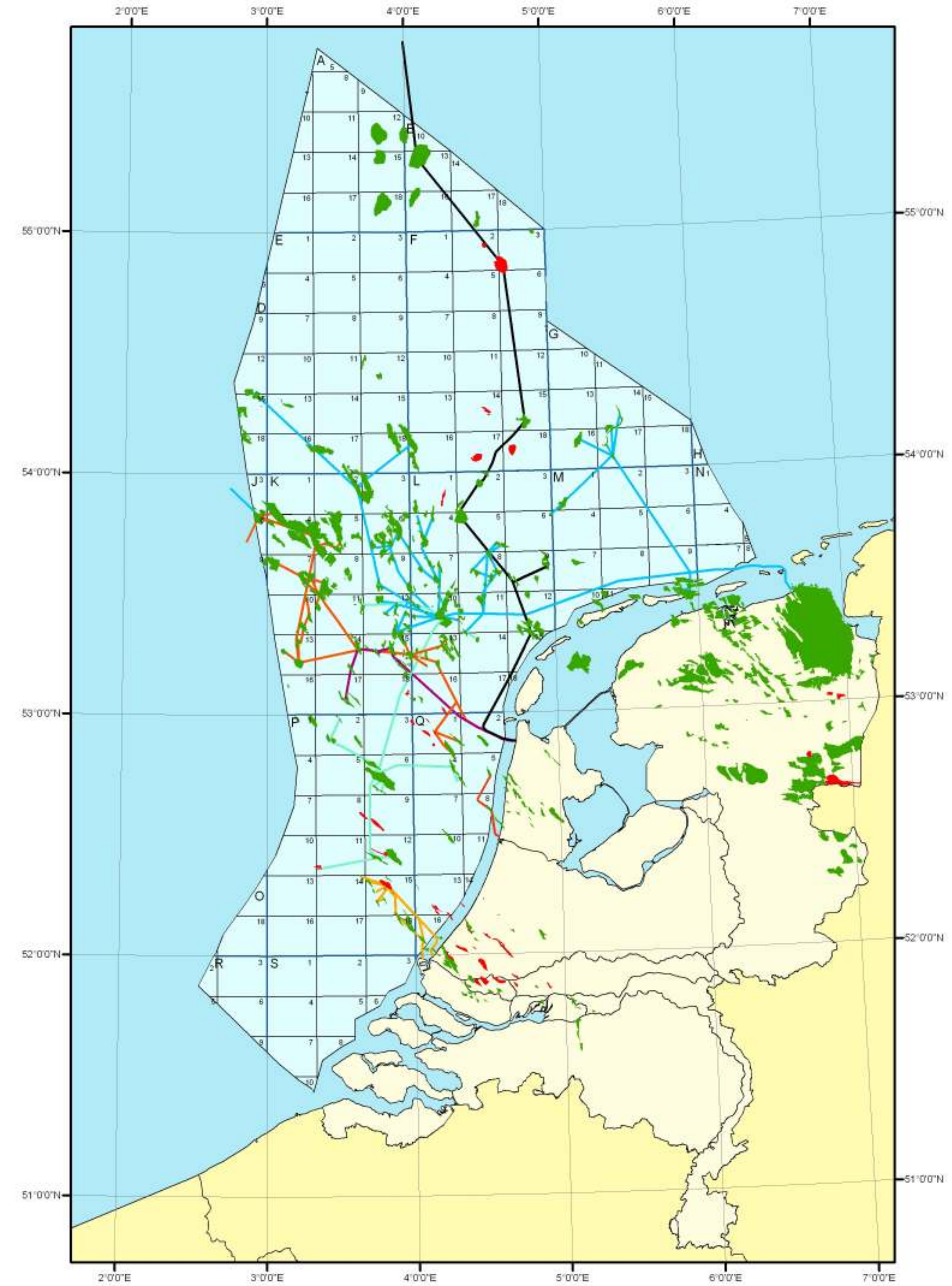
Potential for CO_2 storage in depleted gas fields on the Dutch Continental Shelf

Phase 1: Technical assessment



Netherlands Oil and Gas Exploration and Production Association

Ministry of Economic Affairs

COLOPHON

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

Phase 1: Technical assessment

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EXECUTIVE SUMMARY

General

Global warming is considered to be a major threat for the worldwide environment. By the efforts of the IPCC (International Panel on Climate Change) and others, global warming and the adverse effects on the environment are now considered as proven and a broad spread support is developing that far reaching measures will be necessary to at least limit the global warming effect. This requires a transition towards a sustainable energy supply that depends less on fossil fuels. In the period of transition however extensive efforts are required to cope with the effects, including measures to mitigate the effects of global warming and sea level rise.

Reduction of Greenhouse Gas Emissions (GHG) should primarily be accomplished by using sustainable energy sources and energy conservation. However to bridge the period to sustainability, a portfolio of mitigating and adaptation measures is required. Currently Carbon dioxide Capture and Storage (CCS) is considered to be one of the most promising and cost effective options for the transition period, as recently elaborated in an extensive IPCC report. 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. The capture and storage technologies however require a considerable amount of energy, resulting in an overall lower energy efficiency of e.g. power plants that have implemented CCS.

In the Netherlands excellent opportunities seem to be present in the form of a concentration of major CO_2 emission sources in the vicinity of gas reservoirs, that will get depleted in ten to twenty years time. 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. Moreover, the Dutch E&P industry sees opportunities to extend the lifetime of their gas reservoirs by employing them for CO_2 storage. Currently worldwide a few demonstration projects are running, among others the K12-B project of Gaz de France. Before CCS can be applied at large-scale, more knowledge is required on the technology, safety, long term behavior, storage capacity, suitability of reservoirs, etc. Also the economical aspects should be investigated because CCS is currently not yet profitable.

The aim and scope of the study

To investigate the opportunities for CO_2 storage in the Dutch sector of the North sea, the Netherlands Oil and Gas Exploration and Production Association (NOGEPA) together with the Ministry of Economic Affairs of the Netherlands (MEA) have initiated a study to investigate in depth the offshore CO_2 storage capacity including the time frame in which this capacity (reservoirs, installations and pipelines) becomes available. The required study is split in 2 phases. The first phase focuses on technical details of gas reservoirs, installations and pipelines and the second phase on the development of storage scenario's and the cost aspects based on the results of the first study phase. The first phase of the study has been executed in cooperation between DHV BV, unit Industrial Safety and Environment, and TNO's Advisory Group for the MEA.

The final goal of the study is to give detailed insight into the opportunities of CO_2 storage on the DCS. This report of the first phase of the study therefore comprises the detailed investigations into:

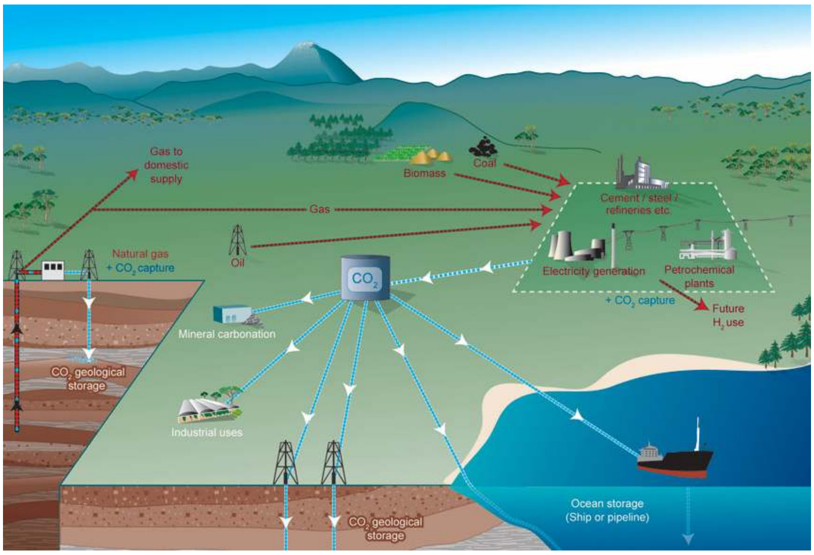
1. The suitability of existing offshore gas reservoirs for CO_2 storage;
2. The capacity, i.e. how much CO_2 can be stored in depleted gas reservoirs and at what rate;
3. The availability and suitability of the existing infrastructure, i.e. which reservoirs, installations and pipelines can be used for CO_2 transport and storage and when they will become available;
4. 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;
5. The transport requirements and options, i.e. at what pressure can (should) the CO_2 be transported and what are requirements with respect to composition and purity:

6 Possible problems or showstoppers, that may hamper or even block CO_2 storage in certain fields.

In the study attention is given to gas reservoirs in the deep subsurface and the gas production installations, that might be reused for CO_2 transport and injection. In total about 150 developed gas fields on the DCS have been assessed.

The data for the assessment were primarily extracted from available data sources, but checked and where necessary completed by the operators. The latter was executed by the researchers through questionnaires and interviews. Next the collected data were assessed in order to enable a well founded judgment on the potential for offshore CO_2 storage. Data in the report are published only in an aggregated form to safeguard confidentiality.

The concept of Carbon Capture and Storage



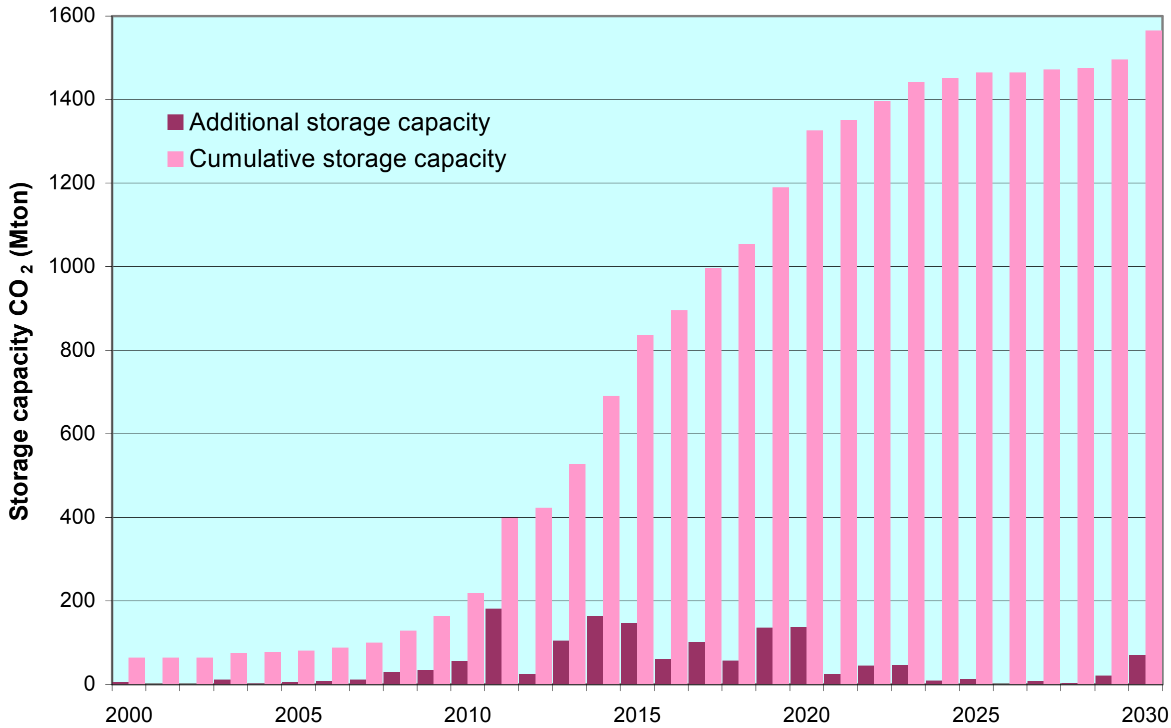
Currently it is foreseen that for large scale CCS the CO_2 is captured and treated up to specification (> 95% CO_2) at the major sources. Suitable sources include power stations, refineries, steel works, etc. Next the CO_2 should be compressed and delivered to a CO_2 transport grid. Short haul CO_2 transport to onshore and near shore locations can take place in the gaseous state, but for long haul transport the dense phase is preferred. Liquefaction can take place at the CO_2 sources or at a central 'landfall' terminal.
For large-scale offshore storage, the CO_2 will be transported via a trunk line and dedicated interfield pipelines to the injection platforms. Here, possibly after heating or boosting, the CO_2 is injected through wells into the depleted gas fields. On the DCS these fields generally are at a depth of 2 to 4 km. When a reservoir is filled, the wells will be sealed.
As gas production through the existing offshore gas transport trunk lines may last up to 2030 or later, it will be required to lay dedicated CO_2 trunk lines. The advantage of new CO_2 pipelines is that the lines can be designed at the optimum conditions for CO_2 transport and can have an optimum routing from sources to sinks.

Expectations are that on the short and medium term up to 2020 merely pilot and demonstration projects will be executed, to build knowledge and show the large-scale feasibility. On the long term, after 2020, CCS is expected to be an proven technology, that operates on a commercial basis, whereby the major funding will be coming from the emission trading system. As the transition to a sustainable worldwide energy supply may last up to at least 2050 but possibly up to 2100, CCS will be applied for several decades. In this study tentatively is assumed that annually about 20 Mton CO_2 will be stored, the equivalent of 4 average size coal fired power stations, over some 40 years.

Wells and reservoirs

Based on the survey it has been assessed, that the **theoretical** storage capacity on the DCS is 1566 Mton[1] CO_2 in 153 fields (according to 2008 estimates and assuming injection up to initial pressure). The distribution of the theoretical CO_2 storage capacity over field sizes is shown in the table. It appears that the 21 largest fields may contain about half of the total storage capacity and will be the key fields to develop storage clusters which may be operated as one storage system. The fields smaller than 2.5 Mton may be too small for efficient storage.

Size category (Mton CO_2)	No. of fields	Storage capacity (Mton CO_2)
< 2.5	46	61
2.5 – 5	28	103
5 - 10	31	226
10 – 20	27	354
20 - 50	19	597
> 50	2	224
Total	**153**	**1566**



Another criterion to judge the suitable of a depleted gas field for CO_2 storage is the injectivity, i.e. how well the injected CO_2 will flow into the reservoir. This depends on the permeability and the thickness of the reservoir. About half of the assessed fields have a fair to good injectivity.

Applying cut off criteria for minimal storage capacity (> 2.5 Mton) and injectivity (> 0.25 Dm) leaves 55 of the assessed fields as suitable for storage. The effective storage capacity in these fields amounts to 918 Mton as shown in the opposite table.

	Number of fields	Storage (Mton)
Theoretical Storage capacity	153	1566
Injectivity cut off	-74	-580
Storage cut off	-46	-61
Abandoned fields	-20	-98
Total storage below cut offs	98	-648
Effective Storage capacity	55	918

1 Although scientifically spoken 'billion tons' (Gton) would have been more appropriate to express the storage capacity, the authors have chosen to use 'million tons' (Mton) to align with previous studies.

Most wells seem to be suitable for CO_2 injection with respect to rating, material, etc. Some wells are reported to have been sheared off by plastic salt layers, which may be a showstopper to use the particular field for CO_2 storage. A point of attention is the fact that cement used for plugging appears to degrade in time. However, cap rocks with plastic behavior (salt and some shale layers) have 'self healing' properties, that can possibly repair conduits through the cap rock.

Drilling new wells in depleted reservoirs is technically complicated due to the low backpressure and costly. The reuse of existing wells is therefore preferred.

Platforms and pipelines

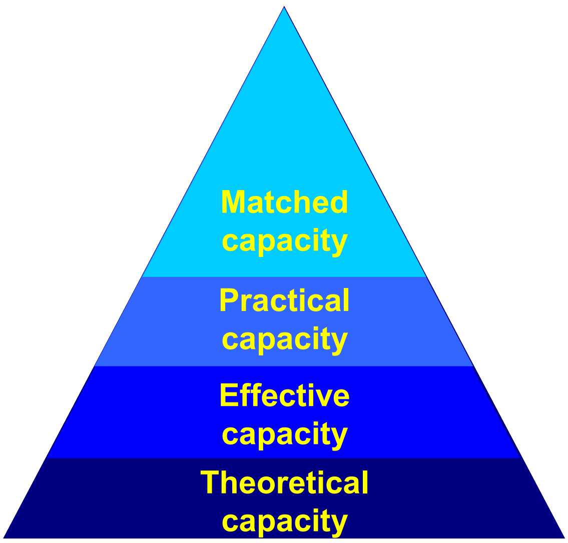
The operators do not foresee major technical objections to use the existing pipelines and platforms for CO_2 transport and injection. To preserve the infrastructure for CO_2 storage, maintenance of (mothballed) platforms is needed and pipelines should be re-certified. As long as the properties of the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

From the survey it follows that it 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 CCS will be costly, Moreover the OSPAR Convention requires that mining installations are removed within two years after cessation of the gas production. Renewed construction of platforms and re-entering wells is technically complicated and costly. It is therefore recommended that mining installations, that appear to be suitable for CO_2 storage, are conserved. Regulatory conditions are to be adapted accordingly.

The major trunk lines may come available too late for CO_2 storage, as this is determined by the last producing gas fields connected to the pipeline. These fields as a matter of fact tend to be the fields at the end of the trunk lines, as those fields were last to be taken into production. Moreover, some trunk lines may be used as trans-boundary gas connectors and will thus do not come available for CO_2 transport at all. For fields that are available earlier than the trunk line a trade off must be made between constructing a new pipeline or to mothball the platform and wells for a longer period to exploit the field when the trunk line becomes available.

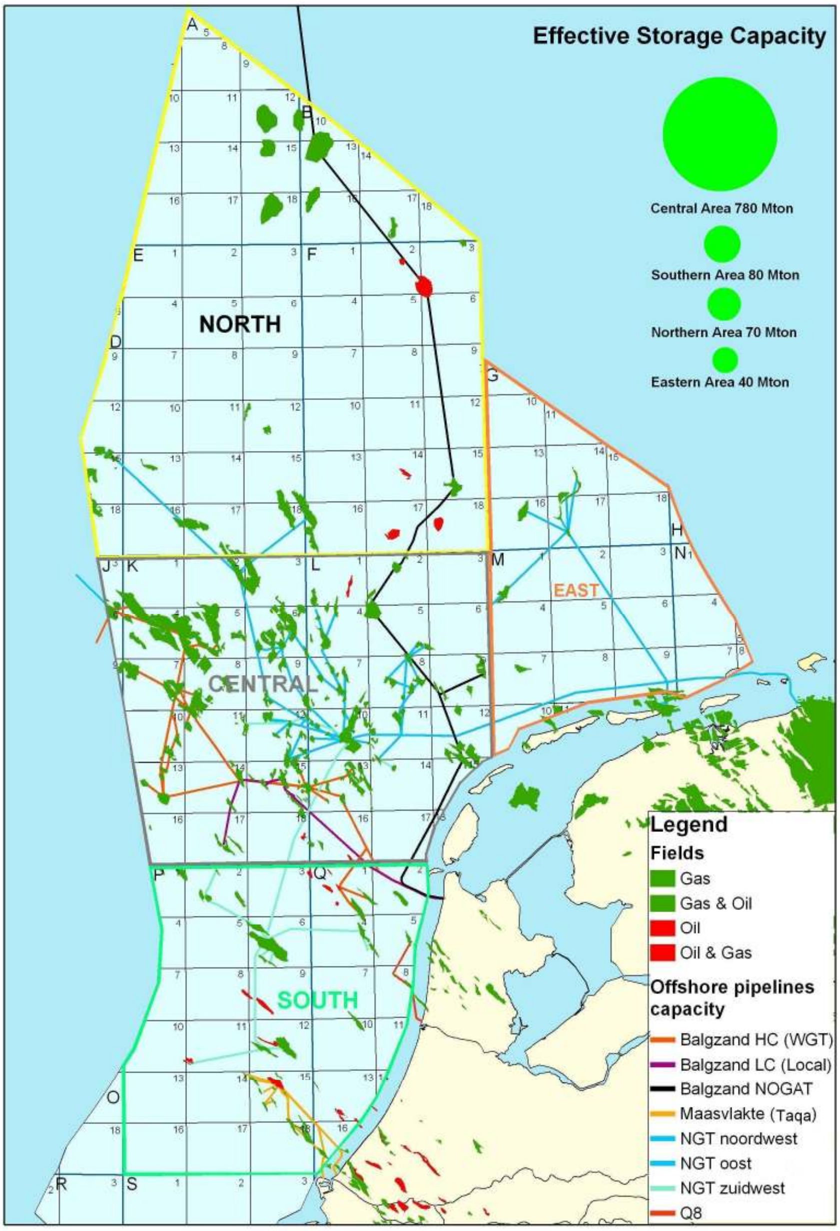
The pressure rating of existing trunk lines ranges from 100 to 130 bar, which may require booster pumps to increase the pipeline capacity and/or to enable tail end filling at an acceptable rate. When dedicated CO_2 pipelines are laid it is possible to specify a higher design pressure (up to about 200 bar) to enable tail end injection without booster pumps and to decrease the pipeline size. The optimum design pressure will be determined by several technical and economic aspects and falls outside the scope of this study. Furthermore it may be required to heat the CO_2 prior to injection in the reservoir to prevent well or reservoir problems. A special point of attention is the energy supply for the heaters and booster pumps at the platforms, as in many cases natural gas will be no longer available on site.

Matched Capacity



In analogy to the gas industry, the Carbon Sequestration Leadership Forum (CSLF) has introduced a storage capacity classification scheme [CSLF 2007]. The scheme introduces the concept of 'matched capacity', that stresses the important link between supply and demand in the CCS chain of capture, transport, injection and storage.

In this study, the CSLF scheme it is put at the very heart of the analysis. Matched capacity has been considered in the context of large scale offshore sequestration, i.e. a rate of 20 Mton/yr (4 power plants) over several decades, starting from 2020 / 2025. In practical terms, clusters of 200 Mton storage capacity are needed to accommodate the CO_2 supply from one coal fired power plant (40 years lifecycle with an annual production of 5 Mton CO_2). Geographically, compact clusters of this size can only be assembled from depleted gas fields in the central offshore K and L quadrants.



As an example a Matched Capacity Case has been evaluated: The output of one large CO_2 point source from the Rotterdam area has been linked to a cluster of gas fields in the K12 / K14 / K15 area in the central offshore. This case is considered to be representative for other clusters in the central offshore K- and L quadrants. It is concluded, that 4 of these 200 Mton clusters can technically be assembled in that area.

To transport the CO_2 from the Rotterdam area to the K and L blocks, use can be made of either a combination of several existing and new pipelines or a complete new trunk line. The assessment shows, that none of the investigated combinations with existing pipelines have sufficient capacity to transport 20 Mton CO_2 per year. Moreover the existing major trunk lines will probable only become available after 2025 – 2030, while large scale CO_2 transport capacity will be needed from 2020 - 2025. The construction of a complete new trunk line also offers the possibility to design it at the optimum design pressure and size. The matched capacity case has explicitly been assessed fro the assumed capacity of 20 Mton CO_2 per year over several decades. This does not mean that smaller clusters do not offer opportunities for CO_2 storage and just for smaller rates existing gas pipelines can offer good transport facilities. Both aspects require further detailed assessment, based on the CO_2 supply from specific sources.

Summarizing, it may be stated that technically the net CO_2 storage capacity on the DCS amounts to somewhat over 900 Mton. Accounting for early removal of platforms and imperfections between demand and supply the actual available capacity may be considerably lower. The 21 largest fields may contain somewhat more than half of the total storage capacity (and will be the core fields to develop storage clusters. According to present day plans, all currently know offshore fields are expected to be depleted before 2030.

Building new platforms and drilling new wells in depleted reservoir is costly and technically complicated. Therefore reuse of existing wells is preferred wherever feasible. Reuse of existing gas transport pipelines for CO_2 transport may be only possible in a limited number of cases as most gas pipelines will be occupied for gas transport for a longer period or have insufficient capacity.

The elaborated example Matched Capacity Case shows that in order to store annually a rate of 20 Mton from sources in the Rotterdam area a number of 200 Mton reservoir clusters is required. Four of these 200 Mton clusters can technically be assembled in the central K and L quadrants on the DCS. To handle the full rate of 20 Mton CO_2 per year a complete new trunk line may be required in time.

It is recommended to assess the costs and economic considerations in the next study phase, whereby several transport and storage scenarios can be evaluated. Also a further elaboration into the reservoir choice and behavior is advised, including an detailed assessment of the wells and any constraints thereof. /the results of this and the next study phase can be used to prepare a ‘road map’ for the future offshore CO_2 storage.

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1 INTRODUCTION

Global warming is considered to be a major threat for the worldwide environment. By the efforts of the IPCC (International Panel on Climate Change) and others, global warming and the adverse effects on the environment are now considered as proven and are creating increasing awareness. Also thanks to Al Gore, by now a broad spread urge is developing that far reaching measures will be necessary to at least limit the global warming effect to about 2 ºC. This requires a transition towards a sustainable energy supply, that does not depend on fossil fuels anymore. In the period of transition however extensive efforts are required to cope with the effects, including measures to mitigate the effects of global warming and sea level rise.

First and for all, reduction of Greenhouse Gas Emissions (GHG) should be accomplished by the use of sustainable energy sources and energy conservation. However, to bridge the period to sustainability, additional measures are required. Currently Carbon dioxide Capture and Storage (CCS) is considered to be one of the most promising and cost effective options for the transition period, as recently elaborated in an extensive IPCC Special report (IPPC 2005). 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 seem to be present in depleted gas reservoirs. Geologically based provisional estimates (EnergieNed 2007) indicate, that in the subsurface of the Netherlands and the Dutch Continental Shelf (DCS) room is available for about 11 000 Mton CO_2. The storage potential mainly is in depleted gas fields: the Groningen field (7 350 Mton), the other onshore fields (1 600 Mton) and offshore fields (1 150 Mton), and for the remainder in depleted oil fields (40 Mton), deep seated coal beds (400 Mton) and aquifers (720 Mton). 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 a few pilot and demonstration projects are running, among which the K12-B project of Gaz de France. However, before CCS can be implemented demonstration projects are required to demonstrate the large-scale aspects of capture, transport and storage. Such demonstration will not only prove the technical feasibility, but also will point out possibilities for economic optimization. As CCS currently is not profitable yet, the demonstration phase will require financial support.

Above mentioned figures are based on public data, which implies that several assumptions are made to calculate the theoretical storage capacity. Moreover, to estimate the injection capacity no proper information was available. To bridge this gap, NOGEPA and the Ministry of Economic Affairs (MEA), each from their own responsibility, embarked on a study to match the available storage and injection capacity for Dutch offshore gas fields (based on propriety data supplied by the operators) and the CO_2 emissions in the Netherlands. Eventually these two studies were integrated. The reason to focus on depleted gas fields is based on the fact that they have many advantages over the other geological opportunities: they comprise most of the storage capacity, their location and reservoir behavior is well known from many years of gas production and they will become available in due time.

The study consists of two phases. The first phase focuses on technical details of gas reservoirs, installations and pipelines, while the second phase concerns the development of storage scenario's and the cost aspects based on the results of the first study phase.

The first phase of the study has been executed in cooperation between DHV BV, unit Industrial Safety and Environment, and TNO's Advisory Group for the MEA, thus making use of the combined fields of expertise of TNO and DHV.

The final goal of the study is to provide NOGEPA, the Dutch E&P operators and the Ministries of Economic Affairs and of Environment with detailed insight in the opportunities of CO_2 storage on the DCS. This report of the first phase of the study therefore comprises the detailed investigations into:

- 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 transport requirements and options, i.e. at what pressure can (should) the CO_2 be transported and what are requirements with respect to composition and purity:
- Possible problems or showstoppers, that may hamper or even block CO_2 storage in certain fields or areas.

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 briefly enters into the exploration and production of natural gas in the Netherlands. In sections 5 and 6, respectively, the results of the sub-surface part (reservoirs and wells) and the surface part (platforms and pipelines) are discussed. In section 7 the match between supply and demand of CO_2 is assessed. Finally in section 8 the CO_2 are discussed in relation to the transport and injection phenomena Detailed background information is included in the appendices.

Although scientifically spoken ‘billion tons’ (Gton) would have been more appropriate to express the storage capacity, the authors have chosen to use ‘million tons’ (Mton) throughout the report to align with previous studies.

2 MAIN CONCLUSIONS AND RECOMMENDATIONS

2.1 Sub surface aspects (well and reservoirs)

Fields

1 Based on the survey it is assessed that the theoretical storage capacity at the NCS is 1566 Mton CO_2 in 153 fields (according to 2008 estimates and assuming injection up to initial pressure). The size distribution of theoretical CO_2 storage capacity of fields is given in the table below. Fields smaller than 2.5 Mton may be too small for efficient storage.

Size category (Mton CO_2)	No. of fields	Theoretical CO_2 capacity (Mton CO_2)
< 2.5	46	61
2.5 - 5	28	103
5 – 10	31	226
10 – 20	27	354
20 - 50	19	597
> 50	2	224
Total	**153**	**1566**

2 The 21 largest fields may contain somewhat more than half of the total storage capacity (821 Mton) and will be the core fields to develop storage clusters, which may be operated as one storage system.

3 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. These cut off criteria do overlap. The effective storage capacity is 918 Mton.

4 The injectivity cut off, i.e. the degree how well the injected CO_2 will flow into the reservoir, depends on the permeability of the reservoir and the thickness of the reservoir layer and is expressed as kh. The injectivity cut off has been set at kh = 0.25 Dm. About 50% of the assessed fields have a fair to good injectivity;

5 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.

6 20 fields have been abandoned; they represent a theoretical storage capacity of 98 Mton.

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

Wells

8 389 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;

9 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.

10 A point of attention is the fact that cement used for e.g. plugging appears to degrade in time. Plastic cap rocks (salt and some shale layers) are favorable with this respect as they tend to be ‘self healing’. Also care should be given to abandoned well in currently producing reservoirs.

