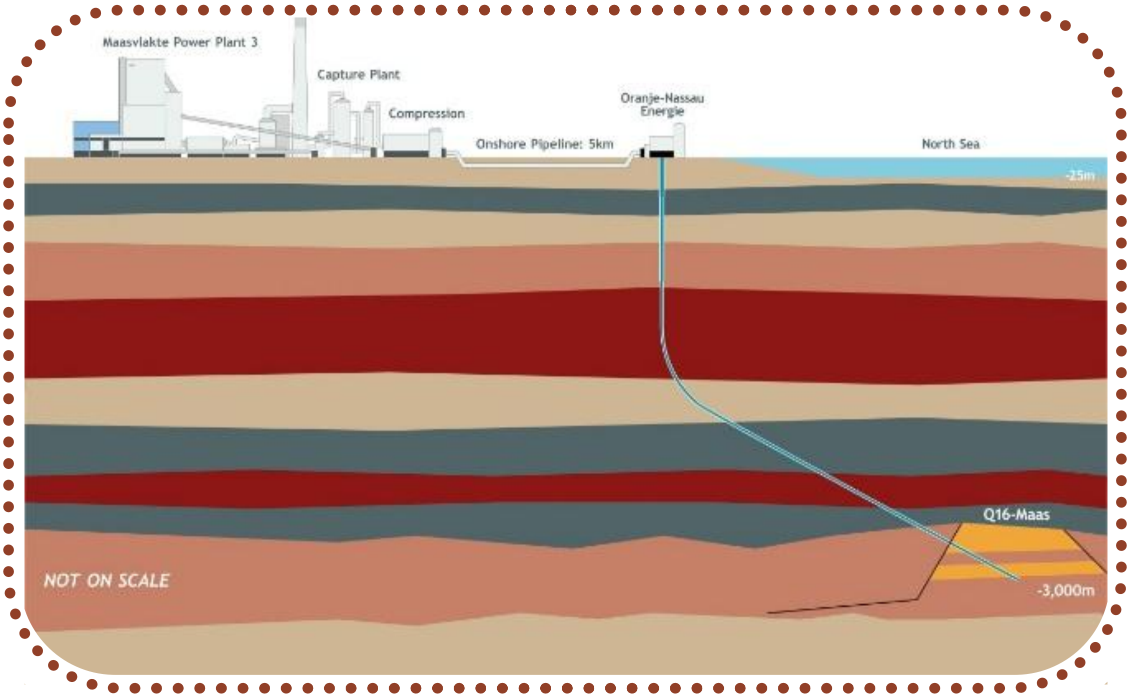
Close-Out Report on CO_2 Storage (P18-4 and Q16-Maas)

Rotterdam Opslag en Afvang Demonstratieproject



Maasvlakte CCS Project C.V.

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Close-Out Report 4 of 11: CO_2 storage (P18-4 and Q16-Maas)

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Index of ROAD Public Close-out Reports

No	Title	Scope
1	Overview	Introduce and summarise the public close-out reports.
2	Capture and Compression	Technical report covering capture, compression and power plant integration.
3	Transport	Technical report covering CO_2 pipeline transport.
4	***CO_2 Storage***	***Both technical and commercial aspects of CO_2 storage for ROAD. Subsurface work required to demonstrate permanent storage is described.***
5	Risk Management	The risk management approach used by ROAD.
6	Permitting and Regulation	Description of the regulatory and permitting framework and process for the ROAD project, including required changes to regulations.
7	Governance and Compliance	Company structure and governance for Maasvlakte CCS Project C.V., the joint venture undertaking the ROAD Project
8	Project Costs and Funding	A presentation of the projected economics of the project, with both projected income and costs.
9	Finance and Control	Description of the financial and control systems, including the costs incurred and grants claimed.
10	Knowledge Sharing	Outline of the Knowledge Sharing & Dissemination plan as developed by the ROAD project and completed KS deliverables and actions
11	Public Engagement	Description of how ROAD organized and managed the Public Engagement process.

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1.1 Introduction

Project Summary

This report summarises the technical and commercial development, design and lessons learnt on geological storage of CO_2 from the CCS demonstration project "ROAD". The ROAD Project (Rotterdam Opslag en Afvang Demonstratieproject) was one of the largest integrated carbon capture and storage (CCS) projects in the world, aiming to install carbon capture on a coal-fired power station in Rotterdam and store the CO2 in an empty off-shore gas-field.

The project ran from 2009 to 2017. The developer was Maasvlakte CCS Project, a joint venture between Uniper (formerly E.ON) and Engie (formerly Electrabel and GDF Suez), with financial support from the EU EEPR program, the Dutch Government, the Port of Rotterdam and the GCCSI.

In the first phase of the project, 2009-2012, the project was developed to final investment decision (FID) based on using the TAQA P18-4 gas-field as the CO_2 storage location. This required a pipeline of approximately 25km from the capture location (Uniper's coal-fired Maasvlakte Power Plant – MPP3), about 5km onshore and 20km off-shore.

Unfortunately, the collapse in the carbon price undermined the original business case, and in 2012 a positive FID was not economically possible. The project then entered a "slow-mode" in which activities focused on reducing the funding gap, either by reducing costs or by securing new funding. In late 2014 a possible new funding structure was identified, and explored in 2015 and 2016. This included additional grants for operation and cost reductions. The cost reduction that could be successfully applied was to change storage sink to Q16-Maas, operated by Oranje Nassau Energie (ONE). This smaller field was much closer, with only a 6 km pipeline required. This resulted in a remobilization of the project late in 2016, and development of the new scheme. However, in mid 2017 work was again halted due to lack of financial and political support, and formally stopped in November 2017.

Scope of this report

This report describes the technical work on the CO_2 storage systems for both phases of the project. In depth work to FID standard was completed for storage in the P18-4 gas reservoir from 2009-2012. This included demonstration of permanent geological storage of CO_2 to support Europe's first CO_2 storage permit application by the operator, TAQA, as well as engineering the equipment required. This storage permit was granted in 2013.

From late 2014 onwards, worked focused on the Q16-Maas field of ONE, including as an option use as a buffer store for CO_2 for use by greenhouses.

The report also contains two sections describing the proposed commercial arrangements between the storage operator and the ROAD project, one for P18-4 and one for Q16-Maas.

Disclaimer

This is a report produced by the ROAD Project. It contains a summary and interpretation of work performed for the ROAD Project, including by third parties, and also work done in collaboration with other parties during the course of the ROAD Project, in particular as part of the Dutch research programme CATO. While this report is provided in good faith, other parties may have different interpretations on the work. Much of the source material is available to the public, and readers are recommended to review the source material where possible for topics of particular interest. Readers should also be aware that both P18 and Q16-Maas reservoirs are subject to ongoing production and ongoing technical study, which has continued after work involving the ROAD Project stopped. As such, the information reported here does not represent the latest understanding of the fields.

1.2 Main Technical Highlights and Lessons Learnt – P18-4

This section summarises the main outcomes of the work on the P18 cluster, and on P18-4 in particular, covering feasibility, pre-FEED and FEED phases from 2009 to 2012. Note that the FEED phase was not completed before the main engineering work was halted in 2012 (start of the "slow mode"). The P18 cluster is a logical first step in the development of offshore CO_2 storage. Its proximity to Rotterdam, its storage capacity (of about 40 Mt in two fields in the cluster, P18-2 and P18-4) and the injection rates that can be accommodated (both fields can store at least 1.1 Mt/yr) make it the preferred location. The cluster, more specifically the P18-4 field, was selected for storage of the CO_2 captured by the ROAD demonstration capture plant in the Rotterdam harbour, which planned to produce CO_2 at a rate of 1.1 Mt/yr. At the time of the study work (2009-2012), production of natural gas was expected to have finished in the P18-4 field by 2015, and around 2018 in the larger P18-2 field.

Feasibility stage

The feasibility stage of the work concluded that the P18-4 gas reservoir is suitable geological structure for CO_2 storage because a thick package of different seals is present above the storage reservoir at P18-4. Faults are present in the primary seal, but these faults are sealing. Thereby, the reservoir has safely contained gas over millions of years. Top seal analysis has shown that top seal integrity and fault stability are not critical factors for injection and storage at P18-4. No seismicity has occurred during production of gas at the storage location. Simulations show that in P18-4 the target rate of 1.1 Mton/year is possible and a total of 8.1 Mton CO_2 can be injected.

Storage system integrity looks into the containment functionality of the CO_2 storage reservoir, which is provided by a set of barriers, i.e. caprock, faults and wells. Dissolution of small amounts of carbonate and sulphides is predicted to occur on the mid-term (in the order of years to decades), but the net effects on mineralogy and porosity are negligible. The corresponding porosity change is a decrease of 0.3 pp (to 8.5%) for the reservoir rock and an increase of 0.2 pp (to 1.2%) for the caprock.

The boundary faults of all three P18 reservoirs are found to be sealing. These faults have large throws and juxtapose the reservoir Bunter sequence against the sealing Upper Germanic Trias mainly. Geomechanical analyses show that possible fault re-activation will affect parts of the fault located at the reservoir level only. The risk of CO_2 penetration into the fault zone and migration in the updip direction above the reservoir is therefore very small. From the 2D simulations and 3D simulations, it was clear that for the true depth (3,400m) of the P18-4 reservoir, no fracturing as a result of the cold CO_2 is expected, which is in line with the earlier results.

Fault F3 between the P18-4 and P15-9 reservoirs: CO_2 injection in the P18-4 field will lead to an increase in pressure and therefore to an increase in differential pressure between the P18-4 and the P15-9 fields, potentially up to 200 bar. The two fields are separated by the so-called F3 fault. There is a possible juxtaposition of reservoir sections across the fault. Very likely, the fault is sealing which is supported by observations on the rock geometry on both sides of the fault, gas compostion and pressure.

The P18 field was not seismically active during production period, based on the KNMI database of recorded induced seismic events associated with hydrocarbon production in the Netherlands.

Well integrity: The P18 field comprises 3 reservoir blocks, penetrated by a total of 7 wells, some of which have been sidetracked. One of these sidetracks also penetrates the caprock and the reservoir. The well P18-2 has several cement plugs, which need to be replaced. The sidetracked P18-2A6 well needs to be abandoned. All other wells are readily accessible and can be remediated. Only in the case of a tremendous drop in temperature for an extended period at the wellhead: and in the top section of the tubing of P18-4A2, might the steel become brittle and crack. Hence the system will be operated to minimise the risk of low temperatures occurring, and the wellhead will be selected to operate at very low temperatures (arctic grade perhaps).

Migration path: Overall it can be stated that the most probable pathway to the surface of CO_2 stored in the P18 gasfield is via leaking wells, leaking directly into the atmosphere and not indirectly via pathways originating in deeper parts of the overburden. Shallow bright spots have been observed above P18-4 which may indicate the presence of shallow gas. The interpretation of the side scan sonar did not show features that can be associated with gas seepage, such as features like pockmarks or gas bubbles in the water column.

Platform: Platform P18-A is located at about 20 km from the shoreline and is a normally unmanned Wellhead Protector Platform (WPP). It is used to produce gas from three reservoirs at a depth of about 3,500 m. The peak in the gas production was reached in 1993. The gas produced at P18-A is transported by pipeline to the much larger platform complex P15-D. The additional loadings on the jacket structure due to the platform modifications for CCS do not result in overstressing in the jacket members or piles. The platform can withstand a ship impact of at least 2.1 [MJ] which correspond to a 3,000 tonne ship traveling at 1 [m/s]. Space was identified on the platform to locate the additional hardware. In conclusion, the existing platform can be adapted for CCS use.

Pre-FEED stage

During the pre-FEED stage, specific modifications to the platform were studied to make it suitable for CO_2 storage. This included connecting the pipeline to the platform P18-A via a riser, installing a stop valve at the end of the riser and a T-connector connecting the riser with the pig installation. A pig would be used to periodically clean the pipe from the landside. Furthermore, a well control panel, a metering skid and a CO_2 venting pipe are needed.

Several engineering options for the wells were also investigated including the re-use of wells, i.e. conversion to operation at higher or at lower emperatures and drilling and completing new wells. The cost of a new well is estimated at 21 M€. For cold CO_2 injection, arctic/cold CO_2 service carbon steel tubing will be required to avoid risk of brittle failure. The worst case scenario has a temperature of -47°C at the wellhead and arctic conditions are considered (and tested) down to -55°C. Safety valve testing at low temperaures was identified as needing to be done.

FEED stage

The platform FEED scope was written and tendered, but the contract was never released due to the halt in work in 2012. The FEED study was planned to cover the full lifecycle of CO_2 steady state injection from 20 barg to a maximum of 350 barg reservoir pressure. It would also include the transient states of ramping up and down, start-up and shut down (Planned and Emergency shutdowns). In the event of shut down of the compressors onshore the pipeline pressure may be allowed to fall to below 50 barg and the CO_2 could cool to between 10 to 20°C which will mean that two phase flow can be experienced at start up.

Risk management

The risk management plan consists of a risk assessment and the corresponding management measures (risk management). The risk assessment is also the foundation for the plan for corrective measures and for the provisional closure plan. The formulation of the monitoring plan is based on these plans.

Risk reduction is achieved by injecting CO_2 with bottom hole pressures (BHP) which are below fracturing condition, avoiding overpressurizing the reservoir above the initial pressure, keeping a safe distance between the injection wells and faults and managing thermal effects of injection.

The monitoring plan includes the parameters, techniques, temporal frequencies, spatial coverage of data acquisition, expected accuracy, threshold values with the definition of normal, increased altert and highest alert with immediate contingency measures.

1.3 Main Technical Highlights and lessons learnt Q16-Maas

The Q16-Maas field is a condensate-rich gas field, located just offshore the Maasvlakte in the Rotterdam harbour area. Discovered in 2011, production started in April 2014 from the well MSG-03X and is planned to cease by the end of 2022.

The work on Q16-Maas was concentrated in 2014, 2015 and early 2016, with some updates and further geological analysis in 2017. The initial work was contained in a study completed by TNO looking at Q16-Maas as a store for the ROAD project and/or as a buffer CO_2 store for greenhouses. Additional benefits from CO_2 injection may arise through the enhancement of gas and condensate production. This was extended by further reservoir and economic modelling by the operator Oranje-Nassau Energie, and engineering studies on the topside facilities. The second phase, completing in summer 2017, was intended to contain more detailed reservoir modelling and geological analysis, with a draft monitoring plan to support permitting. In the event, unexpected water production from the reservoir in 2016 led to a major update of the reservoir model in 2017, and this led to a changed view of the operating scenarios. Because of the stop to work on the project in June 2017, this updated reservoir model is not yet fully assessed.

Pre-Feasibility

The pre-feasibility study concluded that CO_2 can be safely and securely stored in the Q16-Maas field, as the existence of the gas field proves the quality of the caprock. Two items attracted some attention, namely permeability and shallow gas. Although it can be concluded that there may be shallow gas occurrences above the Q16-Maas field, the gas is unlikely to originate from this field. The storage capacity was initially estimated at 1.9 or 2.3 Mt CO_2. Later reservoir analysis by ONE based on likely commercial operation including enhanced condensate recovery gave an increased estimate of the storage capacity of 2.7 Mt.

The studies concluded that pressure changes during depletion are unlikely to destabilize faults; fault reactivation is therefore not expected during production. However, cooling of the reservoir rock due to injection of cold CO_2 into the relatively hot rock could exert significant stress changes, enough to cause fault reactivation and this was considered in the next phase of work. As the well is relatively new, accessible, constructed in compliance with recent regulatory and industry standards, the well does not present a showstopper for envisaged CO_2 injection operations

In the proposed operating regime, production would continued during CO_2 injection for recovery of light oils (condensates). If the facility is acting as a buffer store for greenhouses, high purity CO_2 must also be produced. The existing gas processing unit is not designed for the removal of high purity CO_2 but to achieve methane sales gas specification. Therefore modifications to the equipment are required. The costs of the leading options applicable to ROAD were calculated. Simple separation of condensates from the produced CO_2 is relatively cheap (under 2 M€ capex). Sepration of CO_2 from the gases (natural gas or LPG components) is more expensive, either for sales of hydrocarbon gases or for CO_2 purification for use by greenhouses. Only the cases applicable to ROAD were costed, however feasible technical options were identified for all cases.

Feasibility Studies

The new reservoir data released in 2017 showed a much more active aquifer in Q16-Maas than the earlier models, with faster gas production. In this scenario there is no merit in continuing production after the start of CO_2 injection, and therefore no enhanced condensate recovery nor potential extra sales of natural gas. The estimated storage capacity is reduced slightly to 2.3 Mt. With the existing well design, the active aquifer and high reservoir pressure restricts the injection rate achievable. The target rate of 1.1 Mt/a is only feasible over a short period of about 6 months; 0.2 to 0.3 Mt/a can be sustained for much longer periods. The assumed maximum down-hole pressures were 100% and 110% of the initial reservoir pressure. Due to the timing of the project termination, measures to increase the injection rate, for example by increasing the number of perforations, were not assessed.

The caprock can be assumed to be sealing for CO_2. The effect of injecting cold CO_2 into the warm reservoir was considered in more detail. Because the well may be very close to one fault, the modelling done to date could not eliminate this risk. However, injection into the main reservoir only (leaving to top Röt sandstone) will strongly reduce the risk of thermal-induced stresses causing fracturing at a sealing fault. A more detailed re-evaluation is required based on planned injection strategies with the new reservoir model. Fault stability is not an issue, provided that low temperature CO_2 does not reach faults.

Well cement-casing debonding risk with lower CO_2 temperatures and subsequent CO_2 migration is considered negligible given the short period of CO_2 injection.

Risk management - monitoring

Due to the similarities of the Q16-Maas field and the P18-4 field, the monitoring approach used for the P18-4 monitoring plan were used for the proposed Q16-Maas monitoring plan. Given the preliminary nature of the results presented here, the monitoring scheme could not be populated with quantified values for limits to monitoring parameters

The Q16-Maas field has one key property that renders it quite different from P18-4, which is the active aquifer. The aquifer causes considerable water production and causes pressure in the reservoir to remain high during hydrocarbon production.

1.4 Generic Conclusions and Lessons Learned

Development of CO_2 stores in depleted gas fields:

- The geological data (seismic and well data) from gas production was, in both cases, sufficient to allow characterisation and assessment of the reservoirs for CO_2 storage. No new subsurface measurements were required.
- The ROAD Project has shown that deeply depleted gas fields are suitable locations for CO_2 storage. The fields have been selected and studied in depth. No showstoppers were found, even in detailed subsurface analysis. For P18-4, the licence process was completed and a storage licence was granted following review by the authorities. This points the way forward for future use of depleted gas fields for CO_2 storage.
- A practical engineering and a technical design was developed for each field, in most detail for P18-4. This included the effect of the low initial pressure, the re-completion and re-use of existing wells and the re-use of topside facilities including, for P18-4, an offshore platform.

Heating of CO_2 during startup of injection: At the start of the project heating of the CO_2 stream was thought to be necessary to avoid damage of slugging to the pipeline/well infrastructure, particularly early in the project when P18-4 reservoir pressures are very low. This would mean building a costly heater on the platform. More detailed engineering studies showed that the heater was expensive and caused operational difficulties. Detailed flow assurance modelling concluded that operation was possible without a heater by using an insulated pipeline and appropriate flow control procedures. Further (future) optimisation of the design may even allow the insulation to be removed.

Impact of cool CO_2 on reservoir integrity: At the start of the project it was suspected that injection of cool CO_2 (8-15^oC compared with reservoir tempreatures >100^oC) may lead the formation of thermally induced fractures so the reservoirs were studied using coupled multiphase flow mechanical modelling. For P18-4, no fractures are formed at the actual depth of the storage of 3,400 m, thus injection of cool CO_2 is not problematic. For Q16-Maas, the proposed well is now very close to a sealing fault, which could be stressed by temperature differentials in the rock. For Q16-Maas, this requires further study.

Importance of fault assessment: The P18-4 reservoir is bounded by a fault which separates this reservoir from the P15-9 reservoir. A proper characterisation of its sealing potential is essential for the definition of the storage complex and consequently the potential measures for well abandonment in P15-9.

Influx of water into the reservoir: In the initial stage of CO_2 injection at Q16-Maas, the injected CO_2 stream was meant to enhance the tail-end production of condensates. During primary production, extensive water influx caused the production strategy to be changed. The planned changes to the well location reduce the feasibility of enhanced condensate production during injection of CO_2. This shows the potentially strong impact of field development (which includes such parameters as well lay-out and choice of production intervals) on the re-use of hydrocarbon fields for CO_2 storage and, in the present case, on the potential for benefits from enhanced recovery.

Commercial Arrangements: In both storage cases, a workable commercial framework was agreed between the existing storage operator and the project. Aside from the long term storage liabilities created in the CCS Directive, existing contractual approaches can be applied to CCS. The storage liabilities, however, pose a significant barrier to CCS projects due to the high degree of uncertainty over these liabilities, and the lack of commercial driver for CCS. Solutions were found. However, they require support and flexibility from the regulator, and they rely on the short duration and demonstration nature of the project, so these solutions may not be generally applicable.

2 Introduction

2.1 Introduction and report structure.

The ROAD project was one of the leading European CCS Projects from 2010 to 2017. During that time, a great deal of project development and engineering work was completed, including full design and procurement to allow a possible FID at end 2011 or early 2012.

This report is one of a set of "Close-out" reports written after the formal decision to terminate the project was made in September 2017. The report aims to summarise the technical work done on the CO_2 storage system during the full duration of the project, and highlight lessons learnt. The objective is to give future CCS project developers, and knowledge institutes, the maximum opportunity to use the knowledge gained and lessons learnt by the ROAD project team.

This introductory section to the "Close-out Report Storage" is intended to give the reader the context to understand the detail in the following sections without reading the other Close-out reports. It includes

- A general description of the overall ROAD project, including the history of its development,
- An overview of the technical work done on storage covering objectives, scope and the timing of the work
- An overall description of both the main storage sites.

Following this overview, Part A of the report (Sections 3 – 9) covers the detailed work on storage in the first phase of the project, focusing on the P18-4 reservoir. Part B (Sections 10-12) covers work on Q16-Maas.

There are many highlights and lessons learnt from the work throughout this report. However, those judged most important and most general have been collected and included in the Management Summary in Section 1.

This is a report produced by the ROAD Project. It contains a summary and interpretation of work performed for the ROAD Project, including by third parties, and also work done in collaboration with other parties during the course of the ROAD Project, in particular as part of the Dutch research programme CATO. While this report is provided in good faith, other parties may have different interpretations on the work. Much of the source material is available to the public, and readers are recommended to review the source material where possible for topics of particular interest. Readers should also be aware that both P18 and Q16-Maas reservoirs are subject to ongoing production and ongoing technical study, which has continued after work involving the ROAD Project stopped. As such, the information reported here does not represent the latest understanding of the fields.

2.2 General Project Description

The ROAD Project is the Rotterdam Opslag and Afvang Demonstratieproject (Rotterdam Capture and Storage Demonstration Project) which ran from 2009 to 2017, and was one of the leading integrated Carbon Capture and Storage (CCS) demonstration projects in the world.

The main objective of ROAD was to demonstrate the technical and economic feasibility of a large-scale, integrated CCS chain deployed on power generation. Previously, CCS had primarily been applied in small-scale test facilities in the power industry. Large-scale demonstration projects were needed to show that CCS could be an efficient and effective CO_2 abatement technology. With the knowledge, experience and innovations gained by projects like ROAD, CCS could be deployed on a larger and broader scale: not only on power plants, but also within the energy intensive industries. CCS is one of the transition technologies expected to make a substantial contribution to achieving European and global climate objectives.

ROAD is a joint project initiated in 2009 by E.ON Benelux and Electrabel Nederland (now Uniper Benelux and Engie Nederland). Together they formed the joint venture Maasvlakte CCS Project C.V. which was the project developer. The ROAD Project is co-financed by the European Commission (EC) within the framework of the

European Energy Programme for Recovery (EEPR) and the Government of the Netherlands. The grants amount to € 180 million from the EC and € 150 million from the government of the Netherlands. In addition, the Global CCS Institute is knowledge sharing partner of ROAD and has given a financial support of € 4,3 million to the project. The Port of Rotterdam also agreed to support the project through investment in the CO_2 pipeline.

In the first phase of the project, 2009-2012, the project was developed to final investment decision (FID) based on using the P18-4 gas-field operated by TAQA as the CO_2 storage location. This required a pipeline of approximately 25km from the capture location (Uniper's coal-fired Maasvlakte Power Plant – MPP3), about 5km onshore and 20km off-shore.

Unfortunately, the collapse in the carbon price undermined the original business case, and in 2012 a positive FID was not economically possible. The project then entered a "slow-mode" in which activities focused on reducing the funding gap, either by reducing costs or by securing new funding. In late 2014 a possible new funding structure was identified, and explored in 2015 and 2016. This included additional grants for operation and cost reductions. The cost reduction that could be successfully applied was to change storage sink to a newly developed field, Q16-Maas, operated by Oranje Nassau Energie (ONE). This smaller field was much closer, with only a 6 km pipeline required. This resulted in a remobilization of the project late in 2016, and development of the new scheme. However, in mid 2017 work was again halted, and the grant formally terminated in November 2017.

The ROAD project design applied post combustion technology to capture the CO_2 from the flue gases of a new 1,069 MWe coal-fired power plant (Maasvlakte Power Plant 3, "MPP3") in the port and industrial area of Rotterdam.

The capture unit has a design capacity of 250 MWe equivalent. During the operational phase of the project, approximately 1.1 megatons of CO_2 per year would be capture and stored, with a full-load flow of 47kg/s (169 t/h) of CO_2. For transport and storage two alternatives were developed as described above: storage in the P18-4 reservoir operated by TAQA; and storage in the Q16-Maas reservoir operated by Oranje-Nassau Energie.

After a competitive FEED process, Fluor was selected as the supplier for the capture technology in early 2011. The plant was fully engineered, and long lead items contracted for, ready for an FID in early 2012. All the necessary permitting was completed, with a permit for the capture plant being granted in 2012. Following the delay to the project, an updated design was developed with Fluor in 2017 incorporating lessons learnt from research and development in the intervening years, changes to the MPP3 site, and the impact of the changes to the transport and storage system. A revision to the permit was under development when the project was halted.

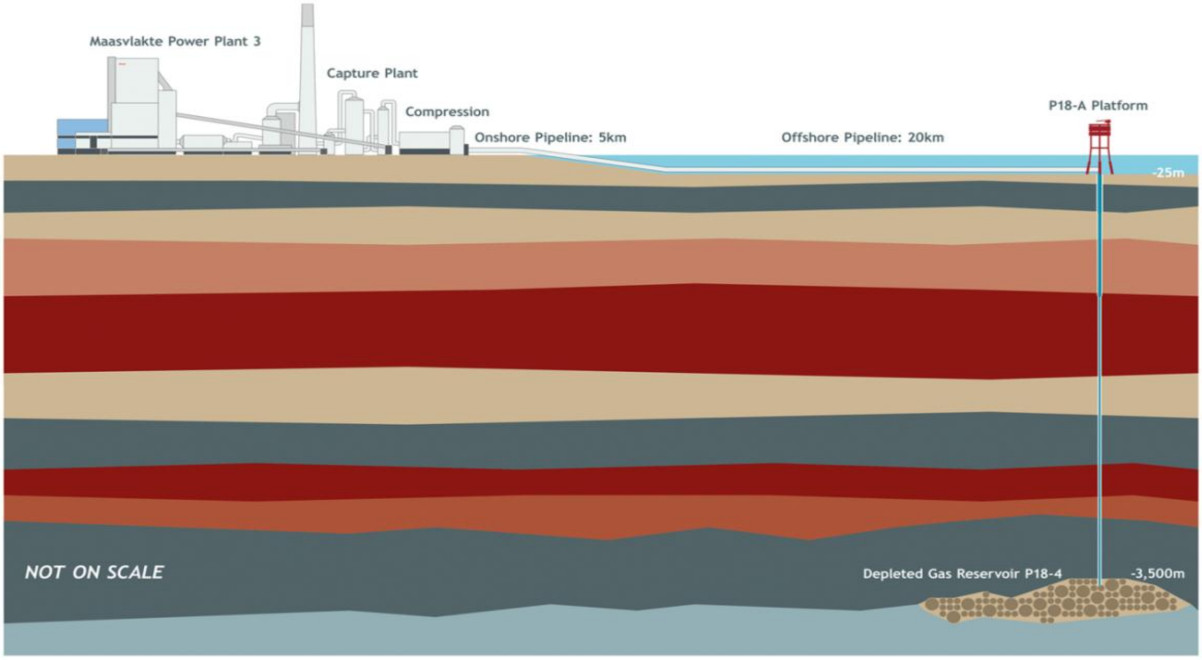
For storage in P18-4

From the capture unit the CO_2 would be compressed and transported through a pipeline: 5 kilometers over land and about 20 kilometers across the seabed to the P18-A platform in the North Sea. The pipeline has a transport capacity of around 5 million tonnes per year. It is designed for a maximum pressure of 140 bar and a maximum temperature of 80 °C. The CO_2 would be injected from the platform P18-A into depleted gas reservoir P18-4. The estimated storage capacity of reservoir P18-4 is approximately 8 million tonnes. Figure 2.1 shows the schematic illustration of this.

P18-4 is part of the P18 block which also includes the larger P18-2 and also a small field, P18-6. These depleted gas reservoirs are about 3.5 km below the seabed under the North Sea about 20km from the Dutch coastline, and have a combined CO_2 storage capacity of around 35 Mt.

The ROAD Project with storage in P18-4 was fully developed for FID at the end of 2011, including all engineering, regulatory and permit requirements. A CO_2 storage permit was granted in 2013, the first such permit in Europe. Unfortunately, a positive FID was not possible due to funding problems, and in 2012 technical project development on P18-4 was halted.

