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CO_2 injection as a mitigation measure for land subsidence

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Summary

Subsidence is a known consequence of liquid or gas production from the subsurface. The mechanism by which porous rock deforms and compacts under the influence of a fluid pressure change is well understood. Any decrease in fluid pressure will result in a proportional increase of the (compressive) effective stress in the porous reservoir rock i.e. more of the overburden weight must now be borne by the grain-to-grain contacts of the geological material itself. The rock skeleton will compact whereas the amount of compaction will be primarily related to the compressibility of the compacting layer. In the case of poorly consolidated reservoir rock and specific rock types such as chalk, reordering of grain particles and collapse of rock skeleton (i.e. pore collapse) may occur.
Next to the increase of effective stress in the produced reservoir unit, the stress field in adjacent formations (i.e. confining beds, caprock, bottom and lateral aquifer) will also change due to: (i) poro-elastic coupling between the reservoir and the surrounding rock; (ii) pressure communication between the reservoir and the adjacent aquifers; and (iii) progressive drainage of the surrounding rock. The amount of stress change in adjacent formation is commonly one to two orders of magnitude lower than the stress change in the compacting reservoir and it can be either positive (the effective stress becomes more compressive) or negative (the effective stress becomes less compressive). Quantification of stress changes in and around compacting reservoirs requires geomechanical numerical modelling (finite element modelling) because of the structurally/geometrically complex settings of many fields, variability in the geo-materials' properties and complex constitutive behavior of geo-materials.

Injection of CO_2 with as aim of optimum pressure maintenance i.e. stabilizing pore pressure of a gas reservoir in which gas production takes place, can be best achieved by injecting CO_2 in the same layer from which the gas is produced. Mixing CO_2 with the gas during gas production can easily take place especially in reservoirs with layers with a high permeability contrast. In the case of a heterogeneous gas reservoir system, no optimal use can be made of the density and viscosity differences between water/gas and CO_2/water/gas.
If CO_2 is injected under the gas reservoir, the CO_2 will move upwards as a result of its lower density and viscosity with respect to water, until it reaches the gas-water contact. As CO_2 is heavier and more viscous than gas, the density difference between CO_2 and gas will ensure gradual migration of CO_2 into the gas column. The disadvantage of this schema is however that the pressure communication of an injection position under the gas reservoir is probably less attractive than the pressure communication if injection takes place directly into the gas producing zone The CO_2 injectivity of wells in the gas zone is larger than in the water zone, because of the required initial multi phase injection pressure. For this reason the pressure maintenance by direct injection of CO_2 in the gas column is preferred.

The overall benefit and effect on subsidence of a CO_2-injection operation to prevent or mitigate subsidence has to be investigated by means of a feasibility study. Mainly due to the uniqueness of any storage location in the subsurface will it be

difficult, are better impossible, to give here a generic solution. All dynamic features of a CO_2–injection operation have to be studied in order to fit the goals set and to maximize positively all other effects.

Contents

1 Introduction

Subsidence is a known consequence of liquid or gas production from the subsurface. Subsidence is caused by the pressure drop in the reservoir, which can be partly or entirely compensated by injection of a liquid or gas near or in the gas- or liquid containing formation.
We consider CO_2 injection as a mitigation measure for anthropogenic land subsidence caused by production of gas or fluids or both from a hydrocarbon- or geothermal reservoir. Specific geological and operational conditions were assumed to exist. The reservoir rock consists of a weak or poorly consolidated porous rock. The operational conditions are characterized by the lack of aquifer support resulting in large pressure gradients throughout the reservoir in the production period.
The injection concept that will be worked out is the injection of CO_2 near or in the production fluid formation.
We will start off with a small introduction of the general cause and circumstances of land subsidence.

2 Subsidence

The first observation concerning land subsidence due to fluid removal dates back to the beginning of the twentieth century with the first scientific report on the event written by two geologists (Pratt and Johnson, 1926). Their conclusion was that "*the cause of the subsidence is to be found in the extensive extraction of oil, water, gas, and sand from beneath the affected area",* which was located above the oil field of Goose Creek, S. Jacinto Bay, Texas. The early assumptions of Pratt and Johnson was to be later confirmed and reconfirmed by countless examples of anthropogenic land subsidence, and supported by geomechanical theory as well. Classical examples of subsidence due to hydrocarbon extraction are the Wilmington oil field in California (Mayuga and Allen, 1969), the Ekofisk oil field in chalk in the Norwegian sector of the North Sea (Nagel, 1998) and the Groningen gas field in the northern part of the Netherlands (Doornhof, 1992; Houtenbos, 2000).