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

2.2 Surface aspects (platforms and pipelines)

12 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;

13 Transport of CO_2 in the dense phase is preferred in order to optimally use the available pipeline capacity and to prevent the need for injection compression at all injection platforms. For dense phase transport a minimum CO_2 pressure of about 85 bar is required, while non-condensables shall be less than 4%. To prevent corrosion, the water content shall be less than 500 ppm;

14 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;

15 The pressure rating of existing trunk lines ranges from 100 to 130 bar, which may require booster pumps to increase the pipeline capacity and/or to enable tail end filling at an acceptable rate. When dedicated CO_2 pipelines are laid it is possible to specify a higher design pressure (up to about 200 bar) to enable tail end injection without booster pumps and/or to decrease the pipeline size. The optimum design pressure will be determined on several technical and economic aspects and falls outside the scope of this study;

16 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 will be quite costly, Moreover the OSPAR Convention requires that mining installations are removed within two years after cessation of the gas production. Renewed construction of platforms and re-entering wells is technically complicated and costly. It is therefore recommended that mining installations, that are appear to be fit for CO_2 storage, should be conserved by setting up the necessary conditions;

17 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. Some trunk lines moreover may be used for trans boundary gas connectors and will thus do not come available for CO_2 transport at all. For fields that are available earlier than the trunk line a trade off must be made between constructing a new pipeline or to mothball the platform and wells for a longer period to exploit the field when the trunk line becomes available;

18 A major uncertainty is the fact that by the increasing energy demand and rising gas prices reservoirs can be exploited economically longer. This prolonged tail end gas production will delay the availability of reservoirs for CO_2 storage;

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

2.3 Matched capacity

20 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 and L quadrants 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;

21 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 may be required.

2.4 Recommendations

1 It is recommended to assess the costs (CAPEX en OPEX) and economic considerations in the next study phase, whereby several transport and storage scenarios can be evaluated;

2 Also a detailed assessment of the reservoir choice and behavior is advised, including an detailed assessment of the wells and any constraints thereof. This should include a assessment of abandoned well is currently producing fields and the possible impact of these wells on the effective storage capacity.

3 A further elaboration the concept of matched capacity will yield a better understanding of the possibilities and constraints of CO_2 storage in time and can results in a 'road map' for the future offshore CO_2 storage;

4 Based on such a road map also scenarios can be developed for transport systems, including a appraisal of reuse of pipelines versus new ones and the preferred diameter, routing, rating, etc. for new pipelines.

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 objective of this project is therefore:

> Provide detailed data on the CO_2 storage potential on the DCS by conducting a survey of all individual offshore reservoirs, wells, platforms and pipelines that might be used for offshore CO_2 storage.

In order to reach this objective it is required to collect specific data on the suitability and CO_2 storage capacity of the gas fields, the availability of platforms and finally the point in time when the reservoirs, installations and pipelines can be expected to become available for CO_2 storage. This last point should answer the question if and when the existing gas transport pipelines (interfield and trunk lines) can be used to transport the CO_2 to the reservoirs. The study is aimed at CO_2 storage in depleted gas reservoirs and the level of detail is chosen to comply with the goals of this phase of the study. Of course, making a detailed storage plan would require even more detailed and location specific information. The scope of work includes the following aspects:

1. **Reservoir and well information, including their suitability for CO_2 injection and storage:** Assessment of available gas reservoirs on the DCS, including their capacity, number of available wells, reservoir properties (e.g. injectivity) and the timing that the fields are expected to become depleted; The question whether a reservoir is suited for CO_2 storage concerns both reservoir and well properties;
2. **Mining installations:** Assessment of the current gas production installations, their suitability for CO_2 injection and the timing that they are expected to be abandoned;
3. **Pipeline systems:** Assessment of the current offshore pipelines (both interfield and trunk lines), their suitability for CO_2 transport (e.g. pressure rating, capacity, material properties) and the timing that they are expected to be no longer needed for gas transport;
4. **Pipeline pressure:** Assessment of the optimum required pipeline pressure for CO_2 transport and injection. For the existing piping systems the degree of freedom is limited to the design rating off the pipelines, for new systems the pipelines can be designed at the optimum transport pressure;
5. **Planning considerations:** High level assessment indicating when reservoirs, installations and pipelines may become available for CO_2 storage and how this fits with the need and planning for CO_2 storage. This will be detailed out in the second phase.

This studies aims primarily at the available storage capacity. Were applicable potential risks have been identified, but this study explicitly does not aim at risks nor at the effects thereof on the available storage capacity nor at people, nature or environment.

3.2 Information

From the three decades of natural gas production on the DCS, 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:

- The TNO DINO database, with data on the Dutch onshore and offshore gas and oil reservoirs. Although parts of the information in this database are confidential, the involved parties (MEA and E&P operators) have agreed to use these data, but present the results in an aggregated and anonymous form, where appropriate;
- Information, acquired through a questionnaire from the offshore E&P operators concerning the suitability of their reservoirs and (technical) data on their platforms and pipelines.
- Information in the operator's Company Environmental Plans, especially with respect to information concerning the surface infrastructure and expected production end dates;

- In-house expertise at DHV and TNO;
- Information on the Dutch Oil and Gas portal www.nlog.nl .

Furthermore various other information sources on CCS were used for this study.

Eight operators with offshore production assets (all members of NOGEPA) and NOGEPA have cooperated in this study, namely:

- Nederlandse Aardolie Maatschappij (NAM)
- Total Exploration and Production Nederland B.V.
- Gaz de France Production Nederland B.V.
- Wintershall Noordzee B.V.
- Chevron Nederland B.V.
- PetroCanada Nederland B.V.
- TAQA Energy B.V.
- Venture Production Nederland BV

3.3 Project approach

The study was directed at offshore gas reservoirs[2] that are or have been producing, as these fields offer the best opportunities for CO_2 storage. In the project, the following activities have been carried out:

Activity 1: Survey of the capacity and suitability of offshore reservoirs and wells for CO_2 storage
Currently on the DCS severable hundreds gas fields are identified of which about 150 have been developed. Most of the developed reservoirs are still in production, but the production of a few dozens of fields has already been stopped and platforms at those fields have been partially removed. For this study only information was collected that is considered essential to answer questions on the capacity and suitability of reservoirs for CO_2 storage. Most information, including reservoir properties and capacity, number of wells, etc. was extracted from the TNO DINO database and missing data were supplied by the operators. In order to collect the essential data from the operators in consultation with the working group a questionnaire was developed and interviews were held. The questionnaires were 'pre'-filled with available information by TNO / DHV to minimize the work load for the operators.

Activity 2: Survey of the suitability and availability of installations and pipelines
On the DCS dozens of gas production installations are present: (central) treatment platforms, satellite platforms and sub-sea completions. On the main platforms the produced gas is dried (removal of water) and where necessary compressed. The produced gas and condensate is then transported to shore by a system of pipelines, consisting of trunk lines and dedicated interfield lines that connect the various installations to the trunk lines. The majority of the gas is transported through the main gas transport lines of the West Gas Transportleiding (WGT), the Noord Gas Transportleiding (NGT) and the Noordelijke Offshore Gastransportleiding (NOGAT). Onshore the gas and condensate from the trunk lines is treated and the natural gas is then delivered to the national grid of Gasunie Transport Services. In addition, gas is transported to shore by dedicated pipelines, e.g. from K15 (the LoCal pipeline), Q8 and P15 blocks. Reusing this infrastructure can offer big economic benefits, given that the installations are technically suitable for CO_2 handling and that they are timely available.

The assessment of the suitability and availability was based on public information sources, questionnaires and interviews with the offshore active operators. Combined with technical and physical requirements the transport capacity of the pipelines could been assessed. A schematic overview of the

2 Depleted oil reservoirs on the DCS might also be used for CO_2 storage, but they are excluded in this study because of their limited storage capacity. Furthermore, deep coal layers and aquifers might also be used for storage, but these options have been kept to be outside the scope of this project because their practical use is very uncertain, particularly offshore.

surveyed data in activities 1 and 2 is included in appendix 4. The economic evaluation is to be dealt with in the next project phase.

Activity 3: Assessment of the optimum pipeline pressure for CO_2 transport

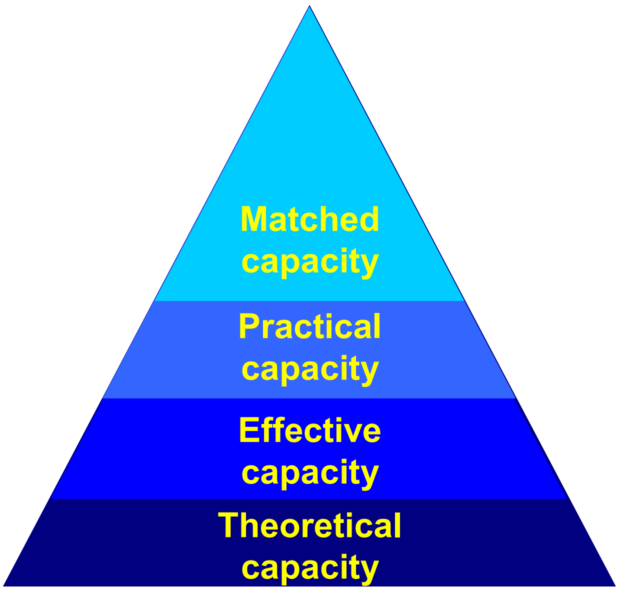
At the major industrial sources onshore CO_2 is generally released in a very diluted form at almost atmospheric pressure. Capturing facilities are therefore necessary to concentrate and purify the CO_2 to the required transport and injection specification.

To transport the captured CO_2 from the sources (e.g. power stations) to the sinks (i.e. depleted gas reservoirs) several options are possible, including transport in the dense or gaseous phase, transport pressure levels, use of booster stations, etc. Based on the boundary conditions of the existing gas infrastructure and technical considerations the optimum pipeline pressure for CO_2 transport could be assessed. Hereby two cases were considered, namely 1) transport through existing pipelines, whereby the maximum pressure generally is limited to about 100 - 130 bar and 2) transport through new dedicated pipelines, whereby higher pressures may be applied.

Based on a literature survey also the generally accepted composition of the supplied CO_2 was assessed, considering the demands of the transport system, mining installations, wells and reservoirs.

Activity 4: Matched capacity assessment

In analogy to the gas industry, the Carbon Sequestration Leadership Forum (CSLF) has introduced a storage capacity classification scheme [CSLF 2007]. The scheme introduces the concept of 'matched capacity', that stresses the important link between supply and demand in the CCS chain of capture, transport, injection and storage. In this study, the CSLF scheme it is put at the very heart of the analysis.



The CSLF classification scheme entails the following steps:

- Theoretical capacity : Filling all available pore space, only physical limits are taken into account;
- Effective capacity : Applying geological and engineering constraints / cut offs;
- Practical capacity : Applying other – indirect – constraints, e.g. of techno-economic or legal nature;
- Matched capacity : Matching sources and sinks in terms of volumes and rates.

4 OVERVIEW OF THE DUTCH OFFSHORE GAS PRODUCTION

The exploration and production of natural gas in the Netherlands was triggered by the discovery of the giant Groningen gas field in 1959, almost 50 years ago. After the opening of the Dutch Continental Shelf (DCS) for exploration in 1968, a recoverable volume of around 200 bcm was discovered before offshore production actually started in 1975. Production gradually increased until 1995, when the offshore production rate reached around 25 bcm per year. Over this period, the volume of remaining reserves was maintained between 250 and 360 bcm due to new discoveries and field revisions. Since 1998 the remaining reserves are decreasing.

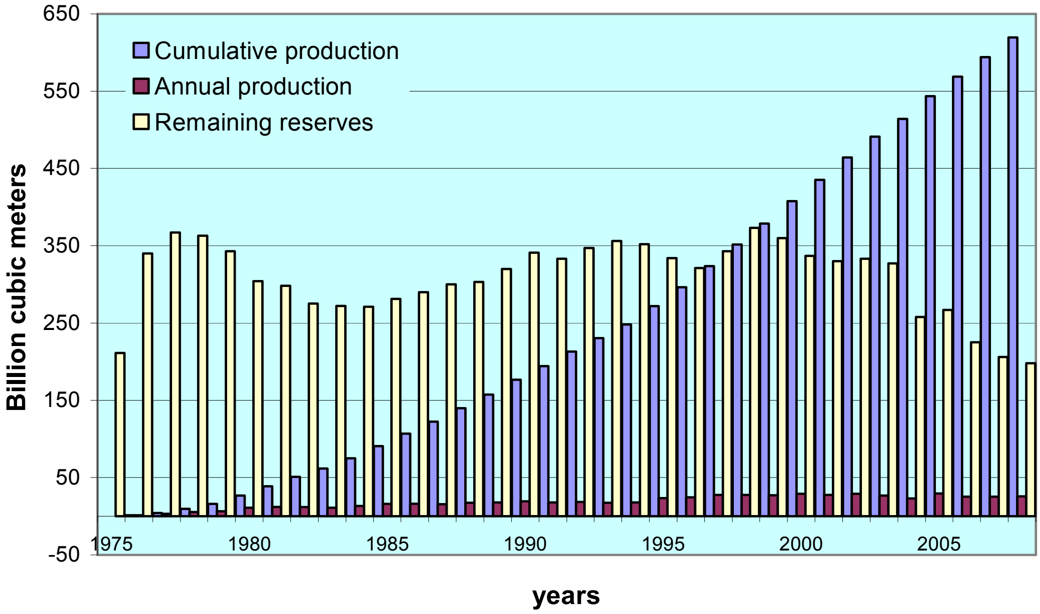


Figure 4-1 Reserves and production of natural gas on the Dutch Continental Shelf

Currently over 150 gas fields have been developed on the DCS. Most of the developed reservoirs are still in production, but at 34 gas fields the gas production already has (temporarily) ceased and at some of those fields platforms have been (partially) removed.

The Netherlands portfolio of natural gas assets has become mature by now: many fields are in decline and reserves additions from exploration decrease. Indeed, the total production rate of the onshore and offshore small fields has come off from a plateau rate of around 45 bcm / year and is expected to further decline over the coming years. Figure 4-2, shows the annual gas production in the Netherlands from 2000 onwards and the forecast for the next 25 years as of 2008. From discovered fields (excluding the Groningen field) some 300 bcm will be produced in the next 25 years. Production from future discoveries is estimated to be in the order of 100 bcm in total.

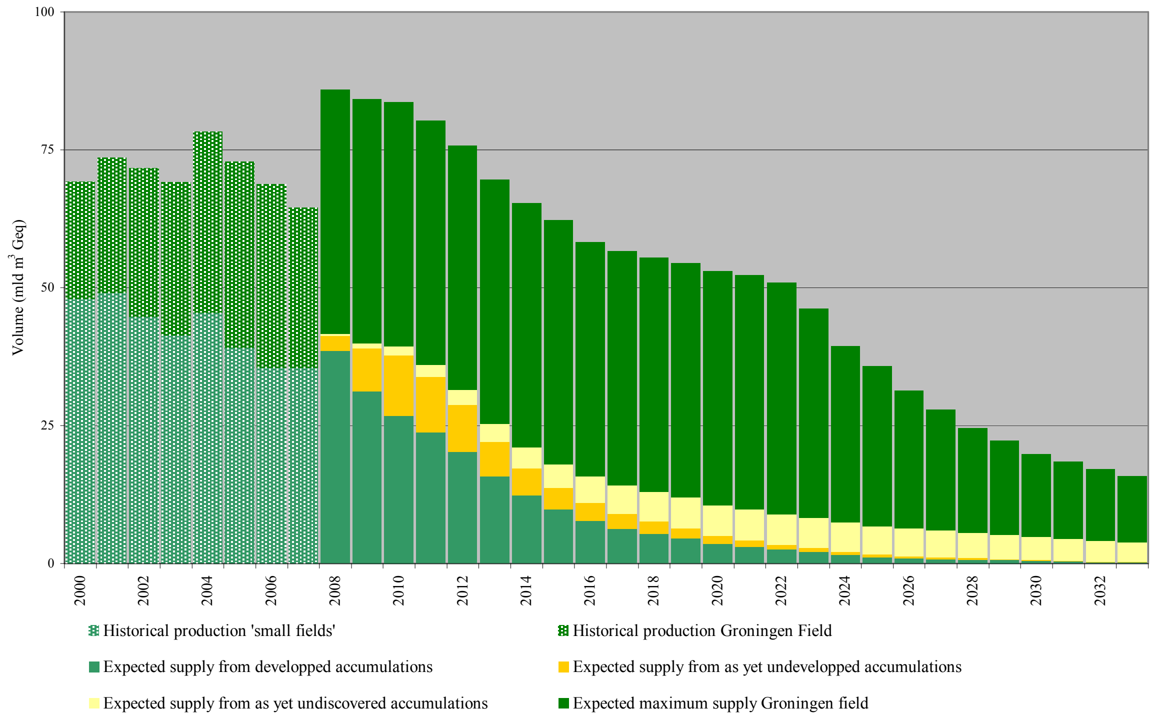


Figure 4-2: Natural gas production in the Netherlands as of 2000 and the prognosed production up to 2033 (source: Annual report Oil and Gas 2007)

The Dutch offshore gas production from the small fields now is expected to end in 20 to 30 years from now. This is the current understanding, based on information from operators in which they have included current gas prices and actual economic conditions. Sharp increase of the energy prices over the last years illustrate that the present estimates may very well change in the (near) future. The direct consequence may be that production form current fields and installations is be prolonged and exploration will be intensified. Also the past has shown that dates for platform abandonment tend to be prolonged as new developments continue to be taken into production. It is important to realize that this report presents the current understanding and does not include possible future situations.

The produced gas is transported to shore via an extensive infrastructure consisting of various types of facilities and pipelines. Production facilities can be differentiated into: central (treatment) platforms, satellite platforms and subsea developments. At satellite platforms gas is produced from one or more wells and sometimes free water is removed, whereupon the gas is exported to a treatment platform. Sub-sea developments are basic installations placed at the seabed, where gas is produced from one well, whereupon the gas with all associated liquids is exported to a satellite or treatment platform. At treatment platforms gas may be produced from one or more wells. The locally produced gas and/or gas from other installations is treated, comprising of gas drying (removal of water) and compression. The offshore treatment is directed to meet the transport requirement for gas transport through the trunk lines, generally made of carbon steel.

The produced gas and condensate is transported to shore via a system of pipelines, consisting of trunk lines and dedicated interfield lines from the various installations that tie into the trunk lines. Onshore the gas and condensate from the trunk lines is further treated and the natural gas is then delivered to the national grid of Gasunie Transport Services.

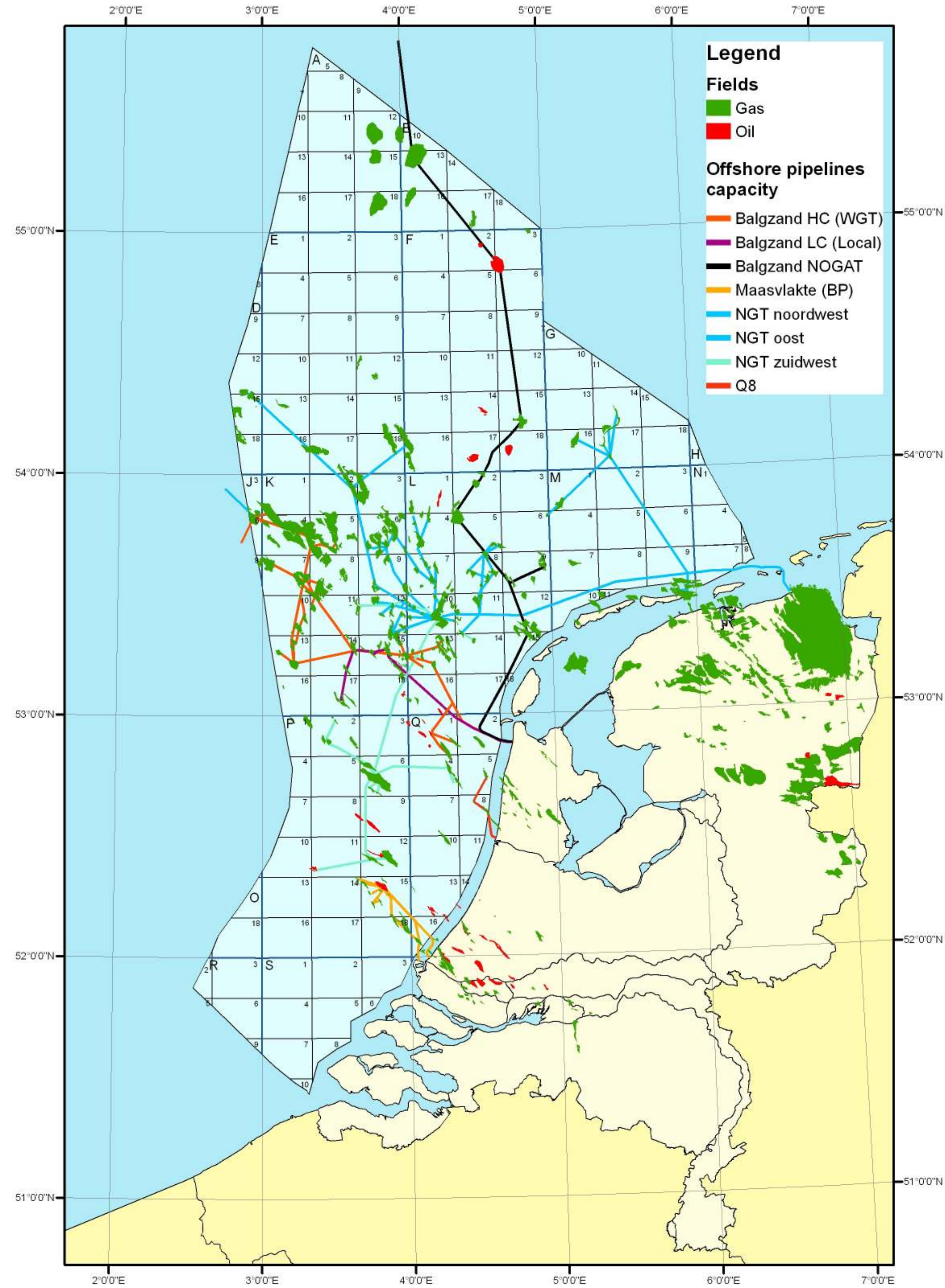


Figure 4-3: Overview of the offshore natural gas reservoirs and trunk lines

The majority of the gas is transported through three main gas trunk lines:

- The Noord Gas Transportleiding (NGT) transporting high caloric gas from the north western part of the DCS, size 36”, length 330 km, landfall in Uithuizermeden (Groningen);
- The Noordelijke Offshore Gastransportleiding (NOGAT) transporting high caloric gas from the north eastern part of the DCS, size 36”, length 144 km, landfall in Den Helder. The NOGAT has an extension to the Danish sector;

- The West Gas Transportleiding (WGT) transporting high caloric gas from the central western part of the DCS, size 36”, length 121 km, landfall in Den Helder;

In addition, some of the gas is transported to shore through dedicated pipelines,

- The LoCal pipeline transporting low caloric gas from the central western part of the DCS, size 24”, length 74 km, landfall in Den Helder;
- The Q8 pipeline transporting gas from the western part of the DCS, size 10”, length 14 km, landfall in Velsen (west of Amsterdam);
- The P15 pipeline transporting gas from the southern part of the DCS, size 26”, length 40 km, landfall in Rotterdam Maasvlakte.

From the above outlined present and expected future situation of the DCS natural gas development two observation can be drawn:

1 In the forthcoming years quite a number of depleted gas fields will become available for subsurface CO_2 storage;
2 The currently available infrastructure (wells, platforms and pipelines) should be reused for CO_2 storage as soon as possible after cessation of natural gas production. Redevelopment from scratch is cost-ineffective and technically complicated (use it or lose it).

This study aims at detailing the above general high level observations in order to obtain an accurate and up to date survey of the offshore potential for CO_2 storage and the applicable time frame.

5 SUBSURFACE MATTERS (RESERVOIRS AND WELLS)

This section comprises an overview of the capacity to inject and store CO_2, in the gas reservoirs on the DCS and a brief overview of the available wells and their suitability for injection.

5.1 Reservoirs and data

Reservoirs considered
As mentioned this study focuses on storage in depleted gas reservoirs and does not consider oil reservoirs. The reason to neglect the oil reservoirs is that the available storage capacity is much smaller than that in gas reservoirs, due to a lower recovery factor, lower compressibility and water injection to support pressure. Moreover oil reservoirs tend to be produced with more wells than gas reservoirs which eventually increases the risk of leakage at well bores.

The storage capacity calculated in this section concerns the theoretical and effective storage capacity as described by the CSLF classification (cf. section 3).

Data on 153 gas reservoirs has been collected (see appendix 2) and comprise:

- All currently producing gas fields,
- Some fields where production has (temporarily) ceased;
- Fields which have not yet commenced to produce, but have a firm Field Development Plan.

Gas fields, where facilities already have been dismantled are not considered here. Also, fields without a firm development plan nor undrilled prospective volumes have been considered. Finally, reservoirs at a depth shallower than 800 meters have been disregarded, since they are not capable of storing dense supercritical CO_2.

Data
The information in the project database on the gas fields consists of the following:

- Field and operator name;
- Platform name(s): the platform(s) through which the field is produced;
- Evacuation system: The name of the trunk line system to which the field is connected (e.g. NGT, WGT, NOGAT, etc);
- Stratigraphic level of the reservoir;
- Status: (not yet) producing, suspended or abandoned;
- Average degree of injectivity of the field;
- Pressure: the initial pressure and the pressure at the time of abandonment;
- Hydrocarbons initially in place (dynamic);
- Ultimate recovery (UR) of natural gas: as a measure of pore volume available for storage;
- Seal type: salt or clay as an indication of quality;
- End of field life: year at which the field now is expected to become available for storage;
- Number of active wells in field: number of wells available for injection;
- Remark: any comment (e.g. suitability for storage / showstoppers).

For confidentiality reasons certain data per field are not disclosed in this report.

5.2 Theoretical storage capacity of gas reservoirs

The theoretical CO_2 storage capacity is determined assuming that the pore volume occupied by produced gas would be replaced by the same pore volume of CO_2 at the initial reservoir pressure and temperature. This here is defined as 100% degree of filling.

The theoretical CO_2 storage capacity of each gas field has been calculated form the ultimate recovery (UR) volume of natural gas. The UR data, as provided by the DCS operators, are estimates based on present day economics and production technology. Based on the properties of CO_2, the pressure and temperature of the reservoir a conversion factor has been applied to convert the volume of natural gas into the mass of storable CO_2 (see appendix 3).

This results in a theoretical storage capacity of 1566 Mton of CO_2. Note that this is without any technical or economical cut offs applied.

The calculation of the theoretical storage capacity serves to characterize the total gas fields portfolio and allows for a first pass cutoff. If, for technical, economic or safety reasons the maximum storage pressure will remain below initial pressure, the storage capacity will be reduced. This is further elaborated on in section 7.

To calculate the availability of the theoretical storage capacity over time three different approaches have been followed (again, these are present day estimates which may change due to economic, policy or technical reasons):

1. A **field approach** where the storage capacity is added to the portfolio as soon as the production of a field has ceased;
2. A **platform cluster approach** where the storage capacity is added to the portfolio as soon as the production of all fields connected to a cluster of platforms has ceased;
3. A **trunk line approach** where the storage capacity per trunk line is added to the portfolio as soon as the production of the last connected field has ceased.

5.2.1 End of field life approach

Based on production forecasts, the expected year of end of field life was submitted by the operators. Figure 5-1 shows the theoretical storage capacity over time expressed in Mton CO_2. Both the annual addition and the cumulative capacity are shown. In 2030 all currently producing DCS fields are expected to have ceased production.

Figure 5-1 and Table 5-1 show the increase in availability of storage capacity. By 2020, 85% of the (theoretical) storage capacity will be available. This number rises to 94% in 2025 and finally to 100% in 2030.

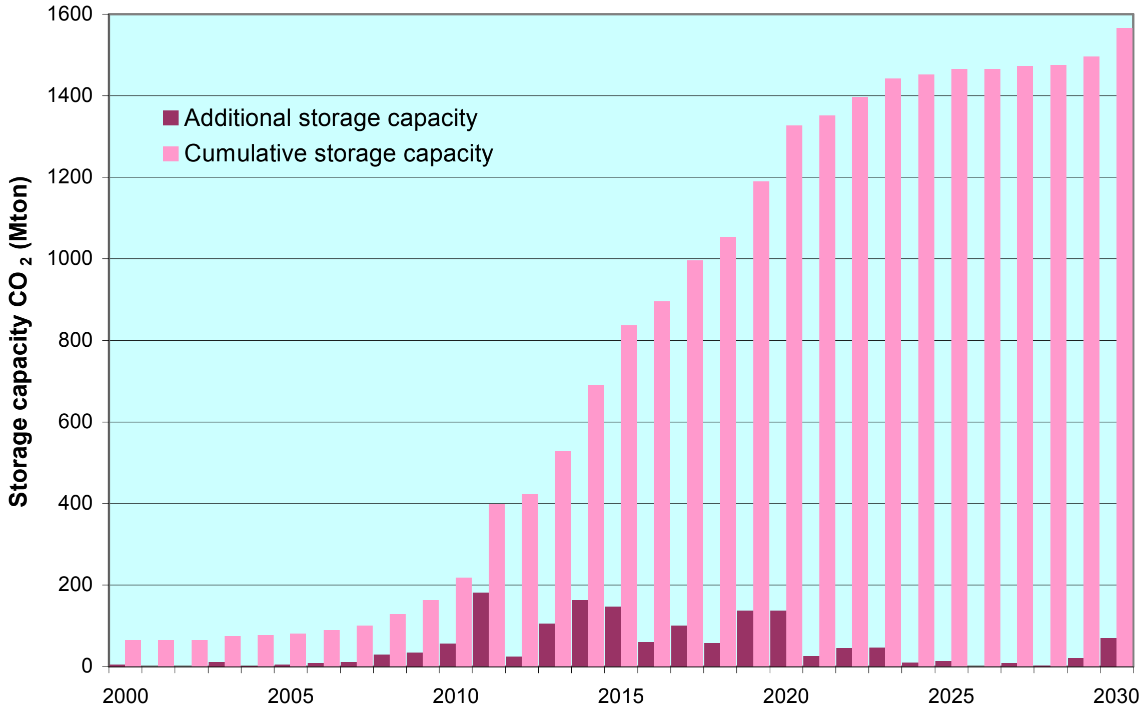


Figure 5-1: Available theoretical CO_2 storage capacity based on expected end of field life

Year	% of final capacity	Theoretical CO_2 storage capacity (Mton)
2010	14	218
2015	53	837
2020	85	1327
2025	94	1465
2030	100	1566

Table 5-1: Availability of theoretical CO_2 storage capacity for the period 2010 – 2030 based on the volume of produced gas

5.2.2 Platform cluster approach

The second approach is to consider clusters of platforms. Clusters can be composed of groups of platforms (treatment platforms, satellites and sub sea installations) that are connected by a pipeline infrastructure. This approach implies that a cluster can be considered as a kind of 'super field' consisting of multiple reservoirs with a central injection location. An example of such a cluster is the 'G17d-A' cluster which consist of the following platforms and their connected fields: G17d-A, G17a-S1 (sub sea), G14-A, G16a-A, L6d-S1 (sub sea) and G14-B.

