ZEP Advisory Council 59

05th June 2019

Agenda Item 11: Review of Network Work Programmes

11.a. Network Policy and Economics

Appended to this paper is the following pre-read:

11.a. Network Policy and Economics (NWPE) update

11.a.i. Madrid Forum draft: ZEP Overall Comments

11.a.ii. Madrid Forum final version: ZEP Comments

11.a.iii. ZEP response to EIB Energy Lending Policy consultation

11.a.iv. ZEP speaking points for Innovation Fund Expert Group meeting

11.a.v. ZEP letter to Mr Holzleitner on joint ZEP/EC Innovation Fund Workshop

11.a.vi. European Commission Reply to Mr Graeme Sweeney RE Innovation Fund Workshop

11.a.vii. European Commission Questions for Sectoral Workshops

11.a.viii. Draft response to consultation on the 4th list of candidate PCI cross-border CO2 infrastructure projects

11.b. Network Technology

Appended to this paper are the following pre-reads:

11.b. Network Technology update

11.b.i. NWT meeting agenda 4th June 2019

11.b.ii. TWG Collaboration across the CCS chain, report *'CO2 safety in the North Sea – Implications for the CO_2 Storage Directive Financial Security requirement'* for approval by the AC

The AC are invited to approve the draft report

11.b.iii. Joint ZEP / ERA NET ACT workshop summary note (14th March) on frameworks for CCS risk sharing and business model selection.

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05th June 2019

Agenda item 11.a. Network Policy and Economics update

Co-chairs: Lamberto Eldering (Equinor), Kim ByeBruun (Shell), Jonas Helseth (Bellona)

The next Network Policy and Economics meeting will take place on the 18th July at Science 14, Rue de la Science, in Brussels. The agenda is in preparation, and invites to speakers have been sent.

Madrid Forum:

Lamberto Eldering presented "**The Narrative for Decarbonised Gas in the Context of CCS**" at the 2nd Madrid Forum CCU & CCS Task Force Workshop on 16th April. The workshop concentrated on discussing the draft Madrid Forum report on the role of CCS and CCU and the future of gas networks.

ZEP submitted two documents in response to the first draft of the report, the first consisted of comments on the report, the second was an overview of the report including ZEPs recommendations; including concerns about the proposal to consider all CCU technologies equally for the EU ETS without a life cycle analysis (see pre-read 11.a.i.)

The final version of the report was circulated in mid-May, ZEP once again responded with an overview document highlighting areas for improvement, including the omission of a section explaining how a favourable 2020 gas package can help enable CCS and CCU (see pre-read 11.a.ii). The final version of the report was submitted to the European Commission on 22nd May, the results of the report are being officially presented on the 5-6th June at the Madrid Forum.

Consultations:

A response to the European Investment Bank (EIB) on its **Future Lending Policy** consultation was draft and circulated to the network for comment; the final version was submitted on 29th March and circulated to members; this is attached as pre-read 11.a.iii.

DG COMP launched a public consultation on a '**Fitness Check on State Aid legislation'**; part of this process also includes a more focussed consultation on the '**Evaluation of the Guidelines on State aid for Environmental Protection**'. It will be critically important that CCS remains eligible for state aid. A response to both consultations will be prepared with members ahead of submission of both consultations on 10th July.

Temporary Working Group Policy and Funding

Chair: Theo Mitchell (Enerfair)

Following the announcement by the Commission at the March Advisory Council Meeting, ZEP and the European Commission will host a CCS sectoral workshop on the design of the first call of the

Innovation Fund. This was discussed at the expert group meeting on 28th March. Ahead of the meeting speaking notes were prepared for Graeme Sweeney, who represented ZEP on the expert panel, and an invitation to co-host a workshop was sent to Mr Holzleitner (HoU DG CLIMA); these are attached as pre-reads 11.a.iv. and 11.a.v. respectively.

Following a reply from the Commission on April 4th (see pre-read 11.a.vi), dialogue with DG CLIMA to organise a date and venue was initiated, and general questions to guide the sectoral workshops were circulated; see pre-read 11.a.vii. After an in-depth conversation between the ZEP Chair and DG CLIMA, it was agreed that the workshops will take place on **6th September, in Oslo**, following the 5th September High-Level EU-Norway CCS Conference. ZEP will help review the invitation list for the high level meeting to ensure all major industry CCS stakeholders are represented.

Temporary Working Group PCIs

Chair: Lamberto Eldering (Equinor)

Following the announcement of the **candidate PCI projects in cross-border CO_2 transport networks**, a public consultation was launched. The objective of the consultation is to seek views on the specific projects. The secretariat drafted a response which supports all proposed CO_2 transport PCIs. This draft was circulated to the TWG on 17th May for comment ahead of submission which is due on 9th June; the draft is attached as pre-read 11.a.viii.

ZEP Comments on the Madrid Forum CCS and CCU Taskforce Report: The Potential for CCU and CCS in Europe

Report to the 32nd Meeting of the European Gas Regulatory Forum 5-6 June, 2019

The draft report circulated to Taskforce members was subsequently circulated to a temporary working group with an interest in the Madrid Forum Report process and outcome. ZEP has a wide member base and in order to input into report commenting any response will have to be agreed upon by a group of members, often including several interactions before the final document is circulated to the Advisory Council Executive Committee for ratification and delivery. As such a consultation style response has been drafted, this summarises the key take away opinions of ZEP.

This report is a good opportunity for multiple stakeholders to provide the European Commission with constructive solutions to enable CCS and CCU and help the EU achieve its climate objectives. It is key to emphasise that the enabling of CCUS has benefits not just in immediate emissions reductions, but also in retaining jobs, enabling economic growth, and providing a just transition in a decarbonised Europe.

The role of gas regulators, operators and networks in a future for CCS and CCU is the centre piece of the report

This commissioned piece of work entrusted to the Madrid Forum is a unique opportunity to engage with gas regulators, TSOs, and DSOs on CCS and CCU. Many of the Madrid Forum Members and individuals within the departments of the European Commission may not have been exposed greatly to CCS and CCU. Therefore, this is a vital opportunity to disseminate the principles, history and current status of CCS and CCU to a wider audience, whilst also learning from these members to gain insight into the European TSO and DSO perspectives on CCS and CCU.

It is encouraging that the report includes a section on the regulatory aspects of CO2 transport and repeatedly refers to the regulators. Chapter 11 is the culmination of this and provides a valuable insight into CCS and CCU in the context of the Madrid Forum members. ZEP recommends that this chapter is expanded upon, is included in the Executive Summary, and summarised within the conclusions.

The Connecting Europe Facility is a European Commission funding initiative which has a series of calls aimed at developing cross-border CO_2 infrastructure. There is a strong portfolio of projects from the 3rd CO_2 infrastructure call which have secured funding; this includes the PORTHOS, Acorn and Northern Lights Projects. Furthermore, there are currently 5 projects under review for the 4th CO_2 infrastructure call, including Ervia's Cork CCS proposal. The chapter which focuses on the

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potential transportation, transmission, and regulation of CO_2 would dovetail well with the current CEF PCI funding mechanism for development of cross border CO_2 transport infrastructure.

Recognising what mechanisms have been emplaced by the Commission to help enable CCS and CCU is just as powerful as recognising what may inhibit the deployment of CCS and CCU technologies.

Storage Principles, Mechanisms and Risk must be explained simply and correctly

This report will be presented to the European Commission, made publically available, and hopefully will be a document which is well referenced in the future. In light of the new audience this report may reach, wording must be simple, precise, and correct, especially when explaining some of the geological principles and risks.

Whilst the aim of this report is to address CCS and CCU from the viewpoint of the Madrid Forum, a simple introduction to CCS is required. There is already an introduction to CCS, perhaps this section could briefly outline some technical aspects such as trap type, formation type, reservoir characteristics, storage mechanisms, pressure effects, induced seismicity and plume migration. These areas are often misunderstood people new to CCS and specifically the CO_2 storage in reservoir rocks.

The phrasing is especially important when trying to convey the often negligible levels of risk associated with CO_2 storage operations. This is risk to human health, the environment and storage leakage. Whilst there are ongoing discussions on how to quantify these risks, there have been no observed leakages to date, and current literature supports the extraordinarily low chances of any leakage and even lower changes of significant leakage (DECC 2012[1], Alcade et al 2018[2], LeGuen et al 2008[3]).

> *9.1 The perceived risk of CO2 leakage from storage locations has contributed to public concern with CCS.* ***Any leakage may have both global and local risks, as CO2 is both a greenhouse gas contributing to climate change and could also negatively impact local ecosystems, groundwater and humans****. ..... Over time,* ***the risk of leakage decreases, as the CO2 migrates in the reservoir away from the injection location****.*

This paragraph highlights both points discussed. Opening the paragraph emphasising how low leakage chance is provides a clearer message to the reader. Secondly, the final sentence although not technically wrong, is only part of the explanation as to why leakage risk decreases over time.

[1] https://www.gov.uk/government/publications/co2-storage-liabilities-in-the-north-sea-an-assessment-of-risks-and-financial-consequences-summary-report-for-decc-may-2012
[2] https://www.nature.com/articles/s41467-018-04423-1
[3] Le Guen, Y., Le Gouevec, J., Chammas, R., Gerard, B., Poupard, O., Van Der Beken, A. and Jammes, L., 2008, January. CO2 Storage-Managing the Risk Associated with Well Leakage over Long Timescales. In *SPE Asia Pacific Oil and Gas Conference and Exhibition*. Society of Petroleum Engineers. https://www.onepetro.org/conference-paper/SPE-116424-MS

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Other factors which also contribute to risk reductions are:

- The pressure equilibrating. In stores where pressure will increase significantly as a result of injection, over time once injection has ceased, the pressure gradient will equilibrate, and in certain sites the pressure will continue to fall close to the hydrostatic pressure of the formation. Risk of storage failure is highest during injection periods, once this stops, risk falls significantly.
- Plume migration is not the answer to the risk solution, in fact, plume migration results in a higher CO_2 footprint. This larger surface area **may** contain uncertainties, such as legacy wells or subseismic faults, which when combined may not reduce risk at all.
- The CO2 within the rock undergoes transformation often trapping it in a more 'secure' form. Over time, once injected the CO2 will be found in the formation in 4 states. 1) as injected liquid/gas, 2) trapped in minute pore throats against sand by capillary forces grains (in a conventional clastic reservoir), 3) dissolved in the formation waters, 4) mineralised often as calcium carbonate within the formation pore space. [see IPCC 2005 Report on CCS[4]]

A Life Cycle Analysis (LCA) methodology for CCU Technologies must be confirmed by the European Commission

One of the major topics of conversation during the 2nd Workshop concerned CCU technologies, the ETS and 'Carbon Accountability'. This highlights the lack of a defined LCA methodology which once applied will help define CCU technologies to allow discussions on how to assess these technologies within the ETS and the ongoing EU Sustainable Taxonomy work. ZEP recommends the European Commission prioritise defining this methodology to enable the recognition of carbon emission reducing CCU technologies in various EU initiatives.

ZEP has published some work outlining initial thoughts on CCU technologies and how different processes have different real emissions reductions. CCUS technologies can broadly be classified into four classes ranging from permanent CCS storage to short term sequestration (Table 1)[5].

The most contentious CCU technologies are those with Low Sink Factors such as the production of synthetic hydrocarbon fuels, often known as e-fuels. All processes should be individually classified with a Life Cycle Analysis to be able to quantify their long-term climate mitigation before consideration within European funding initiatives such as the ETS.

[4] https://www.ipcc.ch/site/assets/uploads/2018/03/srccs_wholereport-1.pdf
[5] http://www.zeroemissionsplatform.eu/downloads/1660.html

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	Sequestration period of CO_2	Use of materials in which CO_2 is captured	Indicative Sink Factor	Examples
Bio-CCS	Permanent	Permanent storage, no use	>100%	Provided the biomass involved is sustainably sourced, the capture and storage of biogenic CO2 from any industrial bio- conversion or combustion process can yield negative emissions
CCS	Permanent	Permanent storage, no use	100%	
Enhanced Oil Recovery	Depending on project: permanent	Can be permanent storage, depending on project	95 – 100%	
CCU				
Long term	> 100 years	Building materials, aggregates	40 – 75%	mineralisation (CO_2 -Olivine), nanocarbon
Medium term	10 – 100 years	Building materials	10 – 40%	Carbon8, Blueplanet, Solida, CarbonCure
Short term	< 10 years	Fuels, feedstock, food, lightweight building materials, plastics	0 – 10%	Power to Fuels (e.g. methane, methanol). Biofuels (microalgae) formic acid, bioplastics.

Table 1: Indicative applied sink factor to different types of CCS and CCU[6]

[6] Table 1, ZEP 2017, Climate solutions for EU industry: interaction between electrification, CO2 use and CO2 storage. http://www.zeroemissionsplatform.eu/downloads/1660.html

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ZEP Comments on the Final Version of the Madrid Forum CCS and CCU Taskforce Report: The Potential for CCU and CCS in Europe

21st May 2019.

Report to the 32nd Meeting of the European Gas Regulatory Forum 5-6 June, 2019

No recommendation to the Commission on how the gas package can enable CCS and CCU

As discussed during the regular teleconferences. The report Madrid Forum report needs to make an explicit request for the European Commission to recognise how amendments to the current gas package can help enable the deployment of CCS and CCU in Europe.

Removal of the CCS storage principle explanation section.

ZEP provided some input on the last iteration of comments on the report on how to present storage principles. This can be very technically complex, but for many who will read the Madrid Forum CCS and CCU report in the commission and within the Madrid Forum CCS will be a relatively new technology. It is essential that CO_2 storage principles are understood, especially the basic principles. Trapping mechanisms, plume behaviour, reservoir types, pressure regimes and CO_2 over time are a few areas which should be included.

Asset re-use and decommissioning.

See the paragraph overleaf. There are very few assets which can simply be reused for CO_2 injection. It is a more complex process than presented – the technical specifications of pipes and wells mean many are unsuitable for CO_2 transport and injection. Furthermore, in most offshore areas there is no current roadmap/decommissioning pathway which identifies infrastructure suitable for re-use (this would be a good recommendation to member states).

Upfront storage costs in abandoned fields will normally be cheaper than saline aquifers due to the vast array of data gathered during convention oil and gas exploration (appraisal wells, seismic surveys, reservoir studies, reservoir cores etc etc). For a saline aquifer, projects start with in general a lower knowledge base.

During the development of an abandoned field for CO2 storage – provided all legacy wells are abandoned to a CO_2 resistant standard (an assumption in itself) – the cost of development would be very similar i.e. drilling an injection well and building injection facilities.

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7.1(out of sequence) Costs, technical and regulatory aspects of CO_2 storage

The cost of CO_2 storage depends from location to location, but in general it is highest in offshore deep saline aquifers. The storage capacity in deep saline aquifers is much greater compared to onshore basins or offshore depleted oil and gas fields; these deep saline formations therefore have a better scaling-up and cost reduction potential.[68] The upfront storage costs are lower in depleted oil and gas fields due to the presence of infrastructure that can be (re)used for CO_2 injection. However, risks associated with securing legacy wells for storage operations may add additional risks and costs

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Public Consultation on the EIB Energy Lending Policy

Response from the Zero Emission Technology and Innovation Platform (ZEP)

ZEP welcome the approach of the European Investment Bank (EIB) in recognising that decarbonisation goals will be achieved using a variety of technologies, including those to decarbonise heat. ZEP is encouraged by the identification of the need for a flexible investment framework, as one solution cannot be applicable across different regions of Europe.

Funding alignment with member state and the European Commission's ambitions is essential to deliver decarbonisation and unlock investment. The EIB Energy Lending Policies objective to align with the EU funding mechanisms, the Long-term strategy and with member states National Energy and Climate Plans (NECPs) will deliver the required stable mechanisms to encourage industrial and governmental decarbonisation investment.

General

Q1: Do paragraphs 15-27 above provide a reasonable characterisation of the long-term energy transformation? Are there additional dimensions that the Bank should consider when reviewing its Energy Lending Policy?

There is an assumption that limiting green house gas emissions can only be achieved by the cessation of fossil fuel use. The rapid phasing out of fossil fuels has been shown to be more expensive and have a greater detrimental societal impact [1] than utilising a portfolio of decarbonisation technologies including fossil fuels with carbon capture and storage.

We agree with the points raised in Paragraph 17, however CCS should be more central to plans to allow the fairest social and economic energy transition. According to the IPCC 5th Assessment Report on Climate Change, in scenarios which deliver on the Paris climate goals without CCS, the cost rose by 138% and there were fewer scenarios which could achieve sufficient emissions reduction[2]. There is still a need to make fossil fuel usage with CCS compatible with lending policy.

Carbon capture, utilisation and storage technologies are covered by many of the funding policies mentioned within the EIB Energy Lending Policy document, such as the SET-Plan. However, CCS and CCU are not given the explicit exposure in this document which befits their importance to decarbonisation plans outlined in member states NECPs, and by the European Commission.

Important negative emission technologies have not been recognised in the EIB Energy Lending Policy Plans. Technologies such as bio-energy carbon capture and storage (BECCS), and direct air capture carbon storage (DACCS) have been highlighted as essential to decarbonise Europe in a net-zero scenario[3]. Currently there are no incentives in place to encourage the development of

[1] https://www.ipcc.ch/site/assets/uploads/2018/02/SYR_AR5_FINAL_full.pdf
[2] As Above
[3] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52018DC0773

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negative emissions. ZEP calls for the EIB to highlight the need for investment and policy incentives for negative emissions technologies.

ZEP welcomes the EIB's recognition that hydrogen has a growing role in the decarbonisation challenge of Europe. However, we feel the full potential of hydrogen generation from both steam gas reforming (SMR) with CCS and electrolysis of water has not been adequately considered. Hydrogen can have many cross-sector decarbonising applications such as transport, power generation[4] and heating[5]. The EIB should consider in their future Energy Lending Policy the potential for a European hydrogen economy.

It seems unlikely that electricity alone will be sufficient to deal with hard to decarbonise sectors such as heavy industry and cement production. There is an increasing awareness that hydrogen has a central role across several sectors. Hydrogen can open sector coupling, for example hydrogen production with steam methane reforming, this cross sector opportunity requires support, but can unlock a global hydrogen market for 'blue' and 'green' hydrogen.

Q2: As set out in Box 1, the Bank believes it has a robust framework to ensure that energy projects being financed are compatible with long-term climate targets. Do you agree? Are there areas where the Bank can improve?

We agree that an economic test is necessary when financing energy projects. The EPS is effective at prohibiting certain activities such as power generation using unabated coal. However, the EPS alone will not incentivise other technologies such as CCGT gas-fired power generation with CCS.

Q3: Within the broad areas of renewables, energy efficiency and energy grids, are there particular areas where you feel the Bank could have higher impact?