In the case of groundwater extraction, the maximum recorded subsidence amounts to as much as 14 m, while the depth of pumping wells may range from those tapping very shallow water table aquifers just close to the ground surface to those tapping very deep (4000-5000 m) gas/oil reservoirs.

Over gas/oil fields, the subsidence usually takes on a bowl-shaped appearance with the largest downward displacement occurring near the centre of the field. The border of the bowl may roughly resemble the shape of the field although it may extend up to twice or more the area surrounded by the outline of the underlying reservoir. In the case of extensive pumped aquifer systems, the overall extent of the sinking area can be much larger, totalling as much as 13 500 km^2 in the case of the S. Joaquin Valley, California (Poland and Lofgren, 1984), and l2 000 km^2 in the Houston-Galveston area, Texas (Gabrysch, 1984). By distinction, subsiding areas over gas/oil fields never reach such a large size.

The analysis and the prediction of the expected anthropogenic land subsidence due to fluid or gas subtraction is not an easy task. An exploration study of the area of interest is required with the detailed description of the basin geology and geometry and the reconstruction of its geological history. Geomechanical and hydraulic properties are of the utmost importance. Preconsolidation stress, zones or areas of overpressure, and faults must all be reliably identified in formations located at a great burial depth. Advanced technology (2-D and 3-D seismic surveys, *in situ* geophysical measurements, explorative boreholes, field tests, laboratory analyses) can be of great help. Much progress has also been made in accurately recording and monitoring the ground surface movements. Advances have also been accomplished in measuring compaction in aquifer systems and reservoirs by borehole extensometers and radioactive markers, respectively.

3 Mechanics of land subsidence due to fluid production

The mechanism that relates anthropogenic land subsidence to fluid production is that of subsurface sediment compaction caused by changes of the stress distribution within the rock skeleton. In a normal situation the fluid pressure increases with depth in a hydrostatic way i.e. it is dependable on the gravity of the formation water and increases by some 1.0 bar for every 10 meter of depth. The introduction of a production well into a natural fluid flow system produces a disturbance that propagates its effect in space and time through the geological layer. Around the well, a cone of depression in the fluid, or pore pressure in the pumped formation, develops and expands laterally, and to a minor extent also vertically. The intensity of the pressure drop at any point of the porous medium and the time lag between the inception of withdrawal and the arrival of the effect at that point depend on the distance of the point from the well area, on the geometric and geologic configuration of the subsurface basin, on its boundary conditions, and on the fluid-dynamic and geomechanical properties of both fluid and formation, specifically fluid density and viscosity, and medium intrinsic permeability, porosity, and compressibility.
The mechanism by which rock deforms and compacts under the influence of a fluid pressure change is well understood. The geostatic (or lithostatic) pressure (which also represents the total vertical stress) at any place in the subsurface is a result of the total weight of all material above this point i.e. it is the sum of the rock material and it's containing liquids. This basic principle is best illustrated in figure 1.

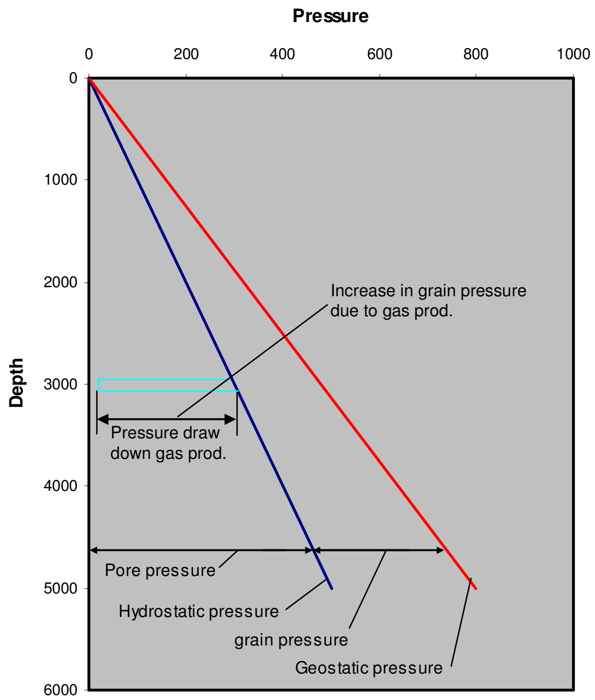

Figure 1: Graphical presentation to demonstrate the effect of the subsurface pore pressure changes on the vertical effective stress (i.e. grain or rock pressure).

