ZEP Advisory Council 57

05th December 2018

Agenda Item 9: Review of Network 2018 Work Programmes

9.a. Network Policy and Economics

Appended to this paper is the following pre-read:

9.a. Network Policy and Economics update

9.a.i. NWPE October meeting minutes

9.a.ii. ZEP support for inclusion of CO_2 storage and hydrogen within CEF

9.b. Network Technology

Appended to this paper are the following pre-reads:

9.b. Network Technology update

9.b.i. NWT meeting agenda 31st October

9.b.ii. NWT October meeting minutes

9.b.iii. TWG Collaboration across the CCS chain, WS1 report for review

The AC are invited to approve the draft report

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6th Floor, 10 Dean Farrar Street, London, UK
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ZEP ACEC 57

5th December 2018

Agenda item 9.a. Network Policy and Economics update

Co-chairs: Lamberto Eldering (Equinor), John MacArthur (Shell), Jonas Helseth (Bellona)

A meeting of the Network took place on the 11th October. Draft minutes of the meeting are attached.

It was agreed that the Network would ask the AC in December to endorse Kim Bye Bruun as a co-chair of the Network in place of John MacArthur.

Temporary Working Group Policy and Funding

Chair: Theo Mitchell (Enerfair)

At the meeting in October the Network was asked to support proposals put forward by Equinor to the Connecting Europe Facility regulation which propose inclusion of CO_2 storage and for hydrogen. The amendments are attached for information; as the deadline for amendments in the Parliament had passed, these have been shared with Council members and also with the Commission and the Rapporteurs on the file for information.

The next meeting of the Innovation Fund Expert Group takes place on the 4th December. The Draft Delegated Act was circulated to the Network for comment. Many of ZEP's recommendations have been taken on board; including the ability to fund part-chain projects, and the provision of development funding.

Temporary Working Group PCIs

Chair: Lamberto Eldering (Equinor)

There was a meeting of the Thematic Group for CO2 PCIs on 7 November. The Commission announced that applications for inclusion on the 4th list of PCIs would run from 7th November to 7th March 2019.

The thematic group accepted that the same methodology and template be used as developed for the last selection process by ECORYS and RAMBOLL. The Joint Research Centre will assess the projects for this call.

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Agenda item 9.a.i: NWPE October meeting minutes

Attendance

Nikki Brain, ZEP Secretariat
Kim Bye Bruun, Shell
Amélie Carron, Air Liquide
Eric De Coninck, Arcelor Mittal
Caterina de Matteis, IOGP
Dominik Hatiar, Equinor
Hallvard Høydalsvik
Lamberto Eldering, Equinor
Theo Mitchell, Enerfair Engagement
Tim Peeters, Tata

By phone
Paula Coussy, IFP Energies Nouvelles

Items 1 & 2: Introduction and network update

Introduction

- The minutes of the last meeting were approved pending one amendment: Claude Heller missing from attendance list.

- It was noted that Kim Bye Bruun, Shell was substituting for John MacArthur as co-chair, and that a request would be made at the next AC to formally elect Kim as a co-chair.

Network update

Connecting Europe Facility

- NB provided an overview of the progress on the Connecting Europe Facility regulation. Amendments had been tabled and a vote will take place on 22 November in the ITRE and TRANS committees which are jointly responsible for the file. It is expected the Council will produce its position by the end of the year and trilogues will begin in early 2019.

- DK said that Equinor had produced a set of recommended amendments and shared these with the Rapporteurs and shadow Rapporteurs. He noted that as the CEF is the only instrument to fund the feasibility and construction of CCS projects operating today.

- Equinor's position includes a recommendation to include CO_2 storage within the scope of the CEF, given that CO_2 transport by pipeline is much less costly that appraisal and

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development of stores. A project will not progress on development of a pipeline alone. CO_2 storage in the North Sea has strong cross-border implications.

- It was noted that the CEF was established to develop gas infrastructure to increase European security of supply; as this issue is largely addressed, the fund needs a new purpose and is therefore now more focused on renewables and electricity interconnection.
- Equinor proposed to add a hydrogen "pillar" to the CEF alongside natural gas, electricity and CO2 transport. Hydrogen Europe are supportive of the proposal and interested in helping to take it forward.
- It was suggested the target should be MEPs on the ITRE Committee with potential hydrogen projects in their country.
- AC said that the link between hydrogen and CCS is not clear to many, and it is important to demonstrate how hydrogen benefits the economics of CCS development.
- LE said that ZEP has an existing position on the value of hydrogen, and was likely to support the inclusion of a hydrogen pillar.
- It was agreed that the Secretariat would draft a letter of support and get feedback from the Network, before sending to the ACEC for approval.

<u>TWG P&F</u>

- TM said that a draft of the Commission's Long Term Emissions Reduction Strategy had been widely leaked. It is clear that officials in CLIMA wish to minimise the role of CCS; this is in line with comments made publically by DG Mauro Petriccione on the lack of development on CCS in Europe.
- TM noted the German DG for climate and industry had stood up to Petriccione on CCS at the Green Growth Summit on 8 October, saying it was needed for industry and the Commission needed to get the policy right this time.
- TM said the Canete cabinet had said CCS and BECCS were not included in the modelling as no numerical evidence had been put forward in the consultation. TM said ZEP should put together two pages of targeted data and evidence for the modelling teams, including latest evidence on capture costs, storage costs, and project economics with and also meet with the Political Strategy Centre. It was agreed this would be added as a priority for Graeme's engagement on 30 October.
- TM said a second meeting on the expert group on the Innovation Fund was due to take place in November, but there was not a date confirmed yet. The delegates are likely to receive a draft Delegated Act beforehand; it was agreed the Network would suggest amendments once this is available.

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Item 3: Chair's update

- GS noted that the SET-Plan IWG is looking for additional co-chairs for sub-groups.
- GS said that Luke Warren had represented ZEP at Gassnova's CCS Safari. The message was clear that Norway should have access to European funds to progress its project.
- GS said that feedback from ZEP's event on the Long Term Strategy had been positive, especially providing people with links to the Port of Rotterdam projects. DK asked whether ZEP had followed up with Christian Holzleitner's office. It was agreed he should be included as a target for GS upcoming engagement.
- GS said the European Court of Auditors was undertaking a review of the value for money of ETS related policy activity. A meeting is scheduled for 23rd October; ZEP should attend.
- GS said ZEP should provide feedback to the Commission on the leaked draft of the Long Term Strategy. TM said there were two things that needed to be addressed; firstly the Commission's claim that CCS was not modelled as no-one had provided numbers in the consultation; and secondly the political angle. It was suggested that a 2 page document with up-to date cost figures and references was provided to modellers. Secondly, urgent engagement was needed on the political aspect.
- It was agreed that Network Technology should be asked to produce a 2-page modelling summary; and that the EPSC should be an urgent target for engagement on the 30th. GS suggested that the co-chairs of the SET-Plan could also engage with the Commission.

Item 4: 2020 Gas Package and opportunities for hydrogen

- CDM said that IOGP had organised an event with ZEP earlier in the year. A key item that came out of the workshop was how the organisations could collaborate on the role of hydrogen within the 2020 gas package.
- CDM said there was a knowledge gap on the potential for "blue" or CCS derived hydrogen. CDM said that grid operators need to maintain the lowest costs possible, and therefore hydrogen was seen as prohibitive. However, the Leeds H21 projects showed how it is possible to supply hydrogen at the entry point of distribution networks, rather than by transmission networks. CDM said there is an opportunity in the gas package to incentivise DSOs to install compatible pipelines during upgrades, and to allow use of CCS through the networks' RAB, allowing the cost of hydrogen and CCS to be socialised over time.
- CDM said IOGP is proposing a study to draw together data on costs and benefits to inform advocacy work on the package. They have asked SINTEF to produce a report, and are looking for co-funding by the end of October.
- It was noted there were several existing studies and projects looking at grid conversion to hydrogen already. CDM said this would be different as it would have a European rather than regional focus, and would look at transport between countries, as well as ensuring the

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gas package facilitated such projects. It was agreed that work to date should be taken into account to avoid duplication.

- AC said if IOGP wanted to stress the importance of size, the study could look at the volumes of renewable generation needed for electrolysis.

- LE said that as with the Connecting Europe Facility, the Gas Package would switch focus from security of supply towards low carbon. Therefore this study would help the debate. LE said ZEP support would likely be promoting the outcome of the report; and stressing the need for CCS infrastructure to enable hydrogen conversion.

- CDM said there would be a steering committee for the report. It was agreed that IOGP should follow up with GS to discuss ZEP participation.

Item 5: TWG Collaboration across the CCS Chain

- HH presented the work of workstream 1 of the TWG Collaboration across the CCS Chain in Network Technology, which focuses on storage related risk (see presentation slides).

- The draft report takes 10 potential events and monetises the risk, based on likelihood and estimated cost of correction.

- It was noted that the risks are low as the study focuses on the North Sea, where there is very high regulation in place for offshore operations. The risk may be greater in less well regulated areas globally.

- It was suggested that in order for the evidence to be accepted as robust. And therefore useful for engaging government, perhaps the NWT would want to invite academics to review the paper. HH said he would take this suggestion back to the Network.

- It was suggested that the conclusions make it much more clear what CO2 leakage would actually mean, in terms of damage i.e. there would be no explosions, risk to human life, and minimal risk to wildlife. Public perception of CO2 storage is that it is not safe; therefore it would be good to outline what the risks actually are, as well as the low probability of an event occurring.

- It was agreed the ERG would provide further advice on messaging for the report.

Item 6: AOB and next meeting

- It was noted that a revised ToR for TWG Policy & Finance had been approved at AC55. TM is currently Chair and would appreciate a co-chair. It was agreed the Secretariat would distribute the revised ToR with an invitation for new members and a co-chair.

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- LE said that there are roles available for co-chairs of some of the sub-groups in the SET-Plan IWG, including for modelling. He said that going forward it would be useful to coordinate the work of relevant sub-groups with the work of the Network.

- It was agreed the next meeting should take place in late January/ early February.

Actions

Action		Owner	Completed
1	Draft a letter of support for Equinor's CEF position and get feedback from the NWPE ahead of ACEC call	Sec	
1	Produce two pages of targeted data and evidence for LTS modellers	NWT Sec	
1	Share draft Delegated Act with network when available	TM/GS	
2	Christian Holzleitner's office to be added as a target for GS upcoming engagement.	Sec	
4	It was agreed that IOGP would liaise with GS to discuss ZEP participation.	Sec/CDM/GS	
6	Distribute the revised ToR for TWG P&F with an invitation for new members and a co-chair.	Sec	

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ZEP support for inclusion of CO_2 storage and Hydrogen within the Connecting Europe Facility 2021-2027

ZEP would like to propose the below amendments to the Connecting Europe Facility regulation. These suggestions are in line with the Commission's objective for 60% of CEF funds to contribute to climate objectives, and are based on two key proposals:

1) Inclusion of CO_2 storage appraisal in the scope of the Connecting Europe Facility

CO_2 transport and storage must be developed together to provide enabling infrastructure for capture projects. Currently, the Connecting Europe Facility is the only available source of European funding for feasibility studies and development of CO_2 infrastructure. Developing CO_2 storage infrastructure accessible by multiple Member States via cross-border transportation can overcome the barrier to decarbonisation faced by Member States without their own access to offshore CO_2 storage capacity.

2) Introduction of a pillar for low-carbon hydrogen (transportation and storage)

ZEP sees this firstly as an opportunity to provide a new low-carbon energy vector for the rapid transition required in Europe, and also as an opportunity to improve the economics of CCS development in key industrial clusters in Europe, with benefits for multiple Member States.

Both low-carbon hydrogen and CCS are important tools for industrial decarbonisation. Hydrogen produced in a low-carbon way can be used to replace hydrocarbon feedstock for industrial energy use. As ZEP's 2017 report "Commercial Scale Feasibility of Clean Hydrogen" and the Northern Gas Networks Leeds H21 study have both highlighted, combining hydrogen production through reformation of natural gas with CCS is the cheapest way to produce low-carbon hydrogen. This will continue to be the only viable way of producing low-carbon hydrogen in large enough volumes for industrial-scale use until at least 2030. Producing large volumes of hydrogen with CCS also has the benefit of providing volumes of CO_2 to develop regional storage assets, reducing the cost of storage of CO_2 from industry, as the costs can be socialised.

CCS is also the only option available for removing process emissions from industries such as steel and cement. The necessity of having both these tools available for industry was highlighted in the recent report Industrial Value Chain: A Bridge Towards a Carbon Neutral Europe, produced as input from Europe's Energy Intensive Industries to the EU's Long Term Strategy on emissions reductions. Furthermore, producing hydrogen at scale could enable use within Europe's existing gas networks for heating, and for transport purposes.

If it would be useful to discuss these issues in greater detail, please contact the ZEP Secretariat nikki.brain@zeroemissionsplatform.eu to arrange a meeting.

Commission proposal	Amendment
Recital 4	
...Actions under this Programme are expected to contribute 60% of the overall financial envelope of the Programme to climate objectives, based inter alia on the following Rio markers: i) 100% for the expenditures relating to railway infrastructure, *alternative fuels, clean* urban transport, electricity transmission, electricity storage, smart grids, CO2 transportation and renewable energy; ii) 40% for inland waterways and multimodal transport, and gas infrastructure - *if enabling increased use of renewable hydrogen or bio-methane.*	Actions under this Programme are expected to contribute 60% of the overall financial envelope of the Programme to climate objectives, based inter alia on the following Rio markers: i) 100% for the expenditures relating to railway infrastructure, *alternative fuels, clean* urban transport, electricity transmission, electricity storage, smart grids, CO2 transportation *from collection points to storage locations, CO2 storage appraisal* and renewable energy; ii) 40% for inland waterways and multimodal transport, and gas infrastructure - *if enabling increased use of sustainable hydrogen or bio-methane.*
Recital 20	
... The Commission will aim at increasing the number of cross-border smart grid, innovative storage as well as carbon dioxide transportation projects to be supported under the Programme.	...The Commission will aim at increasing the number of cross-border smart grid, innovative storage, *hydrogen transport, as well as* carbon dioxide transportation *and storage appraisal* projects to be supported under the Programme.
Objectives: Article 3 – paragraph 2 – point b	
In the energy sector, to contribute to the development of projects of common interest relating to further integration of the internal energy market, interoperability of networks across borders and sectors, facilitating decarbonisation and ensuring security of supply, and to facilitate cross-border cooperation in the area of renewable energy;	In the energy sector, to contribute to the development of projects of common interest relating to further integration of the internal energy market, interoperability of networks across borders and sectors, ensuring security of supply, and to facilitate cross-border cooperation in the area of renewable energy*; sustainable hydrogen transport infrastructure and CO2 transportation and storage*
Budget: Article 4 – paragraph 4 – point b	
up to EUR 8,650,000,000 for the specific objectives referred to in Article 3(2)(b), out of which up to 10% for the cross-border projects in the field of renewable energy	up to EUR 8,650,000,000 for the specific objectives referred to in Article 3(2)(b), out of which up to *10%* for the cross-border *or regional projects with cross-border decarbonisation significance* in the field of renewable energy*, carbon capture transportation and storage appraisal and sustainable hydrogen transport*
Award criteria: Article 13 – paragraph 1 – point c	
Cross border dimension	Cross border or *regional dimension <u>with</u> positive cross border decarbonisation enabling effects*

Eligible costs: Article 15 – point a	
only expenditure incurred in Member States may be eligible, except where the project of common interest or cross-border projects in the field of renewable energy involves the territory of one or more third countries as referred to in Article 5 or Article 11 paragraph 4 of this Regulation or international waters and where the action is indispensable to the achievement of the objectives of the project concerned;	only expenditure incurred in Member States may be eligible, except where the project of common interest or cross-border projects in the field of renewable energy*, CO2 transportation and storage and hydrogen transportation* involves the territory of one or more third countries as referred to in Article 5 or Article 11 paragraph 4 of this Regulation or international waters and where the action is indispensable to the achievement of the objectives of the project concerned;
Expected generated Union added value: Annex – 1.4.2	
energy, it covers infrastructure projects with cross-border relevance in electricity transmission and storage, gas, CO2 transportation and smart grids at the interface between transmission and distribution networks as well as increasing the intelligence of the transmission networks. It also covers targeted cross-border renewable energy deployment and planning involving at least two Member States.	energy, it covers infrastructure projects with cross-border relevance in electricity transmission and storage, gas, *hydrogen transport*, CO2 transportation *and storage* and smart grids at the interface between transmission and distribution networks as well as increasing the intelligence of the transmission networks. It also covers targeted cross-b order renewable energy deployment and planning involving at least two Member States.

