The Effect of Well Completion Fluid Loss on Productivity Evaluation in Tight Sand Gas Reservoir: A Case Study from East China Sea Gas Well

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Abstract: Fluid loss is inevitable in the well drilling and completion, which may cause series of formation damage such as clay swelling, solid plugging and water blocking. In tight sand gas reservoir, water blocking has become the major damage factor for economical developing. In deliverability test, water blocking will bring an inaccurate productivity test result to affect the following development strategy. With the development of East China Sea gas field, well drilling is focusing on the deeper tight sand formation. The tiny pore throat and high capillary pressure can bring out serious water blocking damage during well drilling and completion. The damaged zone can mislead the resource assessment and productivity evaluation. In this paper, an exploration well X in East China Sea gas field is selected as the research target to investigate the water blocking mechanism and physical process during well drilling and completion process. This study compares the productivity performance of X well with fluid loss and no fluid loss models through numerical modeling approach based on the actual data. Sensitive studies are also performed in the simulation. Results show that the excessive fluid invasion pressure and lower matrix permeability will result in serious water blocking damage to mislead the resource assessment and productivity evaluation even in underbalanced well drilling. Interestingly, extending shut-in time can make the gas production rate quickly reach the peak value in the early production stage, while it can decrease the cumulative gas production in whole production process. This study can provide an avenue to initiate quantitative analysis on resource assessment, and gas productivity evaluation strategy after water invasion during the well drilling and completion in tight sand gas reservoir of East China Sea.

Keywords: Tight gas reservoir; Fluid loss; Well completion; Water blocking; Deliverability test.

1. INTRODUCTION

Major breakthroughs of deep tight gas exploration were made at the East China Sea region in recent years and ten billion stored gas resources have been confirmed. But the main formation of this reservoir is usually at the depth of 3500~4500m with high temperature and high pressure (HTHP), low permeability and micro pores characterization, which allows the formation to be easily damaged during well drilling and completion. The most crucial damage is the water blocking and jamin effect caused by capillary resistance, which can dramatically decrease gas relative permeability and bring out inaccurate productivity evaluation for the tight sand gas layer. The most general phenomenon in exploration is that the gas layer is active, but the layer character in the test is of low permeability with low gas production, little water output and no commercial exploitation value. Well logging interpretation often gives an unusually high-water saturation, and the gas reserve calculation deviation is large. For deep tight gas reservoir, the effective development is difficult because of the harsh abysmal sea condition, while the tight gas reservoir at East China Sea is a typical example.

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To make a proper development strategy and achieve the maximum economic benefits of tight sand gas reservoir, the correct resource assessment and productivity evaluation become critically important. In tight sand gas reservoir, water blocking has become the major damage factor for economical developing. If we do not take any method to lower water blocking damage during well drilling and completion process, it will mislead project design and even lead to the failure of investment. Hence, it is usually a high-risk job for the exploration well drilling and completion in tight sand gas reservoir.

Hydraulic fracturing in vertical or horizontal wells is the common strategy in order to efficiently develop tight sand gas reservoirs [1]. However, hydraulic fracturing cannot be easily performed in offshore drilling platform due to the limited space in offshore platform. Due to different influence factor, especially the unavoidable well completion fluid loss, we usually get the abnormal high-water saturation and ultra-low productivity, which cause the delay of gas layer found and inaccuracy of productivity estimation. The issue of fluid loss/invasion has been widely studied in the past, Keelan and Koepf [2] noted that the reason for the decreasing of gas relative permeability is the occurence of water blocking. Holdicht [3] indicated that if the water saturation in pores is too high, the pressure of reservoir couldn't

E-ISSN: 2409-787X/20

overcome the capillary pressure after the well completion hence the ideal productivity cannot be obtained unless the water in pores is completely driven out. Bennion *et al*. [4] discussed the mechanism of water blocking in tight gas reservoir, the study pointed out that the controlling factor of water blocking is the gathering and retention of liquid in gas reservoir. The lower the permeability is, the greater the damage is. Zhou *et al*. [5] investigated the impact of different water saturation, flowing differential pressure, and wettability on water blocking through Poiseuille law. Wills *et al*. [6] used a two phase 3-D numerical simulation model to investigate hydraulic fracture cleanup for both slick water and gelled fluids, showing that the pressure drawdown, shut-in times, and perforation placement all had significant effect on fracture face damage and clean-up potential. Tsar *et al*. [7] studied the trap damage with water-based fluid compared with oil-based fluid in a tight gas reservoir. Bahrami *et al*. [8] analyzed the productivity with different initial water saturation and critical water saturation, indicating that S_{wi}（initial water saturation）might be normal, or in some cases, lower than S_{wc}（critical water saturation） due to water phase vaporization into the gas phase. The simulation study confirmed that the water blocking damage will be more serious with greater different value between the S_{wi} and S_{wc}. Ghanbari and Dehghanpour [9] indicated that controlling the fluid loss is the key to exploit a tight sand gas reservoir successfully.

As is shown in above studies, many different factors can affect the water invasion in the tight formation, which can cause serious formation damage to lower gas productivity. How and why the engineering factors and formation condition affect the resource assessment and productivity evaluation of East China Sea tight gas field is an interesting topic. In the deliverability test, accurate gas productivity will determine the economical production strategy. Hence, it is important to understand the actual deliverability and correct the productivity under the damage of water invasion.

In this paper, an exploration well X in East China Sea gas filed is selected as the research target to investigate the water blocking mechanism and physical process during well drilling and completion process. The influence of well completion fluid density, shut-in time, matrix permeability on water invasion, flow back and regained gas productivity are investigated. To achieve the goal of this study, a 3-D reservoir model for exploration well X is designed based on real data. The gas productivity with and without water block are simulated. Sensitive studies are performed to comprehend how the well completion fluid density, shut-in time and matrix permeability affect the gas production under water blocking in this tight gas reservoir. This study aims at quantitative analysis on how the well completion fluid loss affects the productivity data in deliverability test in tight gas sand reservoir. Technique results can be used a guideline to rectify deliverability test result and obtain the real reserves evaluation in exploration well.

2. FLUID LOSS IN WELL DRILLING AND COMPLETION

Water saturation is a key index in reserves evaluation and productivity assessment. Tight gas reservoir usually has a low initial water saturation (S_{wi}) because of evaporation and compaction before exploitation, amount of irreducible and immobile water saturation will be much higher due to the reduction in porosity and abundant micro-porosity. In initial situation, water in the pores can't flow until the water saturation exceeds the critical saturation (S_{wc}).When the tight gas reservoir is put into development, the drilling and completion fluid invasion can cause water saturation near the wellbore to increase from low value (S_{wi}) to mobility state. Holditch [3] studied the relative permeability in tight gas reservoir, the relationship between permeability and water saturation in tight gas reservoir was revealed. Ward and Morrow [10] did some work on capillary pressure and relative permeability in low permeability sandstones, they concluded that the capillary imbibition plays a key role in the water invasion.

