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TNO report

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Injection-Related Induced Seismicity and its relevance to Nitrogen Injection: Description of Dutch field cases

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Contents

1 Introduction

Pressure maintenance by injection of nitrogen into a reservoir is considered to be one of the potential options to mitigate induced seismicity during gas production. However, injection of nitrogen itself may be the cause of unwanted induced seismicity. At this stage it is unclear what seismic hazards are related to nitrogen injection.

In literature, numerous field cases are described of injection-related induced seismicity, e.g. related to deep waste water injection, hydraulic fracturing for shale gas, Enhanced Oil and Gas Recovery (EOR and EGR) and Enhanced Geothermal Systems (EGS). NAM requested TNO to perform a generic study to estimate the potential for induced seismicity caused by the injection of nitrogen in a producing gas reservoir and to specify general operational guidelines for nitrogen injection to reduce the potential of injection-related seismicity. As part of this generic study, a review of the literature on injection-related induced/triggered seismicity worldwide was performed. Results of this literature study have been reported in TNO-report 2014 R11761. The next part of the study is subject of the current report and focusses on Dutch injection field cases: A description and general analysis is made of a number of injection field cases in The Netherlands, i.e. the underground gas storage sites of Norg, Grijpskerk and Bergermeer, and the water injection cases of Borgsweer, Weststellingwerf and the Twente water disposal fields. General characteristics of the fields, in terms of geology, reservoir characteristics and faults, pressure evolution and the ‘lessons learned’ on the relation between injection, seismicity, operational strategies and the occurrence of seismicity are presented in this report. This description and general analysis of the field cases is based on data publicly available for Bergermeer UGS and Weststellingwerf water injection, whereas in case of NAM field cases, data and reports containing background information on field geology and pressure evolution supplied by NAM were used.

Chapter 2 of this report summarizes the main characteristics of the injection field cases described in this report, in terms of reservoir characteristics, volumes injected, pressures and seismicity recorded, whereas the report concludes with chapter 3 in which the main lessons learned from the injection cases are discussed. Literature and reports referred to in the report are listed in the references chapter found at the back of the report.

2 Description of Dutch injection field cases

In this chapter the main characteristics of the injection field cases of Norg, Grijpskerk, Bergermeer, Borgsweer, Weststellingwerf and the Twente water disposal fields are described.

2.1 Norg Underground Gas Storage

The Norg UGS facility is a former partially depleted gas field, located in the north of the Dutch Province of Drenthe. An outline of the gas field is given in Figure 1.

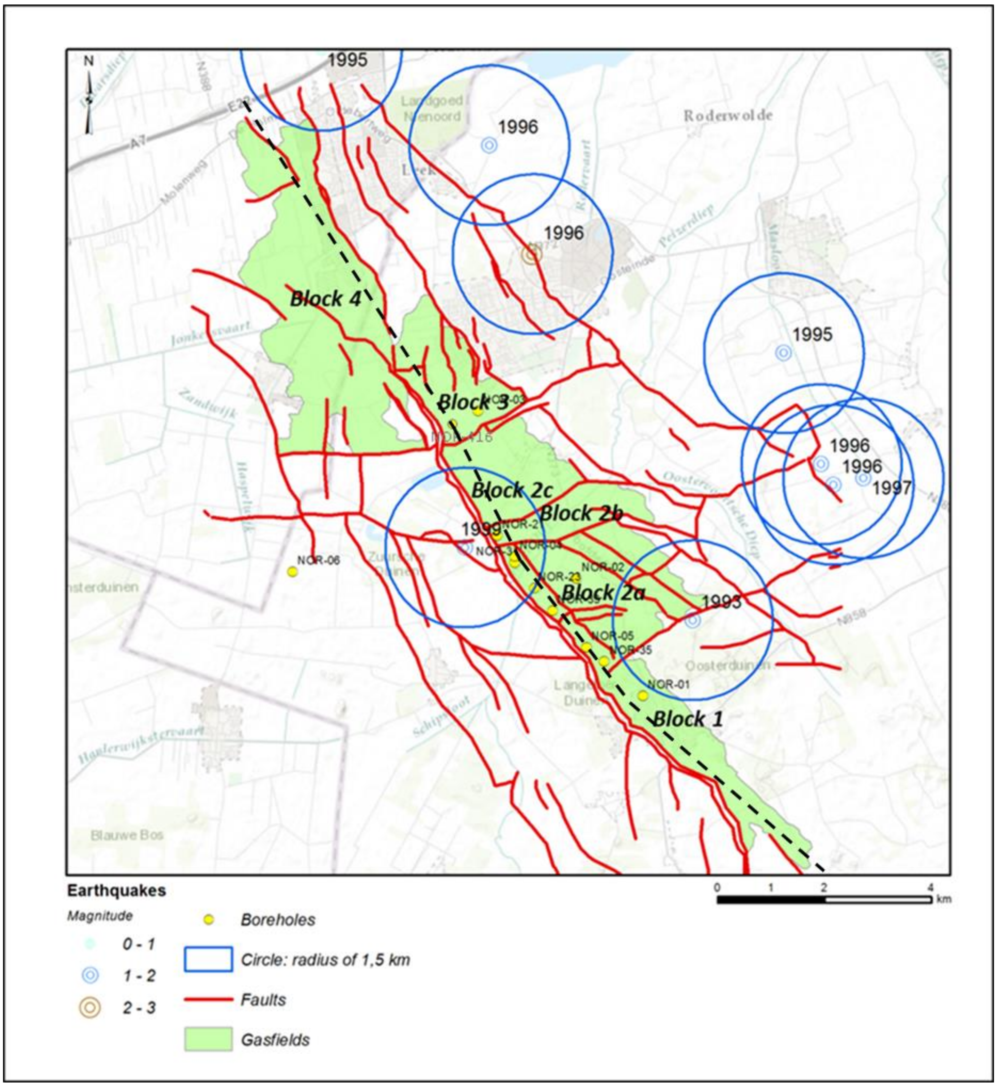

Figure 1. Structural map of the Norg field showing faults, location of production/injection wells and location of seismic events at reservoir level. The blue circle gives an indication of the uncertainty in the location of the seismic events (1.5 km). Dashed line presents the location of the vertical cross section in Figure 2.

The gas field consists of a 2670 m deep NE-dipping Rotliegend Slochteren and Lower Ten Boer sandstone reservoir The Slochteren and Lower Ten Boer reservoir rocks consist of fine to coarse sandstone deposits, with local conglomerates. The reservoir rocks have an average net thickness of 140 m, and the sandstones have porosities of around 18.5% and a permeability of 550 mD (Nagelhout et al, 1997). The geological structure of the field is determined by spill points in the northern and southern part of the field and both NNW-SSE and ENE-WSW striking faults (NAM, 2010-a, Nagelhout et al., 1997). At the western side, the Norg reservoir is bounded by a NNW-SSE striking normal fault, which has a throw up to 250 m (Nagelhout et al., 1997). The reservoir consists of several compartments, which are separated by ENE-WSW striking internal faults (see Figure 1), with fault throws of tens of meters. Fault dips generally vary between 63° and 72° (Nagelhout et al., 1997). The caprock is formed by the Upper Ten Boer and Zechstein rocks, which consist of alternating claystone, dolomites, anhydrites and halites. In the overburden a WE graben structure is present. The reservoir is underlain by Carboniferous rocks, consisting of claystones and coals (NAM, 2010-a, Nagelhout et al., 1997).

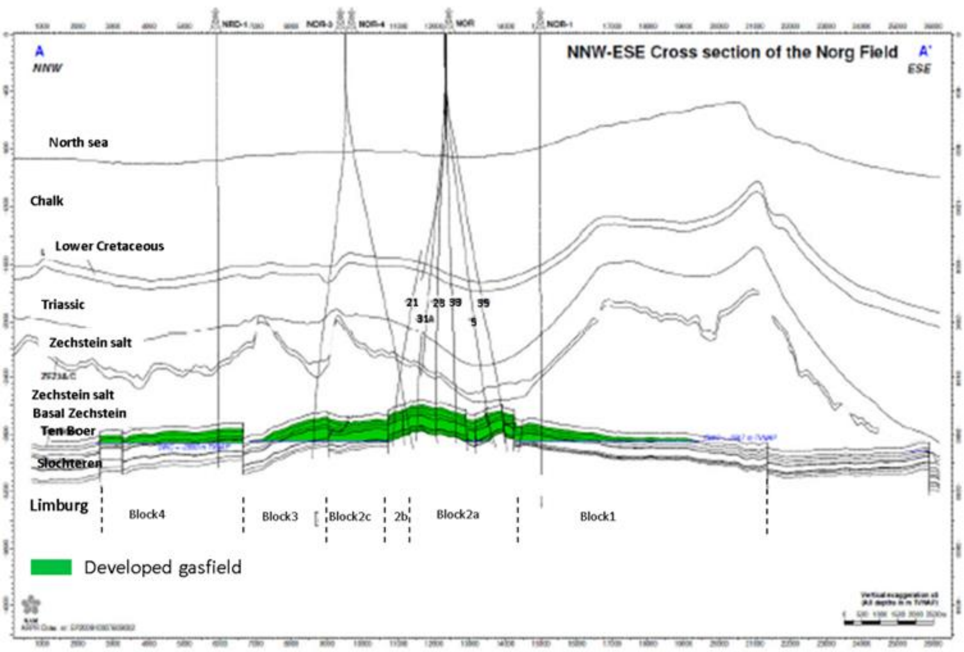

Figure 2. NNW-SSE cross section through the Norg field (NAM, 2010-a). Location of this cross section is shown in Figure 1.

The Norg field was operated as a conventional gas field from 1983 until 1995 (NAM, 2010-a). In the period 1995 to 1997 the field was converted into an underground gas storage facility. Original working gas volume for the Norg underground gas storage facility was 3000 million Nm^3. Recently licenses were obtained to operate the facility at a working gas volume of 7000 million Nm^3 at average pressure levels between 235 bar and 327 bar for all reservoir blocks other than reservoir block 2. For this reservoir block the Norg UGS facility can be operated at slightly higher pressure variations, with average reservoir pressures between 225 bar and 347 bar, and maximum injection pressures of 360 bar (Ministerie van Economische Zaken, 26 juni 2014 and Ministerie van Economische Zaken, 15 augustus 2015).

During the first period of underground gas storage, injection/production wells NOR-5, NOR-23, NOR-31, NOR-33 and NOR-35 located in block 2a, and well NOR-21 in block 2b were used for UGS operations, see Figure 1 and Figure 2. During recent years additional wells NOR-41, NOR-43 and NOR-416 were drilled. Wells NOR-41 and NOR-43 have been operational since end 2014/start 2015, whereas NOR-416 has been since the end of 2012. All injection/production wells are located relatively close to the fault bounding the reservoir in the west at distances less than 250 m. At this boundary fault, reservoir rocks are mainly juxtaposed against Zechstein salt rocks. The gas water contact is encountered at a depth of 2847 m. Gas is injected into the gas-bearing zone of the reservoir. The expected temperature at reservoir level lies around 95 ^{0}C (assuming a temperature gradient of 31 ^{0}C/km). Gas is injected at temperatures generally varying between 90-95 ºC, similar to temperatures at reservoir level (NAM, 2010-a).

Two earthquakes were recorded in the vicinity of the Norg gas field. The first earthquake M 1.5 was recorded during field production in March 1993, before the operation of the gas field as an underground gas storage facility. The second earthquake M 1.1 was recorded in 1999, during the operation as underground gas storage facility. The uncertainty of the (lateral and vertical) location of the earthquakes is large and with lateral uncertainties up to 1.5 km it is difficult to assign the earthquakes to the mapped faults.

Figure 3 shows the evolution of pressures during primary depletion and during UGS operations in the Norg gas field. These pressure data provided by NAM were derived from a history-matched reservoir model. The timing of both seismic events is also shown in this figure. The upper plot in Figure 3 shows the evolution of average field pressures in the reservoir. During primary depletion, the average pressure in the reservoir decreases from 327 bar to approximately 210 bar. During injection and subsequent pressure cycling, average reservoir pressures increase to approximately virgin reservoir pressures, and following pressure cycling takes place within the range of 270 to 327 bar (average simulated field pressures). Bottom hole pressures at the location of the individual wells are also presented in the upper plot. This plot shows that the timing of the first earthquake coincides with low pressure levels in the reservoir. The second earthquake takes place after a period of injection and re-pressurization of the reservoir and coincides with high average field pressures of the reservoir, which are close to initial pressure levels. Pressure plots for individual wells show that during injection, pressures close to the injection well can locally exceed initial reservoir pressures. At the timing of the second seismic event pressure levels at wells NOR-21, NOR-23, NOR-31, NOR-33, NOR-35 and NOR-5 were very close to or even exceeding initial reservoir pressures. No additional seismicity was recorded during higher pressures around the wells in subsequent years.

In Figure 4 production rates during primary depletion and injection/production rates during UGS operations are presented. It can be seen that injection rates in the field vary over time, with maximum injection rates up to 27.5 million m^3/day. The first seismic event during primary depletion took place at relatively high production rates as compared to the earlier production period. During higher production rates in subsequent years no additional seismicity was recorded.

