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APPLICATION OF GAS-ASSISTED GRAVITY DRAINAGE (GAGD) TO IMPROVE OIL RECOVERY OF RANG DONG BASEMENT RESERVOIR

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Summary

As an option to improve the ultimate oil recovery factor of the Rang Dong field, a feasibility study of gas-assisted gravity drainage (GAGD) application was carried out for the fractured basement reservoir with a single-well Huff 'n' Puff pilot test applied on a high water-cut producer. This paper aims to provide an in-depth understanding about such case study, which includes details on candidate selection, gas injection scheme, on-site execution, results of flow-back, post-job review and lessons learned.

The pilot test of GAGD was recorded with a good oil rate and low water-cut during flowing back after gas injection and shut-in for gas segregation, which suggests the positive effectiveness of GAGD to some degree. The expansion of the GAGD application to other wells and areas in the field would be encouraged in any similar situation. On the other hand, the results of this pilot test shed a light into further optimisation of the candidate selection and gas injection scheme by material balance analysis and reservoir simulation respectively.

Key words: Fractured basement, production, IOR, EOR, GAGD, pilot test, Rang Dong field.

1. Introduction

1.1. General information

Block 15-2 is located offshore of southern Vietnam, approximately 120 km off Vung Tau at the mouth of the Mekong River (Figure 1). After the production sharing contract (PSC) was signed in 1992, extensive exploration and development activities were carried out, and as a result, the first oils were achieved from the Rang Dong and Phuong Dong fields in 1998 and 2008 respectively.

As the largest field of this block, the Rang Dong field has achieved cumulative oil production of approximately 240 million barrels mainly from fractured basement and Lower Miocene sandstone reservoirs to date. The full field scale application of hydrocarbon gas enhanced oil recovery (HCG EOR) with water alternating gas injection (WAG) has been deployed at the Lower Miocene sandstone reservoir since 2014 while the basement reservoir has been produced mainly by the bottom water drive mechanism.

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1.2. Issues of the basement reservoir

The fractured basement reservoir of the Rang Dong field has been put into production since 1998 and passed the peak of 40,000 - 50,000 barrels of oil per day with intensive development activities in the period of 2002 - 2006. Since then, the production has been declining and remains at 5,000 barrels of oil per day with a water-cut of 80 - 90% recently.

The severest problem of the oil production is a rapid increase of the water-cut [1]. Figure 2 shows the water-cut trends in the individual wells. Many wells have problems of a high water-cut because the wells commence a rapid decline once the initial water-cut increase is observed.

Water injection had been implemented since 2003, however, it sometimes caused severe water breakthroughs. The cyclic production and production-injection patterns had been applied in several wells, but the impact was limited. Under such a situation, the estimated ultimate recovery factor (RF) of the basement reservoir was only 18%. Improvement of the recovery factor is critical for maximising the project value, but this is challenging due to the unique nature of the fractured basement reservoir.

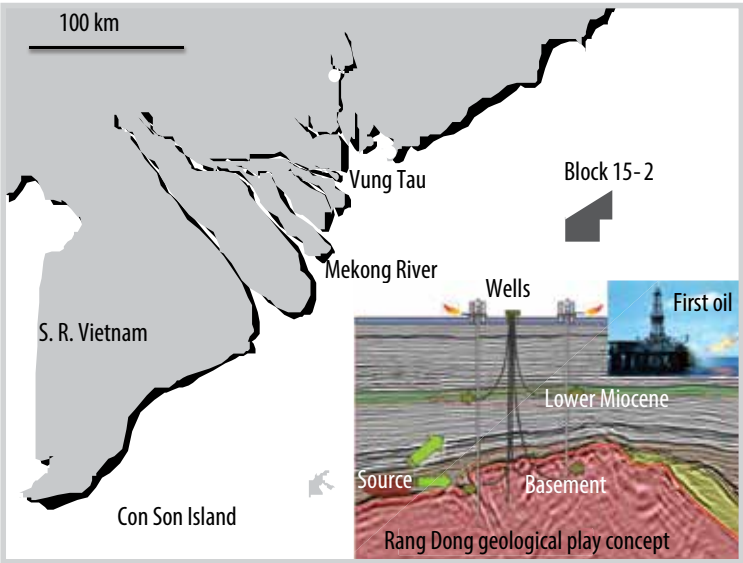
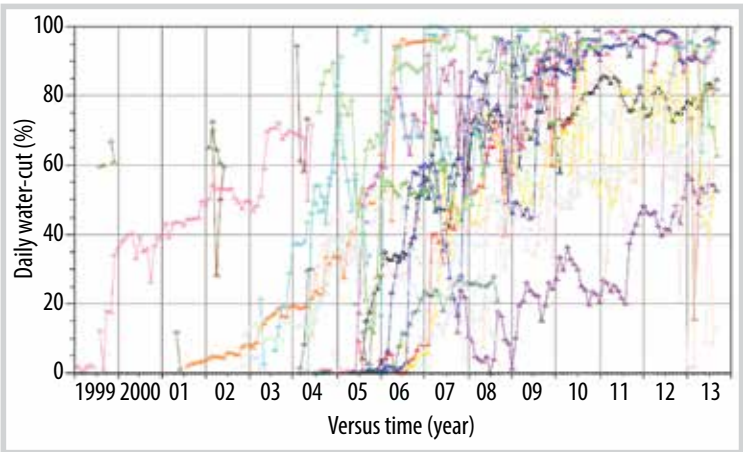


Figure 1. *Location map of Block 15-2 and geological play concept.*



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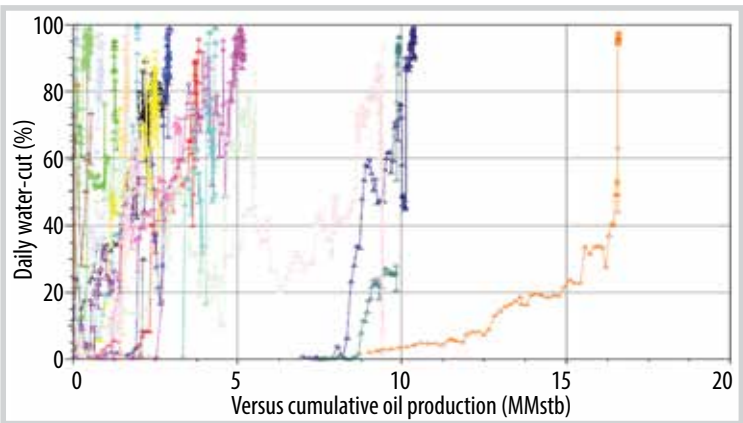

(b)

Figure 2. *Water-cut trends in the individual wells.*

For further improvement of the recovery factor, additional drilling for the attic potential remaining above the producing depth of the existing wells can be considered subject to technical and economical justifications. Meanwhile, the option of acid treatment, water shut-off and GAGD can be exercised and matured as one of the possible IOR techniques.

