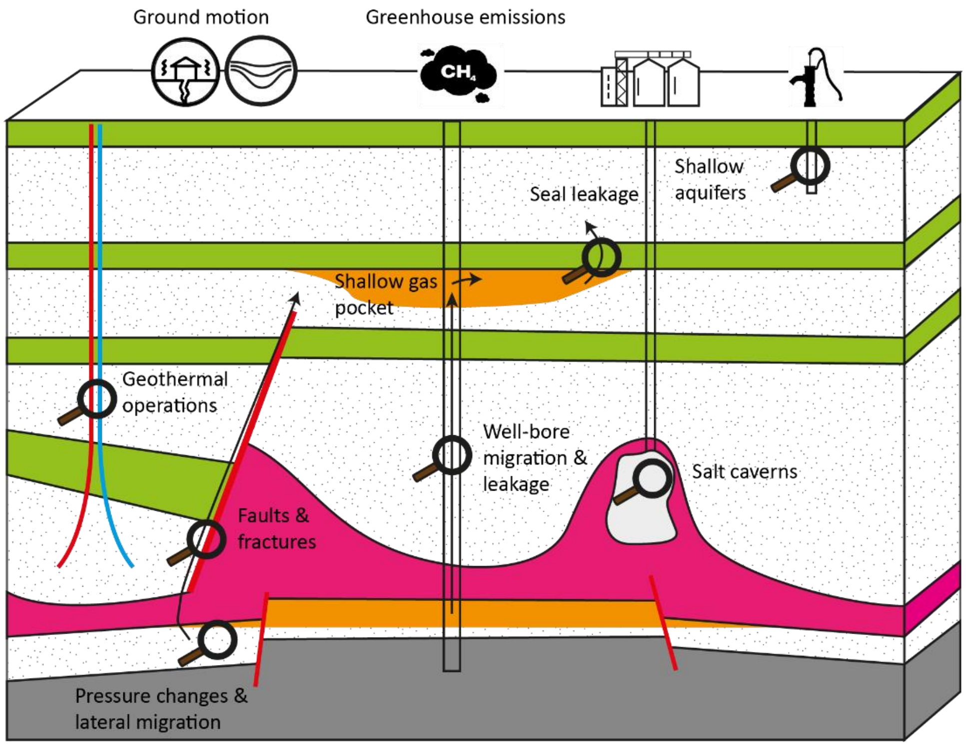
KEM-19 - Evaluation of post-abandonment fluid migration and ground motion risks in subsurface exploitation operations in the Netherlands



Literature Review - Phase-1

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Executive summary

As the energy transition continues, oil and gas production will steadily decline and more fields will be abandoned. Risks related to exploration, production and deployment are relatively well managed. However, risks associated with long-term large-scale fluid migration between fields after abandonment have received less attention. Similarly, risks associated with long term methane leakage through abandoned oil and gas wells are poorly understood. This study presents a literature review on processes and impacts associated with long-term fluid migration and wellbore leakage. This report is a deliverable of the first phase of KEM-19 project "Evaluation of post-abandonment fluid migration and ground motion risks in subsurface exploitation operations in the Netherlands". The end objective of the project is to define the regional hazard and risk assessment method and practices for post-abandonment effects of gas fields.

There is a substantial amount of evidence of connectivity between gas reservoirs and adjacent aquifers. This suggests that long-term fluid migration and pressure equilibration between a gas field and its surrounding area is to be expected. This might lead to subsidence and seismicity, and could potentially lead to the upward migration of gas from the reservoir. Possible migration pathways include (reactivated) faults or locally weak seals on top of aquifers adjacent to gas fields. The depletion and unexpected gas accumulations resulting from long term fluid migration, can pose risks for future subsurface operations. We propose a case study with a multipronged approach to investigate the risks stemming from these complex processes. We intend to use numerical modelling to assess the levels of fluid migration in the regional context of the Groningen gas field. In addition, semi-analytical and conceptual models will be utilized to assess the impact of pressure re-distribution on ground motion and nearby operations.

A review of the global well leakage case studies indicates that abandoned wellbores could act as leakage pathways. There are several factors that could increase the risk of well leakage, such as presence of shallow gas accumulations, and poor well design. The gas leakage due to both long-term fluid migration and from wellbore integrity loss could lead to methane contamination of shallow aquifers, and the atmosphere. Numerical simulations have been successfully employed to assess the magnitude of methane leakage into shallow aquifers and the atmosphere. We propose to conduct a case study based on a hypothetical well in the Groningen field to assess the risks of well leakage on shallow aquifers. The goal is to provide estimates of possible methane leakage levels in the Dutch subsurface, including the extent of methane plume development over centuries. This information is paramount in designing successful monitoring and mitigation strategies.

The ISO 31.000 standard for risk management is recommended as a starting point for the development of a risk assessment framework in the current study. Existing examples of risk assessment (and management) frameworks for geothermal energy production, CO_2 storage and gas production provide useful information for the development of a framework for regional assessment and management of fluid migration and leakage resulting from abandoned gas reservoirs. The framework is a basis for the development of methods and workflows for the hazard (and risk) assessment of mining activities after

their abandonment with special reference to leakage of fluids (gas or brine). A high-level summary of the findings of this report is provided in Table 3.

1 Introduction

As the energy transition continues, oil and gas production will steadily decline and more and more oil and gas wells will be abandoned. On the other hand, there is an expected increase of new activities in the subsurface of the Netherlands, such as energy production using geothermal sources and re-use of oil- and gas reservoirs for storage of hydrocarbons and carbon dioxide (Verweij et al. 2012). Risks and impacts of all these activities during exploration, production and deployment are relatively well managed. However, the risks after the period of active deployment (e.g., production, storage) can still develop long after the activity has ceased (van Gessel, 2019; Lemay et al., 2019) and no risk assessment framework is currently available for long-term abandonment. Therefore, this project aims to define the regional hazard and risk assessment method and practices, so that risks can be mitigated and negative impacts can be prevented.

Post-abandonment risks can occur over long time-scales and large spatial scales. For instance, fluid migration processes are believed to continue well beyond the operational time spans and the field boundaries of gas production. Potential effects include changes in pore pressure and associated ground motion, (re)activation of faults, possible vertical migration of gas and/or brine out of the reservoir. In addition, on the long term, wellbore integrity and associated gas leakage is a potential hazard. Ultimately, fluid migration can affect shallow groundwater resources but also impacts the conditions for future use of the subsurface, such as underground storage of energy carriers in produced fields or salt caverns, or geothermal operations.

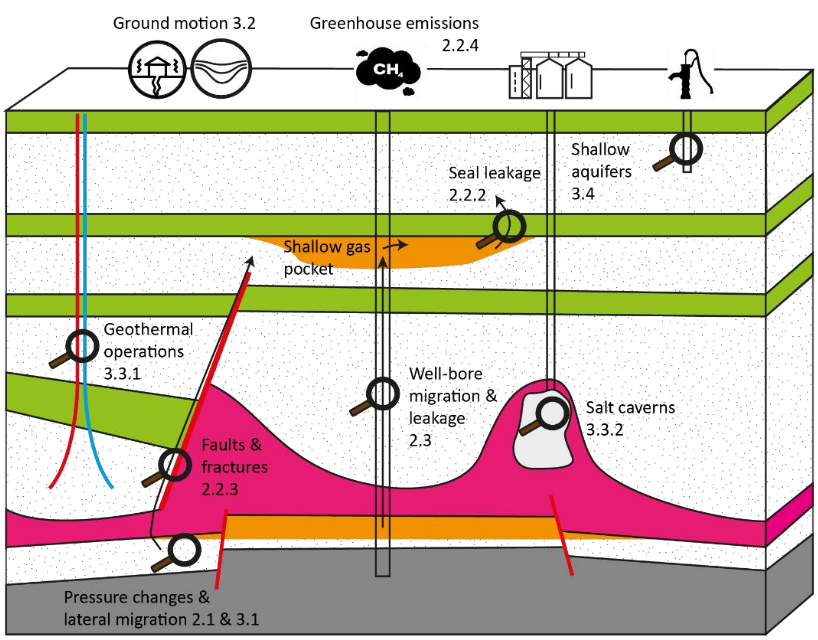

Figure 1. *Schematic representation of impacts and pathways of post abandonment fluid migration*

The aim of this document is to provide a comprehensive literature review on relevant processes and impacts associated with long-term fluid migration and wellbore leakage after gas fields abandonment. It discusses fluid migration between adjacent reservoirs, upward fluid migration and migration pathways, wellbore fluid migration and leakage. In addition, impacts of fluid migration on ground motion, on future subsurface operations (i.e. salt caverns, geothermal operations) and on shallow groundwater aquifers are discussed. Finally, risk assessment and management frameworks to address post-abandonment fluid migration risks are discussed.

This report is the deliverable of Phase 1 of KEM-19 project "Evaluation of post-abandonment fluid migration and ground motion risks in subsurface exploitation operations in the Netherlands" as commissioned by Ministry of Economic Affairs and Climate Policy (EZK).

The structure of this report is as follows. Section 1.1 describes the geological setting of the Groningen field, which is used as case study . Chapter 2 summarizes the literature review regarding long term fluid migration in abandoned fields, both on a field-scale and at the wellbore level. Chapter 3, reviews the potential adverse impacts of fluid migration on ground motion, shallow aquifers, and nearby operations. Chapter 4, describes the fundamentals of a suitable risk assessment framework. Chapter, 5 provides the major conclusions of this report, and Chapter 6 outlines the details of our proposed plan for the next phase of this project. A high-level summary of the findings of this report is provided in Table 3.

1.1 Groningen geological setting

The area of the Groningen Gas Field was selected as the case study area for this project. During the lifetime of the field itself more than 350 wells were drilled that are now in different stages of well lifetime and abandonment. Several other hydrocarbon fields are located in a similar geological setting in the North-East of the Netherlands onshore region.

The main reservoir of the Groningen Gas Field is the Upper Permian/Rotliegend Slochteren Sandstones. These sands were deposited under a dry arid climate in aeolian, fluvial or mixed conditions along the southern fringe of the Southern Permian Basin. The southernmost part of the Groningen Gas Field is located close to the southern extent of the Slochteren Formation in the area (Figure 2) and consists of higher percentages of a conglomeratic facies while the northern most part is close to the basin edge where increasing amounts of mudstone intercalations can be observed (de Jager and Visser, 2017, Grötsch et al. 2011). The area of the Groningen Gas field can therefore be seen as a good analogue for most of the Dutch Rotliegend gas fields (Figure 2). The Slochteren Formation is the most important reservoir in the Netherlands on- and offshore with about 2/3rd of the total gas production even excluding the Groningen Gas field (Annual review 2019). The sediments of the Upper Rotliegend unconformably overly the uplifted and eroded Upper Carboniferous and can be seen to onlap onto the Base Permian Unconformity from north to south (Grötsch et al. 2011).

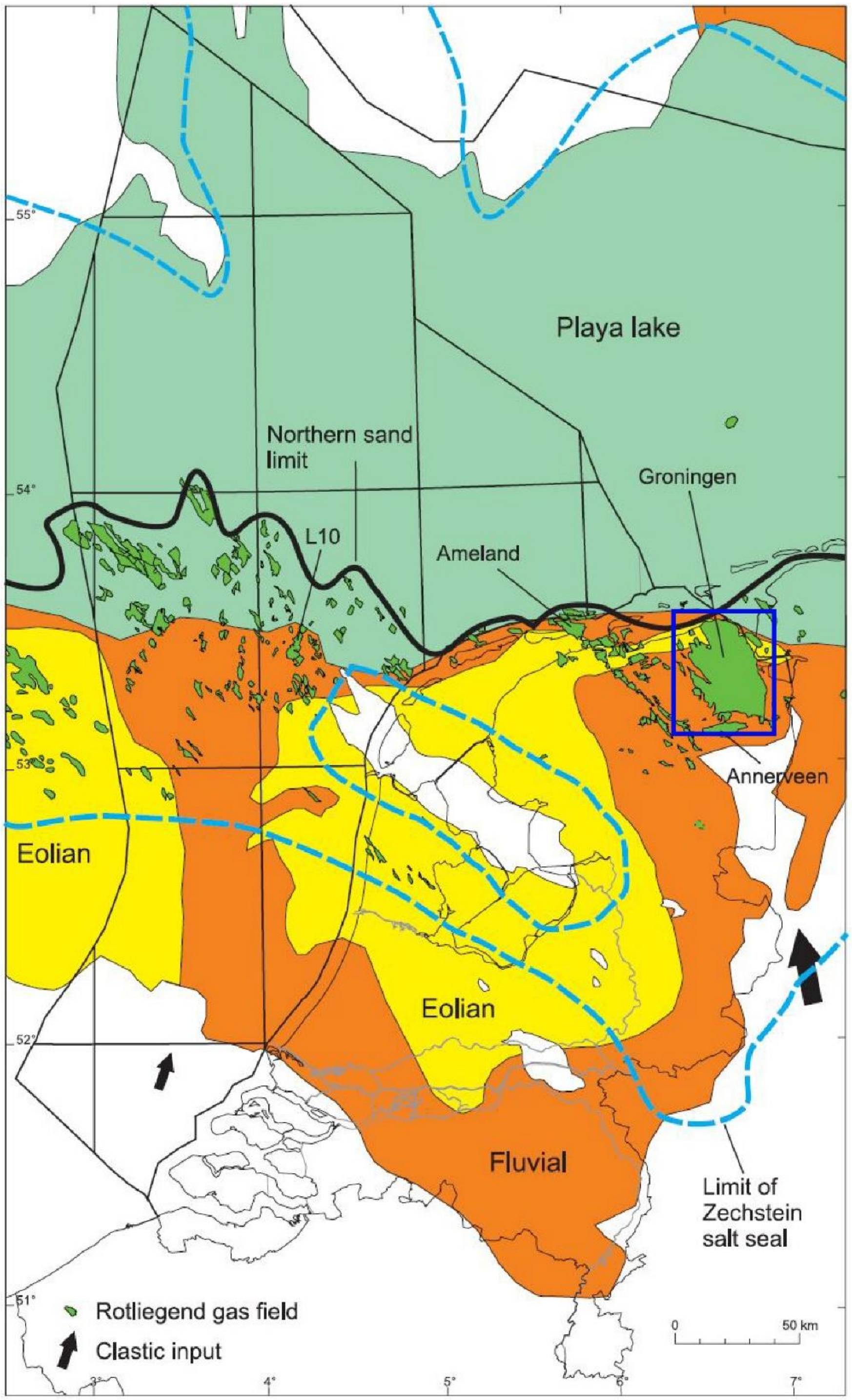

Figure 2. Play system map of the Upper Rotliegend Slochteren Formation showing the general depositional environments, the northern extent of the Rotliegend reservoir facies (black line) as well as the southern extent of the Zechstein top seal (blue striped line). The dark blue line shows the location of Figures 3, 5 and 6. (from de Jager & Geluk, 2007)

Halites and anhydrites of Zechstein age form the main seal for the Groningen Gas Field as well as most of the Rotliegend gas fields in the Dutch subsurface. The thickness of Zechstein deposits controls to a large extent not only the presence of gas above or below the Zechstein but also the structural style and history as well as the fault pattern of the overlying strata. The Groningen area shows Zechstein thicknesses between 50 m to more than 1500 m in varying structural configurations (layer cake, salt diapirs as well as thin Zechstein due to salt withdrawal, Figure 3) and is therefore considered a good example for Paleozoic gas fields with Zechstein salt present.

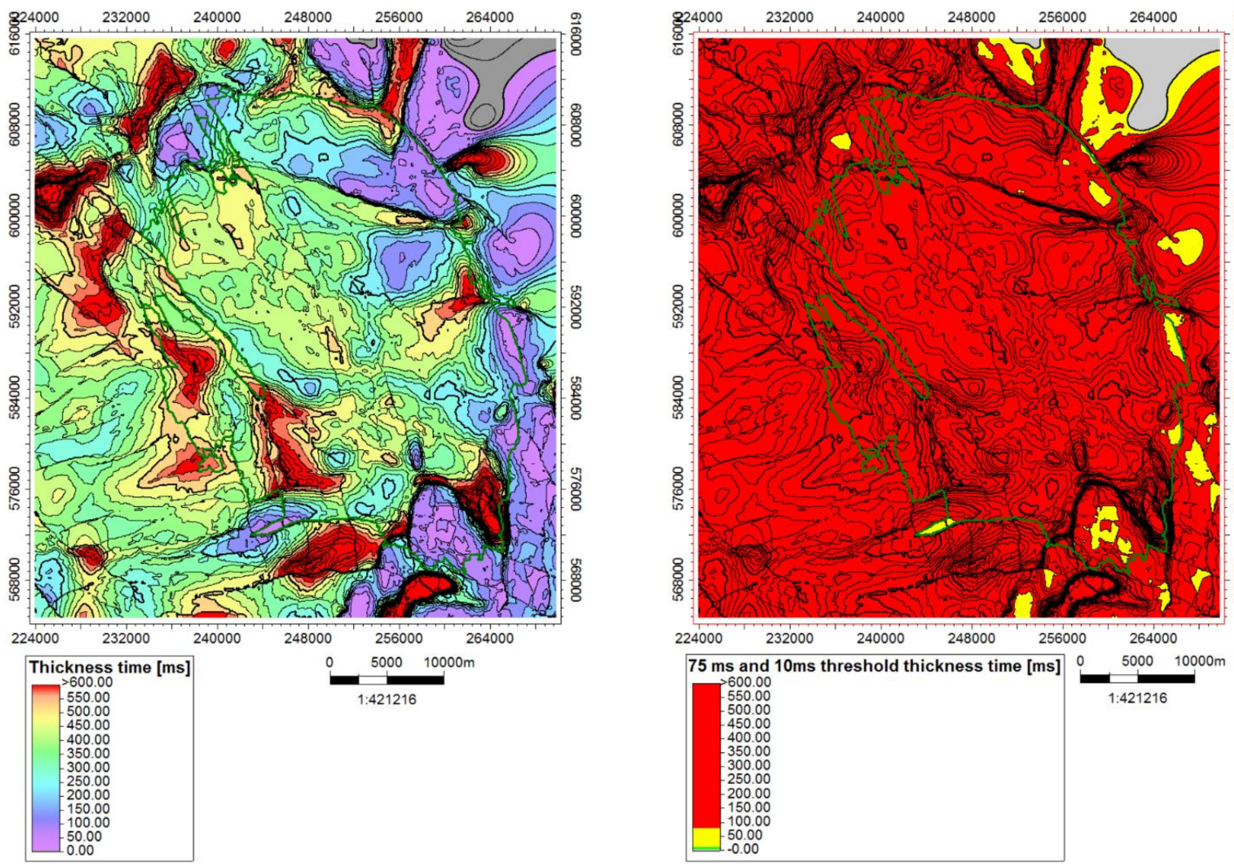

Figure 3. Isochore maps of the Zechstein in milliseconds (ms). The figure on the right highlights areas with thicknesses of 10-75 ms (The 10ms threshold was chosen because a 50m thick anhydrite layer corresponds to approximately 10ms, assuming a velocity of 5900m/s. The 75ms threshold was distinguished because this corresponds to 300m of salt at a velocity of 4500m/s and around 50m of anhydrite at 5900 m/s.) in yellow and of less than 10 ms in green (not present in study area). The green outline shows the original gas water contact from the Groningen Gas Field (from Logeman, 2017 – NAM report).

The overburden of the Groningen Gas Field is typical for platform structural settings in the Dutch subsurface, with Upper Triassic and Jurassic sediments mostly absent (Kombrink et al. 2012), though some remnants are still found along the southern and eastern margin of the field, close to the edge of the Lower Saxony Basin as well as in rim-synclines along salt structures (Figure 4). These sediments are overlain by shales of Lower Cretaceous age and thick Upper Cretaceous chalk. The deposits of the Cenozoic are dominated by deeper marine clays and marls from the Palaeocene to Miocene and during the Pliocene to Pleistocene by fluvial sediments of the Eridanos and the Rhine deltas. During the Quaternary the area was influenced by glaciations.

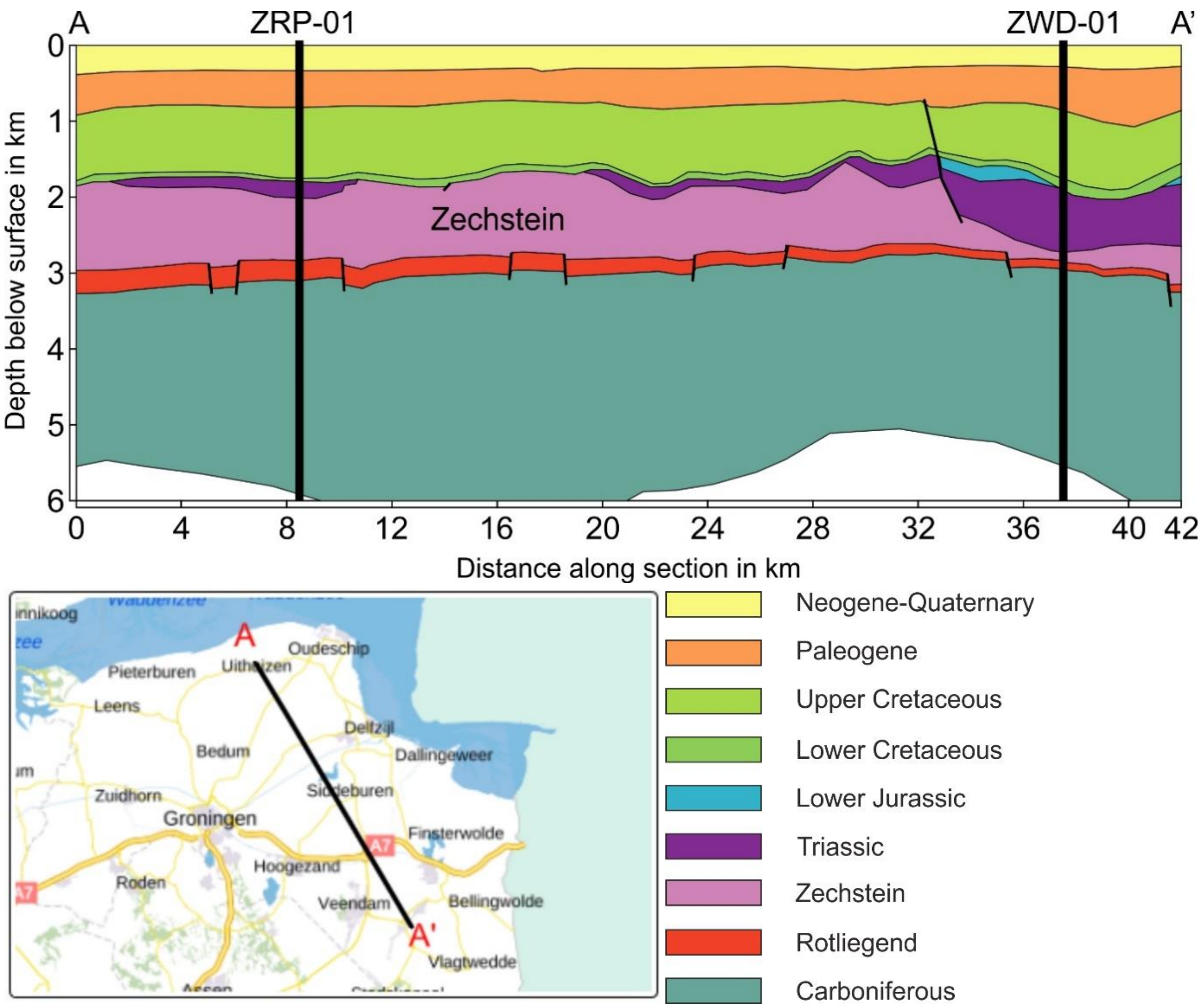

Figure 4. 2D Cross section through the Groningen Gas Field from NNW to SSE, crossing wells ZRP-01 and ZWD-01 showing the main structures and formations in the area (redrawn from www.dinoloket.nl)

Structural setting of the Groningen area

The Groningen Gas Field is located on the Groningen Platform (Kombrink et al. 2012) which is marked by the absence of Jurassic rift sediments and uplift and erosion at the end of the Carboniferous and during the Middle to Late Jurassic.

