BETTER WATER PRODUCTION FORECASTS FOR ENHANCED PERFORMANCES

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Key words : UGS, water production, performance

INTRODUCTION

European gas flexibility context

The days of strong year-on-year growth in European natural gas demand are gone. The residential, commercial, and industrial sectors will stagnate or decline, with growth limited to the power generation sector. The growing intermittency of the latter, due to the increased renewable generation, is leading furthermore to gas backup needs.

The supply picture is also changing as new import routes open up and indigenous production declines (the role that unconventional sources could play in Europe remains unclear so far).

This new picture is leading to increasing seasonal and short-term flexibility requirements, providing support for underground gas storage (UGS) and strengthening the key role UGS will have to play in the future.

Europe currently has around 90 bcm of working storage capacity. Capacity in Germany, Italy and France accounts for more than half of the total working storage capacity in Europe.

The majority of storage capacity relies on depleted fields - 70 percent of the European total - with 19% relying on aquifers and 10% on salt caverns. Salt cavern UGS are mainly located in a narrow band in Northwest Europe. UGS facilities in Central and Southeast Europe are almost entirely depleted fields, while in France aquifer storage facilities dominate, accounting for 92 percents of French storage capacity.

Aquifer storage facilities are converted from naturally occurring underground water reservoirs. They are extensively used worldwide usually for seasonal storage rather than fast deliverability, and thus operated on a single annual cycle (gas injection in summer and gas withdrawal in winter).

However, the recent years have seen the development of multi-annual gas cycling to optimize the value of the facilities. Moreover, where a number of aquifer facilities are in common ownership, high degrees of flexibility can be created and marketed for example by using some facilities for injection and some for withdrawal at any point in time.

Storengy's commercial offer in France is built upon grouping 13 aquifers and salt caverns UGS in order to combine their physical characteristics and thus creating a wider flexibility product line for our customers.

Storengy is an affiliate of GDF SUEZ dedicated to the underground storage of natural gas. With a total storage capacity of 12.5 bcm, Storengy is the first natural gas storage operator in Europe.

Storengy's know-how, acquired over the past fifty years, is used to develop, operate and commercialize natural gas storage capacities in several countries. Storengy is one of the few companies with recognized expertise in technical, economic and regulatory areas, covering all UGS technologies.

Impact in terms of performance and operations

The above described new operational conditions have stressed the need to improve both the pressure and water history matching of the numerical models used for storage performance evaluation and daily withdrawal follow-up. This is of a major concern at the end of the gas withdrawal period, which is critical to evaluate the gas storage deliverability. Another concern is the management of the produced water. Currently in France, it cannot be re-injected in the reservoir and has to be handled outside. This work is focused on the recent efforts made to improve the reliability of the water production prognosis by different approaches.

Contribution of this work

This work is focusing on the description of several approaches that were developed and implemented to improve the water production forecasts.

The first part of the paper is dedicated to a state of the art on the relevant mechanisms at the origin of the water production and the approaches available to model them either at a local scale (well) or at a global scale (site).

Several field cases are presented to illustrate how such methodologies were integrated in our in-house workflow and how they can provide strong indicators to anticipate, reduce the water production and therefore enhance the performance by steering the injection/withdrawal strategy:

- The examples related to the forecasts at the well scale will emphasis the ability to anticipate and limit the coning effect (suction of the gas/water interface).
- The examples dedicated to large scale simulation clearly put in light the importance of a rigorous reservoir description (petrophysic and geologic) to obtain relevant water production evolution as a function of time.

The multi-annual gas storage behavior in term of water production is discussed in the next part. Because a given level of storage cycling corresponds to a given equilibrium state with the aquifer, increasing the gas withdrawal mode makes the aquifer adapt (time dependent). It leads to amplified water saturation variations leading to a water production increase over several years. This effect is highly dependent on the reservoir properties (water saturation hysteresis) and also the aquifer activity.

Finally conclusions and perspectives are drawn about the results obtained using these revisited approaches and their ability to better anticipate future performances of storages under non standard operational modes.

MECANISMS RESPONSIBLE FOR WATER PRODUCTION

The water production is a wide issue that impacts both the E&P and the UGS activities:

- E&P: when the aquifer is active, the water table (level) can evolve as a function of time during the field depletion leading to high water cut at the end of the production period. Nevertheless, a pressure maintenance is often needed by gas or/and water injection and a special attention must be paid on the well placement in order to prevent the injected fluids to breakthrough too quickly at the production wells. (Craft and Hawkins, 1990). Depending on the fluids availability and the reservoir configuration, gas and water injections can also be combined (simultaneously or alternatively) to better control the water front movement (Christiansen et al., 1998).

- UGS: when storages are developed in depleted reservoirs (oil or gas) with active aquifers or directly in deep aquifers, the pressure cycles lead to annual lateral and vertical movement of gas/water interface (Tek, 1987; de Moegen and Giouse, 1989). In order to limit the water production, it is therefore important to monitor the gas withdrawal rate as a function of the well positions towards the central part of the storage (lateral interface) and also their structural position (bottom interface).

In the gas/water context, three mechanisms are the main water production drivers: the reservoir heterogeneities, the petrophysical properties and the gravity segregation control.

Reservoir heterogeneities

The most important heterogeneities are faults/fractures and preferential permeability pathways due to the geological depositional mode (fluviatil, eolian,…) and/or secondary phenomena (erosion, subsidence, diagenesis, …). An integrated approach is recommended to identify them. For example, seismic can only detect significant faults whereas well imaging and well tests are often used in addition to characterize the subseismic resolution fractures.