As is shown in above figures, the water blocking mechanism can be briefly illustrated; the matrix of tight gas reservoir is filled with gas at the initial condition with a low water saturation due to vaporization and compaction. Once the formation is opened, the drilling and completion fluid invasion is unavoidable and relative gas permeability near the borehole will decrease sharply with the water saturation increasing. After the shut-in time, the retained water in pore throat is difficult to be driven out by gas flow due to the strong capillary pressure. Hence, the water saturation will stay at the irreducible section to bring out inefficient gas flow ability, and the deliverability test is not accurate and cannot reflect the real gas productivity.

3. RESERVOIR MODEL DESCRIPTION

3.1. Model Set-Up

Tight gas reservoirs normally have production problems due to very low matrix permeability and they may not produce gas with real rates under water blocking damage [11]. The damage is difficult to relieve without stimulation and advanced completion techniques, so we usually get inaccurate productivity in the deliverability test. In this paper, we use CMG-IMEX simulator to study the effect of well completion fluid loss in the tight gas reservoir based on the real data of the exploration well X from the East China Sea. The simulator is a widely recognized software to model gas production based on black oil model. Exploration well X is at the depth of 4200 m under the sea level. To restore the real formation condition, we set the matrix permeability according to the reservoir core analysis data which shows that the formation permeability ranges from 0.17mD to 0.67 mD at different depths. The initial pressure and temperature is 53.5 MPa and 170.8℃ respectively, indicating that the gas reservoir is a typical HPHT tight sand gas reservoir. The model is based on a 19×19×13 cartesian grid in the X, Y, and Z direction, respectively. Figure **1** shows the total reservoir volume is 170m×170m×100m. An injection well is set at the center of the model (grid 10, 10, 1to11) to simulate the well completion fluid loss process. Figure **4** shows a producing well X is set at the same location to simulate deliverability test.

The local grid refinement (LGR) with logarithmic cell spacing method is employed to reduce the numerical dispersion effect especially for capturing accurate water distribution during well completion fluid loss and flow back. Capillary pressure is the crucial factor for water suction and retention, capillary hysteresis is also observed in the lab experiment. We set the capillary pressure and capillary hysteresis in the model referring to the lab data (Figure **2**). The flooding experiment is conducted in the lab. Figure **3** depicts the relative

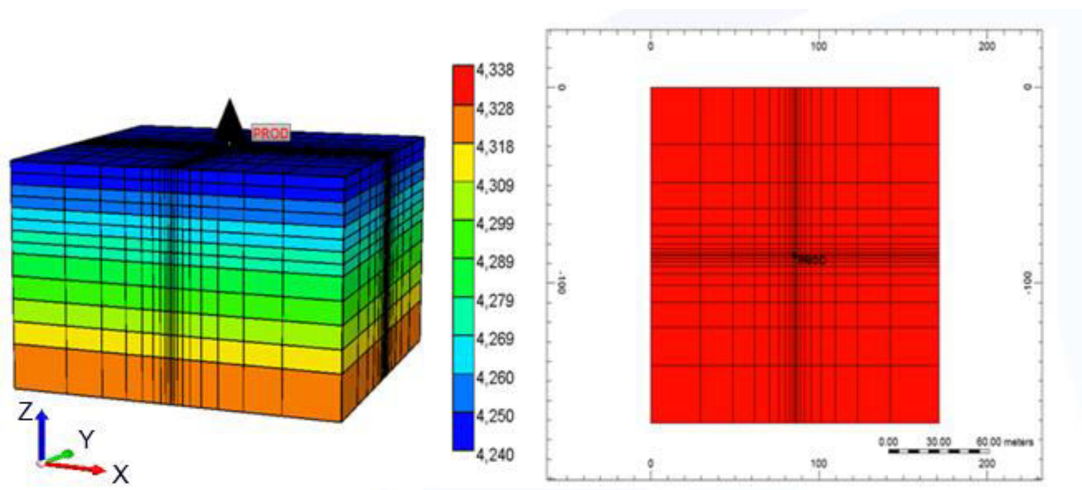

Figure 1: Reservoir model 3-D view and planform (showing grid sizes in X, Y and Z directions).

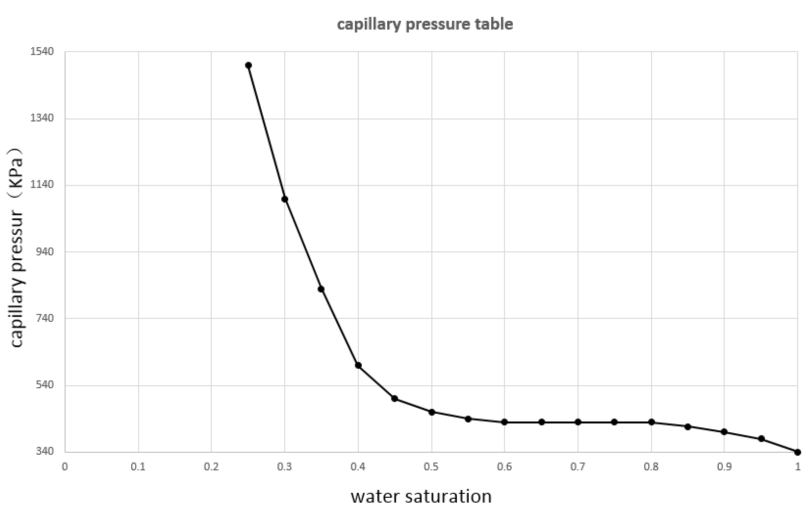

Figure 2: The relationship between water saturation and capillary pressure (data from tight gas reservoir in East China Sea, 2013).

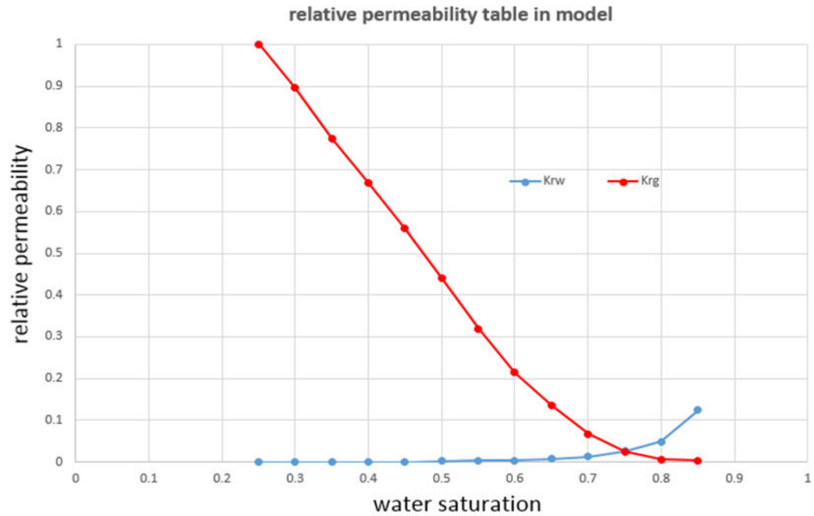

Figure 3: Relative permeability curves used for simulation (data from tight gas reservoir in East China Sea, 2013).