The stress considered above is the total stresses. According to the theory of stress separation in its simple form, based on the Terzaghi´s principle of effective stress, the total stress in soil can be separated into the effective, i.e., intergranular stress and the pore pressure, i.e. neutral stress:

$$\sigma' = \sigma - I\,p \qquad \text{Eq. (1)}$$

where: σ' - effective stress, σ - total stress, p - pore pressure, I - unit tensor.

The basic principle of the stress separation theory is that a change in the effective stress causes all deformation of the rock mass (e.g. compaction, distortion).
It can now be concluded that any decrease in fluid pressure will result in a proportional increase of the effective stress, i.e. the rock pressure as more of the overburden load must now be borne by the grain-to-grain contacts of the geological material itself... The rock skeleton will compact whereas the amount of compaction will be primarily related to the compressibility of the compacting layer. In the case of poorly consolidated reservoir rock and specific rock types such as chalk, reordering of grain particles and collapse of rock skeleton (i.e. pore collapse) may occur.
Next to the increase of effective stress in the produced reservoir unit, the stress field in adjacent formations (i.e. confining beds, caprock, bottom and lateral aquifer) will also change due to:

(i) poro-elastic coupling between the reservoir and the surrounding rock;
(ii) pressure communication between the reservoir and the adjacent aquifers; and
(iii) (iii) progressive drainage of the surrounding rock.

The amount of stress change in adjacent formation is commonly one to two orders of magnitude lower than the stress change in the compacting reservoir. The stress change can be either positive (the effective stress becomes more compressive) or negative (the effective stress becomes less compressive).
Due to poro-elastic coupling between the compacting reservoir and the surrounding rock, the effects of reservoir compaction extend to the ground surface, which therefore subsides.
If the depleted units are seated deeply into the basin, as in the case of a typical gas/oil reservoir, the elastic response of the subsurface to the reservoir compaction resembles that caused by a set of infinitely small sources of compaction located in a semi-infinite elastic medium. The surrounding rocks absorb part of the compaction, i.e. the loss of support, due to the local pressure drawdown, and the actual land settlement depends primarily on depth, volume, and compressibility of the reservoir and the elastic properties of the adjacent formations. This principle of representing the compacting reservoir by a set of centres of compaction was used to develop a semi-analytic program for subsidence calculation (Fokker and Orlic, 2006).
Typically, the magnitude of land subsidence above gas/oil fields is smaller than the amount of reservoir compaction. The reason is stress re-distribution (i.e. arching) above the compacting reservoir by which a part of the vertical overburden load is taken over by reservoir abutments. However, the subsidence bowl spreads over a larger area than the extent of the field itself.

Conversely, aquifer systems are generally shallower and have a much larger areal extent than gas/oil fields. For these systems, the existence of a central zone may be conceived where reservoir compaction is not contrasted by the overburden and simply migrates to the ground surface with a subsidence spreading factor equal to one (i.e. the magnitudes of reservoir compaction and land subsidence are practically equal).

4 Controlling Factors

Four factors may partially combine to produce measurable settlement records:
1. shallow burial depth of the pressure depleted layers;
2. highly compressible reservoir rock deposited in alluvial or shallow marine environments;
3. large pore pressure decline; and
4. large thickness of the depressurized fluid bearing sediments.

Unless the gas/oil fields are over pressurized, factors (1) and (3) are mutually exclusive, while they can be both associated with factors (2) and (4). For a large subsidence to occur, however, a soft compacting rock is needed and/or a large pressure drawdown. To give a few examples, Mexico City sank by 9 m with a maximum pressure decline of only 0.7 MPa because of the extremely soft high-porosity soils of the compacting shallow formations located within the upper 50 m of the reservoir, while the 9 m and the 6.7 m settlement reported from Wilgminton (Allen, 1969a) and Ekofisk (Zaman et al., 1995; Hermansen et al., 2000) oil fields, respectively, are accounted for by the pronounced pore pressure drop (exceeding 20 MPa in the latter) combined with the large thickness of the compacting units. The Ekofisk case is a very interesting one in that the reservoir rock – chalk - has exhibited a sudden increase in compressibility at some stage of the field development with a large irreversible deformation defined as "pore collapse", which is believed to be the main reason for the increased subsidence over the field (Zaman et al., 1995).

