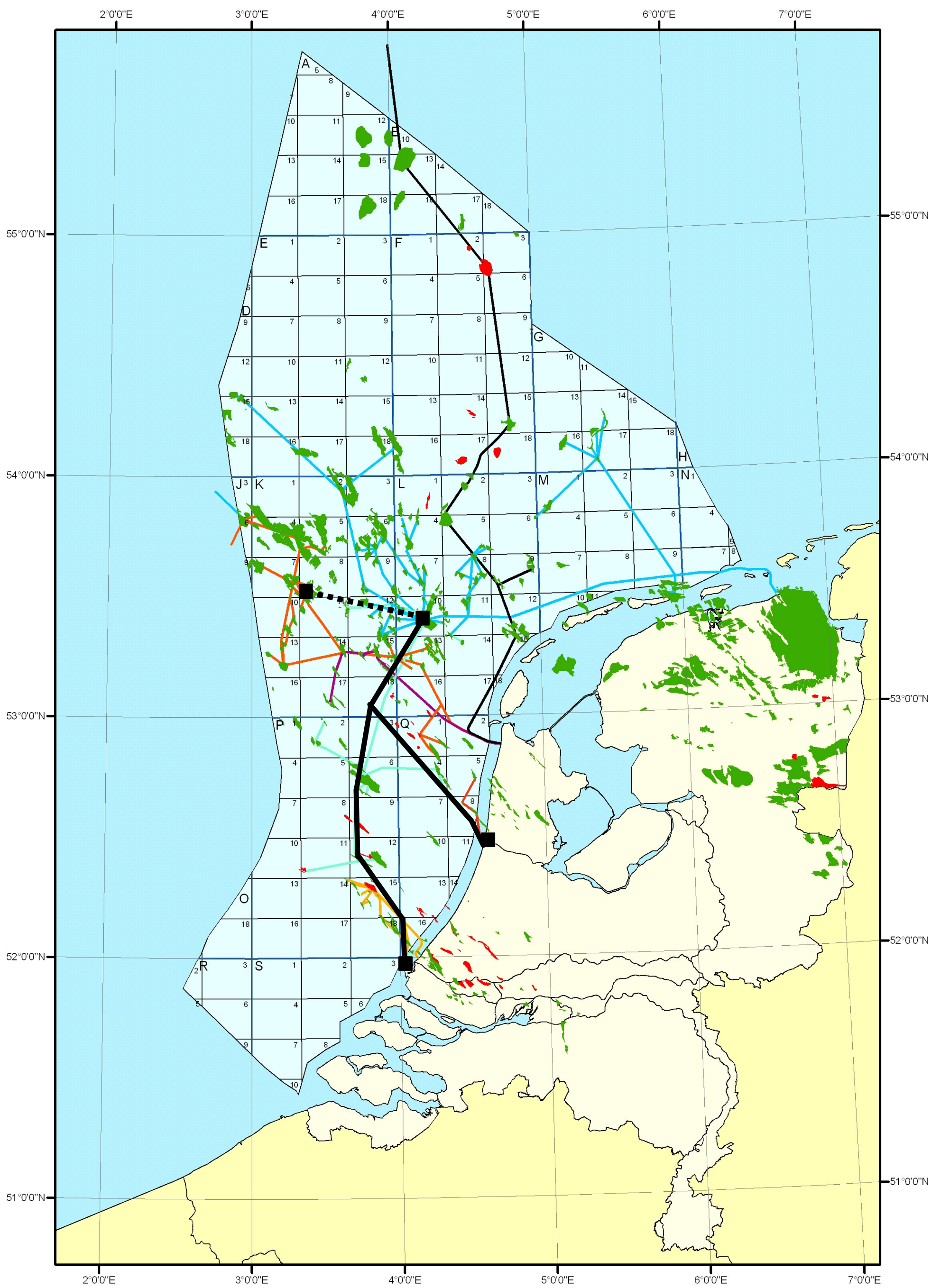
Potential for CO_2 storage in depleted gas fields on the Netherlands Continental Shelf

Phase 2: Costs of transport and storage



Netherlands Oil and Gas Exploration and Production Association

COLOPHON

Potential for CO_2 storage in depleted gas fields at the Dutch Continental Shelf

Phase 2: Costs of transport and storage

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EXECUTIVE SUMMARY

Context

At this stage in the development of Carbon Capture and Storage (CCS) in the Netherlands, more detailed insight is needed in the costs of CCS. For this purpose an investigation was carried out that focused on the infrastructure for transport and injection of CO_2 in depleted offshore gas reservoirs, and in particular the costs thereof. Moreover, the injection concept, as presented in the phase 1 study was detailed out. In that Phase 1 study it was concluded, that before 2030 effectively 900 Mton storage capacity will become available, but that trunk lines and additional CO_2 transport infrastructure are needed.

Base case

In the project the costs were investigated of an offshore CO_2 transport and storage network consisting of trunk lines, main landing platforms, wellhead platforms and interfield pipelines. A base case was defined assuming a yearly CO_2 supply of 20 Mton from Rotterdam and 10 Mton from IJmuiden. In the base case, the CO_2 is transported from the Maasvlakte to the L10-A platform by a 36 inch pipeline with a length of 180 km. In addition, a 24 inch pipeline from IJmuiden with a length 70 km is projected, that ties in into the 36 inch pipeline. It is planned that from L10-A the trunk line will be further extended, at first to the K7 / K8 blocks. For further CO_2 transport to the wellhead platforms and injection into the fields in the K & L blocks existing interfield pipelines will be used.

The base case further assumes that on average 4 main (landing) platforms (CO_2 transport hubs) and 20 satellites (on average 4 injection wells per platform) are simultaneously in use for injection. This concerns both fields in the prefill phase, fields at plateau filling rate and fields in the end-of life filling phase. The fields at plateau filling rate will handle the (major part of the) supplied 30 Mton of CO_2 per year and in general they will be able to maintain this plateau rate over a period of 3 to 8 years depending on the reservoir sizes and characteristics.

Costs of pipelines

The total investment cost for the realization of the 36 inch pipeline is estimated at 380 million euros. The total cost for the 24 inch pipeline is estimated at 128 million euros. These costs are based upon average 2008 price levels and depend strongly on the actual steel prices, the lay barge costs and the costs of specials like e.g. crossings (shipping lanes, other pipelines) and the number of tie-in points.

Variants for pipeline construction

Two variants on the base case were considered:
Variant 1: Stepwise realization of the 36 inch pipeline: In the first step a pipeline is constructed to the P18 reservoirs, 20 km from the Maasvlakte; in the second step the pipeline is extended to P-6A; Finally, the pipeline is extended to L10-A. Main advantage of a stepwise construction is that investments are spread over time; disadvantage is an increase of CAPEX.
Variant 2: Separate trunk lines: Realisation of a 36 inch pipeline from the Maasvlakte to L10-A, and separate 24 inch trunk line from IJmuiden to K7/K8. Costs are comparable to base case, while possibly more operational flexibility is achieved.

Costs of platform modifications

Platform modifications to convert an existing gas treatment platform into a main (landing) platform include the connection of the CO_2 risers, piping modifications, installation of CO_2 monitoring and control systems, and the separation of gas systems. The total investment costs for the modification of one main landing platform are estimated at 16 million euros.
Platform modifications to convert an existing gas production satellite into a CO_2 injection platform include the disconnection of gas systems, installation of CO_2 heaters, well intervention, and the installation of monitoring and control systems. The total investment costs for the modification of a well head platform are estimated at 7 million euros.

Operational costs
The OPEX for the offshore facilities, wells and interfield pipelines includes the costs for operation and inspection, maintenance, logistics, CO_2 monitoring, etc. The OPEX can be divided in the expenses for the period that a platform is mothballed and in hibernation and for the period of actual CO_2 injection. It is expected that during CO_2 injection the facilities operate in a way similar to the gas production operation. Following this reasoning, the OPEX could be derived from the present OPEX for natural gas production. The OPEX for well head platforms are estimated to equal the present OPEX of gas production satellites (i.e. on average 5 million euro per year per platform). The OPEX of main landing platforms are estimated to be half of the present OPEX of gas treatment platforms (i.e. on average 10 million euro per year per platform), because most existing gas production facilities will be obsolete for CO_2 injection.

Overall costs
In the tables below the overall costs for the injection of 30 Mton/year are given, using the base case assumptions for the full use of the storage potential of the K & L blocks:

CAPEX overall (base case)	CAPEX
CAPEX supply and installation pipelines	685 M€
CAPEX modification 60 satellites	432 M€
CAPEX modification 12 main landing platforms	192 M€
Grand total CAPEX	**1300 M€**

OPEX overall (base case)	OPEX
OPEX trunk lines	3 M€/yr
OPEX 20 satellites	100 M€/yr
OPEX 4 main landing platforms	40 M€/yr
Grand total OPEX	**143 M€/yr**

Preliminary overall cost assessment
An indicative – very rough - cost assessment illustrates that over the full period of 30 years the costs for offshore transport and storage amounts to about 8 euro per ton CO_2. A significant part of these costs are due to the OPEX and hence they seem to provide the best opportunities for cost cutting, moreover because their accuracy is limited. Therefore a more detailed assessment into the OPEX is recommended, e.g. into the options to reducing the number of concurrent injecting platforms, options to reduce the OPEX per platform by innovative operational concepts, etc.

Uncertainties in costs
The study gives a good impression of specific costs related to CCS. In order to develop a more detailed business case in a later stage, further assessment is recommended on a number of items:

1. The possibility to reuse the major part of the present infrastructure, i.e. platforms, wells and interfield pipelines. For CO_2 storage it is required to significantly increase the lifetime of the facilities and it is unclear how this will influence the maintenance and inspection costs over a prolonged period of time. In any case, it is important to preserve the current facilities for CO_2 storage. An investigation into cost effective preservation options seems worthwhile;
2. The operational conditions for injection are not clearly defined and therefore the related investments and operational costs cannot be estimated in detail;
3. The costs of monitoring are not clear yet, as the monitoring requirements are still under discussion at the EU level.

Injection considerations
Additional insight is needed for determining the most cost effective injection strategy of CO_2 in a low pressure reservoir. In order to control the CO_2 injection it might be necessary to place a down hole flow restriction. Furthermore, pre heating of the (decompressed) CO_2 stream might be needed to prevent phase changes in the well tubing and the risk of damaging the lining of the tubing.

In this study it has tacitly been assumed that all wells, that are operational now, will be suited and available for CO_2 injection at reasonable cost and without major modification. However, these wells have not been designed for low temperature CO_2 injection and an extended life time (after a hibernation period of several years). Detailed well design studies on the re-use of former gas wells may point at certain technical or cost barriers.

Planning considerations (injection)
Injection studies of TNO illustrate the need for a master plan to be able to inject at a plateau level of 30 Mton per year over a prolonged period of time. When a first set of reservoirs is not completely full yet, one has to connect a number of new reservoirs to avoid break ups in the injection capacity. The order in which reservoirs will be connected depends on many parameters, including the planning and realization of trunk pipelines, end of gas production dates, and the technical condition of the existing infrastructure (e.g. costs of life time extensions). Moreover the volume of CO_2 supplied in time is an important parameter and clarity and security on the supply is essential. It is clear; direction is needed to determine the order of fields to be injected.

Planning considerations (realization of infrastructure)
The phase 1 study showed that for the CO_2 transport from the western Netherlands to the K & L blocks new trunk lines are required. Various options exist to realize these trunk lines, i.e. either construction of the whole trunk lines in one go or stepwise. The latter concept implies, that first the trunk lines are laid to near shore fields (in blocks P15 / P18, Q8 and P6 / Q4) which are initially filled with CO_2 during the running in period of CCS as from about 2015. Later on, these trunk lines can be extended to the K & L blocks that will provide the major capacity for CO_2 storage.

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1 INTRODUCTION

1.1 General

Carbon dioxide Capture and Storage (CCS) is considered to be one of the most promising and cost effective options for the transition period (2020 -2050) on the way to a fully sustainable energy supply. In the CCS chain, carbon dioxide (CO_2) is captured at major emission sources like refineries and power stations, transported by pipeline or ship to a suitable sink and stored in depleted natural gas reservoirs, aquifers, etc. or used for enhanced oil or gas recovery.

In the Netherlands excellent opportunities exist because of the availability of many gas reservoirs. The opportunities may take advantage of the fact that in time part of the existing gas infrastructure may become available for transport of the captured CO_2.

Early implementation of CCS in the Netherlands will promote the development of innovations and expertise that could be marketed abroad and generate high value export opportunities for the Dutch economy. In addition, the Dutch E&P industry has opportunities to extend the lifetime and recovery of their gas reservoirs by employing them for CO_2 storage. Currently, worldwide only a few pilot and demonstration projects are running, among which the K12-B project of GDF SUEZ E&P Nederland B.V. However, before CCS can be implemented demonstration projects are required to demonstrate the large-scale aspects of capture, transport and storage. Such demonstration projects not only prove the technical feasibility, but particularly will point out possibilities for economic optimization. As CCS currently is not profitable yet, the demonstration phase will require additional financial support.

In 2008, NOGEPA and the Ministry of Economic Affairs (MEA), each from their own responsibility, embarked on a study on the available storage and injection capacity for Dutch offshore gas fields. This study was carried out in cooperation by DHV BV and TNO and was completed mid 2008. The study gained in depth information on the CO_2 storage capacity in depleted offshore gas fields and is hereafter referred as the phase 1 study.

1.2 The phase 2 study

Following the estimation of the storage and injection capacity of the Dutch continental shelf, the next phase of this research addresses the related capital and operational costs. Reliable cost data will enable the development of a business case for the realization of CCS in the Netherlands. The phase 2 study focuses at the costs aspects, particularly those for new trunk lines from Rotterdam and IJmuiden to transport the CO_2 to the depleted offshore reservoirs. This study only considers the costs for the offshore part of the required facilities and includes costs for e.g. offshore trunk lines, platform modification, well interventions, etc. Excluded are the cost of the onshore part of the required facilities. These costs are currently being estimated by the Rotterdam Climate Initiative (RCI) and include costs for e.g. onshore trunk lines, compressor station, landfall, etc.

To estimate the costs of the offshore part with the sufficient accuracy it was required to detail out the design and route for the offshore trunk lines from Rotterdam and IJmuiden and the mothballing and modifications of offshore satellites and main platforms.
To model the future CO_2 program TNO calculated examples for the injection profiles for two clusters of gas fields. This exercise is a further elaboration of the ‘Matched Capacity Concept’ as outlined in the phase 1 study. For the time being the work for the development of the offshore CO_2 storage focuses on the gas fields in the K & L blocks of the NCS, because – as shown in the phase 1 study - the fields in these blocks represent about 90% of the total effective CO_2 storage capacity.

The combined result of both phases provides detailed insight in the opportunities of offshore CO_2 storage to the stakeholders NOGEPA, the Dutch E&P operators, the Ministry of Economic Affairs and the Ministry of Environment, including:

- The suitability of existing offshore gas reservoirs for CO_2 storage;
- The capacity, i.e. how much CO_2 can be stored and at what rate;

- The availability and suitability of the existing infrastructure, i.e. which reservoirs, installations and pipelines can be used for CO_2 storage and when will they become available;
- The way demand and supply can be matched, i.e. a tentative development of a storage model with respect to capacity, geographic location and time;
- The capital costs (CAPEX) for the installation of a new CO_2 transport trunk line from shore to the offshore reservoirs and the mothballing and adaptation of the existing offshore platforms
- The operational costs (OPEX) to operate the pipeline and platforms during the injection of CO_2.