Petrophysical properties

<u>a key input</u>

The multiphase flow of gas and water in porous medium is governed by the generalized Darcy equations which introduce the concept of effective and relative permeability (K_r). These very important parameters rule out the flowing properties of both phases as a function of their own saturation. The petrophysical property "hidden" behind the relative permeability is the capillary pressure (P_c) because it determines the saturation state according to the pressure in the gas and the water phase. Both K_r and P_c are therefore important, to obtain a relevant picture of the fluid distribution and mobility in the reservoir.

In practice, capillary pressure is often neglected at the reservoir scale in a gas/water context. If this assumption can be applied when the lateral pressure gradients are usually moderate within the reservoir (E&P context), it is none valid in the context of UGS where significant pressure variations occur as a function of time (especially at high solicitation mode).

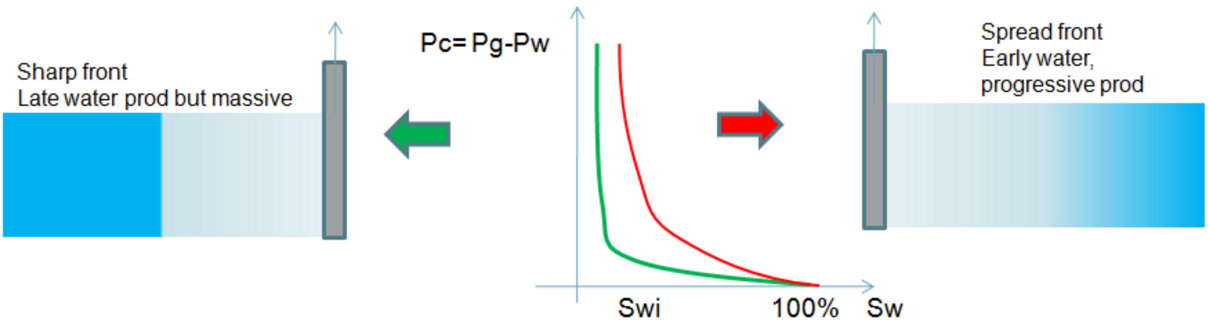


Figure 1: Importance of capillary pressure on the shape of water saturation front

The Figure 1 illustrates how the shape of the P_c curve can affect the shape of the water saturation front during withdrawal and impact the type of water production:

- When capillary forces are small (high reservoir permeability), the water displacement is rather piston like (sharp front). In this case, the water production comes late but is significant afterwards.
- When capillary forces are high, the water front is more spread leading to early mobility of the water but with a progressive increase.

A proper characterization the petrophysical properties in the laboratory associated with a history matching of the water production are therefore key steps to fix the level of capillary forces in a simulation model (examples shown in the next part).

Hysteresis effect

An additional complexity is provided by the hysteresis effect which states that the gas and water distributions within the porous medium differ depending if the gas saturation increases (drainage) or decreases (imbibition). Hysteresis is due to fluid rearrangements at the pore scale (snap-off, film flow, ..) as described by Lenormand et al. (1983). It leads at the end of the imbibition process to a trapped gas saturation (Sgr), which is completely disconnected and therefore non mobile (Billiote et al., 1993). Typical Sgr values range between 20-40% depending on the reservoir (Suzanne et al., 2003). The Land equation (1968) is often used to deduce the trapped gas saturation from the initial one (Sgi).

$$\frac{1}{S_{gr}} - \frac{1}{S_{gi}} = C$$

where C is a constant representative of the reservoir rock and Sgi the initial gas saturation before imbibition.

As hysteresis changes the fluid distribution, it conducts to important changes in terms of fluid mobility and therefore to a very large impact on the relative permeability curves (Figure 2). This has been shown by core measurements in a two or three phase context by a large number of experimental studies (Colonna et al., 1972; Braun and Holland, 1995). This hysteresis is introduced in the numerical through interpolation and renormalization techniques from bounding curves in order to obtain the intermediate P_c and K_r curves whatever the saturation path (Killough, 1976; Carlson, 1981)

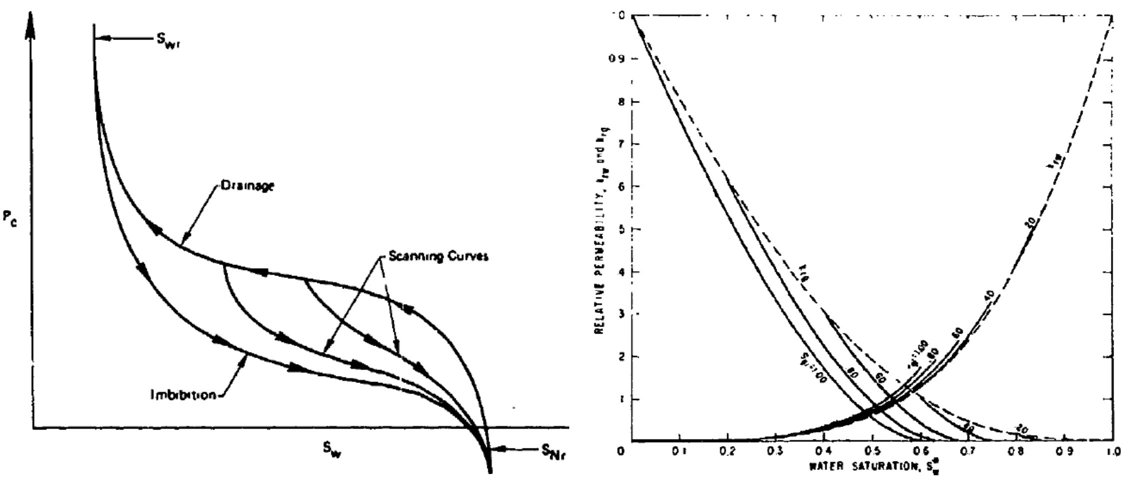


Figure 2: Hysteresis effect on capillary pressure and relative permeability curves

Because the storage activity induces frequent changes between drainage and imbibition modes, large parts of the reservoir are affected by hysteresis. It is therefore of primary importance to account properly for these mechanisms in the models and to parameterize them in a careful manner.