1.3. Gas-assisted gravity drainage concept

The GAGD process [3 - 8] is developed to overcome the limitations of conventional horizontal displacement such as water injection, gas injection, and WAG. The GAGD process attempts to flood the reservoir vertically by injecting gas at the top of the pay zone, using vertical wells and producing oil from horizontal wells placed near the oil-water-contact (OWC) (Figure 3).

Numerous projects have been initiated in the USA and Canada, and some have resulted in significant improvement of oil recovery. Most of the projects are established for dipped clastic or carbonate reservoirs of onshore fields.

In the Yates field (Midland, the USA), the GAGD process was applied to a naturally fractured carbonate reservoir in the 1970s and successfully enhanced oil production out of the matured field [3].

GAGD is a proven technology in terms of reservoir engineering for the improvement of oil recovery.

1.4. Applicability of GAGD for fractured basement

The existing producers of the Rang Dong basement reservoir were normally drilled horizontally at approximately 200 - 300 m deeper from top of the basement. In case of a rapid water breakthrough from the bottom, the attic above the wellbore might still have remaining oil potential (named as oil band). JVPC had applied water injection aiming at pressure maintenance and horizontal displacement of oil, but the impact on the improvement of oil recovery was limited. GAGD is probably one of the most effective techniques to displace the oil band to the producers.

The characteristics of the Rang Dong basement reservoir appear to be preferable, especially in terms of dominant gravitational force existing in high-angled permeable fractures. Some published papers [4, 5] introduce the empirical screening criteria of GAGD as shown in Table 1.

The properties of the Rang Dong basement reservoir mostly satisfy the above criteria. Furthermore, a source of high-pressure gas (as high as 3,200 psi at surface) is available through the operation of the HCG EOR program for the Lower Miocene sandstone reservoir, and it provides an advantage for this GAGD pilot test.

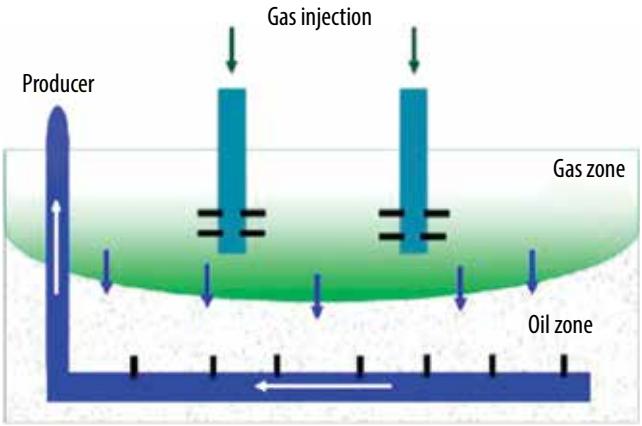

Figure 3. *Schema of GAGD application.*

2. Case study [1, 2]

2.1. GAGD Huff 'n' Puff pilot test

GAGD is probably one of the most effective techniques to improve oil recovery out of the basement reservoir. To ensure the effectiveness, the pilot test of GAGD was selected with minimised scope of work utilising the existing water out producer and with minimum facility modification for low implementation cost. The GAGD Huff 'n' Puff process (Figure 4) consists of 3 steps as i) gas injection, ii) gas migration and stabilisation, then iii) production.

2.2. Well candidate selection

Initially, there were 3 candidates nominated out of all the basement producers relating to the fact that the high-pressure gas injection system and test separator for appropriate monitoring are available with a minimum facility modification needed for those wells.

Table 1. *Screening criteria of GAGD*

Parameter	Rang Dong basement	Screening criteria
Vertical reservoir permeability	> 1,000 mD	> 300 mD
Bed dip angle	60 ~ 80 degree	> 10 degree
Oil viscosity	Free flow	Free flow
Spreading coefficient	Positive	Positive
Waterflood residual-oil satuation	Not specified	Substantial (range not specified)

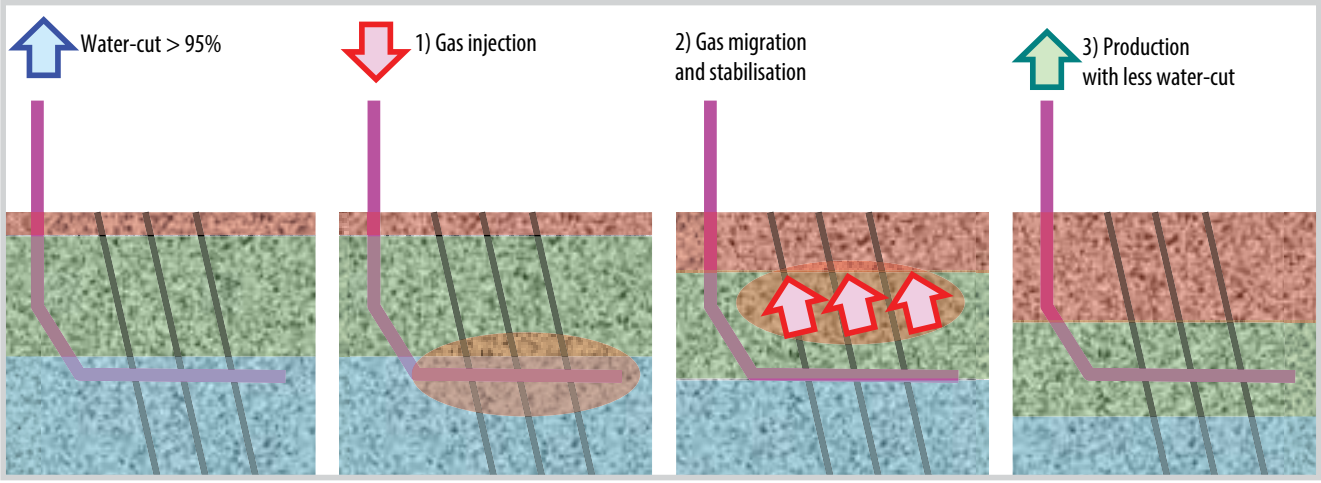

Figure 4. *Schema of GAGD pilot test.*

Table 2. *Well selection criteria for GAGD pilot test*

Selection criteria	Well A	Well B	Well C
High water-cut	70 - 100%	90 - 95%	95 - 100%
Expected oil/gas above wellbore	253 m	227 m	64 m
Reservoir pressure below injection pressure of 4,000 psi	Yes	Yes	Yes
Isolated segment for minimised injection volume	Yes	Possible	No
Gravity segregation expected	Yes	Unknown	Yes
Final ranking	I	II	III