We think the four key themes of the EIB Energy Lending Policy are correct and welcomed. The themes clearly prioritise action on climate change and target multiple sectors and technologies. It is not clear how the areas of renewables, energy efficiency and energy grids in this question relate to the four key themes, these areas questioned are too narrow to deliver on the Paris Climate goals alone.

Bio-energy power with carbon capture and storage (BECCS) is defined as a renewable technology which has been overlooked in the EIB document. This technology has the potential to not only produce reliable electricity but also drive negative emissions in Europe[6]. The bank should consider technologies which have a negative emissions footprint as an essential component of the decarbonisation challenge.

Q4: How can EIB reinforce its impact towards ensuring affordability, addressing social and regional disparities and support a just energy transformation?

The EIB should focus more on CCS and CCU technologies as a vital part of the solution to delivering the most affordable and socially just pathway to decarbonising Europe. As shown by the

[4] http://hydrogencouncil.com/wp-content/uploads/2017/06/Hydrogen-Council-Vision-Document.pdf
[5] https://www.northerngasnetworks.co.uk/h21-noe/H21-NoE-26Nov18-v1.0.pdf
[6] http://www.etipbioenergy.eu/images/EBTP-ZEP-Report-Bio-CCS-The-Way-Forward.pdf

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IPCC[7] and IEA[8] CCS technology deployment will deliver the lowest cost of living whilst achieving climate goals. CCU and CCS technologies will be essential for energy intensive heavy industry regions to remain globally competitive whilst decarbonising.

Theme 2: Decarbonising Power and Heat (Annex II)

Q8: Declining costs and competitive auctions are transforming a number of renewable markets (e.g. onshore wind, utility-scale PV). How can the Bank best support these relatively mature technologies? In the context of increasing market integration, is there a need for financial instruments to help attract long-term private finance?

Encouragingly the bank express a desire to align with the NECPs from member states, with half of member states mentioning CCS, CCU, or hydrogen production with CCS in their NECPs this should be reflected by the EIBs future planning. We encourage the EIB to dedicate resources to have an explicit focus and work programmes dedicated to CCS, CCU and hydrogen deployment. The EIB should remain cognitive that member states NECP's outline activities proposed for 2030s will help deliver the ambition of climate neutrality in 2050.

The decarbonisation of heat systems is seen as a challenge for Europe which the bank expressed a desire to support. However, hydrogen heating is only mentioned briefly as a solution to the heat decarbonisation challenge. Hydrogen heat networks with hydrogen production from natural gas and CCS has the potential to provide large scale affordable heat decarbonisation on a national scale[9]. Hydrogen has an important role for domestic and industrial heat demands which electrification alone is not likely to affordably achieve.

Q9: Does the EPS for power generation remain an appropriate safeguard? Do you agree that adjustment should be made to support flexibility and adequacy? In light of recent developments in renewables, the Paris Agreement and the Sustainable Development Goals, would an exemption to the EPS for power plants in least developed countries continue to be justified?

The EPS is an effective safeguard against high emitting sources such as unabated coal. However this does not support low carbon desirable alternatives such as fossil fuel based power generation with CCS.

The EIB should financially support nations to build carbon capture facilities on their new fossil fuel power plants. Globally, many countries have recently built and will build in the coming decade's fossil fuel, especially coal-fired power plants. The EIB need a credible strategy on how CO_2 emission from these plants can be abated.

[7] https://www.ipcc.ch/site/assets/uploads/2018/02/SYR_AR5_FINAL_full.pdf
[8] Energy Technology Perspectives, 2017. International Energy Agency (IEA)
[9] https://www.northerngasnetworks.co.uk/h21-noe/H21-NoE-26Nov18-v1.0.pdf

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Theme 3: New energy technologies and business models (Annex III)

Q11: The Bank has developed a number of products – both financial and advisory - targeted to supporting innovative energy projects. Do you have a view on these instruments? Can the Bank improve or better target the financing needs of the energy demonstration sector?

So far from a CCS and CCU perspective it has not been clear that the financing services have been supportive. For example ECOFIN only provided loans to CCS project; these have only been view of very limited value to CCS project developers.

Q12: Some renewable technologies or applications remain relatively expensive. Should the Bank continue to finance such projects, even in the absence of an innovative component?

The EIB should be aware that immature technologies which are currently expensive, but necessary for the energy transition, need support to bring them down the cost curve. As shown by other technologies such as offshore wind, once a technology begins to mature, costs will reduce significantly.

The European Court of Auditors report[10] into the NER300 and EEPR funding mechanisms, highlighted importance of financial stability given by reliable long term commitments to invest in a CCS project[11]. This reliable financing is essential when Member States and industry are moving towards a FID and construction. The EIB have a central role in facilitating CCS and CCU deployment in its early stages.

Theme 4: Securing the infrastructure needed during the transition. (Annex IV)

Q14: What is your view on the investment needed in gas infrastructure to meet Europe's long-term climate and energy policy goals, while completing the internal energy market and ensuring security of supply? What approach could strike the right balance to prevent the economic risk of stranded assets?

Europe's gas network still has key a role to play in the decarbonisation of Europe. Not only will gas still be required as an important feedstock for hydrogen production using steam methane reformers, biogas volumes will increase in the gas network. In the longer term, as a result of a growing hydrogen economy, repurposing current gas infrastructure to transport and store hydrogen could lower the economic risk of stranded assets.

In line with the Connecting European Facility (CEF) funding instrument from the European Commission, the EIB needs to recognise the requirement for investment in CO_2 infrastructure and storage sites.

Q15: Should the Bank refrain from supporting hydrocarbon production, in addition to exploration? If so, should gas be treated the same as oil? Within and outside the EU?

[10] https://www.eca.europa.eu/Lists/ECADocuments/SR18_24/SR_CCS_EN.pdf
[11] Lessons and evidence derived from UK CCS Programmes, 2008-2015, CCSA, 2015. Accessible from: http://www.ccsassociation.org/press-centre/reports-and-publications/lessons-learned/

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Hydrocarbon production will still have a role to play in a climate-neutral scenario. The establishment of a blue hydrogen economy will rely on gas production from steam methane reformers and CCS to provide low-carbon hydrogen. Gas also has a role to play to provide reliable low-carbon electricity production from CCGT, with CCS.

As modelled by the IPCC[12] and IEA[13] the most achievable climate change scenarios see hydrocarbons production and combustion with CCS. The EIB should give consideration in the role it can play in addressing fugitive emissions associated from hydrocarbon production, transport, and storage.

[12] https://www.ipcc.ch/site/assets/uploads/2018/02/SYR_AR5_FINAL_full.pdf
[13] Energy Technology Perspectives, 2017. International Energy Agency (IEA)

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ZEP Innovation Fund Expert Group Meeting 28th March

9:30-12:00:

Panel Discussion on synergies and complementarities of the Innovation Fund with National Funding Programmes for R&I and other European Funding mechanisms.

Q&A Tour de Table Questions:

Key messages:

CCUS fund across European Commission initiatives need to be **complimentary and consistent**. This includes a cross-initiative homogenous mechanism to deal with project withdrawal or funding shortages.

Make sure the funding mechanism of the Innovation Fund is aligned with the European financial framework, including **Future Lending Policy of the EIB** and the ongoing **TEG Sustainable Taxonomy work**. Encourage the EC to engage with this process across internal departments to ensure essential technologies are not excluded from 'Sustainable Investment' status.

ZEP encourages the European Commission to be cognitive that Member States 2030 plans outlined in their National Energy and Climate Plans should lay the **foundation for delivery of a climate-neutral scenario in 2050**.

ZEP encourages the EC to reach out to national programmes when nations are developing investment models for immature technologies to **ensure funding streams from the commission (such as the IF) and EIB are not blocked by business model design**.

The **SET-Plan** should be the primary tool for the EC to interact with member states R&I programmes.

1. **What is the best way to explore the synergies with Horizon 2020 and Horizon Europe, including joint undertakings and PPPs?**

2. **Are there any current or future national R&I programmes, which can help projects close their financial gap?**

Some examples of National R&I programmes:

<u>UK</u>:

BEIS CCUS Innovation Funding now £24m increased from £15m after a number of strong submissions

BEIS Hydrogen Supply Programme: £20m to investigate potential use of hydrogen in heating and gas networks.

BEL: Science for Sustainable Development (70m EUR over 8 research themes, including Energy, and CLIMATE), BRAIN-2, (117mEUR for science in Be) and FED-tWIN (cross centre research collaboration fund)

GER: CO2-Plus and CO2-WIN, £17.5m+ to focus on CCU and using CO2 as a feedstock.

CRO: National Feasibility Study to appraise full-chain potential for CCUS in Croatia

3. **Are there any current or future national R&I programmes – open for projects in earlier or later stages of development – which can help build the project pipeline of the Innovation Fund and subsequently help commercialization?**

UK: ISCF: £180m of matched Government Industry funding for the deployment of the first CCUS cluster in the Mid 2020s

4. **Are there any existing national programmes for project development assistance with which the Innovation Fund could team up?**

UK: Decarbonising Industry Challenge: £315m announced to decarbonise industry, including potential to use CCUS

NL: In the process of developing a dedicated CCS policy.

IRE: 5 year CCS review to potentially allocate funds and regulation for CCUS

5. **What is the best way to involve other national Ministries, promotional banks, or agencies responsible for low-carbon funding?**

12:00-13:30:

Presentation and discussion of next steps, outreach and stakeholder engagement

Q&A Tour de Table

Key Messages:

ZEP encourages a close relationship with the EC. ZEP members can then disseminate up-to-date information on the Innovation Fund to a very wide CCU and CCS audience.

ZEP members are keen to be involved in the design of the innovation fund first call.

ZEP is happy to co-host a CCS/CCU sectoral workshop on the design of this fund, and will continue to have regular working group meetings/workshops on the bid submission process.

1. **What would be the best way to raise awareness about the Innovation Fund and mobilize project proponents to prepare excellent submissions?**

Host sectoral workshops on the design of the calls.

The Commission should give examples or criteria of excellent submissions.

2. **Are you aware of any upcoming events focused on industry, low-carbon innovation, energy transition organized by Member States and/or industry sectors where the Commission could present the Innovation Fund?**

The 10th Trondheim CCS Conference Norway, 17-19th June 2019.
The EU Sustainable Energy Week 17-21st June 2019
EERA annual Conference
Norwegian CCS Summit 5th September, 2019
CATO events, Netherlands
EGU Annual General Assembly, April 2019 (2020)
GHGT-15, 2020

3. **Are you planning any dedicated events on the Innovation Fund?**

There is a proposal for a ZEP/EC co-hosted sectoral workshop for CCS and CCU projects on the design of the first call of the innovation fund. A TWG has been established and work with the EC will be disseminated to members, looking to potential IF focussed workshops in the future.

ZEP AC 05.06.2019
Agenda Item 11.a.v.
ZEP Letter to Mr Holzleitner on joint ZEP/EC Innovation Fund Workshop

For the attention of
Christian Holzleitner
Head of Unit Land Use and Finance for Innovation
DG CLIMA
European Commission
B-1049 Brussels
Belgium

Date: **25 March 2019**

Dear Mr Holzleitner.

I hope you have been well since our event on the EU Long-Term Strategy in September and thank you again for your excellent presentation. Following the ZEP Advisory Council meeting on the 7th March we were pleased to hear the announcement from your colleague that the European Commission will be looking to co-host a sectoral workshop with ZEP on the design of the Innovation Fund's first call.

There is appetite amongst our members to attend a CCUS sector workshop and provide input to the European Commission. We would like to propose a Brussels-based workshop between industry and the European Commission to explore opportunities for CCS and CCU projects in the Innovation Fund, hosted by the European Commission and ZEP. This workshop would help to disseminate knowledge and awareness of the Innovation Fund design amongst ZEP members (and the wider CCS and CCU sectors) and provide a forum for ZEP stakeholders to input ideas to the Commission on the design of the Innovation Fund's first call.

I look forward to hearing from you soon,

With kind regards,

Graeme Sweeney
Chairman ETP-ZEP

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EUROPEAN COMMISSION
DIRECTORATE-GENERAL
CLIMATE ACTION
Directorate C – Climate strategy, governance and emissions from non-trading sectors
CLIMA.C.3 – Land Use and Finance for Innovation

Brussels, 4th April 2019

Mr Graeme Sweeney
Chairman ETP-ZEP
ZEP Secretariat,
CCSA Offices, 10 Dean Farrar Street,
London SW1H 0HX

Dear Mr Sweeney,

I would like to thank you warmly for your suggestion to organise a workshop on CCS and CCU projects for the Innovation Fund. We welcome your initiative very much.

With regard to the further organisation, I would like to refer to the last expert group meeting on the Innovation Fund where we presented our ideas for outreach events in 2019. We are currently preparing a questionnaire to provide further guidance for the organisation of industry workshops and will soon send it out together with all the minutes and the presentations from the expert group meeting.

We are looking forward to hearing on your further proposals with regard to date, participants, and agenda.

Yours sincerely,

(e-signed)
Christian HOLZLEITNER
Head of Unit

Cc : Roman Doubrava, Maria Velkova, Melina Boneva (CLIMA.C.3)

Electronically signed on 04/04/2019 11:49 (UTC+02) in accordance with article 4.2 (Validity of electronic documents) of Commission Decision 2004/563

European Commission Questions for Sectoral Workshops

Presentation of key features of projects in your sector

Describe the project in relation to the objectives and requirements of the Innovation Fund:

- What is the innovative technology and key elements that need demonstration before commercialization? What are the products (final, intermediate or by-products)? What is the technological readiness level of the project and of its different distinct elements? How innovative is the project in comparison to the state-of-the-art?
- What are the capital expenditure, operational costs and benefits over 10-year period related to the innovative project? What is the level of certainty over envisaged costs and benefits? What are the key variables influencing them?
- What is the financing gap and how do you expect to address it?
- What is the GHG emission reduction potential of the project in comparison to a conventional project of the same scale?
- What is the size of the potential market of the products (final, intermediate and by-products)?
- What is the expected project development timeline? Has the project already done pre-/feasibility study, FEED study? What steps need to be taken/conditions met before Final Investment Decision?
- Is the project dependent on other projects, development of infrastructure or adoption/amendment of certain EU or national regulation?

Questions for discussion

Selection criteria

- Effectiveness of GHG avoidance potential
  - Will the existing monitoring, reporting, verification (MRV) requirements under the EU Emission Trading System (ETS) be applicable to innovative plants in your sector? If not, what further guidance needs to be prepared for a fair evaluation of the GHG emission reduction potentials of different projects in your sector?
  - Which role do you see for life-cycle assessment (LCA) in calculating and verifying the GHG emission avoidance potential? What are the critical points that need to be considered when undertaking an LCA for projects in your sector?
- Degree of innovation
  - How can the degree of innovation in comparison to the state-of-the art be best evaluated?
- Project maturity
  - Which criteria should be used to evaluate project maturity?
    - Business plan, capacity of the promoters behind the project
    - Financial structure (private investors, other public support, strength of commitments)
    - Societal acceptance

        - Legal setup and permitting
        - Stage of project development (concluded feasibility studies, FEED, etc.)
    - What are the essential elements that need to be in place for a project to be able to reach financial close within 4 years? Should a completed feasibility study be made a condition for applying for the Innovation Fund?
    - What are the key risks and barriers to implementation, respectively pre-conditions for projects to go ahead?
- Wide-spread application
    - Should projects indicate their potential market and at what level (European/global), or should this be determined by market statistics? If the latter, what are the most reliable sources for your sector?
- Relevant cost calculation
    - Are there any specific issues that sector projects may face with the application of the definition of relevant cost from the Regulation?
    - Are the conventional production costs easy to estimate with confidence? If not, can price of conventional product be used as a comparator?
    - What are the key variable factors determining the financial gap?
    - What are the financial risks and how best they can be evaluated?
- What weights, if any, should be applied to different selection criteria?

Milestones

- What is the expected timeline to financial close and entry into operation for innovative projects in your sector?
- What are the key milestones before financial close, e.g. feasibility or FEED study, permitting, State-Aid approval, etc. and before full entry into operation, e.g. how long are the construction, testing and commissioning periods?
- How should the grant be optimally disbursed over the project life cycle? To what milestones can/should disbursements be linked?

Project development assistance

- Will project development assistance (PDA) be useful for projects in the sector? If yes, what types of assistance?
- Should there be maximum amounts for different types of PDA and what would these levels be, taking into account that PDA support will count towards the 60% maximum support by the Innovation Fund?
- Should projects be required to publish the results of any studies done with PDA, if they decide not to apply for Innovation Fund full support or are discontinued?
- Should FEED be financed by PDA or only after successful application for an Innovation Fund award?

Knowledge-sharing requirements

- What type of technical, economic, project management, regulatory and permitting information will be useful to share with other projects from the sector in order to speed up the uptake of the innovative technologies and to advance the regulatory environment without at the same time

compromising the legitimate intellectual property rights, the competitiveness and the first-mover advantage of the companies involved in the projects?

- What types of knowledge-sharing activities should the implementing body organize for projects benefiting from Innovation Fund (and other EU programmes) and for the general public?

What should be the form of knowledge sharing tools that would be useful for the market?

Consultation on the list of candidate Projects of Common Interest in cross-border carbon dioxide transport infrastructure

Response from the Zero Emissions Technology and Emissions Platform (ZEP)
June, 2019

The European Zero Emission Technology and Innovation Platform (ZEP) is the European Technology and Innovation Platform (ETIP) established to provide advice to the European Commission on the research, demonstration and deployment of CCS and CCU technologies.

Support for PCIs for CO_2 Transport

Carbon capture and storage deployment in Europe has progressed slower than expected due to a variety of factors, but the need for CCS remains greater than ever given the ratification of the Paris Agreement. Unlocking investments in CO_2 infrastructure can, in turn, remove the barriers to investments in CCS seen by many energy intensive industries and power sector emitters.

Meeting the objective and aspirations of the Paris Agreement will require CO_2 transportation infrastructure networks that can serve multiple sectors of the economy. Infrastructure planning is essential to secure and protect the future of emissions intensive industries and encourage investments in these economically important sectors, especially as CO_2 emissions become increasingly constrained.

In Europe, many emissions intensive industries (industrial and power) are located in tight geographical areas e.g. Teesside (UK), Rotterdam (NL), Herøya (NO), Ruhrgebiet (DE), Grangemouth (UK) and Antwerp (BE). In addition, some industrial and manufacturing clusters are close to excellent and extensive geological CO_2 storage opportunities and existing pipelines, e.g. the North Sea Basin and co-located with power generation facilities (with large source of emissions).

With the development of a shared network of CO_2 transportation infrastructure, CO_2 emitters located in close proximity to each other can benefit from using a strategically sized infrastructure. Therefore, multiple sources of CO_2 in a tight geographical location make infrastructure planning easier and less costly. CO_2 transportation infrastructure networks built with spare capacity allows for investment decision to be de-risked for the emitter, ultimately supporting the transition towards a low-carbon economy.