Figure 2.1 Schematic overview of the ROAD Project using storage in P18-4



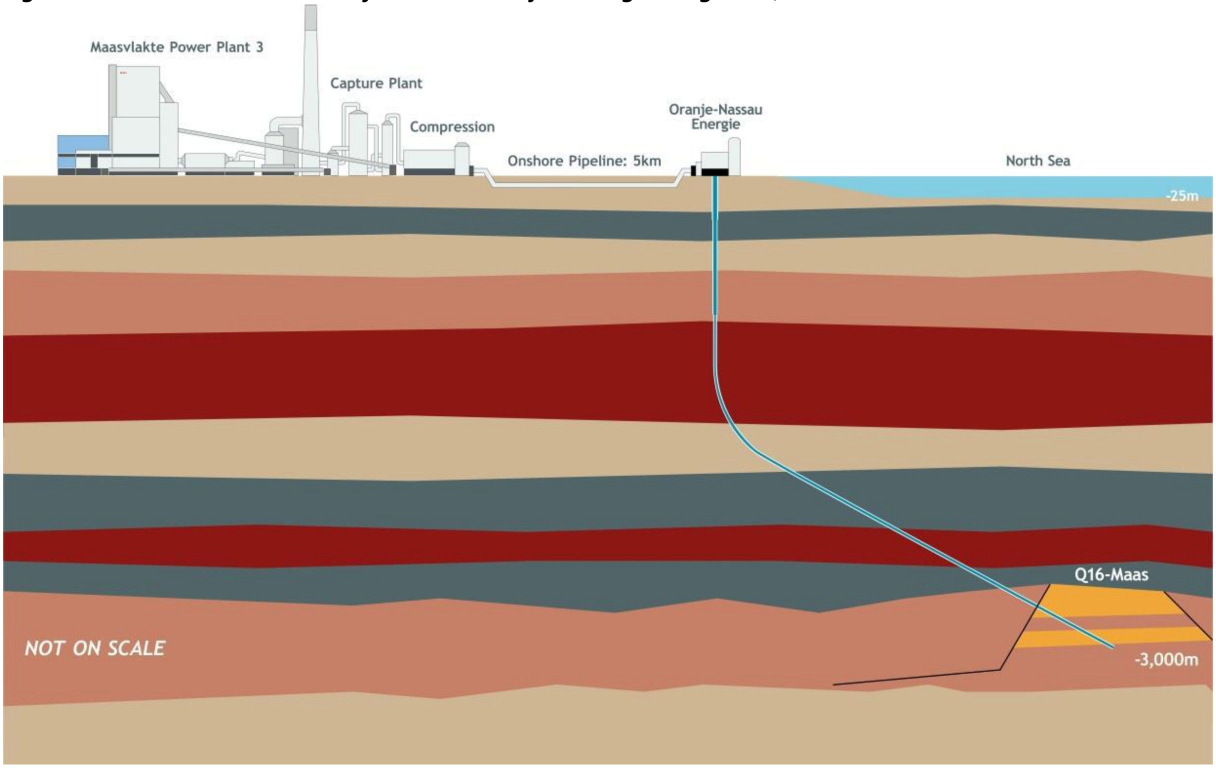
For storage in Q16-Maas

From the capture unit the CO_2 would be compressed and transported through a pipeline over land to the current ONE-production site Q16-Maas (Figure 2.2). The selected pipeline design would have a transport capacity of in excess of 6Mt/year. It was designed for a maximum pressure of 40 bar although in the first phase operation at 20 bar was planned. Final compression to injection pressure (around 80 bar) would be at the injection site.

The Q16-Maas reservoir is located just off-shore from the Maasvlakte, and is reached by a long-reach well, drilled from on-shore. The well is about 5km long, and travels approximately 3km down to reach the reservoir depth, and 3 km horizontally (off-shore) to reach the reservoir location. The reservoir is relatively new (production started in 2014) and was not due to finish production until 2022. Therefore this scheme involved the drilling of a second well to accelerate gas production and so allow CO_2 injection to start in 2020. This second well would also allow co-production of modest amounts of condensate (and possibly natural gas) during CO_2 injection. The estimated storage capacity of reservoir Q16-Maas is between 2 and 4 million tonnes.

This reservoir was identified as a possible storage location only at the end of 2014, with project development running through 2015-2017. Due to funding uncertainties, the work focused on feasibility, cost estimation and concept design to the level required for permitting. Therefore a lower level of detail is available for this storage location, compared to P18-4. It should also be noted that unexpected water production was experienced from Q16-Maas in 2016, leading Oranje-Nassau Energie to issue a revised reservoir model and production plan in May 2017. Since this was only shortly before the ROAD work was halted, the ROAD plans for Q16-Maas were not fully amended to reflect this new production data.

Figure 2.2 Schematic overview of the ROAD Project using storage in Q16-Maas



2.3 Overview of the Technical Work

Objectives

The storage site development should meet the following objectives:

- Assurance of the technical performance of the reservoir in terms of storage capacity and injectivity
- Assurance of the safety and environmental performance of the storage site including the wells and the platform including compliance with all regulatory requirements
- Suitable engineered designs of the platform and the wells
- Cost analysis of the additional investments and operations during the full storage lifetime

Scope of Work

These objectives were to be met in the project in a staged approach:

- Conceptual design phase optionally subdivided in the
  - Pre-feasibility stage
  - Feasibility stage
- Detailed engineering design phase optionally subdivided in the
  - Pre-FEED stage
  - FEED stage

The FEED establishes the basis for contracting and procurement of manufacturing and construction of the facility. For storage, this was planned to be done immediately after a positive FID for the project had been taken.

For P18-4, the other three stages (pre-feasibility, feasibility and pre-FEED) were completed and the FEED study was defined and tendered for (but not performed).

For Q16-Maas, only the pre-feasibilty and feasibility studies were completed before the technical work was put on hold. Furthermore, a new reservoir model became available in spring 2017 showing a much more active aquifer than expected which significantly affects planned gas production and CO_2 injection regimes, and also substantially reduces the feasible CO_2 injection rates. This new modelled has only been applied to CO_2 injection on a preliminary basis, and therefore some aspects of the feasibility of Q16-Maas, particularly the scope for improving the maximum practicable injection flow rate, need to be reassessed. Nevertheless, the results from the pre-feasibility and feasibility studies (mostly using the original reservoir model) are reported here.

The work for the development of CO_2 storage at the P18-4 gas and Q16-Maas fields was split in the following main tasks:

1. Topside and well engineering, and geological investigation
2. Contracting and procurement
3. Construction and pre-commissioning of the storage unit

Timetable

The timetable of the work is given in Table 2.1 below, grouped into the tasks described above. The larger part of the results on CO_2 storage development at P18-4 relates to the first main task (Feasibility Stage). The work on P18-4 was halted after selection of the winning proposal for the FEED study but which was not granted. Activities continued with the investigation of the alternative storage site Q16-Maas. The work on Q16-Maas ended after the feasibility studies for the wells and the top side facilities (gas separation).

Table 2.1 ROAD storage development timeline with development stages and main topics; numbers refer to sections in the report; light green = pre-feasibility, green = feasibility, light blue = pre-FEED, blue = FEED

Development stage and main topics	2009	2010	2011	2012	2013	2014	2015	2016	2017
P18 Feasibility stage									
• 4.1-4.4 Subsurface and wells									
• 4.5 & 4.6 Platform									
• 7 Risk management plan									
• 8 Environmental impact									
P18 Pre-FEED stage									
• 5.1-5.3 Platform									
• 5.4 Well									
P18 FEED stage									
• 6 Platform scope					***Not completed***				
Q16 Pre-feasibility stage									
• 9.1-9.3 Subsurface and well									
• 9.4 Gas separation									
• 9.5 Costs and revenues									
Q16 Feasibility stage									
• 10.1-10.3 Subsurface and wells									
• 10.4 Gas separation									

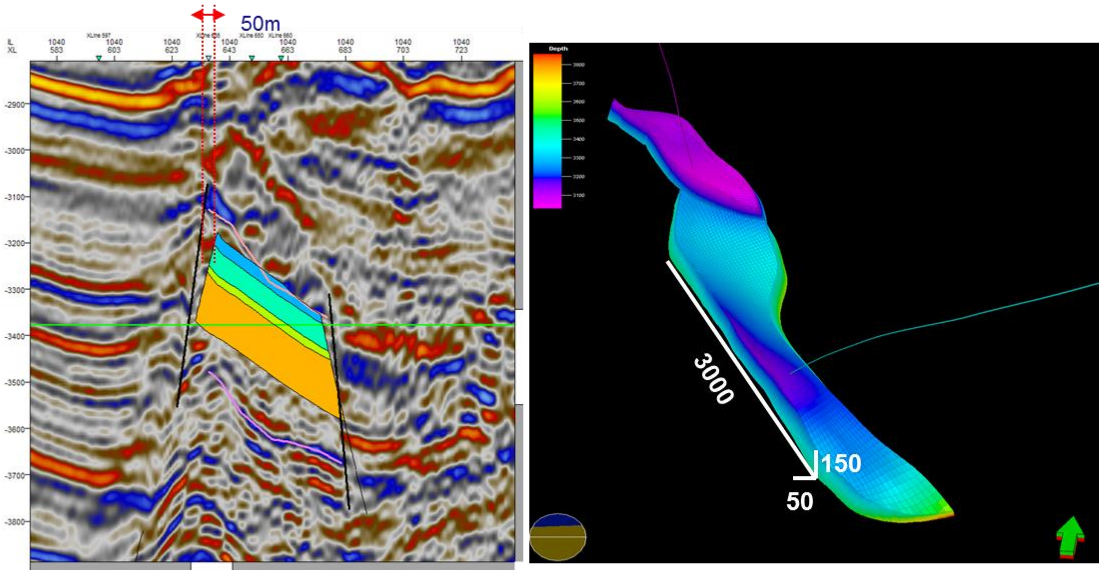
2.4 Overall Description of Storage Locations P18-4 and Q16-Maas

P18-4

High-calorific value gas has been produced from the P18 fields since 1993. It is trapped in Triassic-aged sandstones of mixed fluvial/aeolian origin below impermeable layers of clay. The P18 fields consist of three reservoirs that are bound by a system of NW-SE oriented normal faults, which are sealing because of juxtaposition of permeable reservoir intervals with impermeable intervals in the overburden. Reservoir P18-4 has one compartment (Figure 2.3).

The P18-4 gas reservoir is suitable geological structure for CO_2 storage because a thick package of different seals is present above the storage reservoir and bounding faults are sealing. No seismicity has occurred during production of gas at the storage location.

Figure 2.3 Seismic cross-section through the block P18-4 (left) and 3D view of the reservoir interval of block P18-4 (right).



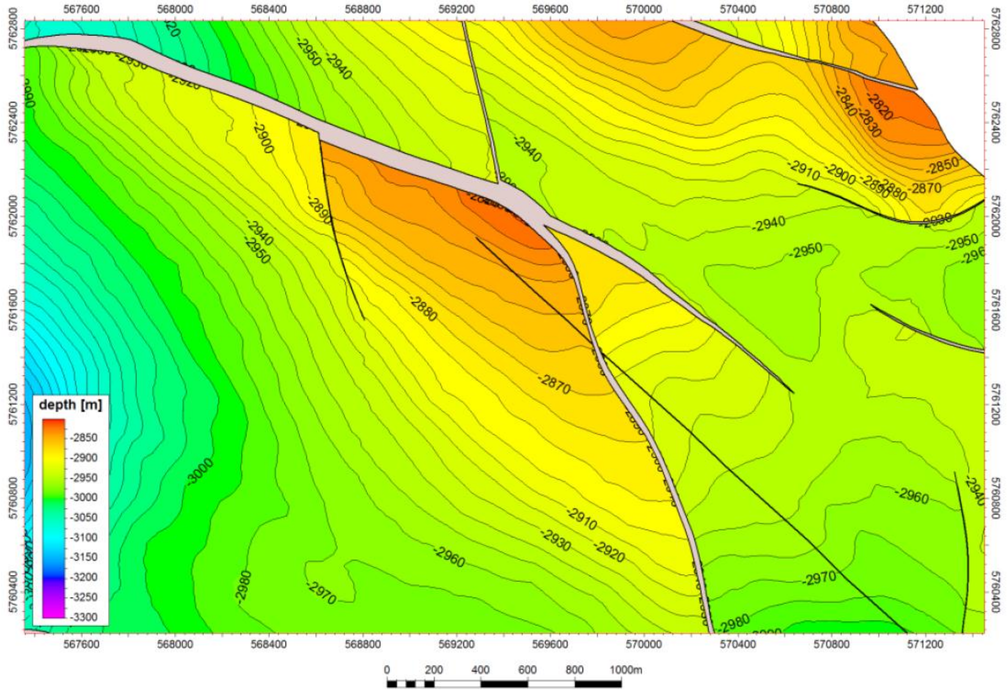
Q16-Maas

The Q16-Maas gasfield (

Figure 2.4) was discovered by the MSG-03x exploration well in 2011. The reservoir consists of rocks of Triassic age. Various normal faults together define the northern and north-eastern limits of the reservoir. Two smaller faults split the reservoir into three compartments, but it is not known whether those faults are sealing. The western fault seems to be of limited importance (it quickly dies out in a southern direction), whereas the downthrown segment beyond the eastern fault probably contains at best a very small amount of gas only.

In principle, CO_2 can be safely and securely stored in the Q16-Maas field, as the existence of the gas field proves the quality of the caprock.

Figure 2.4. The top main reservoir map of the Q16-Maas field.

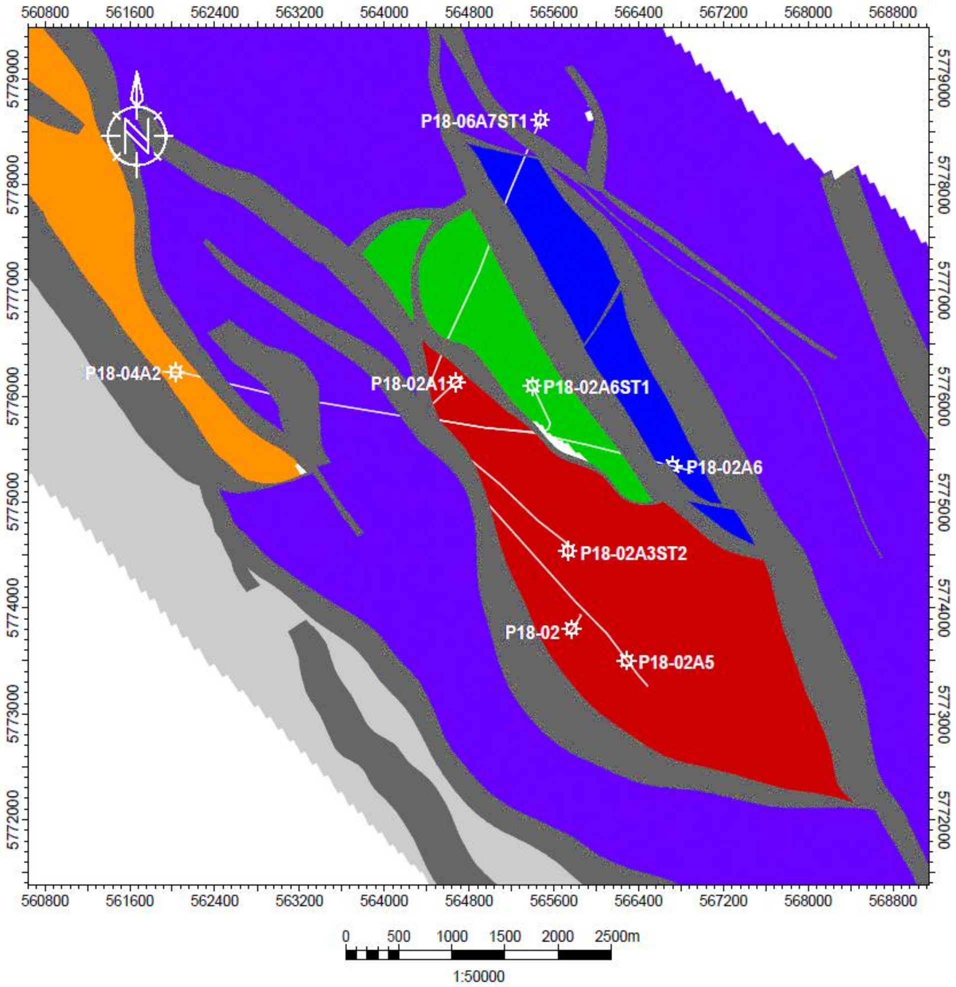


Section A: P18-4

3 Storage Selection

The storage site selection was conducted in 2008 and 2009 and already reported in 2011 [Weerd, 2011]. There were three gas fields in the P18 offshore block that were near the end of their production. Due to their relatively small distance to the Maasvlakte they are very suitable for a CO_2 storage project in Rotterdam. The gas fields are managed by the company TAQA on behalf of the owners, being TAQA EBN, Dana and Dyas. The fields in the P18 block (shown in ***Figure 3.1***) are isolated horst blocks surrounded by faults.

Figure 3.1 Layout of the P18 field , with position of wells at the top of the reservoir interval (top Bunter). Orange: P18-4 block; Red: P18-2, compartment I; Green: P18-2, compartment II; Blue: P18-2, compartment III; P18-6: block drilled by P18-06A7ST1 just north of the P18-2 block.



The reservoir in de P18 fields is formed by sandstone layers of the Triassic. This Triassic reservoir is informally referred to as Bunter. The seal or caprock on top of the gas-holding reservoir is formed by a thick envelope of shale from the Triassic, 150 to 180 m thick. A Jurassic clay envelope of 400 to 500 m thick on top of the Triassic seal ensures sealing. There are also thick clay envelopes present in the Cretaceous and Tertiary layers.

The P18 fields are laterally sealed by faults. These faults are mapped by means of seismic study; only the big faults are mapped. There is quite a difference in the vertical displacements of these faults. Along these faults, Triassic reservoir sandstone is found on one side of the fault plane and Jurassic or Triassic shale on the other. These faults seal well and allow no gas to permeate. For faults with lesser vertical displacement Triassic reservoir sandstone is present along both sides of the fault. These faults thus have a vertical displacement of less than 210 m. These faults can allow gas to permeate; pressure measurements in the reservoirs during the production period indeed show that that some of these faults allow gas to permeate.

The P18 cluster was a logical first step in the development of offshore CO_2 storage. Its proximity to Rotterdam, its storage capacity (of about 40 Mt in two fields in the cluster, P18-2 and P18-4) and the injection rates that can be accommodated (both fields can store at least 1.1 Mt/yr) all make it suitable. The cluster, more specifically the P18-4 field, was selected for storage of the CO_2 captured by the ROAD Project, which planned to produce CO_2 at a rate of 1.1 Mt/yr. In 2011, the production of natural gas was expected to finish by 2015 for the P18-4 field and around 2018 for the P18-2 field.

In 2009, TNO (Inventory of potential locations for demonstration project CO_2 storage, TNO 2009) made an inventory of suitable gas reservoirs in the North Sea, which become available after 2012 and have a storage capacity between 0.5 and 10 Mton CO_2. Subsequently, locations complying to these requirements, were assessed on the basis of the AMESCO criteria [Royal Haskoning, 2011a].

The AMESCO project [Croezen et al., 2007: Section 8.1] formulated a set of criteria for the selection of gas reservoirs suitable for CO_2 storage. A summary of the AMESCO selection criteria is presented in Table 3.1.

CRITERIA	GOOD CHARACTERISTICS
Existing and former penetrations	
Number of wells abandoned before 1985	As few as possible
Number of abandoned wells in total	As few as possible
Number of wells to be abandoned	As few as possible
Reservoir	
Depth of reservoir	More than about 800m, but not much deeper
Water in reservoir	As little as possible
Faults	
Fault approach to surface	As deep as possible
Number of faults	As few as possible
Assessed fault permeability	Uniformly low
Cap rock	
Permeability	As low as possible
Self-healing potential	High
Thickness	As large as possible
Reservoir rock	
Injectability	High
Porosity	High
Chemical reactivity	Low
Homogeneity	High
Earth tremor likelihood during injection	Low
Reservoir gas	
CO_2 in original gas phase in reservoir	High proportion
H_2S and BTEX in reservoir gas phase	Low proportion
Surface features and uses	
Land use above reservoir	Agricultural
Proximity of vulnerable objects to potential leakage paths from the reservoir	As far as possible

Table 3.1 Overview of the AMESCO selection criteria for CO_2 storage in depleted gas reservoirs

Three sets of offshore storage reservoirs resulted from this evaluation, which fulfil almost all AMESCO criteria:

- Castricum Zee and Q8-A reservoirs operated by Wintershall at a distance of about 100 km from the MPP3 plant;
- P15-E and –C with larger reservoirs in the blocks P15 and P18 operated by Taqa at a distance of less than 25 km from the MPP3 plant;
- P6-D reservoir operated by Wintershall at a distance of about 150 km from the MPP3 plant.

The gas reservoirs in the blocks P15 and P18 are the closest to the power plant. The P18 reservoirs were preferred, because the P15 reservoirs were expected to produce for a longer period and are further away from the CO_2 source.

The P18 block with the preferred gas reservoirs is recognized as potential storage location in the National Water Plan (Nationaal Waterplan). The almost depleted gas reservoirs in this block are located at a depth of almost 3.5 km below the seafloor at a distance of about 20 km from The Maasvlakte. The reservoirs have a summed effective storage capacity of about 35 Mt.

A comparison of the individual reservoirs in P18 resulted in the following:

- The reservoirs and wells in P18 offer sufficient possibilities for storing a total volume of at least 4 Mt CO_2 (this being the minimum required by the Dutch grant of 2010) with an average injection rate of 1.1 Mt per annum.
- P18-4 and P18-6 are suitable for CO_2 storage during the period of 2015 to 2020. The storage capacity and injectivity of P18-6 are relatively small.
- For the use of the largest storage reservoir, P18-2, some technical issues will need to be solved, in particular the qualification of the abandoned exploration well and the removal of the side-track in P18-6A7.
- The cement quality at the level of the caprock is uncertain for some of the wells.

A summary of the evaluation for the three P18 reservoirs is presented in Tabl. From this table, the reasons for the selection of P18-4 is clear.

Table 3.2 Overview of the evaluation of the storage reservoirs in the P18 Block

Criteria	P18-2	P18-4	P18-6
Geological conditions			
Type of reservoir rock	++	++	++
Caprock	++	++	++
Reservoir depth	++	++	++
Faults	+	+	+
Subsurface movement during production			
Probability of seismicity	++	++	++
Ground movement	+	+	+
Reservoir properties			
Storage capacity	++	++	-
Injectivity	++	++	- -
Water influx	++	++	0
Presence of natural CO_2	+	+	+
Other gases than natural gas	++	++	++
Timing	+	++	++
Reservoir gas characteristics			
Initial pressure	++	++	++
Residual pressure	++	++	++
Presence of natural gas	++	++	+
Composition CO_2 injection stream	++	++	++
Potential chemical reactivity	++	++	++
Wells			
Operational wells	+	++	-
Abandonment points of interest	- -	++	++
Abandoned wells	+	++	++
Well cementing)	-	-	-
Situation at sealevel			
Distance of reservoir to source	++	++	++
Re-use options of present infrastructure	++	++	++
Use of the area near the injection location	++	++	++
Boundary conditions policy, law and regulation			
CO_2 storage policy	++	++	++
Plans for reservoir use	++	++	++
Impact on other gas producing reservoirs	++	+	++

4 Feasibility study on P18-4

The CATO2-report CATO2-WP3.01-D06 entitled “Feasibility study P18” [Vandeweijer et al., 2011] describes the feasibility study for CO_2 injection in the depleted P18 gas field as carried out in 2009 and 2010. At that time, CO_2 injection was planned to start in 2015. Based on this report, a number of issues were identified and prioritized both by the ROAD project and by the CATO2 project, for further attention. The main outcomes of the additional work have also been included in this chapter. The focus in this report has shifted from the whole P18 field (i.e. P18-2, P18-4 and P18-6) to the P18-4 field only, since this is the compartment where injection was envisaged in the demonstration phase of the ROAD Project. The feasibility study is organized by technical discipline, i.e. geology, reservoir engineering including thermal effects, geochemical and geomechanical effects, and monitoring.

The feasibility study of the P18 cluster as a whole showed that injection could start by the end of 2015. Existing wells that would be used for injection will need a workover: replacement of the tubing, installation of downhole equipment (if necessary) and redesign of wellhead and wellhead controls. There are no abandoned wells that can no longer be accessed. One well will need to be either abandoned, or re-opened, but this is deemed feasible.

During the slow mode (2013 to 2014), ROAD considered applying for NER-300 funding, which would require operation for a minimum of 10 years. An inventory of all activities required to be completed before injection can start showed that the timeline associated with the NER300 funding is feasible for the P18 cluster. Depending on the amount of CO_2 stored, the unit cost of storage is 39.1 €/t CO_2 (for a stored volume of 5.5 Mt), or 7.6 €/t CO_2 (for a stored volume of 25 Mt). These cost estimates include well work-overs, platform modifications, a pipeline and onshore facilities, but OPEX sharing with the P15 platform are excluded.

The risks identified in the feasibility study concern the quality of the wells and, more specifically, the sealing quality of the wells at the caprock level. All wells are accessible and remediation work is feasible, but one well work-over is difficult, requiring the removal of a temporary plug.

Once the P18-4 field was selected for storage of the CO_2 from the ROAD project (with a storage capacity of about 8 Mt),there was consideration whether TAQA could also offer additional storage to a third party. The P18-2 field would need to be brought online for CO_2 storage, at least compartment III of this field. This implies a work-over of a diverted well (lifting a temporary plug).

If the third party access was required before cessation of production in P18-2, TAQA considered that this could be managed by injecting combined volumes into P18-4 for a limited period before opening P18-2 for storage.

Table 4.1 Overview of terminology for codes of well, reseroirs etc. [Royal haskoning, 2016a]

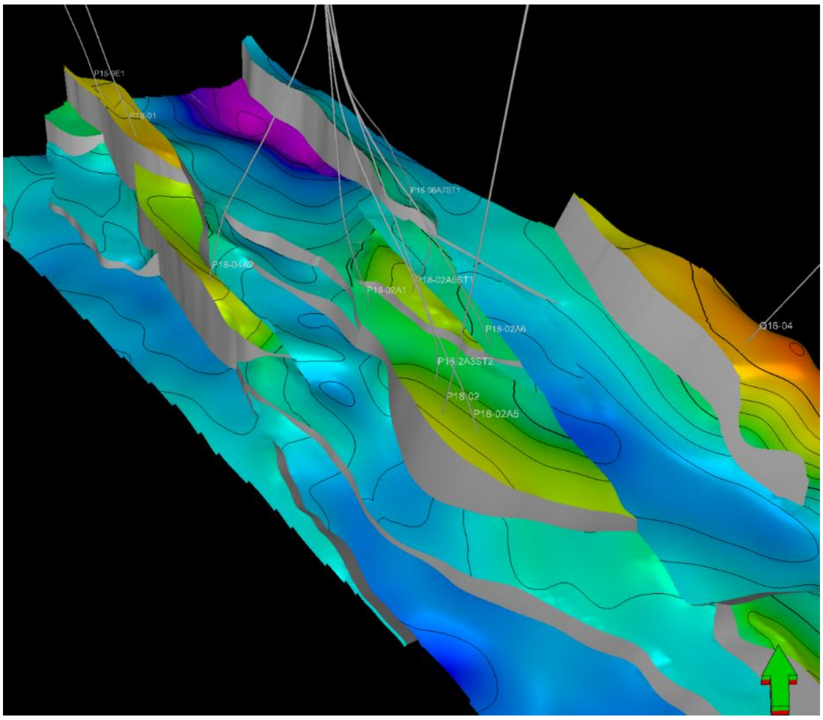
	Name	Explanation
Block	P18	Refers to Block P18 on the North Sea
Platform	P18-A	Refers to satellite platform P18-A on the North Sea
Reservoirs	P18-2	Refers to reservoir P18-2
	P18-2-I	Refers to compartment I of reservoir P18-2
	P18-2-II	Refers to compartment 2 of reservoir P18-2
	P18-2-III	Refers to compartment 3 of reservoir P18-2
	P18-4	Refers to reservoir P18-4
	P18-6	Refers to reservoir P18-6
Wells	P18-02	Exploration well P18-2
	P18-2A1	Production well P18-2A1 in reservoir P18-2-I
	P18-2A3	Production well P18-2A3 in reservoir P18-2-I
	P18-2A5	Production well P18-2A5 in reservoir P18-2-I
	P18-2A6	Production well (suspended) P18-2A6 in reservoir P18-2-III
	P18-2A6-S1	Producing side track of P18-2A6 in reservoir P18-2-II
	P18-4A2	Production well P18-4A2 in reservoir P18-4
	P18-6A7	Production well P18-6A7 in reservoir P18-6

4.1 Geology and petrophysics

This section describes the reservoir geology, overburden and petrophysics of the P18 gas fields, based on the feasibility study reporting in 2011 [Vandeweijer et al., 2011]. In particular, it addresses the potential storage volume based on GIIP, discuss the properties and sealing quality of the caprock and overburden, and indicate the level of uncertainty in the information provided.The field is located in the offshore part of the Dutch sector, 20 km off the coast of the "2nd Maasvlakte", the latest extension to the port of Rotterdam.

High-caloric gas is being produced from the P18 fields since 1993. It is trapped in Triassic-aged sandstones of mixed fluvial/aeolian origin below impermeable layers of clay. The P18 fields consist of three reservoirs that are bound by a system of NW-SE oriented normal faults, which are sealing because of juxtaposition of permeable reservoir intervals with impermeable intervals in the overburden (Figure 4.1). Reservoir P18-2 has three compartments, whereas reservoirs P18-4 and P18-6 each have one compartment. The top of the compartments lies at depths between 3175 m and 3455 m below sea level. Production data suggests that most faults between the compartments are sealing, except for the one between compartments P18-02I and P18-02II, which is not sealing in the current situation.

Figure 4.1 3D view of the top of the P18 reservoirs. Faults are shown in grey.



The P18-4 gas reservoir is suitable geological structure for CO_2 storage because:

- A thick package of different seals is present above the storage reservoir at P18-4. Faults are present in the primary seal, but these faults are sealing.
- Permeable reservoir facies are juxtaposed against impermeable shales in the overburden. Thereby, the reservoir has safely contained gas over millions of years. Although impossible to rule out completely, it is not likely that the sealing properties of the basin-bounding faults have been compromised.
- The largest stress changes develop at the end of depletion of the gas reservoir. Top seal analysis has shown that top seal integrity and fault stability are not critical factors for injection and storage at P18-4. No seismicity has occurred during production of gas at the storage location.

4.2 Reservoir

Average gross reservoir thickness in the production wells is 200 m. Average NTG of the four individual production zones identified in the reservoir (0.62-0.96) increases from base to top over the reservoir interval. NTG stands for net-to-gross ratio and is an an indication of the percentage of the reservoir rock which is suitable for CO_2 storage (or gas production). Average porosity is highest in the upper zone (7-13%), is slightly lower in the middle two zones (5-9%), and lowest in the lower zone (3-5%). Permeabilities were calculated based on a porosity-permeability relation, i.e., they follow the same trend. They are highest in the upper zone (2-207mD), lower in the middle two zones (0.1-0.8mD), and lowest in the lower zone (< 0.1mD). Combined thickness of the upper and middle two zones is approx. 100m, as is the thickness of the lower zone. Average water saturations are lowest in the upper (0.24-0.47) and lower of the middle two zones (0.32-0.42), and highest in the lower zone (0.78-0.92).

4.3 Seal

The primary seal to the P18 reservoirs is 150 m thick, and consists of impermeable siltstones, claystones, evaporites and dolostones that directly overlie the reservoir. Closure along the reservoir-bounding faults is obtained by juxtaposition of permeable reservoir intervals with impermeable intervals in the overburden. Most of the bounding faults do not continue further upward into the overburden than the shales of the Altena group, the secondary seal, which is approx. 500m thick. Faults that do penetrate the primary and secondary seal are rare. It is unlikely that their sealing capacity has been compromised, since higher up in the overburden additional seals with substantial thickness are located.

4.4 Gas initially in place (GIIP)

Dynamic GIIP of the P18 field, estimated based on production data available at the time of the study, was 17.22BCM. GIIP estimates obtained from the reservoir model were substantially lower: 15.39BCM. For block P18-02, the discrepancy between static and dynamic GIIP is only about 7%, which can easily be attributed to differences in porosity and average water saturation between the wells and the property model.

For block P18-04 and P18-06, the discrepancy is much higher, and likely attributed to a combination of under- and overestimated property values (porosity, water saturation) and reservoir structural uncertainty, i.e., reservoir-bounding faults that are slightly off in lateral position and dip compared to the 3D seismic.

