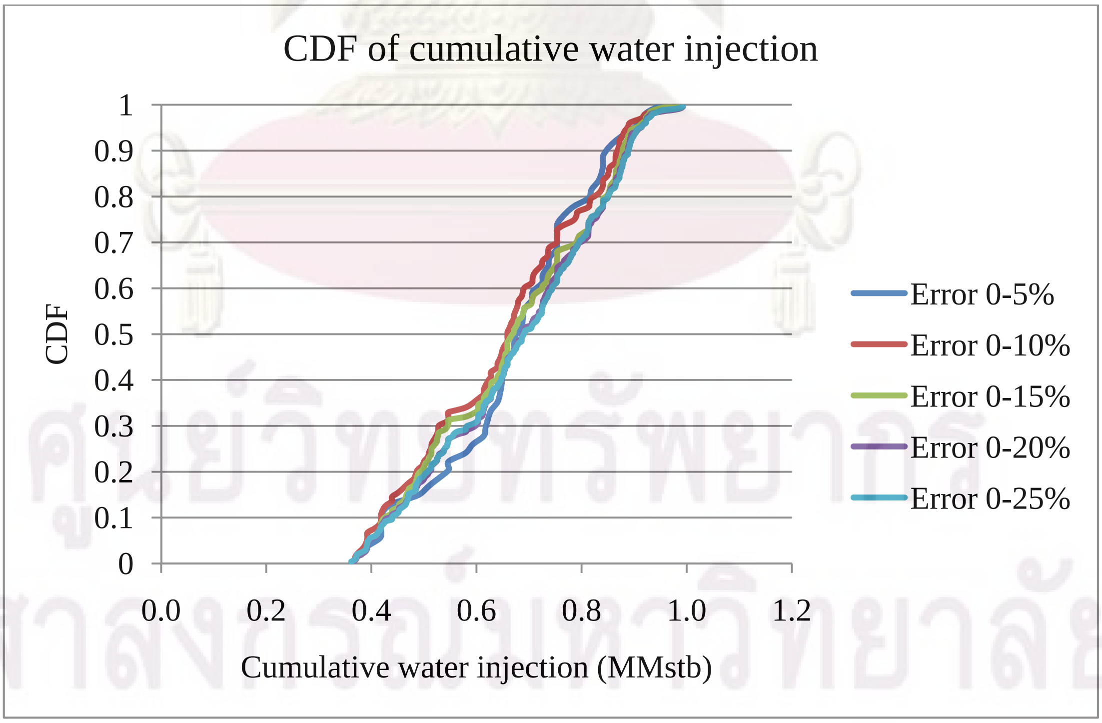

Figure 5-69 : CDF of cumulative water injection for different ranges of acceptable error (Verification period starts at two-third of production history)

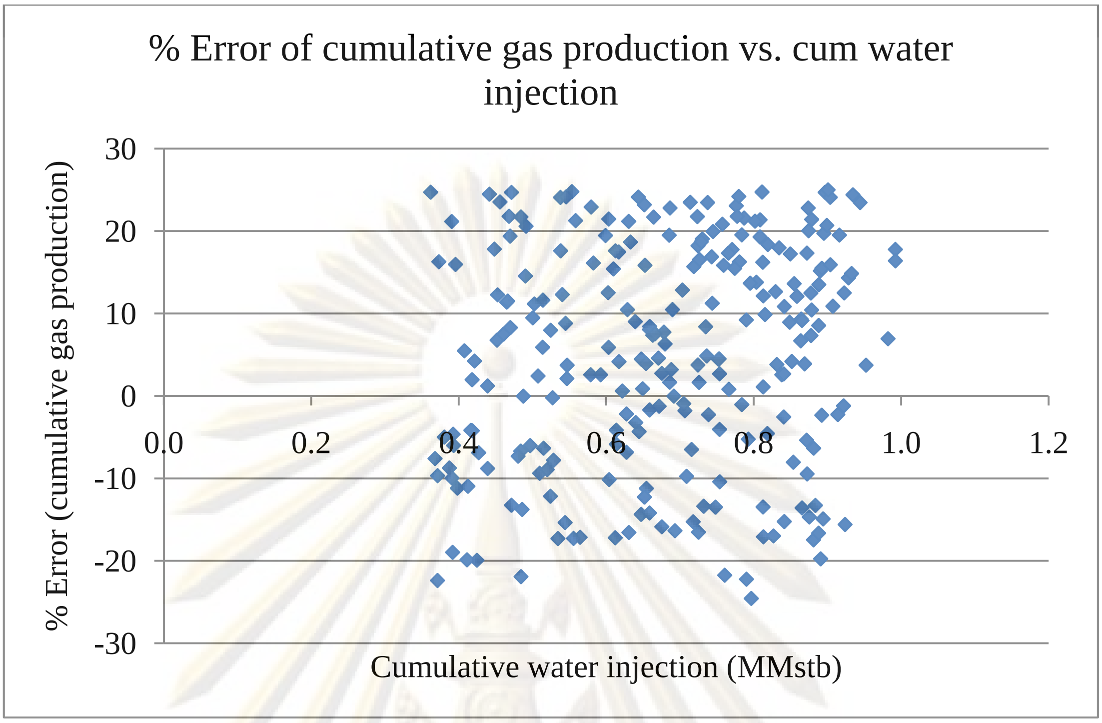

Figure 5-70 : % Error of cumulative gas production against cumulative water injection (Verification period starts at two-third of production history)

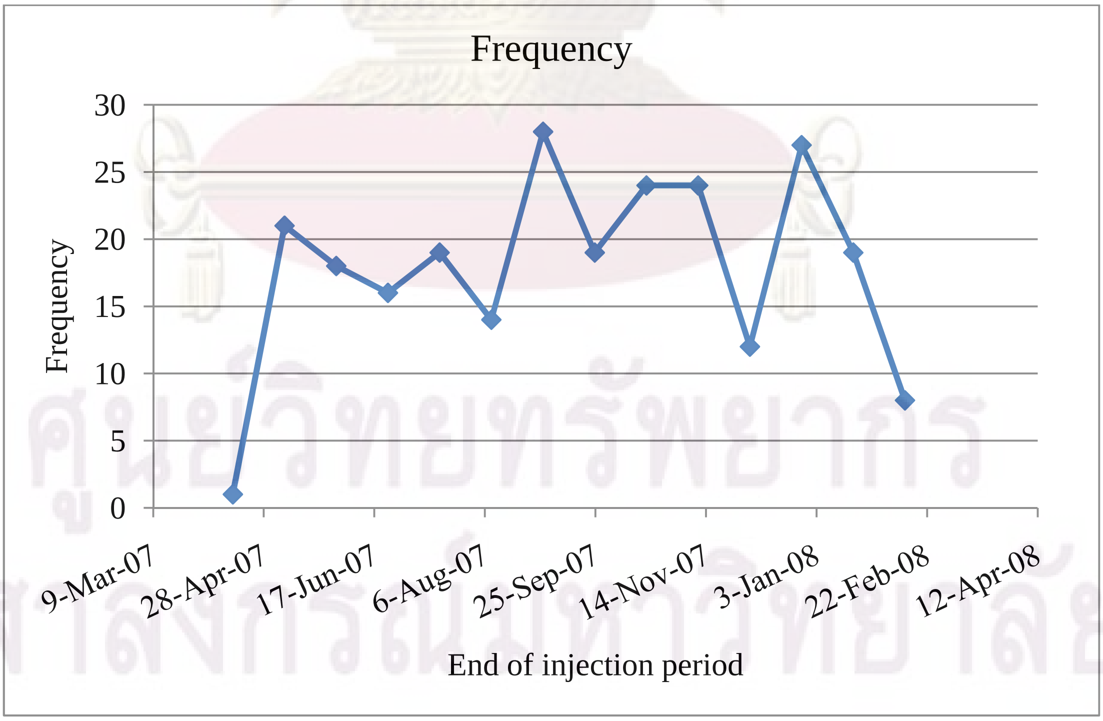

Figure 5-71 : Distribution of end of injection period (Verification period starts at two-third of production history)

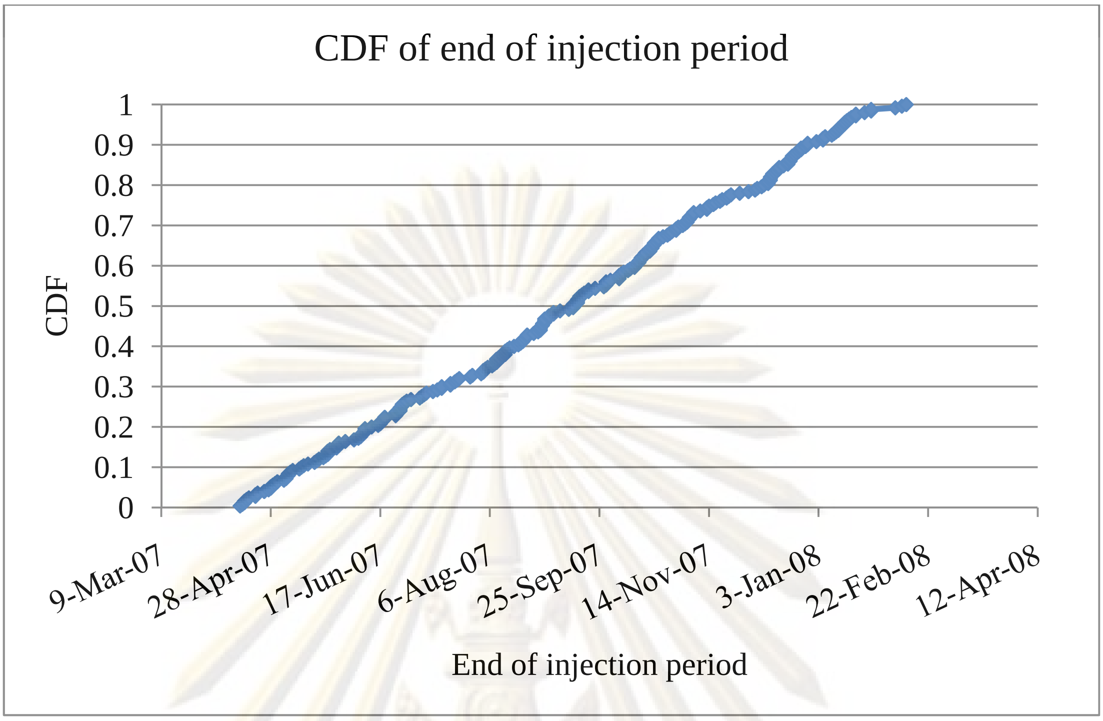

Figure 5-72 : CDF of end of injection period
(Verification period starts at two-third of production history)

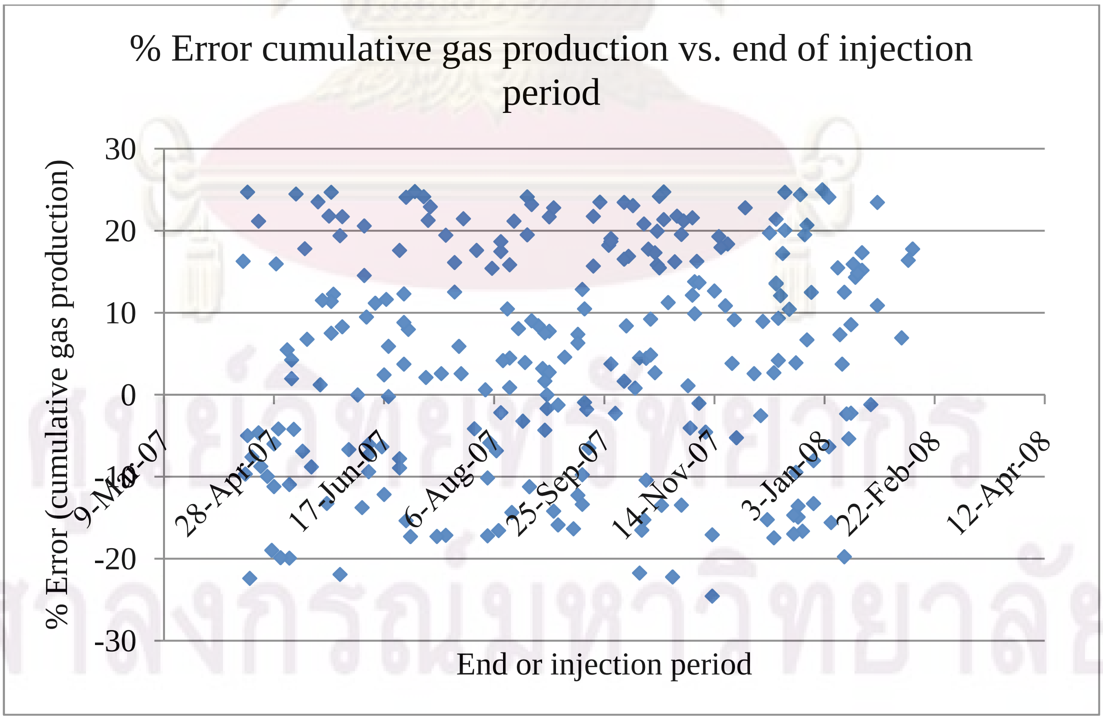

Figure 5-73 : % Error of cumulative gas production against end of injection period
(Verification period starts at two-third of production history)

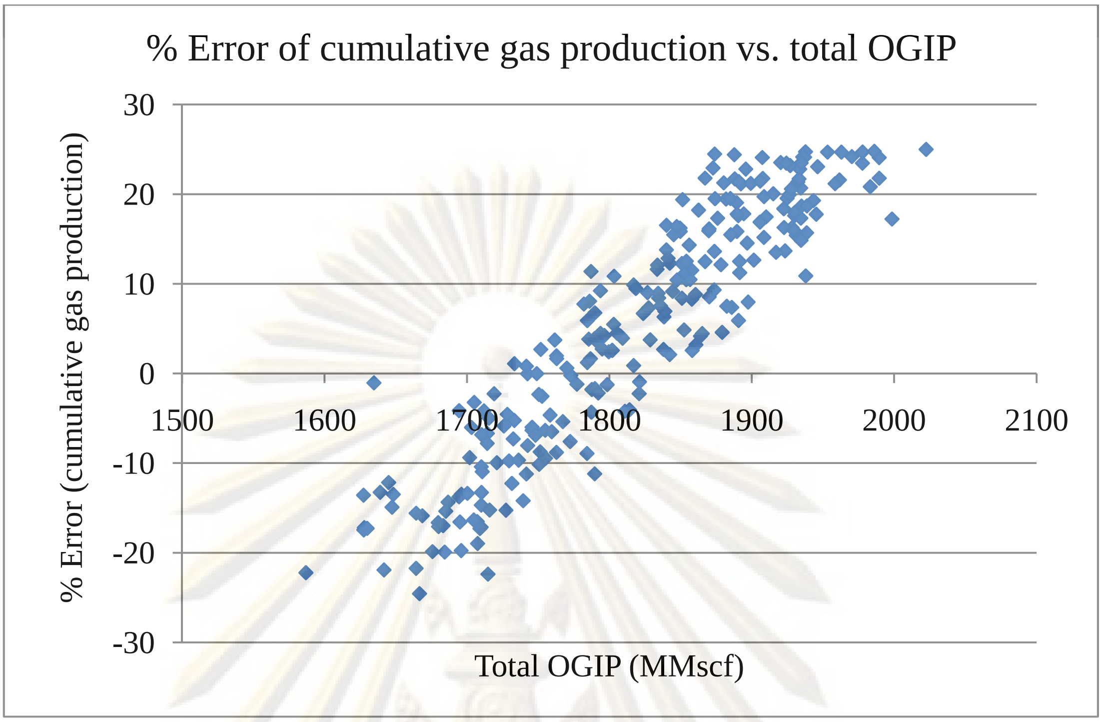

Figure 5-74 : % Error of cumulative gas production against total OGIP
(Verification period starts at two-third of production history)

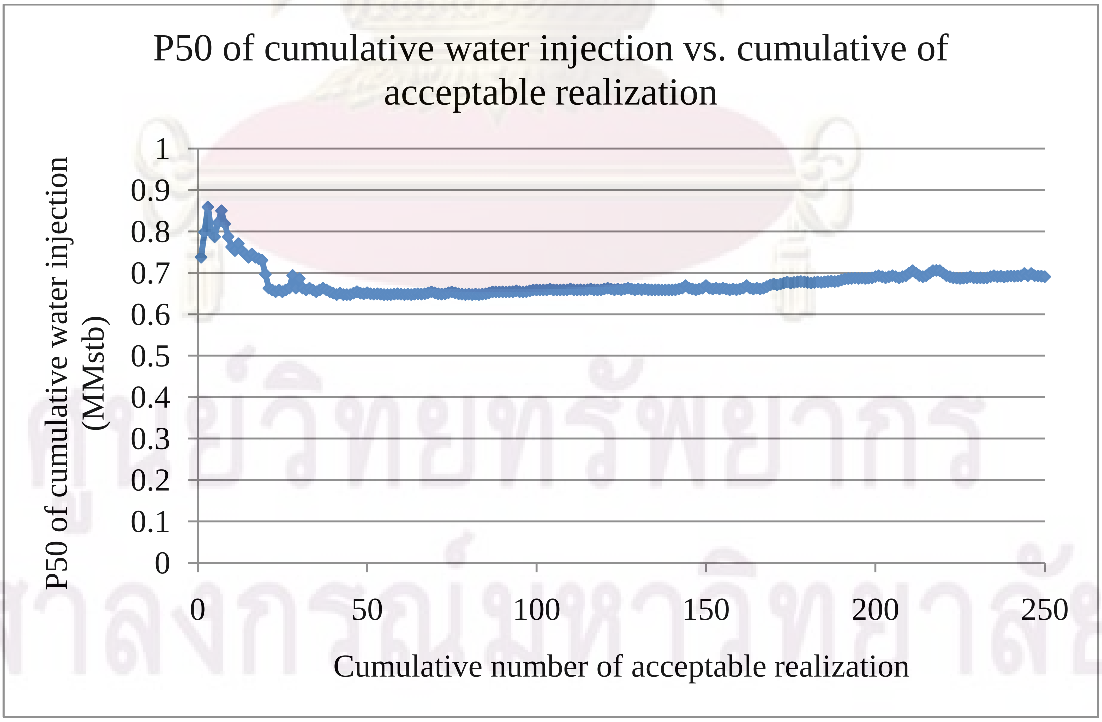

Figure 5-75 : P50 of cumulative water injection against cumulative number of acceptable realization

Table 5-18 : Prediction results

Prediction Results	**Generated history**	**Verification starts at beginning of production history**	**Verification starts at 2/3 production history**
Cumulative water injection (MMstb)	1.21	0.78	0.69
End of injection period	18th Oct 09	13th Nov 07	13th Sep 07
Acceptable realization		250	250
Total realization		301	2144
Prediction time		27 Hr 15 Min	20 Hr 35 Min

CHAPTER VI
CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

The objective of this study is to investigate a probabilistic approach to estimate cumulative water injection into multilayer depleted reservoirs. The model in this study is a comingled well that is connected to multilayer reservoirs. If the well is still producing at the current time, the future production and injection volume is hard to predict as the remaining reservoir pressure and GIP are unknown. The probabilistic approach is applied in order to find the solution accounting for three uncertainties. These uncertainties are rate allocation, OGIP, and injection skin.

