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Porthos CCS storage permit review

Final technical assessment and recommendations

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NORCE cannot be held liable for expert opinion provided if the Porthos project experiences anomalies that are due to operation outside of the envelope presented in the permit documents or due to factors that could not be reasonably predicted given the current state of knowledge for CO_2 storage operations and monitoring.

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1 Table of Contents

1 Purpose of this review

This report describes the expert review of the Porthos CO_2 storage application at the request of the Dutch State Supervision of Mines (SSM). The technical review has been carried out based on the reports provided: the main application and annexes. Some additional documents were obtained during the course of the contract in communication with SSM that provided additional clarification.

This report is centered around two primary review focus areas: (1) Reservoir behavior and risk identification; and (2) Role of reservoir monitoring and modelling. A secondary review focus was also addressed regarding impact assessment of leakage and role of relative pressure differences. This report represents a final assessment of the operational and monitoring plans that addresses questions within the primary and secondary focus areas requested by SSM. Recommendations for improvements in each focus area are provided based on the available knowledge.

The review is limited to assessment of the modeling approach and subsequent monitoring plans as they are presented in the permit documents. An independent verification of the modeling and analysis of results provided by the storage permit application is outside the scope of this work. In addition, our verification is limited to reviewing technical risks and safe operations with respect to the storage reservoir and seal integrity, while evaluation of risks related to human health and safety are not addressed herein.

The storage permit application and associated annexes is a lengthy set of documents, and it is not our intention to provide a line-by-line analysis. In our assessment, we examine if the storage permit application addresses the main questions related to storage risk in a technically sound manner, i.e. whether the approach taking by Porthos and the conclusions they reached on storage risk are based on the best available knowledge. The main permit application is predominantly a high-level summary that contained very little technical detail. We reviewed the annexes when necessary to understand the technical assumptions and underpinnings to the conclusions stated in the main permit application. In the event of inconsistencies, the main permit application is taken as predominant

In our assessment, we observed in several cases a lack of clarity regarding the underpinnings to conclusions of the Porthos application with regard to risk of leakage or undesired seismic events. In these cases, conclusions themselves are plausible based on the results shown, but it is more difficult to assess the validity based on the provided information related to parameter selection and model input. We have pointed out how this uncertainty could be reduced to bolster the conclusions and leave it up to SSM to determine if further details are to be obtained.

We emphasize that the assessment and subsequent recommendations provided in this review have been carried out based on NORCE expertise and on the best available knowledge in CO_2 storage. We note that there have been no full-scale CCS projects to date that have injected CO_2 into depleted gas reservoirs similar to Porthos where the extent of reservoir depletion is a major factor affecting reservoir cooling under CO_2 injection.

2 Executive Summary

The Porthos storage project is characterized by CO_2 injection into a depleted gas reservoir. Injected CO_2 will be stored in a closed structural trap that previously contained natural gas. The pressure depletion due to historic gas production is substantial and therefore the reservoir will undergo cooling due to Joule-Thomson effects. The reduction in temperature, although localized, will likely lead to thermal fractures. One focus of the Porthos permit application is understanding the thermal impacts on storage integrity risk through modeling and designing a monitoring plan. The main findings of this review can be summarized as follows.

Chapter 3: The Porthos permit application has followed an acceptable and reasonable approach to identifying, modeling and mitigating risks to storage integrity. Industry standard practices and tools are applied when available. The current understanding of the reservoir is a good as can be expected given that (a) there are limits on transferring reservoir understanding based solely on gas depletion to CO_2 injection with regard to thermal and seismic impacts and (b) there are no other existing CO_2 storage projects into substantially depleted gas reservoirs. Therefore, the true behavior of thermal fracturing and fault stability coupled to CO_2 injection is highly uncertain and can only be better constrained with monitoring data once storage operations have commenced.

Chapter 4: The core of the Porthos modeling-monitoring program for storage integrity is to measure pressure and temperature in the wellbore, which can be used to infer response of the reservoir to re-pressurization and cooling by applying the models. The bulk behavior of the reservoir can be followed sufficiently with this approach, i.e. the reservoir pressure at datum is maintained with the prescribed limits and the temperature limits are respected to ensure reservoir cooling does not propagate beyond the bounds determined by the modelling. However, the details of the evolution of thermal fractures in the reservoir/caprock and the impact of cooling on fault stability will be lacking. Microseismic monitoring can be a valuable addition in order to calibrate the thermal fracturing models and fault stability models and produce a high degree of uncertainty for the modeling-monitoring plan.

Chapter 5: The main feature of the Porthos application is the imposed upper limit on reservoir pressure of 351 bar at a prescribed datum (3,400 m). This limit is equal to the pressure in the hydrostatic surroundings and significantly lower than the virgin reservoir pressure (pre-production). Porthos argues that 351 bar is selected in order to maintain a pressure barrier with respect to the surroundings, and as such CO_2 cannot escape through any vertical leakage pathways that may evolve along wells, faults or through the caprock due to reservoir cooling. We find a major flaw in this argumentation and show that the choice of 351 bar at datum (3,400 m) will result in an overpressure of approximately 8 bar in the CO_2 fluid phase with respect to the surroundings at the shallowest depth in the reservoir (approx. 3,200). This implies that at the end of injection CO_2 will leak if a fracture or micro-annulus exists. There is also a risk that this overpressure will increase over time due to long-term equilibration with the surroundings, but this is secondary and highly uncertain. We recommend that the pressure limit be lowered in order to maintain the pressure barrier at all locations in the storage complex. Alternatively, Porthos may keep the 351 bar limit, but then a revised monitoring-modeling plan is needed to control for leakage to overlying water-bearing aquifers.

3 Reservoir behaviour and risk identification

3.1 Introduction and highlights

This chapter focuses on three subjects: a) The reservoir behaviour in response to the proposed CO_2 injection (fluid migration, pressure evolution), b) The impact of Joule-Thompson cooling effects due to the depressurization behaviour of CO_2 during injection in the reservoir, and (c) the caprock integrity in response to the fluid pressure, rock temperature and stress evolution.

The main questions addressed are:

1. Is the reservoir behaviour sufficiently understood for risk identification?
2. Are modelling assumptions and modelling predictions viable?
3. Are the risks for integrity of storage-complex (reservoir, caprock and faults) well identified?
4. Can the risk (leakage) be mitigated (operational measures) if failure of barrier is suspected?

We organized our response to these questions in sub-sections below. Our approach was to examine the permit documents holistically as there are many components involving geology, geophysics, geomechanics, reservoir engineering, numerical simulation, etc. that are combined to assess risk. We do not perform a line-by-line assessment, but rather highlight specific aspects that we found relevant for discussion. References to the annex (Bijlage) are made where necessary.

We note that our evaluation in this section is constrained by the assumption made by Porthos that a pressure barrier is maintained with respect to the reservoir surrounding at the end of injection. A pressure barrier implies that the direction of the pressure gradient, and therefore the direction of flow, is inwards into the reservoir from the surroundings. This assumption is based on the reference pressure being constrained to 351 bar at a datum depth of 3,400 m. Porthos argues that this operational bandwidth is sufficient to ensure that if or when a leakage pathway is created due to thermal effects, CO_2 cannot escape due to a pressure barrier created by the higher-pressure surroundings. (This is notwithstanding the exception of locally higher bottomhole pressure (BHP) at the wells during the later phase of injection which is temporary and limited in magnitude, see Stage 3, Figure 23, Bijlage 13 for more clarification). In this section, we focus on the methods, assumptions and conclusions regarding risk identification and mitigation if a pressure barrier was truly in place as assumed. We argue in Chapter 5 that this assumption is poorly grounded and provide a more detailed assessment and separate recommendation in that chapter.

3.1.1 Assessment highlights:

- We are generally convinced that all risks have been identified and characterized according to the best available knowledge.
- The analysis is kept simple when possible, while putting emphasis on complex modeling and simulation on the most important risks related to thermal effects.
- The assessment generally follows industry practice, commercial modeling tools are used, no red flags.
- We identified several shortcomings related to coupled thermal-hydro-mechanical (THM) modeling. This adds uncertainty to the Porthos modelling outcomes, but the impact of this

uncertainty on Porthos conclusions is difficult to judge given the highly nonlinear and complex behavior of coupled THM processes. That said, improving modelling by taking a more sophisticated approach is unlikely to resolve the general difficulties with predicting behavior of a geologic system without previous data under similar conditions. There is very little seismic activity and negligible thermal effects under gas depletion to help calibrate the models. Therefore, it is necessary to be cautious when interpreting the results as predictive, and to update the models as data are obtained under CO2 injection.

- In terms of monitoring data required to calibrate the THM models, Porthos has stated that well data (temperature and pressure) are sufficient for model calibration. We do not agree. Well data can indicate fracturing is occurring in the reservoir, but the fractures themselves cannot be calibrated uniquely from pressure/temperature data alone. In addition, pressure/temperature data are not sensitive to caprock breach or fault instability. A reliable calibration of thermal behavior is not feasible without additional data, such as microseismic data.
- The disjointed approach performed by several different parties does not build confidence that the Porthos team themselves have full control over all the components.

3.1.2 Recommendation Summary

Suggested recommendations:

- While we agree that the operational bandwidths are correctly defined to mitigate risk of leakage from the P-18 site, we nevertheless recommend that Porthos consider the added value of additional monitoring data, in particular microseismic monitoring, to calibrate the coupled thermal-geomechanical models. Sufficient calibration of these models is needed to understand and characterize the failure of the barriers with regard to fractures or fault stability. Better calibrated models can increase confidence that the operational limits on temperature continue to be valid and appropriate throughout the storage project. We emphasize that a loss of integrity by caprock breach or fault slip are themselves not an indication of leakage risk as long as a pressure barrier is maintained at the completion of the injection period. The well data (temperature and pressure) is sufficient to ensure that a pressure barrier is maintained and leakage is mitigated in the event of integrity loss.
- A major criticism is the lack of an integrated workflow connecting all the elements: flow modelling thermal modelling, geomechanical assessment, flow assurance, wellbore leakage, etc. that form the core of the risk assessment and mitigation planning. The workflow is clearly ad-hoc and reduces confidence. In the event of an anomaly or suspected failure, a main concern is the ability of Porthos to activate a workflow to identify the behavior and take remediative action, and to do so in a timely manner. The transfer of information between different components introduces user error which is very difficult to pick up. In addition, the plethora of different units used throughout the permit documents by itself would make it hard and error-prone to restart the process if and when needed. These hard to predict errors could be small or large. We suggest that the Porthos team build an integrated workflow that unifies the learnings into a single and simplified process that uses fewer disparate models, grids, and software. A process that is more streamlined will be easier to apply for understanding the source of anomalies if they occur.

3.2 Reservoir behaviour

Question: *Is the reservoir behaviour sufficiently understood for risk identification*?