Gravity segregation control (to prevent coning or cusping)

All along the injection and production phases, there is a permanent competition between the viscous forces (resulting from the pressure drop to produce the fluids) and the gravity forces (resulting from the density difference between the gas and the water phases). During injection, the gravity tends to limit the fingering in the reservoir (digitations) since it favors segregation of gas in the upper part of the reservoir. During withdrawal, the gravity helps maintaining the water in the bottom part of the structure. Nevertheless, for a given distance between the well and the gas/water interface, the gravity force has a maximum value whereas the viscous force can vary according to the gas flowrate required on the well. It is therefore important to adjust the gas withdrawal rate so that the gravity force remains predominant and can play its stabilizing role to prevent the water from breaking through at the well. This effect is called coning or cusping depending on the water is coming respectively from the bottom or the lateral gas/water interface.

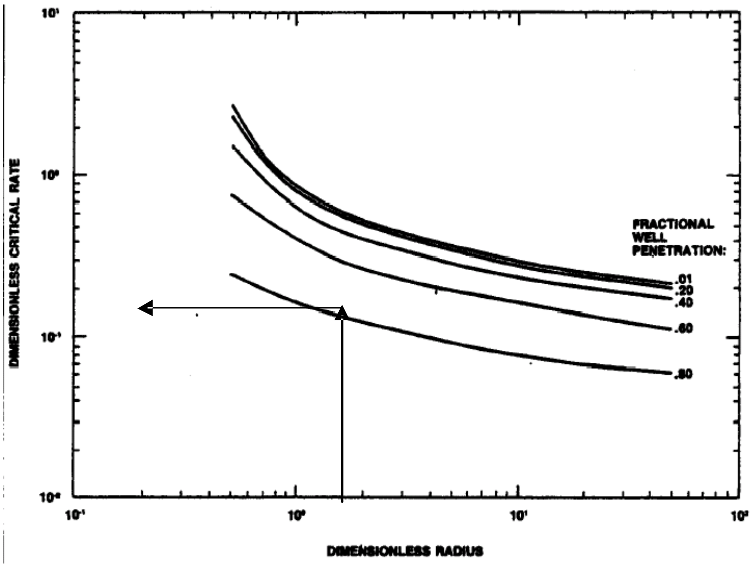


Figure 3 : Chart Q_{cD} versus r_D for several well penetration values (Hoyland et al., 1989)

The principle of the available coning models is based on the early works from Muskat et Wyckoff (1935) progressively improved by several research groups (Hoyland et al., 1989). The critical rate to avoid coning is obtained using a chart which provides adimensional variables Q_{cD} (gas rate) as a function of r_D (drainage radius) for several percentages of the well penetration (distance between the well bottom and the interface) :

$$Q_{cD} = \frac{40667 \times \mu_g \times B_g}{h_t^2 \times (\rho_w - \rho_g) \times k_H} \times Q_c$$

$$r_D = \frac{r_e}{h_t}\sqrt{\frac{k_V}{k_H}}$$

Once r_D and the well penetration calculated, Q_{cD} is deduced from the chart (Figure 3). Then the critical flowrate Qc can be easily obtained from the reservoir properties in the vicinity of the well.

Several types of well configurations towards the coning effect are illustrated in Figure 4:

- At moderate gas flowrate, the bottom gas/water interface is deformed in the vicinity of the well but there is no direct connection with the well (recommended operating mode at low water/gas ratio).
- At gas flow rate exceeding a critical value Qc then a direct connection is established with the well and the water production increases dramatically. As stated by the above described equation, the main drivers are the reservoir permeability (horizontal and vertical) and the distance from the interface. As this distance evolves with the inventory of the storage, it means that the critical rate value must be adjusted all along the withdrawal.