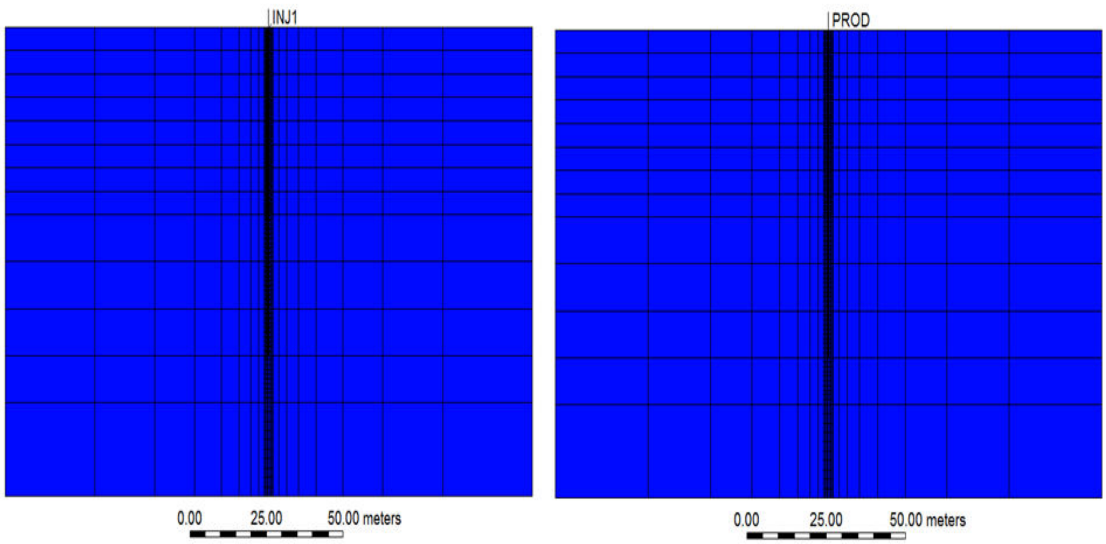

Figure 4: X well position in the model (injection and production well are in the same perforated zone).

Table 1: Base Parameters of Simulation Model

No. of Grids in x, y and z Directions	Reservoir height (m)	Reservoir Permeability (mD)	Matrix Porosity (%)	Gas S.G (air=1)
19*19*13	100	0.17-0.67	9	0.7
Critical water saturation	Initial water saturation	Initial pressure (kPa)	Reservoir temperature (^{o}C)	Gas-water contact
0.55	0.25	53500	170.8	4500m

permeability curve in this model after summarizing the expatiatory lab data. More details about this model are summarized in Table **1**.

3.2. The Model Calibration

The deliverability test lasts about one month, after 20 days of shut in time, the well is opened three times with four different diameter flow nozzles to observe gas productivity and monitor bottom hole flow pressure. To match the deliverability test data, we mainly adjust the uncertainty parameters such as relative permeability curves, capillary pressure and capillary hysteresis to perform model calibration. Figure **5** shows that the model validation result matches well with the historical

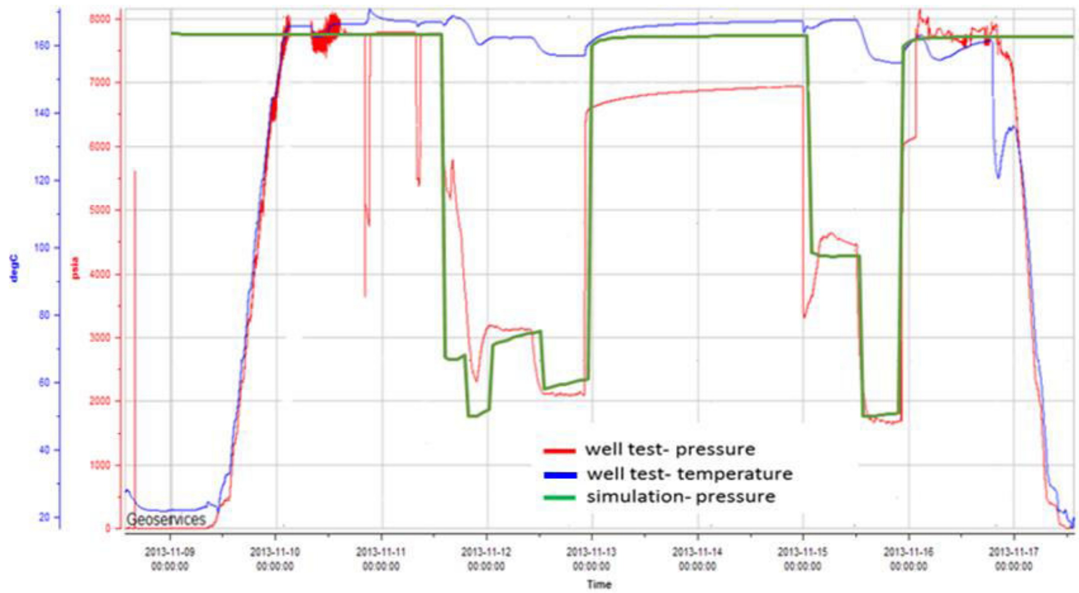

Figure 5: Test history data match of well bottom pressure.

Table 2: Pressure and Production History Match with Four Different Flow Nozzles

Flow Nozzles (mm)	Test Pressure (kPa)	Simulation Pressure (kPa)	Error
4.76	21472	20500	4%
6.35	14366	14680	2%
3.18	30654	29500	3%
7.14	11420	11900	4%
Cumulative gas production	test cumulative gas production (m^3)	simulation cumulative gas production (m^3)	error
	83892	89910	7%

pressure data. More details are summarized in Table **2**. Hence, the calibrated model can be used for the subsequent study.

3.3. Productivity Evaluation under the Fluid Loss

The small amount of well completion fluid invasion can induce serious formation damage in tight sand gas reservoir. We observe the water invasion in the 3-D result, which shows that the invasion water is difficult to be removed even in the great drawdown pressure of production. In the deliverability test, the water saturation near the borehole increased from initial 25% to the peak value of 68% after 3 days fluid loss. Figure **6** shows that the water saturation keeps at about 45% during the whole deliverability test, which is obviously higher than the initial water saturation and the gas relativity permeability is seriously damaged.

Figure **7** compares the difference of absolute open-flow capacity for the two scenarios, indicating that the absolute open-flow capacity without fluid loss is almost three times as fluid loss considering case. The gas rate from the simulation indicates the gas reservoir is expected to have favourable productivity without the fluid loss in the depletion development.