ZEP has highlighted through various reports the economic challenges for investments in CCUS infrastructure projects, in particular CO_2 transport and storage.

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In its 2014 report on a Business Case for Commercial CO_2 Transport and Storage[1] ZEP identified the need for innovative business models, which align commercial interests across the entire CCS chain; and given the long lead times – 6 to 10 years for both pipelines and storage sites – demonstrated the need for developments to start now, ahead of wide-scale deployment. The report was followed by An Executable Plan for CCS in Europe[2], which built on the earlier concept of CO_2 "Market Makers" to support the deployment of CCS by de-risking infrastructure investments.

In your opinion, is a proposed project significantly contributing to market integration/sustainability/security of supply/competition and therefore needed from an EU energy policy perspective?

ZEP believes that all five proposals contribute to the criteria set out for CO_2 transport projects under the TEN-E regulations. Developing shared infrastructure for CO_2 transport and storage will increase security by allowing interconnection between stores and emitters. Resources can be used most efficiently by developing economies of scale through shared transport and storage infrastructure.

CCS is vital to enabling avoidance of CO_2 emissions in key sectors of the EU economy, contributing to the long- term sustainability of Energy Intensive Industries; and can further provide a cost effective method of decarbonisation in heat, transport and power. Given that some areas of Europe are strategically better placed to develop CCS than others, cross- border transportation of CO_2 will be vital to ensure efficient use of resources so that benefit can be shared between regions.

All five project proposals submitted will significantly contribute to the sustainability of European industries in a low carbon future. Furthermore, the development of CO_2 transport infrastructure can contribute significantly to security of supply in Europe, allowing the continued use of a wider range of energy sources.

Developing strategic CO_2 transport infrastructure will enable a CO_2 market to develop between Member States, enabling industries located in multiple Member States to benefit from CCS, and contributing to wider market integration and competition.

[1] http://www.zeroemissionsplatform.eu/downloads/1523.html
[2] http://www.zeroemissionsplatform.eu/downloads/1545.html

European Technology Platform for Zero Emission Fossil Fuel Power Plants

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ZEP Advisory Council 59

05th June 2019

Agenda Item 11.b.: Network Technology update

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

The next NWT meeting takes place on 4th June 2019 and will consider how to progress the new work item activities identified in the 2019-2020 work programme. The agenda is attached a pre-read 11.b.i.

TWG Collaboration across the CCS chain

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

WS1 (storage-related risks):
Following the recommendations from the AC in December 2018, WS1's draft report has been reviewed by the IEA GHG, Bellona and the TWG. This has generated a significant number of comments that have been addressed by the Secretariat. The report has also been reviewed by the ERG with regards to key messaging, communication and dissemination.

The final report is appended as pre-read 11.b.ii. for approval by the AC. Note that this document is not for wider circulation.

The AC are invited to approve the report.

Once approval is granted by the AC, the Secretariat will conduct a final proof-read. The report will then be sent back to the TWG member companies for final approval. This is expected to take up to 4 weeks. At the same time, the report will be professionally formatted.

After this process is completed the report will be released. The communications group proposed a 'soft' report launch. This proposal was approved at the December AC.

WS2 (risk sharing in a CCS network):
WS2 held a second joint ZEP & ERA-NET ACT workshop on 14th March. The workshop achieved a high level of participation with representatives from industry, Member States, research or advisory organisations, NGOs, the European Commission, etc.

A workshop summary note is attached as pre-read 11.b.iii. The TWG will start the process of drafting a report shortly. This report will build on the recommendations from the first workstream and the material from the workshop.

TWG CCU and Sink Factor Methodology

TWG Chair: Rob van der Meer (Heidelberg Cement)

The Ramboll study commissioned by DG CLIMA has been released on 6th May and is available via this link. The TWG will meet on 29th May to discuss ZEP's response. The intention is to develop a short position on this by the Advisory Council meeting and this can then be provided as input to the European Commission.

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ZEP Network Technology

Meeting Agenda: 4th June 2019

Copernico Science 14
Rue de la Science 14b, 1000 Bruxelles, Belgium

11:00 – 15:30 CEST

Item		Lead Presenter	Time
1	Introduction, tour de table, safety notices	Co-Chairs	15mins 11:00 - 11:15
2	Policy update: • EU Taxonomy for Sustainable Finance progress update • European issues & SET-Plan IWG9	Graeme Sweeney Marine d'Elloy	30mins 11:15 - 11:45
3	Session on CCU & Life Cycle Analysis (LCA) • Presentation of work from CCU TWG[1] • Group discussion on preliminary conclusions	Rob van der Meer Arthur Heberle	45mins 11:45 - 12:30
	Lunch		30mins 12:30-13:00
4	Session on CO_2 transport • Presentation and discussion on potential Network Technology work on risks and costs related to the transportation of CO_2	Haroun Mahgerefteh	30mins 13:00-13:30
5	Session on capture rates • Presentation of new IEAGHG study on capture rate assumptions in modelling ('CCS in Energy and Climate Scenarios') • Discussion on recent IEAGHG study ('Towards Zero Emissions CCS in Power Plants Using Higher Capture Rates or Biomass'), key conclusion and potential applicability to industrial plants and hydrogen	Keith Burnard Earl Goetheer (tbc)	60mins 13:30- 14:30
6	Progress update on WS2 Collaboration across the CCS chain • Presentation on outcomes from the ERA-NET ACT & ZEP joint workshop • Discussion on report key messages	Ward Goldthorpe	45mins 14:30-15:15
7	Next steps:	Co-Chairs	15mins

[1] The TWG is undertaking a review of the following studies:
- https://publications.europa.eu/en/publication-detail/-/publication/7656142c-7083-11e9-9f05-01aa75ed71a1/language-en
- http://www.co2value.eu/wp-content/uploads/2018/10/Global_CO2_Initiative_TEA_LCA_Guidelines-Final.August-2018.pdf

• Chairs' summary • NWT forward-look and next meeting • AOB	15:15-15:30

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CO_2 Storage Safety in the North Sea: Implications for the CO_2 Storage Directive Financial Security Requirement

TWG Collaboration across the CCS chain
Workstream 1

Executive Summary

1. Key messages

- CO_2 underground storage is a safe and mature technology ready for broad implementation, as evidenced by over twenty years of successful storage offshore in Norway, combined with more recent onshore storage in Canada. In Europe, CCS benefits from a clear set of regulations and requirements under the 2009 EU CO_2 Storage Directive that ensure the identification of appropriate storage sites and the safety of subsequent operation.

- CCS is required for rapid and large scale decarbonisation of major point sources, such as diverse heavy industrial emitters. CCS provides robustness to decarbonisation strategies, especially for industrial clusters, and enables a just transition for industrial communities. CO_2 transport and storage is required for a large variety of emissions sources, tackling process emissions and addressing the concept of 'unavoidable emissions' that would otherwise continue to be emitted to the atmosphere.

- For climate stabilisation, captured CO_2 must be permanently prevented from reaching the atmosphere. For a typical offshore North Sea storage site, the report concludes that both the likelihood and the potential volumes of released CO_2 in a theoretic incident are very low and decrease with time. It can be expected that 99.99% of the injected CO_2 remains in the subsurface permanently. In the extremely unlikely event of a small CO_2 leak, this will have a minor localised influence on the marine environment, as these ecosystems are naturally resilient to minor fluctuations in CO_2 concentrations. With quick remediation, even an extremely unlikely major leakage event will have a limited and temporary effect on marine ecosystems, affecting a small area of 10-100's km^2. Any environmental consequences would be relatively limited and far lower than an equivalent event from current oil and gas production activities. The overall ongoing, accelerating impacts of climate change and related ocean acidification of marine habitats are not questionable but indeed unfolding before our eyes, and will rapidly become irreversible unless large-scale, urgent action is taken.

- Since 2009/10, fewer CCS projects have been implemented than envisaged. This has largely been due to a number of factors such as the lack of clear incentives and the lower than expected industrial output after the financial crisis in 2008. The further analysis in this report identified the financial liabilities for CO_2 storage development as a key reason for the limited industry interest in applying for storage permits in a number of countries. Under the EU CO_2 Storage Directive (in particular Guidance Document 4), operators or owners of a CO_2 storage facility are required to provide significant financial securities prior to operations to cover normal obligation, as required to ensure proper operation of a storage site. However, the Directive could risk imposing large amounts for extremely low probability incidents. The consequent financial burden such securities

add to each individual project undermines project development, causing reluctance of the private sector to invest, with as a consequence increasing societal cost for reducing emissions at scale (ZEP, 2017).

- Involved parties should develop and agree on a Monitoring, Measuring and Verification (MMV) program that is fit for purpose for the identified risks (addressing both impact and probability). Clarification and recognition of the difference between monitoring requirements for various types of storage sites in Guidance Document 4 is required, e.g. for techniques pre-and post closure of storage in pressure depleted structures compared to aquifers are different. Moreover, a clear split between the essential elements of the Financial Security (decommissioning obligations, conformance monitoring) and extremely unlikely elements (leakage, non-conformance monitoring), would help the industry to accelerate deployment without undermining monitoring and safety mechanisms. The former should be detailed and required under each storage permit. The latter could be arranged on a country or sectoral basis where the competent authority would make arrangements with the industry to set aside a fund to cover such unlikely events.

- As with other scaling technologies, the financial implications of CO_2 storage operations and monitoring will be reduced with growing economies of scale and a competitive market for services and technology providers. Getting initial CO_2 transport and storage infrastructure built at a European scale is critical to enable industrial decarbonisation and allow innovation through existing R&D efforts and deployment of new technologies, increasing efficiency and provide major savings to the economy.

2. Background

This report was prepared under the European Zero Emission Technology and Innovation Platform (ZEP) project “Collaboration across the CCS Chain” and is the result of the workstream focusing on CO_2 storage-related risks. The objectives of the report are to: 1) Analyse 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 learning from current projects; 4) Identify areas of major uncertainties or gaps in knowledge; and 5) Discuss the legislation (EU Storage Directive) requirements for CO_2 leakage risk monitoring, mitigation and liability.

Carbon Capture and Storage (CCS) is a set of technologies, which extract the CO_2 from process emissions generated through the manufacture of products such as steel, chemicals and cement, as well as from emissions in refining and hydrogen production, and store the CO_2 securely and permanently underground to stop emissions from entering the atmosphere[1].

[1] An introduction to Carbon Capture and Storage (CCS) can be accessed via the following link: https://iopscience.iop.org/book/978-0-7503-1581-4.

3. Analysis and findings

Geological storage of CO_2 has been demonstrated in Europe and farther afield for over 20 years. A key concern for Governments is understanding the real and perceived risk associated with storing CO_2 in the subsurface, in order to enable the scale-up of CCS activity in Europe. Risk in this report is defined as the product of probability multiplied by consequence.

This report is based on a summary of experience from global CO_2 storage projects to date (such as Statoil's Sleipner project and Total's Lacq project) – from pilot to industrial scale – along with published risk estimates, unpublished risk studies for North Sea storage sites, and further evaluation by a group of industry and research specialists with expertise in CO_2 storage.

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 can be expected to be similarly effective at containing CO_2. Importantly, for most CO_2 storage sites, stored CO_2 becomes safer over time, meaning the longer it has been in the subsurface the lower the risk of a leak, as more CO_2 is immobilised (trapped in isolated bubbles in pores, dissolved in the pore water and binds bound chemically, as minerals to the surrounding rock). Once the CO_2 storage site is closed, and injection of CO_2 stops, the risk of CO_2 release reduces significantly.

The analysis reported here assesses several types of risk under two broad categories. One, the containment risk, relates to the concern that is probably most present in the public mind, addressing the possibility of a CO_2 leak from the designated storage site. The other refers to site performance risks, including; the possibility that less CO_2 can be stored than expected, other operational risks that are comparable to those experienced in oil and gas development operations with the same health and safety requirements being applied, and commercial/financial risks, particularly relating to the financial penalty required by the operator with respect to the risk profile of CO_2 leakage.

This report assesses ten theoretical CO_2 leakage scenarios in light of the containment risk, assessing their probability, impact, duration, and cost implications. These scenarios are set out in the table below and address a range of possibilities from minor leaks to major store failure. The assumed case is a national storage site injecting a total of 100 million tons at 2000-3000 m depth, over a period of 50 years. The site includes one injection well and one abandoned well. The probabilities listed in the table relate to the likelihood of the specified events to occur during a period of 500 years from injection commencement. The amounts listed are the theoretically estimated quantities of CO_2 lost in the linked ocean-atmosphere system during the specified event. It is important to note that the ten scenarios cannot take place at the same time, as some events are mutually exclusive.

Additionally, it should be noted that the environmental consequences of a CO_2 leak vary depending on the size and location of the leak. Carbon dioxide 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. To escape from the primary geological store deep underground, CO_2 would first have to percolate through the overlying rocks. Much of the CO_2 would be trapped or dissolve in overlying formation waters before reaching the seafloor – reducing the magnitude of any leak. Marine ecosystems are naturally resilient to CO_2 fluctuations, though prolonged exposure to increased CO_2 concentrations affects marine communities by lowering the pH of the surrounding seawater. Concentrations from high leakage rates are, however, highly unlikely to occur even in the incident of a CO_2 leak (see table below). Any leak or seepage will however be localised, and the footprint of disruption will be 100-1000's of times smaller than current habitat destruction from other anthropogenic activities, such as trawling or offshore aggregate mining (Jones et al., 2015; Blackford et al., 2018).

Scenario	Probability over 500 years including lifetime of the project and post closure (%)	Peak Leakage Rate (t/d)	Duration of leak (years)	Total Mass Leaked (tons)	Risked Leaked mass (tons)	Total Remediation cost (€m)	Risked cost (€)
Minor leakage; fault & fracture	0.2	100	50 years	1,825,000	3,800	97	194,000
Moderate leakage; fault & fracture	0.05	700	12 years	3,066,000	1,550	178	89,000
Severe leakage; fault & fracture	0.005	5,000	4 years	7,300,000	365	589	29,450
Active well leakage	0.5	50	250 days	12,500	62.5	10,4	52,000
Active well blowout	0.15	5,000	250 days	1,250,000	1,875	93	139,500
Abandoned well blowout	0.1	3,000	1 years	1,095,000	1,100	88	88,000
Seepage in abandoned well	0.5	7	100 years	255,500	1,250	34	170,000
Severe well problem, no repair successful	0.005	6,000	2 years	4,380,000	215	524	26,200
Leak from installation	0.25	100	5 days	500	1.25	15	37,500
Undesired plume spread	0.03	0	N/A	N/A	N/A	110	15,000
Total					10,219	1838	**840,650**

Two key conclusions can be drawn from this table:

- **The probability of <u>any</u> of these ten scenarios occurring is extremely low.**
- **Adding together the risked cost for <u>all</u> scenarios – and therefore taking into account mutually exclusive incidents – results in a total possible risked cost for one storage project of €840,650 – less than €1 million. As described below, this is several orders of magnitude less than the above defined worst-case scenario cost of €589 million, which owners and operators are required to set aside Financial Security to cover in the EU CO2 Storage Directive.**

For all currently operational projects, no geological release of CO_2 to the surface or the sea floor has been detected. In addition, these operational projects all highlight the importance of utilising stringent Monitoring, Measuring and Verification (MMV) as well as maintenance and remediation procedures. Based on this experience of CCS projects over the past decades, as well as the available knowledge of the subsurface and the above findings of the conducted analysis, this report expects over 99,99% of injected CO_2 to remain in the subsurface for at least 500 years including during the operation phase and post closure. This assessment 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*".

In case of a CO_2 leak, under Guidance Document 4 (Financial Security and Liability) of the EU CO_2 Storage 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. A deposit is also 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%) of the CO_2 released. It is highlighted in this report that applying a defined worst-case scenario could require remediation costs for each individual CO_2 storage site in the order of €600 million. The probability of such a severe event is estimated at less than one in 10,000 projects.

Taking into account the findings on the probabilities of the containment risk associated with CO_2 storage this report suggests that the total cost risk for one storage project amounts to less than €1 million (even taking into account mutually exclusive incidents). 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 defined worst-case scenario cost of €589 million.

Requiring operators to set aside Financial Security to cover a worst-case scenario remediation cost in the current magnitude will place a heavy burden on any storage business case and obstruct the development of CO_2 storage projects. In fact, no individual operator can afford to set aside funds to cover such highly unlikely events for every project, and no other ongoing business operates under an equivalent requirement. In other industries (e.g. oil and gas industry) similar risks are usually absorbed by an insurance system. Such an insurance or guarantee system, initiated by the authorities, for sharing the risk for the CCS industry would significantly reduce the barrier of entry currently faced 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 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.

4. Conclusion

Through the EU CO_2 storage directive, a clear and comprehensive framework exists to assess, monitor and safely operate a CO_2 storage site. The directive's provisions lay out significant technical and financial prerequisites for the development of CCS in Europe that ensure operators have to take the highest safeguards. Based on the analyses of this report, the containment risk (i.e. the risk of a leakage of CO_2) can be considered minor – with scenario probabilities ranging between 0. 005% and 0.5% – and over 99.99% of injected CO_2 is expected to remain underground for at least 500 years. It is important to note that the longer CO_2 remains in the ground, the safer it becomes as it migrates and binds with pre-existing minerals in the subsurface. In addition, operational experience to date demonstrates that geological CO_2 storage is proven technology, ready for wider implementation. CCS can therefore be counted upon as a key climate mitigation solution.

However, as the EU directive also transfers full financial responsibility for potential incidents to the operator, assurances have to be established that cover costs for all potential eventualities for each individual project site before operation. Yet, applying an unrealistic worst-case scenario cost to a CO_2 storage project imposes a heavy burden on 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 well-below 2°C.

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1. Context

This report has been prepared under the ZEP project "Collaboration across the CCS Chain" by a workstream focusing on geological storage risks. The project's overall objective is to lay out experience developed from over half a century of oil and gas production and twenty years of CO_2 storage in the North Sea, thereby helping and enabling the development of European offshore CCS project(s).

This document will be used as technical basis for the second workstream "Risk sharing across the CCS chain", which focuses on outlining available options for sharing or allocating risks and liabilities associated with CCS projects between the chain actors in different organisational models (comprising multiple sources and multiple storage sites).

The objectives of this report are to: 1) Analyse 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) Identify areas of major uncertainties or gaps in knowledge; and 5) Discuss the legislation (EU Storage Directive) requirements for CO_2 leakage risk monitoring, mitigation and liability.

The analysis revolves primarily around technical issues and risked cost, but the report also touches on European legislation. 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 risk for CO_2 leakage is extremely low and the operator can prove in any eventuality that they are capable of handling it in a predictable manner. 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.