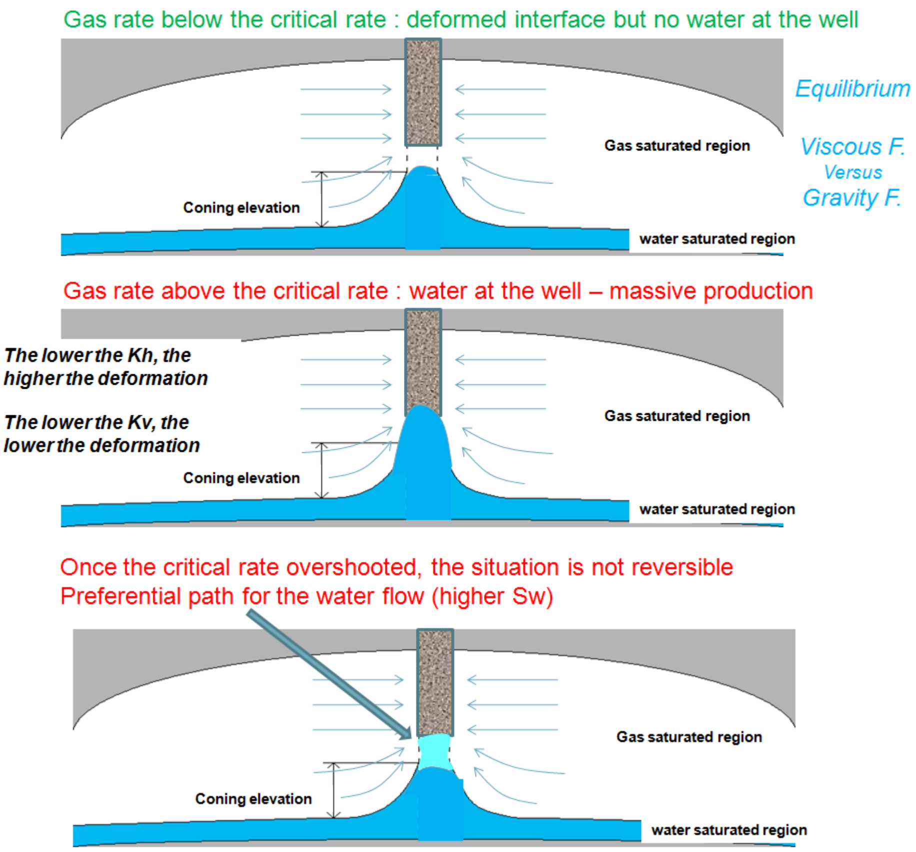


Figure 4: Coning water production mechanism

- The coning is also hysteresis sensitive. In the case the critical rate was overshooted and decreased rapidly back again, then a preferential water flow path remains between the gas/water interface and the well. It makes the value of the critical rate be lower comparing to the initial condition and reduce considerably the capacity of the well for the end of withdrawal. In this case, the possible remediation solutions are either to re-inject a significant volume of gas to decrease the water saturation in the by-pass area or to set up a non permanent plug in the well in order to reduce the producing level to the upper part.

The example below (Figure 4) illustrates that the coning effect must be anticipated by adequate recommendations per well in order to remain in the optimized configuration during the withdrawal.

MODELLING OF THE WATER PRODUCTION

Well scale

Two approaches have been followed. The first one consists in modeling the coning effect at the well scale and identifying if massive water production observed for some wells could be attributed to this effect. The second one aims at taking into account the outputs from this model to set up relevant recommendations per well to avoid coning for the forthcoming withdrawing campaigns.

<u>Coning modelling</u>

As an accurate deformation of the gas/water interface in the vicinity of the different wells requires a very fine gridding with numerical models (and therefore significant CPU resources), analytical or semi-analytical approaches are very suitable in this case compared to 3D models. Roughly more than 1 million cells using this approach would be needed to refine sufficiently the model, especially in the vertical direction, which is not compatible with the fast performance calculation time required for operational support.

The formalisms described in the previous section have been implemented in an existing code which is a fully implicit in-house simulator with a 1D radial geometry taking into account the structural shape of the reservoir (Schaaf et al., 2008; Egermann et al., 2009). The main advantage of this code is its computing performance (fast calculation time) and its ability to include all the parameters that rule the behavior of the saturation profile and the pressure (K_r and P_c with hysteresis). This code is used on a routine basis for operational purposes to obtain the average field reservoir pressure (namely) evolution with respect to the gas cycling.

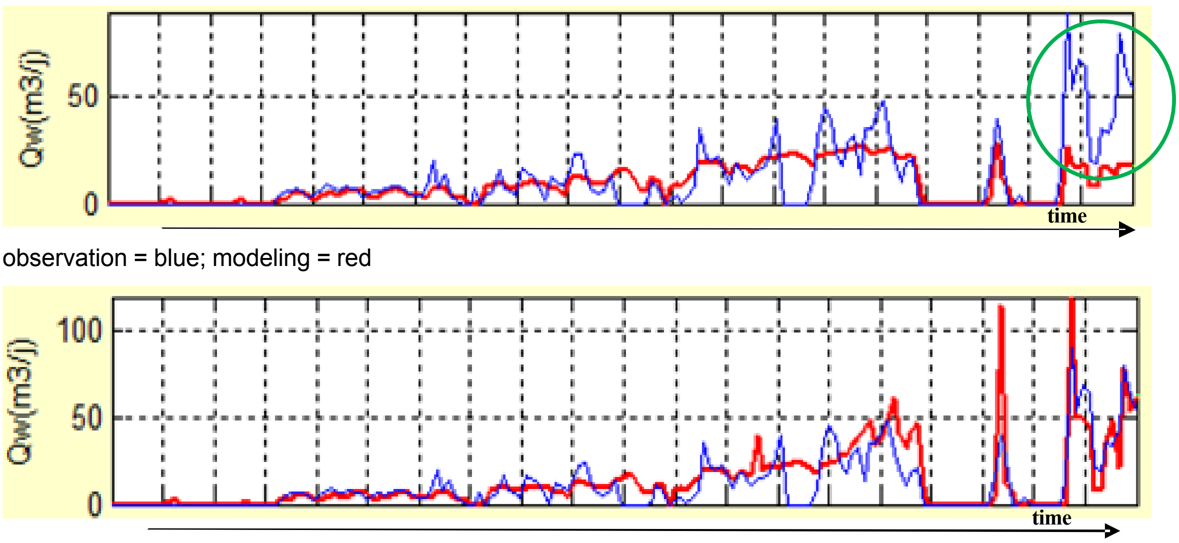


Figure 5: Modeling of water production observed on one well (upper: without coning option; lower: with coning option)

Each well is documented in terms of structural position and local petrophysical properties (especially the permeability). The global position of the interface in the storage is given by the model. The coning equations are used to update the critical rate during withdrawal:

- If the well rate is below the critical rate, standard Darcy's law applies.
- If not, a water coning production law is added using a simple empirical correlation with the excess of rate above the critical rate.