There are two types of model created in this study. A test model is used to verify the methodology, and an actual model is created from real existing well information.

The predicted cumulative water injection, end of injection period, and total OGIP for the test model show that probabilistic estimation is a reliable method. Relation between parameters can be concluded as follows:

1. OGIP has significant effect on cumulative water injection. With higher OGIP, the reservoir can produce more, and it can store higher volume of water.
2. Injection skin has little effect on cumulative water injection but has important effect on the amount of time needed to inject water until the reservoir pressure reaches its original pressure.
3. The results from probabilistic approach are generated in the form of statistical distribution. The distribution of prediction results covers the range that actual solution falls in. The values of P10, P50, and P90 obtained from the distribution can be used to assess the uncertainly of water injection volume.
4. Cumulative water injection obtained from two different lengths of verification periods is close to actual cumulative water injection. The

verification starts at two-third of production history cases has narrower distribution of results. Since the two methods provide similar answers, the methodology is not sensitive to the length of verification period.

5. The required number of acceptable realizations is around 50 although the algorithm is run until the number of acceptable realizations is 250.

6.2 Recommendations

The following points are recommended for future study:

1. In this study, only gas reservoirs are used to verify the methodology. In order to provide more application of probabilistic approach, oil reservoirs should be considered.
2. The comingled well connects to both oil and gas reservoirs should be considered.