Some reservoirs and aquifers may be over consolidated (e.g. the Venezuela fields). Over consolidation tends to reduce the early subsidence rate with a sudden growth at some stage of production, when the in situ stress exceeds a threshold stress equal to the highest stress experienced by the sediment during geological history. If the water or gas/oil bearing sediments are preconsolidated, it may be very difficult to predict anthropogenic land subsidence prior to the field/aquifer development. Preconsolidation might have been caused in the geological past by uplift followed by erosion of the sediments overlying the fluid bearing layers or by fluid overpressure or by loading by the ice during glacial periods. The aforementioned processes may have led to a reservoir/aquifer system expansion which was much smaller than the original virgin, mostly unrecoverable compaction. When pore pressure lowers due to fluid production, a reloading of the depleted formations takes place. Initial compaction, and hence land settlement, are small. However, as soon as the maximum experienced load is overcome, rock compression occurs on the virgin loading curve with a sudden increase of compressibility, and of the resulting subsidence rate. If there is a significant compressibility contrast between the reservoir and the cap rock, land may even rise when fluid is removed (Ferronato et al., 2001). This might occur in case when the reservoir is overconsolidated and stiffer than the confining bed (and this further ad to the complexity of a reliable land subsidence prediction above over consolidated reservoirs).

Another factor that may influence the effect of subsidence is the presence of faults within the developed system and the overburden, as in the case, for instance, of Las Vegas (Amelung et al., 1999). Faults may weaken the porous medium structure and make both the analysis and the prediction more difficult. When a gas/oil field is considered, an additional source of complexity is the lateral/bottom aquifer (called water drive). Pore-pressure drawdown may extend to the waterdrive as well, and induce further land subsidence as a consequence of the waterdrive compaction, even after the wells are shut down and the field is abandoned. It is not uncommon that land settlement around a field still continues for several years after the cessation of pumping or production as the result of the residual waterdrive compaction (Bmi et al., 2000).

4.1 Subsidence Delay

Hettema at al, (2002) have looked at subsidence timing for a number of hydrocarbon fields. They analysed data from eight fields and the data suggest a subsidence versus reservoir depletion relation as depicted schematically in Figure 2. When depletion starts there may be a subsidence delay. The most reliable data for the presence of subsidence delay are those for the Groningen, Ameland and Troll fields. After the subsidence delay period, there is a phase referred to in the Figure 2 as near-linear subsidence, where a linear relation is observed between subsidence and depletion. The subsidence during this period is small, in the order of centimetres, usually does not have operational consequences and it is therefore often overlooked or not measured in the field (e.g. in case of the Ekofisk field the first measurement was made after 8 years of production). After the near-linear subsidence phase, the accelerated subsidence phase follows, characterized by a significantly larger subsidence, often in the order of meters. When data are not recorded during the near-linear subsidence period it is often assumed that there is no subsidence, which may be a misinterpretation of the data. This is illustrated in Figure 2 where in the absence of early subsidence measurements, the data during the accelerated subsidence period are extrapolated to zero subsidence resulting in an apparent significant subsidence delay. For these reasons, the amount of reliable field data on the initial part of the subsidence-depletion relation is too limited to draw definite conclusions on the subsidence delay issue. It can be argued that the subsidence-depletion behaviour of Figure 2 applies to all reservoirs provided that they are sufficiently depleted. Depletion may produce sufficiently large effective stresses in the reservoir to cause extensive reservoir compaction, e.g. due to pore collapse and gain crushing, and/or trigger other non-reversible failure mechanisms, such as arch collapse, activation of existing or creation of new faults, etc. Reservoirs where the transition point has been exceeded are characterized by significant subsidence (e.g. Ekofisk, Valhall, Bolivar Coast).
Hattema's analysis suggests that there are two classes of reservoirs:

- Class I of reservoirs in the near-linear subsidence regime. They are usually well cemented, often old (older than of Cretaceous age) and at present deep (> 2 km). Subsidence is often small (less than a few decimetres).
- Class II of reservoirs in the accelerated subsidence regime. They are usually un-cemented or poorly cemented granular aggregates like sand, silt, chalk and diatomite, bounded together by small amounts of cement or capillary forces. These are often of high porosity, young (younger than of

Cretaceous age) and presently buried at relatively shallow depths (often < 2 km, with the exception of the highly over-pressured chalk reservoirs). Initially, in their near-linear subsidence period, these reservoirs show little compaction and subsidence