Our assessment with regard to this question is strongly linked to the modelling assumptions and predictions discussed later in Section 3.3, which delves into more of the details on different components to reservoir behavior including pressure, fluid flow, thermal, geomechanical effects. However, here we have evaluated where Porthos has correctly identified risks from a high-level understanding of reservoir behavior.

Assessment:

- CO_2 storage into a depleted gas reservoir gives the advantage of a production history that allows for a higher level of understanding of reservoir behavior at the outset than for CO_2 storage in an untested saline aquifer. History matched models, reservoir response to depletion, behavior of faults are all aspects provide valuable information and gives a great deal of confidence to the prediction of the system under CO_2 storage.
- CO_2 storage in a closed structural trap leaves very little room for uncertainty as to where the CO_2 will migrate once injected into the reservoir, i.e. CO_2 will accumulate in the same way that natural gas was trapped for geologic time[1]. The closed storage setting of the P-18 site allows for a greater degree of flexibility in the approach to understanding reservoir behavior, which the Porthos project has rightly taken advantage of in performing their assessment of risk. For instance, there is no emphasis on the impact of heterogeneity on CO_2 flow as small variations in the rock permeability/porosity and associated properties will have little bearing on the eventual CO_2 accumulation in the structural trap. This reduces the complexity of the modeling and eliminates the need for many simulations exploring heterogeneity. Also, the choice to store CO_2 defined structural closure means there no possibility of CO_2 reaching a "spill point" and migrate away from the original structure into other zones that could incur more risk.
- The greatest risk in moving from gas production to CO_2 storage is the thermal effects due to injection of pressurized CO_2 into a low-pressure reservoir. Porthos was correct to address this issue thoroughly in a series of studies that identified and assessed the impact of thermal effects on risk of leakage and seismicity. Several modeling studies were performed. We agree that all risks due to cooling of the reservoir have been identified. Section 3.3.3 discusses in more detail the assumptions and predictions of the thermal modelling.

Recommendation:

- Risk identification has been satisfactorily performed. There are no shortcomings of significance at this high-level view.

[1] This is barring any leakage pathways introduced by operation of the field as both in gas production and in CO_2 storage. This aspect is addressed further later.

3.3 Modelling assumptions and predictions

This section addresses the question: *Are modelling assumptions and modelling predictions viable*? The review covers the following modeling components:

- Characterization of the storage complex
- Sub-surface modeling
- Thermal modeling
- Geomechanics and fault stability

An assessment and recommendation are provided for each component specifically.

3.3.1 Characterization of storage complex

The storage complex is described in Section II (chapter 2) of the Application Document, with additional information provided mainly in Annex (Bijlage) 7 (partly also in Annex 8). The documentation provides geological description of the region, the storage reservoir(s), the caprock and the overburden formations, including consideration of potential migration routes in case of CO_2 spilling or leakage.

Assessment*:* We find the characterization and documentation of the storage complex as a whole (i.e., application document + Appendix 7) is adequate and sufficient to qualify the complex for CO_2 storage. Relevant items are covered, and text and figures are sufficiently clear and understandable. Evaluations follow good industry standards. The evaluations are also backed by a wide-ranging set of references (Appendix 7).

Recommendations*:* For better completeness, an excerpt of "Migration paths" (Chapter 11 in Annex 7) could be included in the application document.

3.3.2 Sub-surface modelling

Sub-surface modelling in this context shall include:

- Construction of the geological framework based on seismic interpretations (of faults and surfaces) and well-log data (the static model).
- Assessment of petrophysical properties based on core measurements and well-log interpretation and distribution of such parameters within the storage reservoir.
- Establishment of dynamic (simulation) model(s) with up-scaling of reservoir parameters.
- Simulation of production history (history-matching) and forecasting of CO_2 storage performances.
- Well performance evaluations (injectivity)

The reservoir modelling is described in Chapter 3 of Section II in the Application document, and in Annex 8.

The static modelling is based on the Petrel (®Schlumberger) platform, while the dynamic modelling has been done in two versions:

- Eclipse 300 (®Schlumberger) for history-matching and isothermal forecasting (at initial reservoir temperature)
- GEM (®Computer Modelling Group) for forecasting included temperature effects.

In addition to the static and dynamic modelling, reservoir volumetric analyses have been verified using industry recognized P/Z curves.

Assessment: The sub-surface modeling has been performed based on well-established software applications and done in accordance with industry practice. The CO_2 trapping assessment tool (PetroCharge Express of IES) used in the CO_2 migration analysis is unknown to us, and we are thus not in the position to qualify its applicability. The potential migration routes in case of spilling (due to overfilling), leakage through faults and/or leakage along wells have however been properly identified and evaluated.

Formations, faults and compartments are adequately described and illustrated. The resolution of the geological structure grid of 50 by 50 m laterally and an average of approximately 4 m vertically in the key formations appears adequate for capturing the main heterogeneities, taking well spacing and inherent parameter distribution uncertainty into account.

Even though the sub-surface evaluations are of lesser details than one would expect for an oil and gas greenfield (or brownfield) development, we consider it fit for the purpose of a CO_2 storage project.

The reservoir parameters have been distributed using statistical Kriging (a well-recognized industry practice). It appears though that only one realization of the reservoir has been brought forward to the dynamic modelling, history matched and used for further evaluation. Ideally, a few more realizations could have been tested, at least through the history matching, potentially giving more credibility to the realization selected. However, taking the long production history into account, and the fact that reservoir volume by compartment will be the main history-matching parameter for this field type, it's unlikely that an alternative realization would bring along another conclusion with respect to the quality and feasibility of the reservoir as a CO_2 storage.

The quality of the presented history-match is acceptable. Using volume multipliers on regional (compartment) basis is commonplace, but the multiplier used for Compartment III (P-18-2-A6ST1) of 0.75 is a bit excessive. A common range is between 0.9 and 1.1, however numbers outside of this range are possible in consultation with a reservoir geologist. Moving the seemingly arbitrary placed artificial barrier (Intra_3)) between Compartment III and IV would be more credible (Application Document, Section II, Figure 7). However, since Compartment III is considered to be isolated and for now is not included for storage, this is not a vital issue.

Only one PLT is reported – taken in P18-2-A5S1 well (no mentioning of date), upon which the overall balance of reservoir quality (permeability-thickness values) between formations appears to have been tuned. This may be considered a weakness in the reservoir qualification, as monitoring of the CO_2 distribution is part of reservoir surveillance plan and may also be important in view of calculation temperature distribution and thermal effects.

There appears to be some level of inconsistency between the dynamic modelling work presented in the Application Document compared to the report given in Annex 8. This applies to the modelling software used (GEM vs Eclipse 300), and also to the settings of well performance (injectivity indices).

The well performance (productivity/injectivity) evaluations are reported in Annex 9 and only briefly mentioned in the Application Document. The evaluations are mainly done by pressure transient analysis (PTA), using the well-known Saphir software (®Kappa), an industry standard approach. Both analytical and numerical methods have been applied. The behavior of the pressure transients is explained by the presence of high permeability sand lenses in the vicinity of the wells. We are somewhat hesitant to this explanation, as in our opinion (based on a quick look) the PTA derivative might just as well signify nearby flow barriers (e.g. sub-seismic faults). However, being one or the other or combination of both, we find it hard to believe that this will be a significant issue with respect to well capacity conclusions.

The PTAs and the following inflow performance (IPR) analyses (multi-rate tests) and Rate Transient Analysis (RTA) indicate some variation in well skin factor over the production history, which could be due to condensate banking and/or precipitation of fine in well vicinity. However, the variation is not severe and should not cause concern. Any condensate in the vicinity of the wells should be rapidly dissolved and removed once the CO_2 injection starts.

The well injectivity calculations have only been done for high temperature (60 °C), not for the low temperature (15-20 °C) likely to occur during the transition from gas phase to dense phase injection. Even though this shall not alter any conclusions, we believe it should be done for sake of completeness. Beyond that, we support the steps taken to quantify and qualify the well injection performances and concur with the conclusion that sufficient well capacity is available to meet the CO_2 supply.

Recommendations: In order to enhance the reservoir models with respect to the reservoir quality and injectivity in the different formations, and thus be in a better position to estimate the distribution of the CO_2 plume, we recommend a PLT (Production Logging Tool) program be included in the Monitoring Plan.

Care should be taken to ensure collection of sufficient downhole pressure, temperature and rate data to enable transient pressure analyses of planned (and sporadic) well shut-ins, and potentially also well start-ups. All pressure and temperature records (or at least a representative sub-set) should be kept on file for the duration of the project to enable time-laps analyses in order to potentially reveal any dynamic changes to the reservoirs structure and/or properties as cooling and pressure increase take place. Proper pressure, temperature and rate measurements on individual well basis are instrumental in maintenance of the dynamic reservoir models and thus the monitoring of the CO_2 storage.

For sake of completeness a well injectivity calculation (Prosper software) for the low pressure, low temperature (e.g. 30 bar, 20 °C) should also be presented.

The well injectivity evaluations presented in Annex 9 should be more elaborated/documented in the Application Document.

A more uniform presentation of the dynamic modeling between the Application Document and the Annexes would ease the understanding and assessment of results.

To ease the reader's understanding of the well performance evaluations described in Annex 9, the Forchheimer model (equation) used in the evaluations should be stated in the text.

3.3.3 Thermal modelling

The thermal modelling is presented in several documents (in varying details) and the results and implications summarized in the Application Document. This spreading of information over many documents has made it challenging (and time consuming) to make a comprehensive review.

Thermal modeling is based on the industry standard GEM (®CMG) software including the Barton-Bandis fracture model for simulation of thermal induced fracturing. Temperature modelling has also been done using the TOUGH2 simulator (Annex 8) to demonstrate the near well temperature development during the low temperature injection period, including cooling of the overburden above the injection point.

Assessment: The GEM simulation software and the Barton-Bandis model are recognized tools for reservoir temperature modelling and thermal induced fracture propagation.

The modelling set-up and simulation procedures seem adequate with respect to the reservoir at hand and band-width injection in terms of rates and pressures.

The scenarios study appears only to include high temperature (40+ °C) injection while the flow assurance evaluations (FAS) indicate that low temperature injection (15-20 °C) may persist over a long time (years) during the transition period as envisioned in figure 40 in Section III of the Application document. We believe this low temperature period should be considered in the simulations, or at the least discussed in the documentation if believed for any reason to be irrelevant. The TOUGH2 simulations presented in Figure 6-14 in Annex 7 – even though using a somewhat excessive rate 1.13 Mt/year (35 kg/s) for the transition period – indicate that low temperature (20 °C) may be in a radius up to 100+ m from the injector and 10+ m into the overburden.

The map of temperature at end of injection presented in Figure 17 in Section II of the Application Document, showing very low (15 °C) temperature around injectors, seems to be inconsistent with temperature modelling presented elsewhere (in Annexes).