Figure **8** shows the variation of well bottom-hole pressure after well completion when production with constant gas rate of 50000m^3/d in 10 days. We can see that the fluid loss model needs more pressure drop to maintain the gas rate comparing with the no fluid loss model.In Figure **9**, after 7 years production with gas rate of 50000m^3/d, the cumlative gas without fluid loss reaches at $5.5\times10^7 m^3$ and the model with fluid loss can only reaches at $4.9\times10^7 m^3$. For no fluid loss model, the

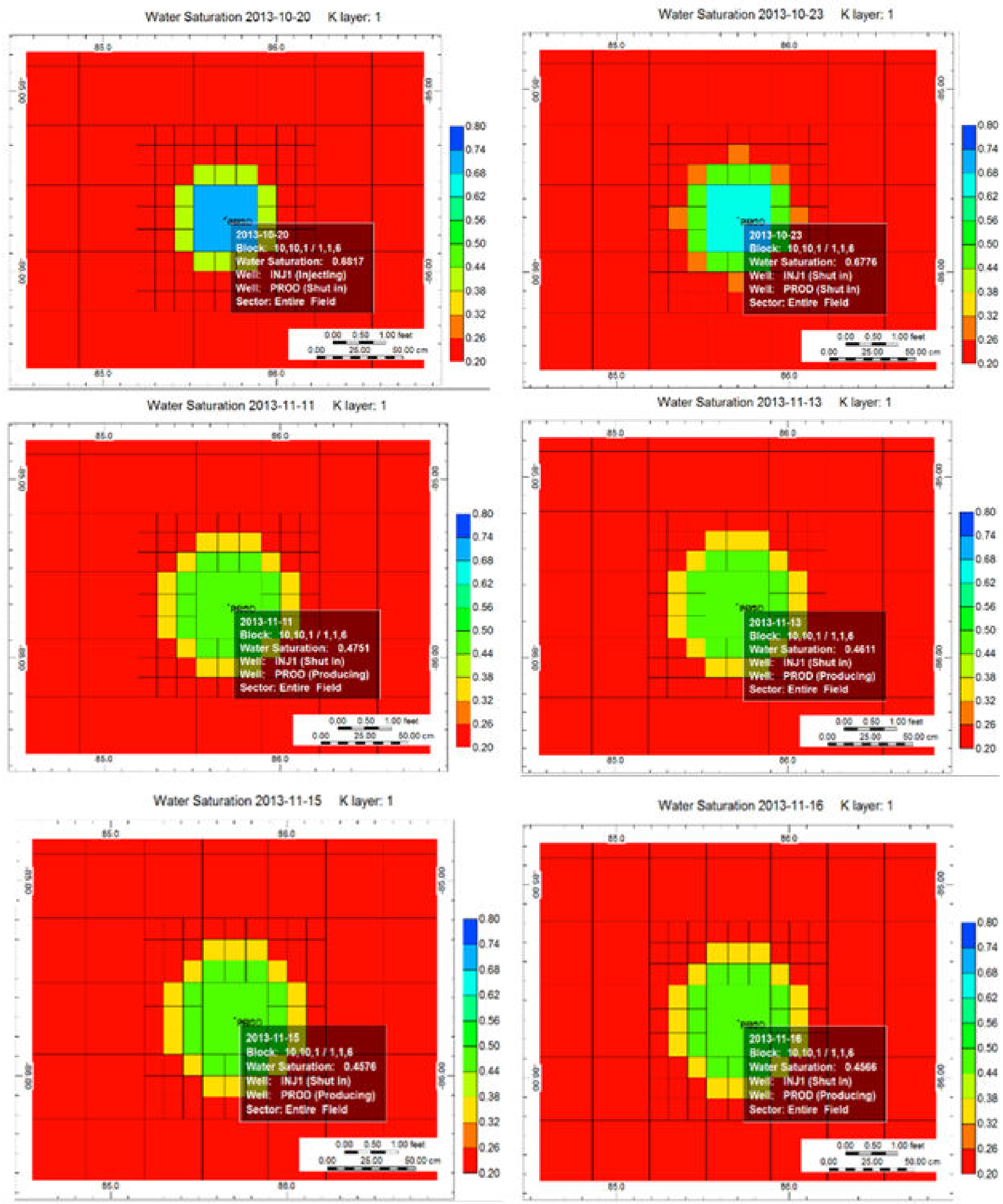

Figure 6: Change of the water saturation near the wellbore (grid10,10,1) in the simulation.

stable gas production period lasts about 700days, while only last about 350 days for fluid loss considering model as shown in Figure **10**. What is interesting is that the productivity drop rate of the model with fluid loss is slower than the no fluid loss model and it keeps a higher gas rate in the last period of production.The possible reason is that the retention water in the pores offer the potential pressurization of gas reservoir to withstand pressure decline.

4. SENSITIVITY ANALYSIS

4.1. Effect of Well Fluid Density on Productivity Evaluation

Proper choice of working fluid can guaranty the success of well drilling and completion, different density fluids mean different wellbore pressure, which can be used to determine the invasion volume, depth and

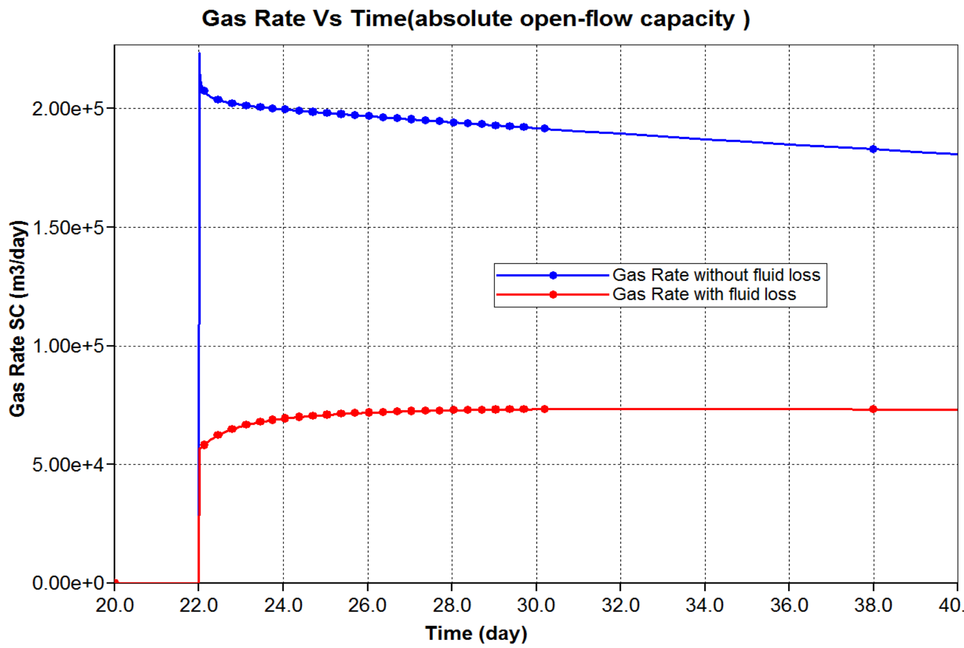

Figure 7: Absolute open-flow capacity without fluid loss and with fluid loss.