The first step consists in adjusting the physical parameters of the model for taking into account the past withdrawal campaign observations. The Figure 5 shows the quality of history matching obtained for the overall water production gathered from all the wells. The upper plot illustrates that the beginning, or early time, of the withdrawal campaign is properly reproduced using standard approach (Darcy) but the late, massive water production is missed.

The semi-analytical approach enables to account for an extra water production at the end of withdrawal due to coning. A blind test was conducted to check the quality of the forecasts using the same parameters on another withdrawal campaign. The Figure 6 shows the ability of the tool to anticipate the well behaviors in a predictive manner.

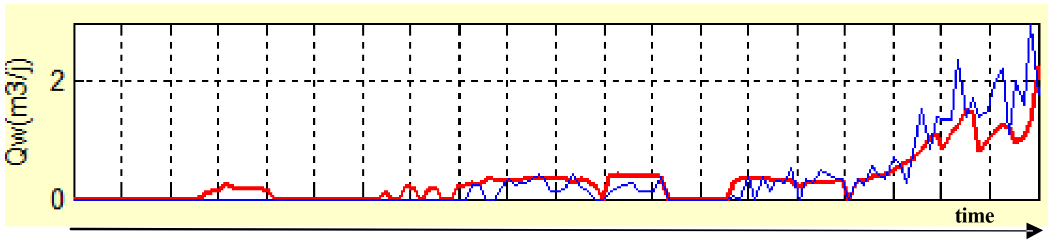


Figure 6: Example of a blind test on a well showing the coning effect well predicted

<u>Anticipation of the coning</u>

As the coning can be limited by adequate flow rate constrains as a function of the inventory during withdrawal, a dedicated work was conducted to revisit the past production data. The last three campaigns were carefully analyzed to identify, well by well, the periods of production when coning effect was taking place without any doubt (rather constant gas flowrate and steep water production increase). The output of this process was "experimental" critical gas flowrate values represented as a function of the inventory.

As these "experimental" points corresponds rather to low inventory values, the coning theoretical equations were used to complete the Q_c evolution over the whole range of inventory. The result of this approach is shown in Figure 7 (left). A very good consistency is found between the critical rate obtained through different campaigns (colored dot) and the empirical model succeeds very well in reconciliating and extrapolating these data (dash line). The complete results of the analysis (Figure 7 right) show the important differences of behavior depending on the wells (critical rates vary typically in a range of a factor two). It confirms that each well must be operated in a specific manner to reduce the risks of water influx. It also illustrates how important are the past production data analysis to improve performances during withdrawal. Each new reservoir response is then very valuable and, as such, must be analyzed and integrated to better prepare and anticipate the behavior of the forthcoming campaigns.

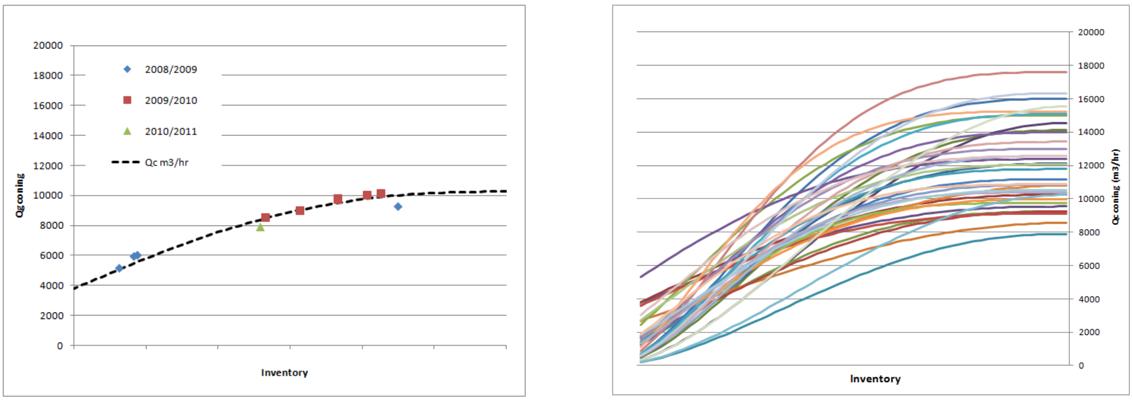


Figure 7: Analysis of the production data for coning critical rate determination (left) and extrapolation over the whole range of inventory (right)

Global scale

In terms of global and large scale water production, numerical models are more adapted since they can include heterogeneities and handle accurately the two-phase Darcy flow in the reservoir as well as the global deformation of the gas/water contact.