Even though covering a relevant range of injection scenarios, sensitivities to a wider selection of geo-mechanical properties could have been studied, enhancing the credibility of the evaluations. In the thermal simulations presented, only two geo-mechanical properties are varied, i.e. Biot Coefficient and Poisson Ratio (Annex 12, Table 4), and these also within fairly narrow ranges compared to the uncertainty range presented in Table 2 (Annex 12). For instance, the rock heat capacity and thermal conductivity, which should be relevant for the calculation of temperature distribution, are kept constant at 1000 J/(Kg·K), and 2 (W/m·K) respectively. The heat capacity may vary between 850 – 1000 J/kgK . A lower rock heat capacity will lead to stronger cooling effects. Thermal conductivities measured on sandstone samples form Norwegian Shelf varied from 2.0 W/mK and 4.3 W/mK (Midttømme 1997) higher thermal conductivities will increase the heat flow and prevent critical low temperatures.

We also notice that Young's modulus and the Poisson's ratio included in Table 2 (Annex 12) are somewhat different to those presented in Annex 14 (Core Test Evaluation) and in the supplementary material. Also, the rock heat capacity, heat conductivity and thermal expansion coefficient is said to be measured, but no documentation has been found.

Recommendations: Downhole pressure and temperature recording facility of sufficient quality and frequency should be in installed in order to detect eventual onset of thermal fracturing and evaluate the longer-term development of fracture propagation and general well performance.

The thermal fracture modelling should also be done using the low temperature (e.g. 15-20 °C) injection taking place during the transition period. As a minimum the potential effect of such injection should be elaborated.

Evaluation (simulation) of sensitivity to heat related coefficients such as heat capacity, conductivity, and thermal expansion would increase the credibility of the thermal modelling.

The temperature map shown in Figure 17 in Section II of the Application Document shows a very different temperature from those presented in other reports. An explanation or elaboration should be warranted.

3.3.4 Geomechanics and fault stability and caprock breach

The geomechanics of the storage complex (reservoir and caprock) has been studied by coupling the results of the thermal (and stress) modelling in GEM with finite element modelling (FEM) of the in-situ stress development using COMSOL (a recognized tool for this purpose). The results are reported in Annex 12, in Chapter 3 of Section II in the application document, and in supplementary document: "Geomechanical study of fault Stability and Caprock breach in P18 during planned CO2 injection".

Assessment:

Generally speaking, the various aspects and risk of fault destabilization and caprock breach seem to have been thoroughly considered, modelled, simulated, discussed, and concluded.

Modeling choice and assumptions: The dual-permeability thermal modeling used to model thermal fractures in the reservoir (Section 4.3.3) failed when applied to model caprock breach. In addition, GEM is less suited to model stress changes in the over- and underburden due to depletion and injection. This led Porthos to take a different approach, which was to couple the results of the GEM dynamic modelling for pressure and temperature with COMSOL FEM for geomechanics. We generally concur that this approach can be suitable, but the reasoning behind the choice to couple GEM to COMSOL was not at all discussed. It should be noted that coupling of thermal-hydro-mechanical (THM) behavior for multiphase/multicomponent fluid systems with the potential for thermal fracturing is a challenging research topic that has not been fully resolved by the research community. It is not clear if Porthos considered other approaches, such as TOUGH2-FLAC3D (LBNL) or CODE_BRIGHT (UPC) that are integrated simulators and have been developed by top experts in the field. COMSOL has been used to perform the fully coupled THM problem applied to CO2 storage at In Salah (Bjørnarå et al. 2010). However, we realize this approach requires expertise to ensure the accuracy of flow simulations in COMSOL FEM that is usually beyond a typical engineer's capability.

We recognize that the added challenges of the P-18 site with regard to existing hydrocarbons, and therefore GEM is a reasonable choice for the compositional modelling. Another advantage is the familiarity of GEM to petroleum engineers compared to other specialized codes (and the ability to reuse previous simulation results is also attractive). But while GEM and COMSOL are both established simulators in their own right, the chosen THM coupling is in a way "novel" (we are not aware of any previous application of this particular coupling) it is therefore not clear if this approach has been benchmarked with other tested THM simulators for a simpler problem (e.g. one of the mentioned above). We do not believe the Porthos coupled approach is state-of-the-art, which may be still sufficient if this can be shown by comparison with a more sophisticated approach. A discussion of modeling choices, pros and cons, is warranted given the highly challenging nature of coupled THM modeling.

With any THM modeling choice there will be errors, but these should be understood and acknowledged. This discussion is lacking from the Porthos documents. One weakness was identified by the authors, which is the lack of back-coupling or feedback of the more precise FEM stress calculation to the dynamic modelling. Doing a fully back-coupled exercise for one or two of the most critical cases could enhance the confidence of the evaluations. But given the highly uncertain nature of coupled THM modeling in general, this back-coupling may not add much value given (a) uncertainties in thermal/mechanical parameters, and (b) the above-mentioned issues with coupling two separate simulators in a novel way.

To conclude the discussion of modeling choices and assumptions, there are several weaknesses that could be improved by consulting expertise in THM simulation. However, a more sophisticated THM approach may likely not resolve the underlying uncertainty with regard to modeling a very complex set of processes involved in thermal fracturing and fault stability. State-of-the-art THM modeling is only an approximation of the real system, and the true behavior is unknown. Although this can be said about any model, this uncertainty is acute for THM since the presence of minute imperfections in the rock can affect fracturing in ways not yet fully understood. In addition, the P-18 reservoir will be subject to entirely different temperature regime and stress path under CO2 injection than existed during completion, and its response can never be certain.

Therefore, the best way to understand the quality of the modeling is by observing reservoir behavior and testing the model against the observations during the injection phase. However, the reliance on solely temperature and pressure data in the wells is dubious. If a pressure signal indicates fracturing, then the fracture size should be monitored. The Fenics 2020 report acknowledges (p46, Bijlage 12) that "It may be feasible to infer fracture size from the injectivity, but the pressure behavior is likely insensitive to fracture size and the usual method of inferring fracture size from pressure fall-offs is complicated by the phase behavior of the CO2." Microseismicity monitoring can be used to localize fracture evolution and help to calibrate the models.

In terms of caprock breach, monitoring pressure and temperature will not indicate fracture height. We do not agree with the statement (p46, Bijlage 12) that "the initiation of a thermal fracture can be observed from the fall in injection pressure" A caprock breach will have a negligible impact on injectivity as the caprock matrix is nearly impermeable and fracture volumes are small. There will not be a detectable pressure signal to which the models can be calibrated, and any slight signal will be overwhelmed by thermal fracturing in the reservoir. Microseismic monitoring is a more feasible approach to calibrate the models in the event of thermal fractures in the caprock.

Input parameters: The essential input parameters for the stress simulations are listed and commented upon in Table 2 of Annex 12. Although the sensitivity ranges simulated appear reasonable, we are somewhat worried the full uncertainty range has not been covered for some parameters, especially the scenario with high thermal expansion coefficient, high Young's modulus, low heat capacity, high vertical stress and low least radial stress. Our advice would be to vary groups of parameters rather than the individual numbers to clarify what would be the 'base case' and 'worst case' scenario. Even though a complete uncertainty range may not have been covered, we are of the opinion that the worst-case scenario has sufficient safety margin to sustain the conclusion of safe storage with respect to fault stability and caprock breach.

Overall, based on the modelling and analysis reported we consider the reservoir formations themselves fully suitable for permanent underground CO_2 storage. The CO_2 injection should not have any negative impact on the reservoir rock itself, and any thermal induced fracturing should lead to improved injectivity and enhance the flexibility in well utilization.

The role of thermal fracturing in conducting the cooling effect of CO_2 injection towards important faults and caprock appears well understood and properly modelled (with caveats discussed above). Like for the thermal modelling we observe that stress modelling appears only been done for "high" temperature injection situation, while the low temperature injection caused by Joule-Thompson effect seem to have been ignored.

Although we find the fault stability modelling approach (Mohr-Coulomb) suitable, we see the documentation of this study somewhat vague, with lack of clarity on the input used for the various scenarios. It is for instance dubious how the base case and worst case are defined. Important information such as fault dip angle is no found – only the variation used (± 10°) used in sensitivities is stated. It would thus be difficult if not impossible to replicate the modelling based on the information provided.

The calculations indicate that fault cohesion must be in the order of 50 bar or more to avoid seismicity above M=2 during depletion. As acknowledged by the authors, this parameter has significant uncertainty as it is not possible to obtain values by direct measurement and the lack of seismicity observations being the ground for estimations are not fully understood. The comparison with cohesion of intact rock (200 bar) is not very relevant. Even though the likelihood of fault activation caused by local cooling is deemed low and will be further reduced as the reservoir pore-pressure is increased, and an eventual fault destabilization not necessary being crucial for the total integrity of the storage complex, we still believe that adequate monitoring to detect such events should be implemented.

The caprock integrity is only evaluated for the P18-2-A1 well area, claiming it to be the most hazardous area in terms of injection pressure and caprock cooling. Based on other reports, the P18-2-A5 well appears to give the strongest cooling effect to overburden, while the pressure effect being similar. However, NORCE agrees with the outcome of the evaluation that the cooling of the overburden, and thus the potential of thermal fracturing, will only propagate a few 10's of meters into the caprock and thus pose no risk of caprock breach.

Recommendations: The period of low temperature injection should be included in the simulations, or at least elaborated upon in the documentation.

Even though it might not modify any conclusion, geomechanics simulations with a lower rock heat capacity (e.g. 700 – 800 J/(Kg·K) could enhance the credibility of the evaluations.

Recognizing the relatively strong cohesion value (50 bar) required to maintain local fault stability during reservoir depletion, and the poor understanding of this phenomenon, an acoustic surveillance to detect eventual fault destabilization – particularly in the P18-2-A1 well – should be implemented.

Modeling uncertainties are unresolvable with today's simulation and the best approach to having more confidence in the history matching calibration is to have additional seismicity monitoring.

3.4 Risk identification

Are the risks for integrity of storage-complex (reservoir, caprock and faults) well identified?

Porthos has properly identified the risks to integrity in the documentation provided, and we do not see any other risk possibilities than those covered by the study reports.

Based on the available documentation, combined with NORCE's own expertise, experience, and judgment, we consider any essential leakage out of the storage complex, within a human timescale, highly unlikely given that a pressure barrier is maintained with respect to the surroundings.

The risk of seismicity has been identified and assessed to be unlikely. The reasoning is based on an assessment that indicates a previously quiet seismic behavior is a good indication that future behavior will be similar. However, the lack of seismic activity is bit of mystery that could be illuminated with micro-seismic data. The lack of data is also a disadvantage in terms of effective calibration of fault stability models. We recommend microseismic monitoring not for early warning but for learnings about fault stability when storing CO_2 into depleted gas reservoirs.

However, beyond the CO_2 storage demonstration pilot done in the Lacq field (2010-2012), this project of storing CO_2 in a depleted gas field, with very low starting pressure of estimated 20 bar, is as far as we know a first of its kind on world basis. Unforeseen behavior may therefore not be ruled out.