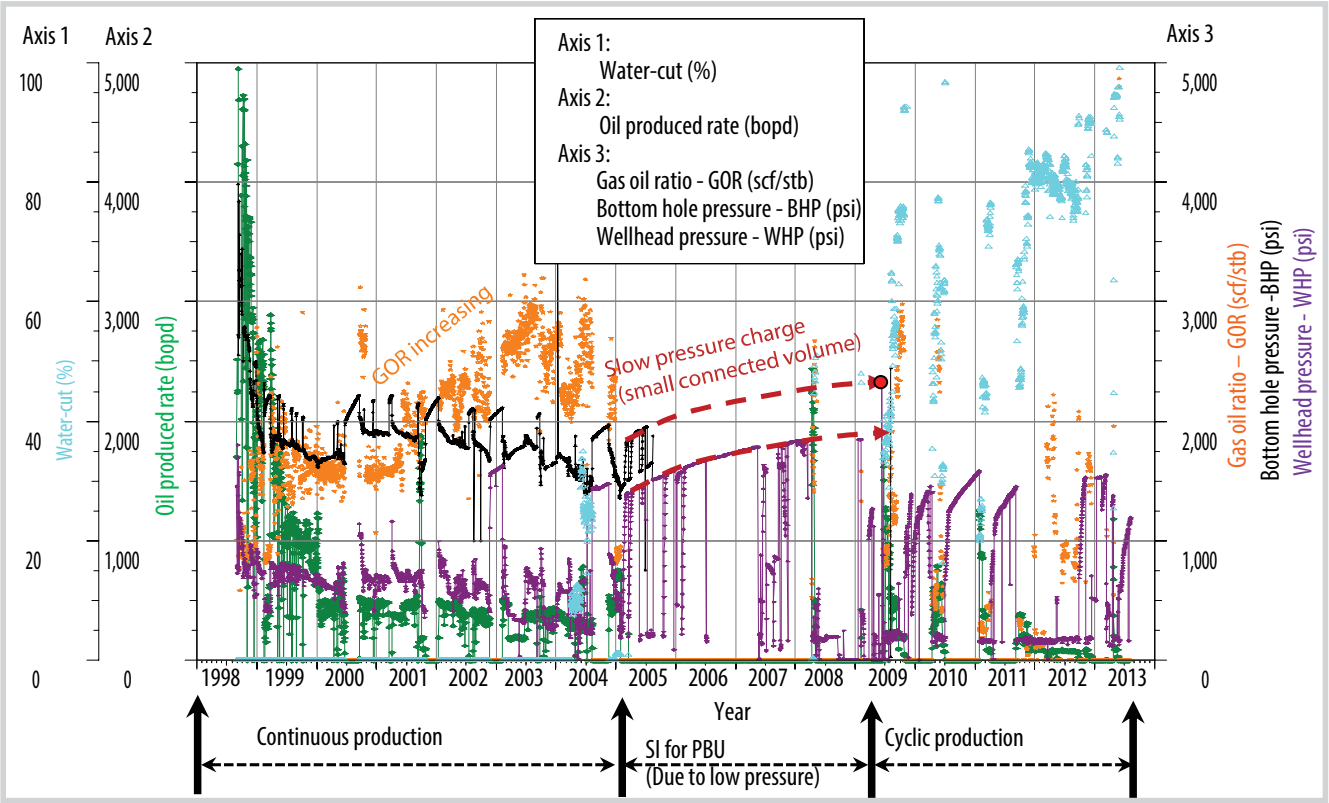

Figure 5. *Production performance of well A.*

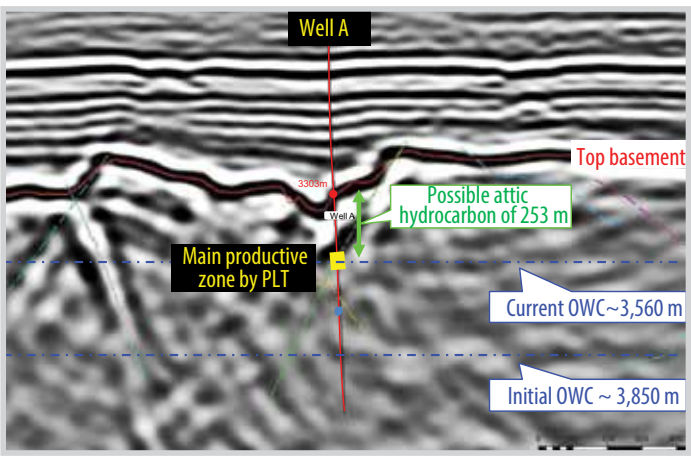

Figure 6. *Seismic section along well A and relating sub-surface information.*

Well selection criteria: These candidates were reviewed through production performance. Well profile and rank are shown in Table 2 for final selection.

Being ranked as the most preferable candidate, Well A was selected for the GAGD Huff 'n' Puff pilot test. The well performance (Figure 5) indicated the existence of oil band and the impact of gravity segregation during cyclic production (i.e., the water-cut was reduced right after opening the well, giving a period of shut-in due to high water-cut). The slow pressure build-up (PBU) suggests a small volume connected to the well, and subsequently, a small volume of gas injection is required.

The well trajectory and seismic section along well A (Figure 6) show a remaining oil/gas column of 253 m still expected above the producing fracture depth level.

2.3. Simulation study for pilot test design

The reservoir simulation was utilised for pre-GAGD design of the pilot test including the prediction of the gas injection scheme.

- Sector model and history matching

The seismic faults or fractures connected to the well were geologically modelled, and as a result, a sector model for an area of around 0.6 km^2 was built for simulation and history matching. The settings of the model are described as follows.

+ Initial OWC is assumed at 3,850 m (as mid-depth in-between oil-down-to and structural spill point), and no gas cap exists initially for the undersaturated oil reservoir.

+ Saturation pressure of 4,800 psi, oil formation volume factor of 1.678 reservoir barrel/stock tank barrel (rb/stb), and solution gas-oil ratio (GOR) of 1,204 scf/stb are set in the model.