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APPENDICES

APPENDIX A

Additional results from generation of production profile

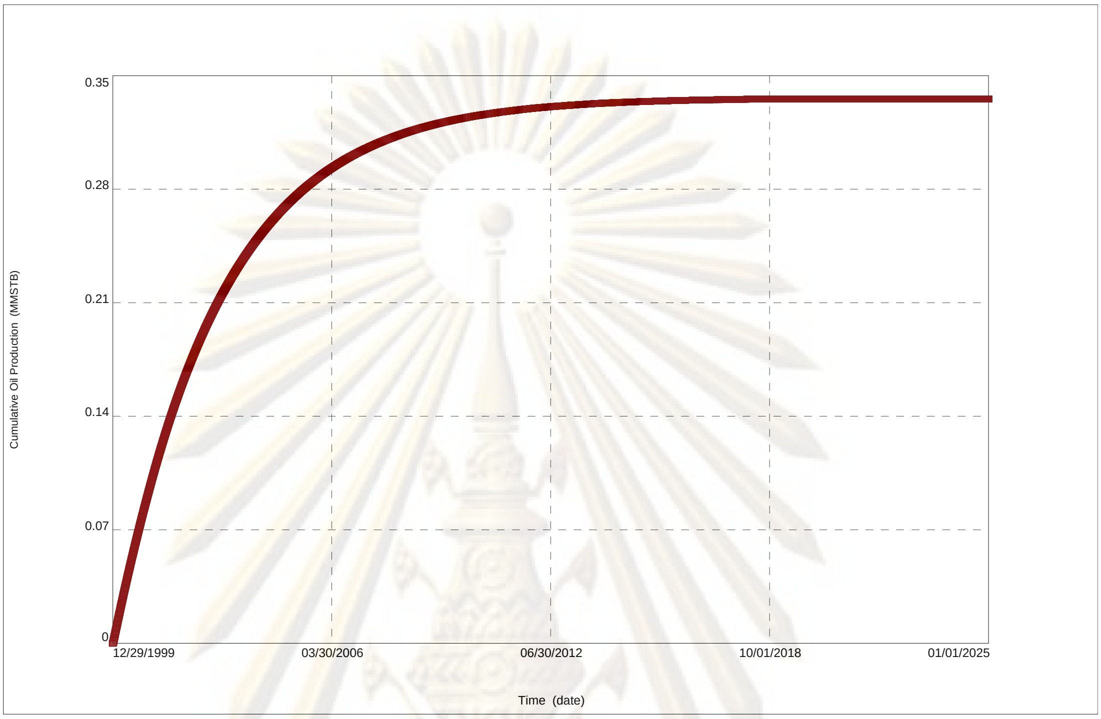

Figure A-1 : Cumulative oil production of production well

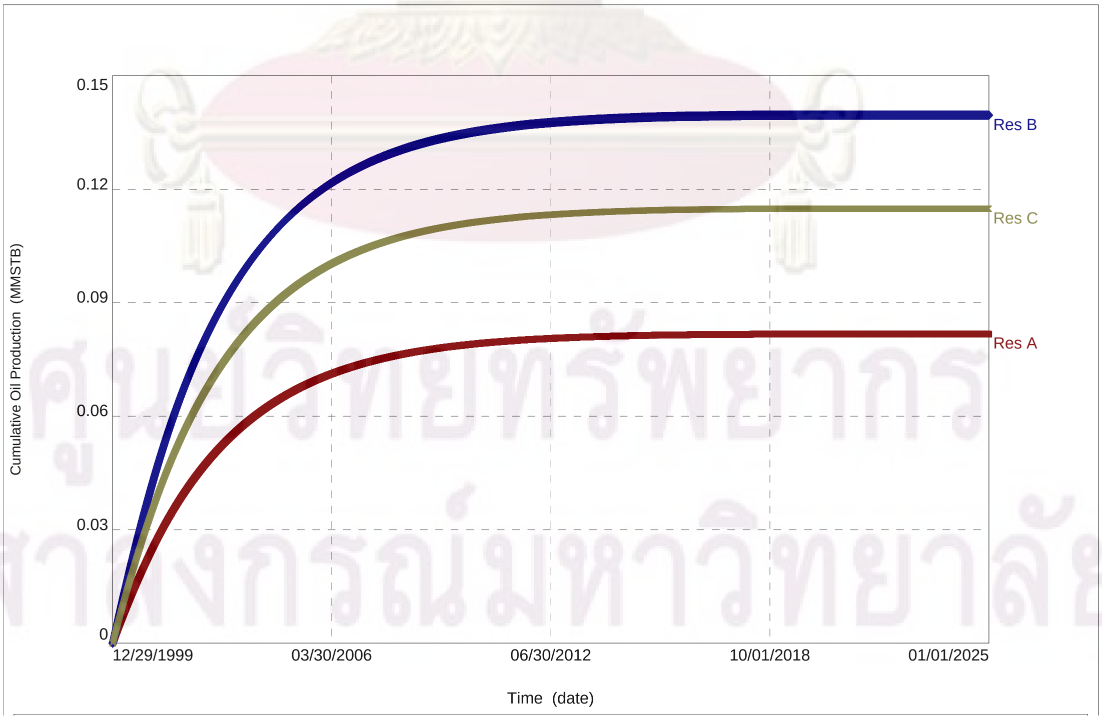

Figure A-2 : Cumulative oil production for each reservoir

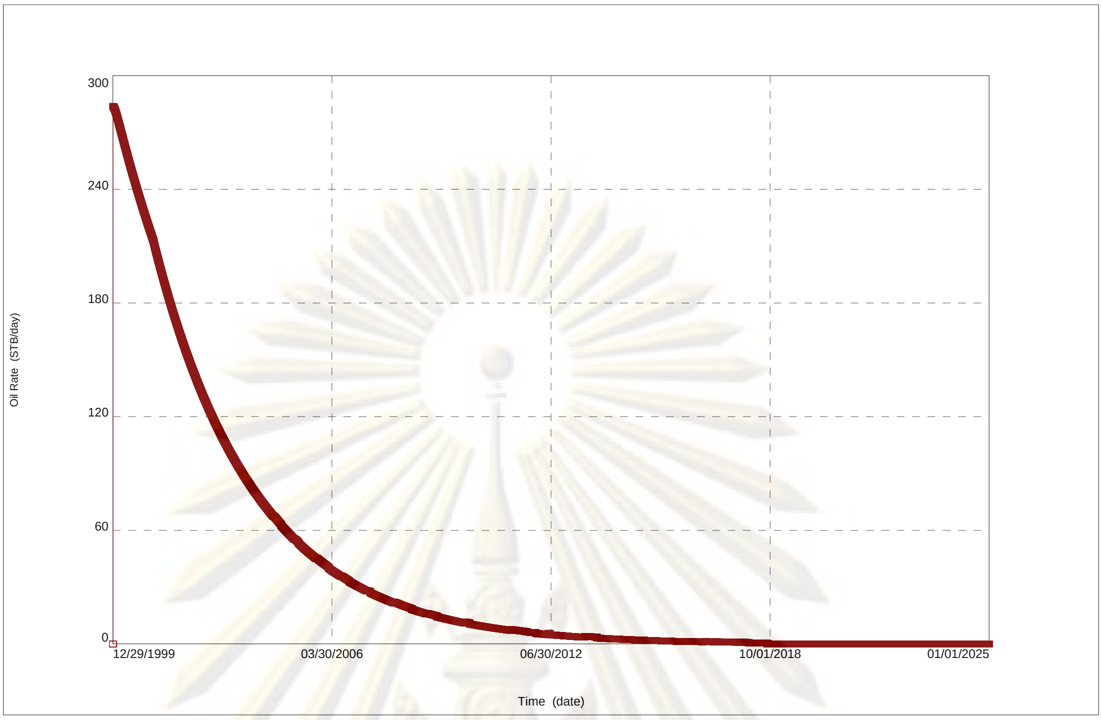

Figure A-3 : Oil production rate of production well

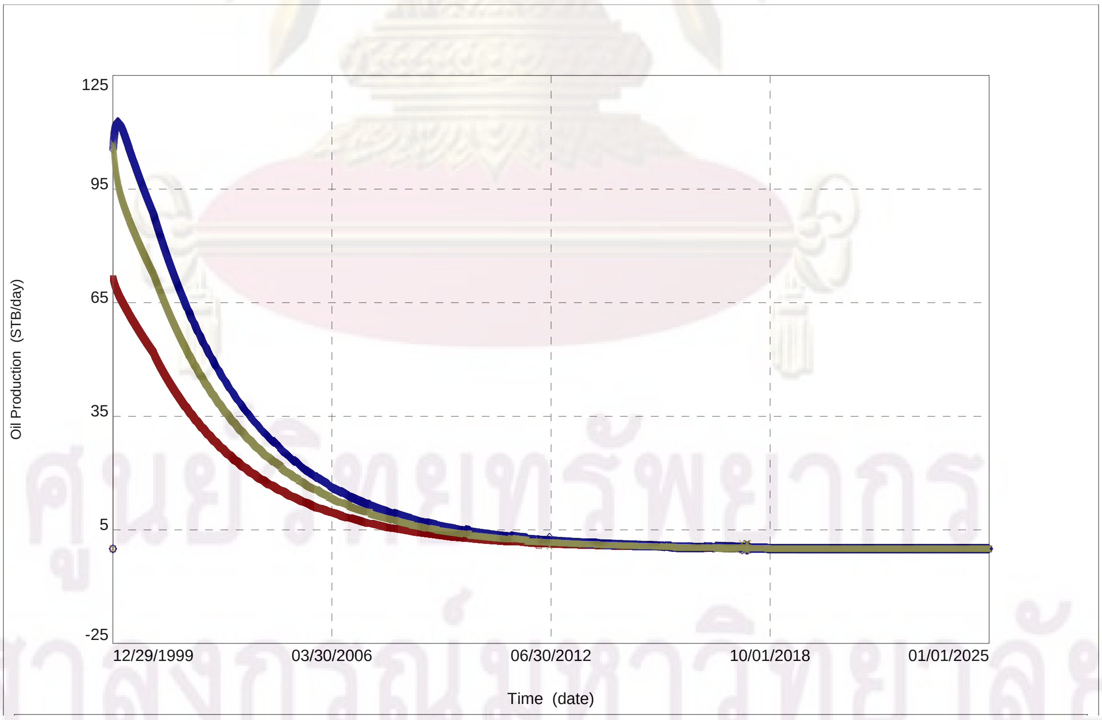

Figure A-4 : Oil production rate for each reservoir

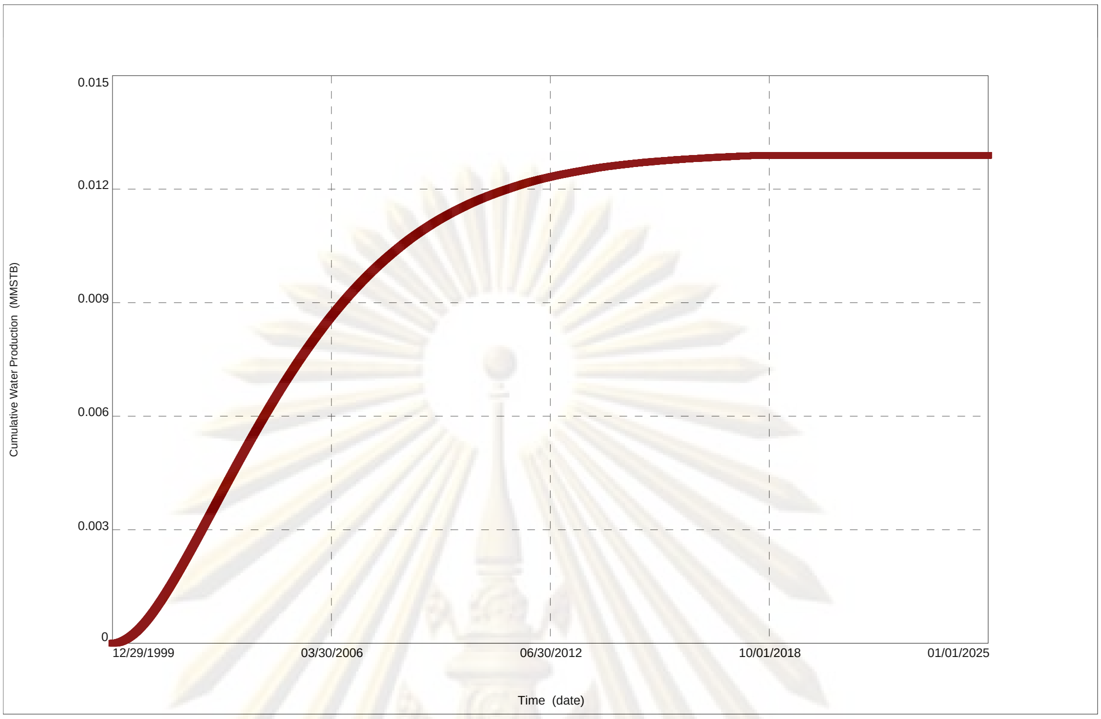

Figure A-5 : Cumulative water production of production well

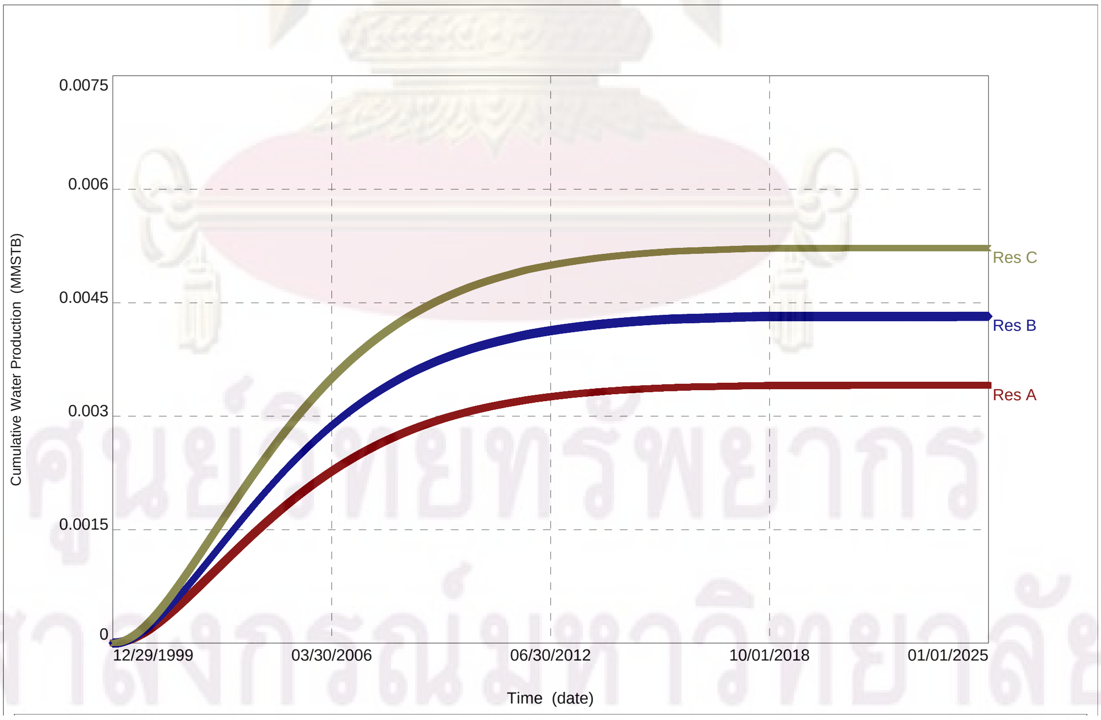

Figure A-6 : Cumulative water production for each reservoir

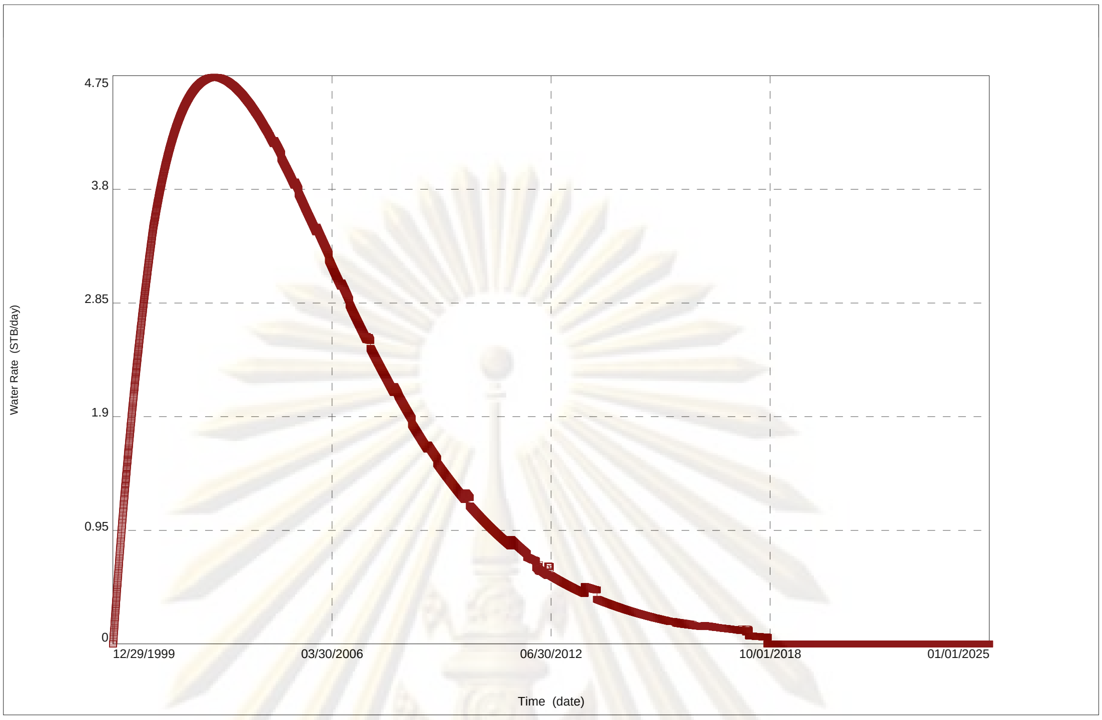

Figure A-7 : Water production rate of production well

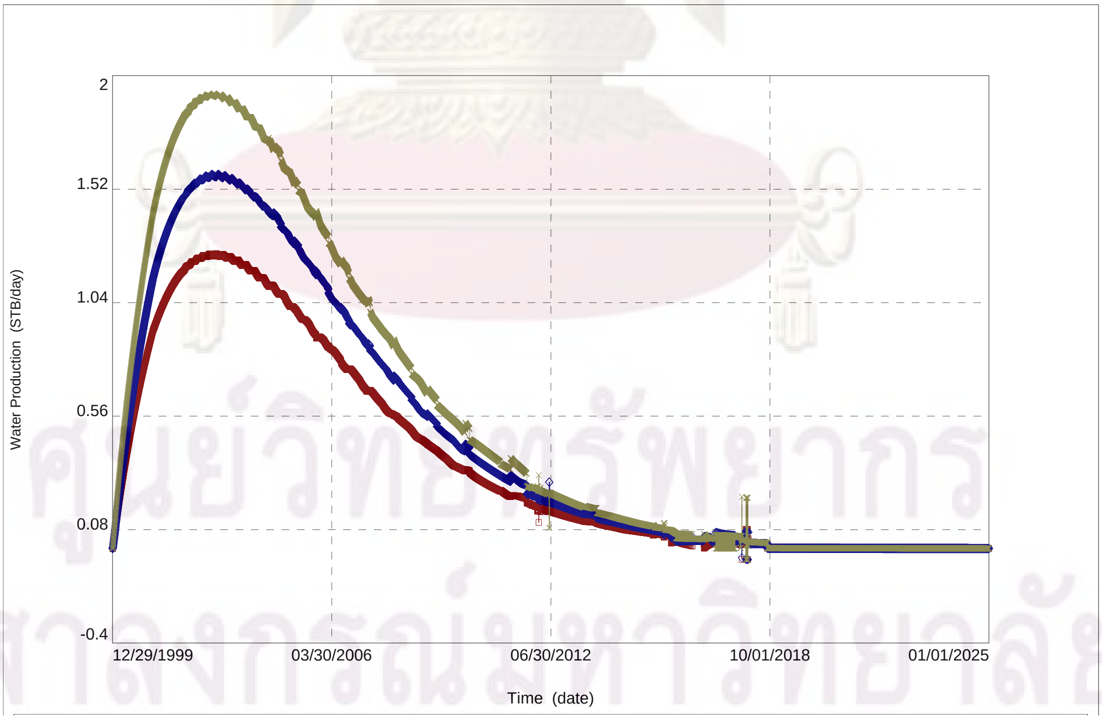

Figure A-8 : Water production rate for each reservoir

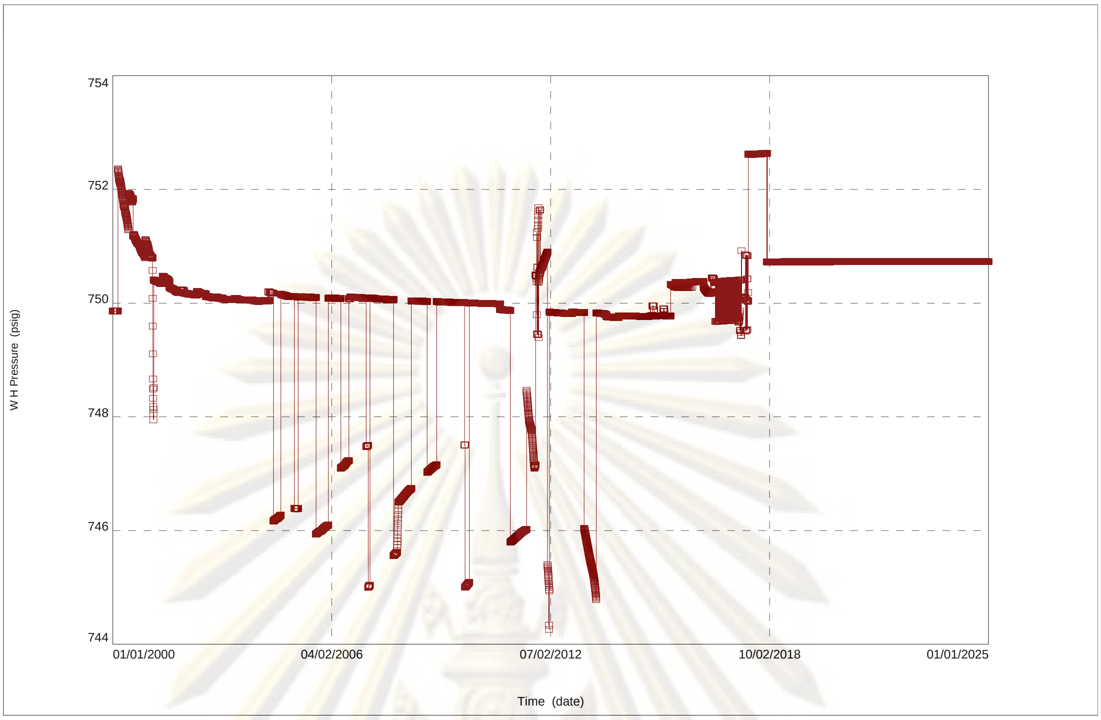

Figure A-9 : Well head pressure

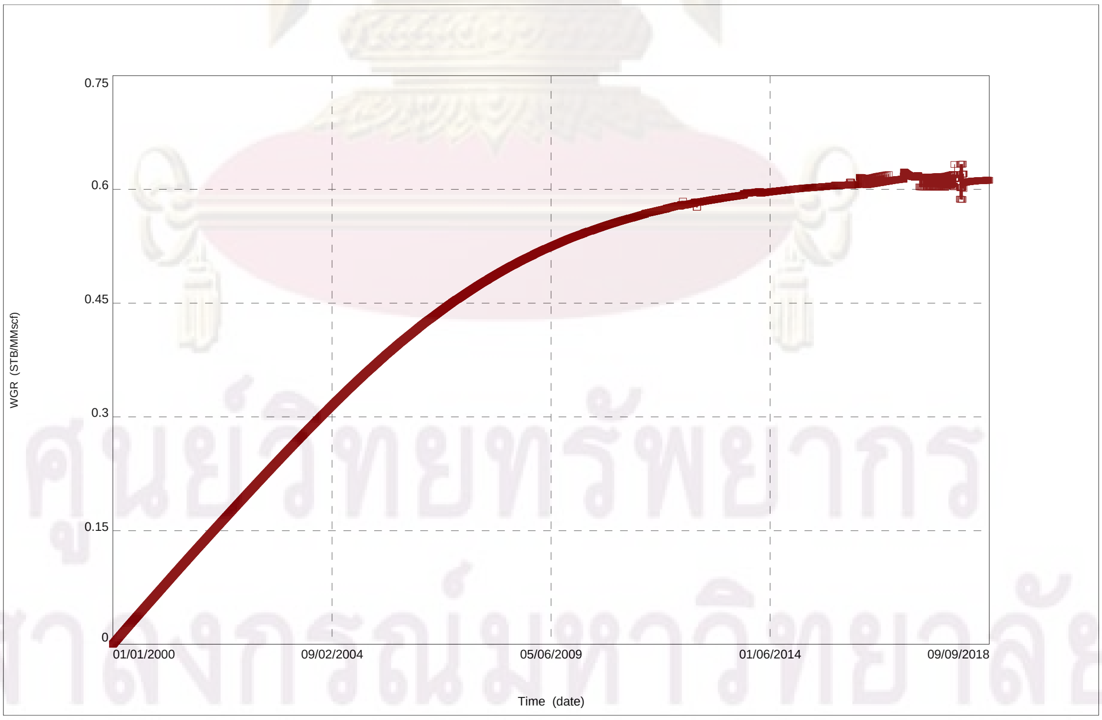

Figure A-10 : Water gas ratio

APPENDIX B

Procedure to set up multilayer reservoirs model with IPM and procedure to use OpenServer Excel spreadsheet.

1) Procedure to construct multilayer reservoir model.

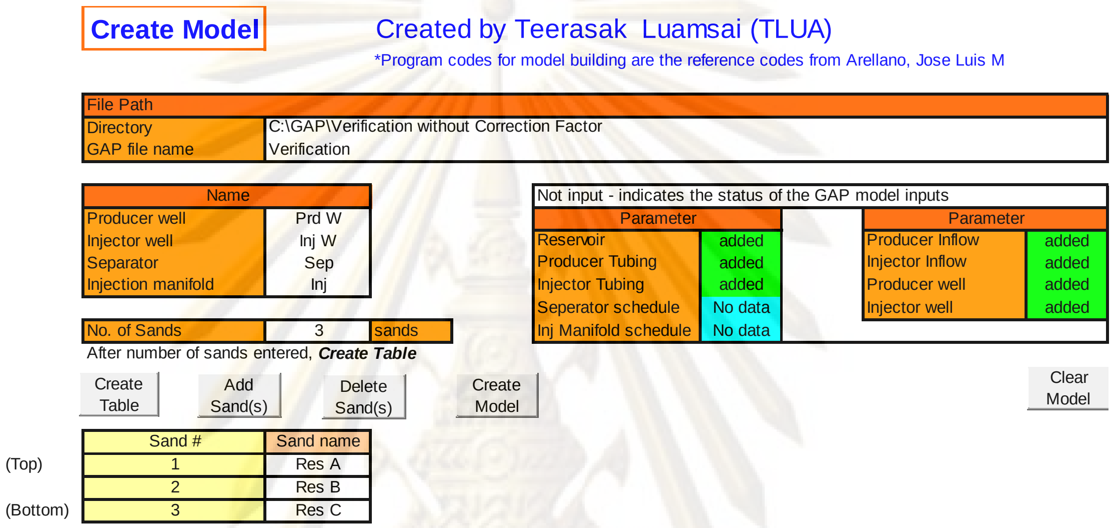

Figure B-1 : Input screen

1) Input required information to build the multilayer reservoirs model

   a) Directory to collect IPM files

   b) GAP file name

   c) Production well's name

   d) Injection well's name

   e) Separator's name

   f) Injection manifold name

2) Create table to input reservoir name

3) Click on "Create Model" button

2) Transfer required information to created model

1) Reservoirs information

2). Production inflow

3) Injection inflow

4) Well information

5) Tubing

6) Production and injection schedule

After transfer information to IPM, status of GAP model change from red to green color that shows in figure B-1. VLP and IPR are created automatically in this step.

3) Allocate well production rate into each reservoir

1) Set production schedule for each reservoir

2) Calculate production rate for each reservoir by using Microsoft Excel Macro

4) Set up and run OpenServer

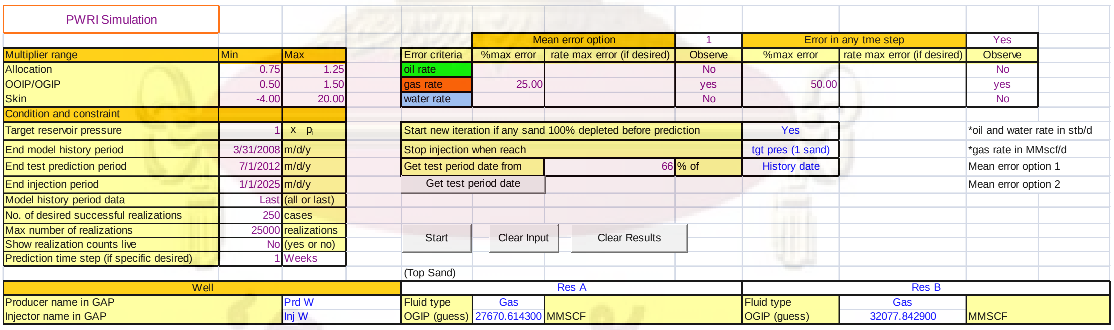

Figure B-2 : OpenServer input screen

1) Input ranges of correction factors

2) Specify target pressure

3) Specify the end of MBAL simulation

4) Specify the end of verification period

5) Specify the end of injection period

6) Input desired acceptable realization number

7) Input total realization number

8) Select time step

9) Select error calculation method

10) Input acceptable error

11) Input estimated OGIP

11) Click on “Start” button to run prediction

12) When the OpenServer run finished, plots of results are created

APPENDIX C

Results of Test Model

The verification period starts at the beginning of production history (5.1.4.1)

Table C-1 : Test model (Verification starts at the beginning of production history) 1 to 20 acceptable realization

Acceptable realization	Total realization	Stop injection Date	Injected water (MMstb)	Mean production rate at testing period			Error						Res A			Res B			Res C		
							percent			actual value			Multiply factor			Multiply factor			Multiply factor		
				Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Oil rate	Gas rate	Water rate	Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Flow rate	OIP	skin	Flow rate	OIP	skin	Flow rate	OIP	skin
1	1	9/7/2018	71.885460		15.039618			3.016			0.440289		0.9475	0.9101	5.4349	1.0980	0.7046	19.7860	1.1994	1.2742	8.4891
2	5	1/5/2018	62.950808		13.600392			-6.842			-0.998936		0.8433	1.0533	9.9994	0.7916	0.8813	19.7347	0.7565	0.7379	17.2169
3	7	4/27/2018	70.313562		15.021640			2.893			0.422312		0.9442	0.9148	10.1042	0.9867	1.1145	4.0584	1.2098	0.8979	3.8312
4	9	4/20/2018	66.642866		15.185571			4.016			0.586242		1.1728	0.9066	8.9529	1.1369	1.4277	16.9767	0.9070	0.6547	4.1833
5	13	11/17/2017	61.305766		14.403048			-1.344			-0.196280		1.1137	0.5995	-0.8455	1.2090	1.4735	18.1489	1.1630	0.7062	8.8360
6	17	5/18/2018	69.653207		14.615960			0.114			0.016631		0.8156	0.5386	-1.5070	0.8052	0.9391	3.2365	1.0498	1.2728	9.7643
7	18	7/21/2017	61.844188		13.079309			-10.412			-1.520019		1.1751	0.5447	13.9314	1.0897	0.8743	6.5192	0.9507	1.0440	-0.3783
8	19	3/23/2018	70.298061		15.035517			2.988			0.436189		1.0462	1.2136	-2.7006	1.1088	1.0364	8.6365	0.9653	0.7393	3.1060
9	22	8/18/2017	62.652526		13.337928			-8.640			-1.261401		1.2099	0.5464	15.9483	1.1845	0.7399	15.3953	1.0062	1.2108	-2.7870
10	23	2/16/2018	66.586952		14.166156			-2.967			-0.433172		0.8705	0.8008	17.1529	1.0521	0.9250	-1.2982	1.0743	0.9977	13.0322
11	24	7/21/2017	59.624439		13.490543			-7.595			-1.108785		1.1169	1.0389	19.7877	0.8265	1.0431	-1.1355	1.0544	0.5835	16.8434
12	27	1/26/2018	65.913325		14.344068			-1.748			-0.255261		1.1256	0.9756	17.0659	1.0335	1.2002	-0.2313	1.0771	0.6479	16.4147
13	28	9/22/2017	65.229308		13.771337			-5.671			-0.827991		0.9315	1.0754	-0.9912	0.9918	0.6556	4.3153	1.1679	0.9549	0.1484
14	32	1/26/2018	66.457563		14.969612			2.536			0.370283		1.0142	1.0979	17.7733	1.2076	1.2254	1.7305	1.1600	0.6470	4.2773
15	34	1/12/2018	66.820577		14.073596			-3.601			-0.525733		0.8060	0.8282	0.6578	0.8796	0.6758	19.9378	0.7839	1.1840	2.5729
16	36	6/22/2018	69.378284		14.534125			-0.447			-0.065203		0.9688	0.7590	14.8855	0.7991	0.7830	10.8948	1.2073	1.2264	8.2815
17	37	11/17/2017	62.707961		13.051819			-10.600			-1.547510		0.9245	0.6849	8.8405	0.8713	0.8453	8.0342	1.0167	0.9562	12.3500
18	45	10/13/2017	60.995524		13.502971			-7.510			-1.096358		0.8989	1.3896	7.6466	0.7979	0.5384	3.2151	1.2190	0.7686	17.5099
19	46	1/19/2018	65.537466		14.274147			-2.227			-0.325181		1.0859	0.8885	19.9517	1.0476	0.8165	11.7027	0.8810	1.0473	4.3389
20	51	5/18/2018	65.443400		15.600210			6.856			1.000881		1.2023	1.4861	19.8630	1.1211	1.0169	17.7798	1.1116	0.6535	15.1744

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Table C-1 : Test model (Verification starts at the beginning of production history) 21 to 50 acceptable realization