In Figure 5-2 the available theoretical storage capacity based on platform cluster approach is shown for the period up to 2030. This approach assumes that a cluster of platforms becomes available only after gas production from the cluster has ceased at the last producing platform. As Figure 5-2 shows, the availability of storage capacity is postponed compared to the field by field approach in Figure 5-1. In the years 2020 until 2023 an equivalent of 969 Mton of the theoretical storage capacity is expected to be released, This represents almost two-thirds of the total capacity of 1566 Mton. Considering clusters of fields implies that less favorable fields in the 'super field' (by volume or injection rate) may hitch hike on the better performing gas fields without too much extra costs.

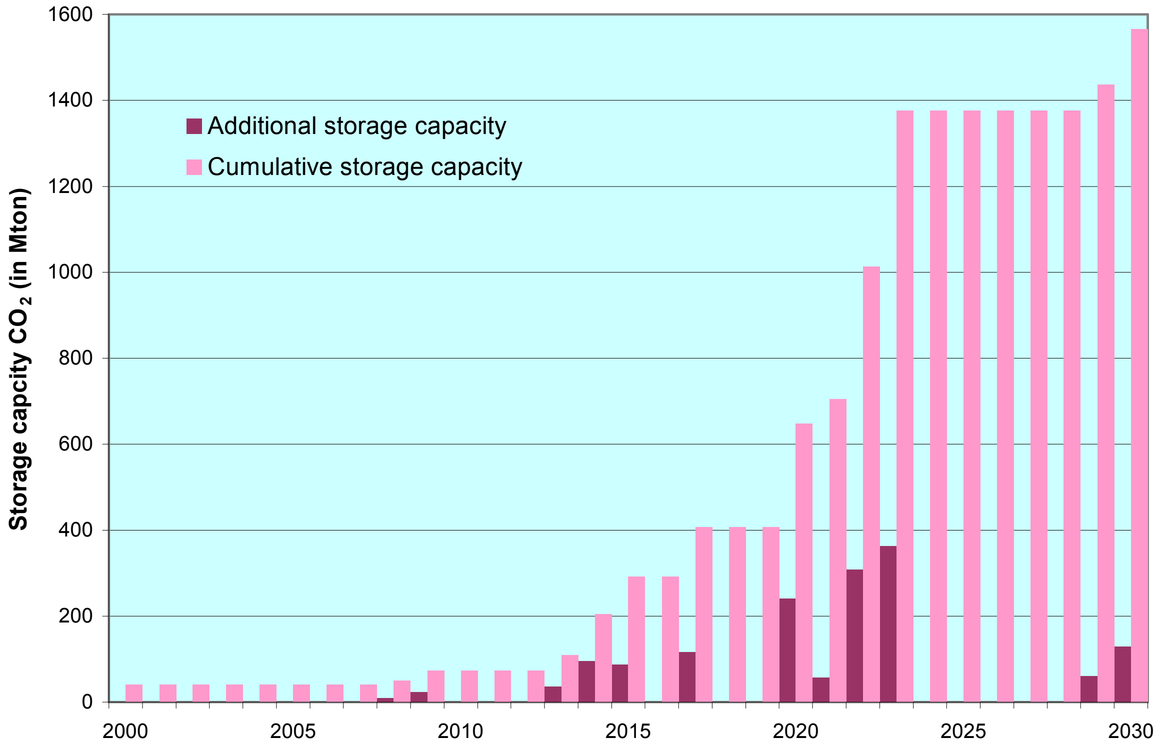


Figure 5-2: Available theoretical storage capacity based on platform cluster approach

Table 5-2 compares the availability of theoretical storage capacity between the field approach and the platform cluster approach.

Year	% of final capacity field by field	% of final capacity by platform cluster
2010	14	5
2015	53	19
2020	85	41
2025	94	88
2030	100	100

Table 5-2: Comparison of availability per end of field life versus platform cluster approach

5.2.3 Trunk line approach

The third approach is to cluster fields by trunk line. This is a rather conservative approach as it implies that the cluster only becomes available after the last platform connected to a trunk line has ceased production. In the calculations branches of trunk lines (e.g. the southern branch of the NGT) are considered as a separate unit. Based on the current expected closure dates of the linked platforms, the NGT Zuidwest, Q8 and Maasvlakte trunk lines will become available before 2015, the LoCal, NGT Noordwest and NOGAT will be available in 2023 while the WGT will continue production until 2030. New gas developments and prolonged production of existing fields will delay the availability for CO_2 transport.

5.3 Effective storage capacity

Following the CSLF classification (see section 3.3), the effective part of a storage portfolio results from applying geological and engineering cut-offs and constraints. Two types are considered here:

1 Volume and injectivity cut offs;

2 Status constraints; i.e. abandoned fields

In addition, qualitatively, some possible constraints resulting from reservoir properties will be discussed. It is noted that the cut offs presented here have been applied at the total DCS portfolio level. In specific cases or projects, these can be more detailed by modeling, including economics and optimization.

5.3.1 Injectivity cut off

Injectivity is proportional to the permeability-thickness (kh) of a reservoir, as determined from well tests. Practical experience from gas production shows that the gas recovery factor strongly decreases below the level of kh = 0.25 Dm, indicating that the internal resistance to gas flow within the reservoir becomes dominant. The same would hold for trying to fill a depleted gas field with CO_2.

Figure 5-3 shows the theoretical storage capacity for the different classes of reservoir quality expressed in terms of kh. The graph shows for example that almost 200 Mton of the theoretical storage capacity has a kh larger than 2 Dm. It also shows that 985 Mton of the storage capacity has a kh larger than the cut off 0.25 Dm. This would imply that 580 Mton of theoretical storage capacity (i.e. 37% of the total) would not be favorable in terms of injectivity.

In cases where these low permeability fields can easily be co-injected with other (better quality) fields, they may still be used, depending on economics. This will not be the case if these fields are isolated / remote fields with the need of a significant dedicated infrastructural development.

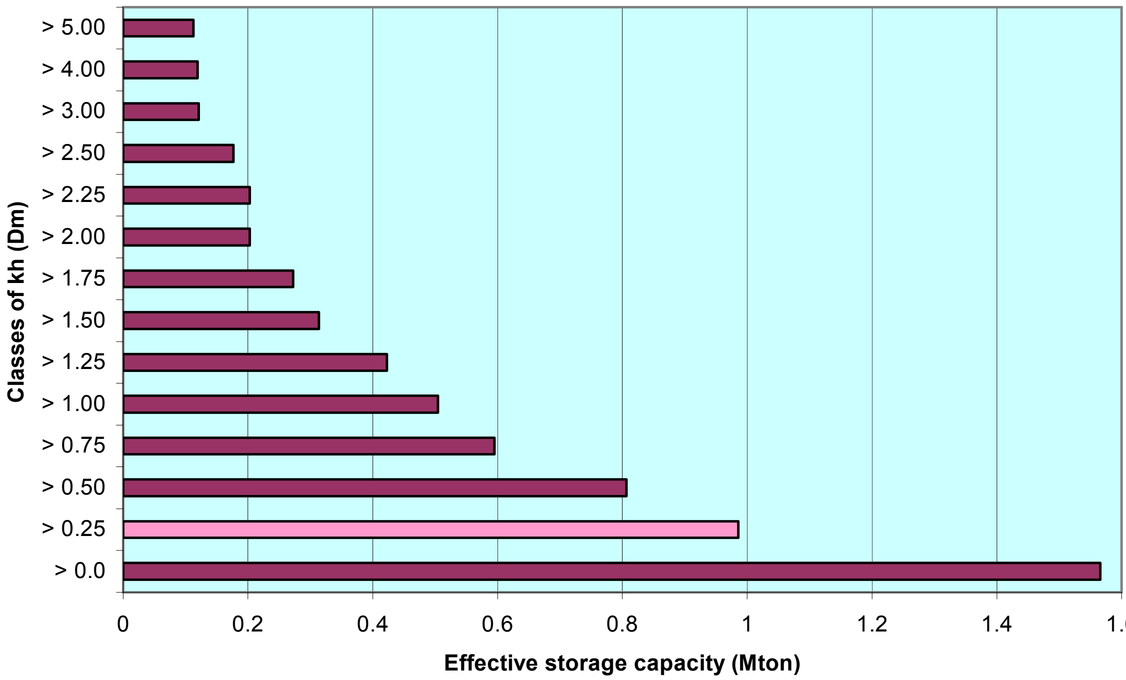


Figure 5-3: Theoretical storage capacity for the different classes of injectivity in terms of kh

5.3.2 Storage capacity cut off

Smaller fields in a cluster may be hooked up for additional storage volume. However, there will be a lower limit to size for gas fields to be an effective part of a cluster. Economics will tell where these limits are. For now, we have adopted a cut off on storage capacity at 2.5 Mton. This cut off capacity would be equivalent to the supply from one coal fired power plant for only half a year. The contribution of such a small field to the sustained injection capacity would be even more modest.

In Figure 5-4 the gas fields are categorized based on theoretical storage capacity. The graph shows the number of fields per category on the left axis and the total storage capacity per category on the right axis. Table 5-3 shows that 61 Mton of the storage capacity is below the volumetric cut off of 2.5 Mton. Half of this volume is also below the injectivity cut off. Fields with a theoretical storage capacity > 10 Mton carry the larger part of the total storage capacity.

Size category (Mton CO_2)	No. of fields	Theoretical CO_2 capacity (Mton CO_2)
< 2.5	46	61
2.5 - 5	28	103
5 – 10	31	226
10 – 20	27	354
20 - 50	19	597
> 50	2	224
Total	**153**	**1566**

Table 5-3: Field size distribution of theoretical CO_2 storage capacity

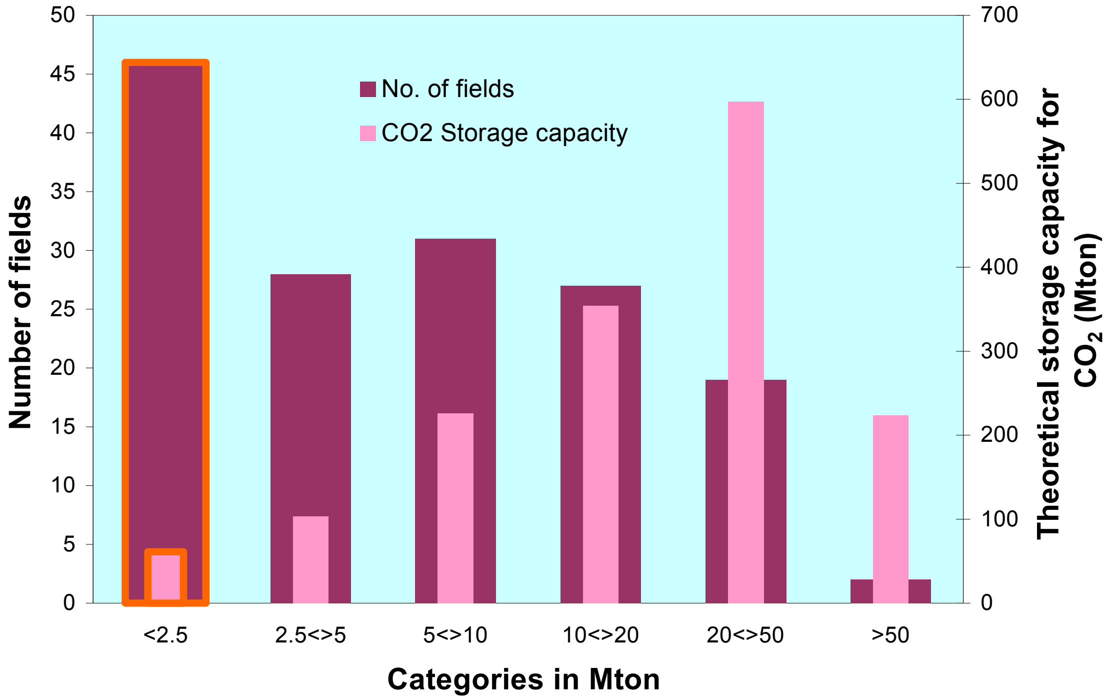


Figure 5-4: **Field size distribution of (theoretical) CO_2 storage capacity, fields below 0.25 Dm cut off are bordered in orange**

5.3.3 Abandoned gas fields

As reported by the operators in 2007 the gas production of 21 DCS gas fields has ceased and by now the fields are abandoned, meaning that the wells are plugged and the mining installations are removed according to the regulations. Re-entering these fields is considered very costly and technically complicated. For this study these fields are considered as unusable for future (see appendix 2, status code 'A'). The capacity of these abandoned fields adds up to 91 Mton, of which 52 Mton is below the 0.25 Dm kh-cut off or the 2.5 Mton volumetric cut off. This leaves an additional reduction of 39 Mton.

5.3.4 Effective storage capacity

Effective storage capacity, determined after applying the above discussed cut offs, brings the total number of candidate NCS gas fields from a total of 153 down to a more manageable, but still fairly large, number of 55 fields. The effect of the cut offs on the storage volume is a reduction of 650 Mton from 1566 to 918 Mton (Table 5-4). Figure 5-5 shows the distribution of kh and (theoretical) storage capacity over all 153 fields considered. The graph shows the application of the 0.25 Dm cut off for kh as well as the 2.5 Mton cut off for storage capacity.

	Number of fields	Storage (Mton)
Theoretical Storage capacity	153	1566
Injectivity cut off	-74	-580
Storage cut off	-46	-61
Abandoned fields	-20	-98
Total storage below cut offs	98	-648
Effective Storage capacity	55	918

Table 5-4: **Effective storage capacity as derived from the theoretical storage capacity**

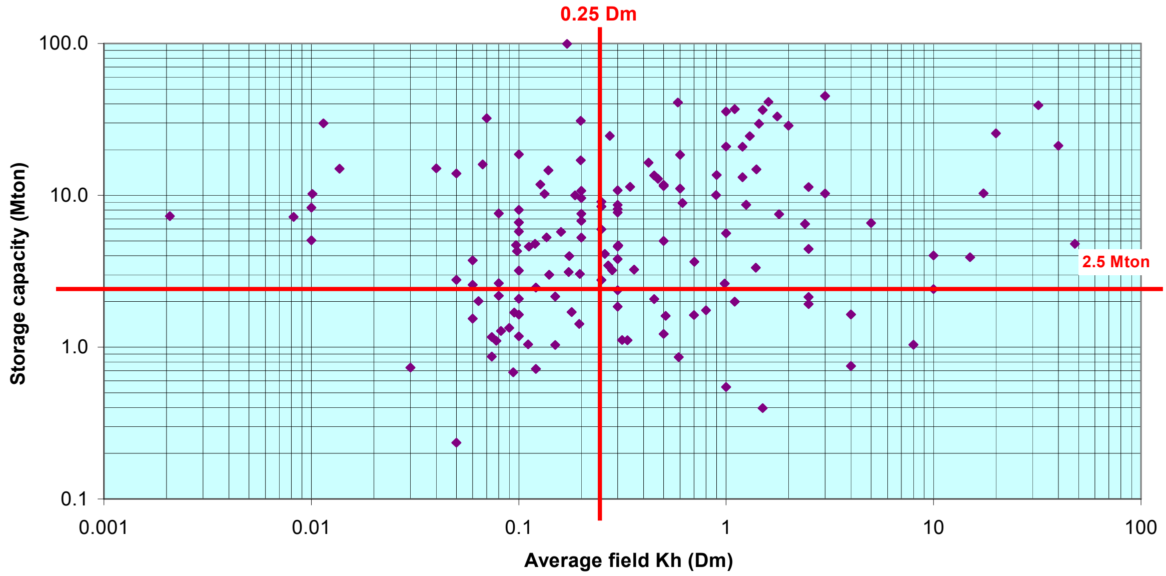


Figure 5-5: Permeability-thickness of fields versus theoretical CO_2 storage capacity, showing applied cut offs

5.3.5 Effects of reservoir and fluid properties

Interviews with operators as well as a literature survey have pointed at some constraints on CO_2 injection stemming from static or dynamic geological reservoir properties. Below, these are described, but it has not been attempted to fully quantify their impact on the storage and injection capacity, because these effects are very site specific. Well testing at the stage of converting a depleted gas field into a CO_2 storage will tell the net effect on injectivity, whereas the effect on storage capacity only shows up in the late life of the CO_2 store. Yet, it has to be noted that these effects lead to a reduction of injectivity and/or storage volume, rather than an increase. Therefore, all figures quoted in this report are to be considered optimistic in this sense.

Seal lithology
Gas fields in the Netherlands are dominantly sealed by cap rocks consisting of rock salt, clay stones, silt stones or a combination. Rock salt seals tend to be more favorable due to their rheological properties. The gas fields in the Rotliegend Sandstones (such as in the K and L quadrants) are mainly sealed by Zechstein Salt. However, onshore a natural gas field with 68% CO_2 content is effectively sealed by a claystone.

Reservoir lithology
The vast majority of the NCS gas fields are in a sandstone / shaly sand type of reservoir lithology. Only a few are in a carbonate type of lithology. From EOR CO_2 flooding experience, reservoir lithology does not seem not be prohibitive.

Permeability heterogeneity
In heterogeneous reservoirs, CO_2 will first enter the highly permeable layers, and only from thereon fill the less permeable parts. Heterogeneity will therefore have an impact on the filling efficiency of a depleted gas field, i.e. the same kh-value may give rise to different filling in reservoirs with different heterogeneity.

Compartmentalization
Some gas fields may be divided in compartments. These compartments may have different characteristics. In addition, each of the compartments will have to be accessed by a well.

Active water encroachment
As a general rule, the DCS gas fields do not experience an active aquifer support. Only in the shallower less faulted fields, some aquifer influx has been detected. Therefore, the reduction of storage

potential due to decrease of gas filled pore volume by water encroachment is estimated to be minor, in the order of a few percent on the total volume during production life. However, some fields may have to wait 20 to 40 years after cessation of production, before they are activated for CO_2 storage. Water influx may have (undetectedly) significantly increased over that period of time.

Reduction of injectivity and/or storage capacity due to production
This may occur due to e.g. reservoir compaction, near well bore accumulation of fines, hysteresis in the relative permeability and capillary pressure characteristics. Vertical reservoir compaction in deep gas reservoirs typically is in the order of 5% over the full production lifetime. Part of this compaction will be irreversible, leading to a loss of storage capacity in the order of a few percent. Perhaps more importantly, the permeability of the reservoir may have decreased, the more so in low permeability reservoirs with small pore throats. Also the dehydration effect of CO_2 in the near well bore region of the reservoir has to be accounted for.

Mixing of injected CO_2 with natural gas
Mixing of the injected CO_2 with the remaining natural gas will result in a net lower density than the linear combination of the density of the components. This is likely to cause a slight long term increasing effect on the pressure inside the storage volume.

5.3.6 Summary of findings on CO_2 storage capacity

- The total **theoretical** storage CO_2 capacity in depleted gas field at the DCS is 1566 Mton (according to 2008 estimates and assuming injection up to initial pressure);
- The largest **theoretical** storage capacity lies in the category of 20 to 50 Mton (19 fields, 597 Mton);
- Two fields have a **theoretical** storage capacity larger than 50 Mton;
- The 21 largest fields will be the key fields to develop storage clusters which may be operated as one storage system; These 21 largest fields contain slightly over one half of the total **theoretical** storage capacity (821 Mton).
- The **effective** storage capacity is 918 Mton divided over 55 fields. This has been derived by applying:
  - a permeability-thickness cut off at kh < 0.25 Dm (74 fields have a kh ≤ 0.25 Dm);
  - a volumetric cut off of a minimum 2.5 Mton CO_2 storage capacity;
  - a disregard of abandoned fields.
- According to present day plans, all currently know offshore fields are expected to be depleted before 2030.

5.4 Wells: General and explanation of terms

Data
For every well a set of data has been prepared. Data came partly from the DINO database at TNO and partly from the operators. Below is a listing of the data available in the project database:

- Name
- Status (producing / suspended / P&A)
- Tubing diameter (inch)
- Permeability-thickness at the well (Dm)
- Maximum pressures (bar)
- Material properties (carbon or stainless steel)
- Show stoppers for CO_2 storage
- Comments

Use of data
The information on wells has been primarily used to calculate injectivity and to determine the suitability of wells for CO_2 injection. To calculate the injectivity of the well and reservoir, the well configuration (inside diameter of the casing / tubing) is one of the parameters. The actual calculations take the field properties such as permeability and reservoir dimensions in consideration. Section 7 gives further information on this subject.

5.4.1 Suitability for CO_2 injection

Suitability of the wells is established form the material properties of the casing and tubing, the maximum allowed pressure and well status. All wells are reported to have stainless steel tubings (mainly 13% Cr-80, some 22% Cr-125), some may have a carbon steel flow line. Maximum allowed pressures for the wells based on material properties are reported in the range form 5 000 to 10 000 psi (330 to 660 bar). All wells have been designed for the production of natural gas at the initial pressure of the reservoir which was around hydrostatic pressure at the depth concerned. The maximum injection pressure during the injection phase of CO_2 will be no higher than the initial pressure of the gas field plus the overpressure to enable the tail end injection (for further details see section 7). This implies that under normal conditions, from a material properties point of view, all wells should be suitable for CO_2 injection.

5.4.2 Well integrity

Experience from industrial analogues has shown that the biggest risks of CO_2 storage originates from leakage of poor quality or aged injection wells or leakage from abandoned wells. The operators have reported on 389 wells:

- 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.

Main remarks concern abandoned, restriction (fish) in tubing, small diameter string installed, (perforations) plugged/cemented, sub sea completion, leakages, low kh, sand producer and halite precipitation. This may include for instance exploration wells that were not re-entered as production well or wells that have been plugged and abandoned for other reasons. Such wells may potentially be a risk for reservoir leakage. Present data set does not allow to draw firm conclusions on the status of the wells.

5.4.3 Well conduction through reservoir seals

Without any further detailing, the fields have been divided into a category with salt layers as a top seal and layers with clay seals. Appendix 2 lists all the fields and their seal type (salt / shale). Due to the fact that the natural gas reservoir seal has proven to be tight over millions of years, all present seals can be considered as suitable. A point of attention is however that a well through a reservoir seal may be a leak source, e.g. when the cementing has aged. Seals that tend to flow under stress are preferable. This accounts for salt seals and some shale seals. In case of less competent cementing of casing, the rheologic seal behavior will tend to close the gap between seal formation and the casing of the well.

6 SURFACE MATTERS (INSTALLATIONS AND PIPELINES)

This section comprises an overview of the existing offshore natural gas infrastructure and the possible reuse of the existing facilities once they become obsolete for gas production. The surface assets that may be relevant for CO_2 storage include the existing gas production and treatment platforms and the gas transport pipelines, both interfield and trunk lines. Onshore installations like CO_2 capture installations and land based booster stations are not considered. Where relevant an outlook is given to missing elements in the infrastructure or on options where a mismatch exists in the timing that installations will be abandoned for gas production and when they are needed for CO_2 storage (see section 7).

First the methodology is discussed, followed by the results of the interviews with the operators. These interviews were aimed at identifying possible bottlenecks and showstoppers for CO_2 storage and other points of attention. Next the results of the data survey concerning platforms and pipelines are clarified and discussed. Finally an overview is given of the results, conclusions and recommendations.

6.1 Study methodology, starting points and terms

To assess the availability of surface installations and piping the approach outlined in §3.3 was followed. For this part of the study some specific attention points are:

- Only gas installations are taken into consideration;
- Where applicable oil pipelines might also be used for CO_2 transport, given that their pressure rating is at least 100 bar;

6.2 Findings form the interviews with the operators

The eight producing operators on the DCS have been interviewed within the framework of this study to assess the possibilities, possible bottlenecks, challenges and/or showstoppers regarding the reuse of their installations for CO_2 storage purposes.

Platform issues

Currently most platforms are designed for a lifetime of 30 years, while for CO_2 storage lifetime extension up to 2050 and beyond may be required. Meanwhile most platforms originate from the past century. No significant problems are expected by the operators to prolong the life of platforms to use them for CO_2 storage, as long as appropriate maintenance is carried out. One operator reports that the jackets are expected to have a somewhat longer lifetime. When maintenance is stopped, the topside will degrade rather quickly. Continuous maintenance is therefore needed, even when platforms are temporarily abandoned awaiting reuse for CO_2 storage. As it is likely that many platforms will cease production (long) before reuse for CO_2 storage, good mothballing is essential and best practices should be developed to accommodate that. According to several operators, mothballing a platform will amount to about 10% of the platform abandonment costs (i.e. approx. 1 M€ / yr for satellites and 3 – 5 M€ / yr for central complexes). Generally it is remarked by the operators that platforms should be reused as soon as possible for CO_2 storage in order to avoid maintenance and integrity problems (use them or loose them). The cost to reinstate a platform, that has already gone into a bad shape, are reported to be quite high. Cost related aspects will be further detailed in phase 2 of the project.

When platforms are used for CO_2 storage, they will require energy for pumps, heaters and other utilities. The energy demand will be considerable. In the initial phase heating of the CO_2 might be required (see chapter 8) and at the end of the injection period pumps may be necessary to fill the reservoir to the desired end pressure. At platforms that currently use produced gas for electricity generation, other means of energy supply must be found to fulfill the energy demand, once gas production ceases. Currently it is not clear how this should be done. In some cases tail end production from the same or a nearby reservoir may be used to produce the required energy.

According to the OSPAR Convention platforms at abandoned reservoirs shall be removed within two years. As a consequence, platforms that are suitable have to be reused for CO_2 storage within two years after ending gas production or legislation should be changed to allow for bridging the gap to CCS.

Platforms that are relatively far from shore and will become available for CO_2 storage relatively early, have a high chance that the current gas transport pipelines are still in use by platforms downstream. The transport of CO_2 from the shore to the platform by means of existing pipelines then is not possible while the construction of a new pipeline will be too expensive for smaller fields. In such a case, it is not likely that the platform (and associated gas fields) can be used for CO_2 storage within two years after the platform becomes available.

Gas transport pipelines

For gas transport pipelines a distinction is made between interfield lines and trunk lines. Interfield pipelines transport produced gas from satellite platforms and subsea completions to central treatment platforms. Gas transported through interfield pipelines is generally wet, although at many platforms free water is separated. Interfield pipelines are in general made of carbon steel (CS), but also stainless steel (SS) is applied. In CS pipelines small amounts of corrosion inhibitor are injected to prevent corrosion. Trunk lines transport dried gas from treatment platforms to shore. All trunk lines on the DCS are CS and corrosion inhibitor is injected as a precaution.

As will be shown in section 8, both inter field en trunk pipelines are suitable for CO_2 transport as long as the composition of the CO_2 remains within specifications and have the proper pressure rating. It is suggested by an operator that PVC liners inside CS pipelines are a possible option if corrosion due to water, H_2S and other components in the CO_2 poses a problem for CS pipelines, but the actual applicability on the pipeline systems on the DCS is unknown. Preference however is, that the supplied CO_2 meets the quality requirements to avoid additional investments and/or injection of corrosion inhibitor or other additives. Anyhow recertification of transport pipelines will be required if the pipeline is used for CO_2 transport and/or after expiration of the certification period (generally 30 years).

Some operators indicate that they expect that the flanged pipelines connections are the determining elements for the overall pipeline pressure rating. These flanged connections can be replaced if the pressure rating of piping systems is to be increased. The costs are estimated about 1 million Euro for each connection.

Interference with other activities

The southern North sea is intensively used for other activities, which now and in future impose spatial claims. This includes among others shipping and fishery, wind turbine farms, sand production, sea nature reserves, military training areas, etc. At present in the spatial planning of the DCS it is assumed that most mining installations will be removed by 2030. Prolonged use of the mining installations can result in interferences. E.g. nearby wind turbines can restrict helicopter approach and establishment of nature reserves might restrict activities in protected areas. NOGEPA is in contact with other stakeholders to discuss and follow up this issue. For this studies it is assumed that, in spite of those threats all available mining installations can be used for CO_2 transport and injection.

6.3 Transport and injection options: reuse versus new

In order to optimize the economics of CCS, reuse of existing gas production infrastructure is attractive. With respect to pipelines there are however some constraints that can influence the decision for future reuse:

- The pressure rating of existing pipelines limits their capacity. From the questionnaires it appears that pipeline pressure ratings vary from less than 100 bar to over 340 bar. The rating of the main trunk lines varies from 100 to 136 bar. The weakest chain in a pipeline system determines the maximum allowable transport pressure. However, when at central platforms the pressure is increased by booster pumps or decreased by choking, sub-systems can operate at different pressure levels;
- To refill a depleted gas reservoir back to its original pressure (generally 250 – 500 bar; see plot in Appendix 3) after a certain time when the reservoir pressure increases, the installation of booster pumps will be required. Without booster pumps the tail end injection rate and/or degree of filling will otherwise be reduced. The optimal timing of installing booster pumps depends on a number of

factors, including reservoir properties, supply pressure, CO_2 prices, etc.; this will be further elaborated in section 7;

- When comparing the maximum supply capacity of pipelines with the maximum injectivity of wells and fields, it is difficult to make general conclusions as to which element in the whole chain is the limiting factor. The assessment demonstrates that both the transport capacity and the maximum injection capacity into a depleted reservoir show a large scatter. Moreover, the tail end injection capacity rate decreases due to the increasing back pressure. When actually selecting CO_2 storage clusters investigations should prove whether it may be cost effective to replace some piping sections or to install booster pumps in the case that the transport capacity proofs to be a limiting factor. Such an assessment should be worked out at a detailed project level, considering all relevant parameters, including CAPEX and OPEX, the desired storage rate, the availability of other nearby sinks, the remuneration for injected CO_2, etc.;
- The reuse of pipelines makes the infrastructure less flexible for optimization with respect to capacity, economics, etc. When a natural gas reservoir is depleted and thus in principle is available for CO_2 storage, the pipelines may still be in use for other fields. Especially when fields at the end of a pipeline network become available at an early stage, it will take quite some time before the entire pipeline to the shore becomes available. On the other hand, if fields at the end of a pipeline network are expected to be depleted relatively late (as is for example the case for the WGT pipeline), the pipeline network cannot be used for CO_2 transport either. Mothballing the wells and installations for a long period will be very expensive. Therefore, when no new pipelines would be constructed, the existing installations may be lost for CO_2 storage. From the data supplied by the operators in the questionnaires, both cases do appear;
- When new pipelines are installed, higher design pressure rates can be specified, allowing for a higher inlet pressure and allowable pressure drop over the pipeline. Moreover when a higher pressure level is selected, no booster pumps for end of life filling of reservoirs will be needed. This is the more advantageous, as the power needs on the platforms can be reduced. Moreover, new pipeline infrastructure increases the optimum use of gas fields for CO_2 transport, because fields with a late year of production cessation do not hamper other fields to be used for CO_2 storage. The required rating and size of new pipelines depends on the required capacity and an economic optimization.