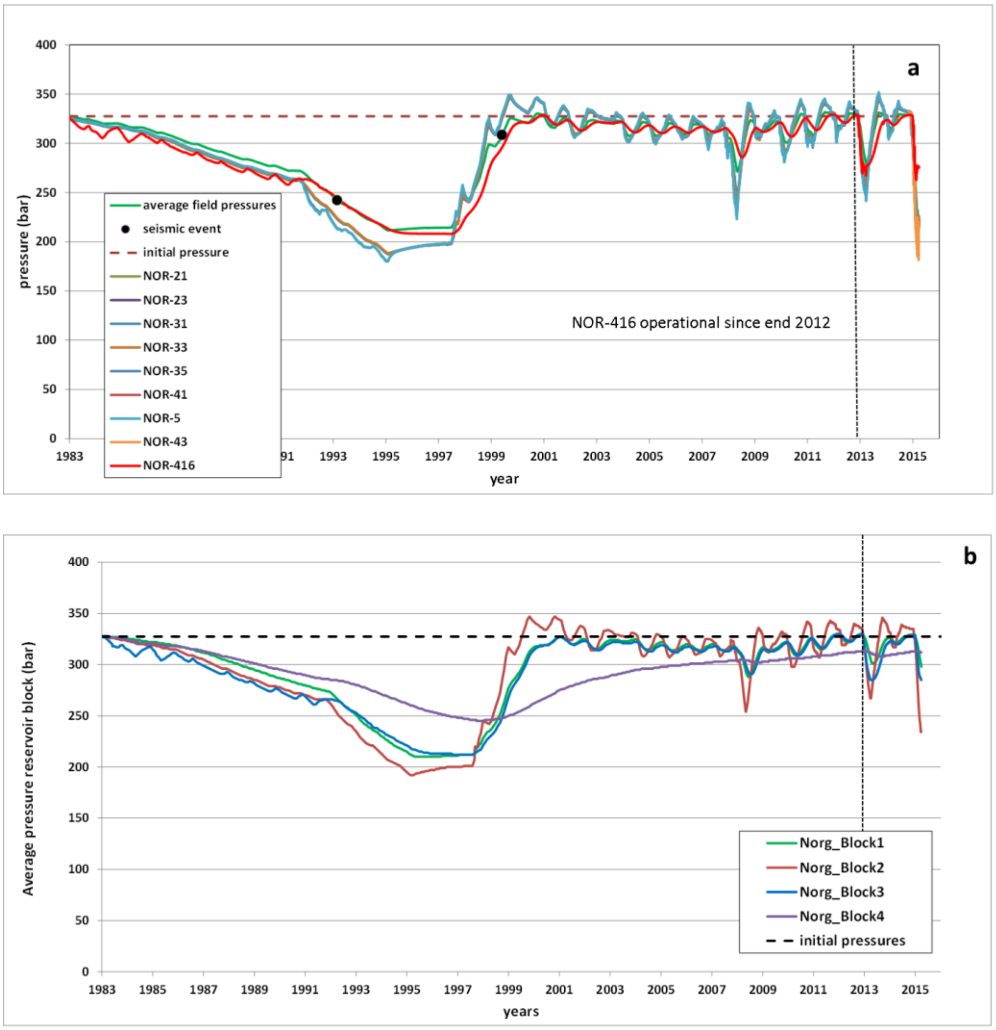

Figure 3. Pressure evolution up to end of March 2015 in the Norg gas field: a) Average field pressure and pressures at individual well locations. The first part (up to 1995) shows pressure evolution during primary depletion of the field, the second part shows pressure evolution during underground gas storage operations. b) Average pressures of the reservoir blocks. Pressures shown are simulated pressures, obtained from a history-matched reservoir model, and were provided by NAM. Well NOR-416 in block 3 is operational since the end of year 2012 and its start is indicated by a vertical dashed line in both pressure evolution plots.

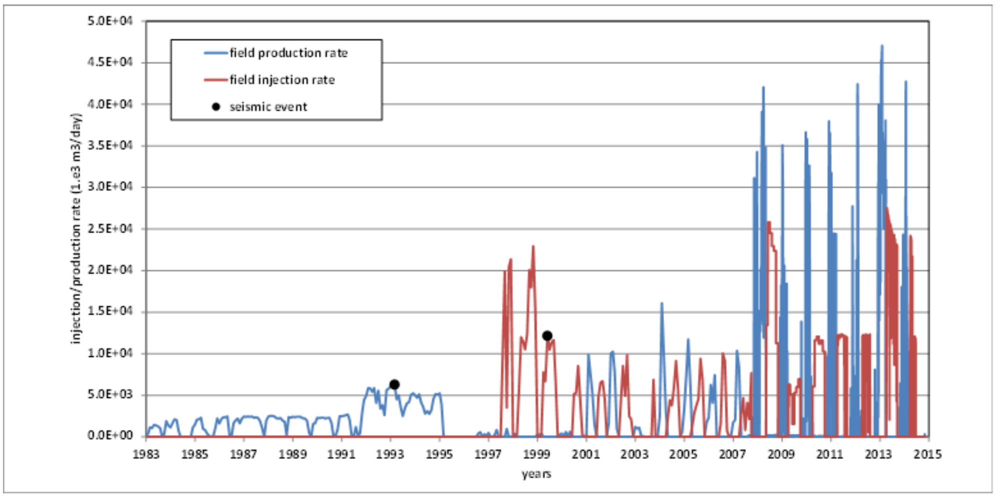

Figure 4. Production and injection rates during primary depletion and during underground gas storage operations (injection/production cycling). These data on production and injection rates up to end March 2015 were provided by NAM.

Pressure differences during UGS operations within the main block (2a) appear to be generally limited to 25 to 30 bar, assuming well data are representative for the entire reservoir in block 2. Figure 3 shows the pressure evolution for well NOR-416, operational since the end of year 2012, and which is located in reservoir block 3 in the northern part of the Norg field. Pressure data in the period before the operation of well NOR-416 indicate that although pressure communication exists between the reservoir blocks 2 and 3, pressure differences over blocks can reach up to almost 70 bar. In a geomechanical modelling study by Nagelhout et al. (1997) pressure differences between the main block 2 and block 1 and 3 are assumed. A pressure difference of 80 bar across the internal faults bounding block 2 is reported in this study for the first injection cycle, which is slightly higher than observed in Figure 3. Pressure differences over faults bounding reservoir blocks during primary depletion were assumed to be limited to 20 bar, which is consistent with the maximum pressure differences between block 2 and 3 obtained from the history-matched reservoir model (25 bar). Pressure differences during primary depletion between reservoir block 3 and block 4, however, are expected to be larger (Figure 3b). The geomechanical modelling study that is performed by Nagelhout et al. (1997) on the potential of fault reactivation during re-pressurization of the reservoir for underground gas storage, uses an irreversible stress path for primary depletion and re-pressurization, and assumes that 52% of the primary elastic deformation is not recovered during re-pressurization. This study shows that fault slip is favored during primary depletion and compaction, but only a very limited amount of additional slip is found for re-pressurization and pressure cycling. Hence, this geomechanical modelling study cannot explain the occurrence of the second seismic event during re-pressurization.

2.2 Grijpskerk Underground Gas Storage

The Grijpskerk UGS facility is a formerly depleted gas field, located in the Dutch Province of Groningen. An outline of the gas field is given in Figure 5, whereas a vertical cross section through the Grijpskerk field is shown in Figure 6. Production in the Grijpskerk reservoir took place in the period 1993-1994, which was followed by a temporary shut-in of the field until the end of 1996 and a conversion of the field into an underground gas storage facility. Since early 1997, the field is used for underground gas storage. In total 10 injection/production wells are used, being the wells GRK-1A, GRK-2, GRK-11, GRK-13, GRK-15, GRK-17, GRK-21, GRK-43, GRK-45 and GRK-47 (for specific locations, see Figure 5). These wells are all located in the south-western part of the reservoir, within 250 m of the reservoir bounding normal fault at the south-west of the reservoir. Well GRK-3 is currently in use as an observation well. Recently, the total working gas volume of the Grijpskerk UGS facility has been extended from 1500 million Nm^3 to 2400 million Nm^3 at reservoir average reservoir pressures between 245 bar and 393 bar (Ministerie van Economische Zaken, 31 januari 2014).

The gas field consists of NE-dipping Rotliegend Slochteren reservoir sandstones at a depth of approximately 3300 m, which have a thickness of around 220 m. The caprock is formed by the Upper Ten Boer and Zechstein rocks, which consists of alternating claystone, dolomites, anhydrites and halites. The reservoir is underlain by Carboniferous rocks, consisting of claystones and coals (NAM, 2010-b).

During primary depletion, reservoir pressures were decreased from an initial value of 393 bar to approximately 340 bar. No seismicity was recorded during the primary depletion phase. From 1997 up to 2015, the average pressure range during cycling for underground gas storage varied between 257 bar and 384 bar. Pressure evolution for individual wells as found in Figure 7 show that during injection and production, pressures close to the injection well can locally be higher and lower, respectively, than average reservoir pressures. Differences between individual injection/production wells can be large, as is shown in Figure 7. During pressure cycling for underground gas storage two seismic events were recorded. The first seismic event of M 1.3 was recorded in March, 1997, at a relatively low average reservoir pressure of around 280 bar. A second seismic event of M 1.5 was recorded only recently in March 2015, at a reservoir pressure of around 270 bar. The uncertainty of the (lateral and vertical) location of the earthquakes is large and with lateral uncertainties up to 1.5 km it is difficult to assign the earthquake to the mapped faults.

In Figure 8 production rates during primary depletion and injection/production rates during UGS operations are shown. It can be seen that injection rates in the field vary over time, with maximum injection rates up to 14.8 million m^3/day. Production rates during UGS operations varied with maximum production rates up to 29.7 million m^3/day. Both seismic events took place during production at average rates of around 9 million m^3/day.

Gas is injected at temperatures between 80 ^{0}C and 95 ^{0}C, which is below the expected temperature at reservoir level of around 115 ^{0}C (assuming a temperature gradient of 31 ^{0}C/km).

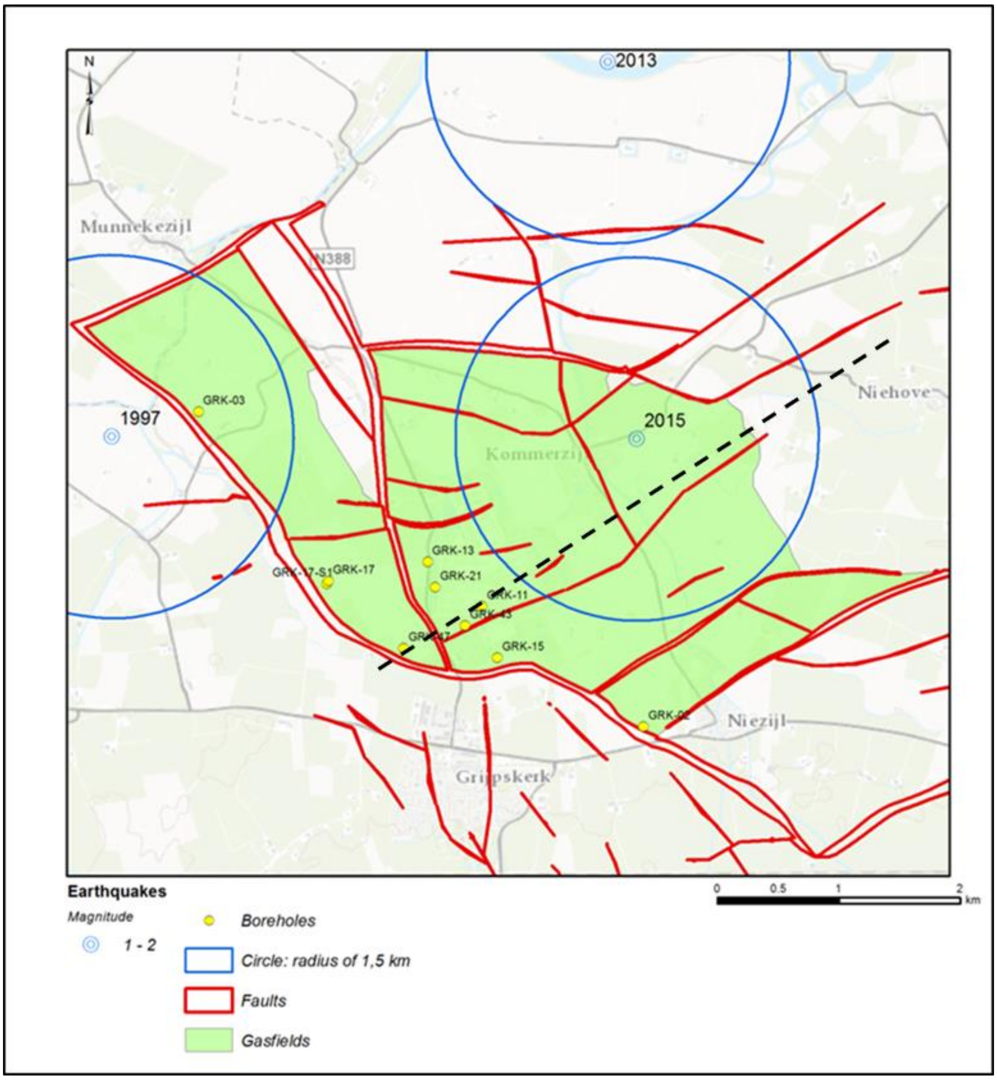

Figure 5. Structural map of the Grijpskerk field, showing faults, location of production/injection wells and location of seismic events at reservoir level. The blue circle gives an indication of the uncertainty in the location of the seismic events (1.5 km). Dashed line presents the location of the vertical cross section in Figure 6.