The fault pattern in the Carboniferous and Rotliegend sediments shows normal faults trending mainly NNW-SSE with some minor faults trending E-W and N-S (Figure 5). Some small pop-up structures in the Rotliegend are seen as evidence for the influence of compressional movements during the Late Cretaceous to Paleogene. The different stress directions during these later tectonic phases suggest oblique movement along these faults as well. The thick salt layer acts as detachment layer between the Paleozoic and the Mesozoic (Figure 4) and hard linked faults are only expected where the total Zechstein thickness is less than 50 m (i.e., less than 10 ms; Figure 6). The Mesozoic fault pattern can be mostly linked to salt tectonic activity as either crestal faults on top of large salt walls or diapirs or as collapse structures mostly linked to salt withdrawal (Logeman, 2017). Most of these faults were identified close to the margin of the reservoir or to the outside of it, The faults with a larger throw are mainly related to salt withdrawal and can be seen in the southern part of the reservoir (see Figure 4 and Paragraph 3.3.2.3 for a schematic description of the types of faults in the area). The thick Upper Cretaceous Chalk deposits as well as the Paleogene show only minor influence of the tectonic inversion pulses during these times (Grötsch et al. 2011).

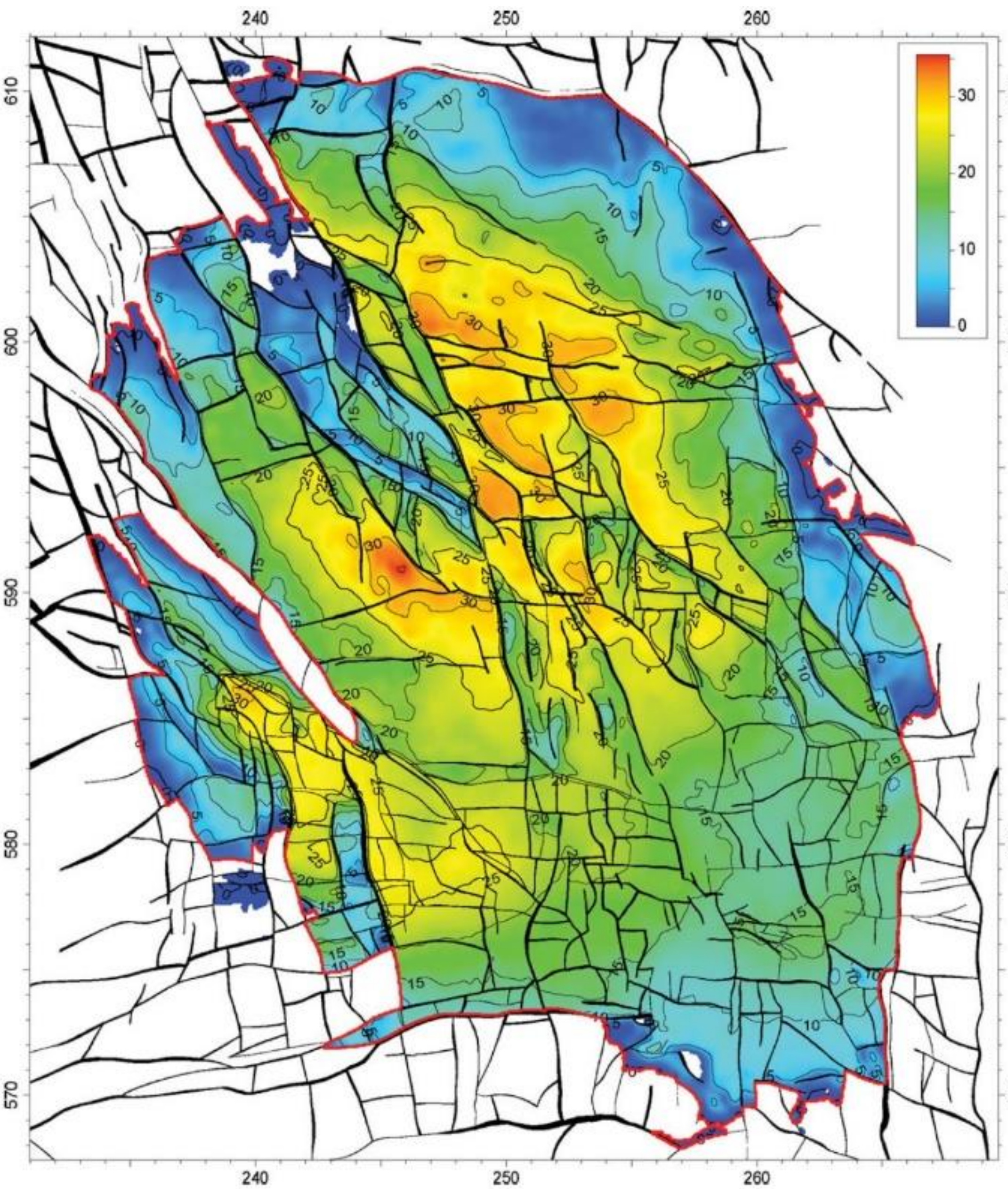

Figure 5. Map of the Groningen Gas Field Rotliegend fault interpretation with the initial net hydrocarbon column height map in m (from de Jager and Visser, 2017)

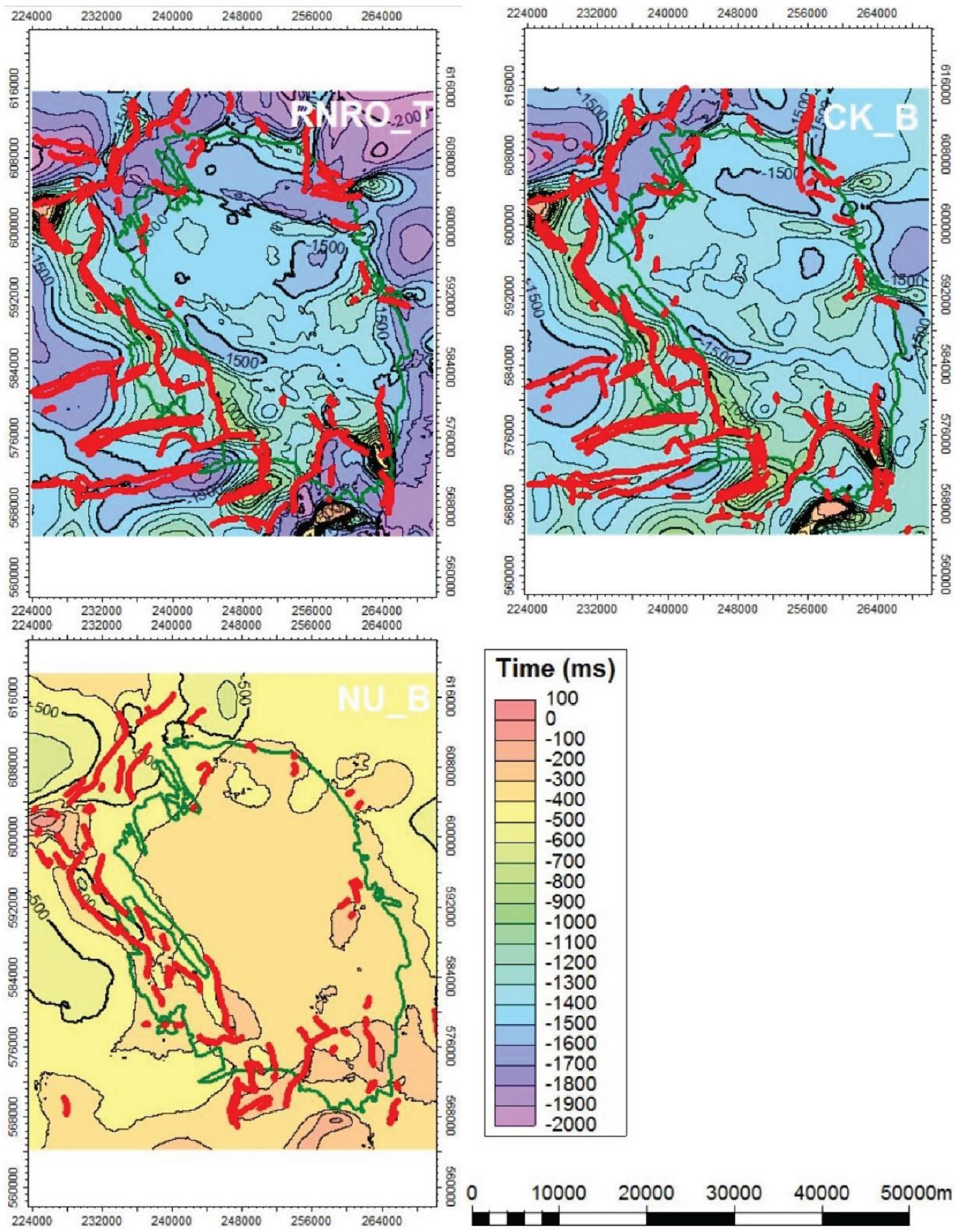

Figure 6. Fault intersection interpretation for the Mesozoic intervals of the Groningen Gas Field area on time depths maps of the respective seismic horizons (RNRO – Triassic, CK – Upper Cretaceous, NU – Neogene-Quaternary, from Logeman, 2017 – NAM)

2 Fluid migration after abandonment of depleted gas fields

Production of oil and gas leads to pore pressure drops and fluid flow at the reservoir level. Over the past decades, 70 gas fields and their associated wells have been abandoned in the Dutch onshore, of which 54 permanently (Jaarverslag Delfstoffen 2019). More fields are still in production but will be abandoned in the future. After production ceases, the pore pressures in the reservoir redistribute towards a new equilibrium which is associated with fluid flow and potential ground motion. These processes can take place over long time frames (Verweij et al., 2011). In this chapter the processes related to post-abandonment fluid migration will be discussed.

This chapter is structured as follow: Section 2.1 discusses fluid migration between adjacent fields; Section 2.2, focuses on upward fluid migration of methane from the reservoir to the atmosphere and to shallow aquifers; Section 2.3 reviews wellbore migration and leakage.

2.1 Fluid migration between adjacent fields

Migration of fluids occurs in most subsurface conditions albeit at different time and spatial scales. At geological time scales, the subsurface acts as a hydrodynamic system (Verweij et al., 2012; Muggeridge 2012; Peters and Verweij, 2012). In systems with high connectivity, near-hydrostatic pressures are likely, because fluids can move to keep the pressure in equilibrium. High overpressures as found in the offshore north of the Netherlands indicate limited connectivity even at geological time scales. The water is trapped during burial and cannot escape (or escapes very slowly) so that pressures stay elevated.

At the production time scale (30 to 50 years for most fields), only relatively large fluxes (i.e. high rates of fluid migration) are relevant, such as those resulting from strong aquifer drive or pressure equilibration between adjacent fields that are well connected. At the intermediate time scales relevant for this study (hundreds of years), understanding fluid migration is more difficult. On one hand, the smaller fluxes relevant at these time scales may not have been observed during production. On the other hand, the really small fluxes relevant at geological time scales which are responsible for pre-production pressure are most likely not relevant for the intermediate time scale. One of the main factors determining the size of the fluxes (fluid migration) between adjacent fields is the fault permeability, which is a very uncertain factor and has been studied at different time scales (Peters and Verweij, 2012; Miocic, et al., 2019; Ojik et al., 2019).

The focus area of this study is the northern part of The Netherlands, which is a prolific gas province: in the eastern part, the large Groningen gas field dominates the area (Figure 7). Near the Groningen gas field there are many smaller gas fields, which are in production or have been produced in the past. Some small gas accumulations have not been produced, for example in the south-east of the Groningen field. A multitude of smaller fields is present more to the west. Most of these also produce from the Slochteren Formation, but also from shallower formations, sometimes at the same location, e.g. in Weststellingwerf. Shallower formation from which production occurs are for example the Ommelanden Formation (Chalk Group) in e.g. Harlingen Upper Cretaceous, the Friesland Member (Rijnland Group) in e.g. Franeker and Opeinde, the Vlieland Sandstone Formation (Rijnland Group) in e.g. Weststellingwerf and Harlingen Lower Cretaceous and a variety of shallower formations in the Schoonebeek area to the south. In addition, two gas storage sites are present in the Rotliegend Formation: Norg and Grijpskerk (fields shown in blue in Figure 7). Most fields are between 1500 - 3500 m deep, however the shallowest produced layer of the De Wijk field is between 400 and 500 m depth and produces from the Lower North Sea Group.

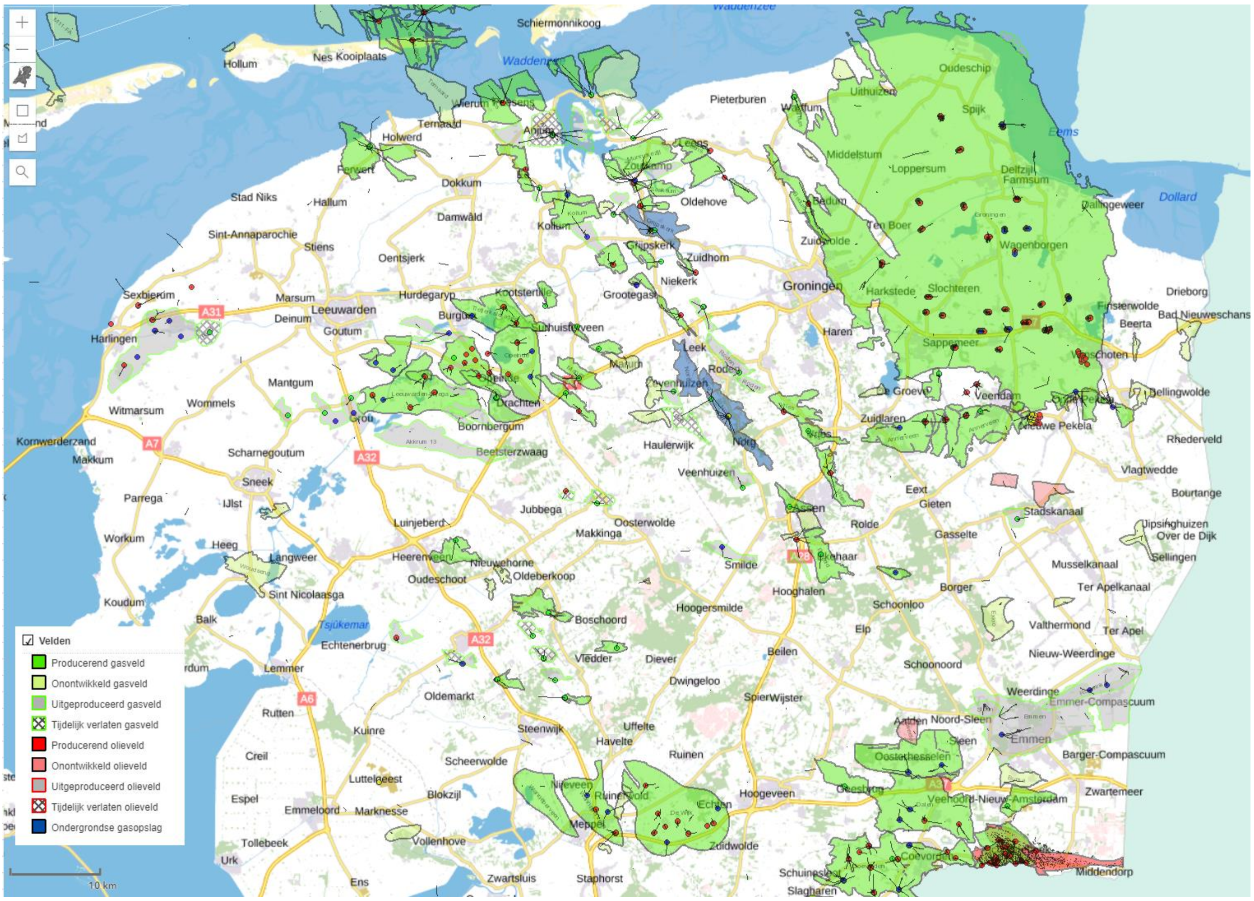

Figure 7. Overview of oil and gas fields in the northern part of The Netherlands (source: nlog.nl).

Fluid migration occurs during the entire lifetime of an oil or gas field and in many cases continues after abandonment. Many gas fields have a water leg, aquifer or some low permeable deposits connected to it. These connected formations will deplete due to fluid migration resulting from depletion in the gas field. After abandonment, fluid migration continues and causes pressure equilibration between the gas field and connected formations. Usually this results in a rise in pressure in the abandoned reservoir (not above initial pressure) and a decrease in the surrounding formations which may contain other subsurface activities. Only in very isolated reservoirs, the pressure remains constant after abandonment.

Downhole evidence of fluid migration is more likely to be found during production due to a higher level of monitoring and thus more chance of observing the migration. All gas and oil reservoirs with strong aquifer drive experience fluid migration: water flows into the gas or oil zone, which results in a pressure decline in the aquifer. Due to the low compressibility of water (compared to gas), a small water flux can already result in a relatively large change in pressure.

Evidence of fluid migration can be found in many places in the north of The Netherlands:

- (Strong) aquifer drive indicated by e.g. a high water cut during production; examples are the Roden gas field (van der Molen et al., 2020), Norg Langelo (DBI, 2017), Groningen aquifers (van Oeveren et al., 2018; NAM, 2020), Ameland (NAM, 2017)
- Reservoirs found below expected virgin pressure or experiencing pressure depletion due to production in other fields: for example Zuidwending, Zuidwending East and Annerveen gas fields just south of the Groningen field which experience pressure depletion from the Groningen field, although delayed (Burkitov et al., 2016).
- Observations of a rise of the free water level in gas wells (Burkitov et al., 2016, Zeeuw en Geurtsen, 2018)
- Observations of pressure increase in shut-in and/or abandoned reservoirs (Roden gas field)
- Observed depletion in adjoining formations: an example is the clear indication of depletion (Vos, 2003) and compaction (Kole et al. 2020) in Carboniferous deposits underlying the Groningen gas field.
- Subsidence above aquifers connected to a gas field may indicate aquifer compaction associated with depletion (Fokker et al. 2016; 2018, NAM, 2020)

From this evidence it is clear that the pressure depletion in the Groningen field and other fields influences the pressure in adjacent aquifers and gas fields (and other subsurface activities). How far this influence extends over longer time scales (100s of years), will be studied in the next phase of this project.

The following factors are expected to play a role for the magnitude of fluid migration between fields:

- The size and permeability of the aquifer attached to a gas field: when a large aquifer (large volume of water) is connected to an oil or gas field this provides much scope for fluid migration. The presence of a large, permeable aquifer is indicated during production by aquifer drive and water encroachment or high water cut in wells.
- The size of a gas field: the larger a gas fields and the amount of produced gas, the larger the amount of water that can migrate.
- The absence of flow barriers (e.g. sealing faults or low permeability zones): if there are no flow barriers, fluid can migrate over larger areas than with flow barriers.
- Presence of open faults with an offset that can enable pressure communication between different formations.
- Poor seal quality (e.g. thin, heterogeneous): above gas fields the seal has been proven historically, but in the adjoining aquifers areas might occur with poor seal quality. This could enable pressure communication with overlying formations and thus fluid migration.

2.2 Vertical fluid migration

This paragraph discusses the migration pathways of fluids from the reservoir, and evidence for leakage into shallow aquifers and the atmosphere. Wellbores fluid migration will be discussed separately in Section 2.3.

2.2.1 Potential leakage pathways

Potential pathways for migration and/or leakage of gas have been studied most extensively for storage of gases and in particular CO_2. An exception is the study by Raynauld et al. (2016) who presents a case study addressing risk to groundwater resources resulting from petroleum production looking at "potential preferential fluid migration paths between the reservoir level and shallow aquifers". Leakage along wells and surface spills were identified as main risk factors. The impact of depletion was not considered.

The following possible leakage pathways for migration of gas have been identified in the literature (e.g. Hepple and Benson, 2005; Hawkes et al., 2005, IEA GHG, 2007; Raynauld et al., 2016):

- Leakage resulting from failure of the seal (Section 2.2.2)
- Leakage of gas along (reactivated) faults or fractured zones (Section 2.2.3)
- Leakage along wells (Section 2.3)
- Gas migration across spills for fields originally 'filled to spill' (if there are fields that are not produced in the vicinity): due to a lowering of the pressure, gas expands and might move beyond the original spill point. No evidence of this ever occurring was found.

Since after depletion the reservoir forms a pressure sink, only buoyant fluids (e.g. gas) are expected to escape out of the reservoir. If connectivity between adjacent aquifers or overburden exists, fluids such as brine are expected to flow towards the pressure sink, so towards the depleted reservoir.

2.2.2 Caprock seal leakage

No reservoir cap rock or trap has ever been shown to be a perfect seal to hydrocarbon migration over extended periods of geological time (Evans and West, 2008). In general, shales are more prone to leakage than salt rocks due to higher permeabilities and more heterogenous properties (Evans and West, 2008). Etiope (2008) has shown that migration of hydrocarbons out of the trap into overlying sequences is more common than might generally be thought or presumed. Natural pathways and mechanisms result in hydrocarbon liquids and gases very gradually leaking from the reservoir rock. The hydrocarbons generally dissipate through the overlying sequences, sometimes reaching the earth's surface but in such small quantities and over such long periods of geological time that they rarely present a problem. A number of studies calculated the diffusion rates and fluxes through a caprock indicating losses ranging from 500 to 20,000 m^3/yr (Evans and West, 2008).

Caprock seal leakage occurs by membrane seal failure or hydraulic seal failure. Membrane seal failure can occur when gas transport is through the pre-existing pore system of the cap rock due to overpressures in the underlying gas column, and to changes in permeability due to chemical reactions with gas or brines (Espinoza, 2017). A case where caprock seal leakage after abandonment was investigated was in the Medicine Hat gas field in Alberta, Canada. In this particular case, potential leakage to an adjacent shallow aquifer could occur as a result of commingled abandonment of wells (Lemay et al., 2019). In this case, different geological units were connected by perforations at different levels for many (> 20.000) gas wells. This could result in pressure conditions exceeding pre-production values and therefore possible caprock seal leakage, that could impact adjacent drinking water aquifers.

Hydraulic seal failure may occur through hydraulic failure (microfracturing) of the cap rock, associated with faulting or by overpressure. Overpressure mechanisms are: a) sediment/tectonic/glacial loading, b) increase in fluid volume by temperature increase, production of water by diagenetic and metamorphic processes (for example mineral dehydration), generation of hydrocarbons (maturation, cracking) and c) fluid movement and associated redistribution of overpressures. Verweij et al. (2012) calculated the regional distribution of fluid overpressure in the Dutch subsurface showing that regional differences in fluid overpressure can be explained by the distribution of permeability barriers like salt deposits restricting fluid flow and burial history (differential sediment loading).

For reservoir abandonment in general, membrane or hydraulic seal failure is not expected to take place after abandonment since pressures will remain below initial pressures. Accumulation of migrated gas in shallow pockets may result in pressures exceeding the membrane seal pressure and further vertical gas migration may occur, but there is no indication that this occurs more often after abandonment.

In addition to mechanical effects, the integrity of caprock integrity could also be affected by geochemical reactions. Geochemical interactions between the caprock and formation fluids may lead to an increase in permeability. However, the impact of geochemical degradation has been found to be negligible on time scales smaller than 1000 years (Griffioen et al., 2017).

2.2.3 Leakage along faults

Fractures and faults can be conduits that can facilitate gas migration. For the purpose of potential storage of CO_2 in depleted gas fields, possibilities for leakage along faults has been studied by e.g. Miocic et al. (2019), Rutqvist (2012) and Moritz (2015). Miocic et al. (2019) studied the leakage rates from natural CO_2 reservoirs in Arizona (USA) over long time scales and Rutqvist (2012) from the existing storage site In Salah, which is analogues to the geological settings found in North-West Europe. In general, leakage along faults was not identified as a major risk, however CCS sites can be selected to avoid this risk, whereas this is not the case for abandoned oil and gas fields. Although depletion generally reduces the permeability of fractures (Wiprut and Zoback, 2000; 2002), it is well known from the Groningen field that depletion and compaction can change the stress conditions around faults resulting in reactivation of the fault (e.g. Candela et al., 2019). This might change the permeability of faults and fractures.