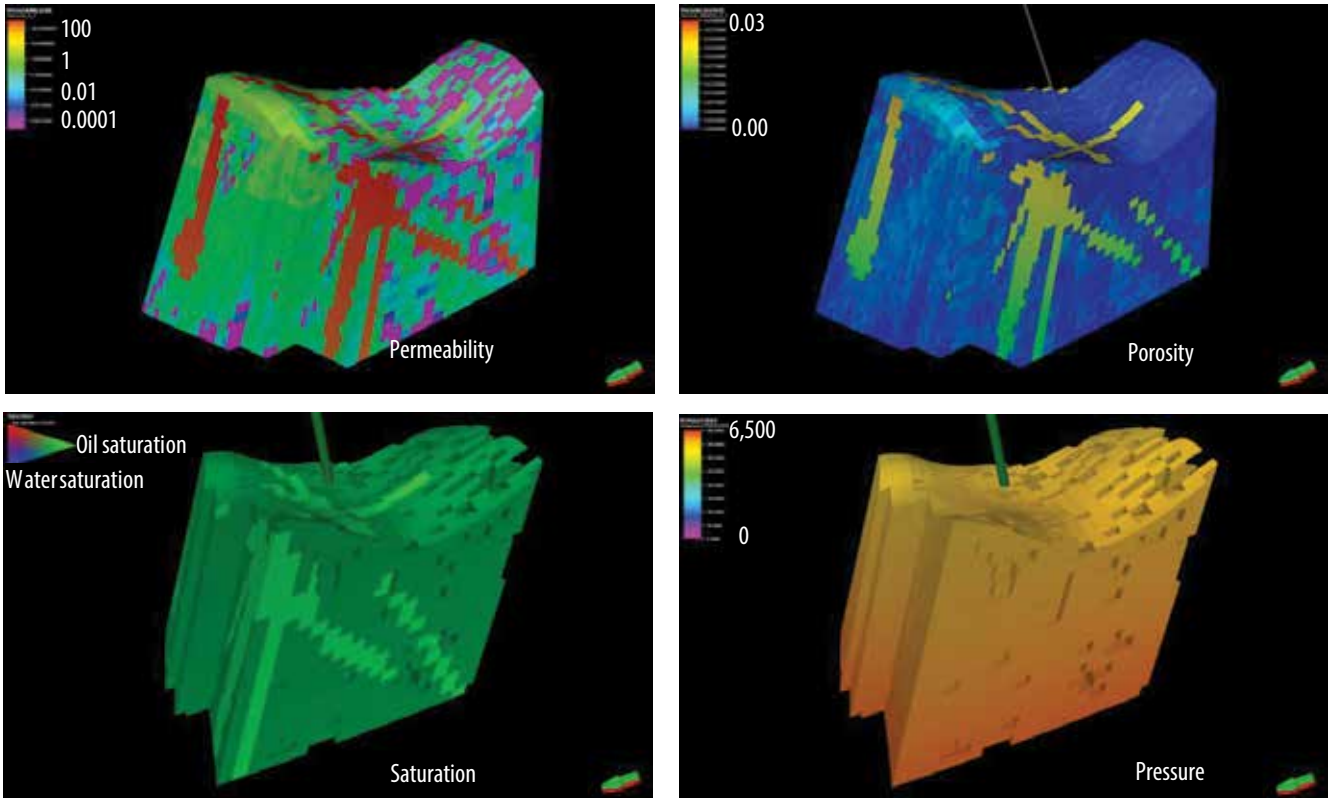

Figure 7. *Reservoir properties of sector model.*

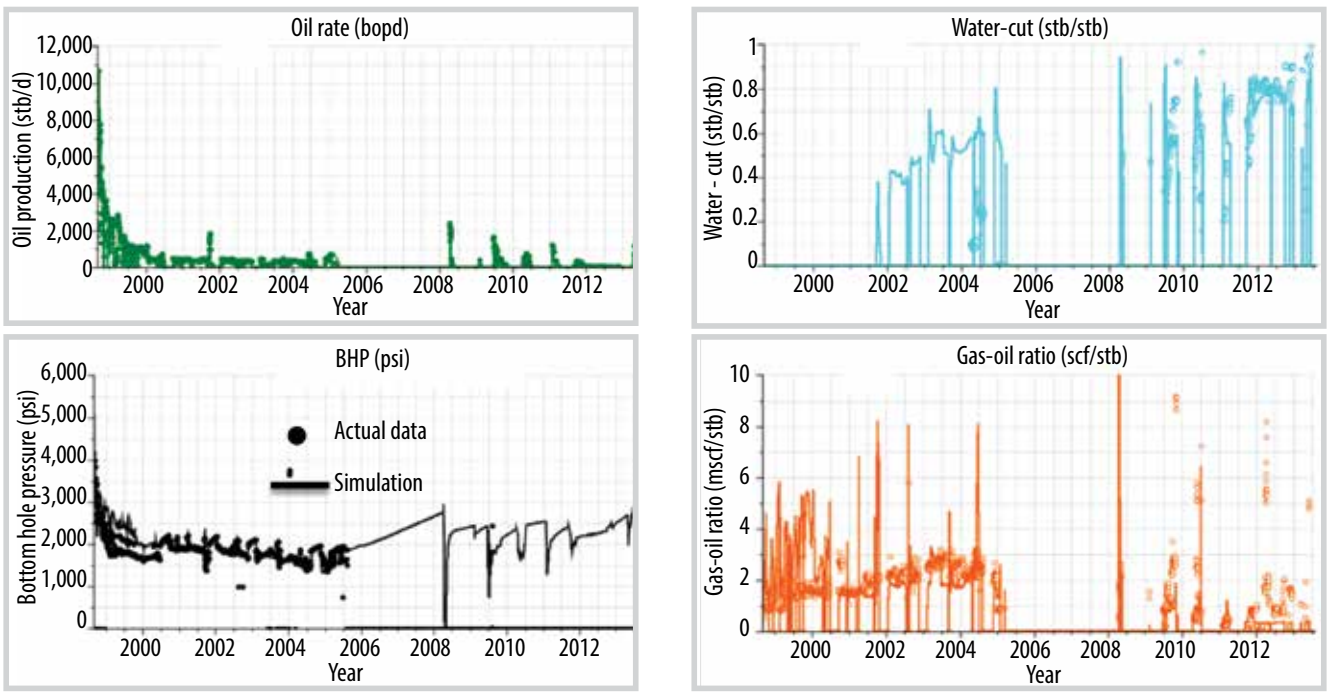

Figure 8. *History matching of well A.*

+ Initial reservoir pressure is at 5,320 psi at datum depth of 3,500 m in vertical depth.

+ Straight X-shaped relative permeability for cells of highly permeable fractures, and a curve shaped one for the others are assumed for fractured basement reservoir.

+ Carter Tracy aquifer is set at the bottom.

+ Modelling OIIP of 5.0 MMstb (1.27 MMstb in primary fracture cell, and 3.78 MMstb in others) is matched with OIIP estimated by material balance analysis.

The result of properties modelling for the connected seismic faults based on the above-mentioned settings is demonstrated in Figure 7.