In the next sections these subjects are detailed out. First the conclusions are given in section 2. In section 3 the scope and methodology are described. Section 4, contributed by TNO, deals with the injection clusters and injection profiles. In the following section 5 transport and heating aspects are discussed. In section 6 the results of the cost estimate for the CO_2 transport trunk line and the modification to the offshore installations are presented.

1.3 Main conclusions phase 1 study

Sub surface aspects (well and reservoirs)

1 Based on the survey it is assessed that the theoretical storage capacity at the NCS is 1566 Mton CO_2 in 153 fields;

2 The effective storage capacity is estimated at 918 Mton CO_2. The effective storage capacity is derived by applying a cut of for injectivity and one for minimum storage capacity. Moreover, already abandoned fields have not been taken into account, since the wells have been abandoned and no access is available.
The injectivity concerns the degree how well the injected CO_2 will flow into the reservoir and depends on the permeability of the reservoir and the thickness of the reservoir layer. About 50% of the assessed fields have a fair to good injectivity. The minimal storage capacity cut off has been set at 2.5 Mton. 46 fields, with a cumulative storage capacity of 61 Mton, are below this cut off. 20 fields have been abandoned; they represent a theoretical storage capacity of 98 Mton;

3 According to present day plans, all currently know offshore fields are expected to be depleted before 2030;

4 389 wells have been reported on; 104 of these wells were reported to have a restriction to be used as an injection well or as being some sort a risk for integrity of the well. 26 wells were plugged and abandoned. Some wells are reported to be sheared off by plastic salt layers, which may be a showstopper to use the field for CO_2 storage;

5 Based on their design specifications most wells seem to be suitable for CO_2 injection in terms of rating and material. The present status of individual wells have not been investigated;

6 Drilling new wells in a depleted reservoir is technically complicated due to the low backpressure and costly. Therefore reuse of existing wells is preferred.

Surface aspects (platforms and pipelines)

7 The operators do not foresee major technical objections to use the existing pipelines and platforms as for CO_2 transport and injection. To preserve the infrastructure for CO_2 storage, maintenance of (mothballed) platforms is needed and pipelines should be re-certified anyhow. As long as the properties of the transported CO_2 gas are according to specification, thus avoiding corrosion, the existing carbon steel pipelines are considered suitable for CO_2 transport;

8 Transport of CO_2 in the dense phase is preferred (minimum CO_2 pressure about 85 bar) in order to optimally use the available pipeline capacity and to prevent the need for injection compression at all injection platforms;

9 It may be required to heat the CO_2 prior to injection in the reservoir to prevent well or reservoir problems. Boosting the CO_2 can be required to keep a acceptable filling rate at tail end injection. A special point of attention is therefore the energy supply for the heaters and booster pumps, as natural gas will in most cases be no longer available;

10 From the survey it follows that is likely that a significant part of the platforms will cease production before there is a large scale demand for CO_2 storage. The risk exists that platforms may be abandoned and removed, unless there is clear prospect for reuse for CO_2 storage. Long term mothballing to preserve installations for CO_2 storage is preferred as renewed construction of platforms and re-entering wells is technically complicated and costly.

11 The major trunk lines may be available too late for large scale CO_2 storage as this is determined by the last producing gas fields. These fields as a matter of fact tend to be the fields at the end of the trunk lines, as those fields were last taken into production.

12 As rebuilding a complete new infrastructure for CO_2 storage will be expensive and technically challenging, reuse is preferred whenever possible.

Matched capacity

13 In the study an example Matched Capacity Case has been evaluated, assuming that that annually a rate of 20 Mton CO_2 from sources in the Rotterdam area should be stored. Starting from 2020 / 2025 over several decades totally about 200 Mton should then be stored in a cluster of gas fields. It is assessed, that in the central offshore K & L blocks 4 of these 200 Mton clusters can technically be assembled that also can manage the required annual rate. This case is considered to be representative for other clusters;

14 To transport the CO_2 from the Rotterdam area to the K and L blocks use can be made of some existing trunk lines, but anyway some new pipeline section will be required. To handle the full rate of the Matched Capacity Case a complete new trunk line will be required.

2 MAIN CONCLUSIONS AND RECOMMENDATIONS

2.1 Conclusions

Pipeline routing and key figures base case
The project investigates the costs of an offshore CO_2 transport and storage network consisting of trunk lines, main landing platforms, wellhead platforms and interfield pipelines. This infrastructure enables large scale CO_2 injection into depleted gas fields. A base case was designed assuming a annual CO_2 supply of 20 Mton from Rotterdam and 10 Mton from IJmuiden. In the base case, the CO_2 is transported to the L10-A platform by a 36 inch pipeline from the Maasvlakte is needed plus a 24 inch pipeline from IJmuiden, that ties in into the 36 inch pipeline approximately 70 km before the 36 inch line reaches L10-A. For further transport to the wellhead platforms and injection into the fields in the K and L blocks the use of existing interfield piping is assumed.

CAPEX pipelines
The total investment cost for the realization of the 36 inch pipeline (Maasvlakte to L10-A, length 180 km) is estimated at 380 million euros. The total cost for the 24 inch pipeline (Ijmuiden to tie-in point at 36” trunk line, length 70 km) is estimated at 128 million euros. These costs are based upon average 2008 price levels and depend strongly on the actual steel prices, the lay barge costs and the costs of specials like e.g. crossings (ship lanes, other pipelines, cables) and the number of tie-in points. An additional 24” pipeline from the 36 inch trunk lines to the K7/K8 fields is estimated at 166 million euros.

Platform modifications
On the basis of a first and very basic injection assessment a typical number of on average 80 wells (20 satellites) seems realistic to inject an amount of 30 Mton of CO_2 per year. Besides wells on plateau injection rate, this also includes wells on reduced rates, i.e. 1) wells in the prefill phase (gaseous prefill-ing until the reservoir is sufficiently pressurized for dense phase filling) and 2) wells in the decline filling phase. To supply CO_2 to the satellites it is assumed that on average 4 main landing platforms will be in operation as CO_2 transport hub.

Modifications for a main landing platform include revamp of the piping systems and modification of the monitoring and control system. Modifications for the satellites include the installation of control and monitoring systems and the placement of mobile heating facilities to compensate for the temperature drop encountered when dense CO_2 (>85 bar) is decompressed to the initial low pressure levels of the gas fields (down hole pressure 30 – 60 bar).

Because of logistic reasons, there will be a period of several years (typically 5 – 15 years) between the end of gas production and the start of CO_2 injection. Consequently most platforms must be kept in a state of hibernation before they can be used for CO_2 injection.

CAPEX platform modifications
The total CAPEX for the modification of one main landing platform is estimated at 16 million euros. The total CAPEX for one satellite is estimated at 7 million euros. The total amount of CO_2 that can be in-jected by this number of satellites strongly depends on the capacity of the fields in the cluster where the satellites are located.

Operational costs (OPEX)
The OPEX for the offshore facilities, wells and interfield pipelines includes the costs for operation and inspection, maintenance, logistics, CO_2 monitoring, etc. The OPEX can be divided into the period of mothballing and during injection. It is expected that during CO_2 injection the satellites operate generally accordingly as during the present gas production and the OPEX will therefore equal the present OPEX for natural gas production. For main landing platforms the operations are less complex than during gas production, therefore the OPEX during CO_2 transport are considered to be half of the current OPEX.

Injection profiles
Injection profiles were calculated for various clusters in the K & L blocks as an example to develop a scheme for filling the depleted offshore gas fields. The CO_2 injection profiles as presented in section 4.3 are to be considered as high cases in terms of volumes and low cases in terms of the associated costs.

2.2 Recommendations

Use of P18 fields in the initial phase (2016 - 2020)
The study primarily focuses on the period of 2020 onwards, assuming a CO_2 capture of 30 Mton per year. In the period 2014 to 2020 the CO_2 production will increase, depending on the planning for realization of full scale CO_2 capture projects in the west of the Netherlands. Consequently, the full transport and storage infrastructure, as described in the base case, will not be needed from day one. Therefore a variant is worked out, where the first flow of CO_2 from the Maasvlakte is stored in the P18 fields with a maximum rate of 5 Mton / year. For CO_2 transport the first part of the planned 36“ CO_2 trunk line from the Maasvlakte to L10-A is used. In this case the 36“ CO_2 trunk line will be constructed in phases, initially from the Maasvlakte to P18-A and later the extension from P18-A to L10-A. The total CAPEX for the pipeline and platform modifications for the P18 variant only are estimated at 100 million euro. By using the existing interfield gas pipeline to P15-A these reservoirs can be easily deployed for CO_2 storage as well. The CO_2 for the initial low rate filling may possibly be supplied in gaseous phase thus saving on compression and liquefaction costs. A further development of this alternative includes the construction in three steps, first to P18, then to P6 and finally to L10.

Develop injection pilot
Additional insight is needed to optimise the injection strategy of CO_2 in a low pressure reservoir considering safety, costs, capacity, etc. This involves 1) the mitigation of the effect of temperature effects which may occur when CO_2 decompresses whilst being injected into the low pressure reservoir, 2) what is the optimal balance between minimizing the energy consumption for heating the decompressed CO_2 and maximizing the rate of injection. Furthermore, in the pilot, alternative technical solutions to control the injection rate and temperature effects could be tested like the use of orifices or control valves that are positioned in the tubing at the bottom of the well.
Apart from additional research, we therefore recommend to test full scale CO_2 injection in practice, especially with respect to the injection of dense phase CO_2 into low pressure reservoirs. This test should include 1) injection of gasified and heated CO_2, 2) injection of dense phase CO_2 by means of down hole flow control and 3) injection of unheated CO_2 (both in the dense and gaseous phase).

Investigate feasibility of life time extension of platforms
All supporting structures like jackets, piles and decks have originally been designed for a fatigue life of 25 - 35 years. When the fatigue lifetime has been consumed a lifetime extension project has to be launched. Such project consists of a remodelling exercise of the structure in combination with an intensive offshore survey by divers and diving support vessels. The required lifetime extensions for the CCS project are considerable because the total lifetime of some platforms should be stretched to over 50 years. It is assumed that in all cases lifetime extension is possible but there could be situations that a lifetime extension is not feasible unless expensive repair works are executed[1].
It is recommended to perform an investigation to the present situation regarding the full integrity of supporting structures and their potential for lifetime extension. This study assumes full availability of all existing platforms.

Perform detailed analysis into the OPEX
The OPEX are just as important for the overall CO_2 transport and storage costs as the CAPEX. However, the uncertainties in the cost estimates for the OPEX are significantly higher than those for CAPEX. This is caused by several factors. First of all, the operational conditions for injection are not clearly defined and therefore the related investments and operational costs cannot be estimated in detail. Secondly, the costs of monitoring during injection and after abandonment are not clear yet, as the

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[1] Costs for life time extensions of platforms or pipelines are not included in the cost estimates in this report.

monitoring requirements are still under discussion (including EU CCS monitoring for the reservoir integrity and EU ETS emission trading monitoring for accounting emission rights and/or (inter) national regulations, like the Dutch Mining Act and OSPAR). At this phase, the operational costs for platforms during CO_2 injection and storage are derived from the present operational costs during gas production.

Perform a study into the minimum CO_2 quality requirements
In this study the supplied CO_2 is assumed to meet the OCAP quality requirements. For CO_2 storage these requirements may be too strict, because they are based on application of the CO_2 as base material in the chemical industry and for CO_2 fertilization in green houses, resulting in unnecessary treatment costs and energy consumption. In order to determine if less strict requirements are acceptable – and thus reducing the costs of CO_2 capture – an additional study is recommended. This study should focus on the required minimum CO_2 quality in view of corrosivity, the requirements of the CCS directive and contents of non-condensables. Based on the specified low water content (< 40 ppm) no specific anti-corrosion measures were anticipated nor was coating of the pipelines foreseen as means of corrosion prevention. Non-condensables shift the liquefaction point of CO_2 to higher pressures but are in itself not harmful for the transport system. It is expected that an optimum exists between the costs for transport and injection measures and the costs needed to capture with certain specifications.

Perform friction loss study
The energy demand for the compressors to liquefy and transport the CO_2 is significant. To optimize the compressor operations and pipeline design it is recommended to conduct a detailed friction loss study. This study can also asses the cost effectiveness to coat pipelines internally for friction reduction. Furthermore, the prospect to install additional boosters on remote offshore platforms can be evaluated.

Optimize the development order for the reservoirs
Injection studies of TNO illustrated the need for a master plan to be able to inject at a plateau level of 30 Mton per year over a prolonged period of time. When a first set of reservoirs is not completely full yet, one has to connect a number of new reservoirs to avoid hick ups in the storage capacity. The order in which reservoirs will be connected is dependent on many parameters, including:

- Planning of realization of trunk pipelines, tie-ins and interconnecting lines;
- End of gas production dates;
- Reservoir properties (e.g. size, permeability, number of good wells available);
- The optimal combination of small and large fields to obtain the plateau level required;
- Available pipeline capacities (trunk lines, interfield connections);
- Optimal transport routes and acceptable pressure drops in the transport system (e.g. minimize need for decentralized compression);
- Planning issues related to mothballing and overhaul.

Moreover the volume of CO_2 supplied in time – in this study assumed to be 30 Mton per year without periodical fluctuations – is an important parameter and clarity on the supply is essential. It is clear; direction is needed to determine the order of fields to be injected, as a suboptimal order can lead to unnecessary investments and significantly higher costs.

Other studies

- Perform a detailed data analyses of the mechanical situation of the projected CO_2 injection platforms and well status;
- Make a final assessment of pipeline size, routing and line-up.
- Investigate the possibility and extent of reservoir fraccing due to injection of cold CO_2 and/or injection at high rates.
- Study on monitoring needs and optimizing the monitoring costs, in the light of the European discussion on the CCS monitoring requirements.

3 SCOPE AND METHODOLOGY

3.1 Aim and scope of the project

Recent studies have rendered a lot of valuable information about the potential for CCS in the Netherlands including an overview of the major emission sources, techniques for CO_2 capture and options for transport and storage. The limitation of these studies is however that the investigations have been carried out at a generic level, while for the actual large-scale implementation of CCS in depth information is required.

The first part of the required in depth information regarding the geological and technical aspects of the CO_2 storage potential at the Netherlands Continental Shelf (NCS) has been detailed out in the first phase of this study. The first phase aimed at two aspects:

1 Assessment of the possibilities of using existing platforms and infrastructure for the offshore transport and underground storage of CO_2;

2 Assessment the suitability of offshore reservoirs for CO_2 storage.

Phase 1 was carried out by DHV and TNO and gave valuable insight into the offshore storage capacities on the NCS and the time frame for the reservoirs and infrastructure becoming available.

This second phase of the offshore study aims at the assessment of the capital and operational costs of offshore CO_2 storage. The objective of this project stage is:

Provide a realistic cost estimate of the transport and the injection and storage costs of CO_2 storage at the NCS

Phase two is based on the data gathered and produced in phase 1, it was decided (during phase 1) not to update these figures during the cause of the study. Of course one should bear in mind that in reality these figures will constantly be adjusted to the circumstances.