6.4 Transport capacity and availability of pipeline systems

The total capacity of the offshore system is determined by the capacity of the pipelines, the wells, the reservoir injectivity and the presence of booster stations. The capacity of the pipelines is determined amongst other by the length, diameter and pressure rating of the pipeline system. This study uses the D'Arcy - Weisbach equation to calculate indicative pipeline capacities. The answers to the questionnaire show, that the pressure rating varies considerably between the various parts of the network. In a network of pipelines the pipeline with the lowest capacity determines ultimately the maximum capacity. Although some high pressure rating pipelines have a potential high capacity, it will not be possible to use this high pressure rating if pipelines downstream have a lower pressure rating.

The assessment of the availability of pipelines for CO_2 transport shows that interfield lines and sections of trunk lines gradually will become available in the period between 2015 and 2030. Based on current abandonment data whole trunk lines systems would become available as form about 2025, but as exploration and development of new prospects continues, the availability of trunk lines is uncertain. A trunk line system is theoretically only then available for CO_2 transport, when the last gas producers in the system has ceased production. Moreover some trunk lines might also be reused for other purposes, like trans boundary gas connectors or to transport gas from possible future offshore gas storages. Therefore due care must be taken in reckoning with reuse of major trunk lines for CO_2 transport. This however does not mean that where possible existing pipelines should be reused for CO_2 transport because of the possible cost savings.

To indicate the pipeline capacity on the DCS, the maps in appendix 5 show the year of availability and interfield capacity, i.e. the capacity of the pipeline between two platforms. The capacity is normalized to Mton per year at 1 bar pressure drop. To calculate the capacity of a pipeline at a different pressure drop, the normalized capacity must be multiplied with the square root of the specified pressure drop. For example, to calculate the capacity for a pressure drop of 15 bar for a pipeline with a normalized capacity of 0.7 Mton/year, the following calculation is made:

Capacity (@15 bar) = 0.7 Mton / year (@ 1 bar) * $\sqrt{15}$) = 2.7 Mton/year (@ 15 bar)

6.5 Platform availability

The abandonment dates are based on the reported date in the most recent BMPs ('Bedrijfs Milieu Plannen' or Company Environmental Plans). It is stressed however that the abandonment dates may alter due to the changing gas prices. If the gas price remains high, the abandonment date will shift, since it is economically viable to extent the exploitation of the gas fields. The figures 6-2 show the expected abandonment dates of the platforms based on the insights of the operators. For example, there are 4 platforms expected to cease production after 2028. These platforms actually reside at the end of a pipeline tree, thereby determining the entire end date of this pipeline.

The current legislation requires operators to remove platforms after final cessation of production. The Dutch Mining act requires that inactive mining installations are removed, whereby the Minister of Economic Affairs can determine a period and conditions. The OSPAR Convention requires that platforms are to be removed within two years after final cessation of the production. A two years term would mean that, if CCS would start on large scale in 2015 already more than 30% of the platforms on the DCS will be abandoned and removed and will not be available for CO_2 storage anymore. In 2020, the year assumed in this study for take off of large scale CCS (see section 7), this already may have increased to around 80%.

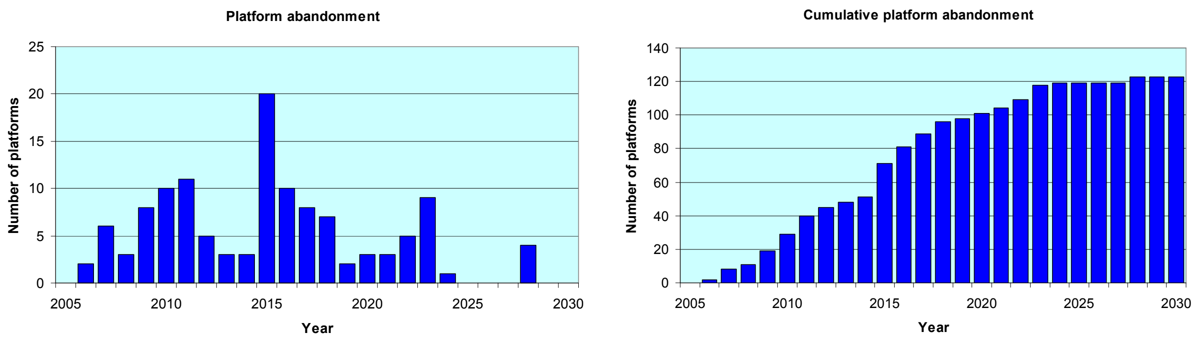


Figure 6-1: Expected year of abandonment of platforms (left: per year; right: cumulative) based on the BMP data

Clustering

The current offshore pipelines are structured around six trunk lines as indicated in Table 6-1, four long ones (> 70 km) and two shorter ones (< 40 km). As the table shows, the trunk lines (perhaps with the exception of the Q8 pipeline) have a considerable CO_2 transport capacity. Given the average yearly CO_2 emissions of a typical large coal fired power station of about 5 Mton CO_2 / year, as an example the NOGAT trunk line could transport the captured emissions of about 5 power stations[3].

Truckline	From	To	Diameter [Inch]	Length [km]	Available for CO_2 transport [year]	Pressure rating [bar]	Capacity @ available ΔP [Mton/year]	Capacity @ ΔP=15 bar [Mton/year]
NGT	L10-AR	Uithuizen	36	330	2023	136	41	22
NOGAT	L2-FA-1	Callantsoog	36	144.2	2023	110	32	25
WGT	K13-AP	Callantsoog	36	120.5	2028	99	26	27
Local	K15-FB-1	Callantsoog	24	74.3	2020	100	12	12
Q8 pipeline	Q8-A	Wijk aan Zee	10	13.7	2008	90	2	3
P15 pipeline	P15-D	Maasvlakte	26	40.1	2015	100	19	19

Table 6-1: Overview of the trunk lines with estimated CO_2 transport capacities

3 The oil pipeline IJmuiden to the Q1 oil fields with a diameter of 20 inch has a pressure rating of over 140 bar, i.e. suitable for CO_2 transport.

Notes to Table 6-1:

1 Capacities are estimated on general assumptions for the properties of the transported CO_2 and physical characteristics of the pipelines (i.e. roughness). For engineering purposes more detailed calculations are required;

2 The *Capacity @ available Δp* is based on the difference between the actual pressure rating per trunk line and minimum pipeline pressure of 85 bar. A minimum pressure of 85 bar is required in order to remain in the dense phase flow regime. Hence, the allowable pressure drop for the NGT line is 51 bar, while this would be only 14 bar for the WGT;

3 The *capacity @ Δp = 15 bar* is based on an assumed fixed pressure drop of 15 bar for all trunk lines over their full length;

4 The *Available for CO_2 transport* years for the trunk lines are based on the report of the respective trunk line operators and the indicated end-of-field-life based on current knowledge. The end date may be extended when new field developments will be connected or existing production is prolonged.

5 The *Available for CO_2 transport* year is based on the year that the last connected platform ceases natural gas production. Certain upstream line sections might become available sooner for CO_2 transport although the newest developments are generally located upstream. Neither possible optimization between natural gas versus CO_2 transport here is taken into consideration, nor the option to reroute certain end of life natural gas streams.

Apart from straightforward use of existing pipelines, combinations of existing pipelines and new pipelines give opportunities to use the CO_2 storage potential more effectively. Some examples are:

- The fields in blocks P15 and P18 lie close to shore and nearby the port of Rotterdam. This cluster of fields shows short term potential for CO_2 storage in combination with the plans to build new coal fired power plants at the Maasvlakte in the coming years;
- The Q8-A reservoir is currently studied for a CO_2 storage demonstration as part of the Rotterdam Climate Initiative. Wintershall expects to gain a lot of knowledge from this project concerning operation, field behavior, permitting, ownership of CO_2, financing, legislative aspects and other practical issues;
- Expected production end dates of reservoirs connected to the NGT vary form 2008 to 2023. The southern branch of the NGT reaches end of production earlier, around 2015. A possibility to access fields connected to this NGT branch earlier is to install a shortcut pipeline from the P15 trunk line to the P12 platform (connected to the NGT). In this way a connection to the P12 fields and further to the L10 platforms is created before the NGT will be wholly available for CO_2. Moreover the P15 trunk line is connected to the Maasvlakte, an area that has potential sources for carbon capture in the form of ('capture ready') coal fired power plants;
- Rearrangement of gas production platforms by connecting them to other trunk lines may make free a trunk line for CO_2 transport earlier. For instance platforms currently evacuating through the LoCal pipeline might be reconnected to the WGT, thus making the LoCal available for CO_2. This however requires contract negotiations between the platform and trunk line operators;
- Due to the late availability of the trunk lines some fields in the regions like L5, L7 and L8 can only be used for CO_2 storage on the short term if new pipelines are laid. A trade off has to be made between investment costs for new pipelines and costs for mothballing the platforms until the trunk line is available (under the condition that it is allowed to mothball the platform for longer than 2 years).

6.6 Required equipment at platforms

To facilitate CO_2 injection at platforms, a limited number of process installations are required:

- Risers, manifold and wellheads;
- Optionally heaters to heat up the CO_2 for initial filling in order to compensate for temperature decrease by the J-T effect. More details on heaters can be found in section 8;

- Optionally booster pumps for tail end filling and/or to compensate for pipeline transport losses or increase transport capacity;
- Well test and control equipment;
- Vent and blow down facilities. A point of attention with respect to blow down is that gaseous or liquid CO_2 solidifies when the pressure is decreased to atmospheric conditions (comparable with the effect of CO_2 fire extinguishers). For more details refer to section 8;
- Process control and safeguarding, safety facilities, etc.;
- Power generation.

At the platform the normal facilities as lighting, accommodation (optionally), rescue means and a helideck for the larger platforms will remain required. Most existing gas treatment facilities like gas – liquid separation, gas drying facilities will become obsolete.

As indicated earlier in this chapter, it is currently not clear, how platforms will acquire their energy when they are used for CO_2 storage, as gas is then not longer available. Possible options for energy supply include gas from other platforms, electricity from offshore wind farms or diesel.

6.7 Summary of findings on pipelines and installations

1 A major uncertainty considering the availability of existing pipelines and platforms is the 'out of operation' or abandonment year. As oil and gas prices keep on increasing, the fields can be longer exploited economically, delaying their availability for CO_2 storage ;

2 The operators do not foresee technical showstoppers for the use of the existing pipelines and platforms, provided that certain conditions are met. To preserve the infrastructure for CO_2 transport and storage, maintenance of (mothballed) platforms is needed and pipelines should be re-certified. As long as the properties of the transported CO_2 gas are such that corrosion is avoided (see section 8), the existing carbon steel pipelines should be suitable for CO_2 transport.

3 From the survey it follows that it is likely that a significant part of the infrastructure (especially platforms) will not be available for CO_2 storage, if platforms have to be dismantled and removed within two years after ending the gas production. It is therefore recommended to investigate the possibilities to extent the period possible for mothballing platforms for those structures that show a good perspective for reuse within CO_2 storage projects.

4 Furthermore the study shows that the possibility of reuse of infrastructure is highly dependent on the expected end-of-production time of reservoirs. The more remote fields delay the use of the trunk lines as they are among the fields that are expected to produce beyond 2020. For fields that are available earlier than the trunk line a trade off must be made between installing a new pipeline to make the field available to CO_2 storage or to mothball the platform and wells for a longer period to exploit the field when the trunk line becomes available.

5 In this study, the economic viability to use the existing infrastructure is not considered. During the interviews and discussions some indicative economic figures were discussed, indicating that the costs of CO_2 transport can be considerable. As operations have to take place offshore, the costs for maintenance, construction and repairs are relatively high. It is therefore recommended to further investigate the costs involved in the transportation of CO_2 to offshore reservoirs.

7 PRACTICAL AND MATCHED CAPACITY

7.1 Introduction

In section 5 the effective CO_2 storage capacity in depleted offshore gas fields has been assessed considering cut off criteria for storage size and injectivity (permeability-thickness). However, the result of 920 Mton storage capacity is probably rather optimistic as a number of other factors play a role.

For that reason, in this section the CSLF methodology is further pursued. First, the practical – surface related – factors are discussed, that may have an impact on storage capacity. Next, the concept of Matched capacity is introduced and elaborated on. Finally, a case is presented where Matched Capacity is illustrated in a large scale CCS offshore scenario.

7.2 Practical capacity

In the CSLF scheme the Practical storage capacity is determined from the Effective capacity by including other factors, that may have an impact on availability and accessibility of storage sinks. These factors may be of a technical, commercial, environmental, spatial planning, legal or even political nature. In addition, some competition for use of mid to large size, highly permeable gas fields for gas buffering (UGS) projects may emerge, particularly near shore.

In this study we address two of these factors. First the geographical spread, as it is an important consideration in assembling practical storage clusters and subsequently the practically obtainable filling degree of gas reservoirs.

It is beyond the scope of this study to quantify the impact of these factors on the storage capacity as it is impossible to forecast how the offshore landscape will look like in 2020 and beyond. The access to and availability of the larger storage fields is however crucial for building a portfolio of suitable storage and injection clusters. Thus to optimize the conversion of effective capacity into practical capacity this process should be part of the planning process for the DCS.

7.2.1 Clustering

The practicality of storage capacity must be analyzed against a background of what 'large scale' CCS actually means. Here we are looking at point sources (e.g. coal fired power plants), that would typically deliver 5 Mton CO_2 per year over an expected life cycle of some 40 years. The total required storage capacity for one point source would then be around 200 Mton.

From the portfolio of offshore sinks it is clear that no single gas field is capable of storing 200 Mton CO_2 volume-wise. Let alone, that a single field would be capable to accommodate a constant yearly injection rate of more than 5 Mton/yr over decades. Filling a reservoir will gradually increase the reservoir pressure en hence decrease the pressure difference between well and reservoir, that drives the injection rate.

From the above arguments it follows, that even storing one 'batch' of 200 Mton CO_2 from a single point source will require the availability, development, operation and maintenance of a cluster of gas fields over a long period of time.

A cluster of gas fields, by nature, will consist of fields of variable size and injectivity. Regarding the large scale and long term needs for storage and injection, a cluster should at least contain a few 'core' fields, that – in combination - can carry the larger part of the required constant injection capacity over several years.

The map in Figure 7-1 shows the geographical distribution of the offshore gas fields. From the dataset acquired for this project it follows, that geographical clusters with a storage capacity in the order of 200 Mton can only be formed in the central offshore area, i.e. the K and L quadrants. The fields in the northern offshore (A, B, D, E and F quadrants) and eastern offshore (G, M and N quadrants) are too remote for practical tie-in into central offshore clusters. The fields in the southern offshore (P and Q quadrants) may be candidates for early (before 2020) near shore projects, that may be step stones towards large scale CCS in the central offshore.

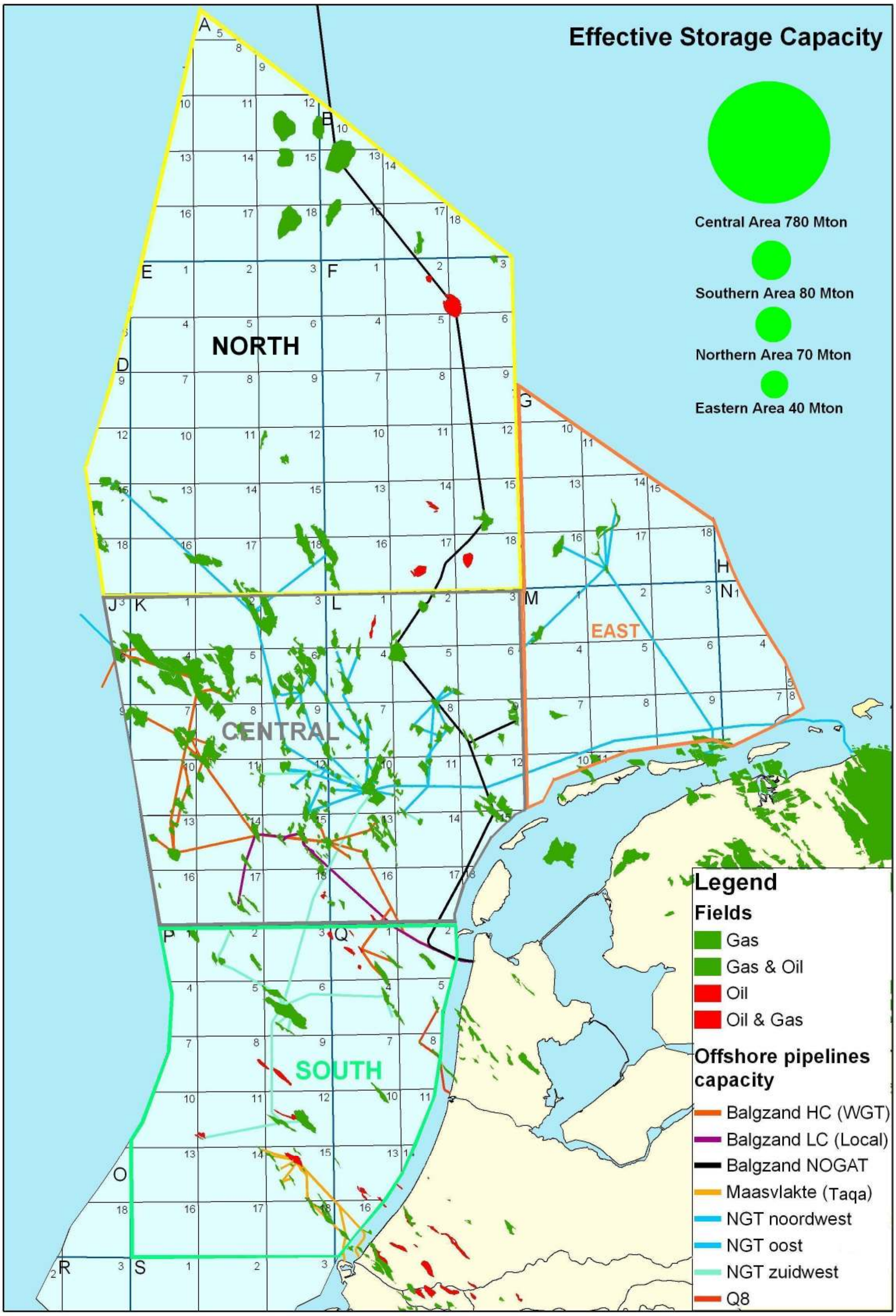


Figure 7-1: Map showing the area distribution of the effective storage capacity in depleted offshore gas fields

Table 7-1 shows the distribution of the effective storage capacity over the offshore areas mentioned above. It is concluded, that from a practical point of view and in the context of large scale CCS a maximum of four clusters of 200 Mton storage capacity each can be assembled in the Dutch offshore.

Area	Quadrant	Theoretical capacity [Mton]	Effective capacity [Mton]
North	A, B, D, E, F	100	70
East	G, M, N	40	40
Central	K, L	1230	780
South	P, Q	190	80

Table 7-1: Area distribution of effective storage capacity

7.2.2 Injection pressure constraints

In section 5, the storage capacity has been evaluated assuming that each gas field would be filled to its original gas pressure. The degree of filling in this case is defined as 100%. However, the maximum injection pressure and the maximum reservoir pressure dictate the actual degree of filling of a reservoir. The CO_2 delivery pressure at the injection site has been assumed at 85 bar. The Flowing well head pressure (FWHP) has been constrained at 160 bar (using local boosting).

Figure 7-2 shows a plot of the injection pressure versus depth with and without local boosting, assuming that the (average) CO_2 density in the well bore is 700 kg/m^3 and friction losses can be neglected.

Most DCS gas fields have an initial pressure close to the hydrostatic pressure in the subsurface. The hydrostatic pressure gradient is shown in Figure 7-2. Most DCS gas fields are in the initial pressure range of 300 to 500 bar (see Appendix 2) and in a depth range between 2.5 and 4 km. This implies that without local boosting the gas fields on average can only be filled to some 80% of their theoretical maximum volume. With the help of local boosting, the remaining storage volume could in principle be filled as well. Under the heading of matched capacity, this is further addressed in the next paragraph.

The degree of filling of a reservoir could be enhanced by increasing the injection pressure and/or the maximum reservoir pressure. The feasibility should result from detailed economic and safety studies, which is beyond the scope of this report. Qualitatively it can be stated, that the last quantities of CO_2 to be injected into a storage are the most costly and energy consuming ones. Therefore, for economic reasons, reservoirs may not be filled to 100%.

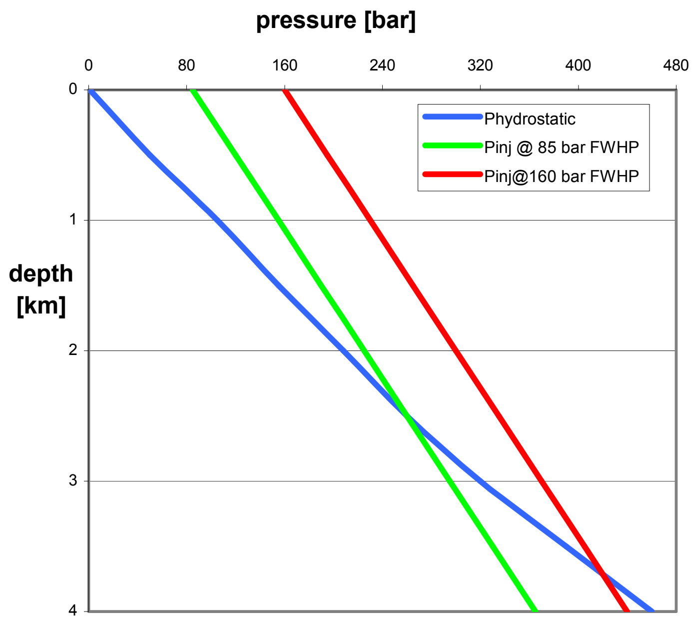


Figure 7-2: Injection pressure versus hydrostatic pressure

7.3 Matched capacity

In the CSLF scheme, the concept of matched capacity refers to the CCS chain of source, transport and injection into the storage. Capacity is called ‘matched’, if the rates along the chain do match, both from a technical point of view as from a business and legal angle. Here we will concentrate on the technical aspects of matched capacity at three levels:

§ 7.3.1 The match of storage volume, i.e. having sufficient storage clusters timely available

§ 7.3.2 The match of injection capacity, i.e. the management of CO_2 injection within a cluster

§ 7.3.3 The injection profile of individual fields of wells

7.3.1 Volume matching

According to present planning, the vast majority of gas fields are assumed to be depleted in the period 2010 – 2020. In fact, the year 2020 has been assumed to be the year in which large scale CCS in the Netherlands might take off. If both assumptions were right, there could be a smooth transition of depleted gas fields into CO_2 storage clusters, provided that the already depleted fields have been kept available for sequestration (mothballed) and have not been permanently abandoned in the mean time.

The OSPAR Convention now requires offshore facilities and wells to be abandoned within 2 years after the cessation of production from the facility. Following that track, by the year 2020 the vast majority of facilities and wells will have been permanently abandoned. Access and redevelopment for CO_2 storage would then have become extremely costly, if not impossible. It is therefore of utmost importance, that facilities and wells – in as far technically reasonably possible - be ‘mothballed’, so that they can be re-entered en re-used for CO_2 storage. At least the options to do so should be kept open and regulation should be adapted to that.

On the other hand, cost-wise and logistically it is not reasonable to expect, that all DCS facilities and wells will qualify for long term mothballing. It would be more efficient to invest in conserving only those assets, that are likely to be part of a future storage cluster. Stakeholders (power sector, offshore operators, regulators, …) should cooperate in defining a ‘Masterplan’ [WGC 2006]. In such a Masterplan, both the possible synergies and conflicts between gas production and CO_2 storage should be investigated. Indeed, the lifetime of gas fields and infrastructure may on average be significantly longer than has been derived here from the current views and plans of operators. The Dutch mining and energy policy is directed at getting the most out of our gas resources. Extended exploration, tail end gas production and tight gas developments may extend the production profiles, supported by rising gas prices and low cost development and production technologies. But such a development would not necessarily be a threat to CO_2 storage. If carefully planned there may be many cases of synergies, e.g. where prolonged tail end production may bridge the gap in the conversion process of a cluster of fields from production mode into CO_2 storage mode. The challenge is to create maximum flexibility and synergies in the re-use of the offshore assets.

In conclusion, a Masterplan is needed for paving the way, or at least keep the options open, to large scale CCS. Without such a plan, the risk is that substantial parts of the Practical portfolio for applying CO_2 storage on the DCS will be permanently lost.

7.3.2 Managing cluster injection

Common practice in gas industry

In the gas industry, matching supply and demand is an ongoing technical challenge. On the demand side, there are short term fluctuations and seasonal variations that have to be supplied from gas sources that in principle deliver a constant gas flow from a certain contracted cluster of fields.

Within a cluster of gas fields in a license area, the operator has to manage the production streams from the different fields into an output stream, that meets the gas contract conditions. This requires field management and timely investments in production capacity (infill drilling, compression).

Usually fields are produced at a constant plateau rate for several years, until decline sets in. The plateau (rate and duration) is dictated by field characteristics (volume and productivity), by the rationale not to over-invest in production capacity and by depletion rules set out in gas contracts. Decisions on whether or not to invest in further production capacity (infill wells, compression) should be taken near the end of the plateau period. The cessation of production is dictated by negative balance between running costs and expected production revenues.

In the Netherlands, an extensive mid stream system is in place, managed by Gasunie Transport Services, that further matches supply and demand with the help of the Groningen field as swing producer and a number of gas storage buffers.

Best practice in CO_2 storage ?

So far high rate CO_2 injection in an depleted gas field has not been done in actual practice anywhere in the world so far. The K12-B test of Gaz de France [www.k12-b.nl] on the DCS probably comes closest, although injection rates of 30 kton/yr are still modest compared to what will be required in large scale operations. Practical experience in operating clusters of fields in large scale CO_2 storage mode is even more remote. However, knowledge, experience and data gained in the gas production mode of the CO_2 storage candidate fields is very valuable and can be used to provide an outlook to how large scale CO_2 injection may look like.

Batch contracts
It can be envisaged, that a company running a large point source of CO_2 wishes to have sufficient certainty as to the availability of storage and injection capacity, before investing in expensive capture installations and transport facilities (purification, compression and flow lines). The company may wish to have a (long term) contract with other parties that can provide these services. The contract then would pertain to a batch of CO_2 (say 200 Mton) to be stored during the life cycle of the installations that generate and capture CO_2. The service providers should have a transport license and storage license for the cluster of depleted gas fields at stake. Moreover in future authorities may require certainty of CO_2 capturing, transport, injection and long term storage as a necessary license condition for new power stations.

Modes of operation & injection strategy
In the scenario assumed above, the cluster of storage fields would be filled at a constant rate of a few percent per year over several decades. The storage operator might choose to run all the cluster fields in parallel throughout the contract duration. The drawback of this mode of operation is, that all assets should be kept operational throughout, which is not cost effective. At the other extreme, the operator may choose to run the fields in a purely sequential mode, activating a new field within the cluster only when the first field comes off a 'plateau' like injection profile into decline. This may seem the most cost effective approach, since only the minimum of assets is active at any time (the other assets are in hibernation). But as stated earlier, no single depleted gas field at de DCS is capable of handling the output of one large point source. Therefore, there will always be the need to run some fields in parallel.

In short: only by making a Storage Development Plan and adequate scheduling of the various injection points within a cluster can a constant rate of CO_2 be accommodated at minimized costs.

Some spare backup injection capacity may be required in order to accommodate occasional technical failure in one of the storage fields. Within a cluster, this may easily be handled, unless a large storage field fails. In some cases, venting the surplus of CO_2 may be the most cost effective solution, although at the expense of CO_2 credits.

7.3.3 Operational constraints on injection

Above, CO_2 storage has been treated at the portfolio level and from the viewpoint of managing a cluster of storage fields. However, also at the individual field or well level there are constraints on the injection capacity that need to be addressed.

Injectivity
The recent AMESCO study [AMESCO 2007] states: 'First indications of injection rates based on desk top studies and reservoir simulations range from 0.2 - 0.5 Mton/year'. In a recent study by the UK and

Norwegian governments [BERR 2007], an injection capacity of 0.75 - 1.25 Mton/year per well has been assumed.

Indeed, since there has been no high rate field test in depleted gas fields so far, injectivity for CO_2 at high rates for now can only be determined by modeling, using the relevant reservoir engineering principles and dynamic reservoir properties as derived from the gas production phase. From gas production experience it is to be expected, that injection rates may considerably vary from field to field (and even from well to well within a field).

Free flow Injection profile
Under the constraint of a constant flowing wellhead pressure only, the CO_2 injection profile will always start at a maximum injection rate and then immediately go into decline. The decline time constant is a function of kh.

Plateau injection phase
A declining type of injection profile does not match the constant mass flow of CO_2 that has to be injected. As in regular gas production operations, a plateau type injection profile will have to be imposed e.g. by choking the inflow and/or gradually increasing the FWHP. The plateau injection rate will therefore be less than the maximum injection rate. There is a trade off to be made between plateau injection rate and the length of the plateau. The storage operator will have to play with the control over the plateau rates of the various fields within the storage cluster in order to match injection with supply and keep the system balanced. For this reason it is not possible to present a unique injection profile of individual gas fields.

Early injection phase
Several studies have pointed at effects, that may occur in the very early stages of injecting CO_2 into a depleted reservoir. Many of these effects are related to the fact that at the initial condition CO_2 will be in the gaseous state. During initial injection flashing may occur, resulting in (unwanted) flow and pressure effects in the wells and in the near well bore region in the reservoir, such as:

- High velocity ('non Darcy') flow régime;
- Joule –Thompson cooling due to expansion of CO_2;
- Phase change from supercritical to gas phase.

In principle these effects all give rise to additional resistance to the CO_2 injection flow. However, a controlled plateau injection profile probably will not give rise to such high velocities, that the extra resistance can significantly reduce the injection rate. But this has to be verified for individual cases. Injection tests will give relevant data on these processes. A remedial action might be to pre-fill a depleted gas field at a moderate rate and from thereon accelerate to the desired plateau injection level. In the build-up phase the injection rate will be restricted in order to manage pressure and temperature effects.