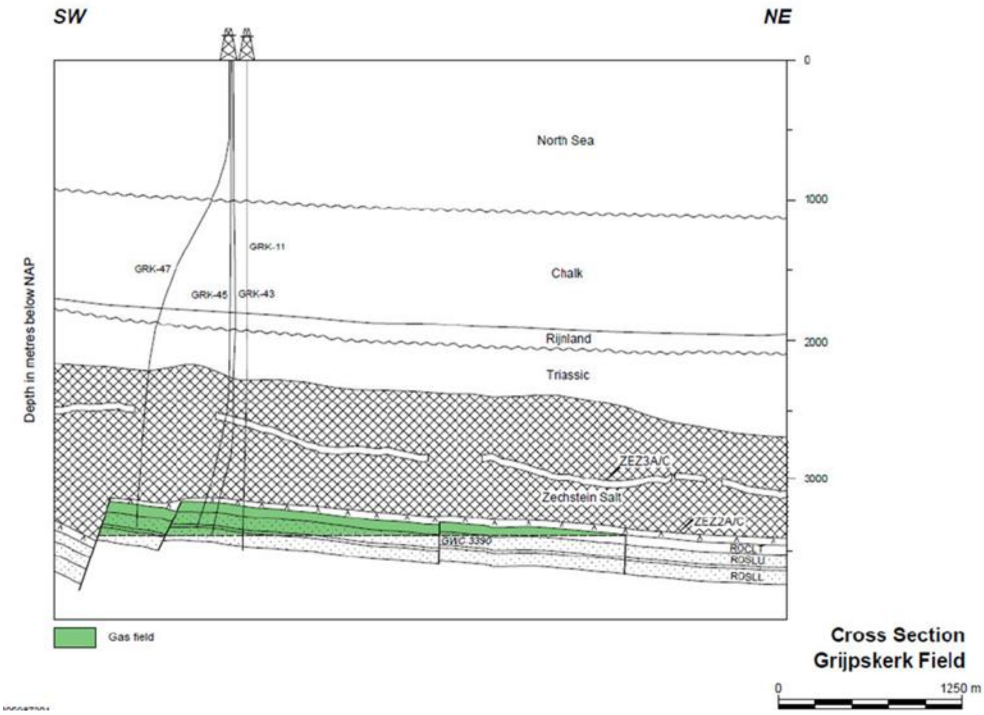

Figure 6. SW-NE cross section of the Grijpskerk field (NAM, 2010-b). Location of this cross section is shown in Figure 5.

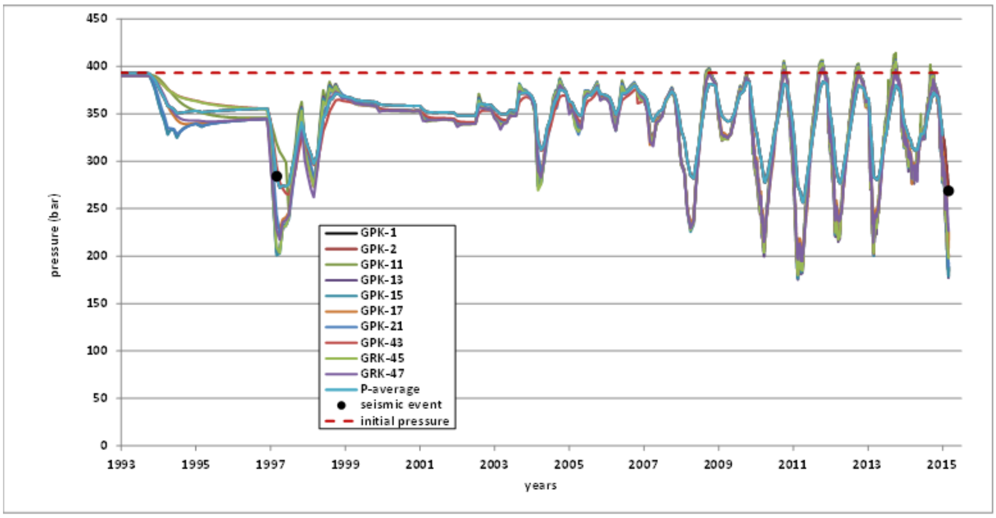

Figure 7. Pressure evolution up to beginning of 2015 in the Grijpskerk gas field: The first part (up to 1995) shows pressure evolution during primary depletion of the field, the second part shows evolution during underground gas storage operations. Pressures shown are simulated pressures, obtained from a history-matched reservoir model, and were provided by NAM.

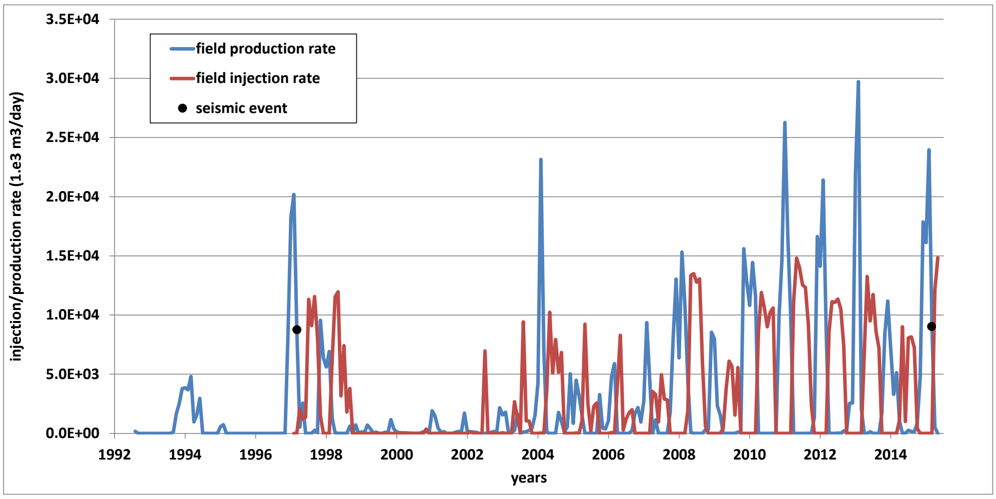

Figure 8. Production and injection rates during primary depletion and during underground gas storage operations (injection/production cycling). These data on production and injection rates up to May 2015 were provided by NAM.

2.3 Water disposal in the Weststellingwerf-01 injection well

The Weststellingwerf gas field is located in the south of the Dutch Province of Friesland and an outline of the gas field and structural map of the field is shown in Figure 9. It consists of three gas-bearing formations, being the Rotliegend sandstones and the Zechstein 1 and Zechstein 2 carbonates (see cross section Figure 10). Gas has only been shortly produced from the Rotliegend and Zechstein 1 formation as production was stopped due to problems with waterflooding of the single production well WSF-01 well (see Figure 9). From 1998 to 2004 gas has been produced from the Zechstein-2 carbonates. Cold water injection started in 2008 (Bois et al, 2013). Since 1998, gas is being produced from the Vlieland sandstone formation in the nearby Noordwolde field (well NWD-01) well, which is located at the southeast of the Weststellingwerf field (see Figure 9 and Figure 10).

The Zechstein carbonates are encountered at a depth between 1860 and 1980 m (see Figure 10). The gas water contact is located at a depth of 1967 m. The gross reservoir thickness of the Zechstein-2 carbonates is 24 m, with a net-to-gross ratio of 58%, an average porosity of 7% and a permeability of 9.5 mD (Total, 2003). The initial reservoir pressure was 222 bar and reservoir temperature is around 77^{0}C. The geological structure of the Weststellingwerf field is characterized by sets of E-W, NW-SE, WNW-ESE, and N-S striking normal faults, both bounding and intersecting the reservoir. A vertical cross section through the field, presenting the location of the well WSF-01 in this field, is shown in Figure 10.

During primary field depletion from 1998 to 2004 pore pressures in the reservoir were decreased from 222 bar to around 52 bar (Bois et al, 2013). During water injection starting in 2008, up to November 2009 pore pressures in the vicinity of the WSF-01 well were increased again up to 150 bar. The temperature decrease is estimated to be around 6.1^{o}C, localized around the injection well WSF-01 (Figure 11).

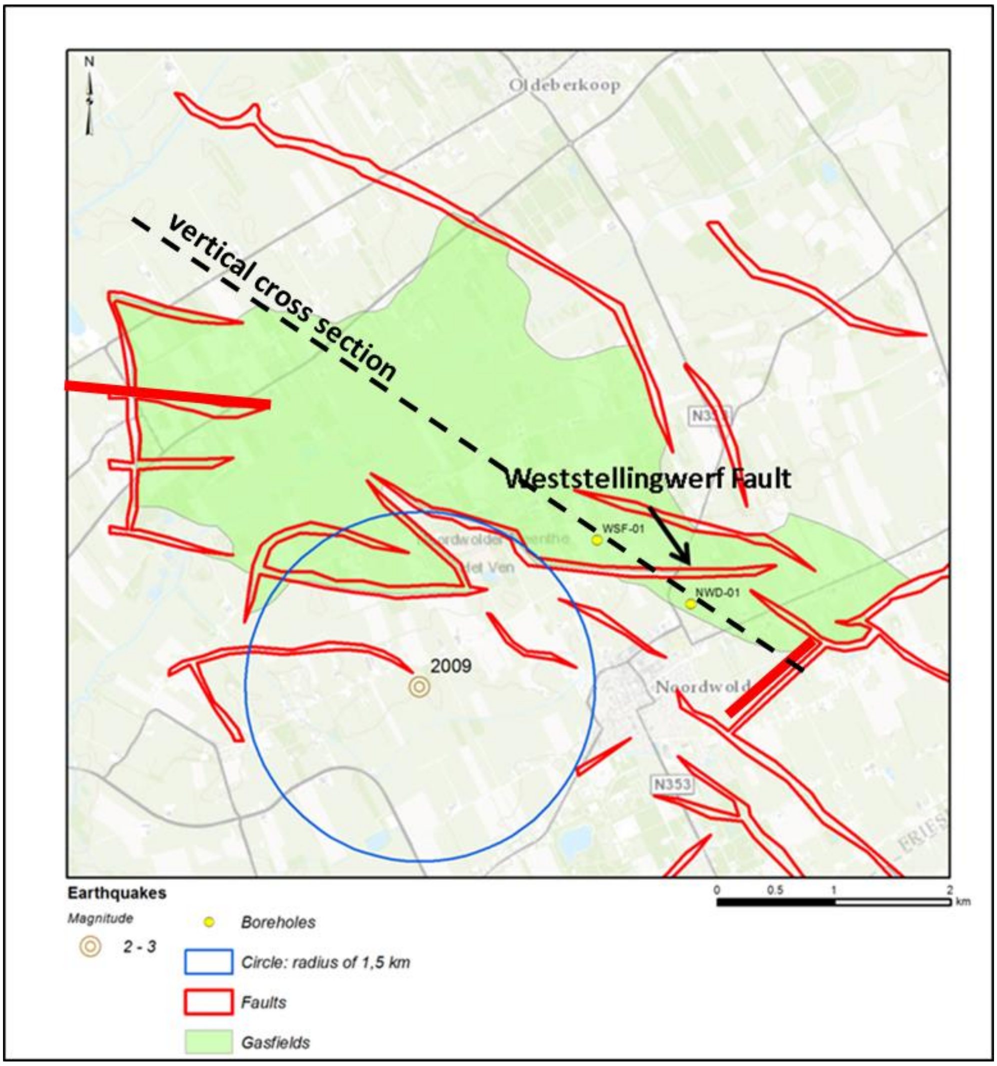

Figure 9. Structural map of the Weststellingwerf gas field, showing location of wells WSF-01 and NWD-01 at reservoir level, faults and recorded seismicity in the vicinity of the gas field. The blue circle gives an indication of the location uncertainty (1.5 km). Dashed line presents the location of the vertical cross section in Figure 10.