In Enhanced Geothermal Systems (EGS), the increase in permeability due to reactivation of faults and fractures is used for creating the geothermal system (see e.g. Olasolo et al., 2016 for a general overview of EGS), however this is in hard, brittle rock. The fractures or faults stay open due to the self-propping effect (e.g. Zimmerman et al., 2011). In softer, sedimentary rocks, fault permeability (or more often: fault sealing capacity) is often estimated via the Shale Gouge Ratio which depends to a large extent on the amount of clay or shale (AAPG wiki). How the permeability of such faults changes in the case of reactivation is more difficult to predict (Zoback and Gorelick, 2012 and the associated response by Juanes et al 2012; Jeanne et al., 2018).

Salt diapirs and associated faults and fractures could also be a risk factor for upward fluid migration. The well-known gas seeps above the Tommeliten gas field, for example, in the Norwegian sector of the North Sea lie above a salt diapir (Niemann et al., 2005). Faults above the diapir act as conduits for the gas rising from depth to the near surface, with gas also widely distributed throughout the upper part of the sediment column. A leakage pathway along faults and fractures associated with diapirs could be relevant for the Groningen gas field as well, since salt diapirs are present along its fringes and the diapir – rock contact may be fractured. For this to happen, first the fluid needs to escape from the reservoir through the seal.

Changes in pore pressures and water ingress after abandonment in the Groningen gas field may result in reactivation of faults leading to potential leakage pathways. As stated in Section 1.1, this is only expected an issue if the Zechstein seal is thinner than 50 m (Van Veen et al., 2012). Open faults and fractures can play an important role as migration pathway through the overburden, but the properties are difficult to predict. Faults associated with diapirs deserve special attention.

2.2.4 Leakage to the atmosphere

Hydrocarbons naturally and spontaneously emerge at the surface in all continents (Etiope, 2015; Hovland 2012), as indications of over-filling of some conventional reservoirs or geological interruptions such as faults and fractures. Natural seeps are the oldest oil and gas prospecting tools. Seepage can appear as either macro-seeps or micro-seeps, where macro-seeps produce focused streams of gas bubbles or oil droplets. This focused migration is generally an indication of a subsurface with fractures or faults that make up migration routes (Tveit et al., 2020). Micro-seep is evidence of a more widespread, dispersed exhalation of gas through a permeable subsurface, usually detected by taking samples of sediment pore water or measuring dissolved gas concentrations in the seawater above the expected seepage area (Etiope, 2015).

In order to evaluate the possible impact of thermogenic gas emissions from abandoned fields to the atmosphere, it is important to have an estimate of natural emissions without anthropogenic influence. Etiope (2009) provides an estimate of methane seepage (macro and micro) to the atmosphere from all literature information from European countries (seismics and direct measurements). On a continental level, the total yearly methane emissions were estimated in the order of 3 x 10^6 tons. The potential yearly micro-seepage in northern Netherlands, based on the oil-gas field area onshore, was estimated is in the order of 8 x 10^3 tons (Etiope, 2009).

On a global level, Etiope and Klusman (2002) estimate the total methane flux from present day land-based sedimentary basins of the world to be 70 x 10^6 ton/yr. This total flux value is reduced, however, to 7 x 10^6 ton towards the atmosphere due to the 90% methanotrophic consumption (net sink) of methane that occurs in the soils of the sedimentary basins during the micro-seepage process. Kvenvolden and Rogers (2004) estimate the total contribution to the atmosphere from geological sources to be 45 x 10^6 ton/yr. The work of Bothroyd (2017) considered whether faults bounding hydrocarbon-bearing basins could be conduits for methane release to the atmosphere. The analysis showed that hydrocarbon basins did not have a significantly different CH_4 flux compared to non-hydrocarbon basins.

In conclusion, no evidence for concentrated natural large scale methane flux to the atmosphere is found from gas fields, at most a constant background flux. However, how fluxes after post-abandonment evolve is uncertain since no abandoned gas field has been monitored over su long time periods.

2.2.5 Leakage to shallow aquifers

Methane is naturally present in groundwater and it is not considered a hazard unless its concentration rises to concerning levels (> 10 mg/l) (Eltschlager et al, 2001). Methane in the subsurface is generated via two paths: bacterial metabolic consumption of organic matter creates methane at shallow depths (referred to as biogenic methane), and at deep depths thermal cracking of organic matter due to the high pressure and temperature conditions (referred to as thermogenic methane) (e.g. Ing, 2015). Thermogenic gas is usually associated with coal, oil and gas fields and is not regularly found in shallow aquifers (e.g.

Schloemer et al., 2016). Thermogenic gas is found, if at all, in such low concentrations that it can be negligible compared to biogenic gas.

A baseline survey of dissolved methane in aquifers in the UK showed that CH_4 is ubiquitous, albeit at low levels (< 1000 µg/l) (Moritz et al., 2015). They concluded that methane in these shallow aquifers is mostly from biogenic origin, although methane from thermogenic origin may locally be important. The concentrations, however, do not warrant further investigation.

In the Netherlands, the most recent study on methane by Schout (2020) indicated that the median concentration is only 0.2 mg/L while 7.5% of the samples exceed 10 mg/L. This percentage is significantly more than observed in neighbouring countries. High methane concentrations are found in shallow groundwater in the coastal provinces, where Holocene peats and marine clays overly the aquifers. For these shallow aquifers, the median concentrations reached 4.0 mg/L whereas the concentrations are lower at larger depths. Other prominent sources of dissolved methane in Dutch shallow groundwater are the marine Eem Formation and the glacial Peelo Formation, which are both found in the northern part of the Netherlands. Thermogenic methane has only been found in shallow aquifers near Sleen, where a blow-out took place in a gas well in 1965.

No evidence for high concentrations of thermogenic methane in the shallow subsurface is found. In the Netherlands, only biogenic methane is found and thermogenic methane at a known well bore leakage location.

2.3 Wellbore migration and leakage

The oil and gas industry is responsible for significant levels of methane emission in the atmosphere through deliberate flaring and venting or unintentional fugitive leakages through equipment and wellbores (Bachu, 2017). Fugitive emissions have been reported as a significant source of GHG emissions in Canada (Conference Board of Canada, 2011), United States (US EPA, 2017; Kang et al., 2016; Omara et al., 2016), and the North Sea (Vielstadte et al., 2015; Vielstadte et al., 2017; Bottner et al., 2020). Fugitive emissions include leakage along or through active or abandoned wells. The cause and magnitude of leakage through wells needs to be understood, in order to enable governments to set effective policy in mitigating fugitive emissions. Aside from a source of GHG emissions, methane leakage along wells could contaminate shallow water sources (Harrison, 1983; Kelly et al., 1985; Sherwood et al., 2016; Darrah et al., 2014; Osborn et al., 2011).

In Section 2.3.1 we discuss various leakage pathways potentially present in the wellbores. This enables better understanding of the factors that could indicate higher leakage potential for some wells. In Section 2.3.2, we focus on methane emission measurement campaigns around the world. This section provides evidence of methane leakage at well sites into both the atmosphere and shallow aquifers. In Section 2.3.3, we outline different modelling studies on well leakage to identify gaps in knowledge and to gather information regarding the applicable tools and modelling techniques.

2.3.1 Wellbore leakage pathways

There are several types of cement failure that could occur in a wellbore, jeopardizing the cement integrity. The stress state in the wellbore changes throughout the life of the well, from the drilling stage, to completion, well testing, stimulation, production, and injection phases. The cement can debond from the casing or the formation, creating what is called a “microannulus” (Gasda et al., 2004; Roy et al., 2018). Cement can also undergo shear failure, tensile cracks, and disking (horizontal cracks in the cement sheath which are not generally considered to be a leakage risk)depending on the downhole conditions and cement properties (Bois et al., 2011). Well integrity could also be jeopardized by a damaged casing or pipe connections. Figure 8 illustrates various possible leakage pathways that could lead to well leakage. The well leaks can manifest in the form of sustained casing pressure (SCP) measured at the wellhead, surface casing vent flow (SCVF), casing failure (CF), and gas migration (GM) observed as gas bubbling in the ponded area near the wellhead.

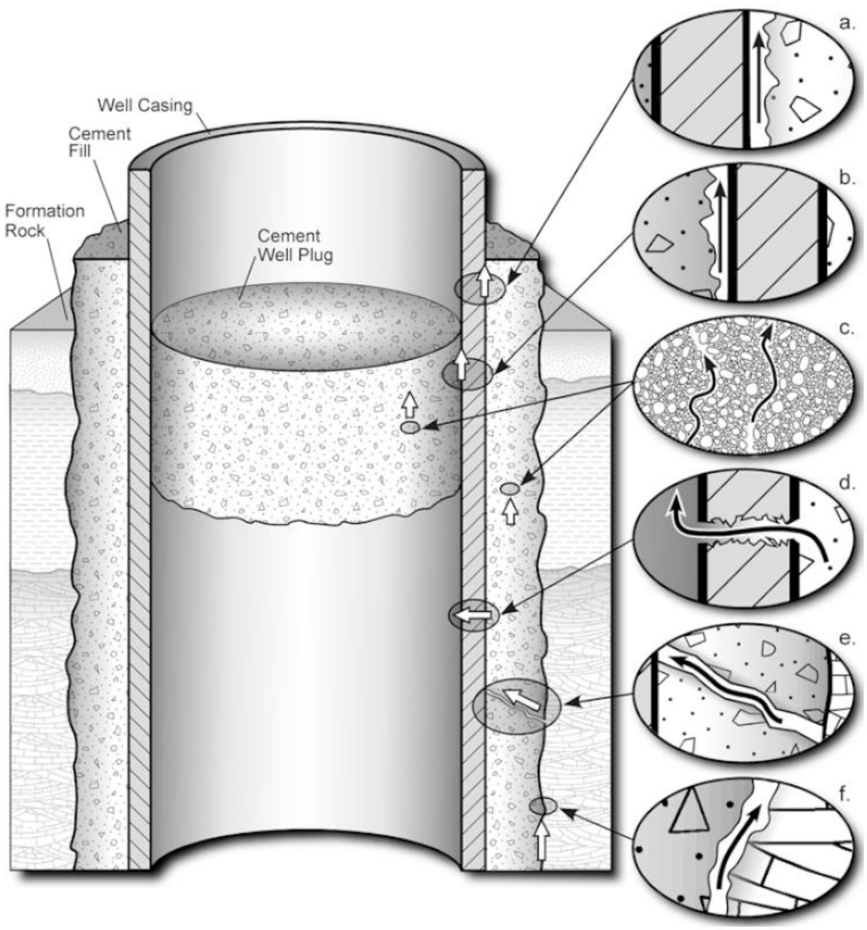

Figure 8: Various leakage pathways that could cause well leakage (Gasda et al., 2004).

The following pathways in wellbores have been identified in the literature as possible routes for fluid leakage. It should be noted that the mere presence of a flow pathway is not sufficient for a well to leak. A source of gas and sufficient pressure gradient are also necessary conditions for well leakage to occur.

1. Fluids can leak through the cement sheath due to cement mechanical failure and chemical interactions. This could occur due to high stresses induced by well operations such as pressure

testing, or hydraulic fracturing; poor cement quality leading to high shrinkage and weak cement structure; changes in wellbore temperature due to injection of hot or cold fluids; chemical interactions between cement and in-situ fluids (Gill et al., 2012; King and King, 2013; Bois et al., 2011, Wasch and Koenen, 2019)
2. Poor cement placement practices can create leakage pathways. Cement channels could form due to poor mud removal or casing centralization. Gas migration through cement during curing could form permanent high permeability pathways (Dusseault et al., 2000; Davies et al., 2014).
3. Fluids can leak through the uncemented portion of the annulus. This depends on the local abandonment regulations as in some regions operators can leave a portion of the casing uncemented. This is particularly important for older wells that were abandoned before more rigorous abandonment practices were in place (Bachu, 2017).
4. Fluid leakage can occur at the interfaces between the casing, cement and the formation. This could be caused by cement shrinkage, or a drop in casing pressure and temperature during well operations (Moghadam et al., 2020).
5. Fluids can leak through the damaged casing wall or connections. This could be exacerbated in a corrosive environment (King and King, 2013).
6. Leakage can occur through cement plugs (Davies et al., 2014).

The focus of this report is on wells that are properly plugged and pressure tested before abandonment, as is the case for all on-shore wells in the Netherlands. These wells could still provide a leak pathway on the outside of the casing through the annular cement. Therefore, leakage through the casing and plugs are not in the scope of this work.

2.3.2 Well leakage measurements

Leakage of oil and gas wells has received considerable attention in recent years. Two approaches may be used to investigate potential leakage in active and abandoned wells. First approach is field campaigns, where potential leakage fluxes are measured by sampling at the surface, in the unsaturated zone or the groundwater. Second approach is desk campaigns, where a large amount of data is analyzed to find evidence of well failure. The data is typically collected by the local authority overseeing the operation and maintenance of oil and gas wells. The reports from public regulatory bodies, and companies are also submitted to these organizations. The former approach provides quantitative estimates of field scale leakage rates. The latter, provides a statistical analysis on the percentage of wells that are expected to fail, with no quantitative leakage estimates. It is generally recognized that underreporting may occur for the latter, which implies that the reports are likely an underestimation (e.g., Williams et al., 2020). There are several published well leakage campaigns in different countries. The reports are outlined in the following, with a summary presented in Table 1.

Table 1: Meta-data of well leakage campaigns in different countries

Region	Type of Study	No of wells/% failure or defect	Type of wells	Reference
On-shore				
Alberta (Can)	Desk	316,439/4.6%	Active/abandoned	Watson and Bachu (2009)
Alberta (Can)	Desk	450,000/4.9% SCVF, 1.4% CF, 0.73% GM	Active/abandoned	Bachu (2017)
British Columbia (Can)	Field	17/53%$^{\$}$	Abandoned	Williams et al. (2020)
Netherlands	Field	29/3.4%	Abandoned	Schout et al. (2019)
Netherlands	Field	185/no *significant* leakage	Abandoned	ECN (2017)
Netherlands	Desk	986/2.3%	Active	SodM (2019)
Pennsylvania (US)	Desk	3,533/2.6%	Active	Considine et al. (2013)
Pennsylvania (US)	Desk	6,466/3.4%	Active	Vidic et al. (2013)
Pennsylvania (US)	Desk	8,030/1.27%	Active	Davies et al. (2014)
Pennsylvania (US)	Desk	32,678/1.9%	Active	Ingraffea et al. (2014)
Pennsylvania (US)	Field	31/71%	Abandoned	Pekney et al. (2018)
Colorado (US)	Desk	3,923/13.8%	Active/suspended	Lackey et al. (2017)
Colorado (US)	Desk	11,617/3.3%	Active/suspended	Fleckenstein et al. (2015)
Colorado, Wyoming, Utah, and Ohio (US)	Field	138/6.5%	Abandoned	Townsend-Small et al. (2016)
Oklahoma (US)	Field	53/62.3%$^{\$}$	Abandoned	Williams et al. (2020)
United Kingdom	Field	102/30%	Abandoned	Boothroyd et al. (2016)
United Kingdom	Desk	143/0.7%	Active	Davies et al. (2014)
Offshore				
Gulf of Mexico (US)	Field/desk	502/1.8%	Abandoned	Kaiser (2017)
Gulf of Mexico (US)	Desk	15,500/43%	Active/abandoned	Brufatto et al. (2003)
North Sea	Field/Desk	43/65%	Abandoned	Bottner et al. (2020)

$^{\$}$ classified as methane flux > 10^{-3} g h^{-1}

Canada

Operators in Alberta, Canada, are obliged to report any leakage from their wells to Alberta Energy Regulator (AER), which is the provincial regulatory body. This has led to a large systematic collection of leakage data over time in the province. Several studies spanning more than a decade have analyzed the data (Bachu and Watson, 2006; Watson and Bachu, 2008; Watson and Bachu, 2009, Bachu, 2017). As of 2013, nearly 7% of the 450,000 wells in Alberta (including conventional and thermal oil and gas wells) show some form of gas leakage (CF, SCVF, SCP, GM). Some wells show more than one form of gas leak.

Only leaks that are measurable at the surface are reported. Therefore, gas leaks along the wellbore that do not reach the surface, but possibly diffuse into other permeable formations such as shallow aquifers are not included in these numbers. Actual leakage rates were not measured and thus are not available in the AER database. Watson and Bachu (2009) determined that the leakage pathways are predominately due to time-independent mechanical factors during completion, operations, and abandonment. These factors can lead to cement failure which allows for gas to flow upwards. 559 wells in the AER database included gas source analyses. Most of the wells show gas leakage from a formation at a shallower depth than the target formation. On average, the ratio of the depth of the gas leak to the target formation was 0.42 (Bachu, 2017). Most of the well leaks indicated a thermogenic gas source, although in some cases biogenic methane likely from shallow groundwater aquifers was also detected. Only eight wells out of the 559 show clear signs of leakage from the producing formation. Their results show that in most cases, mechanical failure of cement outside the casing provides the leakage pathway for methane, while the source of leakage is likely the shallower gas formations (such as coal beds) that are hydrostatic or over-pressured.

Recently, Williams et al. (2020) investigated methane emissions from abandoned oil and gas wells in Canada and the United States. As part of their investigation, they performed field monitoring at abandoned wells in both British Columbia (Canada) and Oklahoma (US). From the figures, it can be deduced that 9 out of 17 wells (53%) showed methane leakage above 10^{-3} g h^{-1} (0.01 kg/yr) in Oklahoma, and 33 out of 53 wells (62.3%) show leaks in British Columbia. They further conclude that cumulative methane emissions from abandoned wells are highly uncertain while according to current insights, the 10^{th} and 11^{th} largest anthropogenic methane emission source in the U.S. and Canada, respectively.

The Netherlands

Three investigations are available on potential leakage of on-shore oil and gas wells. Schout et al. (2019) analyzed surface methane concentrations at 29 abandoned well sites in the Netherlands (1 oil and 28 gas wells). The wells were plugged, cut and buried to a depth of approximately 3 meters. They measured methane concentrations at the surface within a 15 m radius of the wells. In addition, static chamber measurements were conducted on 22 of the 29 wells by drilling a 1 m deep hole above the abandoned well site. They identified 1 out of 28 wells that leaks methane due to well integrity failure (3.68%). One m and 2 m deep holes show progressively higher fluxes of methane at the MON-02 well site. They estimated a methane leakage of 3880 kg/year at 2 m depth below the surface. The methane was of thermogenic origin likely from the Holland Greensand Member, a gas bearing formation in the Netherlands at a depth of 1420 to 1481 m. The target formation (Monster formation) is at a depth of 2800 to 3000 m. Their investigation shows that for the cut and buried wells, surface measurements of methane concentration may not identify existing leakages: gas dispersion in the unsaturated zone with (aerobic) methane oxidation reduce the methane concentration significantly upon which the methane does not reach the surface.

ECN (2017) investigated 185 plugged and abandoned wells with a mobile device supported with static chamber measurements at a limited number of sites. Their investigation is essentially a site investigation and not a well investigation as a number of wells may be present at a single site. They did not observe significant well leakage but anomalous methane concentrations were observed at 10 sites that could not be explained. Gas bubbles were also observed at a few well cellars while the methane leakage was observed to be below the detection limit of 0.2 g (CH_4) h^{-1} (1.7 kg/yr). Methane was not detected at the MON-02 site which illustrates that different monitoring techniques have different detection levels.

SodM (2019) performed a desk study on potential leakage of gas wells and other deep wells in operation. Based on the information provided by the operators, they found that at 23 out of 986 wells (i.e., 2.3%) indicate gas leakage due to ''external leak or seep outside conductor'', where 10 of these wells show biogenic methane and the rest thermogenic methane. The leakage rates were small from a few liters up to 115 L of methane per day for one well.

Further, Schout et al. (2018) investigated the impact of an underground blowout on groundwater chemistry. The incident occurred during the drilling of a gas well in the Netherlands in 1965. They identified elevated methane concentrations (up to 44 mg/L) in the groundwater as far as 500 m downstream of the location of the blowout. The methane is thermogenic in origin from the Sleen reservoir at 2 km depth below the surface. They concluded that persistently high methane concentrations near the site indicates a continuous leak from the reservoir. Methane oxidation could lead to natural attenuation of the methane plume. Therefore, the monitoring locations should be as close as possible to the leak location and ideally include multiple measurement locations.

United States

Pennsylvania has seen a significant increase of oil and gas activity in the past two decades due to the development of the Marcellus shale (Kargbo et al., 2010). Hydraulic fracturing is commonly used to allow for economic production of hydrocarbon from shale formations. There have been concerns regarding the impact of gas production and hydraulic fracturing on groundwater quality in Pennsylvania. Osborn et al. (2011) analyzed samples from shallow groundwater systems overlying the Marcellus shale in Pennsylvania and Utica shale in New York. They reported an average methane concentration of 19.2 mg/L in water wells within 1 km of a gas well, likely thermogenic in origin. An average of 1.1 mg/L was observed in wells that were in nonactive areas, with predominantly biogenic origin. They found no evidence of fracturing fluid leakage into the groundwater. Darrah et al. (2014) also analyzed samples from water wells overlying the Marcellus shale. They found seven clusters of fugitive gas emissions in their data. Four of the clusters were traced to thermogenic origin gas from intermediate formations, and three were linked to the producing gas target. Kang et al. (2014) conducted surface methane leakage measurements on 19 abandoned wells in Pennsylvania. They reported an average surface leak rate of 99 kg/year with predominantly thermogenic origin. Kang et al. (2016) studied 53 unplugged and 35 plugged abandoned wells also in Pennsylvania. Their results indicated an average leak rate of 193 and 131 kg(methane) y^{-1} for the unplugged and plugged wells, respectively. Some wells showed leakage rates that were two orders of magnitude higher than average. Pekney et al. (2018) measured methane leakage at 31 well sites. 22 wells showed some level of surface leakage at an average of 250 kg/year. The measurements were repeated after 2 years on high emitter wells and the results indicate that flow rates are sustained through time. In other studies that focus on Pennsylvania, Considine et al. (2013) studied 3533 wells and found 2.6% of the wells show integrity loss. Vidic et al. (2013) found well construction problems for 3.4% of 6,466 wells and 0.24% with leakage to fresh groundwater. Davies et al. (2014) found that 6.26% of 8,030 wells studied had well integrity issues while 1.27% of them leaked to the surface. Finally, Ingraffea et al. (2014) investigated conventional and unconventional wells for the period 2000-2012 and found that 1.9% of 32,678 wells had loss of well integrity.

Lackey et al. (2017) analyzed SCP data from 3923 active and suspended oil and gas wells in the Wattenberg Test Zone (WTZ), in Colorado. The data was obtained from the Colorado Oil and Gas Conservation Commission (COGCC). They determined that 13.8% of the wells show some level of integrity loss based on SCP values. Fleckenstein et al. (2015) reported that 388 of 11,617 wells (3.3%) in Wattenberg field in Colorado have short surface casings and uncemented intermediate casings which could pose as "possible barrier" failures. McMahon et al. (2018) analyzed water samples from 15 monitoring wells in Colorado over a period of 7 years (2011-2016). Three of these wells were within 50 meters of an abandoned gas well. Thermogenic methane at high concentrations between 16 and 20 mg/L was found in one of the wells. Methane concentration did not materially change over the seven-year duration of the study. However, methane was not detected at the surface near the wellsite. They postulate that the presence of an 18 m unsaturated zone at the monitoring well location potentially oxidizes the degassed methane. Therefore, no free methane will reach the surface and the leak is virtually undetectable. The abandoned gas well has a 1000 m uncemented zone outside its production casing. Sherwood et al. (2016) investigated the levels of methane concentration in 924 water wells in Denver-Julesburg Basin of northeastern Colorado. 261 wells (28.2%) showed over 1 mg/L of dissolved methane. The majority of the wells showed microbial methane linked to shallow coal seams. Only 42 wells contained thermogenic methane likely from underlying oil and gas formations. They put the risk of thermogenic stray gas in water wells to be between 0.12 to 4.5%, in the DJ Basin.

Townsend-Small et al. (2016) measured surface methane emissions from 138 abandoned wells in four states (Colorado, Wyoming, Utah, and Ohio). Only 9 of the 138 wells (6.5%) showed a positive methane release at the surface. 8 of the 9 leaky wells were unplugged. Their isotopic analysis of the leaked methane showed the presence of both thermogenic and biogenic methane in wells. The biogenic methane was likely sourced from the coal bed methane (CBM) layers commonly found in all four states in the study. They reported an average surface leak rate of 88 kg/year for the unplugged wells and nearly zero for plugged wells. Riddick et al. (2018) measured the surficial methane leakage at 112 plugged, 147 unplugged, and 79 active gas wells in West Virginia. The plugged wells on average leaked 1 kg/yr, while the unplugged and active wells leaked considerably more methane at 27 and 1,218 kg/yr, respectively. Their results indicate that unplugged wells leak an order of magnitude more than plugged wells. Also, in WV only 2% of abandoned wells are deemed to be high emitters (above 876 kg/yr). Active wells show significantly higher surface methane emissions than previously understood.