3.5 Mitigation measures

Can the risk (leakage) be mitigated (operational measures) if failure of barrier is suspected?

A crucial aspect of this CO_2 storage project is that injection will be into a pressure-depleted reservoir for the whole injection period. Any leakage out of the storage compartments will thus not be conceivable before the end of injection. Leakage could be potentially triggered by aquifer activation, tectonic settings or other mechanisms causing the pressure at the top of the CO_2 column to exceed the hydrostatic pressure of the surrounding, combined with a leakage pathway created by effects of injection.

As for the current state of technology there are no realistic corrective measures for the long-term leakage risk along faults and fractures, except controlled back production of the CO_2 to lower the reservoir pressure. As this project is the first of its kind, it is difficult to calibrate the models to fully exclude the possibility of long-term leakage (see 3.3.4). It is therefore important that additional monitoring systems, as acoustic surveillance to detect induced seismicity be implemented (refer to Chapter 4), such that the THM-fracturing models can be calibrated with more confidence. Better understanding of thermal impacts, i.e. fracturing, under CO_2 injection, which is a new setting than previously seen, could be valuable for reducing uncertainties and mitigate issues that are unforeseen with today's technology.

We also recommend that one of the injectors be converted to a monitoring well instead of plugged and abandoned so that long-term reservoir pressure changes due to aquifer activation can be monitored (see Chapter 5 for further discussion on this point).

References

Bjørnarå et al. 2010. Modeling CO_2 storage Using Coupled Reservoir-Geomechanical Analysis. https://www.comsol.com/paper/modeling-co-sub-2-sub-storage-using-coupled-reservoir-geomechanical-analysis-8822

4 Role of Reservoir Monitoring and Modeling

4.1 Introduction and highlights

This section focuses on the following aspects: (a) Use of monitoring data (in well, via distributed sensing technologies (DxS) using fiber optics and pressure gauge) as input to models, (b) Use of reservoir, geophysical and geomechanical models for indirect monitoring and early warning for risk mitigation (leakage or seismicity), (c) Substantiation and use of operational bandwidths (e.g. temperature range and maximum pressures).

The main questions addressed are:

1. Are the bandwidths from the models clearly explained, adequate for safe operation and uncertainties sufficiently taken into account?
2. Is the monitoring-and-modelling practically feasible, in the sense that operation within the reservoir bandwidths can be checked?
3. Is the monitoring-and-modelling suitable for early warning on the failure of barriers?
4. Is the monitoring-and-modelling suitable for determining actual CO_2-migration and leakage?

These questions concern both modeling and monitoring. As the former has been addressed thoroughly in Chapter 3, we focus the details of this assessment on the latter. References to the annex (Bijlage) are made where necessary.

As in Chapter 3, our assessment and recommendations are constrained by the assumption made by Porthos that a negative pressure gradient is maintained at all locations in the reservoir at the end of injection by maintaining a reservoir pressure of 351 bar at datum depth. In this section, our assessment is conditioned on the assumption that a pressure barrier is truly in place. Later in Chapter 5, we argue that this assumption is poorly grounded and provide a more detailed assessment and separate recommendation in that chapter. We note that further advice on operational bandwidths and recommended monitoring is given in Chapter 5.

4.1.1 Assessment highlights

- The monitoring plan provided is only a draft monitoring plan, and as such lacks many details with regard to the design, installation and operation of the monitoring equipment. The planned monitoring is sufficient for safe operation of the injections, but it will not fulfill the criteria set in Article 29 of the Mining Decree for monitoring the CO_2 in the reservoir.
- The monitoring plan is based on modeling and understanding of reservoir behavior due to CO_2 injection into a closed, pressure-depleted storage reservoir. As discussed in Section 3.2, there is very little uncertainty on the movement of CO_2 within the reservoir, i.e. CO_2 will accumulate in the same structural trap occupied previously by methane. As such, there is very little added value from extensive monitoring of CO_2 migration *within the reservoir* for the purpose of risk of leakage.
- *Is the monitoring-and-modelling practically feasible, in the sense that operation within the reservoir bandwidths can be checked?* The models have shown that thermal effects are the largest risk to leakage and/or seismic activity, and our assessment thereof is found in the previous chapter. Thermal fracturing will more than likely occur within the reservoir due to the unavoidably strong cooling, but thermal fracturing (refer to earlier assessment) in and of itself is not a detriment to the project. The modeling has shown that maintaining an injection temperature and pressure within defined bandwidths (which are largely determined by flow assurance) is sufficient to ensure that fracturing will not lead to unwanted effects in the caprock nor at faults. We conclude the bandwidths from the models are clearly explained, adequate for safe operation and uncertainties sufficiently taken into account. Therefore, the main purpose of monitoring is to ensure that operational bandwidths are respected during the course of the project.
- *Is the monitoring-and-modelling practically feasible, in the sense that operation within the reservoir bandwidths can be checked?* It is worth pointing out that temperature is by and large the most important controlling parameter connected to risk. The monitoring plan will monitor downhole temperature, which is the sole means of observing temperature (indirectly) in the reservoir. The technical feasibility of downhole temperature monitoring is well established, assuming the equipment is installed and operated according to best practice. However, we highlight that the temperature and pressure is measured up to the packer and not beyond.
- *Is the monitoring-and-modelling suitable for early warning on the failure of barriers?* In this assessment we include the reservoir/caprock system. Well integrity is not included. The concept of early warning for a reservoir/caprock system is very dependent on the process under consideration.
- Here, we interpret failure of the barriers first to mean that a caprock breach has occurred or fault stability compromised. The leakage question is addressed further below. Porthos proposes to combine well pressure and temperature monitoring with modeling to give an early warning of a barrier failure. We do not fully agree. As discussed in Section 3.3.4, we are concerned that the uncertainties and weaknesses of the coupled thermal-hydro-mechanical modeling approach, the inability to calibrate fracture extent from well pressure and temperature data alone, and the lack of previous seismic data to calibrate

the fault stability modeling, additional monitoring data is needed for early warning of a caprock breach or fault slip. We emphasize (as Porthos has) that these failures do not necessary lead to leakage if a pressure barrier is maintained, but the suitability of the monitoring-modeling for leakage detection is addressed below.

- *Is the monitoring-and-modelling suitable for determining actual CO2-migration and leakage?* Through modeling of CO_2 migration (Fig 13, kap 3.4.2) and understanding the storage setting, Porthos has concluded that monitoring the actual CO_2 migration in the reservoir is non-essential for ensuring a safe operation. We agree with this conclusion. As such, leakage cannot be detected or imaged directly from the reservoir itself and expected leakage rates if they occur through microannuli would be too slow to detect. The option to monitor overlying aquifers is one way to monitor directly for leakage if a pressure barrier is not maintained, and we discuss this further in Section 5. Our assessment is that the monitoring-and-modelling is suitable for determining leakage with respect to checking that operation is within the bandwidths and that a pressure barrier is maintained. Leakage is very unlikely to occur so long as these criteria are met. It must be a very strong signal in temperature and pressure to distinguish a leakage from normal flow inside the reservoir that do not pose a risk of leakage.
- DAS technology can be deployed for monitoring flow of CO_2 through microannuli as well as for microseismic events. Detecting microseismic events are needed to meet the requirements of Annex II of the CCS Directive in a) detecting significant irregularities e) assessing the effectiveness of any corrective actions taken and f) updating the assessment of the safety and integrity of the storage complex in the short and long term including the assessment of whether the stored CO2 will be completely and permanently contained DAS technology has improved significantly recently (ex by use of helical fiber) and it is recommended to investigate additional passive and active applications for use of DAS.

4.1.2 Recommendation summary:

Critical recommendations:

- It is expected that a detailed plan is produced that addresses specific aspects described in more detail in the following sub-sections.

Suggested recommendations

- Although the modeling has shown that seismic risk is negligible, it is curious to the expert team why the DAS equipment that is planned should not be deployed to monitor for seismic activity. We emphasize that expanded microseismic monitoring based on the planned installation that we recommend would not be for the purposes of "early warning" or leakage mitigation but for the valuable learnings that could be gained. As the first-of-its-kind industrial-scale storage injection into a severely pressure depleted gas reservoir, the Porthos project is a valuable opportunity to learn more about mechanisms such as fault stability and thermal fracturing, both of which are very active areas of research both for CCS and other subsurface applications such as geothermal energy. We highly recommend the Porthos project team up with a research organization to carry out additional seismic monitoring, perhaps with external funding. A flagship project such as

Porthos has the opportunity to share unique data with the CO_2 storage community, whose research effort the operators have surely benefited from in designing this project.

- In order to enhance the reservoir models with respect to the reservoir quality and injectivity in the different formations (as discussed in 3.3.2), and thus be in a better position to estimate the distribution of the CO_2 plume, we recommend a PLT (Production Logging Tool) program be included in the Monitoring Plan.

4.2 Monitoring assumptions and plan

4.2.1 Draft Monitoring Plan

Monitoring is described in Draft Monitoring Plan. Section IV: Monitoring Plan for the Integral P18 storage complex. According to the Draft Plan the monitoring shall cover:

- regular monitoring for general operations
- regular monitoring for risk management
- monitoring carried out in the undesirable event of significant irregularities.

The draft of the Monitoring Plan shall meet the requirements of Annex, part 1 of the CCS Directive and aims at

a. Comparing the actual and the modelled behaviour of the CO_2 and other stored substances as well as the formation water in the site
b. Detecting significant irregularities
c. Detecting CO_2 and other substances
d. Detecting significant adverse effects on the surrounding environment, including in particular on drinking water, on human populations, or on users of the surrounding biosphere.
e. Assessing the effectiveness of any corrective actions taken
f. Updating the assessment of the safety and integrity of the storage complex in the short and long term, including the assessment of whether the stored CO_2 will be completely and permanently contained.

The injection of CO_2 into the P18 reservoir is divided into four phases

- Pre-injection
- Operational phase
- Post-injection phase
- Post closure and transfer of responsibility

Chapter 4 is divided in the four monitoring sub-areas used in the Draft Monitoring Plan.

- Operational
- Distribution of CO_2 in the reservoir
- Leakage paths.
- Surrounding area and the environment.

<u>Assessment</u>: The Draft Monitoring Plan assumes monitoring of the storage complex integrity by downhole pressure and temperature measurements. We find this to be an acceptable approach.

As long as the project keeps injection rates within the operational bandwidth suggested, modelling results show that pressure buildup and propagation stay below critical and that the chance of unwanted fracturing of the caprock or reactivation of faults is negligible.

The Draft Monitoring Plan also states an ambition to monitor CO_2 plume movement as well as potential effects of the injection on the surrounding environment, but does not present a plan how this will be done. As such information is not mandatory from a safety risk perspective, we think it is acceptable that this will be developed at a later stage.