In order to reach the objective of phase two it was required to collect specific data on the transport and injection infrastructure and the level of detail is chosen to comply with the goals of this phase of the study. Of course, making a detailed business plan for offshore CO_2 storage would require even more detailed and location specific information. The scope of work includes the following aspects:

1 **Costs of the CO_2 transport trunk line.** The cost estimate both concerns the capital costs (investment) to construct the pipelines and the operational costs to operate them. The starting points for the trunk lines are that they should transport CO_2 from Rotterdam (20 Mton / yr) and IJmuiden (10 Mton / yr) to the central part of the NCS (K & L blocks). The K & L blocks contain the major part of the Dutch offshore CO_2 storage capacity. The mentioned CO_2 rates should be transported as from 2020;

2 **Costs of injection infrastructure (platforms, wells and interfield pipelines).** The cost estimate concerns the capital costs to adapt the existing offshore platforms for the purpose of CO_2 injection and operational costs during the actual injection. It is assumed that neither new offshore installations nor new wells are required. The required modifications on the platforms include the installation of extra equipment (pumps, heaters and other facilities), modification of piping and installation of control and monitoring facilities;

3 **Costs for mothballing platforms.** The phase 1 study showed that when gas production is ceased at a platform it can in many cases not be used directly for injection of CO_2. Therefore it is required to mothball them, i.e. bring them in a kind of hibernation (safeguarding, cleaning, removal of obsolete equipment and conservation). The study includes the capital expenditure for mothballing platforms and the operational costs during the time that they are mothballed.

3.2 Starting points and assumptions base case

The following basic conditions apply:

Main trunk lines and infrastructure

- CO_2 is supplied from Rotterdam (20 Mton / yr) and IJmuiden, 10 Mton / yr). The running-in period starts with 1 Mton / yr in 2012 and scales up to 5 Mton / yr in 2016. Full rate CO_2 supply starts from 2020 and will run at least up to 2050. By then the estimated available storage capacity at the NCS of 900 Mton will be fully deployed (30 Mton / yr times 30 years);
- The main pipeline will run from the north side of the existing Maasvlakte[2] to platform L10-A (180 km) with a branch connection from IJmuiden that ties in at the pipeline from the Maasvlakte (70 km). On the way to L10-A branches are foreseen to P18 and P6;
- CO_2 sinks are the depleted gas reservoirs in the K & L blocks of the NCS, in particular the in phase 1 defined clusters: L10 / K12, K7 / K8 and P18 / P15, P6 / Q4. The field selection and filling strategy has been executed in line with the matched capacity concept as outlined in phase 1. This study has shown that the depleted gas reservoirs in the K & L blocks provide the major part of the effective offshore CO_2 storage capacity (800 out of 900 Mton). The potential in other fields should however not be regarded as ineffective, especially near shore fields like P18 / P15, P6 and Q4 / Q8 can provide good options in e.g. the running-in period.
- Abandonment scenarios, as described in phase 1, will determine the timing of availability of field and clusters for CCS. Uncertainties relating to the time of end-of-production will not be taken into account as gas production prevails over CO_2 storage;
- The pipeline routing follows existing infrastructure as much as possible, taking into account wind parks, shipping lanes, anchor locations, etc. The crossing of the Eurogeul to the Maasvlakte is based on “direct lay” method. Water depth requirements to be respected are -27 m LAT with a minimum ground coverage of 1 meter;
- All wells, platforms and interfield lines are suitable for CO_2 storage, i.e. no contingency is taken for drilling of new wells or construction of new platforms or pipelines;
- End of life abandonment costs are not included, as these costs are already accounted for in the natural gas operation.

Pipeline design

- Design pressure: 200 bar, operating pressure: 160 bar, design temperature: -10 to +50 ºC;
- CO_2 quality: OCAP quality, water < 40 ppm (no need special steel). In principle for CO_2 storage it suffices if the supplied CO_2 stream is non corrosive, meets the requirements of the CCS directive and contains not more than a few percent of non-condensables. The OCAP quality is for various components too strict because the OCAP quality requirements are set based upon use as raw material for the process industry and for CO_2 fertilization of green houses;
- Pipeline material: carbon steel class L450 MB (typical for gas trunk lines); to be confirmed by a corrosion assessment. Outside coating: concrete, landfalls and riser epoxy coated (~ 5 km). No inside coating for friction reduction or corrosion control;
- 10% contingency for pipe line purchase (e.g. fabrication losses).

Monitoring

Monitoring is required both for ETS (European Emission Trading Scheme for green house gases) and for the European CCS directive. Both directives are still in development. The aim of ETS monitoring is primarily to account the injected CO_2 and subtract losses over the whole CCS system. The aim of CCS monitoring is primarily to guard the integrity of the reservoir. For both purposes the required monitoring

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[2] At present landfall at the north side of the Maasvlakte seems preferable. RCI still keeps the options open to land at the south side of the Maasvlakte or just north of Hoek van Holland. These options are not accounted in this study but especially the option to land at the south side of the Maasvlakte can have considerable impact on the pipeline route due to looping to avoid crossing the restricted anchoring areas and can create a significant cost increase.

systems are not defined yet and for this study therefore a cost estimate is made based on the expected future directives.

- ETS monitoring is assumed to consist of accurate flow meters onshore, on all landing platforms and at the wellhead platforms;
- CCS monitoring is assumed to consist of equipment to monitor the wells and reservoir. To what content CCS monitoring shall be continued after abandonment is not clear yet. Also the way of monitoring is not yet defined and therefore the facilities for this purpose could not be assessed.
- Both ETS and CCS monitoring systems require regular inspection, maintenance and interventions.

Reuse and mothballing[3]

- Existing utilities to be used as much as possible, existing process equipment will be isolated and cleaned;
- Integrity of jackets and decks are in most case designed for “fatigue-life” of 25 - 30 years. Assumed lifetime extensions are possible at limited costs for the duration of the CO_2 injection phase (+ 20 years). Costs for lifetime extensions are not included in this study;
- All wells assigned are in good condition, no excessive leaks to annuli and suitable for CO_2 injection;
- All existing interfield lines are fit for CO_2 injection and still certified;
- Major maintenance work, work-overs, replacement of platforms or drilling of new wells in case the existing infrastructure proofs to be not suitable or not available will include major investments and increase the overall costs for offshore CO_2 storage;
- Definition of mothballing: ‘Conservation of an installation with the intention to re-use it later’.

CO_2 injection and heating

- In this study fields are considered to have 3 filling stages:
  1. Prefill stage, i.e. initial filling with gaseous CO_2. When dense phase is supplied the CO_2 will be heated to prevent possible adverse low temperature effects;
  2. Plateau rate filling, full rate dense phase CO_2 filling at a plateau rate that can be maintained for several years;
  3. End-of-life filling, dense phase CO_2 filling at a gradually declining rate to complete the reservoir filling.

  This means that during full rate storage of 30 Mton of CO_2 per year a significant number of reservoirs will be filled simultaneously, whereby reservoirs are in various stages, i.e. prefill, plateau and end-of-life filling;
- The base case for the initial stage filling of the reservoir is filling with gaseous heated CO_2. To this end at the satellites the supplied dense phase CO_2 will be expanded, whereby the occurring Joule – Thompson cooling effect will be compensated by heaters. After initial filling the plateau rate filing can be executed with unheated dense phase CO_2. Other optional techniques for expansion and heaters, like down hole restriction orifices, are dealt with as variants. The precise pressure when heating can be stopped strongly depends upon the fact whether a down hole restriction device (valve or orifice) will be placed.
- The required temporary heating equipment will be placed on the wellhead platforms and will be gas or diesel fired. For the cost estimate diesel fired heating is assumed;
- Further investigation into heating concept is required and the technical necessity is yet to be confirmed for well and/or reservoir engineering.

[3] NOTE: This study assumes that all present offshore gas production infrastructure (wells, platforms and interfield pipelines) can be reused for CO_2 transport and injection. In contrast the BERR report assumes that only 50% of the platforms and 50% of the wells can be reused. BERR does however not give a good reference or basis for this assumption. The assumption of full availability should probably be considered as optimistic.

Cost engineering

- Costs will be limited to the offshore parts of the pipeline and the offshore infrastructure. the scope limit: is the lay down head at 300 m offshore from coast line;
- Accuracy of the investment cost estimate is + / - 30% under the defined assumptions. Per item the accuracy of the cost estimate may differ, e.g. the accuracy of the trunk lines tends to be higher than that of the platforms;
- All costs are presented in euros on 2008 price levels.

Alternatives

As alternative to the base case scenario the following cases are investigated:

- A separate trunk line directly from IJmuiden connecting to the K7 / K8 cluster. This alternative consist of the following main elements:
  - A 36” trunk line from the Maasvlakte to L10-A;
  - A 24” trunk line from IJmuiden to K7 / K8;
  - A sub sea connection (not pigable) between both trunk lines at the crossing of the pipeline to increase flexibility.
- Storage during the initial period (2014 / 16 – 2020) in the P18 reservoirs of TAQA, located offshore about 20 km west of Hoek van Holland. For this alternative the main 36” trunk line will initially only be laid to TAQA’s P18-A satellite platform and later extended to L10-A. Possibly also a further stepwise extension to first P6 and eventually to L10-A can be considered;
- Possibility for down hole choking;
- Possibility for supply of gaseous CO_2.

3.3 Information

From the three decades of natural gas production at the NCS, a lot of information exists, that is well suited to serve as baseline data for this study. In particular the following data have been used:

- Information, acquired from the offshore E&P operators concerning the technical and cost data on their platforms and pipelines.
- In-house expertise at DHV;
- Information from vendors and pipeline construction companies;
- Public information on CCS and studies.

3.4 Project approach

The following activities have been carried out to estimate the CAPEX and OPEX of the required facilities and modifications for CO_2 storage in depleted gas reservoirs on the NCS:

1. Definition of base case and possible variants (sources, sinks timing, and cost engineering);
2. Consolidation of base case with the NOGEPA Workgroup;
3. Definition of pipeline route to comply with base case and to minimize obstacles;
4. Consolidation of route with Rijkswaterstaat, Directie Noordzee;
5. Agreement of landfall Maasvlakte and IJmuiden with RCI;
6. Calculation of hardware (pipelines, platforms, equipment, etc.);
7. Cost calculations;
8. Analysis and feedback.

4 INJECTION CLUSTERS AND INJECTION PROFILES

4.1 Introduction

As input to their cost estimates on the storage part of the CCS chain, DHV has asked TNO to provide typical CO_2 injection profiles for a number of gas field clusters that are deemed to be part of the early development of CO_2 transport and storage on the Netherlands Continental shelf. Phase 1 of this study has shown, that the K & L blocks are hosting most of the storage capacity for CO_2 on the Netherlands Continental shelf.

Figure 4-1 shows the gas field clusters in the K & L area. Per cluster, the theoretical storage capacity (in Mton) and the expected last year of gas production are shown (according to 2008 operators views, see phase 1 report). The proposed new CO_2 trunk line to L10-A and the optional extension to K8-FA are shown in black. The existing pipeline infrastructure is shown in grey.

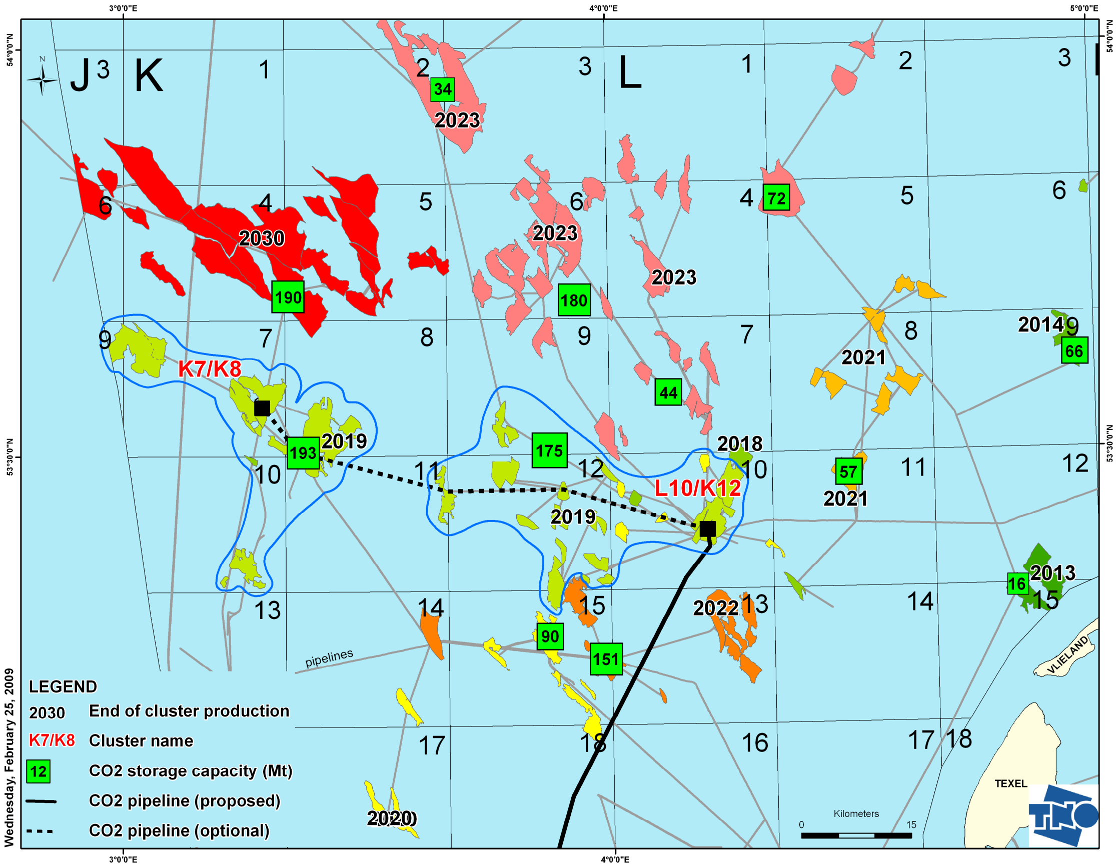


Figure 4-1: Map of the K & L blocks showing the gas fields with theoretical storage capacity per cluster of fields

About 400 Mton of the theoretical storage capacity in the K & L area is connected to the present day interfield infrastructure via the L10-A central platform. Another 400 Mton is connected to the infrastructure via the K08-FA platform. For this reason large scale CO_2 injection (i.e. 30 Mton starting between 2020 and 2025) is envisaged to start from these platforms and the nearby cluster fields.

In addition, smaller scale near shore storage projects (up to 5 Mton / yr) are foreseen in the P & Q blocks , serving as stepping stones and learning projects as from 2012. Here the gas fields in block P18 have been chosen as an example for costing the early part of the infrastructure and storage development and to demonstrate offshore large scale CO_2 storage.

As an example injection profiles have been calculated for a cluster of fields representing the L10 / K12 area and one representing the K7 / K8 area. These clusters are indicated on the map in Figure 4-1 by blue envelops.

In section 4.2 the injection modelling is discussed. At the level of individual gas fields, TNO has used the same gas field CO_2 injection model as the one that has been applied in phase 1 of this project. At the level of clusters, the injection profiles of individual fields have been combined, taking into account the typical requirements as set out in phase 2, in particular regarding supply rate, volume and pressure. Typical output is the number of central platforms, satellite platforms and wells, that will be operational under the assumed constraints, cq. be in hibernation awaiting injection. The results are presented in section 4.3.