Acceptable realization	Total realization	Stop injection Date	Injected water (MMstb)	Mean production rate at testing period			Error						Res A			Res B			Res C		
							percent			actual value			Multiply factor			Multiply factor			Multiply factor		
				Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Oil rate	Gas rate	Water rate	Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Flow rate	OIP	skin	Flow rate	OIP	skin	Flow rate	OIP	skin
21	52	10/19/2018	74.342622		15.608124			6.910			1.008796		0.9595	0.5945	15.9847	0.8066	1.0696	8.0558	0.7774	1.2993	4.9229
22	54	7/20/2018	71.838379		15.180451			3.980			0.581122		0.9588	0.7369	19.2202	1.1961	1.1625	1.8369	1.1033	1.0230	8.6162
23	57	5/25/2018	69.122219		15.398523			5.474			0.799195		0.8141	0.6348	16.0228	1.1212	1.2576	17.8145	0.8230	1.0587	0.0276
24	60	5/11/2018	67.130307		14.486274			-0.774			-0.113054		1.1708	1.0923	14.2575	1.1142	0.5413	13.3999	1.2485	1.1767	10.9030
25	62	4/13/2018	70.712996		15.214444			4.213			0.615116		1.0963	0.9764	2.2123	0.8271	1.1550	7.7126	1.1732	0.8502	-1.0670
26	66	4/13/2018	66.062724		14.716296			0.801			0.116968		0.7541	1.1951	17.2131	1.2296	0.8818	12.9500	0.8689	0.8328	14.0016
27	67	7/20/2018	68.673414		14.576332			-0.158			-0.022996		0.8867	0.6979	0.0724	0.8384	1.0882	16.6929	1.1169	1.0069	18.3104
28	81	1/5/2018	66.421196		14.330052			-1.844			-0.269277		1.0886	1.4191	0.5474	0.9168	0.9267	6.4629	1.2362	0.5480	10.9161
29	82	4/20/2018	68.259867		14.445048			-1.057			-0.154280		0.9887	0.9014	6.2928	0.8048	0.7650	3.9848	0.9004	1.1152	14.5754
30	86	4/20/2018	67.229189		14.866073			1.827			0.266745		1.0899	1.2500	12.2141	0.7860	1.0329	9.3905	1.1339	0.6826	14.3500
31	89	12/8/2017	63.618555		13.480807			-7.661			-1.118521		0.8400	0.8160	14.3564	0.9339	1.1333	3.0207	0.9639	0.6734	19.7882
32	91	8/17/2018	74.496751		15.515441			6.275			0.916112		0.7784	0.5263	-2.7320	0.9001	1.2443	-1.8747	0.8772	1.1777	6.4561
33	94	10/12/2018	72.848648		15.519636			6.304			0.920308		0.8994	0.6948	19.3624	1.1323	0.9112	1.5318	0.8639	1.3468	13.6667
34	98	12/15/2017	66.033659		14.379496			-1.506			-0.219832		0.7720	0.8260	0.8164	1.2333	1.3911	5.7377	0.9359	0.5995	0.8455
35	99	11/24/2017	66.293172		13.865914			-5.024			-0.733414		1.1335	0.5907	10.2079	1.0743	1.1886	-2.3816	1.2304	0.8692	5.5379
36	101	12/15/2017	63.268527		13.751252			-5.809			-0.848076		0.9475	0.7397	7.2853	0.7973	1.2588	11.7725	1.2220	0.6696	14.4169
37	104	12/22/2017	66.566705		14.045850			-3.791			-0.553478		1.0482	0.6165	14.2635	0.8981	1.1895	0.6686	1.1801	0.8813	4.7369
38	106	9/14/2018	72.063943		15.509492			6.234			0.910163		0.9359	0.6266	13.7595	1.1193	0.8376	-0.8474	1.0192	1.4649	13.8683
39	114	7/13/2018	70.478903		15.172001			3.923			0.572673		0.9076	0.9369	12.5443	0.8543	0.7546	-2.0224	0.7711	1.2332	15.3560
40	116	9/1/2017	61.913803		13.946152			-4.474			-0.653177		0.8743	0.9251	-0.9705	0.7968	1.2225	14.6463	0.8219	0.5940	-3.5237
41	121	8/3/2018	72.581173		15.332215			5.020			0.732886		0.9518	0.5222	10.3117	1.2212	1.0249	11.5895	1.1720	1.3433	1.7779
42	123	1/5/2018	66.625948		14.758032			1.087			0.158703		0.9845	1.2941	7.7059	0.7683	0.7941	4.8126	1.0005	0.8429	1.3915
43	124	11/10/2017	64.801244		14.071210			-3.617			-0.528119		1.1762	1.0854	7.3883	0.9031	0.6534	18.3792	0.8105	1.0042	-0.6497
44	125	11/17/2017	66.685873		14.122974			-3.263			-0.476354		1.1064	0.9638	3.4820	1.0486	0.7863	1.7723	1.0346	0.9882	0.6480
45	126	6/22/2018	71.255474		14.884127			1.951			0.284798		0.9017	0.6586	17.3138	1.0021	1.4342	-2.7929	1.2497	0.7849	16.0531
46	127	2/16/2018	68.034609		14.714577			0.789			0.115249		0.8008	0.6039	17.8881	0.8129	0.9773	15.3342	1.0120	1.2058	-3.3787
47	130	3/30/2018	67.040583		14.792544			1.323			0.193216		1.1496	0.7793	16.5250	1.1544	1.3165	12.1330	1.0424	0.7793	2.5967
48	133	10/26/2018	74.444202		15.668142			7.321			1.068814		0.9080	1.0147	8.7273	1.0528	0.7943	7.7805	1.1700	1.2314	7.3911
49	134	9/7/2018	70.406304		15.675708			7.373			1.076380		0.8073	1.2788	15.3398	1.1793	0.5518	-0.7910	0.9114	1.2471	15.8071
50	138	3/23/2018	67.597888		14.463842			-0.928			-0.135487		1.0840	0.8915	15.3353	0.9624	1.2826	1.2281	0.7534	0.6615	17.2338

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Table C-1 : Test model (Verification starts at the beginning of production history) 51 to 80 acceptable realization

Acceptable realization	Total realization	Stop injection Date	Injected water (MMstb)	Mean production rate at testing period			Error						Res A			Res B			Res C		
							percent			actual value			Multiply factor			Multiply factor			Multiply factor		
				Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Oil rate	Gas rate	Water rate	Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Flow rate	OIP	skin	Flow rate	OIP	skin	Flow rate	OIP	skin
51	146	5/11/2018	70.871878		14.905030			2.094			0.305702		1.0952	0.7177	10.5736	0.9866	0.7500	9.8573	1.1013	1.3580	0.8134
52	147	1/26/2018	66.478956		14.133653			-3.190			-0.465676		0.8338	0.7674	17.4873	0.9720	0.5386	6.9976	0.7597	1.3667	2.2486
53	151	9/21/2018	71.371691		15.187749			4.030			0.588421		0.8190	0.5387	1.4767	0.9848	0.8810	6.2399	1.2231	1.4330	14.3903
54	155	8/31/2018	70.761969		15.075903			3.264			0.476575		0.7912	0.6910	-2.2107	1.0906	0.8972	9.3231	0.8694	1.2781	18.5776
55	156	8/3/2018	70.299403		15.012419			2.830			0.413091		0.9947	1.0285	14.8960	0.8322	0.9314	7.1676	1.1821	0.9726	14.0505
56	158	12/15/2017	62.972431		13.291681			-8.957			-1.307647		0.8224	0.7535	10.9485	1.0015	0.9591	12.1620	0.8729	0.8438	15.1118
57	161	2/2/2018	68.347688		14.472694			-0.867			-0.126634		0.9595	1.4231	-1.5323	1.1738	0.7559	-2.7683	1.0742	0.7249	11.5202
58	164	2/16/2018	69.671719		15.093312			3.384			0.493984		0.9812	1.4399	0.6026	0.9027	0.8898	-1.2350	1.0993	0.7071	-0.3936
59	167	10/6/2017	61.707114		13.541937			-7.243			-1.057392		0.8211	0.5181	3.5749	0.7972	1.0967	17.1983	0.8916	0.9489	4.7562
60	173	8/18/2017	61.699520		13.563554			-7.095			-1.035775		1.0819	0.9550	4.9347	0.8174	0.8940	19.6534	1.0802	0.7956	-2.7130
61	183	5/11/2018	69.840941		15.287187			4.712			0.687859		1.1312	0.9840	5.8863	0.8407	1.2379	12.0305	1.0271	0.7837	-0.0403
62	185	6/23/2017	61.227004		13.142642			-9.978			-1.456686		0.9880	0.7115	15.4413	1.0817	0.6890	9.4471	1.0269	1.0927	-3.0346
63	187	6/1/2018	68.832536		15.104893			3.463			0.505564		1.1587	1.4812	5.6052	1.1631	0.5162	-3.0195	0.7834	1.0139	17.7906
64	188	7/21/2017	61.537697		13.206742			-9.539			-1.392587		1.1886	0.9957	7.0096	0.9728	0.7187	2.9961	1.1250	0.8568	3.5566
65	189	1/4/2019	74.118023		15.681802			7.415			1.082474		1.1836	0.8064	9.6356	1.1400	1.1175	16.1344	0.7597	1.1050	13.5936
66	194	4/20/2018	69.346701		14.938380			2.322			0.339052		0.7537	0.8592	-3.3392	0.7868	0.9987	18.8112	1.2174	1.0294	4.8057
67	195	11/24/2017	64.610804		13.552131			-7.173			-1.047198		0.8747	0.6456	4.3094	0.8221	0.6948	3.6510	0.7604	1.2135	7.4294
68	196	3/2/2018	67.191948		14.355693			-1.669			-0.243635		1.1080	0.8069	17.0996	0.7739	1.3247	0.9389	0.9181	0.6694	15.0895
69	199	4/20/2018	68.028986		14.289781			-2.120			-0.309547		0.9522	0.6974	4.9306	1.2027	1.0504	9.5890	1.2164	0.9882	11.2101
70	200	10/20/2017	60.819955		14.266498			-2.280			-0.332830		1.2095	0.8457	-0.9888	0.8933	1.4369	18.2053	0.9754	0.5224	11.2875
71	203	8/3/2018	71.064238		15.590782			6.791			0.991454		1.2185	1.0154	17.5691	1.0997	1.1516	10.9987	0.8756	0.8945	6.0053
72	204	4/6/2018	69.545747		15.504034			6.197			0.904706		0.7833	0.8591	1.1510	0.8641	1.1496	18.9663	1.1744	1.0011	-3.5376
73	205	4/20/2018	68.432649		14.954924			2.436			0.355596		0.8260	0.8848	2.3964	0.8660	1.1162	18.2932	0.8725	0.9072	5.7929
74	208	5/19/2017	61.171820		12.972446			-11.144			-1.626882		1.0436	0.7857	-1.7502	0.8677	1.1390	0.0930	0.9980	0.5997	0.8138
75	209	11/9/2018	73.093167		15.502102			6.184			0.902774		0.7583	0.6954	-2.8521	1.1437	1.2786	12.0515	0.7530	1.0124	15.4799
76	210	6/22/2018	72.419874		15.349307			5.137			0.749979		0.8105	1.2130	2.8180	0.9795	0.8910	1.9377	0.8937	0.9295	7.1319
77	211	6/30/2017	58.957793		13.223232			-9.426			-1.376096		0.9664	1.3965	6.5211	1.1791	0.6108	-2.7629	0.7613	0.6470	12.5075
78	214	12/30/2016	54.059654		13.269523			-9.109			-1.329805		0.9379	1.2612	16.2727	1.2418	0.5699	6.8752	1.1107	0.7968	-2.5860
79	217	4/20/2018	69.891101		15.093402			3.384			0.494074		1.0907	1.0985	7.3092	1.1310	1.3422	1.1569	0.9936	0.5653	8.8957
80	218	2/2/2018	69.141513		15.195916			4.086			0.596588		1.0486	1.1630	9.1080	0.8866	0.7322	-2.8054	1.1830	1.0823	-3.0198

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Table C-1 : Test model (Verification starts at the beginning of production history) 81 to 110 acceptable realization

Acceptable realization	Total realization	Stop injection Date	Injected water (MMstb)	Mean production rate at testing period			Error						Res A			Res B			Res C		
							percent			actual value			Multiply factor			Multiply factor			Multiply factor		
				Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Oil rate	Gas rate	Water rate	Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Flow rate	OIP	skin	Flow rate	OIP	skin	Flow rate	OIP	skin
81	219	3/30/2018	67.017527		15.077465			3.275			0.478136		0.9997	1.4931	6.7004	0.7578	0.9270	17.8807	0.8643	0.6298	1.0318
82	222	12/22/2017	64.789754		14.281170			-2.179			-0.318158		1.1647	0.6460	-2.5675	1.0313	1.2805	12.8823	1.2068	0.8201	4.9338
83	223	8/31/2018	72.666759		15.617152			6.972			1.017823		0.7516	0.8105	7.1346	1.1928	0.8068	-3.4990	1.1749	1.3695	14.4023
84	225	12/22/2017	61.808021		13.771249			-5.672			-0.828080		1.1389	0.5080	12.0699	0.9230	1.2273	19.7707	0.8391	0.8816	11.8661
85	226	3/23/2018	69.960073		14.958855			2.463			0.359527		0.8435	0.7753	17.7405	1.0918	0.9863	0.9061	1.2044	1.1101	0.5191
86	228	7/6/2018	71.470685		14.940064			2.334			0.340736		1.2286	0.8056	5.0486	0.8511	1.1953	-0.9894	1.2139	0.8950	19.6190
87	231	3/23/2018	67.593175		14.957763			2.455			0.358435		1.0963	1.1990	10.0922	0.8948	1.1363	8.9506	1.2354	0.6464	3.0867
88	233	6/8/2018	72.181680		15.106424			3.473			0.507095		1.2393	0.6647	11.0417	1.0354	0.6809	6.3729	1.1367	1.5000	-0.4933
89	234	9/29/2017	63.261181		13.520097			-7.392			-1.079231		0.7755	1.1005	1.5000	1.1921	0.8571	11.1373	1.0893	0.7083	7.2961
90	235	5/4/2018	68.007585		14.460227			-0.953			-0.139102		1.0022	0.8786	14.8728	1.0898	0.8747	2.4294	1.0060	1.0368	15.6879
91	236	10/27/2017	63.473785		13.366124			-8.447			-1.233205		0.8047	0.6951	-1.9901	1.0451	1.1486	5.8019	1.0208	0.7327	13.7192
92	237	12/22/2017	64.551008		15.205665			4.153			0.606337		0.7622	1.4362	13.6644	1.1380	0.8549	11.9405	0.9393	0.7625	-3.5028
93	240	4/13/2018	69.440992		14.822558			1.529			0.223230		1.0505	1.0993	1.7820	1.2160	1.0079	10.7365	0.9702	0.8134	7.1626
94	241	10/13/2017	64.406160		13.672461			-6.349			-0.926867		1.0941	1.3931	-1.4809	1.0638	0.8574	-1.5954	0.8355	0.5097	19.0201
95	242	5/12/2017	59.327314		13.243869			-9.284			-1.355460		1.1429	0.9215	16.7891	0.8915	0.9841	-0.0278	0.8989	0.6825	-0.3150
96	243	3/2/2018	68.250409		14.206909			-2.688			-0.392419		1.1096	0.5042	10.8368	1.1853	0.8255	3.1497	1.0294	1.3262	2.6900
97	247	12/22/2017	67.101507		14.566846			-0.222			-0.032483		1.2075	0.9241	12.3901	1.2113	0.9812	3.8468	1.0231	0.9256	-1.9721
98	253	3/30/2018	66.582634		13.993004			-4.153			-0.606324		0.7938	0.5768	2.5535	0.9687	0.8389	19.2604	1.2336	1.2178	7.5759
99	254	9/21/2018	72.574012		15.412427			5.569			0.813099		0.7879	0.9585	10.4809	0.7919	0.5021	13.2072	0.8161	1.4909	7.0485
100	256	8/31/2018	72.267067		15.578139			6.704			0.978811		1.1958	1.0273	3.8136	1.1453	1.3288	10.3123	0.8063	0.7242	13.9240
101	259	9/22/2017	63.555924		14.656877			0.394			0.057548		0.8131	1.2498	13.2994	0.9795	1.1020	-3.8600	0.9947	0.5819	1.5853
102	260	4/20/2018	68.725683		15.019693			2.879			0.420365		0.8718	1.4943	4.8779	0.9118	0.8292	0.4146	0.8415	0.7057	14.2308
103	262	12/8/2017	63.488273		13.336844			-8.648			-1.262484		0.8056	0.5946	8.8311	0.8065	1.1279	6.6268	0.8505	0.8241	14.8790
104	264	1/19/2018	64.603268		13.908480			-4.732			-0.690849		1.0450	1.3994	4.2366	0.8113	0.6060	10.4801	1.0731	0.7742	16.6095
105	265	1/12/2018	66.409404		14.573461			-0.177			-0.025868		1.0863	0.9258	18.7187	0.9643	0.6473	16.4210	1.1279	1.2263	-0.8749
106	273	8/31/2018	74.209007		15.470624			5.968			0.871295		1.1519	0.6569	4.8975	0.9496	1.3051	-2.9927	1.1567	1.0126	13.4987
107	278	9/14/2018	71.621053		15.607463			6.905			1.008135		0.8184	0.9985	18.1097	0.8209	1.3252	7.8009	1.0244	0.7554	14.3273
108	279	4/28/2017	54.959560		13.076368			-10.432			-1.522960		1.2177	1.2805	18.2404	1.0726	0.5089	1.4892	0.8889	0.8018	13.5206
109	283	2/9/2018	69.744193		14.840712			1.653			0.241384		0.7955	0.7633	-0.8847	1.0150	0.9976	8.1415	1.1904	1.0870	-2.7666
110	284	9/15/2017	62.598221		13.949295			-4.452			-0.650033		0.9155	1.1131	12.8573	1.2154	0.9928	-0.4960	0.8762	0.6550	7.8808

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Table C-1 : Test model (Verification starts at the beginning of production history) 111 to 140 acceptable realization

Acceptable realization	Total realization	Stop injection Date	Injected water (MMstb)	Mean production rate at testing period			Error						Res A			Res B			Res C		
							percent			actual value			Multiply factor			Multiply factor			Multiply factor		
				Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Oil rate	Gas rate	Water rate	Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Flow rate	OIP	skin	Flow rate	OIP	skin	Flow rate	OIP	skin
111	287	1/5/2018	62.905114		13.618207			-6.720			-0.981122		0.8200	0.9756	16.6568	0.8565	0.5770	10.4280	0.8583	1.0752	14.6403
112	291	5/18/2018	71.922732		15.107206			3.479			0.507878		1.0603	0.9524	3.1222	0.7748	0.8178	-1.4079	1.2172	1.1518	4.9680
113	292	1/26/2018	65.609579		14.029880			-3.901			-0.569448		1.0830	1.2592	5.1894	1.2293	0.7422	4.5470	0.8796	0.7821	15.1328
114	293	7/28/2017	62.428834		13.606912			-6.798			-0.992416		1.1646	0.8426	16.6758	0.9277	0.8777	-2.4916	1.1741	0.9054	0.4877
115	297	8/11/2017	60.889314		13.199960			-9.585			-1.399368		0.8412	1.1214	8.6152	1.1964	0.8469	-3.9197	0.8780	0.6428	17.1013
116	300	1/12/2018	69.101794		14.528584			-0.485			-0.070744		1.2223	0.8891	-0.3522	1.0723	0.5733	11.5377	0.7867	1.3134	-2.4363
117	301	1/5/2018	63.024084		14.110883			-3.346			-0.488445		1.1437	0.8601	8.3855	1.0658	1.3091	16.3601	0.8770	0.5970	14.4894
118	306	1/5/2018	66.146835		14.915714			2.167			0.316386		1.2042	1.4484	7.4470	0.8064	0.5640	7.9008	1.1077	0.9608	0.1922
119	309	5/25/2018	72.948803		15.499618			6.167			0.900289		0.8083	0.9978	6.9748	1.0423	0.6195	-1.2428	1.2235	1.3704	-2.1970
120	311	6/23/2017	58.293393		12.973260			-11.138			-1.626068		1.1518	0.6083	7.4530	0.9187	1.2534	12.2480	1.0300	0.6350	4.0549
121	313	9/7/2018	71.231932		15.551216			6.520			0.951887		1.1038	1.2190	10.9452	0.9162	0.5303	1.5151	0.7589	1.2890	14.5227
122	318	4/13/2018	68.063465		15.282755			4.681			0.683426		0.8167	1.1099	18.5128	1.0426	1.3413	2.9513	0.8023	0.5930	8.2964
123	322	3/3/2017	56.620259		13.735773			-5.915			-0.863555		1.2439	1.1838	19.4049	0.9825	0.6047	2.5441	0.9749	0.9104	-1.7891
124	326	7/21/2017	60.812215		13.044567			-10.650			-1.554761		1.0958	1.1573	4.4925	1.1682	0.8314	-1.6547	0.9746	0.6010	15.1155
125	328	10/20/2017	63.397992		13.846351			-5.158			-0.752978		1.0299	1.0944	7.3205	1.0131	0.7694	18.7963	1.0302	0.8514	0.4572
126	331	10/13/2017	60.957061		14.307073			-2.002			-0.292255		0.7610	0.6424	8.4014	0.8514	1.4690	16.3431	1.0136	0.6591	-2.0517
127	332	4/6/2018	68.998719		14.615206			0.109			0.015878		0.9446	0.9685	6.2018	0.9382	0.6259	2.8371	1.1843	1.2202	7.2812
128	336	4/6/2018	66.828687		14.737604			0.947			0.138276		0.8663	1.1426	2.8399	1.0992	1.2841	14.4711	1.2043	0.5167	17.2342
129	337	12/15/2017	64.869754		14.089526			-3.492			-0.509802		1.0099	1.1024	3.0834	1.0555	1.0663	12.5497	1.0180	0.6230	7.0711
130	343	5/25/2018	67.799837		15.327918			4.991			0.728590		0.8867	1.1917	18.1868	1.2075	0.9873	17.2508	0.8711	0.8553	6.4341
131	346	12/14/2018	74.901441		15.650289			7.199			1.050960		0.8803	0.7639	1.9738	1.1926	0.9176	8.3491	1.2363	1.3122	12.2609
132	347	11/17/2017	64.408524		13.512745			-7.443			-1.086583		0.8732	0.6112	3.9219	1.0270	0.7885	12.5229	0.7632	1.1485	4.1851
133	350	7/14/2017	59.962112		13.136249			-10.022			-1.463079		0.9188	0.6394	13.6163	0.9814	1.0873	12.4422	1.0948	0.7893	-0.0800
134	352	5/26/2017	59.445249		13.857644			-5.080			-0.741684		1.0694	1.0648	19.8398	1.2217	0.8780	2.8846	0.9542	0.7787	-3.2455
135	353	3/2/2018	64.882807		13.989819			-4.175			-0.609510		0.8048	0.5035	13.9665	0.9383	0.7856	3.1297	1.1291	1.3226	16.6427
136	356	11/17/2017	63.778912		14.562097			-0.255			-0.037231		0.8324	1.2325	15.5978	0.9279	0.7536	1.1584	1.0371	0.8906	6.2896
137	357	1/26/2018	66.326568		14.408719			-1.306			-0.190609		0.8741	1.2466	7.8065	0.9223	0.8223	-3.7525	1.0391	0.7895	14.3762
138	363	5/5/2017	59.854924		12.897741			-11.655			-1.701587		0.9883	0.7789	-1.7756	0.8485	1.1525	4.5987	1.1106	0.5795	-1.9923
139	365	10/27/2017	63.987590		13.543447			-7.232			-1.055881		1.0099	0.8259	8.3754	0.9276	0.9192	-3.4348	0.9725	0.8695	16.3500
140	371	7/20/2018	68.788971		14.849515			1.714			0.250186		0.9272	1.1337	15.6001	1.1786	0.7800	11.2030	1.1172	0.9968	15.0003

