TU Clausthal

Review of the 3 NAM Reports

1. **Geology description of Twente Gas Fields: Tubbergen, Tubbergen-Mander and Rossum-Weerselo (EP201310201845)**
2. **Halite dissolution modelling of water injection into Carbonate gas reservoirs with a Halite seal (EP201310203080)**
3. **Subsidence caused by halite dissolution due to Water injection into depleted Carbonate gas reservoirs incased Halite (EP201310204177)**

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1. Review Fundamentals

This review of the 3 NAM reports (EP201310201845, EP201310203080 and EP201310204177) is based on our proposal dated on 30 June 2015 and the corresponding order of the State Supervision of Mines, Ministry of Economic Affairs, The Netherlands, dated on 6 July 2015.

According to the agreement a comprehensive review of the three reports was deemed necessary to re-examine the study assumptions (i.e. conservative and non-conservative), modelling approaches and conclusions. The main bone of contention behind the review is to establish whether the reported large scale volumes of fresh water injection in the Zechstein carbonate reservoirs (ZEZ2C & ZEZ3C) can be a sustainable safe operation in the long-term (more than 1,000 years). Some concerns exist about the long term stability of the halite seal (e.g. cavern development, breach of confinement) due to the halite dissolution in the low salt-saturated injection water.

Besides the 3 NAM reports additional data was obtained about fault juxtapositions and NaCl concentrations in the formation water in the study fields (measured in the Zechstein reservoir samples: 207-227 g/L (=207,000 – 227,000 ppm) in well TUB-4 in the year 1954 and 237-252 g/L in well ROW-9 in the year 1979). However, in such analyses always exists some uncertainties as to whether the water samples consisted wholly of aquifer water or a mixture of aquifer and production water. This issue of uncertainties has been circumvented in the 3 NAM reports by using a higher NaCl concentration in the range of 210-270 g/L.

2. Review of the Geology Report (EP201310201845)

This geology report is in total well researched and based on seismic results, logging data, well tests, lab experiments and a history matching to the gas production data, but naturally also on a few assumptions. The review focuses on the most important and critical points: including the reservoir rock Carbonate, the permeability of Carbonate and the K_v/ K_h ratio, the cap rocks Anhydrite and Halite and fault juxtapositions.

The reported large scale volume of low saline production water from the Schoonebeek Oilfield is currently being re-injected into the Zechstein carbonate reservoirs (ZEZ2C & ZEZ3C) of three old gas fields (TUB: Tubbergen, ROW: Rossum-Weerselo, TUM: Tubbergen-Mander) in the Twente area.

TUB and ROW have a comparable geological setting (in terms of geology, Zechstein sequence, lithostratigraphic sub-divisions): The Zechstein in TUB consists of 4 evaporitic cycles (Z1-Z4). From the bottom up, each cycle comprises a sequence of Clay-Carbonates-Anhydrites-Salts and Halites/Anhydrites. The Zechstein 2 Carbonate (ZEZ2C) and the Zechstein 3 carbonate (ZEZ3C) are considered reservoirs as well as the injection horizons. On top of the reservoirs, ZEZ2C and the ZEZ3C, exists the regionally deposited Zeichstein 2 Anhydrite (ZEZ2A roof: 2-5 m thickness) and Zeichstein 3 Anhydrite (ZEZ3A roof: 5-15 m thickness), respectively. Furthermore, ZEZ3A is a laterally continuous Anhydrite layer 5 to 15 m in thickness. Above the ZEZ3A exists salts and Halites of the Zechstein 3-4 cycle and on top of the ZEZ3H, generally, the Red Salt Clay (ZEZ4R) and the overlying Zechstein 4 Halite (ZEZ4H) can be observed.

The ZEZ2C and ZEZ3C Carbonates are generally characterized by dolomitic layers interspersed by Anhydrites. In the ZEZ3C Carbonates these dolomitic layers are typically 10-50 cm thick whereas the interspersed Anhydrites range in thickness cm to dm. In the ZEZ2C Carbonates the dolomitic and interspersed Anhydritic layers are much thicker (both 4-5 m).