There are 15,500 active and non-active wells in outer continental shelf of the Gulf of Mexico. It is estimated that 6,692 (43%) of those wells show SCP for at least one casing annulus (Davies et al., 2014;

Brufatto et al., 2003). Kaiser (2017) focused on 502 abandoned wells in the Gulf of Mexico and concluded that 9 of them (1.8%) had to be repaired following reported leakage.

UK and Norway

Boothroyd et al. (2016) measured methane concentration in the soil above abandoned (decommissioned) oil and gas wells in the UK. They investigated 102 wells and found that 30% (31 wells) of them indicate methane concentrations higher than the background. They did not find the source of methane but concluded that the leaks were likely due to well integrity issues. They reported an average leak rate of 364 kg/year with a maximum leak of 8604 kg/year for a well that was not properly abandoned. Davies et al. (2014) reviewed the data for 143 onshore active wells in the United Kingdom and determined that 1 well (0.7%) was leaking due to cement failure.

Vieldstadte et al. (2015) quantified methane gas release at three abandoned gas wells in the Norwegian sector of the North Sea. They found methane leakage rates of 1-19 tons per year. Chemical analyses indicated that the gas is primarily biogenic. Vieldstadte et al. (2017) used these data to estimate the gas release from abandoned gas wells in the North Sea. Bottner et al. (2020) documented gas release at decommissioned hydrocarbon wells in the UK sector of the North Sea using water column imaging and 3D seismic data. They pointed out that gas release from the sea floor occurred near 28 of the 43 wells studied (65%). The source of the gas release was assumed to be shallow biogenic gas pockets. The latter two studies were strongly criticized by TNO on their data interpretation and assumptions to estimate anthropogenic methane losses across the North Sea as well as the anthropogenic versus natural origin of the methane leaking (TNO, 2018; 2019; Wilpshaar et al., 2020).

2.3.3 Well leakage modelling

Direct measurement of methane leakage along wellbores is a difficult task. A leak might not be detectable at the surface but could still contaminate shallow groundwater (Schout et al., 2020). Numerical modelling can assist in understanding the mechanisms of gas leakage along abandoned wells and the important parameters that control the leakage rate. In addition, numerical modelling can be used to design more effective monitoring strategies. Several studies exist in the literature that focus on modelling to understand the consequences of well leakage (Nowamooz et al., 2015; Caroll et al., 2014; Postma et al. 2019). Some studies focus on understanding the rate of leakage and its sensitivity to important geological and wellbore parameters (Rice et al., 2018; Nowamooz et al., 2015; Reagan et al., 2015), others have attempted to use field measures of leakage to estimate the permeability of leakage pathways (Tao and Bryant, 2014; Kang et al., 2015). The former provide important lessons in modelling techniques and analyses, and the latter provide clarity on the input parameters for the numerical models. Most leakage studies, however, focus on CO_2 leakage along wellbores in the context of carbon sequestration (Harvey et al., 2013; Keating et al., 2014).

Matrix permeability of intact cement in an annulus is measured to be less than 1 microdarcy (Stormont et al., 2018; Bachu and Bennion, 2009). Therefore, it should provide an effective barrier to flow if the cement is perfectly bonded to the casing and the formation. However, documented presence of leaky wells indicate loss of seal capacity in some cases. Crow et al. (2010) and Gasda et al. (2013) analyzed the cement integrity of several wells using a Vertical Interference Test (VIT). This test measures the hydraulic connection between the annular cement across a section of the well, as demonstrated in *Figure 9*. Gasda et al. (2013) reported a range of 1 to 100 mD for the effective permeability of the cement sheath behind the casing from 3 datasets, while Crow et al. (2010) estimated a value between 0.5 to 1 mD for a single well. Tao and Bryant (2014) used SCP and SCVF data from 300 oil and gas wells in combination with a Monte-Carlo simulation technique to estimate the effective permeability of the annular cement. Their results indicate that annular cement permeability could vary between 0.01 and 10 mD. Kang et al. (2015) used methane emission data from 42 wells in Pennsylvania to estimate the effective permeability of the abandoned wells. Their results indicate well permeability in the range of 10-6 to 100 mD. Their database included both plugged and unplugged wells. For unplugged wells, the effective permeability estimates refer to the combination of flow paths inside and outside the wells. The effective permeability for the plugged wells ranged between 10-4 and 10 mD, with an average of 0.4 mD. A recent study by TNO reported a range of 0.5 to 100 mD (equivalent to a microannulus aperture of 10 to 50 microns) for the cement sheath permeability (Moghadam et al., 2020). Their study analyzed leakage measurements from 10 datasets in the literature, each including 19 to 147 wells.

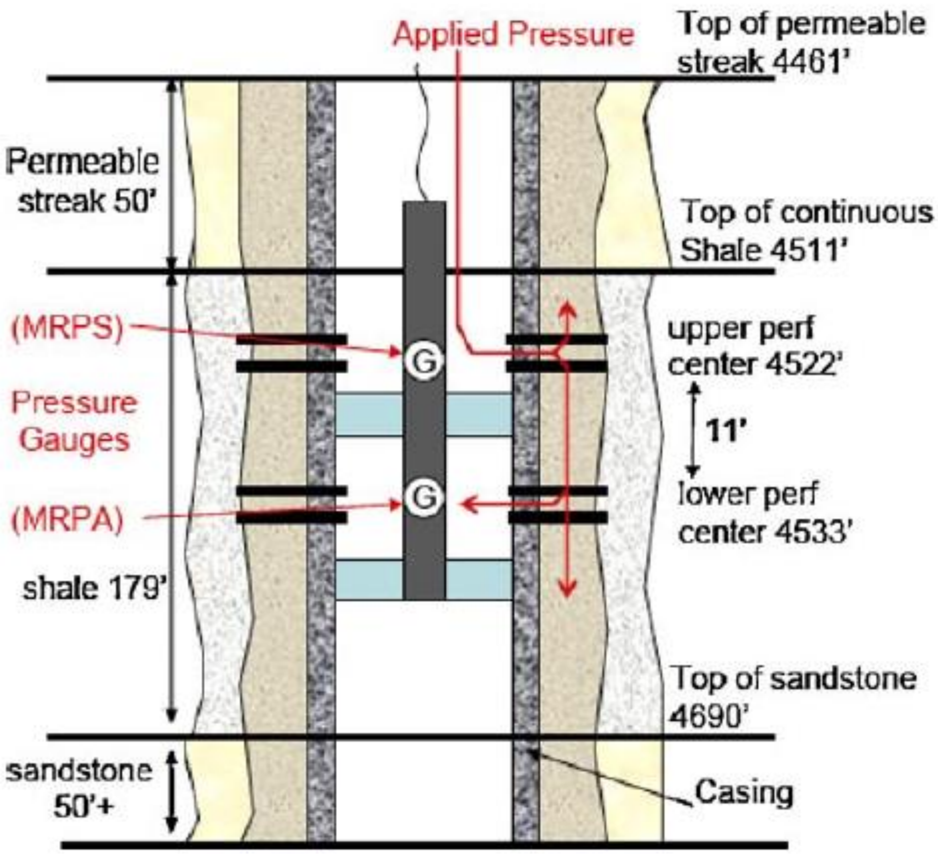

Figure 9: The schematic of a Vertical Interference Test (Crow et al., 2010).

Hu et al. (2012) used a combined reservoir/wellbore simulator to analyze the problem of brine leakage to a shallow aquifer through an open wellbore. The leakage in their model was caused due to excess pore pressure in a deep saline aquifer as a result of CO_2 injection. Their results show that the rate of upwards brine leakage decreases with an increase in brine salinity. Higher salinity effectively reduces the pressure gradient that drives the brine upwards, due to gravity. They concluded that if CO_2 injection creates an overpressure between 0.1 to 0.5 MPa in the deep aquifer (depending on the brine salinity), brine could leak into the shallow aquifer. However, they assumed open flow in the well, so the flow rate through a damaged cement would be considerably less. Doble et al. (2018) used MODFLOW-USGS software package to model the inter-aquifer brine leakage associated with abandoned Coalbed Methane (CBM) wells in Australia. They only looked at crossflow of water between aquifers and concluded that leakage is controlled by the well conductivity and aquifer permeabilities.

Lavrov and Torsaeter (2018) conducted a numerical study to calculate the CO_2 leakage through a microannulus at the debonded surface between the casing and cement. They treated the aperture as a stochastic variable and concluded that the poorly known parameters such as microannulus aperture, have a major impact on the magnitude of leakage. Therefore, they recommended that focus should be on representing the uncertain parameters in the numerical models rather than developing more mathematically advanced models. Their work only modelled the leakage along a wellbore without including the impact of nearby formations.

Carroll et al. (2014) described the impact of CO_2 leaks along abandoned wells on shallow aquifers. They assumed various levels of CO_2 leakage and simulated the impact on an aquifer using a 2D, multiphase reactive simulator. They did not model the CO_2 flow across the wellbore, or the impact of other permeable formations between the target and the aquifer. They concluded that CO_2 leakage could significantly change the pH of the groundwater; however, the plume will likely not reach far distances and the risk should be limited. They used the TOUGH2 reservoir simulator to model flow in porous media. Postma et al. (2019) used the new estimates of the annular permeability of wells (Kang et al., 2015; Tao and Bryant, 2014) to estimate the field scale leakage of CO_2 through neighboring abandoned wells. They created a hypothetical scenario of a CO_2 injector well surrounded by a large number of leaky abandoned wells. A conceptual representation of their model results is presented in Figure 10. Their model only included advective flow. Their results show that CO_2 leakage as a percentage of the total CO_2 injected will be very small over a long time frame. The numerical work was conducted using ELSA (Estimated Leakage using Semi-analytical Analysis), a previously developed reservoir simulator that uses a set of analytical and semi-analytical solutions for CO_2 injection. Humez et al. (2011) conducted a similar study but focused on the geochemical interactions of CO_2 with the shallow aquifers, using TOUGHREACT.

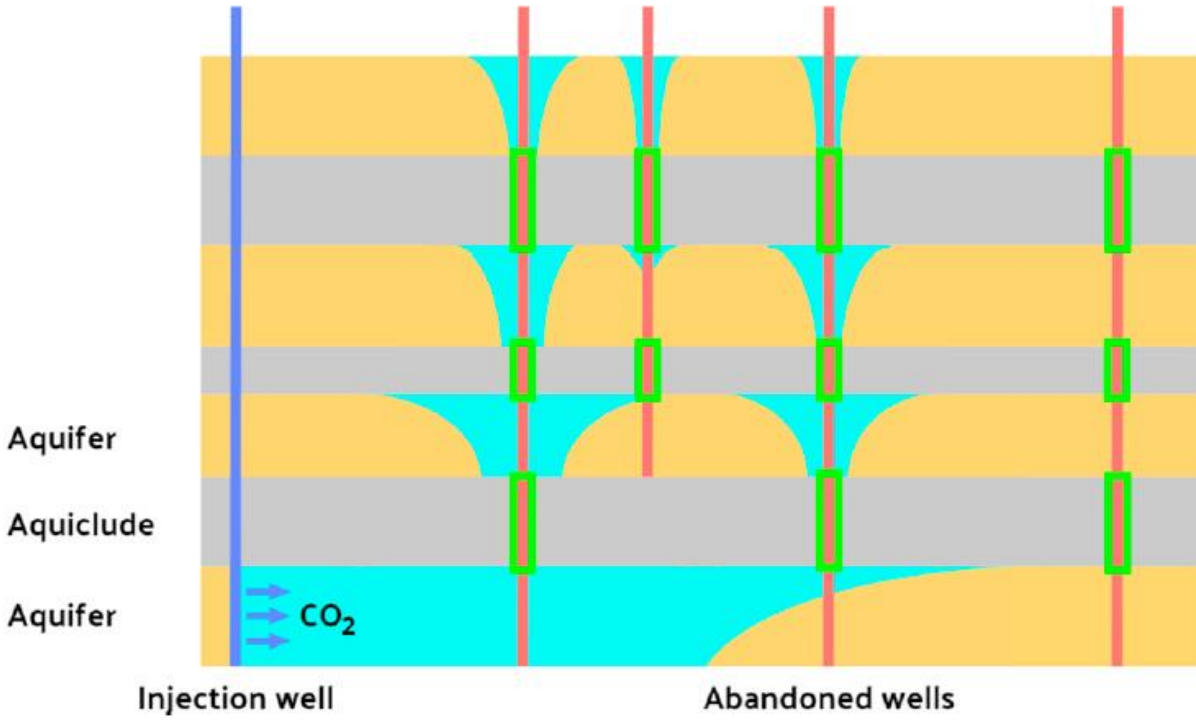

Figure 10: The schematic of the model developed by Postma et al. (2019). All wells are assumed to provide a leakage pathway across the geological seals, as represented by the green color. The image is adapted from Kavetski et al. (2006).

Nowamooz et al. (2015) conducted numerical simulations to investigate the impact of leakage along an abandoned shale gas well in Quebec, Canada. They used a 2D, two-phase, two-component, isothermal model using the DUMux simulation package. They tested a non-isothermal case and concluded that temperature impacts were not significant and the isothermal model is sufficient to describe the process. The model included advective and diffusive flow. Conceptually the model included a cement section that connected all the formations to the base of an aquifer. The aquifer itself was not modelled. Also, the impact of potential gas pockets such as CBM layers was not considered. Figure 11 illustrates the geometry of their model. Their results show that if cement quality is adequate (permeability less than 1 mD) the leak rates will be less than 0.01 m^3/day which is below the minimum reported vent flow in Quebec. In that case, the permeability of the target formation does not impact the leakage rate. However, when cement quality is poor (permeability above 10 mD) the target formation's permeability can become important and lead to higher leakage rates. They did not find significant levels of brine leakage. Their model did not provide the details of methane dissolved in the aquifer and the evolution of the plume to assist monitoring strategies.

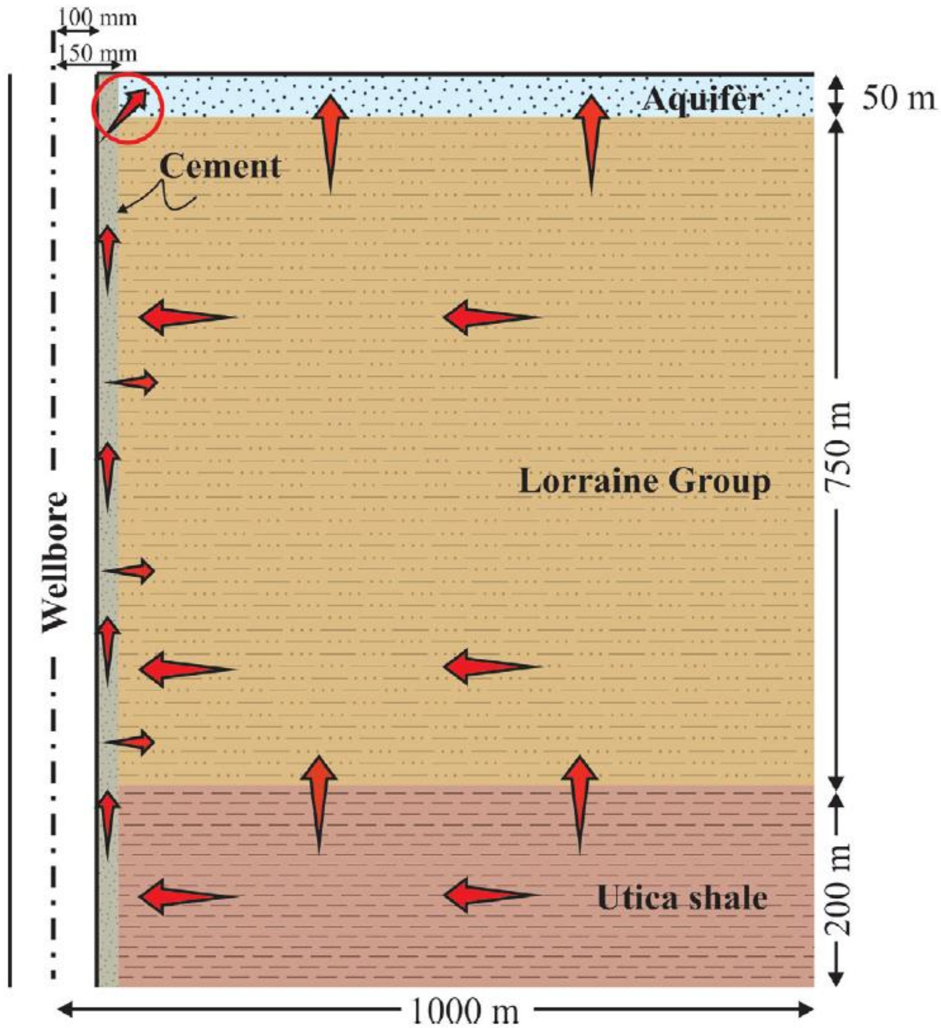

Figure 11: The model geometry used by Nowamooz et al. (2015) to estimate methane leakage into a shallow aquifer in Quebec, Canada. The arrows demonstrate possible gas flow directions into and out of the different formations.

Schout et al. (2020) studied the impact of groundwater flow on the retention of methane leakage in a shallow aquifer. They assumed a fixed leak rate through a small area at the base of an aquifer. They used a 3D, two-phase, two-component model based in DUMux. They concluded that the retention of methane due to dissolution into laterally flowing groundwater can be significant. Methane retention will be amplified in the presence of fine-grained intercalated layers. They concluded that depending on the groundwater velocity, leakage rate, and flow properties of the formation, methane can be retained in the aquifer for years or decades before reaching the surface. In their work, flow along the abandoned well and the impact of shallow gas pockets and brine formations were not included. Reagan et al. (2015) conducted a comprehensive sensitivity analysis to investigate the impact of fractures/faults and well integrity failure on methane leakage from tight gas wells. They used the TOUGH+RealGasH2O simulator which models the non-isothermal two-phase, two-component flow of water and methane. The model geometry assumed that the well connects the target formation to the shallow aquifer. The overburden was assumed to be impermeable. They concluded that the cement permeability and the target formation pressure and permeability were the most consequential parameters in determining gas leakage into the aquifer. They noted that in all their cases water flowed downwards along the leaky well. Roy et al. (2016) used a reactive transport simulator to investigate the attenuation of dissolved methane in water for confined and unconfined aquifers. They concluded that in both confined and unconfined aquifers methane oxidation could attenuate a migrating dissolved methane plume. This effect was stronger in unconfined aquifers. However, this natural attenuation is sensitive to the leak rate and duration and the background geochemistry present in the water. Rice et al. (2018) used the TOUGH2 EOS7C package to investigate methane leakage from a wellbore upwards into an aquifer. They assumed that the source of leakage is 20-30 meters below the aquifer’s base. Therefore, they modelled the leak as if it is stemming from the formation below the aquifer instead of modelling flow along the wellbore. Their base case shows plume diameter of 350 meters at the base of the aquifer after 100 years. They ran a sensitivity analysis and emphasized the need for two-phase flow modelling and accurate estimates of relative permeabilities and capillary pressure relationships.

3 Potential impacts of fluid migration and pressure redistribution.

3.1 Impact of pressure depletion

The reduction in pressure in the area surrounding an abandoned gas field can have a range of effects:

- The reduced pressure can mobilize gas that was not previously mobile, such as gas below free water level which is present below the Groningen field (Elk and Doornhof (eds.) 2019) or gas in fields that are filled to spill.
- Unexpectedly low pressure can pose risks for future drilling activities, in particular lost circulation (i.e. uncontrolled loss of drilling fluid or cement slurry to the formation (petrowiki.spe.org)). Lost circulation can have a range of negative results such as loss of well control, lack of cement integrity, loss of reservoir productivity and in rare cases induced seismicity (Dost, 2012).
- Reduced pressure can create operational problems for geothermal systems, for example, because sand production is a larger problem in depleted reservoirs than in reservoirs with virgin pressure or due to increased pumping requirements.

The change in pressure causes changes in in-situ stresses, which could potentially cause ground motion (compaction, subsidence, induced seismicity) at some (vertical or lateral) distance of the originally produced field. Subsidence and induced seismicity is discussed in the Section 3.2. Fault reactivation due to changes in in-situ stress could lead to changes in permeability of faults and of seals if the seal is crossed by faults.

In addition to these effects on deep subsurface use, pressure changes could potentially change deep regional flow patterns. Due to a large pressure 'sink' in the deep subsurface, shallower groundwater systems (up to 1000 m depth) might be affected and upward groundwater flow might be reduced resulting in reduced seepage and associated changes in water quality in shallow aquifers and/or at the surface. This occurs for example for large groundwater extractions, e.g. La Mancha area in Spain (Esteban and Albiac, 2012), lignite mines in Germany. In general, it is expected that the subsurface in the North of The Netherlands has too many low permeability layers between the gas fields and the groundwater flow (e.g. Zechstein) to make this possible.

3.2 Impact on ground motion

3.2.1 Surface deformation

A change in pore pressure or temperature in a reservoir volume causes a mechanical response: a change in effective stresses and associated reservoir compaction or dilation (Geertsma, 1973). A poro-elastic compaction volume is to first order proportional to the volume of the depleted rock mass, to the pressure change, and to the compaction coefficient: $\Delta V_{compaction,PE} = c_m \cdot \Delta P \cdot V_{depletion}$. The compaction coefficient is inversely proportional to the elastic modulus of the formation; $c_m = \alpha_{Biot} \frac{1-2\nu}{2G(1-\nu)}$. A thermoelastic compaction volume is to first order proportional to the cooled volume, the temperature decrease, and the thermal expansion coefficient $\Delta V_{compaction,TE} = 3\alpha_T \cdot \Delta T \cdot V_{\Delta T}$.

Subsidence due to a volume change at a single position at certain depth is distributed over an area extending to lateral distances of the same order as the depth of the source (Geertsma, 1973). The volume of the subsidence bowl is of the same order as the compaction volume, although not necessarily exactly the same. Moreover, the shape of the surface subsidence pattern depends on the lithological buildup of the subsurface and the shape of the compacting source (Fokker and Osinga, 2018).

The Groningen gas field in the northeastern Netherlands field has caused ~40 cm of subsidence during the lifetime of the field (Smith et al, 2019; NAM, 2020). Now, the thickness of the reservoir is of the order of 200 m and the pressure depletion about 250 bar; the large area of the field almost reduces the distribution of compaction volume over the surface area to a ratio of order unity between vertical reservoir compaction and subsidence (Van Thienen-Visser et al, 2017). If expected pressure distribution volumes and pressure change magnitudes are much smaller for long-term fluid migration than what we have seen in the Groningen gas field, they would therefore result in much smaller surface movement signals. The first assessment to be made, therefore, is the size and magnitude of the pressure redistribution. The compressibility of water is much lower than the compressibility of gas; as a result, a small water flux can already result in large changes in pressure. A redistribution of the pressure over the gas-bearing and water-bearing parts of the subsurface can thus cause additional subsidence.

Generally, surface movement induced by pressure changes in the deep subsurface is distributed over a large area, as already indicated above. Differential movements then are small. As is often the case, however, complications can occur. These are related to the complexity of the subsurface. A nice educational example is the CO_2 injection in the In Salah carbon dioxide storage site in Algeria (Vasco et al, 2019). The project involved a long-term storage of waste CO_2 associated with natural gas production in several Algerian fields. The injection was in rather low-porosity and thin layers, facilitating rather large pressure increases. The geological setting thus made the project a perfect field laboratory: effects expected for full-scale CCS could be studied on smaller temporal and spatial scales. A large consortium was set up to use several geophysical, geochemical, and production techniques to monitor the behavior of the injected CO_2 (Mathieson et al, 2011).

One of the techniques to monitor In Salah's performance was with satellite monitoring of surface movement. The method used is interferometric SAR with persistent scatterers, PS-InSAR. PS-InSAR measures precise changes in backscattered radar waves over time, and enables mm-accuracy monitoring of the earth surface movements (Feretti, 2014). The technique worked rather well in the desert environment of In Salah with its many stable boulders working as persistent scatterers. Above the three injection wells, typical surface heave rates of 0.5 cm/year were observed in the beginning. The pattern of deformation was used to identify the preferred direction of flow in the reservoir (Vasco et al, 2008).

