The feasibility of CO₂ storage in the depleted P18-4 gas field offshore the Netherlands (the ROAD project)

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A B S T R A C T

Near the coast of Rotterdam CO₂ storage in the depleted P18-4 gas field is planned to start in 2015 as one of the six selected European demonstration projects under the European Energy Programme for Recovery (EEPR). This project is referred to as the ROAD project. ROAD (a Dutch acronym for Rotterdam Capture and Storage Demonstration project) is a joint project by E.ON Benelux and Electrabel Nederland/GDF SUEZ Group and is financially supported by the European Commission and the Dutch state.

A post-combustion carbon capture unit will be retrofitted to EONs’ Maasvlakte Power Plant 3 (MPP3), a new 1100 MWe coal-fired power plant in the port of Rotterdam. The capture unit has a capacity of 250 MWe equivalent and aims to capture 1.1 million tonnes of CO₂ per year. A 20 km long insulated pipeline will be constructed to the existing offshore platform operated by TAQA and an existing well will be worked over and re-used for injection. Natural gas production in the P18-4 field is projected to end just before the start of the CO₂ injection. In this first phase a total storage of around 5 Mt CO₂ is envisaged with an injection timeframe of 5 years.

1. Introduction

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The gas fields in block P18-A (P18-2, P18-4 and P18-6) are situated at approximately 3500 m depth below sea level. The clastic reservoir rocks are part of the Triassic Main Buntsandstein Subgroup and the primary seal for the gas fields consists of discomformably overlying siltstones, claystones, evaporites and dolostones. The P18 gas fields including P18-4 are located in a heavily faulted area and consist mainly of fault bounded compartments, which are (at least on production time scales) hydraulically isolated from their surroundings.

This paper provides an overview of a feasibility study focused on CO₂ injection in the P18-4 gas field.

2. Geological background

2.1. Depositional setting

The Triassic sediments of the reservoir of the P18-4 gas field and its primary seal are of epicontinental character. They can be subdivided into two groups, the Lower Germanic Trias Group and the Upper Germanic Trias Group (Fig. 1).
The Lower Germanic Trias Group is of Late Permian to Early Triassic age and comprises clastic sediments, deposited in a lacustrine and fluvial setting with local aeolian influences. It comprises the Lower Buntsandstein, Volpriehausen, Dethfurth and Hardegsen Formations of which the last three are gas bearing in the P18-4 field.

Subtle unconformities in the deposits of the Lower Germanic Trias Group indicate new sedimentary cycles, and possibly periods of minor tectonic uplift. Alternating sea levels caused fluvial influence repeatedly extending far into the basin, where even aeolian sandstones occasionally can be found. On structural highs sedimentary sequences are condensed and/or reduced in thickness due to erosion.

The boundary between the Upper and Lower Germanic Trias is formed by the Hardegsen or Base Solling Unconformity, which forms a regionally well-correlatable event (Ziegler, 1990; Geluk and Rößing, 1997, 1999; Geluk, 2005). Directly above the unconformity lie the clay stones and evaporites of the Solling Clay stone and Röt Formations.

The Upper Germanic Trias Group is of middle to late Triassic age and comprises an alternation of fine-grained clastics, carbonates and evaporites deposited in alternating shallow, restricted-marine, inland-playa lake and floodplain settings. It holds the Solingen, Rot, Muschelkalk and Keuper Formations. The Upper Germanic Trias Group forms the primary seal of the P18-4 field.

2.2. Structural history

The reservoir of Triassic age represents a part of the post-Variscan sedimentary mega-cycle. The deposition and deformation of the reservoir rocks was strongly controlled by a sequence of rift pulses that started in the Late Triassic, and lasted until the Late Cretaceous. It can be subdivided into a pre-rift, syn-rift and post-rift stage.

The pre-rift stage started in the Early Triassic and was characterized by regional subsidence. Sedimentation occurred under semi-arid to continental conditions in a slightly north dipping basin. At the southern margin of this basin, the area of the P18 block (Fig. 2), initially fine-grained lacustrine sediments were laid down, followed by a sandy fluvial and aeolian succession: the Main Buntsandstein Subgroup. These sediments were derived from the nearby London-Brabant Massif to the south, and the Rhenish Massif to the southeast, which formed part of the northern rim of the Variscanorogenic belt (Geluk et al., 1996; Van Balen et al., 2000).