In contrast to both TUB and ROW, Halites are virtually absent in TUM (apart from a Shale/Halite mixture on top of the ZEZ3C), although the carbonate reservoirs in all three gas fields are very comparable. The reason is most likely the more intense tectonic activity, causing the salts being "squeezed" out over geological time scales. That means the sealed cap rocks in TUM are not salts but clay-like rocks (e.g. shale, clay stone, siltstone etc.), *therefore it was not necessary to study Halite dissolution and induced subsidence in TUM*. However, also here both carbonate reservoirs ZEZ2C and ZEZ3C are bounded to the base and top by the laterally continuous Anhydrite layers.

ZEZ2A and ZEZ3A Anhydrite (CaSO₄): Worldwide many depleted oil and gas reservoir are capped by anhydrite cap rock. Generally, the ZEZ2A and ZEZ3A Anhydrite are almost impermeable (K<10 nD, Hangx et al. 2011), non-soluble (solubility in pure water at 20°C: 2g/L, Klimchouk 1996) and un-faulted. When exposed to water, Anhydrite readily transforms, at the atmosphere pressure and up to 58°C, to the more commonly occurring gypsum ($CaSO_4 \cdot 2H_2O$) by the absorption of water, increasing its volume by up to 60.8%. Above 58°C Anhydrite converts into the stable form of $CaSO_4$, no more transformation into gypsum happens (Gysel 2002, Klimchouk 1996). In the TUB and ROW fields, the Anhydrite is not totally free of small fractures (Figs. 10-12 in the geology report: EP201310201845).

It is logic that the laterally continuous and non-soluble anhydrite layers directly above and below the Carbonate injection reservoir form a perfect barrier and prevent the injection fluids in the reservoirs to get in contact with the under- and overlying halite sections. Otherwise, the halite in direct contact with the reservoir Carbonates would have been dissolved and removed by the formation water (NaCl in the formation water: 210-270 g/L, NaCl in the salt saturated water: 300-320 g/L) during the long geological age of the Zechstein basin (more than 200 million years) or the formation water in the reservoirs should have become fully saturated. It can be concluded that the reservoirs ZEZ2C and ZEZ3C are directly capped by the anhydrite cap rock and there are no direct contact of the reservoirs with the Halites as well as no existence of big anhydrite windows, which have been found e.g. in a German potash mine.

The fault juxtapositions, the corresponding minimum and maximum fault throws as well as "juxtaposition diagrams" were derived from the geometrical aspects of the Zechstein 2 & 3 Cycle (Fig. 16 in the geological report: EP201310201845). The geometrical aspects of ZEZ2 & ZEZ3, the distance from well to fault (50 – 1,000 m), the fault length (50 – 2200 m), the maximal fault offset (5 – 80 m) and the rules to predict fault juxtaposition (Carbonate/Halite, Carbonate/Anhydrite, Carbonate/Carbonate) are realistic and logic.

The worst case scenarios regarding Halite dissolution must be a shorter distance from well to fault, a longer fault with a smaller off-set, and the cross-fault juxtapositions between the injection horizons (ZEZ2C & ZEZ3C) and the halite horizons (ZEZ2H & ZEZ3H): Z2C-Z2H juxtaposition with a fault throw of 25-75 m, Z2C-Z3H juxtaposition with a fault throw of 120-215 m and Z3C-Z3H juxtaposition with a fault throw of 30-130 m. In such cases the faults are unique elements separating the injection horizons from the halite horizons. Fortunately, near these faults further reduction in both horizontal and vertical permeability in the carbonate formations is expected due to salt creep deformation which causes fractures near the faults to be filled with salt.

Average matrix permeability measured from core plugs of ZEZ2C and ZEZ3C is around 0.1 mD and bulk fluid-flow is expected to be governed by natural fracture distribution. The (horizontal) permeability K_h measured from well ROW-5 in a more densely fractured area is in the order of 1D, and from well ROW-9 in the un-faulted area in the order of 10 – 20 mD. The vertical permeability K_v is limited and governed by the interlayered anhydrite banks in the ZEZ2C and ZEZ3C Carbonates, hence suggested to having a level of the average matrix permeability of 0.1 mD measured from core plugs (***too high because of too small sample size***

as well as no sufficient consideration of interspersed Anhydritic layers). The K_v / K_h ratio is accordingly estimated to a maximum range from 0.01 – 0.005 (0.1 mD/10 mD - 0.1 mD/20 mD) in un-faulted reservoirs and 0.0001 (0.1 mD/1000 mD) in faulted reservoirs, *which is a little higher than the reported range of 10^{-4} to $5*10^{-3}$ for un-faulted areas (see the geology report: EP201310201845).*