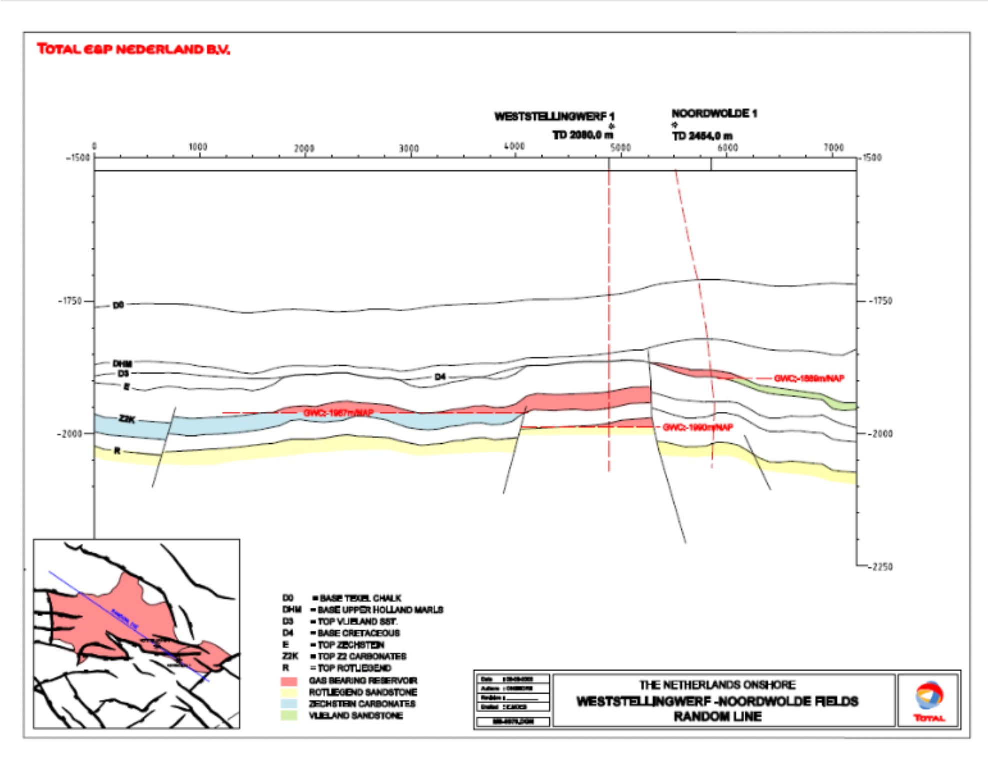

Figure 10. WNW-ESE cross section through the Weststellingwerf field (Total, 2003). Location of this cross section is shown in Figure 9.

In November 2009 an M 2.8 seismic event was recorded by the KNMI monitoring network, in the vicinity of the Weststellingwerf field (for location of seismic event, see Figure 9). Due to its shallow depth of around 2 km, the earthquake is assumed to be induced by subsurface operations. From seismograms, KNMI interpreted a fault movement on an E-W striking normal fault with a source radius of 203±25 m and a stress drop of 8±7 bar (Dost et al., 2012). According to Bois et al (2013) the seismic event can potentially be related to reactivation of the Weststellingwerf fault, which is located at some 300 m to the southeast of the WSF-01 well and has a similar E-W strike as derived for the source mechanism of the seismic event. The occurrence of the seismic event is interpreted to be related to water injection activities in the WSF-01 well, see the publication of Bois et al., 2013.

In this paper the potential mechanisms underlying the seismic event close to the injection well are analyzed. Figure 11 shows the evolution of pressures and temperatures in the reservoir, due to gas production and the injection of water into the field. The authors conclude that stresses on the Weststellingwerf fault moved towards more critical conditions due to pressure depletion during the first production phase of the Weststellingwerf field. Although no seismicity was observed during the primary depletion phase, water-weakening upon a first contact with water, due to diffusion of water along the Weststellingwerf fault may have triggered the fault reactivation and seismicity on this fault (Figure 12). According to the authors, this water-weakening of the Weststellingwerf fault can be caused by a combination of fault lubrication, which results in a decrease in fault friction angle, and the annihilation of capillary pressure, which results in a break-down of fault gouge cohesion.

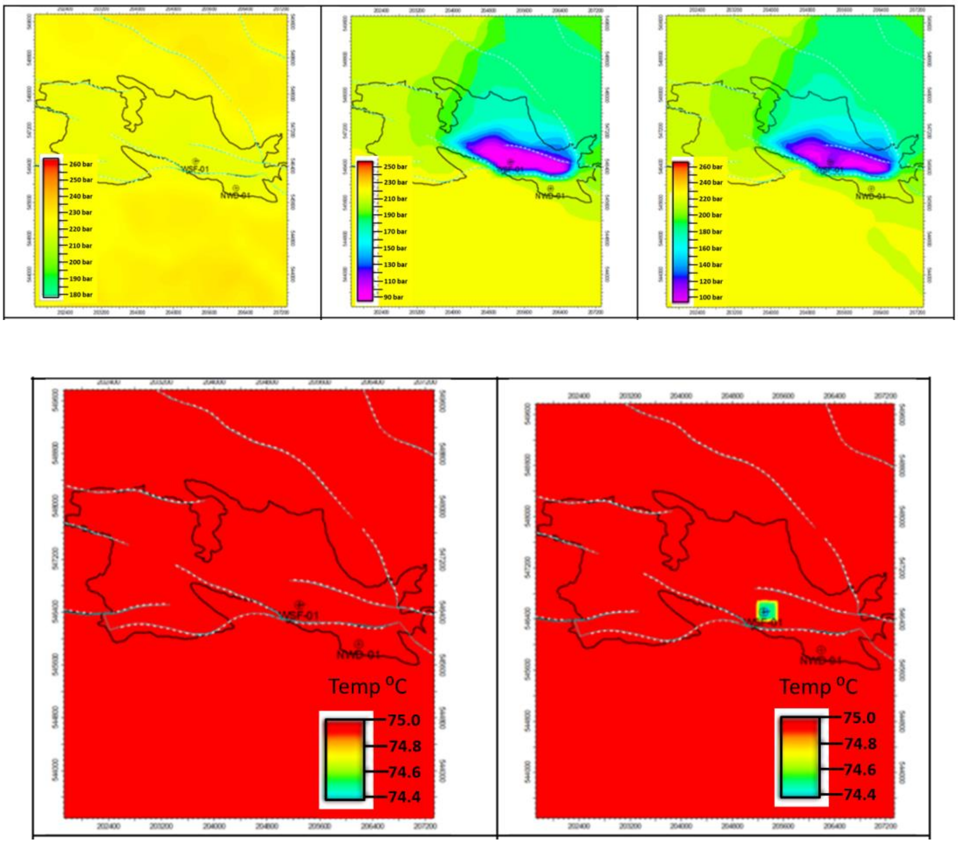

Figure 11. Top: Modelled evolution of pore pressure in the Weststellngwerf field during primary depletion and during injection of water in well WSF-01, at the timing of the seismic events. Left picture shows initial reservoir pressures, whereas central and right picture show the reservoir pressures just before the start of injection and at the timing of the seismic event, respectively. Bottom: Modelled evolution of temperature in the Weststellingwerf field due to injection of cold water into the reservoir. Bottom left picture shows the temperature at the start of production and bottom right picture the temperature at the timing of the seismic event. Source: Adapted from Bois et al. 2013.

The authors also conclude that reservoir re-pressurization due to the injection of water (up to levels below initial reservoir pressures) tends to increase the effective normal stresses on the Weststellingwerf fault. Hence, this mechanism cannot explain reactivation of the Weststellingwerf fault. The authors state that the thermal stress changes due to the injection of cold water are generally limited to the near-well area and are too small to cause fault reactivation (Figure 11). In their publication, the authors do not address the possibility of the reactivation of unidentified faults closer to the injection well, neither the effect of re-equilibration of pore pressures after production stopped in the Weststellingwerf field, which might also be a plausible explanation for the recorded seismicity.

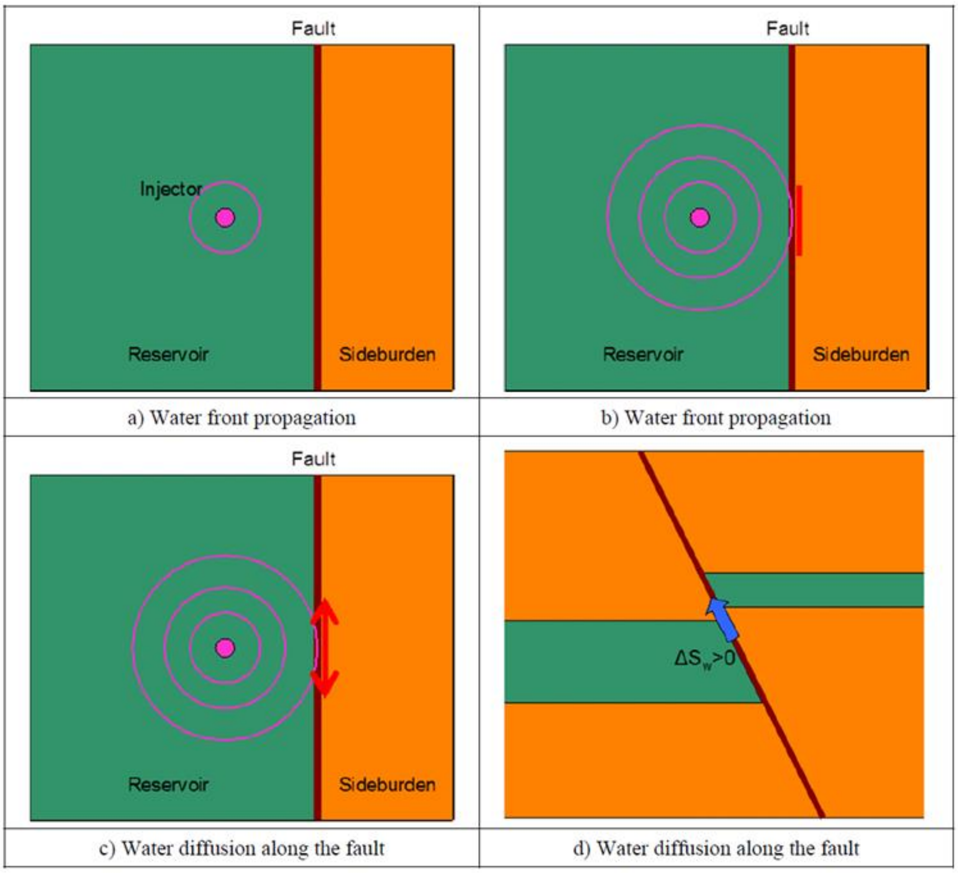

Figure 12. Schematic representation of water-weakening mechanism causing fault reactivation and seismicity. Source: Bois et al., 2013.

2.4 Water disposal in the Borgsweer injection well

Since the 1970's water produced from the Groningen system and other on- and offshore fields has been injected into the Borgsweer injection wells, which are located in the eastern part of the Groningen field in the Dutch Province of Groningen. At the Borgsweer location, the production water is injected in the water leg of the lower Slochteren reservoir sandstone, at a depth below 2971 m TVDNAP (GWC). At the same time, and from a different production location, gas is produced from the higher gas bearing Slochteren sandstone. Until recently, water injection took place via the BRW-04 well, with BRW-2A as a back-up well for injection. In 2013 a new injection well BRW-5 was drilled, which is now used as replacement for the BRW-4 injection well. No gas production takes place from the Borgsweer location; the nearest production cluster to the Borgsweer location is Amsweer.

As shown in Figure 13, both injection wells BRW-4 and BRW-5 are located close to an N-S striking fault intersecting the reservoir. Here, BRW-4 is located to the west of the N-S fault, at a distance of approximately 250 m, and BRW-5 intersects the reservoir to the east of the fault at a distance of around 150 m. The offset of the N-S striking normal fault is limited; close to the injection well the fault offset is around 15-25 m. A further 400 m to the north a second NNW-SSE striking normal fault with an offset between 25-30 m is encountered.

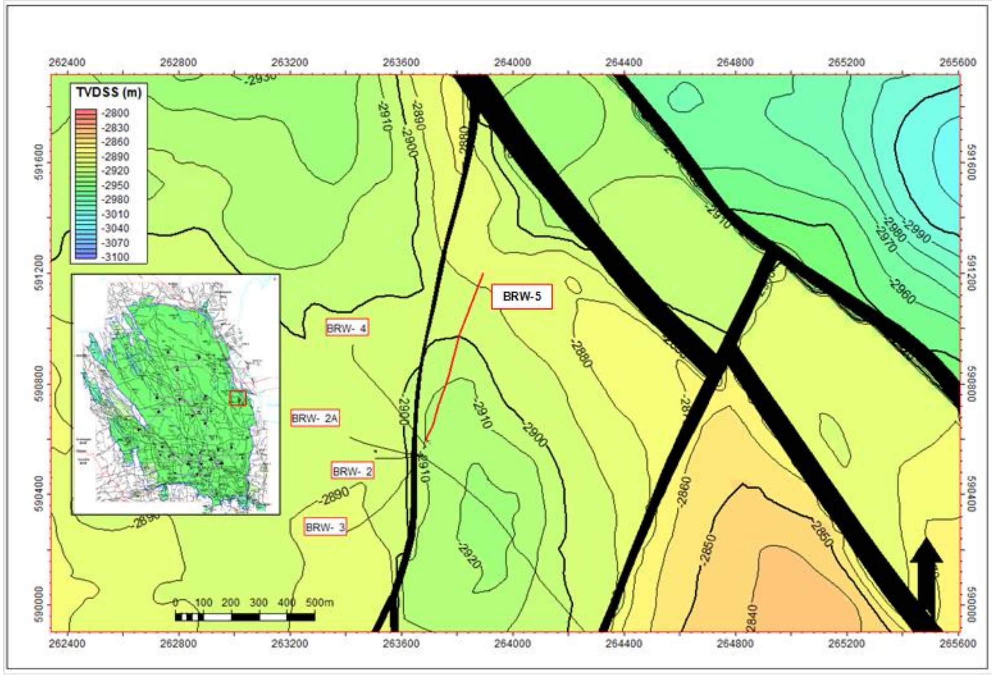

Figure 13. Location of the Borgsweer wells in the eastern part of the Groningen field at reservoir level. BRW-4 is the injection well, BRW-5 the injection well used as replacement for BRW-4, and BRW-2A is a back-up well for injection. Source: NAM-report EP201306210959, 2013.