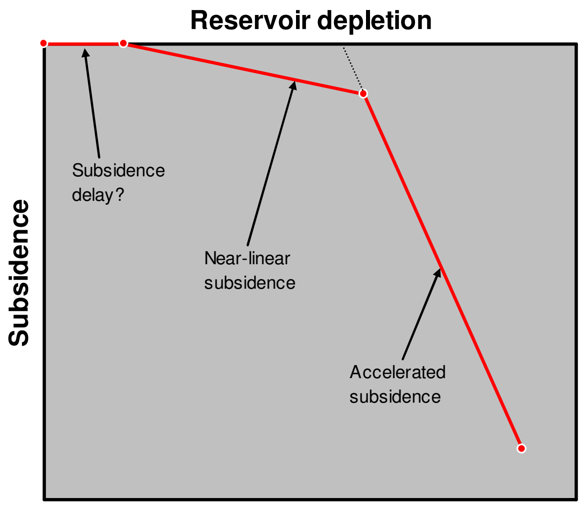

Figure 2: Schematic of subsidence versus reservoir depletion relation (after: Hettema)

Further concluded Hettema on basis of a theoretical model, time-delay effects due to the inertia of the overburden could be ruled out as a mechanism for the subsidence delay effect. For the shallow reservoirs, natural over compaction has the potential to cause the observed subsidence-depletion delays. The deeper reservoirs are more than enough over pressured to explain their subsidence depletion delay, but due to their long burial history they have probably not experienced the maximum over-compaction as determined from today's reservoir over-pressures, because:

- they could have been over-pressured gradually during natural compaction.
- at higher temperatures (above about 120OC), other mechanisms of over pressurisation and compaction may become active in sandstone.

The reservoir compaction-related delay mechanisms are difficult to quantify from laboratory measurements, because the results are extremely sensitive to possible core damage. There is no correlation between the subsidence delay values and the depth/width ratio of the reservoirs, but more investigations are needed to rule out stress changes and arching of the overburden as a cause for the subsidence-depletion delay.

5 CO_2 injection as a mitigation measure

The only controlling factor of subsidence that we are able to manipulate is the actual fluid or pore pressure drop as a result of gas or liquid extraction. Further, do we know what is the threshold pressure drop at which a particular reservoir rock starts to deform in a non-elastic manner, i.e. the rock deformation becomes irreversible? It can be argued that at least a part of the (initial) compaction, in the initial period of reservoir production, will be elastic and reversible after re-pressurization; in all other cases compaction is irreversible as a result of destructive skeleton deformation or sand grain re-ordering. From the point of CO_2 injection as a mitigation measure for land subsidence, it is now easy to conclude that in nearly all cases, CO_2 injection has to be started at the earliest opportunity and in such a way that large pressure gradients in the reservoir are prevented. With this last statement we directly hit one of the possibly conflicting interests. From a point of preventing compaction and subsequently mitigating subsidence we like to maintain a stable and near original pressure, on the other hand for the purpose of optimizing fluid or gas production we may need substantial pressure gradients to create and maintain an economical production rate. It is clear that an optimal injection schema is very dependable on reservoir technical situation, the local geological setting and overall local production strategy.

Another important issue can be the large difference in individual flow properties of all fluids involved. Produced gas, water or oil will stay near a gas or liquid when brought the surface. In contrast, CO_2 at atmospheric conditions will compact 300 to 400 times when injected at depths beyond 800 meters and will get a near liquid type of density. This density is still not high enough to prevent it from migrating upwards in water type of environment as a result of buoyancy effects. Basically, gas is lighter than formation water and CO_2 and CO_2 is lighter than water. Over time, gravitational effects will separate the fluid phases. In this competition of individual fluid effects the result of differences in fluid viscosity hasn't be mentioned. Especially in the case of pressure gradients, the relative low viscosity of CO_2 could result in favourable mobility ratios for CO_2 in relation to other fluids and could result in early breakthrough of injected CO_2 in the oil or gas production system. In all it is clear that CO_2 injection as a measure to mitigate land subsidence is a feasible option which requires location specific solutions to classical gas and fluid flow problems. In the following sections we will test the above concepts by using synthetic numerical models based on the typical Dutch type of gas reservoirs.

6 Injection of CO_2 close or in gas accumulation

CO_2 is a gas which has a density of 1.8684 kilogrammes/m3 under atmospheric conditions. By injection of CO_2 in the subsurface compression will take place. Also the temperature will increase (the geothermal gradient is approx. 0.033 oC/m). As the pressure and temperature increase CO_2 will become supercritical above 74 bar and 31 oC. In that situation CO_2 is still a gas but has a near liquid type of density (low). The supercritical CO_2 will have a density of approx. 634 kilogrammes/m3 at reservoir conditions for a gas reservoir in the Rotliegend geological formation in the North part of the Netherlands at a depth of 3000 mSS and a temperature of 109 oC. The density of CO_2 at these conditions has a value of those between gas and of water. Under these circumstances, injected CO_2 will migrate to the boundary layer between gas and water if injected in the same formation (Figure 3.).