Above KB-502, one of the injectors, however, an anomaly in the surface movement was observed: a double-lobed pattern of surface movement indicative for the hydraulic aperture opening of a vertical fracture. Vasco et al (2010) inverted the data to learn about its causes and concluded that a combination of reservoir inflation and a variable aperture change within a vertical damage zone could well explain the observations. The location of the aperture change was established to be above the reservoir, in a vertical zone of about 80 m; the magnitudes of dilation ranged to values of 6 cm. The existence of a vertically opening fracture zone was later corroborated by a study in which satellite data with different line of sight directions were combined and both vertical and east-west horizontal movements were quantified (Rucci et al, 2013; Figure 12).

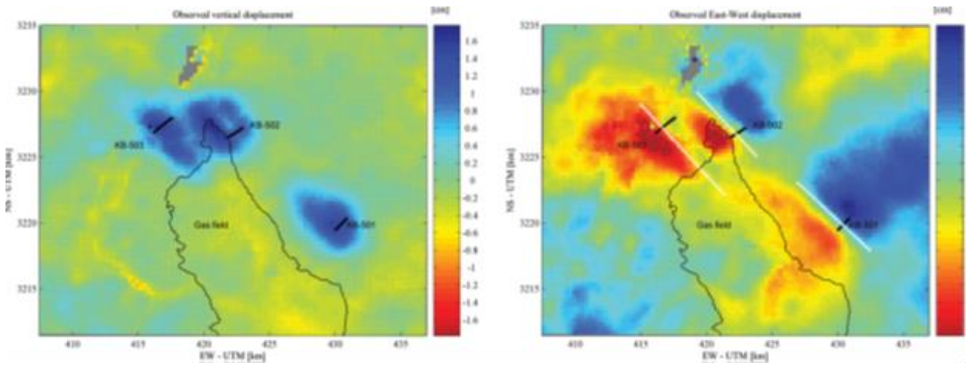

Figure 12 Reproduced from Rucci et al (2013) (a) Vertical displacement, in centimetres, between July 2004 and May 2008. Upward motion is positive (blue) and downward motion, or subsidence is negative (red). The thick black lines indicate the extent of each of the three horizontal wells (KB-501, KB-502 and KB-503) within the reservoir. The approximate location of the gas field is indicated by the thin black curve. (b) Horizontal displacement for the same time period. Eastward motion is positive (blue) whereas motion to the west is negative (red). As in (a), the horizontal extent of the injection wells is denoted by the thick solid black lines. The approximate location of the gas field is indicated by the thin black curve. The dashed white lines indicate the traces of the three damage zones used in the inversion of the displacement data.

The Groningen analogue and the In Salah field laboratory show that surface movement can occur as a result of reservoir pressurization or depressurization, and leakage. Expected values of movement are critically dependent on the extent and magnitude of the pressure changes. Because the origin of the movement is usually at considerable depth – km scale – the surface movements extend over a similar area. This is also the case if the source is localized, as with the opening fracture zone in In Salah. Differential movements at the surface are consequently very small, well below norms for damage to infrastructure or buildings. The main subsidence risk to be considered is the effect of large water-bearing layers losing pressure by redistribution of the pore fluid.

There is also a second observation. If fluid movement occurs, it might be difficult to identify, while still posing a risk to the environment other than risks related to surface movement. Surface movement monitoring can be a powerful means to identify leakage. Many studies have shown that surface movement measurements are helpful in identifying reservoir structure and pressure distribution (see, e.g. Segall, 1992; Marchina, 1996; Fokker et al, 2012, 2016; Zoccarato et al, 2016, Békési et al, 2020). The In Salah study, however, adds an important feature: surface movement monitoring can also be instrumental in the identification of leakage (Vasco et al, 2010, 2019). It should be regarded as a welcome addition to other techniques targeted at leakage detection. Changes in effective stress after field abandonment may also lead to fault reactivation and therefore induced seismicity.

3.2.2 Induced seismicity: small earthquakes

In the context of this study, we include ground motion in the form of earthquakes. Much work has been performed on this subject, and valuable reviews are available (Gaucher et al, 2015; Buijze et al, 2019; Candela et al, 2018; Van Wees et al, 2014, 2018). A change in pore pressure or in in-situ temperature affects the stresses, both locally and at distances away from the distortion. Depletion of aquifers connected to a gas field, even after abandonment of the gas field, will thus cause changes in the criticality of faults present in the subsurface. Too large criticality can result in exceedance of the slip resistance and induce slip behavior. When the fault is slip-weakening, seismicity may take place. A first estimate of such behavior is therefore a slip tendency assessment. Approaches range from 1D analytical to 2D and 3D finite element studies on fault reactivation, with little or much detail on the geological context and the dynamic reservoir development (ter Heege et al, 2018).

3.3 Impact on future subsurface operations

The use of the subsurface will continue even after cessation of gas production, e.g. for storage in produced fields or salt caverns (gas, compressed air, hydrogen, geothermal energy). The use of geothermal energy will increase in the near future due to the energy transition: the Dutch Climate Act (2019) contains a list of measures to achieve the goal of a reduction of CO_2 emissions by at least 49% in 2030 relative to 1990. The heating sector will realize the growth of the use of sustainable heating sources including a.o. geothermal heat. Recently the “Masterplan Aardwarmte Nederland”, was published by DAGO (Dutch Association of Geothermal Operators), Stichting Platform Geothermie, stichting Warmtenetwerk and EBN, supported by EZK. According to this document, the number of geothermal doublets in operation is predicted to be 175 in 2030 and 700 in 2050.

3.3.1 Relation geothermal with abandoned gas fields in the Netherlands

The aquifers suitable for geothermal activities are often the same as the oil and gas reservoirs. Beneficial of this overlap is the possibility that the reservoir serves as the recipient of the water produced from the geothermal exploration. However, a deep-seated geothermal project positioned close to an abandoned gas field, may cause subsurface interference. The extraction of geothermal energy may affect the pressure distribution in or around the abandoned gas field or vice versa. Brouwer et al (2005), performed a study on the effects of overpressure and temperature changes in the Lower Cretaceous IJsselmonde Sandstone Member. The reason for this study was the need for thermal energy at Barendrecht, near Rotterdam. A gas field to be abandoned could serve as a recipient of the water produced. They found that if reinjection of water takes place under overpressure conditions, the pressure changes in the direct vicinity of the wells due to the extraction of geothermal energy are limited, i.e. no more than 1 bar at a distance of 1 km. Thermo-elastic effects may occur as well, depending on the temperature of the injected water. Pressure change of 50 bar may occur if the formation is cooled by more than 50 degrees Celsius, which would locally cause a compaction of 2 to 3 cm at reservoir level (ca. 1100 m deep, in this specific case in Barendrecht). The effects would be negligible at the surface. Since geothermal is a rather new development, there is besides the study of Brouwer et al. (2005), no other international or national literature available on the impact of abandoned gas fields on geothermal operations.

At several places in the world, the possibility of using abandoned gas and oil reservoirs for geothermal are studied. Jun Yao et al. (2019) and Mehmood et al. (2019) studied the possibility to use abandoned oil wells for geothermal production in Pakistan. They show that this is a new method to overcome the required energy demands. They use the geological data that was gathered for drilling oil and gas wells, for constructing a geothermal reservoir model. Furthermore, there are initiatives in the Netherlands to explore this possibility to use old gas and oil wells for geothermal operations in Middenmeer (RVO: G2G from Gas to geothermal, https://www.rvo.nl/subsidies-regelingen/projecten/g2g-van-gas-naar-geothermie).

At this moment there are no active geothermal operations in the province of Groningen. However, there are plans for geothermal operations at the west side of the Groningen gas field and southwest of the gas field, geothermal operations are already installed (Luttelgeest at 1800 m depth). There is technical potential based on the aquifer properties and temperature models, that geothermal is possible in the province of Groningen (ThermoGIS.nlgis/ Warming Up program). However, SodM advises not to apply geothermal in areas where seismic activity is present, since it will be complicated to distinguish between seismic activity that is already present in Groningen from gas extractions and new induced seismicity from geothermal activities (see Buijze et al. 2019). In the planning of new geothermal activities, the proximity of old abandoned wells should be taken into account, where the distance depends on the presence of faults between the abandoned well and the geothermal well.

3.3.2 Impact on salt caverns

This paragraph discusses whether the abandonment of gas fields and long-term fluid migration afterwards could potentially jeopardize the stability of salt caverns, with focus on the Groningen setting. For this purpose, first the situation in the northern Netherlands is sketched, then case histories of failures of salt caverns across the world are evaluated and finally potential interactions are discussed.

3.3.2.1 Gas fields and salt caverns in the northern Netherlands

Three salt cavern concessions exist in the north of the Netherlands: Barradeel, Veendam and Adolf van Nassau (Table 2; Figure 13). The Barradeel concession for Halite (NaCl) is a deep concession (>2500 m) active since 1995 which is situated near the abandoned Harlingen gas field in the shallower Cretaceous deposits. The unconventional depth of both the salt caverns and the gas field makes the Barradeel concession less suitable as a case study for post-abandonment risks. The Veendam and Adolf van Nassau concessions are in close vicinity of gas fields. At the Adolf van Nassau concessions (and extensions) Halite is produced from salt diapirs of Zechstein salts. At the Veendam concession, magnesium salt (bischofite: $MgCl_2$) is produced from a salt pillow in the Zechstein salts (Geluk et al., 2007).

Salt caverns may play an important role in the energy transition for the storage of energy carriers (methane and hydrogen gas) or pressurized air (Wetten en Van Gessel, 2020). Already, in the Adolf van Nassau concession near Zuidwending, a total of six salt caverns have been created specifically for the storage of methane. In addition, two caverns are being created that will hosts a pilot for Hydrogen gas storage. These dedicated caverns are designed in such a way that they have optimal dimensions. Therefore, they are smaller than caverns made for salt mining purposes, and have a depth between 1000 and 1500 m. This means that the roof lies deeper in the salt diapir.

The deepest of the salt caverns near the Groningen field has its base at approximately 1800 m (Table 2) whereas the gas fields are situated below about 3000 m depth. Hence, the resulting salt caverns overlie the Groningen gas field as indicated in Figure 14). At these locations, there is about 1 km of rock salt present between the gas field and the salt caverns.

*Table 2 Salt concessions (including extensions) in the North of the Netherlands in the vicinity of gas fields (Geluk et al., 2007; Kroon et al., 2003; Nedmag, 2018). *The present number of caverns is a best estimate based on available information in 2020.*

Concession	Owner	Salt Formation	Type	Caverns*	Depth
Adolf van Nassau	Nouryon	Zechstein 2 NaCl	Salt diapirs	19	600 - 1600 m
Veendam	NedMag	Zechstein 3 MgCl2	Salt pillow	13	1600 – 1800 m
Barradeel	Frisia	Zechstein 2 NaCl	Layered	4	2500 – 3000 m

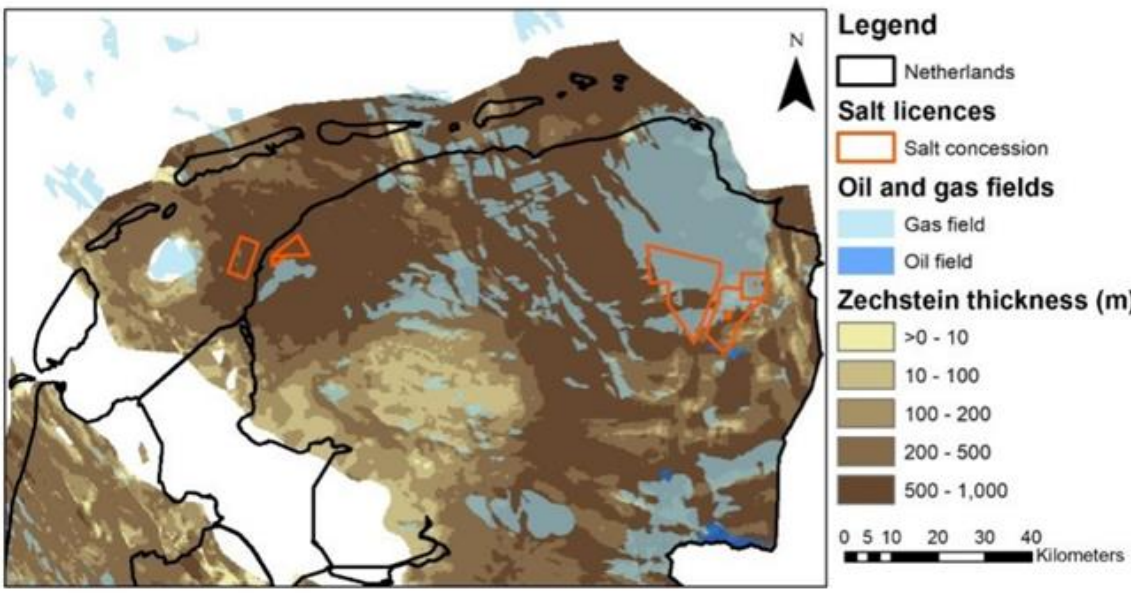

Figure 13 Thickness of the Zechstein Formation (onshore) and the location of oil and gas fields in relation to salt concessions.

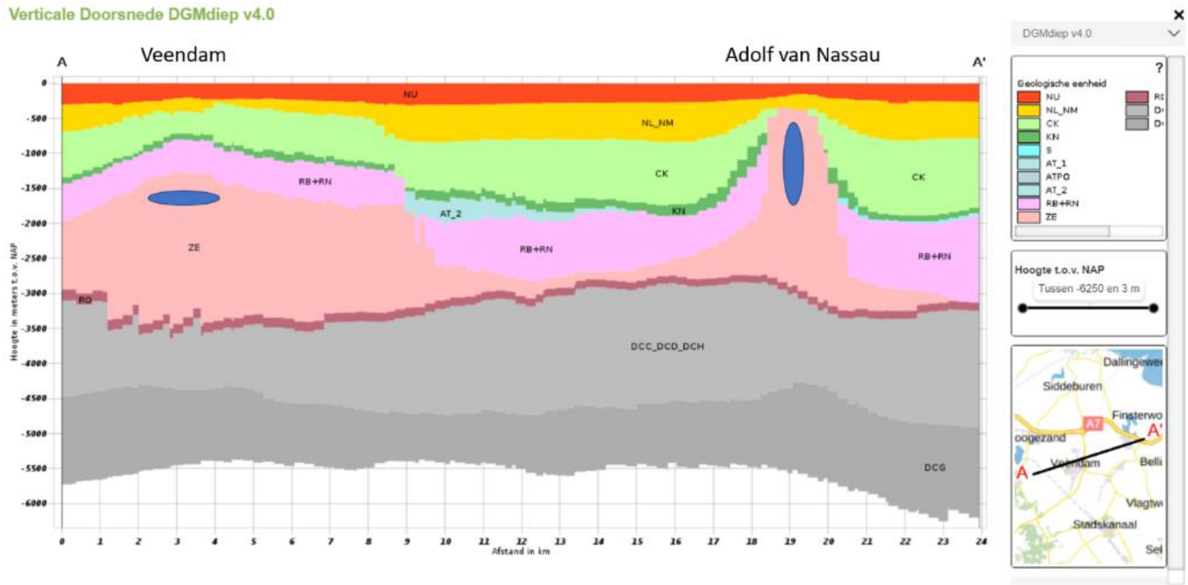

Figure 14 Cross section in DGMdiep 4.0 through the Veendam and Adolf van Nassau concessions with the depth range of salt caverns (blue ovals) indicated and the location of the Rotliegend deposits (Ro) that act as reservoir rocks below the Zechstein Salts (Ze) that make up the seal (Source: dinoloket.nl).

The Barradeel concession is in the vicinity of the Harlingen gas field, which lies shallower in the Cretaceous Chalk at a depth of approximately 1000m. This field was abandoned in 2008 when subsidence rates were higher than predicted (Vermillion Energy, 2010).

3.3.2.2 Case histories of salt cavern failure

Several reviews about salt cavern failure have been published, most notably Evans (2008), Evans and West (2008), Van Duijne et al. (2012) and Berest et al. (2019). These studies were mainly focused on salt caverns that are used for the storage of hydrocarbons in both gaseous and liquid form. In addition, the fate of abandoned salt caverns has been investigated.

The use of salt caverns for the storage of hydrocarbons in both gaseous and liquid form started in the USA in the 1940s and in Europe in the 1950s (Querio, 1980; Thoms and Gehle, 1995). In 1996, there were 396 of such storage sites (Evans, 2008). Until 2008, thirty-six accounts of incidents at underground salt cavern storage facilities worldwide have been retraced (Evans, 2008). Almost all incidents are due to human error and poor safety controls and checks (Evans, 2008; Van Duijne et al., 2012) and could therefore have been avoided. Human-caused errors include well problems (well/casing/plug problems/failure including blowout and loss of wellhead pressure), design failure (site characterization, caprock performance, leaching, sinkholes, fractures), operational failure (overpressure, salt creep, cavern communication, roof collapse) and above-ground infrastructure failure. Only two of the thirty-six known incidents described in Evans (2008) may be related to natural failure of the cavern: a roof collapse in 1996 at Loop (West Texas, Seni and Johnson, 2005) and leakage out of a salt dome storage at Sulphur, Louisiana, leading to increased pressures in the formation outside eventually leading to a blowout at the drilling site of an oil exploration well nearby. The latter can, however, also be attributed to human failure, if the leakage would have been noted.

After abandonment, salt caverns will slowly converge due to salt creep over the course of thousands of years (Nedmag, 2018). As a consequence, the pressure of the brine in the cavern will gradually increase. This process continues until ruptures form in the roof of the salt cavern, and the brine will dissipate in the formations overlying the caverns (NedMAG, 2018). The amounts of brine released can be drastically reduced by first bleeding off the brine before closure. For the Veendam caverns, this brine seepage is expected to be up to 0.5 m^3/hour per cavern using this bleed off procedure (Nedmag, 2018). Also, the 40,000 m^3 of gasoil that is used to stabilize the roof of the salt caverns during production will bleed into the overlying formation. In the Veendam concession, the gasoil is expected to stay being absorbed by the Zechstein salt, or in the worst-case leak into the pores of the Buntsandstein or Vlieland sandstone. It is not expected to migrate through the overlying Vlieland claystone (Nedmag, 2018). At this location, the risk of pollution of groundwater used for drinking is considered to be negligible (Nedmag, 2018).

3.3.2.3 Potential interaction between gas fields abandonment and salt caverns

The abandonment of gas fields results in long term fluid migration as the pressures equilibrate. Near the production well, this will result in an increase in pressures and further away pressures will decrease. However, the pressures near the production well will always remain below the initial pressure before production started. In this process of equilibration faults may potentially be reactivated.

Before these faults would have an effect on the overlying salt caverns, they need to cross the Zechstein salts. Salt may deform either in a ductile (plastic) or brittle manner, depending on the temperature, stress state and deformation rate. Thick salt beds experience brittle fracture only at very shallow near-surface depths (tens of meters) and typically unsaturated conditions, and possibly during very high strain rates, as might be associated with major faults defining sedimentary basins (Evans, 2008). In other cases with fault displacement, the viscoplastic rock salt will under normal lithostatic pressures undergo crystal plastic deformation and creep. Hence, the salt will effectively absorb the fault behaviour.

For the Groningen gas field, Logeman (2017) investigated the relation between faults above the Zechstein and faults below the Zechstein. They made a distinction between hard linked, soft linked and unlinked faults (Figure 15) following the work of Ten Veen et al. (2012). Hard linked faults are faults above and below the salt layer that are in direct contact. It is assumed that this can only occur when the Zechstein is less than 50 m thick since the base exists of a 50 m anhydrite layer that is brittle. Soft linked faults are faults above and below the salt layer that are spatially related, but are not connected. This is dependent on the ratio between the basement fault offsets and the salt thickness. Ten Veen (2012) showed in a quantitative fault analysis that such soft linked faults only occur with a salt thickness of less than 300 m. Lastly, non-linked faults are faults that are completely decoupled by thick salt which is related to situations where the salt is thicker than 300 m.

Since the thickness of the salt layer between the salt caverns and the Rotliegend gas field of about 1 km is much larger than 300 m, it is not expected that reactivation of faults below the Zechstein salt as linked to post-abandonment fluid migration will affect salt cavern stability.

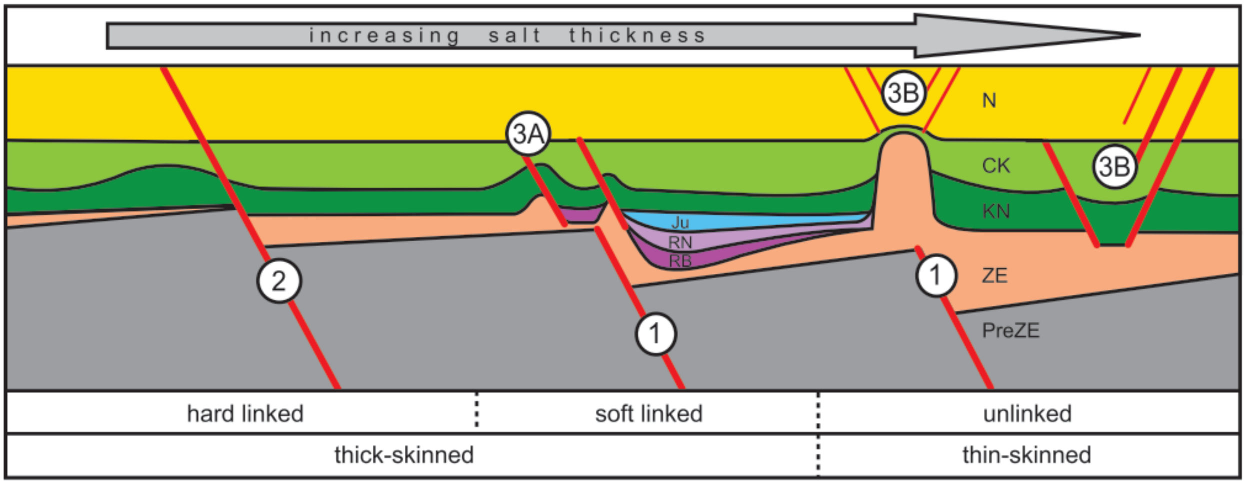

Figure 15. Linking of faults below and above a salt cover. Left) hard linked fault; Middle) soft linked fault; and right) unlinked fault (From Logeman, 2017, van Winden, 2015, ten Veen et al., 2012). 1) are faults that terminate upward in Zechstein salts thick) 2) Faults originating below salt but also affecting younger units (where salt is thin); 3A) Faults that are spatially linked to salt structures and their associated sub faults, but are not connected to them; 3B) faults that are not linked to sub-salt faults, but which may be linked to salt structures.

Another possible interaction between fluid migration due to gas field abandonment and salt caverns would be a potential slight decrease in pore pressures in the formation surrounding the salt diapir. This is only possible if there is pressure communication between the gas field and surrounding aquifers below the Zechstein salts and the aquifers above the Zechstein seal surrounding the diapir. This could occur for instance because of a hard-linked permeable fault in an area with thin Zechstein salts, or the local absence of this salt seal. This scenario should be taken into account when designing new caverns near the edge of the diapirs.

3.4 Impact on shallow aquifers

The impact of methane emissions on the shallow aquifers and specifically on the groundwater quality and possible emission of pure phase methane to the atmosphere depends on the solubility of methane in the shallow aquifer. Methane does not react in the pure phase, only when dissolved. In the unsaturated zone, this usually happens very quickly by oxidation, as is also mentioned in Section 2.3: Schout et al. (2019), stated that methane oxidation reduces the methane concentration resulting from well bore leakage significantly. When dissolved in the saturated zone, methane can change groundwater chemistry, leading to potential water quality degradation (Tangerankoo, 2020, Stuyfzand et al. 1994). This paragraph describes methane solubility from gas wellbores and the impact on groundwater quality and the microbial community in the shallow aquifer. There is no literature available on the solubility of thermogenic methane from upward fluid migration.