The Slochteren reservoir at the Borgsweer area consists of sandstones with a high net-to-gross ratio, with porosities between 15 and 20% and permeabilities between 10 and 100 mD. The lower part of the sandstone reservoir is of a slightly less quality. Initial reservoir temperatures in the Slochteren sandstone are around 105 ^{0}C. Local cooling up to 30 ºC around the injection well is expected due to the injection of the cold water.

Figure 14 shows the injection rates and total volumes injected in the BRW-4 well since the start of injection in the early 1970’s up to year 2013. Injection rates varied between 500 and approximately 3000 m^3/day, with total volumes injected up to 18 million m^3.

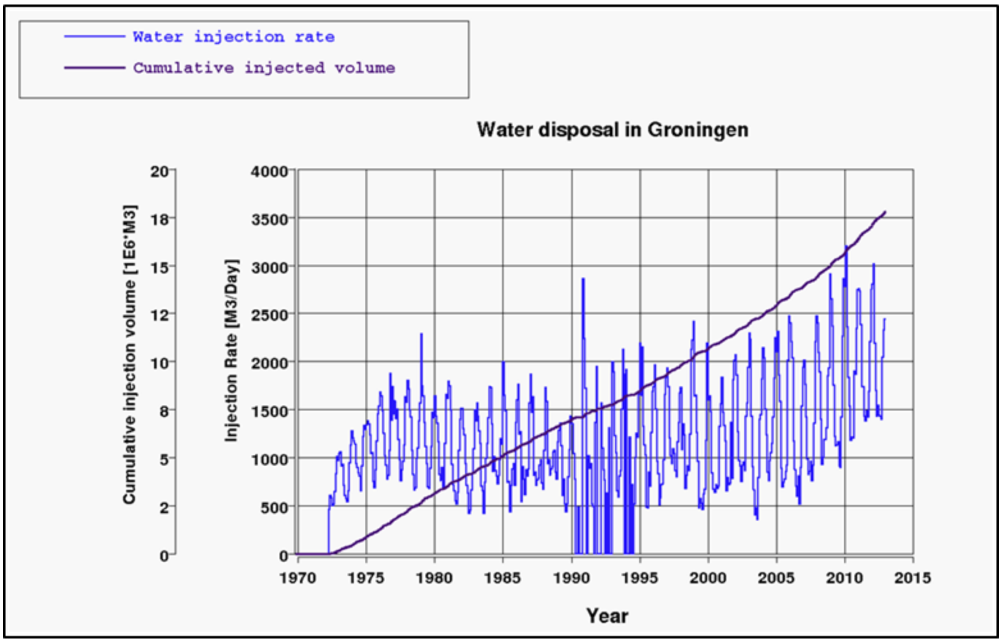

Figure 14. Plot of injection rates and cumulative injection volumes in the BRW-4 injection well. Source: NAM-report EP201306210959, 2013.

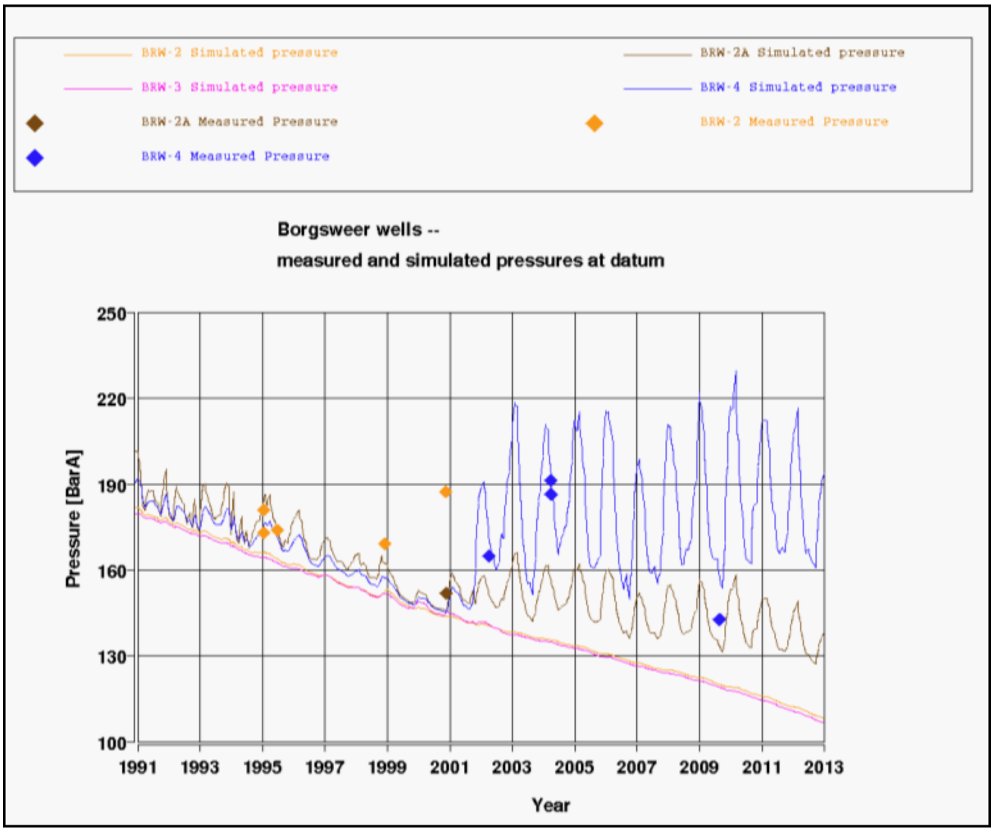

Figure 15. Bottom hole pressures measured in the Borgsweer wells BRW-2, BRW-2A and BRW-4. Simulated pressures for these wells, and for BRW-3, are shown as continuous solid lines. Source: NAM-report EP201306210959, 2013.

During the injection, bottom hole pressures in the BRW-4 well varied between 140 bar and 225 bar (Figure 15), well below the initial (virgin) reservoir pressure of 346 bar. NAM dynamic modelling results show that pressure variations are expected to occur locally in the area close to the injection well (NAM-report EP201306210959, 2013). Figure 15 shows the pressure evolution simulated for the BRW-2 and BRW-3 wells which are located several hundred meters to the south of the BRW-4 injection well. Pressure variations in these wells are much smaller than observed and modelled for the BRW-4 injection well.

Until recently no seismicity was recorded in direct vicinity of the area. Figure 16 shows the location of seismicity (up to March 1st, 2015) in the area to the west of the Borgsweer injection site. In June 2013 and April 2015, a magnitude M 1.3 seismic event was recorded at two kilometers to the west of the Borgsweer injection wells. However, as simultaneous depletion and injection is ongoing in the Borgsweer area, it is not possible to directly relate the seismic event to the injection operations.

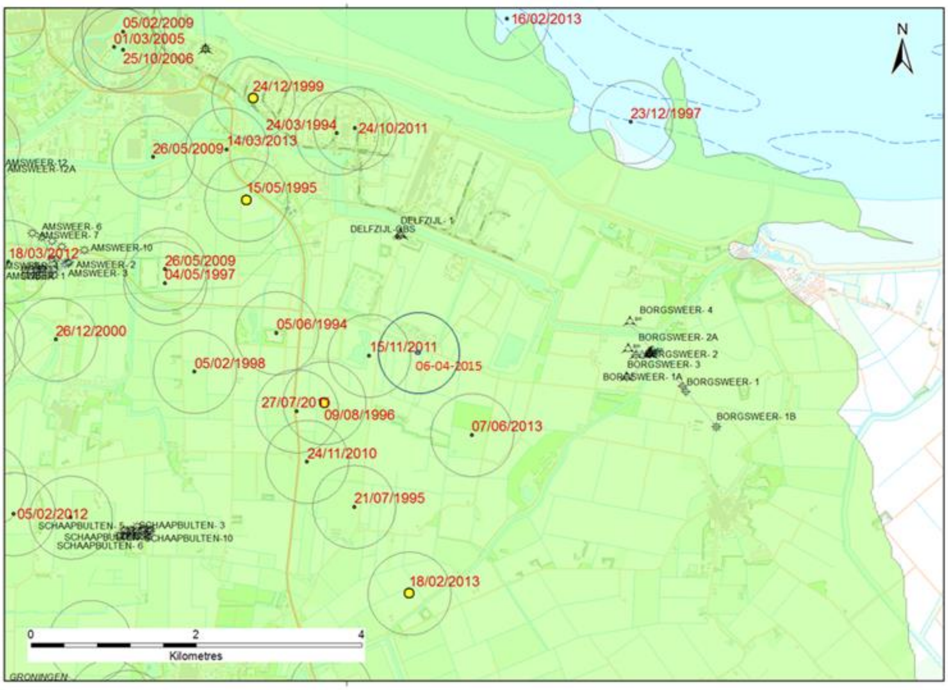

Figure 16. Seismic events recorded in the region to the west of the Borgsweer injection wells. Locations of the wells are presented at reservoir level. All events are shown till end June 2013 (Source: NAM-report EP201306210959, 2013). In addition the recent M=1.3 seismic event (April 2015) is shown.

2.5 Bergermeer Underground Gas Storage

The Bergermeer UGS facility is a formerly depleted gas field, located in the Dutch Province of Noord-Holland. An outline of the gas field is given in Figure 17, whereas a vertical cross section through the Bergermeer field is shown in Figure 18. Production in the Bergermeer field took place from 1972 to 2007, which was followed by a temporary shut-in of the field until the end of 2010 and a conversion of the field into an underground gas storage facility. Cushion gas injection into the Bergermeer field started at the end of 2010. The locations of both the old production wells, used for primary depletion of the field and the new injection wells are shown in Figure 19. As required in the UGS-license, all injection wells for underground gas storage are located at a distance larger than 250 m of the major faults intersecting and bounding the reservoir (see Figure 19).

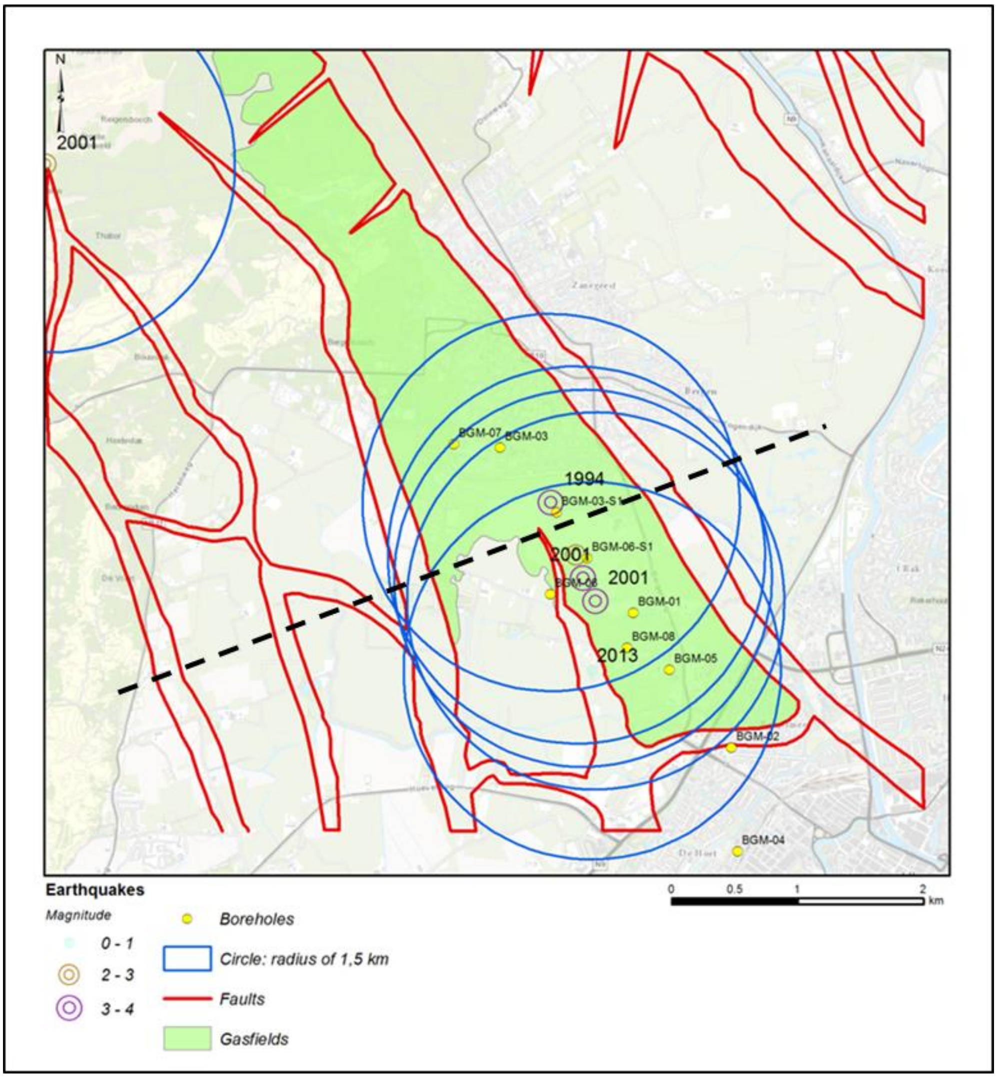

Figure 17. Structural map of the Bergermeer gas field, showing location of 'old' production wells at reservoir level, faults and recorded seismicity in the vicinity of the gas field. Dashed line presents the location of the vertical cross section in Figure 18b.