Active rifting started in the Middle Triassic when several rift pulses broke up the basin into a number of NW-SE trending fault-bounded sub-basins (De Jager, 2007). One of the sub-basins formed was the West Netherlands Basin (WNB), a well-known oil and gas province in the Netherlands that also contains the P18-4 gas field (Fig. 2). From Middle to Late Triassic, during the Early Kimmerian rift phase, the WNB was formed, a structurally rather simple large-scale half-graben, bounded to the north by a major fault zone (Geluk, 1999). During the Late Triassic to Early Cretaceous, riftintensified, and faulting caused differential subsidence of the various subunits of the basin (Van Balen et al., 2000). The strongest rifting occurred during the Late Jurassic to Early Cretaceous (Van Wijhe, 1987; De Jager et al., 1996; Racero-Baena and Drake, 1996). This caused the breaking-up of the basin into various sub-units, and large thickness variations in the Late Jurassic basin infill, i.e., thick in the basins and thin or absent on the highs. The rifting occurred in several discrete pulses of short duration in the time-span from Kimmeridgian to Barremian. Rifting gradually ceased during the Aptian-Albian (Van Wijhe, 1987), but subsidence of the WNB continued into the Late Cretaceous (Van Balen et al., 2000).

Finally, compressional forces during the Late Cretaceous caused the inversion of the WNB (Van Wijhe, 1987). On seismic, major fault zones display reverse movements, indicating that older basin-bounding faults were reactivated. Many of the oil-bearing anticlinal structures have been formed during this phase (De Jager et al., 1996; Racero-Baena and Drake, 1996). The overall style of the inversion movements, with both a reverse vertical and a horizontal
component, suggests they developed in response to transpression (dextral-strike-slip; Van Wijhe, 1987; Dronkers and Mrozek, 1991; Racero-Baena and Drake, 1996).

2.3. Reservoir geology

The structures that contain the gas reservoirs are bound by a system of NW-SE oriented faults in a horst and graben configuration (Fig. 3), with a sinistral strike-slip component. Gas field P18-4 is bounded by faults F4 and F5 to the west and east respectively, and separated from the P15-9 field, visible in the upper left corner of Fig. 3, by fault F3.

The reservoir rocks of the P18-4 field belong to the Main Buntsandstein Subgroup, a cyclic alternation of (sub-) arkosic sandstones and clayey siltstones of approximately 200 m in thickness.

The Volpriehausen Formation is the oldest formation of the Main Buntsandstein Subgroup. Its origin is mainly fluvial, but it has also some aeolian sediments. It consists of braided river deposits interbedded with subordinate flood-plain and crevasse-splay deposits and locally dune deposits (Ames and Farfan, 1996). The Volpriehausen Formation is a clean sandstone with a blocky appearance on gamma-ray logs (Fig. 4) that contains high percentages of calcite and dolomite (Geluk et al., 1996). On gamma-ray logs, it is clearly distinguished from the Rogenstein Claystone Member below by a marked increase in gamma-ray readings. The Rogenstein Claystone member forms the basal seal to the reservoirs. The thickness in well P18-04A2, the only well penetrating the P18-4 gas field, is 111 m.

The Detfurth Formation is composed of a Lower and an Upper Detfurth Sandstone Member. It consists mainly of aeolian sediment (dunes), and some fluvial deposits (Ames and Farfan, 1996). It is marked by low gamma-ray values due to its high quartz grain content and because it is quartz-cemented (Geluk et al., 1996). It is distinguished from the Volpriehausen Formation by a well-correlatable interval of high gamma-ray readings (Detfurth Unconformity) and two clearly recognizable coarsening upwards sequences (Fig. 4). The thickness varies slightly over the P18-4 field and measures 19 m in well P18-04A2.

The Upper Detfurth Sandstone Member is separated from the Lower Detfurth Sandstone Member by a second well-correlatable interval of high-gamma-ray readings and a single coarsening-upward sequence. It is penetrated by all the wells in the P18 fields (P18-2, P18-4 and P18-6). Its thickness ranges between 47 m and 50 m and measures 49 m in well P18-04A2.