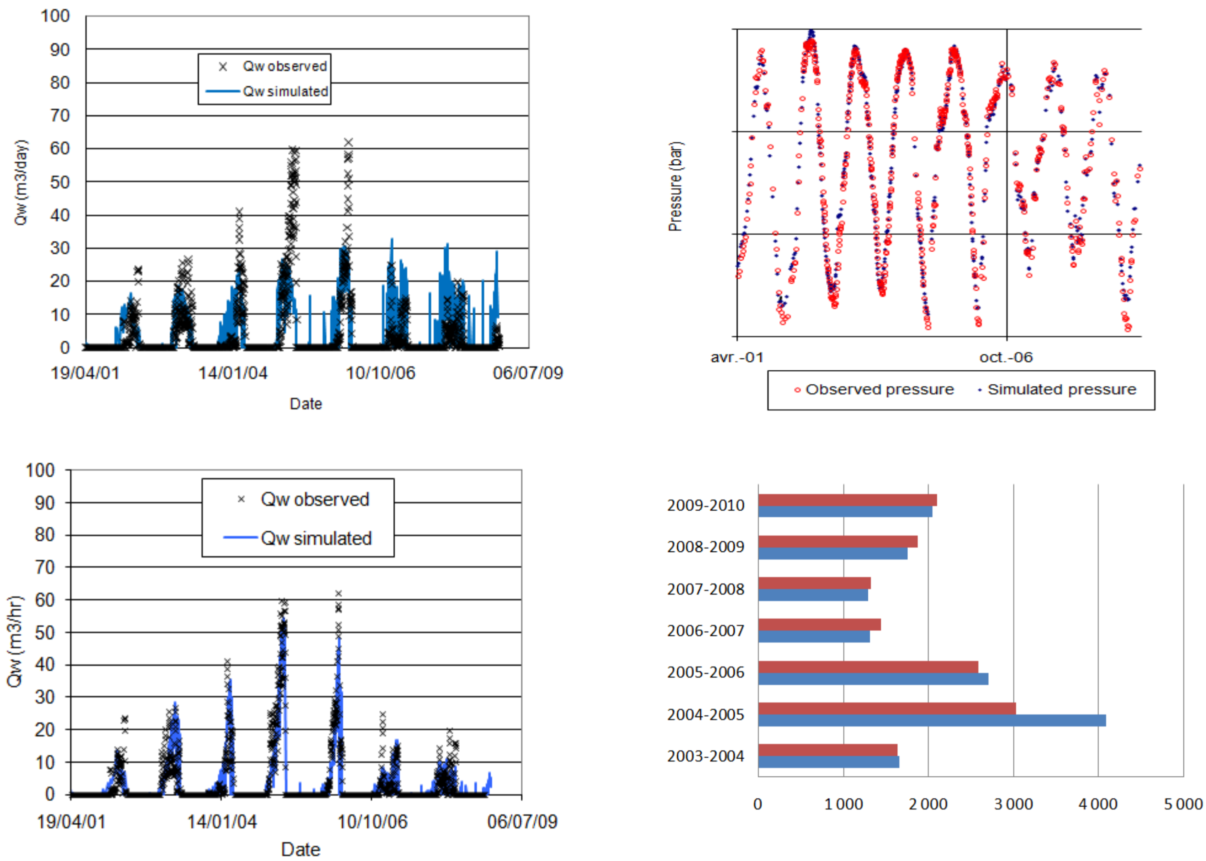


Figure 8: Water production modeling (global scale) : illustration of importance of capillary pressure impact (pressure match but not the produced water : top plots) and improvements obtained with P_c adjustments (daily water rate and cumulative: bottom plots)

As reminded in the state of the art section, the reservoir heterogeneities and the petrophysical properties are key parameters to history match the water production. This latest point is illustrated in the example depicted in Figure 8.

In a first step, the P_c curve (capillary forces) was fixed and the K_r curves (viscous forces) were adjusted only to reproduce the pressure behavior observed on site. As expected a very good match was obtained for pressure (right top plot) but the water production evolution was not properly reproduced (campaigns with high water rates underestimated and others overestimated). In a second step, the P_c curve was adjusted, then the K_r curves were slightly modified and a good agreement was obtained on both the pressure and the water data (daily rates and cumulative per year).

Another illustration of the water production history matching using a numerical model is provided in Figure 9. It is worth pointing out that both instantaneous (daily rate) and cumulative productions are very well reproduced. Such agreement has been obtained by an automatic history matching process where both pressure and water production data have been incorporated into an objective function to minimize by changing key parameter values within a given range (defined by the user).

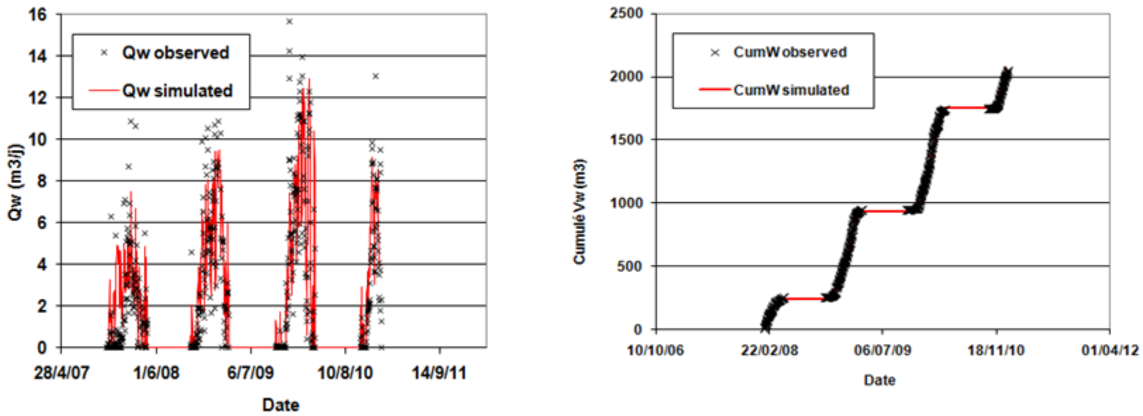


Figure 9: Global automatic water production history matching

These two examples confirm that the capillary forces play a huge role in the kinetics of water production though their impact on the water saturation distribution in the reservoir in a context (gas storage), where the pressure gradient are high (typically several bar difference between the center and the edge of the storage). Such examples clearly evidence that petrophysical properties deserve a dedicated attention during the reservoir evaluation process (rock typing, characterization through laboratory measurements). 3D modeling illustrates very well both the lateral and the vertical extension of the mixed area where both gas and water are mobile depending on the period of storage (green area in the left top view: Figure 10).