As in phase 1, the profiles have been determined using the injectivity as derived from historical gas production performance data. However, as was already indicated in the phase 1 report, there are thermodynamic and/or mechanical constraints on the CO_2 injection, that have to be accounted for in the overall strategy and management of the cluster injection process. The possible impact of these effects on costs is elaborated more in detail in section 4.4.

4.2 Injection modelling

4.2.1 Field level

Model
For the individual fields within the clusters injection profiles have been calculated with an analytical fast model. The reservoir and well parameters for this model have been taken from the phase 1 database. The reservoir (depleted gas field) is represented as a 'tank', characterized by initial pressure and temperature, the dynamic GIIP (gas initially in place), the (field) average kh (injectivity, determined by the permeability and thickness) and the abandonment pressure.

An injection well in a field is characterized by vertical depth and tubing size. The number of injection wells has been taken to be equal to the presently active wells in a field (implicitly assuming that these wells will be available and re-usable for CO_2 injection later on). Each well is represented by 10 segments, allowing to build a temperature, pressure and hence density depth profile along the well. Pressure losses due to friction were neglected: at plateau rate, the CO_2 in the well is supposed to be (mostly) in the supercritical phase with a relatively high density (comparable to oil) but low viscosity (comparable to natural gas). Note that some pre-heating at the well heads will be required.

The inflow model equation accounts for a Darcy and a non Darcy component; the coefficients to this equation have been derived from natural gas production test data in the initial stage of the gas field and have been converted to equivalent coefficients for CO_2 injection.

Cut offs
In the phase 1 report, cut offs have been applied at the total portfolio level on storage volume (> 1 bcm of gas production equivalent) and on injectivity (kh > 0.25 D.m). It was also remarked there, that at project level cut offs may be more relaxed, depending on the specific local conditions.

Pressure constraints
The Flowing Well Head Pressure (FWHP) has been maximized at 160 bara (as in phase 1). Note that his involves local boosting of the pipeline delivery pressure of 85 bar. The reservoir pressure has been constrained at the original gas field pressure.

Injection profile constraints
For the calculation of the injection profiles a certain degree of filling at plateau rate was assumed. One scenario is to choose the injection rate in such a way that 80% of its storage capacity can be filled at this plateau rate (as was done in phase 1); the other scenario assumes a more accelerated injection profile implying a lower, 50%, filling degree at plateau rate. After reaching this 50% filling degree the injection rate goes into decline. These two scenarios are considered to be a technical low rate and a high rate injection scenario: a more accelerated profile seems unpractical, because then storage fields will have to become operational in a very fast sequence, whereas a slower profile does not make full use of the available injection capacity. Of course, operational and economical factors will eventually decide, which (intermediate) profile will be favourable for a particular field. It may be conjectured, that

the larger fields will be kept at a ‘slow’ profile, accommodating the larger part of the base load CO_2 supply, and that the smaller fields would benefit from a more accelerated profile, superimposed on that of the larger fields as infill.

4.2.2 Cluster level

The injection profiles of clusters have been optimized by manually fitting the injection rates of the individual fields to the supplied amount of CO_2. For this exercise, individual field profiles have not been adjusted to exactly match the supply, but in reality the injection rate may be tuned to optimize the results. The main goal here is to demonstrate that in principle a cluster can accommodate the assumed amount of CO_2 supplied for a number of years. It also shows at what time scale a next cluster will have to be developed for continuity reasons. As a consequence the CO_2 infrastructure will have to be expanded beyond the L10 / K12 and K7 / K8 clusters in due time. Logical candidates will be the central platforms in the northern L7 / L4 blocks and the K4 / K5 blocks.

4.3 Injection profile scenarios for selected clusters

4.3.1 The L10/ K12 cluster

The L10-A central platform is the central hub for the fields in the blocks K9, K12 and L10 (Suez GdF) and K6, L4, and L7 (Total). The theoretical storage capacity of these fields is around 400 Mton. For this study we focus on a subgroup of selected fields in the two southern blocks. This is what we call the L10 / K12 cluster which consists of several fields west of the L10-A central platform with a theoretical storage capacity of approximately 175 Mton.

L10 / K12 cluster
L10-CDA*
K12-B
K12-D
K12-G
K12-S3

Table 4-1: List of fields in the L10 / K12 cluster

* L10-CDA stands for Central Development Area, which consist of a number of fields/ reservoir blocks.

The 50% injection profile can accommodate an annual 30 Mton supply of CO_2 for some 4 years only (Figure 4-2). After that the decline is very rapid. The 80% injection profile shows an overall plateau rate above 20 Mton / yr for some 6 years. These results imply, that the L10 / K12 cluster can not accommodate the full 30 Mton / yr supply on a stand alone basis for many years. Decline in the 80% fill is not as fast as in the 50% injection profile leaving a more gradual transition to the next injection cluster. In general, optimizing the injection profile seems to be appropriate by tuning the injection in the larger fields while the small fields are filled upon there maximum economic injection rate.

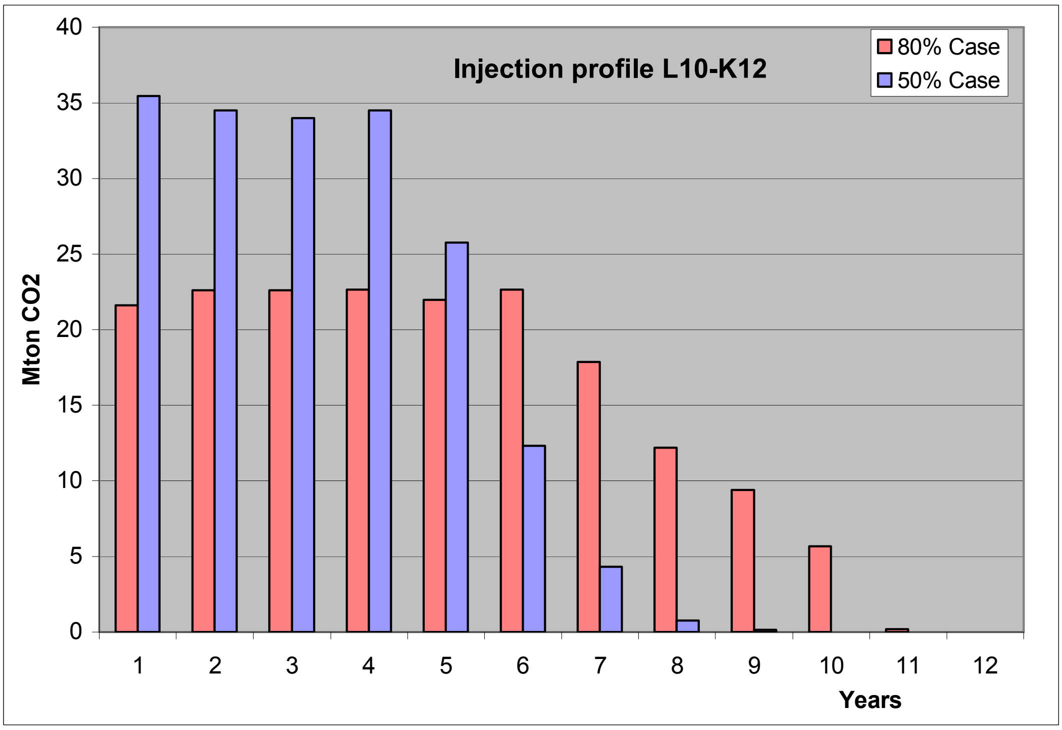


Figure 4-2: Injection profiles for the L10 / K12 cluster

4.3.2 The K7/K8 cluster

The K7/K8 cluster has a theoretical storage capacity of about 235 Mton. The map in Figure 4-1 shows the field outlines and Table 4-2 lists the field names.

K7 / K8 cluster
K07-FA
K07-FB
K07-FC
K07-FD
K07-FE
K08-FA
K10-B

Table 4-2: List of fields in the K7 / K8 cluster

The calculated injection profiles are presented in Figure 4-3. The 50% injection profile of the K7 / K8 cluster shows a relatively short plateau of only 4 years and injection rates, that are much higher than the assumed supply of CO_2. This implies that the injection rate has to be scaled down towards the 80% injection rate. This 80% profile shows that the injection capacity would match a 30 Mton / yr supply of CO_2 for some 7 years. Even that scenario is not likely to occur, since it would imply that all CO_2 from Rotterdam and IJmuiden would (and could) be directed to the K7 / K8 cluster, which is not compatible with the pipeline capacity layout. For a supply rate of 10 Mton / yr (from IJmuiden only), the best strategy seems to develop the large fields in the cluster in a phased manner (not use all wells simultaneously) to match supply and demand in a cost effective manner.

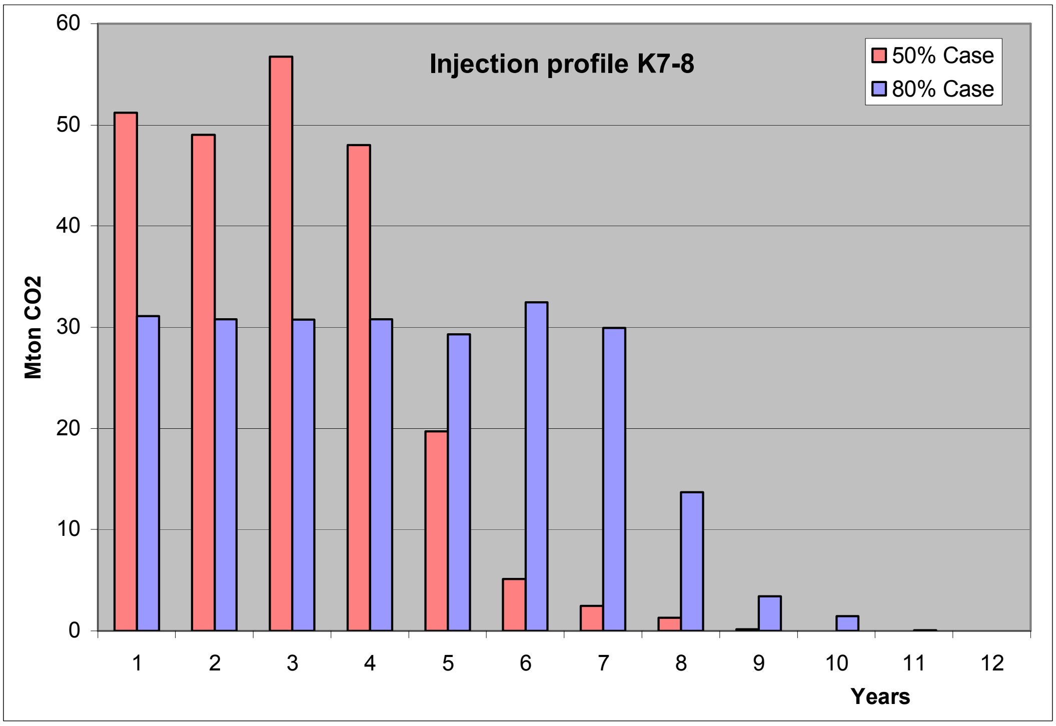


Figure 4-3: Injection profiles for the K7/K8 cluster

4.4 The P18 cluster

The P18 cluster comprises only two fields with a theoretical storage capacity of some 37 Mton. The main reason to include this cluster in the start up phase is the geographical position just offshore the Rotterdam area and on the route towards the L10 / K12 cluster.

Capture of CO_2 is expected to gradually increase towards the assumed annual level of 20 Mton / yr from the Rotterdam area. In the early phase the P18 cluster, which is expected to be timely available (2014/16), may be used to accommodate the initial stream (few Mton / yr) of CO_2. This option provides the opportunity to later construct the major part of the trunk line thus saving costs. Moreover it can serve as an experimental character to gain experience. Once the CO_2 capture is in full swing, the trunk line may be extended towards the K & L blocks. Around 2014/16, a number of fields in block P15 may be available for CO_2 injection as well (approximately 25 Mton).

4.5 Thermal & mechanical effects on CO_2 injection in low pressure gas fields

Because of the lack of high rate dense phase CO_2 injection field tests in deeply depleted gas fields, uncertainties do exist on the thermo-mechanical behaviour of the wells and reservoirs during injection. Large scale demo projects and further research will have to yield more information on what constraints exist for the maximum inflow and maximum injection pressure. If not properly managed, they may cause thermal and mechanical effects on wells and near well reservoir zones, and thereby on injectivity. Mitigation or preventive measures to reduce these effects are briefly discussed below.

Abandonment pressures

Figure 4-4 shows the predicted abandonment pressures (operator's figures from phase 1) versus the theoretical CO_2 storage capacity for the gas field in the K & L area. As can be seen, abandonment pressures mostly are in the range between 20 and 70 bar. It is assumed, that the down hole abandonment pressure will also be the reservoir pressure, when – years later on - the CO_2 injection process is started. If dense phase CO_2 would be injected from day one, large pressure differentials between bottom hole and reservoir may arise.

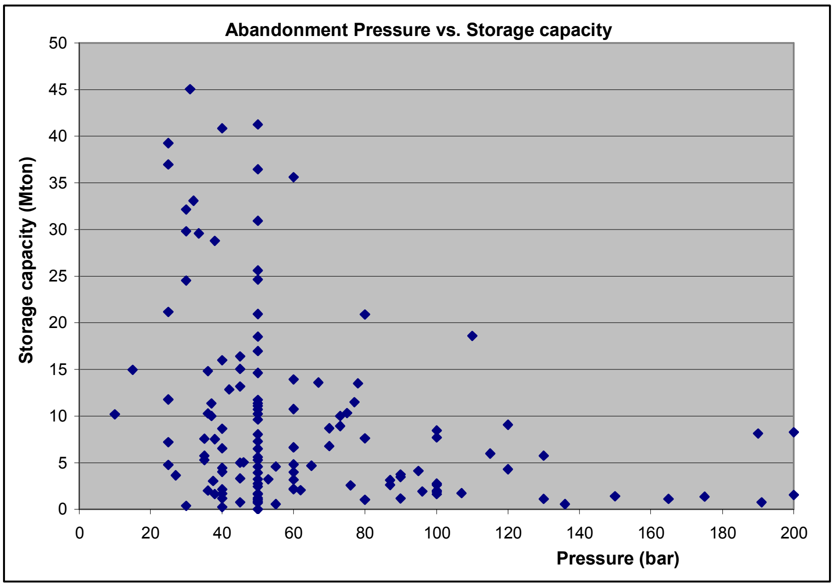


Figure 4-4: Abandonment pressures (down hole) versus the theoretical storage capacity

Note from Figure 4-4, that a fraction of the fields with theoretical capacity below 10 Mton is expected to have an elevated abandonment pressure (70 – 200+ bara). This is linked to poor recovery, either because of poor reservoir permeability/ connectivity, absence of (or remoteness from) compression facilities, and/or an active aquifer. These fields are not likely to suffer from severe thermal of mechanical effects during early injection, but because of their small storage capacity they do not represent a large part of the total storage and injection capacity.

Thermal effects

Phase behaviour of CO_2 may necessitate a start up phase before high injection rates may be achieved (refer to section 5.3). This may be the case when the gas field was abandoned at a very low pressure and this low pressure has persisted to the moment of starting CO_2 injection. Expansion of CO_2 into the reservoir may damage the reservoir and/or tubing due to the fast and strong cooling that will occur.