The Hardegsen Formation is the youngest formation of the Main Buntsandstein Subgroup. It is recognized by an increase

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**Fig. 2.** Map view after Geluk, 2007: Subcrop map of the Hardegsen Unconformity (=top reservoirs P18). Colours indicate formations; from dark to light grey: lower Buntsandstein Fm., Volpriehausen Fm., Detfurth Fm., Hardegsen Fm., grey: platform areas. WNB, West-Netherlands Basin.
Fig. 3. 3D view of the top of the P18 fields. Faults are shown in grey, well traces are shown in red.

Fig. 4. Gamma-ray (GR) log (dark coloring indicating shale, light coloring indicating sandstone), neutron porosity (NPHI) log, and bulk density (RHOB) log over the reservoir interval in the P18-01 well located in the adjacent P15-9 field and in the P18-04A2 well in the P18-4 reservoir. Note the difference in true vertical depth (SSTVD).
in the gamma-ray values compared to the underlying Detfurth Formation and characterized by sandstones. Furthermore, it displays a well-developed overall coarsening-upward pattern with low gamma-ray values towards the top (Fig. 4). It mainly consists of aeolian deposits and is penetrated by all the wells in the P18 fields. Its thickness in the wells ranges between 24 m and 33 m and measures 29 m in well P18-04A2. Above the Hardegsen Formation, gamma-ray values increase again, first mildly, and then strongly and abruptly (Fig. 4). This mild increase is due to the transition from Hardegsen Formation to the Solling Sandstone Member, which here is included in the Hardegsen reservoir zone. The strong increase is due to the transition from the Solling Sandstone Member to the Solling Claystone Member that forms the basal part of the cap rock to the P18-4 field.

The porosity distribution in the P18-4 field, as observed in wells penetrating the various reservoir compartments of the P18 fields P18-2, P18-4 and P18-6, show quite some heterogeneity. When focusing on the Hardegsen formation a porosity–depth relation displays high variability caused by the different facies. Well P18-04A2 has been assumed characteristic for the P18-4 field. More precisely, the vertical distribution of the porosity as observed in well P18-04A2 has been considered representative and has been maintained over the whole reservoir in a layer-cake model.

2.4. Seal and overburden

The primary seal of the P18 fields are the siltstones, claystones, evaporites and dolostones of the Solling Claystone Member, the Röt Formation, the Muschelkalk Formation, and the Keuper Formation that discomformably overlie the reservoir (Fig. 5). The Solling Claystone Member, deposited in a lacustrine setting, consists of red, green and locally grey claystones. It is the first laterally extensive claystone above the reservoir rocks of the Main Buntsandstein. In well P18-04A2, The Solling Claystone Member has a thickness of approximately 10 m. The overlying Röt Formation consists of thin-bedded claystones, and is approximately 40 m thick. The Muschelkalk Formation consists of claystones, dolomites, and evaporates, and is approximately 70 m thick. The youngest formation in the primary seal is the Keuper Formation, which consists of claystones intercalated with zones of anhydrite and gypsum, and is approximately 40 m thick. In total, the thickness of the primary seal in well P18-04A2 is approximately 200 m. In the primary seal some faults are present. However, these faults appear to be sealing.

Reservoir closure is obtained through impermeable zones above and below the reservoir interval in combination with juxtaposition of permeable reservoir facies against impermeable non-reservoir facies of the Altena Group. A closer look at the 3D seismic reveals that, although most of the reservoir-bounding faults do not continue upward into the overburden than the shales of the Altena Group, some reverse faults, that where formed during the inversion phase, appear to originate around the fault tips of the older reservoir-bounding faults (Fig. 5). Inversion in the vicinity of the P18 block was relatively weak. Therefore, it is unlikely that these inversion faults are reactivation faults that originate from movement along the older basin-bounding faults. Although impossible to rule out completely, it is unlikely that the sealing properties of the basin-bounding faults have been compromised.

![Fig. 5. Left: seismic cross-section through the P18 fields, displaying the reservoir interval (colored layering), the main bounding faults to the reservoirs (bold lines), the main stratigraphic units in the overburden and the faults in the overburden (dashed). A map view of the P18 fields is shown in the upper right corner, with the position of the seismic cross-section indicated. Right: stratigraphy and logs (GR and sonic) of the reservoir interval and overburden of the P18 fields, with aquifers and seals indicated.](http://dx.doi.org/10.1016/j.ijggc.2012.09.010)
Directly above the primary seal lies the Altena Group, a thick succession of marine claystones, siltstones and marls of Early Jurassic age with excellent sealing quality. It also contains the Posidonia Shale Formation that is easily recognized on seismic due to its excellent reflectivity. The Altena Group has a thickness of approximately 500 m in the P18-02 well and acts as a secondary seal.