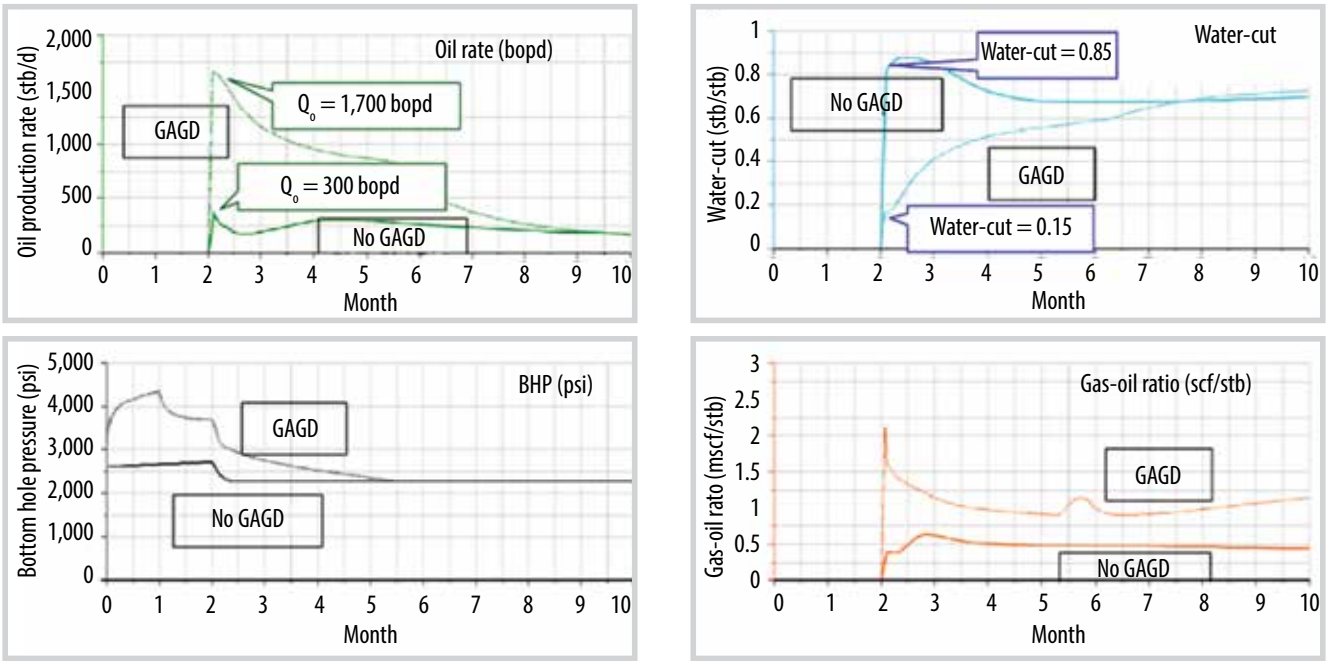

Figure 9. *Prediction of GAGD Huff 'n' Puff.*

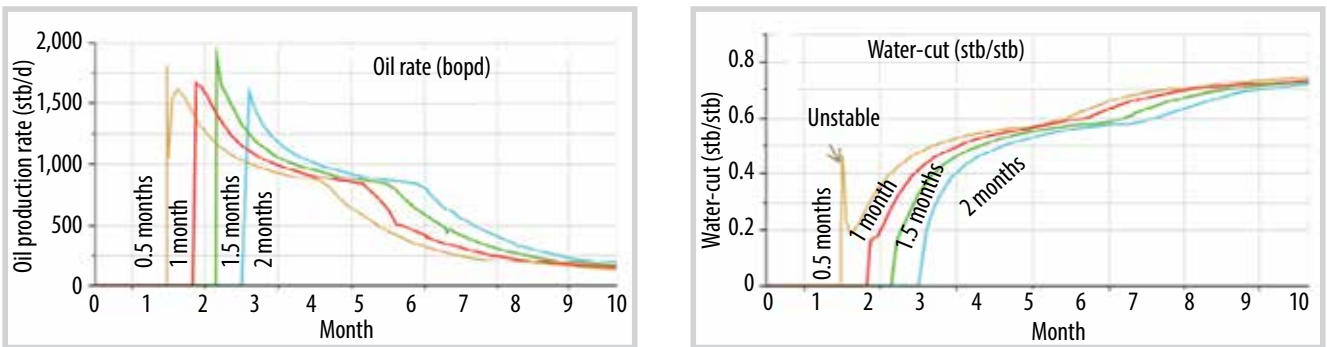

Figure 10. *Sensitivity check for shut-in period.*

The history matching was then carried out, and its result is shown in Figure 8.

+ The history run is controlled by the oil production rate (history data).

+ Simulated water breakthrough is earlier than actual, but the current water-cut at 95% is well converged.

+ Simulated GOR fluctuates, but its increase trend from 2001 to 2005 is matched. Simulated GOR in cyclic operation period is slightly deviated.

+ Flowing and shut-in bottom hole pressure (BHP) are reasonably matched.

- Preliminary injection scheme of GAGD

Based on the obtained result of the modelling and history matching, the preliminary design of the pilot test can be defined by prediction from the model. Three major steps of GAGD schema are set including 1) gas injection (total volume of 0.3 Bcf, injection rate at 10 MMscfd for 1 month), 2) shut-in (1 month for gas migration and stabilisation) and 3) flowing back. A reference case (without GAGD) is also simulated with 2 months shut-in (instead of applying Step 1 and 2 with GAGD), then flowing back. The flow-back is controlled by a liquid rate of 2,000 barrels of oil per day in the simulation.

The results of prediction with GAGD and without GAGD (Figure 9) are summarised below:

+ Oil-rate increases from 300 barrels of oil per day without GAGD to 1,700 barrels of oil per day with GAGD, showing the positive effect of GAGD application.

+ Water-cut reduces from 85% without GAGD to 15% with GAGD.

+ Cumulative oil increment of 0.104 MMstb is predicted with GAGD in the simulated period (10 months after the gas injection).

+ Cumulative gas increment of 0.137 Bcf, approximately 46% of injected gas volume, is recovered after GAGD.

+ Expected oil-water-contact moves down to the producing depth of the existing wells after gas injection and stabilisation.

- Sensitivity check for the design

To finalise the scheme of the pilot test, sensitivity runs of the gas injection volume and a shut-in period are carried out. For example, the sensitivity runs of the shut-in period (Figure 10) shows a fluctuated oil rate and water-cut in the initial flowing period with a 0.5-month shut-in, and a minimum 1-month shut-in would be necessary to let the injected gas migrate and stabilise.

- Finalised injection scheme of GAGD

The design of GAGD pilot test is fine-tuned by a sensitive check and finalised as follows.

+ Execution of the GAGD pilot test has 3 major steps including 1) gas injection of 0.3 Bcf (injection rate of 10 MMscfd for 1 month), 2) shut-in (1 month for gas migration and stabilisation) and 3) flowing back.

+ A contingent plan is prepared for 1) extending the gas injection period for 1 more month in case of a negligible positive response by the initial gas injection, 2) conducting a gradient survey for well monitoring, 3) repeating the Huff 'n' Puff operation in case of success (which could be optimised by the result of the initial test), 4) there is an option of postponing the test if the well declines rapidly.

2.4. Consideration of the applicability for the entire basement reservoir

This first pilot test is considered to provide a critical understanding of the effectiveness of the GAGD technique with a minimal cost of USD 65,000 for facility modification providing the availability of a high-pressure compressor for EOR of the Lower Miocene sandstone reservoir, and a deferment of 0.162 Bcf (54% of total gas injection) as predicted by the reservoir simulation. Subject to the result of the pilot test, the way-forward would be defined accordingly.