Intergovernmental panel on climate change (IPCC) reports have consistently, over many years, identified CCS as a central tool to mitigate climate change. More recently, the IPCC showed CCS to be critical to reach the targets set out in the Paris Agreement (IPCC 2018). Also the European Commission's Long Term Vision "A Cleaner Planet for All" that called for a climate neutral Europe by 2050 stressed the need for enabling a CO_2 infrastructure and CCS for Europe's heavy industries (Directive 2003/87/EC, 2018). Industry currently emits about 20% of total EU emissions. Particularly the cement, steel and chemical sectors require CCS to deeply decarbonise their processes, lacking alternative or timely emission reduction technologies. As outlined in ZEP's report on the "Role of CCUS in a below 2 degrees scenario", CCS can thereby play an essential role in facilitating a Just Transition for Europe's resource intensive industry and safeguard millions of jobs also down the value-chain (ZEP, 2018). However, there has been much less CO_2 storage development activity in Europe than anticipated when the EU established the Storage Directive in 2009. The analysis in this report identified the economic and financial risk of CO_2 storage as a potential key reason for the limited industry interest in applying for storage permits. Under the EU CO_2 Storage Directive (in particular Guidance Document 4), operators or owners of a CO_2 storage facility are required to provide significant financial securities prior to operations to cover both

necessary and normal obligations as well as large amounts for extremely low probability incidents. The consequent financial burden such securities add to each individual project undermines project development, causing reluctance of the private sector to invest. In turn, a lack of investment in CCS projects is increasing the perceived risk. This issue will be explored in more depth in the report.

It is expected that oil and gas companies with broad offshore experience are naturally suited to be operators for early CO_2 storage projects. Additionally, the development of a European CCS industry would ensure new, sustainable opportunities to employ the skill-set of people currently working in the oil and gas industry. The transportation and the storing of CO_2 requires the same full system engineering knowledge in infrastructure, reservoir appraisal, well drilling, and monitoring equipment that is currently applied in the offshore petroleum industry. To date, the European oil and gas industry has conducted their operations with a high level of Health Safety and Environment (HSE) performance. Under their expertise, oil and gas companies operating in Europe have handled the concern of gas leakage reliably and predictably for decades. The concern attributed to CO_2 storage of large quantities or CO_2 being released post-injection is no different.

It is important to note that 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 (Scandpower/NGI, 2012). CO_2 does not combust nor does it create oil slicks. It is naturally present in the atmosphere and marine ecosystems, and once diluted released CO_2 is indistinguishable from other CO_2. All leakages may not reach the sea floor, many CO_2 leaks out of the storage reservoir will be trapped in overlying rock formations. Leakages, if they reach the sea floor, unless in large concentrations pose a low and limited risk to the environment (see section 2.1).

The risk from an operators' perspective 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.

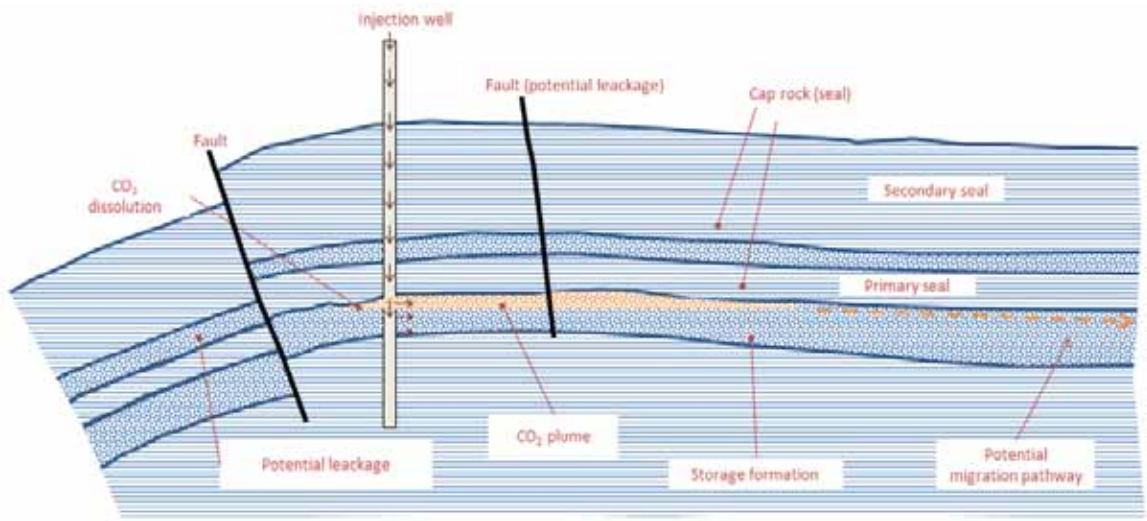
In addition, even if CO_2 does not reach the ocean-atmosphere system, there is an obligation to execute steps (ii) and (iii) if the CO_2 is shown to have left the subsurface volume designated for storage (the "storage complex" as defined in Article 3 of the 2009 EU CCS Directive).

2. Introduction to CO_2 storage

2.1. CO_2 storage principles and definitions

To reduce the emissions of CO_2 to the atmosphere from essential industrial processes, 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 through which it shall not flow out. The storage medium itself is typically a traditional reservoir rock (i.e. a rock formation with a pore space to store in and sufficient permeability so it can be injected into). When the CO_2 is injected into the reservoir rock, it will displace the existing fluids and migrate or 'plume' upwards due to buoyancy. The injected CO_2 will partially mix with the formation waters or in the case of a depleted gas field mix with any residual natural fluids. 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 sufficient lateral extent to accommodate the injected CO_2 plume. 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 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 understood as release to the atmosphere-ocean system;
- 'CO_2 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 linked ocean-atmosphere system is regulated under the ETS Directive.

The following requirements must be fulfilled by a storage site:

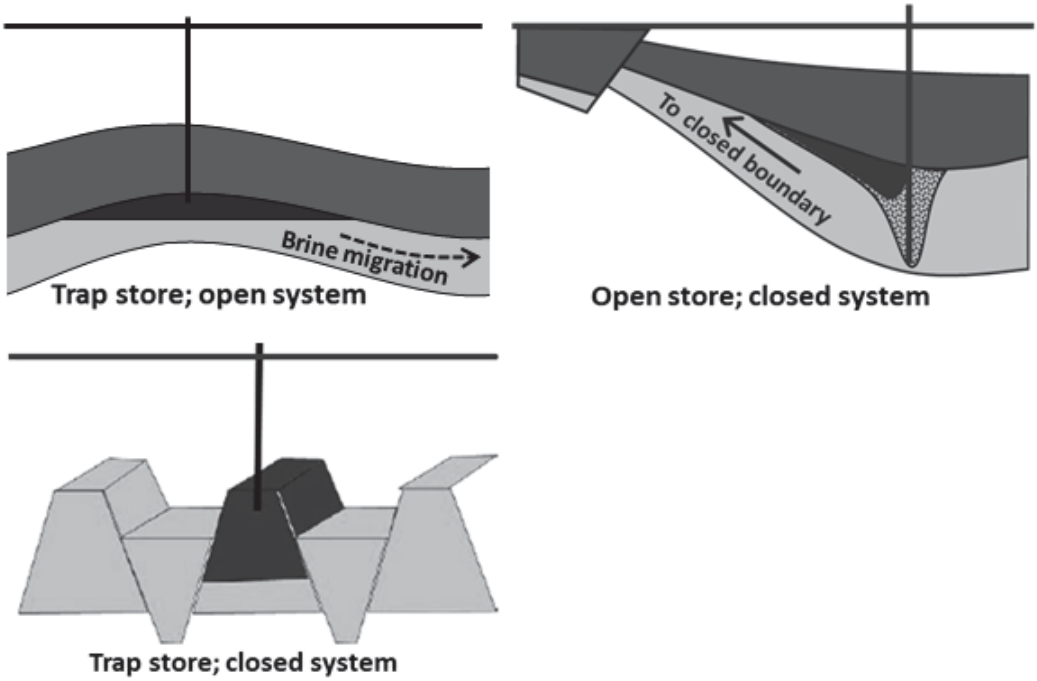
1. Capacity: the storage site must have sufficient capacity to store the required mass/volume of CO_2.
2. Injectivity: the project must be able to inject CO_2 into the geological store at a sufficiently high rate to handle the quantities delivered to the project.
3. Containment: the injected CO_2 must 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 in general consider several broad categories (figure 2):

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

Figure 2. Typical CO_2 storage sites and pressure systems



Carbon dioxide storage differs from most hydrocarbon production scenarios in that there is usually 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 highly saline 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 managed. Similarly, water can be extracted as CO_2 is injected; which is what is intended for the Gorgon CO_2 storage development in Western Australia. The pressure can be maintained at, or below, a target 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.

Most of the risks associated with CO_2 storage are common to all types of storage, although some risks are inherently higher or lower for a particular storage type, as discussed throughout this

document. There are also many similarities between hydrocarbon extraction and CO_2 storage, in terms of development and operational activities and facilities, and the risks associated with these. Consequently, the relatively immature CO_2 storage industry will inherently be linked to 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.

2.2. Definitions of Leakage

The EU CO_2 Storage Directive defines a leakage as CO_2 which is released from the 'storage complex'. A 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. For many low rate leakage and seepage events, much of the CO_2 escaped from the primary storage reservoir will be trapped in overlying formations. The listed leakages defined in this report are all to the biosphere (be that the ocean-floor for geologic leakage and some well leakage; or atmosphere for some well leaks).

Seepage: Minor flow in geologic pathway around a storage site. Mostly spread over a significant area. Hard to detect and monitor. Geologic seepage is uneconomic to remediate; well seepage from active wells can be repaired. Typically less than 5 tons/day. This level of CO_2 release is often equivalent to the natural flux of CO_2 from the North Sea sea floor today without any CO_2 storage

Minor leakage: Minor flow along a geologic fault or leakage pathway, as well as a quite restricted/controlled leak in a well. Geologic leakage in this magnitude is difficult or uneconomic to repair, well leaks can normally be repaired by a standard well work over. Typically 1-50 tons/day.

Moderate leakage: Significant flow along a geologic fault, leakage pathway, or in a well. Geologic leakage can be remediated with a relief well, well leaks can normally be repaired by a standard well work over. Typically 100-500 tons/day.

Major leakage: High flow along geologic fault, leakage pathway, or in well under normal pressures. Will require mitigating action, mostly with relief well. Typically 700-2000 tons/day.

Severe leakage: Full flow along a fault or geologic pathway or full uncontrolled well blow out. Requires immediate action and relief well. Typically 5000 tons/day or even higher.

2.3. Environmental impact of leakage

For deep subsea storage in Europe, much of the CO_2 from a seeping to moderate leak at depth will be trapped or dissolve in overlying formation waters before reaching the seafloor. Marine ecosystems are particularly tolerant to fluctuations in CO_2 concentrations and subsequent short-term variations in seawater acidity. The most vulnerable organisms are those which rely on a calcified shell such as crustaceons, however even these can withstand short periods of moderate acidification. An acidification causing a seawater change of 0.1pH units is considered to have an

impact above seasonal background variation. The environmental impact of a CO_2 leakage will depend on both the severity and longevity of the leak. A small seepage or leak (<1ton/day-10tons/day) will only have a sea floor footprint (delta > 0.1 pH) of a few tens of meters, minor enough that most organisms will relocate before major disruption occurs. A very large leak (>100ton/day) will have a more regional effect, with a km scale footprint and large subsea plume. In extreme cases this could result in death of organisms however this is unlikely (Jones et al., 2015).

These effects on the sea floor ecosystem, even with a large leak, are 100's-1000's of times smaller than current North Sea habitat destruction caused by activities such as trawling and aggregate mining. The possible leakage impact is insignificant when compared to the current path of ecosystem collapse predicted by climate change (Blackford et al 2018).

2.4. Human impact of leakage

Depending on the size and character of a leakage, it is possible,however unlikely, that some CO_2 will reach the sea surface, after which it will be dispersed by the wind. For such a leakage to represent a danger to human health, two conditions must occur:

1. The leakage must be large enough and in a high enough concentration to release a cloud is of substantial volume and concentration.
2. The humans who come into contact with this cloud must be inside it for a long enough period of time to suffer adverse consequences.

Leakage events through the subsurface and water column are spread over large areas and will not be able to develop large concentrated CO_2 clouds on the sea surface. Most of the CO_2 leaked will be trapped by geological formations, or dispersed in the water column.

Carbon dioxide leakages from severe well blowout are more likely to produce a large gas plume in the water column which may reach the surface and produce a significant concentration and volume of CO_2. If vessels are in close proximity to the CO_2 it poses a threat, as once the CO_2 reaches the surface it will 'pool' on the sea surface as it is denser than air, until it is dispersed by the wind. It is highly unlikely that concentrations will reach significant levels for extended periods of time.

The final risk to CO_2 leakage to humans is during the drilling and topside work on dedicated vessels. This is similar to current risk for oil and gas activities, except CO_2 is not flammable, but may cause asphyxiation. Suitable contingency plans to handle possible blowouts of CO_2 must be emplaced for storage operations.

3. Risk assessment

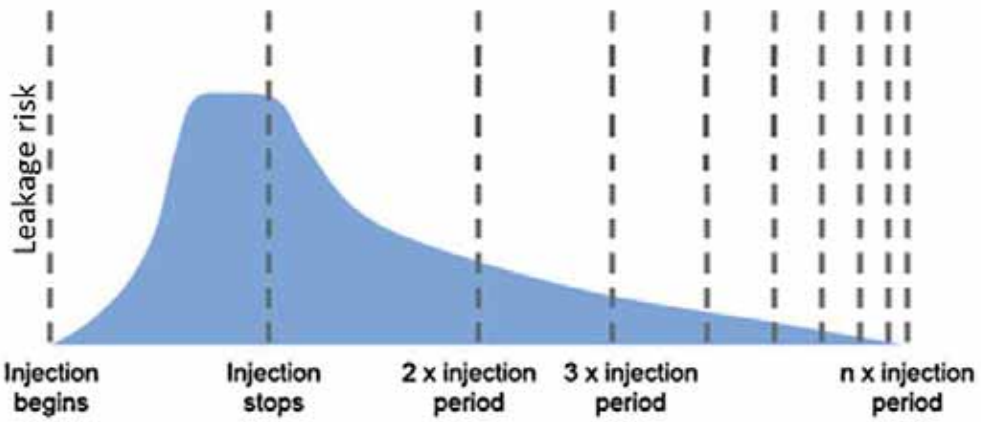
3.1. Major risk areas

This chapter will outline the major risk events and their consequences. Risk is defined as the product of probability multiplied by consequence. 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 unforeseen migration through porous formations or faults (Rubin & De Coninck, 2005). This risk is relevant from the start of injection, builds throughout injection, and may remain beyond closure. Leakage to the oceans and atmosphere can affect the local environment, whereas subsurface leakage outside the storage complex but which does not reach the atmosphere or oceans, can affect the project economics. This report concentrates on containment or leakage risk.
- **The site performance risk** [does it meet expectations?] is linked to successful development and operation of the storage project during appraisal and injection stages, particularly in respect of capacity, injectivity and induced microseismicity. Mitigation of this risk will primarily be additional data acquisition in the appraisal stage and proper monitoring for performance throughout the injection stage. Site performance risk does not influence containment risk and CO_2 leakage; poor site performance will most likely be addressed using current oil and gas production techniques to improve reservoir conditions. Consequences can be modifications to wells and facilities, new wells or in the worst-case, cancellation 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 ocean develops during injection and after closure for migration assisted storage (injection into an open saline formation).

Figure 3. Theoretical development of leakage risk during and after CO_2 injection (DECC, 2012)



3.2. Containment risk

It is essential to any storage location that the caprock (or multiple layers of rock that make up the caprock system) provides complete closure and seal of the storage reservoir and that faults, if present, are not flow pathways A good-quality caprock is more than adequate to isolate CO_2 in the subsurface. Caprock integrity needs to be studied carefully in the appraisal phase using similar technologies than for oil and gas exploration, albeit for different reasons. In the absence of a direct evidence for sealing (like the presence of an oil or gas field) there will always be some residual risk that some migration paths might exist through a caprock. This risk will reduce as monitoring of the CO_2 injection takes place.

Typical caprocks such as shales can theoretically be damaged by pressure increases above their fracture pressure. The likelihood of fracturing the caprock as a result of CO_2 injection depends on the regional stress regime, the magnitude of differential stress, formation pore pressures and the presence of pre-existing brittle fracture features. As long as the pressure does not approach the fracture pressure, the risk is not regarded as significant. The thicker the caprock the less impact such fracturing will have on leakage risk. The potential of reactivation of existing faults is considered as a more significant caprock containment failure risk than the creation of new fractures. Methods for estimating stress and fracturing, as well as the permeability of fractures have been developed. A store where the operational parameters (injection pressures) are kept within the pressure containment capability of the caprock would not be expected to fail. This is similar to operating a pipeline within its design parameters. This risk can therefore be managed in the same way as in normal life.[2]. Pressure management by extracting formation waters (water production) during CO_2 injection can help to control pressure build-up, and in well understood storage sites, even steer the CO_2 plume away from potential risks, such as abandoned wells.

[2] 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.

Produced formation waters can then be treated to remove heavy metals and disposed into the ocean, as is the current practice in many water-producing oil and gas fields.

In most North Sea cases there will be other aquifer formations overlying the caprock, which could accommodate potential leaked CO_2 volumes. These overlying aquifers are included in the EU CO_2 Storage Directive definition of a storage complex together with the individual caprocks above them. It is very unlikely that large volumes of CO_2 will find a highly permeable pathway all the way from the storage reservoir at storage depths of 1000-3000m to the sea floor. Small volumes of CO_2 seeping out at the sea floor will not have a 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 (Jones et al. 2015). Flow in a pathway through the subsurface is difficult or impossible to mitigate. Pressure release from the formation through production of formation water 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 delay or prevent the development of a new local storage site.

Most containment risk can be mitigated for storage in depleted gas fields by keeping the final storage pressure below the pressure of the surrounding rock, i.e. below the original reservoir pressure before gas production.

Seismicity refers to the occurrence or frequency of earthquakes. Seismicity is caused by movement on faults and fractures. The North Sea is exhibits natural seismicity but at a low level when compared to areas of the world on active plate tectonic boundaries like in the Mediterranean. The industry divides seismicity into natural, induced and triggered. Induced seismicity occurs as a result of human activity, be it groundwater extraction, mining, building dams, removing oil and gas, or injecting fluids (including water or CO_2). The energy comes from the activity itself and generally leads to low energy seismicity or microsesimicity. Triggered seismicity has been observed in water disposal operations, this takes place when the human activity “gives nature a push” and triggers natural seismicity. These events can be larger because they have access to the energy caused by natural processes. The process of seismicity involves the formation of a fracture or movement of rocks on each side of a fault. Therefore it is conceivable that there could be fluid flow along the fracture or fault. Studies shows that for induced seismicity it should not be possible to breach the containment system, and this has been backed up by the experience in current storage sites. Significant fracturing and leakage created by induced seismicity has not been observed in ongoing CO_2 storage projects. Part of permitting a storage site in the EU is an assessment of the risk of triggered seismicity and it is unlikely that a site with a high risk of triggered seismicity would be permitted.