TEN-E Regulation for the inclusion of geological CO2 storage

Commission proposal	Amendment
Recital 20	
Following close consultations with all Member States and stakeholders, the Commission has identified 12 strategic trans-European energy infrastructure priorities, the implementation of which by 2020 is essential for the achievement of the Union’s energy and climate policy objectives. These priorities cover different geographic regions or thematic areas in the field of electricity transmission and storage, gas transmission, storage and liquefied or compressed natural gas infrastructure, smart grids, electricity highways, carbon dioxide transport and oil infrastructure.	Following close consultations with all Member States and stakeholders, the Commission has identified 12 strategic trans-European energy infrastructure priorities, the implementation of which by 2020 is essential for the achievement of the Union’s energy and climate policy objectives. These priorities cover different geographic regions or thematic areas in the field of electricity transmission and storage, gas transmission, storage and liquefied or compressed natural gas infrastructure, smart grids, electricity highways, carbon dioxide transport *and storage* and oil infrastructure.

Article 4 – point 2 – sub-point e)	
For carbon dioxide transport projects falling under the energy infrastructure categories set out in Annex II.4, the project is contribute significantly to all of the following specific criteria: (i) the avoidance of carbon dioxide emissions while maintaining security of energy supply; (ii) increasing the resilience and security of carbon dioxide transport; (iii) the efficient use of resources, by enabling the connection of multiple carbon dioxide sources and storage sites via common infrastructure and minimising environmental burden and risks.	For carbon dioxide transport projects falling under the energy infrastructure categories set out in Annex II.4, the project ~~is~~ *must* contribute significantly to all of the following specific criteria: (i) the avoidance of carbon dioxide emissions while maintaining security of energy supply; (ii) increasing the resilience and security of carbon dioxide transport *and storage*; (iii) the efficient use of resources, by enabling the connection of multiple carbon dioxide sources and storage sites via common infrastructure and minimising environmental burden and risks.
Annex I – part 4 – point (12)	
Cross-border carbon dioxide network: development of carbon dioxide transport infrastructure between Member States and with neighbouring third countries in view of the deployment of carbon dioxide capture and storage.	Cross-border carbon dioxide network: development of carbon dioxide transport *and storage* infrastructure between Member States and with neighbouring third countries in view of the deployment of carbon dioxide capture and storage.
Annex II – paragraph 4) – point b)	
Facilities for liquefaction and buffer storage of carbon dioxide in view of its further transportation. This does not include infrastructure within a geological formation used for the permanent geological storage of carbon dioxide pursuant to Directive 2009/31/EC and associated surface and injection facilities;	Facilities for liquefaction and buffer storage of carbon dioxide in view of its further transportation. This ~~does not~~ includes infrastructure within a geological formation used for the permanent geological storage of carbon dioxide pursuant to Directive 2009/31/EC and associated surface and injection facilities;
Annex III – part 2 – point 6)	
Proposed carbon dioxide transport projects falling under the category set out in Annex II.4 shall be presented as part of a plan, developed by at least two Member States, for the development of cross-border carbon dioxide transport and storage infrastructure, to be presented by the Member States concerned or entities designated by those Member States to the Commission.	Proposed carbon dioxide transport *and storage* projects falling under the category set out in Annex II.4 shall be presented as part of a plan, developed by at least two Member States, for the development of cross-border carbon dioxide transport and storage infrastructure, to be presented by the Member States concerned or entities designated by those Member States to the Commission.

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Agenda Item 9.b.: Network Technology update

NWT co-chairs: Filip Neele (TNO), Arthur Heberle (Mitsubishi Hitachi Power Systems)

The NWT meeting took place on 31st October 2018 in Brussels. The meeting agenda is attached as pre-read 9.b.i and the meeting minutes are attached as pre-read 9.b.ii.

TWG Collaboration across the CCS chain

TWG Co-chairs: Ward Goldthorpe (Sustainable Decisions)/Hallvard Høydalsvik (Gassnova)

WS1 (storage-related risks) has produced a draft report, which is appended as pre-read 9.b.iii for review. A dissemination plan has been prepared by the ERG and can be found as pre-read 10.a.x. The intention is to release the report in January.

The AC are invited to approve the draft report. Please note that the formatting will be completed after the approval of the draft report.

WS2 (risk sharing in a CCS network) held two teleconferences since the ERA-NET ACT & ZEP joint workshop on CCS risk and liability sharing which was held on 18th September. The group is in the process of preparing a draft report, consistent with WS1 recommendations and the feedback from the workshop.

TWG CCU and Sink Factor Methodology

TWG Chair: Rob van der Meer (Heidelberg Cement)

The TWG has not been active since the last Advisory Council meeting. It was agreed that the group will meet after the release of the Ramboll study, commissioned by DG CLIMA, to discuss ZEP's response. The group will also consider its response to the IASS report.

The Ramboll study is expected to be published by end-November.

In the meantime, RvdM and AH agreed to prepare a one pager on ZEP's position regarding LCA. The TWG will not develop a new methodology but rather focus on inputting into the Commission's work on defining LCA methodology.

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ZEP Network Technology

DRAFT Meeting Agenda: Wednesday 31st October 2018

Rue du Champ de Mars 21, floor -1, room -1/044.

11:00 – 15:30 CET

Item		Lead Presenter	Time
1	Introduction, tour de table, safety notices	Co-Chairs	15mins 11:00-11:15
2	Policy update: • European issues update • SET-Plan IWG9	Marine d'Elloy	30mins 11:15-11:45
3	Session on capture rates & CCUS modelling: assumptions and limitations • Key conclusions from IEA GHG recent work on capture rates • Group discussion	Artur Heberle (Mitsubishi) Earl Goetheer	45mins 11:45-12:30
	Lunch		30mins 12:30-13:00
5	Session on blue hydrogen • Presentation & update: Magnum Project • Blue hydrogen and current political landscape • Group discussion	 Lamberto Eldering (Equinor) Claude Heller (Air Liquide)	45mins 13:00-13:45
6	Presentation of the North Sea Energy Innovation Project • Discussion	TNO	45mins 13:45-14:30
7	Progress update • TWG CCU & Sink Factor Methodology o LCA & the European Commission (update on ongoing studies) o TWG next steps • TWG Collaboration across the CCS chain o Key conclusions of WS1 report on risks associated with geological storage of CO_2 and cost estimates o Update on progress WS2 report	Filip Neele Rob van der Meer Marine d'Elloy	45mins 14:30-15.15
8	Next steps: • AOB • Chairs' summary • NWT forward-look • Next meeting	Co-Chairs	15mins 15:15-15.30

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Agenda item 9.b.ii.: NWT October meeting minutes

Attendance

Amélie	Carron	Air Liquide
Ana	Šerdoner	Bellona
Arthur	Heberle	Mitsubishi Hitachi Power Systems (NWT Co-Chair)
Claude	Heller	Air Liquide
Eric	De Coninck	ArcelorMittal
Ermenegilda	Boccabella	ET Europe
Fabrice	Devaux	Total
Filip	Neele	TNO (NWT Co-Chair)
Han	Greijn	ET Europe
Isabelle	Czernichowski	BRGM
Lamberto	Eldering	Equinor
Maria João	Duarte	Mitsubishi Hitachi Power Systems
Marine	d'Elloy	ZEP Secretariat
Nikki	Brain	ZEP Secretariat
Rob	Van der Meer	Heidelberg Cement
Valériane	Buslot	Bellona

Item 1: Introduction and issues update

Filip Neele (FN) and Arthur Heberle (AH) introduced the meeting agenda. AH apologised on behalf of Earl Goetheer, who was unable to join the meeting and present the IEA GHG's publication on capture rates.

The meeting agenda was adopted.

Item 2: Policy update (European issues and SET-Plan IWG9)

MD updated the Network on ZEP's recent policy activities, including the COP24 Resolution and the Connecting Europe Facility (CEF) Review.

AH said that ZEP should follow the CEF Review closely since some amendments could have negative impacts on CCUS investments.

With regards to the COP24 Resolution, IC asked who put the amendment (Recital R) forward. MD said the amendment was put forward by the Greens in the DEV Committee. RvdM said the

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wording came from Greenpeace Netherlands. NC said that the wording was also very similar to that of the ETC Group, which published a paper on CCS in October 2018.

MD gave an update on the status of CEF 2018/2019 Energy calls and the Commission's proposal for the establishment of a framework to facilitate sustainable investment.

MD said that the SET-Plan held a plenary meeting on 20th September. The meeting discussed IWG9 proposed structure, subgroups draft terms of reference and forward work plan. The meeting included updates from the European Commission and on the Norwegian full-scale project.

MD said the next meeting will be taking place on 26th March in the Hague.

MD said that the Commission opened a call under H2020 to provide resources to support and coordinate the IWG9's activities. A consortium led by CCSA applied. The Commission is expected to share its decision by Q4 2018 / Q1 2019.

Item 3: Progress update on working groups

TWG CCU & Sink Factor Methodology
RvdM updated the group on TWG CCU & Sink Factor Methodology. There are several ongoing or recently published LCA studies. The two main studies are a study from a consortium led by Ramboll and a study from a consortium led by the IASS Potsdam.

The publication of the Ramboll study has been postponed more than three times. Therefore the TWG had to cancel several of its meetings. MD said the study is expected to be published by end-November.

RvdM said the TWG will meet to discuss both studies' findings.

RvdM and AH agreed that they will draft a short two pager on key messages from ZEP, i.e. highlighting that LCAs should look at the whole life cycle chain to assess the climate mitigation benefits of CCU technologies.

TWG Collaboration across the CCS chain
FN said the work undertaken by the TWG is highly relevant to the Netherlands.

FN said that workstream 1 (storage –related risks) completed a report, which is currently reviewed by the ERG. The Secretariat will work on report proofreading.

FN presented report findings. FN said the report should highlight that the likelihood of all ten scenarios occurring at the same time is zero.

AC asked whether the report quantifies leakage volumes. FN said that the report does quantify leakage volumes.

AC said that the report would benefit from an external review. MD said that the IEA GHG showed interest in reviewing the report. FN said that BRGM already provided comments on the report.

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IC suggested splitting the report into two parts; one on CO_2 storage in Europe and the second on offshore storage in the North Sea. After a discussion it was agreed that the work should be exclusively focused on offshore storage in the North Sea.

IC suggested adapting to title of the report to make it clear that it is focused on the North Sea.

FD asked whether the report considers risks of leakage for CO_2 transport. FD and RvdM said it be would very valuable. FN said that the report does not consider CO_2 transport. The report focuses on storage because there is a strong emphasis on storage leakage in the CCS Directive.

It was agreed that the TWG would look for data and try to add a paragraph on transport-related leakage.

Item 4: Blue Hydrogen

LE gave an update on the Magnum Project. Partners are approaching the next decision gate. LE emphasised the importance of the current political context in the Netherlands.

EC asked what the expectations are in terms of project cost. LE said estimated costs are close to those outlined in the last feasibility study.

FN asked whether the Network could support the project in a useful way. LE said current work is internal. However, ZEP could help with visibility and advocacy.

EC asked whether the Netherlands have a scheme to support CO_2 electricity. LE said such scheme does not exist, but government has acknowledged that focus should be on abatement as opposed to renewable energy only. There is an ongoing process to redefine this.

CH discussed the current political context for blue hydrogen and the findings from the ZEP's hydrogen report. CH said that the estimations around the price of natural gas in the report were too high. However, the report was very valuable because it calculated the difference in cost between blue and green hydrogen over time – and it was the first time that time was added to the picture.

CH emphasised that deploying infrastructure for blue hydrogen will also benefit the development of green hydrogen.

CH said Hydrogen Europe understands that a mix of blue and green hydrogen is needed and encouraged ZEP to connect with Jorgo Chatzimarkakis.

Item 5: Session on capture rates & CCUS modelling

The group had a short discussion on capture rates.

AH said one of the key conclusions from the IEA GHG report is that the size of the plant is key in determining the cost of capture.

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NB explained that recent modelling studies (i.e. DG ENER ASSET study) assume 90% capture rates as a maximum, whilst higher rates are achievable. This tends to push CCS out of climate modelling. It was agreed that the Network will need to address this by potentially initiating a piece of work on capture rates. The Network will review the IEA GHG report on capture rates first.

RvdM said that a lower capture percentage will initially be needed to achieve economical feasibility; however, longer-term industry will have to attain 100% capture to reach climate targets.

Item 6: North Sea Energy Project

FN presented TNO's North Sea Energy Project, which looks at system integration in the North Sea. The objectives of the programme are to 1) increase insight into the interplay between different users and interests relevant for the strategic planning of energy activities in the North Sea domain; 2) provide insight into the human capital agenda for the offshore sector and present the regulatory framework for offshore system integration; 3) provide insights into the techno-economic status of potential offshore energy system integration options and assess the commercial value for the Netherlands of further developing these options.

The project considers gas production, gas reuse, and future reuse for hydrogen. It was agreed that the project could inform future work.

Item 7: AOB

MD said that the High Level Expert Group on Energy Intensive Industries held a meeting on 9th October. The focus of the meeting was a presentation of the recent report *Industrial Value Chain: A Bridge towards a Carbon Neutral Europe,* which was developed by a group of eleven industry sectors as their input to the EC Long Term Strategy.

The report can be downloaded from here:
https://www.ies.be/files/Industrial_Value_Chain_25sept.pdf.

MD said it would be useful to look at the report and assess whether ZEP feels comfortable with the conclusions. AH volunteered to read through the report.

Actions

Action		Owner
3	ERG and Secretariat to proofread WS1 report and work on messaging	ERG + Secretariat
3	TWG CCU to produce a short paper on ZEP's position regarding LCA	TWG CCU
5	Network chairs to follow-up on the capture rates discussion after the publication of the IEA GHG report	FN + AH
7	AH to read through the EEIs report	AH

ZEP Secretariat,
Carbon Capture and Storage Association
6th Floor, 10 Dean Farrar Street, London, UK
www.zeroemissionsplatform.eu

ZEP Secretariat,
Carbon Capture and Storage Association
6th Floor, 10 Dean Farrar Street, London, UK
www.zeroemissionsplatform.eu

ZEP WORKING GROUP 'COLLABORATION ACROSS THE CCS CHAIN'

CO_2 STORAGE SAFETY IN THE NORTH SEA

Executive Summary

1. Overarching conclusions:

- CO_2 underground storage is a safe technology ready for broad implementation.
- ZEP's analysis concludes that for a typical North Sea site, which would be the most probable area for the next European CO_2 storage projects, both the probability of CO_2 release and the expected volumes of CO_2 release are very low.
- CCS is a relatively straightforward technology frustrated by strict regulations (in the form of the European CO_2 Storage Directive) imposed by the authorities which incur heavy legislative and disproportionate financial burden on the operators. This leads to reluctance from the private sector to invest, in turn increasing the perceived risk.
- The overall need for CCS to decarbonise power production and heavy industry in Europe remains genuine and urgent. Fewer CCS projects have been implemented than envisaged in 2009/10. Given the lack of practical experience it would not currently be appropriate, and could be counterproductive, to reopen the CO_2 Storage Directive for significant changes. However, some clarifications and softening of Guidance Document 4 (on Financial Security) could help.
- Involved parties should strive to develop and agree a Monitoring, Measuring and Verification (MMV) program that is fit for purpose for the identified risks (addressing both impact and probability). Excessive monitoring costs and financial security funds could act as a significant blocker to the widespread deployment of CCS in Europe.
- The urgency and scale of required emissions reduction, and the current costs for CCS, demand that current technologies are implemented at scale while R&D continues into new technologies which can incrementally improve the efficiency and economics of CCS deployment.

2. Background

Carbon Capture and Storage (CCS) is a set of technologies which remove CO_2 from industrial processes such as power generation, steel and cement production, and refining, and store the CO_2 permanently 1-2km underground to stop emissions to the atmosphere.

This report was prepared under the ZEP project "Collaboration across the CCS Chain" and is the result of work stream 1: storage-related risks. The purpose of this report is to 1) summarise the most relevant risk areas associated with geological CO_2 storage in the North Sea; 2) estimate the risk level of such storage; 3) summarise major lessons learned from ongoing projects and 4) identify areas of major uncertainties or gaps in knowledge.

3. Detailed conclusions

Geological storage of CO_2 has been demonstrated globally over the past 20 years however, it is not currently taking place on a large scale. A key concern for governments is understanding the risk associated with storing CO_2 in the subsurface, in order to enable scale-up of CCS activity. This report covers several types of risk which will have an impact on the economics of a project; performance risk (the operator can store less CO_2 than expected), operational risk (operational risks associated with CO_2 storage are comparable to those already known from oil and gas development operations and the same health and safety requirements will be applied), containment risk (the CO_2 leaks from the designated storage site) and commercial/financial risk (the operator is required to pay a financial penalty related to an unrealistic and disproportionate risk profile of CO_2 leakage). This report concludes that the most likely risk posed by CO_2 storage is commercial risk.