Late injection phase
In gas production, plateau production extends until some 50% of the reserves has been produced. Then production starts to decline and is stopped at a minimum economic rate. Usually, the recovery factor (ratio of gas ultimately produced over gas initially in place) is in the order of 75% without compression and may rise to 90% with compression. Inevitably, some tail end production is lost.

The same principles will hold for CO_2 injection. It is assumed here, that in practice 80% of the effective storage volume will be filled at plateau rate.

Modeling
For this study, TNO has developed a 'fast' (Excel based) model, that calculates a CO_2 injection profile for given reservoir conditions (abandonment pressure and ultimate recovery from the gas production phase) and flow or pressure constraints during the CO_2 injection phase.

The model consists of a well flow module, a reservoir inflow module and a material balance module. An important model feature is the way the specific thermodynamic properties of CO_2 do influence the well performance. Although pressure loss due to friction in the tubing is included, in practice this appears to be a minor effect on the total well performance, which is gravity dominated. The well inflow module is calibrated against gas production test data, that are converted to CO_2 injection parameters using PVT characteristics.

The fast model has been calibrated against the - very limited – set of available numerical CO_2 injection studies on Dutch gas fields, in particular: Barendrecht-Ziedewij [NAM 2008], Q8-A (courtesy Wintershall Noordzee) and K12-B [CATO 2006; WGC 2006a].

The fast model has been applied in the evaluation of the Matched Capacity case. Input data for the model were derived from the answers of the operators to the questionnaire issued for this project. At a later stage, the modeling is to be extended to a multi-field cluster type of storage, in which technical and economic optimization can be studied.

7.4 Matched capacity case

7.4.1 Source

In our example case, the Maasvlakte in the Rotterdam Rijnmond area was chosen as the source area for large scale CO_2 storage offshore the Netherlands. Output rates have been assumed starting at 10 Mton/yr in 2020 and increasing to 20 Mton/yr in 2025 and beyond. This scenario broadly complies with the scenario as currently carried by the Rotterdam Climate Initiative. For the example storage cluster a 5 Mton/yr demand injection rate over 40 years was imposed, i.e. one quarter of the assumed total Maasvlakte output.

It is noted that this scenario is not a prediction and does not imply that until 2020 nothing will happen. On the contrary, the period up to 2020 should be used to gain experience and to gradually increase the amount of stored CO_2, perhaps using near shore storage locations in the offshore P- and Q quadrants or demo sites like K12-B.

7.4.2 Storage cluster

Description

The storage cluster was chosen to consist of the gas fields in the blocks K12, K14 and K15. This area is located at the southern edge of the central offshore K&L quadrants (see maps in Figure 7-4 and Figure 7-5). It is the area within the K&L quadrants, that is closest to the sources at Maasvlakte. Table 7-2 lists all fields that have been develop in the K12/14/15 area so far. The total theoretical capacity of these 23 fields is 260 Mton. As Figure 7-3 shows, the cluster is a representative subset of the total portfolio of offshore gas fields, both in terms of storage size and injectivity (proportional to kh). Other offshore clusters can therefore be expected to behave similarly under large scale CO_2 storage conditions.

Field	*Evacuation system*
K12-A	NGT east branch
K12-B	NGT east branch
K12-C	NGT east branch
K12-D	NGT east branch
K12-E	NGT east branch
K12-G	NGT east branch
K12-S1	NGT east branch
K12-S2	NGT east branch
K12-S3	NGT east branch
K14-FA	LoCal / WGT
K14-FB	LoCal
K15-FA	WGT
K15-FA SW	WGT
K15-FB	LoCal

Field	*Evacuation system*
K15-FB NE	LoCal
K15-FC	LoCal
K15-FE	WGT
K15-FG	WGT
K15-FJ	LoCal
K15-FK	LoCal
K15-FL	WGT
K15-FM	LoCal
K15-FO	LoCal

Table 7-2: Developed gas fields in the blocks K12, K14 and K15

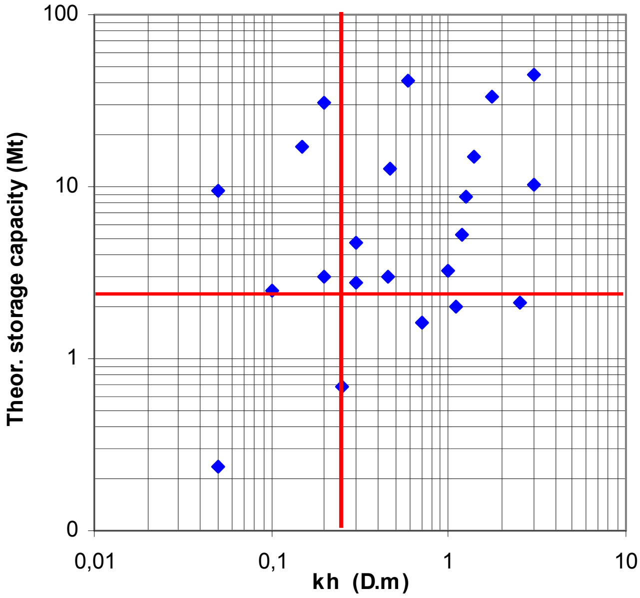


Figure 7-3: K12/14/15 storage cluster: distribution of field characteristics

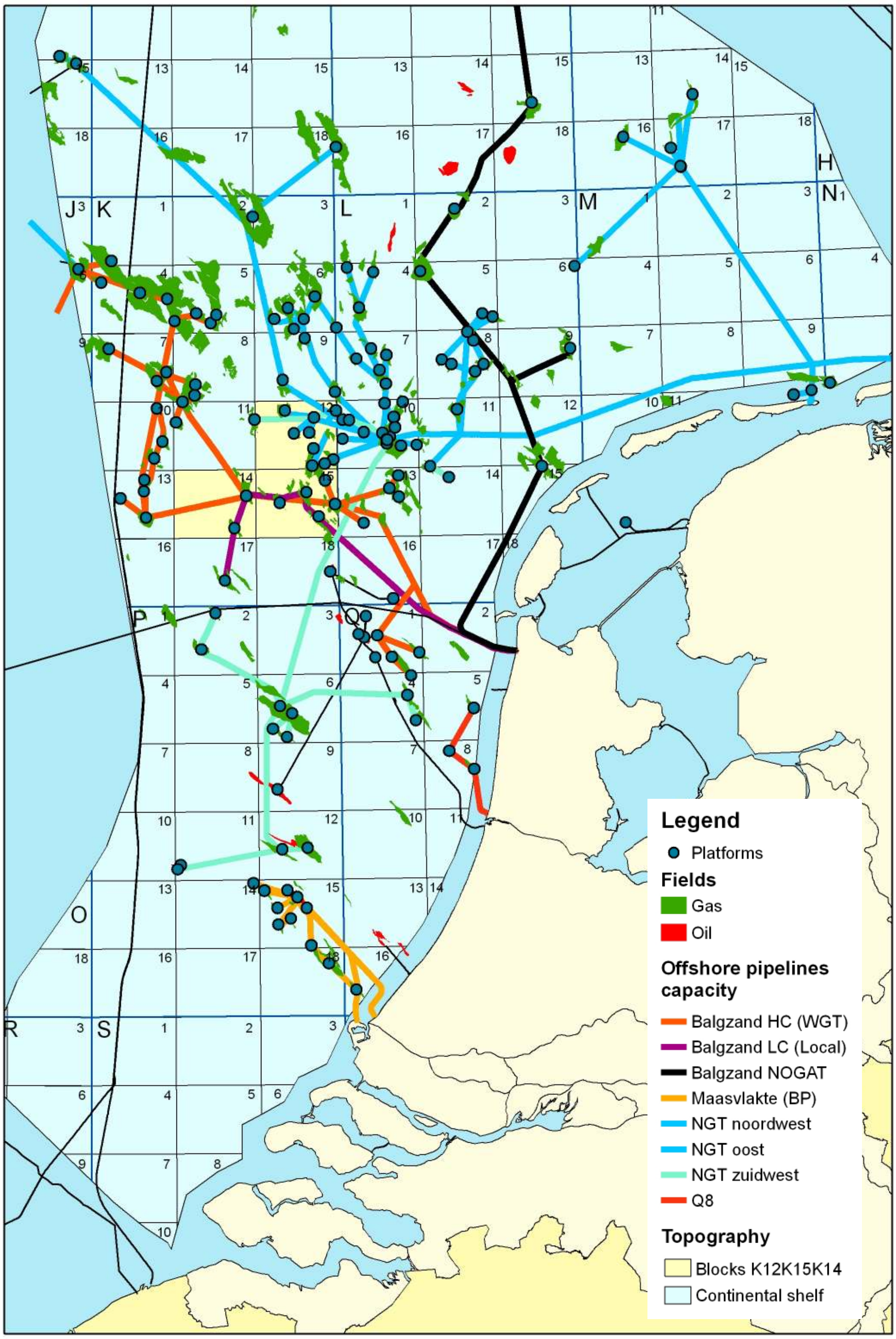


Figure 7-4: Map showing the location of the K12/14/15 storage cluster

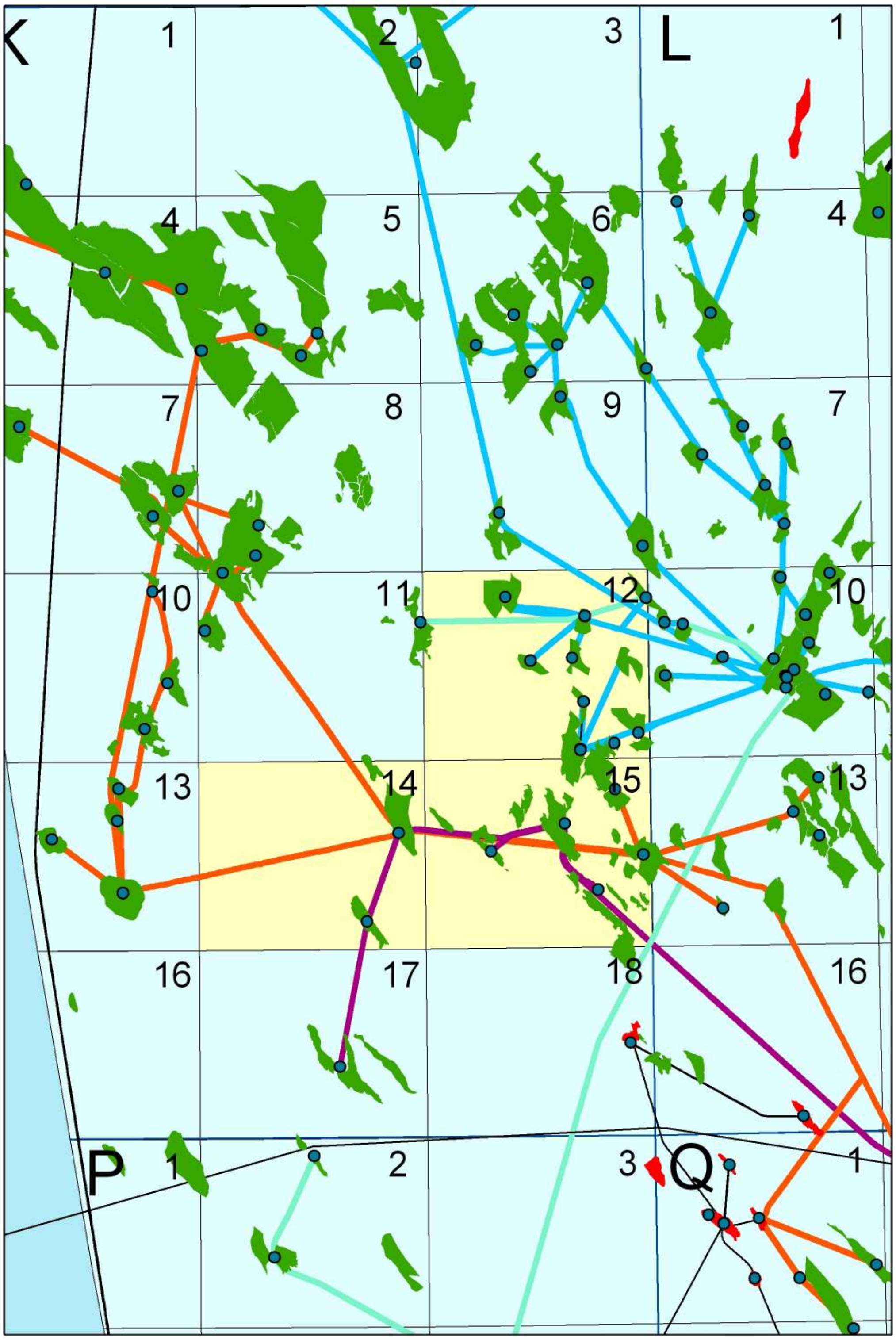


Figure 7-5: **Map showing the location of storage cluster area at the Dutch continental shelf, zooming in on the K12/14/15 storage cluster area. For legend refer to Figure 7-4**

7.4.3 Availability

The current production from the K12/14/15 cluster relies on three evacuation systems. According to current planning, the NGT east branch will be idle by 2020. In our example case the storage project would therefore most likely start in block K12.

The Local system now is expected to become idle in 2022. Therefore core fields in blocks K14 and K15 would be planned after the K12 core fields will have lost their injection capacity.

Finally, the WGT trunk line now is expected to become available in 2030 (assuming that it will not be used longer for cross border transport with the UKCS). Fields in K14/K15 along this line therefore will probably have to be rerouted to the other lines for CCS within the cluster.

As mentioned earlier however, sufficient care should be taken when reckoning with the availability of major trunk line systems for CO_2 transport. It is expected that by the raising energy prices, production of existing assets will be prolonged and exploration and production will be intensified resulting in connection of new prospects on the trunk lines.

7.4.4 Injection capacity

Injection strategy
In line with the discussion in paragraph 6, for each gas field in the cluster the plateau injection profile has been determined, at which the field will be filled to 80% of its effective capacity under the constraint of a maximum FWHP of 160 bar.

Modeling results
Table 7-3 shows the results of the fast model injectivity calculations for the gas fields in the K12/14/15 cluster. Excluding the already abandoned fields and merging small separate compartments into one field, a total of 18 gas fields remains for CO_2 injection. Note, that all currently not abandoned wells have been taken into account as future CO_2 injection wells.

Primary model outputs are the plateau rate and plateau length up to a 80% filling of the reservoir. Derived numbers are the quantities of CO_2 stored under various cut offs. As the table shows, the net effect of the storage size cut off is minor (2%). The cut off at kh = 0.25 Dm however, has a significant impact (20%). In particular, the modeling shows that fields 4 and 5 would fall below the cut off, whereas they do contribute more to the overall plateau profile than some of the much smaller fields. Therefore, there is a reason not to apply the kh cut off too rigorously in the context of a cluster of gas fields. As stated earlier, detailed economics will decide, where the actual cut offs will be laid. Looking at the range of values for the CO_2 stored, a total of around 200 Mton in these 18 gas fields seems technically feasible, provided that all existing assets (wells, facilities) remain available over several decades.

As to the injection strategy to arrive at a plateau of 5 Mton/yr over a 40 years period:

- Fields 1 – 5 clearly show the largest plateau injection rate in the order of 4 to 5 Mton/yr each. These fields are to be the core fields for the Storage plan in this example case. If put in sequence, these 5 fields might sustain a 4 to 5 Mton/yr injection rate for close to 35 years.
- The other 13 fields are to be fitted into the injection planning scheme according to economics within the cluster.

Field	Plateau rate	Plateau length	CO_2 stored	CO_2 stored @ size cut off	CO_2 stored @ kh cut off	CO_2 stored @ size and kh cut off
	Mton/yr	yr	Mton	Mton	Mton	Mton
1	4.3	10.2	43.9	43.9	43.9	43.9
2	5.0	7.7	38.4	38.4	38.4	38.4
3	4.3	7.4	31.6	31.6	31.6	31.6
4	4.3	6.5	27.9	27.9		
5	5.7	2.9	16.6	16.6		
6	1.4	9.5	13.4	13.4	13.4	13.4
7	2.2	5.9	12.7	12.7	12.7	12.7
8	1.4	7.1	10.2	10.2	10.2	10.2
9	0.7	11.8	8.4	8.4	8.4	8.4

10	0.3	14.9	5.1	5.1	5.1	5.1
11	0.3	14.7	4.6	4.6	4.6	4.6
12	2.2	1.4	3.1	3.1	3.1	3.1
13	0.7	4.1	3.0	3.0		
14	0.6	4.4	2.7	2.7	2.7	2.7
15	0.7	2.7	2.0		2.0	
16	0.7	2.1	1.5		1.5	
17	0.2	3.8	0.8		0.8	
18	0.7	0.9	0.7		0.7	
Cum			**227**	**222**	**179**	**174**

Table 7-3: Fast model results for the K12/14/15 cluster fields. All data refer to the plateau injection phase until a fill of 80% of the total storage capacity

7.5 Transport

In analyzing the transport of CO_2 from the Maasvlakte source area to the K12/14/15 storage area through existing pipelines, it has been assumed, that gas transport always has priority over CO_2 transport.

To determine the possible use of existing pipelines, the capacity of possible trajectories were calculated taking into regard the date of availability. The capacity of the trajectories is calculated by using the D'Arcy-Weisbach equation. As many assumptions have to be made for these calculations (i.e. roughness, velocity, etc), the results should be regarded as indicative only. The assumed minimum delivery pressure at the platform is 85 bar in order to avoid the two phase flow regime.

A possible route is shown in the table below. For this trajectory it is assumed that a new pipeline will be installed from P15-D to P12-SW. The capacity of this pipeline should be such that it is not the restricting link in the trajectory.

From	To	Length [km]	Diameter (inch)	Abandonment date [year]	Max. pressure rating [bar]
Maasvlakte	P15-D	40.1	26	2015	100
P15-D	P12-SW	13.5	-	New	
P12-SW	P6-A	42.0	12	2015	201
P6-A	L10-AR	78.7	20	2015	121
L10-AR	K12-BP	21.4	18	2017	136

Table 7-4: Possible pipeline route to transport CO_2 from the Maasvlakte via P15 to the K12/14/15 cluster fields through as much as possible existing pipelines

The inlet pressure of the piping system is determined by the pipeline from the Maasvlakte to P15-D with a maximum pressure rating of 100 bar. Calculations show that the rating of the pipeline from P12-SW to P6-A to the overall limiting factor for the system. The overall capacity for the trajectory is in this case approximately 2.4 Mton/year. The pressure drop for the entire system in this case is 15 bar.

Alternatively, to increase the capacity of this trajectory, a booster station can be installed at P12-SW to make optimal use of the higher pressure rating of the downstream pipelines. This booster station can increase the capacity of the whole system to 6 Mton/year. To further increase capacity, a new pipeline can be installed from P15-D to P6-A (length approx. 53 km). This can increase the capacity to 9 Mton/year.

To facilitate the injection of CO_2 in the K14 + K15 fields, new pipelines (and booster pumps) can be installed between K12 and the K14 and K15 blocks.

Concluding, through the piping system described above not more than approximately 6 Mton/year can be transported. This system therefore does not provide sufficient capacity for the considered case.

Alternatively to further increase the capacity the LoCal pipeline can be used. This trajectory will any way not be available before 2020. To connect the Maasvlakte to the LoCal pipeline a new pipeline of approximately 105 km has to be laid. The table below shows the pipelines used for this route:

From	To	Length [km]	Diameter (inch)	Abandonment date [year]	Max. pressure rating [bar]
Maasvlakte	LoCal	105	-	New	
LoCal	K-15-FB-1	74.3	24	2020	100
K-15-FB-1	K-14-FA-1	16.6	16	2021	100
K-15-FB-1	K-15-FC-1	7.9	10	2004	120
K-15-FB-1	K-15-FK-1	8	10	2021	120
K-14-FA-1	K-14-FB-1	9.2	10	2021	100

Table 7-5: Possible pipeline route to transport CO_2 from the Maasvlakte via the existing LoCal pipeline to the K12/14/15 cluster fields

Without using any boosters and assuming a pressure drop of 15 bar from the entry of the LoCal pipeline to the end of the system (K-14-FB) the capacity is estimated at 3.6 Mton/year. However, with a booster station installed at K15-FB to facilitate the K-15 and the K14 platforms, the capacity at K15-FB increases to 12 Mton/year.

The combined capacity using both piping systems described above, including installing booster stations and new pipelines (total length approximately 120 km), is still less than the required 20 Mton/year as from 2025. Moreover it is questionable whether all piping segments will be available in due time.

The capacity of the nearby located WGT to K13-AP is approximately 26 Mton/year. The WGT runs close to K15 K14 en K12. However due to continued exploration and possible international connections, it is not expected that this trunk line can be used for CO_2 transport in the near future and is therefore not considered as a viable option.

To enable the transport of 10 Mton/year in 2020 and 20 Mton in 2025 it can be concluded from the above conclusions, that a new pipeline shows the best perspective. The distance between the Maasvlakte and the K12 fields is approximately 150 km, which is only approximately 30 km longer than the extra required pipelines segments in the combined piping systems described above. The new pipeline should be located such that it can be connected to existing interfield pipelines as much as possible to transport the CO_2 to the various wells in the fields addressed in this case.

Constructing a new pipeline has the opportunity to design it optimally for CO_2 transport with respect to delivery pressure, capacity and pressure drop. Installing booster pumps can be avoided when CO_2 arrives at the platform at a sufficient high pressure. Amongst other variables, the required delivery pressure, the maximum pressure rating, economics and the length determine the pipeline diameter. Indicatively, the required diameter for a capacity of 20 Mton at about 150 bar is approx. 28 inch assuming a pressure drop of 40 bar for a pipeline of approximately 150 km.

Note: The above assessment on the pipelines is dedicatedly made for the considered case of 10 / 20 Mton / year CO_2 transport starting by about 2020. In the pilot and demonstration phase between 2010 and 2020 the existing pipelines offers good and cost effective options to transport considerable amount of CO_2 with relatively restricted investments. For instance by the laying of 13.5 km new pipeline a CO_2 transport capacity of approximately 2.4 Mton/year to the L10 and K12 blocks can be realized.

7.6 Summarizing the matched capacity case

Matched Capacity example

The Maasvlakte to K12/14/15 storage area example case has shown, that:

- Large scale CCS probably will need the construction of new trunk lines for CO_2 transport
- 200 Mton may be stored in a cluster of 250 Mton theoretical capacity, provided all fields and wells remain available
- Core fields (in this case 5) are operated in sequence
- Smaller fields are fitted into the injection profile

Clustering potential

Large scale CO_2 storage will require clusters of fields of some 200 Mton storage capacity and 5 Mton/yr injection capacity each. These conditions can practically only be met in the central offshore K&L quadrants. Here about 4 of these clusters may be projected.

In other parts of the DCS, the fields are either too small or too remote to form an adequate cluster for large scale CO_2 storage.

Injection potential

An injection rate of 20 Mton/yr can be accommodated for several decades in the central Dutch offshore sector, provided all necessary assets will remain available in this time frame. This is the equivalent of 4 large coal fired power plants. Larger storage demand scenario's are unlikely to be technically realistic.

Pipelines routing and use

For the current case the existing pipelines do not have enough capacity to transport 20 Mton CO_2 per year to the reservoirs. A new pipeline from the Maasvlakte to the K12, K14 and K15 blocks is therefore considered to be preferred. At the K12, K14 and K15 blocks the new pipeline can be connected to existing interfield pipelines to distribute the CO_2 to the individual platforms and reservoirs.

7.7 Recommendations

All results from the above analysis are the result of technical evaluation only. It is recommended to screen the results including costs and economics in phase 2.

In addition, a network injection model has to be applied to optimize the scheduling of the storage fields.

8 CONSIDERATIONS ON CO_2 PROPERTIES

To transport CO_2 from the point of capture (e.g. a power plant) to the point of storage (i.e. a gas reservoir) the pressure and temperature conditions will change resulting in changes in density and viscosity (possibly including phase transitions) affecting the transport characteristics. In this chapter the main implications for CO_2 transport and storage are discussed. The topic is analyzed in more detail in Appendix 1.

8.1 Physical properties of CO_2

In the transport and injection part of the CCS chain, pressures may vary between 40 bar to about 500 bar, while temperatures range from 4ºC to about 150ºC. These ranges determine the physical states of the CO_2. Figure 8-1 shows the different states of pure CO_2 as a function of pressure and temperature. It is important to realize, that CO_2 will be in the dense (supercritical) state, when temperature is above 31.1ºC and pressure above 73.9 bar. In the supercritical state a substance has the density of a fluid, but acts like a gas-like compressible and low viscosity fluid. Hence it will fill the reservoir to a high degree.

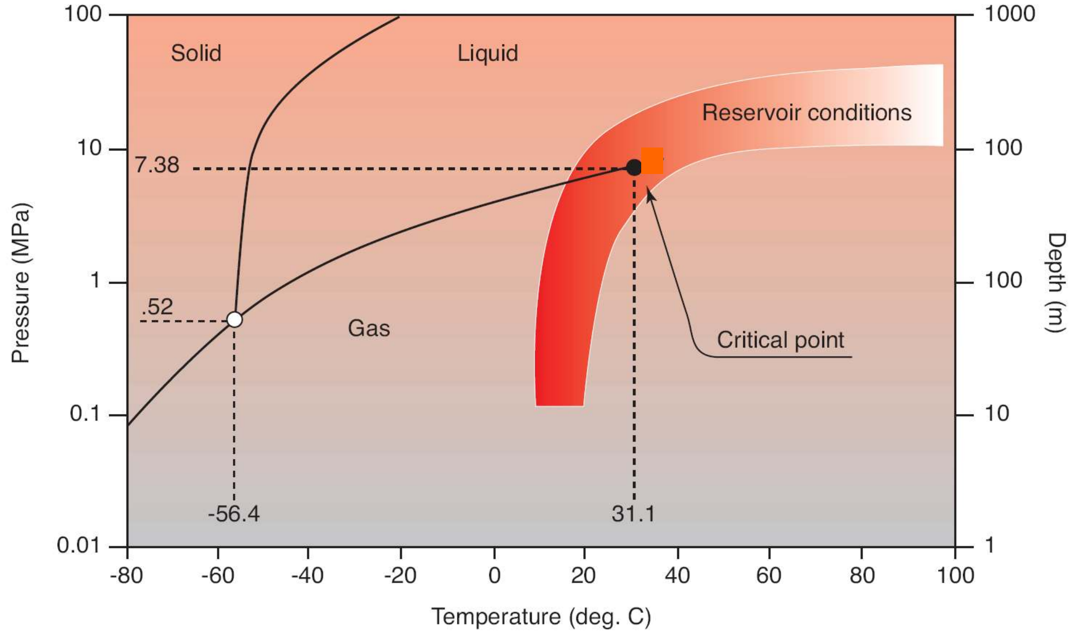


Figure 8-1: Pressure and temperature conditions for pure CO_2 transport and storage [Van der Meer 2005]

The upper pressure rating of the pipelines and the requirement to avoid two-phase flow determines the pressure in the pipeline system for CO_2 transport. For the existing pipeline systems on the DCS, the maximum operating pressure generally ranges from 100 to 130 bar. To avoid two-phase-flow long haul CO_2 transport should be executed preferably in the dense phase, which means that the required pressure under practical CCS conditions (temperature, CO_2 composition, etc.) should generally remain above about 85 bar. For gaseous phase transport the pressure should remain below about 40 bar. The density of CO_2 varies considerable with varying temperature and pressure. In the dense phase (reservoir conditions) the density is in the range between 500 and 750 kg/m^3. During transport the density lies around 800 kg/m^3 due to the lower temperature. In Table 8-1a summary is given of pressures, temperatures and densities relevant for offshore CO_2 transport and storage.

Situation	Pressure [bar]	Temperature [ºC]	Density [kg/m^3]	State
Transport pipeline	85 -100	4 30	904 592	Liquid
Reservoir initial state	40 60	150 100	53 100	Gas
Reservoir end state	300 400	150 100	500 765	Dense (Supercritical)

Table 8-1: CO_2 properties relevant for pipelines and reservoirs (assuming pure CO_2)

Most gases tend to cool down when the pressure is decreased. When the pressure is decreased over a choke valve (isenthalpic, i.e. no labor extraction) this is referred to as the Joule –Thomson (J – T) cooling effect and this phenomenon is applied at large-scale in industrial and domestic cooling. The Joule –Thomson cooling effect strongly depends on the substance and the actual pressure and temperatures. The J – T effect is only substantial in the gaseous or two-phase state.

In full scale CCs operation, the CO_2 will generally be supplied at the reservoir interface at a pressure of at least 300 bar (including the hydrostatic pressure). The temperature of the CO_2 increases during the flow from the wellhead to the reservoir interface due to geothermal heating, The actual temperature increase depends on the thermal conductivities of the earth layers and flow rates of the CO_2 and is difficulty to quantify in a general sense. In the presence of non-condensables the phase transition is shifted to higher pressures resulting in a somewhat higher J-T effect. At the start of the injection (initial state) the reservoir pressure can be below 35 bar. Then, additional heating might be necessary, as by choking the CO_2 (with a temperature of about 4 - 12ºC) to a pressure below 35 bar, the CO_2 cools down to sub 0ºC. Possible problems that can arise due to this cooling include freezing of residual water and formation of hydrates (with H_2O or CH_4) in the reservoir resulting in a reduced injectivity. Moreover the effect of extreme cooling in reservoirs generates thermals stress that could fracture the formation.

For high CO_2 rates the amount of required heating can be substantial. The theoretical required heat to compensate for the J-T cooling is approximately 240 kJ/kg for the injection into a reservoir at 30 bar pressure. For a well with medium injectivity (0.5 Mton/year), the required heating is approximately 3.8 MW. Due to the heating, the density and flow velocities of the CO_2 will change. When the CO_2 expands in a reservoir at 30 bar it will turn into the gaseous state, resulting in a much lower density (approximately a factor 30 lower). This affects the maximum injectivity of the reservoir in the start up phase. This effect should accounted for in the engineering phase, where detailed (modeling) studies will be required. It may turn out be required to prevent any adverse effects to heat up and evaporate the CO_2 at the platform in the initial state until the reservoir pressure has increased sufficiently that injection in the dense phase is possible.