GIIP estimates as obtained from the static model suffer from structural uncertainty, i.e., reservoir-bounding faults that are slightly off in lateral position and dip compared to the 3D seismic and from discrepancies in petrophysical properties such as e.g. porosity and water saturation between the reservoir model and the values from the production wells A re-interpretation of the faults in the reservoir model directly from the 3D seismic data will improve the quality of the reservoir model, and the GIIP estimates. An effort can be made to improve the match between the property model and the wells, especially for block P18-6, where the mismatch in GIIP is 40%. Facies-based property modelling will improve the quality of the model by adding heterogeneity to the reservoir based on geological concepts. Such heterogeneity, which is inevitably present in any reservoir, may have large effect on the injection in and subsequent migration of CO_2 through the reservoir.

4.5 Dynamic reservoir modellling

An analytical model study of P18 revealed that in P18-2 and P18-4 the target rate of 1.1 Mt/y can be realised and the total injection period needed to fill up the reservoir to the initial pressure is 28 years and 7 years, respectively. In contrast the target rate cannot be realised in P18-6. The low permeability gives rise to a high FBHP (flowing bottom hole pressure) in order to realise the target rate, exceeding the maximum allowed.

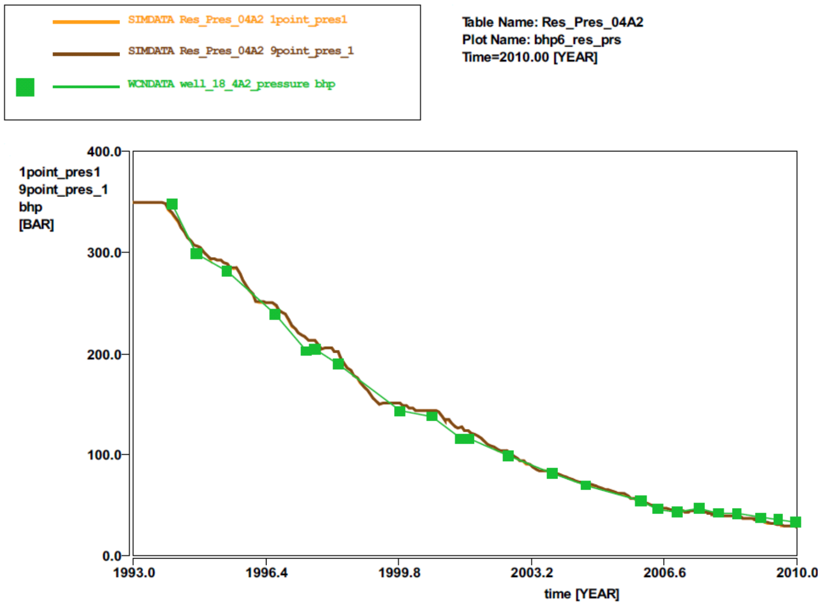
The original static model of P18 from TAQA Energy B.V. had large uncertainties because the volumes from the p/Z analysis did not correspond with the static model, especially for the compartments P18-4 and P18-6. In P18-4, no adjustment has to be made to match the actual flow performance. The volume balance was incorrect. The structural re-interpretation of this compartment gave the correct volumes of this compartment. Simulations showed that in P18-4 the target rate of 1.1 Mton/year is possible and a total of 8.1 Mton CO_2 can be injected.

At a later stage both the geological model and the reservoir model were improved by adjusting the permeability by:

- Adjustment of the pore volume of P18-4 by repositioning of the eastbounding fault within uncertainty of seismic resolution
- Adjustment of spatial porosity distribution
- Adjustment of upscaling pars, e.g. no of layers

These modifications resulted in a satisfactory history match of the gas production history (Figure 4.2); a mismatch can still be observed during the shut-in periods [Arts et al., 2011].

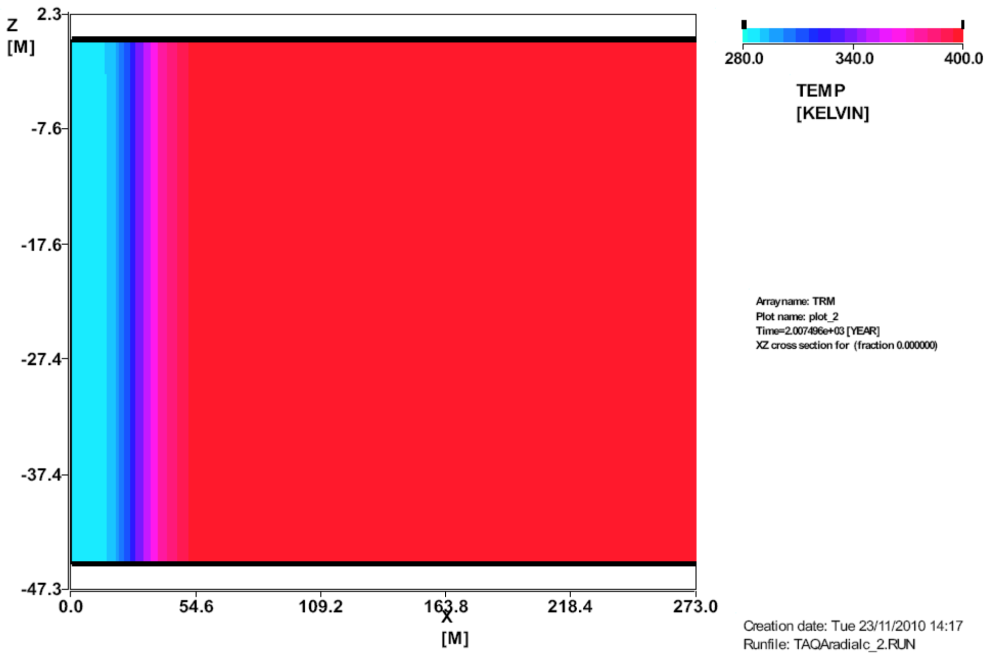
Figure 4.2 Reservoir pressure of the dynamic P18 model (brown line), measured shut-in pressures (green markers) of well P18-4A2.



4.6 Thermal aspects

In the P18-4 compartment, cool CO_2 will be injected into a formation with a temperature of 120°C. The impact of fluctuations of the injection rates and that of a complete shut-in on the temperature profile within the reservoir were modelled in various scenarios (*Figure*Figure 4.3). No temperatures below those of the injected fluid were observed. This means that the Joule-Thompson effect is negligible just after the start of the injection as well as right after a shut-in.

Figure 4.3 Temperature profile around the well after 1 year of CO_2 injection, with a bottomhole temperature of 285 K.



To understand the effect of the temperature of the injected CO_2 on the reservoir two injection scenarios were studied, a “warm” injection scenario with a bottom hole temperature (BHT) of 285 K and a “cold” scenario with a BHT of 259 K.

The cold injection scenario (259 K) rapidly results in near well temperatures of 273 K, after which the reservoir simulator stopped due to internal model threshold. Predicting the impact of freezing conditions within the reservoir is complex. The aforementioned thermal effects are likely to be more pronounced at the lower temperatures. The cold injection may also result in freezing of the connate water in the reservoir.

It is unknown whether freezing conditions lead to risks or technical problems during the injection. It was therefore concluded that for at the moment some heating of the CO_2 is required before injection in order to stay out of the freezing - and even the hydrate conditions in the near well area. Only after further investigation or a pilot test has shown that colder injection is feasible, it may be possible to reduce the temperature of the injected CO_2.

Thermal fracturing due to injection of cold CO_2

Cooling of the reservoir with the cold CO_2 will induce thermal stresses, similar to those resulting from injection of cold water. The thermal stresses around the well can promote the propagation of fractures into the reservoir and possibly the caprock. This is usually called thermally induced fracturing. In contrast to cold water injection, for CO_2 injection thermally induced fracturing is usually not taken into account.

Follow-up work in CATO2 WP3.09 D14 [Arts et al., 2011] concluded that the fracturing will occur at the stage when the BHP exceeds a level that was reduced by cooling of the formation due to the difference in temperature between the CO_2 and the reservoir rock of more than 100°C. In case of fracturing of the reservoir rock, there is a risk of fracture growth into the caprock and mechanical damage of the top seal. Although limited fracture growth into the seal may not be harmful, induced fractures still provide access routes for CO_2 and brine penetration into the seal. The potential for fracture growth into the top seal is dependent on several geological, geomechanical, temperature field, reservoir and well engineering parameters and has to be studied separately in case of intentional hydro-fracturing of the reservoir.

The P18-4 reservoir was modelled by a modified TOUGH2/ECO2M module, which was semi-automatically coupled to the DIANA software tool [Loeve et al., 2014]. The ECO2M module was modified to enable the simulation of the transition of gaseous to liquid CO_2, needed for the pressure temperature conditions investigated in P18-4. From the 2D simulations and 3D simulations, it was clear that for the true depth (3400m) of the P18-4 reservoir, no fracturing as a result of the cold CO_2 is expected, which is in line with the earlier results.

4.7 Storage System Integrity

This section on storage system integrity looks into the containment functionality of the CO_2 storage reservoir, which is provide by a set of barriers, i.e. caprock, faults and wells. The barrier functions are influenced by chemical, thermal, mechanical and fluid transport processes.

4.8 Geochemical interaction with reservoir and seal

When CO_2 is injected into the reservoir system with caprock, the pH of the formation water will initially decrease to a value of 3.5 and 3.2 for the reservoir and caprock respectively, due to the formation of carbonic acid. Dissolution of small amounts of carbonate and sulfides, which is predicted to occur on the mid-term (in the order of years to decades), will buffer the pH to a value of 4.2 and 4.3 respectively. The effects on mineralogy and porosity are negligible.

It is predicted that the mineralogical assemblage will have been changed significantly once thermodynamic equilibrium is established, which may take thousands of years. The corresponding porosity change is a decrease of 0.3 pp (to 8.5%) for the reservoir rock and an increase of 0.2 pp (to 1.2%) for the caprock.

Since the initially computed formation water and mineral assemblage of both reservoir and caprock are not in equilibrium reference calculations were performed to investigate the equilibrium assemblage without CO_2 injection. The results show that the assemblage changes significantly.

However, if CO_2 injection would occur in the reference assemblage, the mineralogy and porosity change would be equal to CO_2 injection into a reservoir with caprock in a meta-stable phase.

Furthermore, the final mineral assemblage is relatively insensitive to the methodology of formation water computation.

The presence of O_2 as an impurity in the CO_2 stream is predicted not to have a significant effect on the short-term. On the mid-term the model shows a slight increase in pyrite dissolution and anhydrite precipitation. Effects on porosity are negligible. Long-term effects are similar to the baseline and therefore also to the reference. Follow-up work [Arts et al., 2011] specified that the possible effect of O_2 on the reservoir, 0.05 bar of O_2 is used as input in the model (log Px = -1.30), corresponding to 160 ppm; effects are very limited.

Near Werkendam is a CO_2 rich gas field which can be used as an analogue for CO_2 storage. The Werkendam aquifer and Barendrecht-Ziedewij gas field were compared, with partial dissolution of K-feldspar grains ($KAlSi_3O_8$) and anhydrite cement ($CaSO_4$), and the formation of small amounts of Mg-rich siderite ($MgFe(CO_3)_2$), barite ($BaSO_4$) and quartz (SiO_2) in the Werkendam sample.

Long term effects of CO_2 on the basis of natural analogues

Long term effects were studied on the basis of reservoir sandstones of the Green River Well (Utah) that have been naturally exposed to CO_2 influx and on a pilot study of measuring capillary pressures in an experimental set-up during compaction and fracturing of porous rocks.

Micro X-ray tomography imaging of reservoir sandstones from the Green River well (Utah) reveal the presence of carbonate precipitation in the pores due to long-term exposure to natural CO_2. Carbonate can clearly be distinguished in the CT dataset from quartz grains and porosity. Both Entrada and Navajo sandstone formations in the Green River well have been analysed with micro CT. The Entrada sandstone exhibits widespread carbonate precipitation (up to 60% of infill of the original porosity), with the largest amount of carbonates at the boundary with the underlying Carmel caprock. In an interval of a meter from the contact, carbonate precipitation decreases sharply till ~20%. The porosity is significantly reduced in the lowest 1 meter. Pore connectivity and thereby permeability is significantly affected by the long-term CO_2 exposure. On the other hand the Navajo sandstone shows predominantly isolated spots of carbonate precipitation (up to 20% of the original porosity). Because carbonate precipitation is not present throughout the samples, the permeability of the formation is likely not affected significantly by the CO_2 exposure. The 3D distribution of the phases and the 3D shapes of the pores in these CO_2 affected sandstones can be used for improved rock characterization and for characterization of the pore connectivity within these samples.

The Terratek cell at the Geoscience and Engineering Laboratory at TU Delft has been successfully updated to measure CO_2-water capillary pressures during deformation of porous samples. The first results show that capillary pressure is very sensitive to small variations in porosity/pore sizes due to increased compaction at higher and higher confining pressures. Secondly it is shown that capillary pressure changes can be monitored over time during continuous deformation until fracturing of the sample. Future experiments can investigate the more detailed changes in capillary pressure when fracturing or compaction experiments are performed at very slow deformation rates. Subtle changes in capillary pressures may then be linked to small deformational changes within the sample.

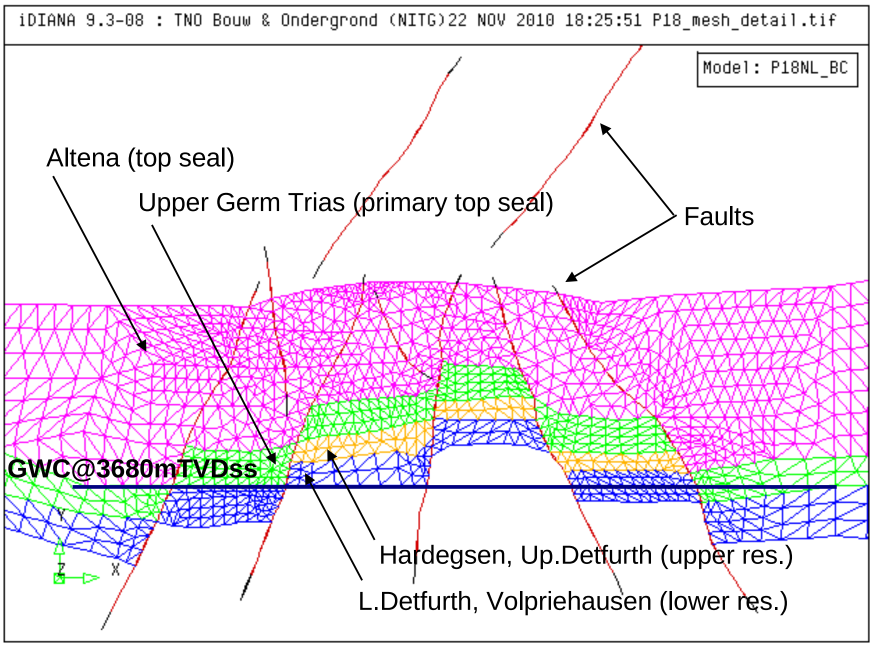
Two studies of naturally CO_2-reacted sandstones [Hangx, 2013] suggest that in either case CO_2/brine/rock chemical interactions are not pervasive enough to result in significant change in strength and elastic properties, or may lead to a slight positive effect (strengthening of the rock), as a result of mineral reaction, such as dolomite precipitation.

4.9 Geomechanical interaction with seal and fault

Top seal integrity and fault stability do not represent critical factors for injection and storage of CO_2 in the depleted P18 field.

The primary top seal overlying the Bunter reservoir is represented by a 50 m thick layer of the lower part of Upper Germanic Trias. The seal comprises (from top to base): Röt Claystone Member, Main Röt Evaporite Mb and Solling Claystone Mb. The primary top seal is covered by a 100 m thick upper part of Upper Germanic Trias (Muschelkalk and Keuper) and a 300-400 m thick Altena Group which also represent sealing formations (Figure 4.4).

Figure 4.4 Central part of a mesh for a 2D plane strain finite element DIANA model of the P18 field showing the main faults, reservoir and top seal.



No direct measurements of the sealing characteristics of the primary top seal were available. The measurements on core from Röt and Solling taken from well P15-14 in the neighbouring block P15 can be used as analogue for the P18 field. The true top seal in P15 is provided by thinly interbedded and interlaminated shale and very fine-grained sandstone to siltstone. These lithofacies contain type A seals which are capable of supporting gas-column heights in excess of 300 m.

The anhydrite content in the primary seal is variable. As anhydrite can react with CO_2 in the presence of water, it is necessary to quantify the effects of possible geochemical reactions on the mechanical and transport properties of bulk/intact anhydrite and fault gouge anhydrite material.

The primary top seal (Röt and Solling) is comprised of a hard, brittle and competent rock. The rock strength properties of the top seal were determined by triaxial tests on core in HPT lab of Utrecht University. The value of rock properties are as follows: Young's modulus E=20 to 30 GPa, unconfined compressive strength UCS= 93 MPa, cohesion c=27 MPa and friction angle ϕ=28°.

The largest stress changes and the associated poro-mechanical effects on the top- and side seals occur when the reservoir is fully depleted. The largest stress changes occur near the edges of the reservoir compartments (and segments) where stress concentrations occur. Due to the high strength of the top seal, the poro-mechanical effects on the bulk/intact top seal are expected to be weak. However, plastic deformation of the top seal (and the reservoir rock) may occur locally at the edges of depleting/expanding compartments, having in mind the natural variability of (shear) strength which can exist in these rocks.

Combined poro-mechanical effects, due to pore pressure increase, and the thermal effects, due to injection of cold CO_2 into the hot reservoir, may cause hydro-fracturing of the reservoir rock and possibly, the top- and side seals. The risk of induced hydro-fracturing increases in the later stage of CO_2 injection when the reservoir is almost re-pressurized to the initial pressure.

Risks associated with induced fracturing of the reservoir rock are related to the possibility of forming:

- Fractures in the top seal allowing CO_2 migration out of the containment.
- Possible spill paths for lateral escape of CO_2 from the containment.

- Pathways for direct hydraulic communication between the injection well and faults, leading to direct charging of faults by the injected CO_2 and, consequently, to fault instability and slip, which may affect sealing capacity of faults.

The boundary faults of all three compartments are found to be sealing. These faults have large throws and juxtapose the reservoir Bunter sequence against the sealing Upper Germanic Trias and occasionally a lower part of Altena.

The internal faults which split compartment P18-2 into three segments are mostly conductive. These faults have much smaller throws than the boundary faults. Generally, reservoir sand is juxtaposed against sand across the internal faults and the shale gouge ratio (SGR) is low.

The largest stress changes and the associated poro-mechanical effects on faults occur near the edges of the depleting/expanding reservoir compartments. The potential for fault reactivation generally increases during reservoir depletion, but likely does not lead to fault slip and reactivation. However, fault slip may occur locally at the edges of reservoir compartments, having in mind the natural variability of shear strength properties in fault rocks and local stress perturbations nearby faults.

During injection, the potential for fault reactivation generally decreases providing that the CO_2 is not injected directly into the fault zone and the thermal effects of injection are negligible.

The P18 field was not seismically active during production period, based on the KNMI database of recorded induced seismic events associated with hydrocarbon production in the Netherlands.

No production-related induced seismicity has been recorded so far in other hydrocarbon fields in the Western part of the Netherlands. The detection limit of the KNMI seismic network was M2.5 until 1995 and M1-1.5 on Richter scale afterwards.

Current seismic analysis practices do not allow predictions of the magnitude of possible future seismic events related to fluid injection into reservoirs. Quantitative Probabilistic Seismic Hazard Analysis (PSHA) of induced earthquakes associated with CO_2 injection is not yet possible because of lack of data.

The effects of production and subsequent CO_2 injection on seabed deformation are minor. The maximum production-related subsidence amounts to 5 to 7.5 cm, which is considered to be of little practical importance. During injection period, the production-related subsidence will be reduced.

Geomechanical-related risks of fracturing and fault re-activation can be (partially) reduced by:

- Injecting CO_2 with bottom hole pressures (BHP) which are below fracturing condition.
- Avoid overpressurizing the reservoir above the initial pressure.
- Keeping a safe distance between the injection wells and faults to avoid direct charging of faults by injected CO_2 through natural or induced fractures.
- Managing thermal effects of injection.

Geomechanical analyses [Arts et al., 2011] show that possible fault re-activation will affect parts of the fault located at the reservoir level only. The risk of CO_2 penetration into the fault zone and migration in the updip direction above the reservoir is therefore very small.

Reactivation potential of simulated faults under CO_2 storage

The question was considered whether chemical changes due to CO_2-rock contact can lead to a loss of frictional strength and fault stability on the short and long term [Samuelson et al., 2012]. Direct shear experiments were conducted on simulated fault gouges which mimicked the mineralogic evolution of a fault zone of simple starting mineralogy as it equilibrated with its surroundings at pressure, temperature, and CO_2 pressure conditions relevant to CCS reservoirs. Experiments were also conducted on pure gouges of the constituent minerals of the aging fault gouge mixtures, and also on gouges in which the quartz/magnesite content was systematically varied in an effort to determine what types of mineral alteration might influence CCS fault zone friction.

Methods used:

a. Short-term laboratory experiments on North Sea reservoir sandstones and caprocks

b. Direct shear experiments on:

   1. simulated fault gouges mimicking the mineralogic evolution of a fault zone of simple starting mineralogy

   2. pure gouges of the constituent minerals of the aging fault gouge mixtures

   3. gouges with varying quartz/magnesite content

In conclusion, reservoir faults should behave aseismically both before and after the addition of CO_2.. All tested materials exhibit predominantly velocity strengthening behavior, and that neither the addition of brine nor supercritical CO_2 has any clear, strong influence on friction velocity dependence

Care must be taken when siting CCS projects in reservoirs with faults rich in carbonate minerals, or in which carbonate minerals will likely precipitate, in order to minimize the risk of microseismicity associated with CO_2 storage on the long term. Below 50% magnesite content, gouges exhibited exclusively velocity strengthening behavior, at 50% magnesite and above the gouges displayed some tendency for velocity weakening slip.

Faults will heal after slip. The strength of fault healing depends on the hold time between two events. Healing is the stronger in the presence of CO_2 compared to other fluids. Healing and sealing of anhydrite rocks takes only tens of years under upper crustal conditions [Hangx et al., 2014].

A large number of direct shear experiments have now been performed at Utrecht University on simulated fault gouge derived from P18-type Röt and Solling claystone/marl, Bunter (Hardegsen) sandstone, and 50:50 mixtures thereof. These mixtures simulate the full range of fault rock compositions expected in faults transecting the P18 reservoir. Our conclusion is that supercritical carbon-dioxide has very little short term influence on fault friction (μ) or on slip stability, indicating that CO_2 sequestration will not adversely affect the reactivation or stability of fault zones bounding Bunter reservoirs such as those in the P18 field, at least on timescales where reaction is limited (e.g. 100-1000 years).

4.10 Fault F3 between the P18-4 and P15-9 reservoirs

CO_2 injection in the P18-4 field will lead to an increase in pressure and therefore to an increase in differential pressure between the P18-4 and the P15-9 fields, potentially up to 200 bar. The two fields are separated by the so-called F3 fault. There is a possible juxtaposition of reservoir sections across the fault (CATO2 WP3.09 D14). Very likely, the fault is sealing which is supported by the following observations:

- Reservoir properties and geological considerations indicates that the P18-04 field is an isolated horst block, fault bounded on all sides. The faults on the west, south and east have non-reservoir rock of Upper Triassic and Jurassic age juxtaposed against the reservoir; therefore these faults are believed to be sealing.
- Gas composition indicates that no gas mixing has taken place over geological timescales.
- P/Z analysis indicates that the fault F3 between the P18-4 and P15-09E1 fields is strongly believed to be sealing on a production time scale.

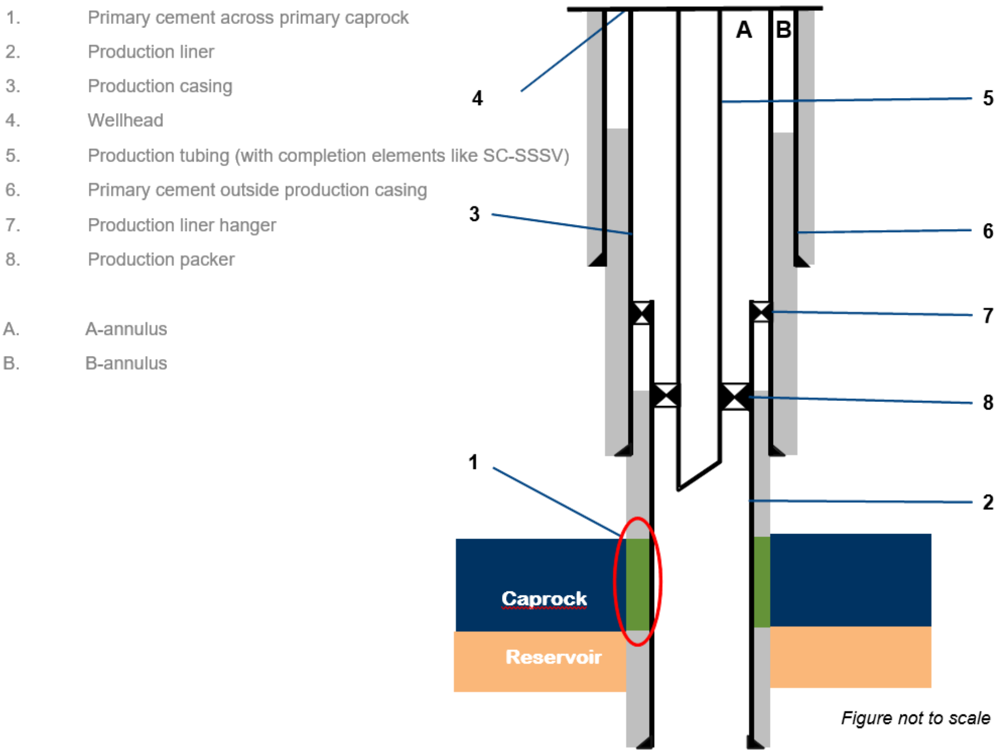
- Throughout depletion of both fields, the pressure in P15-9 was always lower than in P18-4. If the fault between P15-9 and P18-4 was not sealing, one should observe a flow from P18-4 towards P15-9.

Note that up to now no large pressure differences between the two reservoirs have occurred, since production has been performed almost simultaneously.

4.11 Well integrity

CO_2 storage was being considered in TAQA's P18 gas field. In the context of the CATO-2 project, the suitability of the existing wells in the field was investigated for injection and long-term storage of CO_2 [Vandeweijer et al., 2011; Akemu et al., 2011]. The well integrity assessment covers the operational phase of the injection project (decades) and the long-term post-abandonment phase. The study aimed to evaluate of the relevant well system barriers (see Figure 4.5) to identify potential showstoppers and recommendations on remedial actions and abandonment strategies. This report presents progress until September 2010, but does not describe the final conclusions of the well integrity assessment of the P18 field.

Figure 4.5 Generic P18 well showing the various well barriers.



The P18 field comprises 3 reservoir blocks, penetrated by a total of 7 wells, some of which have been sidetracked. One of these sidetracks also penetrates the caprock and the reservoir.

One of the wells, P18-2, is plugged with several cement plugs. The current layout of plugs in P18-2 is inadequate for long-term containment of CO_2, as it provides likely migration pathways from the reservoir to shallower levels, bypassing the caprock. In order to improve the quality of this well, it is required to re-enter the well, which is technical feasible according to TAQA. Subsequently, the existing cement plugs should be drilled out and an abandonment plug of sufficient length should be positioned across the primary and/or secondary caprock. Since cement-to-casing bonding is poor, it is recommended to place pancake-type abandonment plugs.

Special attention is drawn to the sidetracked P18-2A6 well. From the limited available data it is uncertain how exactly the parent hole was suspended. It seems that the current layout is unsatisfactory for CO_2 storage.

Moreover, since the parent well forms the only penetration to the P18-2 III block, it might be beneficial to not only properly abandon the parent well, but actually use it for CO_2 injection in that block in order to mitigate large pressure differences between the reservoir blocks. This would require adequate abandonment of the P18-2A6st sidetrack and fishing of the whipstock. Subsequently, the P18-2A6 parent well needs to be recompleted to enable CO_2 injection.

All other wells are readily accessible and can be remediated. Most of these show questionable cement sheath quality at caprock level from CBL data or lack data to verify this. Inadequate primary cement poses a risk to long-term integrity, but could also affect the operational phase.

However, these wells can be accessed and, in order to prepare them for CO_2 storage, it is recommended to re-evaluate and, if required, remediate the cement sheath quality at least over caprock level.

When considering wells that will be used for CO_2 injection it is recommended to check the packer operating envelope against CO_2 injection scenarios. Potential elastomers and wellhead configuration should also be verified and adapted where required. Moreover, it is suggested to adjust completion materials (tubing, tubing hanger and packer) to corrosive circumstances, in case corrosion mitigation measures are not already in place.

Abandonment - either (re)abandonment of wells that will not play a part in injection or monitoring, or abandonment of injection and monitoring wells after injection ceases - can be designed specifically for CO_2 storage. At present, there are two general options to permanently seal a wellbore for CO_2 containment. If the quality of the primary cement sheath is ensured over critical intervals, traditional abandonment plugs can be positioned and tested at caprock level.

Alternatively, and especially in the case of questionable cement sheaths, pancake plugs can be used at caprock level. This would involve milling out of the casing, annular cement and part of the formation, followed by placement of cement in the cavity. This procedure would effectively reduce the number of material interfaces, which could form potential migration pathways. However, this operation may pose difficulty particularly in horizontal or strongly deviated wells. Both of these options should be accompanied by additional plugs higher up the well, according to common practice and as prescribed by governing abandonment regulations.

The maximum leakage rates along the well path for an assumed annulus width of 0.01 mm were 209 kg/year (casing-cement bond) and 330 kg/year (cement bond –formation) [Arts et al., 2011].

Well barriers to CO_2 leakage

This section describes the plans in early 2012 to ensure CO_2 leakage did not occur, supplemented by the results of CATO-funded research in 2013 and 2014.

The existing tubing and packer of the well (P18-4A2) would be replaced. Leakage at the surface, via the tubing or the annulus is prevented by several safety devices and lines of defence. Only if a very large drop in temperature ocurs for an extended period at the wellhead and in the top section of the tubing, the steel might become brittle and crack. Hence the system will be operated to minimise the risk of low temperatures occurring, and the wellhead will be selected to operate at very low temperatures (arctic grade perhaps).

If low temperatures are detected, the system will be designed to protect itself and shut in long before low temperatures can do damage. When shut in, the temperature will rise again.

High velocity in the well might erode the smallest diameter sections, like the tailpipe and the subsurface safety valve (SSSV), or cause vibrations in the tailpipe. Vibration will be minimised by equipment selection and perhaps by shortening the tailpipe to the minimum. Erosion will be eliminated by filtering all particles out of the CO_2 at Maasvlakte. Even if these effects lead to a leak from inside the tubing to the annulus the CO_2 would remain in the well, no escape is possible.

If injection is regularly started up and stopped there may be temperature variation in the well which will cause the tubing to contract and expand. This could affect the ability of the packer to seal against the casing and cause CO_2 to flow from downhole, around the packer into the annulus. The risk of this will be minimised by packer selection and probably by setting the tubing in compression in the well, so that contracting cannot affect the packer. Even if these effects lead to a leak to the annulus the CO_2 would remain in the well, no escape is possible.