But in the Halite dissolution report (EP201310203080) the K_v / K_h ratio (10^{-3} and 10^{-4} used in most cases) has been used as a variable to test the sensitivity of the model results to this factor, for a sensitivity analysis around establishing convection cells the much higher K_v / K_h ratios between 10^{-3} and 1 were used. In the subsidence report (EP201310204177) a single K_v / K_h ratio of 10^{-2} was used. In summary, the used range of the K_v / K_h ratio is based on but in some cases much higher than the measurements and estimations, therefore conservative, realistic and acceptable.

3. Review of the Halite Dissolution Report (EP201310203080)

It is logic that Halite dissolution can only occur when the low saline production water, re-injected in the Zechstein carbonate reservoirs (ZEZ2C & ZEZ3C Carbonate) of the TUB and ROW old gas fields, is able to connect to and flow directly past Halite rock (= rock salt).

3.1 Modelling assumptions of halite dissolution

Reservoir properties of the ZEZ2C & ZEZ3C Carbonate: The used parameters and their ranges in Table 2.1 of this Halite dissolution report (EP201310203080) are partially assumed in consideration of the well test results (e.g. absolute fracture permeability 25 mD and a range 25-250 mD, effective medium permeability 177 mD and a range 13-2500 mD), partially measured from core plugs (matrix porosity 3% and a range 1-6%, matrix permeability 0.1 mD and a range 0.1-10 mD), partially derived from a history matching to gas production data (e.g. fracture porosity 1% and a range 0.25-1%) and partially based on core observation (e.g. fracture aperture 1 mm and a range 0.5-2 mm, matrix block dimension 0.2 m and a range 0.1-0.4 m). *In summary, the used parameters and their ranges in Table 2.1 (EP201310203080) are representative and suitable.*

The Halite dissolution methods 1 & 2 and their implementation in Dynamo-MoReS: Both models can be used to simulate the Halite dissolution and the brine transport with a few assumptions. E.g. with the first method the dissolved cavity geometry and the porosity development of halite can be explicitly calculated. In the second method (mass tracking) the salinity of water is tracked with consideration of total mass balance. However, both methods neglect the fact that the halite dissolution on the water-halite contact can generate a cavity near in the halite formation near the contact surface, but the not dissolved halite formation remains still nonporous and impermeable. The Darcy law is applicable for flow only in porous median and not in the dissolved cavity. Furthermore, the induced permeability change is not easy to assume. Also the time-dependent dissolution process is not explicit considered. *The method 2 is a simplified version (without explicit dissolution process just a balance between the needed maximum Halite mass in pore water of the carbonate cells at the carbonate-halite boundary and the dissolved halite mass of the halite cells at the carbonate-halite boundary) of the method 1.*

Halite dissolution scenarios: Halite can be dissolved only in direct contact/connection with not fully saturated water (e.g. NaCl concentration < 300g/L). In this report, three near-wellbore scenarios and two far-field scenarios identified, described and modeled with the simulator Dynamo-MoReS:

Scenario 1 – Cement crack (3.1, 4.1 & 5.1 in the Halite dissolution report: EP201310203080)

In fact, a poor wellbore cement job can induce cracks in cement, which can be easily detected by monitoring programs (e.g. cement bond logging) and must be repaired quickly. Under the assumption of a crack in the cement section between the top carbonate and the bottom halite (= mightiness of the anhydrite) and the injection plan (water salinity: 100g/L, injection rate: 2,500 m³/d, injection duration: 20 years, shut-in period: 1,000 years), it would last more than 1,000 years for the salinity to change across the 10 m anhydrite interval because the dominated flow mechanism is the diffusion process. *This assumption is conservative but not conservative enough, because the crack in the annual wellbore cement could be extended from the top carbonate across the anhydrite and halite interval to the top halite. However, it takes the same time duration of more than 1,000 years for the salinity to change across only 10 m anhydrite interval. In this time duration all cracked cement sections should have been detected and repaired.*

Scenario 2 – Cement crack and casing leak (3.2, 4.2 & 5.2 in the Halite dissolution report: EP201310203080)