The rest of the overburden is formed by several geological formations, some of which are assumed to have sealing properties. The oldest is the Lower Cretaceous Supergroup, which has thickness of approximately 1000 m. It consists of several formations and in the location close to the P18-4 field, some of the sandstone layers present in this interval are gas or oil bearing (e.g. Rijswijk Member, Rijn Member), which demonstrates the sealing quality of the numerous claystone intervals in this succession. The Lower Cretaceous appears largely unfaulted, which further increases the sealing potential of these rocks. Above the Lower Cretaceous Supergroup lies the Upper Cretaceous Supergroup with a thickness of approximately 1400 m. The influx of fine-grained clastics into the marine realm of the Lower Cretaceous diminished and a fairly uniform succession of marls and limestones of the Texel and Ommelanden Formations developed. These sediments have an earthy texture and are commonly known as 'Chalk'. The sealing properties of these formations are questionable although few of the larger faults penetrate this interval. The youngest sediments in the overburden are part of the North Sea Supergroup. The North Sea Supergroup consists mainly of siliciclastic sediments and has a thickness of approximately 1000 m over the P18-4 field. The North Sea Super group overlies the Chalk Group unconformably. On seismic, it appears as largely unfaulted. Clayey sequences are abundant, especially in the lower part, which are thought to be capable seals.

2.5. Shallow gas accumulations

On seismic small, shallow bright spots and disturbances (diameter approximately 100 m) along and near fault lines can be identified (Fig. 6). It is likely that these bright spots and disturbances are related to shallow gas. The origin of the gas could be biogenic, but it could potentially also have originated deeper, in which case it must have migrated upward and possibly also laterally through transmissive faults and permeable layers. Considering the excellent sealing quality of the primary seal of the P18 reservoirs, and the difference in age and dip of the faults in layers above and below the Altena Group, it is unlikely that these potential shallow gas accumulations are related to the P18 reservoirs from which gas is produced. More likely, it originates from either the Posidonia Shale Formation in the overlying Altena Group, which is responsible for charging many Upper Jurassic and Lower Cretaceous reservoirs in the vicinity (De Jager et al., 1996), or from shallower layers by biogenic processes.

3. History match based on gas production of P18-4

As already indicated, the P18-4 field is a reservoir, which consists of one gas charged compartment and is bounded by faults. Production well P18-04A2 is drilled in the southern part of this compartment. Production of the P18-4 field started in 1993 and is projected to end in 2015.

3.1. Upscaled model

Two versions of upscaled geological models have been used for flow simulations. The first (model 1) contains 9 layers whereas the second (model 2) contains 18 layers. The exact subdivision of model 1 is shown in Fig. 7. Note that for model 2, each model 1 layer is split in 2 layers.

On top of that two regionally present shale layers have been identified, that have been incorporated as no flow boundaries. These shale layers typically have thicknesses in the meter range on the log data, justifying the no flow boundary modeling. These shale layers are located between the Upper Detfurth–Lower Detfurth and the Lower Detfurth–Volpriehausen.

Especially in terms of pressure behavior, no significant difference was noticed between the two models. Therefore the coarser model 1 has been used in current simulations.
For the permeability a porosity–permeability (poro–perm) relation has been used. From this poro–perm relation a log with the horizontal permeability $KH$ has been constructed. Core data shows approximately a vertical versus horizontal permeability ratio $Kv/Kh$ = 1/10 determined at a pressure of 55 bar. Based on the latter the $Kv$ log has been constructed derived from the $Kh$ log. Finally, both logs have been upscaled independently, with a harmonic averaging for the $Kv$ and an arithmetic averaging for the $Kh$.

The upscaled logs lead to an injectivity of $KH = 13,643$ mDm considering only the perforated parts of the well for $H$.

A multiplier of 0.6 is required to match the $KH = 8200$ mDm with a skin of $-3.1$, that results from the well test dating from August 1997. Note, that this difference can be explained by the different scale (or range) of the measurement sensitivities: the well test provides an average of the $KH$ over a large part of the reservoir, whereas the log data only sees the near-well region. The observed differences are not uncommon.