The report models ten theoretical CO_2 leakage scenarios, assessing the probability, impact, duration and cost implications. These scenarios are set out below:

Scenario	Probability (%)	Rate t/d	Duration	Lost mass (t/year)	Consequence	Corrective invest. **(M€)**	CO_2 quota **cost (M€)**	Risked cost **(€)**
Low leakage; fault & fracture	0.002	100	50 years	38,000	CO2-cost + monitoring		57	194,000
Moderate leak: fault & fracture	0.0005	700	12 years	258,333	Relief well+ monitoring	50	93	89,000
Severe leakage; fault & fracture	0.00005	5000	4 years	1,825,000	New site+ depressurise	320	219	29,450
Active well leakage	0.005	50	250 days	8562	workover	10	0,4	52,000
Active well blow out	0.0015	5000	250 days	856164	Relief well	50	38	139,500
Legacy well blowout	0.001	3000	1 years	1,100,000	Relief well	50	33	88,000
Seepage in legacy well	0.005	7	100 years	2500	CO2-cost, + monitoring		7	170,000
Severe well problem, no repair successful	0.00005	6000	2 years	2,150,000	Depressurise & new site	320	129	26,200
Leak from installation	0.0025	100	5 days	6.8	Shut-in and repair	15	0	37,500
Undesired plume spread	0.0003	-	-	-	Water production	50		

A number of key messages can be drawn from this table and CO_2 leakage in general:

- It is important to note that the ten scenarios cannot take place at the same time, as some events are mutually exclusive.
- The report concludes that 99,9% of injected CO_2 is expected to remain in the subsurface. This is consistent with the 2005 IPCC Special Report on CCS which found that "*the fraction [of CO_2] retained in appropriately selected and managed reservoirs is very likely to exceed 99% over 100 years, and is likely to exceed 99% over 1000 years*".
- Once a CO_2 storage site is closed, the risk of a CO_2 release reduces exponentially and 50 years after closure the residual risk for most projects will be minor. Over time this risk reduces further as more and more CO_2 is immobilised (binds chemically to the surrounding rock).
- The North Sea basin contains oil, condensate and gas trapped in a large variety of reservoirs. There are numerous extensive caprocks that are known to be effective seals for oil and gas and they are all likely to be highly effective at containing CO_2.

A summary of experience to date from CO_2 storage projects worldwide is also included in the report (such as Statoil's Sleipner project and Total's Lacq project) – from pilot to industrial scale – along with published risk estimates and further evaluation by a group of industry and research specialists with expertise in CO_2 storage. For all operational projects, no geological release of CO_2 to the surface or the sea floor has been detected so far. Furthermore, these operational projects all highlight the importance of utilising stringent Monitoring, Measuring and Verification (MMV) as well as maintenance and remediation procedures. This report concludes that based on operational experience to date, geological CO_2 storage is proven technology, ready for wide implementation and CCS can therefore be counted upon as a key climate mitigation solution.

This report finds that the biggest challenge related to CO_2 storage is contained within the EU CO_2 Storage Directive, Guidance Document 4 (Financial Security and Liability). Under this Directive, the owners of a CO_2 storage site are liable for the cost of leaked CO_2 equivalent to the carbon price under the EU Emissions Trading Scheme at the time of leakage. Additionally, a cash deposit is required at handover of site ownership to the national authorities to cover potential future costs. However, under Guidance Document 4, the owners of a CO_2 storage site are liable for the cost of a total (100%) CO_2 release. If a theoretical worst-case scenario is applied, the remediation cost for a single CO_2 storage site could be in the order of €600 million. However, such a severe event is expected to happen only in less than one of 10,000 projects. The analysis in this report shows that the total risk **for one storage project, taking event probabilities into account, amounts to less than €1 million.** This can be considered as a typical risk for a well planned and developed North Sea storage project, and is several orders of magnitude less than the worst-**case scenario cost of €600 million**. If operators are required to set aside Financial Security to cover a worst-case scenario remediation cost, this will place a heavy burden on any storage business case and obstruct the development of a sound CO_2 storage business.

No individual operator can afford to set aside funds to cover such unlikely events for every project, and no other ongoing business operates under an equivalent requirement. In other industries similar risks are usually absorbed by an insurance system (e.g. in the petroleum industry). A guarantee or insurance system, initiated by the authorities, for sharing the risk for the CCS industry would significantly reduce the burden currently carried by first-mover projects and proactively encourage CCS deployment. An alternative approach could be a fund held centrally with contributions according to the probability-weighted risk costs. As there initially will be too few projects for an operative insurance system, the liability will initially need to be shared between government and the private sector. Practical experience to date from certain countries demonstrates that Governments will need to exercise considerable flexibility in defining the Financial Security. Mechanisms for sharing of leakage-related liability and economic risks across the CCS chain need to be developed to encourage investment into CO_2 geological storage. A ZEP report exploring the latter issue will be released shortly.

To conclude, applying an unrealistic worst-case scenario cost to a CO_2 storage project imposes a heavy burden to the business case of a CCS project, resulting in reluctance from the private sector to invest, in turn increasing the perceived risk. This could delay and even completely stall the urgent deployment of CCS, thereby resulting in failure to achieve the Paris Agreement goals of limiting the global temperature increase to below 2°C.

Table of Contents

1. Context

This report has been prepared under the ZEP project "Collaboration across the CCS Chain" and is the result of work stream 1: storage-related risks. The purpose of the document is to 1) summarise the most relevant risk areas associated with geological CO_2 storage in the North Sea; 2) estimate the risk level of such storage; 3) summarise major lessons learned from ongoing projects; 4) and identify areas of major uncertainties or gaps in knowledge. The focus is primarily on technical issues, but the report also touches on legislation. The estimated risk level in this report should be seen as a class risk for a typical well-planned North Sea storage site. For evaluating and permitting an individual storage site, a specific assessment of the relevant site has to be performed.

This document will be used as technical basis for work stream 2; "Risk sharing across the CCS chain". The objective of work stream 2 is to outline the options available for sharing or allocating risk and liability in different organisational models for CCS networks (comprising multiple sources and multiple storage sites). The project's focus is to enable the development of the first European offshore CCS project/s. The EU Storage Directive (Ref 1) sets strict requirements for CO_2 leakage risk monitoring, mitigation and liability, as well as four specific levels of planning and financial guaranties for the operators of underground CO_2 storage. The European Commission must approve any storage permit based on an extensively documented application. It is apparent that the Commission will not approve any CO_2 storage project unless its leakage risk is very low and the operator is capable of handling it in a predictable manner.

There has been much less CO_2 storage activity in Europe than anticipated when the EU established the Storage Directive in 2009. This lack of progress can be attributed to the absence of a defined commercial model for CCS, as well as the heavy constrains operators face, both in terms of finance and legislation. The latter will be discussed throughout the report.

It is expected that oil and gas companies with broad offshore experience are the likely operators for early CO_2 storage projects. Offshore petroleum activities are very similar to offshore CO_2 storage, include many of the same operations and work tasks. To date, the European oil and gas industry has conducted their operations with a high level of Health Safety and Environment (HSE) performance.

The additional risk attributed to the new CO_2 storage industry compared with previous oil and gas activities is the risk of releasing large quantities of CO_2. However, oil and gas companies have handled the risk of gas leakage reliably and predictably for decades. The consequences of a release of CO_2 from a geological store are significantly lower than for oil or gas seen from a personal safety and a local environmental perspective (Ref 10). CO_2 does not combust nor does it create oil slicks. It is naturally present in the atmosphere and once diluted released CO_2 is indistinguishable from other CO_2. Only in high concentrations can it cause harm to the environment, and has the potential to alter the pH of water. The risk posed by CO_2 storage is more commercial in nature. A financial penalty is attached to the release of CO_2 into the linked ocean-atmosphere system. This penalty comes in three parts,

(i) Direct requirement to purchase ETS allowances at the prevailing cost at the time of release, which is likely to be higher than at the time of injection.

(ii) Obligation to execute a "corrective measures" plan – i.e. limit the quantity released.

(iii) Obligation to continue to monitor the system until it can be shown that there will be no more leakage.

In addition, even if CO_2 does not reach the ocean-atmosphere system, there is an obligation to execute steps (ii) and (iii) if the CO_2 is shown to have left the subsurface volume designated for storage (the “storage complex”).

2. Introduction to CO_2 Storage

Power generation from fossil fuels and many industrial processes generate CO_2. To reduce the emissions of CO_2 to the atmosphere, CO_2 must be captured before it is emitted, transported to a suitable storage site and injected there. The CO_2 must be stored so that it will remain within a defined location, where it will not create any adverse impacts. To make sure the CO_2 remains, it must be injected into a reservoir with defined boundaries of which it shall not flow out. The storage medium itself is typically a traditional reservoir rock (i.e. a rock formation with large pore space to store in and high permeability so it can be easily injected into). When the CO_2 is injected into the reservoir rock, it will displace the existing fluids and migrate upwards due to buoyancy or mix in the case of a gas field. To prevent the CO_2 from migrating out of the designated reservoir, the reservoir must be capped by an impermeable rock formation: a sealing cap rock. When the CO_2 cannot migrate further up, it will spread sideways beneath the cap rock. It is therefore beneficial that the cap rock forms a trap with a geometry that provides impermeable lateral boundaries until sufficient depth. The drawing below illustrates this principle.

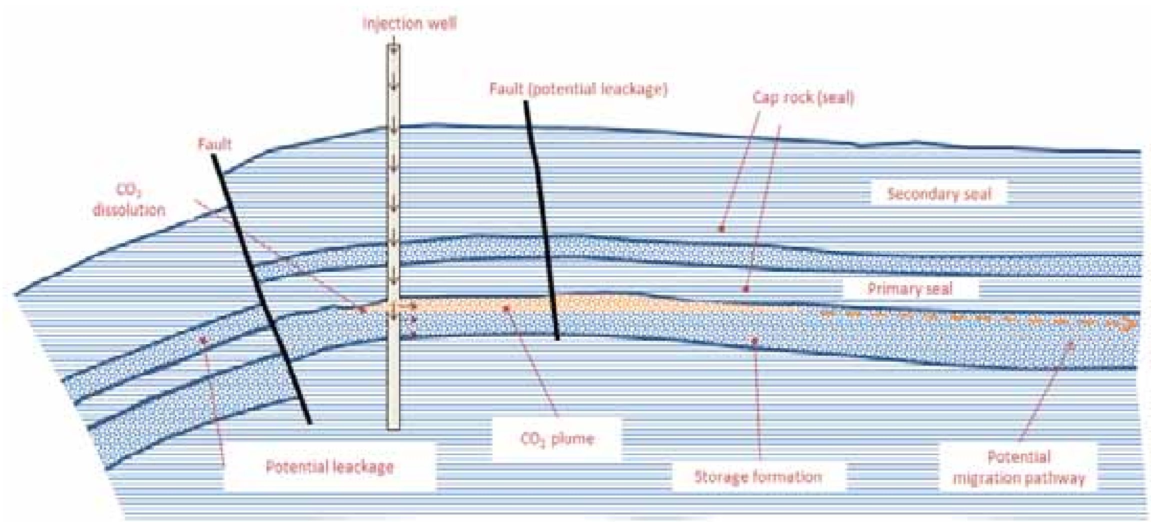

Figure 1. Illustration of a geological storage with potential pathways for leakage.

Article 3 of the EU CCS Directive (Ref 1) lists the following definitions:

- ‘Geological storage of CO_2’ means injection accompanied by storage of CO_2 streams in underground geological formations;

- ‘Storage site’ means a defined volume area within a geological formation used for the geological storage of CO_2 and associated surface and injection facilities;
- ‘Leakage’ means any release of CO_2 from the storage complex, however, mostly used for release to the atmosphere/ocean system;
- ‘CO2 plume’ means the dispersing volume of CO_2 in the geological formation;
- ‘Storage complex’ means the storage site and surrounding geological domain which can have an effect on overall storage integrity and security; that is, secondary containment formations.

Under these definitions, CO_2 might migrate out of the storage site but stay in the storage complex. The leak out of storage complex is covered in the CCS Directive and the leak to the atmosphere is regulated under the ETS Directive (Ref 2).

The following requirements must be fulfilled by a storage site:

1. Capacity: the storage site must have sufficient capacity to store the required mass/volume of CO_2.
2. Injectivity: the project must be able to inject CO_2 into the geological store at a sufficiently high rate to handle the quantities delivered to the project.
3. Containment: the injected CO_2 must remain safely contained in the geological store (the storage complex as defined by the project).
4. Monitoring and remediation: the project must be able to show that the store is performing as expected, and be able to repair anything that does not perform as required.

A demonstration of these elements will be required to obtain an injection and storage permit by national authorities and the EU administration. A rigorous assessment of the storage project risks is an essential part of the application process. These risks, and their quantification, are discussed in chapters 3 and 4.

Geological storage sites for CO_2 fall into several broad categories (figure 2):

- Aquifer storage versus storage in oil or gas fields;
- Storage in a closure (or trap) versus a store with an open structure;
- Isolated storage with closed pressure boundaries (sealing faults or rock variation prevents the release of pressure from the store) versus stores with open boundaries;
- Storage sites at virgin (hydrostatic) pressure versus sites with reduced pressure below hydrostatic, e.g. due to hydrocarbon production at or close to the site.

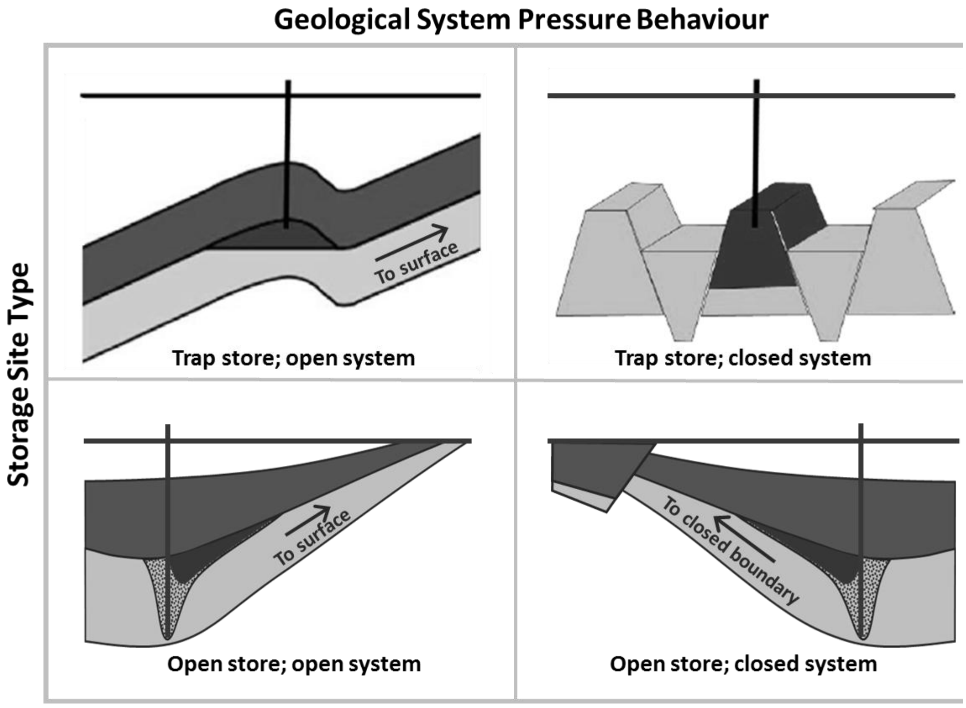

Figure 2. Different storage site types

CO_2 storage differs from most hydrocarbon production scenarios in that there is often a net addition of material to the subsurface, as opposed to a net removal of material. But the details depend on the exact configuration of the storage project, so it is important not to generalise from one type of project to another.

For pure CO_2 injection into a saline formation, like the Sleipner case (see Chapter 5.2), CO_2 is injected into pores in the rock that are already filled with water. This addition of CO_2 increases the subsurface pressure and pushes water away. The subsurface is left with higher pressure than before injection started. In large aquifers like Sleipner the pressure increase is hardly measurable. For primary hydrocarbon production, oil or gas is removed from pores in the rock and the pressure reduces.

In many cases there are more aspects than those described. For hydrocarbon development, water is often pumped into the subsurface to flush oil and gas out, and the reservoir pressure can be maintained. Similarly, water can be extracted as CO_2 is injected; which is what the Gorgon CO_2 storage development in Western Australia intends to do. The pressure can be maintained at or below initial pressure through this extraction of water. CO_2 can also be injected into a depleted oil or gas field for storage, re-pressuring the reservoir to a point that the final pressure is still below the initial pressure. In this case the subsurface can after CO_2 injection have less pressure than before the start of the hydrocarbon production project.