When calculating the total heat demand two considerations should be kept in mind:

1 Heating the injected CO_2 will normally only be required in the initial filling phase of a reservori. As soon as the reservoir pressure has risen enough, CO_2 will be injected in the dense phase and no phase transition and thus no substantial J-T cooling will occur anymore. This means that only at platforms where injection just started heating will be required;

2 In the above calculation of the energy demand to compensate for the J-T cooling the heat up during the flow through the well tubing by geothermal heating has conservatively been neglected. The actual heat input in heaters will therefore be less.

In addition to heating, booster pumps will also consume power. For instance: to boost the above flow rate of 0.5 Mton/year from 85 to 160 bar a pump power of about 200 kW is required.

Concluding, due to the physical properties of CO_2, in principle a high degree of reservoir filling is possible. However, due to the Joule-Thomson effect, heating of CO_2 might be necessary in the initial state for fields with a low reservoir pressure, which can require significant amounts of energy and may affect the initial injection rate considerably.

8.2 Contaminants

The captured CO_2 will be contaminated with other substances. For the transport of CO_2 the most important impurities will be water, H_2S, SO_2, O_2, N_2, CH_4, Ar, H_2 and possible particulate matter. The quality of the CO_2 depends on the capturing process, abatement technologies and after-treatment of the gas prior to compression (e.g. drying).

Main concern for CCS is the corrosion of the applied materials: mainly carbon steel has been applied in pipelines and process installations on the DCS. For corrosion to occur, the presence of an acid (e.g. CO_2, H_2S or SO_2), water or O_2 is necessary. When the CO_2 is dry (i.e. above the dew point / no liquid water) and/or in supercritical state, there is no important risk of corrosion [Chilly *et al.* 2005]. According to literature [EnergieNed 2007], water levels of 300 – 500 ppm are accepted by industry for CO_2 transport through carbon steel pipelines. However, the use of small amounts of corrosion inhibitor to protect the pipeline may be necessary. It is recommended to test the corrosion rate on the actual pipelines as soon as the actual gas composition for CCS is known. To avoid compatibility problems with the existing pipeline infrastructure and the captured CO_2 in a later stage (when costs could already be made for the preservation of infrastructure) it is suggested that the stakeholders set the CO_2 composition requirements at an early stage.

Some components in the supplied CO_2 may also interfere with the reservoir rock. This concerns among other acid formation (H_2S, SO_2 and NO_x), oxidation (O_2) and solids.

Non-condensables in the CO_2 result in a higher liquefaction pressure and in a somewhat stronger J-T effect. A higher fraction of non-condensables in the CO_2 will hence result in an increased minimum transport pressure in order to remain in the dense phase.

In EnergieNed 2007 and Dynamism 2007, the following composition is proposed for long haul transport to the reservoirs through carbon steel pipelines:

Component	Proposed conditions	Reason / Remarks
CO_2	> 95 %	'Overwhelmingly CO_2'
H_2O	< 500 ppm	Corrosion, lower level recommended
O_2	Aquifer: < 4% EOR: 100 -1000 ppm	Figures mentioned for EOR, much uncertainty on effects of O_2 in reservoirs.
H_2S	< 200 ppm	Corrosion / Safety and health
H_2	< 4 vol%	H_2 cracking of steel
Total non-condensables	< 4 vol%	Phase transition at higher pressures
SO_2, NO_x	100 ppm	Corrosion / Safety and health
CO	2000 ppm	Health and safety considerations
Pressure	> 85 bar	Required for dense phase transport

Table 8-2: Overview of the typical requirements and properties for CO_2 pipeline transport

8.3 Transport capacity and transport facilities

In the 2007 BERR report, calculations are presented that show the relation between pipeline diameter and CO_2 transport capacity. In Figure 8-2, the transport capacity of various pipeline sizes is shown for a CO_2 supply pressure of 100 bar and a delivery pressure of 85 bar, i.e. the situation that the CO_2 would be transported through existing pipelines with a limited pressure rating. The flow velocity varies from about 2.1 m/s to about 1.6 m/s. In case new pipelines with a higher pressure rating are laid, the inlet pressure can be raised to increase the transport capacity. In annex 1 the graphs for the capacity related to length are given for supply pressures of 180 bar and 220 bar. For reference it can be assumed that a coal fired power plant of 1000 MWe as is planned on the Maasvlakte will have an annual

CO_2 emission of about 5 Mton/year, of which about 4.5 Mton/year may be captured, i.e. a flow rate of 500 ton / hr.

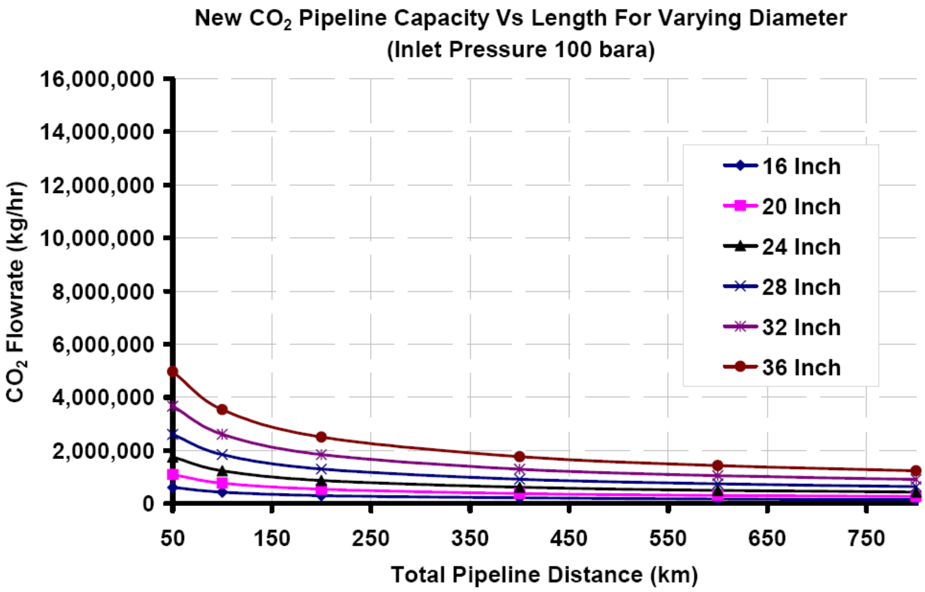


Figure 8-2: CO_2 flow rate related to the internal pipeline diameter and length for a supply pressure of 100 bar and a delivery pressure of 85 bar (a flow of 10 Mton/year equals an hourly flow of 1.1 million kg/h) (BERR 2007)

To determine the pipeline capacity of the existing pipelines in this study, the D'Arcy-Weisbach equation has been used. As only the diameter, length and permissible pressure drop are known, assumptions are made for the roughness, Reynolds coefficient, viscosity and density. The calculated values are in good agreement with the values presented in literature (BERR 2007). The calculated values only have the purpose to show whether the capacity of the pipelines could be a limiting factor for the maximum injection rate. For engineering purposes more detailed calculations are necessary.

Booster stations

Booster stations may be necessary to compensate for the pressure drop during long haul transport and/or increase the capacity:

- A technical / economic optimization should show how the required transport capacity can best be met, i.e. by large diameter pipeline with a moderate pressure drop, by a pipeline with a higher pressure rating and a higher pressure drop, by booster stations or a combination of those;
- In case the required capacity is close to the maximum of an existing pipeline, a booster station may increase the capacity of the pipeline enough to make it usable for CO_2 transport without the need to invest in a new pipeline.
- The available pressure drop over the pipeline is determined by the maximum pressure for which the pipeline is certified for and the minimum delivery pressure for which it is ensured that the gas will remain in the dense phase.
- Booster stations are preferably installed at existing platforms; in some cases, a new intermediate platform may be needed.

Pumps and compressors

The CO_2 arrives in the dense state at the platforms at 85 bar minimum. For a CO_2 column of 3500 m the total static pressure added by the column is about 250 bar (assuming a density of 700 kg/m^3). Including the initial pressure of 85 bar at the platform, the bottom hole pressure then is about 335 bar, whereas initial reservoir pressures at 3500 m are in the order of 400 bar. A booster pump then is required to further fill the reservoir and to boost the injection rate in a nearly filled reservoir. The investment in a booster pump at the injection platform should be judged against the option not to further fill the reservoir, but rather change to a new storage reservoir.

Vent and blow down facilities

A point of attention for blow down of pipelines or platform facilities is, that gaseous or liquid CO_2 solidifies when the pressure is decreased to atmospheric conditions. While venting, the CO_2 will form a kind of CO_2 snow, which might block the vent facility. The vent and blow down facilities should be designed to allow for this effect and the vents should blow down to a safe location due to the asphyxiating effects of CO_2.

8.4 Risks and hazards

There are several risks related to CCS. In the IPCC special report on CCS (IPPC 2005) ample attention is paid to potential risks and hazard. The following major points are addressed:

- When CO_2 is released to atmosphere, it presents a risks for asphyxiation to people present. The physiological and toxicological effects are well understood. At concentrations above about 2%, CO_2 has a strong effect on the respiratory system and above 7 – 10 % it can cause unconsciousness and death. Concentrations below 1% do not show any adverse effect on humans;
- When CO_2 leaks from a reservoir, the CO_2 can migrate through the water to the atmosphere. Depending on the leakage rate it might also completely dissolve in the sea water. Then biological impacts to the sea bottom and marine life is a point of concern;
- In case of blow outs (major uncontrolled releases due to loss of well control) CO_2 gas bubbles can surface and may lead to dangerous situations for ships and other vessels. Contrary to gas blow outs, CO_2 blow outs do not have the risk of ignition;
- Well integrity and leaks from abandoned wells. It is not clear to all operators on the DCS what the quality is of previously abandoned wells. Especially the cement well plugs can be of concern, also because of possible aging of the cement. Ultimately the weakest well in a reservoir will determine up to what pressure a reservoir can be considered safe for CO_2 storage. Well repair of reinforcement might be possible but costly. In Figure 8-3 potential leakages along an (abandoned) well are shown;
- Injection under pressures substantially higher than original formation pressures can cause stress in the subsurface containment system and might lead to induced seismicity;
- The possibility of chemical reactions between CO_2 or contaminants with (components of) the underground formation.

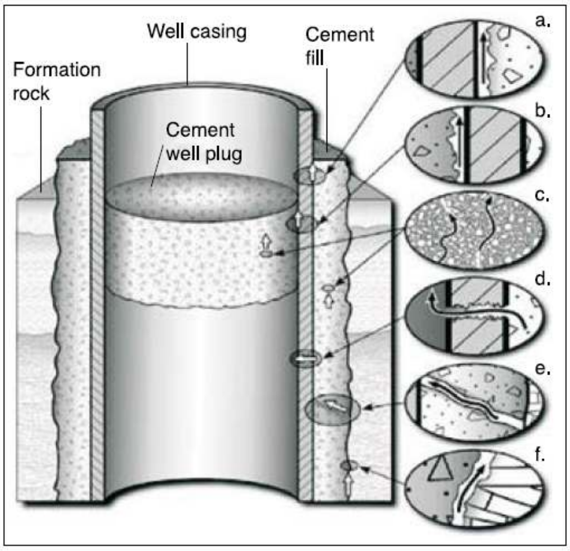


Figure 8-3 Possible leakage pathways in an abandoned well: (a) and (b) between casing and cement wall and plug, respectively; (c) through cement plugs; (d) through casing; (e) through cement wall; and (f) between the cement wall and rock (after Gasda et al. 2004)

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10 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
DCS	Dutch Continental Shelf, for this study assumed to include the Dutch 12 miles zone and the Dutch Exclusive Economic sector of the North sea
EOR / EGR	Enhanced Oil Recovery / Enhanced Gas Recovery
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
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 labor 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)
NGT	Noord Gas Transportleiding transporting high caloric gas from the north western part of the DCS, landfall in Uithuizermeden (Groningen)
NOGAT	Noordelijke Offshore Gastransportleiding (NOGAT) transporting high caloric gas from the north eastern part of the DCS, landfall in Den Helder
NOGEPA	Netherlands Oil and Gas Exploration and Production Association, the branch organization of onshore and offshore E&P companies
ppm	Part per million
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 DCS, landfall in Den Helder

APPENDIX 1 Transport considerations

Pressure and temperature

The properties of CO_2 vary with changing pressure and temperature as shown in Figure I- 1 [IPCC Special Report on Carbon dioxide Capture and Storage. From this figure some important features of CO_2 can be derived. At atmospheric pressure CO_2 will be in the solid state at low temperatures. By increasing temperature the solid CO_2 will sublime directly to the vapor / gas state. When applying pressure to CO_2 at 20 ºC, the CO_2 will turn from vapor to liquid at the saturation pressure. At temperatures higher than the critical point and pressures above 73.9 bar, CO_2 is in the supercritical state. This is important for CO_2 storage as the end pressure in reservoirs will be above 73.9 bar while the temperature at reservoirs will be far above 31.1 ºC. In the supercritical state the density can be quite large (> 1000 kg/m^3). It is important to realize that the phase change from the liquid to supercritical phase does not require energy.

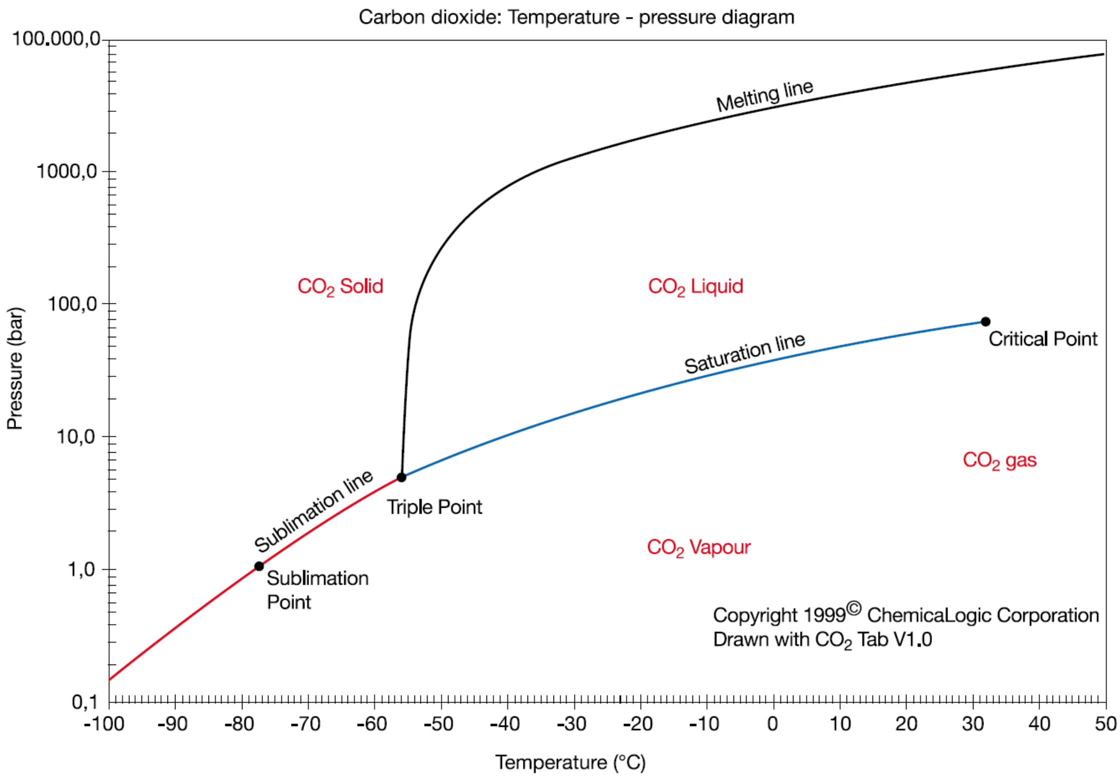


Figure I- 1: Pressure - temperature diagram of CO_2 including phase transitions

Density and viscosity

The density of CO_2 will change during the transport of CO_2 as the density depends on temperature and pressure (refer to Figure I- 2).

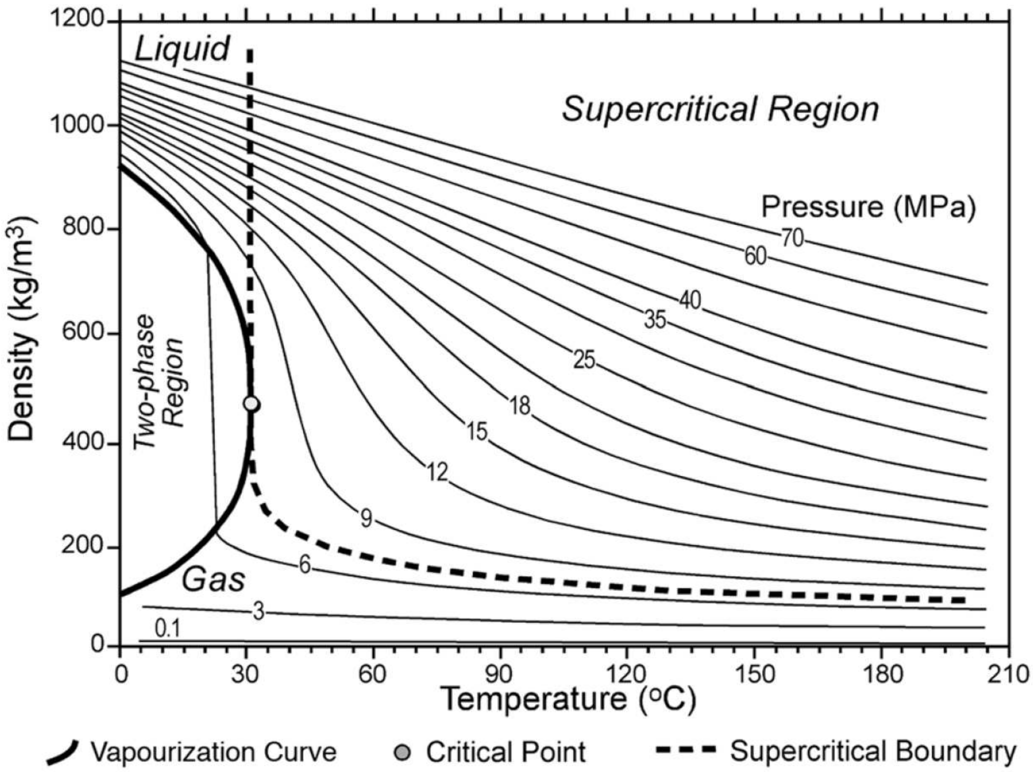


Figure I- 2: Density of CO_2 as function of pressure and temperature

From the figure it follows that the density can vary considerable with changing temperature. To determine the capacity of pipelines and reservoirs, these variations should be taken into account. For pipelines from shore to platforms, the density will be high, as temperature is around 4º – 20º at pressures above 85 bar. The CO_2 will thus be in the dense state with a density of over 800 kg/m^3. For the capacity of reservoirs the end situation should be regarded, with temperatures of around 150 – 200ºC and pressures in de range of 200 - 350 bar. The CO_2 will then be in supercritical state with densities of about 600 kg/m^3.

The viscosity is of importance for the determination of the pressure drop in pipelines. In the annex the relation between viscosity, pressure and temperature is shown graphically and it appears that the viscosity of CO_2 strongly depends on the temperature and pressure.

Contaminants

The captured CO_2 will be contaminated with other substances. For the transport of CO_2 the most important impurities will be water, H_2S, SO_2, O_2, N_2, CH_4, Ar, H_2 and possible particulate matter. The quality of the CO_2 depends on the capturing process, abatement technologies and after-treatment of the gas prior to compression (e.g. drying).

Main concern for CCS is the corrosion of the applied materials, mainly carbon steel applied in pipelines and process installation. For the occurrence of corrosion the presence of an acid (e.g. CO_2, H_2S or SO_2), water or O_2 is necessary. When the CO_2 is dry (i.e. above the dew point / no liquid water) and/or in supercritical state there is no important risk of corrosion [Cailly *et al* 2005]. According to literature [EnergieNed 2007] water levels of 300 – 500 ppm are accepted by industries for CO_2 transport through carbon steel pipelines. However, the use of small amounts of corrosion inhibitors to protect the pipeline may be necessary. It is recommended to test the corrosion rate on the actual pipelines as soon as the actual gas composition for CCS is known.

H_2S in the presence of water will form sulfuric acid which in turn will lead to corrosion of carbon steel pipelines. When no free water is present, iron sulfide will be formed from the reaction of H_2S and the carbon steel pipeline. The iron sulfide will act as a protective layer that prevents corrosion of the pipeline. This process however also results in the formation of atomic hydrogen that can enter the metal matrix and

can result in sulfide stress corrosion cracking. Besides H_2S is toxic. When a blow out might occur, high concentrations of H_2S can involve a safety risk, especially for pipelines that are land-based. To ensure that CO_2 is the limiting risk factor, the H_2S concentration should remain below 200 ppm[l].
Furthermore, hydrogen ions can diffuse in the metal matrix, causing the carbon steel pipelines to become brittle. Therefore, H_2 concentrations should be limited, especially at higher H_2 partial pressures.

Hydrates can be formed when free water and CO_2, CH_4 and/or H_2S are present at low temperatures and high pressures. Hydrates can cause problems in the pipelines (blockage) and at the injection point of the wells. If the CO_2 gas flow has a sufficient low water content (i.e. below 500 ppm = 368 mg/m^3 at 25ºC, 1 bar), hydrate formation is not to be expected. In Appendix 2 a graphical representation is given of water solubility in CO_2 and CO_2-CH_4 mixtures [Austegard et al. 2006].

Non condensable gases like N_2, O_2, NO, CO, H_2, CH_4, Ar will result in a shift of the phase diagram of CO_2, by which the CO_2 will remain at higher pressures in the gas phase. As a result increased pressures are required for transport in the dense phase.

Some components in the supplied CO_2 may also interfere with the reservoir rock. This concerns among other acid formation (H_2S, SO_2 and NO_x), oxidation (O_2) and solids.

In EnergieNed 2007 and Dynamis 2007, the following composition is proposed for long haul transport to the reservoirs through carbon steel pipelines:

Component	Proposed conditions	Reason / Remarks
H_2O	< 500 ppm	Corrosion, lower level recommended
CO_2	> 95 %	'Overwhelmingly CO_2'
O_2	Aquifer: < 4% EOR: 100 -1000 ppm	Figures mentioned for EOR, much uncertainty on effects of O_2 in reservoirs.
H_2S	< 200 ppm	Corrosion / Safety and health
H_2	< 4 vol%	H_2 cracking of steel
Total non-condensables	< 4 vol%	Phase transition at higher pressures
SO_2, NO_x	100 ppm	Corrosion / Safety and health
CO	2000 ppm	Health and safety considerations
Pressure	> 85 bar	Required for dense phase transport

Table I- 1: Overview of the typical requirements and properties for CO_2 pipeline transport

Joule - Thomson Cooling

Most gases tend to cool down when the pressure is decreased. When the pressure is decreased over a choke valve (isenthalpic, i.e. no labor extraction) this is referred to as the Joule –Thomson (J – T) cooling effect and this phenomena is at large-scale applied in industrial and domestic cooling. When labor is extracted from the gas e.g. by expansion over an turbine, the cooling effect will be larger than at isenthalpic cooling. The Joule –Thomson cooling effect strongly depends on the substance and the actual pressure and temperatures. In practice is J – T effect is read off from a pressure – enthalpy diagram for the concerned substance[4]. Effectively the J – T effect only occurs at substance in the gaseous or two-phase state.
For CCS the CO_2 will generally be supplied at the wellhead with a pressure of at least 300 bar (including the hydrostatic pressure) and a temperature of 4 - 12ºC (sea water temperature). In the table below the Joule –Thomson cooling is shown for pure CO_2 at 10, 20 and 30ºC. In the presence of non-condensables the phase transition is shifted to higher pressures resulting in a somewhat higher J-T effect.
The theoretically needed heating to prevent cooling down to temperatures below zero can be derived from the log p-H diagram. The CO_2 must be heated to ensure that the temperature is above 0ºC after choking. The CO_2 arrives at the platform at about 85 bar (dense phase). After heating of the CO_2 to about

4 To read the J-T cooling form a log p – H diagram a vertical line (isenthalpic cooling) should be drawn from the initial state (p and T) to the final pressure. At that point the final temperature can be read off.

75ºC the CO_2 is still in the dense phase. After throttling CO_2 to about 40 bar, the temperature drops to about 10ºC and it can be transported in the gaseous phase (with a density of about 85 kg/m^3). From the log p-H diagram it follows that the required heat is in that case ΔH = 240 kJ/kg. For a well with a medium injectivity of 0.5 Mton/year the required energy is then approximately 3.8 MW.

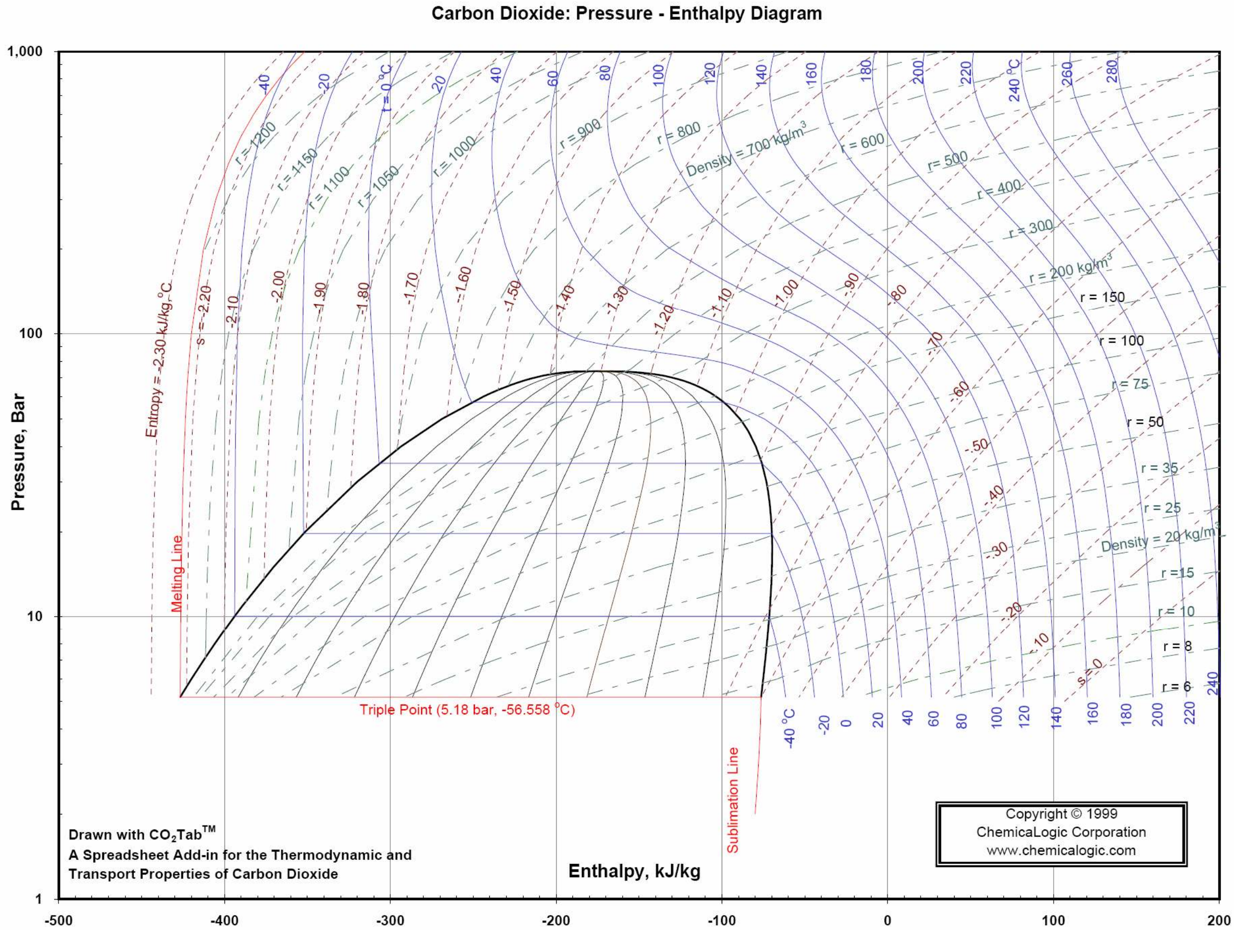


Figure I- 3: Log p-H diagram for CO_2

Pressure range	J-T cooling at an inlet temperature of		
	10 ºC	20 ºC	30 ºC
Saturation pressure	43 bar	58 bar	75 bar
300 → 70 bar	-	-	30→ 28 ºC
300 → 60 bar	-	-	30→ 22 ºC
300 → 50 bar	-	20→ 14 ºC	30→ 14 ºC
300 → 40 bar	10→ 5 ºC	20→ 5 ºC	30→ 5 ºC
300 → 30 bar	10→ -6 ºC	20→ -6 ºC	30→ -6 ºC

Table I- 2: Theoretical isenthalpic Joule –Thomson cooling for CO_2 of 90 bar and 10ºC

Possible conditions of CO_2 for offshore storage

When CO_2 is transported from the capture facility to the reservoir, different pressure and temperature levels will be encountered:

Transfer from shore to platform:

The upper limit of the pressure is determined by the maximum operating pressure of the pipeline. For existing gas pipelines the maximum operating pressure is in most cases limited at about 100 bar. The

lower pressure limit is determined by the required transport rate and properties. Generally it is desired to avoid 2 phase flow. For dense phase transport the minimum required pressure is 85 bar, depending on the temperature and the amount of non-condensables. For gaseous phase transport the maximum pressure ranges up to about 40 bar.
For economic long-haul transport generally dense phase transport is favored. Therefore in practice the operating pressure ranges from 85 to 130 bar for existing gas pipelines and from 85 up to 300 bar for new ones. The temperature of the CO_2 will be largely determined by the supply conditions (20 to > 100º C) and the seabed temperature 10º C and 4º C. At higher supply temperatures the CO_2 in the pipeline will be gradually cooled by the seawater during transport.

Transfer from platform to reservoir:
In the **initial** state, the reservoir will have a low pressure of about 40 bar, while the CO_2 supply pressure will be at least 85 bar (see above). In the **mature** state, the pressure of the reservoir will reach to the original reservoir pressure (generally about 300 - 400 bar). According to Oldenburg (2006) a typical pressure drop for CO_2 injection will range between 5 -10 bar for high quality gas reservoirs, depending on the CO_2 injection rate and the injectivity of the well. Reservoirs that have a high permeability will have a smaller pressure drop. On the other hand the pressure will increase because of the hydrostatic column and gravity. The temperature increases with depth. Assuming an average geothermal gradient of 30ºC per km, the temperature of reservoirs at will range from 100ºC to 150ºC.