Outside the casing, the cement is the seal to prevent CO_2 flowing outside the casing up the well bore to the sea bed. The cement is continuous over 100s of metres and the probability of a continuous path to the surface is extremely low. The reservoir pressure of the storage reservoir will never be raised above the original pressure of the reservoir, hence the hydrostatic pressure above the reservoir will always be greater than the reservoir itself. If any leakage were possible, the pressure gradient would drive any mobil fluids from outside the reservoir into the reservoir.

In summary, the CO_2 might in extreme circumstances have some impact on the steel, equipment and cement, but the CO_2 will not cause the P18-4 well to leak.

There will continue to be research on every aspect relating to temperature, flow regime, erosion, materials, equipment, cement which will further define the constraints and operating regimes for safest practise.

Degradation of wellbore cement

In the context of ensuring containment of a CO_2 storage system, the integrity of wellbores is a topic of major importance. The degradation of wellbore cement in the presence of carbonized, acid fluids poses risks of forming leakage pathways with time. This risk has continued to be researched during the slow-mode through CATO. The results of the experiments and reactive transport models suggest that if the cement is intact and has a tight bonding to the reservoir rock, then the limited availability of CO_2-saturated brine can lead to enhanced, instead of reduced cement sealing properties and to higher mechanical strength of the cement [Koenen et al., 2014] [Hangx et al., 2014]. When reacting in excess brine, calcium carbonate dissolution can continue causing enhanced migration of dissolved CO_2, and a decrease in mechanical strength.

The models were able to support the observations of the continuous dissolution of calcium carbonates in excess brine, and the stabilization of the calcium carbonates in the absence of excess brine. The experimental results showed a large influence of heterogeneities in the cement which cannot easily be simulated by geochemical models. Also, improved knowledge of reaction rates would be required to better predict the complex interaction of element diffusion and mineral reactions. Yet, the ability of the models to simulate the overall geochemical interactions between cement and carbonized brine provides confidence in the use of such models for the long-term prediction of cement integrity.

A major CATO study was that of [Hangx et al., 2014], which reported as follows. In the context of CO_2 storage in depleted oil and gas reservoirs, the most likely routes for CO_2 leakage to the surface or to overlying structures from the storage complex are provided by either existing or re-activated fractures or by wellbores penetrating the geological layers. Chemo-mechanical processes triggered by changes in the state of stress or temperature, in and near the wellbore, might lead to fractures forming in the cement sheath or in the cement plugs. Such fractures could provide pathways for CO_2 leakage to the atmosphere or overlying formations, compromising the integrity of the storage site. Thus, it is critical to investigate how CO_2 will influence the integrity of wellbore cements on the longer term, considering both chemical and mechanical effects.

The main objective of that study was to measure the changes in strength of carbonation fronts developed in cement samples due to exposure of the material to CO_2 and solution, under conditions similar to those found in wells (T = 65°C, PCO_2 = 8 MPa), to assess the risk of cement failure caused by stress and temperature changes.

A series of mechanical tests were performed on Class G Portland cement samples, exposed to supercritical CO_2 and solution for various periods of time (1, 2, 3, 4, 5 and 6 months), using the so-called core scratching technique to evaluate the unconfined compressive strength (UCS) as a function of exposure time.

Overall, four different zones were observed within the sample material over time, in line with observations made in other studies. From the edge of the sample inwards, these were: 1) a porous, silica- and calcite-depleted layer, 2) a less porous carbonate-rich layer, 3) a more porous, thin layer depleted in calcium, and 4) the initial cement. Overall, it can be seen that long-term (5-6 months) exposure to CO_2-rich solution leads to a strengthening of the cement by a factor of 2-3 after about 5 months, after which the material weakens again. Whether cement weakening by CO_2/solution/cement interactions will result in wellbore cement failure depends on the in-situ conditions. The potential of significant mechanical weakening of the cement particularly depends on the extent of buffering of the acid CO_2-solution by the cement. Though under lab-conditions this may be the case, as suggested by our own results, studies on cement retrieved from CO_2-exposed fields show that the degradation rate slows down rapidly with time, limiting the degree of reaction mainly to the formation of carbonate-rich zones.

4.12 Potential migration paths

A Petrel model of the overburden was constructed, which is based on public available data and data provided by TAQA. Based on the geological model and selected hypothetical migration scenarios, a qualitative evaluation of the possible pathways was developed. The main conclusion considered the migration in the Bunter sandstone that could result from a hypothetical overfilling the reservoir. In the near term, the CO_2 would remain trapped within the aquifer, and finally will migrate towards the adjacent gas reservoirs. In the hypothetical case of a shortcut along the wellbore leading to CO_2 migration in the aquifers of the overburden, the CO_2 will remain trapped within the aquifers. However, migration of CO_2 along faults in the overburden (above the Altena Group) to a shallower aquifer level cannot be completely excluded.

Overall it can be stated that the most probable pathway to the surface of CO_2 stored in the P18 gasfield is via leaking wells, leaking directly into the atmosphere and not indirectly via pathways originating in deeper parts of the overburden.

Shallow gas and existing natural (paleo-) fluid migration pathways

In the Dutch North Sea many bright spots can be observed on seismic data at shallow depths, particularly in the A, B and F blocks. These can often be associated with the presence of shallow biogenic gas, formed in situ at shallow depth, but in some cases also with the migration of deeper thermogenic gas toward shallower strata. In the latter case, the bright spot can either result from the direct presence of gas, or from diagenetic effects caused by “old” fluid/gas migration (referred to as paleo fluid/gas migration pathways). The main question is, to what extent the fluid/gas migration pathway is still active and to what extent it might form a pathway for CO_2 to the shallow subsurface or even to the sea bottom [Arts et al., 2013].

A first (baseline) analysis of the overburden of the P18-4 reservoir was made based on existing data. To this end 12-channel 2D seismic lines, chirp and 3.5 kHz source 2D lines together with side scan sonar data have been collected and interpreted in combination with the 3D seismic data that was also used for the characterization of the reservoir.

The study [Arts et al., 2013] aimed to assess possible gas seepage or migration pathways in the P18 area. The study supported the planning of a CATO2 marine survey to be carried out in the first half of 2014, specifically identifying the more sensitive areas.

The following conclusions were drawn:

- The interpretation of the side scan sonar did not show features that can be associated with gas seepage, such as features like pockmarks or gas bubbles in the water column.
- The 3D seismic data show the presence of shallow faults extending to the near surface (>200 ms). These shallow faults are connected to the deeper parts, and thus may act as potential pathways for gas to migrate upwards to the surface. Higher resolution seismic data is needed to improve the interpretation.
- Shallow bright spots have been observed. Higher resolution seismic data can support the interpretation of these features in terms of the presence or migration of fluids/gas and the underlying processes.
- The proposed survey planned in the first half of 2014 should focus on detailed mapping of shallow fault zones. Acquisition of soil samples is recommended at these locations, in order to determine whether there is an increased gas (CH_4 and CO_2) content, compared to surrounding areas.

4.13 Engineering concepts for platform

TAQA Energy planned to upgrade the existing P18-A platform (Figure 4.6) or the new OD 22" CO_2 riser caisson to support a 16" riser to the topsides. On the platform, pipeline manifolds, monitoring, metering and control equipment will be needed. Heating was also included as an option in the work. Iv-Oil & Gas b.v. was requested to check the platform's capacity to receive the caisson and associate equipment on the deck structure.

Figure 4.6 Picture of the P18-A platform.

The topside consists of a Helideck, Mezzanine deck, Production deck and Subcellar deck and facilitates six wells. The distance between the deck legs is 10.000 [m] x 10.000 [m]. The jacket structure comprises of four tubular jacket legs braced by horizontal framings at EL (+) 6.000 [m] and EL (-) 25.000 [m]. The platform is founded on four piles of 1070 [mm] outside diameter and 40 [mm] wall thickness. These piles are driven through the legs and are welded on the top.

The structural model constructed by Iv-Oil & Gas for theit check included the following appurtenances: two 20" conductors, four 30" conductors, one 16" riser (original), one 22" caisson (installed in 1998), two 8" risers in the 22" caisson (included as member overrides), one 2"riser in the 22" caisson (included as member overrides), one future 22" caisson (for the CO_2 riser), one 16" CO_2 riser, walkways at top framing of jacket (included as member overrides), and stair from jacket top framing to cellar deck (included as member overrides). The model excluded the following appurtenances: piggy back riser on the 16" riser and one 12" sump caisson on leg A1.

The analyses were performed to check the P18/A platform's capacity to receive the caisson and associate equipment on the deck structure. The jacket has been analysed for 1 year environmental conditions (operational) and for 50 years environmental conditions (survival). In addition to the in-place analysis, fatigue, ship impact and post impact analyses were performed on the jacket. The topside primary structure was checked for the additional loadings.

Conclusions and reccommendations

The additional loadings on the jacket structure do not result in overstressing in the jacket members or piles (maximum unity checks [UCs] of 0.72 and 0.88). There are no punching shear unity checks larger than 0.82. The lowest safety factor of the foundation piles is 1.65 at leg B2, whereas 1.5 is the required minimum. The fatigue analysis revealed a minimum life of 480 years.

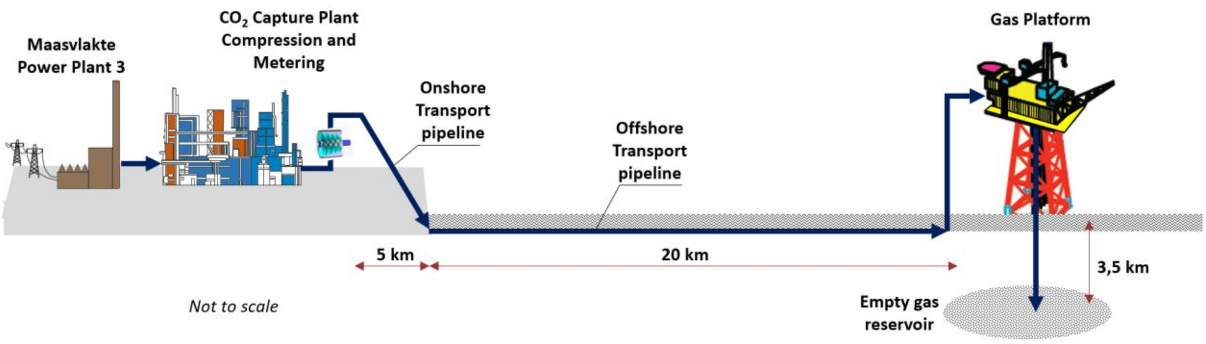
The ship impact analysis showed that the platform can withstand a ship impact of at least 2.1 [MJ] which corresponds to a 3,000 tonne ship traveling at 1 [m/s]. The post impact dent and missing brace analysis did not show any overstressings.

In the topside analysis ΔUCs were calculated and added to the original UCs. The result did not show any overstressing in the topside.

In the original report, the air gap was designed as the clearance between the wave crest position (50 year wave) and the bottom of steel (B.o.S.) of the production deck. This distance is verified in the airgap analysis to be larger than 1.5 [m]. However, current regulation would require ISO wave data and 1.5 [m] to the B.o.S. of the subcellardeck. This requirement will not be met by the P18/A platform. The airgap results and the seastate used should be part of the discussion with the certifying authority when recertification will be required.

The results of the analyses in this report did not reveal an inevitable structural problem for the Road Project on the P18/A topside, jacket or piles. As the platform is required to be recertified in the near future it is advised to require the 100 year Environmental Data according to the ISO standard and more detailed information on the topside weight.

Figure 4.7 Schematic of ROAD system. [ROAD, 2010]



The CO_2 arriving at the injection platform may contain particulates picked up from the pipeline or impurities. If these particulates enter the reservoir, they may cause clogging, reducing the injectivity to a point where a well work-over may be required. To prevent fouling, 2x100% CO_2 Process System Filters shall be provided on the manifold. The filters will operate on a duty / standby basis that shall allow the duty filter to be changed over when it is clogged without stopping CO_2 injection. A bypass of the filters shall be installed when no filtration is necessary.

It is recommended to remove the provision for a subsea Y spool at riser base, for the following reasons: the requirement for future extension seems quite remote and uncertain; considering the low water depth (25m), a surface tie-in is less complex (and probably less costly) than a subsea tie-in; and the provision for the subsea Y spool may not be relevant practically [Marchand, 2012].

The expansion spool of 16 m is used. The spool will be buried during the life time; therefore no hydrodynamic loads are applied for the operational case [Zeetech, 2011].)

5 Pre-FEED of the P18A and P18-4 offshore facilities

This section summarises the work done in the pre-FEED phase of the development of the P18-4 storage option developed by ROAD and TAQA in 2010 and 2011.

5.1 Platform pre-FEED

Platform P18-A is located at about 20 km from the shoreline. It is used to produce gas from three reservoirs at a depth of about 3,500 m. The peak in the gas production was reached in 1993. The gas produced at P18-A is transported per pipeline to the much larger platform complex P15-D.

The platform needs to be modified to make it suitable for CO_2 storage:

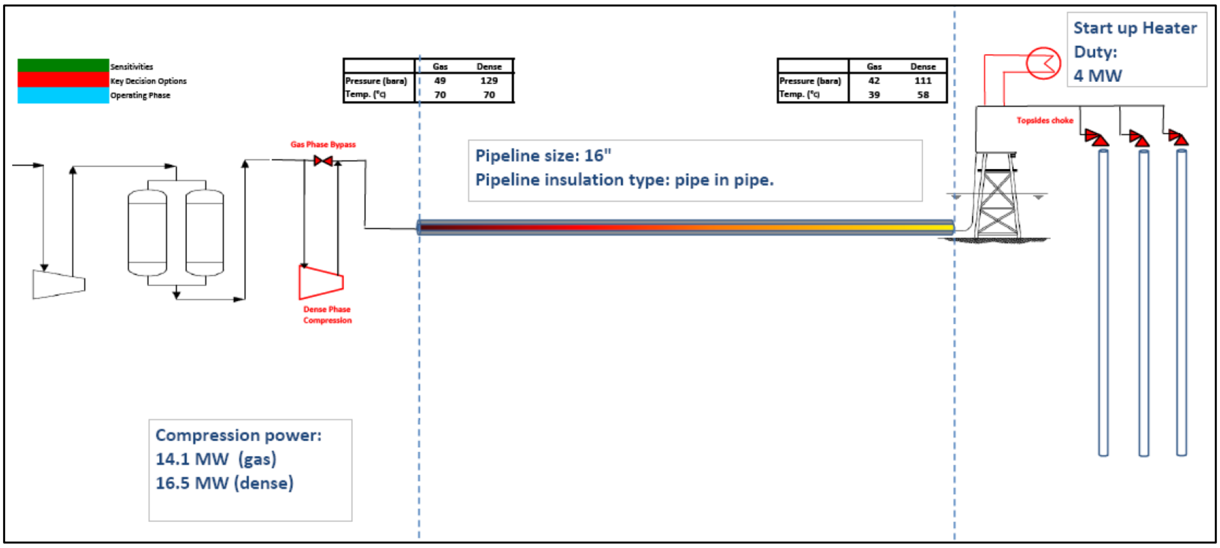
- The pipeline will be connected to the platform P18-A via a riser, which is a vertical pipeline from the seafloor to the platform.
- A stop valve will be placed at the end of the riser, which will close in case of failure. A T-connector will be placed after the stop valve connecting the riser with the pig installation. A pig is used to periodically clean the tube from the landside.
- The wells present on the platform can be connected to the pipeline.
- A control panel will be placed above the existing panel to operate the wells.
- A metering skid will be installed for measuring the CO_2 flow, pressure and temperature.
- A CO_2 venting pipe will be installed on the platform.

5.2 Offshore heating options

As part of the facilities on the normally unmanned offshore Platfrom P18-A, a start-up heater was included to heat the CO_2 fluid during start-up after a prolonged shut-in (Figure 5.1). This heater was removed from the design in 2013 when flow assurance modelling concluded that operation was feasible without it (see Section 4.1.1 Flow Assurance and Ref 6 of the Close-Out Report Transport for more detail on this). However, it was included throughout the pre-FEED stage of the project and is therefore reported here. Three options were considered:

- Electric heater would be the less space consuming and have limited operational impact. On the other hand a considerable investment would be necessary for the electrical power cable
- Diesel fired heater would save the cost of a power cable but requires more modification on the platform including a deck extension. Also operational costs of diesel bunkering need to be considered.
- Gas fired heater appears to be the most attractive option but needs to assure continued gas production on P18-A or import from P15.

Figure 5.1 Start-up heater development option with insulated pipeline and initial gas phase operation switching to dense phase.



The estimates for the heating options have been produced by Genesis Oil & Gas Consultants Ltd. for the Comparison of Offshore Heating Options report for the Concept Study for Transportation & Processing CO_2 Offshore, delivered in October 2010.

As part of the facilities to be realized offshore, a start-up heater has been defined to heat the CO_2 fluid during start-up after prolonged shut-down. Based on equipment size limitations and operational aspects regarding the normally unmanned platform P18-A, Genesis identified an electric heater as the most suitable solution for a start-up heater.

Those elements from the Phase 2 cost estimate that are influenced by the start-up heater have been re-evaluated for the fired heater options.

The costs for the subsea pipeline as originally estimated will be reduced by 4.1 million € by taking out the costs for the power cable procurement, the umbilical lay vessel day rate and the associated engineering and project management costs.

The cost estimated for the horizontal directional drilling (HDD) under the Yangtze harbour and the shipping lane will be reduced as well as a result of taking the power cable out of the scope, by an additional €3.7 million.

For the three alternative fired heater options, costs for the modifications on P18-A have been separately estimated, thus are not displayed in the table below. An allowance was made for additional pipework and valves to supply the diesel and heating medium. The instrument count was also increased to account for the greater complexity of a fired heater system. The overall cost estimates are shown in Table 5.1.

Table 5.1 Comparative cost estimates for different offshore heating options from October 2010, not including costs for modifications on the P18-A platform.

CAPEX estimated costs [mln €]	**Base case** Electric	**Option 1** direct diesel fired	**Option 2** indirect diesel fired	**Option 3** direct gas fired
Onshore plant	73.4	73.4	73.4	73.4
Pipeline & cable	77.1	69.3	69.3	69.3
Riser	1.4	1.4	1.4	1.4
P18-A modifications	19.0	20.8	22.1	19.3
Total Surface CAPEX	170.9	164.8	166.2	163.4

The cost estimate comparison shows that the savings realized by avoiding the installation of a power cable are partly compensated by increased modification costs for the P18-A platform. CAPEX savings of between €4.5M and €7.5M can be realised with a fired heater depending on the type of fired heater system selected. It should be noted that the additional OPEX costs of diesel bunkering are not included. Fired heaters are also likely to be less reliable than electric heaters so increased platform visits maybe be required. Remote operation of fired heaters is not routinely performed on current offshore platforms.

The response received from fired heater suppliers has overall been relatively incomplete. Most suppliers offered standard equipment, not suitable for hazardous area classification or for location outdoors. For this reason a relatively conservative approach was adopted in the cost estimate, basing the cost on the highest received bid.

For the indirect fired heater option, the weight load of the P18-A platform approaches the platform weight limits. For all three studied options, the required equipment can be accommodated on the platform. The location of the fired heater requires the construction of a cantilevered deck extension.

The option to realize a direct diesel fired heater need to be further detailed before a cost estimate of sufficient accuracy can be achieved.

Direct gas fired heating appears to be the most attractive option, but it requires consideration of the continued gas production on P18-A or import from P15 in combination with the phased CO_2 injection and resulting pressurization of the reservoirs.

In further considering this option, a two deck heater module was developed in 2011, to be placed on the south-west side of P18-A between rows A1 and A at the Mezzanine Deck (EL + 24.150) and contains the following (main) equipment, structural and architectural elements: indirect gas fired heater package, injection manifold, fuel gas skid (to feed the gas heater from gas well or gas export line), temporary pig trap (for pipeline dewatering and for periodical pipeline inspection), existing AFFF Premix Unit (X-1701), crane boom rest, maintenance platform, stair case, wind wall. The main dimensions of the heater module are 9m x 6m x 6m (L x W x H). Electrical and instrument works were included as well in order to minimize the offshore works to the maximum possible extend.

Offshore modifications to the P18-A platform include creating space for the heater module; structural modifications (new access platform, deck penetration for the CO_2 riser, hatch for access to ESD valve by platform crane, ladder access, and installation of new CO_2 riser caisson, preferable hangoff type); and piping modifications.

5.3 Well pre-FEED

The well engineering study has been completed by AGR Petroleum Services and conclusions have been taken from their report. Discussion took place AGR, Genesis and TAQA to align the assumed well engineering cost estimate norms with TAQA experience of recent drilling campaigns on P18-A. This resulted in a significant reduction in the initial cost estimates. The main conclusions from the well engineering study were as follows:

- Re-use of existing wells
  - Well P18-A-6A7 can be used as a "warm" CO_2 (Option 1A/C) injector as it stands, with the existing 4-1/2" completion. There would be zero well costs downstream of the injection choke. The well is not suitable for cold injection without a workover.
  - All other wells cannot be used without workover for either warm or cold CO_2 operation. With the exception of P18-A-6A7 all other wells have retrievable completion packer which may pull out the tubing resulting in containment failure. In addition the down hole material and equipment is not designed for low temperature.
- Conversion of wells to warm temperature operation (Option 1A/1C)
  - The old casing with a new completion suitable for 0 °C but with a permanent packer.
  - Estimated cost is €4.1 million and will take 11 days.
- Conversion of wells to low temperature operation (Option 2C)
  - This converts the well to a low temperature injector by installing a new section of 9-5/8" casing from the mudline suspension to the wellhead with low temperature (arctic service) casing hanger; Plus installing new completion with low temperature tubulars and elastomers.
  - The conversion is estimated to cost €5.4 million and take 16 days.
- New wells
  - New well can be drilled from surface (from P18-A-2 platform). They would be designed for CO_2 injection service with large bore (7") completion and low temperature, CO_2 resistant equipment and materials.
  - The wells will be expensive relative to a re-completion, because of the long time required for drilling these deep wells in hard formations with significant drilling hazards of mud loss into the depleted reservoir;
  - The additional cost for bigger tubing (7" vs. 4.5") and low temperature equipment/materials is insignificant compared to the overall cost of the well;
  - The main sensitivity for the cost will be the day rate of the rig.
  - The new well is estimated to cost ~€21million and take 75 days.
  - The main risk is drilling through the depleted reservoir section which could lead to severe delays and potential requirement for sidetracks. The mitigation is to drill this section vertically using oil based mud. The possibility of leaving the reservoir uncased (open hole completion) should also be considered.
- Stress analysis on tubing and casing
  - The heat transfer from the tubing to the casing has been calculated using the OLGA mode assuming brine in the annulus. The calculated tubing and casing temperatures were used in the well stress model
  - The casing in the existing wells has been analysed and there are no concerns, even under transient cold injection cases, under the "worst case" assumptions.

- The proposed tubing for new wells has been analysed and there are no concerns under any of the proposed cases even in the "worst case" scenarios. This is because new tubing and packers can be selected that can withstand the high cooling loads.

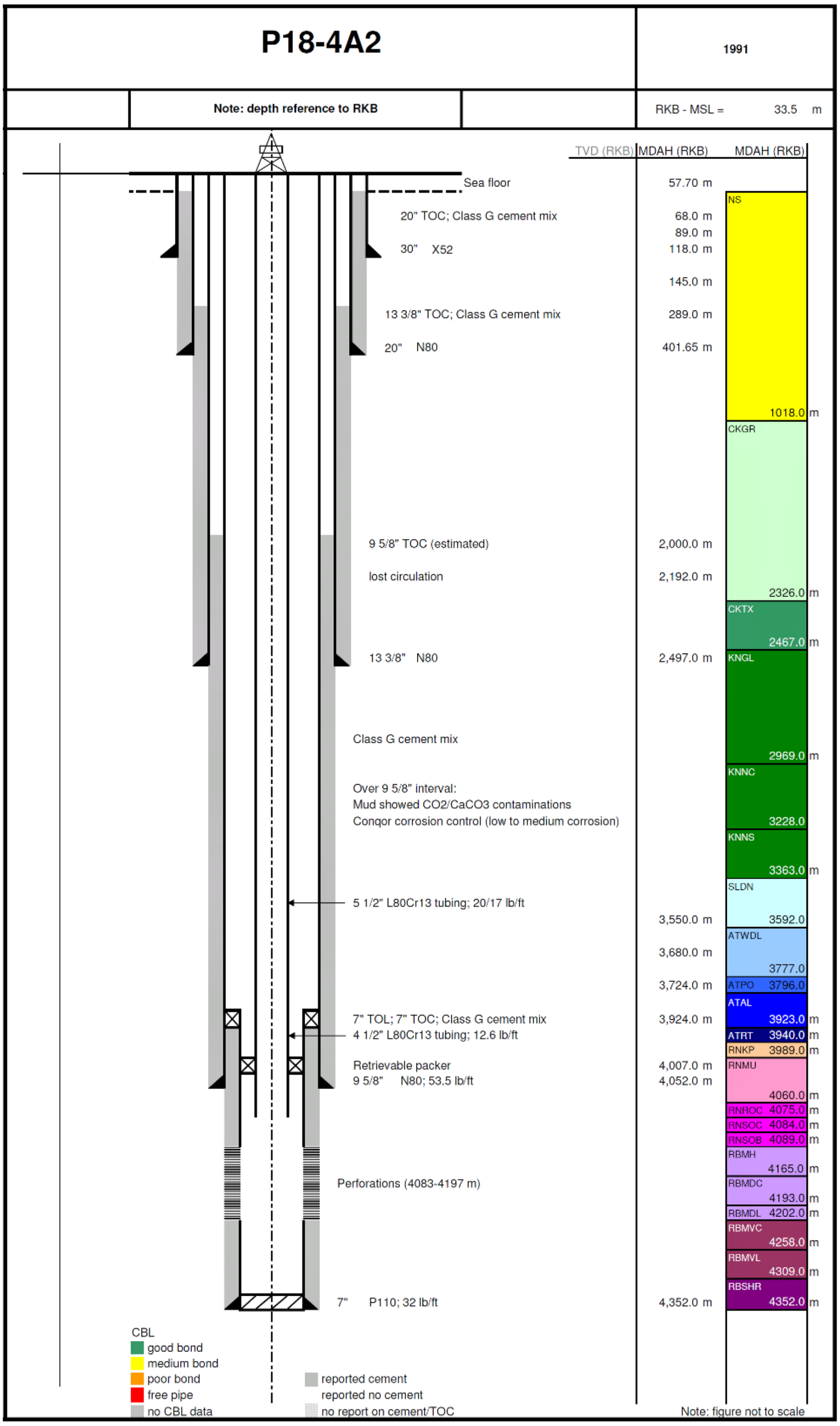
- Steel integrity
  - Carbon steel is satisfactory for CO_2 injection under both warm and cold cases, subject to no free water being present. Reservoir drying around the wellbore by under saturated CO_2 is expected to minimise corrosion risk of the liner even in the event of initial formation water being present.
  - For cold CO_2 injection, Arctic/Cold CO_2 service carbon steel tubing will be required to avoid brittle failure. The worst case scenario has a temperature of -47°C at wellhead and arctic conditions are considered (and tested) down to -55°C.
  - The existing production casing is technically unsuitable for transient conditions (-20°C casing), however a number of options exist to mitigate this issue. The casing could potentially be re-rated if the details of heat treatments can be sourced. Alternatively, temperatures below approximately -10°C could be avoided by insulating the annulus void with aerogel or other insulating fluids. Gels can be difficult to use in annulus service as it requires perfect distribution of the gel over the entire annulus. Poor distribution could lead to casing cold spots where failure could then occur.

- Cement integrity
  - The cement for the production casing has not been designed for CO_2 service and so may suffer chemical attack. However this is not a well integrity issue as any deterioration of the liner cement will not escalate into leaks into the annulus or to the overburden.
  - The metal casing will expand and contract at a different rate to the cement under cold conditions. This may break the bond between the cement and the casing allowing a CO_2 leak. This could lead to CO_2 rising into the overburden. There are still multiple barriers between the leak and the surface. Large leaks would be detected by 4D seismic but would be very unlikely to reach the surface.

- Dense phase injection into depleted reservoir
  - Standard completion equipment can be used to allow dense phase injection into a depleted reservoir.
  - The initial injection would be through a small number of holes in a perforated joint.
  - As the reservoir pressure increased, plugs would be removed by slickline to increase the injection volume. This is a technique used in Canada. However, the ability to intervene on a remote platform and the tolerance to debris, will be issues that have to be addressed.
  - Smart downhole valves are not considered suitable for these downhole conditions without extensive testing.

Note that in the subsequent flow assurance modelling, the option of cold CO_2 injection was dropped. Therefore only some of the above comments are applicable to the selected ROAD design.

Figure5.2 P18-4A2 well schematics with CBL interpretation (left-hand side) and stratigraphy (right-hand side).



5.4 Detailed design Well P18-04-A2 and cost estimation

Following the selection of the P18-4 reservoir for the ROAD demonstration phase, the well design and required recompletion were considered in more detail. WEP were asked to evaluate the integrity of the P18-04-A2 well (

*Figure*Figure 5.2) and to design a workover and evaluation plan to verify the integrity and to make the necessary adjustments to the well for CO_2 storage. Also the plans for abandonment were included and an abandonment plan made. The well integrity assessment covered both the operational phase of the injection project and the long-term post-abandonment phase.
Their report contains a design and work program outline for:

- Production tubing retrieval, Cement and casing evaluation & Recompletion
- Abandonment with a full-bore formation plug ("pancake" plug)

Tubing stress analysis with WellCat show that all modelled loads within the proposed well design are within the minimum acceptable design factor as specified by TAQA. There is however only a small additional safety factor for some of the load cases and given the fact that there is some uncertainty in the load cases and no sensitivity analysis has been done on the load cases this might be unsatisfactory. Calculation of the packer operating envelope shows that the currently identified packer would be just suitable; altering the packer setting method can further improve this. It is recommended to review the load cases, their uncertainty and their sensitivity in collaboration with TNO before starting the tendering process. In case the results with the new data stay unsatisfactory it is recommended to use a higher grade material for the completion components and alter the packer setting method.

Two phase flow at the safety valve: It is as of yet unclear whether the high flow rate two phase flow may cause problems at the safety valve. As this is a quite uncommon problem, information on this is very difficult to obtain and needs further detailing in the procurement phase.

Lead time: The current maximum lead time of the identified materials is about a year, this would also be the timeframe to start searching for a rig.

As part of the abandonment plan, costs were included for CO_2-safe abandonment of the P15-9 wells. It was not known if this would be necessary in practice, but with the available knowledge, the possibility of migration of CO_2 from P18-4 into the P15-9 reservoir could not be completely excluded (see Section 4.10 for technical details on the fault and Section 7.5 for contingency corrective measures plan).

Cost estimation summary:

Table 5.2 Cost estimation summary (20%, 2011 prices) excluding waiting on weather, assuming mobilization from NL, and excluding upfront final engineering, from January 2011. FFP stands for "Full-bore Formation Plug".