3.4.1 Methane solubility and natural attenuation

Taherdangkoo et al. (2020) modelled the migration of methane from gas wellbores into shallow groundwater on a basin scale. A two-dimensional, two-phase flow, two component numerical model was used. The impact of methane solubility on fluid migration dynamics and leakage rates into shallow subsurface was evaluated. Hydrostatic pressure is lower at shallow depth, which leads to a significant decrease in the density of the gas phase and thus the release of dissolved methane into the gas phase. Consequently, more highly buoyant free-phase methane appears at shallow depth with the consequence of increasing the upward flow rate. Comparison between miscible and immiscible flow models shows slightly different methane plume sizes and travel times to groundwater. This is due to the low solubility of methane in the ambient water, particularly at shallow depth. The influence of methane solubility on gas transport becomes less significant once the plume spreads at shallow groundwater as the aqueous solubility of methane decreases with decreasing hydrostatic pressure. Another conclusion from their modelling work is that gas leakage rate and leakage period are among the most important factors controlling the magnitude of methane migration to shallow depths. The persistent long-term leakage leads to the accumulation of large amounts of methane in the overburden, which could potentially be transported into the shallow aquifer system. Results indicate that long-term methane leakage poses higher risks to groundwater in comparison to the rapid migration along fractures and faults or during drilling operations. Their simulations indicate that the complex shape of the methane plume in the subsurface, the arrival time to groundwater, and distances from a leaky gas well vary significantly based on hydrogeological characteristics of formations intercalated between aquifer and gas reservoir.

Schout et al. (2020) studied the impact of groundwater flow on methane gas migration and to what extent methane migration is impacted by methane dissolution. They used two-phase, two component numerical simulations. They assume that, in spite of the low solubility of methane, dissolutive retention could be important in the shallow part of unconsolidated groundwater systems. They performed a sensitivity analysis including permeabilities, groundwater velocity, depth of the leak, and the velocity and shape of the upwardly migrating gas plume. Results show that for the most commonly observed methane leakage rates (0.1–10 $m^3.d^{-1}$), unconsolidated aquifer systems with lateral groundwater flow can retain significant amounts of migrating methane due to dissolution.

The abovementioned literature mentions that methane sorption is negligible which means that dissolved methane is mobile and spreads with groundwater velocity (conservative transport).

3.4.2 Shallow aquifer groundwater quality

With the introduction of methane from the deep subsurface into the groundwater system, its chemistry including redox conditions and pH may be changed and leads to altering the water quality by mobilizing and increasing concentration of undesirable elements. Microorganisms gain their energy and grow from electron transfer process referred to as redox reactions, and methane has the role of electron donor in these processes. Depending on their redox state, groundwater aquifers may contain electron acceptors and electron donors in the solid or aqueous state. Important ones are dissolved oxygen, nitrate, sulphate, Fe-oxyhydroxides and sedimentary organic matter. Ingression of thermogenic methane results in reduction of electron acceptors if available and associated oxidation of methane by methanotrophic bacteria and production of compounds like Fe-sulphide. Generally, and based on the redox ladder concept, methane is preferentially oxidized by oxygen and then followed by nitrate, nitrite, manganese (IV,III), iron(III) and sulfate (Roy et al., 2016; Berta., 2017). However, not all of these redox reactions may be present for methane oxidation and some may be bypassed. The actual occurrence of the sequence of redox reactions depends on local conditions, such as the availability of electron acceptors and kinetic inhibition of specific reactions. For example, in a study on impacts of infiltration of cattle slurry into groundwater in two sites in England, results shown that no manganese and iron reduction sequence was present (Gooddy et al., 2002).

Although oxidation of migrated methane can attenuate its concentration, diminish transport in groundwater and prevent further upward migration, it can deteriorate the water quality and cause health and safety problems by releasing harmful contaminants. For instance, hydrogen sulfide is one of the products from coupled methane oxidation and sulfate reduction, which is associated with strong and unpleasant odor and is extremely flammable and highly toxic (Roy et al. 2016). It should be noted that the anaerobic oxidation of methane in groundwater is a slow process which is controlled by microbial population, and with its intrusion into the aquifer it might remain there for a relatively long time. To illustrate this, methane intrusion into a shallow aquifer was simulated in a laboratory study by Berta et al. (2015) and geochemical effects of methane on the groundwater were studied. Results showed that in the one-year runtime of the experiment, no significant decrease in methane concentration was observed. In addition, no notable changes in other properties such as electrical conductivity, pH, total dissolved organic carbon and dissolved ions were detected in the samples. Berta et al. explained the reasons for this slow response were the long time for microorganism to increase in number (which in the study, it was 7 months for doubling the number), and the low energy yield of the methanotrophic reaction, under these conditions. In a field study in western Canada (Van Stempvoort et al., 2005), methane concentration in an aquifer near a hydrocarbon production site was observed for a period of over seven years. Authors found that the methane in groundwater which was caused by a leakage from an abandoned oil producing well, had elevated concentration with an average of 10.4 mg/l even 8 years after the leakage and having a descending trend during this time.

Methane oxidation and reduction of the electron acceptors in groundwater may lead to secondary impacts on water quality by releasing and mobilizing trace metals. However, the release of trace metals is possibly dependent on the phase status in the redox ladder. As was observed in a field study in Colorado, USA (Wolfe et al., 2017), production of sulphides from SO_4 reduction favors the immobilization of metals through the formation of insoluble sulfide precipitates. Oppositely, reduction of Fe-oxyhydroxides may mobilise trace metals sorbed to these oxides like arsenic, chromium, cobalt and nickel (Ziegler et al., 2016, Riedinger et al., 2014). Mobilization of these toxic metals and their transport by water flow and reaching to the water extraction wells, is a hazardous phenomenon that can endanger human health.

3.4.3 Impact on microbial community

Recent studies have shown that changes in key microbial population reflects the dynamics of important biogeochemical processes (Ruff et al., 2015). Marine and aquifer sediments are known to host microbial communities as diverse as those found in soils. Different parameters such as temperature, sediment type and water depth, methane concentration and electron acceptor availability, have influence on the microbial community composition (Ruff et al., 2015). Methane in the soil and groundwater can be oxidized by methanotrophic bacteria that use it as their energy source. Thus, the population and activity of these bacteria could be high when the environment is enriched with thermogenic methane. Also, exposure of soils to elevated methane concentration might activate methanotrophic bacteria that were dormant before, since lack of resources is one of the features that triggers microbial dormancy (Yin et al., 2020; Lennon and Jones, 2011). In addition to methane-oxidizing archaea, other microorganism can be assembled in methane seepage areas.

In a controlled natural gas leakage simulation study in Ontario, Canada, it was observed that the microbial community had a diverse profile (Forde et al., 2019). Results showed that the formed microorganism community included aerobic methane oxidizer taxa, denitrifier taxon, methyltrophs, sulfate reducing and iron reducing bacteria. In another methane gas injection into a shallow groundwater experiment, results showed that methane releases strongly altered microbial community and stimulated growth of both aerobic methanotrophic bacteria and aerobic methylotrophic despite low oxygen concentration in the groundwater (Cahill et al., 2017). Authors observed that methane injection significantly changed indigenous microbial communities without any sign of recovery even after more than 250 days from injection. As mentioned before, methane intrusion induces reduction of dissolved oxygen if present and subsequently creates more anoxic environment; thus, it is expected that a number of anaerobe bacteria such as *Euryarchaeota* increase as it was shown by (He et al., 2015). In this field research, authors studied the microbial community composition in a wetland in USA with regard to methane emission, and they suggested that availability of oxygen is probably the limiting factor controlling the methantrophs population.

4 Proposed risk assessment and management framework

Risk assessment and management frameworks (RAFs) have been developed for various subsurface technologies including geothermal energy production (Okenwilo, 2016; Lohne et al., 2018), gas production (van Elk et al., 2017) and CO_2 storage (OSPAR, 2007; EC, 2011). These examples provide useful building blocks for a framework on the assessment and management of risks resulting from natural gas production after abandonment, which includes but is not necessarily restricted to the risk of unintended migration of natural gas or brines to the shallow subsurface and emission towards the atmosphere and the risk of undesired ground motion.

After introducing the risk management context, some examples of existing risk assessment frameworks from the literature will be briefly presented which may have added value for the risk assessment framework developed in the present project.

4.1 Risk management context

The ISO 31.000 (2nd edition 2018) Standard on Risk Management which has been adopted by the Nederlands Normalisatie Instituut (NNI, 2018), provides a useful starting point for the development of a framework for risk assessment and risk management of regional post-abandonment mining risks. This framework will enable the systematic assessment of local mining activities aggregated at a regional level. Vice versa the regional assessment will provide boundary conditions for assessing the risk of future local (geothermal) mining activities.

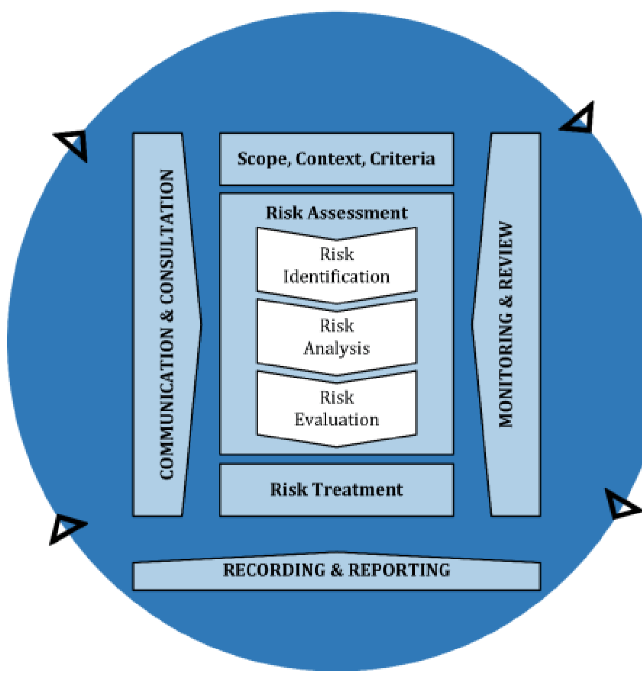

Figure 16 Risk management process in ISO Standard 30.100 (NNI, 2018)

It consists of the following basis steps: define scope and criteria, perform risk assessment, define risk treatment and develop monitoring plan. Outcome of these exercises must be communicated with stakeholders and results be recorded (see Figure 16). Risk management is a continuous cyclic process through all stages of subsurface activities from the preparation stage up to and including the post-abandonment stage (represented by the arrows in Figure 16).

4.2 Review of existing risk assessment and management frameworks

The identified frameworks for other subsurface applications will be described in the next sections. They may serve as examples for the development of a framework in the current study.

4.2.1 Existing frameworks for geothermal energy production

Production of geothermal energy is a fast growing business and requires a good standard for safe production of geothermal heat, which has been notified by the regulator (SodM) and the operators (DAGO) in the Netherlands. Figure 17 shows the risk management process adopted for the hazard and risk assessment of geothermal well operations in the Netherlands (Ikenwilo, 2016). They follow the *EN ISO 17776:2002 standard for the hazard and risk assessment of offshore production installations*.

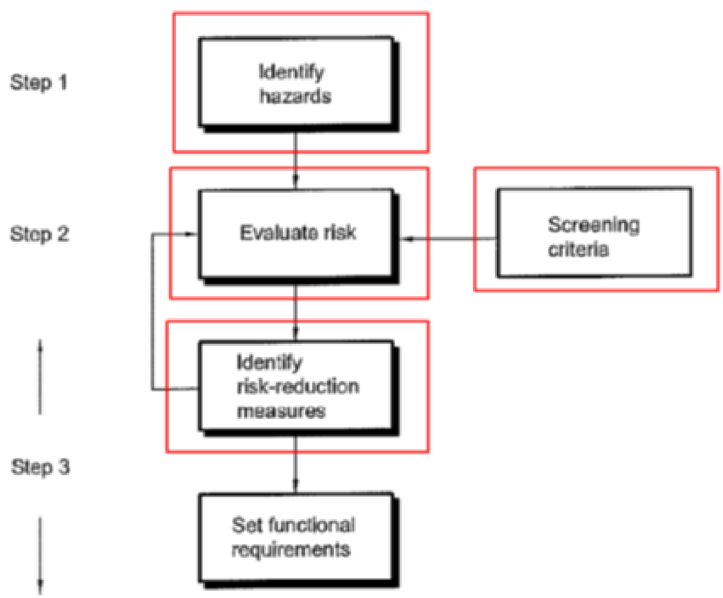

Figure 17 Flow diagram proposed for geothermal energy production projects in the Netherlands (Ikenwilo, 2016)

The H2020 Geothermica GeoWell project studied innovations for high temperature geothermal energy production. Part of this work was dedicated to risk assessment and structural reliability analysis of high temperature geothermal wells. The project resulted in a framework for risk management of high-temperature geothermal wells based on the ISO 31.000 standard (Lohne et al., 2018).

Figure *18* depicts the overall structure of the GeoWell risk management framework with the following main elements:

- Defining the risk management context including objectives, criteria, conceptual design, geographical and geological setting and resources;
- Risk assessment sub-divided into risk identification, analysis and evaluation;
- Monitoring and risk reduction;
- Continuous communication with stakeholders and risk review.

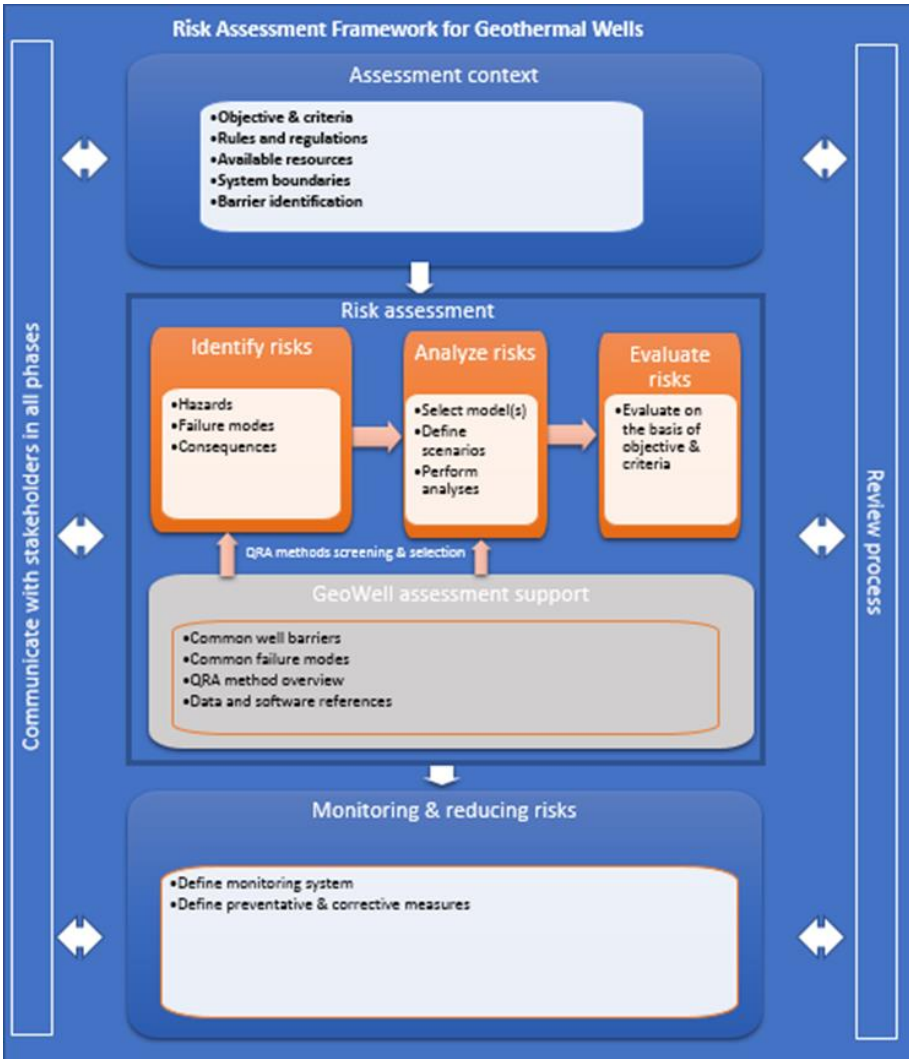

Figure 18 Framework proposed for (high-temperature) geothermal wells in the GeoWell project (Lohne et al.; 2018)

4.2.2 Existing frameworks for CO_2 storage

Stringent regulation on the permanent storage in the subsurface and under the seabed was developed by the European Commission in the Storage Directive (EC, 2009) and the OSPAR Convention (OSPAR, 2007), respectively. In addition, the Commission has developed guidelines for the implementation of the European regulation on risk management (EC, 2011). The OSPAR parties, which represent countries around the Northeast Atlantic, have designed a detailed framework for risk assessment and management of CO_2 streams for the implementation of CO_2 storage below the seabed, which is lined up with the London Protocol and the EU Storage Directive (EC, 2009).

The OSPAR guidelines and framework identified 5 consecutive phases, from planning to post-closure (Figure *19*). The post-closure phase is most relevant in the context of the present report on post-abandonment risks. In the post-closure phase, the stages of exposure and effects assessment, risk characterization (risk assessment), and monitoring and mitigation (risk management) are key. Exposure assessment evaluates the characterisation and movement of the CO_2 plume, effects assessment gathers information on the response of receptors and these assessments are integrated in risk characterisation to estimate the potential impact. Each individual step is extensively described in the framework (OSPAR, 2007). The current report focuses on the exposure assessment and risk characterization stages.

	Problem formulation	Site selection & characterisation	Exposure assessment	Effects assessment	Risk characterisation	Risk management (monitoring & mitigation)
Planning	☑	☑	☑	☑	☑	☑
Construction		☑	☑	☑	☑	☑
Operation		☑	☑	☑	☑	☑
Site-closure			☑	☑	☑	☑
Post-closure			☑	☑	☑	☑

Figure 19 *Lifetime phases of a CO_2 storage project and the applicable principal stages of the OSPAR Framework for risk assessment and management of CO_2 streams (OSPAR, 2007). The stage and related main phases of the framework in the green dashed rectangular area of relevance here.*

The guideline documents to the implementation of the Storage Directive hold a detailed description of lifecycle risk management for safe and environmentally sound CO_2 storage (EC, 2011; Figure 20). Although there are differences in wording and vocabulary compared with the OSPAR framework they have the same structure.

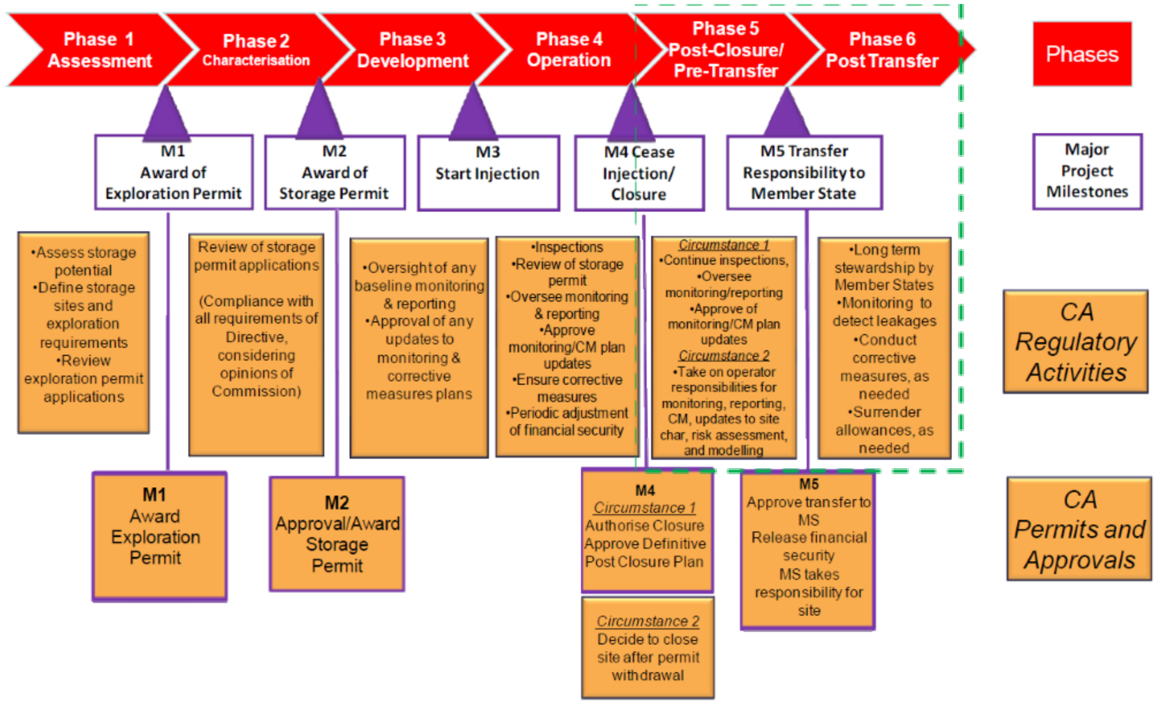

Figure 20. Lifetime stages, milestones and main risk management activities. The stages and activities in the green dashed rectangular area of relevance here (EC,2011).

All this work has eventually resulted in a dedicated standard for CO_2 storage, which is based on the ISO 31.000 standard for risk management and depicted in Figure 21 (ISO, 2017). The main components of this process serve as an example for the framework to be developed in the current study.

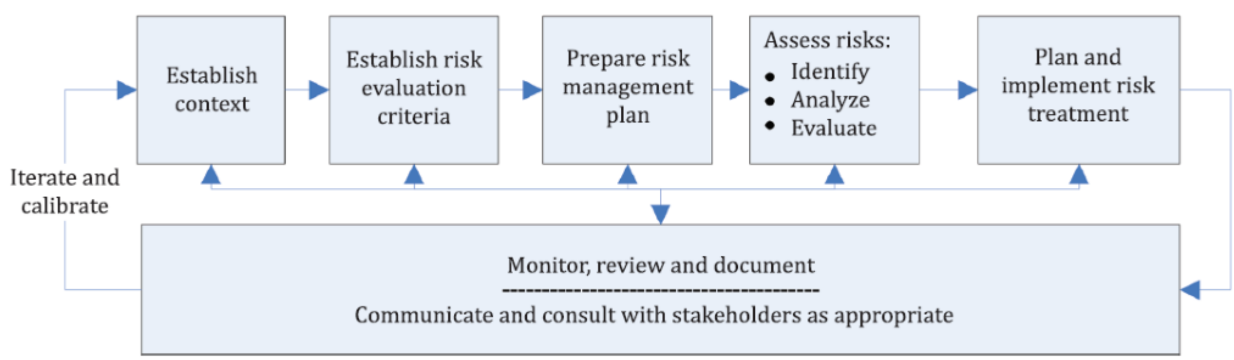

Figure 21 CO_2 storage in the ISO Standard 27914 (1st edition, 2017-10), which is aligned with the ISO 31.000 standard (ISO, 2017)

4.2.3 Existing framework for gas production and induced seismicity

NAM has developed a fully probabilistic integrated method for assessing the seismic risk in order to obtain a proper understanding of the risk level of induced seismicity. It represents the complete chain from root cause to human safety as represented in Figure *22*. The method is based on the physico-mathematical concept of Cornell back in 1968, which is a widely recognized approach for quantitative assessment of seismic risk and may also serve the design of the framework in the current study. In particular the subdivision in hazard and risk assessment is of interest here.

Hazard assessment is restricted to the analysis and evaluation of possible causes (root events) leading to an undesired event (e.g. leakage or ground motion). Risk assessment includes hazard assessment and the potential consequences (impact or effect) of the undesired event on men, environment or infrastructure. The analysis of consequences is split in exposure analysis and effect analysis.

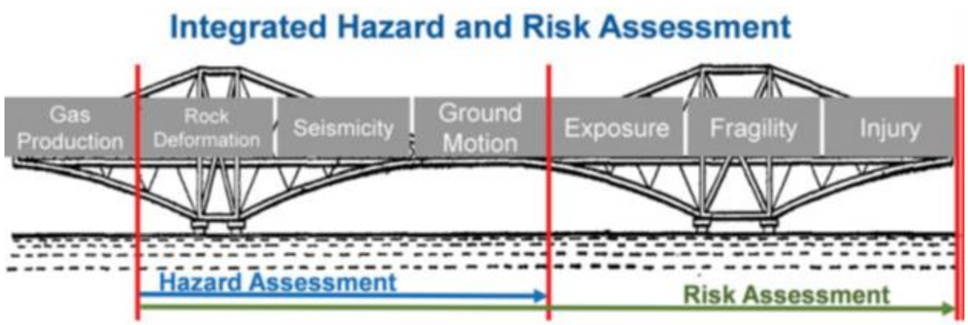

Figure 22 Visual representation of the concept for hazard and risk assessment of induced seismicity at the Groningen field (van Elk et al., 2017)

4.3 Proposed risk assessment and management framework (v1.0)

The proposed framework builds on the ISO 31.000 standard for risk management and work done on designing a risk assessment framework in the GeoWell project (Lohne et al., 2018). It is a first version of a framework for the regional assessment of mining activities after their abandonment, particularly in relation to gas production.