Mechanical effects

High injection rates and pressures may cause reservoir damage and mechanical fracturing. Unintentional fracture initiation can be prevented by controlling the maximum injection pressure. Note that fracs may also have a positive effect on the injection rate, as long as they are initiated as a proper frac job according to industry standards (this principle of hydraulic fracturing as a well stimulation technique has been in use in the oil and gas industry since 1947).

Since depletion of a gas field lowers the stress gradient of the reservoir formation, fracture conditions in the reservoir occur at a lower stress. This means that the fracture propagation will likely be contained within the reservoir These favourable circumstances apply in particular to the sub-Zechstein Salt reservoirs, as the rheological behaviour of the salt will prevent the fracs from cutting through the top seal of the reservoir. On the other hand, propagation of a frac down into the underlying water bearing zones should be prevented as this may cause influx of formation water which has a negative effect on the storage and injection capacity. Unintended fracturing of the reservoir formation can be avoided, if bottom hole injection pressures are lower than the minimum (horizontal) stress (while compensating for temperature effects), Slow injection during the start up phase and/or heating of the injected CO_2 at the well head will mitigate this risk. This implies a heating system and an energy source on the platform adding extra costs to the process. A carefully planned schedule of injection into smaller fields may optimize the use of mobile heating and pumping facilities.

When CO_2 in the reservoir does not occur in the gaseous phase anymore, injection can be accelerated. However it may still be necessary to control the down hole pressures in order to prevent unwanted mechanical effects to occur. Depending on the particular injection strategy within a cluster, the injection stream should be controlled at a certain plateau level. A simple and cheap way of controlling might be to use wireline interchangeable orifices. A more flexible way, but also more expensive and not yet an industry standard, would be to install down hole control valves. The necessity for these measures will have to be determined per individual case.

4.6 Discussion

To put the CO_2 injection profiles presented in section 4.3 in the right perspective, the following remarks apply:

- **Model uncertainty**
  Various CO_2 injection models (different authors, analytical vs. numerical etc.) do not seem to agree on their predictions. Benchmarks on simulation models, such as performed in the oil and gas world, have not been undertaken yet for CO_2 storage modelling. The task of comparing the models has only recently been taken up (e.g. SPE, TNO). Of course, the final benchmark would be a field test which, however, is not available yet. For that reason, model uncertainty is still present, that can have significant impact on the injection predictions.
- **Thermal and mechanical effects**
  As pointed out above, CO_2 injection is likely to pose some problems, that qualitatively may be alike to injection in gas storage projects but, because of the special PVT properties of CO_2 and because high rate injection is planned to start at low pressures, are probably more enhanced.
- **Reuse of former gas wells and well design**
  In this study it has tacitly been assumed that all wells, that are operational now, will be suited and available for CO_2 injection at reasonable cost and without major modification. However, these wells have not been designed for high rate dense phase CO_2 injection and extended life time (after a hibernation period of several years). Detailed well design studies on the re-use of former gas wells may point at certain technical or cost barriers.
- **Choice of clusters versus pipelines**
  The volume and supply rates of CO_2 to the modelled clusters has been idealized by only looking at the long term targets as presented by the Rotterdam and IJmuiden area: the market for large scale CCS still has to emerge, organize and prove itself. Therefore, the scheme of pipelines and associated storage clusters is only one possible scenario out of a broad spectrum. Eventually, the match between demand and supply of transport, injection and storage capacity may be less favourable then assumed here.

5 TRUNK LINE AND HEATERS DIMENSIONS AND RATING

5.1 Pipeline design

The capacity of pipelines has been calculated by means of the D'Arcy Weisbach formula.

$$\Delta P = \lambda \cdot \left(\frac{L}{d_h} \right) \cdot \left(\frac{\rho \cdot v^2}{2} \right)$$

ΔP = pressure loss [Pa]
λ = D'Arcy - Weisbach friction coefficient [-]
L = Length of the pipeline [m]
d_h = hydraulic diameter [m]
ρ = density [kg/m^3]
v = velocity [m/s]

Besides other parameters, the capacity depends on the length (180 km) and diameter of the pipeline, flow speed and the friction coefficient, which depends merely on the inside pipeline roughness. The used friction coefficient is based on literature data for commercial steel pipe. Furthermore assumptions are made for density and dynamic viscosity. Calculations by means of the D'Arcy Weisbach formula give an approximation of the capacity, any disturbances in the pipeline as T-nodes, curves etc are not included. For the actual engineering more detailed calculations are required.

The basis for the pipeline diameter calculation is based on the assumption that the CO_2 is transported in the dense phase (> 85 bar) and that also at the most remote platform in the K and L blocks the CO_2 should arrive in the dense phase (approximately at 100 bar). Furthermore general accepted ranges are applied for the flow velocity in order to keep the pressure drop within acceptable limits.

Calculations show that a 30" pipeline would be required for the Rotterdam branch and a 16" pipeline for the IJmuiden branch. As these calculations do not include the pressure drop effects of T-nodes, curves etc, the pipeline diameters used for the cost calculations are chosen conservatively, i.e. 36" and 24" respectively for the Rotterdam and IJmuiden branch.
The design pressure of the pipelines should be 200 bar (maximum operating pressure is 160 bar), the design temperature should be -10 up to +50ºC.

Application of an inside coating can reduce the pressure drop and thus the required pumping capacity. In the applied calculations however uncoated carbon has been assumed. During engineering the cost effectiveness of a coating can be assessed.

5.2 Pipeline routes

The Dutch part of the North Sea is intensively used by a wide variety of functions, including shipping, oil and gas production, wind farms, military zones, fishery, etc. Also for future use a number of claims are laid on the area, like for future wind farms. For the routes of the 36" trunk line from Rotterdam and the 24" line from IJmuiden therefore account should be given to many aspects including:

- Definition of the most optimum pipeline route to serve all future injection clusters
- Avoid restricted areas like anchoring zones and minimize obstacles like pipeline crossings, wrecks in order to minimize the costs for the pipelines;
- Selection of the most suitable pipe laying methods and the method to make the crossing of the Eurogeul to Rotterdam;

The pipeline routing study resulted in a preliminary route for both trunk lines that was discussed with Rijkswaterstaat and adopted for the cost estimate in section 6. The preliminary route is outlined in the map in Figure 5-1. The map in Figure 5-2 zooms in to the actual plan area and includes information on other existing and planned activities in the area, which need attention while designing the pipeline route.

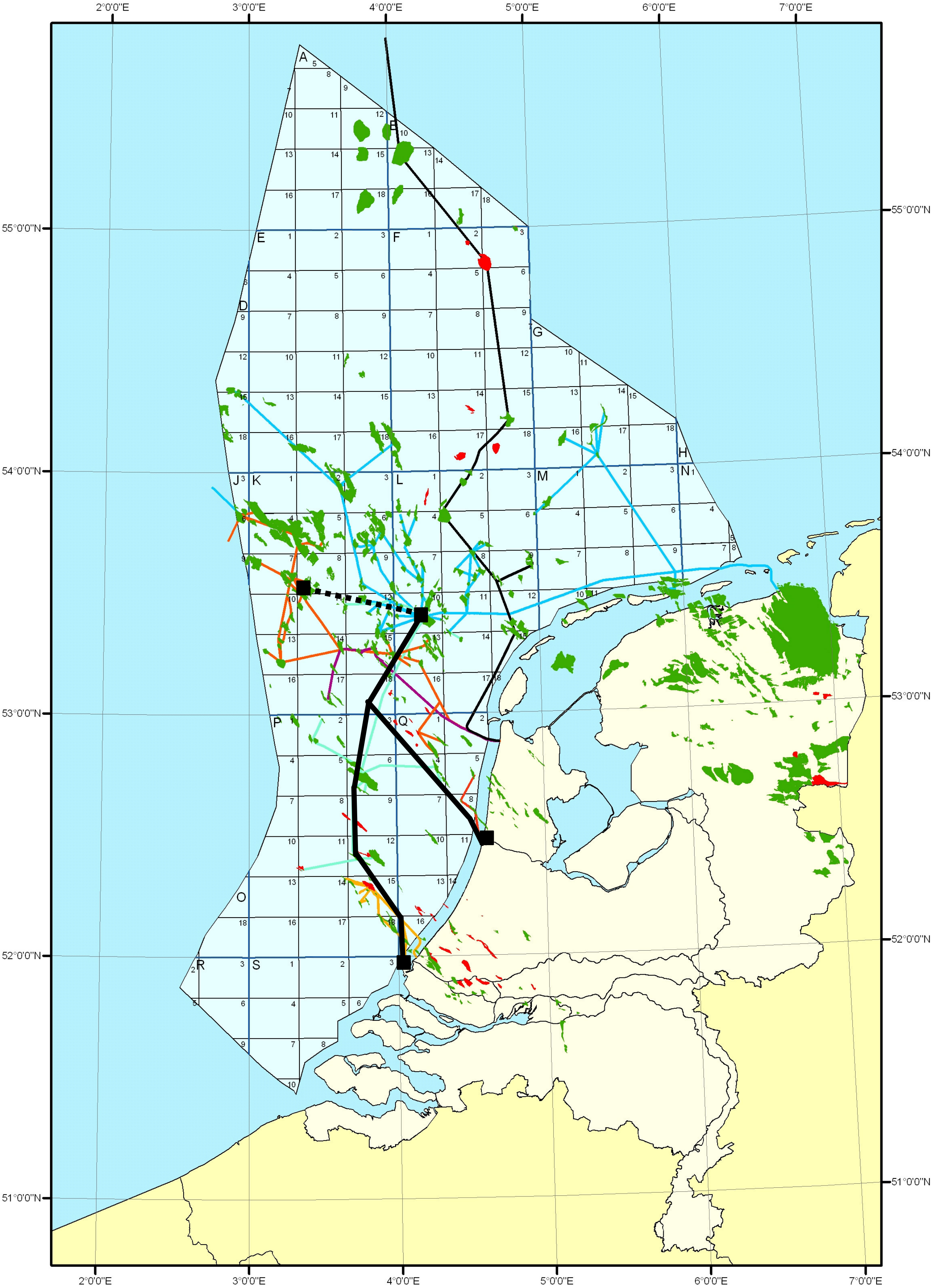


Figure 5-1: Preliminary routes for the CO_2 trunk lines to transport the CO_2 from the Maasvlakte (36") and IJmuiden (24") to the K & L block on the NCS

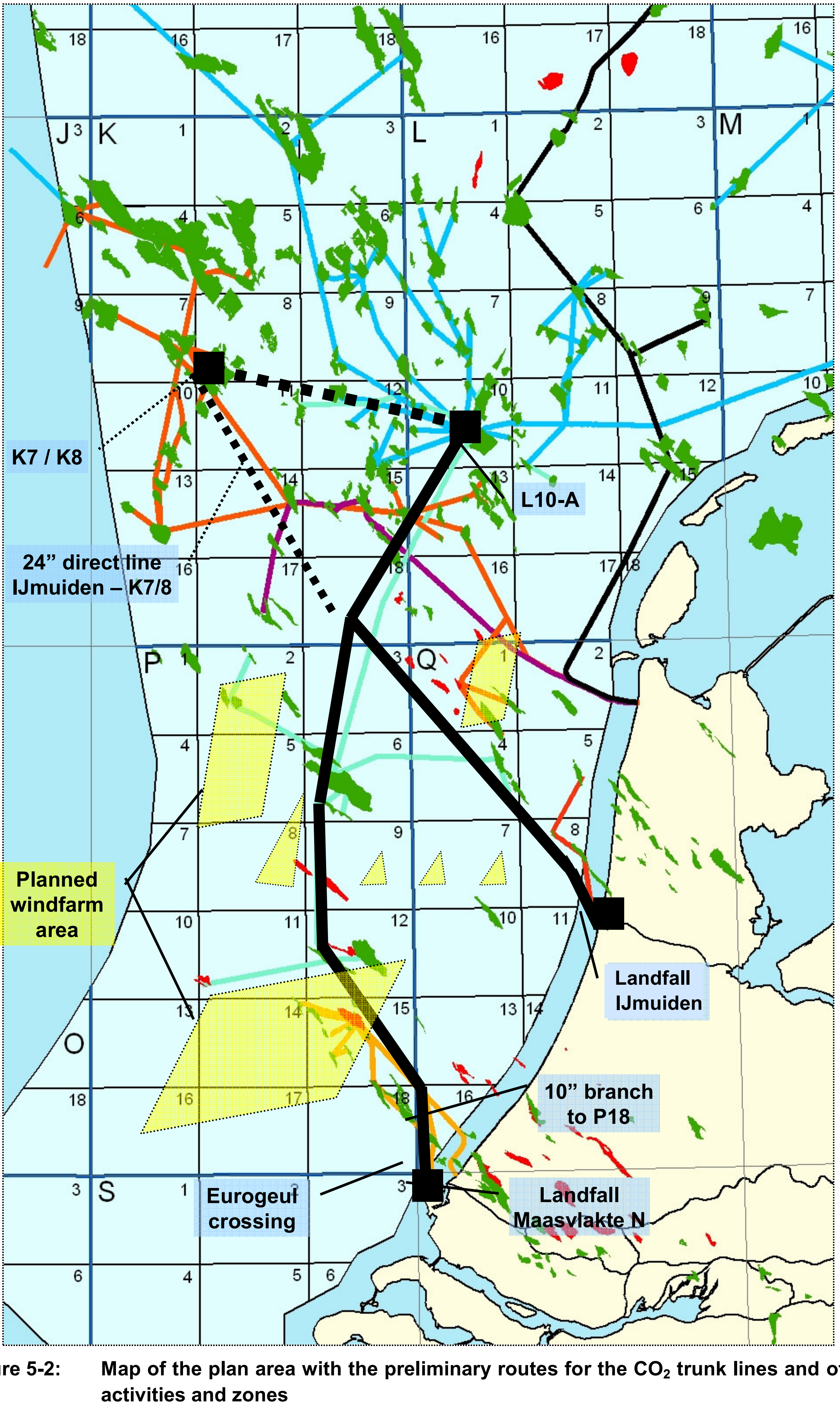


Figure 5-2: Map of the plan area with the preliminary routes for the CO_2 trunk lines and other activities and zones

5.3 Injection behaviour and initial phase heating

Problem statement

CO_2 will be delivered at the CO_2 offshore hubs in the dense liquid phase with a pressure of at least 85 bar and a temperature of 10 ºC (average sea water temperature). However, at the start of the filling process, depleted gas fields will have a gas pressure in the range of 30 to 60 bar and reservoir temperature in the order of 120 ºC. The below table summarizes the most important parameters.

CO_2 supply dense phase	Reservoir abandonment properties	CO_2 properties
Pressure ≥ 85 bar Temperature = 10 ºC Phase = liquid	Avg. pressure = 30 - 60 bar Temperature = 120 ºC Phase = gaseous Reservoir depth: 3 – 4 km (avg.)	Critical point 31.1 ºC and 73.9 bar

Table 5-1: Starting points for analysis CO_2 injection behaviour and initial phase heating

If there would be no control on the injection flow, in the initial stage of filling there would be huge differentials at bottom hole both in pressure (drop of 300+ bar, including the static head of dense CO_2) and in temperature (increase of 100 ºC). These differentials in pressure and temperature are likely to cause undesirable mechanical and thermal (and coupled) effects on the tubing and the reservoir, such as cooling and fraccing.