3. Implementation of GAGD pilot test [2]

3.1. Gas injection operation

The GAGD Huff 'n' Puff pilot test commenced the gas injection and a stable injection rate of 10 MMscfd was initially achieved as designed (Figure 11). After injecting a total gas volume of approximately 40 MMscf, the well-head

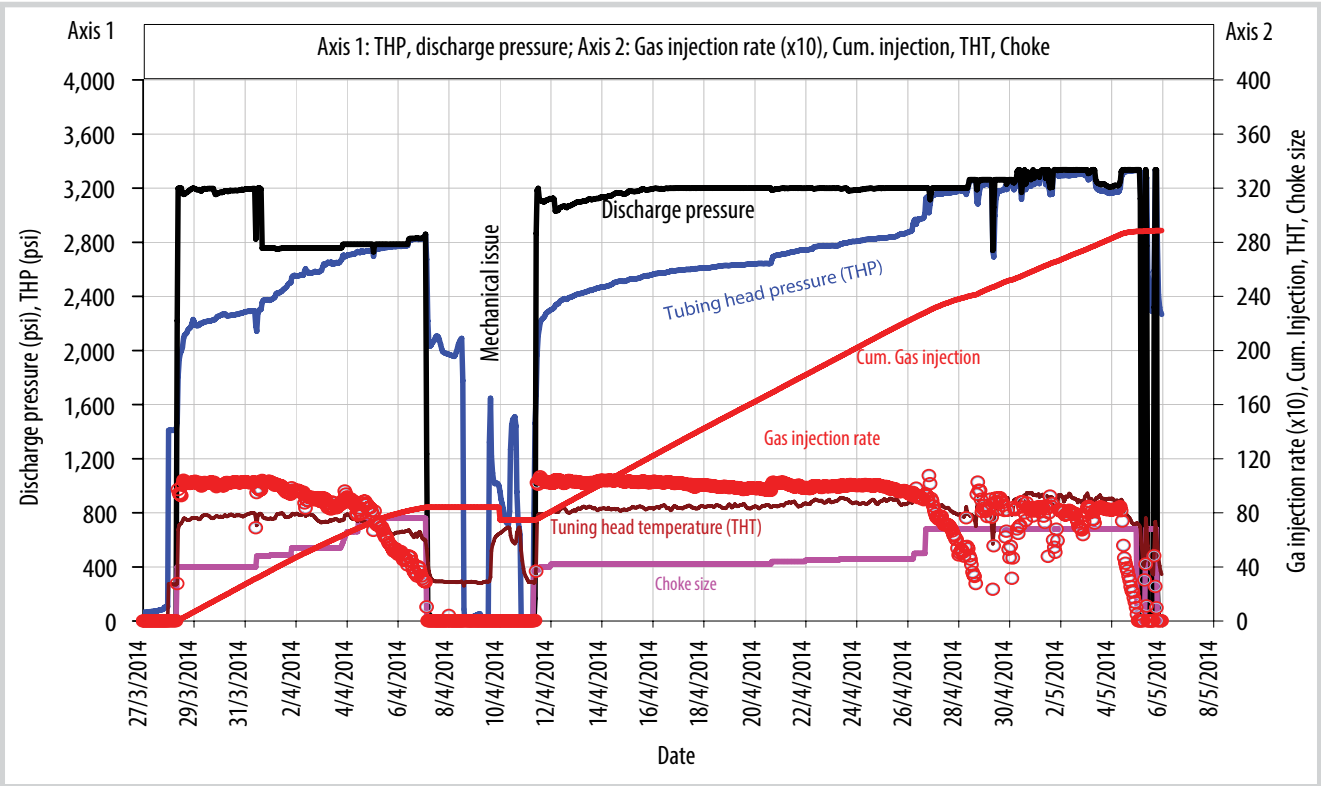

Figure 11. *Operation of gas injection.*

pressure started to increase, and the injection rate declined accordingly. The flow-back of 10 MMscf injected gas was performed, the gas injection was then resumed. It is noted that due to the exiting pack-off in the shallow section in the well, it was impossible to run the gauge cutter to check the tubing condition, and therefore, this reduction of gas injectivity was assumed to be a possible mechanical restriction inside the tubing and/or gas trapped near the wellbore reservoir zone caused by the gas injection, and it was released by flow-back. For the remaining injection period until the end of the injection phase, the gas injectivity was maintained at an almost stable rate.

A total of 298 MMscf of gas was injected into the reservoir (including 10 MMscf bled off). The designed injection target volume of 300 MMscf (0.3 Bcf) was almost achieved.

3.2. Performance of flow-back

- First flow-back cycle

After the gas injection and shut-in, the well was reconnected to the production line and re-opened on for flow-back. The initial flow was worse than the prediction. A total of 40 MMscf of gas was produced together with condensate during the first cycle of flow-back.

- Second flow-back cycle

The well was shut-in for a few days, and then re-opened with flowing gas and condensate. A total of 15 MMscf of gas was produced in this cycle.

- Third flow-back cycle

After a few days of shut-in, the well was re-opened, and it was still producing gas and condensate. A total of 35 MMscf of gas was produced in this cycle.

- Fourth flow-back cycle

The well was shut in for approximately 3 weeks, then re-opened, but still producing only gas and condensate. A total of 60 MMscf of gas was produced in this cycle.

A total of 50% of injected gas was produced from the above-mentioned 4 cycles of flow-back, i.e., 150 MMscf produced versus 300 MMscf of injected gas.

- Fifth flow-back cycle

The well was re-opened after 2 months of shut-in. Improvement was observed in this cycle with a higher oil rate and low water-cut in the first week. Water-cut then started increasing and quickly resumed to a high level (90 - 95%) as before the gas injection.