Sites have also been observed to be secure under exposure to natural seismicity. In Japan storage sites have been exposed to large natural earthquakes and have not leaked. This makes intuitive sense as oil and gas fields exist in areas of natural seismicity, like California, Italy, Japan, New Zealand and Indonesia to name but a few.

Wells are deliberately designed to transport fluids and gasses across geological seals. Detailed analysis, such as that done for the former Peterhead CCS project, show that wells are the elements of a storage site considered to have the largest potential leakage risk. Wells can be divided into different categories depending on the stage in their lifecycle and their design parameters; during drilling and completion; during injection or production; after plugging and abandonment. Wells can be drilled for oil and gas activities or by other users of the subsurface. They can have modern construction techniques or be over one hundred years old.

A key part of any CO_2 storage appraisal and subsequent permitting activity is to identify all wells in the area that will be impacted by the development and to assess their integrity. Any site that has a risk of the CO_2 connecting with a well of unknown status or one assessed to have a high risk of leakage (i.e. one which does not have effective subsurface isolation plugs) will not be permitted unless the wells are repaired (further information can be found in Tucker, 2018).

If flow does occur, the flow through wells can take place with limited volumes and rates through restricted leak routes (outside casing, poor cement etc). During the development phase (when a drilling rig is on site) it is possible for a full bore well flow to take place. This is often termed a blowout. When this occurs the full bore is open to flow and the operator then has to cap it or drill a relief well to stop the flow.

The risk of blowouts 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 water filled or depleted reservoirs. Blowout during regular injection in wells with modern completion is also unlikely. The highest blowout 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 no such events for CO_2 storage injection are yet known. For a theoretical CO_2 storage site with purpose drilled CO_2 injection and observation wells, the higher probability Leakage scenarios will result in limited leakage rates 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 the leakage potential of abandoned wells penetrating the storage site. When the abandoned wells were plugged, the possibility of future CO_2 injection in their neighbourhood was usually not taken into consideration, therefore some of them may not seal off the storage reservoir against CO_2 entering the well or flowing via the well into other permeable formations. It is usually not feasible, or is very costly to re-enter and repair these abandoned wells. If there are uncertainties about the condition of an abandoned well the best course of action is to select storage sites away from it. Most depleted hydrocarbon fields have a number of such abandoned wells, which require particular attention and care. Applicable to all abandoned 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 around abandoned wells, and the time horizon is unknown.

Minor leakages related to wells in operation can normally be repaired. In many cases a drilling rig will be required, which makes mitigation relatively costly. Although extremely unlikely, a full blowout is a very serious matter. In the worst case a relief well must be drilled, which can take a few months with a drilling rig, releasing a significant volume of CO_2 for which equivalent ETS allowances must be purchased. Ironically, though a full well blowout is spectacular, the fact that it only takes a few months to repair, means that it will release a limited quantity of CO_2. The withdrawn Shell Peterhead/Goldeneye project in 2015 assessed this to be less than half a million tonnes for their scenario. A minor leakage related to an abandoned well, which typically cannot be repaired by re-entering the well, 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. This should be considered in the case of an open storage unit with no trap (e.g. Quest project), or where the targeted closure (or trap) is incomplete. For storage reservoirs where the seal 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 repeat seismic reflection surveying.

Migration of the CO_2 plume out of the bounds of the storage complex increases the possibility of encountering fluid pathways to the surface via faults, abandoned wells or hydraulic connection with other reservoirs. These boundaries will be characterised during the site appraisal, and a combination of comprehensive flow modelling and monitoring will lower the risk of undesirable migration significantly.

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 barriers and valves, such leakages can be limited and stopped on relatively 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 CO_2 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, particularly with CO_2 dissolved in formation waters, regardless of how extensive the monitoring program is. However, there has been significant technological progress monitoring CO_2 plume migration over the last 20 years, exemplified by research at the Sleipner storage facility in the North Sea (See Section 5.2). 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.

3.3. Performance risk

The performance risk relates to the storage site performing to the predicted levels, this is dependent on the presence and quality of storage rock, seal and trap and is separate to CO_2

containment risk. This risk/uncertainty can be considerably reduced through data acquisition and analysis during exploration and appraisal prior to injection. Additional wells, seismic surveys 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 (including potentially developing a second store) and reduced injection. Performance risk must be regarded primarily as an operator or owner's risk. In light of the unlikelihood of performance issues, the consequences will 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 by poor reservoir quality, higher than expected formation pressures, or by an ineffective well completion. There are many examples where well completions have been modified and considerably improved after the start of injection (Hansen et al., 2005), for example wells have been cleaned, deepened, acidized, fractured and gravelled for sand protection. 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.

The forecast storage resource is the best engineering estimate based on limited knowledge of the subsurface. The knowledge is limited because we have to extrapolate from a few boreholes and from geophysical remote sensing.

Once injection starts, or additional borehole or geophysical data become available, the forecast of capacity will always alter.

Experience from the oil and gas industry shows that volumetric forecasts can go up or down. If the storage formation is smaller or less connected than expected, or the underground structure turns out to have a different shape than that interpreted the forecast can go down. If the opposite occurs it can go up. Operators manage this risk by using ranges, defining the most probable case (P50), low probability case (P10) and high probability case (P90).

Where there is timely recognition of the a performance issue, appropriate actions can be taken, such as reducing injection rates or plume steering by producing formation waters. 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 CO_2 storage developments utilising depleted oil and gas fields than for a saline aquifer store. 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 performance risk than more virgin areas because they also might be partly pressure depleted and profit from overlapping data coverage

and mapping with the nearby oil and gas fields. 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 that 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 obligations 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 (Wilday et al 2009; Harper, 2011;)
- The drilling targets are water filled or have lower pressures;
- The injection facilities are much simpler than petroleum production facilities.

4. Studies on magnitude of CO_2 storage risk

Several publications give recommendations in respect of risk assessment (Rajesh et al., 2005; DOE/NETL, 2017). Quantitative approaches are challenging due to the very wide ranges of 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: CO_2 Storage Liabilities in the North Sea (DECC, 2012)**
- **Gassnova's leakage risk studies (Scandpower/NGI, 2012)**

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 ocean and atmosphere system. The basis for both studies is statistics and data dossiers including extensive North Sea petroleum activity.

DECC and Gassnova data provide representative assessments (rate and frequency) which are used in this report. The scale of the risk is representative but actual risk for any project will vary depending on site (existing wells and geology), storage concept (water 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 (2012) 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).

The numbers are based upon earlier work performed by SINTEF on North Sea statistics (Randhol & Carlsen, 2008). 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.

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.

Table 1. Leakage parameters for two leakage scenarios with five active wells (DECC, 2012). Probability quoted for leak event occurrence is over 20 year injection period.

Scenario	Low level leakage	Uncontrolled blowout
Probability of leakage event (%)	0,01-0,1	0,001-0,01
Flow rate tons/day	0,1- 10	5000
Duration	0,5-20 years	3-6 months
Dynamic control	Well shut in/reduced	Injection halted
Potential leakage Amount	18-73000 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

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 abandoned 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 abandoned 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 6 abandoned wells in a 200Mt storage case with probability of leakage over 100 years.

Table 2. Leakage parameters for two leakage scenarios in 6 abandoned wells (DECC, 2012). Probability quoted for leak event occurrence is over a period of 100 years.

Scenario	Low level leakage	Complete breakdown of plugging system
Probability of leakage (%)	0,12-0,5	0,0001-0,01
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	90-180000 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	

The paper by LeGuan et al., (2009) 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 permittable 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 seal is present and continuous across the storage site, and is not absent locally.

Faults and fractures are considered to be the main potential geological conduits for the movement of CO_2 beyond the boundaries of the storage site through the seal. Leakage of CO_2 may occur by migration along pre existing pathways in the form of a fault, fault zone or fracture system, by reactivation of a pre 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 more prevalent in older and deeper formations in the North Sea, but it is unusual for them to extend all the way from the depths of a potential CO_2 storage through overlying seal to the seafloor. This is important as the lack of a direct route substantially reduces the risk of fault leakage. The presence of faults 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 and across faults is not a new problem when trying to understand the hydrodynamics of the subsurface; however, modelling results often are associated with high degrees of uncertainty.

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/m^2 (Busch, 2010). 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.

The fault reactivation will mostly be initiated by externally induced seismic events. The probability of such events is very low in the North Sea. Fault reactivation does not mean that a fault becomes a flow path, for flow to occur the fault has to remain both open and not clogged by sealing rock types. The shale gas industry knows this well and has to “prop open” fractures with sand of engineered proppant materials otherwise the fractures close up again. Additionally, a potential CO_2 leakage cannot occur unless the CO_2 plume migrates to the open 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.

Table 3. Leakage parameters for 3 leakage scenarios in existing and activated faults (for a 200Mt storage site DECC, 2012). Probability quoted for leak event occurrence is over a 20 year injection period and 80 year post closure period.

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	

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 (<0,01%) for sites permittable under the CCS Directive. Risk is here defined as risked mass leaked (frequency x leak rate x leak duration) in million tonnes (Mt) of CO_2 leaked from the storage site.

The DECC report (DECC 2012) 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 (Scandpower/NGI, 2012; Scandpower, 2010). The results were presented at various conferences (Hansen, 2012; Christensen, 2013; Høydalsvik, 2014).

A large number of leakage scenarios with faults, fractures and seal failure were assessed. Potential leakage paths were generated in form of event trees and branch probabilities established based on expert judgement. An intact seal 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 sealing 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 160 million tonnes injected in total over a period of 50 years, 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. For severe leaks corrective measures are expected to be initiated soon, while the smaller seepages will continue until they cease naturally.

Four elements were investigated: two major faults, induced fractures and subseismic faults (faults unseen by the coarse resolution of a seismic survey). The theoretical leaked quantities were calculated for a considerable number of scenarios (branches of a risk tree) for each of the four elements, with each scenario having a probability of occurrence assigned to it. Only two selected scenarios for each of the four elements are shown in table 4 to illustrate the span. The leakage rates modelled were dynamic over the duration of the leakage period. This means the peak leakage rate is not constant over the duration of the leak, as the rate varied over time. Summation

of all risked leaked amounts for the scenarios for an element yielded the total theoretical amount leaked for the element (last column in Table 4), provided as a fraction of the total injected quantity. The summarised total risked leakage volumes of all scenarios and elements are 0,009% of the injected volume.

Table 4. Leakage parameters of a selection of leakage scenarios in various faults and induced fractures of a deep North Sea aquifer storage (Scandpower/NGI, 2012). Probability quoted for leak event occurrence is over the 50 years injection project lifetime and 500 years post closure period.

Elements/ events	Probability of leakage (%)	Peak leakage rate (tons/day)	Total leaked amount (Mt)	Theoretical amount leaked (% of injected CO2)	
				Per Scenario	Element/ Event Total
Major fault 1	0,0007	192	13,77 Mt	0,00006	0,00013
	0,000009	4041	90,5 Mt	0,000005	
Major fault 2	0,0007	767	55,08 Mt	0,00024	0,00037
	0,000009	3660	104,4 Mt	0,000006	
Induced fracture	0,00004	95,9	8,57 Mt	0,0000021	0,0000045
	0,0000000045	8191	120,5 Mt	0,0000000034	
Subseismic faults	0,0146	49	4,3 Mt	0,00039	0,0083
	0,00018	1632	24 Mt	0,000027	

The blowout potential and risk for active wells were estimated. The calculated release rate of a blowout from a natural CO_2 containing reservoir at the Sheep Mountain Field in 1982 was 10,378 tons per day (200 million standard cubic feet per day). It should be noted that Sheep Mountain is a natural CO_2 gas field, penetrated for extraction, rather than a CO_2 storage site where increased pressure by injection is controlled. This example indicates that a leakage rate of 9000 tons per day for a full flow blowout of CO_2 can be possible. Based on this and Scandpowers (Scandpower/NGI, 2012) data dossier for frequency and length of blowouts during drilling, gas injection and workover operations, Table 5 was established with two scenarios for 50 years of injection to illustrate the span. With these data the total expected leakage volume from active wells is calculated to be 0,00123% of injected volumes (Scandpower/NGI, 2012).

Table 5. Leakage probabilities and parameters for two scenarios of flow in active wells over a 50 year injection period (Scandpower/NGI, 2012).

Scenario	Probability (%)	Flow (tons/day)	Duration (days)	Lost amount (Mt)

Full well flow	0,225	8640	63	0,54
Restricted flow	0,55	2160	63	0,14

For abandoned 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 DECC (DECC 2012, Appendix A1) 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 0,01 - 0,001%. In a specific scenario where the abandoned 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 abandoned well with poor, 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 0,05%. 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. The term remediation cost in this report includes costs for remediation to occur and costs incurred by the release of CO_2 to the ocean-atmosphere system. 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 (table 6). The values in table 6 have been derived, using conservatism and best judgement. A more detailed explanation for the interpretation of these values is given in Appendix A.

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 are site-specific and influenced by storage site type (as discussed in chapter 2). 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 abandoned 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 connected ocean-atmosphere system during the specified event.

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. CO_2 cost is to be paid for ETS allowances.

No.	Scenario	Probability of leakage (%)	Peak Leakage Rate (t/d)	Duration (in years)	Total Mass Lost (tons)	Risked lost mass (tons)	Consequence
1	Minor leakage; fault & fracture	0.2	100	50 years	1,825,000	3,800	CO2-cost + monitoring
2	Moderate leak: fault & fracture	0.05	700	12 years	3,066,000	1,550	Relief well + monitoring
3	Severe leakage; fault & fracture	0.005	5000	4 years	7,300,000	365	New site+ depressurise
4	Active well leakage	0.5	50	250 days	12,500	62.5	Well workover
5	Active well blowout	0.15	5000	250 days	1,250,000	1,875	Relief well
6	Abandoned well blowout	0.1	3000	1 years	1,095,000	1,100	Relief well
7	Seepage in abandoned well	0.5	7	100 years	255,500	1,250	CO2-cost, + monitoring
8	Severe well problem, no repair successful	0.005	6000	2 years	4,380,000	215	Depressurise & new site
9	Leak from installation	0.25	100	5 days	500	1.25	Shut-in and repair
10	Undesired plume spread	0.03	0	N/A	N/A	N/A	Water production
Summarised						10,219	

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 0,0007% and 0,01%; 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 noted 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 an abandoned 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 0,03% 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 utilised statistical data from petroleum activities. A recent study indicates, however, that some studies estimate for pipeline failure risk was too high (Duncan & Wang, 2014).

The summarised risked leakage amount for all scenarios in table 6 equals approximately 10, 200 tons CO_2 or just more than 0,01% of the injected volume.. Thus, including the conservative treatment of leakage risk, we can presume 99,99 % of injected CO_2 is expected to remain in the subsurface for at least 500 years including the injection and post closure periods.

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 database, gives somewhat higher numbers for leakages (Alcalde et al., 2018). 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% that leakage remains below 0.0008% per year. It is important to note that the two studies, which served as basis for this report, used selected well-suited sites for their analyses, for CO_2 storage sites in the future in Europe, only well-suited sites will be selected as to comply with the CCS Storage Directive (or future equivalent).

There are studies giving recommendations for detailed cost estimation for storage related issues (IEAGHG, 2017). 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.

Table 7. Cost assumptions used for risk calculations.

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

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 drilling rig could be used and the cost reduction would be 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 more every time we monitor.

Table 8. Remediation cost for the leakage scenarios or potential events defined in table 6. Probability quoted for leak event occurrence is over the project life time including post closure period. Note many scenarios cannot simultaneously occur.

No.	Scenario	Corrective invest (€M)	CO_2 quota cost (€M)	Operation cost (€M)	Total Remediation cost (€M)	Probability (%)	Risked cost (€)
1	Minor leakage; fault & fracture	0	57	40 (8 seismic surveys)	97	0,2	194000

2	Moderate leak: fault & fracture	50	93	25+10	178	0,05	89000
3	Severe leakage; fault & fracture	320	219	50	589	0,005	29450
4	Well leakage	10	0,4	0	10,4	0,5	52000
5	Blowout	50	38	5	93	0,15	139500
6	Abandoned well blowout	50	33	5	88	0,1	88000
7	Seepage in abandoned well	0	7	25 (5 seism. surveys)	34	0,5	170000
8	Severe well problem	320	129	75	524	0,005	26200
9	Leak from installation	15	0	0	15	0,25	37500
10	Undesired plume spread	50	0	50+10 (2 seis. surveys)	110	0,03	15000
	Summarized	865	576	295	1838	0,51	840650

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 abandoned 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 below.

Figure 4. Remediation costs and risked costs for the scenarios defined in table 6.