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Table C-1 : Test model (Verification starts at the beginning of production history) 141 to 170 acceptable realization

Acceptable realization	Total realization	Stop injection Date	Injected water (MMstb)	Mean production rate at testing period			Error						Res A			Res B			Res C		
							percent			actual value			Multiply factor			Multiply factor			Multiply factor		
				Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Oil rate	Gas rate	Water rate	Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Flow rate	OIP	skin	Flow rate	OIP	skin	Flow rate	OIP	skin
141	372	11/24/2017	68.366716		14.348606			-1.717			-0.250723		1.0894	0.7988	-0.2924	0.9349	0.7378	0.7953	1.2139	1.2018	-3.0202
142	377	4/13/2018	68.838829		15.237486			4.371			0.638158		1.1796	1.1853	1.7263	0.7698	1.1970	15.2338	0.8616	0.6552	-1.3195
143	378	3/23/2018	67.067940		14.821784			1.524			0.222456		1.1861	0.8978	6.4022	0.9771	1.3694	11.8276	0.9027	0.6453	5.5343
144	380	8/10/2018	70.349444		14.829626			1.577			0.230297		0.9585	0.7661	11.4159	0.9355	0.8096	8.1376	1.1062	1.2523	14.0511
145	383	5/5/2017	58.467161		13.867833			-5.010			-0.731496		0.8942	1.3910	10.4016	0.8709	0.6579	0.2807	0.7917	0.7265	-3.1783
146	387	9/8/2017	61.238623		13.542041			-7.242			-1.057288		1.0884	0.9953	17.3182	1.1059	0.8788	4.0011	0.9148	0.7741	9.7498
147	389	12/8/2017	65.996416		13.768735			-5.689			-0.830594		0.8291	0.5168	3.8036	0.9038	0.9192	-0.8638	0.9922	1.1512	6.0704
148	391	1/12/2018	64.171577		14.251609			-2.382			-0.347720		1.0854	1.2336	13.8141	1.0677	0.8366	1.5844	0.8586	0.7576	16.7858
149	394	3/16/2018	69.059148		14.856353			1.761			0.257025		1.1401	0.8171	18.6144	0.9217	1.4248	-2.7044	1.2113	0.6650	9.8168
150	397	6/22/2018	67.625189		15.015118			2.848			0.415790		0.9565	1.3643	13.8191	0.9784	0.5244	18.9161	1.1171	1.0800	11.7506
151	398	11/17/2017	62.531456		14.418107			-1.241			-0.181221		0.9506	1.1919	17.8735	0.9165	0.9102	15.4059	0.8858	0.7545	0.8230
152	403	10/20/2017	64.042242		13.399142			-8.221			-1.200186		0.7755	1.0451	-1.9690	0.7628	0.8281	6.8693	1.1024	0.7549	13.1245
153	404	4/6/2018	68.198828		14.901652			2.071			0.302324		0.7614	1.1290	13.3975	0.8793	0.6262	8.0361	1.1239	1.1491	4.3257
154	405	8/31/2018	74.129914		15.549565			6.509			0.950236		1.1113	0.7805	6.6264	1.0239	1.0048	5.9415	0.8266	1.2010	4.3326
155	406	9/2/2016	48.557702		12.905545			-11.602			-1.693784		1.0969	1.4415	17.7677	0.8276	0.5126	10.0689	0.9774	0.6433	3.7968
156	407	12/22/2017	65.005018		14.917804			2.181			0.318476		1.1087	1.4316	10.3109	1.2007	0.7871	7.3013	1.1009	0.7729	2.0141
157	408	12/1/2017	65.076661		13.794628			-5.512			-0.804700		1.1942	0.6364	9.2535	0.9907	0.7254	19.8412	1.1853	1.2373	0.7913
158	409	4/20/2018	67.089077		14.269340			-2.260			-0.329989		0.9646	0.7435	8.3060	1.1915	0.5722	11.2213	0.7658	1.3799	11.5383
159	410	9/8/2017	60.729451		13.631331			-6.630			-0.967998		0.8312	1.3672	8.1722	1.1955	0.6556	12.5880	0.7859	0.7037	9.0422
160	413	8/25/2017	64.968670		13.632161			-6.625			-0.967167		1.1605	0.6512	1.2895	0.9530	1.1118	-2.8768	1.1208	0.8484	0.2750
161	414	2/9/2018	65.836228		14.274246			-2.227			-0.325082		0.8200	1.0756	6.6478	1.0621	1.1763	9.6346	1.1250	0.5792	13.4814
162	415	9/22/2017	62.475526		13.107460			-10.219			-1.491868		0.7921	0.5218	-3.3603	0.8473	0.7754	9.5405	0.8840	1.1562	6.6197
163	416	3/2/2018	67.283375		14.846906			1.696			0.247578		0.7612	1.2940	9.3471	1.0379	0.7299	7.3522	0.8617	0.9175	5.8825
164	421	9/21/2018	71.714964		15.527808			6.360			0.928480		1.2215	1.2155	11.7186	1.0777	1.0640	9.7052	1.1992	0.8060	16.9215
165	425	2/23/2018	66.591878		15.162336			3.856			0.563008		0.8509	1.1741	18.0271	1.1108	0.8625	14.2829	0.9915	0.9499	0.1782
166	426	11/9/2018	72.917531		15.672015			7.348			1.072686		0.7709	1.0353	8.3821	0.9060	0.6139	7.8612	0.9093	1.3795	16.0142
167	427	8/31/2018	70.872673		15.068740			3.215			0.469412		0.8393	0.5625	-1.2660	0.9956	1.1904	13.8294	0.8508	1.1129	11.5378
168	428	5/25/2018	69.080587		14.659002			0.409			0.059674		1.2485	0.6109	13.8056	0.9731	0.7720	3.1834	1.0211	1.3755	10.2691
169	429	6/1/2018	72.009447		15.439361			5.754			0.840033		0.9970	1.4155	1.5296	0.9390	0.5118	7.8830	0.8333	1.1322	1.0558
170	433	4/13/2018	69.777257		14.730845			0.901			0.131516		1.0116	1.3951	-3.7965	0.9290	0.9263	9.4019	1.0428	0.6412	17.3775

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Table C-1 : Test model (Verification starts at the beginning of production history) 171 to 200 acceptable realization

Acceptable realization	Total realization	Stop injection Date	Injected water (MMstb)	Mean production rate at testing period			Error						Res A			Res B			Res C		
							percent			actual value			Multiply factor			Multiply factor			Multiply factor		
				Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Oil rate	Gas rate	Water rate	Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Flow rate	OIP	skin	Flow rate	OIP	skin	Flow rate	OIP	skin
171	437	11/17/2017	66.001208		13.933002			-4.564			-0.666326		0.7677	1.3752	-2.6697	0.8482	0.8036	-3.1821	1.1292	0.6195	18.2403
172	439	8/3/2018	72.748123		15.491834			6.113			0.892505		0.8878	0.8200	13.8633	0.9646	1.1640	5.4332	1.0060	1.0162	5.2514
173	440	3/16/2018	64.500888		13.486458			-7.623			-1.112871		1.1399	0.6052	8.5916	1.2100	0.7868	18.7096	0.8590	1.1498	13.5377
174	441	6/29/2018	70.377309		15.175651			3.948			0.576323		1.0835	1.0087	16.8445	1.0883	1.0920	-2.7928	0.8152	0.8743	18.7759
175	444	7/28/2017	61.691703		13.323748			-8.737			-1.275580		1.1500	1.1669	4.2606	0.7904	0.7448	2.0745	1.2227	0.7221	5.3267
176	447	11/10/2017	64.068893		13.753663			-5.792			-0.845665		1.2134	0.7792	18.9383	0.8265	1.2442	-0.4228	0.7791	0.6524	12.7119
177	450	3/16/2018	66.500211		15.109737			3.496			0.510409		0.9527	0.7245	8.0243	1.0032	1.4178	15.6889	1.0342	0.7907	0.7679
178	451	1/12/2018	65.685056		14.637036			0.258			0.037708		0.9961	1.1785	10.7846	0.7570	1.1320	7.4300	0.8397	0.6064	-0.0215
179	453	11/9/2018	74.632441		15.586969			6.765			0.987641		1.0812	0.7976	11.4707	1.1271	1.1843	2.5254	0.8839	1.0337	12.7309
180	454	9/8/2017	61.856687		13.431898			-7.996			-1.167430		1.2189	0.9342	8.0065	0.9272	1.0793	8.8618	1.0629	0.6214	4.3902
181	457	11/24/2017	62.403303		13.591661			-6.902			-1.007667		0.7649	0.6572	2.7075	1.0696	0.5766	2.5621	1.0131	1.3186	16.3796
182	459	11/9/2018	73.783842		15.384402			5.377			0.785074		1.1846	1.0902	3.0006	1.2440	0.8059	11.7917	1.0956	1.1080	13.8643
183	461	1/19/2018	67.492092		14.692369			0.637			0.093041		0.9409	0.7536	3.0035	1.1059	1.4351	4.8822	1.1485	0.6746	-3.2047
184	467	7/20/2018	68.914344		15.378424			5.337			0.779096		0.8667	0.9426	11.6742	0.8007	1.3136	18.7680	1.0541	0.7653	10.9440
185	471	10/5/2018	73.544075		15.363350			5.233			0.764021		0.9024	0.6780	11.3790	0.9061	1.0668	2.3758	0.7567	1.1897	11.4540
186	472	10/13/2017	66.876929		14.174688			-2.909			-0.424640		1.0940	1.0795	-2.5926	0.8532	0.9899	-0.9101	0.8181	0.7249	-0.5861
187	473	3/16/2018	65.255610		14.072333			-3.610			-0.526996		1.0589	1.1968	10.8140	0.7902	0.7921	10.4252	1.1059	0.7931	19.2426
188	474	5/25/2018	70.881626		14.929537			2.262			0.330209		0.9237	0.7589	3.6521	0.9773	0.7195	19.8860	0.9192	1.3580	1.4349
189	476	4/27/2018	73.432985		15.397255			5.466			0.797926		1.2253	0.9267	-2.9607	0.9802	0.8851	0.5500	1.2186	1.1659	-1.5341
190	478	5/18/2018	70.149594		15.315075			4.903			0.715746		1.2460	1.2655	7.1390	0.8676	1.0404	7.6530	0.8644	0.7483	4.4512
191	479	4/20/2018	67.577721		15.117754			3.551			0.518426		0.8237	1.0063	17.2934	0.7572	1.2572	11.9637	0.9214	0.7171	-0.3027
192	485	6/29/2018	73.787189		15.589141			6.780			0.989812		0.9152	0.9579	5.2177	0.9865	1.1341	-1.3254	1.1284	0.9543	3.6130
193	487	6/1/2018	68.801970		15.055452			3.124			0.456124		0.8743	1.1867	13.0478	0.7588	0.5521	2.0919	1.1435	1.2002	10.1378
194	488	1/26/2018	65.810532		15.530920			6.381			0.931592		1.0618	1.3697	17.4127	1.0435	0.5701	19.0311	1.2169	1.1325	-0.2808
195	490	10/27/2017	65.774597		14.386891			-1.455			-0.212437		0.7888	0.8934	13.7917	1.2300	1.3434	-2.8701	0.8362	0.5914	-2.7847
196	491	4/27/2018	67.310077		15.405103			5.519			0.805775		0.8575	1.3402	16.6749	0.9423	0.7204	17.0609	0.9128	0.9954	6.1806
197	494	11/10/2017	64.677330		13.966229			-4.336			-0.633099		1.0318	0.8638	16.8571	1.2411	1.0880	-1.9209	1.0200	0.7657	8.9312
198	497	11/10/2017	62.736421		13.535940			-7.284			-1.063388		0.8431	1.0165	5.7793	0.9488	1.0409	12.4380	1.0654	0.6111	14.9781
199	498	3/16/2018	68.291819		15.004712			2.777			0.405384		0.9231	0.6892	11.0445	1.2492	1.4049	8.4358	0.8869	0.8098	-3.8958
200	509	3/23/2018	70.948496		15.188782			4.038			0.589453		1.2268	0.7288	18.6940	0.8498	1.2242	-2.7896	0.8942	0.9757	-0.8889

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Table C-1 : Test model (Verification starts at the beginning of production history) 201 to 230 acceptable realization

Acceptable realization	Total realization	Stop injection Date	Injected water (MMstb)	Mean production rate at testing period			Error						Res A			Res B			Res C		
							percent			actual value			Multiply factor			Multiply factor			Multiply factor		
				Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Oil rate	Gas rate	Water rate	Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Flow rate	OIP	skin	Flow rate	OIP	skin	Flow rate	OIP	skin
201	511	11/24/2017	61.458469		14.497111			-0.700			-0.102218		0.7588	0.5223	-3.7405	1.0331	1.4474	19.7381	1.0374	0.8071	7.3556
202	515	11/3/2017	65.572828		14.466548			-0.909			-0.132780		1.0404	0.9213	18.1098	0.9043	0.7688	0.7823	1.0567	1.1004	-2.0628
203	516	12/1/2017	61.315468		13.642103			-6.557			-0.957226		1.2387	1.0708	19.0302	1.0511	0.8392	17.2209	1.2356	0.7695	15.5224
204	518	7/27/2018	71.679515		15.029001			2.943			0.429673		0.9295	0.8848	-0.8386	0.8570	0.9051	4.2253	1.0891	1.1108	15.8152
205	523	12/8/2017	65.942549		14.270880			-2.250			-0.328448		1.1612	0.9926	-1.3214	1.0564	1.3347	5.3149	0.9008	0.5011	6.1232
206	525	4/27/2018	66.400061		15.471997			5.977			0.872668		1.2432	1.3439	18.8852	0.9603	1.1286	11.8742	1.1459	0.6386	8.4077
207	526	5/4/2018	66.987220		13.938321			-4.528			-0.661007		1.1001	0.9811	3.0287	1.1691	0.6791	19.3466	1.0244	1.0375	14.7821
208	530	9/8/2017	59.021570		13.313958			-8.804			-1.285370		0.8336	1.3770	10.6497	1.1922	0.6145	11.3679	1.0662	0.6752	19.5653
209	531	6/30/2017	60.588784		13.198744			-9.593			-1.400585		0.9254	1.2601	2.9664	0.7506	0.5008	18.8596	1.2330	0.8470	0.2646
210	533	7/27/2018	70.709002		15.475355			6.000			0.876027		1.0006	1.1955	3.7314	1.0491	1.3187	12.6578	1.1709	0.5837	14.0902
211	540	3/9/2018	66.756935		14.211475			-2.657			-0.387854		1.1099	0.6824	0.5578	0.8107	1.3469	6.8373	1.0869	0.7196	16.0755
212	542	11/17/2017	65.535770		13.653882			-6.476			-0.945447		0.9697	1.0878	-3.0437	0.9192	0.9217	1.5242	1.1038	0.6845	15.8679
213	545	9/14/2018	74.645844		15.657392			7.247			1.058064		1.2420	0.9183	-3.8909	1.0183	0.7664	3.7597	0.7766	1.3297	8.5798
214	554	5/18/2018	71.214806		14.921398			2.206			0.322070		1.0721	0.6165	6.7822	1.1755	1.0230	-2.3745	0.8317	1.1935	7.8267
215	555	4/20/2018	71.394624		15.030732			2.955			0.431404		1.0319	0.8535	-2.8163	1.1250	0.6245	-0.5394	1.0908	1.3892	3.7028
216	556	6/23/2017	56.194580		13.905471			-4.753			-0.693857		1.1720	1.4585	19.0954	1.1510	0.5108	8.7476	0.8920	0.8139	13.2756
217	557	10/26/2018	72.875435		15.464228			5.924			0.864899		0.8279	0.5021	10.8486	1.1399	1.2975	10.5002	0.8997	1.1390	9.4813
218	561	5/11/2018	72.271177		15.292679			4.749			0.693350		0.8105	0.6229	6.9983	1.1410	0.8764	10.6384	0.8308	1.3912	-3.1954
219	563	1/5/2018	65.606445		13.721463			-6.013			-0.877866		1.1713	0.5866	17.0984	1.1513	0.6612	8.7342	1.0527	1.3208	2.8292
220	569	9/1/2017	63.682435		13.499090			-7.536			-1.100238		0.7836	0.9034	4.5793	1.1976	0.9551	0.5489	1.1704	0.7690	4.1132
221	571	1/26/2018	64.092451		15.071986			3.238			0.472658		1.2166	1.4282	17.1331	1.1760	0.6030	9.2249	1.1851	0.9704	8.5730
222	572	10/27/2017	63.083204		14.971372			2.548			0.372043		1.0450	1.3473	17.1432	1.0628	1.0681	-1.3890	0.8773	0.5956	10.6649
223	574	7/21/2017	60.875054		13.519495			-7.396			-1.079833		1.2377	1.1309	9.4297	1.0263	0.6486	16.6669	1.1428	0.8721	-2.7493
224	579	6/15/2018	69.037417		15.541436			6.453			0.942108		1.0003	1.4458	11.1661	0.9872	1.0841	6.6750	1.2324	0.6132	16.0747
225	584	12/29/2017	64.506810		13.700703			-6.155			-0.898626		0.9343	0.5023	-3.5823	1.2164	0.7979	2.0811	0.7955	1.2594	12.8745
226	585	7/6/2018	72.938298		15.260387			4.528			0.661059		0.9092	0.8614	-0.8224	0.8831	0.5909	7.3467	1.2393	1.4570	2.9414
227	586	9/22/2017	60.759113		13.254630			-9.211			-1.344698		0.7573	0.8729	0.5097	0.8758	1.1231	15.5422	0.9941	0.5973	18.2791
228	589	6/15/2018	72.084379		15.371385			5.288			0.772057		1.0809	0.5738	14.4970	0.9118	1.2222	6.4441	1.2099	1.1328	-0.5177
229	596	3/9/2018	68.058623		15.022674			2.900			0.423346		1.1168	0.7798	0.0510	1.2500	1.3318	11.7181	1.0761	0.8083	0.3522
230	598	12/8/2017	65.082548		14.718004			0.813			0.118675		0.9037	1.3773	8.3978	0.8506	1.0779	2.1422	1.0473	0.5166	2.1867