P18-4A2	Recompletion	€	**7 602 589**
	FFP	€	**5 065 245**
	Final abandonment	€	**3 247 984**
	Alternative abandonment in one action	€	**5 763 779**
P18-1	Re-entry and final abandonment with FFP	€	**6 021 807**
P15-9	E1 Conversion to monitoring well	€	**500 000**
	E1 Additional abandonment costs FFP	€	**656 250**
	E2 Additional abandonment costs FFP	€	**656 250**

The costs shown in *Table*Table 5.2 are the 20% cost estimates using 2011 prices, excluding the costs from waiting on weather, assuming mobilisation from the Netherlands, and excluding the upfront final engineering. *Table*, Table 5.4, Table 5.5 and Table 5.6 show cost estimates of various aspects of the project, using 2011 prices, while Figure 5.3 shows the final chosen completion design.

Table 5.3 Cost estimation for workover of P18-4A2 based on using a jack-up rig (2011 prices).

Estimated preparation cost	€	372 000
Estimated operational cost	€	7 230 589
Grand total	€	7 602 589

Table 5.4 Cost estimation Full-bore Formation Plug of P18-4A2 based on using a jack-up rig (2011 prices).

Estimated preparation cost	€	372 000
Estimated operational cost	€	4 693 245
Grand total	€	5 065 245

Table 5.5 Cost estimation for final abandonment of P18-4A2 based on using a jack-up rig (2011 prices).

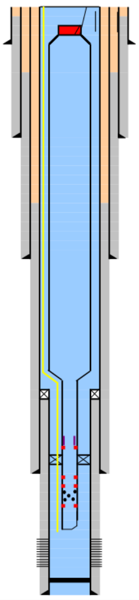
Estimated preparation cost	€	372 000
Estimated operational cost	€	2 875 984
Grand total	€	3 247 984

Table 5.6 Cost estimation Full-bore Formation Plug and final abandonment of P18-4A2 based on using a jack-up rig (2011 prices).

Estimated preparation cost	€	372 000
Estimated operational cost	€	5 391 779
Grand total	€	5 763 779

Figure 5.3 Final completion design. [Heekeren, 2011b]

Final completion design 5 1/2” to surface



Rough dimensions:

122 m	ID 4.562 inch
3785 m	ID 6.094 inch
165 m	ID 3.826 inch

Detailed dimensions:

Item	Length [m]	Depth [m]	ID [inch]	ID [mm]
Tubing	114.3	0.0	4.778	121.361
SCSSSV	5.4	114.3	4.562	115.875
X-over	3.0	119.7	4.778	121.361
Tubing	3785.4	122.7	6.094	154.788
X-over	3.0	3908.1	3.826	97.180
Tubing	119.0	3911.1	3.826	97.180
SSD	5.3	4030.1	3.753	95.326
Packer	8.3	4035.4	2.880	73.152
Tubing	10.8	4043.7	3.826	97.180
P gauge	6.0	4054.5	2.922	74.219
P gauge	3.0	4060.5	2.922	74.219
Nipple	1.1	4063.5	2.753	69.926
Perf joint	7.0	4064.5	3.826	97.180
Nipple	1.4	4071.5	2.703	68.656
WEG	0.7	4073.0	2.968	75.387

5.5 Pre-FEED cost estimation

The costs estimates presented here date from 2010 and include a range of scenarios then under consideration. The cost estimates shown in Table 5.7 come from the Phase 1 Report of the Concept Study for Transportation & Processing CO_2 Offshore, released in June 2010. They were made by Genesis Oil & Gas Consultants Ltd. and their in-house Area wide Development Estimate and Planning Tool (ADEPT). This cost is the P50 cost estimate including contracter indirects and client costs (P50 meaning that there’s a 50% chance of a higher final cost and a 50% chance of a lower final cost). The final cost includes an Engineering Design Allowance (EDA), which is a growth factor intended to account for normal design growth throughout the life of the project, accounting for minor design changes, uncertainties in estimated equipment size/weights, minor items of equipment missing due to level of definition, and uncertainties in the bulk estimates. Also included is an unallocated provision to account for project risks, incomplete definition data and inadequate scope definition.

The original scope for Phase 1 did not specify quantitative cost estimates to be completed at this stage. It was considered beneficial for the Option Selection process if high level Capex and energy consumption Opex estimates were produced to allow screening of the development options. It is important to note that the cost estimates are indicative at this stage and do not meet the +/-40% estimate level to be developed during Phase 2.

Costs which are presently excluded are: well costs, Brownfield P18-A cost, risers, structural upgrades if required on P18-A, pipeline crossings and approaches, and pipeline shore crossing.

Capex estimates for the overall development concepts are summarized below along with an indicative overview of the anticipated Opex associated with electrical power consumption associated with both the heating and the compression duties.

Table 5.7 Summary of Phase 1 indicative cost estimates from June 2010.

	Unit	1A	1B	1C	1D	1E	2A	2B	2C	3A	3B	4A	4B	5A
Pipeline Size		16"	16"	16"/8"	16"/8"	14"/10"	16"	16"	16"	16"	16"	28"	16"	16"
Pipeline Insulation		Y	Y	Y	Y	Y	N	N	N	N	N	N	N	N
Pipeline cost	mln €	49	49	70	70	79	28	28	28	28	28	42	28	28
Onshore Compression/Dehy/Deox	mln €	122	122	122	125	122	127	129	128	129	129	112	129	118
Onshore heating	mln €			3	3									
Onshore circulation pump	mln €			0	0									
Offshore compression	mln €											93		
Offshore heating	mln €	5	5			5	40	40			40		40	46
Electrical power cable from shore	mln €	7	7			7	7	7			7	7	7	7
TOTAL CAPEX:	**mln €**	**182**	**182**	**195**	**198**	**212**	**202**	**204**	**156**	**157**	**204**	**254**	**204**	**199**
Heating Power Requirements	MW	4	4	4	4	4	10.5	10.5	0	0	9	10.5	10.5	12.8
Heating Duty Required	%	10%	10%	10%	10%	10%	100%	100%	100%	100%	100%	100%	100%	100%
HEATING OPEX:	**mln €/yr**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**7.4**	**7.4**	**0.0**	**0.0**	**6.3**	**7.4**	**7.4**	**9.0**
Compression Power (Gas Phase)		14.1		14.1		14.1	13.8		13.8					
Compression Power (Dense Phase)		16.5	16.5	16.5	16.5	16.5	15.9	15.9	15.9	15.9	15.9	23.8	14	9.3
Compression Gas Phase Power saving	MW	2.4		2.4		2.4	2.1		2.1					
GAS PHASE OPEX SAVING	**mln €/yr**	**1.7**		**1.7**		**1.7**	**1.5**		**1.5**					

Electrical Power Cost	80	€/MWh

[Genesis, 2010b]: The scenarios defined in Table 5.8 and the cost estimates from Table 5.9 come from the Phase 2 Report of the Concept Study for Transportation & Processing CO_2 Offshore, released in Septemeber 2010 by Genesis Oil & Gas Consultants Ltd.

Table 5.8 Options carried forward from Phase 1 for transportation and processing of CO_2 offshore.

Option	Pipeline	Heating	Choke	CO_2 Transportation Phase
1A	Single pipeline -16” insulated	Offshore start up	Topside –usually fully open	Gas phase initially then dense phase
1B	Single pipeline -16” insulated	Offshore start up	Topside – partially closed	Dense phase only
1C	Dual pipeline - 1x16” insulated 1 x8” non-insulated recirculation line	Onshore start up	Topside –usually fully open	Gas phase initially then dense phase
1D	Dual pipeline - 1x16” insulated 1 x8” non-insulated recirculation line	Onshore start up	Topside – partially closed	Dense phase only
2C	Single pipeline -16” non-insulated	None	Topside – partially closed	Gas phase initially then dense phase

Table 5.9 Overall CAPEX estimates from September 2010. The cases are depicted in a previous table. "DEH" was a sensitivity tested and stands for "Direct Electrical Heating".

P50 CAPEX Estimate	Unit	Case 1A		Case 1A DEH		Case 1C		Case 2C	
		Base	Alt	Base	Alt	Base	Alt	Base	Alt
Onshore Plant - Soft starter, 1 x 100% trai	mln €	**73.4**		**77.8**		**75.7**		**78.3**	
Alt case: VSD	mln €		78.1		82.5		80.5		83
Alt case: 2 x 50% trains	mln €		97.5		101.9		99.8		103
Alt case: VSD + 2 x 50% trains	mln €		102.1		106.5		104.5		107.7
Pipelines and Cables	mln €	**77.1**		**75.7**		**92.4**		**50.7**	
Riser	mln €	**1.4**		**1.4**		**1.6**		**1.4**	
P18 Modifications	mln €	**19.0**		**11.7**		**12.1**		**11.7**	
TOTAL SURFACE CAPEX	mln €	**170.9**		**166.6**		**181.8**		**142.1**	
Well recompletion (1)	mln €	10.8		10.8		10.8		10.8	
TOTAL CAPEX:	mln €	**181.7**		**177.4**		**192.6**		**152.9**	

(1) Well workovers costs are based on a two well workover campaign on P18-6 and P18-4 with a capacity for the demonstration phase only

Regarding the CAPEX estimates, the following assumptions are made:

- Two wells will be completed in a single workover campaign on P18-6 and P18-4. This will provide capacity for the demonstration phase. The well costs are based on completions suitable arctic completions for cold operation. To provide capacity for the full scale project (of 5 million tonnes per annum) all six P18-A wells require re-completion.
- The cost of a further 4 well campaign for the full scale project would cost 17.4M€ (4 x 4M€ per basic cold workover+1.4M€ rig mobilisation and demob).

The following key conclusions can be drawn:

- Overall, option 2C is the lowest CAPEX option. There may be additional scope to reduce the well re-completion cost for option 2C if the number of wells can be reduced, based on a higher capacity per well for denser cold CO_2 injection.
- The lowest cost warm CO_2 injection option with an insulated pipeline is direct electrical heating although the difference between DEH and option 1A with an offshore start up heater is marginal.
- Option 1A has the disadvantage that the pipeline will cool over time following a shutdown. Start-up rates are restricted within the power limitation of the offshore electric heater for around 24 hours until the pipeline warms up. Option 1C both have the advantage that the entire pipeline is kept warm during a shutdown either by re-circulation of the CO_2 (Option 1C) or direct pipeline heating. This speeds up the start up process as the pipeline is already warm. DEH has a similar benefit to 1C but has been discounted as discussed earlier.
- Option 1C is the highest CAPEX option, with the main difference being the cost for the dual pipelines. The cost difference between highest and lowest CAPEX options, 1C and 2C, is only 13%, indicating that CAPEX is not a differentiator between the alternative schemes.

An offshore OPEX estimate has been built up from the anticipated cost elements using norms from the Genesis ADEPT tool and other in-house data. The OPEX in Table 5.10 is forecast.

Table 5.10 Offshore OPEX estimation.

Option	1A/1B	1C/1D	2C
Annual OPEX €mln	5.0	4.7	4.4

As can be seen, there are not anticipated to be material OPEX differences between the alternative designs. These forecasts were compared with analogue data. From a correlation of OPEX v topsides weight for sixteen Normally Unmanned Installations (NUI) in the North Sea, an annual OPEX for P18-A in the proposed service would be €10mln per annum. However, OPEX per tonne of topsides can be seen to vary widely due to the particular circumstances of each facility, and one standard deviation less than the mean would be €4.9mln.

OPEX is traditionally under-estimated during design studies. It is recommended that the tabulated OPEX data be employed in option ranking and project economics, but that the €10mln OPEX forecast is assumed for high OPEX sensitivity cases.

For information, the final design used from 2012 onwards was based on option 1A (warm injection using an insulated pipeline) but without the start-up heater. This was selected as both low cost and achievable from an operational perspective following extensive flow assurance work in 2011-2013 (See Section 4.4.1 of the Close-out Report Transport).

6 Platform FEED scope

The platform FEED was never carried out, but the scope of work was written, and indeed tendered. This section gives the scope of work for the proposed platform FEED. Note that this specification now includes the selected operating regime based on the flow assurance work (section 4.1.1 of the Close-out Report Transport) although the platform heater is still included as an option.

P18-A is a Wellhead Protector Platform (WPP) and a normally unmanned installation. Its revamping is a brown field modification of a gas producing well platform.

The contractor will have to take into account that on the P18-A Platform there will be continuing gas production/transport during the P18-A Platform modifications and during subsequent CO_2 injection operations and that gas production (P18-2) and transport (Q16-A) should not be interrupted unless continued production or transportation is considered unavoidable or unsafe. The contractor to identify in HAZID, SIMOPS and constructability study, which activities would require stopping gas production/transportation.

Although there are 6 slots and 6 wells on the P18-A Platform it is not likely that all existing wells will be suitable for CO_2 injection. Hence the injection header may be designed for only 4 or 5 connections, rather than 6. The final choice to be advised before the FEED Study begins.

Current estimates for injection rate into the P18-4 well are for a maximum of 1.5 MTPA or 47.6 kg/s and a minimum of 0.6 MTPA or 19.0 kg/s. It is not yet confirmed whether it is best to fill the reservoirs from low pressure to final pressure one at a time, or to fill them together such that the reservoir pressure rises synchronously. It is expected that it is unwise to half fill one reservoir and then co-inject in a reservoir with a much lower pressure. At this time it is intended to inject in the P18-4 reservoir only and that should be the main focus of this study. The contractor is welcome to highlight opportunities and constraints with regard to such co-injection strategy.

P18-A Platform modifications must ensure that CO_2 receipt and injection operations can be performed safely and reliably and not impact the other operations and purposes of the P18-A Platform. The operating envelope will steadily evolve as the reservoir pressure increases. The FEED Study must recognise the lifecycle of CO_2 steady state injection from 20 barg to a maximum of 350 barg reservoir pressure. The FEED Study must also recognise the transient states of ramping up and down, start-up and shut down (Planned and Emergency shutdowns) . It is anticipated that for much and possibly all of the injection period of the ROAD project the pipeline will be operating at between 60 and 90 barg and between 40 to 60°C, which means the CO_2 will be in ”dense” phase. In the event of shut down of the compressors onshore the pipeline pressure may be allowed to fall to below 50 barg and the CO_2 could cool to between 10 to 20°C which will mean that two phase flow can be experienced at start up. Choking flow offshore should be avoided because warm (above 30°C) CO_2 must be injected particularly while reservoir pressure is below 70 bar, to avoid excessively low temperatures at the bottom of the well due to the injected CO_2 flashing or transitioning to gas. It is possible that leaving the platform choke valve open after a shut down of the compressors onshore could allow reservoir fluids to enter the well bore once the system has equalized. Such reverse flow should be avoided so that water does not enter the well bore, hence the timing of the shut-in of the choke valve is likely to be a critical operating parameter. It is expected that the best moment to open the choke valve offshore is when the pressures across the valve are equal.

A temporary vertical pig receiver will be used by the Pipeline Contractor for pipeline dewatering. It is important that enough space is reserved above the top of the riser for installation and removal of the temporary pig receiver.

A temporary pig receiver should be included on the P18-A Platform to allow for periodical inspection of the pipeline. Adequate space must be reserved to enable removal of the pigs.

Metering equipment capable of measuring the flow rate of dense phase CO_2 will be required. The optimum system would also be capable of measuring occasional two phase flow. However, the fiscal flow rate will be measured onshore and the offshore meters will be used for allocation only. The contractor is welcome to propose suitable allocation metering alternatives or procedures.

Monitoring of pressure and temperature at several points on the P18-A Platform and within the well will be required. There may be analytical devices required to measure quality of the CO_2 and presence of contaminants.

The ability to vent CO_2 downstream of the choke valve (or other isolating valve between the pipeline and the P18-A Platform) and upstream of the well head should be included. Special attention should be paid to the risk of venting CO_2, particularly to human health and to operation of hydrocarbon-fuelled machines; hence the outlet of the vent should be selected carefully.

Documentation of as-built facilities is available for initial P18-A Platform construction and subsequent riser modifications.

All studies and considerations to date have identified the preferred location for the 16” riser to be close to the Eastern leg of the P18-A Platform (platform SE). The contractor is required to confirm the optimum location for the riser.

The modifications will require the minimum platform shut down. Consideration of maximum use of skid mounted equipment and prefab piping is therefore anticipated.

6.1 Summary of Technical Scope

The P18-A platform is an unmanned, remotely operated well platform. It produces gas, which is sent un-treated to the P15-C production platform.

For the ROAD project demonstration phase, P18-A will be modified in order to inject CO_2 in the P18-4 depleted gas reservoir. Main modifications are:

- New CO_2 riser;
- Addition of a back pressure control valve to control pipeline flow regime and limit slugging impact
- Provision for a temporary intelligent pig receiver;
- New injection header for up to 4 to 5 wells
- Installation of one injection flow line to P18-4A2 wellhead;
- Addition of a CO_2 vent system;
- Allow for well monitoring and well maintenance (wire-line, coil tubing, clean-up and testing activities...);
- Related modifications on: structures, instrumentation and control, utilities etc...

After modifications, the platform will remain unmanned and remotely operated.

Gas production and CO_2 injection will occur simultaneously for an expected period of two years.

Production and possible future well work over can be possible simultaneously.

Metering Summary: Fiscal Metering is foreseen at the onshore capture plant. When several wells will inject CO_2 on P18 platform, flow rate allocation to the different wells will be required. This could be achieved by having a flow meter on each flow line. Other means of allocation may be proposed.

The Well Control Panel (WCP) is located on P/18-A, whereas Process Shutdown System (PSS) is located on the principal (manned) control platform P/15.

Platform modification battery limit shall begin at the top of the riser. There is the isolation valve (above splash zone) which closes in case of emergency (by low pressure alarm indicating a possible leak on the platform).

Venting and pigging facilities shall be provided downstream. A start-up heater may optionally be considered for transient operations.

Filtration summary. It shall be defined if filtering facilities have to be installed (see *Figure 6.1*).

Double Block and Bleed valves are foreseen on the CO_2 injection manifold in case of future connection to others wells, to be realised without stopping injection into P/18-4A well.

Moisture measurements shall be installed on CO_2 manifold as chromatograph shall be placed rather in the onshore part.

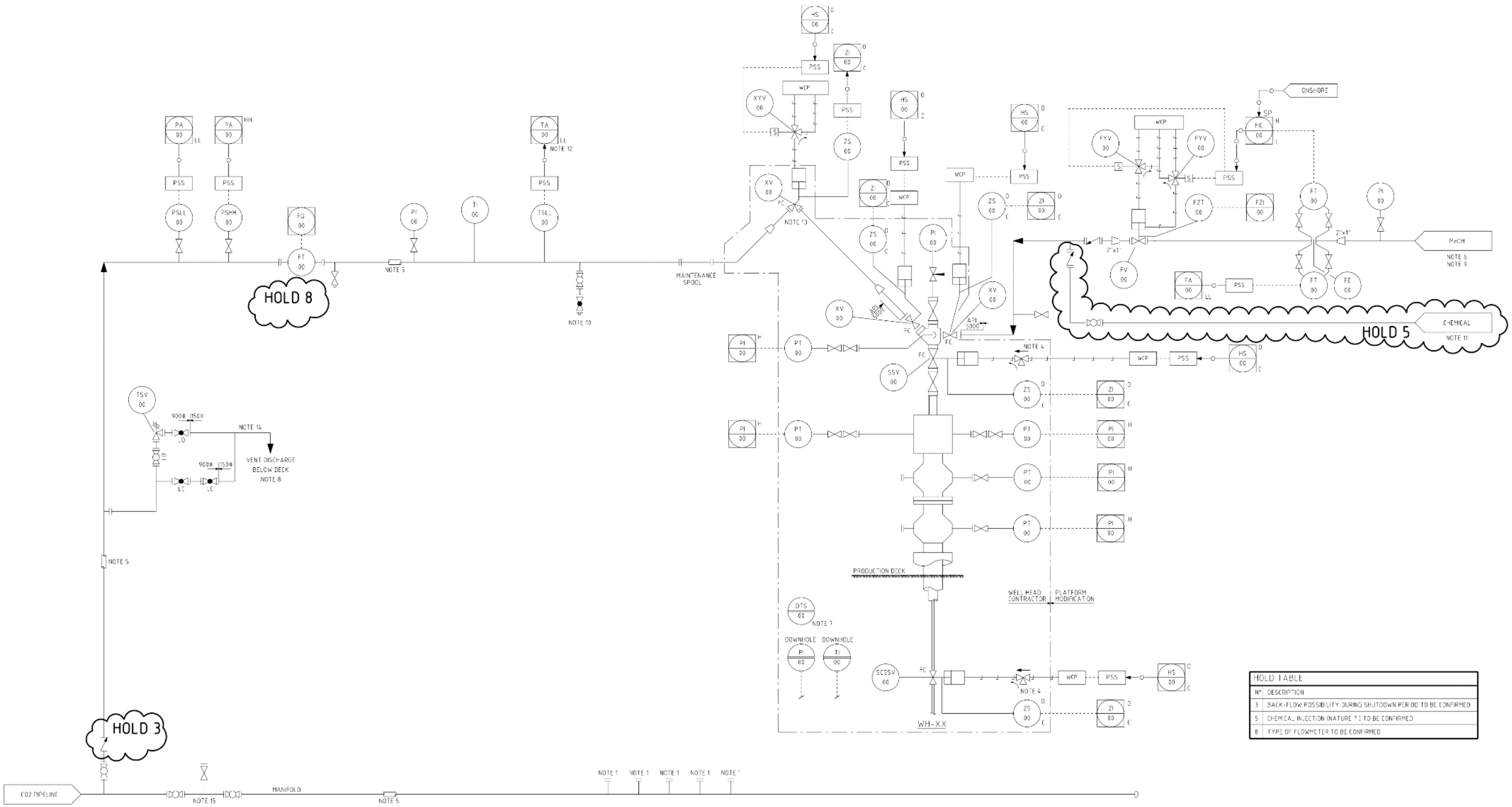
The injection line to the well shall be connected on the CO_2 manifold. This line is equipped with: check valve in order to prevent back flow from the well, flow meter, temperature and pressure indications/protections, and a choke valve. The injection rate may be regulated by the choke valve prior to the wellhead, which may be controlled by the pressure at the CO_2 injection manifold (maximum operating pressure of 128 barg).The bottom initial well pressure is 20 barg and is expected to be about 350 barg at the end of the injection period.

Low temperature alarms and protection shall be installed downstream of the choke valve in order to maintain a minimal temperature of 15°C to avoid hydrates formation down hole, and a minimal temperature of -10°C to protect the casing. Injection of methanol in the wellhead shall be foreseen by connecting on the existing methanol system. Chemicals injection may be foreseen, too.

High temperatures protection by TSV shall be installed in all sections where CO_2 can be trapped between closed valves.

Platform modification battery limit shall end at the well head.

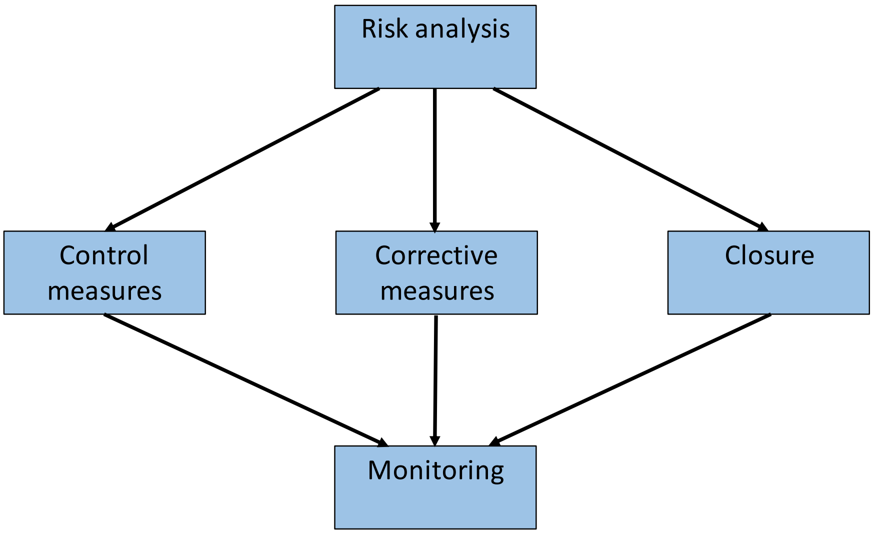
Figure 6.1 Piping and instrumentation diagram of P18-A platform modifications and connection with P18-4A wellhead.



7 Risk management including monitoring and logging

The risk management plan consists of a risk assessment and the corresponding management measures (risk management). The risk assessment is also the foundation for the plan for corrective measures and for the provisional closure plan. The formulation of the monitoring plan is based on these plans (Figure 7.1).

Figure 7.1 Consistent and coherent risk management plan.



7.1 Risk assessment

The risks for migration out of the reservoir into the overburden or for leakage at the sea bottom are considered minimal for P18, which is a depleted gasfield with no active aquifer drive. The latter is demonstrated by the straight production P/z curves. Currently the reservoir is well below hydrostatic pressure.

Geomechanical-related risks of fracturing and fault re-activation are small and can be (partially) reduced by:

- Injecting CO_2 with bottom hole pressures (BHP) which are below fracturing condition.
- Avoid overpressurizing the reservoir above the initial pressure.
- Keeping a safe distance between the injection wells and faults to avoid direct charging of faults by injected CO_2 through natural or induced fractures. Wells closest to faults are wells P18-02A1, P18-02A6, P18-04A2 and P18-06A7ST1. The latter requires most caution, since the injectivity of the P18-06 reservoir is of the least quality.
- Managing thermal effects of injection

During injection, the potential for fault reactivation generally decreases providing that the CO_2 is not injected directly into the fault zone and the thermal effects of injection are negligible. The risk of induced hydro-fracturing increases in the later stage of CO_2 injection when the reservoir is almost re-pressurized to the initial pressure.

Based on the KNMI database of recorded induced seismic events associated with hydrocarbon production in the Netherlands, the P18 field was not seismically active during its production period. The detection limit of the KNMI seismic network was M2.5 until 1995 and M1-1.5 on Richter scale afterwards. No major seismic activity is therefore expected.

The caprock has proved to be gas tight based on the production history. However, there are indications on seismic data of natural shallow gas up to the seabottom along and near faults. The origin of the shallow gas is unknown. Considering the excellent sealing quality of the primary seal of the P18 reservoir, and the difference in age and dip of the faults in layers above and below the Altena Group, it is unlikely that these potential shallow gas accumulations are related to the P18 reservoirs from which gas is produced. More likely, it originates from either the Posidonia Shale Formation in the overlying Altena Group, which is responsible for charging many Upper Jurassic and lower Cretaceous reservoirs in the vicinity or from shallower layers by biogenic processes.

Furthermore, since the properties of CO_2, especially in combination with connate water, are different from methane, it means that dissolution and precipitation of minerals, respectively creating or blocking migration pathways, needs to be thoroughly investigated.

Furthermore the possibility of fault reactivation needs attention, since the reservoir has been depressured (depleted) and CO_2 injection would involve repressuring. On top of that a possible geochemical-geomechanical interaction must be investigated (see Chapter 6). The modeling results show that short-term mineralogical and porosity changes, induced by dissolved CO_2 and corresponding pH decrease, are negligible. On the long-term (thousands of years) mineral reactions will result in a porosity decrease of 0.3 percentage point (pp) for the reservoir and a porosity increase of 0.2 pp for the caprock. The presence of O2 as an impurity in the CO_2 stream does not seem to have significant consequences regarding the short-, mid- and long-term geochemical effects of CO_2 storage.

The injectivity of the reservoir is considered to be especially an issue in the P18-6 field. The main reservoir is heterogeneous with potentially rapid lateral facies changes typical of a fluviatile setting. This may lead to problems during injection such as local pressure build-up. This will be noticed immediately by monitoring the required injection pressure. Apart from geological heterogeneity of the reservoir, near wellbore effects such as salt precipitation or Joule Thompson effects (like freezing) of the CO_2 due to adiabatic expansion do not appear to cause uncontrollable risks (see Chapter 4). The latter may give rise to thermal fraccing. The expectation is, that this will only influence a relatively small part of the reservoir close to the wellbore. In terms of migration of CO_2 into the overburden the main potential pathways considered are along existing or new wellbores A more detailed analysis of the state of the existing wells has been investigated. Characterization and proper abandonment of these wells followed by well integrity measurements is necessary. In the worst case this may require a workover of one or more of the wells.

Laterally the reservoir is constrained by a structural closure and sealing faults. Migration within the reservoir is therefore not a crucial parameter to monitor. However, it does provide input for the predictive simulation models demonstrating a proper understanding of the reservoir and associated flow processes.

Emergency Stop Valve (ESV)

Emergency Stop Valve has a function of shutting down the well automatically in case of emergency. This piece of equipment is mounted in the well at a depth of several hundreds of metres. This device has been tested for oil and gas wells and needs to be proven for the thermal conditions that can be expected in CO_2 injection wells.

Shell reported on the ESV (they use the term SSSV which stands for Subsurface Safety Valve) in their well design for Goldeneye (Shell, 2015: 3.5 Safety Valve, p40/41), op. cit:

"The tubing volume between the Christmas tree and the SSSV is approximately 6.3 m^3. Should this volume be released to atmosphere the SSSV temperature will drop close to the triple point (-56.6°C). If the SSSV has a migration path across the flapper for dense phase CO_2 to cross then further cooling will take place localised to the SSSV. SSSVs currently available on the market will require additional testing/qualification and possibly some design modifications to suit the conditions in the well in this highly unlikely event. This information has been formally shared with SSSV vendors."

The current SSSV designs are rated down to -7 ^oC, and the question remains if this is good enough for CO_2 storage. In some design scenarios temperature goes down close to the triple point. That does not mean that the current designs won't work at these lower temperatures, but proper operation under low temperatures would need further proof.

7.2 Monitoring plan (MMV)

This section describes the monitoring plan developed as part of the permitting process for CO_2 storage [Vandeweijer et al., 2011; ROAD, 2011b]. The aim of the plan is to monitor the CO_2 in the reservoir to verify that it is permanently stored, and to detect any unforeseen behaviour so that remedial measures can be taken if necessary. The main overview is given by *Figure*Figures 7.2, 7.3 and 7.4. The second column describes the parameters to be monitored. These parameters follow both from the mandatory monitoring obligations as stipulated by the storage directive and from the risk assessment.
The 3rd column indicates the proposed technique adopted to measure the parameter. A more detailed description of the technique is provided outside the table. The 4th column indicates the category of monitoring (mandatory, required, contingency). The fifth and sixth columns give a description both of the temporal frequencies (column 5 and spatial coverage (column 6) of the data acquisition foreseen in the different phases of the project (preinjection, injection and post-injection including long-term stewardship after transfer of responsibility). The rationale behind the monitoring strategy related to the identified risks is described in the following section.

Column 7 provides a description of the expected accuracy of the monitoring method and of expected values that indicate normal behavior. Therefore this column is colored green. The 8th column indicates threshold values, where normal behavior as anticipated stops and where irregularities start. As long as the measured values remain below these threshold values, no actions are required (green column). In case however the values come above the threshold values, one enters the 8th column colored orange with specific actions defined. This stage is considered as an increased alert phase, where behavior starts to deviate from expectations. This could for example lead to recalibration of the models, but when persisting to more stringent measures.

In case the monitor values come above the identified threshold in the 9th column coloured red, the highest alert phase starts and immediate actions (or contingency measures) as defined in the second subcolumn of column 9 are required.