In the **initial** state the CO_2 pressure will decrease from the supply level of say 90 bar to the down hole pressure of say 40 bar, i.e. an initial pressure drop of 50 bar. The temperature will on the one hand decrease by the Joule -Thomson cooling (refer to section above) and on the other hand increase because of the increasing geothermal temperature. In the worst case scenario, it is assumed that there will be no heating up of the until it has reached the reservoir and that the complete pressure drop occurs in the flow line. In this case the down hole conditions of the CO_2 will be 40 bar and 5ºC, i.e. part of the CO_2 is in the dense phase and part in the gaseous phase. The cooling effect will then be located at some distance from the well. Possible problems that could arise due to the cooling include the freezing of residual water or the formation of hydrates (with H_2O or CH_4) in the reservoir resulting in reduced injectivity. Moreover the effect of extreme cold in reservoirs generates thermal stress that could fracture the formation. To determine the exact effects detailed (modeling) studies are required. It may be required to prevent any adverse effects to heat up and gasify the CO_2 at the platform in the initial state until the reservoir pressure has increased sufficiently.

In the **mature** state the CO_2 will remain in the dense phase and at a certain moment it may even be required to actually pump the CO_2 into the reservoir, depending on the supply pressure and the reservoir depth. The CO_2 temperature in this case will increase only because of the geothermal temperature. Because of the temperature increase a phase transition from the liquid to the supercritical phase will occur when the critical point is reached (31.0 bar and 73.7ºC for pure CO_2). In the supercritical state an substance has the density of a fluid, but acts like a gas-like compressible fluid. Hence it will fill the reservoir to a high degree. In the figure below the approximate reservoir conditions are shown in the p-T plot.

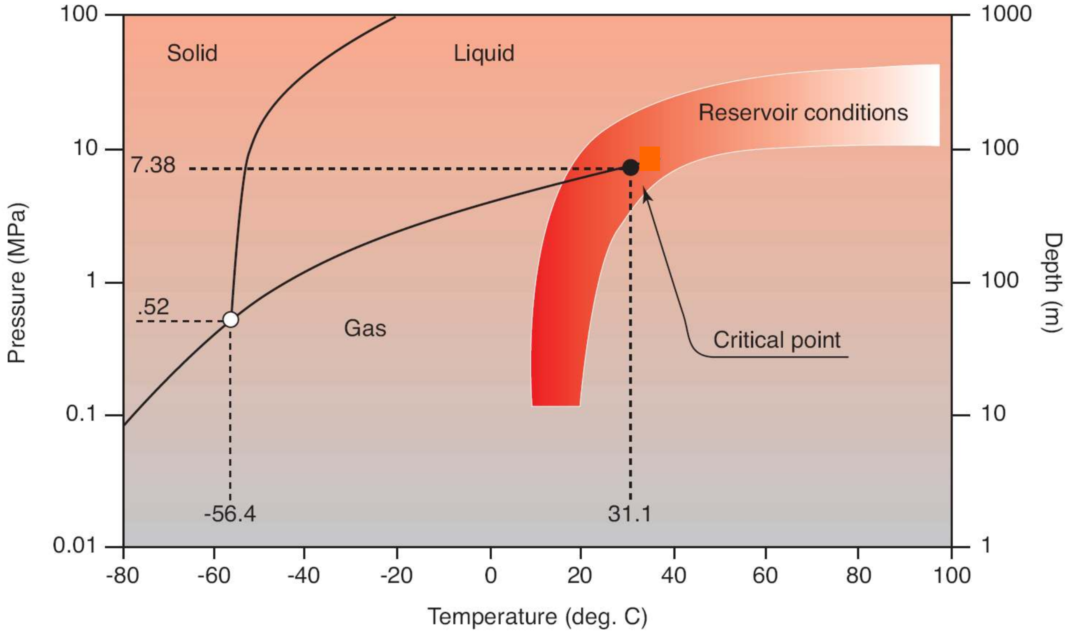


Figure I- 4: Pressure and temperature conditions for CO_2 transport and storage, assuming pure CO_2

In the table the properties for the various states are given.

Situation	**Pressure [bar]**	**Temperature [ºC]**	**Density [kg/m^3]**	**State**
Transport pipeline	85 -100	4 30	904 592	Liquid
Reservoir initial state	40 60	150 100	53 100	Gas
Reservoir end state	300 400	150 100	500 765	Supercritical

Table I- 3: Relevant CO_2 properties in pipelines and reservoirs (assuming pure CO_2)

Detailed diagrams CO_2 properties

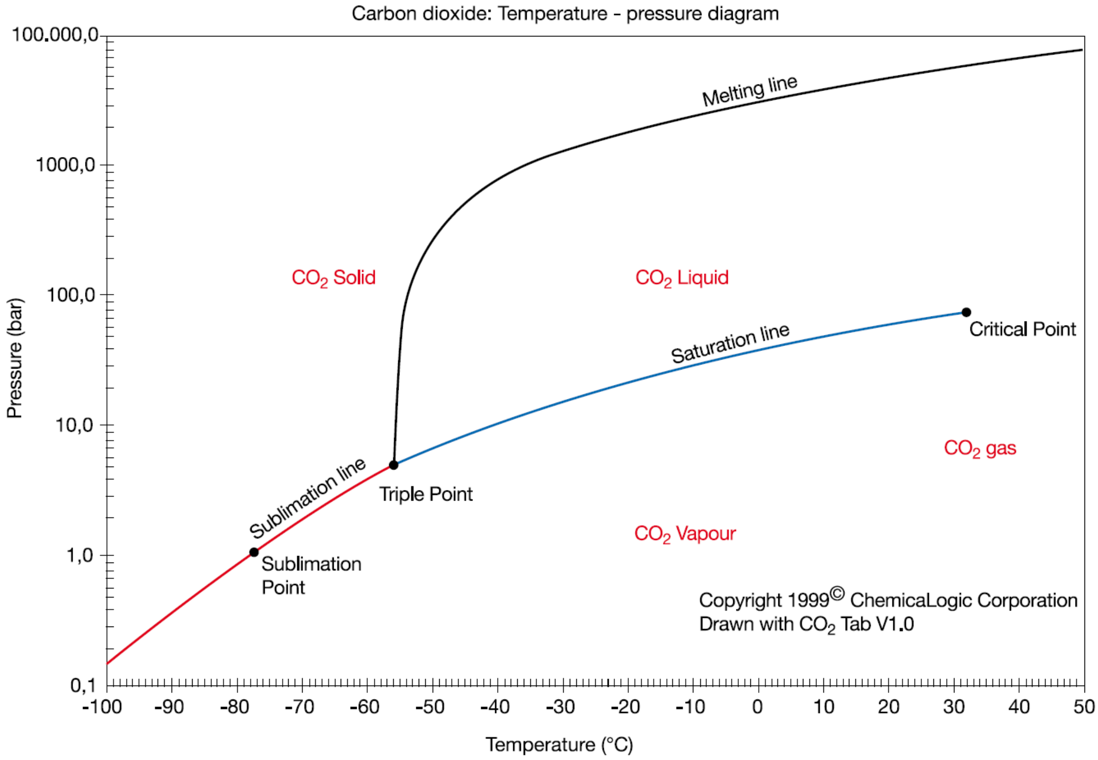


Figure I- 5: Pressure - temperature diagram of CO_2 including phase transitions

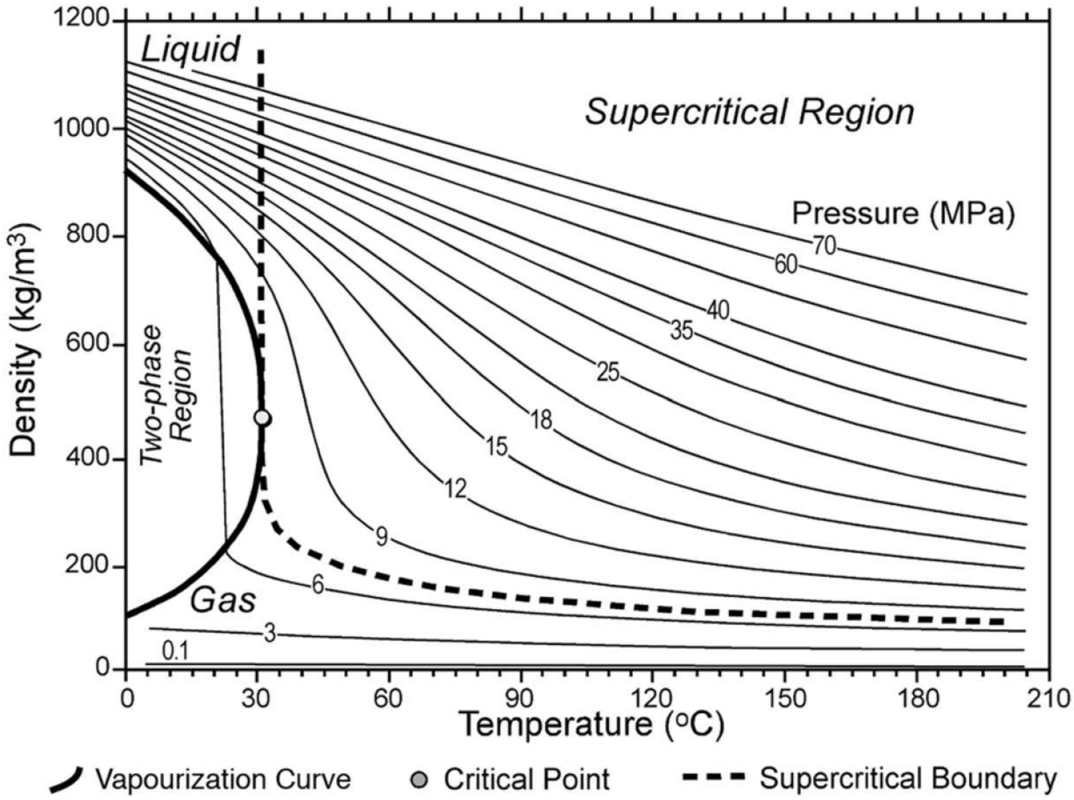


Figure I- 6: Density of CO_2 as function of pressure and temperature

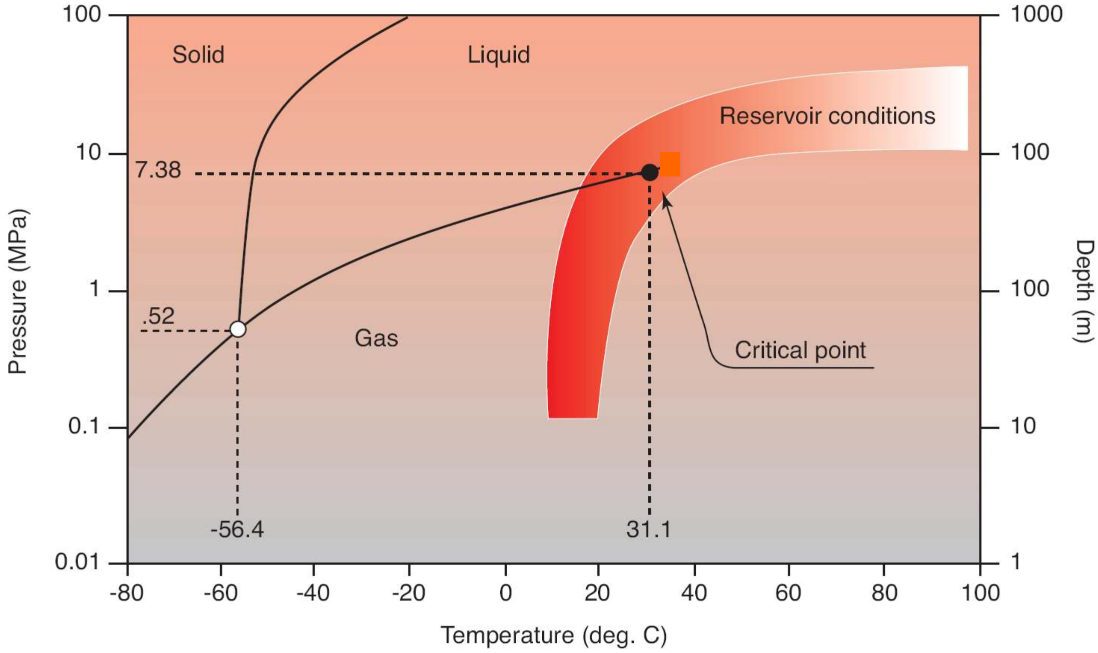


Figure I- 7: **Pressure and temperature conditions for CO_2 transport and storage, assuming pure CO_2 [Van der Meer 2005]**

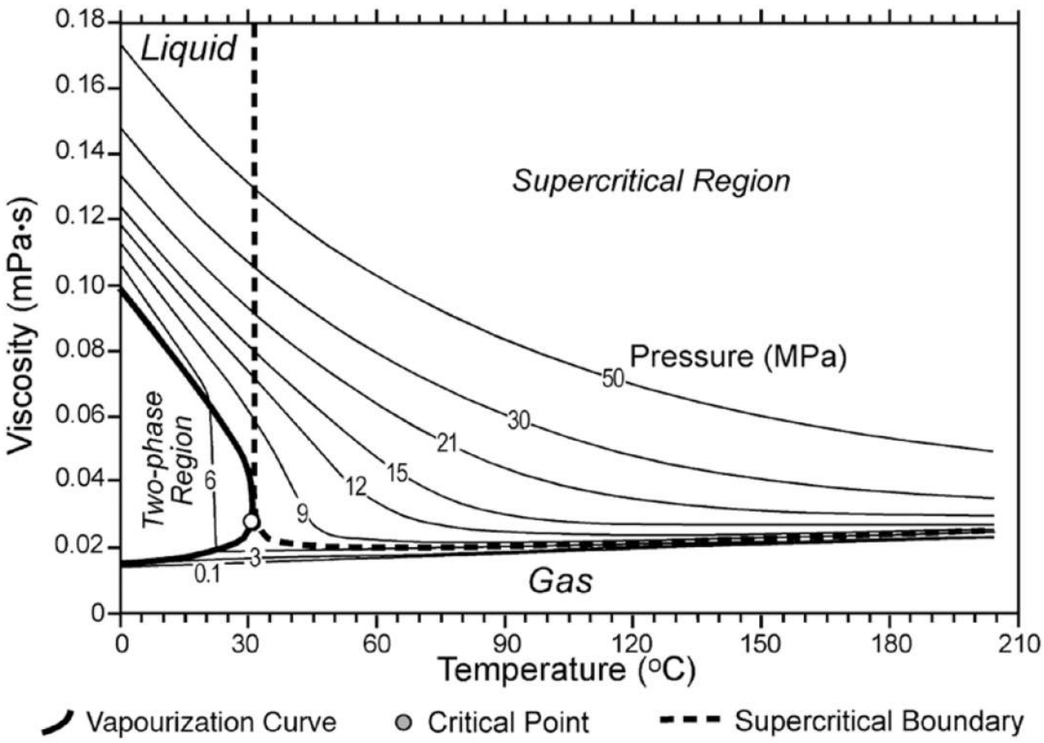


Figure I- 8: **Viscosity as function of temperature and pressure**

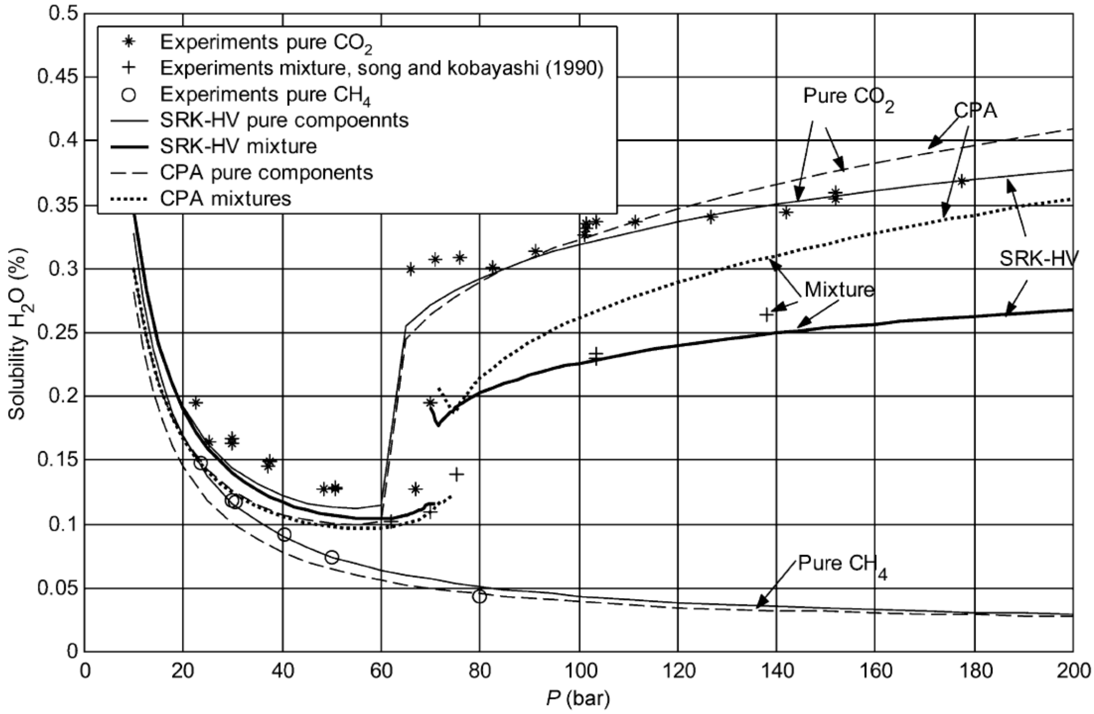


Figure I- 9: Solubility of H_2O in a mixture of CO_2 and 5.31% CH_4 at 25ºC

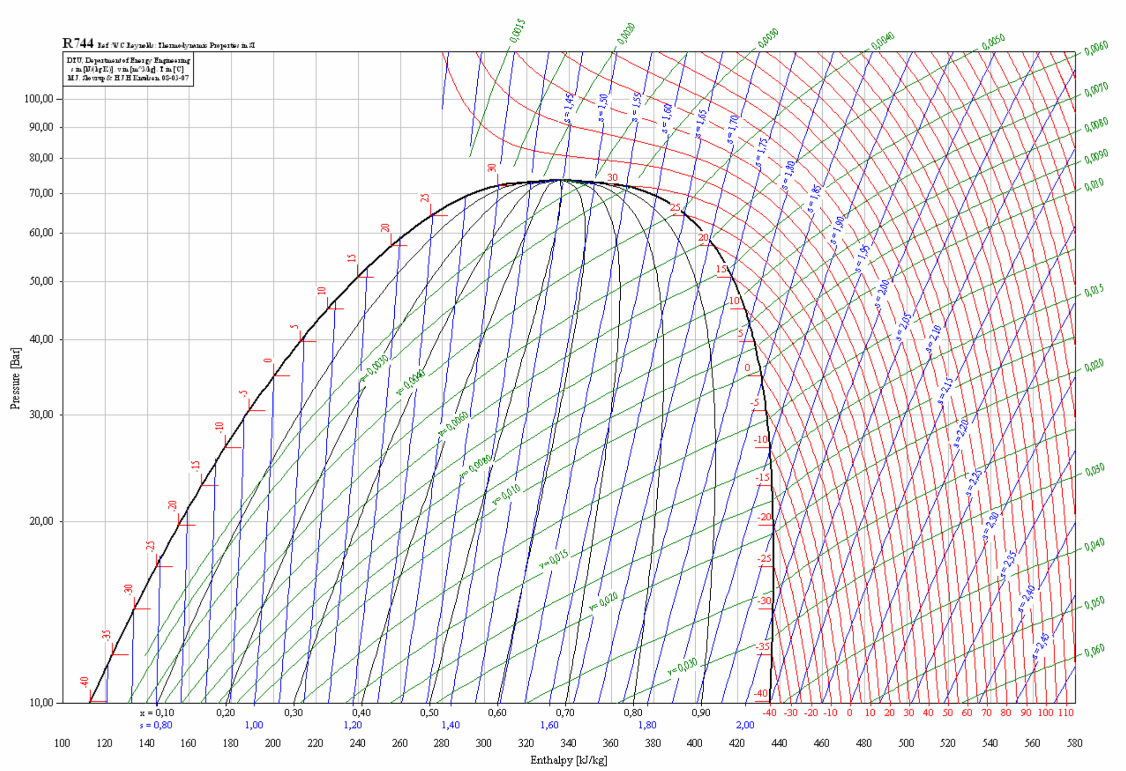


Figure I- 10: Log p-H diagram for CO_2

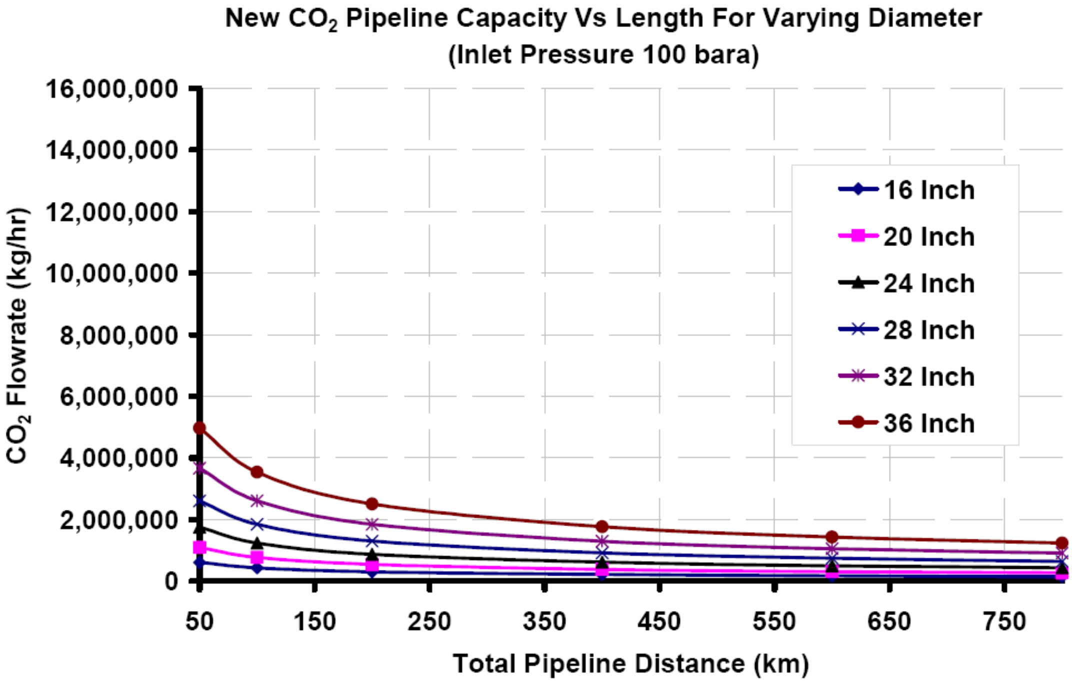


Figure I- 11: CO_2 flow rate related to pipeline diameter and length for an inlet pressure of 100 bar

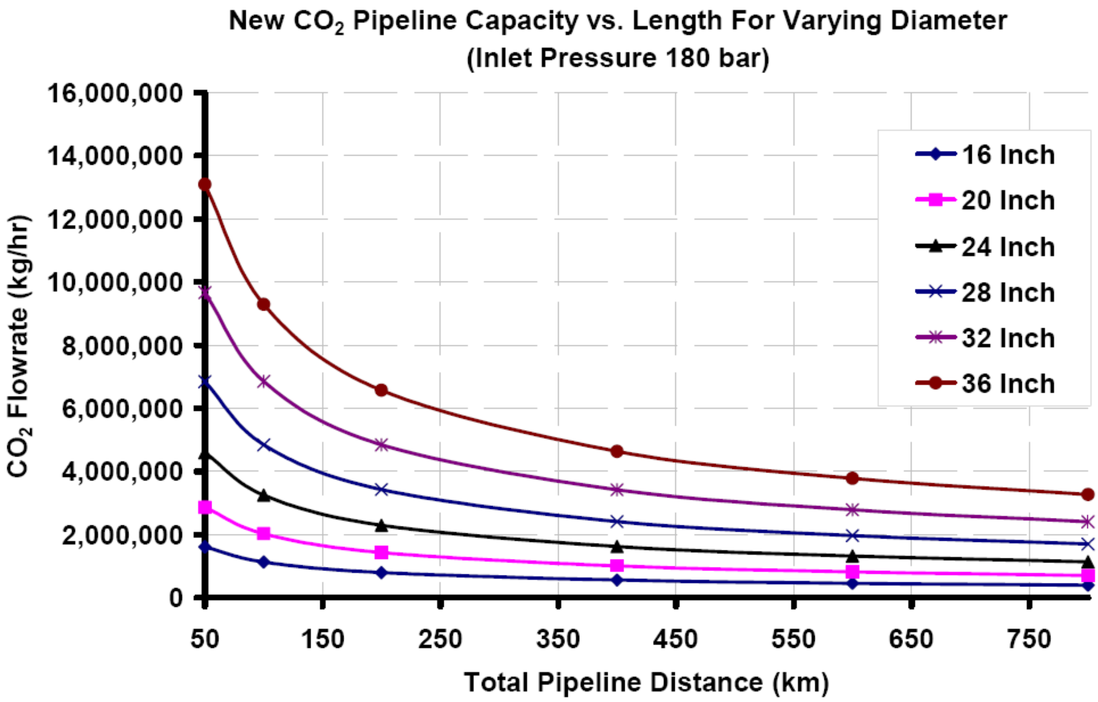


Figure I- 12: Capacity of pipelines of various diameter for inlet pressure of 180 bar

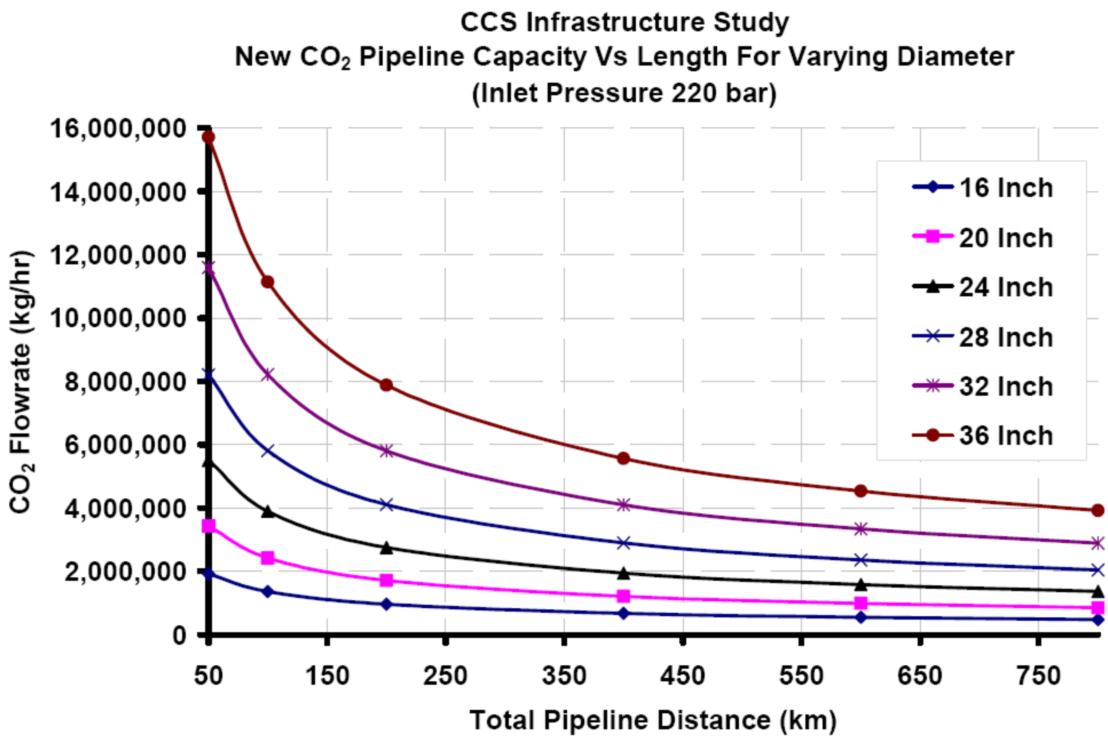


Figure I- 13: Capacity of pipelines of various diameter for inlet pressure of 220 bar