In comparison with the scenario 1, the assumed crack is longer (extended to the middle halite) and connected additionally with a leak point in the wellbore casing located opposite the halite interval). It is logic that the amount of water passing through the casing leak is limited by the conductivity and the size of the cement crack. A constant height (5 cm) of the casing leak and 3% of total injected water through this casing leak into the halite are assumed. *The assumptions are, because of no consideration of salt creep and cavity convergence, very conservative and hence acceptable.*

According to the report, the dissolved cavity volume grows at a constant rate of ca. 20 m³/year. This result is logic and in line with the constant water flow rate through the leak point. *Following is a simple calculation of halite mass balance:*

- ➢ *Water (very low salinity: 1,000 ppm) injection rate in one injection well: 1,000 m³/day (not 2,500 m³/day after the email from Eilard.HS@shell.com on 9th March 2016!) x 365 day/year ⟹ 365,000 m³/year*

- ➢ *0.03(not 3% after the email from Eilard.HS@shell.com on 9th March 2016!) of total injected water passing through the casing leak: 365,000 m³/year x 0.03% ⟹ 109.5 m³/year*

- ➢ *7 m³ injected water with the salinity of 1,000 ppm can dissolve approximately 1 m³ halite in case of 100% salt saturation with the salinity of 300,000 ppm: 109.5 m³/year the injected water passing through the casing leak ⟹ 15.6 m³/year halite dissolution < 20 m³/year in the Halite dissolution report (EP201310201080), therefore, the reported result is conservative.*

- ➢ *The halite dissolution occurs only at the water-halite contact surface, therefore, the larger the water-halite contact surface the more the halite dissolution as well as the bigger the dissolved salt cavity in the same time duration. At the beginning the water-halite contact surface was only 5 cm height cylinder, after 20 years of water injection it becomes a cylinder cavity of ca. 15 m height and 3 m radius (see Fig. 5.2 in the Halite dissolution report: EP201310201080). The calculated cavity volume in the halite formation grow at a constant rate 20 m³/year in 20 years of the water injection, which is the outcome of the modeling with some simplifications and limitations.*

- ➢ *A range of the cavity convergence could be estimated according to the measured salt convergences of a heated open well filled with crushed salt in the framework of DEBOVA-II field test in the Asse mine at a depth of 800 m (Rothfuchs 1999) and of the*

30 m milled open well section at a depth of 3,100 m in the Altmark natural gas field (Hou et al. 2012a): It is between 15% /year and 85%/year.

➢ *Most important of all is that a leaky casing must be detected and repaired by the operator as soon as possible and not later than e.g. a half year, such that a maximum cavity volume of ca. 1,955 m^3 in the halite formation should not be exceeded in this scenario.*

Scenario 3 – Hydraulic fracturing (3.3, 4.3 & 5.3 in the Halite dissolution report: EP201310203080)

In this scenario, a hydraulic fracture is assumed to be induced by water injection and to extend over the full height of both the carbonate and anhydrite layers with a half length of 70 m in the anhydrite formation and 350 m in the carbonate formation. *This assumption is very conservative. Generally, a hydraulic (not natural) fracture can only be initiated and propagated if the pore pressure exceeds the breakdown pressure ($>>\sigma_h$) and the propagation pressure ($>\sigma_h$), respectively. Therefore the injection pressure (value unknown) and the maximum pore pressure in both the ZEZ2C and ZEZ3C reservoirs must be obviously smaller than σ_h (value unknown) in the carbonate formations. In the worst case, however, a hydraulic fracture can be initiated and propagated in the carbonate formation without extending vertically into the so-called stress barriers (i.e. the top and bottom anhydrite formations) unless a direct pathway through faults exists (see scenarios 4 & 5). According to my experience with the Northern German Basin, the value of σ_h in the Zechstein halite, anhydrite and carbonate layers is about 100%, 85-95% and 60-80% that of σ_v, respectively, such that any hydraulic fracture that develops in the carbonate formation can only be propagated in the horizontal direction, and therefore limited in the vertical direction (Hou et al. 2012c).*

Scenario 3 was modeled with a simple 3D box and the Halite dissolution method 1 (void space modeled explicitly). But this model is unstable and only 1 day of water injection could be simulated. According to the results the dissolution occurs at the fracture-halite boundary, which is logical. A horizontal layer of dissolution is also generated. However, the simulation is not stable and must be stopped after only 1 day of water injection. The reasons may be firstly due to the assumption that fracture porosity is 1 and secondly that flow in the fracture is not Darcy flow and much faster and that it requires much smaller time steps to achieve the fluid mass balance. As above mentioned, Halite dissolution method 2 is much simpler and numerically more stable than method 1.