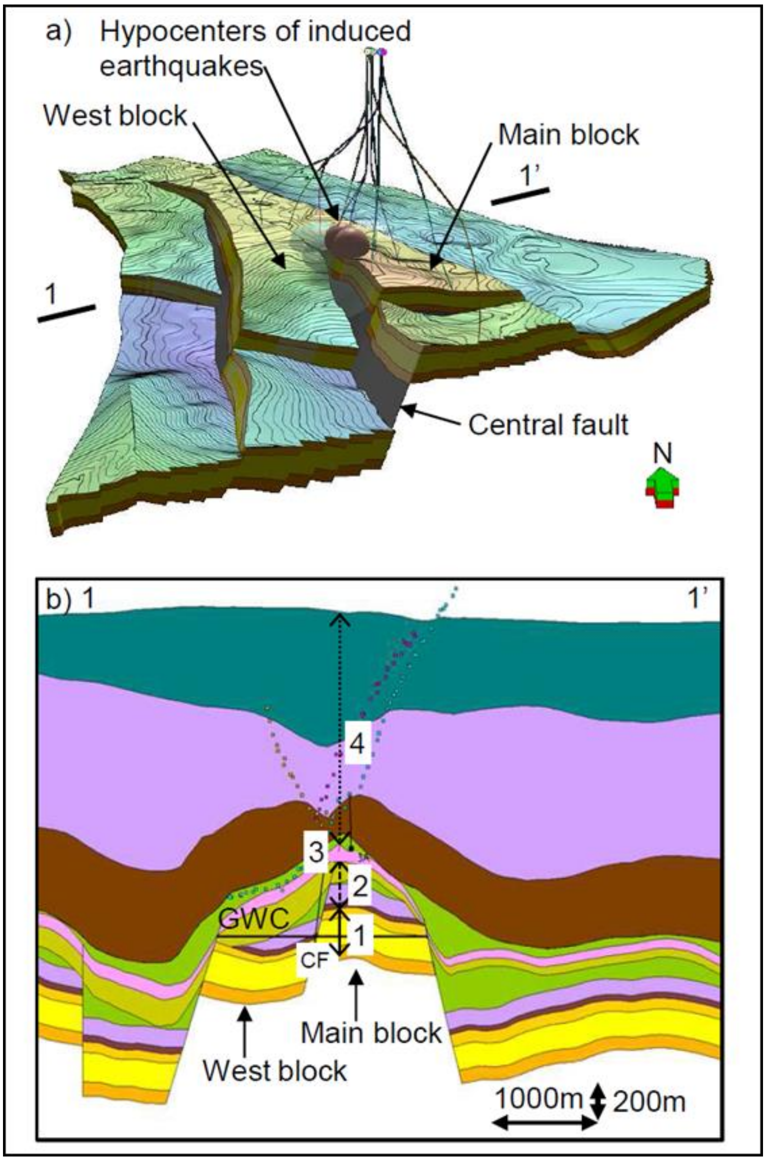

Figure 18. Reservoir structure of the Bergermeer field, a) showing the Main reservoir block, western reservoir block and the Central fault (CF) intersecting the gas reservoir. Four seismic events during primary production have been localized at the Central fault and spheres at the tip of the Central fault are interpreted locations of these seismic events. b) Cross section through the reservoir (location of this cross section is shown in Figure 17): 1) Slochteren Sandstone reservoir, 2) Zechstein Formation (mixed lithology caprock), 3) Zechstein halite caprock, 4) Overburden. Source: Orlic et al., 2013.

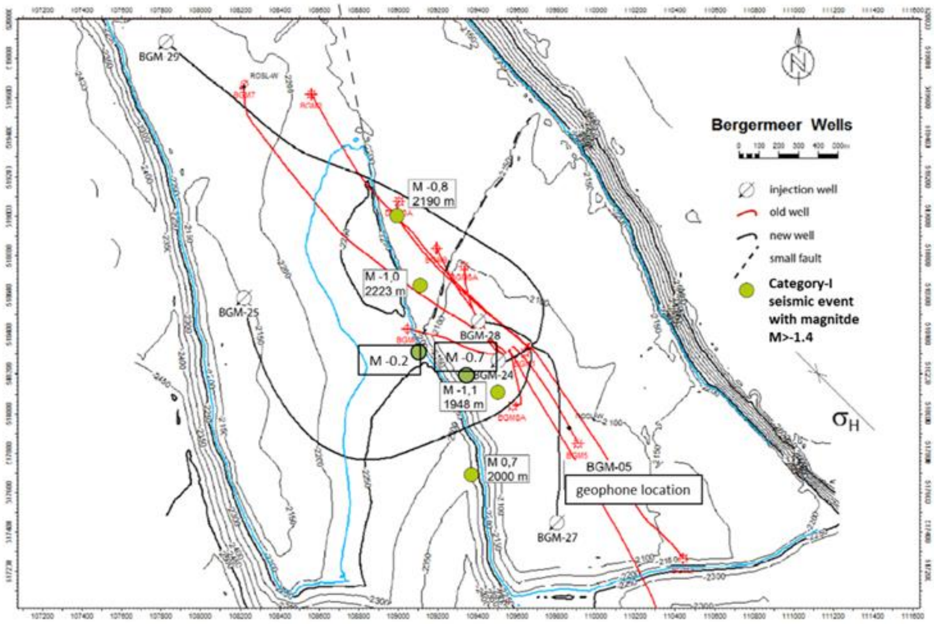

Figure 19. Bergermeer reservoir, showing location of the new injection wells (black lines) and location of larger seismic events (green dots) recorded by the downhole micro-seismic monitoring array in well BGM-05. Source: Adapted from TAQA, 2015.

The gas field consists of two reservoir blocks, a structurally high main block and a deeper lying western block, which are intersected by a partially sealing Central fault. This Central fault has a dip of 60-65^0 towards the SSW, and has an increasing offset towards the southeast (see Figure 17). The reservoir is bounded by NW-SE and E-W striking boundary faults (see Figure 17). The north-western part of the structure is closed by a low-relief saddle. The top of the reservoir lies at a depth of approximately 2100 to 2200, m and the average thickness of the reservoir rock is around 200 m. The reservoir rocks consist of Rotliegend Slochteren sandstones, with generally high porosities of 15-30%. The caprock of the Bergermeer field is formed by the Zechstein rocks, which consists of alternating claystone, dolomites, anhydrites and halites. The reservoir is underlain by Carboniferous rocks (Orlic, 2013).

During primary depletion, reservoir pressures were decreased from 228 bar to approximately 15 bar at the end of production. In 1994 and 2001, during primary depletion of the reservoir, four seismic events were recorded with magnitudes varying between M 3.0 and M 3.5.The four seismic events were interpreted by KNMI to be located close to the tip of the Central fault (see also Figure 17 and Figure 18). Average reservoir pressures in 1994 at the timing of the first two events were around 50 bar, whereas average reservoir pressures at the timing of the second series of events in 2001 were around 25 bar (TNO-report 2008-U-R1-71/B).

For monitoring purposes a down-hole micro-seismic array has been installed in well BGM-05, just above reservoir level. Since the start of injection a large number of micro-seismic events has been recorded by this downhole array as presented in Figure 19 (which shows the location of the largest 6 events with magnitudes M >-1.4) and Figure 20 (which shows all recorded events). The largest seismic event recorded during injection of cushion gas is an M 0.7 seismic event from October

2013, which was interpreted to be located close to the Central fault (TAQA, 2015). However, it is worth noting here that as only one well is used for monitoring, uncertainties in the location of the seismic events are still large (up to several hundreds of meters at a distance of one km) and strongly depend on the distance of the seismic event to the monitoring well (Kraaijpoel, pers. comm.). From Figure 20 it can be seen that average reservoir pressures at the timing of the M 0.7 event were around 75 bar, with a limited differential pressure over the Central fault of around 30 bar (TAQA, 2015).

Orlic et al. (2013) modelled the stress evolution on faults in the Bergermeer field and 3D models of the field were constructed to incorporate the complex 3D geometrical structure of the field and faults. Results for the depletion phase showed the spatial and temporal development of a critically stressed fault section, which corresponds to the approximate timing and locations of the seismic events recorded during gas production. Modelling results also show that stress paths on the fault during injection are not reversible, predominantly due to the fault slip which occurred during the primary depletion phase. Modelling results indicate that additional fault slip during the first phase of gas injection is possible on the critically stressed section of the fault (Figure 21). Areas reactivated in depletion and the first phase of gas injection only partially overlap due to different pore pressure loading and a stress drop on the fault section reactivated during gas production. The 3D models constructed show a stabilization of the faults after the end of the first injection phase. The authors conclude that seismicity after the end of the first injection phase is not expected and faults ultimately stabilize, but seismicity during the early stage of injection in the depleted reservoir cannot be excluded. Up till now, modelling results are still consistent with monitoring results (with the largest seismic events during injection being localized at the Central fault and seismicity occurring during re-pressurization of the reservoir), although the ultimate stabilization forecasted by the models cannot yet be validated by the monitoring data.

In addition to the effect of re-pressurization and pressure cycling Orlic et al. (2013) analyze the effect of cooling due to injection of cold gas. Thermal contraction of the reservoir rocks locally leads to a reduction of the normal stress and to an increase of shear stress on the fault, and therefore to an increase in the reactivation potential of the fault (Figure 22). However, thermal effects are expected to be limited, as large temperature changes are limited to the near-well area.

A number of operational requirements were prescribed by the supervisor for underground gas storage. In addition to lower and upper bounds imposed for average reservoir pressures, a minimum distance between the location of the injection wells at reservoir level and major faults intersecting and bounding the reservoir is required. A minimum distance of 250 m is required to minimise the effect of thermal stresses on the faults and to minimize the probability of direct injection into permeable faults (TNO-report 2008-U-R1-71/B). Furthermore, in the Bergermeer field the injection strategy is such that the pressure differences over the Central fault are as low as possible.

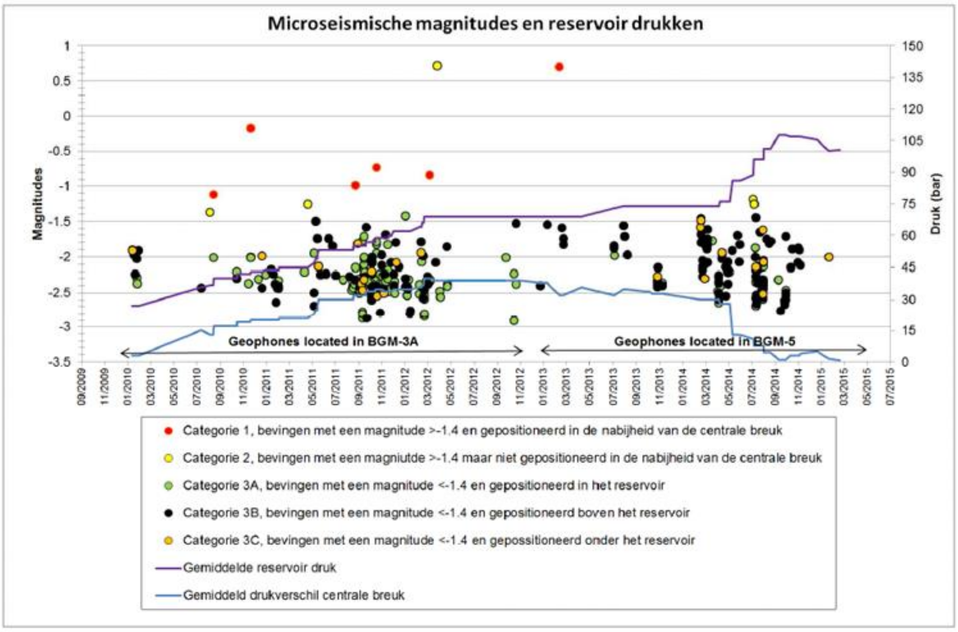

Figure 20. Seismic events recorded by down-hole seismometers and evolution of (differential) pressures in the Bergermeer reservoir. Source: TAQA, 2015.

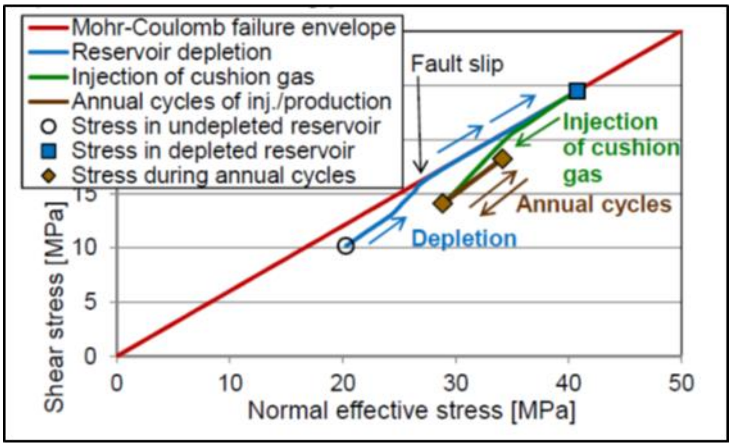

Figure 21. Stress paths on the Central fault in the Bergermeer reservoir during primary depletion, injection of cushion gas and annual pressure cycling. Source: Orlic et al., 2013.