Recommendations: In our opinion, information about plume movement may help the operator to optimize injection and operations and that a plan for subsurface imaging would strengthen the application document.

4.2.2 Monitoring of sub-area Operational

Sub area Operational is all measured parameters that are necessary to continue operating within the operational limits of the system. The continuous measurements also serve as input to the process control with the aim of remaining within the defined operating envelope.

Assessment: The monitoring parameters and technologies for the operational sub area are shown in Table 5 in the Draft Monitoring Plan. All monitoring is planned only in the injection phase according to Table 5 (Wellhead pressure and temperature is also included in the post-injection phase in Table 7).

By normal monitoring of Porthos the purposed monitoring should be sufficient to fulfill the objectives in the operational phase

- To keep the composition of the CO_2 to be injected within predefined margins
- To keep the injection temperature and pressures in the wells within predefined bandwidths
- To record flow measurements based on which a mass balance is prepared annually to track down any deviations that might indicate the migration away of CO_2
- To check the integrity of the system of wells by monitoring annular pressures

Distributed Temperature Sensing DTS

It is not described how the fiber for DTS will be installed in the well. In loop is preferable since a single cable need to be calibrated in the bottom of the well in addition to the temperature sensor at the wellhead.

Recommendations: It will give valuable information to start the DTS in the pre-injection phase. The baseline temperature measurement will detect temperature anomalies caused by groundwater zones or variation in thermal conductivities and/or temperature variation due to installation of the fiber and coupling to the tubing.

4.2.3 Monitoring sub-area Distribution of CO_2 in the reservoir:

Distribution of CO_2 in the reservoir: within this come the measured parameters that are used to detect whether the behaviour of the CO_2 injected into the reservoir and of the reservoir itself are in line with the behaviour predicted based on the dynamic and geomechanical models.

Assessment: Distribution of CO_2 in the reservoir will be monitored by bottom hole pressure measurement and DTS in the well. This will be performed once a year in injection during temporary containment of the well and in the post-injection phase. In case of irregularities in pressure and temperature, a monitoring program with stepwise stabilizing the bottom hole pressure and temperature will be performed

4D seismic is investigated for monitoring the plume distribution in an additional document but concluded that it might be challenging to detect the CO_2 plume in the reservoir.

The planned monitoring is sufficient for safe operation of the injections, but there are some technical limitations that we have flagged with respect to different elements of the Mining decree

a. *"Comparing the actual and the modelled behaviour of the CO_2 and other stored substances as well as the formation water in the site"* Since there are no direct information of the CO2 in the reservoir the modelled behaviour of the CO2 in the reservoir cannot be verified
b. "*Detecting significant irregularities"* Irregularities in the CO2 behavior and distribution in the reservoir cannot be detected
c. *"Detecting CO_2 and other substances"* CO2 in the reservoir is not directly monitored and thereby not detected
d. *Detecting significant adverse effects on the surrounding environment, including in particular on drinking water, on human populations, or on users of the surrounding biosphere*. OK
e. *Assessing the effectiveness of any corrective actions taken.* The effectiveness of any corrective actions on the CO2 behavior and distribution in the storage cannot be assessed
f. *Updating the assessment of the safety and integrity of the storage complex in the short and long term, including the assessment of whether the stored CO_2 will be completely and permanently contained.* The assessment of the safety and integrity of the storage complex in the short and long term cannot be updated

With reference to the draft monitoring plan the CO_2 plume distribution in the reservoir will not be monitored directly and the modelled behavior of the CO_2 cannot be verified nor detect significant irregularities in the CO_2 flow and pathways *in the reservoir*. However, as described in Section 3, the closed structural trap of the P-18 site and operational conditions chosen by the Porthos project imply that detailed knowledge of CO_2 flowpaths in the reservoir is not necessary to carry out the storage project with respect to risk mitigation. There is little doubt that in the absence of vertical pathways induced by thermal or geomechanical effects, CO_2 will accumulate in the same structure that the original gas occupied.

However, without a more direct approach to monitoring CO_2 movement in the reservoir it will be difficult to optimize the injection due to storage capacity without information of the CO_2 plume distribution and flow in the reservoir.

In addition, the draft monitoring plan stated that the choice of monitoring technology shall be based on the best practices available at the time of design regarding

b)) Technologies that can provide information on the pressure-volume behavior and the distribution in horizontal and vertical directions of the CO_2 plume in the reservoir, more specifically, to refine the numerical 3D simulation on the 3D geological models of the reservoirs elaborated pursuant to Article 4 and Annex I of the CCS Directive.

Recommendations: Combined 4D – gravity and seafloor- deformation surveys are a mature technology for geophysical monitoring of offshore reservoirs (Lien et al.2017) and has successfully been used for monitoring the CO_2 plumes at Sleipner (Ruiz et al 2017) and Snøhvit (Ruiz et al 2020) CO_2 storage projects. The learnings from these studies, although performed in saline aquifers, could be transferred to the Porthos project with further investigation. We would recommend 4D gravity and seafloor deformation survey to considered for the Porthos project. It is important to know the distribution of CO_2 e.g in relation to where the microseismic events occurs in the event there is any uncertainty in the modeled behavior.

4.2.4 Monitoring sub-area Leakage paths and integrity

Leakage paths: within this come the activities that are carried out to monitor the potential leakage paths identified in the risk analysis.

Assessment: Normal monitoring for leakage paths and integrity is shown in Table 5 in the Draft Monitoring Plan. Near well leakage and well integrity is focused. In addition to the draft monitoring plan, 4D seismic is considered to monitor leakage to the above Rijnland group.

The monitoring is sufficient for safe monitoring of leakage paths and integrity.

DAS

Since DAS will be installed the DAS fiber can also be used for passive monitoring of microseismic events and it is recommended to consider investigating this possibility. Then DAS need to be recorded continuously. More details of the Microseismic events may be used for risk assessment and seal integrity and to indicate the plume distribution in the reservoir.

Monitoring of microseismic events by downholes geophones is successfully performed at Illinois Basin-Decatur CCS project (Goertz-Allman et al., 2017) . The experience is that noise from the CO_2 injections is lower than from oil and gas production and has low impact on the detection of microseismic events.

4D seismic

Even though the risk for leakage from the reservoir is microscopic, industry standard 4D seismic survey could be used to detect leakage not only in the Rijnland group, but also follow the underground CO_2 flow if leakage occurs. There is additional discussion on recommendations to monitor the overlying aquifers in Chapter 5. In brief, CO_2 leakage into a water-bearing formation can lead to accumulation of CO_2 free phase that forms an interface with the resident fluid. It is akin to a shallow gas accumulations that are often picked up in seismic surveys. For CO_2 storage seismic surveys of Sleipner and Snøhvit (CO_2 injection into aquifers) detects the reflection from the interface between CO_2 and brine (whereas there is no interface between CO_2 and methane). This reflected signal is used to observe the accumulated CO_2 plume. In the absence of shadowing, the resolution of seismic can detect plumes greater than 1 meter in thickness. Dissolved CO_2 cannot be detected by time-lapse seismic.

4D surveys before and after a blowout connected to drilling of well 4-14 in the Southern part of North Sea in 1989 manage to detect the gas flow from the deeper reservoir up to shallow thin sand layers in the overburden (Landrø et al 2019). Landrø et al (2021) has also demonstrated use of 3D seismic data and diving waves for detecting shallow overburden gas layers.

Recommendations: We recommend that more details of the DAS, as type of fiber, fibre configuration, coupling to the tubing, site for the interrogator, data management etc. be included in the monitoring plan.

4.2.5 Monitoring Plan

The Monitoring Plan shall be updated, supplemented and detailed at least three months prior to commencement of CO_2 injection. This plan will also be updated in the event of significant changes and in any case every 5 years and/or at the same time as the other plans. The update will be based on changes to the assessed leakage risk, changes to the assessed risks to the environment and human health, new scientific knowledge, and improvements in best available techniques.

The monitoring plan shall provide details of the monitoring to be carried out during the main stages of the project, including the monitoring prior to, during and after injection, as well as the post-closure period. The following elements shall be specified for each stage:

a) The monitored parameters
b) The monitoring technology used and a justification for the choice of that technology
c) The locations where monitoring is carried out and the reasons for that spatial distribution
d) The monitoring frequency and the reasons for that spread over time.

The parameters to be monitored shall be chosen so as to serve the monitoring purposes. The Monitoring Plan shall include at least the continuous or periodic monitoring of the following items:

a) The volatile emission of CO_2 at the injection facility
b) The volumetric CO_2 stream in the injection wells
c) The CO_2 pressure and temperature in the injection wells (to determine the mass flow rate)
d) The chemical analysis of the injected material
e) Reservoir temperature and pressure (to determine CO_2 phase behaviour and phase state).

The choice of monitoring technology shall be based on best practices available at the time of design. The following options will be considered and used according to the needs and availability of the techniques:

a) Technologies enabling the detection of the presence, location and migration routes of CO_2 in the subsurface and at the surface;
b) Technologies that can provide information on the pressure-volume behaviour and the distribution in horizontal and vertical directions of the CO_2 plume in the reservoir, more

specifically, to refine the numerical 3D simulation on the 3D geological models of the reservoirs elaborated pursuant to Article 4 and Annex I of the CCS Directive.

c) (c) Technologies enabling a wide areal distribution to gather information on any previously potential migration paths within the storage complex and its surroundings in case of significant irregularities or leakage (migration of CO_2 out of the storage complex).

In addition, at least once a year, the permit holder shall provide the competent authority with the results of the monitoring of the stored CO_2, specifying the technology used.11

Assessment: We find that updating the Monitoring Plan 3 months prior to commencement of injection and thereafter on a regular basis is a reasonable approach and in line with common industry practice.

Recommendations: Our assessment finds no shortcomings, and we have no further recommendations.

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5 Secondary focus area

5.1 Summary

In this chapter, we address the following: (1) Impact assessment of leakage scenarios to the overburden; geochemical/mechanical or environmental. (2) Impact of leak rate of CO_2 (or conjoining gasses) to overburden. (3) Role of relative pressure differences between reservoir and overburden (supposedly downward pressure gradient).

In summary, it could be concluded in Chapters 3 and 4 above that the leakage risk assessment is done on the good level. Generally, the data used, analysis carried, and conclusions are good. Here, we review the injection and storage operation plan with regard to the impact of leakage and the role of pressure differences, evaluating if the plan is judged to be sufficient to minimize leakage risks.

This chapter starts with short background and general overview of leakage possibility / assessment. It continues with applications to the P-18 site and further recommendations.