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Table C-1 : Test model (Verification starts at the beginning of production history) 231 to 250 acceptable realization

Acceptable realization	Total realization	Stop injection Date	Injected water (MMstb)	Mean production rate at testing period			Error						Res A			Res B			Res C		
							percent			actual value			Multiply factor			Multiply factor			Multiply factor		
				Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Oil rate	Gas rate	Water rate	Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Flow rate	OIP	skin	Flow rate	OIP	skin	Flow rate	OIP	skin
231	599	1/26/2018	65.565033		13.727208			-5.974			-0.872120		1.1400	0.6058	3.1385	0.7838	0.7772	16.1313	0.9149	1.2021	6.0851
232	600	3/16/2018	65.301675		14.394993			-1.400			-0.204335		0.9985	0.8250	13.0650	0.9956	1.4165	11.3581	1.1362	0.5804	15.8856
233	601	1/12/2018	66.711492		14.674768			0.517			0.075440		0.7621	1.2697	7.3474	0.7948	0.7753	7.0703	0.8117	0.8633	1.5719
234	606	10/19/2018	72.821790		15.334560			5.036			0.735231		0.9229	0.7536	16.1828	0.9440	1.0318	3.1563	1.1883	1.1568	16.0369
235	607	1/26/2018	68.184293		14.787004			1.286			0.187676		1.0936	0.8998	16.4088	0.8404	0.6078	0.5255	0.8680	1.3224	-1.7126
236	610	6/29/2018	69.938797		15.466537			5.940			0.867209		1.2435	1.2953	10.2570	1.0421	1.3049	5.8251	0.9022	0.5174	14.3558
237	611	4/7/2017	57.147903		14.141352			-3.137			-0.457977		1.2408	1.3663	16.5217	0.9596	0.5407	3.7933	0.7648	0.9014	-1.3353
238	614	1/26/2018	67.611747		14.341723			-1.765			-0.257605		0.8789	1.0442	-1.9346	0.9402	0.7468	19.3464	0.9823	1.0018	3.9531
239	615	4/27/2018	69.386780		14.729720			0.893			0.130391		0.9434	1.1827	2.3306	0.8821	1.0852	5.5590	0.8444	0.6624	16.7904
240	619	4/6/2018	66.605057		14.232378			-2.513			-0.366950		0.9770	1.0261	4.8835	1.0818	1.0250	15.8199	0.8756	0.7454	17.7494
241	626	1/19/2018	68.501499		14.443293			-1.069			-0.156035		0.9027	1.2203	-1.9724	1.1031	1.1329	-1.6296	1.1347	0.5374	14.6492
242	632	9/29/2017	64.320221		14.013949			-4.010			-0.585380		0.8006	0.8405	16.0005	0.9172	0.7930	7.6232	1.0754	1.0578	-3.1234
243	633	3/16/2018	65.981562		14.268676			-2.265			-0.330652		0.7761	0.9772	16.0602	0.9629	0.9431	11.7492	1.1152	0.8635	12.0830
244	642	10/6/2017	63.179550		13.202658			-9.567			-1.396670		0.7995	0.5269	16.8030	1.2028	1.3518	-2.4339	1.1836	0.6516	16.9960
245	645	3/2/2018	69.096072		14.849817			1.716			0.250488		0.8172	0.9219	12.9348	0.7662	0.6925	6.0991	0.8628	1.2403	-0.8875
246	647	12/15/2017	63.398122		14.492576			-0.731			-0.106752		0.8455	0.7880	-3.7698	0.9352	1.3257	18.6967	1.0008	0.7085	9.3681
247	648	9/15/2017	60.147975		13.168165			-9.803			-1.431163		0.8259	0.9967	9.6118	0.7596	0.9268	18.9624	1.0749	0.6620	11.8391
248	649	8/31/2018	74.124394		15.568277			6.637			0.968949		1.1859	1.3301	-3.2462	0.9796	1.0248	7.3202	0.9826	0.7605	15.9143
249	652	1/12/2018	64.634461		13.483320			-7.644			-1.116009		1.0848	0.7818	6.7607	1.1427	0.5511	19.5676	0.8827	1.2245	6.8681
250	653	6/30/2017	62.992849		13.262598			-9.156			-1.336730		0.8813	0.7068	0.4029	1.1768	0.7168	6.6239	1.2283	1.0930	-3.7497

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The verification period starts at two-third of production history (5.1.4.2)

Table C-2 : Test model (Verification starts at two-third or history production) 1 to 20 acceptable realization

Acceptable realization	Total realization	Stop injection Date	Injected water (MMstb)	Mean production rate at testing period			Error						Res A			Res B			Res C		
							percent			actual value			Multiply factor			Multiply factor			Multiply factor		
				Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Oil rate	Gas rate	Water rate	Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Flow rate	OIP	skin	Flow rate	OIP	skin	Flow rate	OIP	skin
1	18	5/6/2018	68.061725		2.090567			-4.359			-0.095287		0.8332	0.8387	14.4704	0.9711	0.9122	-0.1280	0.9270	1.0460	19.6539
2	24	4/22/2018	69.809821		2.091811			-4.302			-0.094043		0.9219	1.0202	-3.3215	1.1733	1.0241	4.4581	0.8221	0.8037	15.7644
3	73	5/6/2018	68.127092		2.162126			-1.086			-0.023728		0.8811	1.0121	9.1228	0.8044	0.6311	4.8757	0.9959	1.1713	13.7601
4	190	2/18/2018	63.911294		2.713555			24.142			0.527701		1.2368	1.4116	15.6111	0.9234	0.7011	17.0852	1.0498	0.8443	12.6086
5	209	9/2/2018	69.835814		2.190910			0.231			0.005056		0.8010	0.7168	10.6505	1.1327	0.8863	16.1688	0.9343	1.1738	13.2530
6	285	4/1/2018	66.408152		2.036265			-6.843			-0.149589		1.0262	0.8895	-2.3881	1.0571	1.1620	19.4265	1.1427	0.7779	16.5535
7	296	3/4/2018	66.058887		1.903285			-12.927			-0.282569		0.8842	0.7637	15.5902	1.2450	1.2075	14.0292	1.0120	0.8243	5.6326
8	302	3/18/2018	66.971502		2.233332			2.172			0.047478		1.0816	1.0429	15.6116	1.1853	1.0588	3.9764	0.7501	0.7661	13.2574
9	318	1/7/2018	66.765516		2.240499			2.500			0.054645		0.7528	0.8186	-2.3879	0.7797	1.3337	8.3063	0.7991	0.6974	0.7730
10	433	4/8/2018	66.071568		2.354594			7.720			0.168740		1.1182	0.7582	3.7859	1.0235	1.2211	19.8010	1.1415	0.8546	12.7406
11	435	11/5/2017	64.514485		1.723240			-21.164			-0.462614		1.1009	1.3436	6.7645	0.8571	0.9368	3.5190	0.8268	0.6042	1.1253
12	487	10/22/2017	62.052825		2.518320			15.210			0.332466		1.0577	0.8408	-1.8974	1.1482	1.4037	19.0179	0.9997	0.6411	-0.4110
13	543	4/29/2018	69.668983		2.228108			1.933			0.042254		1.1864	0.9455	0.8426	1.0098	0.6636	15.1645	1.0788	1.2009	5.5490
14	556	3/11/2018	68.792832		1.790295			-18.096			-0.395558		1.1657	1.0960	-0.1589	0.9417	1.0534	2.6990	0.8924	0.6962	15.8562
15	572	4/15/2018	68.986310		2.471294			13.059			0.285440		0.9994	1.0121	7.4513	1.0933	0.9943	5.5632	0.8854	0.8674	9.6792
16	679	1/28/2018	69.037287		2.401612			9.871			0.215758		0.9633	0.7751	-1.9392	0.7942	1.2664	1.7234	0.8486	0.8057	1.7321
17	773	3/4/2018	67.734245		2.012670			-7.923			-0.173184		0.8264	0.9634	-1.9634	0.8412	1.0311	14.8404	0.8302	0.8359	8.7479
18	850	2/11/2018	67.583570		2.012972			-7.909			-0.172882		1.1404	1.1677	-1.4171	0.9935	1.1302	9.2625	0.8087	0.5896	11.7986
19	881	4/15/2018	68.864246		2.052984			-6.079			-0.132870		1.0527	1.0725	-1.3238	0.8883	1.1240	7.5751	0.9484	0.6712	19.5838
20	970	6/24/2018	68.292682		2.160498			-1.160			-0.025356		1.1731	0.9597	10.5035	1.0146	0.9488	18.3337	0.8256	0.9248	15.0859

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Table C-2 : Test model (Verification starts at two-third or history production) 21 to 50 acceptable realization

Acceptable realization	Total realization	Stop injection Date	Injected water (MMstb)	Mean production rate at testing period			Error						Res A			Res B			Res C		
							percent			actual value			Multiply factor			Multiply factor			Multiply factor		
				Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Oil rate	Gas rate	Water rate	Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Flow rate	OIP	skin	Flow rate	OIP	skin	Flow rate	OIP	skin
21	994	4/8/2018	69.515890		2.592593			18.608			0.406739		0.8526	0.8872	9.6377	0.7804	1.1689	-0.1903	0.7716	0.8194	9.5226
22	1018	1/21/2018	63.623862		2.435964			11.442			0.250111		1.0766	1.1688	16.9002	1.1351	1.0729	19.2734	0.9087	0.6734	-3.1229
23	1096	7/1/2018	70.138813		2.392509			9.454			0.206655		0.9187	1.1620	-2.2574	0.8501	0.7536	19.2673	1.0711	0.9625	14.8325
24	1106	4/1/2018	68.237634		2.620059			19.864			0.434205		0.9337	0.8255	11.2028	0.8381	0.9128	18.5270	0.9140	1.0990	1.6329
25	1109	1/28/2018	65.876675		1.777291			-18.691			-0.408563		1.1272	1.1568	11.4277	0.9377	1.0168	3.9523	0.7943	0.6810	13.5568
26	1146	1/21/2018	63.002596		1.738920			-20.447			-0.446934		1.1616	1.4845	12.1480	0.9108	0.7211	13.6726	0.8647	0.6924	19.2517
27	1184	4/29/2018	69.212059		1.969075			-9.917			-0.216779		0.9762	0.7538	-3.7143	1.2415	0.7808	13.6245	1.0806	1.2235	7.8019
28	1210	5/27/2018	67.072764		2.352777			7.637			0.166923		0.9956	1.1655	15.6500	0.8087	0.7119	8.4139	0.9090	0.9945	16.2867
29	1234	4/1/2018	67.910052		2.371510			8.494			0.185656		0.8570	0.8282	17.5892	0.8169	1.1694	6.1776	0.7634	0.8468	7.7508
30	1259	6/3/2018	69.649586		2.154112			-1.452			-0.031742		1.1008	0.7725	6.1039	1.1605	1.1035	1.2573	1.2266	0.9317	19.1414
31	1327	9/3/2017	63.417731		1.927602			-11.815			-0.258252		0.9154	1.0313	19.9314	0.8565	0.7021	-2.7648	1.1245	1.0731	-1.6737
32	1334	12/3/2017	65.639547		1.766633			-19.179			-0.419221		1.2170	1.2043	-0.8447	1.1675	1.0994	13.2084	0.8884	0.5693	-2.0285
33	1393	7/8/2018	69.784318		2.333868			6.771			0.148014		0.9715	0.7397	-0.1959	1.0747	1.0923	8.7294	0.8736	0.9818	17.5066
34	1492	2/11/2018	65.889179		2.704243			23.716			0.518389		1.1076	1.0517	18.7874	0.8486	0.8655	15.5806	0.8481	0.9714	2.0491
35	1625	12/10/2017	65.464714		1.941743			-11.168			-0.244111		0.9792	1.1407	9.9152	1.0551	0.8197	14.4048	1.1092	0.8830	-2.5459
36	1634	1/28/2018	69.307602		2.545043			16.432			0.359189		0.8540	0.8049	1.4302	0.7981	0.8000	10.9599	0.9966	1.2110	-3.0116
37	1645	12/3/2017	62.347477		2.352706			7.633			0.166852		1.2345	1.3521	15.4115	0.8609	0.9377	17.4129	0.9141	0.6469	-1.0614
38	1729	9/17/2017	62.195089		2.352047			7.603			0.166193		1.1441	1.3715	12.9242	1.1174	0.8697	5.8217	0.9705	0.6933	-3.6282
39	1733	4/15/2018	65.831753		1.823207			-16.591			-0.362647		0.9318	0.8087	18.2437	1.0188	1.2095	16.2377	0.8788	0.7820	13.5002
40	1880	3/18/2018	68.984826		1.936911			-11.389			-0.248943		0.9659	0.7817	1.8894	0.9256	0.8471	0.1371	1.2239	1.1373	9.7927
41	1888	4/8/2018	67.906363		2.622332			19.968			0.436478		0.9802	0.9344	-2.5484	1.0262	1.0928	17.9694	1.1489	0.8516	10.2387
42	1896	2/18/2018	66.636504		2.591549			18.560			0.405695		0.8860	1.0370	16.2778	0.9397	0.8910	11.1329	0.7961	0.9506	3.3219
43	1922	4/29/2018	69.596658		2.351690			7.587			0.165836		1.1330	0.7081	10.3539	1.2186	0.9957	-1.0470	1.1811	1.0951	11.2168
44	2048	5/20/2018	68.576936		1.917949			-12.256			-0.267905		0.8267	0.7281	17.9283	1.0874	1.0809	6.7175	0.8816	0.9668	11.9599
45	2054	12/24/2017	63.069009		2.055132			-5.980			-0.130722		1.1043	1.3091	15.3526	1.1552	0.8894	15.5242	0.7575	0.6990	7.8009
46	2072	3/11/2018	67.974691		2.236792			2.330			0.050938		0.8445	0.6104	-0.5765	1.1583	1.3387	7.0104	1.2329	0.8545	5.7462
47	2138	4/1/2018	69.723326		2.068315			-5.377			-0.117538		1.1831	0.8951	0.6797	0.9876	1.0421	0.5243	0.9913	0.8843	10.8563
48	2144	5/13/2018	68.669552		2.708334			23.903			0.522480		0.9546	0.6661	9.1717	1.1592	0.9228	-2.1046	1.1749	1.2231	17.7014
49	2158	5/6/2018	69.196928		2.688702			23.005			0.502849		1.2394	1.1653	4.9070	1.1184	0.6701	18.4723	1.1371	1.0588	6.1225
50	2159	4/15/2018	69.104997		2.562621			17.237			0.376767		1.1799	0.7688	9.2481	1.0253	1.3472	3.0571	0.9504	0.7527	10.0444

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Table C-2 : Test model (Verification starts at two-third or history production) 51 to 80 acceptable realization

Acceptable realization	Total realization	Stop injection Date	Injected water (MMstb)	Mean production rate at testing period			Error						Res A			Res B			Res C		
							percent			actual value			Multiply factor			Multiply factor			Multiply factor		
				Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Oil rate	Gas rate	Water rate	Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Flow rate	OIP	skin	Flow rate	OIP	skin	Flow rate	OIP	skin
51	2251	7/8/2018	68.966899		2.682585			22.725			0.496731		1.2099	1.0087	9.4058	0.8344	1.1432	11.9985	0.9200	0.7555	19.4766
52	2256	11/12/2017	67.998771		1.927714			-11.810			-0.258140		1.1325	1.3462	-3.7452	0.9015	0.8436	-1.1204	0.9318	0.7024	-0.9514
53	2314	4/8/2018	68.077429		1.925856			-11.895			-0.259998		0.9628	0.6364	15.2987	0.8215	0.9708	13.6324	1.2203	1.1398	4.6375
54	2318	2/4/2018	65.919510		2.501360			14.434			0.315506		1.1478	0.8849	13.9078	0.9758	1.1129	17.1970	0.9108	0.8633	-2.7326
55	2322	4/1/2018	70.498808		2.487989			13.822			0.302135		0.9080	0.7836	-0.0014	0.9779	1.0927	-2.5212	0.9631	0.9590	8.2593
56	2361	4/8/2018	68.945695		2.413330			10.407			0.227476		1.0029	0.8522	3.0486	0.8854	1.0691	9.8490	1.0075	0.9212	7.0889
57	2386	12/31/2017	69.107746		1.666642			-23.753			-0.519212		0.9841	0.7215	-3.3221	0.8871	0.9849	-3.0034	1.0106	1.0396	2.0390
58	2513	12/3/2017	65.174999		2.276199			4.133			0.090345		1.0957	1.3016	9.0954	1.0946	1.0082	0.4243	0.8541	0.6163	6.2154
59	2520	3/25/2018	68.228231		2.283507			4.468			0.097653		1.0499	0.9241	13.4365	0.9189	0.8695	-3.2958	1.0398	1.0338	11.9661
60	2534	6/10/2018	67.073731		2.502112			14.468			0.316258		0.8260	1.1375	18.2923	0.7839	0.7302	9.9644	0.7715	1.0111	16.2027
61	2549	6/17/2018	68.355387		1.916240			-12.335			-0.269614		0.8350	0.6077	4.0968	1.1437	1.2379	11.0885	1.2498	0.9211	15.7173
62	2573	1/14/2018	67.553277		2.102319			-3.822			-0.083535		0.9279	0.6691	10.4039	1.0713	1.0993	9.0436	1.1294	1.0123	-3.2772
63	2595	2/25/2018	70.015437		2.205835			0.914			0.019981		1.1539	0.8668	-2.8226	0.7631	1.2321	-3.1544	0.9762	0.7487	10.4490
64	2659	3/18/2018	65.005297		2.230206			2.029			0.044352		1.1190	0.8443	11.4505	1.1021	1.3293	17.3443	0.7874	0.6809	12.4995
65	2684	3/18/2018	68.747451		2.526325			15.576			0.340471		1.1359	0.8321	17.3244	1.2012	0.8419	-1.2338	0.8845	1.1523	3.6034
66	2702	4/8/2018	70.483340		2.722481			24.550			0.536628		1.1126	0.7795	-3.2021	0.8267	0.9362	-2.0611	1.2475	1.1222	8.8055
67	2824	4/8/2018	64.523962		1.936220			-11.420			-0.249633		1.1834	1.0481	17.5846	1.0524	1.1649	19.7325	0.7876	0.6453	16.4631
68	2843	2/11/2018	67.342774		2.305447			5.471			0.119593		0.9289	0.9323	17.3324	1.1461	0.7457	-3.2135	1.1099	1.1405	4.9092
69	2922	5/14/2017	57.456085		1.897125			-13.209			-0.288729		1.1675	1.4604	17.7606	0.7793	0.6230	-2.1206	1.1317	0.8110	4.9979
70	2940	12/17/2017	65.360948		2.423308			10.863			0.237454		1.2239	1.2820	10.3058	0.8726	0.9150	2.2745	0.9700	0.7269	5.2205
71	2989	3/18/2018	66.173048		1.735305			-20.612			-0.450549		1.0595	1.0941	13.1740	1.0719	0.9227	13.5961	1.0982	0.8101	11.9770
72	3036	5/27/2018	69.714699		2.071361			-5.238			-0.114492		1.1873	0.9615	-1.0146	1.0116	0.9228	9.2563	0.9028	0.9396	14.2136
73	3037	5/20/2018	69.112352		2.577943			17.938			0.392089		1.1777	1.1798	-3.7390	1.1772	0.9427	19.6956	1.0894	0.7933	16.5974
74	3144	5/27/2018	68.967653		1.898140			-13.163			-0.287713		0.8235	0.7995	12.1971	1.1506	0.9662	7.3643	1.0308	1.0119	11.6600
75	3189	4/1/2018	67.298950		1.985476			-9.167			-0.200378		0.8154	0.8100	12.2744	0.8280	0.7393	-2.7656	1.1336	1.2164	16.2436
76	3463	5/13/2018	67.476727		2.123734			-2.842			-0.062120		0.7565	0.8968	0.3258	0.8791	1.1977	15.7907	0.7633	0.7471	19.9435
77	3556	3/18/2018	68.797046		2.366926			8.284			0.181072		1.0904	0.9658	3.5674	1.0586	1.2663	3.1522	0.7747	0.6531	11.0995
78	3619	1/7/2018	65.911686		2.046951			-6.355			-0.138903		0.8901	0.7945	3.3982	1.0059	1.1432	15.7932	0.9879	0.8701	1.2767
79	3637	1/28/2018	69.247682		2.539697			16.188			0.353843		0.8900	0.9503	-0.9582	0.8805	0.6514	19.3013	1.0223	1.2318	-3.0644
80	3726	5/27/2018	68.368658		2.497545			14.259			0.311691		0.7567	0.5855	7.6753	1.1483	1.1789	14.1299	1.0834	1.0368	8.7627