Most of the risks associated with CO_2 storage are common to all types of store, although some risks are inherently higher or lower for a particular storage type, as discussed throughout this document. There are also many similarities between the hydrocarbon extraction and CO_2 storage industry, in terms of development and operational activities and facilities, and the risks associated with these. Consequently, the relatively immature CO_2 storage industry can draw on the wealth of experience and incident data from the hydrocarbon industry to assess and manage storage project risk, given an understanding of where CO_2 storage and hydrocarbon extraction differ, and which data can be appropriately used.

3. Major Risk Areas

This chapter will outline the major risk events and their consequences. The risks are set out below under two main categories;

- The containment risk [does it leak?] covers all events where CO_2 escapes out of the storage complex in an unplanned way. This includes failure of caprock, wells and equipment, as well as extensive migration through porous formations or faults (Ref 42). This risk is relevant from start of injection, builds throughout injection, and may remain beyond closure. Leakage to the atmosphere can affect the local environment, whereas leakage outside the storage complex but not to the atmosphere, can affect the project economics. Effects of such leakage can be global (less positive contribution to CO_2 emission reduction) and local, such as damage to human health or the immediate environment. This report concentrates on containment or leakage risk.
- The site performance risk [does it conform to expectations?] is linked to successful development and operation of the storage project during appraisal and injection stages, particularly in respect of capacity and injectivity. Mitigation of this risk will primarily be additional data acquisition in the appraisal stage and proper monitoring for performance throughout the injection stage. Consequences can be modifications to wells and facilities, new wells or in the worst-case, cancelation of the project. In all circumstances it will create additional costs to the operator or site owner.

Figure 3 shows qualitatively how leakage risk to the atmosphere or sea bottom develops during injection and after closure.

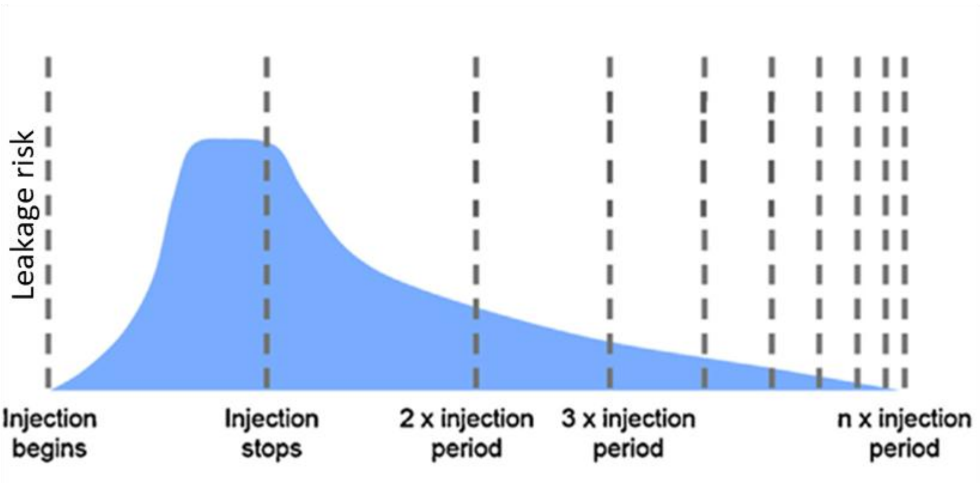

Figure 3. Theoretical development of leakage risk during and after CO_2 injection (ref 4).

3.1. Containment risk

It is essential to any storage location that the caprock provides complete closure and seal of the storage reservoir and that faults, if present, are not pathways and cannot be re-activated by the injection. A good-quality caprock is more than adequate to isolate CO_2 in the subsurface. Caprock integrity should be studied carefully in the appraisal phase, for different reasons than for oil and gas exploration, but using similar technologies. Even so it can be a challenge to achieve a high degree of certainty about caprock integrity prior to full-scale injection as for hydrocarbon fields, where discovery proves caprock integrity. For storage sites bordering outside areas, monitoring the plume development is required to ensure it stays within the closure.

Caprock can theoretically be damaged by injection. The likelihood of fracturing the caprock depends on the tectonic environment, the magnitude of differential stress and the presence of brittle fracture features. As long as the pressure does not exceed the initial level, the risk is not regarded as significant. However, if the pressure exceeds the measured leak-off pressure of the caprock, the risk for fracturing gets high. The thicker the caprock the less impact such fracturing will have on leakage risk. The potential of reactivating existing faults is considered as a more significant caprock risk than the creation of new fractures. Methods for estimating stress and fracturing, as well as permeability of fractures have been developed. The experience in this entire area is, however, limited. It is therefore recommended to operate with significant safety factors[1]. The pressure can in some cases be kept at an acceptable level by extracting water (water production) during CO_2 injection. The produced water needs to be disposed of at a significant cost.

The consequence of a leaking caprock can be limited to severe. In most North Sea cases there will be layers above to accommodate the leaking volumes. These layers should be included in the definition of the storage complex together with the caprock above them. Such migrating CO_2 could affect hydrocarbon resources located in these layers. It is very unlikely that large volumes of CO_2 will find a high permeable pathway all the way from the storage reservoir at storage depths of 2000-3000m to the sea floor. Small volumes of CO_2 seeping out at the sea floor will not have more significant impact than the natural hydrocarbon seeps we have today in the North Sea. Small volumes of CO_2 might influence marine life a few meters from the exit point. Flow in a pathway through the subsurface is difficult or impossible to mitigate. Pressure release from the formation through production of brine or CO_2 from new or existing wells might be the only solution. A major leakage into the sea will typically require immediate cessation of injection, most likely permanently and consequently the development of a new storage site.

Seismicity relates to tectonic activity in the underground. Severe seismicity can create faults and fractures. The North Sea is characterised with low natural seismicity. However, oil and gas production activity has induced some low energy seismicity. More intensive seismicity is

[1] In engineering, a safety factor, expresses how much stronger a system is than it needs to be for an intended load. Many systems such as buildings or bridges are intentionally built much stronger than needed for normal usage to allow for emergency situations, unexpected loads, misuse, or degradation.

noticed in the vicinity of high pressure gas storage developments. Significant fracturing and leakage created by induced seismicity has not been experienced or documented so far.

Wells are the elements of a storage site considered to have the largest probability of being pathways for leakage from underground CO_2 storage. Injection wells (or other operational wells such as monitoring wells or water producers) can in theory experience gas flow during drilling and completion, during injection or even after closure. In the appraisal and development phase a flow of brine and hydrocarbons might occur. Legacy wells, which are old abandoned wells drilled for other purposes than CO_2 storage, can behave as leak pathways if the injected CO_2 reaches them underground. The flow through wells can occur with limited volumes and rates through restricted leak routes (outside casing, poor cement etc) or develop into full well blow-outs. The consequence of severe blow-outs during injection and thereafter can be reduced by locating the injection well in such a way that the plume will migrate away from the legacy well.

The risk of blow-outs in CO_2 wells during the appraisal and development phases will be significantly lower than for oil and gas wells, as the target of CO_2 wells are either brine filled or depleted reservoirs. Blow-outs during regular injection in wells with modern completions is also unlikely. The highest blow-out risk is during activities such as well repairs and recompletions in the late injection phase, when well equipment has aged and reservoir pressure increased. Nevertheless, it should be noted that hardly any such events are yet known. The more likely leakage scenarios with purpose-drilled wells (injection and observation wells), are those with limited leakage rates and volumes either just outside the casing or resulting from equipment failures in the well itself, during the late life of the well or after closure.

The least predictable element is legacy decommissioned wells penetrating the storage site. When they were plugged, CO_2 injection in their neighbourhood was usually not taken into consideration and some of them may thus not seal off the storage reservoir against CO_2 entering the well or flowing into other permeable formations. It is usually not feasible, or very costly to re-enter and repair them. If there are uncertainties about the condition of a legacy well the best course of action is to select storage sites away from it. Most depleted hydrocarbon fields have a number of such legacy wells, which require particular attention and care. Applicable to all decommissioned wells, there is a general expectation that shale, clay and salt layers will spread and squeeze and thereby seal naturally any penetrations over time, hence old wells become a steadily reducing risk. However, there is no experience documenting this process, and the time horizon is unknown.

Leakages with minor flow rates related to wells in operation can normally be repaired. In many cases a drilling rig will be required, which makes mitigation relatively costly. A full blow-out is, however, a very serious matter. In the worst case a relief well must be drilled, which can take months with a drilling rig, releasing large volumes of CO_2 for which equivalent ETS allowances must be purchased. A minor leakage related to a legacy well, which typically cannot be repaired, might also require a relief well with associated costs.

CO_2 plume migration out of the storage complex might occur if the injected CO_2 does not behave as expected, in the case of an open storage concept (no trap e.g. Quest project), or the targeted closure (or trap) is incomplete. Where the caprock continues laterally with good quality over a relatively flat and wide area around the storage complex, this might not be a concern. The plume must be monitored however, mostly by seismic. Migration out of the storage complex can cause significant damage, or encounter flow pathways to surface, where the caprock formation dips more steeply, or in complex geological structures, faulted areas and in regions with other subsurface resources. Sites with potential for such challenges must be thoroughly appraised before development and carefully monitored during operation.

During injection, CO_2 will, in many cases, displace formation brine. Consequently, brine might migrate out of the storage site and into surrounding areas. Closer to shore this could cause damage to sources of drinking water, but this is not the case for the North Sea region.

Leakage can also occur from pipelines, subsea installations and other facilities. Such events will be comparable to experience from the petroleum industry with similar probabilities, mitigation and consequences. With the policy of double boundaries and valves, such leakages can be limited and stopped on relative short notice. Repairs might, however, take some time and require expensive equipment. No major consequences for the environment are expected, but there may be economic consequences if there is a liability towards the suppliers.

Monitoring is an important measure for controlling the injected volumes and is the basis for preventing leaks. Unfortunately it is difficult to document full control of volumes far underground, regardless of how extensive the monitoring program is. The best strategy is to identify the parameters which can give warnings at an early stage and develop a program for measuring these at realistic intervals. It must further be considered that CO_2 is part of any natural environment and can have other sources than the storage site.

3.2. Performance Risk

The performance risk is dependent on the presence and quality of storage rock, caprock and trap. This risk/uncertainty can be considerably reduced through data acquisition and analysis during exploration and appraisal prior to injection. Additional wells, seismic and expert studies for mapping purposes are expensive and will load the project with more costs upfront. If the results are negative and do not allow a storage development, these early costs will be sunk. The consequences, if limitations in storage performance are first experienced in the operation phase, are repairs, modifications and reduced injection. If repairs are successful and injection adapted, this risk will not affect the environment significantly. Performance risk must be regarded mainly as an operator or owner's risk. It can, however, have large impact on the economics of the project, and in the worst case require abandonment of the project and the selection of a new site.

Low injectivity can be caused either by poor reservoir quality or by an ineffective well completion. There are many examples where well completions have been modified and considerably improved after the start of injection. Wells have been cleaned, deepened, fractured and gravelled for sand protection etc. These operations normally require a drilling rig and add costs to the project. In the worst case the injection rate must be reduced and additional injection wells might be required.

Reduced capacity is normally a result of new information or interpretation based on experience gained in the operation phase. Reduced capacity can be caused by imperfections in the caprock, unexpected plume behaviour, or incomplete closure, allowing CO_2 to migrate out of the storage complex if the originally planned CO_2 volume is injected. Where there is timely recognition of the situation, remediation action can be taken and no damage to the environment should occur. This illustrates the importance of adequate monitoring during the early stages of the injection phase. The consequence of reduced capacity is the requirement to develop alternative storage capacity, which might have a large economic impact for operators and owners.

The performance risk is generally lower for a storage development utilising depleted oil and gas fields than for a saline aquifers. There is likely to be a larger body of well and seismic data available from the depleted field site. Additionally, a wealth of productivity and dynamic fluid behaviour data will have been collected and modelled during the oil or gas field production operations. Barriers and flow pathways will have been mapped and effective completions developed. Aquifers around produced fields will have less risk than more virgin areas because they also might be partly depleted and profit from good reservoir characterisation nearby.

Most operational risks are comparable to those already known from petroleum development operations. The North Sea governments intend to utilise the same health and safety requirements for CO_2 storage as is currently applied to the petroleum industry. Storage facilities are comparable to simple subsea petroleum production facilities, and the operation itself is expected to require fewer interventions. Operators will in most cases have a liability to inject CO_2 from suppliers. This implies a potential economic risk in case of low injectivity and during periods of no injection due to repairs.

The operational risk level is in general lower than in the petroleum industry as:

- CO_2 is less dangerous to life and facilities than petroleum products (Ref 10);
- The drilling targets are water filled or have lower pressures;
- The injection facilities are much simpler.

4. Estimates of magnitude of risks

Risk is defined as the product of probability multiplied by consequence. Several publications give recommendations in respect of risk assessment (Ref 5 and 6). Quantitative approaches are challenging due to very wide ranges in key parameters, multiple methodologies, large technical uncertainty and very low probabilities. There is little industry experience with leakage estimation. Reliable quantification of leakage and leakage risk requires better calibration of models and input parameters from real historic experience. However, a view of the risk and risk-level has been formulated based on the results of available studies.

Available studies are largely based on raw data and methodology from the petroleum and gas storage industries. These industries work in the same geologic provinces and formations, and perform the same or similar operations. Two studies, which cover a broad range of aspects, are referred here:

- DECC/AGR report: CO2 Storage Liabilities in the North Sea
- **Gassnova's leakage risk studies**

Both studies focus on quantifying the probability of events and listing possible consequences and potential mitigating measures. In this report, the cost of consequences and corrective measures will be additionally estimated and the risk level and structure illustrated. The probability of leakage quoted in this report is defined for the lifetime of the respective projects including the post-closure period. All leaks to which costs are allocated are leaks to the atmosphere. The basis for both studies is statistics and data dossiers including extensive North Sea petroleum activity.

DECC and Gassnova data provide representative assessments (rate & frequency) which are used in this report. Scale of risk is representative but actual risk for any project will vary depending on site (existing wells and geology), storage concept (e.g. brine or hydrocarbon filled site, operating and final pressures) and development (e.g. number and operating life of active wells). The cases discussed (DECC, Gassnova and document case) all have different injection phase durations and well numbers.

4.1. DECC/AGR report

The DECC study (Ref 4) focused on four main possible pathways for potential leakage identified in previous research, namely faults, caprocks, operating and abandoned wells. The purpose was to develop an expert view on representative parameters for offshore UK North Sea storage (i.e. hazards, leak rate, duration, dynamic controls, probability of leakage) for the four main pathways. The key results are summarised below.

Table 1 gives summary parameters and scenarios for potential leakage from active wells. The chosen scenarios illustrate the span of potential leakages. Active wells are defined as all wells utilised for injection, observation and water extraction as well as wells under drilling or interventions.

Scenario	Low level leakage	Uncontrolled blow out
Probability of leakage event	0,0001-0,001	0,00001-0,0001
Flow rate tons/day	1- 10	5000
Duration	0,5-20 years	3-6 months
Dynamic control	Well shut in/reduced	Injection halted
Potential leakage Amount	180-73000 tonnes	0,45-0,9 million tonnes
% of stored volumes	0-0,036	0,22-0,45
Long term consequences	Injection reduced or stopped	Injection halted until remediation completed
Corrective measures	Work over with rig	Relief well drilled, 60-90 days

Table 1. Leakage parameters for two leakage scenarios in active wells (Ref 4). Probability quoted for leak event occurrence is over the project life time including the post closure period.

The numbers are based upon earlier work performed by SINTEF on North Sea statistics (Ref 7). They are estimated assuming a notional storage project development with 5 injection wells, injecting a total of 200 million tonnes over a 20-year injection period.

Abandoned wells penetrating the storage reservoir pose a risk of leakage because they represent a direct pathway to the surface. Both pre-existing wells from petroleum activities and decommissioned CO_2 wells are considered. Records for abandoned wells are not always complete and available, and methods adopted have varied over time and between different operating companies. The potential storage formation might not have been the target for hydrocarbon production and therefore legacy wells may not have been plugged to an acceptable standard. Previously active CO_2 wells will be plugged in a “fit-for-purpose” manner and represent an extremely low risk of leakage. Table 2 gives summary parameters for two scenarios representing potential leakage from abandoned wells.

Scenario	Low level leakage	Complete breakdown of plugging system
Probability of leakage	0,0012-0,005	0,000001-0,0001
Leakage rate, t/d	0,6 - 6	1000
Duration of leakage	1-100 years	3-6 months
Dynamic control option	Manage reservoir pressure	Halt Injection temporarily
Potential amount lost	220-220000 tonnes	90000-180000 tonnes
% of stored volume lost	0,0001-0,1	0,045-0,09
Immediate consequence	Consider reducing injection	Halt injection until well repaired
Corrective measures	Re-entry very difficult; observe and consider relief well	Relief well to intersect leaking well
Variation of risk	Increasing over injection phase	

Table 2. Leakage parameters for two leakage scenarios in legacy wells (Ref 4). Probability quoted for leak event occurrence is over the project lifetime including the post-closure period.