In summary, the following conclusions and suggestions can be drawn:

➢ *Based on the results of only 1 day of water injection, no judicious analysis and conclusions can be drawn.*

➢ *The injection pressure (unknown) and the maximum pore pressure in the ZEZ2C and ZEZ3C reservoirs must be obviously smaller than the minimum horizontal stress σ_h (unknown) in the carbonate formations, in order to avoid creation of any hydraulic fractures in the carbonate formations.*

➢ *A hydraulic fracture could possibly form in the carbonate formation but not in the anhydrite formation due to the existence of stress barriers. Therefore scenario 3 is much too conservative.*

➢ *The Halite dissolution method 2 should be resorted to. If it also proves unstable, the half length of hydraulic fracture in the anhydrite formation should be reduced from 70 m to e.g. just 1 m.*

Scenario 4 – Water flowing past juxtaposed Halite in faulted areas (3.4, 4.4 & 5.4 in the Halite dissolution report: EP201310203080)

Scenario 4 studied a critical situation of fault juxtapositions whereby a fault juxtaposes halite against the carbonate reservoir laterally. In this first far-field scenario, 6 different cases (see Tab. 5.1 in NAM report EP201310203080) were simulated for the injection period of 20 years with a constant water injection rate of 2,500 m^3/d, and the halite dissolution method 1 was chosen in the Dynamo-MoRes. The study of these 6 cases is quite interesting as it gives the influence of well-fault distance (140 m or 1,000 m), fault throw size (25 m, 35 m or 40 m) and the K_v/K_h ratio (0.001 or 0.0001).

The following assumptions are used in all the 6 cases: Single porosity system in the carbonate formations, no explicit consideration of faults in the carbonate on carbonate contact across the fault (no fault offset and length, no permeability difference between near-fault and far-fault areas as well as between the fault and the carbonate formations), no lateral flow from the carbonate formation into the adjacent anhydrite or halite formation, no dissolution of the anhydrite, etc. Below is the analysis of concrete parameters used in the numerical modeling:

➢ The fault throw of 35 m and the carbonate on carbonate contact across the fault of 15 m corresponds to the carbonate-halite interface of 25 m (cases 1 – 4 in Table 5.1), whereas cases 5 and 6 have the carbonate-halite interface of 30 and 15 m, respectively. It is clear and logic that the longer a carbonate-halite interface the more the halite dissolution. Because the average Zechstein 2 & 3 halite and carbonate interval are 8 m & 65.3 m and 39.4 m & 68.9 m respectively (see Tab. 2.1 of the subsidence report EP201310204177), a carbonate-halite interface of 15-30 m is a reasonable assumption.

➢ The distance from well to fault varies from 50 to 1,000 m in the geological report (EP201310201845) vs. 140 m and 1,000 m in the dissolution report (EP201310203080). It is logic that the shorter the distance from well to fault the greater the halite dissolution.

➢ The maximal fault offset is between 5 and 80 m (NAM report: EP201310201845), which is not noticed in the 6 dissolution cases (NAM report: EP201310203080).

➢ The K_v/K_h ratio of 0.001 or 0.0001 is used in the 6 dissolution cases. As mentioned in my review of the geology report (EP201310201845), the K_v/K_h ratio of the carbonate formation is estimated between 0.01 and 0.005 for un-faulted reservoirs and 0.0001 for faulted reservoirs. Naturally, the bigger the K_v/K_h ratio, the more injection water flows across and up a fault to the carbonate-halite interface.