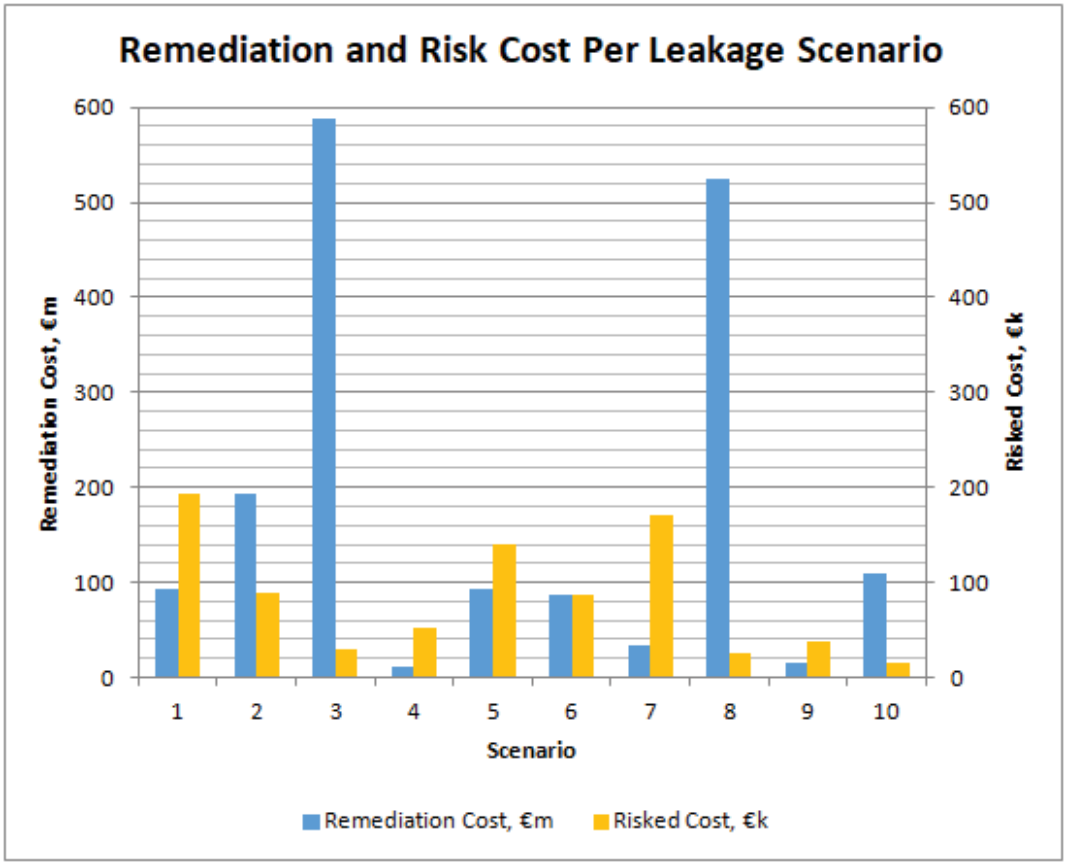
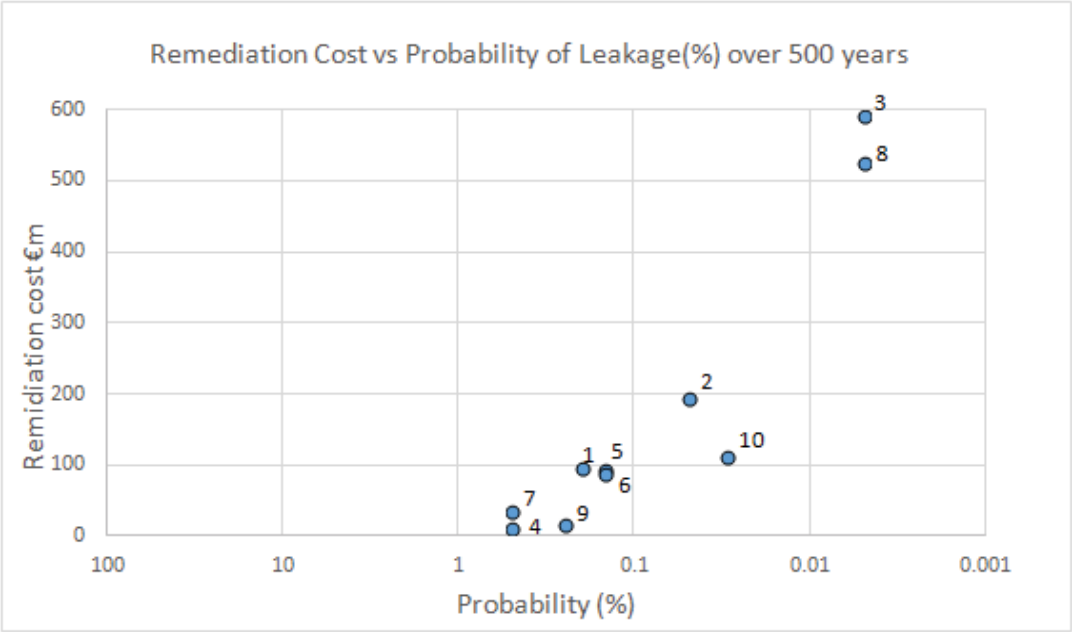


Figure 5. Remediation costs for the events numbered in table 6, related to their probability of leakage in a storage site over 500 years (including the injection and post-injection phases).

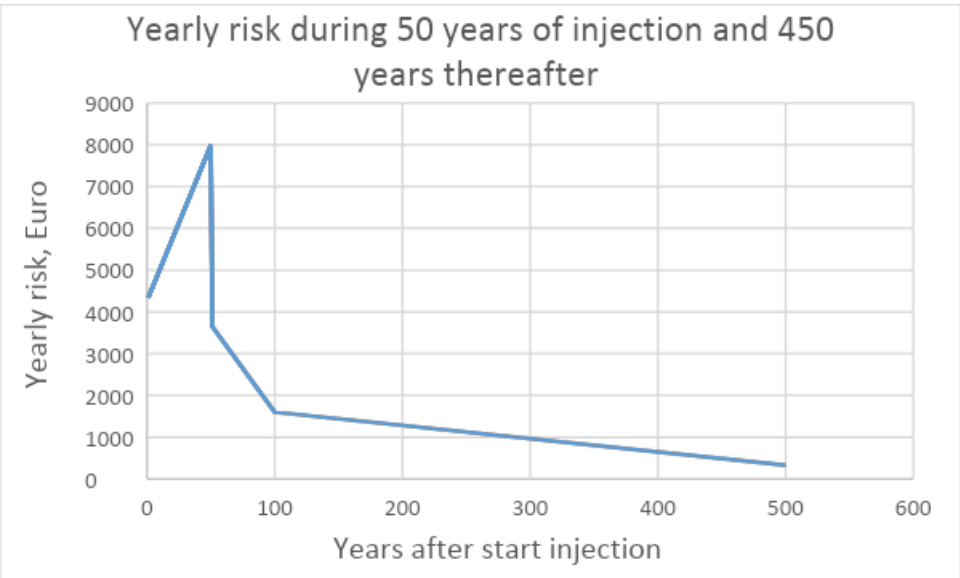


Our analysis shows that the total risk for the entire assessed storage project, taking event probabilities into account, amounts to €0,85 million. This is to be regarded as the class risk for a well planned and developed North Sea storage project. This amount is dramatically less than the theoretical worst-case remediation cost for a single case, which is in the order of €589 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 are 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 (Rubin & De Coninck, 2005; DECC 2012). 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 for 50 years of injection and 450 years post-closure.



The important message from 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 € 840,650.

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 which may operate 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 pressure). 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 blowout is not to be expected. An important element is also potential abandoned wells.

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, the following leakage scenarios in the general assessment (table 8) are disregarded here:

- Severe leakage through faults and fractures
- Blowout in abandoned well
- Severe well problems

The probabilities of the remaining well related events were reduced by 1/3 because of low storage pressure and a detailed insight in the behaviour of the storage reservoir that is the result of the period of hydrocarbon production. In this case a storage capacity of 20 million tons is assumed, which is 20% of the capacity of the first assessment. The injection period lasts for 10 years.

Table 9. Remediation cost for the leakage scenarios or potential events applicable for a depleted field. Probability quoted for leak event occurrence is over the project life time including post closure period.

Scenario	Corrective invest (€m)	CO_2 quota cost (€m)	Operation cost (€m)	Total (€m)	Probability (%)	Risked cost (€)
Minor leakage; fault & fracture	monitoring	11	10 (seism. surveys)	21	0,2	42000
Moderate leak: fault & fracture	50 (relief well or new site)	19	5+2	76	0,05	3800

Well leakage	5 (repair)	0,1	0	5,1	0.5	25500
Well blowout	20 (well sidetrack)	7,6	5	33	0,05	16500
Seepage in abandoned well	monitoring	1,4	5 (seism. surveys)	6,4	0,2	12800
Leak from installation	3 (repair)	0	0	3	0,25	7500
Undesired plume spread	10 (compensation)	0	10+2 (seis. surveys)	22	0,03	6600
Summarized		39		166		148900

Table 9 shows that if everything goes wrong in this depleted field scenario at the simultaneously, (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. A case study from a natural gas storage facility leak has been included as a worst case analogy for a potential CO2 storage site.

The chapter can be summarised as follows:

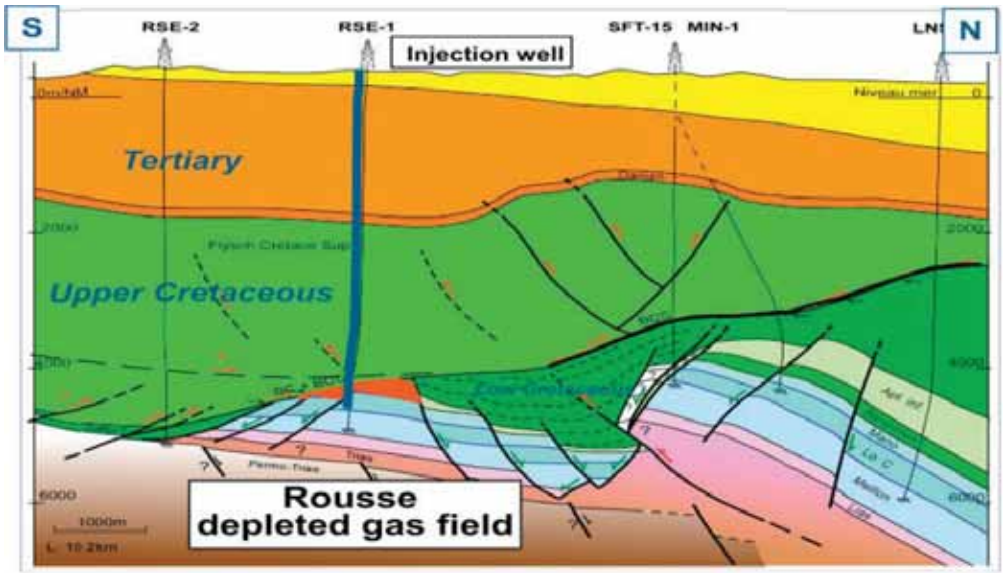
- No geological leakage to the surface has been detected so far;
- No blowout in modern CO_2 storage wells is known: one leakage in an exploration well without required safety equipment and old completion (1953, USA) has been observed;
- Few projects experienced restricted injectivity, which could be 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 reductions 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 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-Rousse Gas Field in the Aquitane Basin, approximately 800 kilometers SW of Paris. The depleted deep gas reservoir (unprecedented in Europe) was chosen as storage site, located onshore five kilometers south of the town 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 (Biteau et al 2006). 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 overlapping the Rousse horst constitutes the reservoir seal. Three main Upper Cretaceous seal units and associated lithological types have been identified (Monne & Prinnet, 2013).

Figure 7. Schematic of the Lacq storage site in Rousse depleted gas field (Monnet & Prinnet, 2013).



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 preservation of a hydrocarbon accumulation for millions of years. The knowledge acquired during many years of operation in the Rousse field, complimented 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 highly unlikely 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 (GCCSI, 2015). 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 formation waters of the sandy Utsira Formation nearby. At the end of 2017, a total of 17.2 million tonnes 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 (Miljødirektoratet, 2016). 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 0,01% during the injection period and 0,1% 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 abandoned 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 (Furre et al 2017, Liebscher & Münch, 2016) 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 predicted and 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 (Hansen et al., 2005). 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 of 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 (Hansen et al,, 2013).

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 saline formation water-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.

CO_2 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 seal 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 (Vandeweijer et al., 2011). 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 favourable 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_2 related 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.

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 of 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 (Bergmann et al., 2016). 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 (Arts et al., 2011). This system has been used to continuously record passive seismic data (Paap & Steeghs, 2016).

The entire operation of geological storage of CO_2 at the Ketzin site was conducted safely and reliably (Martens et al., 2015; Liebscher &Münch, 2016). 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 (Ringrose et al., 2011). Injection commenced over a 7 year period from 2004 to 2011 subsequently storing over 3.8Mt of CO_2 in a 20m thick aquifer in the subsurface (Matheison et al, 2010; Zeboudj, 2017). 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 1900m deep Carboniferous sandstone unit at the Krechba field. Three horizontal injection wells are used to inject the CO_2 into the down-dip aquifer leg of the gas reservoir.. 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 300m thick lower caprock, they are unlikely to propagate further through the 600m thick upper caprock. No leakage has been observed and all indications are that the CO_2 remains safely contained within the storage complex,. In June 2007 some tracers were detected at the wellhead of an appraisal well (KB-5), furthermore, raised CO_2 concentrations were also monitored around KB-5, this well is now fully plugged and abandoned (Ringrose et al, 2009; Ringrose et al, 2013). 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. Abandoned well 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 abandoned of the In Salah project will be the pioneering deployment and interpretation of a unique set of MMV technologies.

5.7. Aliso Canyon: analogue of a well blowout in a storage site

Aliso Canyon is a natural gas store in California, which utilises a depleted oilfield including the conversion of some of the abandoned oil wells into gas injectors / producers. From October 2015 to February 2016 blowout of converted injection well caused a severe leakage of stored natural gas in one of the largest greenhouse gas releases in the US (0.13 GSm3 reported: Lindeberg et al. 2017). This case study is often cited as an analogy for a worst case scenario for a well blowout in a CO_2 storage site. It must be emphasised that the production well was drilled in 1953, and converted in the 1970s to a lower standard compared to wells in the North Sea, and a CO_2 storage site today would not be permitted to store in a similar location in Europe. Nonetheless, the leakage as a result of gas injection and the associated remediation process are transferable to a CO_2 leakage scenario.

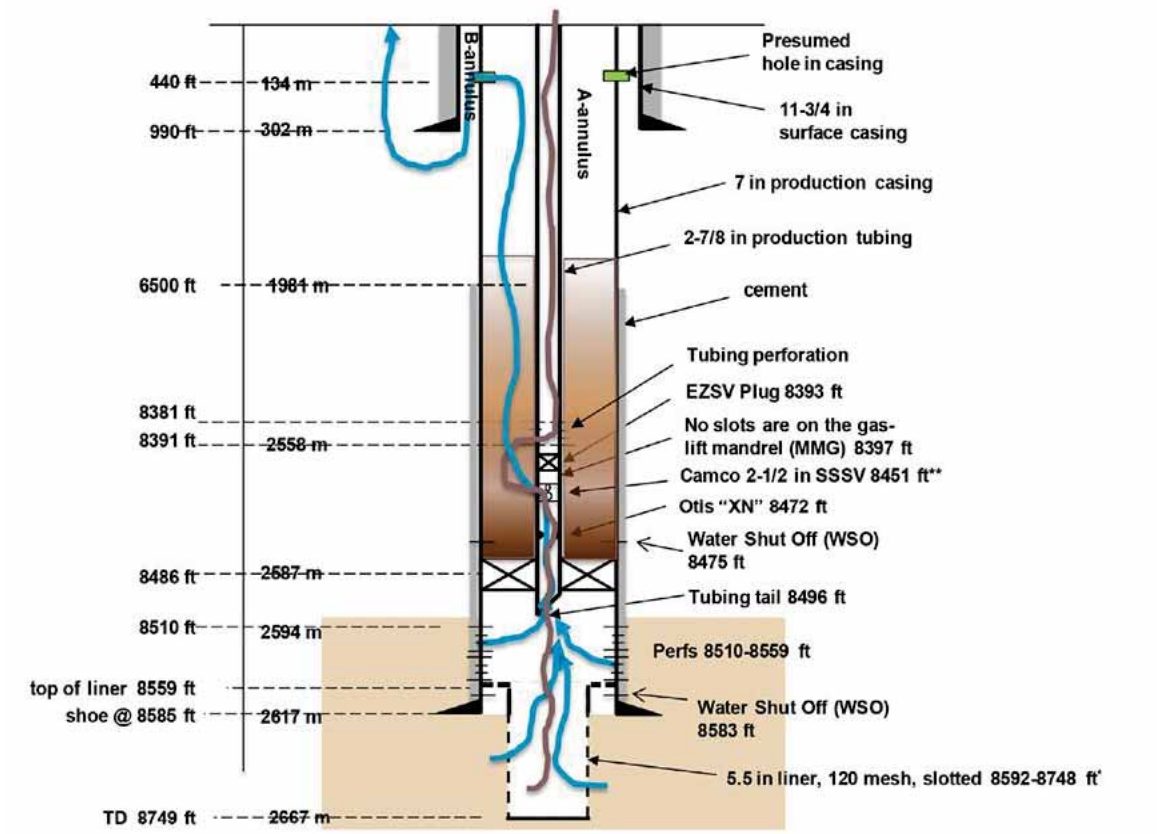
As a result of the leak, the released gas had been odorised using Mercaptons, as is common for residential gas supplies, and this bad smell led to the displacement of many local residents from their homes. The gas leak was widely publicised in the global press, and has triggered a new focus on the safety and regulation of gas storage activities in the US (PIPES act 2016 to require the establishment of minimum safety standards).

It has been modelled that if a similar leakage was to occur in a CO_2 storage site, the total volumes are rate of leakage would be lower with CO_2 gas compared to natural gas. This is due to the differing physical properties of the gases. In total 2.8% of the stored natural gas was lost during the Aliso Canyon leak, the equivalent loss from a CO_2 storage site would have been at most 0.37% of the stored volume (Lindeberg et al., 2017).

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 8. 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 abandoned 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 abandoned 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.

It must be pointed out that the EU storage regulations would not have permitted injection well configurations like those used in Aliso Canyon.

5.8. Quest by Shell

The Quest carbon capture and storage (CCS) facility is operated by Shell on behalf of the Athabasca Oil Sands Project, 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 3Mt of CO_2, and achieved this milestone ahead of schedule (Alberta Department of Energy, 2016). Carbon dioxide generated at the Scotford upgrader hydrogen manufacturing units has been captured and stored subsurface since 23rd of 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 1Mt per year. The project injected up to 1.2 million tons over a one-year period, which is the most stored in one calendar year by a CCS project to date.

Figure 9. On the left: Map indicating locations of the Scotford upgrader (CO2 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 vertical seismic profile (VSP) monitoring has been

able to visualise the developing CO_2 plume subsurface, which has not been detected beyond the expected area.

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.

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 (Alberta Department of Energy, 2016). Operational challenges have been minor; for example, corrosion of a wastewater pipe caused by the acidity of the Quest wastewater, and minor facility leaks, none of which were of significant.

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 at lower power, 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 both foreseen and unforeseen events, the latter related to leakages of CO_2, and for extra monitoring, remediation etc.

Guidance Document 4 for the CO_2 Storage Directive gives strict interpretation of the Directive in respect of Financial Security. One aspect 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 by each competent authority 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. 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 parent 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 100% probability events such as decommissioning and monitoring as well as low-probability events assuming that they will occur. This results in large security amounts of more than € 60 million over the initial 5 year period as set out in the permits. The class risk for a

similar, however twice as large storage site, estimated in Chapter 5.4 is € 150.000 for the low probability events. The entire un-risked remediation costs for all potential events of this larger site amounts to €150 million disregarding abandoned wells.

With a total capital investment for the storage part of the original ROAD project (P18-4) of around €30 million, the Financial Security of more than €60 million () imposes a heavy burden on the business case of the storage project. All of the low probability elements are extremely unlikely to occur and many cannot physically happen simultaneously.