The objective of the present study is to firstly assess if and to what extent fluids (gas or brine) will migrate to shallow aquifers or to the earth's surface where it may adversely impact the environment, human beings, utilities or resources. Secondly, the possible consequences of pressure redistribution for ground motion (subsidence, uplift or seismicity) will be evaluated. The focus is on hazard assessment, the degree to which gas production may lead to undesired fluid leakage or ground motion after abandonment of the gas field. Furthermore, the assessment will look at regional effects of fluid migration at gas fields after their abandonment.

The framework is a basis for the development of methods and workflows for the hazard (and risk) assessment of mining activities after their abandonment with special reference to leakage of fluids (gas or brine).

The examples of risk assessment and management in combination with the ISO standard 31000 which were introduced in the previous sections of Chapter 4, provide useful building blocks for the definition of a framework in the current study and consists of the following main steps (Figure 23):

- Establishment of the context

- Risk identification and screening
- Quantitative risk analysis and evaluation
- Monitoring and risk reduction
- Stakeholder communication and risk review.

4.3.1 Establishment of the context

The first step in the process is to define the context of the risk assessment and management of fluid migration and leakage from abandoned gas fields. The context deals with the specific objectives of the risk assessment and management, the acceptance criteria to be evaluated, the reservoir fluid containment concept with barriers and system boundaries, the site-specific geological and geographical setting and resources needed.

Objectives describe what the risk assessment and management is aiming at in identifying and evaluating the risk related to fluids migration and leakage from abandoned mining sites, e.g., gas production, defining monitoring requirements and minimizing damage. It should include any regulations or requirements as to how the risk assessment and management is to be performed.

A good understanding of the reservoir fluid containment concept is essential for the execution of the risk assessment and management, for the identification of possible causes of loss of containment. The system boundaries will define which subsurface and well compartments are included in or excluded from the risk assessment.

The setting of the gas reservoir and related well infrastructure is especially important for characterizing the quality of the geological and well barriers and barrier deficiencies. Understanding of the geographical setting including population density, protected water resources, natural reserves and built-up areas.

Criteria or indicators are to be defined which are measures for hazard or risk related to fluids migration and leakage, and ground motion after abandonment of depleted gas reservoirs. They can either be quantitative or qualitative, relate to the possible damage resulting from fluid migration and leakage, and ground motion or can be indicators of increasing risk (e.g., pressure, temperature, corrosion etc.).

A successfully executed risk assessment and management requires the availability of sufficient qualified resources. This includes budget and personnel resources with required competences and skills, data and information concerning the abandoned depleted gas reservoir site, as well as tools for the risk assessment and management.

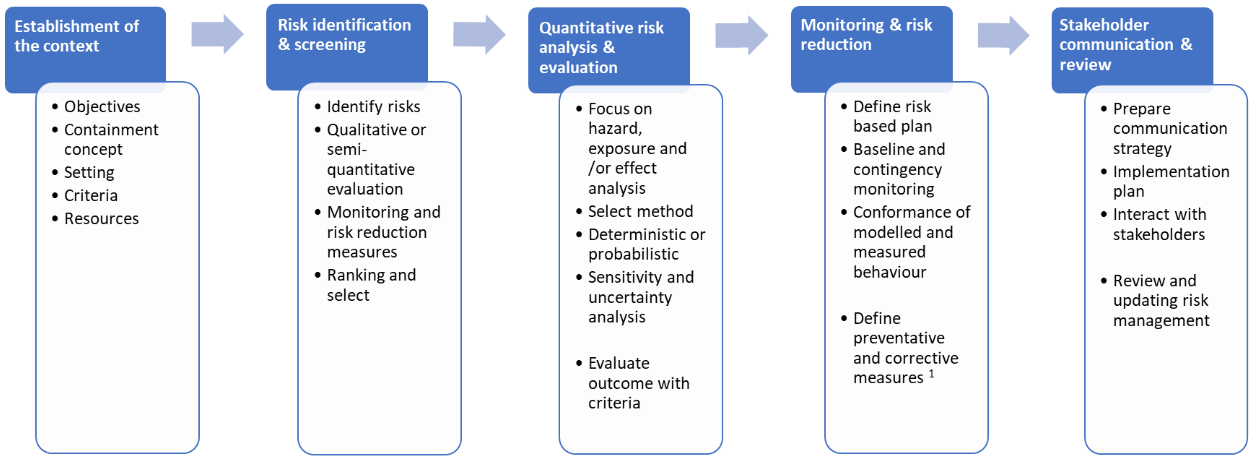

Figure 23. The proposed framework for risk assessment and management of fluid leakage from abandoned depleted gas reservoirs sites (v1.0); [1]Not in scope of current study

4.3.2 Risk identification and screening

A comprehensive overview of risk factors is to be assembled once the context of the risk assessment has been defined. Such an exercise may start with the identification of possible well barrier failure modes and their causes, which is also referred to with hazard identification. Depending on the assessment objectives, the identification could be limited to this part or extended to the identification of consequences of unintended loss of fluids from the gas reservoir, those that could lead to damage to the environment, human beings, built-up areas and subsurface or surface resources. This complete set of activities is referred to as risk identification. Special attention is to be directed to the occurrence of cascading events resulting in adverse consequences.

The identified risks are qualitatively or semi-quantitatively characterized in terms of probability and severity of the impact. This offers the possibility for ranking and screening the various risks. A first evaluation of possible risk treatment and its expected reducing effect on the risk level is to be included. Risk treatment includes monitoring, preventative or corrective measures.

A preventative measure helps to reduce or avoid an irregularity (threat or consequence) before it is detected and a corrective measure reduces or completely neutralizes an irregularity after it has been detected.

An appropriate method for risk identification and screening is to be selected or is prescribed by existing regulation. Various methods based on expert judgment and supporting databases are available; a broadly applied method is the bow-tie risk assessment in combination with risk registers and risk matrices (see also Van Gessel et al., 2019). Bow-tie risk management is a practical concept for risk management of undesired events linking their potential causes and consequences in a logical manner and subsequently help define barriers including monitoring to reduce the risks to acceptable levels (Figure 24).

Bow-tie risk management has a lot of terminology which varies strongly among users of this concept. The following basic terms and definitions are proposed:

- Hazard: condition which may lead to damage (of men, environment or infrastructure). In the present study this is the presence of abandoned gas fields through loss of control;
- Undesired event: loss of control leading to damage, e.g. leakage of gas or brine or ground motion;
- Cause (or threat): possible origin of undesired event;
- Consequence (or impact): possible effect of undesired event leading to exposure and damage;
- Barrier: measure to reduce the likelihood and magnitude of damage, which can be classified as preventative, detective or corrective action.

The undesired events could include migration of fluids (gas, brines, formation water or a mixture) out of the reservoir after ceasing production and abandonment of the site. This method enables efficient communication of risks.

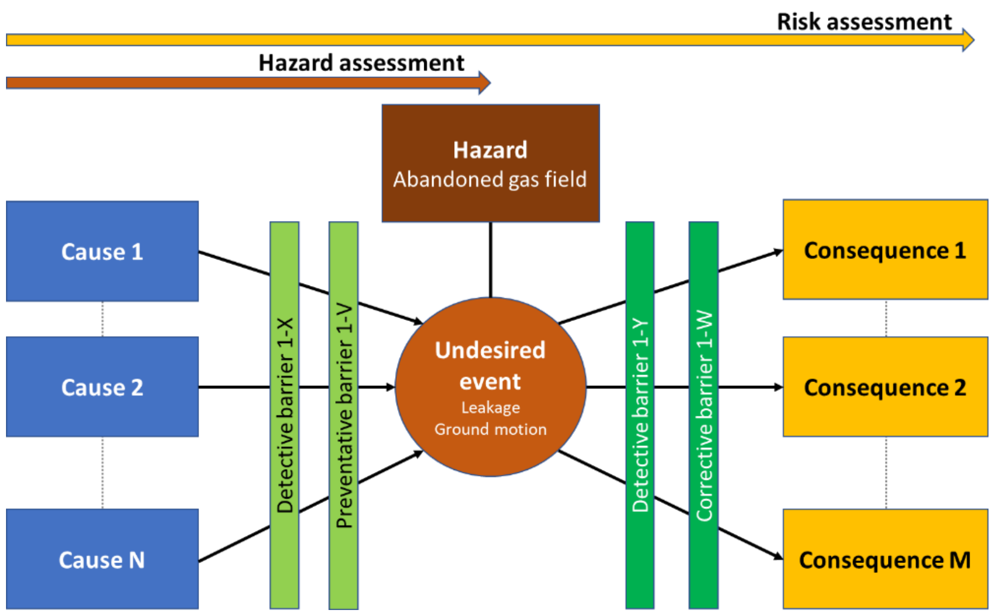

Figure 24. Bow-tie risk management concept with its principal elements and scope of hazard assessment versus risk assessment

The overview of risks and their assessment is to be updated and recorded during all stages of the project lifetime including the stage after abandonment of subsurface mining activities, which can come to an end once the risk is proven to remain at a sufficiently low level. Note that the updating and recording step is not part of the scope in the present study.

4.3.3 Quantitative risk analysis and evaluation

Based on the criticality of the identified hazards and risks, quantitative analysis is to be performed in a staged manner with methods varying from simple analytical models to complex coupled multi-physics numerical models. The required level of complexity of the analysis very much depends on the nature of the risks to be quantified. In some instances, a ‘back-of-the-envelope’ quantitative analysis is sufficient;

in other situations, one may need to use sophisticated coupled Thermo-Hydro-Mechanical-Chemical models. Choices are to be made whether deterministic approaches are sufficient or fully probabilistic assessment lines are necessary.

Depending on the assessment objective, the hazards are to be quantified in terms of resulting fluid migration and leakage (hazard analysis), i.e., concentration or rates. Fluid migration paths need to be quantified in other type of analyses leading to the exposure in the shallow subsurface or at the earth's surface (exposure analysis). Finally, the effects of exposure to various receptors (e.g. environment, drinking water resources, human beings) can be quantified (effects analysis). The temporal and spatial scales of the impact of the hazards on the release of fluids, exposure to fluids and effects to receptors are to be characterized. Some consequences may be local and sudden whereas others are more diffusive over a larger area.

A lot of site-specific information including the characterization of uncertainties is required to execute a quantitative analysis. Uncertainties that remain in the subsurface characterization, need to be addressed. To understand the influence of the uncertainties on the risk level, one may perform sensitivity analysis to identify the most relevant parameters in the quantitative risk analysis. The outcome of the analyses will be evaluated in a comparison to the criteria and indicators for risk acceptance and a conclusion on compliance will be drawn. Any critical uncertainties for the outcome of the evaluation will be identified and follow-up work may be defined to further reduce these uncertainties.

4.3.4 Monitoring and risk reduction

The outcome of the risk assessment provides the context for risk-based monitoring strategies, and the required duration and intensity of monitoring activities. It will also serve as a basis for defining measures to reduce the risk level, e.g. preventive measures during the abandonment of mining sites. Monitoring provides evidence for the undesired migration or accumulation of fluids originating from the abandoned subsurface mining activities or their absence. A monitoring plan is to be established with monitoring parameters which are adjusted to the identified performance and risk criteria, and any associated indicators or proxies. Suitable monitoring technologies with monitoring locations and targets, durations and sampling frequencies are part of the plan.

The output from monitoring is regularly verified for conformance with the expected modelled behaviour of the subsurface. In case the observed behaviour is deviating from the expected behaviour, follow-up mitigation or remediation actions may be necessary. The initial monitoring system (like measurement of ground movement or groundwater quality) may need to be extended with additional monitoring activities to understand the nature of the fluid leakage and its consequences. If the deviating behaviour has been resolved, the additional monitoring can be stopped.

Risk reduction measures may be emplaced to reduce and keep the risks at ALARA (as low as reasonably achievable) levels. Developing these measures already starts in the phase of risk identification. Once risks have been identified, potential reduction measures can be assigned to individual risks.

4.3.5 Stakeholders communication and risk review

Regular communication with and engagement of stakeholders is an integral part of risk assessment and management. Different groups of stakeholders can be identified with different interests, i.e., industrial mining companies (business case), regulator and inspector (compliance with safety and environment rules), local public (safety and environment), local authorities (socio-economic wellbeing) and local companies (interference with their business). Proper communication and engagement require a communication strategy and implementation plan.

The presented framework for risk assessment and management of subsurface mining sites after their abandonment requires regular review and updating of risk management actions so that the risk is kept at a low, acceptable level. New data, rules or criteria, or monitoring results may require updating all or part of the risk assessment and management work. This makes the risk assessment and management work of cyclic nature.

Plans for updating must be made, whether initiated at periodic intervals or triggered by events. Significant deviations should be documented, approved and distributed to the stakeholders. Thus, the holistic overview gained in the planning stage should be used to describe how changes are dealt with.

5 Conclusions

5.1 Fluid migration

For long-term fluid migration after field abandonment we distinguished the following mechanisms:

- Migration between adjacent fields and/or aquifers
- Vertical fluid migration out or into the field
- Migration and leakage along wellbores

Migration between adjacent fields

After oil and gas production ceases, pore pressures redistribute towards a new equilibrium, which is associated with fluid flow. There is much evidence of fluid flow during production, such as: strong aquifer drive, reservoirs found below virgin pressure or experiencing pressure depletion, observations of free water levels in wells, observations of pressure increase in shut-in abandoned reservoirs, observed depletion of adjoining formations, and subsidence above aquifers connected to a gas field. This suggests connectivity between adjacent fields. When such gas fields are abandoned, the equilibration of pressures can take long and occur over large distances. Usually this results in a rise in pressure in the abandoned reservoir and a decrease in the surrounding area.

The following risk factors are identified for fluids migration between adjacent fields

- The size and permeability of the aquifer attached to a gas field.
- The size of a gas field (large gas fields, higher risk)
- Absence of flow barriers
- Presence of open faults enabling pressure communication between different formations
- Poor seal quality (e.g. thin, heterogeneous).
- Deep groundwater flow-systems

Vertical fluid migration

Vertical migration of gas from fields is a natural process over geological timescales, since no seal is perfect. However, observed natural fluxes to the atmosphere or shallow aquifers are considered minimal. Potential leakage pathways from the reservoir are caprock seal leakage, leakage along faults, and gas migration across spills for fields originally ‘filled-to-spill’. Caprock seal leakage is associated with overpressures. Since after abandonment, pressures are not expected to exceed virgin pressures, this is not considered to be process leading to leakage from the reservoir after abandonment. However, for shallow gas pockets in which gas accumulation takes place it could be a factor to consider. Leakage along faults could occur if the changes in pore pressures related to fluid migration lead to the reactivation of faults thereby changing the permeability. In Groningen, this is only expected to be an issue if the Zechstein seal is thinner than 50 m. Upward fluid migration through shallower strata can occur through faults. Especially faults associated with salt diapirs are identified to be a risk factor.

Upward migration of brine is not expected, since the pressures in the abandoned gas reservoir are lower than in the surrounding. Hence, brine is expected to flow into the reservoir after seal failure rather than out of the reservoir.

Risks resulting from potential upward gas migration are related to gas leakage to shallow aquifers and the atmosphere, drilling risks due to the accumulation and unexpected presence of gas pockets, and accumulation of methane to explosive amounts in e.g. poorly ventilated cellars. At present, known gas leakage at surface occurs mostly from shallow sources (up to ~1000 m depth) (e.g. Wilpshaar et al., 2020). Hence, this gas is mostly from a biogenic origin and not derived from deep sources.

The following risk factors are identified for upward gas migration:

- Presence of faults, in particular faults that extend beyond the seal (Zechstein) to the shallow subsurface.
- Poor seal quality (e.g. thin, heterogeneous).
- Depth of the field: For deep gas fields, even if the primary seal fails or faults become conductive, shallower sealing layers may stop or delay the upward migration. In general, the shallower the field, the less this effect is.

Mechanical effects of the pressure depletion on faults and sealing layers should be included in the analysis of potential risk factors, since the properties might be changed due to pressure changes. On one hand faults are expected to become less permeable with lower pressures. On the other hand, faults can be re-activated or new faults can form due to the pressure changes, potentially increasing the overall permeability.

5.2 Methane leakage at abandoned wells

Field measurements of methane leakage at abandoned wells is done by either measuring the flux of methane at the wellhead, or by measuring methane concentration in shallow aquifers. Due to the difference in well abandonment regulations and geology, different regions report various levels of well integrity loss. A review of several measurements in the literature indicates that on average surface leakage of methane at wellheads is relatively small; However, high-emitting cases can exist. Measurements of methane concentration in shallow aquifers indicate that dangerous levels of methane could leak into the groundwater while undetectable at the surface, due to the dissipation and oxidation of methane in the soil. The levels of dissolved methane can drop sharply with distance from the leakage source. Water samples from up to a 1 km radius of a leaky abandoned well have shown elevated levels of dissolved methane. The extent of plume migration depends on the pressure and permeability of the methane source, permeability of the leakage pathway, and regional aquifer properties. Understanding these mechanisms is critical to design an effective and economic monitoring strategy. The following risk factors can help in identifying high risk areas:

- Poor well abandonment and construction: Abandonment and completion regulations are constantly evolving. The wells that have been spudded and abandoned decades ago were likely under more relaxed laws concerning cementing depths. Particularly, the following cases could demand closer attention:
  - wells that have a shallow surface casing relative to the ground water level,
  - deviated wells,
  - wells with a large uncemented section,
  - wells that are exposed to corrosive fluids,

- wells that have experienced extreme pressure and temperature changes (thermal operations, CCS, etc.),
- wells with inadequate cement plugs inside the production casing.

- Presence of shallow gas sources: The source of leaking gas, whether biogenic or thermogenic, is in most cases a shallow formation. This includes coal seams, brine formations with biogenic methane, or non-producing formations with thermogenic gas.

5.3 Impacts of fluid migration

The following impacts of fluid migration were identified and discussed:

- Impact on ground motion
- Impact on subsurface operations (including geothermal operations and salt caverns)
- Impact on shallow aquifers

Impact of atmospheric methane emissions is not discussed as such. It should be realized that this has a negative impact on climate change and could potentially lead to hazardous (explosive) situations if it would accumulate below man-made structures, such as basements.

Impacts on ground motion are expected since the long-term fluid migration is associated with pore pressure changes which leads to changes in effective stresses and associated compaction or dilatation, and seismicity. The volume of the expected subsidence bowl is of the same order as the compaction volume, and the radius of the surface area of the compaction bowl is similar to the depth of the source. The main risk related to subsidence to be considered is the effect of large water-bearing layers losing pressure by redistribution of the pore fluid. The main risk related to seismicity is the reactivation of faults. The first identification of such risk is through the value of the slip tendency on faults.

No case histories of potential interferences between salt-caverns and geothermal operations and long-term post-abandonment fluid migration could be found in literature. The salt caverns adjacent to the Groningen gas field are separated from the gas reservoirs by a Zechstein salt layer of over 1 km between salt caverns and gas fields is. This is expected to be too large for eventual faults to have an effect on salt caverns. Potential pressure effects in the formation adjacent to the salt domes could occur over time if connectivity exists between the aquifers and the formations above the seal. The consequences of such a depletion should be taken into account when desiigning new caverns for storage purposes. Leaky well bores penetrating formations in which geothermal operations take place are identified as a risk. In addition, if geothermal operations are planned in former gas fields, the low pressures involve risks, such as increased sand production. In general, the reduction in pressure and formation of gas pockets in the area surrounding an abandoned gas field can have a range of different effects on subsurface operations, such as risks for future drilling activities.

When migrating methane reaches shallow aquifers, only a small amount of methane dissolves in the groundwater. Since methane does not react in the pure phase, only when dissolved, most of the methane will flow upwards in the shallow aquifers until it is collected below a low permeable layer or is emitted to the atmosphere, as is already mentioned in the conclusions on wellbore leakage. In the unsaturated zone oxidation of dissolved methane happens very quickly. In the saturated zone, dissolved methane can change groundwater chemistry through changing redox and pH, leading to potential water quality degradation: undesirable elements can have increased concentrations or can be mobilized. Furthermore, the microbial community, essential for biogeochemical processes in shallow groundwater, can be affected by the presence of dissolved methane. Brine is not expected to reach shallow aquifers since it is not buoyant and the depleted reservoir acts as a pressure sink.

The events associated with long term abandonment gas fields, the risk factors involved, and impacts are summarized in Table 3.

Table 3 Overview of undesired events, risks factors and impacts associated with long term gas fields abandonment

Undesired event	Cause (threat), Risk factors	Impact
Lateral fluid migration	• Large, permeable aquifers • Size of a gas field (large gas fields, higher risk) • Presence of open faults enabling pressure communication between different formations • Absence of flow barriers	To subsurface operations: • Drilling failure, due to the accumulation and unexpected presence of gas • Effects of depletion on drilling and operations related to salt caverns, geothermal, gas storage
		Ground motion • Depletion of large aquifer bodies leading to subsidence • Changes in effective stresses leading to seismicity
Leakage / vertical fluid migration	• Presence of faults, in particular faults that extend beyond the seal (Zechstein) to the shallow subsurface and can be reactivated • Poor seal quality (e.g. thin, heterogeneous). • Shallow gas fields • Presence of gas that can be mobilized due to e.g. depletion: gas below free water level (FWL), virgin fields filled to spill	To shallow aquifer: • Methane contamination • Alteration of microbial system • Groundwater quality
		To atmosphere: • Methane release into atmosphere (GHG) • Explosion risk
		To deep groundwater system: • Changes to deep groundwater circulation
Wellbore leakage	• Presence of shallow gas formations • Wells that have a shallow surface casing relative to the ground water level • Deviated wells • Wells with a large uncemented section	To shallow aquifer: • Methane contamination • Alteration of microbial system • Groundwater quality
		To atmosphere: • Methane release into atmosphere (GHG)

	• Wells that are exposed to corrosive fluids • Wells that have experienced extreme pressure and temperature changes (thermal operations, CCS, etc.)	• Explosion risk

5.4 Risk assessment and management framework

The ISO 31.000 standard for risk management is recommended as a starting point for the development of a framework in the current study. Existing examples of risk assessment (and management) frameworks for geothermal energy production, CO_2 storage and gas production provide useful information for the development of a framework for regional assessment and management of fluid migration and leakage resulting from abandoned gas reservoirs. The possibility of developing a suitable framework for the present study can be confirmed.

A first version of the risk assessment (and management) framework (v1.0) has been presented in Section 4.3 and consists of the following main steps:

- Establishment of the assessment context
- Risk identification and screening
- Quantitative risk analysis and evaluation
- Monitoring and risk reduction
- Stakeholder communication and risk review.

6 Proposed activities for Phase 2

This chapter touches on the details of our proposed plan for the next phase of this project and it provides a description of the modelling approaches, tools and data to be used. In Phase-2 the project has been subdivided in three main work packages (WP):

- WP2 Post-abandonment fluid migration and ground motion related risk assessment
- WP3 Post-abandonment well leakage risk
- WP4 Recommendations for leakage and ground motion hazard and risk assessment framework

6.1 Proposed approach for work package 2

In WP2 numerical simulations are planned to further investigate the effects of abandoned gas fields on adjacent fields and shallow aquifers. The approach is described as follows.

6.1.1 Regional modelling

In the first part a simplified, regional numerical fluid flow model will be developed to evaluate the lateral and vertical extent of the pressure redistribution after depletion (assuming no leakage to the surface). The result of this simulation will give insight into the temporal and spatial scale of the pressure redistribution. Based on the simulated pressure distribution, subsidence and seismicity potential will be analysed.