In summary, all assumptions for the 6 dissolution cases are reasonable, some being conservative and others not conservative enough. The simulation results are also logical, e.g. the simulations indicate that halite could be dissolved on both sides of the fault when injection water reaches the carbonate-halite interface. *The question of "how much halite could be dissolved in the 20 years injection phase" was not answered in all the 6 cases.*

In the second part, namely the investigation of the post injection behavior, only a small 2D box model (5 m x 15 m) of the carbonate reservoir was simulated by using the halite dissolution method 2. The modeled carbonate reservoir is filled with fresh water and the dissolution script is applied to the right side face of the model with 2.5 m (from the model top to middle) exposed to halite (Fig. 5.10 in the dissolution report: EP201310203080). A K_v/K_h ratio of 1 is assumed. Since there is no water injection in the post injection phase anymore and the dominating flow mechanism, as a result of the halite dissolution, is the density driven convection and not the Darcy flow (Fig. 5.11 in the dissolution report: EP201310203080), the

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K_v/K_h ratio should have a much smaller influence on the halite dissolution than in the water injection phase (Fig. 5.12 in the dissolution report: EP201310203080).

The simulation results in Fig. 5.11 and Fig. 5.12 (EP201310203080) show only limited halite dissolutions:

➢ t=1.9 years: A maximum dissolution distance of the order of 0.3 m at the very model top, decreasing quickly with depth.

➢ t =232 years: Almost the same dissolution distance of the order of a few dm for both K_v/K_h ratios of 1 and 0.01 in the whole 2.5 m section exposed to halite.

➢ t =23,200 years: Almost the same dissolution distance of the order of 3.0 m for the K_v/K_h ratio of 0.01 in the whole 2.5 m section exposed to halite, and a range of 1.5-4.0 m for the K_v/K_h ratio of 1.

➢ t =232,000 years: Almost the same dissolution distance of the order of 6.0 m for the K_v/K_h ratio of 0.01 in the whole 2.5 m section exposed to halite.

These halite dissolutions would become even much smaller when the salt creep induced convergence was considered. In fact, the boundary conditions (e.g. model top, bottom and left side: closed or open boundary?) are not given here, but have a great influence on halite dissolution. In case of the closed boundary conditions, e.g. the case of a dissolution distance of the order of 6.0 m for a K_v/K_h ratio of 0.01 in the whole 2.5 m section exposed to halite, it means 15 m^3 (= 2.5 x 6 x 1 m^3) halite dissolved, which needs 105 m^3 water with a salinity of 1.000 ppm, but the whole model has a geometry volume of just 75 m^3 (= 5 x 15 x 1 m^3) and a pore water volume of only 1.8 m^3 (= 75 m^3 x 3% porosity x 80% water saturation). The closed boundary condition was used in all cases.

Scenario 5 – Convection loops at faulted areas in down-dip flanks of reservoir (3.5, 4.5 & 5.5 in the Halite dissolution report: EP201310203080)

Scenario 5 is the second and last of the far-field cases, which studied the direct connection case between the reservoir and the overlying halite formation at faults with a larger offset than the intermediate anhydrite layer. *The assumptions*, that the halite layer is in direct contact with the carbonate formation vertically and that a direct contact length is 1,700 m, *are very conservative*. Such cases are similar to the case of anhydrite-windows (1,700 m without the anhydrite layer). *The selected 5 convection cases, with the given values of 2D model heights (0.3 m, 5 m & 50 m) and K_v/K_h ratios (1, 0.01 & 0.001) (Tab. 5.2 in the dissolution report: EP201310203080), based on a solid and logic analysis are reasonable. Particularly interesting is the observation that case 5 represents the entire Zechstein 2 or 3 carbonate with a K_v/K_h ratio of 0.01 as a worst case scenario for convection driven dissolution.*

All 5 cases are investigated numerically by the halite dissolution method 2 and analytically by the methods developed for CO_2 dissolution in brine. Additional 10 cases (together 15 cases: 3 heights of 0.3, 5 & 50 m and 5 K_v/K_h ratios of 1, 0.1, 0.01, 0.001 & 0.0001) have been studied analytically. The used parameters are almost identical in both analytical and numerical studies except for the initial water saturation of 80% in numerical simulations and 85% in analytical estimations.