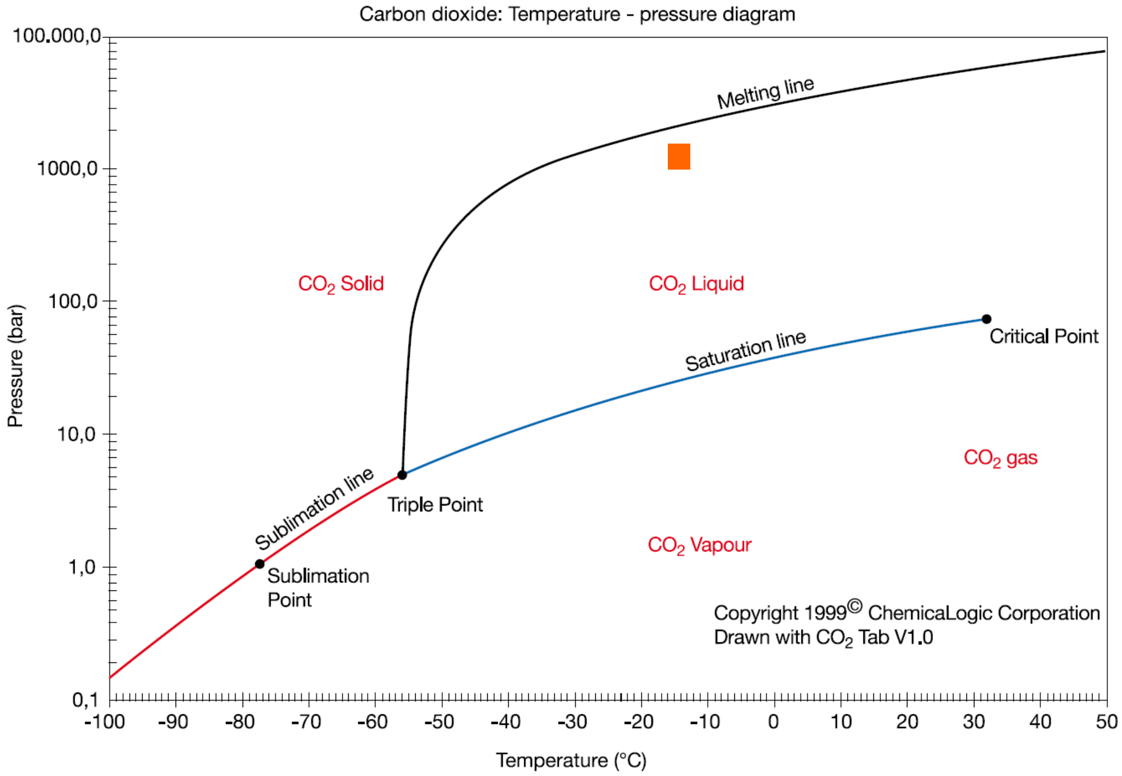


Figure 5-3: Pressure and temperature conditions for pure CO_2 including phase transitions

Some kind of control is to be installed to prevent or at least reduce these effects below a certain manageable and affordable minimum. The objective of a strategy for initial stage filling of depleted gas fields from a high rate dense phase CO_2 stream should be to optimize the injection rate, while minimizing investing in control mechanisms and energy loss (through thermodynamic mechanisms: phase transitions/ flashing, Joule-Thompson cooling) or energy consumption (through external heat input). Although it is beyond the scope of this report to determine this strategy in detail, some general considerations are given below, that indicate what costs might be involved.

Preventive / mitigating measures
Two types of measures to control adverse effects are considered:

1. Placement of a down hole flow restriction (restriction orifice or (control) valve)
   With a down hole flow restriction the injected CO_2 in the tubing will remain in the dense phase. When the CO_2 is throttled over the flow restriction flashing will occur as long as the pressure is below 73.9 bar and the temperature is below 31.1 ºC (critical point). Above the critical point the liquid will directly transit from the liquid into the supercritical phase without adverse temperature or volume effects. In this case the heating can remain limited (10 ºC to 40 ºC). When the pressure drop over the injection tubing and the reservoir back pressure increases enough the heating and flow restriction can be removed.
2. No down hole flow restriction
   Without a down hole flow restriction and without heating initially flashing will occur over the injection path. Even when the reservoir pressure increases it is possible that the injected CO_2 first flashes and at lower depths again becomes liquid. Also then free flow injection rates without a (down hole) flow restriction may be so high that fraccing of the reservoir may occur. Possible fraccing is beyond the scope of this study and may require additional investigation. In order to control these effects it will be required to vaporize and heat the supplied CO_2 until the pressure drop over the injection tubing and the reservoir back pressure are high enough to remove the vaporization unit.

Without a down hole flow restriction a vaporization unit is required consisting of a heater and a choke valve. Downstream the vaporization unit the piping should be sized for gas phase flow. Also in case of a down hole flow restriction initially some heating may be required but the required duration and heating power will be lower, while anyway no evaporation of the supplied CO_2 is required.

Estimate of the required heating power
For this study it is assumed that that skid mounted removable heaters will be placed on the satellite platforms. The required capacity of the heaters depends on the injection rate, the down hole pressure and the required temperature rise. Furthermore it is assumed that during the initial filling only a limited CO_2 flow is heated, thus limiting the size of the heaters. Preferably the heaters should be natural gas fired from still producing wells, but if no gas is available they should be diesel fired.

Based on the thermodynamic properties it can be calculated that based on the above considerations the initial heating requirement will be about 60 to 70 kWh per ton of CO_2 injected in case of a vaporization unit and considerably less at only liquid phase heating. This figure does not take into account the geothermal heating in the well. Moreover, as the reservoir pressure gradually increases, the heating power requirement decreases Therefore the quoted 60 to 70 kWh / ton CO_2 is to be considered a (theoretical) maximum value.

The required capacity on a specific platform cannot be determined yet as this depends on too many uncertain factors. But as an example, on a platform, from which a reservoir is pre-filled at an injection rate of 0.1 Mton / year (i.e. 135 000 Nm^3 / day) of gaseous CO_2, the required heating power for pure CO_2 would be approximately 1 MW (equivalent to almost one million Nm^3 of natural gas consumption per year).

Pre-fill strategy for a cluster
Effective heating can be accomplished by adapting a scheme in which some reservoirs in a cluster are in the initial filling phase and hence need heating until the reservoirs can be filled in the dense phase. Concurrently pre-filled reservoirs can be filled in the dense phase at plateau rate without heating. Adapting such a scheme will require central storage management, but will save considerably on installed heating capacity and on overall energy consumption. Initially, when the supply rate is still low (few Mton per year) it might be possible to transport gaseous CO_2 from shore to pre-fill the envisaged storage cluster. Gaseous filling rates will be lower that plateau rate dense phase filling rates because of physical limitations, while also the wish to limit the heater capacity leads to reduced filling rates at the prefill phase.

Concluding

Concluding can be stated that to control the CO_2 injection several arguments plead to place a down hole flow restriction. A down hole restriction orifice is proven technology and can be applied in most wells by a wireline operation. It will be however required that when the reservoir gradually fills to replace the orifice by one with a bigger hole (less flow resistance). In principle better control might be reached by down hole flow control valve, but this is considered no proven technology.

6 RESULTS OF THE COST ESTIMATE

6.1 General

This section comprises an overview of capital and operational costs of the new CO_2 trunk lines, namely the 36” trunk line from Rotterdam to L10 and the 24” line from IJmuiden to the tie-n point at the 36” line. Furthermore it includes an overview of the costs related to the platform modifications.

Before starting the cost estimate the base case was defined. Also the variants to the base case that have to be taken into account were defined (refer to section 3). After consolidation of the base case with the NOGEPA workgroup the estimating process started. The most important actions that were executed to make the cost estimate consisted of:

- Definition of the most optimum pipeline route to serve all future injection clusters and to minimize obstacles like pipeline crossings, restricted areas like anchoring and military zones, wrecks;
- Consolidation of the proposed trajectory with Rijkswaterstaat Directie Noordzee;
- Consolidation of the proposed starting points from the Maasvlakte II and the IJmuiden area with RCI;
- Definition of the specification for the piping materials. The specification was launched to Europipe in Germany which is one of the major pipeline manufacturers in the world;
- Evaluation and selection of the most suitable method to cross of the Eurogeul to Rotterdam;
- Evaluation and final selection of the various laying methods resulted in the selection of the traditional “S-lay” partly in combination with “trenching” and “shore pull” for the landfalls. This method most suitable and commonly applied in the Southern part of the North Sea;
- Based on the price/ton provided by Europipe for the manufacturing, external coating, inspection and transport of the pipe joints made the cost calculation to the need with a surplus of 10%;
- Definition of the kind and extend of surveys required. For that Fugro in Leidschendam was contacted. Based on the defined trajectory and available historic data the list with minimum required type of surveys was defined.
- Analyzing the available proven technology and methods to be applied for the piping “specials” like crossing details with existing pipeline and telephone cables. Equal-tees and unequal-tees connected to the 36 “main trunk line”;
- Performing a quick scan for the risks of vortex shedding and upheaval buckling on the pipe stability in this part of the North Sea;
- Definition of the scope of work for mothballing to prepare for the hibernation phase;
- Definition of the operational condition during the hibernation phase;
- Definition of the scope of work to prepare a satellite platform for the CO_2 injection phase;
- Definition of the scope of work to prepare a main platform for the CO_2 injection phase.

For cross reference, technical and financial data of 36” Balgzand - Bacton line (BBL) were collected. The BBL pipeline project has been completed in 2006 and is comparable with the CCS pipeline. The BBL pipeline is 36” with an external coating and a concrete outer layer to create stability of the pipe on the seabed. The design pressure of the BBL line is 137.4 bar.

6.2 Specific elements of cost estimate

6.2.1 Pipe laying method and lay barges

The lay barge construction is by far the most frequently used technique for marine pipeline construction. It remains the method of choice for most pipelines. Lay barge construction is versatile, flexible and self contained. It is expensive to mobilize a lay barge from a remote location to the North Sea. These mob - demob costs have been included in the estimate. Once the barge is onsite it can start work and operate as efficiently with minimal support from the shore. It has little competition as a method for installing large diameter lines and competes aggressively with reel-and-tow techniques.

The method envisaged for this estimate is the S-lay. The construction is based on a moored or dynamically positioned barge on which the pipeline is built on a ramp. Lengths of pipe are lined up at the upper end of the ramp and [pass through a series of welding stations as the barge moves forward.

Two lay barge vessels have been looked at:

1 Pipe Lay barge: Lorelay

Owner: Allseas.
Capacity from 2” to 36”
Tensioner cap: 20 m / min
Crane cap: 300 tons at 14 m
7 Single joint welding stations
1 NDT station
Dynamic positioning system
Full NMD 3/LR DP AA
2 coating stations
Typical operational rate 2008: 1 M€ / day

2 Pipe Lay Barge: Castoro Sei

Owner: Saipem
Capacity from 2” to 60”
Tensioner cap. 3 m / min
Crane cap: 60 tons at 60 m
7 Single joint welding stations
1 NDT station
Dynamic positioning system:
Full NMD 3/LR DP AA
2 coating stations
Typical Operational rate 2008: 0.7 M€ / day

6.2.2 Sub-sea crossings

On the route from the Maasvlakte II to L10-A, various crossings have to be made with existing pipelines and cables. The crossing with smaller diameter line which are buried are less problematic then crossing a equal diameter none buried pipeline. Both situations will cross our scope. Most commonly applied crossing method is the installation of concrete mattresses in combination with rock dump and special precaution for cathodic protection. This cost estimate used this method.

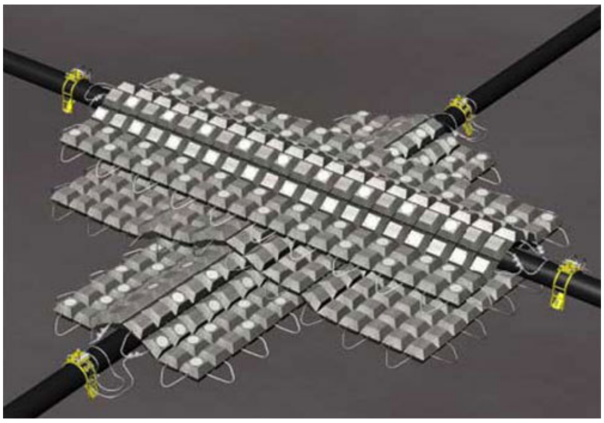


Figure 6-1: Sub-sea crossing arrangement

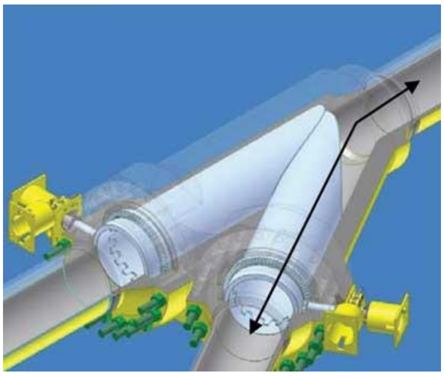
Typical costs
- 8 M€ for a 36” x 36” pipe line crossing
- 4 M€ for a 36” x 8” pipe line crossing

6.2.3 Tie-ins and tabbing

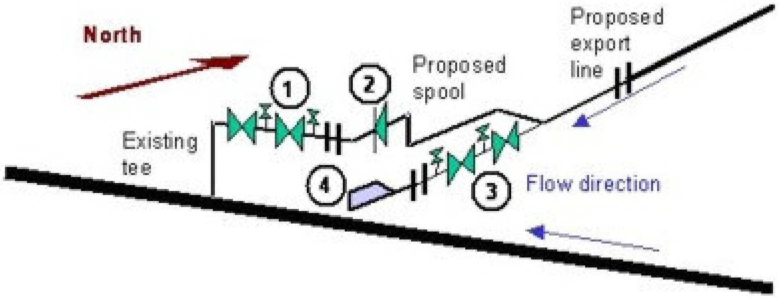
The 36" trunk line will include various tabbing and tie-ins. These are special configurations needed to connect a CO_2 injection cluster or to allow the inlet flow from the 24" feed from IJmuiden. A very important criterion is the requirement for pigging, especially intelligent pigging in view of the risk for corrosion. This cost estimate includes intelligent pigging for only the main 36" trunk line from Masvlakte1 to L10A.

This cost estimate does not include intelligent pigging for the side streams for CO_2 injection into clusters other then L10-A. A corrosion assessment should proof to which extend pigging facilities are mandatory to be installed. The cost estimate includes the cost for dewatering after pressure test as part of the offshore construction phase.

The pictures below show typical configurations for optional pigging facilities. Such facility includes full bore valves and piping arrangement. Such arrangements have to be secured on the seabed and to be protected by a protection frame. The protection frame is required to make the system resistant against trawler beams of fisher boats.



Equal-Y pigging arrangement



Typical tab to connect an injection cluster

Figure 6-2: Arrangement for tie-ins and tabbings

Cleaning foam pigs

Intelligent pig for liquid

Intelligent pig for gas

Figure 6-3: Typical arrangement for corrosion monitoring by intelligent pigging, typical cost: 15 M€

6.2.4 Beach crossings Maasvlakte and IJmuiden

In our situation there are three methods to construct a beach crossing:

1 Horizontal drilling (not taken into account for the Maasvlakte but feasible for IJmuiden);
2 Wet-tow (often applied for inland channels or river crossings);
3 Shore pulling with excavated trench (selected method).