The P18-4 field is almost fully pressure depleted and structurally isolated and sealed (Ministerie van Economische Zaken, 2013 Article 16.2). 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 abandoned 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, after which monitoring options are extremely limited since the CO_2 is permanently stored.

Under the permit there is a requirement to review the Financial Security at intervals, July 2018 being the first opportunity. 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 follows in chapter 7.

7. Discussion

7.1. Leakage risk

As demonstrated in Chapter 4, the risk of leakage from a European CCS project in the North Sea Basin to the ocean or atmosphere is extremely low, and its potential consequences limited. For a representative, hypothetical case evaluated in this report (160 Mt CO_2 injected in total over a period of 20 years, 1 injection well, 1 abandoned well) it can be expected that 99,99 % of injected volumes will remain securely underground for at least 500 years. The class risk of leakage from a well-planned and well developed European storage projects is hereby defined as 0,01% 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 leakage

rates and very limited total leakage amounts. A severe leak from an offshore storage site is expected in only one of 10,000 projects. The financial consequences could be significant to very high, but impact to people and the environment will be minimal 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 abandoned wells (old, plugged wells), because their condition is often uncertain. Such wells should be given particular attention. Leakage via a fault, even given reactivation through increasing injection pressure, carries a lower assessed risk. Caprocks are normally ductile, and this property could prevent even a reactivated fault from providing a leakage pathway to the surface.

The yearly risk related to containment in financial terms is less than €10,000 (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 €0,840 million for one project (Table 8). Because of the low probabilities this is far lower than the remediation cost for most single events, 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 costs of developing and operating the storage site are substantially higher, thus project and operational risks constitute a larger economic 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 saline aquifers and depleted oil and gas fields suitable for CO_2 storage particularly in the North Sea. A large quantity of relevant data is available for planning and assessing potential sites. Oil and 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 gas before sale. Some of these projects are described in Chapter 5. None of them have had leakages of the injected CO_2 volumes. Some have had injection interruptions because of problems with capture technology (at Rousse) or injectivity; however, these were solved using standard industrial technology. In the meantime the site owners had to pay for ETS credits or may be liable for 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. For projects deployed in advance of a comprehensive European framework to deliver a net zero society, the anticipated earning margins for storage site operators will necessarily be kept so low that they in many cases cannot alone carry the liability for extremely unlikely events.

7.2. Liability and Financial Security

As illustrated in chapter 6, European nations 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 thereby undermines any storage business case unnecessarily and obstructs the development of a sound CO_2 storage infrastructure.

No individual operator can afford to set aside working capital to cover all such unlikely eventualities 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 evolved insurance system, this liability will initially need to be shared between government and the private sector.

The EU CCS Directive was reviewed in 2014. The conclusion of this evaluation was that the overall need for CCS to decarbonise particularly industry in Europe remains genuine and urgent. Fewer CCS projects have been implemented than envisaged in 2009/10. There was general agreement that given the lack of practical experience in Europe it would not currently be appropriate, and could be counterproductive, to reopen the Directive for significant changes. However, this report highlights that some clarifications and softening of interpretation in Guidance Document 4 (GD4) could be valuable.

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 CCS project with practical experience of going through the integrated permitting process including storage is ROAD. In 2013 the project developers agreed workable solutions with the Dutch CA that both parties appeared to accept until the first routine review was due. 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 the European Commission.

The referred concerns relate to articles 19 and 20 of the EU CCS Directive and also GD4. 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. GD4 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 benefiting from a clear regulatory safety framework that, however, imposes a heavy legislative and financial burden on the operators. This leads to reluctance from the private sector to invest, in turn increasing the perceived risk, as the lack of large full-scale CCS projects is misconstrued to be based on its high cost and technical immaturity.

7.3. Storage types and their relative leakage risk

Several storage types are listed in chapter 2. The available data is not comprehensive or plentiful enough for a quantitative comparison between different storage types. The assessments in Chapter 4 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 of 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 hydraulic communication with any surrounding geological features to leak to as long as pressure is kept below initial pore pressure. If facilities and wells are still intact on the existing fields and can be reused, development and operation costs might also be substantially reduced.

For the various types of storage sites the following can be said:

- Depleted pressure sites will in general have a lower leakage risk than sites with initial pressure. Fracturing processes and reactivating of faults are pressure and stress 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 the far-reaching pressure footprint of oil and gas production.
- Many abandoned wells at a potential storage site may increase the leakage risk. Normally these wells are more numerous in abandoned oil and gas fields than at aquifer sites. However, abandoned oil and gas field wells have typically been more carefully plugged than dry abandoned exploration wells. The standards for plugging and abandoning of wells

have become more stringent over time, and relevant technology has evolved, which implies that older abandoned wells might bear a larger risk than newer ones.

- 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 abandoned oil or gas fields or aquifer sites) will in general have less risk of well blowout 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.
- The consequences of a CO_2 leakage from an abandoned oil or gas are potentially more severe than from a saline aquifer, this is due to the risk of carrying remnant hydrocarbons to the surface. However, as mentioned, these sites are often pressure depleted.
- In strongly depleted abandoned oil or gas fields, where pressure is reduced far below the surrounding formations, the migration of CO_2 or formation water out of the storage complex is highly unlikely. This reduces risk of impact on, or leakages into, nearby areas. These fields will have leakage-related 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 suitable 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 requires 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, re-use 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 technical specifications of a pipeline are considered key factors in assessing its suitability.

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.

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Appendix A: Decision making for values in Table 6

The scenarios in the two studies from DECC (2012) and Gassnova (Scandpower/NGI, 2012)) are not exact the same. Furthermore some of the scenarios are presented in different ways and in some cases the parameters are slightly different. The numbers which characterise the scenarios in table 6 could therefore not be derived from the figures in the basic studies just by averaging. The numbers in the table 6 had therefore to been derived by using best engineering judgement. Some conservatism has been applied as numbers have been rounded upwards.

The sets of parameters for the scenarios in table 6 are explained below. For each scenario the parameters from the basic studies and those used in table 6 is shown in a table and compared, (probabilities in these tables are in decimal fraction not percentages):

Scenario 1, Minor leakage through fault and fracture:

	Probability	**Leakage rate t/d**	**Duration**	**Lost amount, Mt**
DECC	very low (10^{-4})	1-50	100 years	Up to 1,8
Gassnova	10^{-6}-10^{-3}	50-200	50-200 years	4-14
Table 6 case	$2*10^{-3}$	100	50 years	1,9

The DECC study states that the probability for leakage through fault and fractures is very low (10^{-4}) in geological well-defined North Sea storage sites as we discuss here. The DECC study does not differentiate between low and high leakage rate in this respect. In table 6 is probability set higher for minor leakage than for moderate or high leakage as shown underneath. The choice of duration relates to injection period and total injected volume. Lost amount is calculated by use of the parameters of this case.

Scenario 2; Moderate leakage trough fault and fracture:

	Probability	Leakage rate t/d	Duration	Lost amount, Mt
DECC	very low (10^{-4})	50-250	1-5 years	Less than 0,46
Gassnova	10^{-6} -10^{-4}	800-1700	30-100 years	25
Table 6 case	$5*10^{-4}$	700	12 years	3,1

Same approach is used as above. The probability is set slightly higher than average in the studies to maintain conservatism. Rest of values are approximately set as average between results of the studies.

Scenario 3, Severe leakage trough fault and fracture:

	Probability	Leakage rate t/d	Duration	Lost amount, Mt
DECC	Very low (10^{-4})	1500	1-5 years	0,55-2,7
Gassnova	Typically 10^{-8}	4000	30 years	100

Table 6 case	$5*10^{-5}$	5000	4 years	7,3

Same approach is used as above. The probability was set lower than for moderate leakage above. The leakage rate is set relatively high as it is assumed here that the leakage rate is highest at the beginning and then decline over time. Mitigation measures are implemented early and have effect within shorter time than in the Gassnova scenario.

Scenario 4, Active well leakage:

	Probability	Leakage rate t/d	Duration	Lost amount, Mt
DECC	10^{-4} –10^{-3}	1-10	0.5-20 years	Max 0,7
Gassnova	$5,5*10^{-3}$	2200	60 days	0,14
Table 6 case	$5*10^{-3}$	50	250 days	0,012

The scenarios in the basic studies are quite different and reflect only to some degree the table 6 case. The table 6 case is defined as a moderate leak in a active well, which gets repaired through the well itself. It is applied some conservatism in the applied duration as such operations are often troublesome and getting the relevant tools can be time-consuming. Lost amount is calculated based on the parameters of the case.

Scenario 5, Active well blowout:

	Probability	Leakage rate t/d	Duration	Lost amount, Mt
DECC	10^{-5}-10^{-4}	5000	3-6 months	0,5-0,9
Gassnova	$2,2*10^{-3}$	8600	60 days	0,54
Table 6 case	$15*10^{-4}$	5000	250 days	1,25

This case covers an uncontrolled well blowout, which is mitigated by a relief well. Probability and leakage rate combined, reflects approximately the average between the two basic studies. The duration given in the basic studies is derived from the oil industry. The time for concluding a CO2 blow is set longer and more conservatively, as experience tells that it takes time to contract a rig, particularly if the market is tight. CO_2 would be regarded much less threatening to people, environment and economy than hydrocarbons. It can therefore not expect the same priority in the rig scheduling process.

Scenario 6, Legacy well blow out:

	Probability	Leakage rate t/d	Duration	Lost amount, Mt
DECC	10^{-7}– 10^{-4}	1000	3-6 months	Max 1,8
Gassnova	less 10^{-4}			0,54
Table 6 case	10^{-3}	3000	1 year	1,1

This scenario reflects an aquifer storage in a hydrocarbon explored region of the North Sea. These regions are covered with old exploration wells, of which many are poorly plugged in respect of the potential storage formations or where abandonment documentation is incomplete. The best would be to avoid such wells, however, with a broad CCS implementation this might not be fully possible. In this scenario the storage site has an old exploration well in its neighbourhood. As there is no experience with poorly plugged exploration wells in contact with a storage site, this scenario is assessed conservatively; both probability and leakage rate approximately 60% of an active well (scenario 5). The DECC scenario is regarded too optimistic in light of the lack of experience. A repair might not be possible and the storage might have to be depressurised by a relief well. A well repair, if possible, will take longer than for an active well as the well path and leakage area must be exactly located before repair.

Scenario 7, Seepage in legacy well:

	Probability	Leakage rate t/d	Duration	Lost amount, Mt
DECC	$1\text{-}5*10^{-3}$	0,6 - 6	1-100 years	Max 0,22
Gassnova				
Table 6 case	$5*10^{-3}$	7	100 years	0,25

This scenario reflects seepage in an old legacy well, it might be an exploration well or an abandoned production well in a depleted field. The parameters are taken from the DECC study. The conservative side of the band is thereby applied.

Scenario 8, Severe well problems:

	Probability	Leakage rate t/d	Duration	Lost amount, Mt
DECC	10^{-7}– 10^{-4}	1000	3-6 months	Max 1,8
Gassnova	$2,2*\ 10^{-3}$	8600	60 days	0,54
Table 6 case	$5*10^{-4}$	6000	2 years	4,3

This scenario represents a worst case situation; where the well can not be fully repaired and where the site site must be given up, depressurized and replaced by a new site. This scenario is very unlikely, however not unthinkable and included for the assessment to be complete. Probability and leakage rate combined, reflects approximately the average between the two basic studies. The duration given in the basic studies is derived from oil industry statistics. The time for bringing the CO2 blow to an end and producing back CO2 might realistically require more time than indicating by the both studies.

Scenario 9, Leak from installation:

	Probability	Leakage rate t/d	Duration	Lost amount, tons
Gassnova	0,0025	100	5 days	500

These numbers are based on operational statistics from the North Sea (Scandpower/NGI, 2012).

Scenario 10, Undesired plume spread;

The number is based on a specific site (Scandpower/NGI, 2012). This scenario is, however, entirely dependent on the geology of the specific site, general numbers cannot be given.

ZEP ERA-NET Joint Workshop
A Framework for CCS Risk Sharing and Business Model Selection
14th March 2019
Summary Outcomes

Internal Paper for Discussion Purposes Only

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W. Goldthorpe

Sustainable Decisions Limited

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1 INTRODUCTION

This internal ZEP Temporary Working Group (TWG) paper covers the workshop held at the offices of Weber Shandwick, Avenue de Cortenbergh, 1000, Brussels, Belgium on Thursday 14th March 2019. The workshop was held jointly by the ZEP TWG "Collaboration across the CCS Chain' and ERA-NET project ELEGANCY WP3 with participants from a range of public and private sector stakeholders.

The workshop was designed to discuss and debate a series of topics related to risk sharing, business models and business cases for CCS. The new work being prepared by ELEGANCY WP3 for the selection of business models and the methodology for business cases for H_2-CCS chains was included. This work is now published in the reports "*Interim report detailing the development of business models and commercial structures*" (Deliverable 3.3.3) and "*Interim report detailing the guidelines for the assessment and application of the business case templates in WP5*" (Deliverable 3.3.4), both available on the ELEGANCY website https://www.sintef.no/projectweb/elegancy/publications/. The ZEP temporary working group covered the continuation of its work looking into quantification of storage risks and collaboration across the CCS chain.

This paper presents briefly the workshop outcomes and includes the presentation material used by the ELEGANCY project and ZEP TWG leader. Its purpose is to provide a summary for further TWG discussion and to inform members of the TWG who were unable to attend the workshop.

2 WORKSHOP STRUCTURE

2.1 Structure and Content

The workshop was structured to:

1. Communicate to the participants in the morning sessions all the background information on:
    a. the status of the recent ELEGANCY work and especially:
        i. the methodology and principles being developed for the definition and selection of investable business models;
        ii. the methodology and tools being developed for the definition of business cases based around six main dimensions, and a number of existing assessment protocols;
        iii. the actual business model selection tool; and
    b. the work and outcomes to date of the ZEP temporary working group.
2. Facilitate expert discussion in the afternoon sessions on four main topics, namely:
    a. market development – discussing the critical role of policy in creating initial markets and how this can be realised through collaboration between the public and private sectors;
    b. the regulated asset base business model;
    c. the specific storage leakage liability investment barrier and the role and limitations of each of the actors (public sector, investors, insurance). This included summarising the outcome of the 2012 review from the insurance industry (ClimateWise report), sharing the experience from experts across various projects in Europe, and discussing potential ways forward; and
    d. the need for collaboration between the public and private sectors to make a joint investable business case in order to gain the unequivocal buy-in from both the public and investors.
3. Create opportunities to build connections between all participants.

The slide pack for all the presentations at the workshop, including the programme for the day and details of each of the sessions, is included in Appendix A.

2.2 Participation, Connections and Relationships

The workshop achieved a high level of participation with twenty-five external attendees (excluding the WP3 members) – 8 industry representatives, 6 public sector representatives and 8 representatives from research or advisory organisations and NGOs. The afternoon sessions provided lively debate and experience sharing on the main investment barriers, the need for collaboration between the public sector and private sector to remove these, and how to create joint investable propositions for both sectors.

3 WORKSHOP OUTCOMES

3.1 Market Development

Market failures are a major investment barrier at sector and system level given the scale of the CCS chains being considered. Determining which order sectors and markets should be developed to deliver long term public objectives, and allocating responsibility for their development, needs to be understood and agreed between public and private stakeholders as early as possible.

The key messages below were extracted from the discussion.

- **Incentives and Penalties**
  - There are many existing tools and mechanisms providing different ways of developing markets. The participants felt that overall there needs to be a balance between taxes/penalties and incentives (industrial, consumer behaviour) that addresses the needs of private investors for obtaining and securing the funding for such large infrastructure projects.
  - Existing incentives could be used, reframed, and extended to cover CCS (such as broadening the green electricity levy on consumers in Ireland to include power with CCS) but this approach needs careful planning to address the potential conflict of consumers paying to fund infrastructure which is also used for other purposes such as industrial CCS.

- **The critical importance of national and pan-European cooperation/coordination (and beyond)**
  - Market development of low carbon industrial products cannot be supported and achieved by a country on its own. For example, "green" low emissions cement or steel will only be viable if the markets in which they are used are first created and then supported until a global level playing field materialises.
  - Physical delivery: The synergies between various European projects and the optionality that any specific project offers to facilitate the creation of a European CCS network and H_2 industry should be valued and emphasised in business case assessments (with the associated economic, social and environmental benefits). This will facilitate the justification for complementary EU funding to support a project which improves the development of an EU wide H_2-CCS infrastructure industry (by improving optionality, reducing costs for other projects for example).

- **Market development & the business case**
  - *The concept of market enabler*: It is acknowledged that the shared use of CCS infrastructure by multiple sectors/markets increases the value (financial, economic, social, environmental) of making an initial investment and is the overall long-term justification for that investment. However, the initial investment is usually based on a limited scope with one sector acting as a market enabler for the other sectors. Future potential upside is always value-at-risk. The investment proposal and business case therefore need to present both a competitive base case (the initial investment) and demonstrate how the sources of future value can be realised by enabling the decarbonisation of other sectors through synergies. Decisions by companies and governments are made on the strategic rationale, total potential realisable value and associated optionality but need to be justifiable to the shareholders and public based on the value of a low regrets base case. This conundrum must be resolved collaboratively otherwise experience has shown neither private nor public parties can justify the first-of-a-kind (FOAK) projects.
  - *Sectoral priorities for market development*: the government has a vital responsibility to define and communicate their priorities for sectoral market development to help developers

understand how to structure their business case accordingly. For example, is CCS for power generation the immediate priority and will it be an enabler for decarbonised heating using hydrogen? Or is the immediate priority to build a hydrogen network with CCS which will enable in the future decarbonised power and then industrial CCS? Only early collaboration between government and interested developers can reconcile such choices.

Questions addressed by the participants:

Is government incentivisation instead of taxes/emissions penalties a feasible pathway in the next 5+ years?

- It is not a choice between incentives and penalties but rather a question of finding the right balance between them. This balance also needs to address the uncertainty of sourcing project funding and developing end-use markets.
- Using and reframing existing taxes
    - Discussion on the possibility to use an existing tax (for example the levy placed on consumers' electricity bills in Ireland to subsidise renewable energy) to subsidise power generation through CCS. The levy could potentially act as a bridge to an effective CO_2 carbon price.
    - Such a levy could support transport and storage (T&S) infrastructure and would probably make the incremental cost of additional investment in capture technology viable – and thus contribute to bringing the costs of incremental sector decarbonisation down.
    - However, there are potential issues of conflict if infrastructure is not only connected to power generation but also to industry and it is important to understand which part of a H_2-CCS system or industrial CCS system would be funded by different taxes/levies especially if those are direct imposts socialised through consumer bills.
    - There needs to be a transparent structuring of any levies consistent with a clear business case for a first CCS project, presenting how the project and the levy fit with public preferences and society's objectives.
- Regional/National level: experience shows that public acceptance of a direct levy is greater in local communities with a stake in CO_2 emitting activities such as power generation or industry where the public see direct impacts such as jobs or environmental benefits.