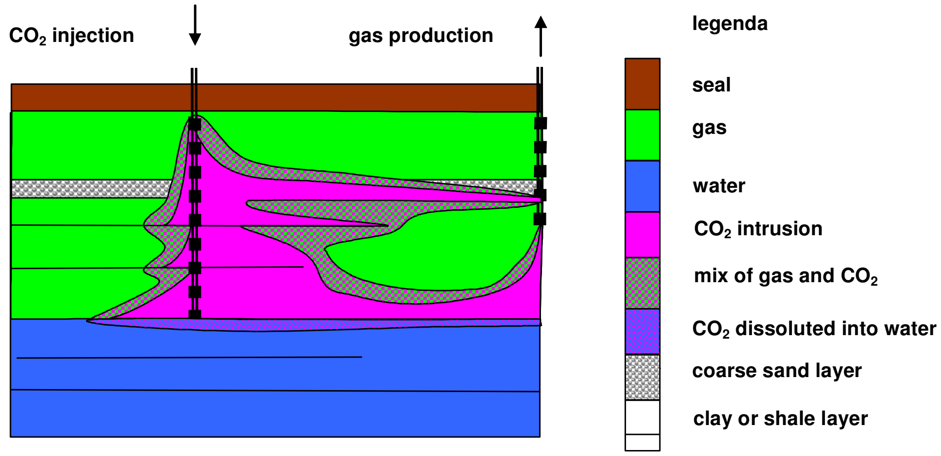

Figure 3: Vertical cross section through a gas accumulation. Gas production in combination with simultaneous CO_2 injection into the produced formation.

CO_2 injected in a water bearing formation will as a direct result of buoyancy effects move upwards to the highest or first impermeable horizontal flow barrier, which could be the seal of a gas accumulation. The consequence for a gas producer to produce a gas mixture of gas and CO_2 is totally different than the consequence to produce a mix of gas and water. In the case of CO_2 the mix will stay in the gas phase and it is expected that the two gasses will mix. Too much water production can, however, kill a gas production well.

The injection of CO_2 in water containing geological layer can cause initial problems. It concerns injection of an inert "gas". At 100% water saturation of the pores the initial displacement pressure must be overcome first. If some gas is present in the pores the initial displacement pressure is much lower. Analogously to peripheral water injection, CO_2 injection can take place on the down dip sides, in the same formation as the gas or at the base of the gas accumulation. CO_2 injection into a gas accumulation is of course also an alternative. The expected distribution pattern is shown in Figure 3.

A disadvantage of this schema is that the travel time of injected CO_2 towards the gas production well is clearly shorter compared to injection under away of the gas accumulation. An advantage is that the injectivity will be higher, because CO_2 behaves like a gas and is injected into gas containing pores. The initial displacement pressure is smaller than for injection of CO_2 into pores filled with only water.

7 CO_2 injection under a gas field

We know from simulation experience that under continuous injection of CO_2 into a water saturated formation, the CO_2 will immediately move upwards as a result of its low density in respect to water and a lower viscosity, to the next horizontal flow barrier and spread itself out in horizontal direction (Figure 4).

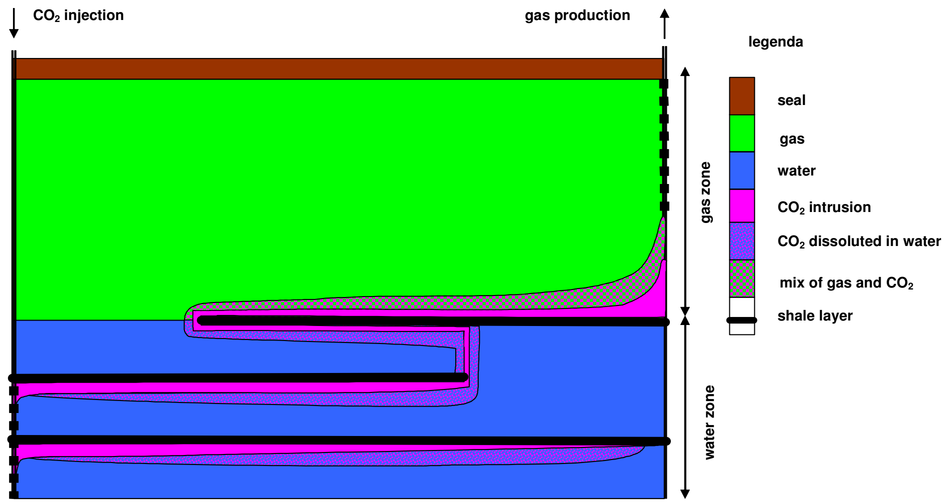

Figure 4: Vertical cross section through the gas accumulation. Gas production by wells with simultaneous CO_2 injection underneath the gas accumulation.