APPENDIX 2 List of field parameters

Nr.	Field Name	Facility Name	Operator	Status	Evacuation system	Reservoir	Seal type	storage capacity (Mton)
1	D12-A	D12-A	Wintershall	P	NGT NW	Carboniferous	salt/claystone	5 - 10
2	D15-A	D15-A	Gaz de France	P	NGT NW	Carb/rotl.	clay/salt	5 - 10
3	D15-A-104	D15-A	Gaz de France	P	NGT NW	Carb/rotl.	clay/salt	<2.5
4	E18-A	E18-NEW	Wintershall	NP	NGT NW	Jura	salt/claystone	10-20
5	F03-FB	F03-FB-1	NAM	P	NOGAT	Jura	claystone	20 - 50
6	F15a-A	F15-A	Total	P	NOGAT	Trias	claystone	10-20
7	F15a-B	F15-A	Total	P	NOGAT	Jura	claystone	5 - 10
8	F16-E	F16-A	Wintershall	P	NGT NW	Carb/rotl.	salt/claystone	10-20
9	G14-A&B	G14-A	Gaz de France	P	NGT NE	Trias	clay	20 - 50
10	G14-C	G14-B	Gaz de France	NP	NGT NE	Trias	clay	2.5 - 5
11	G16a-A	G16-A	Gaz de France	P	NGT NE	Jura	clay	2.5 - 5
12	G17a-S1	G17-S1	Gaz de France	P	NGT NE	Trias	clay	<2.5
13	G17cd-A	G17cd-A	Gaz de France	P	NGT NE	Trias	clay	5 - 10
14	Halfweg	Q01-Halfweg	Chevron	P	WGT	Rotliegend	salt	5 - 10
15	J03-C Unit	J03-C	Total	P	WGT	Rotliegend	salt	10-20
16	K01-A Unit	PE-K1-PA	Total	P	WGT	Rotliegend	salt	20 - 50
17	K02b-A	K02b-A	Gaz de France	P	NGT NW	Carb/rotl.	clay/salt	10-20
18	K04-A	PE-K4-PA	Total	P	WGT	Carboniferous	salt	10-20
19	K04a-D	K04a-D	Total	P	WGT	Carboniferous	salt	<2.5
20	K04a-Z	K4-NEW	Total	NP	WGT	Carboniferous	salt	2.5 - 5
21	K04-B	PE-K4-BE	Total	P	WGT	Carboniferous	salt	5 - 10
22	K04-E	PE-K4-BE	Total	P	WGT	Carb/rotl.	salt	5 - 10
23	K04-N	PE-K5-PA	Total	P	WGT	Rotliegend	salt	<2.5
24	K04-N	PE-K4-PA	Total	P	WGT	Rotliegend	salt	10-20
25	K05a-A	PE-K5-PA	Total	P	WGT	Rotliegend	salt	20 - 50
26	K05a-B	K05-B	Total	P	WGT	Rotliegend	salt	5 - 10
27	K05a-C	PE-K5-EN/C	Total	P	WGT	Carb/rotl.	salt	5 - 10
28	K05a-D	K05-D	Total	P	WGT	Rotliegend	salt	10-20
29	K05a-En	PE-K5-EN/C	Total	P	WGT	Rotliegend	salt	2.5 - 5
30	K05a-Es	K05-D	Total	P	WGT	Rotliegend	salt	<2.5
31	K05-C North	PE-K5-EN/C	Total	NP	WGT	Carb/rotl.	salt	2.5 - 5
32	K05-F	K5-NEW	Total	NP	WGT	Rotliegend	salt	5 - 10
33	K05-G	PE-K5-EN/C	Total	S	WGT	Rotliegend	salt	<2.5
34	K05-U	K5-NEW	Total	NP	WGT	Rotliegend	salt	2.5 - 5
35	K06-A	L04-PN	Total	P	NGT NW	Rotliegend	salt	<2.5
36	K06-C	K06-C	Total	P	NGT NW	Rotliegend	salt	10-20
37	K06-D	K06-D	Total	P	NGT NW	Rotliegend	salt	10-20
38	K06-DN	K06-DN	Total	P	NGT NW	Rotliegend	salt	10-20
39	K06-G	K06-GT	Total	P	NGT NW	Rotliegend	salt	5 - 10
40	K06-N	K06-N	Total	S	NGT NW	Rotliegend	salt	<2.5
41	K06-T	K06-GT	Total	S	NGT NW	Rotliegend	salt	<2.5
42	K07-FA	K07-FA-1	NAM	P	WGT	Rotliegend	salt	10-20
43	K07-FB	K07-FB-1	NAM	P	WGT	Rotliegend	salt	2.5 - 5
44	K07-FC	K08-FA-1	NAM	P	WGT	Rotliegend	salt	10-20
45	K07-FD	K07-FD-1	NAM	P	WGT	Rotliegend	salt	2.5 - 5
46	K07-FE	K07-FD-1	NAM	P	WGT	Rotliegend	salt	<2.5
47	K08-FA	K08-FA-1	NAM	P	WGT	Rotliegend	salt	>51
48	K08-FC	K08-FA-3	NAM	S	WGT	Rotliegend	salt	<2.5

Nr.	Field Name	Facility Name	Operator	Status	Evacuation system	Reservoir	Seal type	storage capacity (Mton)
49	K09ab-A	K09ab-A	Gaz de France	P	NGT NW	Rotliegend	salt	10-20
50	K09ab-B	K09ab-B	Gaz de France	P	NGT NW	Rotliegend	salt	10-20
51	K09c-A	K09c-A	Gaz de France	P	NGT NW	Rotliegend	salt	5 - 10
52	K10-B	K10-B	Wintershall	CP	WGT	Rotliegend	salt	20 - 50
53	K10-V	K10-V (re-moved)	Wintershall	A	WGT	Rotliegend	salt	2.5 - 5
54	K11-FB	K11-B	NAM	CP	NGT SW	Rotliegend	salt	<2.5
55	K12-A	K12-A	Gaz de France	CP	NGT NW	Rotliegend	salt	5 - 10
56	K12-B	K12-BD	Gaz de France	P	NGT NW	Rotliegend	salt	20 - 50
57	K12-C	K12-C	Gaz de France	P	NGT NW	Rotliegend	salt	5 - 10
58	K12-D	K12-D	Gaz de France	P	NGT NW	Rotliegend	salt	2.5 - 5
59	K12-E	K12-E	Gaz de France	CP	NGT NW	Rotliegend	salt	2.5 - 5
60	K12-G	K12-G	Gaz de France	P	NGT NW	Rotliegend	salt	10-20
61	K12-S1	K12-S1	Gaz de France	CP	NGT NW	Rotliegend	salt	2.5 - 5
62	K12-S2	K12-S2	Gaz de France	P	NGT NW	Rotliegend	salt	<2.5
63	K12-S3	K12-S3	Gaz de France	P	NGT NW	Rotliegend	salt	2.5 - 5
64	K14-FA	K14-FA-1	NAM	P	LoCal/WGT	Rotliegend	salt	20 - 50
65	K14-FB	K14-FB-1	NAM	P	LoCal	Rotliegend	salt	10-20
66	K15-FA	K15-FA-1	NAM	P	WGT	Rotliegend	salt	20 - 50
67	K15-FB	K15-FB-1	NAM	P	LoCal	Rotliegend	salt	20 - 50
68	K15-FC	K15-FC-1	NAM	S	LoCal	Rotliegend	salt	5 - 10
69	K15-FE	K15-FA-1	NAM	P	WGT	Rotliegend	salt	2.5 - 5
70	K15-FG	K15-FG-1	NAM	P	WGT	Rotliegend	salt	10-20
71	K15-FJ	K15-FK-1	NAM	P	LoCal	Rotliegend	salt	<2.5
72	K15-FK	K15-FK-1	NAM	P	LoCal	Rotliegend	salt	10-20
73	K15-FL	K15-FG-1	NAM	P	WGT	Rotliegend	salt	2.5 - 5
74	K15-FM	K15-FK-1	NAM	P	LoCal	Rotliegend	salt	<2.5
75	K15-FN	K15-FA-1	NAM	NP	WGT	Rotliegend	salt	<2.5
76	K15-FO	K15-FB-1	NAM	P	LoCal	Rotliegend	salt	<2.5
77	K17-FA	K17-FA-1	NAM	P	LoCal	Rotliegend	salt	5 - 10
78	K18 Golf	K18-NEW	Wintershall	NP	NGT SW	Rotliegend	salt	5 - 10
79	L/11b	UN-L/11B-PA	Chevron	P	NGT NW	Rotliegend	salt	2.5 - 5
80	L01-A	L04-PN	Total	P	NGT NW	Rotliegend	salt	2.5 - 5
81	L02-FA	L02-FA-1	NAM	P	NOGAT	Trias	claystone	10-20
82	L02-FB	L02-FA-1	NAM	P	NOGAT	Trias	claystone	5 - 10
83	L04-A	L04-A	Total	P	NGT NW	Rotliegend	salt	20 - 50
84	L04a-G	L04a-G	Total	P	NGT NW	Rotliegend	salt	2.5 - 5
85	L04-B	L04-B	Total	P	NGT NW	Rotliegend	salt	5 - 10
86	L04-F	L04-PN	Total	P	NGT NW	Rotliegend	salt	2.5 - 5
87	L04-I	L04-PN	Total	P	NGT NW	Rotliegend	salt	2.5 - 5
88	L05-B	L5B	Wintershall	P	NGT NW	Rotliegend	claystone	5 - 10
89	L05-C	L05-C	Wintershall	P	NGT NW	Rotliegend	claystone	10-20
90	L05-FA	L05-FA-1	NAM	P	NOGAT	Trias	claystone	20 - 50
91	L06d	L06d-S1	ATP	P	NGT NE	Jura	clay	<2.5
92	L07-A	L07-A	Total	CP	NGT NW	Rotliegend	salt	<2.5
93	L07-B	L07-B	Total	P	NGT NW	Rotliegend	claystone	20 - 50
94	L07-C	PE-L7-PC	Total	P	NGT NW	Rotliegend	salt	2.5 - 5
95	L07-G	K09ab-A	Total	P	NGT NW	Rotliegend	salt	<2.5
96	L07-H	L07-H	Total	P	NGT NW	Rotliegend	salt	2.5 - 5
97	L07-Hse	L07-H	Total	P	NGT NW	Rotliegend	salt	2.5 - 5

Nr.	Field Name	Facility Name	Operator	Status	Evacuation system	Reservoir	Seal type	storage capacity (Mton)
98	L07-N	L07-N	Total	P	NGT NW	Rotliegend	salt	2.5 - 5
99	L08-A	L08-Alpha	Wintershall	P	NGT NW	Rotliegend	claystone	2.5 - 5
100	L08-A West	L08-Alpha west	Wintershall	P	NGT NW	Rotliegend	claystone	<2.5
101	L08-G	L08-Golf	Wintershall	P	NGT NW	Rotliegend	claystone	5 - 10
102	L08-H	L08-Hotel	Wintershall	P	NGT NW	Rotliegend	claystone	<2.5
103	L08-P	L08-P	Wintershall	P	NGT NW	Rotliegend	claystone	10-20
104	L08-P	L08-P4	Wintershall	P	NGT NW	Rotliegend	claystone	<2.5
105	L09-FC	L09-FF-1	NAM	P	NOGAT	Trias	claystone	<2.5
106	L09-FD	L09-FF-1	NAM	P	NOGAT	Trias	claystone	20 - 50
107	L09-FF	L09-FF-1	NAM	P	NOGAT	Trias	claystone	20 - 50
108	L09-FI	L09-FF-1	NAM	P	NOGAT	Trias	claystone	2.5 - 5
109	L10 CDA	L10-AD	Gaz de France	P	NGT NW	Rotliegend	salt	>50
110	L10-G	L10-G	Gaz de France	P	NGT NW	Rotliegend	salt	<2.5
111	L10-K	L10-K (re-moved)	Gaz de France	CP		Rotliegend	salt	2.5 - 5
112	L10-M	L10-M	Gaz de France	P	NGT NW	Rotliegend	salt	10-20
113	L10-S1	L10-S1 (re-moved)	Gaz de France	CP		Rotliegend	salt	<2.5
114	L10-S2	L10-S2	Gaz de France	P	NGT NW	Rotliegend	salt	<2.5
115	L10-S3	L10-S3	Gaz de France	CP	NGT NW	Rotliegend	salt	<2.5
116	L10-S4	L10-S4	Gaz de France	CP	NGT NW	Rotliegend	salt	<2.5
117	L11-A	L11a-A (re-moved)	Gaz de France	CP		Rotliegend	salt	<2.5
118	L12-FC	L15-FA-1	NAM	P	NOGAT	Rotliegend	salt	<2.5
119	L13-FC	L13-FC-1	NAM	P	WGT	Rotliegend	salt	20 - 50
120	L13-FD	L13-FD-1	NAM	P	WGT	Rotliegend	salt	2.5 - 5
121	L13-FE	L13-FE-1	NAM	P	WGT	Rotliegend	salt	10-20
122	L13-FF	L13-FD-1	NAM	P	WGT	Rotliegend	salt	2.5 - 5
123	L13-FG	L13-FE-1	NAM	P	WGT	Rotliegend	salt	5 - 10
124	L13-FH	L13-FH-1	NAM	CP	WGT	Rotliegend	salt	<2.5
125	L15-FA	L15-FA-1	NAM	P	NOGAT	Rotliegend	salt	10-20
126	Markham	J06-A	Venture	P	WGT	Rotliegend	salt	20 - 50
127	P06 South	P06-S	Wintershall	P	NGT SW	Trias	salt/claystone	<2.5
128	P06-D	P06-D	Wintershall	P	NGT SW	Trias	salt/claystone	5 - 10
129	P06-Main	P06-B	Wintershall	P	NGT SW	Zechstein	salt/claystone	<2.5
130	P06-Main	P06-A	Wintershall	P	NGT SW	Zechstein	salt/claystone	20 - 50
131	P09-A	P09-New	Wintershall	NP	NGT NW	Trias	salt/claystone	<2.5
132	P09-B	P09-New	Wintershall	NP	NGT NW	Trias	salt/claystone	<2.5
133	P12-SW	P12-SW	Wintershall	P	NGT SW	Trias	salt/claystone	5 - 10
134	P14-A	P14 (removed)	Wintershall	A	Maasvlakte (TAQA)	Trias	salt/claystone	5 - 10
135	P15-10	P15-10S	Taqa	S	Maasvlakte (TAQA)	Trias	claystone	<2.5
136	P15-11	P15-F	Taqa	P	Maasvlakte (TAQA)	Trias	claystone	10-20
137	P15-12	P15-12S	Taqa	P	Maasvlakte (TAQA)	Trias	claystone	<2.5
138	P15-13	P15-G	Taqa	P	Maasvlakte (TAQA)	Trias	claystone	5 - 10
139	P15-14	P15-14S	Taqa	P	Maasvlakte (TAQA)	Trias	claystone	<2.5
140	P15-15	P15-A	Taqa	S	Maasvlakte (TAQA)	Trias	claystone	<2.5

Nr.	Field Name	Facility Name	Operator	Status	Evacuation system	Reservoir	Seal type	storage capacity (Mton)
141	P15-16	P15-A	Taqa	P	Maasvlakte (TAQA)	Trias	claystone	<2.5
142	P15-17	P15-A	Taqa	P	Maasvlakte (TAQA)	Trias	claystone	<2.5
143	P15-9	P15-E	Taqa	P	Maasvlakte (TAQA)	Trias	claystone	10-20
144	P18-2	P18 Alpha	Taqa	P	Maasvlakte (TAQA)	Trias	claystone	20 - 50
145	P18-4	P18 Alpha	Taqa	P	Maasvlakte (TAQA)	Trias	claystone	5 - 10
146	P18-6	P18 Alpha	Taqa	P	Maasvlakte (TAQA)	Trias	claystone	<2.5
147	Q01-B	Q04-C	Wintershall	P	WGT	Trias	salt/claystone	20 - 50
148	Q04-A	Q04-A	Wintershall	P	NGT SW	Trias	salt/claystone	5 - 10
149	Q04-B	Q04-B	Wintershall	P	NGT SW	Trias	salt/claystone	5 - 10
150	Q05-A	Q05-A	Wintershall	P	Q08-IJmuiden	Zechstein	salt/claystone	<2.5
151	Q08-A Bunter	Q08-A	Wintershall	S	Q08-IJmuiden	Trias	salt/claystone	5 - 10
152	Q08-B	Q8-B (removed)	Wintershall	A	Q08-IJmuiden	Trias	salt/claystone	<2.5
153	Q16-FA	Q16-FA-1	NAM	P	Maasvlakte (TAQA)	Trias	claystone	10-20

APPENDIX 3 Conversion factor to calculate storage capacity of CO_2 from volume of natural gas produced

In order to convert the known volume of produced natural gas from a field into the amount of CO_2 that can be stored in the available pore space, a conversion factor has been applied derived from earlier work by TNO (Inventarisatie van mogelijkheden voor CO_2 opslag in de Nederlandse ondergrond: RGD / TNO 1995) (see below table). The table gives relation between the volume of gas to be produced to create enough space to store 10 Mton of CO_2. This relation is pressure dependent. From these points a function for the conversion factor C versus the pressure P has been derived:

$$C = a * (P / bar)^{-b}$$

with: a = 15.549 Mt/bcm

b = - 0.3194

Depth (m)	Gas expan-sion factor	Density (kg/m^3)	NPV (10^6 m^3)	UR (10^9 Sm^3)	Pressure (bara)	Conversion $CH_4 \rightarrow CO_2$ (Mt/bcm)
1000	148	390	25.6	3.8	115	2.6
1500	176	520	19.2	3.4	173	2.9
2000	204	575	17.4	3.6	230	2.8
2500	232	605	16.5	3.8	290	2.6
3000	261	608	16.6	4.3	350	2.3
4000	285	624	16	4.6	470	2.2

NPV = net pore volume

UR ultimate quantity of gas to be recovered for storage of 10 Mton CO_2

Table III-1: Theoretical isenthalpic Joule –Thomson cooling for CO_2 of 90 bar and 10ºC

The point at 115 bar (see graph below) has been neglected when calculating the function for the pressure/conversion factor relation. Reason is that this point does not line up with the other points which makes it complicated to have a trend line that fits all the other points. The 115 bar point can be neglected because it is well out of the pressure range in which the gas fields are situated (see histograph below),

Assuming that the initial pressure in a gas field is close to the hydrostatic pressure subsequently enabled to calculate the conversion factor for every field. Although we know this assumption is not always true, it is deemed good enough for the estimates of the CO_2 storage capacity in this phase of the project.

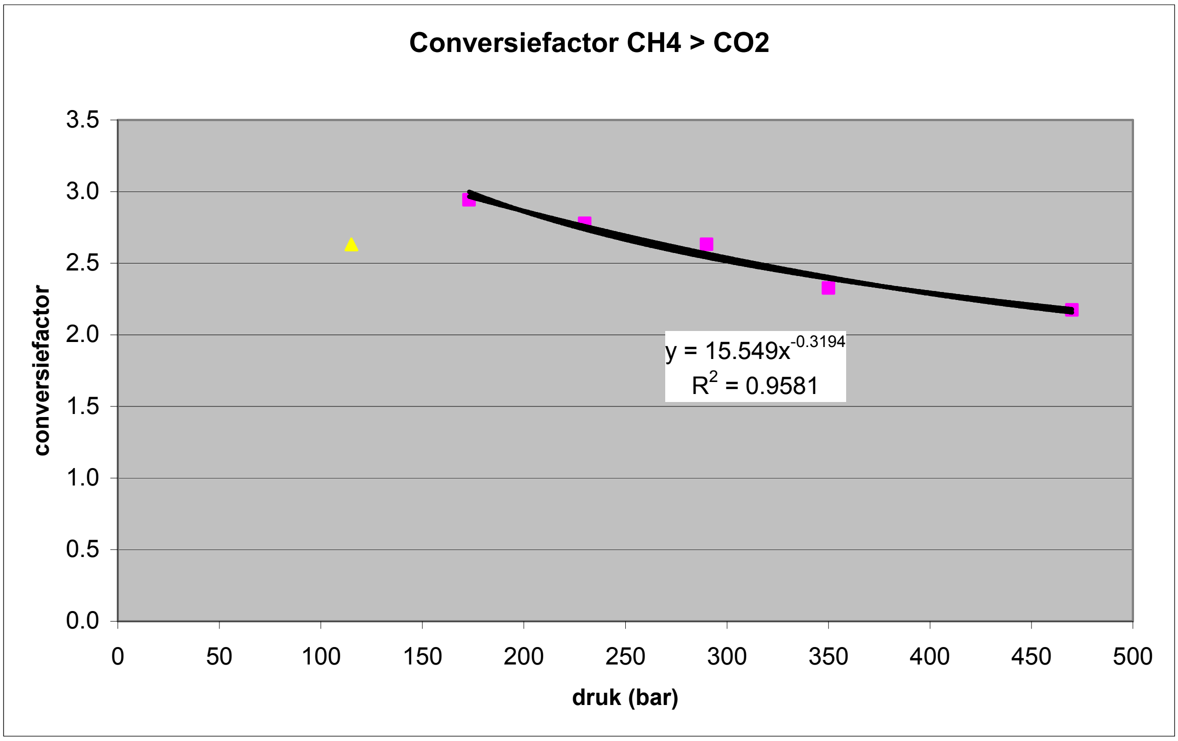


Figure III-1: Conversion factor from bcm CH_4 into Mton CO_2 as function of pressure

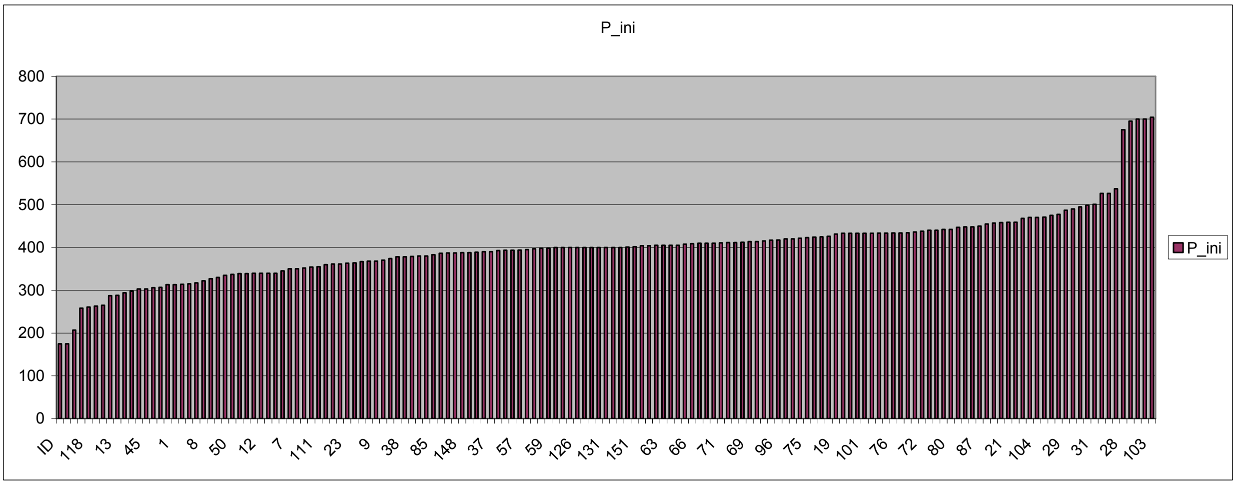


Figure III-2: Overview of the initial pressure for all offshore gas fields on the DCS

Initial pressure for all offshore gas fields shows that almost all initial pressures were between 175 and 470 bar, implying that for the calculation of the conversion factor the point at 115 bar may be neglected.

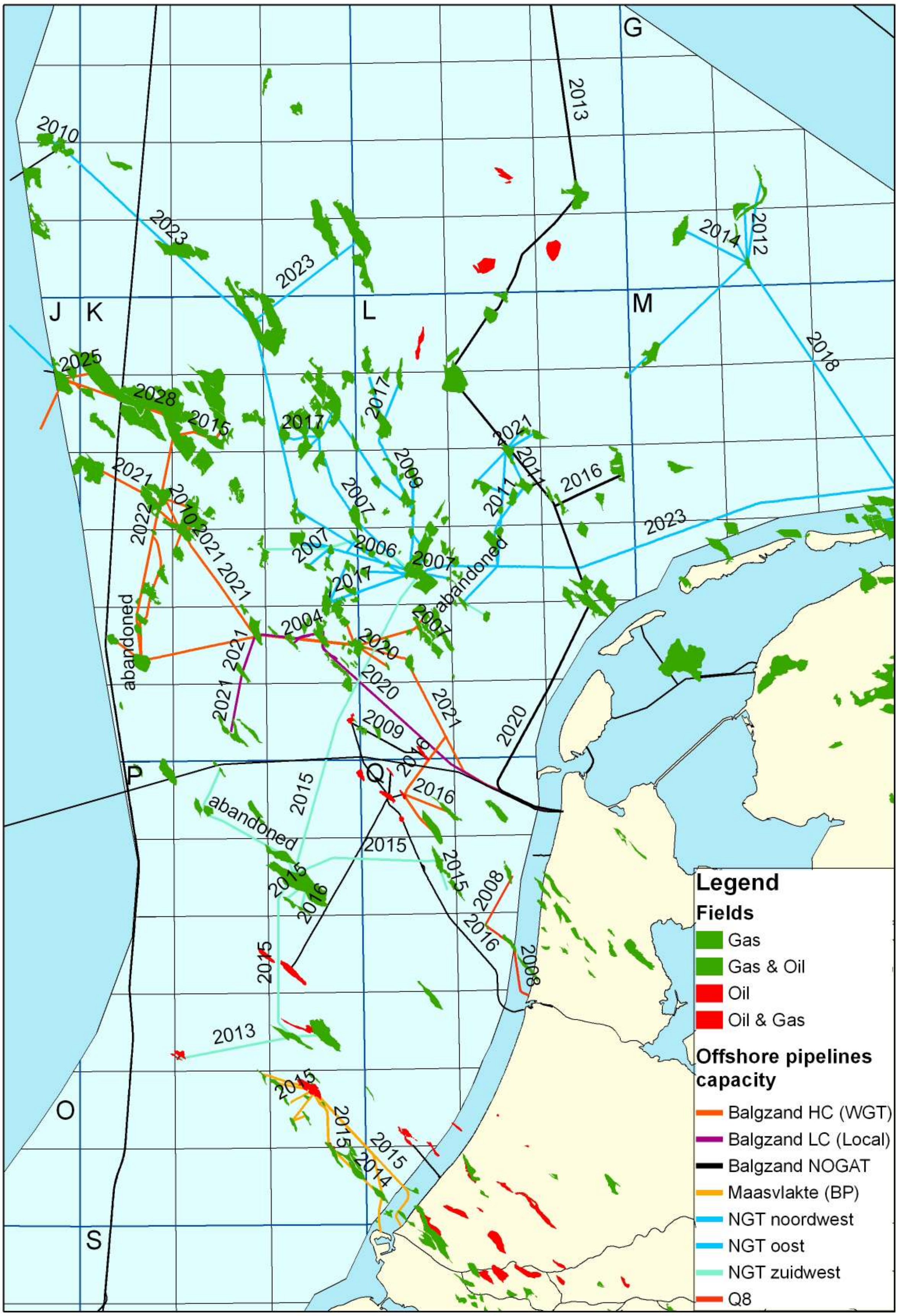
APPENDIX 4 Overview of the main surveyed data and data sources

Reservoir data	Well data	Installation data	Pipeline data
Name / ID Export to platform …	Name / ID / Reservoir Export to platform …	Name / ID / Reservoir(s) Export to …	Name / ID From … - to …
Operator (NAW, contact, etc.)	Operator (NAW, contact, etc.)	Operator (NAW, contact, etc.)	Operator (NAW, contact, etc.)
HCIIP dyn	In operation: yes / no If no: reason / status	In operation? yes / no / mothballed	In operation? yes / no / mothballed
Ultimate recovery	Out of operation (year): in principle based on field plan / BMP	Out of operation (year): in principle based on field plan / BMP	Out of operation (year): in principle based on field plan / BMP
Initial pressure	Suitable for CCS? / Showstoppers	Suitable for CCS? / Showstoppers	Suitable for CCS? / Showstoppers
Showstoppers	Diameter tubing (inch) average	Capacity, possibly based on derived data	Diameter internal (cm)
Number of wells	Injectivity (based on productivity m^3/bar/day) or per	Major overhaul structure < 10 - 20 yr? yes / no	Rating (p / T)
	Rating: default 10 000 lbs / Material: default SS	Material: default CS	Material: default CS

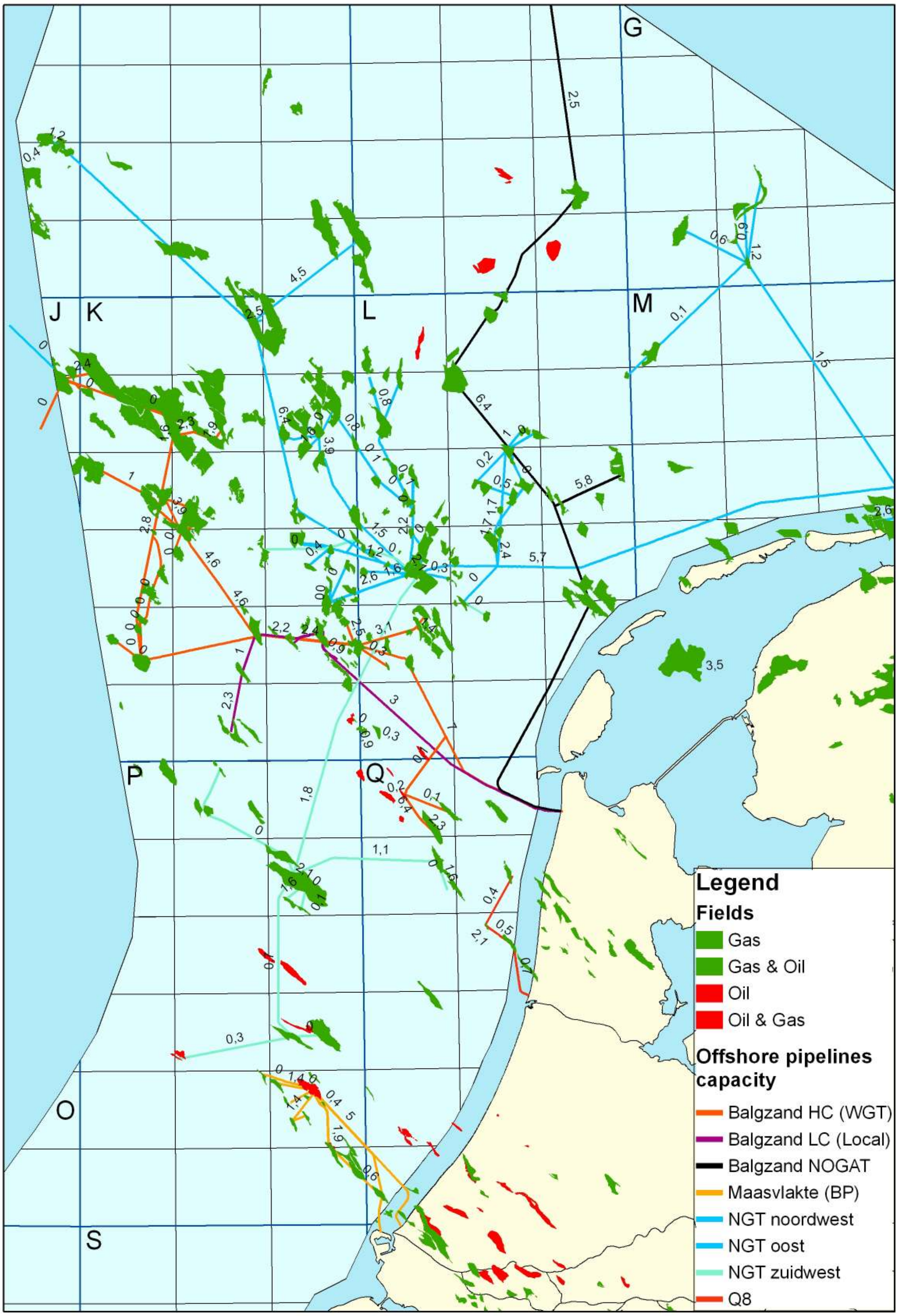
Data sources

(white)	Available data sources at TNO / DHV / public domain
(light yellow)	In principle based on available data sources but to be completed / verified by operator
(yellow)	To be supplied by

APPENDIX 5 Maps with pipeline data



Map 1: Pipelines on the DCS including expected year of availability for CO_2 transport



Map 2: Pipelines on the DCS including their estimated CO_2 transport capacity