### 3.2. P/Z analysis and history match

The $P/Z$ curve (Fig. 8) obtained from the production history of the P18–4 field leads to an estimation of the gas initially in place (GIIP) of 3.2 GNm$^3$ with an estimated uncertainty in the order of 5%. This value is used to calibrate the static geological model. More precisely, the pore volume of the static model is corresponding to the GIIP derived from the $P/Z$ curve. Therefore the uncertainty on the pore volume is estimated in the order of 5% as well. The largest uncertainty on the volume estimation based on the static model can be attributed to structural uncertainty, i.e. the accuracy of the seismically interpreted location of the bounding fault at the eastern part of the reservoir. Within the resolution bounds of the seismic data, this location has been matched to the location best fitting the pore volume. Other uncertainties incorporate the porosity distribution and the residual water saturation. All these individual uncertainties are much larger than the 5%, but the combination is constrained by the uncertainty margin coming from the production history.

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The P18-4 field shows a highly tank-like gas production history, as can be observed on the straight $P/Z$-curve. No deviations of the straight line that could indicate influx from an aquifer or flow of gas from one reservoir to the other (such as the neighboring P15-9 field) are observed.

Fig. 9 shows the comparison between the simulated bottom hole pressures (BHP) and the one derived from the measured well head pressures (WHP) using lift tables. Note, that a negative skin factor of $-3.1$ has been used derived from well test data acquired in August 1997.

The observed match between the simulated and the observed BHPs is satisfactory.

3.3. Simulation of the CO$_2$ injection scenario

The mass of CO$_2$ that can be injected based on the history matched model in this field is estimated at 8 Mt in case of injection up to the original reservoir pressure of 350 bar. In reality this capacity estimation heavily relies on the gas production history, the chosen abandonment pressure and the total amount of gas produced. As already indicated, the estimated uncertainty is in the order of 5%. Forward simulations of the injection scenario show that the average target rate of 1.1 Mt/year, with temporary peak rates up to 1.5 Mt/year, can be sustained.

Based on the currently available history matched model, a forecast for the CO$_2$ injection scenario has been carried out using the base case scenario model assuming a $KH = 8200$ mDm including the presence of the two shale layers. Results are shown in Fig. 10. Initially a purely generic, but realistic injection scenario including fluctuations and periods of no injection has been modeled, but for the sake of clarity the fluctuations have been taken out in Fig. 10 and an average injection rate of 1.1 Mt/year has been assumed. Injection has been continued at this rate until the maximum pressure of 350 bar, similar to the original pressure observed in the gas field.
was reached. In case of a period of 5 years injection, the BHP in the base case would increase to 250 bar, well below the original pressure. To corroborate the estimated total amount of CO₂ that can be injected, the simulation of the injection has been continued with the maximum BHP of 350 bar as a constraint. Using lower injection rates indeed a total amount of 8 Mt CO₂ could be injected with injection ending just before 2025. The corresponding pressure build-up profile is shown as well.

Fig. 11 shows the corresponding difference in BHP and average reservoir pressure in the near well region (i.e. average over the closest cells of the simulation model) for the various scenarios including the base case, high and low permeability cases and taking into account the presence or absence of the two shale layers. This leads to the six combinations reported in the graph. Note: that the influence of the shale layers is negligible. An overpressure of almost 20 bar is required in the worst case scenario.

The difference in required overpressure between the two (extreme) scenarios is in the order of a factor 2 at the start of the injection. In all cases no problems are foreseen for CO₂ injection with the BHP remaining well below the minimum horizontal stress.

The overall pressure in the reservoir at the end of injection will be lower than the original gas pressure in the reservoir prior to production.

4. Uncertainties identified and related monitoring program

4.1. Uncertainties identified

As indicated in the EC Opinion (2012) concerning the design license for permanent storage of CO₂ in the P18-4 field, no show-stoppers have been identified and the storage complex has been considered suitable based on the geological characterization. The EC confirms that a possible juxtaposition of reservoir versus non-reservoir intervals across the fault F3 separating the P18-4 field from the P15-9 field appears to be sealing and does not represent a significant risk factor for CO₂ plume migration. However, to further reduce uncertainity a reinterpretation of the fault using the 3D seismic datasets is recommended. The current interpretation is addressed in more detail hereafter.