The paper by LeGuan (ref 8) has been used to provide probabilities of a variety of potential leakage scenarios.

Given the geology of the North Sea, migration of CO_2 through caprock is not considered a material leakage risk for any storage site permitable under the CCS Directive. The North Sea basin contains oil, condensate and gas trapped in a large variety of reservoirs. There are numerous extensive caprocks that are known to be effective seals for oil, gas and CO_2. Their thicknesses and geology are well known; many are 100s to 1000+ m thick. Different seal formations are present in different regions of the North Sea. They are all likely to be highly effective at containing carbon dioxide. The geological controls on caprock continuity must, however, be understood to ensure that the caprock is present and continuous across the storage site, and is not absent locally e.g. due to erosion, non-deposition, facies changes etc.

Fault zones and fractures are considered to be two of the main potential conduits for the movement of CO_2 beyond the boundaries of the storage site through the caprock. Leakage of CO_2 may occur where there is an existing pathway in the form of a fault, fault zone or fracture system, by reactivation of an existing pathway, by fracturing to create a new pathway resulting from CO_2 injection, or induced by natural seismicity.

The nature of faulting and fracturing will depend on the specific geological structure, tectonics and structural evolution. Faults and fractures are prevalent in older and deeper formations in the North Sea, but it is very unusual for them to extend all the way from the depths of a potential CO_2 storage through overlying caprock to the surface. This is important as the lack of a direct route substantially reduces the risk of fault leakage. Faulting is not necessarily a sign of leakage or potential leakage. There are widespread occurrences in the North Sea where oil and gas has remained contained over millions of years in a reservoir under a faulted caprock. These provide evidence that many faults are sealing. Faults, fault zones and fractures have been studied and have been shown to be highly variable in their ability to transmit fluids. This underlines the need for an assessment of the site-specific leakage potential for any potential storage development. Methodology for modelling of flow along faults is, however, still at an early stage and the results are rather uncertain.

A published range of CO_2 leakage rates via faults from appropriate natural analogues to storage sites is 0.006 and 0.3 t/yr/m2 (Ref 9). None of these analogue sites are in the North

Sea. Faults are expected to be significantly more permeable close to reactivation pressure, and the significance of the fault zone as a leakage conduit is driven by the reservoir pressure. The critical period is therefore during the injection phase, with the probability of reactivation increasing with the injected volume, and decreasing after injection ceases. Where the storage reservoir is connected to a large aquifer, the aquifer might absorb the injected volumes without significant increase in reservoir pressure over long timeframes, and thereby delay the risk development. Reactivation may happen when a particular pressure level is reached, or initiation of flow when a particular pressure differential across a fault is reached.

The fault reactivation will mostly be initiated by externally induced seismic events. The probability of such events is very low in the North Sea. Additionally a potential leakage cannot occur unless the CO_2 plume migrates to the fault/fracture. Seabed seepage of hydrocarbons at a potential storage site might be an indication of pathways and requires particular investigation; even if such hydrocarbon volumes mostly come from shallow sources. Table 3 summarises leakage parameters for faults and fractures.

Scenario	Existing faults, low flow	Existing faults, moderate flow	High flow, activated fault, enhanced by injection
Probability of leakage	Highly site specific, very low in geologically well-defined storage sites		
Potential rates (t/day)	1-50	50-250	1500
Duration of leakage	100 years	1-5 years	1-5 years
Potential leakage amount	0-1,8 Mt, over 100 years	0,018-0,46 Mt including remediation	0,55-2,7 Mt, including remediation
Potential corrective measures	Stop injection, de-pressuring	Stop injection, pressure management, Possible relief well	

Table 3. Leakage parameters for 3 leakage scenarios in existing and activated faults (Ref 4). Probability quoted for leak event occurrence is over the project life time including post closure period.

Pressure relief and management of the storage reservoir can be achieved by production of water from the reservoir. The risk of leakage through reactivated faults and fractures is considered as very low (<0,0001) for sites permittable under the CCS Directive. Risk is here defined as risked mass leaked (frequency x leak rate x leak duration) in Mt.

The DECC report underlines that there are considerable uncertainties involved in the presented results and that the assessment incorporates a high degree of judgement by the authors.

4.2. Gassnova assessment

Gassnova has performed assessments of leakage risk for several saline aquifer storage sites (Ref 10 and 11). The results were presented at various conferences (Ref 12-14).

A large number of leakage scenarios with faults, fractures and caprock failure were assessed. Potential leakage paths were generated in form of event trees and branch probabilities established based on expert judgement. An intact caprock is not regarded as a leakage risk.

Table 4 shows some representative scenarios investigated for a deep site with several seal layers. The closure is partly defined by major faults, which juxtapose a shale formation with the target storage reservoir. The faults extend into the primary seal formation (caprock), but terminate far below the top of the caprock. The calculations are based on a storage development with 50 years of injection, followed by 500 years after site closure. Reservoir pressure is limited to 40 bar above initial (less than 15% above initial). Fault permeability of 10 - 1000 mD and fault lengths of 1 - 5 km were used. Vertical leakage rates were calculated for the faults.

Four elements were investigated: two major faults, induced fractures and subseismic faults. The theoretical leaked quantities were calculated for a considerable number of scenarios, of which only two of each of the four elements are shown in table 4 to illustrate the span. The duration of the leaks varies between 33 and 200 years. For severe leaks corrective measures are expected to be initiated soon, while the smaller seepages last until they cease naturally. The quantities given as total (last column), include all scenarios for a given element (not just the ones listed in the table), and represent % of injected volume. The summarised total risked leakage volumes of all scenarios and elements are 0,009% of the injected volume.

Elements/ events	Probability of leakage	Peak rate, tons/day	Total leaked amount	Theoretical amount leaked	
				Scenario, %	Total, %
Major fault 1	0,000007	200	14 Mt	0,00006	0,00013
	0,00000001	4000	90 Mt	0,000005	
Major fault 2	0,000007	800	55 Mt	0,00025	0,00037
	0,00000001	4000	105 Mt	0,000005	
Induced fracture	0,0000004	100	9 Mt	0,000002	0,0000045
	0,00000000005	9000	110 Mt	0,000000003	
Subseismic faults	0,0015	50	4,3 Mt	0,0004	0,0083
	0,0000018	1700	24 Mt	0,00003	

Table 4. Leakage parameters of a selection of leakage scenarios in various faults and induced fractures of a deep North Sea aquifer storage (Ref 15). Probability quoted for leak event occurrence is over the project lifetime including post closure period.

The blow-out potential and risk for active wells were estimated. The calculated release rate of a blow-out from a CO_2 containing reservoir at the Sheep Mountain Field in 1982 was 200 million standard cubic feet per day. This example indicates that a leakage rate of 9000 tons per day for a full flow blow-out can be possible. Based on this and Scandpowers (Ref 10) data dossier for frequency (0,00015 per well and year) and length of blow-outs during drilling, gas injection and workover operations table 5 was established with two scenarios for 50 year of injection to illustrate the span. With these data the total expected leakage volume from active wells is calculated to be 0,0012 % of injected volumes.

Scenario	Probability	Flow, tons/day	Duration, days	Lost amount, Mt
Full well flow	0,0022	8600	60	0,54
Restricted flow	0,0055	2200	60	0,14

Table 5. Leakage parameters for two scenarios of flow in active wells (Ref 10).

For abandoned legacy wells, which are exposed to the injected CO_2 plume, the quality of the plugging and the available information are critical for assessing leak risk. Work done for Gassnova (Ref 11) indicates high leakage probabilities for poorly plugged wells hit by a CO_2 plume. However, the probability for a total breakdown with free flow is assumed to be very low; in the range of 0,0001 - 0,00001. In a specific scenario where the legacy well is located not far from the potential injection well, it was evaluated that as much as 0,1% of injected CO_2 volumes could be released. The most effective way to reduce this risk is to place the injectors in a location where the probability for the CO_2 to reach any legacy well with poor, unsure or unknown conditions is low.

Potential storage sites might be in the vicinity of hydrocarbon producing fields, introducing a risk of impacting production via CO_2 migration. One such case was assessed, where a potential flow pathway to a shallower hydrocarbon-bearing reservoir was identified. The speed of migration is dependent on dip, permeability, pressure gradient etc. In this case, the communication point lays 30-40 km away from the injection well and the dip is relatively low. The simulation of the storage development showed that the migration of CO_2 plume would take over 200 years to reach the potential communication point. The risk for significant CO_2 migration was estimated to 0,0005. The uncertainty of such an assessment is high. However, dynamic simulation showed that the migration of the CO_2 plume could be controlled in a predictable manner by using water production wells.

4.3. Risk Assessment for representative storage in broad CCS implementation

The purpose of this section is to illustrate the risk structure of CCS projects. We estimate total risk for an assumed case, and illustrate the relationship between probability and remediation cost for various events by assessing relevant conceptual leakage scenarios. Scenarios are based on the work described previously (in chapters 4.1 and 4.2) and the associated quantitative figures (probability, rates, costs) have been estimated by interpolation. Key figures relating to these scenarios are summarised in table 6.

Event probabilities and consequence data covered in this section assume an aquifer storage site in the North Sea. It is worth noting that the containment risks is site-specific and influenced by storage type (hydrocarbon field versus aquifer; trap versus migration store; depleted versus initial pressure). Additionally, the risk is dependent on the planned development, e.g. a larger number of injection wells leads to a greater chance of well leakage, or pressure management via water production might decrease fault and fracture leak risk or well failure risk, but increase risk of leak via plume migration to water producer. Despite this inherent variability the risks quoted below are representative of the approximate scale of the containment risk for a general CO_2 storage project.

The assumed case is a notional storage site injecting 100 million tons at 2000-3000 m depth, over a period of 50 years. The site includes one injection well and one legacy well. The probabilities listed in table 6, relate to the likelihood of the specified events to occur during the project lifetime of 500 years. The amounts listed are the theoretically estimated quantities of CO_2 lost in the atmosphere during the specified event.

Scenario	Probability (%)	Rate t/d	Duration	Lost mass (t/year)	Consequence	Corrective invest. (**M€**)	CO_2 quota cost (**M€**)	Risked cost (**€**)
1. Low leakage; fault & fracture	0.002	100	50 years	38,000	CO2-cost + monitoring		57	194,000
2. Moderate leak: fault & fracture	0.0005	700	12 years	258,333	Relief well+ monitoring	50	93	89,000
3. Severe leakage; fault & fracture	0.00005	5000	4 years	1,825,000	New site+ depressurise	320	219	29,450
4. Active well leakage	0.005	50	250 days	8562	workover	10	0,4	52,000
5. Active well blow out	0.0015	5000	250 days	856164	Relief well	50	38	139,500
6. Legacy well blowout	0.001	3000	1 years	1,100,000	Relief well	50	33	88,000
7. Seepage in legacy well	0.005	7	100 years	2500	CO2-cost, + monitoring		7	170,000
8. Severe well problem, no repair successful	0.00005	6000	2 years	2,150,000	Depressurise & new site	320	129	26,200
9. Leak from installatio n	0.0025	100	5 days	6.8	Shut-in and repair	15	0	37,500
10. Undesired plume spread	0.0003	-	-	-	Water production	50		

Table 6. Leakage parameters for leakage scenarios or potential events in a North Sea CO_2 storage. Some of these events might not be relevant for depleted gas fields. Probability quoted for leak event occurrence is over the project life time including post closure period. CO2 cost is to be paid for ETS allowances.

As previously mentioned, table 6 was developed using data interpolation. For instance, for the 'moderate leak' scenario (number two in the table), input data was taken from tables 4 and 5 respectively; probability 0,000007 and 0,0001, rate 200-800 tons/day and 50-250 tons/day, duration 1,5 years and 50 years. This example also shows that the span in the input data is significant and that a conservative approach was utilised.

It should be noticed that the severe events (scenarios 3 and 8 in the table) are very unlikely to happen. They are, however, included to maintain the conservative approach for our estimate.

The scenario "Seepage in a legacy well" (scenario 7) also illustrates an event of limited impact on third parties (e.g. a neighbouring oil or gas field), and for which a compensation is paid. Undesired plume spread (a subset of migration risk, scenario 10) constitutes a more significant impact on a third party. The probability is set to 0,0003 when action must be initiated and the plume actively managed by water production (derived from above referred studies).

Figures for leakages from installed sea bed facilities are based on Ross Offshore (Ref 15) who utilised statistical data from petroleum activities. A recent study indicates, however, that their estimate for pipeline failure risk was too high (Ref 16).

The summarised risked leakage amount for all scenarios in table 6 equals approximately 13.500 tons CO_2 or just more than 0,01% of the injected volume. To accommodate for a large uncertainty in our estimates we anticipate that 0,1 % might leak. Thus, 99,9 % of injected CO_2 is expected to remain in the subsurface. This could cover a case even with some additional wells. The time spans assumed for various elements range from 200-1000 years.

The two studies on which these calculations are based (chapters 4.1 and 4.2) utilise a broad basis of statistics from petroleum activity in the North Sea. They were performed in technical environments by experienced companies with well-earned reputation. The results of the two studies are internally consistent. This gives confidence that the results are in the right order of magnitude. However as there is limited experience with CO_2 handling, data could only to a limited degree be calibrated to real CO_2 operations.

A study published in 2018, which takes both a regional and generic approach to broad implementation of CCS utilising a worldwide data base, gives somewhat higher numbers for leakages (Ref 17). Regional models and regional data were used. Their base case estimate for release during 100, 1000 and 10000 years respectively in a well-regulated region like the North Sea is approximately 0,02,0,07 and 0,5% of the injected quantity. A Monte-Carlo simulation gave 0,04% and 0,2% for 100 and 1000 years at a probability of 50%. Comparing these studies, it is important to note that the two studies, which served as basis for this report, used selected well-suited sites for their analyses.

There are studies giving recommendations for detailed cost estimation for storage related issues (e.g. Ref 18). However, cost levels change between countries, fluctuate dependant on market situation, are different for different types of facilities and vary with water and reservoir depth. The cost numbers used are therefore approximations based on general experience in the UK and Norway. The cost assumptions are listed in table 7.

Cost category/Operation	Cost assumption
Drilling and completion of one well	50 million €
Yearly operation cost for one well	2,5 million €
One well workover activity	10 million €
Additional seismic services for monitoring	5 million €

Repair of an installation (pipeline/subsea equipment	15 million €
The development of an additional storage site	300 million €
Average ETA allowance cost (“CO_2 price”)	30 €/ton

Table 7. Cost assumptions used for risk calculations.

The development of an additional storage site includes two purposely-drilled wells, a subsea installation and a 100 km pipeline. If an existing, produced field with intact facilities and wells could be utilised, the costs would be considerably lower. However, such a candidate may not be available on short notice when the primary storage fails. For drilling and workover activities the use of a floating vessel is assumed. In shallow waters a jack-up could be used and the cost reduction considerable.

The costs for the consequences of the scenarios listed in table 6, have been calculated based on table 7, and are shown in table 8. For monitoring cost estimation, it is assumed that the monitoring frequency goes down over time, as we learn every time we monitor.

No	Scenario	Corrective invest. M€	CO_2 quota cost, M€	Operation cost, M€	Total M€	Proba-bility	Risked cost, €
1	Low leakage; fault & fracture		57	40 (8 seism. surveys)	97	0,002	194000
2	Moderate leak: fault & fracture	50	93	25+10	178	0,0005	89000
3	Severe leakage; fault & fracture	320	219	50	589	0.00005	29450
4	Well leakage	10	0,4		10,4	0.005	52000
5	Blow out	50	38	5	93	0,0015	139500
6	Legacy well blowout	50	33	5	88	0,001	88000
7	Seepage in legacy well		7	25 (5 seism. surveys)	34	0,005	170000
8	Severe well problem	320	129	75	524	0.00005	26200
9	Leak from installation	15	0		15	0,0025	37500
10	Undesired plume spread	50		50+10 (2seis. surveys)	110	0,0003	
	Summarized		576		1838		825650

Table 8. Remediation cost for the leakage scenarios or potential events defined in table 6.

One third of the remediation costs are made up by payment for ETS allowances. The risk is split equally between geological events, operative wells and legacy wells. For sites with a larger number of wells the risk will be increased accordingly.

Remediation costs and risk for the various scenarios or events are shown in figures 4 and 5.