Assessment highlights:

The pressure barrier at the top of the reservoir will play a major role in ensuring that leakage from the storage reservoir will not occur if a leakage pathway evolves during the course of injection. Porthos has chosen a maximum reservoir pressure of 351 bar at datum depth, which they argue will ensure a pressure barrier with respect to the hydrostatic surroundings. However, there appears to be inconsistency with this reasoning and the actual choice of datum pressure. We explore this inconsistency in this chapter, arguing that the choice of 351 bar at datum depth will only ensure a pressure barrier is maintained *at the datum depth and below*, while all points above the datum depth will experience an overpressure with respect to the surrounding. Thus, leakage will occur if a pathway occurs at the reservoir top at the shallowest depth. Therefore, it is recommended to evaluate the outcome of the scenario in which maximum reservoir pressure at datum depth is reduced by accounting for the buoyancy effect of CO_2 mixed with remaining methane and update injection and storage operation plan. Additional monitoring of above lying aquifer formation can be advised in any case and recommended if operational window remain at the current level.

Moreover, one should remember about methane remaining in the storage reservoir. Being lighter, more mobile, and non-reactive methane would leak first. The monitoring routines need to consider and look for signs of methane leakage as a precursor to CO_2. Due to the difference in buoyancy force, one could also imagine the situation when methane would leak and CO_2 will not.

Recommendations: Our key recommendation is that *either* Porthos reduce the final reservoir pressure to maintain a pressure barrier everywhere in the reservoir at the end of injection *or* revise the modeling-monitoring plan to estimate, detect and mitigate the risk of leakage into the overlying water-bearing formations.

We also advise Porthos to consider a implementing a permanent monitoring well for post-closure observations, which could be achieved by converting one of the injection wells instead of decommissioning. This will allow for post-closure monitoring of pressure to ensure a long-term pressure barrier is maintained.

5.2 Ultimate leakage potential of the P-18 site

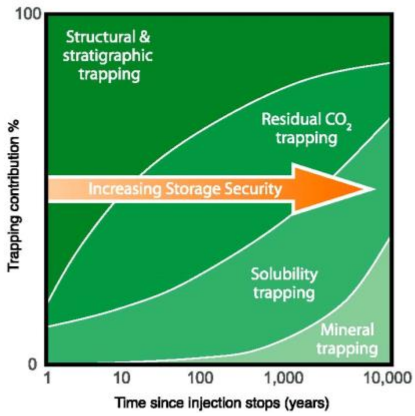
Term leakage refers here to any amount of gas/CO_2 fluid mixture escaping the P18 gas field. The term “fluid mixture” or “light fluid” is used further in the chapter refers to CO_2 (even though it is in supercritical phase), methane gas remaining in-situ or a mixture thereof that is lighter in density than formation water. In different literature sources terms “seepage” for small or slow rate can be used opposed to larger in volume or faster “leakage” of the CO_2. Here we do not make such a distinction and discuss rather possibilities and consequences of any kind of leakages. Also, the term applies to leakages from P-18 site into above laying aquifer, which is considered part of the storage site.

5.2.1 Background

Leakage can never be ruled out with 100% certainty, no matter how small its possibility is and how little consequences it can have. Therefore, it is worth discussing the ultimate leakage potential of the P-18 storage site in the context of overall classification of different storage setting and the implications for long-term immobilization of CO_2. There are several key aspects:

- Long-term immobilization of CO_2 in the storage reservoir
- Type of storage setting
- Top reservoir pressure barrier
- Presence and evolution of potential leakage pathways

Each aspect is taken in turn where first the background is presented and then how the P-18 site fits into the larger context.



Long-term immobilization: There are four main trapping mechanisms that may act to immobilize CO_2 in any storage reservoir. These mechanisms are often listed in order from least to most secure: structural, residual, solubility and mineral. Figure 5.1 visualizes the evolution of trapping over time since injection stops (taken from IPCC report on Geological CO_2 storage, 2005)

- *Structural trapping*, sometimes referred to as stratigraphic trapping, is the presence of an intact caprock barrier to prevent vertical migration. CO_2 exists in a free form when it is structurally trapped, i.e. gas, liquid or supercritical phase depending on the reservoir conditions, which means that CO_2 can be mobilized if a leakage pathway exists or develops. It is important to note that a geological feature such as structural trap that prevents horizontal migration may or may not be involved. Structural trapping is what keeps hydrocarbon accumulations in place.
- *Residual trapping* occurs when injected CO_2 is immobilized in residual form in a "shadow" that forms behind the receding front of a migrating CO_2 plume. For residual trapping to

occur, water must imbibe into the pore space that was originally drained under CO_2 injection. This implies that the injected CO_2 has to migrate away from the original point of injection and not accumulate at the injection well. Residual trapping permanently immobilizes the CO_2 in the pore space.

- *Solubility trapping* occurs when CO_2 dissolves into available water up to the solubility limit of the native brine, usually a few percent by mass. If only residual / connate water is present, then solubility trapping will be a very minor component. If free water is available, CO_2 will dissolve into the water column below the CO_2 plume. Dissolved CO_2 is negatively buoyant (brine density increases by approximately 2% when CO_2 dissolves). CO2-rich brine will sink, which drives a convective process that circulates brine under the CO_2 plume (see Fig. 5.2). Over time, a significant amount of CO_2 can be fixed in the dissolved state via convective mixing. The timescale of dissolution will vary according to the salinity of the brine and the permeability of the formation, with the process occurring within months to years. As with residual trapping, dissolved CO_2 is considered permanently trapped over geologic timescales.

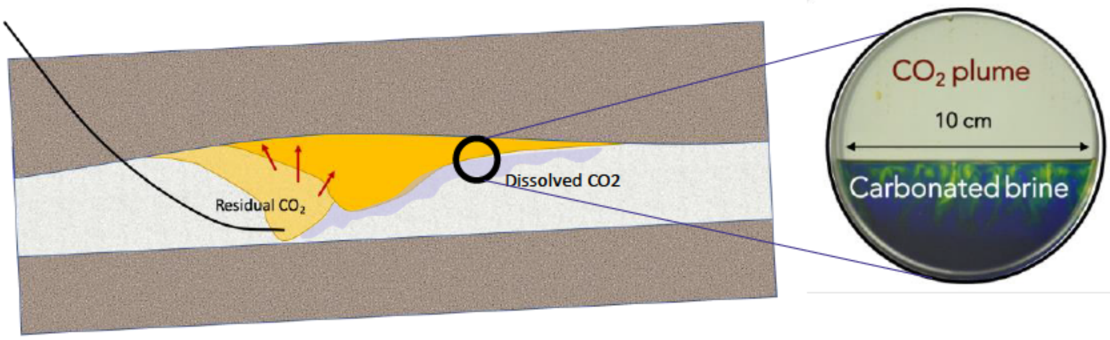


Figure 5.2: Evolution of a CO_2 in an open store. Dark yellow is the mobile CO_2 that is structurally trapped, light yellow is residual CO_2 left behind the receding CO_2 front, and light blue dissolved CO_2 that convects under the migrating plume. The inset shows an experiment that visualizes convection of carbonated brine (yellow-green fingers) in a pure brine column (dark blue) under a CO_2 plume (clear).

- *Mineral trapping* is the most secure, but unless the formation contains highly reactive minerals the mineralization process can take 1000s of years to be of significance. The amount of this highly reactive minerals should also be sufficient to trap considerable volume of CO2. Therefore, one often neglects mineral trapping as a contribution to CO_2 immobilization.

Storage setting: Fig 5.3 below gives an overview schematic of three general classifications of storage systems. The *Closed store* relies solely on immobilizing CO_2 in a structural trap within a confined system. There are essentially no other trapping mechanisms at work in the closed store. The *Open store: trap* relies predominantly on structural trapping within a trap similar to the Closed store. The main difference is the available free water provides open pressure communication to the surroundings and allows CO_2 to dissolve via convective mixing into the water column as described above. The *Open store: migration* does not rely on CO_2 accumulation in a structural trap, but instead allow CO_2 to migrate freely up dip according to buoyancy. In this setting, injected CO_2 is immobilized by relying on up dip migration to activate residual and solubility trapping as the ultimate storage mechanisms. The CO_2 plume may migrate up dip some 10's of kilometers over 100 years or more before CO_2 is completely trapped.

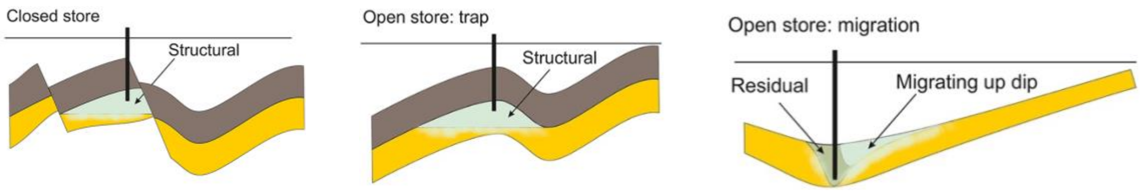


Figure 5.3: Classification of CO_2 *storage settings (Tucker, 2018. https://iopscience.iop.org/book/978-0-7503-1581-4)*

Top reservoir pressure barrier: If a potential leakage pathway exists through the caprock barrier where CO_2 and / or methane in a light fluid mixture that exists as a free phase, then leakage will occur if the pressure in the light fluid phase exceeds the water pressure at the caprock boundary. Here we refer to a general buoyant fluid in the discussion below:

Let us consider for simplicity the case where the storage project is completed and all transient pressure gradients due to injection have dissipated.

For an *Open store: trap* where the formation water is connected to a large available pore volume, then the free water will return to its initial pre-injection hydrostatic pressure. In this system, a column of buoyant fluid will ***always*** exert a buoyancy pressure (or differential pressure) locally at the top of the reservoir equal to

$$P_{fluid,top} - P_{hyd,top} = h_{\text{fluid}}\ (\Delta\rho)\ g \qquad (1)$$

where h_{fluid} is the fluid column height measured from the reservoir top to the free water level, and $\Delta\rho$ is the density difference between brine and CO2/methane fluid. For the P-18 reservoir it is estimated that only around 5% of original methane remains in place (based on the pressure decline). During the injection phase it is reasonable to expect that methane will mix with entering CO_2, however in the long term one could expect the gasses to segregate with methane accumulating on top of CO_2.

For a CO_2, this could be in a range of approximately 3-5 kPa differential pressure per meter of CO_2 column height over hydrostatic, depending on water salinity, reservoir temperature and pressure. For pure methane as high as 8-11 kPa per meter.

There is no mechanism to prevent buoyant fluid pressure from exceeding hydrostatic for an open store. And thus, any open vertical pathway, if created, will always leak fluids (CO_2 and/or methane).

Being lighter, more mobile, and non-reactive methane would leak first. The monitoring routines need to consider and look for signs of methane leakage as a precursor to CO_2. Due to the difference in buoyancy force, one could also imagine the situation when methane would leak, and CO_2 will not.