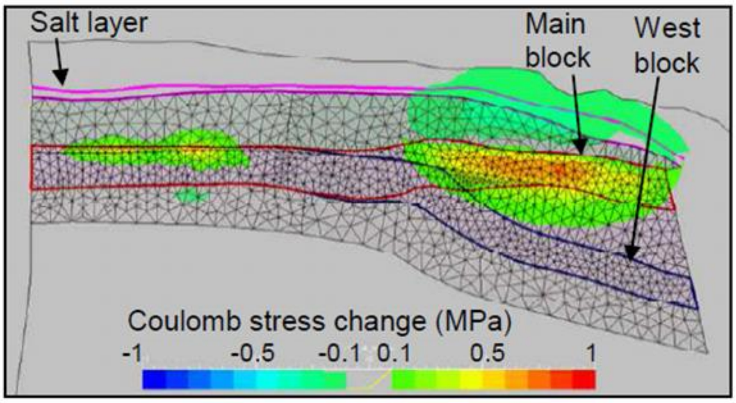

Figure 22. Coulomb stress change on the Central fault in the Bergermeer field due to the thermal effects after 50 annual cycles of gas injection and production. Source: Orlic et al. 2013.

2.6 Water injection into the Twente fields

Since 2011, water produced from the Schoonebeek oil field is injected into three depleted reservoirs in the Twente region, Dutch Province of Overijssel, i.e. the Rossum-Weerselo field, the Tubbergen-Mander field and the Tubbergen field. In case of the latter two fields water is injected into the depleted Zechstein carbonate reservoirs, which are bounded to the base and top by laterally extended anhydrite layers. Main permeability of the carbonate layers is due to the presence of fractures. In case of the Rossum-Weerselo field, water is injected into both the Zechstein carbonates and the deeper Carboniferous sandstone reservoir. Figure 23, Figure 25 and Figure 27 show the geological cross sections of these three fields.

The Tubbergen field consists of two gas accumulations, i.e. the Zechstein reservoir, at a depth of 1300 to 1800 m and the Carboniferous at a depth between 2100 and 2400 m. The field stopped producing in 2009. Water is injected into the Zechstein reservoirs in wells TUB-7 and TUB-10. The Tubbergen Zechstein reservoir consists of a domal structure, which is intersected by a few normal faults of varying strike and dip (see Figure 23 and Figure 24).

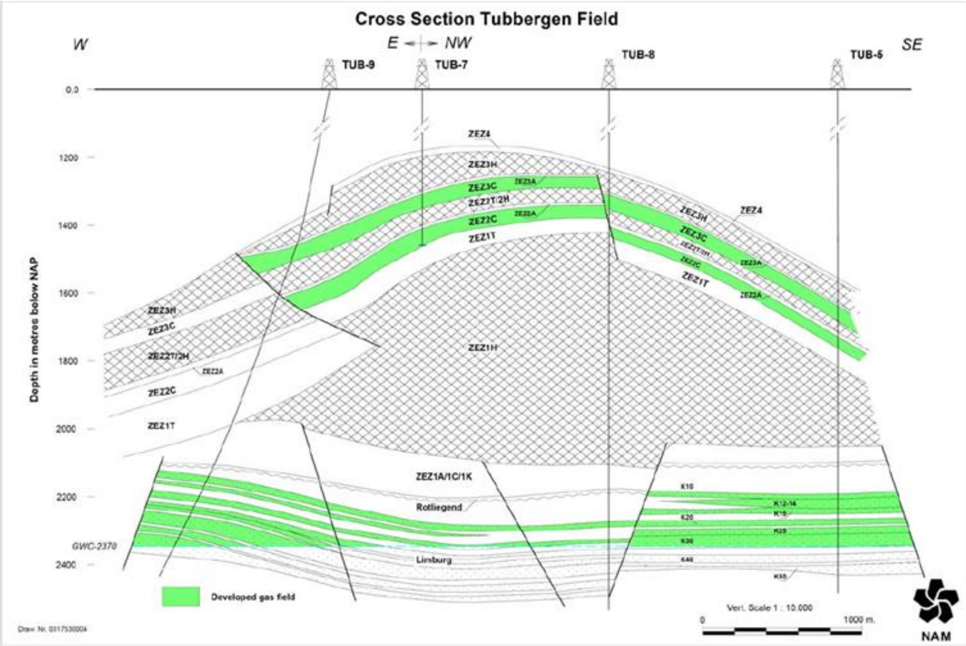

Figure 23. Geological cross section through the Tubbergen field, showing the location of water injection well TUB-7. Source: Rapport EP200808228611 Royal Haskoning, 2006.

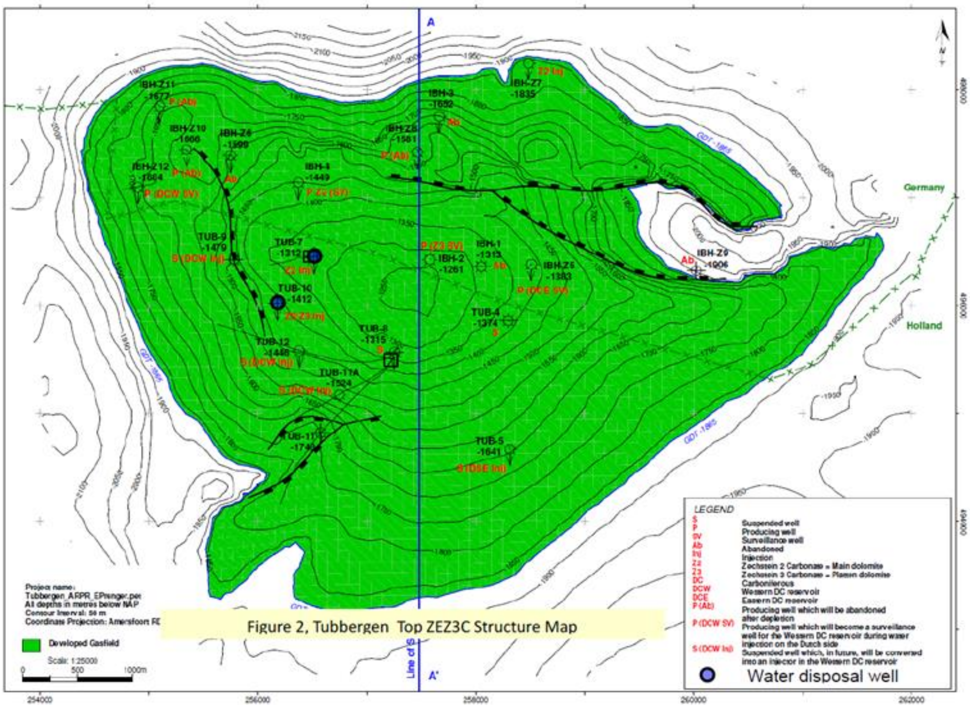

Figure 24. Structural map of the Tubbergen field, showing contours of the top of the ZEZ3C, main faults and location of the water disposal wells TUB-7 and TUB-10 at reservoir level. Source: NAM-report 201310201845, December 2014.

As shown on the structural map, well TUB-7 is located at a distance of more than 500 m from a NNW-SSE striking normal fault, dipping towards east. Injection well TUB-10 is located closer to this fault, at a distance of approximately 250 m.

The original virgin pressure in the reservoir, before reservoir depletion, was 211 bar. Reservoir pressure at the start of injection was 6 bar. Current reservoir pressures in the wells TUB-7 and TUB-10 are reported to be ranging from 7 to 34 bar. Final pressures at the end of the 25 year injection period at the well locations TUB-7 and TUB-10 are expected to remain well below the initial reservoir pressure (NAM-report 201502207168, February 2015). The maximum water injection rates of the individual wells TUB-7 and TUB-10 during the first 4 years of injection were around 2270 m^3/day, whereas on an annual basis average injection rates per well were computed to be less than 1000 m^3/day. During the first 4 years of injection in total 1.7 million m^3 of water has been injected into the field.

Production in the Tubbergen-Mander field started in 1974, whereas currently no production takes place in this field. Wells TUM-1, TUM-2 and TUM-3 are used for water injection into the Zechstein carbonates at a depth of approximately 1600-1800 m. The geological structure of the field is shown in the cross section of Figure 25 and the structural map of Figure 26. In the southwest the reservoir is bounded by a large number of small WNW-ESE and E-W striking normal faults. Injection well TUM-1 is located relatively close to these small faults. The eastern part of the reservoir is bounded by the Gronau fault zone. In the north, the reservoir is bounded by an E-W striking northward dipping normal fault.

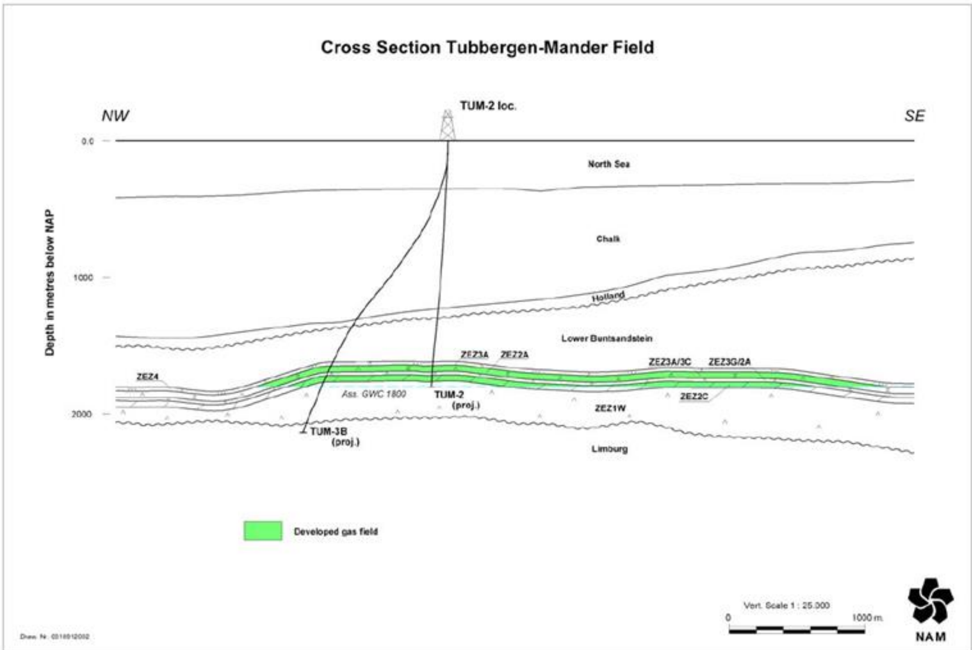

Figure 25. Geological cross section through the Tubbergen-Mander field, showing location of water injection well TUM-2. Source: Rapport EP200808228611 Royal Haskoning, 2006. Location of this cross section is shown in Figure 26.

The original virgin pressure in the reservoir, before reservoir depletion, was 190 bar. Reservoir pressure at the start of injection was ranging from 45 to 67 bar. Current reservoir pressures are around 88 bar. Final pressures at the end of the 25 year injection period at the well locations TUM-1 to TUM-3 are expected to remain below the initial reservoir pressure. The maximum water injection rates of the individual wells TUM-1 to TUM-3 during the first 4 years of injection were around 340 m^3/day. During the first 4 years of injection in total 0.2 million m^3 of water has been injected into the field.

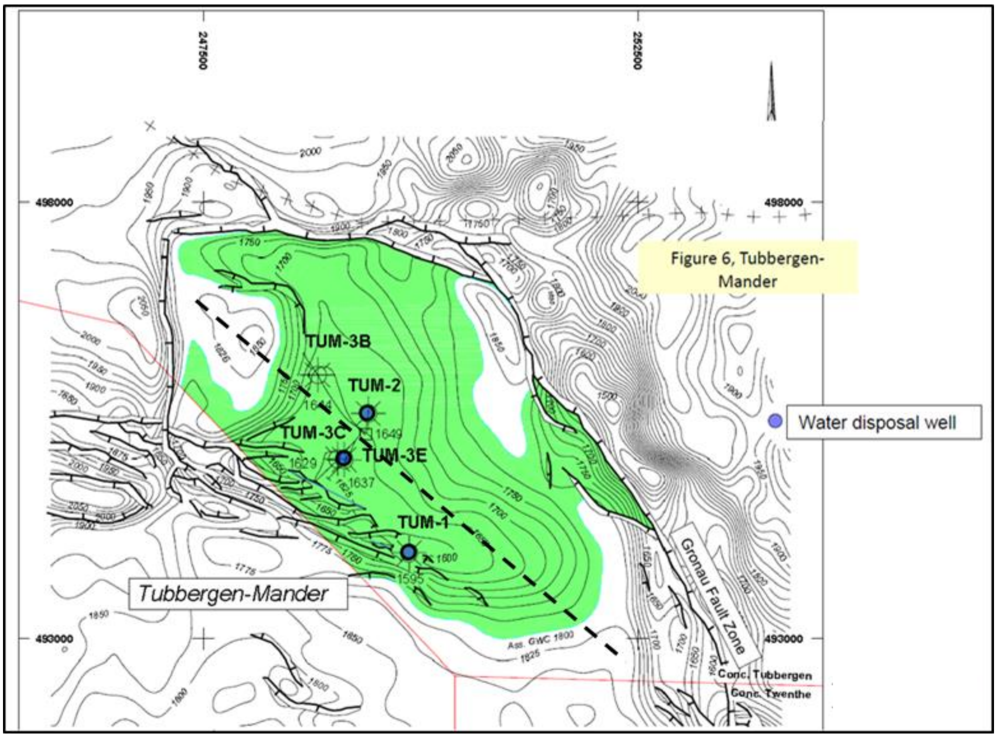

Figure 26. Structural map of the Tubbergen-Mander field, showing contours of the top of the ZEZ3C, main faults and location of the water disposal wells TUM-1, TUM-2 and TUM-3 at reservoir level. Dashed line presents the location of the vertical cross section in Figure 25. Source: NAM-report 201310201845, December 2014.