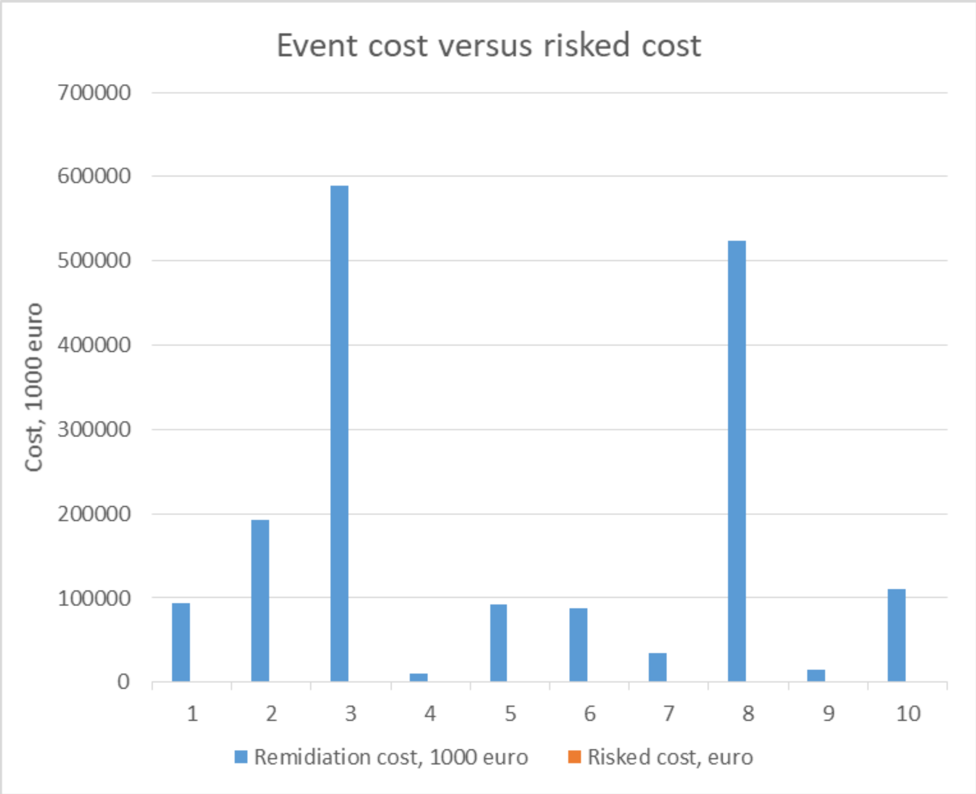

Figure 4. Remediation costs and risk for the scenarios/events defined in table 6.

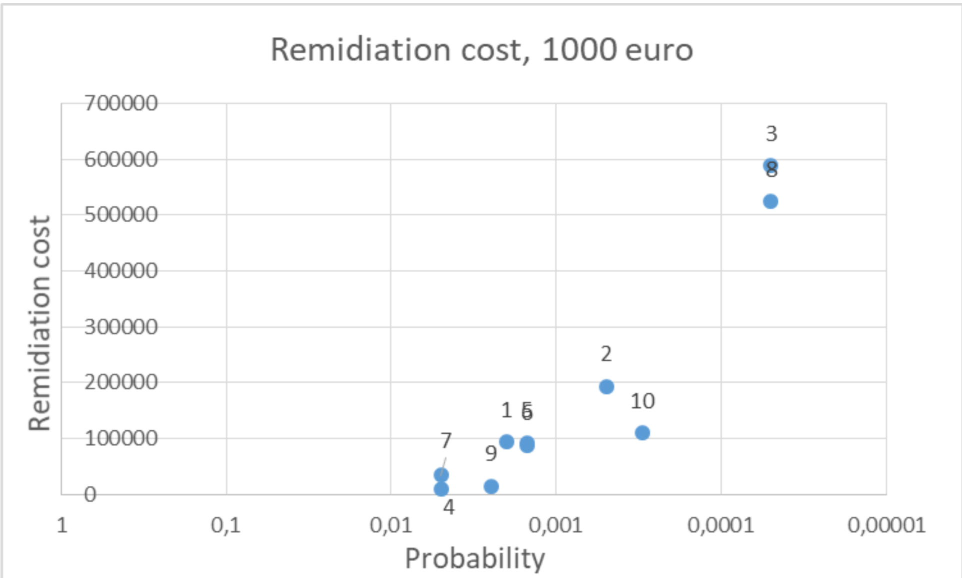

Figure 5. Remediation costs for the events numbered in table 6, related to their probability level.

Our analysis shows that the total risk for the entire assessed storage project, taking event probabilities into account, amounts to € 0,8 million. This is to be regarded as the class risk for a well planned and developed North Sea storage project. This amount is dramatically less than the theoretical worst-case remediation cost for a single case, which is in the order of €600 million (figure 4). However, such a severe event is expected to happen only in less than one of 10,000 projects (figure 5). Remediation cost for more frequent events, which are expected in one of several hundred to thousand projects, are up to a magnitude of € 100 million.

Figure 6 illustrates the risk distributed over the life of a project. Here, the costs of risk elements applicable to the injection phase (events 4, 5, 6, 8 and 9) are averaged over the 50 years of injection. It is common to assume progressively increasing risk during the injection phase, as the amount of CO_2 in the storage site becomes larger, which raises the probability of a leak and the potential amount of CO_2 that can leak. This can be a reasonable approach based on the available data at the time of project planning. However, as injection proceeds and more data is gathered, site understanding, plans and strategies are continuously improved to minimise risk. These opposing trends are difficult to quantify, therefore the risk cost is here drawn as constant during the injection phase.

The costs of the remaining risks, which are applicable for the entire life of the project, are distributed over 250 years for simplicity. The leakage risk for CO_2 storage projects diminishes over time because more and more CO_2 will be immobilised (IPPC 2005, Ref 4). This is indicated as a trend in the figure. Figure 3 shows a more theoretically based risk development, where the risk declines exponentially after closure of the storage site. If this trend is applied, the remaining risk 50 years after closure is less than 20% of the total, indicating a liability of less than € 150,000.

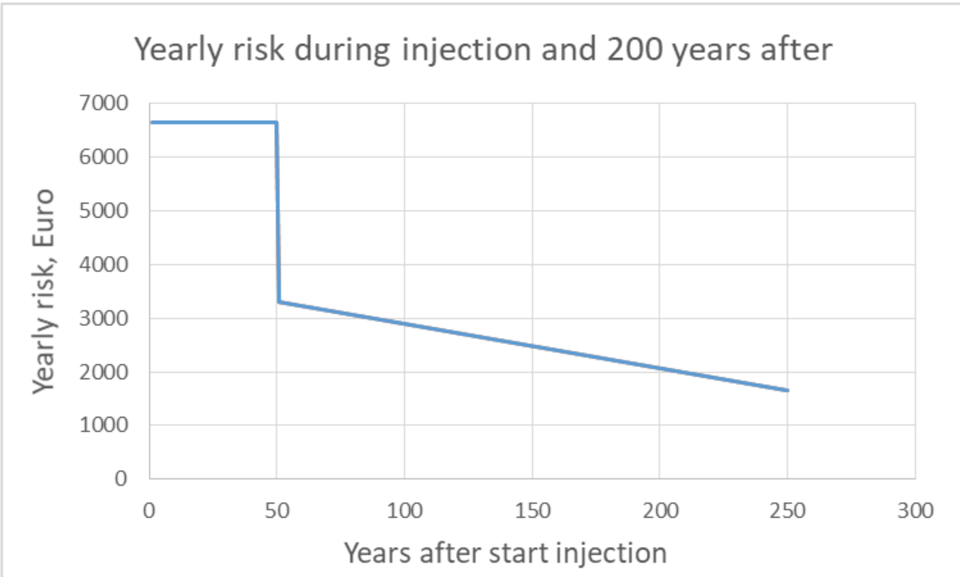

Figure 6. Yearly risk for a typical North Sea storage based on the calculations in this chapter.

The important message of this graph, however, is that the yearly risk is at a magnitude of several thousand Euros during the injection phase and shrinks thereafter. The integral under the curve corresponds to the cumulative risk during the entire project of € 0,8 million.

4.4. Depleted Oil and Gas Fields

The risk assessment performed above (chapter 4.3) is based on saline aquifer storage sites. These storage types are likely to be the most common. However, for the first storage projects with limited capacity, depleted gas and oil fields might be even better candidates. Such candidates might require lower investment and risk. For this reason a risk scenario for a depleted field is developed. It is a theoretical scenario based on the same input as the assessment above, but modified for differences in properties, features and behaviour rather than on specific data from such depleted fields.

For this depleted field assessment it is assumed that the reservoir/storage pressure stays well below the initial value (max. 80-90% of Initial). The integrity of the structure itself is therefore not likely to be affected. Wells are the most likely source of leakage. If the injection well is built, completed and its integrity tested to a wellhead pressure well above the maximum potential flow pressure, a severe uncontrolled blow out is not to be expected. An important element is also potential abandoned legacy wells. A depleted field might further have adjacent fault blocks, which might be affected by CO_2 migration without consequent leakage to the surface.

Table 9 shows the evaluated leakage scenarios and events applicable for a depleted oil or gas field and their estimated remediation costs. For the above reasons, limited reservoir pressure and well integrity tested and properly documented for this limited pressure, the following leakage scenarios in the general assessment (table 8) are disregarded here;

- Severe leakage through faults and fractures
- Blow out in legacy well
- Severe well problems

The probabilities of the remaining well related events were reduced by 1/3 because of low storage pressure and a large geological data base. In this case a storage capacity of 20mtons is assumed, which is 1/5 of the capacity of the first assessment. The injection period lasts for 10 years.

Scenario	Corrective **invest. M€**	CO_2 quota **cost, M€**	Operation **cost, M€**	Total **M€**	Proba-bility	Risked **cost, €**
Low leakage; fault & fracture	monitoring	11	10 (seism. surveys)	21	0,002	42000
Moderate leak: fault & fracture	50 (relief well or new site)	19	5+2	76	0,0005	3800
Well leakage	5 (repair)	0,1		5,1	0.005	25500
Well blowout	20 (well sidetrac	7,6	5	33	0,0005	16500

Seepage in legacy well	monitoring	1,4	5 (seism. surveys)	6,4	0,002	12800
Leak from installation	3 (repair)	0		3	0,0025	7500
Undesired plume spread	10 (com-pensation)		10+2 (seis. surveys)	22	0,0003	6600
Summarized		39		166		148900

Table 9. Remediation cost for the leakage scenarios or potential events applicable for a depleted field.

Table 9 shows that if everything goes wrong in this depleted field scenario at the same time, (which cannot happen as some events are mutually exclusive) the remediation cost could be €166 million, including €39 million in payment for ETS allowances. The analysis shows that the total risk for this entire assessed storage project, taking event probabilities into account, amounts to € 150,000.

5. Operational experience

This chapter assesses experiences from ongoing and completed projects with a focus on challenges, how these were addressed, and lessons learned. It can be summarised as follows:

- No geological leakage to the surface is detected so far;
- No blow-out in modern CO_2 storage wells is known: one leakage in well without required safety equipment and old completion (1953, USA) has been observed;
- Few projects experienced restricted injectivity, which could be improved by well interventions. In one case a new injection well was required;
- Well completion can withstand long term CO_2 injection;
- No effect on rock integrity is observed by injected CO_2 ;
- Seismic has proved to be a reliable tool to monitor plume behaviour;
- Positive experience is gained with a broad suit of monitoring techniques;
- Cost reduction are required for positive business cases;
- Thorough assessment before implementation and regular risk assessments is essential;
- Numerical models for simulating behaviour are under development.

5.1. The Lacq pilot - Project

In 2006, Total decided to invest 60 million euros to launch the first end-to-end industrial chain Carbon Capture and Storage (CCS) project comprising the capture, transport and injection of CO_2 into the depleted gas reservoir of Rousse in the southwest of France. Operated by Total Exploration Production France, the project demonstrated the technical feasibility and reliability of an integrated CCS chain. This CCS pilot was located in the Lacq basin, approximately 800 kilometers from Paris. The depleted deep gas reservoir (unprecedented in Europe) was chosen as storage site, located onshore five kilometers south of the agglomeration of Pau.

The Rousse field reservoirs are located in the Mano and Meillon formations of Upper Jurassic age. They are composed of fractured dolomites and dolomite breccias (Ref 19). The two reservoirs are separated by argillaceous limestones of the Lons and Cagnotte formations, which is both the seal for the Meillon reservoir and the main hydrocarbon source rock. Only the Mano reservoir is used for CO_2 storage. The basal Upper Cretaceous interval overapping the Rousse horst constitutes the reservoir seal. Three main Upper Cretaceous seal units and associated lithological types have been identified.

A 4500m deep injection well was drilled. The main injection phase covers a two-year period with about 360 days of CO_2 injection at an average rate of 90 t/day, and 110 days at an average rate of 65 t/day.

Conclusions on the assessment of risks performed before injection are as follows; CO_2 injection will be carried out in a depleted gas field, whose seal quality has been proven by the existence of a reservoir for millions of years. The knowledge acquired during many years of operation in the Rousse field, completed by new additional characterization work (3D seismic, reservoir modelling including evaluation of geochemical and geomechanical effects) allows for qualifying the site for CO_2 injection. Furthermore, injection operations are performed with a very high safety margin to prevent any possibility of injection-induced mechanical damage or leakage. The injection conditions (timing, flow rate, type of gas) help ensure that the gas plume will remain confined in the reservoir, at a pressure well below the initial pressure, with no risk of migration into the reservoir caprock. Procedures for well control and possibilities of intervention allow mitigating through corrective actions the risk of propagation of any defect in the completion, which could lead to a significant loss in well integrity and create a leakage pathway. The main risk is that of a free well blowout.

Total successfully demonstrated the feasibility of safely storing CO_2 in a depleted underground reservoir by injecting over 51,000 metric tonnes of CO_2 (Ref 20). The operability of a fully integrated carbon capture and storage scheme based on the oxy-combustion CO_2 capture process has been proved.

A resulting R&D challenge is selecting the right parameters, methods and equipment for a safe, economically and technically viable, long-term efficient onshore storage monitoring program.

5.2. Sleipner

Carbon dioxide associated with gas produced from the Sleipner Vest field in the North Sea has since 1996 been separated at the Sleipner T facility and injected into the saline (brine-filled) sandy Utsira Formation nearby. At the end of 2017, a total of 17.2 million tones of CO_2 had been injected. Initially CO_2 storage at the Sleipner Field was approved as an integrated part of the development plan for the field. After introduction of national regulations for CO_2 storage, the approval was confirmed in 2016.

The permitting process in 2016 included a risk assessment (Ref 21). The risk for leakage from the storage site was a major element of this assessment and the probability for leakage was estimated to be in the order of 0,0001 during the injection period and 0,001 in the first 50 years after injection end. The rise in probability over time is due to the progressive spreading of the CO_2 plume which may reach legacy wells.

The Sleipner CO_2 storage site has been a pilot site for offshore saline aquifer storage at industrial scale and has been widely used for research and technology development, particularly within monitoring technology. Monitoring activities have covered a broad range of technologies (Ref 28) and especially seismic surveys have been acquired at high frequency (on average almost every 2nd year); this breadth and intensity of monitoring activity is far above operational requirements. The applied monitoring technologies have successfully mapped the subsurface distribution of CO_2 in the storage formation. There are no indications of leakage into the cap rock or to the sea floor, which provides evidence for containment of CO_2 in the storage formation.

The injection project initially experienced operational challenges related to insufficient injectivity in spite of a highly permeable formation (Ref 22). The cause was interpreted as being due to sand inflow. The perforated interval of the liner was thus supplemented by screens (300 microns hole diameter), which improved injectivity somewhat but not sufficiently. Subsequently, an additional interval was perforated with downward-oriented perforation, supplemented with gravel pack and screens (200 microns), which established sufficient injectivity. Thus, well injectivity has been achieved applying standard industry well intervention methods. These interventions incurred additional costs, but these were limited due to access to the well from the injection platform. Further, CO_2 tax had to be paid for the emitted CO_2 related to the interventions.

5.3. Snøhvit

The Snøhvit Gas Field is a subsea field development in the Barents Sea with processing of the well stream onshore at the Melkøya LNG facility. Injection of CO_2 separated from the produced gas started in 2008. At the end of 2017, almost 5 million tons CO_2 has been injected. Snøhvit CO_2 storage was initially approved as part of the development plan for the Snøhvit hydrocarbon field. Approval was confirmed in 2016, now based on national regulations for CO_2 storage introduced in 2014.

Initially, CO_2 was injected at approx. 2650 m below sea level into the fluvio-deltaic Tubåen Formation, a saline reservoir unit deeper than the producing reservoir unit at the Snøhvit Field (the Stø Formation) and separated from it by approx. 60 to 100 m largely finer-grained sedimentary rocks of the Nordmela Formation. A few months after the start of injection the downhole pressure gauge indicated rapid pressure increases which were interpreted as reduced injectivity due to salt precipitation in the near wellbore formation. Regular injection of batches of a MEG-water mixture improved injectivity (Ref 24).

However, the reservoir pressure still showed an overall rising trend, increasing faster than the reservoir model predicted. When observed pressure approached the formation’s fracture pressure a well intervention was carried out. First, shallower levels of the Tubåen Formation were perforated but this did not result in substantially reduced injection pressure at the required injection rates. Therefore the Tubåen Formation was plugged in 2011 after injection of in total 1.09 Mt CO_2 and the well perforated in the shallower shallow-marine Stø Formation.