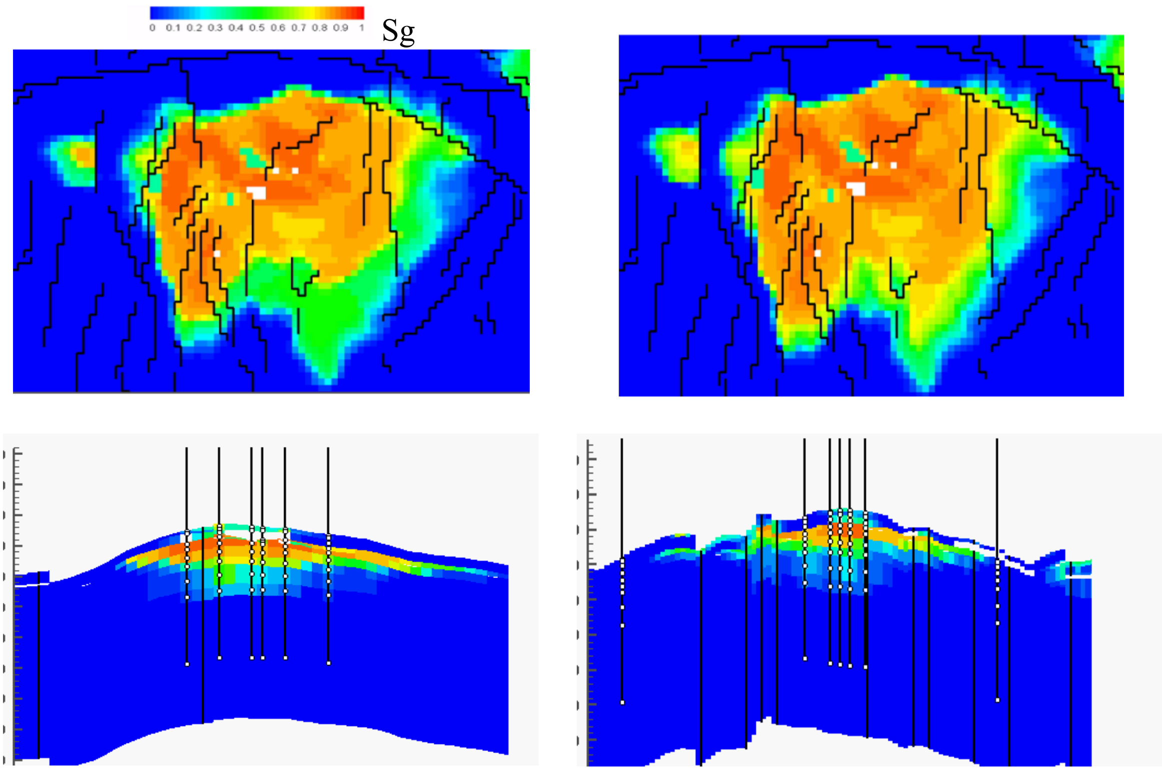
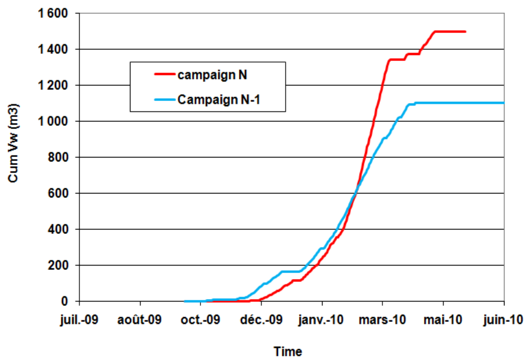


Figure 10 : 3D modeling : top views at low and high inventory (top) and cross sections (bottom)

In terms of modeling, it is therefore of primary importance to pay as much attention to the capillary pressure curves as the relative permeability curves in the context of gas storage to obtain relevant forecasts of pressure and water production.

DISCUSSION

Another important feature which can be deduced from a previous example (Figure 8) is the noticeable variability of the water production regimes depending on the withdrawal campaigns (water daily rates between 60 m3/day and 20 m3/day depending on the campaign). One main explanation is associated to the solicitation (fraction of the working gas produced). Nevertheless it cannot account for the whole water production variability. The Figure 11 (left) shows the observed annual water production for two campaigns in a row with very similar injection/withdrawal strategies. The significant difference in term of water production suggests that a pluri-annual effect takes place. This assumption has also been checked numerically by simulating several cycles with increasing and then decreasing fraction of the working gas produced (Figure 11 left). The annual water production gradually increases and keeps on increasing even when the fraction of working gas produced remains constant. When the solicitation decreases, the annual water production follows the same trend but with a significant hysteresis. At repeated high solicitation mode it is like the UGS has kept a kind of water memory for several cycles.