The most straight foreword way of construction a beach crossing is to excavate a straight trench from above high water mark out to water deep enough to be safely reached by the lay barge or reel ship.

A winch is then installed on the beach at the head of the trench. A pull cable is taken out to the lay barge and shackled to a pull head on the end of the pipe line. The winch then pulls the pipe along the trench from the lay barge to the shore while the barge remains stationary. When the pull head has reached the shore, the lay-barge can start to move forward, away from the shore, laying pipe on the seabed behind it.

Almost all pipelines constructed across beaches and through surf zones are trenched into the sea bed because a pipeline that is not trenched is vulnerable to changes of bed level induced by sediment transport and is exposed by large hydrodynamic forces during storms. The design of the trench is part of the design of the pipeline system and as such has been included in the Estimate for the pipelines and excluded from the estimates from the estimate of CRI.

Notes:

- Rijkswaterstaat does not allow unburied pipes in the coastal zone with a water depth of less then -20 m LAT. This means that here in the sea bottom an offshore trench is needed to be dredged, which is to be refilled after the pipe is laid;
- The beach crossing is agreed to be included in the cost estimate of the onshore part of the infrastructure by RCI and is hence excluded from the scope of work and cost estimate of this offshore study.

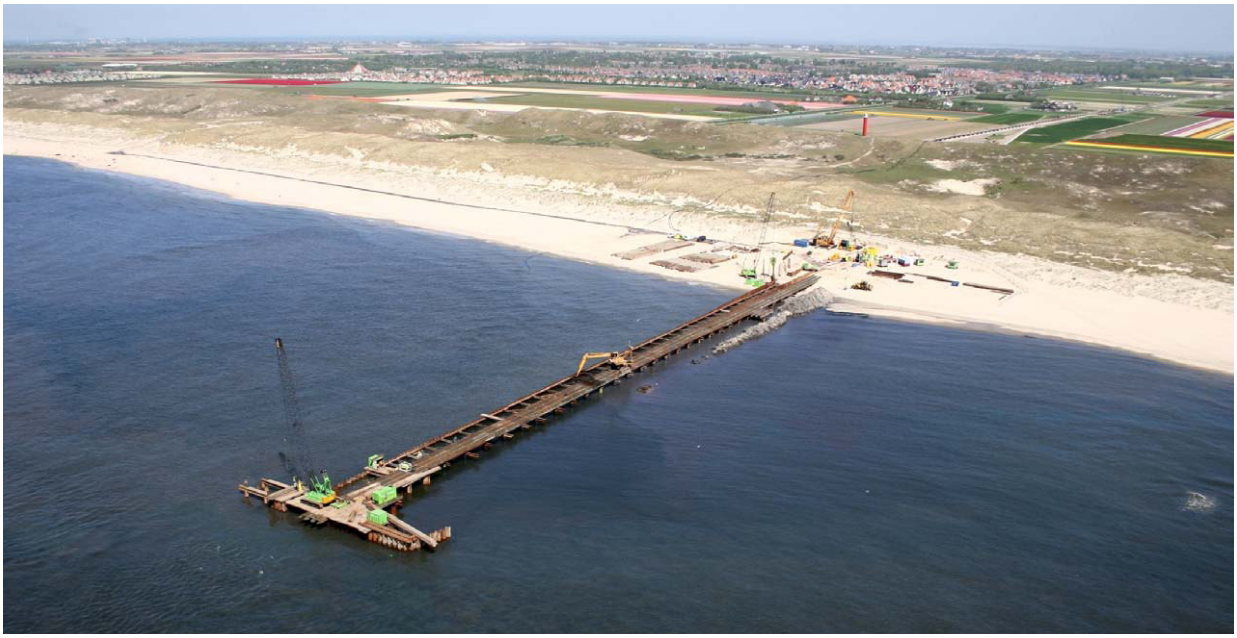


Figure 6-4: Typical shore pulling configuration with excavated trench, based on shore pulling. Approx 300 m sheet piled with excavated cofferdam. Sufficient water depth for pipe lay barge. Start of offshore laying, typical cost: 6 M€

Figure 6-5: Typical beach crossing

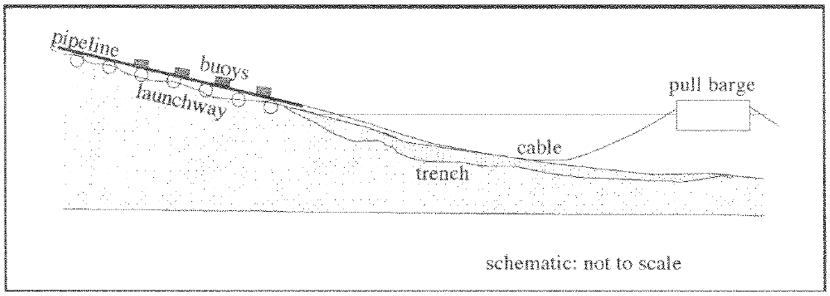


Figure 6-6: Typical beach configuration for the shore pulling method

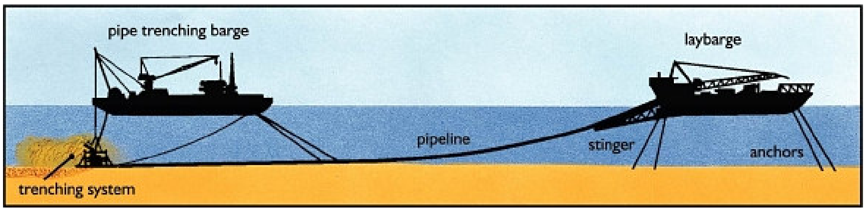


Figure 6-7: Typical pipe laying spread with trench for the first 7 Km till -20 m LAT

6.2.5 Dredging

Based in the information provided by Rijkswaterstaat regarding the actual position of the -20 m LAT water depth around the Maasvlakte II and around IJmuiden, it has been estimate that two trenches of approx 7 kilometres need to be taken into account.

Trenching has been foreseen to be executed by means of a trailing suction hopper dredger. For shallow water other type of dredgers could be envisaged. The trench will has a trapezium shape and a with of 5 meters. The estimated volume of sand and clay to be dredged and discharged at a designated temporary storage area for later re-use during the backfill is approx. 600 000 m^3 per trench. These volumes have been taken into account in the estimate.

Note: The water depth maintained by Rijkswaterstaat for the Eurogeul is -27 m LAT. Rijkswaterstaat requires the pipe at the crossing location of the Eurogeul below this depth and with coverage of 1 meter of sand (meaning -28 m LAT top of pipe).

Suction trailer dredger m.v. Lelystad
Owner: Van Oord
Capacity: 10 311 m^3
Number of suction pipes: 2
Maximum dredging depth: 54 to 70 m
Application: make trapezium trench for crossing Eurogeul
Typical operational rate: 0.1 M€ / day
Estimated cost per offshore trench: 11 M€

6.2.6 Modifications on satellites

The modifications required after having stopped the gas production on a satellite platform consist of three steps:

- Step 1 - Mothballing;
- Step 2 - Hibernation;
- Step 3 - Modifications to prepare for CO_2 injection.

To create mutual understanding of the operational conditions of a satellite, it is important to understand what is meant by mothballing, hibernation and modification.

Definition step 1: Mothballing
Mothballing is a package of one off activities to stop operations, with the objective to reduce OPEX and includes cleaning, conservation and safeguarding of the installation with the intention to re-use it later.

Definition step 2: Hibernation
Hibernation is the period after mothballing whereby OPEX is reduced to a minimum and only meets Company and Authority requirements and the installation is awaiting future plans.

Definition step 3: Modification
Scope for a package of one off construction activities required to be implemented with the objective to convert the installation to the “ready for CO_2 injection” condition.

A typical scope for a mothballing package is:

1. Disconnecting and/or spading of process equipment from wells, vent systems, transport lines and manifolds;
2. Cleaning and conservation of process equipment (put at 1 bar N_2 pressure) in particular equipment what is need for future CO_2 injection;
3. Removing all loose equipment to reduce maintenance interventions such as life boats;
4. Install addition life rafts to cover the interventions during the hibernation phase;
5. Disconnecting utilities systems, fire & gas detection systems, ESD and process control systems;
6. Stop generators but maintain crane and helideck operational;
7. Prepare platform for access by OAS (Offshore Access System);
8. Isolation of the wells by plug setting and blind flanges;
9. Installation uninterrupted power supply system (solar / wind powered) to feed nav aids and minimum lighting;
10. Inspection of the well status to define corrective actions when required.

Typical scope for hibernation:
The hibernation period is not including CAPEX. It is the period before a satellite is converted for CO_2 injection. During this phase it has been estimated that Operation and Maintenance are reduced to a minimum, whereby the integrity of the installation shall not affected. All activities to ensure integrity of the installation during the hibernation phase shall continue. These activities are underwater jacket, riser and top side inspections. Certification shall remain valid and lifetime extensions shall be executed when the fatigue-life has been consumed.

The anticipated number of interventions visits during this period will be maximized to two per year. Access to the platform is anticipated by e.g. an OAS system (see picture below) It is obvious that in case the helicopter deck should be kept fully operational additional OPEX and CAPEX is required. This has been excluded from this estimate. Access by helicopter is only allowed in case of emergency.

Vessel Smit Kamara with OAS system

The minimum requirement for the hibernation phase is to maintain the Navigation Aids (Fog horn and U-code light) operational. Electric power is foreseen to be supplied by solar power with or without support of a small wind mill. Nav Aids systems to be designed for LED technology (existing). Typical power configuration by wind and solar energy.

CO_2 Heating
During the first years heating is required in order to maintain the CO_2 in the dense phase. Independent and mobile diesel or gas fired heater skids have been foreseen to be installed during the CO_2 injection phase. A small generator pack is installed to supply the required e-power for controlling and monitoring of the whole CO_2 injection process. Design is anticipated to be based on the “plug and play” principle with a typical requirement of 60 to 70 kWh / ton of CO_2 injected. For this requirement a more extended study is required.

A typical scope for a modification package is:

1 Install independent heaters pack(s) with their own e-power supply and flow control system;
2 Install and connect the required piping and control systems to allow CO_2 injection;
3 Remove down hole safety valves and plugs;
4 Keep hydraulic master and wing valves operational.
5 Install monitoring and control system for the well annuli;
6 Install monitoring systems for ETS and CCS monitoring;
7 Remove coiled tubing when installed.

In some cases it may be required to replace the total tubing. This is however an expensive operation (several million euros) for which a drilling rig is required for some weeks at the location. The replacement of tubings is not included in the cost estimate just like other well interventions and/or workovers by mobilization of a drilling rig.

6.2.7 Modification on main landing platforms

The modifications required on the main CO_2 landing platforms are;

1 Extent CO_2 risers from +6 m LAT to distribution manifold;
2 Install a distribution manifold;
3 Separate the existing gas manifold to connect the CO_2 distribution manifold;
4 install a CO_2 monitoring and control systems and integrate the CO_2 monitoring and control devices into the existing NCS (Distributed Control Systems);
5 Modify the PCS (process control system) and SSS (safety shut down system);
6 Install monitoring systems for ETS and CCS monitoring.

6.2.8 Approach to determine operational expenditures

The OPEX for offshore CO_2 storage are related to the operation and maintenance of the offshore facilities, wells and interfield pipelines and includes costs for maintenance, inspection, well interventions, logistics, energy, monitoring, control, manning, etc. The OPEX can be divided into two cases:

1. OPEX during the hibernation phase for the main landing platforms and satellites: After the implementation of the mothballing activities, the facilities are brought into a state of hibernation and require only minimum maintenance and inspection;
2. OPEX during the operational CO_2 injection phase for main landing platforms and satellites: During the CO_2 injection phase the facilities operate more or less similar as during the gas production.

The OPEX during injection basically can be determined in two ways. The first approach is top –down, i.e. by starting from the present gas production OPEX and correcting for the new mode. The second approach is bottom up, i.e. by making a cost break down of all foreseeable costs. Because in this stage the first approach is judged to give the best result, this method is adopted in this study.
The present gas production OPEX were derived by taking the total actual OPEX of a typical NCS operator. The uncorrected total OPEX include all operational costs for the operation and maintenance of the offshore facilities, wells and interfield pipelines and fees for the gas transport to shore. First of all the transport fee was subtracted is these are not relevant for CO_2 storage. The remaining OPEX were hereafter divided over the main landing platforms and satellites by using a typical experience ratio.

For satellites the OPEX during CO_2 injection are estimated to be equal to the average OPEX during gas production as determined above. This estimate is justified by the fact that during injection comparable activities take place like maintenance, inspection, well interventions, logistics, energy, monitoring and control. A difference is that during the CO_2 injection phase no gas - liquid separation and production water treatment is required. These costs are however supposed to be substituted by the spreaded costs for initial CO_2 heating. Based on current actual average OPEX for satellites on the NCS the OPEX during CO_2 injection is estimated to equal 5 M€ per year per satellite.

The OPEX during CO_2 injection for main landing platforms are also estimated to be comparable to the average OPEX during gas production, but need correction because during the CO_2 injection no gas compression and dehydration are required, as well some other optimizations are possible. Based upon an analysis of the actual OPEX for gas treatment platforms on the NCS and after correction for items that are not applicable during CO_2 injection the average OPEX during CO_2 injection is estimated to be 10 M€ per year per main landing platform.

6.3 Results: Cost estimates new CO_2 trunk lines

6.3.1 Capital expenditure (CAPEX) new CO_2 trunk lines

Pipeline section	CAPEX
36” from Maasvlakte II north side to L10-A ▪ Pipe supply and laying: 294 M€ ▪ Beach crossing: 7 M€ ▪ Eurogeul crossing: 16 M€ ▪ Tie-ins, tabs and line crossings: 63 M€	380 M€
24” from IJmuiden to tie-in point at 36” pipeline ▪ Pipe supply and laying: 65 M€ ▪ Beach crossing: 15 M€ ▪ Tie-in, tabs, abandonment head and line crossings: 48 M€	128 M€
10” pipeline with riser from 36”x10” tab to landing on P18	11 M€
24” pipeline from 36”x24” tab to K7/K8 ▪ Pipe supply and laying: 124 M€ ▪ Reconnect to abandonment head: 5 M€ ▪ Riser and crossings: 37 M€	166 M€
Total CAPEX pipelines	685 M€

Table 6-1: CAPEX new CO_2 trunk lines

6.3.2 Operational expenditure (OPEX) new CO_2 trunk lines

The operational costs of the trunk lines are estimated at 3.2 M€ / yr, needed for yearly X-Y-Z surveys of the pipelines.