Furthermore the table is divided into different blocks describing the different compartments to be monitored (injection process, injection and monitoring wells, abandoned wells, reservoir integrity, plume tracking, environmental monitoring).

The entire table needs to be updated and submitted to the competent authorities yearly. The monitoring plan is according to the format proposed in [NSBTF, 2009] and the draft EU guidance document [EC, 2011].

Note, that the timing for monitoring of the post injection period including the abandonment of the wells and the decommisioning of the platform and the period to the transfer of liability to the state have not been defined in this plan. The definition of these periods would be subject of discussion with State Supervision of the Mines.

Note that although time-lapse seismic or microgravimetric data are standard tools in the literature to support CO_2 plume tracking, they are not included in the plan for P18. This is because it is a depleted gas reservoir without an active aquifer (so the gas/water contact is not useful) and is also at considerable depth. Therefore the CO_2 in the reservoir would not trigger to a significant signal from these instruments, so they would be ineffective (at the current state of development, 2011). Tracers offer an opportunity for monitoring.

Figure 7.2 Monitoring time table [ROAD, 2011b]

P18 CO2 storage base-case monitoring plan

Mandatory monitoring according to Annex II of the EU directive
Required monitoring
Contingency monitoring
Period of time t.b.d.

Abandonement of injection well
Transfer of responsibility

No.	Parameter	Technique	Pre-injection	Injection	Post-injection	Post-injection (Abandonment)	Post-injection (Transfer of responsibility)
	Injection proces						
1	Injection rate	Flow meter		Continuous			
2	Injection stream CO2 concentration	Gas samples & analysis: online system		Continuous or 1-3 hourly			
3	Injection stream composition	Gas samples & analysis: Additional samples for calibration		Quarterly			
4	Water measurement	Gas measurement		Continuous			
5	Discontinous emissions through leakage, venting or incidents	Combination of techniques		Yearly reporting according to protocol			
	Well						
6	Annular pressure	Pressure device	Baseline	Continuous			
7	Well integrity	Wireline Logging (selection of tool: CBL, PMIT, EMIT, USIT, WAF, optical)	Baseline	Survey	Survey		
8	Well head pressure	Pressure device		Continuous			
9	Well head temperature	Temperature device		Continuous			
10	Plug integrity	Pressure test and inspection				Assessment of the quality of the plug	
	Reservoir integrity						
11	Reservoir pressure (FBHP) (see also line 8)	pressure device		Continuous or monthly with memory gauges (frequency can be adapted according to findings) - (Calculated from FTHP, AND potentially downhole permanent sensor (large risk of failure) or downhole memory gauges)			
12	Reservoir Temperature (FBHT) (see also line 9)	thermometer		Continuous or monthly with memory gauges (frequency can be adapted according to findings) - (Calculated from FTHT AND potentially downhole permanent sensor (large risk of failure) or downhole memory gauges)			
13	Stabilized pressure (CIBHP) (gradient) during shut-in period	pressure device (wireline tool or memory gauge) combined with shut-in		Shut-in pressure measurement every year (Memory gauges combined with shut-in AND if available measurement in monitoring well)			
14	Stabilised temperature (CIBHT) (gradient) during shut-in period	thermometer or DTS (wireline tool or memory gauge) combined with shut-in		Shut-in temperature measurement every year (DTS for permanent installation or memory gauges combined with shut-in AND if available in monitoring well)			
15	Suspected leakage	Time-lapse seismic data acquisition (3D)	Baseline		Survey in case of irregularities		Survey for hand over
	Environmental monitoring						
16	Pockmarks at the seabottom	Multi-beam echosounding	Baseline			Survey, Survey	Survey
17	Presence of shallow gas or gas chimneys in the subsurface	Time-lapse seismic data acquisition (3D)	Baseline				
18	Migration pathways for gas in the shallow subsurface	Time-lapse seismic data acquisition (3D)	Baseline		Survey in case of irregularities		
19	CO2 in soil at pockmarks	Gas samples using vibrocore + lab analysis			Survey in case of irregularities		
20	Bubble detection at wellhead	Acoustic bubble detector			Survey in case of irregularities		
21	Microseismic monitoring	Permanent geophones in monitoring well		Continuous in injection well (considered required monitoring but subject to technical feasibility)			

Figure 7.3 Monitoring plan – injection process and well monitoring [ROAD, 2011b]

No.	Parameter to be monitored*	Technique adopted	Category of monitoring			Project phase and frequency					Location	Normal situation		Alert value		Contingency value	
			Mandatory according to EU	Required (preliminary	Contingency	Pre-inj	Inj	Post-Inj	Post-Inj (abandonment)	Long-term stewardship		Expectation value	Accuracy	> Threshold 1	Action**	> Threshold 2	Contingency measures***
	Injection proces																
1	Injection rate	Flow meter	x				Cont				Well head	Defined rate					
2	Injection stream CO2 concentration	Samples & analysis: online system	x				Cont or 1-3 hourly sampling combined with online analysis system				Compressor station	Defined % for the CO2 concentration of the stream					
3	Injection stream composition (all residual components)	Samples & analysis: Additional samples for calibration	x				Quarterly				Compressor station	Defined % for the composition of the gas					
4	Water measurement	Water measurement	x				Cont				Inlet injection compressor	Specification value					
5	Discontinous emissions through leakage, venting or incidents	Combination of techniques	x				Yearly				Potential leakage points like joints or ventstacks						
	Well																
6	Annular pressure	Pressure device (with alarm value)		x		Baseline	Continuously with remote system for online reading				Well head	Constant pressure			Additional measurements like logging or sampling + analysis of fluids to detect CO2		Investigate causes (sampling) and options to remediate (in the extreme case well abandonment)
7	Well integrity	Wireline Logging (selection of tool: CBL, PMIT, EMIT, USIT, WAF, optical)		x		Baseline	Survey	Survey			Well						
8	Well head pressure	Pressure device	x			Baseline	Continuous	Continuous	Continuous		Well head (injection skid)						
9	Well head temperature	Temperature device	x			Baseline	Continuous	Continuous	Continuous		Well head (injection skid)						
10	Plug integrity	Pressure test and inspection		x					Assessment of the quality of the plug		In the well above the plug				Investigate cause with other measurements (e.g. check deformation of the wellbore, fluid sample)		Redo the plug

Figure 7.4 Monitoring plan – reservoir integrity and environmental monitoring [ROAD, 2011b]

No.	Parameter to be monitored*	Technique adopted	Category of monitoring			Project phase and frequency					Location	Normal situation		Alert value		Contingency value	
			Mandatory according to EU	Required (preliminary)	Contingency	Pre-inj	Inj	Post-Inj	Post-Inj (abandonment)	Long-term stewardship		Expectation value	Accuracy	> Threshold 1	Action**	> Threshold 2	Contingency measures***
	Reservoir integrity																
11	Reservoir pressure (FBHP) (see also line 8)	pressure device	(x)			Baseline data	Cont (TH cont, BH cont or monthly in case memory gauges)	Cont (TH cont, BH cont or monthly in case memory gauges) as long as the well is not suspended			Calculated from FTHP continuous, AND downhole permanent sensor (large risk of failure) OR downhole memory gauges						
12	Reservoir Temperature (FBHT) (see also line 9)	thermometer or DTS	(x)			Baseline data	Cont (TH cont, BH cont or monthly in case memory gauges)	Cont (TH cont, BH cont or monthly in case memory gauges) as long as the well is not suspended			Calculated from FTHT AND potentially downhole permanent sensor (large risk of failure) or downhole memory gauges						
13	Stabilized pressure (CIBHP) (gradient) during shut-in period	pressure device combined with shut-in		x		Baseline data	Every year	Every year as long as the well is not suspended			Calculated from THP, AND permanent downhole sensor (large risk of failure) or downhole memory gauges, combined with shut in						
14	Stabilised temperature (CIBHT) (gradient) during shut-in period	thermometer or DTS combined with shut-in		x		Baseline data	Every year	Every year as long as the well is not suspended			DTS for permanent installation or memory gauges combined with shut-in AND if available in monitoring well						
15	Suspected leakage	Surface seismic survey			x	Baseline	Only when other monitoring indicates leakage	Only when other monitoring indicates leakage	Only when other monitoring indicates leakage	Survey	Marine vessel (seismic acquisition using streamers)						
	Environmental monitoring																
16	Pockmarks at the seabottom	Multi-beam echosounding		x		Baseline			Survey	Survey	Acquisition from a ship				Additional gas sampling + analysis to identify the origin of potential seepage or leakage. In case of leakage, identify the pathway with time-lapse seismic data.		Additional gas sampling + analysis to identify the origin of potential seepage or leakage. In case of leakage, identify the pathway with time-lapse seismic data. Mitigation to potential leaks
17	Presence of shallow gas or gas chimneys in the subsurface	Baseline seismic data		x		Baseline					Baseline seismic data						Additional gas sampling + analysis to identify the origin of potential seepage or leakage. In case of leakage, identify the pathway with time-lapse seismic data. Mitigation to potential leaks
18	Migration pathways for gas in the shallow subsurface	Time-lapse seismic data acquisition (2D or 3D)			x	Baseline	Contingency	Contingency	Contingency	Contingency	Marine acquisition from a vessel						Additional gas sampling + analysis to identify the origin of potential seepage or leakage. In case of leakage, identify the activeness of the pathway with time-lapse seismic data. Mitigation to potential leaks
19	CO2 in soil at pockmarks	Gas samples using vibrocore + lab analysis			x	Contingency	Contingency	Contingency	Contingency	Contingency	Sampling from a vessel						
20	Bubble detection at wellhead	Acoustic bubble detector			x	Contingency	Contingency	Contingency	Contingency	Contingency	Install at the seabottom						
21	Microseismic monitoring	Permanent geophones in injection well		x			Cont	Cont			Injection well at caprock and reservoir level						

*Follows from the risk assessment
** t.b.d. by operator, examples are updating model, additional monitoring, …
*** t.b.d. by operator, examples are stop injection, back-production, well workover, contingency monitoring

7.3 Well logging and monitoring tools

Wells that are planned to be converted for CO_2 injection need preliminary work to evaluate whether the casing and the cementation are in a good state. During and after the injection period the evaluation of the integrity needs to be continually checked. ROAD commissioned work to document all the different tools that can be used for this work and to make recommendations. The tools are listed in Table 7.1

The recommended approach to do is to combine different tools as they complement each other's accuracy:

For instance:

- Multifinger caliper + Sonic tools: sonic tools are sensitive for changes in ID and ovality of the casing. When running a sonic tool together with a MFC the sonic tools can be calibrated to the MFC measurements.
- Sonic + ultrasonic tools: effects of mud or other fluids can be reduced when comparing the differences in measurements
- Multifinger + sonic + ultrasonic: will provide a full picture of the casing and the cement sheet.
- Multifinger + Electromagnetic tools: in this case the electromagnetic tool supplements the high resolution of the MFC. The tools can be run in a gas filled well.
- GR or CCL + other tools: it is a standard procedure to run a CCL or a GR tool to calibrate the depth of the tool with previous logs.

Table 7.1 Application of downhole tools for monitoring CO_2 wells with the name of the specific tool for each application. Green = reasonable to good; orange = possible indication

Type of measurement	Halliburton	Schlumberger	Principle
Tubular wall thickness	MAC	TGS, PMIT	**Multi Finger Calliper**
		EM Pipe Scanner	**Electro Magnetic**
		CPET	**Electric Potential Difference**
		USIT, IS	**Ultra Sonic**
		CBL, CET	**Sonic**
Corrosion evaluation	EyeDeal		**Downhole Camera**
		CPET	**Electric Potential Difference**
Condition of cement sheet	CAST	USIT, IS	**Ultra Sonic**
	CBL	CET, CBL	**Sonic**
presence of micro annuli	CAST	USIT, IS	**Ultra Sonic**
		MSCT	**Sidewall coring**
CO2 presence behind casing	CAST	USIT, IS	**Ultra Sonic**
	RMT	RST	**Sampling**
CO2 leak in well		WAV	**Ultra Sonic Leak Detection**
	DHC		**Downhole Camera**
	DTSHT, Optolog	DTS, ERA	**Permanent Downhole P & T**
flow detection behind casing		WAV	**Ultra Sonic Leak Detection**
	RMT	RST	**Pulsed Neutron**

The monitoring program in terms of the well is divided in three phases: pre-injection phase, injection phase, and post-injection phase.

In the pre-injection phase the casing and the cement over the caprock need to be measured to see if the well is suitable for CO_2 injection. This is only a strict requirement when the evaluation of the well files shows reason to take action, otherwise only the tubing can be checked. The following aspects need to be measured: casing and tubing (corrosion, measure wall thickness; geometry, measure ID; pressure integrity), cement (presence and quality, measure condition of cement sheet; bond between casing/cement, measure presence of micro annuli; bond between cement/formation, measure presence of micro annuli).

During this phase to get proper measurements of the casing and cement the tubing needs to be pulled. The tubing needs to be measured before the start of the injection even if a new tubing is installed in order to have a comparison log for later measurements during the injection phase.

Table 7.2 Recommended monitoring tools to assess casing and cement sheet before CO_2 injection. Note: sonic and ultrasonic can only be run in a fluid-filled well

Minimum measurements:	If doubt exists:
• Multifinger Caliper • Sonic • Ultrasonic • Electro Magnetic	• Neutron • Video

During the injection phase the well needs to be monitored to make sure the casing, tubing and cement sheet remain in good health. The following aspects can be measured: tubing (pressure integrity to detect leaks; corrosion/erosion, measure wall thickness; reservoir and CO_2 behaviour, downhole pressure and temperature).

In case there are serious reasons to question the integrity of the casing and cement sheet one needs to consider killing the well and pulling the tubing to inspect this.

Table 7.3 Recommended monitoring tools during the injection phase. Note: sonic and ultrasonic can only be run in a fluid-filled well

Minimum measurements:	If doubt exists:
• Annulus pressure monitoring • Multifinger Caliper or • Electro Magnetic • Permanent downhole P & T	• Sonic • Ultrasonic • Neutron • Video

When the post-injection phase gets into effect, the well abandonment needs to have good integrity. During this phase the following needs to be monitored: casing (pressure/temperature anomalies that indicate leaks; flow detection outside casing; CO_2 detection inside & outside casing).

Table 7.4 Recommended monitoring tools in the abandonment phase

Minimum measurements:	If doubt exists:
• Multifinger Caliper • Sonic • Ultrasonic • Electro Magnetic	• Pressure monitoring • Permanent downhole P & T • Neutron; • Sidewall Coring; • Sampling outside Casing. • Downhole sampling • Video

7.4 Marine Monitoring above the P18 reservoir

TNO has carried out a high resolution 3D seismic survey off-shore Rotterdam. The new deployment concept that was tested with this survey results in high-quality 3D images of the shallow subsurface at relatively low cost, particularly in comparison with conventional 3D seismic data acquisition. The pilot survey aimed to demonstrate the use of high-resolution 3D seismic for risk assessment and monitoring in CO_2 storage [Vandeweijer et al., 2014].

To our knowledge this is the first high resolution 3D seismic survey that has been acquired offshore in the Netherlands. Target of the survey was the upper thousand meters of the overburden in the vicinity of the P18-4 gas field. The depleted gas field is the candidate CO_2 storage site for the ROAD2020 CCS demonstration project. The seismic survey was carried out as part of the Dutch national CATO-2 CCS research programme.

The data acquisition took place in April 2014 and was carried out in a partnership of TNO, Deltares, and the Netherlands Institute for Sea Research (NIOZ). Data processing and imaging was carried out by TNO and a final processed seismic image cube was made available early 2015 [Steeghs et al., 2014; 2015].

7.5 Corrective measures plan

[Taqa, 2011]: There are five types of corrective measures that can be taken as soon as an undesirable event occurs:

- reporting to the competent authority and communicating with stakeholders
- additional monitoring (intensify or expand)
- adaptation of the operational parameters
- technical adaptation of the system
- large-scale intervention

With regard to the above measures, it is obvious that if an undesirable event takes place a combination of these measures will be used. Needless to say, this combination must be effective in correcting significant irregularities or blocking leaks in order to prevent or stop CO_2 from leaking out of the storage complex. An overview of possible undesirable events and the related corrective measures is presented in **Error! Reference ource not found.**.

Table 7.5 Overview of the relationship between undesirable events and corrective measures.

Event	Consequence	Corrective measure (in addition to communication, informing the competent authorities and stakeholders, etc.)
1 CO_2 outside storage complex/prevent		
CO_2 from well to overlying layers	CO_2 escaping outside reservoir into subsoil	Additional monitoring well cementation Repair cementation
CO_2 from well to biosphere	CO_2 escaping into biosphere	Additional monitoring well Repair cementation
CO_2 from reservoir to biosphere	CO_2 escaping into biosphere	Additional monitoring Stop injection
CO_2 from reservoir to P15-9	CO_2 escaping through fault zone to P15-9	Monitoring P15-9 Measures P15-9
2 Seismic activity caused by the storage		
Reactivation fault zones	Integrity of subsoil affected	Additional monitoring Stop injection
3 Damage		
Damage to the well	Function of well restricted	Repair well
Deterioration reservoir / cover layer (mechanical, chemical or temperature effects)	Integrity of subsoil affected	Additional monitoring Stop injection
4 Monitoring		
Failure of monitoring system	No insight into injection process	Stop injection Adapt monitoring
Conceptual failure of monitoring system	No insight into injection process	Stop injection Adapt monitoring
5 Entire system functioning differently than expected		
Restricted injectivity	Less CO_2 can be stored than foreseen	Adapt pressure and temperature Adapt monitoring
Unexpected behaviour of CO_2 in well or reservoir	Unpredictability of injection	Stop injection Adapt pressure and temperature Adapt monitoring

Optional well abandonment during the operational phase

As part as the ROAD CCS project it is planned to inject CO_2 in the depleted P18-4 gas reservoir. Next to the P18-4 reservoir is the P15-9 reservoir [Heekeren & Poll, 2011]. The reservoirs are separated by a fault – described in section 4.10. Three wells are present in the P15-9 reservoir: two producing wells P15 9E1 & P15 9E2 and one suspended well P18-1. It was concluded that during the production life no problems are envisaged for the wells in the p15-9 field.

To protect against the unlikely event of CO_2 breakthrough into the P15-9 field, additional measures for the abandonment of the P15-9 wells such as Fullbore Formation Plugs (FFP) are the preferred option. Special attention should be given for the P15-9E1 original wellbore in this case. It was advised to leave the P18-1 well in its current state and re-enter & abandon with FFP in case of indications of CO_2 breakthrough.

In case there would be CO_2 migration from the P18-4 field to P15-9 it is advised to abandon the wells with a **Fullbore Formation Plug** (FFP) with CO_2 resistant cement. This plug will be part of the abandonment as regulated by the Dutch mining law. The FFP will consist of a milled window in a caprock interval where the cement and casing are removed by milling out a diameter larger than the most outer casing. Then a balanced cement plug is set against the exposed formation on top of a mechanical bridge plug or cement retainer. The plug is to be set as close to the top of the perforations as possible or above another weak point such as a previously abandoned sidetrack that penetrated the reservoir interval.

8 Environmental impact

This section contains a brief summary of the environmental impact of the CO_2 storage part of the project. More details of the approach to environmental management can be found in the report on permitting and regulation (Close-out Report on Permitting & Regulation).

8.1 Platform

CO_2 leakage may originate from the installations on platform P18-A. Considerations similar to those for the capture installation are applicable to leakage from the platform installations. Because the platform is unmanned during most of the time and possibly it is very windy, it may happen that leakage will be detected only after a longer period of time despite the installation of CO_2 meters on the platform. Large quantities will be detected easily as measurements show that less CO_2 than expected is being injected. However small leakages are possibly less well detectable, which will result in longer periods of CO_2 leakage.

8.2 Storage site

Research showed that the probability that the injected CO_2 will migrate from the reservoir via the wells or faults to other areas is very low. It is of importance that in this very unlikely event of CO_2 migration, the fluid will be trapped in the overburden and will not reach the surface. As no living organisms other than microbes do dwell in the deep subsurface and any migration of CO_2 will not lead to significant negative impacts for the living environment.

8.3 Environmental impact of CO_2 entering the marine ecosystem

The impact of CO_2 leakage on the marine ecological environment is assessed, mainly via the results of two large EU research projects (ECO2 and RISCS) and the British QICS project. Special attention was given to see how the results are applicable for the marine environment in the P18 area [Meekes, 2014].

In general terms the effects of an increased CO_2 level due to leakage are well known and also most relevant impacts on marine life are well known by now. However, most studies also indicate that the impact of CO_2 leakages related to subsurface CO_2 storage on the ecological marine environment cannot be assessed fully with the current state of knowledge. Although much research has been done, as with respect to marine species, only a very limited amount of species has been subjected to changing CO_2 conditions. Depending on the CO_2 concentrations and the duration of the exposure to higher CO_2 concentrations, some species profit, whereas others degrade. Moreover, the marine biological environment is a complex system of breeders and feeders and impact on one species can also change the situation for other species, although that species in itself is less sensitive to increased levels of CO_2. On the other hand a complex system has various self-regulating mechanisms, which gives it a certain stability. But gradual changes may also move the system from one stable state to another, rather different, stable state. A system stability approach as advocated by Scheffer (2009) is recommended for future research.

The very unlikely case of localized release of CO_2 due to well or pipeline failure is probably of a duration of a few weeks, as actions will be taken to stop the CO_2 release. During that period damage may occur on a very local scale. The CO_2 will most probably escape into the water as bubbles, partly dissolve and partly be released to the atmosphere. As the affected area is small and the influence of short duration, the ecosystem is expected to recover with time. Localized release through a fault/fracture or deep well failure may last for a longer time. The release may become apparent through lower pressure than expected in the reservoir. Later on the seeping CO_2 might be detected through repeated seismic surveying or other geophysical monitoring. The area is probably restricted to a lineament-like structure in which CO_2 escapes. The area that is affected and a quantification of the leakage can be determined by acoustic sub-bottom profiling and by chemical sensors at the seabed. An estimation of expected duration should be made in order to prepare a monitoring plan including community composition analysis and microbial essays. It must also be checked whether the most unfavorable situation of the development of a layer of CO_2 rich water just above the water bottom occurs as this may have implications for the ecological monitoring plan. The P18 site satisfies several high level recommendations for off-shore sites with only limited impacts on the ecological environment if any leakage might occur.

Results of the Dutch national BIOMON project can be very suitable to assess the temporal variability of DCS ecosystems, and some stations can be used as a reference for the P18 location. It is recommended to prepare a P18 ecological monitoring plan once it is decided to store CO_2. The plan should indicate what to do with respect to ecological monitoring once a leakage is suspected.

The above must be placed in the context of an ecological marine environment that is changing with time due to increased CO_2 levels and changing temperatures because of climate change. Also the marine environment is subject to other environmental threats such as sand mining and fishing bottom trawling.

Consequences of leakage above P18-4 or along the pipeline route

CO_2 is a naturally occurring non-toxic substance, however acute exposure is high concentrations can cause dizziness and asphyxiation to humans. In the marine environment, only a very limited amount of species have been subjected to changing CO_2 conditions under experimental conditions. Generally speaking, increased dissolved CO_2 levels in water can reduce the pH level, and this is the primary mechanism that can cause ecological damage.

In the very unlikely case of localized release of CO_2 due to well or pipeline failure, the CO_2 will likely escape into the water as bubbles for a period of days to a few weeks, before actions are taken to stop the leak. As the affected area is small and the influence of short duration, the ecosystem is expected to recover with time.

Localized release through a fault/fracture or deep well failure may last for a longer time, until the release may become apparent through lower pressure than expected in the reservoir. Later on the seeping CO_2 might be detected through repeated seismic surveying or other geophysical monitoring. If the CO_2 reduces the pH of the seawater significantly, this could have effects on the community structures of crustacae, molluscs and echinoderm which are immobile. Fish species should not be affected as they can avoid the area.

At P18-4, strong tidal currents prevail, mixing in the seawater column allows dilution of CO_2 which is preferred as it strongly reduces impacts of high concentrations of CO_2 accumulating should leakage occur. Furthermore, neither biodiversity nor the biomass quantity at the location are high, and no coral reef, no maerl bed and no bed of mussels are present.

9 Commercial Framework for P18-4

9.1 Introduction

The commercial structure for permanent geological storage of CO_2 is a key challenge for any CCS project. There are no established business models, and the limited commercial incentive that does exist sits with the CO_2 emitter (to minimise emissions) rather than with the storage operator. The regulatory risks associated with holding a CO_2 licence are very uncertain and may be high. There is a "culture clash" in that the oil and gas business is a high risk, high reward business, in which the produced hydrocarbons are valuable commodities, whereas CO_2 has negative value in this context as a waste from a utility business, and the high rewards are lacking.

It is further complicated by the complex ownership structure of the P18 assets and licences, and the scope for the ownership to change with time. This results in a set a different contracts being required for each of the different legal entities.

This section aims to explain the commercial structure proposed for the ROAD Project which was largely agreed between ROAD and the off-shore parties led by TAQA. We cannot give the full details for reasons of commercial confidentiality, but this chapter aims to explain in principle how the "costs, risks and rewards" were to be allocated between the parties, and how the agreements were structured.

9.2 Principle allocation of Costs, Risk and Rewards

The Offshore Group (led by TAQA, but including EBN, Dyas and Dana) had no strategic interest in developing CO_2 storage at the time these contracts were being developed (2010-2012). Therefore a commercial framework was required which gave them a commercial incentive to allow their assets and licence area to be used. The commercial incentive clearly needed to match the risks, and compensate for all costs.

9.2.1 CO_2 Storage Licence Regulatory Risk

From the outset of negotiation it was apparent that the regulatory risks associated with holding the CO_2 storage licence were a serious problem, both because of the uncertainty at time of contract negotiation, and because the Offshore Group had no strategic interest in being a CO_2 storage operator. It was agreed therefore, that the Offshore group would have the right to transfer the CO_2 storage licence to MCP (the ROAD legal entity) before CO_2 injection starts. In this way, the regulatory risks associated with CO_2 storage were transferred directly to ROAD. This was included in the PUT option contract (see below).

It was the intention of the ROAD JV to ask one of the parent companies (most likely GDF Suez E&P) to hold the storage licence on their behalf. However, this would be finalised and agreed with the regulator only at the same time as the final monitoring, verification and handover plans are agreed with the regulator prior to CO_2 injection. The Offshore Group would only transfer the licence at the point the hydrocarbon recovery was complete. It was considered that ROAD was best placed to handle the CO_2 storage regulatory risk because the regulator (the Dutch Government) is also a principle funder of the project, and therefore ROAD can make the connection between the costs of funding and the costs of storage regulation. The way in which the project sought to minimise the regulatory risk is reported in detail in the Close-out Report on Permitting & Regulation.

9.2.2 Direct and Indirect Costs Associated with CO_2 Injection

Direct costs are incurred by the Offshore Group specifically for modifying the platform to accept and control the CO_2, and inject it into the subsurface. Because these costs were directly attributable to the ROAD Project they were simply passed through as a direct charge. This included both construction and decommissioning costs for the dedicated CO_2 facilities. In this way, the Offshore Group carried no risk and therefore no risk premium was required. There was an obligation to operate the facility to normal industry standards.

Slightly more difficult were the common facilities costs. This is the cost of operating and maintaining the platform. The oil and gas industry has a number of approaches towards allocating common facilities costs among different users. One typical approach is to allocate the costs according to the quantity or the value of the fluid handled. Thus the owner of the field producing the most gas, pays the most for the platform. However, for CO_2 the link between quantity and "value" is quite different from natural gas. It was agreed therefore to split the shared services between hydrocarbon users and CO_2 users of the platform according to the number of wells used by each group. Thus in the scenario where CO_2 is injected into P18-4 (one well), and natural gas is still being produced from P18-2 (three wells), the natural gas users would pay three quarters of the shared facility costs, and the CO_2 users one quarter. As the use of the platform changes with time, this split would naturally also change.

The assumption in the negotiation was that the Offshore Group would continue to operate the platform and the facilities throughout the lifetime of the project, and that the facilities may continue to be used for hydrocarbon production, or indeed they could be offered to other users for CO_2 storage.

9.2.3 Remaining Costs, Risks and Rewards

Most other risks, such as health and safety risks, environmental hazards etc, were handled following normal offshore industry practice for shared facilities. The Offshore Group remains the operator and has the obligation to manage the facilities to good health, safety and environmental standards, and has the right to stop operation if necessary to manage these risks. They also have obligations to follow good industry practise. There is also a mechanism to pass these costs onto the users of the platform and facilities.

The above allocation of costs does give the Offshore group a very modest reward for participation in the project, in that the costs to them of the costs of the shared facilities are reduced while hydrocarbon production and CO_2 injection overlap. However, this was insufficient to provide sufficient commercial incentive, especially as it was possible that no such overlap would occur in practice.

In the agreements were two other rewards / benefits to the Offshore Group which together provided sufficient incentive for a commercial agreement, especially given the minimisation of risk for the Offshore Group as explained above.

- Benefit from delayed decommissioning of the shared facilities (i.e. P18A platform). At the end of hydrocarbon production, the Offshore Group has the obligation to decommission the platform. If CO_2 use means that the platform is operated and maintained for more years, this decommissioning cost can be deferred. While this benefit is recognised, it is hard to quantify as the Offshore Group also carries the risk that rising environmental standards may cause the decommissioning cost to increase with time.
- A commercial tariff was included, which was the principle financial incentive for the Offshore Group. They would receive a payment for keeping the facility available (based on the flow capacity available), and a payment per tonne of CO_2 injected. This last item included a link to the CO_2 price – so that the Offshore Group was paid more if the CO_2 price is higher. In this project, this link was weak, and only in cases of high CO_2 price, because the project is predominantly grant funded. However, it was included so that the Offshore Group would share the benefits should a very high carbon price occur, and it is a principle approach that may be applicable to other projects. The commercial tariff was the subject of much negotiation. The ROAD partners were reluctant to pay a significant profit to a third party on a loss-making demonstration. However, the Offshore Group were stepping into a new business with high political visibility and uncertain risks, and were being asked to take on the project with much lower benefits than normal for their business. Fortunately, an agreement on tariff levels was achieved that was acceptable to all parties, and this was included in the overall economics for the project (see Close-out Report Project Costs and Funding).