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**Fig. 12.** (a) Arbitrary seismic line in map view crossing the F3 fault. (b) Interpretation on the seismic line crossing P15-9 (left) and P18-4 (right). (c) Possible reservoir juxtaposition.

A number of factors have been identified, that indicate integrity of fault F3 at least up to the current state of production:

1. The compositions of the gas produced from P15-9 and from P18-4 are different. The differences in composition are an indication, that no significant gas mixing has taken place over geological timescales.
2. The gas-water contacts (GWC) in P15-9 and P18-4 were different, indicating again no connection between the two fields.
3. The P15-9 field was depleted somewhat more rapidly than the P18-4 field. Hence, throughout depletion of both fields, the pressure in P15-9 was always lower than in P18-4. If the fault F3 between P15-9 and P18-4 were not sealing, one should observe a flow from P18-4 towards P15-9. Such flow from P18-4 towards
P15-9 would be visible in the respective P/Z plots. The P/Z plot for P15-9 would show an upward bending profile due to the gas influx. P18-4 P/Z would bend down due to outflow of gas. This is not at all visible from the P/Z plots. The lines appear very straight.

Moreover, the Lower Volpriehausen reservoir interval in P15-9, potentially connected to the Hardegsen reservoir in P18-4, has a very low permeability making the potential for migrating gas from one compartment to the other relatively small, at least on an operational timescale. Most likely the Volpriehausen will in such a case act as a side seal. Furthermore the two prominent shale layers of 1–2 m thickness observed at the top of the Volpriehausen, and a second one in the Detfurt formation, will act as a secondary barrier in case CO2 would enter the Volpriehausen in the P15-9 field. Finally one should note, that even in case CO2 would migrate into the P15-9 field, this imposes no significant risk, since P15-9 is also a reservoir which has demonstrated to be able to bear (natural) gas on geological timescales.

4.2. Monitoring plan

The envisaged monitoring approach for CO2 storage in the depleted P18-4 gas field builds on the results of the site characterization and the risk assessment. In principle the P18–4 reservoir has been classified as suitable for CO2 storage providing a stable long-term containment (EC Opinion, 2012). These conclusions are essentially based on the knowledge of the reservoir obtained during exploration and production of the fields, the low pressure in the reservoir being brought back to the most stable situation of hydrostatic pressure after ending the CO2 injection, the sealing capacity of the cap rock and the fact that natural gas has been contained in these reservoirs for millions of years. The monitoring system proposed is designed to verify CO2 containment and storage reservoir integrity, while the storage facility is operating and additionally to demonstrate long-term stability after the operational phase. This is achieved either by measuring the absence of any leakage through direct detection methods (for example at the wells), or by verifying indirectly that the CO2 is behaving as expected in the reservoir based on static and dynamic modeling and updating thereof corroborated by monitoring data (for example pressure measurements in the reservoir). The current monitoring plan does include therefore the collection of data such as representative storage pressures and annuli pressures, injected volumes and gas qualities, well integrity measurements and sea bottom measurements. As indicated in the EC Opinion (2012), an update to the existing monitoring plan will be submitted to the competent authorities before start of injection.

5. Discussion and conclusions

This paper provides an overview of the reservoir geology of the nearly depleted gas field P18–4 and first results of the assessment, whether CO2 storage in the P18–4 gas field is feasible. The porosity and permeability of the field are sufficient to inject the targeted amount of CO2 into the reservoir. Particularly the upper part of the reservoir, comprising the Hardegsen Formation and the Detfurt formation, has a good reservoir quality. The structural setting in combination with the presence of the gas trapped over geological timescales indicate the high quality sealing behavior of the bounding faults and of the cap rock. Faults are present, but most of the reservoir-bounding faults do not continue further upward into the overburden than the shales of the Altena Group.

Based on the current knowledge of the field, including the gas production history, no showstoppers have been identified and a positive opinion has been given by the EC in February 2012 on granting a storage license. The storage capacity of the reservoir is estimated at 8 Mt CO2. Injection rates up to 1.5 Mt/year should not lead to any problems, with required pressures well below estimated fracture thresholds. Currently activities are focused on refining the monitoring plan and to study in more detail geochemical, geomechanical and thermal effects on the reservoir rock and seal induced by the CO2 injection.

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