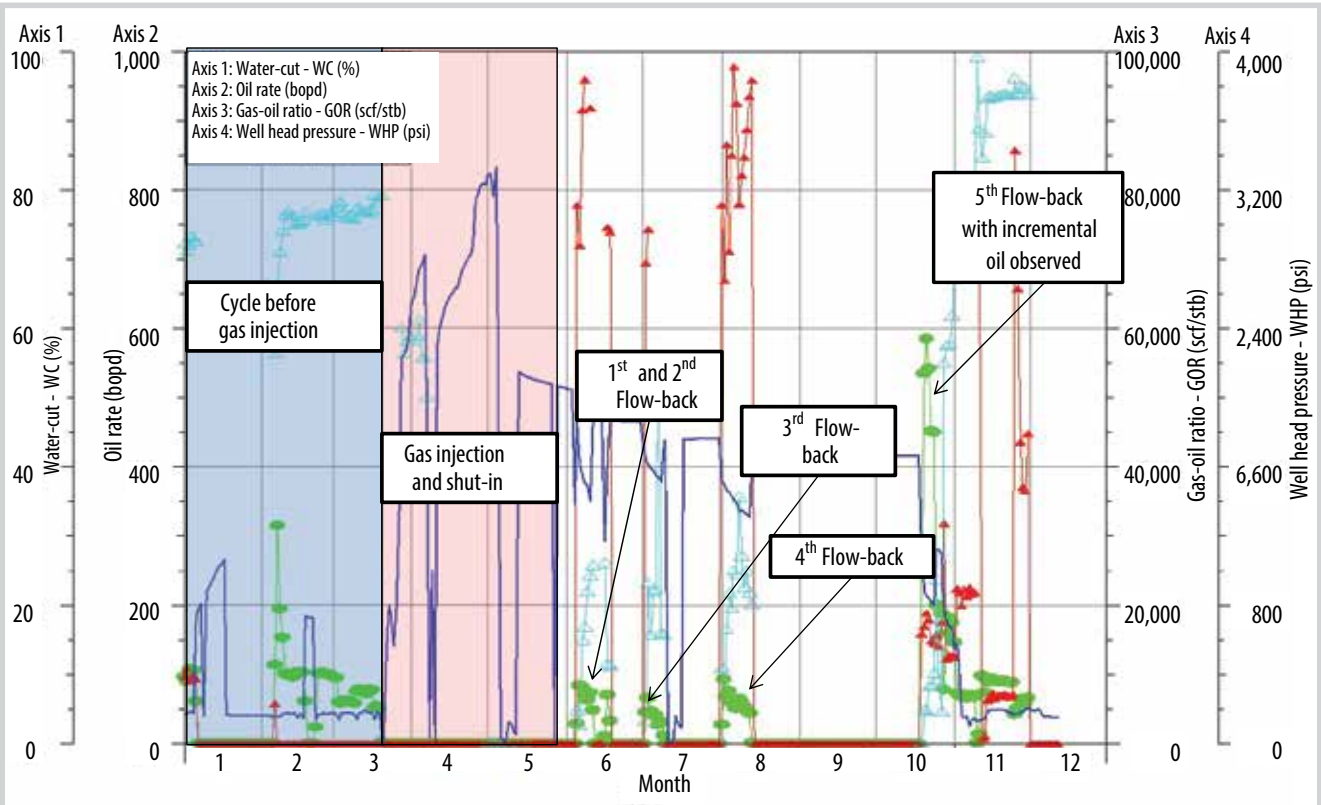

Figure 12. *Performance of gas injection and flow-back.*

A total of 106 MMscf of gas and 6,244 stb of oil were produced in this cycle.

The summary of flow-back performance is shown Figure 12.

4. Post-operation review and lessons learned

4.1. Reservoir simulation

The pre-GAGD sector model predicted a maximum oil rate of 1,700 barrels of oil per day with slow water-cut increasing in several months but the actual result turned out to be less with the oil rate of 600 barrels of oil per day observed in the fifth cycle and water-cut rising rapidly in one week. Such a model captured one of the possible scenarios in its prediction, but it did not fully reflect all the different scenarios relating to the below uncertainties:

+ Current water and gas contacts (OWC, GOC);

+ Permeability and size of aquifer;

+ Vertical (Kv) and horizontal (Kh) permeability for each fracture zone.

To address such uncertainties, sufficient sensitivity analysis would be required during the pre-job design as per the lessons learned from this GAGD pilot test.

4.2. Review of material balance analysis [2]

To better explain the actual performance of the well, the material balance analysis using the multi-tank model was applied in consideration of the difficulty to fully represent uncertainties by the reservoir simulation. The conceptual model of the multi-tank system for material balance analysis is illustrated in Figure 13.

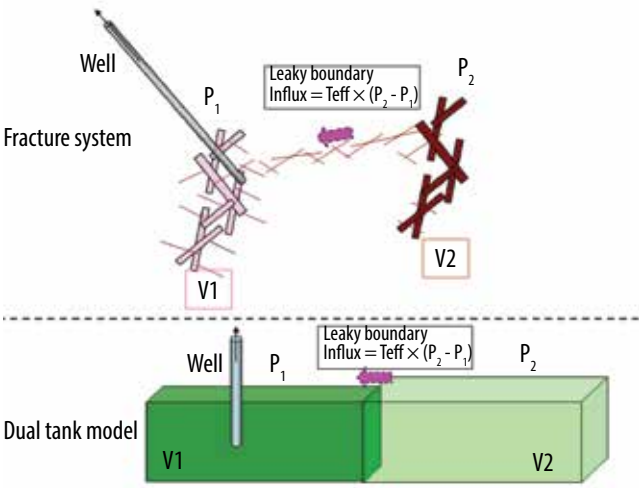

Figure 13. *Concept model of the multi-tank system applied for fractured basement.*

The material balance analysis during pre-job was optimistic in terms of the remaining oil in the main tank (which is connected directly to the wellbore) even though the pressure was well matched. Actual data showed that the remaining oil might be lower than predicted. Therefore, the designed gas injection volume (0.3 Bcf) was too much, and GOC was pushed down below the producing depth level. This is possibly the main reason why only gas was produced until 50% of the injected gas volume was bled off.

The detailed material balance analysis of pre-GAGD is shown in Figure 14. The material balance analysis of post-GAGD was re-evaluated with the pessimistic scenario (less