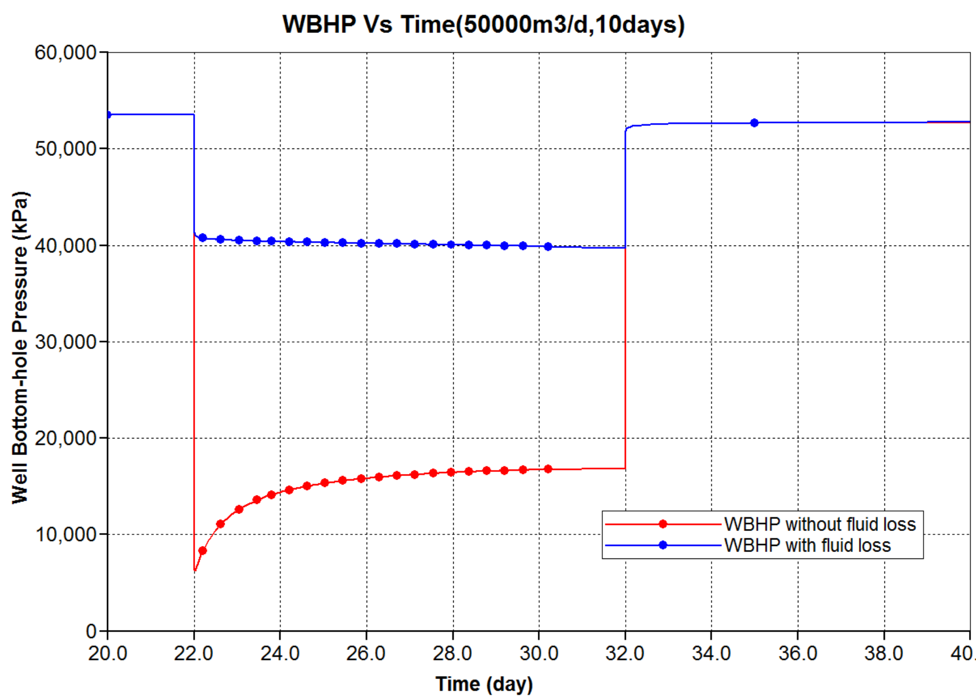

Figure 8: The change of well bottom-hole pressure with constant gasrate of 50000m^3/d in short time.

velocity to evaluate formation damage [12]. In normal well completion process, the fluid loss rate increases with the increasing of positive pressure differential, the high quality filter cake cannot be formed if the positive pressure differential is too low or may be breakdown by a higher positive pressure differential to make a greater invasion of the solid and water. In balanced and overbalanced drilling, the water is more easily to be sucked by the strong capillary pressure, resulting in serious water blocking [13].

Several models of different invasion pressure are built to represent the different fluid density. We set the 53500 kPa as the reference and balanced drilling pressure, underbalanced pressure is set at 53400kPa, 53300kPa, 53200kPa and 52500kPa, respectively.

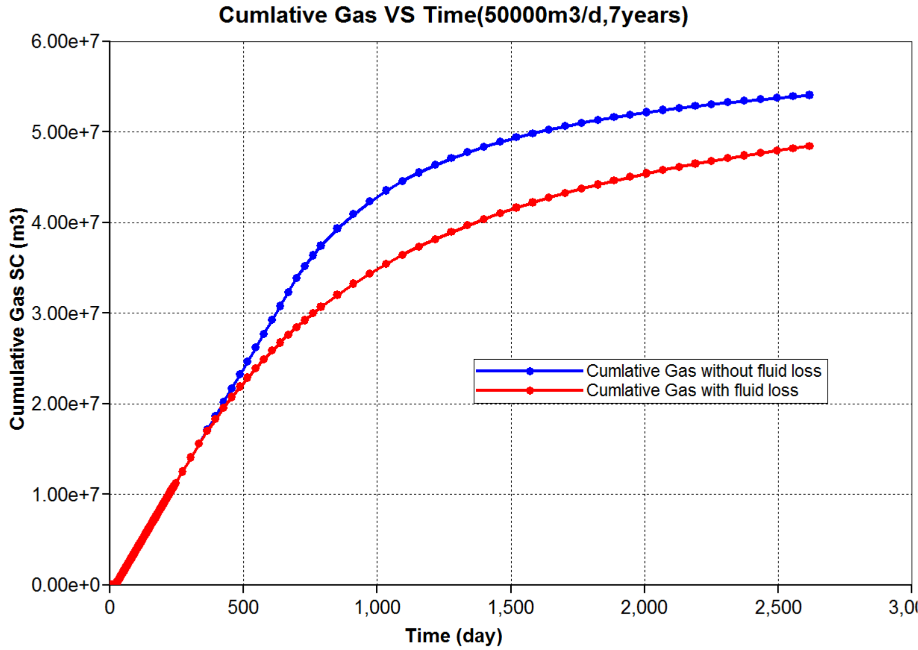

Figure 9: The cumulative gas production with the constant gasrate of 50000m^3/d in long time.

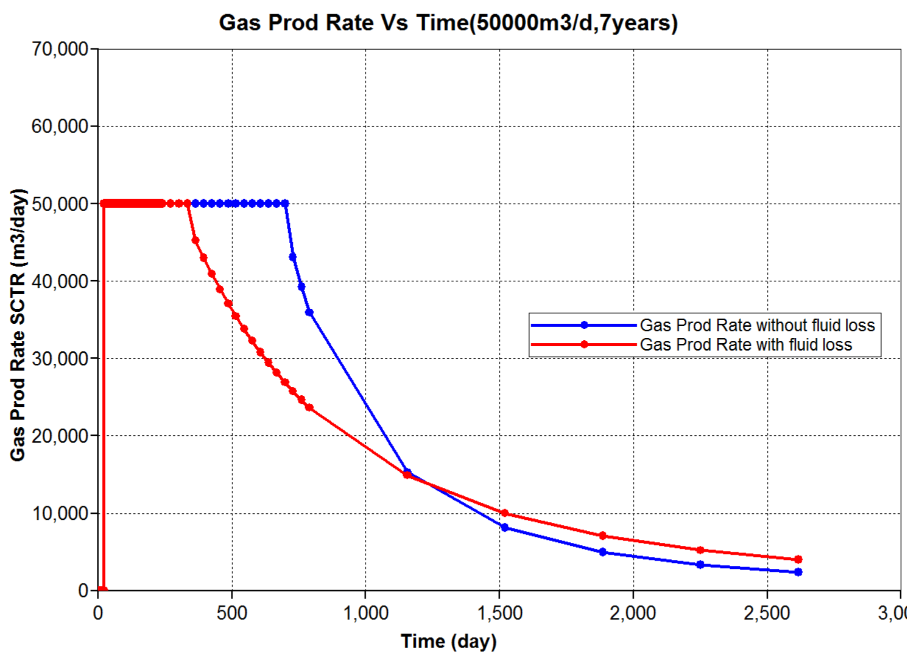

Figure 10: The change of well bottom-hole pressure with the constant gas rate of 50000m^3/d in long time.

Overbalanced pressure is set at 53600 kPa, 53700 kPa, 53800 kPa and 54500 kPa, respectively. According to the simulation result, we can see that the water loss still exists even the invasion pressure below the initial reservoir pressure. This is because of the capillary pressure has a strong suction ability and the negative pressure during underbalanced well drilling still cannot overcome the imbibition. Figure **11** shows that the fluid loss volume is increased with the increasing of invasion pressure. Figure **12** shows that the gas rate drops down obviously with the increasing of fluid invasion pressure, we can see the gas rates are almost the same after the overbalanced drilling. It infers that when the invasion pressure increases to a certain value (equal to well completion fluid density increases to a certain value), the gas rate will keep at stable value, which means that the invasion pressure is no more the influence factor for the gas production when it exceeds this critical value.