As a measure to increase operational flexibility and resilience, in 2016 an additional well was drilled for injection of CO_2 into a brine-filled part of the Stø Formation at a depth approx. between 2500 and 2600 m below sea level. This reduced also the risk for contamination of the produced gas by CO_2 migrating from the injectors towards the producers. Since late 2016 all regular injection has been into the 2nd well.

CO2 storage has been accompanied by a monitoring program which served both operational and research purposes. Its main component is time-lapse seismic 3D monitoring with 4 repeat surveys so far. The seismic monitoring data were instrumental for the understanding of rising pressure in the Tubåen Formation. Leakage into the caprock or to the sea floor has not been observed.

5.4. K12-b.

In 2004 a demonstration project commenced at the K12-B field, offshore The Netherlands, where CO_2 that was separated on-platform from the produced gas was re-injected into one of the compartments of the field (Ref 25). The goal was to investigate the feasibility of CO_2 injection and storage in depleted natural gas fields.

The K12-B gas reservoir is so far the only gas reservoir in the Netherlands into which captured CO_2 has been re-injected. The K12-B gas field is located in the Dutch sector of the North Sea, some 150 km northwest of Amsterdam. Discovered in 1982, gas production started in 1987. The platform is currently operated by Neptune. Gas is produced from the Upper Slochteren Formation (Rotliegend), consisting of siliciclastic sediments of Permian age. The reservoirs are at a depth of approximately 3800 meters below sea level; the temperature of the reservoirs is approximately 128 °C. The gas contains 13% CO_2, which is removed from the gas stream directly offshore on the platform. The cap rock consists of hundreds of meters of rock salts from the Zechstein Super Group, making the most likely migration pathway for any gas, should migration occur at all, migration along the well bores.

The K12-B structure consists of several compartments, which are separated by faults or fault zones. CO_2 injection started in the northern, single-well compartment, compartment 4, by re-use of the B8 well, in 2004. Several injection and back production tests have been carried out in this compartment. Since 2005, over 100kt of CO_2 has been re-injected, mostly into the central, multi-well compartment, compartment 3, by re-use of the B6 well.

Over the years, the K12-B reservoirs have served as a field lab, in which a variety of experiments and monitoring activities have been carried out. Research mainly focused on the conditions of the wells over time, which is of key importance for safety issues. Another goal was to gain a better understanding of the behavior of the CO_2 in the injection wells and the migration of the CO_2 in the reservoir. CO_2 migration in the reservoir is relevant for the assessment of the potential for enhanced gas recovery (EGR) through CO_2 injection.

Monitoring at the production wells provided valuable information on gas composition; chemical tracers enabled the detection of breakthrough at producer wells and investigation of CO_2 migration in nearly depleted gas fields. It also proved vital to have sufficient downhole pressure and temperature data, as the CO_2 can be subject to large density variations. Overall it can be concluded that observations are supported by detailed reservoir model predictions.

The experience at K12-B provides confidence that well integrity can be assured throughout long periods of CO_2. injection. In the case of this field, this is partly based on the favorable properties of the salts from the Zechstein Super Group, the primary seal. K12-B experience helped select efficient and effective well logging tools.

In 2017, production from the two compartments used for the CO_2 injection and back production tests has stopped. All CO_2related operations at the K12-B field were conducted without major complications, supporting the conclusion that safe and secure underground storage in nearly depleted gas reservoirs is technically feasible. During the many projects at this field, several techniques were tested and many processes investigated. Information on the CO_2 injection activities at K12-B can be found in Vandeweijer *et al*. (2011, Ref 25).

5.5. Ketzin CO_2 storage

At the CO_2 sequestration site near Ketzin, Germany, CO_2 was injected into a saline aquifer from June 2008 until August 2013. This is the first on-shore geological storage site in Europe, where a total of about 67 ktons CO_2 were injected. The main goal of the Ketzin site was to improve the understanding of relevant in-situ processes associated with CO_2 storage and to gain practical experience for future CO_2 storage sites. Investigations at the site started in 2004 with site characterisation and baseline surveys, drilling and well instrumentation, set-up of the injection facility and implementation of monitoring techniques (Ref 26). Two observation wells, Ktzi 200 and Ktzi 202, were drilled prior to injection to a depth of 750 m to 800 m at a distance of 50 m to 100 m from each other. At the far monitoring well (Ktzi 202) breakthrough of CO_2 was observed in March 2009.

A seismic monitoring system was designed and implemented, consisting of vertical and horizontal geophones and hydrophones at different locations along a line and at different depths (Ref 27). This system has been used to continuously record passive seismic data (Ref 28).

The entire operation of geological storage of CO_2 at the Ketzin site was conducted safely and reliably (Ref 29 and 30). The spatial distribution of CO_2 could be imaged with a site-specific combination of geochemical and geophysical monitoring techniques. Fluid-rock interactions induced by the injected CO_2 showed no significant effects at the Ketzin pilot site and do not affect the integrity of the reservoir and cap rocks.

5.6. In Salah

The In Salah CCS project in central Algeria is a pioneering onshore CO_2 capture and storage project (Ref 31). Carbon dioxide from several gas fields is removed from the gas production stream in a central gas processing facility and then the CO_2 is compressed, transported and stored underground in the 1.9km deep Carboniferous sandstone unit at the Krechba field. Three long-reach horizontal injection wells are used to inject the CO_2 into the down-dip aquifer leg of the gas reservoir. Injection commenced in 2004 and since then over 3.8Mt of CO_2 has been stored in the subsurface. The storage performance has been monitored using a diverse portfolio of geophysical and geochemical methods, including time-lapse seismic, micro-seismic, wellhead sampling using CO_2 gas tracers, down-hole logging and core analysis, surface gas monitoring, groundwater aquifer monitoring and satellite InSAR data. Routines and procedures for collecting and interpreting these data have been developed, and valuable insights into appropriate Monitoring, Modelling and Verification (MMV) approaches for CO_2 storage have been gained.

Prior to injection start-up, a pre-injection risk register was prepared as part of the initial site assessment and used to design the monitoring programme. Most of these planned monitoring activities were implemented. A key feature of any monitoring programme is the ability to use the monitoring data to respond to field performance and operational developments. The In Salah CCS demonstration project has been important for understanding the value of various monitoring methods applied. Several Quantified Risk Assessments (QRA) have been conducted during the operational phase, integrating all available data to assess both the storage integrity and effectiveness of the storage complex. In 2008, the QRA identified two dominant risks for special focus: (i) the risk of migration to the north, and (ii) the loss of well integrity. The 2010 QRA identified a new dominant risk concerning the potential for vertical leakage into the caprock, based on the results of the integration of the new seismic, satellite data and dynamic/geomechanical models. These risks were in the initial risk register, but new data led to more precise definition of the risks and to approaches for risk mitigation.

Considerable attention has been focused on injection performance and plume development around injection well KB-502, where a fault or fracture zone has behaved as a flow conduit for CO_2 and a focal point for rock failure (in either tension or shear mode). Although all the processes involved are not fully understood, integration of all the available data (figure 6) has led to many new insights into the rock mechanical response to CO_2 injection. It is clear that CO_2 injection has stimulated natural fractures at this location, and may have introduced new hydraulic fractures. Although these fractures do propagate upwards into the lower caprock, they are unlikely to propagate further through the upper caprock. No leakage has been observed and all indications are that the CO_2 remains safely contained within the storage complex. Following the 2010 QRA, the decision was made to reduce CO_2 injection pressures in June 2010. Subsequent analysis of the reservoir, seismic and geomechanical data led to the decision to suspend CO_2 injection in June 2011. The future injection strategy is under review.

Some important general lessons learned can be drawn from this project, as follows:

1. Monitoring should be part of the Field Development Plan (FDP) and routine field operations.
2. The suite of monitoring technologies to be deployed at any CO_2 storage site mainly comprises standard oilfield techniques and practices, with surface monitoring methods derived from standard geotechnical and environmental monitoring practices.
3. Satellite InSAR data has been especially valuable in understanding the geomechanical response to CO_2 injection, but needs to be integrated with high quality reservoir and overburden data and models.
4. The storage monitoring programme needs to be designed to address site-specific leakage risks identified in the selection phase, but also needs to be adapted during the operational phase.
5. Legacy wellbore integrity is a key leakage risk that has to be effectively managed.
6. Acquisition, modelling and integration of a full suite of baseline data, including the overburden, are vital for evaluating long term storage integrity.
7. CO_2 plume development is far from homogeneous and requires high resolution data for reservoir characterisation and modelling.
8. Injection strategies, rates and pressures need to be linked to detailed geomechanical models of the reservoir and the overburden. Early acquisition of geomechanical data in the reservoir and overburden, including extended leak-off tests, is advisable.
9. Regular Risk Assessments should be conducted to inform the on-going operational and monitoring strategies.

Probably the most valuable legacy of the In Salah project will be the pioneering deployment and interpretation of a unique set of MMV technologies.

5.7. Aliso Canyon

Aliso Canyon is a natural gas store in California, which utilises a depleted oilfield including the conversion of some of the legacy oil wells into gas injectors / producers (Ref 32). The 2015 to 2016 leak at the Aliso Canyon natural gas store is frequently reported in the press as one of the largest greenhouse gas releases in the US (0.13 GSm3 reported: Lindeberg et al. 2016. Aliso Canyon leakage as an analogue for worst case CO_2 leakage and quantification of acceptable storage loss). The released gas had been odorised using Mercaptons, as is common for residential gas supplies, and this bad smell led to the displacement of many local residents from their homes. The gas leak was widely publicised in the global press, and has triggered a new focus on the safety and regulation of gas storage activities in the US (PIPES act 2016 to require the establishment of minimum safety standards). The incident is likely to have an impact on regulations and stakeholder risk perception for future CO_2 storage developments.

Although the findings of the incident investigation have yet to report on the root causes, it is understood that one of the injection wells (SS-25) developed casing leaks above the packer allowing natural gas to flow from the A-annulus into B-annulus, and then into the shallow sediments at the base of the surface casing from where it leaked to the surface (Pan et al. 2018), see figure 7. Modeling the Aliso Canyon underground gas storage well blowout and kill operations using the coupled well-reservoir simulator T2Well. The attempted remediation activities (top well kills) resulted in the formation of a large crater around the wellhead. The gas leak was eventually stopped by drilling a relief well, that was able to intersect with the damaged well below the leak point, and inject a mud compound followed by cement to permanently plug the well subsurface. The drilling of the relief well took nearly 40 days (Dec 4th 2015 to Feb 11th 2016).

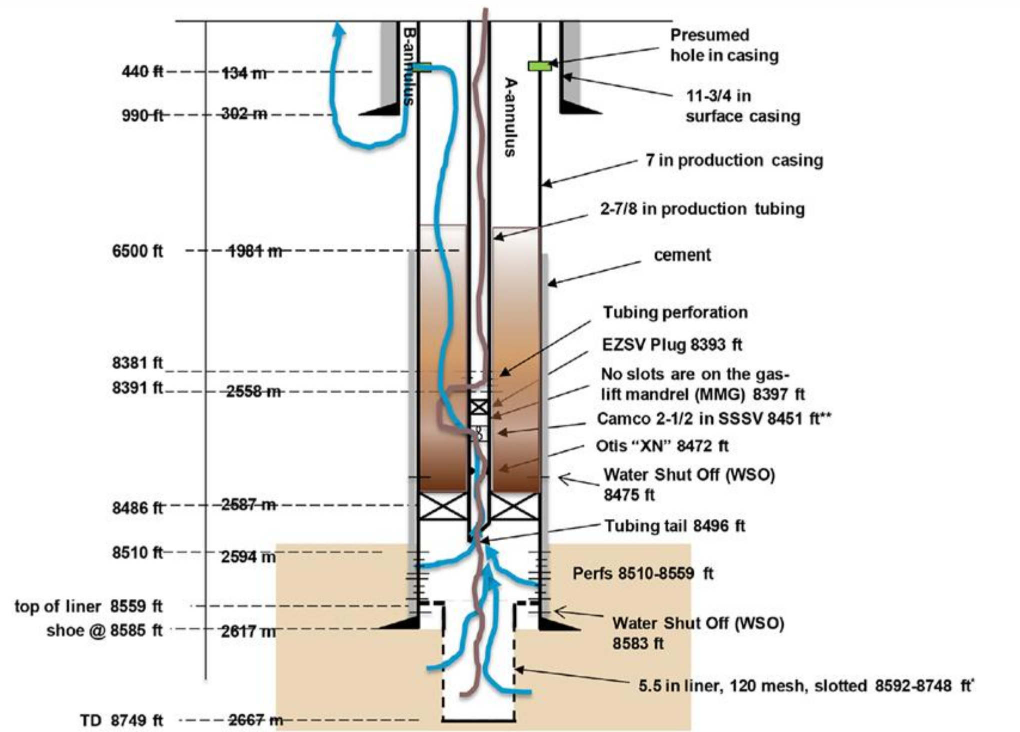

Figure 7. Sketch of the Aliso Canyon SS-25 well and interpreted flowpaths of the leaking hydrocarbon gas (blue) and kill fluid (brown) during one of the unsuccessful well kill attempts. Note that the interconnections between the tubing and the casing resulting from perforations above the tubing plug at 8383 ft, and the SSV slots below the tubing plug (possibly at the original SSSV location).

The leak developed in a converted legacy oil well that was drilled in 1953, and converted to gas storage in 1973. The SSSV (Sub-Surface Safety Valve), which had originally been installed in the oil producer, was removed rather than replaced when it developed a leak during the gas storage phase of the field. US regulations did not require a SSSV to be installed in onshore gas storage wells. Had the SSSV been replaced and operational when the leak occurred, the release could have been stopped quickly and easily. Connections between the tubing and the A-annulus had been added (tubing perforations and an open SSV (Sliding Sleeve Valve); see figure above), which allowed the storage gas to flow via the A-annulus during injection and production. This flow path allowed the stored gas direct access to the casing leak which developed in the A-annulus, and inhibited the action of the injected kill fluid. Production or injection via the A-annulus would not be permitted for a CO_2 storage development, but was possible for Aliso Canyon by the regulatory framework for underground gas storage.

The Aliso Canyon case highlights the importance of good monitoring, maintenance and remediation procedures for all wells which penetrate the storage reservoir (both legacy and operating). Although the development was maintained in accordance with the limited regulatory framework, the cost to the reputation to the operating company and goodwill of the local residents, as well as the financial cost of drilling a relief well, will have been considerable.

5.8. Quest by Shell

The Quest carbon capture and storage (CCS) facility, near Edmonton in Alberta (Canada), has demonstrated that CCS and storage in an open structure can work. In its first three years of operations, Quest captured and safely stored 3 million tons of CO_2, and achieved this milestone ahead of schedule (Ref 32. CO_2 generated at the Scotford upgrader hydrogen manufacturing units has been captured and stored subsurface since 23 August 2015. The CO_2 is transported to the storage site by pipeline, and then injected into the basal Cambrian sandstone, more than 2000m below the surface, at an approximate rate of 1 million tonnes per year. The project injected up to 1.2 million tons over a one-year period, which is a global CCS record.

The Quest facility is operated by Shell on behalf of the Athabasca Oil Sands Project.

Figure 8. On the left: Map indicating locations of the Scotford upgrader (CO_2 source) and Quest storage site. On the right: A Quest injection well.

The storage site was developed with three potential injection wells, see figure 8. To date the wells have performed beyond expectation, with injectivity comparable to the pre-development high case, and limited overpressure development. Repeat VSP monitoring has been able to visualise the developing CO_2 plume subsurface, which has not been detected beyond the expected area.

Reservoir performance to date (analysis of reservoir pressure response), along with injectivity assessments, indicate the project will be capable of sustaining adequate injectivity for the duration of the project life; therefore, no further well development should be required (Ref 33). Operational challenges have been minor; for example, corrosion of a wastewater pipe caused by the low pH of the Quest wastewater (pipe was replaced with 304 stainless steel), and minor facility leaks, none of which were of significant.

The project has been using two of these wells for injection, with the third well reserved for monitoring observations and as a spare to maintain injectivity should one of the injection wells require shut-in for maintenance or remediation. One well injects at a constant rate, while the other varies to meet the storage demand from the hydrogen manufacturing unit. This scheme simplifies the reservoir response for the well injecting at a constant rate, optimizing the monitoring and learning potential.

Using only two wells for injection has reduced project operating expenditure (reduced power and compression requirements), as well as monitoring costs. The compressor is able to operate utilizing 13-15 MW versus 18MW as per the full design. The pre-development appraisal campaign allowed the project to develop sufficient confidence to reduce the initial project well count from eight to three. Given the excellent reservoir properties and pressure dissipation demonstrated, it could be possible to use a single well to inject the entire CO_2 stream.