Water injection into the Rossum-Weerselo field takes place in the Zechstein carbonates, which are located at a depth between 1150 m and 1500 m and in the deeper Carboniferous sandstones. Figure 27 and Figure 28 show the geological structure of the Rossum-Weerselo field. Water injection takes place into wells ROW-2, ROW-4, ROW-5, ROW-7 and ROW-9 (Zechstein) and ROW-3 (Carboniferous). The original reservoir pressure in the Zechstein and Carboniferous reservoir, before reservoir depletion, was 150 bar and 199 bar, respectively. Current pressure in the Zechstein and Carboniferous reservoirs is approximately in the range of 17 to 58 bar, and 142 bar, respectively. The highest reservoir pressure expected in the Zechstein and Carboniferous reservoir at the end of the injection period is expected to remain below the initial reservoir pressure. The maximum water injection rates of the individual Zechstein wells during the first 4 years of injection were around 2200 m^3/day. On an annual basis, average injection rates per well were computed to be less than 1500 m^3/day. During the first 4 years of injection in total 2.8 million m^3 of water has been injected into the Zechstein. Maximum water injection rate in the Carboniferous was 1000 m^3/day and in total 0.04 million m^3 has been injected into the Carboniferous.

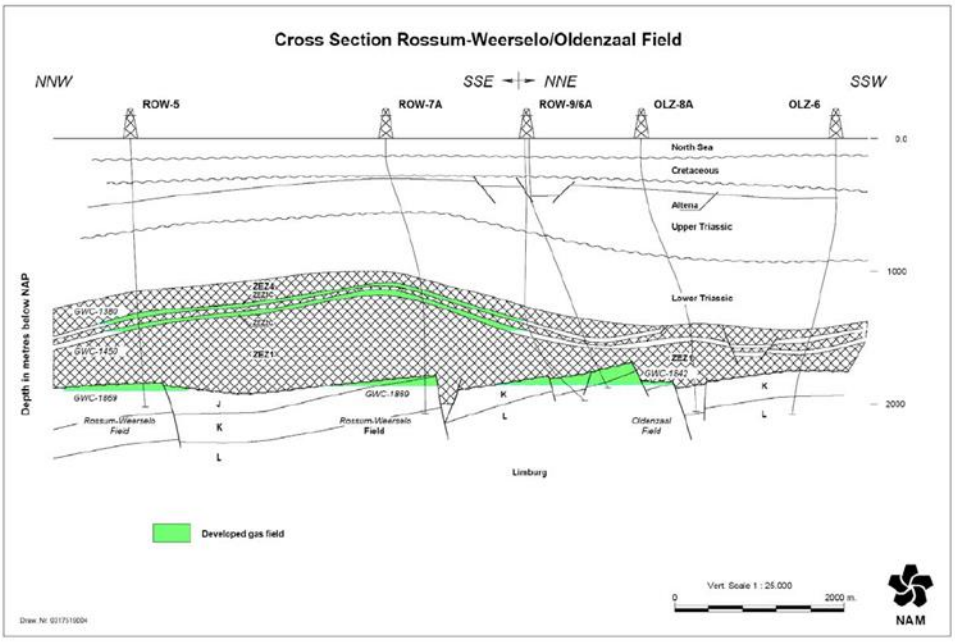

Figure 27. Geological cross section through the Rossum-Weerselo field, showing location of injection well ROW-5. Source: Rapport EP200808228611 Royal Haskoning, 2006.

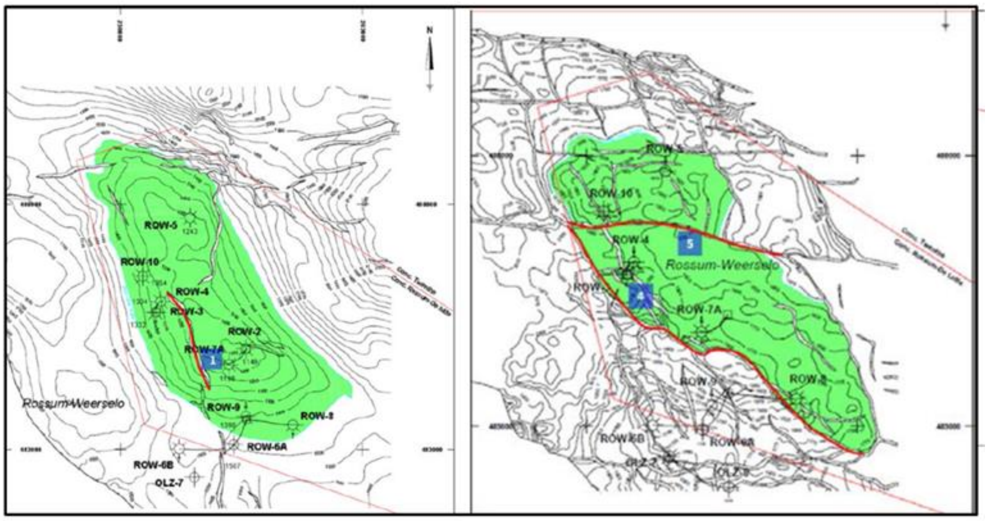

Figure 28. Structural map of the Rossum-Weerselo field, showing contours of the top of the ZEZ2C (left) and Carboniferous (right), main faults and location of the water disposal wells at reservoir level. Source NAM-report 201502207168, February 2015.

Within 25 years, in total 75 million m^3 of production water will be injected into the three Twente fields. Water is injected at temperatures of approximately 20^0C, and therefore some cooling of the reservoir rocks around the wells is expected.

No seismicity has been recorded in the Twente region during field production (1951-2006) and since the start of water injection in 2011.

Results from injection tests indicate that the (pre-depletion) gradient of minimum total horizontal stresses in both the Zechstein Formation and the deeper Carboniferous reservoirs is relatively high (NAM-report 201502207168, February 2015). Horizontal stress gradients of 2.1 bar/10m were derived for the Zechstein, which means initial stress conditions are almost isotropic. Horizontal stress gradients measured in the Carboniferous sandstones were somewhat lower, between 1.85-1.95 bar/10m. Under near-isotropic stress conditions large stress changes are needed to reactivate the faults, which may partially explain the absence of seismicity during both depletion and injection.

3 Discussion and conclusions

Only a limited number of seismic events recorded in The Netherlands are interpreted to be related to injection operations. In all cases seismic events recorded are well below M 3.0.

Five field cases of the injection of production water into a depleted (or in case of Borgsweer a still actively producing) gas reservoir have been described in this report: i.e.:

- Water injection into the Weststellingwerf field: The largest seismic event (M 2.7) which is potentially related to the injection of water was recorded close to the Weststellingwerf field. Bois et al. (2013) poses that the most likely mechanism underlying this seismic event is water weakening of the fault due to diffusion of water into the fault.
- Water injection into the Borgsweer (Groningen) area: Though some seismicity has been recorded in the eastern part of the Groningen area, at two kilometer distance of the Borgsweer injection wells, a clear relation with the injection activities cannot be established, as upper reservoir layers are simultaneously produced.
- Injection of production water of the redeveloped Schoonebeek oil field into the Tubbergen, Tubbergen-Mander and Rossum Weerselo depleted gas fields: No induced seismicity has been recorded in case of these three depleted gas fields, which are used for water injection. Injection operations in these Twente fields started first in 2011 and injected volumes and pressure changes due to injection are therefore still relatively limited.

Three field cases of underground gas storage have been described in this report. All three reservoirs have already shown seismicity during primary reservoir depletion. In all three reservoirs, a limited number of small seismic events (with largest magnitudes ranging between M 0.7 (Bergermeer) and M 1.5 (Grijpskerk) were recorded during underground gas storage operations:

- The Grijpskerk Underground Gas site experienced two seismic events of magnitudes M 1.3 and M 1.5 during Underground Gas Storage operations. Both seismic events were recorded during the production phase, at relatively low pressures.
- An M 1.1 event during injection into the Norg reservoir took place at relatively high injection pressures, which were close to virgin reservoir pressures.
- An M 0.7 event in the Bergermeer reservoir took place during the first re-pressurization period, at pressures well below initial reservoir pressures. Numerous smaller micro-seismic events were recorded by a downhole seismic monitoring array in the Bergermeer reservoir during the injection of cushion and working gas.

In case of the Norg field seismicity during injection took place at pressure levels close to virgin reservoir pressures. In TNO-report 2014 R11761 it has been mentioned that for the majority of the field cases of induced seismicity described worldwide, seismicity was interpreted to be related to an increase in pressure above the original reservoir pressures. All other cases of injection induced seismicity in The Netherlands took place well below the initial reservoir pressures. As discussed in the previous chapter, for Bergermeer the effect of fault slip during depletion and stress transfer may have played a role as causal mechanism of the M 0.7 event. In case of the Weststellingwerf seismicity water weakening has been posed as the most likely mechanism, but several other mechanisms, such as the reactivation of (undetected) faults due stress and temperature changes close to the injection well or the re-equilibration of pressures in the reservoir cannot be entirely excluded. In case of the Borgsweer injection well, seismicity takes place at relatively large distances from the injection well and is likely to be caused by the ongoing depletion of the Groningen field.

In addition to the field cases described above, other field cases of injection into underground reservoirs exist in The Netherlands, which have not been addressed in this report. Examples are the (re-)injection of production water into producing hydrocarbon fields, steam injection into the Schoonebeek oil field, enhanced gas recovery with N_2 as a drive gas in the onshore De Wijk gas field and re-injecting CO_2 into the offshore K12-B field. None of these activities are known to be associated with induced seismicity. An exception is the occurrence of a series of 41 small seismic events, with a maximum magnitude of M 1.4, which was recorded in 2009 near Midlaren over a period of one month (Dost, 2012). This swarm of small seismic events is most probably related to drilling activities and the loss of drilling fluids, approximately 5 km from the epicenter locations, and could in that sense also be interpreted as an example of injection-induced fault reactivation and seismicity.

In general the localization of seismicity is too uncertain to relate the induced seismic events directly to a specific fault. Even in case of the Bergermeer field, where a downhole micro-seismic monitoring array has been installed above the reservoir, vertical and horizontal location accuracy at a distance of 500 m from the monitoring well already mounts to several hundred meters (Kraaijpoel, pers.comm.). In none of the cases of injection induced seismicity information on the source mechanism of the seismic events is available. Due to the lack of data and the uncertainties in both geological, seismological and geomechanical data, in most cases the underlying mechanism which causes the seismic events is still poorly understood.

3.1 Relevance of Dutch injection field cases to nitrogen injection

The injection of nitrogen with the aim of maintaining pressures in a producing reservoir is considered to be one of the options to mitigate seismicity during ongoing production. The extent of the area affected by the nitrogen injection is intended to be large in order to stabilize as many faults as possible, whereas the pressure increase itself is intended to be limited (maintenance, not re-pressurization). The cases of water injection described in this report are less applicable as analogue field cases for nitrogen injection, as the extent of the pressure and temperature changes is generally limited to the near-well area. Furthermore, other mechanisms (such as water-weakening), which are of no relevance to nitrogen injection, may have played a role in the reactivation of faults for the cases of water injection. The injection field cases of UGS can however be regarded as an extreme analogue for nitrogen injection aiming at pressure maintenance in a producing reservoir. Both UGS operations and nitrogen injection have an impact at reservoir-scale, but a much higher pressure increase is reached during UGS operations than is expected for nitrogen injection. In all three UGS cases described in this report, seismicity occurred during the primary depletion period before the start of the first injection cycle, which can be interpreted as an indication that reservoir faults were already (close to) critically stressed at the start of the first injection cycle. No seismicity has been recorded during injection in the Grijpskerk field, while only very limited seismicity occurred during re-pressurization of the Bergermeer and Norg field (M 0.7, respectively M 1.1). In TNO-report 2014 R11761 it has been mentioned that differences in stress path coefficients during production and re-pressurization, due to plastic deformation of the reservoir rocks or fault slip during depletion, can potentially result in fault reactivation during first re-pressurization of the reservoir. The absence of significant seismicity during the re-pressurization of the Bergermeer, Norg and Grijpskerk Rotliegend reservoirs may be interpreted as a first indication that for Rotliegend sandstone reservoirs the effect of differences in stress path coefficients during production and injection on fault stability is limited. However, it should also be kept in mind that differences between individual fields can be very large and mechanisms of fault reactivation are in most cases still poorly understood, which means observations from analogue injection field cases can easily be overinterpreted.

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