For a *Closed store*, the pressure at the reservoir top at the end of injection is dependent on the pressure history prior to and during injection. If the store was pressure-depleted prior to injection and repressurized to a given reference pressure, then the CO_2 pressure should be calculated from the reference pressure and compared to the local hydrostatic pressure at the reservoir top.

$$P_{fluid,top} = P_{datum} - \left(\mathrm{TVD}_{datum} - \mathrm{TVD}_{top}\right) \rho_{fluid}\, g \qquad (2)$$

Let us consider two cases for repressurization of a depleted aquifer and the implications for buoyant fluid pressure at the reservoir top:

(1) The *reference pressure at datum is equal to the hydrostatic pressure* in the surroundings, then a *positive pressure gradient* will exist that is equal to:

$$P_{gas} - P_{Hyd,top} = \left(\mathrm{TVD}_{datum} - \mathrm{TVD}_{top}\right) \Delta\rho\, g \qquad (3)$$

This equation is similar to Equation (1) where there will exist a fluid pressure that exceeds the local hydrostatic pressure for each meter over the datum. Thus, light fluid will leak through any existing vertical pathway found at the reservoir top but *only for locations above the datum*.

(2) The *pressure at the free water level (FWL) returns to hydrostatic pressure* by slow equilibration with the surroundings outside of the closed store. In this case, the light fluid pressure exceeds the local hydrostatic pressure according to Equation (1) for an open store, and buoyant fluid will leak at any point along the reservoir top if a vertical pathway exists.

Given the above discussion, there are two key points to consider for minimizing leakage risk for a closed store that was pressure-depleted prior to injection:

- To maintain a pressure barrier at the caprock, the fluid pressure at top of the reservoir must be below the local hydrostatic pressure at any point at the reservoir top (and thus virtually eliminate the risk of CO_2 or methane escaping. This means that the reference pressure at datum depth must be kept below hydrostatic. The calculation for the allowable pressure at datum follows from the highest point of the reservoir, here denoted as $\mathrm{TVD}_{top,\,min}$

$$P_{datum} = P_{hyd,top,\,min} + \left(\mathrm{TVD}_{datum} - \mathrm{TVD}_{top,\,min}\right) \rho_{fluid}\, g \qquad (4)$$

  For typical CO_2 density range, Equation (4) states that the reference pressure at the datum must be maintained at 6-7 kPa below hydrostatic pressure (at datum) for every meter below the highest point of the reservoir top. For methane this value doubles to approximately 13-14 kPa for every meter.

  If a negative pressure is desired in the reservoir relative to the surroundings, then the pressure at the datum then must be kept below the calculated value in (4), up to a chosen margin of error.

- The uncertainty related to the *rate of pressure equilibration at the FWL* with hydrostatic pressure in the surroundings is a key factor. Unless the virgin pressure state of the reservoir was significantly over- or underpressure, then there is a possibility that the pressure equilibration may occur, albeit within long time frames upwards of several decades or a hundred years or more. These time frames are still relevant for climate purposes, and therefore an estimate should be made. The possibility to detect such slow pressure changes during the lifetime of a gas production or CO_2 storage operations is very low. To make more reasonable estimates of pressure equilibration, knowledge of larger regional hydrodynamics and hydraulic properties at regional scales is needed.

Implications for the P-18 site: Figure 5.4 below illustrates pressure vs depth situation for the P-18 site under different settings. There are several important features to point out.

- The dark blue line showing water (hydrostatic) pressure gradient. This gradient serves as two reference points: (1) the virgin water pressure at the FWL *prior to gas production*, and (2) the pressure in the surroundings, with particular attention to where the blue line crosses the top reservoir.
- The yellow line indicates the pressure gradient for the hydrocarbon gas originally present in the reservoir. This is the also referred to as the *initial gas pressure* in the Porthos application. The difference between the yellow and blue lines indicates there was a 40 bar *over* pressure gradient exerted on the caprock and faults at the highest point in the reservoir before the gas was produced, indicating a strong capillary seal.
- The green line has both a solid and dashed version. We take the dashed line first. We recall from Chapter 3 that Porthos team has specified an upper limit on the reservoir pressure equal to 351 bar at a specified datum equal to 3,400 m. This reference pressure was set in order to maintain a negative pressure gradient with the surroundings. The dashed green line shows the resulting CO_2 pressure above the datum as calculate according to Equation (3). At the shallowest point along the reservoir top (approx 3,200 m), the CO_2 pressure exerts a pressure difference on the surroundings equal to 8 bar. Below the datum, the CO_2 pressure is less than the surroundings. At the FWL, we observe that the resulting water pressure at the end of the Porthos injection will be approximately 12 bar less than hydrostatic.
- The solid green line is the resulting CO_2 pressure vertical profile if the reservoir pressure were to equilibrate with the surroundings. This aquifer re-equilibration is very unlikely to occur in the storage project time frame, but since the initial FWL pressure was hydrostatic, there is likely a very slow re-equilibration process that will occur. The rate of re-equilibration is undetectable from analysis of gas production data and requires a larger regional hydrodynamic analysis to be estimated. It is possible that the re-equilibration can occur over timescales relevant for immobilizing CO_2 to mitigate climate change (100s of years). The point in showing the solid green line is that at some point in the distant future, the CO_2 pressure at the reservoir top according to Equation (3) will increase from 8 bar to 18 bar overpressure relative to the surroundings.
- The red line shows the required CO_2 pressure profile to maintain a *zero-pressure gradient* at the reservoir top. The vertical profile shows the resulting pressure at the datum should less than 343 bar at 3,400 meters (as calculated according to Equation (4)) in order to maintain a pressure barrier at all points along the top reservoir during injection. The value of 343 bar assumes a pure CO_2 column, and will be lower for a CO_2-methane mixture. The important point is that an injection pressure should be chosen such at that a pressure barrier at the reservoir top is maintained at all times during the injection phase. In geological time scale slow aquifer drive (if existent) will contribute to slow pressure rise. It is also important to point out that the location of the dashed green line is determined by operational design, however all locations of the dashed green line will eventually move towards the solid green line due to a very long-term re-equilibration process.

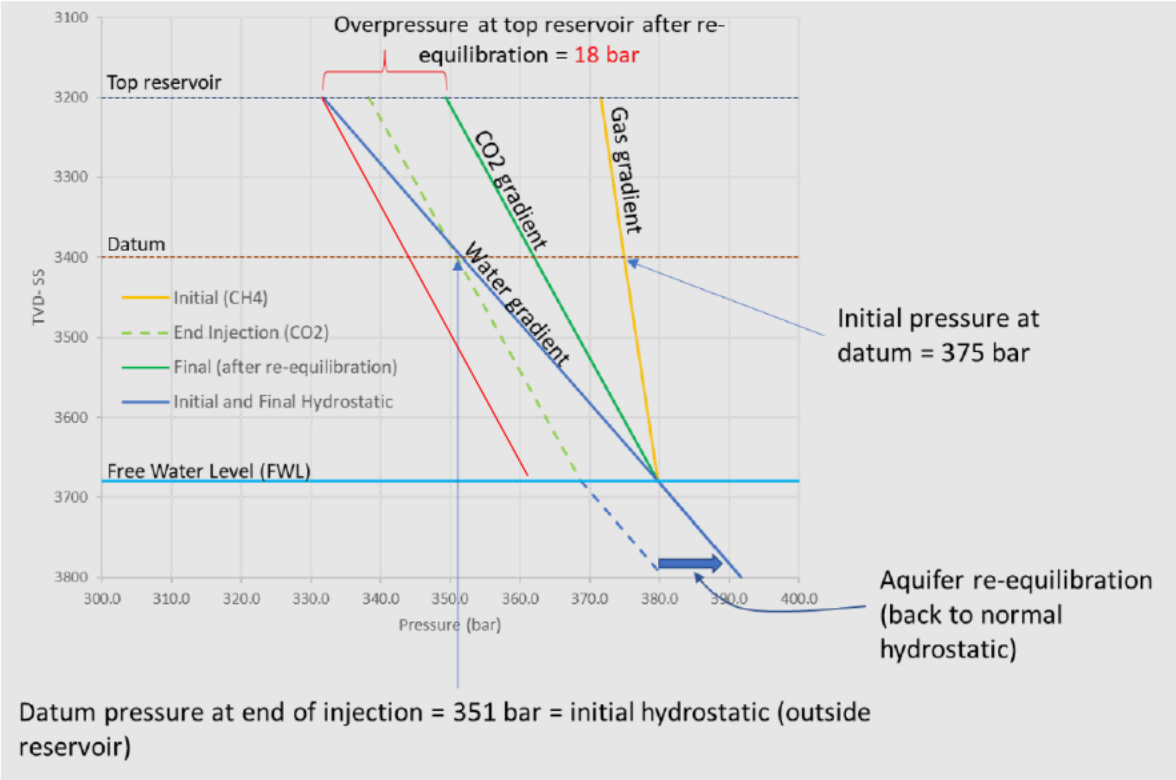


Figure 5.4: Schematic of pressure profiles of existing in the reservoir under different scenarios. See text for more explanation.

__Presence and evolution of potential leakage pathways__:

- Abandoned wells may develop a leakage. Time to abandonment is a factor, the estimate of leakage needs to consider a buoyant fluid overpressure at the depth of the reservoir top at the given well location. The leakage calculation should be made from the time the pressure exceeds local hydrostatic, which may be before injection ceases, until the well is decommissioned.
- Caprock fractures propagate only 10s of meters. CO_2 will enter a fracture but not migrate outside of the fracture since it is not connected to above lying formation.
- Faults are the largest risk for leakage. Characterized by damage zones that are complex and hard to characterize. Faults often do not propagate to surface but may intersect overlying aquifers. A cold front could activate existing weak points in the damage zone to a greater extent than assumed for intact rock. Leakage along a fault may be low but is hard to rule out with 100% certainty. Illustrations in Application permit, Section II, figures 5 and 7, show throughs of up to 400m. Some large faults relate to the mid-Jurassic break-up of Pangea, but they terminate in the Late Jurassic Schieland Group which forms part of the cap-rock. Faults located further up in the stratigraphy are like caused by a combination of thermal subsidence and peripheral effects of the Alpine inversion in at the Mesozoic-Paleogen boundary and appear not connected to the deeper structures.