A phased development might have reduced capital expenditure by drilling only two initial injection wells, and then following this by drilling another well as required based on the injection performance of the first two wells (a spare well is always required to ensure continuous site injection capability). However, in the case of the Quest project all three wells were needed from the project outset to provide the required injectivity performance guarantee that allowed the project to qualify for government capital investment.

6. Experience with Financial Security and Liability

Financial security has been a key point in discussions between operators and authorities in the permit processes of all storage projects and the preparation of such projects in Europe. The EU Directive requires the operators/owners to set aside a Financial Security fund to cover for unforeseen events, particularly related to leakages of CO_2, and for monitoring, remediation etc.

Guidance Document 4 for the Directive gives strict interpretation of the Directive in respect of Financial Security (Ref 36). As bases, it requires potential unwanted events to be defined and cost estimated. Probability reduction of costs is not allowed. As documented in Chapter 4 of this report the probability for leakages is so small that only one in thousand projects might experience such event. The GD4 might also allow for a more flexible approach as its first page includes the words "The aim of the guidance is to strike the right balance between full coverage of obligations as required while at the same time not overpricing the risks in relation to these obligations for early movers."

This following chapter reviews experience with application and approval processes with national authorities and presents an example of the liability issue faced by an applicant for a CO_2 underground storage permit. Member States have shown a broad variation in how they apply the regulations in respect of Financial Security as illustrated by the following examples.

In Norway, there have been CCS operations with CO_2 storage at Sleipner and Snøhvit for more than 20 years, commencing in 1996 and 2006 respectively. The permits for these activities were granted prior to the existence of any CCS specific legal framework. The 2009 EU CCS Directive was implemented in Norway in 2014, through a new chapter in the Petroleum Activities Regulations (PAR), a new chapter in the Pollution Control Regulations (PCR) and a new instrument, namely the CO_2 Storage Regulations (Storage Regulations).

Originally, the CO_2 storage at Sleipner and Snøhvit was permitted subject to the Petroleum Activities Act (PA) and the detailed operations stipulated by the production license and plan for development and operation (PDO), as well as the requirements imposed by e.g. the permits granted subject to the Pollution Control Act (PCA).

Subject to the new legal framework for CCS, Equinor was required to apply for new permits for both Sleipner and Snøhvit by 1 January 2016, subjecting the activities to the new provisions in the PCR. Consequently, after a dialogue with the Norwegian Ministry of Petroleum and Energy, Equinor applied for new permits in October 2015. The new permits were granted by the Norwegian Environmental Agency in 2016 (Ref 41). The 2016 permits replaced parts of the permits originally granted, imposing stricter requirements regarding e.g. monitoring, post closure operations and financial securities than previously required under the emissions permits. However, no new requirements or criteria were imposed in the production licenses as such and no dedicated fund for Financial Security was required to be set aside up front.

In the negotiation of the storage permit for Goldeneye the British authority also exercised considerable flexibility. An agreement was reached on terms regarded as reasonable by the operator. As this permit was not concluded, detailed terms are unknown. The relevant operators for Norwegian and British projects are some of the largest oil companies in the world and they might have given a mother company guarantee for the CCS operation.

Unlike Norwegian and British authorities the Dutch authorities choose to follow the Guidance Document 4 to the letter with the permit for the TAQA storage project P18-4. In this case the Financial Security covers low-probability events close to their full extent as if they will occur. This results in large security amounts of more than € 60 million over the initial 5 year period according to TAQA estimates. The class risk for a similar, however twice as large storage site, estimated in Chapter 5.4 is € 150.000. The entire unrisked remediation costs for all potential events of this larger site amounts to € 150 million disregarding legacy wells.

With a total capital investment for the original ROAD project (P18-4) of less than €30 million, the Financial Security of more than €60 million (ref 34) imposes a heavy burden to the business case of the CCS project. However, most of the risk events are extremely unlikely to occur and many cannot physically happen simultaneously. The cost calculation as applied to P18-4 does not seem to be required by European law.

The P18-4 field is almost fully pressure depleted and structurally isolated and sealed (Ref 35). Its original pressure was 348.5 bar, its current pressure is 20 bar, and its final fill pressure at end of CO_2 injection will not be more than 320 bar according to permit. There are no legacy wells in the structure. The only well in this storage site is the injection well itself, which supplies the only realistic leakage pathway until it gets permanently plugged.

Under the permit there is a requirement to review the Financial Security at intervals, July 2018 being the first opportunity (Ref 37). The permit application includes preliminary elements, recognising that understanding of risk, mitigation and impact would evolve, particularly as the equipment selection, design and operating procedures were not yet defined, just a preliminary concept. As the CO_2 Storage Directive asks for review/update of the entire permit five years after issuing, it is anticipated that a review will begin soon.

A general discussion of the Financial Security topic is found in Chapter 7.2.

7. Discussion and conclusions

7.1. Leakage risk

As demonstrated in Chapter 4 the risk of leakages from European CCS project to the atmosphere is extremely low. It can be expected that 99,9 % of injected volumes will remain securely underground. The class risk of leakage from a well-planned and well developed European storage projects is hereby defined as 0,1% of total injected amounts.

Leakages from wells, facilities or underground features, as well as other accidents are expected to be very rare, if the requirements set out in the EU Storage Directive and relevant petroleum industry standards from the North Sea are applied. The estimates indicate that less than one in one hundred projects will face such unplanned accidents or challenges, and only at low rates and very limited total leakage amounts. A severe leak from an offshore storage site, is expected in only one of 20,000 projects. The consequences could be significant to very high, but are unlikely to harm people, and will lead to minimal impact on the local environment in the short and longer term.

Wells are widely considered as the most likely source of leakage until permanent site closure. The least predictable wells are legacy wells (old, plugged wells), because their condition is often unknown. Such wells should be given particular attention. Leakage via a fault, even given reactivation through increasing injection pressure pressure, carries a lower assessed risk. Caprocks are normally ductile, and this property could prevent even a moving fault from providing a leakage pathway to the surface.

The yearly risk related to containment in financial terms is less than €10000 (figure 6) when event probabilities are taken into account and allowing for some uncertainty in the performed estimates. This number reflects ideally the yearly basis payment for insurance (administration etc in addition). The total risked cost for unplanned events amount to € 0,8 million for one project. Because of the low probabilities this is far lower than the remediation cost for a single event, which can reach several hundreds of millions of euros. 50 years after closure the residual risk for most projects will be minor.

The technical risk as such is lower than with oil and gas activities. Performance risk (risk of reduced injectivity, capacity or third-party impact) can be reduced by good data availability before execution of the project. However, the margins for the operators are substantially lower, thus project and operational risks constitute a larger economical risk.

The two studies which form the basis for these calculations use a broad range of statistics from petroleum activity in the North Sea. They were performed in experienced technical environments by companies with a well-earned reputation. The results of the two studies are internally consistent. This gives confidence that the results are of the right order of magnitude.

There are a great number of structures and depleted oil and gas fields suitable for CO_2 storage particularly in the North Sea. A large amount of relevant data is available for planning and assessing potential sites. Oil & Gas companies, which are the most likely operators for early storage, are operating similar projects today with high level of safety and environmental performance. These companies possess the competence, knowhow and capacity to develop and operate CO_2 storage projects.

A number of projects have already been successfully implemented or completed. Some were pilots and others were established for separation of CO_2 from natural gases before sale. Some of these projects are described in Chapter 6. None of them have had leakages of the injected CO_2 volumes. Some have had minor injection interruptions because of problems with injectivity; however, these were solved using standard industrial technology. In the meantime the site owners had to pay for ETS allowances or CO_2 taxes for released volumes. These projects confirm that geological CO_2 storage is proven technology, ready for wide implementation.

A major challenge is the absence of a functioning market for CO_2 storage. The CO_2 price, such as EU ETS allowances or CO_2 emission tax at present or expected levels, will not cover the cost of capture, transport and storage of CO_2. The anticipated earning margins for storage site operators are in the foreseeable future so low that they cannot carry the full cost in case of (improbable) major leakage.

7.2. Liability and Finance Security

As illustrated in chapter 6, Member States apply different approaches in defining the Financial Security. Norway and the UK have exercised considerable flexibility so far.

The focus on risk can, however, lead to an extremely cautious approach concerning setting aside Financial Security with the storage permits. In the case of P18-4 in the Netherlands the regulators requested a Financial Security figure large enough to cover all events, routine or unplanned, regardless of probability, for a notional monitoring period of 50 years. However, most of the risk events are extremely unlikely to occur and many cannot happen simultaneously. This way of calculation will place a heavy burden on any storage business case and obstruct the development of a sound CO_2 storage business.

No individual operator can afford to set aside funds to cover such unlikely events for every project, and no other ongoing business operates under an equivalent requirement. In other industries similar risks are usually absorbed by an insurance system (e.g. in the petroleum industry). A guarantee or insurance system, initiated by the authorities, for sharing the risk for the CCS industry would significantly reduce the burden currently carried by first-mover projects and proactively encourage CCS deployment. As there initially will be too few projects for an operative insurance system, this liability will initially need to be shared between government and the private sector.

The EU CCS Directive was reviewed in 2014 (Ref 38). The conclusion of this evaluation was that the overall need for CCS to decarbonise power production and heavy industry in Europe remains genuine and urgent. Fewer CCS projects have been implemented than envisaged in 2009/10. Given the lack of practical experience it would not currently be appropriate, and could be counterproductive, to reopen the Directive for significant changes. However, some clarifications and softening of interpretation in Guidance Document 4 could help, as concluded in the summary report.

The review states (quote from the EC review) further that there are some serious concerns among developers regarding the levels and procedures for handover from developers to the member states competent authorities and the financial securities related to future monitoring and leakage from storage sites. The only European CO_2 storage project with practical experience of going through the permitting process is ROAD. In 2013 the project developers agreed workable solutions with the Dutch CA that both parties appeared to accept. This single example suggests that there is still enough flexibility to allow procedures to be agreed and projects to be advanced. Care needs to be taken that the accompanying Guidance Documents do not become over prescriptive, as concluded in the summary report for EC.

The referred concerns relate to articles 19 and 20 but also Guidance Document four. It appears that articles 19 and 20 were written in such a way as to give a relatively high level of flexibility to the Competent Authorities of the member states in deciding when handover should occur and what Financial Security site operators should provide. Guidance Document 4 is intended to help provide some further guidance on these issues. It appears that GD4 is being used as more than guidance, which is leading to calls that the more detailed procedures it suggests will impose high costs on projects. This makes CO_2 storage projects more difficult to progress.

In summary, CCS is a relatively straightforward technology frustrated by strict regulations imposed by the authorities which incur heavy legislative and financial burden on the operators. This leads to reluctance from the private sector to invest, in turn increasing the perceived risk.

7.3. Storage types and their relative leakage risk

Several storage types are listed in chapter 2. The available data is not accurate or plentiful enough for a quantitative comparison between different storage types. The assessments in Chapter 4.3 are broadly based on aquifer sites, for which there is the most available data. A qualitative comparison indicates that empty petroleum fields in hydraulic contact with an aquifer, will offer similar or slightly lower risk for a storage development because the availability of static and dynamic data, and mostly reduced reservoir pressure. Isolated depleted oil and gas fields are perceived to have the lowest risk, since they are not in communication with any surrounding geological features to leak to as long as pressure is kept below initial. If facilities and wells are still intact on the existing fields and can be reused, development and operation costs might be substantially reduced as well.

For the various types of storage sites the following can be adduced;

- Depleted pressure sites will have a lower leakage risk than sites with initial pressure. Fracturing processes and reactivating of faults are pressure driven. Structures are expected to be intact (e.g. faults sealing) at their initial state. Most old oil and gas fields are depressurised, often to a large extent. Similarly, the pressure in many North Sea aquifers has been reduced by oil and gas production.
- Many legacy abandoned wells at a potential storage site may increase the leakage risk. Normally these wells are more numerous in legacy oil and gas fields than at aquifer sites. However, legacy oil and gas field wells have typically been more carefully plugged than dry exploration wells.
- More data is available for depleted oil and gas fields than for more 'virgin' aquifer storage sites. Performance risk is therefore lower. Injectivity and capacity can be more reliably estimated. In particular, dynamic data gathered during the hydrocarbon production phase, will allow better prognosis of future behaviour of a storage development and of any plume migration. This will reduce the injectivity and leakage risks significantly.
- Depressurised sites (including both legacy oil or gas fields or aquifer sites) will in general have less risk of well blow out for all well types and operations (abandoned, injection or observation; during drilling, injection or workover). However, reduced formation pressure may cause drilling challenges though there is ample industry experience with drilling in depleted formations. Such drilling challenges are not exclusively related to CO_2 leakage possibility.
- In strongly depleted legacy oil or gas fields, where pressure is reduced far below the surrounding formations, the migration of CO_2 or brine out of the storage complex is impossible. This reduces/removes risk of impact on, or leakages into, nearby areas. These fields will have risk below the estimates given above.
- Sites with fixed storage boundaries, where pressure can be maintained below initial (e.g. isolated, depleted gas fields), also require less monitoring than a store utilizing a field or aquifer with undefined boundaries and large areal extent. For small projects, depleted and isolated gas fields might be the most economic candidates for storage, however for large volumes aquifers or fields associated with aquifers seem a good alternative.

7.4. Reuse of existing facilities

There is a significant opportunity to deliver additional value to existing assets (i.e. platforms, wells, pipelines) which would otherwise be decommissioned, and thereby help overcome the initial cost hurdle faced by many CCS projects to date, by reducing the initial capital requirement and project's risk. Nevertheless, re-using redundant wells and platforms for CO_2 injection, although technically feasible, carries additional technical and economic risks which must be individually assessed.

Often, the condition of the existing wells is uncertain, and would require considerable assessment and/or remedial intervention to enable re-use. The re-use of offshore platforms can carry high capital and operating costs, and the remaining operational life of these facilities may not match the storage project requirements, in particular large complexes in deeper waters that have been exposed to harsher environments. The re-use of wells and/or platforms is thus primarily a question of economics, and as such, re-use potential is to be assessed on a case-by-case basis.

On the other hand, reuse of pipelines can provide additional value and deliver significant cost savings to a CO_2 transport and storage project. The re-use potential is to be determined on a case-by-case basis; however, research has shown that re-using existing oil and gas pipeline can save between 1-10% of the cost of building and installing a new pipeline. The age, condition and pressure rating of a pipeline are considered key factors in assessing its suitability. Older pipelines which have experienced harsher production environments are likely to have a higher risk profile, as potential for corrosion or other integrity issues is higher.

With respect to the re-use of existing infrastructure for purpose of CO_2 transport and storage it is likely that this will fall under the existing risk and liability management frameworks. Nevertheless, it can be expected that risk and liability-sharing arrangement will be necessary between the public and private sectors, with government-owned entities taking over a larger proportion of the liabilities in particular during the initial period of this emerging industry.

7.5. Conclusions and recommendations

Monitoring costs for leakages which are too small and complex for repair, can make up a significant portion of the operating cost, as current regulation requires extensive monitoring programs for any leakage, including leakage which would have no impact on the nearby environment. Involved parties should strive to develop and agree a program that is fit for purpose for the identified risks (addressing both impact and probability). Excessive monitoring costs and financial security funds could act as a significant blocker to the widespread deployment of CCS in Europe.

Extensive Financial Security Funds will not reduce the risk of leakage. Instead, locking capital into a security fund could reduce the operators' flexibility to handle challenges as they arise. It would be better and more appropriate to develop mechanisms for risk sharing, e.g. a fund held centrally with contributions according to the probability-weighted risk costs, or an insurance system.

CO_2 storage processes have been deployed at various sites for a number of years, proving that the technologies of storage are commercially available at an industrial scale. The most significant contribution to technology development and risk reduction will come through additional experience from the development of full-scale storage projects. With a significant body of data from such projects, the methods and assumptions used in risk assessment could be calibrated to real data, with associated reduced uncertainty. Particular areas for further work are;

- Assessment of the status of old plugged wells, and mitigation methods in case of poor sealing or leakage;

- Prediction of injected CO_2 plume migration and reservoir heterogeneity;
- Prediction of leakage behavior of faults and potential development of fractures;
- Calculation of maximum CO_2 leakage rates under various conditions.

Nevertheless, the urgency and scale of required emissions reduction, and the current costs for CCS, demand that current technologies are implemented at scale while R&D continues into new technologies which can incrementally improve the efficiency and economics of CCS deployment. Priority areas for research can be extracted from the Mission Innovation report (Ref 39).

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9. Working Group members

- Co-chair Hallvard Hoydalsvik
- TNO – Filip Neele
- Total – Fabrice Devaux
- Equinor – Peter Zweigel
- TAQA – Chris Gittins
- Shell – Owain Tucker
- Shell – Lesley Rantell