Fluid flow model

The fluid flow model will be a simplified, regional model inspired by the Groningen area including surrounding aquifers, some small nearby gas fields and underlying Carboniferous deposits. The Zechstein seal is assumed to be a flow and pressure barrier (no-flow boundary). This implies that all formations above the Zechstein are not in pressure communication and therefore they will not be included in this model. Potential fluid/gas migration to shallow layers will be investigated in the second part (see section on conceptual modelling). The regional model will have the following characteristics:

- A limited number of faults is included in the simulation.
- The model will be a 3D, 2-phase flow model.
- Spatial discretization will be in the order of 500 x 500 x 50 m.
- After the hydrostatic initialization, the production phase will be represented in a simplified way: The historical production profile is used, but not the real wells.
- The time period to be simulated (after abandonment) will be at least 200 yrs.
- Gas below free water level is not included, because this is too complex for a regional model.
- Thermal effects are not included.

Since the model is not an exact representation of the Groningen field, the model will not be history gas reservoir matched. Also, history matching of such a large model is a very time-consuming process which is outside the scope of this work. Further, current data constrain the properties of the surrounding aquifers and faults poorly, giving rise to considerable uncertainty even in the case of a careful history match. However, the model should mimic the overall pressure developments in the Groningen area. To achieve this, the GIIP (Gas Initially In Place), the amount of produced gas and the average gas pressure at abandonment will be reproduced. The pressure in the aquifers surrounding the gas field will be analysed via sensitivities and will range around observed pressure behaviour. The sensitivities will be run by varying the permeability of the aquifers and faults in the aquifers. This will result in different pressure distributions at the time of abandonment and in the period after abandonment. The sensitivities will at least include a low, mid and high permeability case for both the aquifer and fault permeability. Also the permeability of the Carboniferous deposits below the Slochteren is uncertain and will be varied. Heterogeneity in the permeability of the aquifers and Carboniferous will only be included in a very limited way since the regional model is too coarse for detailed permeability variations. The analysis is not focused on such details but on identifying scenarios (e.g use of the subsurface) and locations that require more attention in the future.

The uncertainty in the predicted pressure distributions will be large due to the large uncertainty in the extent and permeability of aquifers and the permeability of faults. The results should be interpreted in terms of trends rather than absolute pressures.

The main data sources for the regional model will include depth and thickness maps for the main stratigraphic intervals as interpreted within the DGMdeep projects, including the main reservoirs. The main regional faults will also be based on the regional mapping of the area including more detailed interpretations from the public NAM reports (and the NAM geological model (https://public.yoda.uu.nl/geo/UU01/1QH0MW.html)). Pressure distribution and pressure history for the main reservoir will be based on the detailed information published in the NAM reports, the regional pressure distribution will be based on the results of the Pressure SNS studies. Necessary rock properties will be collected from ThermoGIS, the NAM geological model, the NAM reports and the NLOG database. Missing local information for rock properties, mainly for the sealing layers, will be based on literature (e.g., Yang & Aplin, 2007) and compared to available data for the Dutch subsurface. The software tools to be used are Petrel for creating the geological and reservoir model and Eclipse 100 for the fluid flow. Eclipse 100 is selected because it is fast and robust, can handle large numbers of grid blocks and is very suitable for 2 phase flow (natural gas and brine).

Ground motion

The redistribution of pressure impacts the subsurface stresses and, through the mechanical response of the subsurface, results in surface movement. We will perform an assessment of the slow surface movement, i.e. the subsidence, that results from the pressure redistribution and the associated changed effective stresses. This is mainly an issue when large subsurface volumes experience considerable pressure changes, as might be the case when water in the strata connected to a gas reservoir flows towards the depleted regions. The main uncertainties reside in the calculated pressure fields, therefore we will limit ourselves to AEsubs, a fast semi-analytical model available in TNO, which provides a good first-order subsidence estimate starting from the pressure distribution and the mechanical reservoir behavior (Fokker and Orlic, 2006).

Ground motion in the form of seismicity (earthquakes) is also considered in this study. A change in pore pressure or in in-situ temperature affects the effective stresses, both locally and at distances away from the distortion. The latter effects are generally relative small, and we will discard them in the present study. We will take the modelled aquifer pore pressures and transform them into effective stresses due to the direct pressure effect and changes in poro-elastic stresses in the depleted areas. A simplified 1D analytical or semi-analytical approach will be employed to capture the main effects, possibly in parallel with the subsidence calculations. With the input of a virgin stress field the numbers will be translated into a distribution of the slip tendency for different orientations of faults. A useful approach to identify areas of risk is to assess the percentage of possible fault orientations exceeding the failure envelope (Levandowski et al, 2018).

The simplified, regional numerical fluid flow model in this project does not allow an in-depth evaluation of seismic risk. We will therefore not investigate the effect of fault offset, plasticity, dynamic rupture, or elasticity contrasts. A comprehensive fault reactivation study is beyond the scope of the present investigations. A first guidance can however well be provided by considering the main factors affecting seismicity: the level of aquifer depletion, the thickness of the depleted area, the criticality of the virgin stresses, and the orientation of potentially unstable faults.

6.1.2 Conceptual modelling

In the second part, fluid/gas migration to shallow aquifers will be evaluated using conceptual models. In this part, the focus is on conceptualizing potential migration pathways for gas out of the reservoir through faults or failure of seals (wells will be addressed in WP3). This way we know which combination of risk factors needs to be in place to have migration from the reservoir and to have migration towards the shallow subsurface.

From the present review, it follows that the southern fringe of the Groningen gas field near Veendam appears to be a representative location to analyse different impacts of post-abandonment fluid flow. This area presents the following interesting combination of factors:

- Fringe of the Groningen gas field and influenced by the depletion in the Groningen field (Burkitov et al., 2016, Zeeuw en Geurtsen, 2018).
- Large differences in thickness of the Zechstein Formation seal (as opposed to a continuous thick impervious Zechstein Formation above the majority of the field):
- Locally Zechstein is almost absent which could result in migration pathways
- Large diapirs are present with associated faults and upward migration pathways
- The thin Zechstein also could potentially result in soft linked or hard linked faults connecting the formations above and below the Zechstein Formation
- Highly faulted area with many small gas fields in the Rotliegend (e.g. Annerveen-Veendam, Zuidwending-Oost, en Oude Pekela) (Figure 25 and Figure 26) and some small gas fields that have not been produced (e.g. Langebrug and Beerta). Unproduced fields are at higher pressure and this provides more scope for gas migration out of the reservoir.
- Presence of salt caverns

- High uncertainty in the seismic imaging due to the salt diapirs.
- Representative geological sequence

The following steps are foreseen:

1. Define a number of conceptual models that represent potential migration pathways for gas out of the reservoir through faults or failure of seals
2. Evaluate potential permeability creation in (reactivated) faults and for (compromised) seals via geomechanical processes. Since this is the main uncertainty, the estimation of the permeability for these potential leakage pathways will be done in discussion with an expert group of geomechanics and geologists.

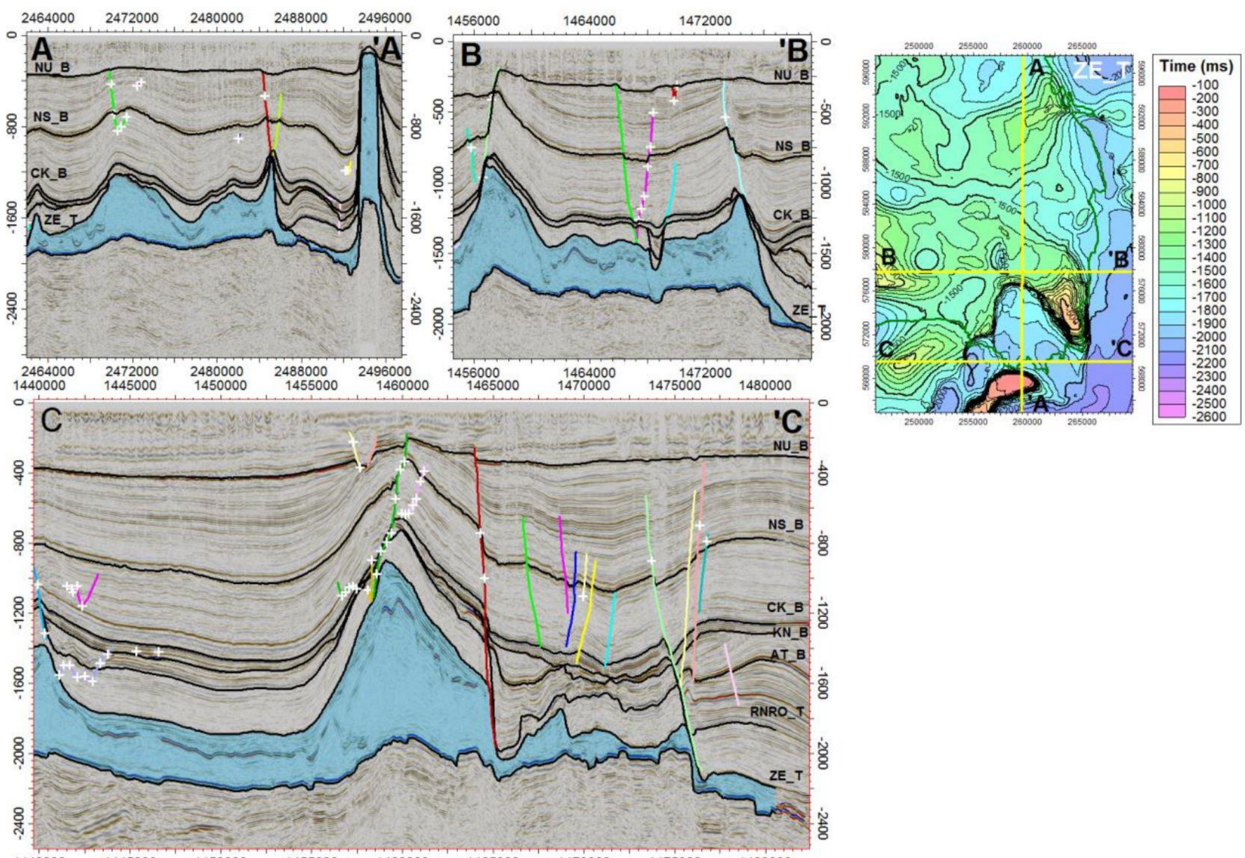

Figure 25. Three seismic cross sections in the south eastern area of the Groningen Field (source: Logeman, 2017)

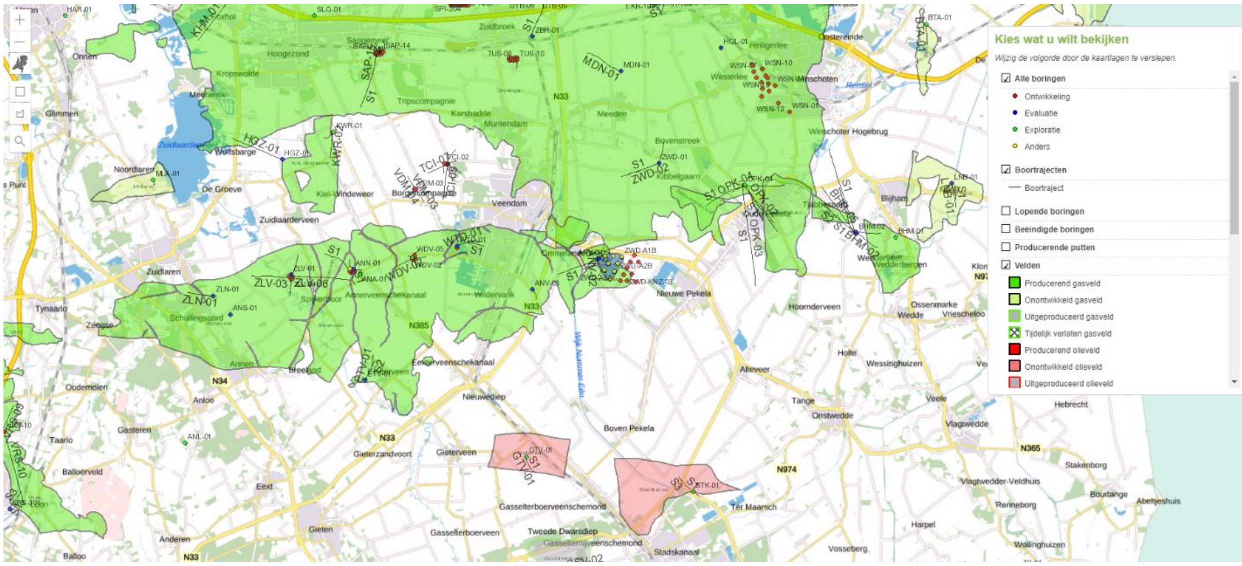

Figure 26. overview of the Veendam area (source: nlog.nl)

6.2 Proposed approach for work package 3

There are at least three interconnected systems at play during methane leakage along a wellbore. The source formation could be the abandoned formation or a shallower formation, or both. Methane flows out of the source formation into the leakage pathway, e.g. the annular cement. If other permeable formations are present, there could be methane or brine exchange between them and the leaky wellbore. The leaking methane could reach shallow aquifers and develop a moving plume through advective and diffusive flow processes over a long time frame. Figure 27 illustrates a schematic of the interconnected subsurface systems that could contribute to methane contamination. The review of field scale measurements of methane emission from abandoned wells indicate that most likely, the source of leakage is a gas bearing formation above the target formation. This is an important realization that is largely missing from the current modelling studies. In addition, the presence of permeable brine formations above the source formation might add another layer of complexity. These formations could allow for methane storage, dampening the impact of leakage on the shallow fresh water aquifers.

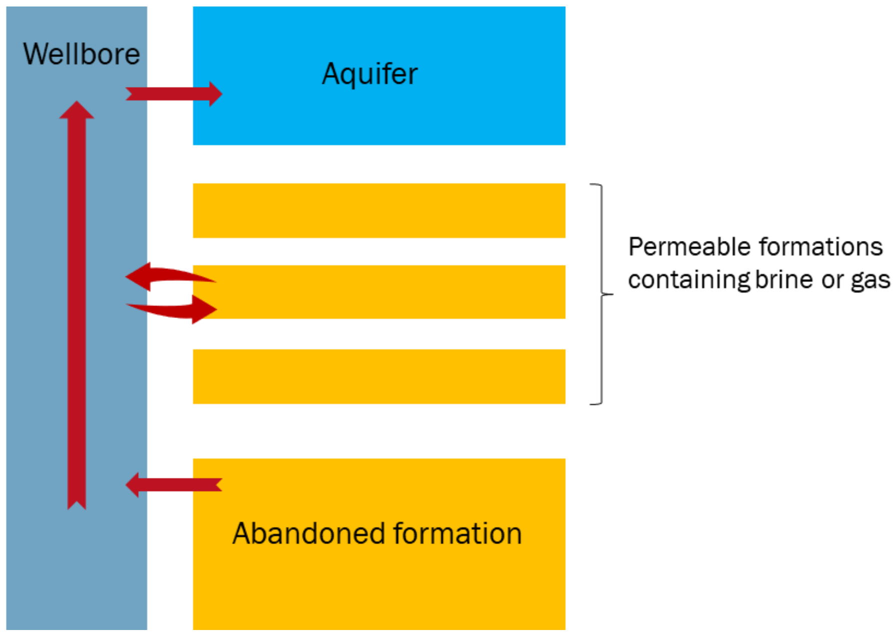

Figure 27. A schematic of the subsurface flow pathways contributing to leakage to the shallow aquifers.

We propose a numerical modelling study that includes the aquifer, underlying formations down to the abandoned zone, and the leakage pathway (wellbore cement). The model will be based on the local geology of the Groningen region in the Netherlands. A 2D-axisymmetric, two-phase, two-component isothermal model is deemed appropriate to describe the potential well leakage along abandoned wells. The model should include methane and water as components and if possible, also include brine or salt. Formations will be assumed homogeneous in this work, therefore the 2D axisymmetric model around the wellbore is sufficient to describe subsurface flow. A separate 3D model of the shallow aquifer may be used to investigate the impact of groundwater velocity on methane plume development. The 3D model will only include the aquifer with a leakage source at its base. The rate of leakage over time at the base of the aquifer will be taken from the 2D model. The 3D model will also include 2 components, and a range of ground water velocities will be considered, as appropriate for the aquifers in the Netherlands.

The goal of the proposed numerical model is to calculate the extent of the methane plume in a shallow aquifer over long time frames (100 years or more). This includes the saturation of free methane near the leakage site and the level of dissolved methane in the water. This enables the regulators and operators to understand the extent of methane contamination of the aquifer over time and judge the necessity of a mitigation strategy. In addition, understanding the expected radius and intensity of the methane plume can assist with the design of monitoring campaigns. Particularly, the rate and location of water sampling needed to monitor the methane levels in aquifers.

The geological setting and formation properties will control the methane contamination levels of shallow aquifers. The focus of the numerical model will be on the wells in the Groningen field, in the Netherlands.

After analyzing the logs and lithostratigraphy of the wells in the area, we determined two typical well schematics in the region, as illustrated in Figure 28. According to Figure 28, the ZRP-01 well intersects a thick section of the Zechstein salt (caprock), while the ZWD-01 well intersects a thin section of the caprock which is replaced by a Triassic claystone. The ZWD-01 well also includes a thicker section of an organic-rich claystone at a depth of nearly 2 km, which could be a source of gas. Both wells intersect shallow coal seams that could also act as sources of methane. Considering the higher potential leakage risks in the ZWD-01 well (thinner Zechstein and thicker organic-rich claystone), the numerical model will be based on the geology at the ZWD-01 well location. The formation properties will be collected from different sources, such as ThermoGIS for the aquifers, well logs and reports from NLOG, and NAM reports. Where relevant data is lacking, we will use estimates based on the values reported in the literature.

A sensitivity analysis will be conducted to assess the impact of important input parameters on leakage rates and plume growth. Critical parameters such as cement's effective permeability, formation pressures and saturations, and petrophysical and multiphase properties will be changed to assess their impact on methane flow rate into the aquifer. The findings will be summarized as a list of criteria that can be used to determine high-risk wells in the Groningen region, in terms of long-term methane leakage. The results will provide a basis for a risk assessment framework to evaluate the post abandonment well leakage risks in the Netherlands. Post-abandonment pressure changes due to fluid migration (identified in WP2) will be used as a boundary condition in the well leakage model.

The majority of the studies reviewed in this report use a version of the TOUGH2 reservoir simulator for the two-phase, two-component simulations. The DUMux simulator has also been used. The main benefit of these packages is that they are open-source (though some commercial GUIs exist for TOUGH2). CMG GEM and ECLIPSE 300 were also identified as suitable tools with similar or superior modelling capabilities. We have evaluated the four identified simulation packages based on their modelling capabilities, user-friendliness and technical support, price or ease of access, and the existing level of experience at TNO. Following the evaluation, we have selected the CMG GEM software package to conduct the proposed numerical simulations. ECLIPSE 300 will be available as back up in case of unforeseen issues.

The input parameters of the leakage model, such as permeability, capillary pressure, gas saturation, etc., are usually highly uncertain. Probabilistic methods such as Monte-Carlo type procedures are more suitable to consider the input uncertainty in such a system. Monte-Carlo simulations are out of the scope of the current project. In addition, geochemical interactions of methane and the formation water will not be considered in this work. These interactions could reduce methane's concentration in groundwater over the years, but lead to the generation of other unwanted compounds. Both the geochemical effects and probabilistic simulations are recommended for future studies.

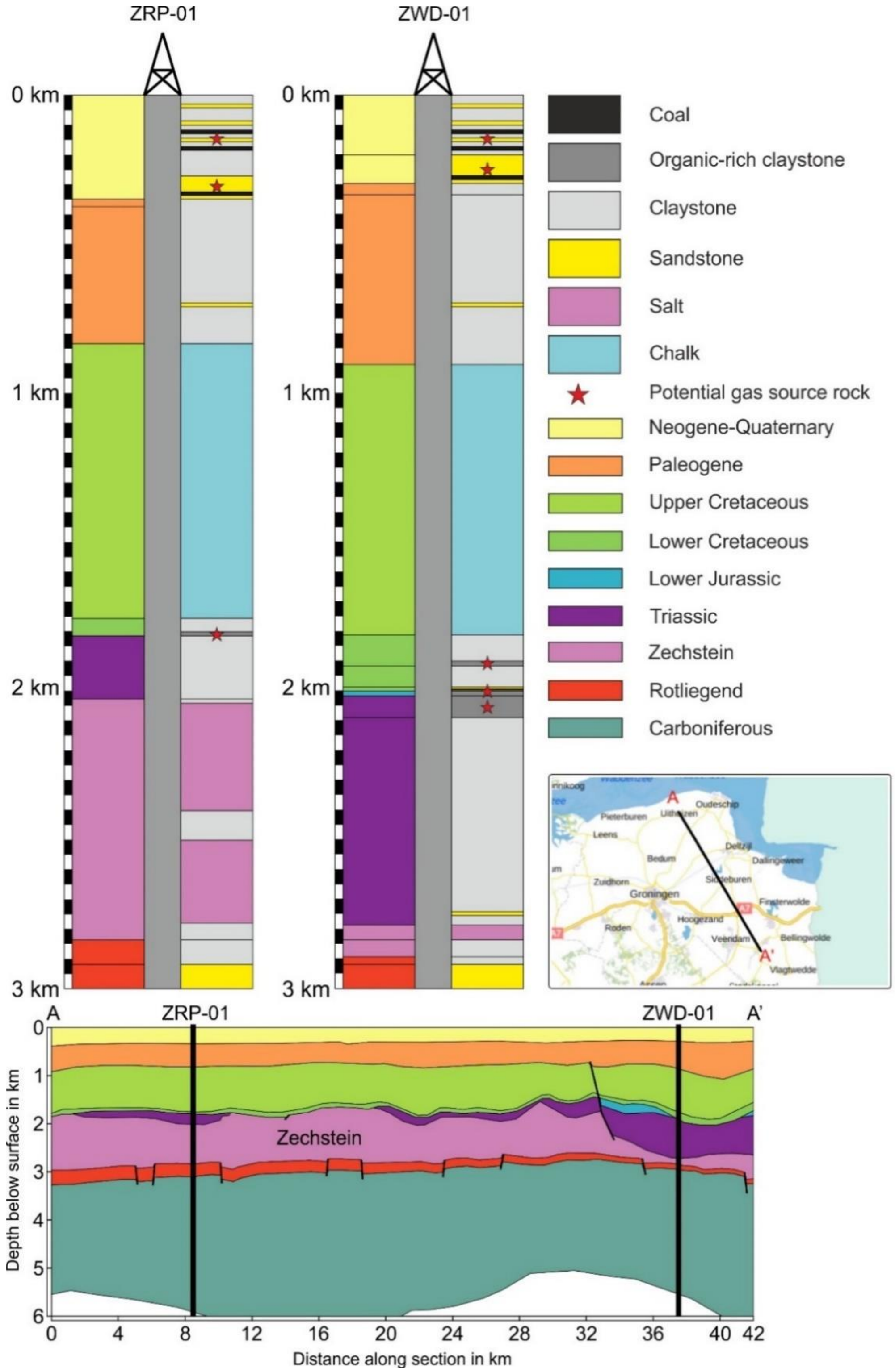

Figure 28: Typical lithostratigraphy of wells in the Groningen region.

6.3 Proposed approach for work package 4

The tasks in WP4 encompass the development of a framework for regional post-abandonment risk management (Task 4.1), development of workflows for hazard and risk assessment integrated in the framework (Task 4.2), development of monitoring strategies integrated in the framework (Task 4.3). In the final phase of the project all results will be reported including the drafting of a public summary (Task 4.4).

The risk management framework presented in Section 4.3 is the basis for further development of the framework in WP4. In the next step, the results of the literature review of fluid migration, pressure redistribution and, seismic and aseismic ground motion (WP 1) will be linked to the framework which will result in a new version. Before the framework can be consolidated, it needs agreement of the scientific reviewer and the Ministry of Economic Affairs and Climate Policy (EZK).

The adjusted framework will serve as a basis for the detailing of the hazard and risk assessment methodology, accompanying workflows and related tools, based on the outcomes of the work in WPs 2 and 3.

The outcome of the assessments of fluid migration and ground motion will be used to develop risk-based monitoring strategies based on input from WP2 and 3. This will be integrated in the risk management framework and may also result in an update of the framework (v2.0) at the end of the project. Recommendations on regional metrics and assessment time scales for post-abandonment risk management will be defined.

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