The results of numerical and analytical simulations are somehow comparable and indicate that the thicker the carbonate layer (ΔH) and the smaller the K_v/K_h ratio, the longer the time duration ($t_{150,000}$) to attain an average salinity of 150,000 ppm (EP201310203080):

➢ For case of K_v/K_h =1: $t_{150,000}$= 0.2 years (ΔH=0.3 m), 2.9 years (ΔH=5 m), 29.2 years (ΔH=50 m)

- For case of ΔH=50 m: $t_{150,000}$= 29.2 years (K_v/K_h =1), 127 years (K_v/K_h =0.1), 884 years (K_v/K_h =0.01), 7,779 years (K_v/K_h =0.001), 74,562 years (K_v/K_h =0.01).

- For convection case 3 in Tab. 5.2 (ΔH=5 m & K_v/K_h =1): $t_{150,000} \approx$ 3 years (numerical result from Fig. 5.16), 2.9 years (analytical result from Tab. 5.3)

- For convection case 6 in Tab. 5.2 (ΔH=50 m & K_v/K_h =0.01): $t_{150,000} \approx$ 5,000 years (numerical result from Fig. 5.19), 884 years (analytical result from Tab. 5.3)

- For convection case 5 in Tab. 5.2 (ΔH=50 m & K_v/K_h =0.001): 8,000 years $<< t_{150,000} <$ 50,000 years (numerical result from Fig. 5.17c-e), $t_{150,000}$= 7,779 years (analytical result from Tab. 5.3)

- For the analytical solution case in Tab. 5.3 (ΔH=50 m & K_v/K_h =0.0001): $t_{150,000}$= 74,562 years

- The analytically calculated time duration $t_{150,000}$ is comparable with the numerical solution in case 3, but much shorter in cases 5 & 6. This means that the analytical method is even more conservative than the conservative numerical model.

- 50 m carbonate formation with 3% porosity and 80% water saturation can dissolve only 0.17 m of halite layer at a salinity of 300,000 ppm (=50 m x 3% x 80% /7) and just 0.086 m at a salinity of 150,000 ppm, respectively. The results of cases 5 & 6 mean that it takes ca. 880 years & ca. 7,800 years to dissolve 0.085 m of the halite layer.

4. Review of the Subsidence Report (EP201310204177)

In order to study the potential subsidence due to halite dissolution, the following conditions were assumed in this report:

- It is logic that Halite dissolution can only occur when the low saline production water, re-injected in the Zechstein carbonate reservoirs (ZEZ2C & ZEZ3C Carbonate) of the TUB and ROW depleted gas fields, is able to contact and flow directly past the halite rock (= rock salt). In reality, both carbonate reservoirs ZEZ2C and ZEZ3C are normally bounded to the base and top by laterally continuous anhydrite layers. The injection water in the in un-faulted areas of the reservoirs has no direct contact with the halite layer, thus no halite dissolution takes place. *Therefore, the assumptions of no anhydrite layers and a direct contact of the injection water in the carbonate formation with the halite layer in the whole reservoir of 5 km diameter are very conservative.*

- The assumption of the fully salt saturation with a salinity of 300,000-320,000 ppm is very conservative, because the formation water salinity measured from the wells TUB-4 and ROW-9 is between 210,000 – 270,000 ppm.

- A K_v/K_h ratio of 0.01 for all carbonate formations (ZEZ2C & ZEZ3C) is assumed in the base case. As analyzed in my review of the geology report, the K_v/K_h ratio is between 0.01 and 0.0001, and therefore this assumption is also conservative.

- The subsidence is deduced in this report only by dissolution of the halite layers in direct contact with the carbonate formations e.g. in faulted areas. No halite dissolution is generally expected in un-faulted areas. Therefore, *the assumption of no explicit consideration of faults for the subsidence calculation is justifiable and acceptable* in combination with the assumption of a direct contact between the halite and carbonate

formations in the whole model and due to almost no influence on the water flowing towards the down dip flanks of the reservoir.

➢ The average interval thicknesses of all Zechstein 1-3 formations in Tab. 2.1 (EP201310204177) are in line with the geology report (EP201310201845).

➢ In reality, Darcy flow and density driven convection or diffusion (hydraulic process), halite dissolution (chemical process), salt creep and subsidence (mechanical process) are coupled to each other and have interactive influences. The sequent approach "firstly Darcy flow of the injection water, secondly halite dissolution till all injection water fully salt saturated, then conversion of the halite dissolution volume into a dissolution or shrinkage strain (Eqs. 1-3 in the subsidence report: EP201310204177) at the top carbonate as input parameter for a geomechanical modelling to calculate the subsidence" used in the subsidence report (EP201310204177) is applicable because the final maximum subsidence is independent of the coupled and sequent approaches, but does not consider the HMC-coupled effects and the explicit salt creep. As a consequence thereof, the subsidence process could become a little slower.