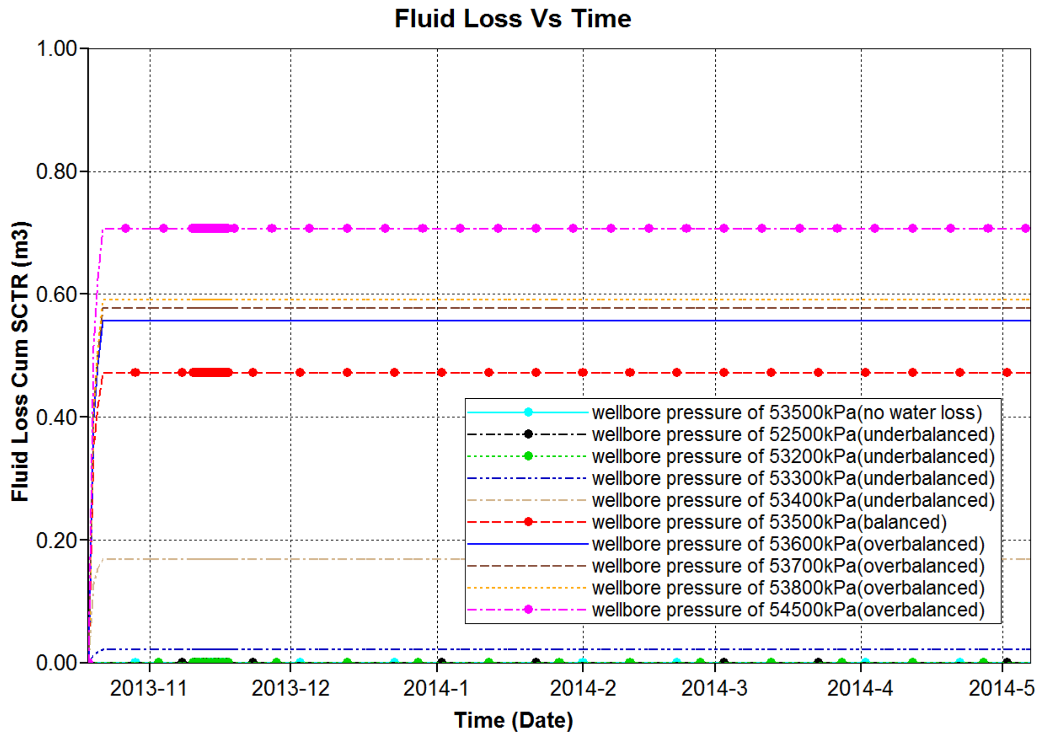

Figure 11: The fluid loss volume with the change of wellbore pressure.

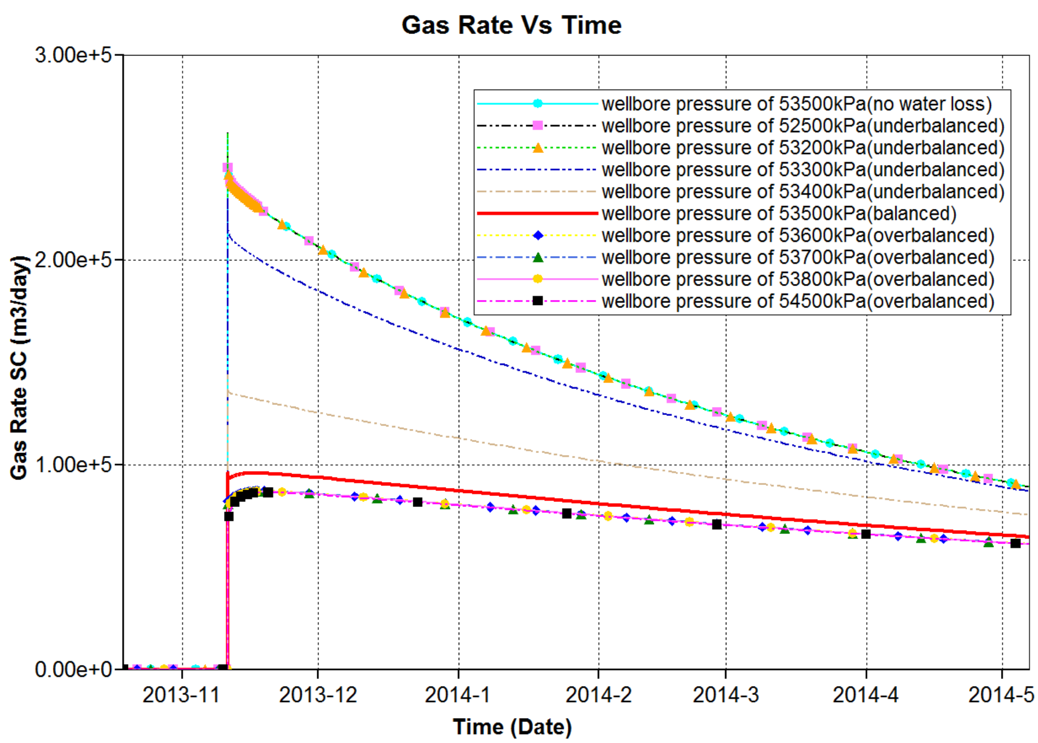

Figure 12: The gas rate with the change of wellbore pressure.

4.2. Effect of Shut-in Time on Productivity Evaluation

There is always shut-in time between the opening of formation and deliverability test, the shut-in time is controlled by the climate, human resource, equipment and working efficiency, so the shut-in time is an uncertainty factor. In this section, we investigate the effect of different shut-in time on the gas production during deliverability test. Therefore, four different simulation cases with 50, 100, 150 and 200 days of

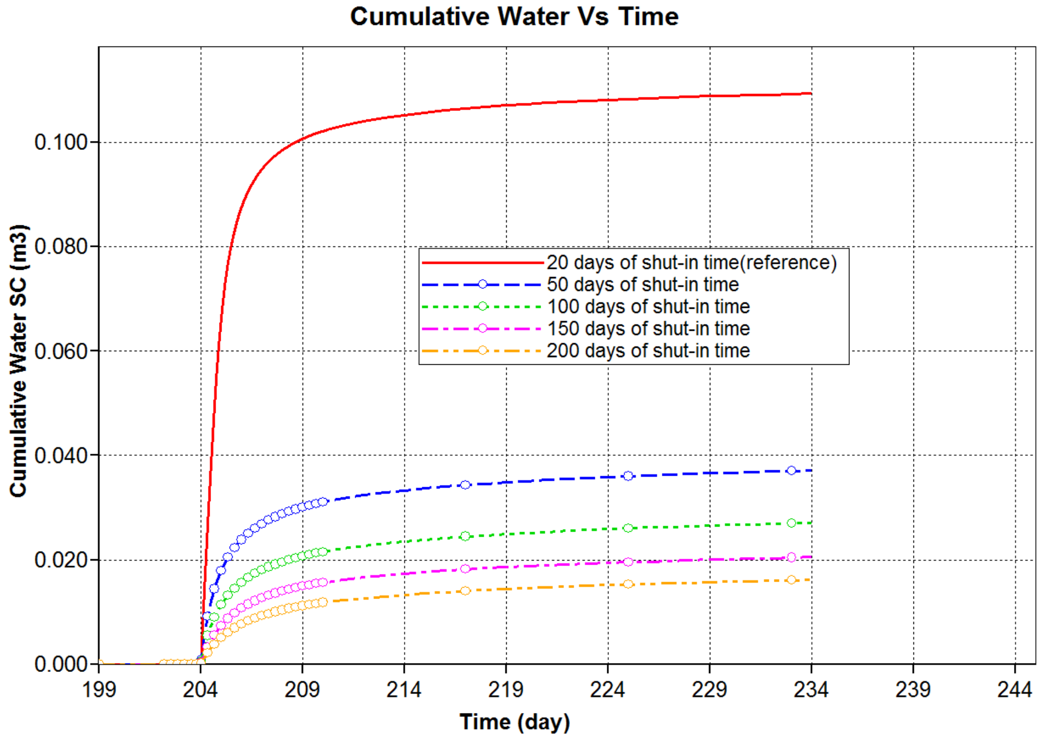

Figure 13: The cumulative water production afterdifferent shut-in time.