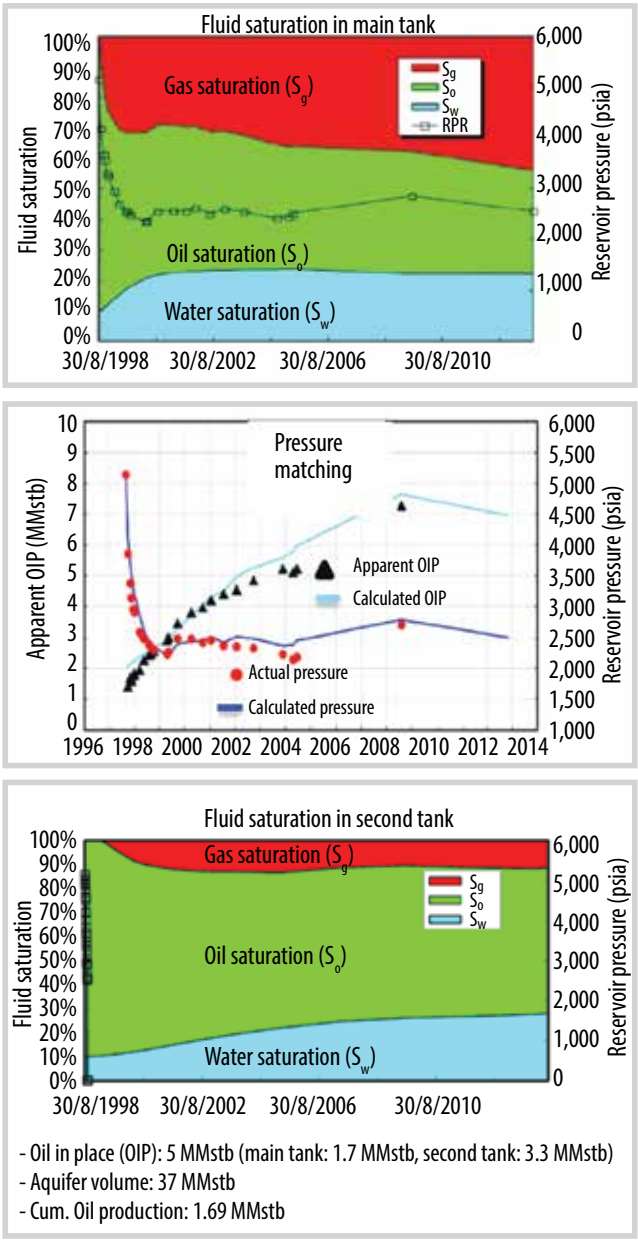

Figure 14. *Pre-GAGD material balance analysis.*

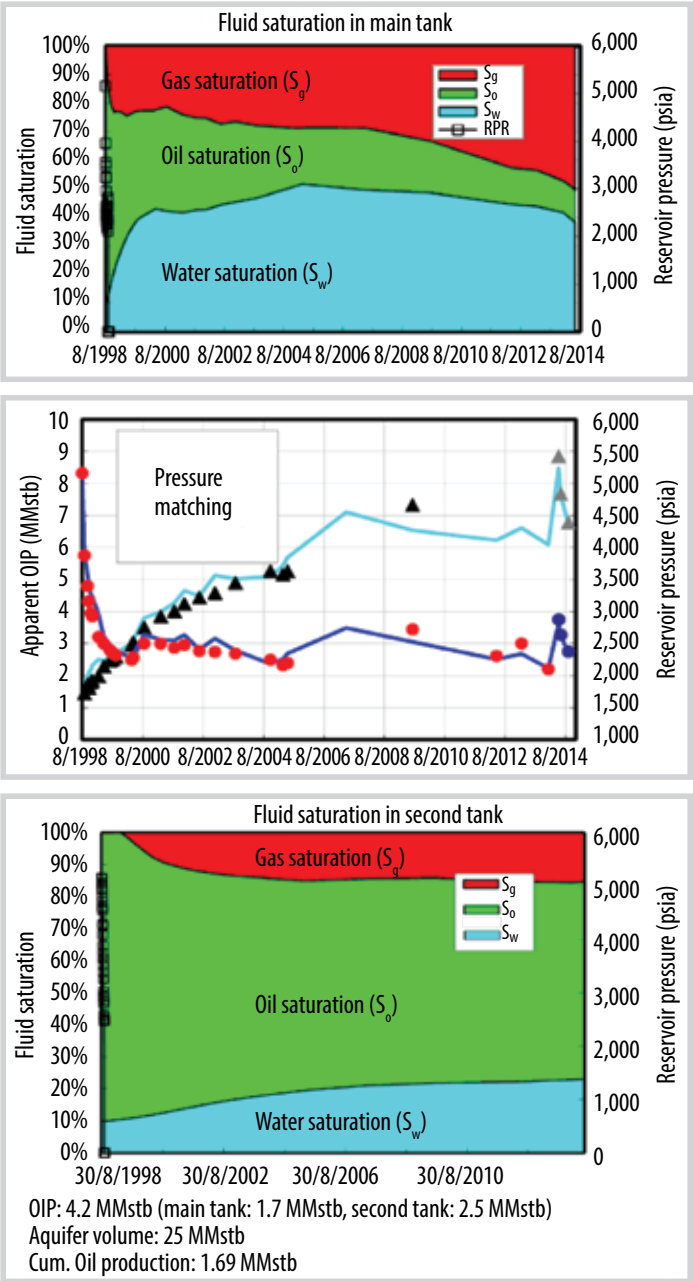

Figure 15. *Post-GAGD material balance analysis.*

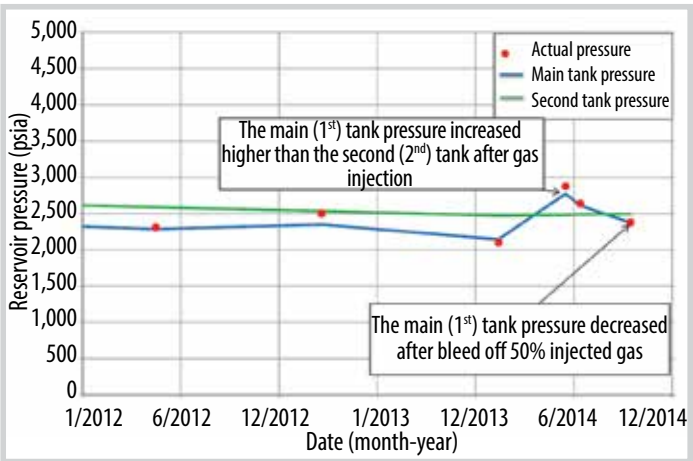

Figure 16. *Pressure profile of the multi-tank system.*

oil remaining). The pressure data (including data after gas injection and flow-back) was re-matched and the detailed result is shown in Figure 15.

Based on the behaviour and analysis of the matched multi-tank system model, the main oil production was supported by influx from the second tank having higher pressure and more remaining oil. After the gas injection phase, the pressure in the main tank increased immediately and became higher than the pressure in the second tank, and then, the influx from the second tank to the main tank was stopped. This could be the other important reason that caused only gas production in several flows back cycles.

To reduce pressure in the main tank below the second tank pressure and to resume the influx of oil, it is necessary to bleed off around 150 MMscf (50% of the injected volume). In fact, the actual performance in the fifth cycle was better after a flow-back of approximately 150 MMscf of injected gas. This is supported by the material balance analysis. The pressure profile of the multi-tank is shown in Figure 16.

4.3. Lessons learned and recommendations

The key lessons learned from this GAGD pilot test are listed below:

- Comprehensive reservoir modelling and simulation for full realisation of uncertainties are essential to design the scheme of gas injection and soaking time robustly.

- It is recommended to apply GAGD IOR in the wells having sufficient remaining oil in the first tank. This will mitigate the risk of high pressure in the main tank caused by gas injection, which then stops oil influx from the second tank.

5. Conclusions

The GAGD pilot test was implemented successfully with the indication of positive effectiveness of gas-assisted gravity drainage. A total of 298 MMscf of hydrocarbon gas was injected into the reservoir and the well was shut-in for oil/gas segregation. The flow-back was then monitored with several cycles (re-opened/closed) applied until the positive impact of GAGD was observed during the fifth cycle with a good oil rate and low water-cut, but water-cut increased quickly after only 1 week.

The simulation model was reasonably matched with production data, but the prediction was a failure. The model couldn't reflect the characteristics of reservoir heterogeneities due to a lack of sufficient sensitivity analysis during the pre-job design.

The material balance analysis was reviewed, showing the root-cause of the failure of prediction regarding the well performance after gas injection attributed to heterogeneities of the reservoir (multi-fracture system). Given such findings, for further application of GAGD, it is recommended to focus on the well/area with good remaining oil in the main fractures (directly connected to the well) and more homogeneous reservoirs.

The result of the pilot test provided a significant insight into the process optimisation of further pilot tests prior to proceeding to large-scale application for the entire basement reservoir.

Acknowledgements

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