The distribution of CO_2 within a water saturated formation gives no reason for mixing: CO_2 is not attracted to water (is inert). However, CO_2 will leave behind a small percentage of water in each pore it ones occupied; this as a result of capillary effects (the estimate is about 10%). Also, CO_2 in small amount will dissolve into the formation water. The horizontal distribution process of CO_2 under the intra-formational seals will continue until the seal layer ends or CO_2 will spill over to a following structure with a higher intra-formational seal. This process continues until the gas bearing formation is reached.

CO_2 is relatively heavy in comparison to natural gas under the same reservoir conditions. Super critical CO_2 will move itself to the boundary layer between natural gas and water. As "gas", the CO_2 will have a tendency to mix with the reservoir gas. Because of this, a mixing zone will arise. However, it is estimated this effect will be modest, because of the small communication between rock pores on large depth, the relatively high viscosity and higher density of CO_2 with respect to the reservoir gas. This mixing effect is one of subject under investigation at the Dietz laboratory of the Technical University of Delft. CO_2 will accumulate at the gas and water interface and will flow in the direction of a gas production well as a result of the gas production. Under the well, where the vertical pressure drop is maximal, CO_2 will flow eventually to the well and a CO_2 tongue will form (figure 4). If, and to what extent this CO_2 flow pattern between injection to production well occurs, will depend on a large number of factors, of which the number of injection wells, the injection rate and the depositional environment of the reservoir rock under the gas accumulation are the most important.

8 Flank injection of CO_2

CO_2 will in the first place move upwards as a result of lower density in comparison to the formation water and accumulate under the cap rock as the CO_2 is injected on the flanks of a gas reservoir into the water saturated part of the formation. The CO_2 will move subsequently in the direction of the gas accumulation as a result of a negative pressure gradient resulting from the ongoing gas production.

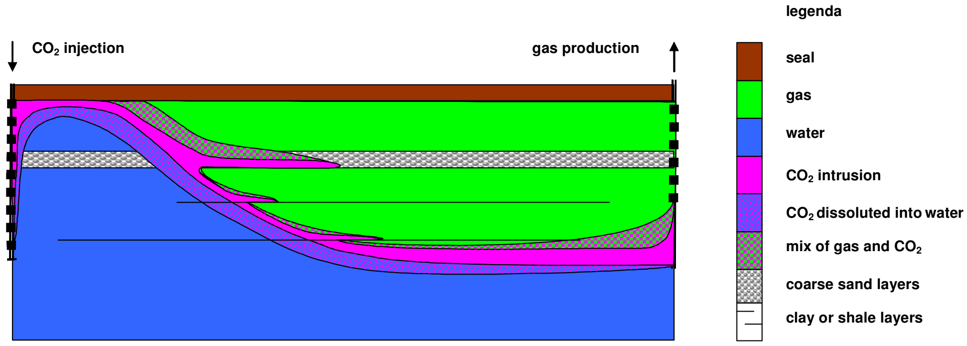

Figure 5: Vertical section through a gas accumulation. Gas production by wells with simultaneous CO_2 injection in the gas accumulation. The vertical dimension has been exaggerated.

Subsequently, CO_2 will accumulate at the interface between gas and water as a result of gravity segregation. In addition, a natural gas – CO_2 mixing zone will form as described previously.
Possible preferential flow paths for CO_2 can be formed in case if high permeable layers present within the reservoir. The cause of this effect is the reduced initial displacement pressure of CO_2 for large pores (high permeability), with respect to fine pores (low permeability). If this impact is the same or larger than the pure gravity segregation effect, then the high permeable layer will be followed by CO_2 as a preferential pathway for migration. Eventually, the area of the gas accumulation under the well will be reached; the CO_2 (in pure form and in mixed composition) will form a tongue and will flow into the well (Figure 5). The travel time of injected CO_2 from CO_2 injection to gas production well can be extended by reducing the injection rate for each well to a minimum.