9.3 The Structure and Contents of the Agreements

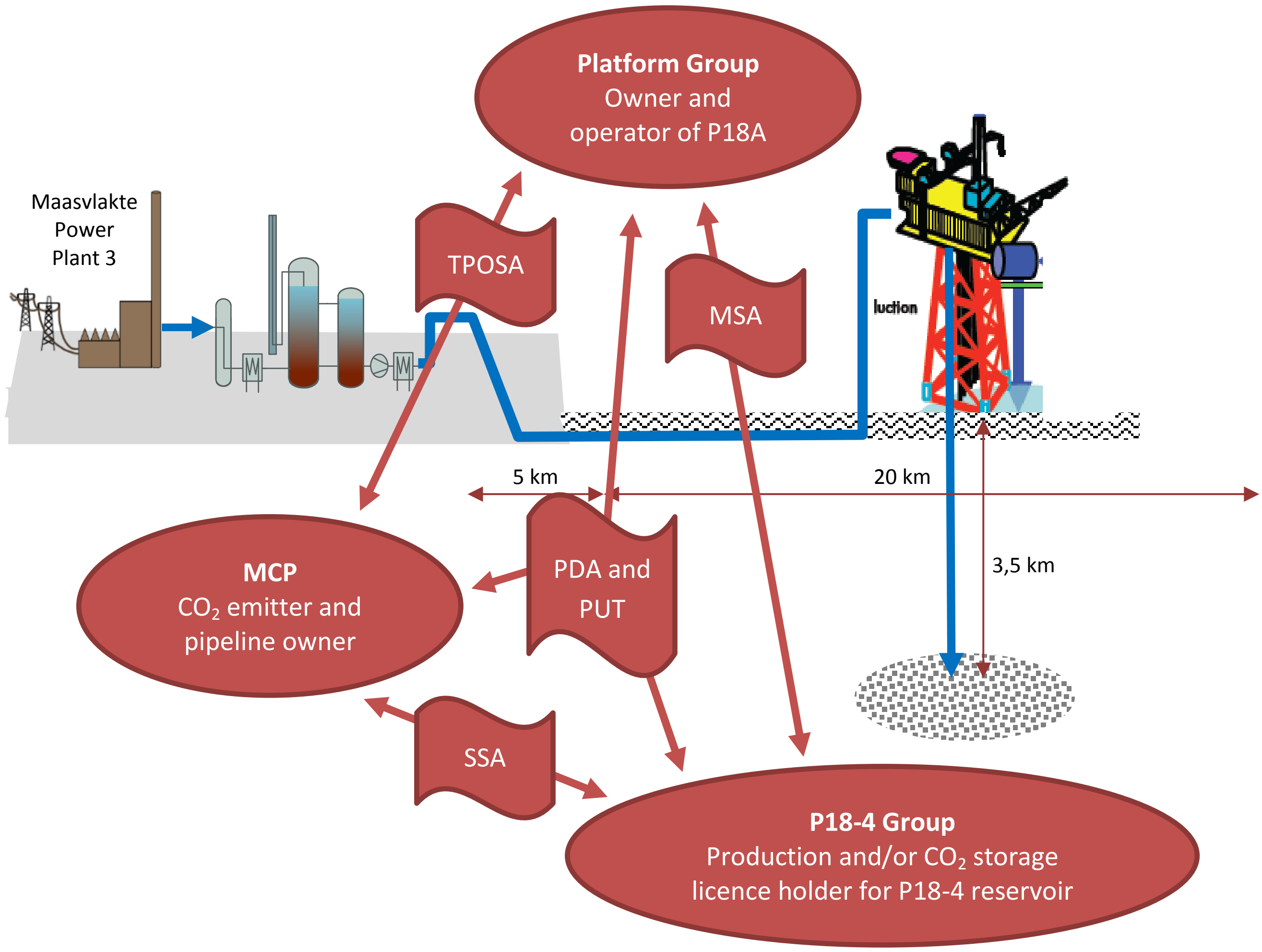
In order to understand the storage agreements, an understanding of the offshore assets and their ownership is needed. The storage site is the P18-4 reservoir, which this is accessed through an existing single well from an existing unmanned platform P18-A. In order to establish contractual agreements for construction and operation of the storage site, a contractual structure is required that takes account of these various separate entities:

- The Platform Group, consisting of the platform owners being TAQA, EBN, DYAS and Dana, TAQA is the operator and represents the Platform Group;
- P18-4 Group, being the holder of the production license and also the applicant for the CO_2 storage license (TAQA), and the beneficiaries of the production, and owner of the P18-4 well (TAQA and EBN) and is represented by TAQA;
- The Offshore Group, which is the Platform Group and the P18-4 Group combined, also represented by TAQA.
- MCP (Maasvlakte CCS Project CV) is the legal entity delivering the ROAD Project

For the storage activities, there is a set of contracts between the different groups, being:

- The Project Development Agreement (PDA) between the Offshore Group and MCP, covering construction and commissioning of all CO_2 handling injection equipment;
- The Transporting, Processing and Operating Services Agreement (TPOSA) between the Platform Group and MCP covering operation and decommissioning;
- The Storage Services Agreement (SSA) between the P18-4 Group and MCP covering operation and decommissioning;
- The PUT option between Offshore Group and MCP concerning the transfer of the CO_2 storage licence to MCP prior to first injection and optionally some physical assets under agreed circumstances.
- The Master Services Agreement (MSA) between the P18-4 Group and the Platform Group covering operation and decommissioning;

An overview of the agreements between all parties is shown in the following scheme. It highlights the key interfaces between the parties, and the associated contractual agreements.



Platform Group
Owner and
operator of P18A
Maasvlakte
Power
Plant 3
TPOSA
MSA
luction
5 km
20 km
3,5 km
MCP
CO_2 emitter and
pipeline owner
PDA and
PUT
SSA
P18-4 Group
Production and/or CO_2 storage
licence holder for P18-4 reservoir

9.3.1 Project Development Agreement

For storage part of ROAD, a specific procurement and construction contract was established: the Project Development Agreement (PDA). The PDA regulated the development, construction and commissioning of all facilities (incl. well) needed for CO_2 handling on the P18A platform, injection and storage of CO_2.

The goal of the PDA was to achieve the procurement and construction with full transparency and cooperation between MCP (the ROAD legal entity) and TAQA (on behalf of the Offshore Group). The contract established an operating committee to plan and oversee the work, including giving approval for all expenditure. The operating committee consisted of two representatives of MCP and two from TAQA, and its decisions must be unanimous.

Under the PDA, TAQA is responsible for delivering the work as the operator of the P18A platform. The work is done on a cost pass-through basis with framework for agreeing the scope of work, the budgets and handling cost overruns and scope changes. The PDA was designed to cover the platform FEED and other technical design steps including health, safety and environmental assessments, the construction and adaptations necessary on the platform, the well design and well modification for CO_2 injection (recompletion), the installation of monitoring equipment, and other requirements of the CO_2 storage licence in terms of demonstrating well and reservoir integrity prior to first injection. The PDA also included commissioning of the facilities with CO_2. However, the PDA also allowed the parties to adapt the scope as necessary as the project proceeds.

9.3.2 Transport, Processing Operating and Services Agreement

The TPOSA covers the services to be provided by TAQA as operator on behalf of the Platform Group, recognising that this is now a multi-user shared facility. It focuses on the operating period of the project (i.e. the period when CO_2 is being injected) but also included the allocation of liabilities for decommissioning. In terms of the cost sharing principles and commercial terms, these are summarised in section 9.2 above (*Principle Allocation of Costs Risks and Rewards*). As with the PDA, an Operating Committee is in place with representatives from both TAQA and MCP which unanimously approves (or not) any modifications / improvements or other changes to the CO_2 equipment, including giving budget authorisation. TAQA is the operator of the platform and the costs of the shared facilities are shared between all users.

The CO_2 remains the property of MCP under this agreement – the Platform Group is simply processing and injecting it for MCP.

The TPOSA includes provisions to allow co-mingling of third party CO_2, in the event that a third party also wants to use the platform for CO_2 storage,

9.3.3 The Storage Services Agreement

The SSA covers the services to be provided by the storage licence holder to MCP during the operating period of the project. It covers the same period as the TPOSA and has the same broad structure. Initially, this is the P18-4 Group as the holder of the hydrocarbon and the CO_2 licences. It also includes a nominal commercial tariff for CO_2 injection. However, under the PUT agreement, the CO_2 storage licence will transfer to MCP (or a company nominated by MCP) and therefore the SSA will no longer be applicable.

9.3.4 The PUT Option Agreement

The PUT Option Agreement covered two topic:

1 Transfer of the CO_2 storage licence before first injection of CO_2

It was agreed that prior to injection of CO_2, the P18-4 Group would transfer the CO_2 storage licence to MCP. This agreement was kept confidential to avoid a possible impact on the permitting of the CO_2 storage licence to TAQA. This was not in fact a PUT option, it was a simple agreement that the licence would be transferred. There was no optionality about this part of the agreement. It was conditional only on regulatory approval.

This agreement was requested by the P18-4 Group arising from the uncertain liabilities associated with the CO_2 storage licence, and the uncertain public and political attitudes to CCS. TAQA had no business interest at the time in becoming a CO_2 storage operator. The other member of the P18-4 Group, EBN, had no legal mandate to be involved in CO_2 storage, it being a state owned and state regulated oil and gas investor.

This would mean that MCP would need to satisfy the Dutch Government regulations for a CO_2 storage licence holder, or find an alternative company to hold the licence on their behalf. Given the strict financial criteria, MCP considered it unlikely that MCP could comply. However, both parent companies Engie and E.ON owned E&P businesses, and therefore the intention was that one of the parent companies would hold the storage licence on behalf of the JV.

Another impact of this transfer was that the SSA would never in fact matter. Because the P18-4 licence would be owned by MCP, the SSA would become a contract between MCP and MCP and therefore irrelevant. However, a further agreement is then required because TAQA would remain the platform operator and would be required to operate the store on behalf of MCP. This extra agreement is the Master Services Agreement (below).

2 PUT Option to transfer the P18-A Platform to MCP

Again this agreement was introduced at the request of the Offshore Group to allow parties to withdraw from CO_2 storage completely by also transferring the P18A platform and operatorship to MCP at a fair market value. Principles for the fair value calculation were agreed, including independent review and arbitration if necessary. The intent was that neither party should gain significant commercial advantage from this transfer. The PUT option could only be exercised once the CO_2 storage licence had been transferred, and before the completion of hydrocarbon recovery from the P18 block. If exercised in full, this would have left MCP as the owner and operator of the entire CCS chain – capture, transport and storage.

Comments on the PUT Option Agreement

The view of MCP was that the requirement for the PUT Option Agreement from the Offshore Group highlighted the reluctance of oil and gas companies to become involved in CCS as a new business, the absence of any business incentives, neither short term nor long term, and nervousness about the future public relations and political impacts of involvement with CCS.

However, MCP recognised that the ROAD Project could only go ahead if sufficient funding and incentives are in place, and provided the regulatory risks around the CO_2 storage licence were adequately handled. And if the negotiation with the Government enabled all these things to be put in place, then it would be acceptable for MCP to be the storage owner and licence holder, just as for members of the Offshore Group. Therefore MCP was willing to accept the proposals in the PUT Option Agreement.

9.3.5 The Master Services Agreement

The MSA between the P18-4 Group and the Platform Group covered operation and decommissioning of the reservoir. The intent was that TAQA as the platform operator on behalf of the platform group would also in practice operate the reservoir, carrying out all maintenance, monitoring, verification etcetera as required to comply with good operator practice and to comply with the CO_2 storage licence. The MSA set out how those services provided by TAQA would be managed and paid for. It was a straightforward cost-based services agreement.

MCP would become a party to the MSA once the CO_2 storage licence (and therefore the P18-4 Group) transfers to MCP ownership prior to first CO_2 injection. The MSA would supercede the SSA.

Section B: Q16-Maas

The Q16-Maas field is a condensate-rich gas field, located just offshore of the Maasvlakte in the Rotterdam harbour area. Discovered in 2011, production started in April 2014 from the well MSG-03X and was planned to cease by the end of 2022. Based on the early production data, it was identified as a possibility for CO_2 storage for ROAD late in 2014. While the plans foresaw production using natural depletion only, a benefit of injecting CO_2 into the field could be enhanced production of gas and condensate. The condensate-gas ratio of the produced gas is reported as about 410 m^3/Mnm^3 in the Winningsplan (at www.nlog.nl); 500 m^3/Mnm^3 was measured at the start of production. The field also produces propane and butance (mostly sold blended as LPG.).

The work on Q16-Maas for ROAD has been split into three sections: 10, 11 and 12, which present the work in roughly chronological order as well as by topic. The first phase was the identification and confirmation that the Q16-Maas was a realistic technical option for CO_2 storage, which was based largely on a “showstopper” study in 2015 by TNO and reported in Section 10 as “Pre-feasibility Study”. The second phase, described in Section 11, was the development of the commercial framework and operating scenarios. This was developed jointly by ROAD and ONE, with additional scenario modelling by ONE in late 2015. This work phase completed with the signing of a commercial Memorandum of Understanding in late 2016 between ROAD and ONE which put the principles of co-operation into a legal framework. The final phase of work, Section 12, continuing right up until the project was suspended in June 2017. This is the technical feasibility study by TNO, which was also intended to deliver much of the geological information required for permitting.

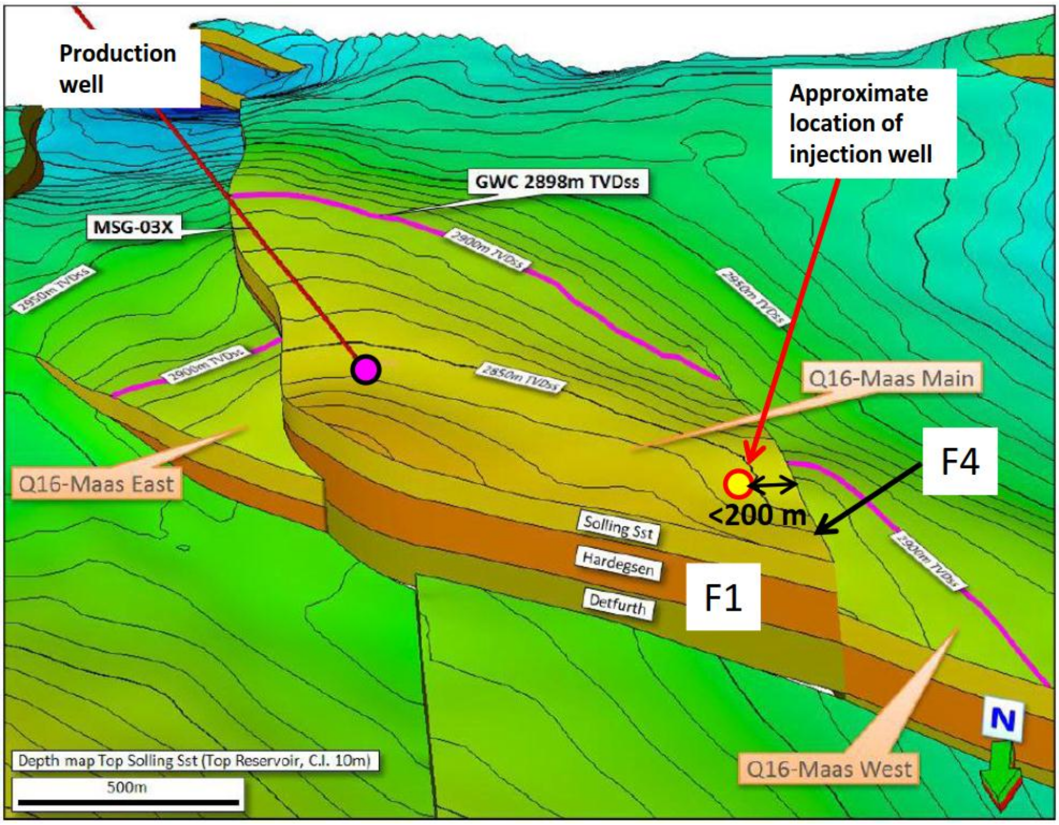
10 Pre-feasibility study

[Neele et al., 2015]: The Q16-Maas field can act as a joint CO_2 storage and buffer project in combination with enhanced production of hydrocarbons (condensate recovery). Based on commercial grounds a single option or a mixture of these options can be developed further. In all cases, a detailed feasibility study is required. No prohibitive technical or engineering issues have been found for storing or buffering CO_2, and simultaneous production of hydrocarbons.

10.1 Geology

The Q16-Maas gasfield (*Figure 10*Figures 10.1 and 10.2) was discovered by the MSG-03x exploration well in 2011. The reservoir consists of rocks of Triassic age. Various normal faults together define the northern and north-eastern limits of the reservoir. The south-western limit is a dip closure (gas-water contact (GWC) is at a depth of 2898 mTVD). Two smaller faults split the reservoir into three compartments, but it is not known whether those faults are sealing. Especially the western fault seems to be of limited importance (it quickly dies out in a southern direction), whereas the downthrown segment beyond the eastern fault probably contains at best a very small amount of gas only.

Figure 10.1 Reservoir structure of the Q16-Maas gas field showing the main faults and locations of the



production and injection wells.

In principle, CO_2 can be safely and securely stored in the Q16-Maas field, as the existence of the gas field proves the quality of the caprock. However, two items attract some attention, namely permeability and shallow gas.

10.2 Shallow gas

The occurrence of shallow gas in this area was mapped by Brouwer & Laban (2005) and one of the presumed accumulations of shallow gas appears to coincide with the Q16-Maas field – at least, in 2D view. When studied in more detail, it was observed that shallow gas may have originated from deeper layers – as concluded by Brouwer & Laban (2005). Yet any migration is thought to have taken place along faults connected to the Maasgeul field rather than the Q16-Maas field.

Although it can be concluded that there may be shallow gas occurrences above the Q16-Maas field, the gas is unlikely to originate from this field. Shallow gas occurrences observed on the seismic data are not considered as show stoppers for Q16-Maas were not further addressed.

10.3 Reservoir permeability

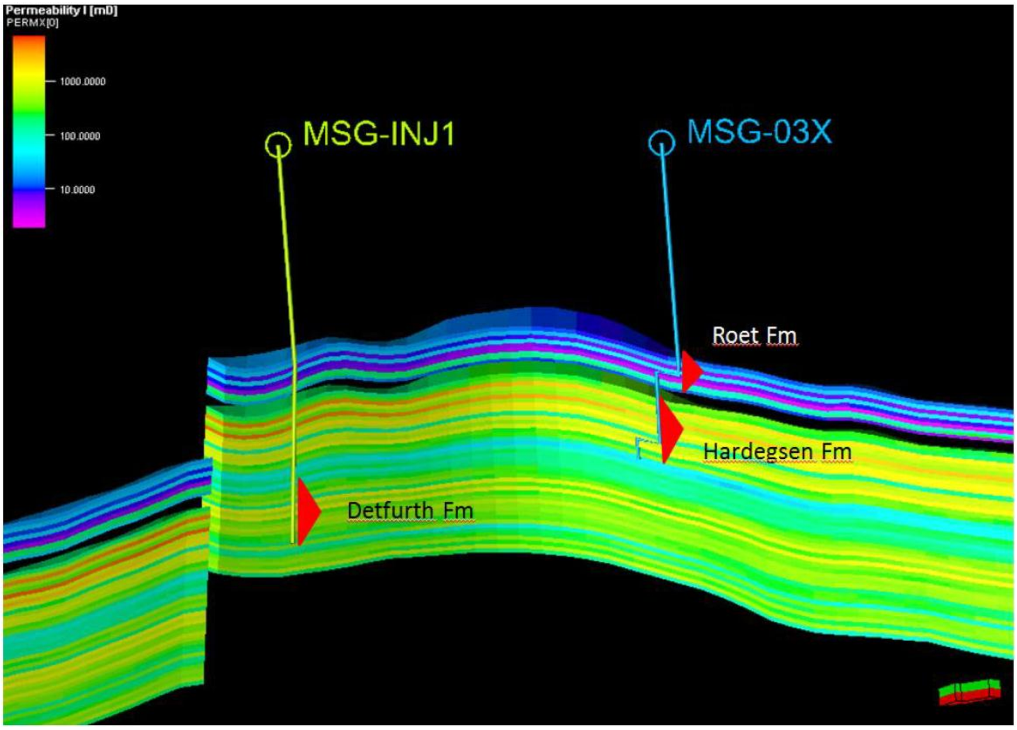
A valid interpretation of the permeability in the geological model is important. If the permeability is underestimated, injection and production rates will be underestimated too, and vice versa. It can be concluded that, although the permeability distribution in the reservoir may be optimized, it must not be seen as a show stopper. As the development of the Hardegsen Formation rocks is slightly different in surrounding wells (not shown in this document), a study of the spatial variation of permeability will be useful.

10.4 Reservoir modelling

Several scenarios for storing or buffering of CO_2 and hydrocarbon production have been analysed. Depending on the chosen scenario, the storage capacity was estimated at 1.9 or 2.3 Mt CO_2.

It is unlikely that the spill points in the Q16-Maas reservoir and in a block juxtaposed to the north of the eastern part of Q16-Maas will be reached by injected CO_2.

Figure 10.2 Perforations of the different wells and formations, with the blue line showing the production



well and the yellow line showing the injection well.

10.5 Storage System integrity

10.6 Fault intergrity

A potential showstopper could be the reactivation of faults in and around the Q16-Maas reservoir during production and injection operations. Fault reactivation can increase permeability of previously sealing fault rocks, creating pathways for gas migration out of the reservoir, which may ultimately lead to leakage. Fault reactivation may also result in (felt) seismicity.

Faults in the Q16-Maas field were stable before production of the field. Pressure changes during depletion are unlikely to destabilize faults; fault reactivation is therefore not expected during production. A pressure increase to 90% of the initial reservoir pressure through injection of CO_2 is also unlikely to cause fault reactivation. However, cooling of the reservoir rock due to injection of cold CO_2 into the relatively hot rock could exert significant stress changes, enough to cause fault reactivation. The impact of thermal stresses on fault stability needs to be investigated in more detail in a follow-up study using flow and geomechanical numerical models.

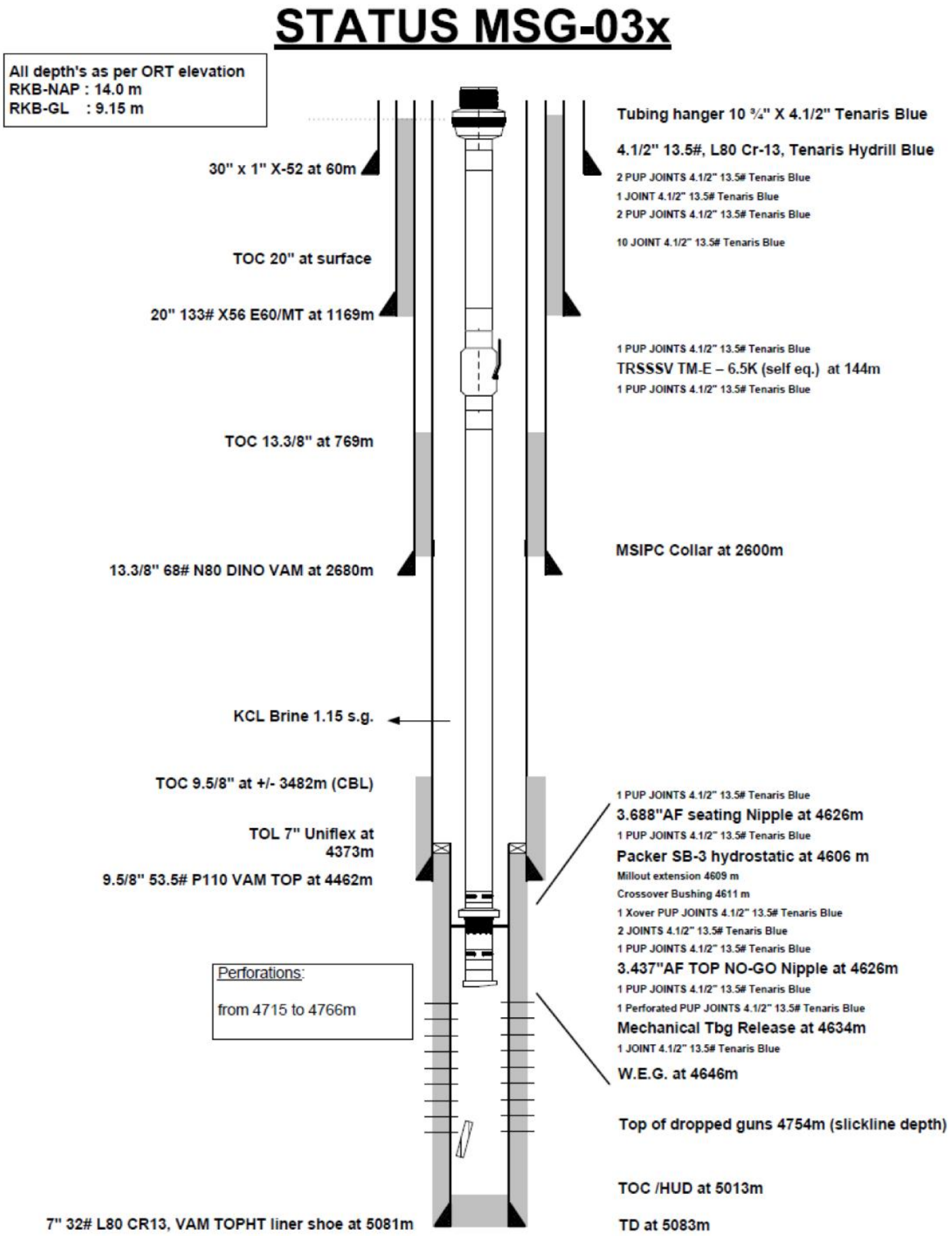
10.7 Integrity of the injection well

A first quick scan of wellbore integrity of the Q-16 Maas field revealed that the current well state could pose a risk to the CO_2 containment. This assessment arises from the fact that limited information was available for this evaluation (e.g. no drilling, cementing or well reports, type of cement unknown). Intervals with unknown or poor cement sheath quality in crucial sections of the wellbore (production casing shoe and A/B annulus along the caprock) can be easily validated/logged again and, if necessary, remediated by standard practices, such as cement squeeze jobs.

However, a comprehensive well integrity evaluation is required before injection commences (i.e. storage permit is requested) which should enlighten details on the actual state of well barriers, particularly along the caprock interval and its performance during the storage operations. Potential well leakage risks, particularly associated with the storage operation itself (expected maximum pressures increase which could harm the well barrier performance) should be assessed by numerical simulations and be regarded in monitoring and abandonment plans.

As the well (Figure 10.3) is relatively new, accessible, constructed in compliance with recent regulatory and industry standards, the well does not present a showstopper for envisaged CO_2 injection operations.

Figure 10.3 Well schematic of well MSG-03x at the Q16-Maas field.



10.8 Chemical interaction of the CO_2 with the reservoir

CO_2 is a non-polar fluid and undergoes chemical reactions in the subsurface with other fluids, rock material, and formation water at supercritical conditions. These reactions are highly dependent on the composition of the fluids present, on the rock mineralogy and on temperature and pressure conditions. Organic species in the hydrocarbon content of Q16-Maas will be present in a produced CO_2 gas stream; concentration norms for a number of these components were not available and need to be identified or defined. Gas separation (see next section) may be necessary to comply to the norms for delivery to the greenhouses. Some minerals in the reservoir rock may dissolve in the formation water, leading to an increase of inorganic species in the formation water.

Overall, the amounts of elements enriched in the formation water (<0.05 mol%), and the amount of water dissolved in CO_2 (1.20 mol%) are very small.

10.9 On-site gas separation

The existing Gas Processing Unit (GPU) is not designed for the removal of CO_2 but to separate the produced gas into separate streams of sales quality methane (and ethane), propane, butane and heavier condensates (C5+). Each of these streams is sold, with the propane and most of the butane blended and sold as LPG. The GPU is pressurised and includes a series of distillation-based separation columns, with a chilled section to separate propane and butane from the lighter natural gas. Due to the liquefaction of CO_2 in this chilled section, and subsequent dissolution of other components in it, the presence of a substantial CO_2 fraction would make the purification of natural gas extremely difficult.

For the ROAD application, only separation of the condensate from the produced CO_2 is required. In this case, with some modification, the existing condensate stabilizing system can be used. Reinjection of the produced CO_2 (with condensate removed) does not require significant additional equipment other than a compressor.

The pre-feasibility study also considered the option to use Q16-Maas as a buffer storae for greenhouses, in which case a CO_2 must also be cleaned to sales quality. This will require conversion of the hydrocarbons in the CO_2 stream to CO_2 by means of either thermal or catalytic oxidation. As a polishing step, an activated carbon bed is required to remove the last trace of organic components before the CO_2 stream enters the OCAP pipeline.

11 Commercial Structure and Operating Scenarios for Q16-Maas

11.1 Introduction

The commercial structure for permanent geological storage of CO_2 is a key challenge for any CCS project. There are no established business models, and the limited commercial incentive that does exist sits with the CO_2 emitter (to minimise emissions) rather than with the storage operator. The regulatory risks associated with holding a CO_2 licence are very uncertain and may be high. There is a "culture clash" in that the oil and gas business is a high risk, high reward business, in which the produced hydrocarbons are valuable commodities, whereas CO_2 has negative value in this context as a waste from a utility business, and the high rewards are lacking.

In this section we describe the progress made in establishing suitable commercial arrangements for combined hydrocarbon production and CO_2 injection at the Q16-Maas field. The commercial framework for Q16-Maas was much less well developed than for P18-4 but the commercial principles were agreed in a Memorandum of Understanding which also covered development work for the project.

Note that everything described here is based on the expectations of reservoir performance and production current in 2015 and early 2016. This included the expectation that commercial production of gas and condensate would continue until the end of 2022 under a business as usual scenario. Gas production would be accelerated by the drilling of a second well in 2017. CO_2 injection through one well would start in January 2020, and store 2.7 MT of CO_2 over three years (based on modelling by Oranje-Nassau Energie). During the CO_2 injection, condensate and, if commercial practicable, also natural gas and LPG would continue to be produced from the other well.

The delay and subsequent termination of the ROAD Project meant that this second well was not drilled. In addition, unexpectedly high water production in 2016 led to a complete revision of the reservoir model and the production forecasts for the business as usual case. Therefore readers should be aware that all the forecast data and economics presented here are now obsolete and would require complete reworking for a future project in Q16-Maas.

Despite the above, it is hoped that the commercial framework developed for Q16-Maas in 2015 and 2016, reported in this section, provides a useful example for future CCS / EOR projects.

11.2 Principle allocation of Costs, Risk and Rewards

Q16-Maas field is operated by Oranje-Nassau Energie (ONE) on behalf of a consortium of owners comprising ONE, EBN, TAQA and Energy06 (Q16-Maas Group). As with P18-4, the owners had no strategic interest in developing CCS. They understood the potential of CCS to be a major climate change mitigation technology and a significant future business in the Dutch North Sea, so they saw some opportunity to learn through the project. They were also keen to be supportive of a project backed by both the Dutch Government and the Port of Rotterdam (landowner for the Q16-Maas site). Therefore they took the position that they would be a facilitator for the CCS project, but would not invest in it themselves.

This led to the principle that the Q16-Maas group would participate as an enabler for the project on a neutral-value basis.

The CCS project, if successful, would create some benefits in terms of accelerated gas production and enhanced condensate recovery. However, it would also create additional costs, both capital and operating costs. Additional benefits for Q16-Maas Group could be offset against additional cost to deliver the neutral-value position. However, additional risks and additional costs of CO_2 injection (which included most of the capital costs and all development costs) would need to be carried by the ROAD Project directly.

11.2.1 CO_2 Storage Licence Regulatory Risk

In the initial development phase of Q16-Maas in 2015, the way that CCS Directive was transposed into Dutch law prohibited the holding of a hydrocarbon production licence and a CO_2 storage licence at the same time for the same reservoir. It was not legal to produce hydrocarbons without a production licence, but CO_2 could in principle be injected into the ground under the production licence for EOR purposes. The project therefore proposed to do the CO_2 injection under the production licence. The effect of this would be that the CO_2 would not be deemed stored under the EU ETS regulations, and therefore the project would lose any financial benefit from carbon credits. However, the advantages of using the production licence in terms of enhanced condensate recovery, additional storage capacity for CO_2 (which results from the continued production) and the avoidance of the monitoring and decommissioning obligations and liabilities associated with the CO_2 storage permit, clearly outweighed the lost financial benefit.