6.4 Results: Costs estimates installations and interfield lines

6.4.1 Capital expenditure (CAPEX) platform modifications

Cost for modifications of one main lading platform	CAPEX
Cleaning and spading of none used process equipment	1.5 M€
36” Riser extension from +6 m LAT to process area incl pigging facilities	5.5 M€
Split manifold for concurrent production & injection	6.8 M€
Preparation piping and ESD systems for reversed flow	1.5 M€
Modification of monitoring and control systems	0.7 M€
Total CAPEX modifications of one main lading platform	16 M€

Table 6-2: Typical CAPEX for modifications at one main landing platform

Costs for modifications one satellite (including mobile heating unit)	CAPEX
Cost for mothballing of one satellite platform	2.5 M€
Heating and power generators (mobile, diesel fired)	2.7 M€
Solar-powered facilities Nav-Aids during the hibernation period	1.2 M€
Preparation of wells for CO_2 injection	0.8 M€
Total CAPEX satellite platform modification	7.2 M€

Table 6-3: Typical CAPEX for modifications at one satellite platform

6.4.2 Operational expenditure (OPEX) installations and interfield lines

Summarized the following operational expenditures are assumed for the offshore platforms, wells and interfield pipelines

Operational expenditures per year of offshore installations	**OPEX**
OPEX during hibernation of one mothballed satellite platform	0.6 M€/yr
OPEX during hibernation of one mothballed treatment centre	1.5 M€/yr
OPEX of one satellite platform during CO_2 injection	5.0 M€/yr
OPEX of one main landing platform during CO_2 injection	10.0 M€/yr

Table 6-4: OPEX offshore installation and interfield pipelines

6.5 Results: Overall costs offshore CO_2 injection

CAPEX overall base case, K & L blocks	**CAPEX**
CAPEX supply and installation pipelines	685 M€
CAPEX modification 60 satellites @ 7.2 M€/yr per satellite	432 M€
CAPEX modification 12 main landing platforms @ 16 M€/yr per landing platform	192 M€
Grand total CAPEX	1309 M€

Table 6-5: Overall CAPEX for the base case assuming modification for CO_2 storage of 12 main landing platforms and 60 satellites in the K and L blocks

OPEX overall (base case) during CO_2 injection	**OPEX**
OPEX trunk lines	3 M€/yr
OPEX 20 satellites @ 5 M€/yr per satellite	100 M€/yr
OPEX 4 main landing platforms @ 10 M€/yr per landing platform	40 M€/yr
Grand total OPEX	143 M€/yr

Table 6-6: Overall OPEX for the base case assuming concurrent CO_2 injection on 20 satellites (prefill, plateau and end-of-life) in the K and L blocks while using 4 main landing platforms

Indicative transport and storage costs per ton stored co$_2$
Based upon the cost data given in the previous sections, an indication of the offshore costs per ton of stored CO_2 can be calculated. Because of the uncertainties in the business model this is inevitably a very rough estimate and should be used with great care. The indication of the cost items for transport and storage is based on the following assumptions:

- The CO_2 is supplied from Rotterdam (20 Mton per year) and IJmuiden (10 Mton per year) over a total period of 30 years, starting from 2020;
- The supplied CO_2 will be stored in the depleted gas fields in the K & L blocks of the Netherlands continental shelf having a total capacity of 800 Mton CO_2. in the end a total number of 12 main landing platforms and 60 satellites have been deployed for CO_2 storage;
- The average hibernation period between the end of gas production and the start of CO_2 injection for each platform is estimated on average at 12 years followed by a 10 years injection period;
- The previously described assumptions for the storage concept and the cost engineering apply;

The average financing costs are based upon a simple annuity method, using a deprivation period for investments in trunk lines and platforms modifications of 30 and 12 years respectively. An interest rate of 6.5 % is applied. This results in the following cost items expressed in annual costs:

- The total CAPEX includes the CAPEX for the trunk lines and the modification of 12 main landing platforms and 60 satellites, in total about 1300 M€. The resulting average costs are 3 € / ton CO_2;
- The total OPEX includes the OPEX for the trunk lines (3 M€ / yr), operation of 4 main landing platforms (40 M€ / yr) and 20 satellites (100 M€ / yr), totalling 143 M€ / yr OPEX. This results in average costs of 5 € / ton CO_2.
  Please note that no OPEX of platforms in hibernation are included in this figure;
- The overall costs specific for offshore CO_2 transport and injection in depleted gas fields amounts to 8 € / ton CO_2. Note this number is highly indicative and should be worked out in a far more detailed business case. Furthermore, onshore caption and/or transport activities like compression are not included in this number.

The indicative cost figures illustrate that the OPEX contributes significantly (60%) to the cost of per ton of CO_2 injected. Therefore they seem to provide the best opportunities for cost cutting, moreover because their accuracy is limited. Therefore a more detailed assessment into the OPEX is recommended, e.g. into the options to reducing the number of concurrent injecting platforms, options to reduce the OPEX per platform by innovative operational concepts, etc.

6.6 Variants on the base case

6.6.1 Step wise construction: CCS trunk line from Maasvlakte to the P18-A satellite and P6

In the start up phase of CCS only a limited quantities CO_2 will be supplied, that can be stored in depleted gas reservoirs that are located nearer to the Rotterdam area. First of all opportunities are present in the P18 reservoirs that are located about 20 km offshore of Hoek van Holland. Here about 37 Mton CO_2 can be stored in total, while as from about 2016 / 18 also via the existing interfield gas line the P15 reservoirs can be used, where an additional 25 Mton could be stored. Next also P6 gives opportunities, located about 100 km north west of the Maasvlakte, which is also connected to the L10-A platform by a 20" pipeline. A stepwise development of the main trunk line can follow the concept that first the 36" trunk line is developed and laid according to the initial plan to the P18-A and a connection to P18-A is made by means of a 10" branch connection. In this case the 36" CO_2 trunk line will end at a carefully selected point to enable recovery of the lay down head. The first part of the 36" CO_2 trunk line includes the land fall at the north side of the Maasvlakte and the Eurogeul crossing.

Next the second part of the 36" trunk line (about 60 km) can be developed and laid according to plan to P6-A and connected by means of a 10" branch connection. In the reservoirs linked to the P6-A platform about 45 Mton CO_2 can be stored in total.

For the case of the step wise construction accounts that all starting points and assumptions as defined for the base case apply, except for the mentioned variables. The CAPEX for the step wise construction will be higher than the CAPEX for the base case, because of the additional costs for the procurement of the material in parts, the temporary facilities for the intermediate ending of the pipeline and the extra mobilization costs for the pipe laying vessels, etc. These additional costs should be paid back by the advantage that part of the expenditure can be made several years later than in the case the whole pipeline is constructed in one time.

An additional advantage of the stepwise construction is that the full size 36” pipeline will have sufficient capacity to transport considerable quantities of gaseous CO_2. This means that the point in time that dense phase CO_2should be supplied can be extended and that part of the depleted reservoirs might be prefilled with gaseous CO_2 without gasification and heating, thus saving on compression and heating costs.

Step wise scenario and scope

- Routing to be prepared for connection to future main clusters;
- Lay the first part of the 36” CCS trunk line to platform P18-A and connect by means of the 10” connection:
  - 36” trunk line from Maasvlakte N routed to a lay down area close to platform P18-A;
  - Installation of one branch-tee 36” x 10”;
  - 2 km 10” pipeline;
  - 10” riser to +6 m LAT;
  - Top side modifications main platform P18-A;
  - Fill the reservoirs connected to the P18-A (and P15) platform, possibly with gaseous CO_2;
- Lay the second part of the 36” CCS trunk line to platform P6-A and connect by means of the 10” connection:
  - Extend the 36” trunk line from P18-A routed to a lay down area close to platform P6-A;
  - Installation of one branch-tee 36” x 10”;
  - 10 km 10” pipeline;
  - 10” riser to +6 m LAT;
  - Top side modifications main platform P18-A;
  - Fill the reservoirs connected to the P6-A satellite, possibly with gaseous CO_2;
  - By means of the existing 20” pipeline between P6-A and L10-A in the start up phase possibly part of the field connected to L10-A can also already be prefilled with gaseous CO_2;
- Complete the 36” CCS trunk line to platform L10-A:
  - Extend the 36” trunk line from P6-A routed to a lay down area close to platform L10-A;
  - Connection to L10-A according original plan;
- Start of full rate CO_2 injection and storage.

Cost estimate P18-A variant

CAPEX overall stepwise construction to P18-A	**CAPEX**
First section 36” trunk line from Maasvlakte North to P18-A (20 km)	
Procurement of 36” and 10” pipe with external coating	52 M€
Laying and welding the pipe	13 M€
One T -branch 36”x10”	9 M€
One pipeline crossing	4 M€
Crossing the Eurogeul with 36” at -29 LAT	16 M€
Landfall	7 M€
Modification of P18-A (risers, manifolds, monitoring, control, heaters, etc.)	16 M€
Total CAPEX for connection to P18-A only	**117 M€**
Second section 36” trunk line from P18-A to P6-A (60 km)	
Procurement of 36” and 10” pipe with external coating	78 M€
Laying and welding the pipe	23 M€
One T -branch 36”x10”	11 M€
Pipeline crossing	17 M€
Modification of P6-A (risers, manifolds, monitoring, control, heaters, etc.)	16 M€
Total CAPEX for extension from P18-A to P6-A only	**145 M€**
Third section 36” trunk line from P6-A to L10-A (100 km)	
Procurement of 36” and 10” pipe with external coating	117 M€
Laying and welding the pipe	35 M€
One T -branch 36”x10”	11 M€
Pipeline crossings	26 M€
Modification of L10-A (risers, manifolds, monitoring, control, heaters, etc.)	16 M€
Total CAPEX for extension from P6-A to L10-A only	**205 M€**
Grand total stepwise construction 36” trunk line	**467 M€**

Table 6-7: Overall CAPEX variant stepwise construction

The operational costs for this variant can be derived from the OPEX of the base case as presented in sections 6.3.2 and 6.4.2 and consist of the OPEX for the P18-A satellite (estimated at about 5 M€ / yr) and the OPEX for the trunk line (X-Y-Z surveys of the pipeline estimated at 1 M€ / yr).

It should however be noted that both the CAPEX and OPEX for the P18-A variant in practice will be underestimated, as this will be the first offshore installation for full scale CO_2 injection and storage. Therefore no use can be made of the learning curve and this variant should therefore be considered more as a full scale demonstration project with the involved costs rather than a matured facility.

Advantages (compared to base case):

- Availability of end production reservoirs (2014 - 2016);
- CO_2 injection can be adjusted to CO_2 supply quantities (less than 5 Mton / yr);
- Shorter realization of the full route, since the Eurogeul crossing and landfall are by then existing;
- Creation of a demonstration facility and period for large scale CO_2 injection and storage.

Disadvantages (compared to base case):

- Three additional mobilization and demobilization of laying spread (4.8 M€ approx.);
- Two additional handlings by Lay vessel to recover and abandon the pipeline heads (13 M€ approx);
- Additional dewatering, gauge pigging and pressure test operations (additional costs approx 0.9 M€);
- CO_2 depressurization and cleaning (additional costs 0.2 M€);
- Market rates for pipe laying spread and delivery of pipe steel. Note: this could be positive as well as negative;
- Design onshore facilities to be adjusted to P18 reservoirs and capturing capacity
- Period of low-pressure filling will be shorter; overall, more heating will be required.

The above CAPEX for stepwise construction of the 36" trunk line of 467 million euro is substantial higher than in case the 36" trunk line would be laid in one go (380 M€) as presented in the base case in section 6.3.1. The price difference is caused by the required additional activities, spreading of the activities over several years and ineffectiveness during procurement. Moreover the later ordering of capital goods presents a risk for price increases, but this is not included in the above figures. The additional costs should be weighted against the early availability of the pipeline, the possibility for gaining expertise and above all the economic advantage of later cash expenditures.

6.6.2 Separate trunk lines from Maasvlakte and IJmuiden

A separate trunk line directly from IJmuiden connecting to the K7 / K8 cluster can offer advantages with respect to flexibility and scheduling of the pipeline construction. This alternative consist of the following main elements:

- A 36" trunk line from the Maasvlakte to L10-A;
- A 24" trunk line from IJmuiden to K7 / K8;
- A sub sea connection (not pigable) between both trunk lines at the crossing of the pipeline to increase flexibility.

Cost estimate separate trunk lines variant

Pipeline section	CAPEX
36" from Maasvlakte 1 north side to L10-A	380 M€
24" from IJmuiden to K8	272 M€
Subsea connection between 36" and 24" lines including remote operated valves	9 M€
10" pipeline from 36"x10" tab to P18-A	11 M€
Total CAPEX pipelines	**672 M€**

Table 6-8: Alternative CAPEX for new CO_2 trunk lines

The above CAPEX for the separate trunk lines of 672 million Euro is comparable with the cost of the integrated trunk lines of the base case as presented in section 6.3.1. This is caused by the fact that the common part of the 36" from Maasvlakte and 24" from IJmuiden is relatively short. Besides the overall length of 24" trunk line is about the same because in the base case anyway a 24" pipeline from L-10A to K7 / K8 is needed. Separate trunk lines seem therefore an attractive alternative, because separate trunk lines provide more flexibility, given that a connection is made between both trunk lines. Please note however that the accuracy of the cost estimate of this alterative is lower than that of the base case. When choosing this alternative a more thorough cost estimate and cost comparison is advised.

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8 TERMS AND ABBREVIATIONS

bcm	Billion cubic meter at ISO conditions (10^9 Nm^3 at 0 ºC and 1.013 bar) 1 bcm natural gas at reservoir conditions equals about 2.5 Mton CO_2 storage
CCS	Carbon Capture and Storage
CH_4	Methane, the main constituent of natural gas
CO_2	Carbon dioxide
Critical point or critical state	The conditions (temperature, pressure), where distinct gas and liquid phases are no longer distinguishable. A super critical substance has for instance the density of a liquid but the flowing properties of a gas
CS	Carbon steel
EOR / EGR	Enhanced Oil Recovery / Enhanced Gas Recovery
ETS	European Emission trading Scheme for greenhouse gases
FWHP	Flowing Well Head Pressure, i.e. the pressure at the well head under flowing (producing) conditions
Gas platforms	Production platforms (satellites) treatment platforms
GHG	Greenhouse Gas, the group of gas that contribute to the global warming effect, including $CO_{2,}$, CH_4, N_2O and SF_6
Gton	Giga ton (one billion kilogram)
Injectivity or injection capacity	Permeability thickness (kh) expressed in D. m (Darcy meter).
Interfield pipelines	Pipelines to transport gas from satellite production platforms to central treatment platforms
Joule –Thomson effect (J – T)	The physical effect that most components show that when the pressure is decreased (isenthalpic, i.e. no labour extraction) the temperature decreases
MEA	Ministry of Economic Affairs
Mothballing	Preserving installations in good conditions during a longer period of being out of production
Mton	Mega ton (one million kilogram)
NCS	Netherlands Continental Shelf
NGT	Noord Gas Transportleiding transporting high caloric gas from the north western part of the NCS, landfall in Uithuizermeden (Groningen)
NOGAT	Noordelijke Offshore Gastransportleiding (NOGAT) transporting high caloric gas from the north eastern part of the NCS, landfall in Den Helder
NOGEPA	Netherlands Oil and Gas Exploration and Production Association, the branch organization of onshore and offshore E&P companies
OAS	Offshore Access System, a system to allow vessels to moor at offshore platform. Both the platform and vessel should be specially equipped for OAS
ppm	Part per million
RCI	Rotterdam Climate Initiative
SS	Stainless steel (alloyed, corrosion resistant steel)
Trunk line	Main transport pipeline for transport of gas from central treatment platforms to shore
WGT	West Gas Transportleiding transporting high caloric gas from the central western part of the NCS, landfall in Den Helder