5.2.2 Implications for the P-18 site

Leakage aspect	Positive assessment	Negative assessment
Long-term immobilization	structural trap that is a proven seal due to hydrocarbon gas accumulation.	Structural trapping is the only trapping mechanism for the closed system and is a least secure form of trapping. No free water, no updip migration and thus no possibility to transform CO_2 into more secure forms of residual and dissolved CO2
Storage setting	structural trap that is a proven seal due to hydrocarbon gas accumulation.	No additional negative aspects not already mentioned above.
Top reservoir pressure barrier	Hydrocarbon gas has larger pressure difference with water gradient due to higher buoyancy compared to CO_2 (see Figure 5.4 above). In a closed store system the pressure is depleted and creates a negative pressure gradient at the outset of injection, while in the open system aquifer support would have caused additional pressure increase Negative pressure gradient throughout the reservoir during most of the operational time period. Post-closure, a negative pressure gradient will be maintained at all points along the reservoir top that lie *below the datum*. This applies to the P18-1A well and the bounding fault.	Negative pressure gradient will gradually turn positive for all locations along the reservoir top *above the datum*. Any thermal fractures that open in the caprock or along the bounding fault will cause CO_2 to escape out of the reservoir. Also, the P18-3A and P18-5A wells will experience a positive pressure gradient that will cause CO_2 to leak during operations if microannuli develop along the wellbores. The positive pressure gradient and thus leakage will persist unless the leakage pathways are repaired or the pressure in the reservoir declines such that the pressure at the datum is constrained by Equation (4). Pressure will decline naturally due to CO_2 leak-off, and the rate of decline will be related to the rate of leakage.
Leakage pathways	CO_2 leakage through the well plug is highly unlikely, it is the easiest to detect and mitigate. CO_2 leakage along wellbores behind the casing will react with cement. For slow leakage rates +	The P18-3A and P18-5A wells have a high risk of leakage prior to abandonment. Leakage estimation during this time period should consider the local CO_2 pressure at the caprock boundary, which will turn positive at an earlier time and persist

small apertures, the reaction will lead to self-healing. Microannuli in the wells will ultimately be remediated by a comprehensive abandonment.

Thermal fracturing of intact caprock has been shown to be limited in vertical extent. Therefore, leakage will likely occur for caprock fractures, but CO_2 will prevented from further leakage once the volume of the fracture is filled with CO_2. The amount leaked will likely be negligible due to vanishingly small fracture volumes.

Faults were originally sealing to hydrocarbon gas. Faults do not extend to surface and thus any fractures that are activated by cooling or slip will be unlikely to provide a pathway to surface.

post-injection up until the planned abandonment intervention. This will lead to higher leakage estimates than previously calculated in Bijlage 13: Well Containment Note.

Faults are very uncertain in terms of their potential for leakage. It cannot be ruled out with 100% certainty that the P-18 will leak along faults when a positive pressure gradient to the surroundings will persist above the datum. Thus, the possibility of CO_2 leakage and accumulation in an overlying aquifer should be considered. One does not know the properties of the fault, so a quantitative risk analysis is not possible, however a sensitivity study could be performed to determine some bounds on leakage. This should be connected with modeling of the secondary aquifer discussed below.

5.2.3 Accessing leakage pathways

Faults

Depending on their properties, faults may serve as barriers (impermeable or low permeable faults with capillary barrier) or as conducting pathways. Changing pressure and temperature change stresses in the reservoir and may cause barrier faults to open and become conductive. The threats of flow through the faults are addressed in SEC III, chapter 5.2. of the Application permit. While the analysis and conclusions drawn seem adequate it should be pointed out, that while strict adherence to maximum injection pressure (mentioned several places in chapter 5.2) is indeed a good measure, the effect of buoyancy (see *Top reservoir pressure barrier* section above) must be included in the maximum injection pressure calculations as well as it will create a pressure drop across the fault as well. Secondly as CO_2 dissolved in water creates a reactive weak carbonic acid solution:

$CO_2 + H_2O \leftrightarrow CO_3^{2-} + 2H^+$

$CO_3^{2-} + 2H^+ \leftrightarrow CO_3^- + H^+$

it may react with the fault rock and potentially activate it.

Sub seismic, i.e. smaller faults invisible on seismic surveys may provide additional barriers or leakage pathways, however their existence could be indicated through, a pressure transient analysis of historical data and during CO_2 injection. The pressure monitoring and analysis during post closer can also help to monitor leakage pathways if leakage eventually becomes large enough (Shchipanov, et al. 2019). In principle, faults should not be considered only lateral leak paths as conductivity *along* not only *across* the fault could not be fully ruled out.

Caprock

Threats and preventive barriers related to Caprock are discussed in chapter 5.3, section III of the application permit. The likelihood of caprock fracturing or chemical degradation is indeed very low. Here, again, keeping CO_2 under the overpressure due to buoyant fluid gradient provides the best barrier in unlikely case of leakage path appearing through the caprock.

Behind the casing in the wells

The wells, as manmade objects become a possible leakage pathway. Wells are discussed in chapter 6, section III of the application permit.

After being plugged and abandoned the leakage through the wellbore is very unlikely, easy to detect and is straightforward to mitigate. The leakage beyond the casing (through cracks in cement or between cement and casing or cement and rock) is more likely and indeed wells are known to leak. The measures presented in above mentioned chapter seem adequate and appearance of micro-annuli (as depicted on Figure 39, section III, Application permit) post-closure connecting the reservoir with the surface without opening up to above laying formations seems highly unlikely. However, the leakage into overlying aquifer could not be ruled out completely, unless, again, the pressure barrier is maintained everywhere in the reservoir by reducing the maximum pressure at the datum from 351 to a more conservative threshold.

5.2.4 CO_2 evolution in secondary aquifer

Any of the above-mentioned leakage pathways would lead to leakage first and foremost into overlying aquifer formations. CO_2 that enters by leakage into overlying formations can be considered as a form of *secondary storage*, where the overlying aquifer acts as an Open store (Fig 5.5) discussed previously. This means that CO_2 will form a new accumulation that will evolve and be immobilized according to the well understood mechanisms: collect in structural traps, migrate up dip and be trapped by dissolution and residual processes. Given the relatively slow leakage rates, the "injection" of CO_2 into one or more overlying aquifers can likely be estimated easily by analytical solutions or semi-analytical solutions (Nordbotten and Celia, 2012; Juanes et al., 2010). In any case, a reasonable estimate can be obtained without a detailed analysis given some reasonable estimate of the depth, porosity, permeability and formation water properties.

Porthos has not characterized the overlying aquifers, but there are indications throughout the documents that a couple of relevant aquifers exist at depth. In particular, the Rijswijk Fm is present that is well known for its oil and gas accumulations. Fig 11-3 (Bijlage) indicates that fault flow to the Rijswijk Fm could occur if a fault seal is compromised during CO_2 injection. Some rudimentary analysis of gas migration was performed in the TNO report (Fig 11-5), but there is no report of aquifer properties (thickness, properties and depth) to make any further assessment. Elsewhere in the report, it appears that Rijswijk shows in stratigraphy maps above P-18 are limited in thickness (approximately 15 m from investigation of tables provided Appendix A of Bijlage 16).

For such a small aquifer, one would expect there is little capacity for CO_2 as a dissolved component. The estimated volume of the aquifer, as stated in in Bijlage 13, Conclusions, is 63,000 (50x50x25m) m^3 and seems extremely small (is water bearing formation really just 50 times 50 meters or the text is misleading) and would not be able to dissolve significant volume of CO_2. At approximately 4% saturation (Permit application, section III, section 5.4.2) of the as reasonable number) only around 5 tones of CO_2 could be dissolved.

As such, any leaked CO_2 that enters the Rijswijk will eventually accumulate in free form according to the structure map of the Rijswijk aquifer (an indication is available in Fig 11-5, Bijlage 7). An estimate of these accumulations could be made to determine how much leaked CO_2 is needed to be visible on seismic. A seismic signal would require a few meters of CO_2 accumulation, which means even small accumulations can be observed.

Accumulated CO_2 in the Rijswijk could find a leakage path to shallower depths. If leakage occurs through Vlieland Claystone via a wellbore it would meet 956 meters of Chalk group. This chalk volume more than enough to chemically react with remaining CO_2.

The above discussion also applies to the collection of aquifers in the overlying stratigraphy in addition to the Rijswijk, including the Nieuwerkerk, Holland, and Texel aquifers. Together with the Chalk group, these seem to provide enough of secondary and tertiary traps to avoid migration of CO_2 to the surface considering that risk of breaking through each of structural trap remains small.

Finally, again, accounting for gas buoyancy forces in planning for the operational window of injection pressure completely removes the risk of CO_2 migration upwards even if leakage path would become available.

5.2.5 Recommendations

We divide up our recommendation into two scenarios.

Scenario 1: Reduce final reservoir pressure

- The key recommendation is to *reduce the operational window for reservoir pressure* to account for CO_2-methane fluid buoyancy effect and maintain a pressure barrier (negative pressure gradient) at every point along the reservoir top to be constrained according to Eq. 4.
- Based on the reservoir production history and CO_2 injection modelling, a reduction in reservoir pressure to *less than 343 bar at datum depth* should only negligibly affect injection rates or total injected volumes.
- There will be a nominal reduction in P-18 storage capacity, but a lower final reservoir pressure will give assurance that any CO_2 and remaining methane in the storage reservoir will be kept below hydrostatic pressure at the shallowest depth and therefore could not leak into overlying formation even if leakage paths are available.
- In connection with lowering the final reservoir pressure, additional simulations may be advised to evaluate CO_2 methane segregation, effect of the potential reduction of injection pressure on CO_2 storage dynamics and total volume of CO_2 stored. This will be necessary to give a more accurate estimate of the maximum reservoir pressure at datum depth that accounts for a small methane cap emerging at the reservoir top.

Scenario 2: Maintain planned reservoir pressure

If Porthos will retain the original plan of 351 bar at datum depth, then we recommend the following:

- Estimate the evolution of CO_2 in secondary aquifers, including migration and trapping, which could be done by analytical or semi-analytical methods. This will entail some coarse estimation of aquifer properties as a first pass. It also is recommended to verify the aquifer volume presented in Bijlage 13, "Conclusions" as its lateral size seem extreme small (50x50 meters). An estimate of maximum amount of CO_2 that could be immobilized long-term by different mechanisms in the overlying aquifers needs to be performed.
- Revise the monitoring program to include periodic seismic surveys to detect CO_2 accumulation in the Rijswijk towards the end of injection and post-closure (which should be coordinated with the modeling of CO_2 evolution to design a cost-effective plan). If CO_2 is not detected, then the monitoring plan can be phased out given a verification of reduced risk.
- Being lighter, more mobile, and non-reactive methane would leak first. The monitoring routines need to consider and look for signs of methane leakage as a precursor to CO_2. Due to the difference in buoyancy force, one could also imagine the situation when methane would leak and CO_2 will not.
- Eventually consider including the overlying aquifer(s) as part the storage complex, allowing for CO_2 migration to a vertical depth below the Chalk group as stored CO_2, albeit outside of the P-18 site.

Long-term consideration:

- We also recommend *converting one of the injectors into a monitoring well* post-closure instead of decommissioning. This will achieve two things: (1) the ability to monitor reservoir pressure for signs of leakage, and (2) the ability to understand the rate of re-equilibration of the P-18 site with the surroundings.
- For instance, the shallowest well (P18-A5) could be a long-term monitoring well located where the CO_2 column is thickest. In addition, the potential for a positive pressure gradient developing at the reservoir top due to re-equilibration with the surroundings will lead to the largest risk. However, a deeper well that is in contact with the FWL may provide more direct observation of the re-equilibration rate.

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