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Table C-2 : Test model (Verification starts at two-third or history production) 81 to 110 acceptable realization

Acceptable realization	Total realization	Stop injection Date	Injected water (MMstb)	Mean production rate at testing period			Error						Res A			Res B			Res C		
							percent			actual value			Multiply factor			Multiply factor			Multiply factor		
				Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Oil rate	Gas rate	Water rate	Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Flow rate	OIP	skin	Flow rate	OIP	skin	Flow rate	OIP	skin
81	3861	2/4/2018	65.076800		1.924547			-11.954			-0.261307		1.0203	1.0904	17.9898	1.1479	0.8032	14.7085	0.9325	0.9351	6.9610
82	3903	4/8/2018	67.299514		2.706382			23.813			0.520528		0.9743	0.7571	12.9428	1.1931	1.2420	13.8607	1.2310	0.8639	4.9706
83	3904	3/11/2018	68.153711		2.440408			11.646			0.254554		0.9698	0.6839	19.7963	1.1580	1.1560	6.9098	1.0762	0.9765	1.4936
84	4154	3/25/2018	68.383031		2.444157			11.817			0.258303		1.1525	0.9544	13.8583	1.0719	0.8303	2.3601	1.1048	1.0584	5.7343
85	4161	6/17/2018	69.599985		2.702350			23.629			0.516496		1.1382	0.8762	15.5608	1.0609	0.7925	7.1888	1.0183	1.1762	7.9401
86	4359	3/18/2018	67.253549		1.984907			-9.193			-0.200947		0.9142	1.0035	15.7479	1.0540	1.0035	-1.0294	0.9815	0.8271	15.0647
87	4374	7/1/2018	70.371492		2.324177			6.328			0.138323		0.7894	0.6555	6.9446	1.1663	1.0078	4.7071	1.1494	1.1215	10.3753
88	4378	6/17/2018	68.852979		2.088337			-4.461			-0.097517		0.9673	0.7646	16.0038	1.2305	1.0929	8.7850	1.1951	0.9413	13.8755
89	4397	5/13/2018	67.393620		2.396552			9.639			0.210698		1.2311	0.8920	14.6152	0.8986	1.2132	12.7500	0.7814	0.7601	13.0824
90	4405	12/10/2017	67.561666		1.765627			-19.225			-0.420227		1.1000	1.0708	3.6198	0.9430	0.7022	3.9019	0.9759	1.0301	-1.3697
91	4413	7/29/2018	69.229875		2.666438			21.986			0.480584		0.9664	0.7491	13.7713	0.7840	0.8265	6.7595	1.0380	1.2418	17.6215
92	4457	12/31/2017	64.955213		1.838127			-15.908			-0.347727		0.8711	1.0463	15.0203	0.9258	0.9123	16.1856	0.8265	0.8649	-0.6769
93	4466	3/11/2018	67.022637		2.155999			-1.366			-0.029855		0.7735	0.9459	12.6890	0.8078	0.9590	15.5670	0.7567	0.9256	4.5174
94	4473	4/8/2018	67.840389		1.892914			-13.402			-0.292940		0.8128	0.7994	17.9765	1.2206	0.7948	14.3220	1.0195	1.1664	4.8993
95	4499	8/12/2018	69.666200		2.252614			3.054			0.066760		0.9214	0.8456	1.5167	0.9685	0.8737	17.2029	0.8365	1.0894	17.2521
96	4620	5/13/2018	70.042802		2.571462			17.641			0.385609		0.8393	0.5832	7.8073	1.0433	1.2301	3.0992	1.0952	1.0008	7.7591
97	4632	6/24/2018	69.469287		2.015577			-7.790			-0.170277		0.9031	0.7436	13.5172	1.1582	1.0176	5.3273	1.0500	1.0194	13.5010
98	4653	7/29/2018	69.218069		2.633970			20.501			0.448116		1.2406	1.2181	7.2699	0.9631	0.7697	19.8608	1.1522	0.9243	17.0259
99	4661	2/25/2018	68.201624		2.329697			6.581			0.143843		0.8958	0.7640	10.0802	0.9187	0.8326	17.8474	1.1785	1.1958	-0.6861
100	4688	4/22/2018	68.919769		2.205554			0.901			0.019700		1.1457	1.0539	0.6084	0.8813	0.5506	8.8490	1.2468	1.2158	11.0496
101	4726	1/21/2018	68.732934		1.813845			-17.019			-0.372009		0.9277	0.9405	0.1854	1.0941	0.8995	3.0415	1.2132	0.9559	3.2022
102	4829	4/22/2018	68.860035		2.380437			8.902			0.194583		1.0772	0.6984	7.3204	1.1459	1.1702	8.3830	0.9004	0.9482	7.4379
103	4877	12/10/2017	66.095301		2.579348			18.002			0.393494		1.1566	1.3878	5.5569	0.7929	0.7540	3.7317	0.9611	0.8035	-1.2823
104	4944	4/15/2018	68.636069		1.957292			-10.456			-0.228562		0.9906	0.8572	14.0361	0.8315	1.2148	-1.3694	0.8172	0.7513	17.5117
105	5026	6/24/2018	70.205170		2.689695			23.050			0.503841		0.7843	0.7750	9.3028	1.1604	0.8095	13.8515	1.2317	1.2359	6.2859
106	5057	4/29/2018	67.623040		2.523961			15.468			0.338107		1.0408	1.1302	10.3939	0.9538	0.9133	16.3248	1.0068	0.8539	10.1262
107	5186	1/28/2018	66.701273		1.896295			-13.247			-0.289558		1.0020	0.6953	15.3151	1.1564	1.1216	11.4325	0.9840	0.9551	-0.3118
108	5227	3/4/2018	68.110635		1.661620			-23.983			-0.524234		0.8926	0.7096	18.0847	0.9390	0.8449	0.0639	1.2411	1.1738	5.4743
109	5254	5/13/2018	67.981131		1.747269			-20.065			-0.438585		0.8381	0.9144	14.7148	1.0044	0.8445	9.8323	0.8083	1.0208	11.6930
110	5284	1/28/2018	64.068159		2.125579			-2.757			-0.060275		1.1967	0.8573	4.5701	1.1067	1.3343	18.4300	0.8730	0.6587	10.9093

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Table C-2 : Test model (Verification starts at two-third or history production) 111 to 140 acceptable realization

Acceptable realization	Total realization	Stop injection Date	Injected water (MMstb)	Mean production rate at testing period			Error						Res A			Res B			Res C		
							percent			actual value			Multiply factor			Multiply factor			Multiply factor		
				Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Oil rate	Gas rate	Water rate	Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Flow rate	OIP	skin	Flow rate	OIP	skin	Flow rate	OIP	skin
111	5315	2/4/2018	68.338805		2.278653			4.245			0.092799		0.9820	0.7032	12.4413	1.1803	1.4209	-0.1695	1.0828	0.7136	2.1653
112	5320	4/22/2018	67.793418		1.698036			-22.317			-0.487818		1.0635	0.9222	5.7265	0.7701	1.0165	13.7740	0.7788	0.8564	13.4367
113	5421	4/22/2018	69.092027		2.389581			9.320			0.203727		1.2085	0.8239	-3.5152	1.0096	0.9556	15.3825	1.1309	1.0432	7.4613
114	5434	1/7/2018	69.023084		1.723299			-21.161			-0.462555		1.0554	0.8625	-3.7180	0.8708	0.9407	0.1926	1.0598	0.9733	2.9261
115	5584	12/17/2017	67.182580		2.135293			-2.313			-0.050561		0.9845	1.0769	8.2995	1.0272	1.0421	-3.7607	0.7918	0.7481	3.9888
116	5613	3/25/2018	65.164452		2.447453			11.968			0.261599		1.2078	0.9860	13.4263	1.1147	1.2202	19.6229	0.9754	0.6849	8.0454
117	5753	2/11/2018	66.421331		2.452463			12.197			0.266609		1.0078	1.2000	10.2581	1.0337	0.7895	16.5843	0.9175	0.9050	2.2916
118	5780	5/27/2018	67.885217		2.484440			13.660			0.298586		1.2185	1.1629	9.6373	1.0040	0.9347	16.1540	1.0434	0.8062	14.9598
119	5880	3/4/2018	67.344729		1.743866			-20.220			-0.441987		1.0739	0.9558	3.8856	0.9525	1.1940	8.3266	0.8098	0.6758	13.1897
120	5945	2/18/2018	65.915725		1.814160			-17.005			-0.371694		1.1502	0.8797	11.6956	0.8066	1.2543	11.4380	0.9672	0.6875	6.7310
121	6006	3/4/2018	67.955945		1.938883			-11.299			-0.246971		1.1538	0.9215	6.0994	1.1186	1.2707	3.6919	0.9072	0.6497	12.0731
122	6011	1/7/2018	68.007679		2.423398			10.867			0.237544		1.0228	1.0098	-3.5810	1.0939	0.8638	18.1887	1.2025	0.9834	-1.2839
123	6025	12/17/2017	65.150928		2.044569			-6.464			-0.141285		1.2128	1.1382	-1.8769	1.1804	1.2139	15.1873	0.7548	0.5402	2.8879
124	6059	12/24/2017	65.339074		2.212555			1.222			0.026701		1.1247	1.0000	17.7024	0.7951	1.1524	5.4060	1.0161	0.7153	0.8621
125	6079	5/6/2018	69.144422		2.644095			20.964			0.458241		0.9127	0.7316	1.4277	1.0439	1.2960	7.4211	1.0872	0.8316	10.7440
126	6087	12/31/2017	66.191600		2.436022			11.445			0.250169		0.8962	1.0489	14.9064	0.9451	1.0457	2.9277	0.8599	0.7905	1.8957
127	6166	7/15/2018	69.349654		2.311394			5.743			0.125540		0.8500	0.8913	-2.6073	0.8204	1.0445	16.0808	0.9924	0.9036	19.1010
128	6233	3/11/2018	66.091874		1.756561			-19.640			-0.429293		1.1307	1.1985	7.1948	1.2312	1.0356	14.8508	0.8453	0.6301	14.7621
129	6260	4/29/2018	68.849898		1.892041			-13.442			-0.293813		1.0629	0.8577	-1.0444	0.8501	0.9336	13.6332	1.2111	0.9965	10.7202
130	6271	4/15/2018	69.334366		2.577201			17.904			0.391347		0.9408	0.8539	-3.4586	1.0328	0.9167	-1.2331	0.8071	1.0699	18.1456
131	6272	4/1/2018	66.884986		2.636738			20.627			0.450885		1.2155	0.9627	15.4879	1.0260	1.0222	17.4476	1.2198	0.8947	4.0436
132	6380	2/4/2018	67.677907		1.909176			-12.658			-0.276678		1.0360	1.1515	5.0385	0.9822	1.0845	-0.1169	0.8791	0.6343	12.9749
133	6392	4/8/2018	69.513202		2.496674			14.220			0.310820		0.7868	0.5936	-0.3528	1.1057	1.3981	2.0254	0.7873	0.8366	8.1431
134	6397	4/1/2018	66.317731		2.677793			22.506			0.491939		1.2227	1.2695	8.0855	0.7729	1.0292	19.2597	0.8290	0.6544	7.2922
135	6430	12/31/2017	68.238572		2.350739			7.543			0.164885		1.1935	1.1208	2.7923	0.8320	0.5754	13.8154	1.0808	1.1530	-3.9036
136	6450	5/27/2018	69.158196		2.584562			18.240			0.398708		1.1535	0.8391	18.6266	1.1859	0.9896	4.0015	1.0996	1.0155	9.9713
137	6457	4/1/2018	66.891878		2.700705			23.554			0.514851		1.1872	1.1423	15.4451	0.9469	0.8297	-2.7562	1.1984	0.9338	17.6511
138	6460	4/29/2018	68.848840		2.110984			-3.425			-0.074870		0.8867	0.6828	-3.2540	1.1541	1.2730	6.7986	1.0040	0.8465	13.1139
139	6505	2/4/2018	68.166901		2.128926			-2.604			-0.056928		0.7620	0.7744	-2.0445	1.0383	1.0154	11.6356	1.1649	1.0058	1.7071
140	6570	5/28/2017	59.130183		1.918747			-12.220			-0.267107		1.2059	1.3079	18.3951	1.0665	0.7831	1.1277	1.2187	0.7853	-0.7025

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Table C-2 : Test model (Verification starts at two-third or history production) 141 to 170 acceptable realization

Acceptable realization	Total realization	Stop injection Date	Injected water (MMstb)	Mean production rate at testing period			Error						Res A			Res B			Res C		
							percent			actual value			Multiply factor			Multiply factor			Multiply factor		
				Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Oil rate	Gas rate	Water rate	Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Flow rate	OIP	skin	Flow rate	OIP	skin	Flow rate	OIP	skin
141	6618	5/13/2018	68.806598		2.005646			-8.244			-0.180208		1.2125	0.7833	6.4117	1.0957	1.1495	8.0109	1.1406	0.8710	13.3486
142	6652	6/3/2018	68.024445		2.001146			-8.450			-0.184708		1.0749	1.1791	7.9450	0.8192	0.6218	12.4066	1.1942	1.0372	16.6747
143	6812	5/13/2018	69.846626		2.396912			9.656			0.211058		1.0594	1.0333	2.5950	0.7977	0.6668	11.3080	0.8688	1.1423	6.9175
144	6888	3/25/2018	68.124162		1.909060			-12.663			-0.276794		1.0480	0.9378	0.4037	1.0052	0.7918	0.9144	1.0083	1.0638	18.5000
145	6930	12/24/2017	62.424747		1.817528			-16.850			-0.368326		0.9907	1.2570	19.8165	0.9138	0.7320	19.4236	1.1031	0.8625	10.2297
146	6967	12/31/2017	68.385200		2.184584			-0.058			-0.001270		1.2483	1.2707	-0.7631	0.8329	0.6427	5.8679	1.2389	0.9622	-0.7199
147	7030	12/17/2017	65.371779		2.064599			-5.547			-0.121255		1.1808	1.3095	7.6151	1.0417	1.0110	4.2397	0.8132	0.5912	4.1456
148	7035	12/31/2017	65.568529		2.328141			6.509			0.142287		1.1850	1.2295	9.2199	0.9935	0.9766	10.6270	0.7827	0.7045	-2.1212
149	7040	1/14/2018	69.248751		1.947109			-10.922			-0.238745		0.7882	0.9356	-0.5107	1.1925	0.9546	-2.9737	1.0034	0.9197	3.5582
150	7077	4/1/2018	69.761811		1.945471			-10.997			-0.240383		0.7659	0.6573	-1.9333	1.1104	1.1454	0.0153	1.1654	0.9662	8.9278
151	7086	5/13/2018	69.428288		2.070572			-5.274			-0.115281		1.1516	0.8527	6.9571	0.7536	0.9143	2.8562	1.1791	1.0325	12.3683
152	7092	1/28/2018	67.707916		2.076260			-5.014			-0.109594		1.2306	0.9552	6.6596	0.9457	0.8593	12.6272	0.9709	1.0025	-0.0797
153	7126	12/31/2017	65.699284		1.769005			-19.070			-0.416849		0.8920	1.0183	5.0005	1.1532	1.0198	17.3599	0.8056	0.7836	-0.0439
154	7163	5/6/2018	66.670873		1.652428			-24.404			-0.533426		0.7600	1.0447	16.6512	0.9999	0.9179	10.6602	0.8823	0.8451	17.7977
155	7246	12/24/2017	66.853548		1.990363			-8.943			-0.195491		0.7748	0.7267	5.3602	1.0743	1.2657	6.8913	1.0211	0.8082	-3.4691
156	7259	4/29/2018	70.023693		2.256019			3.210			0.070165		1.0688	0.7121	6.0467	1.1885	1.3214	-1.3808	0.9083	0.7927	14.4842
157	7267	1/28/2018	66.301971		2.520462			15.308			0.334608		0.8134	0.8832	17.1799	0.8194	1.0543	14.2113	0.8279	0.9182	-3.7671
158	7273	1/21/2018	67.770854		2.700092			23.526			0.514238		1.1816	1.1482	7.8572	1.0288	0.7344	2.7765	0.9135	1.0148	0.2458
159	7278	6/17/2018	69.018718		2.241919			2.565			0.056065		0.8244	0.7545	1.1240	0.8598	0.9720	17.8126	1.2364	1.0697	11.1282
160	7332	2/25/2018	67.918323		1.920037			-12.161			-0.265817		0.9954	1.0433	-0.0552	1.1864	1.2098	6.4160	0.8943	0.6066	13.6202
161	7362	5/13/2018	69.762088		2.207773			1.003			0.021920		0.8839	0.8675	3.6873	1.0925	1.0602	0.3463	1.2425	0.8988	17.8562
162	7463	5/13/2018	68.898598		2.469934			12.996			0.284080		0.9213	0.9159	9.6753	1.0637	0.7202	2.0098	1.0473	1.1901	12.4833
163	7469	11/5/2017	63.210627		1.973362			-9.721			-0.212491		0.9116	0.6997	8.1381	1.2470	1.2361	19.3025	0.8164	0.8541	-3.9382
164	7508	12/31/2017	66.709062		2.434690			11.384			0.248836		1.2356	1.2884	6.4529	0.9651	0.7574	1.5344	0.9350	0.8651	2.3371
165	7569	2/4/2018	66.253456		2.307950			5.586			0.122096		0.9343	0.8898	19.3369	1.2398	0.9981	13.3125	1.0927	0.9458	0.2125
166	7599	3/11/2018	69.474757		2.340386			7.070			0.154532		0.8368	0.8807	7.5109	0.8016	0.9262	-2.5186	0.7559	1.0212	5.1330
167	7609	3/18/2018	69.160355		2.158631			-1.245			-0.027223		0.8070	0.8240	8.2742	0.9075	0.8857	-1.8186	0.9195	1.0870	7.5637
168	7616	11/19/2017	64.530090		2.314909			5.904			0.129055		0.7714	0.8320	0.8409	0.9268	1.1523	19.7592	0.9680	0.8533	-2.5030
169	7648	5/20/2018	69.428526		2.485189			13.694			0.299335		0.8737	0.9108	9.8909	0.9979	0.9368	7.4641	0.7766	0.9991	9.3171
170	7650	7/8/2018	70.283554		2.393441			9.497			0.207587		0.9025	1.2294	-0.3031	0.8686	0.7308	12.8229	0.9492	0.9311	16.4103