➢ The converted dissolution or shrinkage strain is added as loading at the top carbonate. This approach could induce a tensile stress at the carbonate-halite contact, a compaction of the carbonate layer and a volume loss/storage in the carbonate layer even using a high Poisson's ratio (*value unknown*). As consequence thereof, a little smaller subsidence could be simulated.

➢ The water injection rate of 4,000 m^3/d (even only into ZEZ3C, not ZEZ2C) over a period of 20 years, which is much bigger than the used injection rate of 2,500 m^3/d in the dissolution report (EP201310203080), is used numerically to calculate the subsidence in the NAM report (EP201310204177). *In the Halite dissolution report, which aims at investigating the salt dissolution in the area around an injection well, a rate of 2,500 m^3/d is used. This rate represents the expected maximum injection rate per well. In contrast, in the subsidence report, the relevant rate is linked to the total volume injected in a single reservoir rather than the injection volume in a single well. This equates to maximum 4,000 m^3/d. The used injection rates of 2,500 m^3/d for a single well and 4,000 m^3/d for a single reservoir are the maximum values in each case respectively and thus conservative.*

The simulated results of injected water distribution at end of the injection, 20 years and 1,000 years after shut-in (Fig. 3.1 in the subsidence report: EP201310204177) are logic and understandable. In the following, the calculated subsidence on the ground surface is analyzed:

➢ The subsidence bowl, as the result of the shrinkage strain loading, has a maximum of some 12 cm in the center for the base case of the carbonate porosity of 3%.

➢ In a more conservative case of the carbonate porosity of 6% and a concentrated dissolution, the shrinkage strain almost increases 3 times and the maximum subsidence grows from 12 to 14 cm in a more confined bowl.

➢ The above mentioned two simulations do not consider time dependent subsidence.

➢ The total and finale volume of the subsidence bowl must be somehow same as the sum of the dissolved halite volume, which can be calculated from the injection water over 20 years: 29.2 MMm^3 = 4,000 m^3/d x 365 d/year x 20 years. About 7 m^3 injection water can dissolve 1 m^3 halite, 29.2 MMm^3 injection water will dissolve a halite volume of 4.17 MMm^3 as well as induce a subsidence bowl volume of 4.17 MMm^3. When this dissolved halite volume is evenly distributed in the whole top carbonate

surface area (= contact area with the overlying halite layer) of about 16 km^2 (e.g. a circle with a radius of 2.25 km), only 0.26 m thick halite layer is dissolved.

➢ 26 cm is less than 0.05% of the average halite thickness (127 m for the TUB field and 67 m for the ROW field) overlying the upper (ZEZ3C) carbonate injection reservoir.

➢ *The dissolved halite layer of 0.26 m with a radius of 2.25 km and an average depth of 1 km must induce the same maximum subsidence of 0.26 m on the surface, because the corresponding influence area with an additional radius of radius 1.88 km (= 1 km depth x cot28°) is smaller than the dissolved area with a radius of 2.25 km (Hou 1997).*

➢ *The above calculated maximum subsidence of 0.26 m becomes even smaller if the uplift on the ground surface resulting from the 20 years water injection is considered (Hou et al. 2012b).*

In summary, a maximum subsidence of 0.26 m will only be reached due to the time dependent halite dissolution process firstly after a few thousand years (K_v/K_h =0.001) or even after a few ten thousand years (K_v/K_h =0.0001). The corresponding subsidence rate is too small to be measured and the geo-risks are therefore negligible, even under the above mentioned conservative assumptions.

Based on my review of all three reports, it can be concluded that the study assumptions are conservative or even too conservative; modelling approaches and conclusions are logic, realistic and acceptable; the long term stability of the halite seal (e.g. cavern development, breach of confinement) due to the halite dissolution in the low salt-saturated injection water is confirmed; and the reported large scale volumes of fresh water injection in the Zechstein carbonate reservoirs (ZEZ2C & ZEZ3C) can be a sustainable safe operation in the long-term (more than 1,000 years).

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