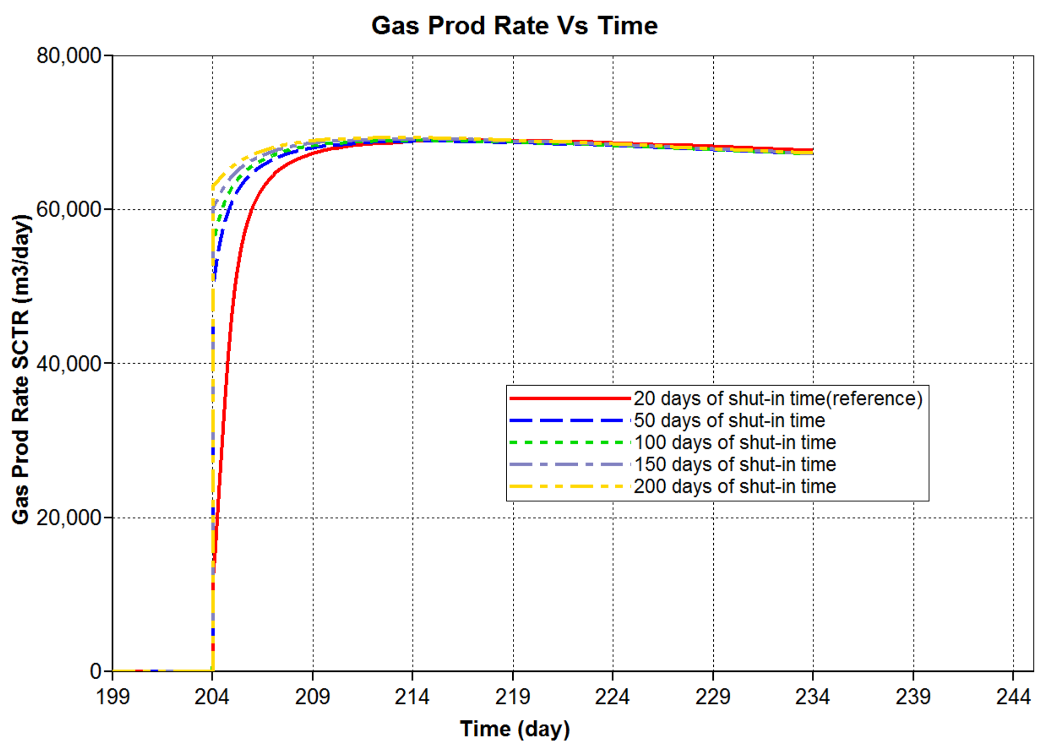

Figure 14: The gas rate after different shut-in time.

shut-in time are established. 20 days of shut-in time is set as the reference（actual shut-in time for exploration well X). Figures **13** and **14** show that the cumulative water production and gas production rate after different shut-in time. With the increasing of shut-in time from 50 days to 200 days, the water production decreases significantly as shown in Table **3**, which means more water is restricted in the pore throat. The simulation result shows that the water recovery ratio is ultra-low due to water blocking. So much water near the wellbore

Table 3: Water Invasion with Different Shut-in Time

Shut-in Time	Water Loss Volume	Cumulative Water Production	Water Recovery
20days	0.9073m^3	0.1093m^3	12.0%
50days		0.0370 m^3	4.07%
100days		0.0271 m^3	2.98%
150days		0.0205 m^3	2.25%
200days		0.0161 m^3	1.77%

is supposed to cause serious damage to the gas flow. But in the early production stage, Figure **14** illustrates a interesting phenomenon which a longer shut-in time brings a faster gas rate peak, this is due to strong counter-current water imbibition which can result in more free gas to be driven from the micro pores to the bigger throat during the longer shut-in period. This is like the gas production performance after fracturing fluid flow black reported by Ghanbari and Dehghanpour [9]. Considering that the mobility of gas is higher than water, when the well is opened for deliverability test, more free gas will be extracted in the early production time after longer shut-in time. Hence, the “abnormal” peak gas rate is exhibited. This phenomenon can be used as reference to improve the understanding of peak oil or gas rate shown during fracturing fluid flow back in tight reservoir.

4.3. Effect of Matrix Permeability on Productivity Evaluation

What make the tight gas reservoir differ from conventional gas reservoir is the ultra low permeability and porosity. Law and Curtis [14] defined the tight gas reservoir as the one whose permeability is below 1 mD. In this section, to study the effect of matrix permeability on productivity evaluation, 4 models with different matrix permeability of 0.001mD, 0.01mD, 0.1mD and 1mD are set and simulated. The damage degree of water invasion in different tight gas reservoir is calculated and compared. With the decrease of the matrix permeability, the leak-off of completion fluid become more difficult and the water saturation near the wellbore will stay at a high level even after a long production time as shown in Figure **15.** Figures **16** and **17** show that the open flow capacity without and with water invasion for the 4 models. Results show that the water invasion radius decreases, and the damage degree is improved with the decrease of reservoir matrix permeability. The productivity damage degree reaches at 83% for the case of 0.001mD matrix permeability as shown in Table **4**, which illustrates that the tighter reservoir can bring out serious formation damage caused by water invasion. Because micropores and strong capillary imbibition dominated in

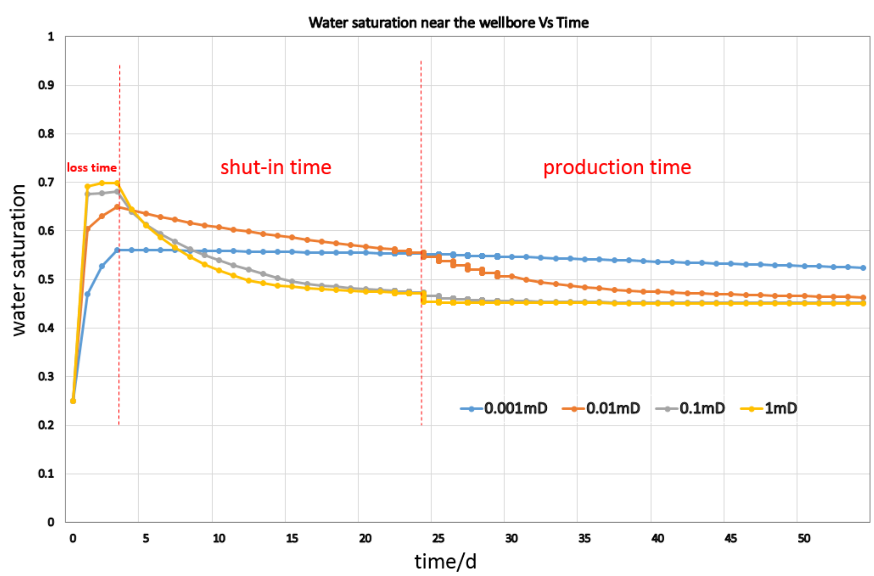

Figure 15: Water saturation near the wellbore (grid 10,10,1) during the simulation.