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Table C-2 : Test model (Verification starts at two-third or history production) 171 to 200 acceptable realization

Acceptable realization	Total realization	Stop injection Date	Injected water (MMstb)	Mean production rate at testing period			Error						Res A			Res B			Res C		
							percent			actual value			Multiply factor			Multiply factor			Multiply factor		
				Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Oil rate	Gas rate	Water rate	Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Flow rate	OIP	skin	Flow rate	OIP	skin	Flow rate	OIP	skin
171	7662	1/28/2018	69.344332		2.238549			2.411			0.052695		0.7689	0.9431	2.3379	0.8864	0.7172	-1.2216	1.2016	1.1519	0.4085
172	7721	3/25/2018	66.710498		2.462859			12.673			0.277006		1.0283	0.8973	11.5384	1.1294	1.2650	12.6187	0.7524	0.7142	7.0619
173	7812	12/17/2017	66.232020		1.881851			-13.908			-0.304003		1.2405	1.3489	4.7341	0.7956	0.8769	-3.7550	0.8144	0.6665	9.0429
174	7861	11/19/2017	65.474811		2.114612			-3.259			-0.071242		1.2323	1.2129	9.4739	0.8823	0.7372	2.4149	1.0863	0.9160	-0.1343
175	7874	12/24/2017	69.205359		2.498463			14.301			0.312609		0.9606	0.9048	-1.1934	0.8403	1.0198	1.7139	0.8781	0.9309	-3.4235
176	7940	1/21/2018	69.577177		2.446978			11.946			0.261124		0.8577	0.7214	5.4799	1.1226	0.9362	0.8498	1.0168	1.1453	-2.7985
177	7972	6/10/2018	70.260316		2.680057			22.609			0.494203		1.2453	0.8026	11.2284	1.2342	1.3035	0.2405	1.0145	0.7732	16.6208
178	7980	12/31/2017	67.495314		1.954094			-10.603			-0.231760		0.9351	0.8440	15.0802	0.8566	1.0159	-3.0164	0.8535	0.9382	2.9964
179	7981	4/1/2018	68.931249		2.337547			6.940			0.151693		1.1310	0.8474	10.3119	0.8108	0.7958	10.8826	0.9583	1.1660	3.0167
180	8059	5/6/2018	70.687006		2.606509			19.244			0.420655		0.8493	0.8571	-2.7254	0.7690	0.5919	11.7285	1.1504	1.3646	2.7774
181	8072	4/1/2018	68.976500		2.001009			-8.456			-0.184845		0.8096	0.6177	0.4392	0.8106	1.0734	7.2314	1.1028	1.0683	5.7790
182	8165	2/11/2018	67.149583		2.021894			-7.501			-0.163960		1.2184	0.8140	19.5830	0.8381	1.0875	4.4195	1.2275	0.9037	4.8559
183	8180	6/17/2018	67.909293		2.617643			19.754			0.431789		1.0458	0.8430	7.7146	0.7660	1.1664	18.1442	1.1823	0.8574	15.8229
184	8186	5/6/2018	67.929611		2.648926			21.185			0.463072		1.2202	1.2190	10.9185	0.9576	0.8661	4.6844	1.1188	0.8376	15.2465
185	8408	7/29/2018	69.687674		2.462405			12.652			0.276551		1.1929	0.8945	-1.2793	1.1186	0.7671	14.7246	1.1803	1.1647	18.2856
186	8437	1/28/2018	67.267388		2.062863			-5.627			-0.122991		1.1880	1.0662	5.8988	1.1767	1.2195	3.7709	0.8445	0.5924	5.9052
187	8440	6/17/2018	68.852460		1.707804			-21.870			-0.478050		1.0251	1.0746	5.0920	0.9829	0.8565	10.5258	1.1917	0.8821	19.1371
188	8570	2/4/2018	64.079693		1.885536			-13.739			-0.300318		0.7672	1.2201	17.2376	0.8406	0.8273	14.6665	0.7733	0.8103	12.4819
189	8667	4/1/2018	67.794788		2.623260			20.011			0.437406		0.8677	0.6571	16.9296	1.1325	1.0247	17.7513	0.9604	1.1310	1.2456
190	8699	7/1/2018	70.719437		2.688335			22.988			0.502481		1.1627	1.0518	-1.3913	0.8752	0.6443	18.2114	0.8812	1.1725	8.8725
191	8818	5/20/2018	68.110950		2.066872			-5.443			-0.118982		0.8969	0.8315	18.4960	0.9108	0.7522	18.4193	1.0285	1.1955	7.1401
192	8854	4/1/2018	68.336330		2.290331			4.780			0.104477		1.0870	1.2173	-2.8877	0.9648	1.0704	13.0094	0.7746	0.6270	17.5528
193	8862	3/11/2018	67.608362		2.555806			16.925			0.369953		1.0695	1.1555	10.8880	1.1247	0.8842	0.9278	1.1285	0.8628	9.5607
194	8877	2/18/2018	66.445371		2.631430			20.385			0.445576		0.9277	0.7982	17.9539	0.9979	1.3481	9.1955	1.0100	0.7324	-3.1381
195	8904	4/22/2018	67.805834		2.209498			1.082			0.023644		1.0018	1.0624	7.3448	0.8718	1.1622	9.4276	0.8177	0.6580	17.4512
196	8938	3/11/2018	68.351458		2.197003			0.510			0.011149		0.8576	0.8927	0.3602	1.2369	1.2523	6.3185	0.8310	0.7067	10.4674
197	8959	12/17/2017	66.947360		1.961458			-10.266			-0.224396		0.8326	0.9055	1.0739	0.9389	0.9292	16.1816	1.1885	0.9676	-2.6351
198	8978	1/7/2018	66.741484		1.755181			-19.703			-0.430673		1.0473	0.8579	17.0329	0.8639	0.8985	4.1684	1.0498	1.0174	2.3133
199	9022	5/13/2018	68.244888		2.279127			4.267			0.093273		0.9899	0.7012	18.1231	1.2131	1.2530	8.3467	1.1275	0.8636	10.9321
200	9032	7/29/2018	68.589174		2.432062			11.264			0.246208		0.8345	0.8669	14.5641	0.8290	0.6036	14.2029	1.2368	1.3312	15.3260

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Table C-2 : Test model (Verification starts at two-third or history production) 201 to 230 acceptable realization

Acceptable realization	Total realization	Stop injection Date	Injected water (MMstb)	Mean production rate at testing period			Error						Res A			Res B			Res C		
							percent			actual value			Multiply factor			Multiply factor			Multiply factor		
				Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Oil rate	Gas rate	Water rate	Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Flow rate	OIP	skin	Flow rate	OIP	skin	Flow rate	OIP	skin
201	9067	4/1/2018	65.072069		2.076604			-4.998			-0.109250		1.0431	1.1952	16.3403	0.8797	0.9011	19.3727	0.7740	0.7787	14.8209
202	9151	5/6/2018	69.087846		2.475942			13.271			0.290088		1.1212	1.1753	0.0683	1.2058	0.8904	16.3699	0.8958	0.8349	12.7857
203	9237	1/21/2018	64.948186		1.858576			-14.973			-0.327278		0.8560	1.2915	11.0548	0.7580	0.8717	8.1383	0.7505	0.7137	12.7966
204	9330	6/10/2018	68.747063		2.091879			-4.299			-0.093975		0.9964	1.1048	6.7035	0.7597	0.9121	11.5461	0.9459	0.8396	18.0110
205	9342	12/3/2017	67.777374		1.889806			-13.544			-0.296048		1.0611	1.4069	-3.1795	0.9193	0.8319	2.2963	0.8115	0.6639	1.9572
206	9343	2/25/2018	67.139330		1.944302			-11.051			-0.241552		1.1085	0.8504	17.5238	1.1093	1.3727	1.0991	0.9635	0.6152	13.3111
207	9371	7/29/2018	69.562664		2.248701			2.875			0.062847		0.8361	0.8160	3.4665	0.8446	0.8481	10.6297	0.9103	1.1351	18.1427
208	9390	3/18/2018	65.551924		2.219245			1.528			0.033391		0.8677	1.1916	12.0069	1.0048	1.0152	18.0718	0.7585	0.6898	9.1275
209	9412	3/11/2018	67.386510		1.742720			-20.273			-0.443134		0.8604	0.8293	17.3036	0.8101	0.9817	6.6362	0.7735	0.9637	7.5704
210	9462	4/29/2018	68.104812		2.627068			20.185			0.441214		1.2180	1.1749	11.3188	1.1163	0.9132	1.6173	0.8739	0.8268	15.0467
211	9552	1/7/2018	65.942506		2.119061			-3.056			-0.066793		0.7919	0.9074	7.0079	0.9463	1.1197	15.1842	1.0106	0.8074	-2.0571
212	9557	7/1/2018	69.693081		2.529438			15.719			0.343584		0.8648	0.6949	7.2598	0.9434	0.9039	16.8880	1.0899	1.2022	7.9533
213	9588	2/25/2018	67.690272		1.952242			-10.687			-0.233612		1.0133	0.9519	-3.7398	1.1685	0.7317	-0.6457	1.1215	1.1097	18.6525
214	9723	2/25/2018	69.049803		2.683219			22.754			0.497365		1.0424	1.0946	-0.1038	1.1906	0.9682	9.3568	1.0712	0.8444	2.4130
215	9738	1/28/2018	66.911616		2.100800			-3.891			-0.085054		1.0581	0.8735	11.8534	1.0151	0.8803	17.8159	0.9519	1.0495	-1.4559
216	9743	3/25/2018	66.518624		1.928605			-11.769			-0.257248		1.1649	1.1565	10.1508	0.9722	0.8556	18.2113	0.9665	0.8380	9.9950
217	9768	3/18/2018	68.379777		1.731311			-20.795			-0.454543		0.8040	1.1032	4.3698	0.8909	0.9324	0.8828	0.7960	0.7941	14.4946
218	9782	2/11/2018	68.906144		1.903923			-12.898			-0.281931		1.1417	1.1803	-0.5600	1.1117	1.0136	-2.3673	0.8387	0.6752	13.8637
219	9807	5/6/2018	70.463346		2.451832			12.168			0.265978		1.1872	0.8187	-3.1563	0.8601	1.3787	-0.6560	1.0327	0.6769	19.4627
220	9882	4/15/2018	69.472701		2.230283			2.033			0.044429		1.1886	1.0295	3.3114	1.0591	0.8352	1.8945	0.9197	0.9785	10.4503
221	9909	2/18/2018	68.857959		1.685799			-22.877			-0.500055		0.8853	1.0329	0.1758	1.2385	1.0712	-2.7861	0.7909	0.7192	17.2544
222	9955	5/6/2018	70.155234		2.262585			3.510			0.076731		1.0855	0.9962	-0.1186	0.8526	1.0353	1.1630	0.9614	0.8272	15.7093
223	10100	5/27/2018	68.715278		2.169999			-0.725			-0.015854		1.1786	1.1856	2.2773	0.7843	0.6208	9.8469	0.8761	1.0468	18.5429
224	10143	4/22/2018	68.686830		2.659624			21.674			0.473770		1.2210	1.1886	7.2616	0.7957	0.6943	8.9608	0.7704	1.0166	7.5006
225	10169	1/14/2018	65.499468		1.942990			-11.111			-0.242864		0.8734	1.0753	9.9303	1.1012	1.0477	14.7139	0.8475	0.7284	-1.5366
226	10197	2/25/2018	66.621138		2.452972			12.220			0.267118		1.2490	1.0273	9.2797	0.9243	1.0802	15.4250	0.8096	0.7779	1.5521
227	10201	2/25/2018	68.584075		1.644790			-24.753			-0.541064		0.9882	1.2313	-1.8078	1.1221	0.9724	2.6169	0.8761	0.6521	17.6889
228	10223	1/7/2018	67.498608		1.826738			-16.429			-0.359116		1.2205	1.2612	-1.7512	1.1453	0.9334	10.0012	1.0523	0.6788	4.3732
229	10240	1/14/2018	68.878386		1.872834			-14.320			-0.313020		0.9456	0.7675	2.2116	1.2358	1.1283	-0.9336	1.0776	0.8902	2.8168
230	10250	5/20/2018	69.472665		2.675084			22.382			0.489230		1.2041	0.9229	14.0390	1.1996	1.1714	-1.9672	1.1241	0.7956	18.0714

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Table C-2 : Test model (Verification starts at two-third or history production) 231 to 250 acceptable realization

Acceptable realization	Total realization	Stop injection Date	Injected water (MMstb)	Mean production rate at testing period			Error						Res A			Res B			Res C		
							percent			actual value			Multiply factor			Multiply factor			Multiply factor		
				Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Oil rate	Gas rate	Water rate	Oil rate (stb/d)	Gas rate (MMscf/d)	Water rate (stb/d)	Flow rate	OIP	skin	Flow rate	OIP	skin	Flow rate	OIP	skin
231	10286	4/29/2018	67.150252		2.246160			2.759			0.060306		1.0144	1.1551	9.7932	1.0613	1.1102	11.5862	0.8175	0.6355	18.4636
232	10323	3/11/2018	67.428537		2.014690			-7.831			-0.171164		0.9726	0.7671	6.7141	0.8403	0.7957	-3.7169	1.2386	1.2016	16.4945
233	10342	8/5/2018	70.032072		2.090054			-4.383			-0.095800		0.7943	0.5847	11.8514	1.1090	1.0273	6.9672	1.1997	1.1414	12.6535
234	10412	5/27/2018	69.409013		2.166303			-0.894			-0.019551		0.8881	0.7322	1.8232	1.1151	0.9969	2.4655	1.2251	1.0589	17.4179
235	10427	12/17/2017	66.252591		2.345352			7.297			0.159498		0.8205	0.8564	-2.3136	1.1033	1.0268	19.5386	1.1230	0.9489	-1.2890
236	10520	5/20/2018	69.006866		1.675610			-23.343			-0.510244		1.0911	1.2430	-0.6348	1.1885	0.7446	11.3015	1.1453	0.8501	19.5244
237	10552	3/4/2018	66.069454		2.063563			-5.595			-0.122291		1.1062	1.4567	5.7759	0.8070	0.6998	18.1976	0.9550	0.7582	11.9506
238	10624	4/29/2018	69.915654		2.593020			18.627			0.407166		1.0916	0.8472	11.0501	0.7890	1.0497	-0.9280	0.9755	0.9572	8.7371
239	10645	12/3/2017	66.947723		1.731392			-20.791			-0.454462		0.9522	1.1010	3.9069	1.2240	0.9361	4.1699	0.9632	0.7917	-1.0618
240	10699	5/27/2018	68.434833		2.106912			-3.611			-0.078942		1.0747	0.8493	13.0498	0.7951	0.9560	13.7096	0.8412	1.0005	10.9141
241	10716	4/15/2018	69.707965		2.230843			2.058			0.044989		1.1327	0.8731	6.3036	0.8773	1.0994	-1.7310	0.9190	0.8636	12.7736
242	10761	1/21/2018	66.475137		2.644301			20.973			0.458447		0.9646	1.1365	14.3354	1.0598	0.9994	-3.5272	0.8055	0.7807	9.7643
243	10800	2/11/2018	68.805076		1.984751			-9.200			-0.201103		0.8568	0.8579	5.6951	1.1117	0.8094	4.5446	0.9332	1.1153	1.5963
244	10813	7/8/2018	70.285330		2.559090			17.075			0.373236		1.0276	0.7012	15.4829	0.7661	1.0893	3.9611	1.1887	1.0336	11.5073
245	10886	1/7/2018	67.200532		1.961984			-10.242			-0.223870		1.1780	0.7272	16.7463	1.1823	1.2405	2.9993	0.9320	0.8294	-1.5932
246	10940	3/4/2018	67.498389		2.465468			12.792			0.279614		0.8984	0.9463	-3.4682	1.1773	1.0884	16.9393	0.8848	0.8333	8.1978
247	10981	5/20/2018	69.880865		2.467858			12.901			0.282004		1.1816	0.9312	5.7243	0.8246	0.9776	4.9140	0.9828	0.9461	11.1169
248	11051	2/18/2018	65.253167		2.632911			20.452			0.447058		1.1308	0.7045	9.5335	1.1408	1.2541	19.6149	1.1993	0.8903	4.1290
249	11103	5/27/2018	68.208641		2.186670			0.037			0.000816		0.9562	1.0547	8.0870	0.9467	0.9055	17.4227	0.8414	0.8920	13.8007
250	11106	4/15/2018	67.065297		2.534589			15.954			0.348735		1.1475	1.0801	16.5103	1.0031	0.8469	12.3017	0.8744	0.9526	9.2171

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APPENDIX D

Example of OpenServer Code

```
Option Explicit
Dim Server As Object
Dim Connected As Integer
Dim lErr As Long
Dim AppName As String
Dim cmd As String
'MBAL Function
Public Sub OpenMBALFile(ByVal filepath As String)
  DoCmd "MBAL.OPENFILE(""" + filepath + """)"
End Sub
Public Sub SaveMBALFile(ByVal filepath As String)
  DoCmd "MBAL.SAVEFILE(""" + filepath + """)"
End Sub
Public Sub RunMBALSim()
  DoCmd "MBAL.MB.RunSimulation"
End Sub
Public Sub DeleteTankHist()
  While DoGet("MBAL.MB.TANK.PRODHIST.COUNT") > 0
    DoSet "MBAL.MB.TANK.PRODHIST[0].DELETE", " "
  Wend
End Sub
Public Sub AddTankHistRow()
  DoSet "MBAL.MB.TANK.PRODHIST.ADD", ""
End Sub
```

VITAE

Teerasak Luamsai was born on November 18, 1983 in Roi-Et, Thailand. He received his B.Sci in Petrochemical Technology from the Faculty of Science, King Mongkut Institute of Technology Ladkrabang in 2006. After graduating, he continues his studies in the Master of Petroleum Engineering program at the Department of Mining and Petroleum Engineering Faculty of Engineering, Chulalongkorn University.