9 Discussion

In this section we will cover some practical issues related to the pro and cons of CO_2 injection as remediation of subsidence. In the first place we asked our self what is needed to replace a certain volume of natural gas with CO_2. We make here the assumption that a gas reservoir is developed for a gas production of 1 billion m^3 (10^9) per year. One (1.) m3 of gas at surface conditions will have a much smaller volume than at reservoir conditions as a result of an increase of the density of the gas due to the increase in pressure and temperature. The conversion factor for natural gas at surface conditions to 3000 m. NAP is in the order of 200. For CO_2 this conversion factor is approx. 340. As a result of the production of 1 billion m^3 natural gas/year some 5 millions m^3/year or 13689 m^3 pore volumes per day will come available. This pore space can be filled with CO_2 to compensate for any lost pressure as result of the gas production. In normal cases it must be possible to inject approx. 1 million m^3/day of CO_2, this means a volume of 1000000/340 = 2941 m^3/day at the here adopted reservoir conditions. We are now able to conclude that we will need 5 CO_2 injection wells to compensate for each 1 billion m^3 produced volume of natural gas.

Furthermore, computer modelling using a numerical oil or gas simulator can be used for a quantitative estimation of the possible effects of CO_2 injection, like for example ECLIPSE. If in addition also the subsidence has to be modelled, a link is needed between a fluid flow model and a geomechanical simulator such as DIANA. This last option is of cause not needed if the subsidence remediation action is based on full pressure maintenance.

Within TNO there is experience with earth surface movement as a result of gas production and gas injection at the gas storage location Norg in the northern part of the Netherlands. For Norg the experience is so far that after gas injection the small subsidence of some cm was entirely compensated. This means that the subsidence was here completely elastic. In case of a large subsidence as a result of gas production, the non elastic part of rock deformation can lead to a reduction in the storage capacity of the natural gas storage location.

10 Conclusions

Subsidence is a known consequence of liquid or gas production from the subsurface. The mechanism by which porous rock deforms and compacts under the influence of a fluid pressure change is well understood. Any decrease in fluid pressure will result in a proportional increase of the (compressive) effective stress in the porous reservoir rock i.e. more of the overburden weight must now be borne by the grain-to-grain contacts of the geological material itself. The rock skeleton will compact whereas the amount of compaction will be primarily related to the compressibility of the compacting layer. In the case of poorly consolidated reservoir rock and specific rock types such as chalk, reordering of grain particles and collapse of rock skeleton (i.e. pore collapse) may occur.
Next to the increase of effective stress in the produced reservoir unit, the stress field in adjacent formations (i.e. confining beds, caprock, bottom and lateral aquifer) will also change due to: (i) poro-elastic coupling between the reservoir and the surrounding rock; (ii) pressure communication between the reservoir and the adjacent aquifers; and (iii) progressive drainage of the surrounding rock. The amount of stress change in adjacent formation is commonly one to two orders of magnitude lower than the stress change in the compacting reservoir and it can be either positive (the effective stress becomes more compressive) or negative (the effective stress becomes less compressive). Quantification of stress changes in and around compacting reservoirs requires geomechanical numerical modelling (finite element modelling) because of the structurally/geometrically complex settings of many fields, variability in the geo-materials' properties and complex constitutive behaviour of geo-materials.

Injection of CO_2 with as aim of optimum pressure maintenance i.e. stabilizing pore pressure of a gas reservoir in which gas production takes place, can be best achieved by injecting CO_2 in the same layer from which the gas is produced. Mixing CO_2 with the gas during gas production can easily take place especially in reservoirs with layers with a high permeability contrast. In the case of a heterogeneous gas reservoir system, no optimal use can be made of the density and viscosity differences between water/gas and CO_2/water/gas.
If CO_2 is injected under the gas reservoir, the CO_2 will move upwards as a result of its lower density and viscosity with respect to water, until it reaches the gas-water contact. As CO_2 is heavier and more viscous than gas, the density difference between CO_2 and gas will ensure gradual migration of CO_2 into the gas column. The disadvantage of this schema is however that the pressure communication of an injection position under the gas reservoir is probably less attractive than the pressure communication if injection takes place directly into the gas producing zone The CO_2 injectivity of wells in the gas zone is larger than in the water zone, because of the required initial multi phase injection pressure. For this reason the pressure maintenance by direct injection of CO_2 in the gas column is preferred.

The overall benefit and effect on subsidence of a CO_2-injection operation to prevent or mitigate subsidence has to be investigated by means of a feasibility study.

Mainly due to the uniqueness of any storage location in the subsurface it will be difficult, or impossible, to give here a generic solution. All dynamic features of a CO_2–injection operation have to be studied in order to fit the goals set and to maximize positively all other effects.

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Furthermore, the following publications are used in the making of this report and can be used as background information.

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12 Signature

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