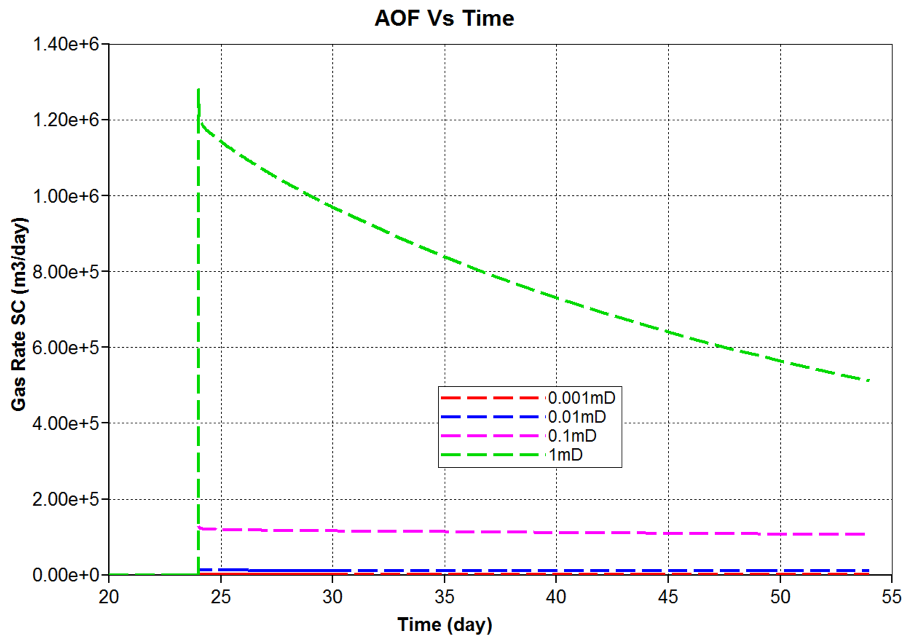

Figure 16: The open flow capacity without water invasion.

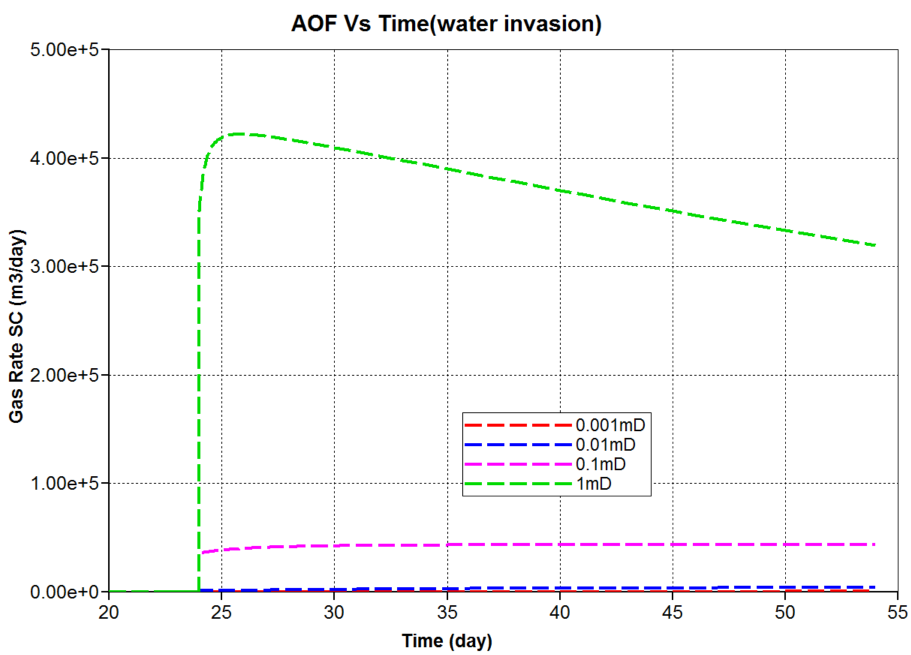

Figure 17: The open flow capacity with water invasion.

the ultra-low permeability reservoir and it is difficult to drive the retention water out from the trap zone even with large pressure drop.

5. CONCLUSIONS

- Well completion fluid loss is unavoidable during well drilling and completion in tight sand reservoir, which can cause water blocking and other potential damage. Hence, the deliverability test is often inaccurate, and it will mislead the resource assessment and productivity evaluation. Reservoir simulation is a useful tool to rectify the evaluation result.

- For the target exploration well X in East China Sea, the simulation result shows that the absolute open-flow capacity with no fluid loss is about three times as the case with fluid loss. The inaccurate deliverability test could make us take wrong development strategies.

Table 4: Different Damage Degree of Different Permeability

Permeability (mD)	Density of Completion Fluid (g/cm^3)	Invasion Radius (m)	Productivity without Water Invasion (m^3/d)	Productivity with Water Invasion (m^3/d)	Damage degree (%)
0.001	1.35	0.2	1212.32	208.747	83
0.01	1.35	0.5	11769.5	3861.18	68
0.1	1.35	1.8	106595	43243.4	60
1	1.35	3.5	511700	319519	38

- The positive pressure in wellbore depends on well completion fluid density, which can affect the invasion of water through the wellbore pressure it offers. Underbalanced drilling might help to reduce the water blocking. However, due to the strong capillary suction in the formations and weak mud cake, the water will invade the near wellbore zone even in the underbalanced drilling if the negative pressure is not high enough to overcome the capillary imbibition. However, balanced drilling and overbalanced drilling can aggravate the invasion depth, resulting in more serious damage to the productivity. While the positive pressure is no more the influence factor for the gas production when it exceeds a critical value

- Longer shut-in time means longer loss fluid diffusion, larger invasion range, and further water invasion near the wellbore. The retention water will impede gas flow and reduce the productivity, but in the early time of production, the gas rate will quickly reach the peak value with longer shut-in time. Because the longer shut-in time means more gas in the micro pores can be driven into the bigger throat through capillary imbibitions during water invasion. This phenomenon can be used as reference to improve the understanding of peak oil or gas rate shown during fracturing fluid flow back in tight reservoir.

- With the decrease of matrix permeability in tight gas reservoir, the water invasion radius decreases, and the productivity damage becomes more serious. The productivity damage degree can reach at 83% for the case of 0.001mD matrix permeability. Ultralow permeability and porosity mean more micro pores and strong capillary imbibition, once the fluid loss occurred, the water is easily to be imbibed into the pores and difficulty to be clean up.

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Received on 11-05-2020 Accepted on 29-06-2020 Published on 09-12-2020

DOI: https://doi.org/10.15377/2409-787X.2020.07.3