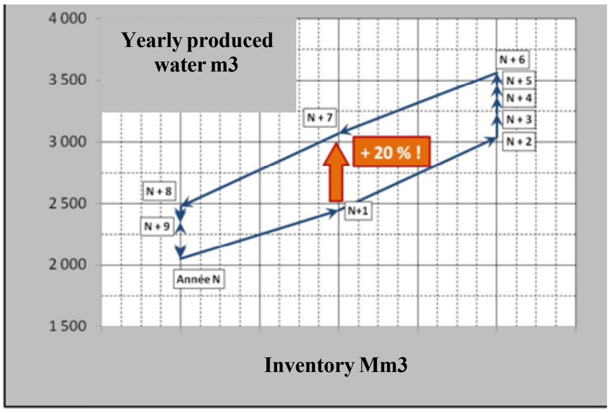


Figure 11: Example of two water production profiles for similar withdrawal campaigns (left) – illustration of the memory effect by increased followed by decreased UGS solicitation (right)

In this case again, the explanation behind the memory effect is related to saturation and hysteresis (through the pressure regime variations). The Figure 12 illustrates how the water saturation transition zone evolves along gas storage cycles. After a pronounced withdrawal period, it can be difficult to restore completely the gas saturation in the producing intervals before the beginning of the next withdrawal period which conducts to increasing water production (as high as 2 or 3 times the standard production). Therefore, above a certain level of solicitation, the aquifer reminds the way the gas storage has been operated in the previous years.

It suggests that the optimum window to operate the storage is just at the threshold when this memory effect remains non significant. This threshold can be overshooted from time to time but not in a repeated manner to keep the performances unchanged. In the case, the memory effectively takes place then the only way to restore the past performance is to reduce the solicitation at least during one campaign.

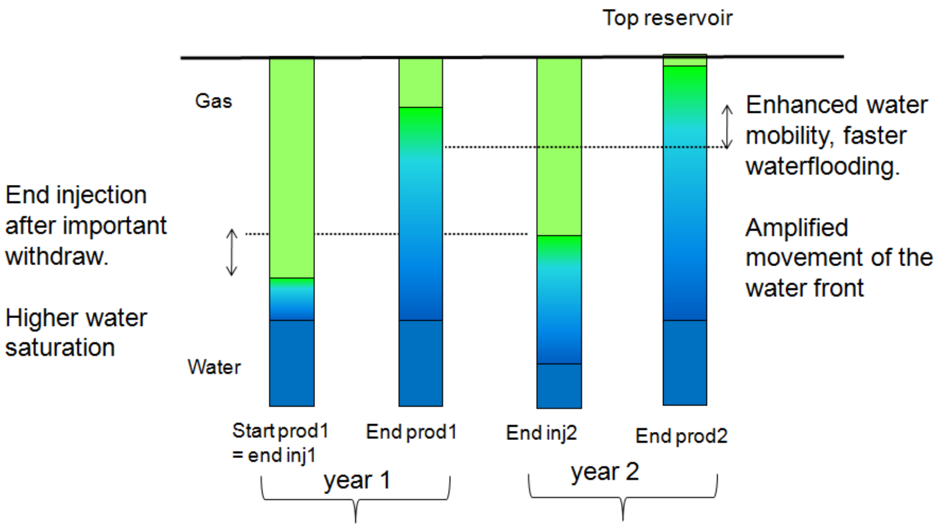


Figure 12: Origin of the multi-annual water production behavior (water saturation in blue color and gas in green)

CONCLUSIONS

The main conclusion of this study is that it is of primary importance to parameterize reservoir models so that they can reproduce both pressure and water histories in a UGS context. This can be achieved only through a consistent representation of the reservoir, its heterogeneities but also through relevant multiphase flow parameters (relative permeabilities and capillary pressure). Using this approach makes it possible to anticipate the reservoir behavior in term of water production both for operation (day to day follow-up for water management) and performance (even multi annual water production) purposes. Examples at the well scale illustrate the coning impact on the water production and provide some practical approaches to limit these phenomena during withdrawal. Examples at larger scale demonstrate the importance of the capillary pressure to reproduce the kinetics of the water production in a UGS context.

Because a given level of storage cycling corresponds to a given equilibrium state with the aquifer, increasing the gas withdrawal mode makes the aquifer adapt (time dependent) and the water saturation change leading to increasing water production over several years. This memory effect of the storage is highly dependent on both the reservoir properties (water saturation hysteresis) and the aquifer activity. It can impact significantly the water production (as high as a factor 2 or 3) in case of repeated high solicitation cycles.

The associated mechanisms behind this memory effect are complex since they result from a coupling between capillary forces (saturation state) and viscous forces (pressure regime: amplitude and duration) which required appropriate modeling tools and parameterization. It is therefore of primary importance to take benefit from each new withdrawal campaign to refine the reservoir models and anticipate this memory effect.

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NOMENCLATURE

C: trapping constant (Land's formalism)

UGS: Underground Gas Storage

S_{gr}: residual gas saturation

K_v: vertical permeability

S_{gr}: residual gas saturation

H_t: total reservoir height

R_D: well drainage radius (adim)

Q_{CD}: critical rate (adim)

P_c: capillary pressure (P_g-P_w)

K_{rg}^I, K_{rg}^D: imbibition and drainage K_{rg}

S_{gc}: critical gas saturation

S_{gi}: initial gas saturation

K_h: horizontal permeability

S_{gi}: initial gas saturation

μ_g: gas viscosity

B_g: gas volumetric factor

$P_{g,w}$: pressure in gas or water

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