The early project evaluation and development was therefore based on avoidance of the CO_2 storage licence regulatory risk by a decision not to apply for a CO_2 storage licence at all. Operation and decommissioning would be under the existing hydrocarbon production regulations and the CO_2 would be deemed to be emitted as far as the EU ETS regulations were concerned.

However, this approach proved to be unacceptable to the Dutch regulatory authorities. Consequently the Dutch Government amended the mining law to allow the holding of both licences at the same time. The details of the regulations for this are discussed in the Close-out Report on Permitting & Regulation.

As with the owners of P18-4, the Q16-Maas group felt it was inappropriate for them to hold the CO_2 storage licence. It did not fit their commercial strategy and was completely inconsistent with the approach of being an enabler of the project on a neutral value basis. Holding the storage licence carries costs, risks and obligtions which must be offset against benefits, and therefore it would effectively mean the Q16-Maas group became an investor in the project.

Therefore the intention was that Maasvlakte CCS Project CV (i.e. the ROAD Project joint venture) would apply for the storage licence.

For P18-4, the intention was that ROAD would use one of the parent companies (most likely GDF Suez E&P) to hold the storage licence. However, for Q16-Maas this was no longer an option. Due to the collapse in the carbon price, the parent companies had no clear commercial incentive for CCS and had agreed with the funders (EC and Dutch Government) to cap their contributions. Since the storage licence holder has, in principle, uncapped liabilities, this was incompatible with the agreed cap on the parent company contribution. However, because Maasvlakte CCS Project CV is a limited liability, it can carry uncapped liabilities without resulting in capped liabilities for the parent companies. Furthermore, Uniper had sold its E&P business, and Engie were in the process of selling theirs, so ROAD had no confidence that a suitable E&P company would belong to either parent at the time of CO_2 injection. Therefore ROAD could not ask the parent companies to hold the storage licence, so another solution to the risks and liabilities was needed.

In order to cover the costs, risks and obligtions of the licence, ROAD and Q16-Maas Group together proposed the establishment of a “CO_2 storage fund” paid for by the CO_2 ETS credits that are gained as a result of holding the licence. This fund would cover all the costs incurred by the storage licence holder (proposed to be ROAD). Assuming a reasonable ETS price and a reasonable risk-appropriate regulatory regime, the fund should contain more than enough funds to cover all the obligations.

However, it is entirely unclear whether this approach would have been acceptable to the Dutch regulatory authorities, and the project was stopped before any formal discussions took place. Maasvlakte CCS Project CV could not comply with all the (principally financial) requirements of a storage licence holder, and could not guarantee the CO_2 storage licence obligations could be met under all possible scenarios. However, refusal to grant a licence on these grounds would result in the project being unable to inject CO_2. We were expecting that the CO_2 storage application by ROAD would, in practice, simply trigger the start of a negotiation between the project and the Dutch regulatory authorities on how to handle the CO_2 storage regulatory risk.

It is now the view of the project team, in common with many other experts on CCS in Europe, that the long term costs, risks and liabilities arising from the CO_2 storage licence obligations must be taken, or at least underwritten, by the national governments if CCS projects are to develop successfully. The regulatory uncertainty is too great to be placed solely onto low-margin grant-funded projects.

11.2.2 Anticipated Operating Scenarios

The details of how the neutral-value principle would be applied had not been worked out at the point the work stopped. However, we did have operating scenarios developed late in 2015 which provided an indication of the range of possible costs and benefits, which were then included in the financial forecasts (given in the Close-out Report Project Costs and Funding). This section explains the operation scenarios at high level.

The business as usual case (BAU, without any CO_2 injection) set the reference point for the neutral-value calculation. This assumed that commercial production of gas and condensate would continue until the end of 2022 using the existing well. In the ROAD Project scenarios, gas production would be accelerated by the drilling of a second well in 2017. CO_2 injection through one well would start in January 2020, and store 2.7 MT of CO_2 over three years (based on modelling by Oranje-Nassau Energie).

In the base case ROAD scenario, it is assumed to be uneconomic to separate natural gas and LPG from the produced CO_2, so natural gas production stops at the start of 2020. Any produced gas and LPG is reinjected with the CO_2. However, condensate is separated and sold. Operation continues until 2.7 Mt of CO_2 are injected, which occurs during 2022. In this case, the benefit from accelerated gas production and increased condensate production only just exceeds the increased costs (higher operating costs and lost gas/LPG production from 2020 onwards). Our estimate was for a €4M benefit that could be used as a contribution towards the capital costs.

The 2015 forecast production for the business as usual case (without CO_2 injection) and for the ROAD base case are shown in Figure 11.1

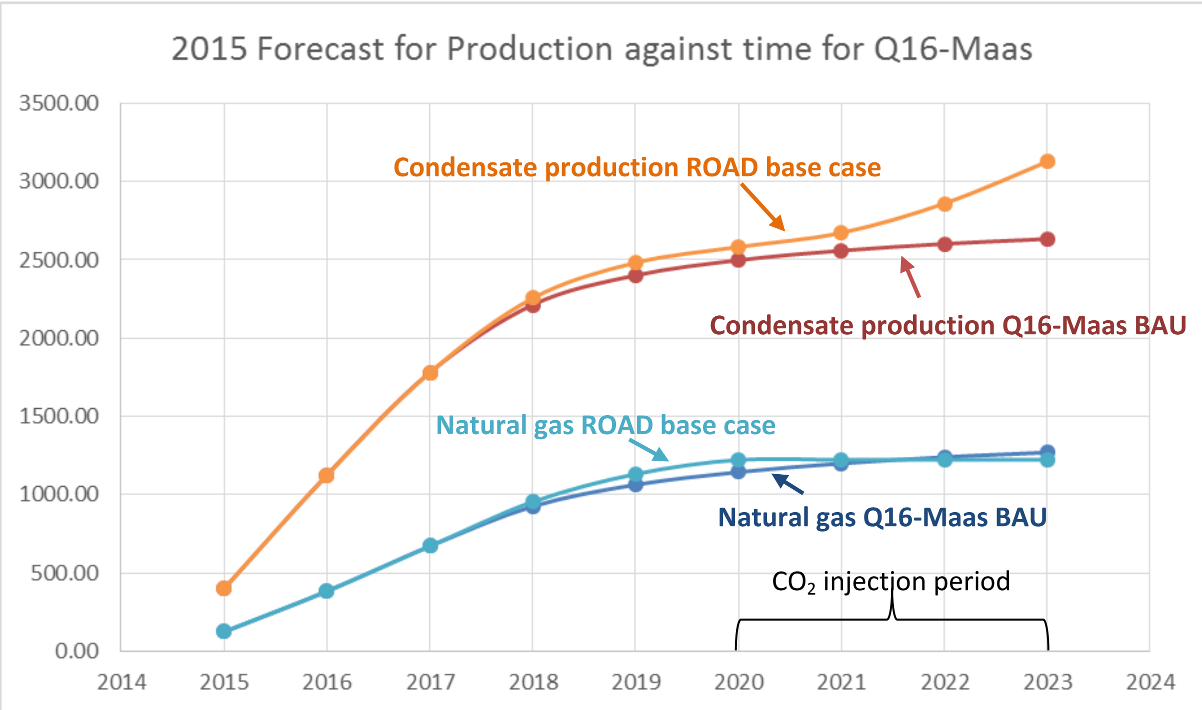
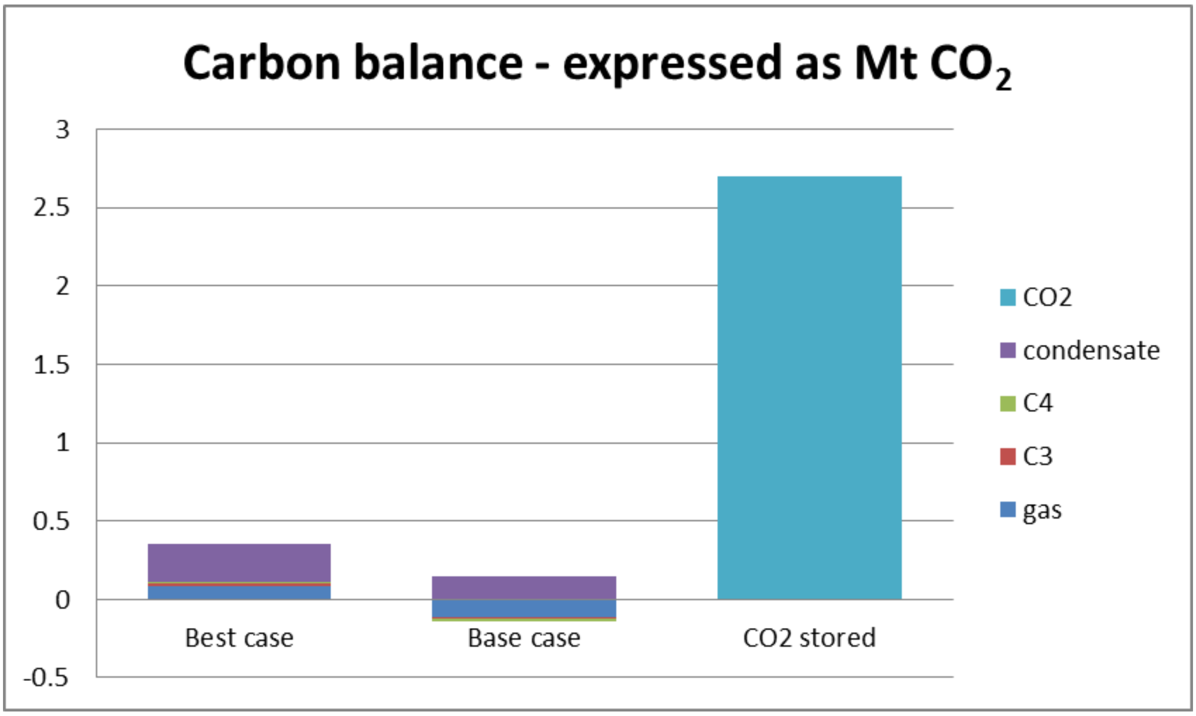


Figure 11.1 2015 Cumulative production forecast for Q16-Maas (mln Nm³ gas and k stb condensate)

An alternative "best case" scenario envisages the installation of membrane separation equipment (and therefore higher capital cost) to enable gas and LPG production to continue until cessation of CO_2 injection in 2022. In this case, the higher revenue from gas and LPG sales, combined with the enhanced condensate recovery allowed in a €28M net benefit from the neutral-value calculation. As noted, it was not at all clear if that increased benefit was in fact sufficient to cover the increased capital costs – that was a matter for further study. Nevertheless the figure of €28M was used as the upside "Revenue from the Action" in the financial analysis of the project (see Close-out Report Project Costs and Funding).

There were some concerns that enhanced hydrocarbon recovery would undermine public support for the project since it could be seen as reducing the net greenhouse gas reduction. In fact, for the base case there is approximately no net enhanced carbon production, since the reduction in total gas production roughly balanced the enhanced condensate production. Even in the base case, the carbon balance is strongly negative. Far more carbon is injected as CO_2 than is produced in the enhanced gas and condensate. The enhanced recovery, although a significant help to the project economics, is in fact almost negligible in terms of carbon. This is shown graphically in Figure 11.2. This graph successfully allayed concerns over a possible negative public reaction to enhanced condensate recovery.

Figure 11.2 Carbon produced against carbon stored
(ROAD base case and ROAD best case enhanced carbon production compared with carbon injected)



11.3 Engineering concepts for gas separation

Once CO_2 is injected into the Maas field, the producing well will see rising CO_2 concentrations. "Sales gas", propane, butane, and condensate can be separated from the CO_2 and recovered from the gas extracted from the field, as the existing field still contains certain amounts of these products (*Figure* Figure 11.3). Fluor carried out an evaluation is based on re-using the existing Q-16 Maas Plant to separate these products. The "sales gas", propane, butane and condensate would be sold once separated (if on spec.), and the CO_2 will be re-injected into the field.

A further analysis looked into options to process in the existing Q-16 Maas Plant the gas extracted from the Q-16 field (rich in CO_2) together with a gas from a 2nd field (with almost no CO_2 content).

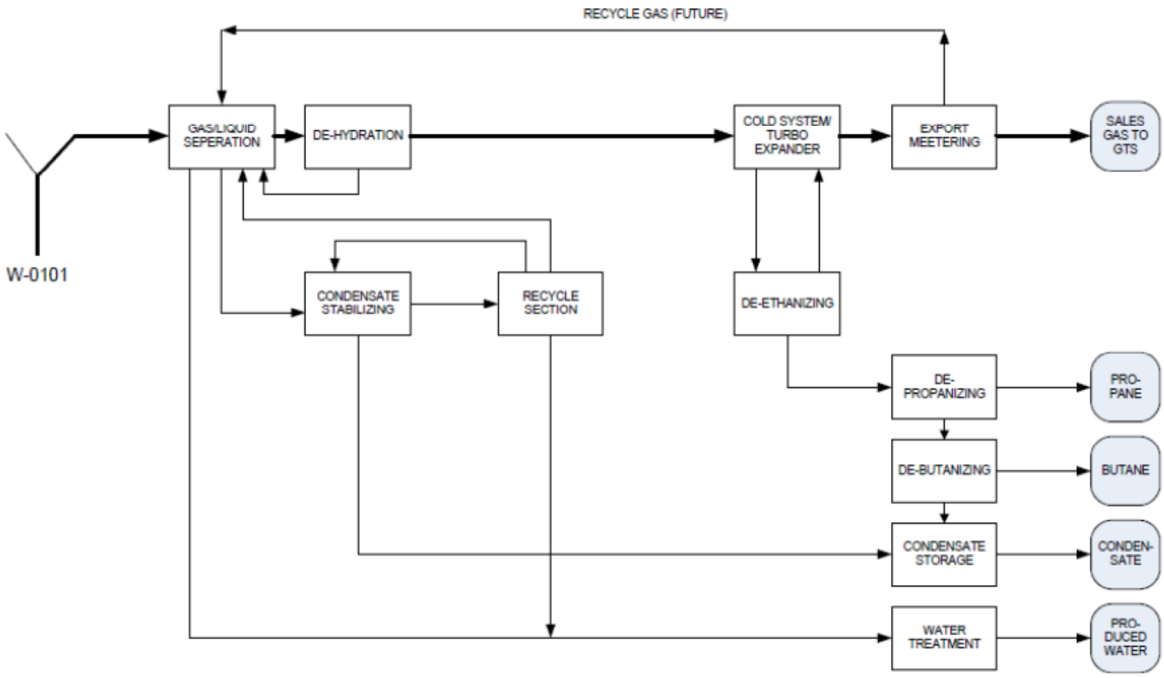


Figure 11.3 Overall process scheme of the existing facility at the industrial site Maasvlakte of Rotterdam

Some propane, butane, and hydrocarbon condensate on specification can be produced by re-using the existing process of the Q-16 Maas plant; however the propane and butane recoveries are low, especially for the cases with high CO_2 content in the feed. With limited investment in upgrading the existing process, the recoveries of propane and butane can be improved significantly, maintaining high the condensate recovery.

However, in order to produce “sales gas” (that is gas compliant with the natural gas specification so it can be sold – in this case predominantly methane but with a significant ethane fraction) a new membrane and associated equipment needs to be installed to separate the CO_2 from the “sales gas”.

For the cases with the feed containing 90 or higher mol% of CO_2, the process behaviour is difficult to predict, encountering several issues, and the recoveries achievable are not that high. Thus, Fluor did not recommend operating the gas separation plant with gases containing 90 or higher mol% of CO_2.

In the optimized case, parts of the de-propanizer and de-butanizer can operate at temperatures approximately of -40°C with CO_2 present, which gives a risk that heavier hydrocarbons solidify. However, according to the simulation models, the heaviest hydrocarbons at the bottoms of the de-butanizer are hexane and toluene with melting temperatures of -95°C, much lower than the operating temperature of the absorber. It seems that this design will operate properly. It was recommended to follow-up this point during more detailed engineering.

Two cases were considered in the analysis of gas separation including gas from a 2nd field:

- Case 1: only condensate is recovered from the Q-16 field gas;
- Case 2: condensate is first recovered from the extracted Q-16 gas and then CO_2 is removed from the gas through a membrane.

The capital investment cost estimated for Case 2 is substantially larger than for Case 1. In general terms, the additional production of sales gas, C3, C4 and C5+ condensate in Case 2 (relative to that in Case 1) must justify the additional investment required for this Case over Case 1 (i.e. the additional investment for the membrane system including permeate recompression).

It was recommended to assess in detail the existing equipment for the selected design case in the next phase of the project, when the composition of the 2nd field gas will be completely defined and confirmed (in this study, the composition of the 2nd field gas was assumed).

The main recommended upgrades to the existing equipment at this stage, in these two cases, are; the upgrade of material to Duplex Stainless Steel (DSS) grades in those systems of the condensate stabilizer section in which carbon steel does not provide sufficient acidic corrosion resistance under the new conditions, and the replacement of the cylinders of the depletion compressor to be able to handle the gas with higher CO_2 content.

A scheme proposed by UOP (an equipment vendor) for the membrane package was the preferred option, which includes the MemGuard pre-treatment system, as it can process gas with CO_2 content up to 90 mol% rather than being limited to 50 mol% CO_2 content. As the 2nd and 3rd stage membranes are only required at later dates (when the CO_2 content exceeds 30% and 70% respectively) there is some possibility for staging the investment.

Cost estimates with an anticipated accuracy of -30/+40% (Class 4) for the various cases (without gas from a 2nd field):

- For condensate recovery only, 1.8 millions euros
- For membrane separation allowing continued sales gas and LPG production - 15.3 millions euros.

These costs estimates were used in the subsequent commercial modelling for the project (with contingenices added to reflect the uncertainties), including the economics presented in the revision to the grant agreement with the EU signed in November 2016.

12 Feasibility study

A further feasibility was planned for 2016 and early 2017 to gather the data and undertake the analysis needed for the CO_2 storage licence application, including more detail on potential risks, and an intial draft monitoring plan. This work was completed and reported in June 2017 [Neele et al., 2017].

However, the work had to be adapted. In mid 2016, ONE observed rapidly rising water production from the Q16-Maas field, which was not predicted by the existing reservoir models. Following additional tests and monitoring, it was concluded that there was a much more active aquifer than expected, that the reservoir was stratified, and that reservoir model therefore needed to be substantially revised. The new reservoir model became available only two months before the end of the feasibility study so it could only be partially included, and not all the work could be properly verified.

According to the new reservoir model, gas and condensate production is faster due to the aquifer pressure support, so the hydrocarbon production is now expected to finish before the CO_2 injection starts. This means that the planned second well is unnecessary, but also that there will be no benefit from enhanced condensate recovery.

The results presented here come from this feasibility study and include this updated understanding, but they should be regarded as preliminary because of the lack of time between receipt of the updated model and completion of the work. They should be verified once a final geological and dynamic model of the reservoir is available.

12.1 Geology and petrophysics

The Q16-Maas gas field was discovered by the MSG-03x exploration well in 2011. The reservoir consists of rocks of Triassic age. Various normal faults together define the northern and north-eastern limits of the reservoir (Figure 12.1). The south-western limit is a dip closure (gas-water contact (GWC) is at a depth of 2898 mTVD). Two smaller faults split the reservoir into three compartments, but it is not known whether those faults are sealing. Especially the western fault seems to be of limited importance (it quickly dies out in a southern direction), whereas the downthrown segment beyond the eastern fault probably contains at best a small amount of gas only.

The initial reservoir conditions of the Q16-Maas field are:

- Temperature: 111.2 °C (384.3 K).
- Pressure: 296.7 bar (29.7 MPa).
- GIIP 1.6 bcm.

12.2 Reservoir

The major part of the reservoir belongs to the Detfurth (RBMD) and Hardegsen (RBMH) Formations, both part of the Main Buntsandstein Subgroup. The vicinity of the elevated London Brabant Massive to the south during the Triassic influenced the deposition of relatively thin sandstone bodies, containing low amounts of clay and silt. Above the Hardegsen Formation the Solling Claystone Member (RNSOC) forms a thin intra-formational seal, above which the upper part of the reservoir belongs to the Upper Bunter Röt Fringe Sandstone Member (RNROF). This part of the reservoir has less favourable reservoir properties than the Main Buntsandstein part. Both porosity and permeability are lower, and the thickness is 15 meters.

12.3 Seal

Claystones of the Lower Röt Fringe Claystone Member and limestones belonging to the Muschelkalk Formation (RNMU) constitute the ultimate top seal. Along the northern boundary, both the Muschelkalk limestones and evaporites of the Keuper (RNKP) Formations are the side-seal.

12.4 Dynamic reservoir modelling

[Neele et al., 2017] Continued learning from the production of the field during 2016 and 2017 led to several updates of the reservoir model and, ultimately, in the construction of an updated geological model. This model was history matched with production data until Q2 2017. Except for the reservoir simulations of injection scenarios, the results presented in this report were derived using a reservoir model that proved to be outdated by the end of the project. It was not feasible to incorporate the latest reservoir model into the study and many of the results presented here are in need of verification once a final model for the Q16-Maas reservoir is available.

With the compositional model four injection scenarios were simulated in which different bottom hole pressure (BHP) constraints were applied. The target injection rate in all scenarios was 1.1 Mt/yr.

1. Max BHP at 300 bar (initial reservoir pressure), blue line in graphs;
2. Max BHP at 330 bar (10% above initial pressure), green line in graphs;
3. Max BHP at 270 bar (10% below initial pressure), light green line in graphs;
4. No BHP constraint, orange line in graphs.

Storage capacity. The theoretical storage capacity is now estimated to be 2.3 Mt CO_2. This value is obtained for the latest update of the reservoir model (May 2017), with both a fluid substitution method and a dynamic injection simulation. Because it is based on the updated reservoir model, it assumes only one well, with no production once CO_2 injection has started. Again, this value is to be confirmed once the production of the field with the new well is completed.

Injection rates. Based on the updated reservoir model, the current well cannot sustain injection rates that are close to the planned production rate of the ROAD capture plant, which is a big change from the earlier modelling. Due to the strong aquifer in the reservoir, 1.5 Mt/yr is not feasible. A lower rate of 1.1 Mt/yr can be injected, but only during a relatively short period of time (about 6 months, assuming that some overpressure can be applied downhole; see Figures 12.1 and 12.2). Rates between 0.2 and 0.3 Mt per year can be sustained for long periods.

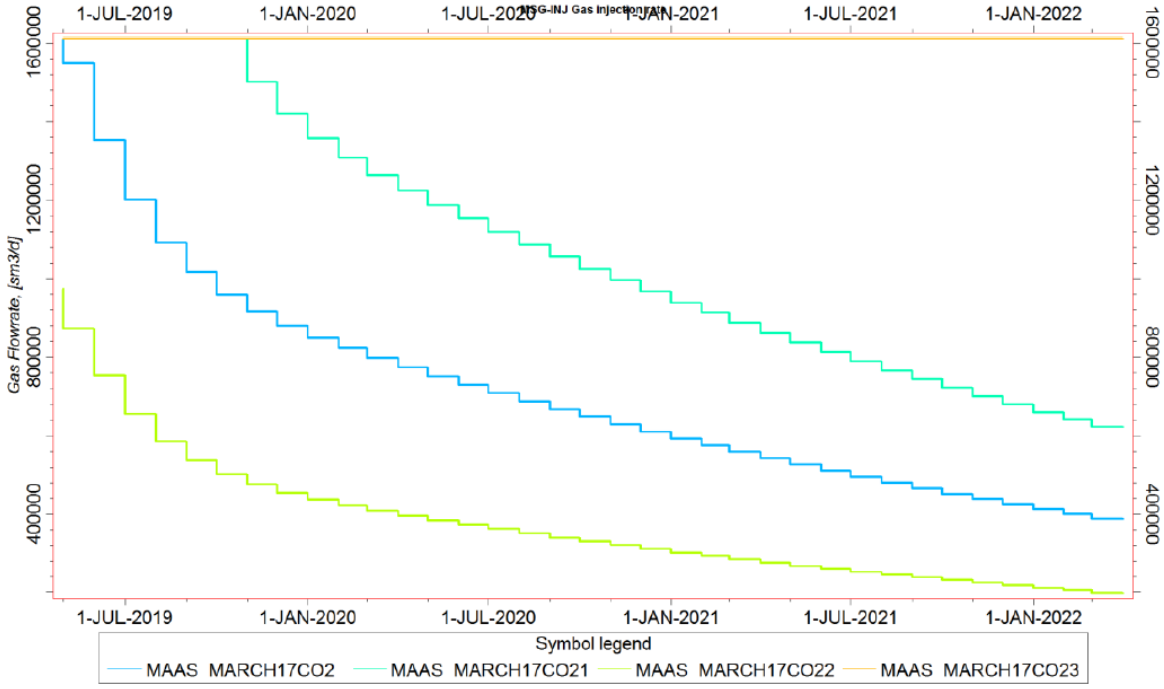


Figure 12.1 Injection rates a function of time for all 4 scenarios

Both storage capacity and injection rates depend on the (average) reservoir pressure and maximum bottom hole pressure that can be safely applied. While in the storage feasibility study of the P18-4 offshore depleted gas field a value of 90% of the initial pressure was used, in this study pressure levels of 100% and 110% of the initial reservoir pressure were used. With the present knowledge about the reservoir and caprock, these higher pressure levels are considered safe.

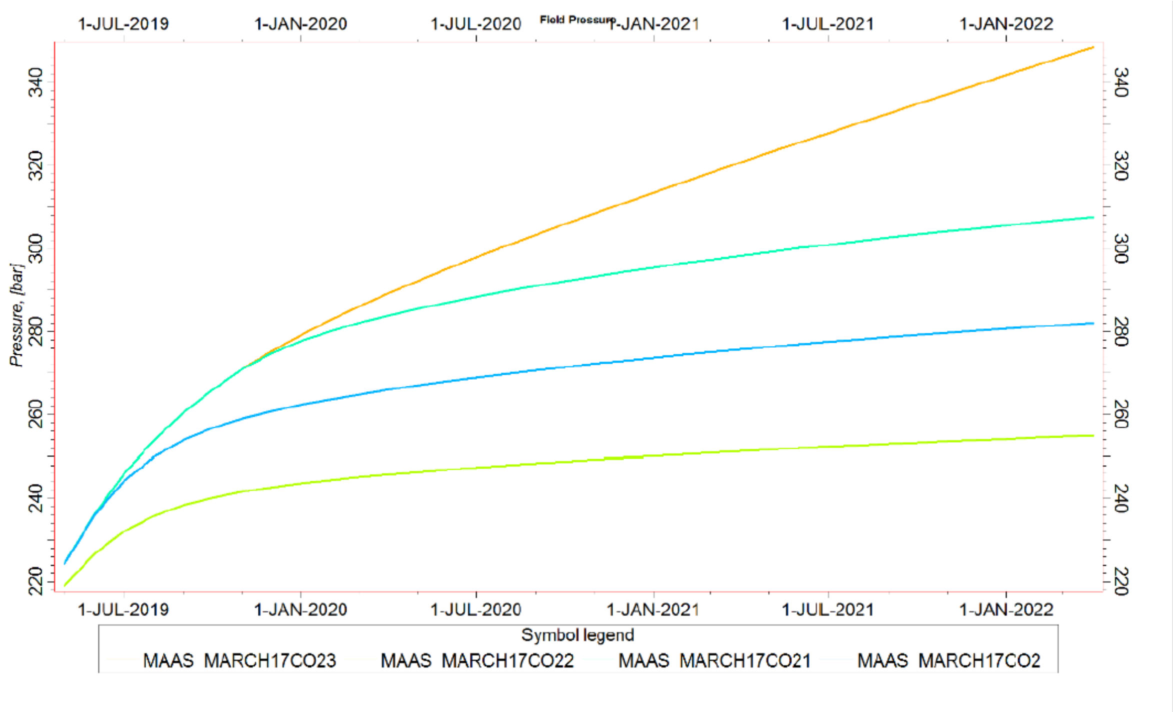


Figure 12.2 Reservoir pressure as function of time for 4 scenarios

Given the stop of the ROAD project, no further consideration of the impact of this substantial reduction in injection rate was made. However, there are some potential remediation measures available: increasing the diameter of the well tubing; and increasing the well perforations to improve injectivity. These have not been assessed and it is not clear whether they would be sufficient. In the worst case, a second well could again be considered.

12.5 Storage System Integrity

12.6 Geochemical interaction with reservoir and seal

Caprock integrity. The caprock can be assumed to be sealing for CO_2. There is no reason to assume that CO_2 will interact with the caprock to result in CO_2 permeating the caprock. Confirmation can be obtained through measurements on caprock samples; it is recommended to collect caprock samples when the side-track MSG-03Y is drilled.

12.7 Geomechanical interaction with seal and fault

Caprock integrity. Temperature and pressure effects cannot be ruled out to have an effect on the caprock. Fractures in the lowermost parts of the caprock, just above the reservoir, may be reactivated when relatively cold CO_2 is injected. Injection into the main reservoir only and not in the thin Röt sandstone will strongly reduce this risk. However, a re-evaluation of the results for the new injection scenario is required.

Faults. Fault stability is not an issue, provided the low temperatures of the injected CO_2 do not reach faults. No specific limits can be given at this time, as the speed at which the temperature front advanced from the injection well depends on many parameters, such as the temperature of the CO_2 and the injection rate. Scenario-specific calculations should be performed when the injection scenario parameters are defined.

12.8 Well integrity

The integrity of the existing well during intermittent injection of relatively cool CO_2 was studied for various temperature levels. The scenarios used represent the worst case. The risk of cement – casing debonding increases with decreasing temperature of the CO_2, but the risk cannot be quantified. Given the short period of CO_2 injection, the risk of CO_2 leaking behind the casing to formations overlying the caprock is considered negligible.

ONE now plans to sidetrack and abandon the existing well, MSG-03X, with the new sidetrack (MSG-03Y) entering the field closer to the sealing faults at the top of the incline. This brings new well integrity issues. The abandoned portion of the well should be monitored, and a new well integrity analysis should be made for the new well.

12.9 Risk management – Monitoring plan

Due to the similarities of the Q16-Maas field and the P18-4 field, the monitoring approach used for the P18-4 monitoring plan were used for the proposed Q16-Maas monitoring plan [Neele et al., 2017]. Given the preliminary nature of the results presented here, the monitoring scheme could not be populated with quantified values for limits to monitoring parameters, such as pressure or temperature. Once a well-understood, fully history matched, compositional reservoir model is available, and the volumes and rates to be stored are known, such limits can be generated along the lines set out in this report.

The Q16-Maas field has one key property that renders it quite different from P18-4, which is the active aquifer. The aquifer causes considerable water production and causes the pressure in the reservoir to remain high during hydrocarbon production. Conversely, injecting CO_2 into the reservoir means recompression of the aquifer, requiring significant well head pressures. An additional effect of the active aquifer is that it is likely to mask any pressure signal from CO_2 migrating out of the reservoir. Key parameters in this regard are the response time of the aquifer and migration rate and volume of the CO_2. Once the final reservoir model is available, a sensitivity study should be done to define the limits of detecting CO_2 migration out of the reservoir through monitoring of reservoir pressure.

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