Is joint European national and regional collaboration, investment and coordination for a first project feasible in the next 5+ years?

- Physical Delivery: participants agreed that there is strong appetite for regional and European collaboration – both between project promoters and between project promoters and Member States. Examples: Norway collaborating with the UK, Norway collaborating with the Netherlands.
- Energy Intensive Industry: the European Commission is working with the High-Level Group of Energy Intensive Industries and the group will develop an industrial Master Plan for a climate neutral industry by 2050 which brings CCS/CCU/H_2 on the agenda. The purpose is to advise and assist the European Commission in developing new policies that can support the transition of industry to climate neutrality.
- Overall, it was felt that although different programmes exist, the momentum in addressing issues through collaboration as well as creating markets for new low carbon products is still lacking.

Is development of a low carbon "blue hydrogen" market a better route to CCS infrastructure than industrial decarbonisation or CCGT power generation with CCS?

- All the sectors have a role to play – not only one sector.
    - However, it is critical that governments define clear priorities at national level to guide the project developers and potential investors in defining and structuring business cases, i.e. in which order the various sectors should complete their transition to low carbon economic activity is dependent on government policy. This needs to be addressed early and in parallel with discussing the actual details of end use market development.
    - There should not be a co-dependency between one another. The key is to find a way of making T&S infrastructure an investible proposition and finding the right way to incentivise each of the sectors that can utilise it. Decisions should be project agnostic, based on the government priorities.

- **Example 1:** Ervia (Ireland) is building a business case which incorporates the additional sources of value from other markets facilitated by their project. The Ervia project is based on the decarbonisation of a power station using CCS. However, Ervia is including in their business case the value of their project acting as an enabler for hydrogen production (and industrial CCS) because of the synergies and the understanding that there is a threshold volume of CO_2 to make the economics of developing CCS infrastructure acceptable.

- **Example 2:** The H-vision project (The Netherlands) and the role of a central T&S organisation.
    - The H-vision project is a feasibility study involving sixteen parties, predominantly from the port of Rotterdam industrial area, collaborating to explore the large-scale production and application of blue hydrogen in the Rotterdam industrial area. The objective is to supply decarbonised energy to replace natural gas and coal using blue hydrogen for a large-scale power plant and a number of major refineries/chemical plants. Additional hydrogen users (industrials, gas customers, etc.) may be connected in later stages. The project is also studying how residual gases from the refining and chemical industry can be utilized to further enhance sustainability.
    - The project is based on a major central supply of hydrogen (linked to concentrated CO_2 capture in single locations) with the possibility of additional multiple smaller suppliers.
    - The project is relying on a second project - the Porthos project - to provide the transportation and storage infrastructure. Porthos is made up of three government owned organisations (Port of Rotterdam Authority, Gasunie and EBN) which together are planning the possibility of a T&S network taking into account all relevant sectors and the strategic priorities and cost effectiveness. Decisions about which party(ies) will construct or run this T&S network have not been taken yet.

- **Example 3:** The UK is looking at which economic sectors can unlock opportunities for industrial CCS (a strategic focus of the government) through complementary development and use of T&S infrastructure. For example, hydrogen used for residential/commercial heating in city conversions could be combined with mechanisms to incentivise industrial decarbonisation using CCS. The UK Secretary of State announced recently that the Government is considering the possibility of mandating an increase of lower emission "green gas" into the national grid, which would represent an important opportunity for hydrogen.

3.2 The Regulated Asset Base Model

The key messages below were extracted from the discussion.

Should the first project be integrated or split into separate emitter/capture plus T&S infrastructure?

- The group concluded that no one size fits all and the answer is very case specific, depending on many parameters as included in the ELEGANCY business model and business case framework.
- In the case of Ervia (as a regulated utility company), the question is about how much of the chain they would consider owning and operating. Modelling work and stakeholder engagement is currently being undertaking in order to answer this question.
- Many lessons have been learned from the projects that have been attempted across Europe in the last ten years. A common conclusion is that whatever split and/or business model is selected, there will need to be consistent government policies over an extended period of time until markets can deliver self-sustaining revenue streams.

Will public/society support the deployment of CO_2 infrastructure (i.e. perceived moral hazard of continued use of fossil fuels in power or heat and transport)? Should energy consumers/taxpayers take the financing, market, development, and operational risks?

- *Trust is the key to answering this question*
  Ervia provided the example that it is trusted by the public as a state-owned company which has been building and operating gas pipelines for more than fifty years. Ervia believes this trust would persist if it was to be the entity that transports CO_2 in Ireland.

- *The importance of education, communication and the narrative*
  Consumers' willingness to pay depends on education and communication (i.e. awareness of the costs of decarbonisation and the costs of meeting 2050 targets). CCS is a least cost and (in some cases) least disruptive option, but the full social and economic value of the investment needs to be better communicated. It is important to realise that CCS provides multiple services:
  - To the emitter - CCS takes care of emissions;
  - To the public - CCS contributes to mitigate climate change by allowing the decarbonisation of multiple sectors over the long term through a balanced 'just transition'. CCS does not only 'deal with waste from industry' but also deals with the side effects of the products that consumers are using. This is a wider social and sustainability dimension, which directly involves consumers. Therefore, it is critical to put the responsibility of consumers at the core of what CCS provides and to communicate a business case and a narrative that explains what CCS will deliver to the public consistent with their expectations.
- Community engagement should not only be limited to one country, or region within one country. For example, in the Netherlands the public benefits from a cement plant which is located right outside of the country (North of Liege). This plant provides 80% of cement to the Netherlands and hence its emissions are a direct consequence of consumption within the Netherlands.

Is delivery of a first split chain RAB business model politically and commercially feasible?

- *The issue of allocating costs to users*
  - The RAB model is based on the principle of providing a service to a body of consumers (market) who are willing to pay for that service. One of the main difficulties for CCUS is that no market exists to contribute to the initial remuneration of the developer/owner of the asset base.
  - The fact that CCUS will be a shared infrastructure servicing multiple end-use consumer markets leads to the problem of how to socialise the costs through the different markets. The consequence is a need for a mechanism and policies to reconcile how to split consumer contributions (and benefits) in different proportions and at different times. The UK has used that consumer contribution model successfully for the Thames Tideway (waste water crossing under the Thames) but the costs and benefits can be directly allocated to one set of customers.

- *Can the RAB model be used for a first project without having a state-owned utility in place?*
  - A levy that fills the gap to remunerate developers would depend on the trajectory of the EU ETS.
  - The workshop felt this model could only work for FOAK CCS infrastructure for electricity because it has a mature consumer market where the developer remuneration can originate.
  - One issue with RAB is that such a model is usually low risk/low return. This is the opposite of the business of oil and gas exploration and production companies, which has a high risk/high return profile. These companies are the only ones who have the capability to build and operate these projects. So private oil and gas companies are unlikely to be interested in such an investment proposition.
  - The difference between what the initial user(s) of the infrastructure can pay and the return on the investment expected by private sector investors - for an infrastructure built at a sufficient scale for further market growth – might be very large. Without mature end use markets this gap would need to be filled by government-backed revenue support mechanisms starting possibly even at the construction phase of a project. This pre-operational phase remuneration mechanism has been used in the previously mentioned UK Thames Tideway project.

- *Integration of pre-construction costs and risks*

  The development of storage takes significant time and cost. This needs to be accounted for early in the business case and model i.e. pre-FEED stage. Some of the storage related risks would need to be included in the remuneration model and supported by government before infrastructure is utilised or even before a final investment decision (FID) is made.

3.3 Geological Storage Leakage Liability and Limitations of Insurance

The key messages below were extracted from the discussion.

- *The Insurance Industry*
  - The participants were reminded of the 2012 ClimateWise Report which was issued by the insurance industry and summarised the options available and limitations to insurance products.
  - The insurance industry can only accept to cover defined events with capped liabilities. There are no off the shelf solutions for the storage liability. A new product (CARI – Carbon Allowance Reimbursement Insurance) was proposed for the operational phase with some limitations.
  - The CARI product concept could possibly be extended to the post-closure phase as an annually renewed policy.
  - Risks need to be shared between all the parties: the competent authorities, storage developers and insurance providers.
  - Questions arising from the ZEP temporary work group are: Can we provide the insurance industry with sufficiently robust quantification of risks? Do we need to get together with the insurance industry and look at quantification of risks and events?

- *Private Investors*
  - The options available to private sector investors are proven, well understood and widely used in oil and gas. The principles of "no unlimited liability" and "the level of private sector liability impacts the expected financial return" apply to the private sector.
  - Under European law, storage operators have the obligation to quantify worst case events/scenarios even if they cannot occur (CO_2 Geological Storage Directive Guidance Document 4) - This led to a requirement in the Dutch ROAD project storage permit to put aside an amount of money worth more than double the project's storage CAPEX – a requirement that is neither feasible nor sustainable.

- *What can be done to move forward?*
  - Continue engagement with insurance industry on developing further solutions for specific projects.
  - Engagement with public sector is required to raise awareness of the issue and understanding that European law is not prescriptive, with guidelines not being regulation, and that there is a need for government to take action to cap limited liabilities at an investable level. There is a need for both public and private sectors to work together to define the mechanisms that they can put in place to address this investment barrier.
  - Likely events and worst-case scenarios should be dealt with separately from one another and in different ways.
  - Class risks could be addressed through a mutual fund, which would involve the participation of countries who intend to use CCS. This will require cross-Europe government support for the initial projects when there is insufficient industry contribution to a funding pool. The Alberta Post-Closure Stewardship Fund is a working example of this solution.

3.4 Public/Private Sector Collaboration to make a Joint Business Case

The discussion highlighted that the following points need to be addressed in the definition of the Business Case:

- *The importance of taking account of the role of citizens in the decision to support CCS infrastructure investment*
    - The discussion highlighted the need to recognise that the public represents a collective which is different from the state.
    - Poor or inconsistent public acceptance of utilisation of CCUS technologies for decarbonisation has been identified as an investment barrier by the ZEP TWG.
    - In most countries, the moral hazard argument is a major barrier to be addressed to gain public support.
    - In parallel, there is a trade-off between frustration and optimisation: there is a frustration about the lack of action (including from the youngest in society), which leads to thinking that it is better to have an expensive solution rather than nothing at all.
- *The mismatch between political mandate and the long-term CCS investment timeline is a barrier*

  Investing in CCS is a long-term process which goes beyond the length of a political mandate. It is also harder to sell the value of FOAK projects because there is less visibility on the project lifetime. Therefore, the business case must demonstrate both the need for urgency (why now?) with reasonable short-term value, and the long-term optionality/incremental value (but with some guarantee that a developer will at least get their money back at an agreed return).

What can be done?
The points below are a list of suggestions/recommendations extracted from this session.

- *Engagement with NGOs to develop a clear message about the role of CCS infrastructure in the long-term energy transition to a low carbon economy.* This is essential in order to educate and inspire people and gain their support for political decisions. NGOs can help connect and integrate with the public's emotions and desire for change and for a low carbon future away from fossil fuels. For example, Bellona described the engagement work in Germany between government and NGOs with the result that Greenpeace is now locally advocating for CCS in industry and the German government ministry has started considering CCS for industry. The challenge is to get an early political commitment, which would be required if Germany is to store its industrial CO_2 in the North Sea.
- *Presenting a green vision of the future and not a grey vision of the future*. The business case for CCS infrastructure needs to show it is an enabler for low carbon markets: blue hydrogen can lead to large scale hydrogen use eventually supplied by green hydrogen, and industrial decarbonisation will lead to "green" products such as cement and steel.
- Importance that *the narrative around CCS should not be seen as competing with renewables* but being complementary.
- Importance of *an assessment framework/protocol which takes into account the economic value argument* (just transition, job creation and costs of the energy transition).

4 THE WAY FORWARD

Sustainable Decisions incorporated the feedback and ideas from the workshop in the ELEGANCY deliverable reports D3.3.3 and D3.3.4 as well as in the business model selection tool and business case templates and assessment tool. The Zero Emissions Platform (ZEP) Temporary Working Group: "Collaboration across the CCS Chain", whose objective also includes providing industry and expert support to the ERA-NET ACT ELEGANCY project, will be developing recommendations for a ZEP report.

A APPENDICES

A.1 Workshop Programme

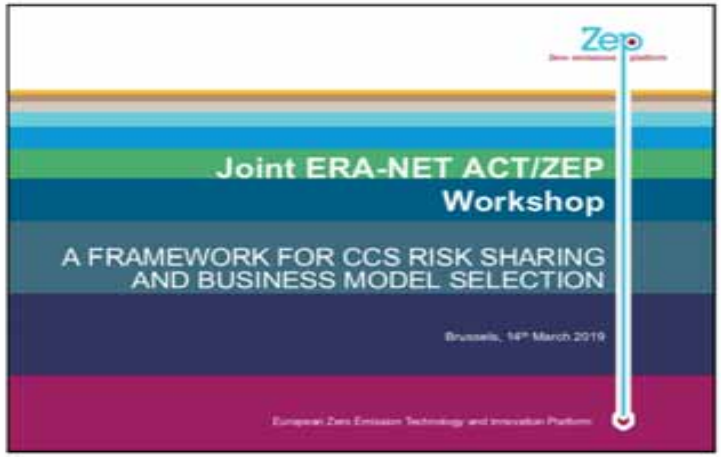
'A Framework for CCS Risk Sharing and Business Model Selection'
Joint Workshop

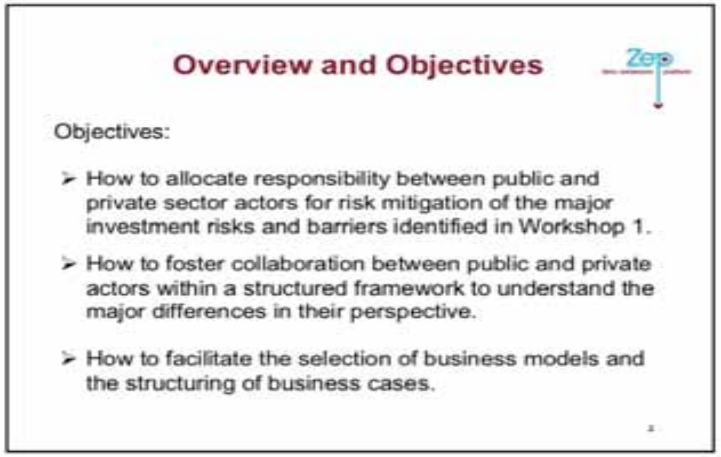
ERA-NET ACT projects ELEGANCY (WP3, WP5) and ALIGN (WP5) & ZEP TWG Collaboration across the CCS chain

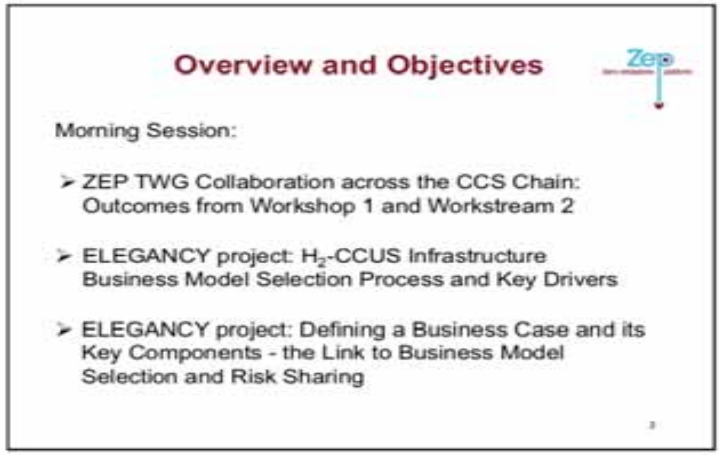
14th March 2019
10:30-16:30
Weber Shandwick Offices, Avenue de Cortenbergh, 1000, Brussels

Time	Session	Presenter/Lead
10:30 – 10:45	Welcome, Overview and Workshop Objectives	Ward Goldthorpe, Marine D'Elloy
10:45 – 11:15	Principal outcomes from Workshop 1 and ZEP TWG CCUS Chain Collaboration Assessment	Ward Goldthorpe
11:15 – 12:00	FOAK CCUS Infrastructure - Business Model Selection Process and Key Drivers	Lionel Avignon Ward Goldthorpe
12:00 – 12:30	What is a Business Case and its key components? Link to Business Model Selection and Risk Sharing	Lionel Avignon
12:30 – 12:35	Summary and next steps	Ward Goldthorpe
12:35 – 13:15	Lunch and Networking	
13:15 – 13:45	The ELEGANCY Business Model Tool – Presentation and Discussion	Lionel Avignon
13:45 – 14:30	Market Development – the Critical Policy and Collaboration Dimension	Ward Goldthorpe
14:30 – 15:00	Regulated Asset Base Business Model	Lionel Avignon Ward Goldthorpe
15:00 – 15:15	Break	
15:15 – 15:45	Geological Storage Leakage Liability and Limitations of Insurance	Ward Goldthorpe
15:45 – 16:15	Public–Private Sector Collaboration: Making the Joint Business Case	Lionel Avignon
16:15 – 16:30	Wrap-up	Ward Goldthorpe

A.2 Slide Pack – Zero Emissions Platform Presentations







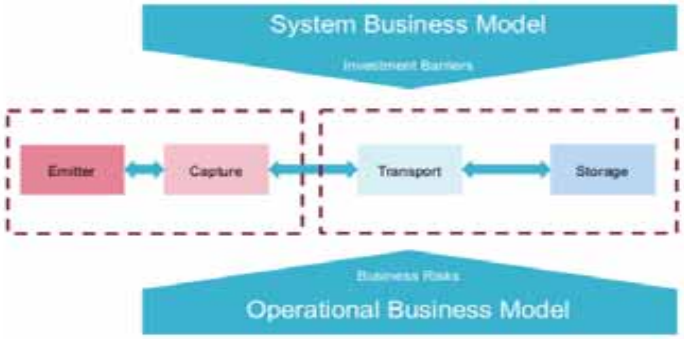
Review of Workshop 1

Objectives:

- To provide a common basis for understanding risk and liability in a CCS chain
- Develop recommendations for removing barriers to investment in CCS chain businesses
- Prioritise risk mitigation mechanisms for sharing risks between CCS chain businesses

5

Priority Barriers and Risks



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Investment Barriers

Investment Barrier	Capture	Transport	Storage
Business interruption	■		
Missing market for service		■	■
No stable long-term government policy	■	■	■
Dependence on co-ordinated deployment	■	■	■
Financial security and leakage liability			■
Intra-chain counterparty performance	■	■	■
Uncertain global climate commitment	■		
Public opinion (some countries)	■	■	■

7

Removing Investment Barriers

Focus Areas

8

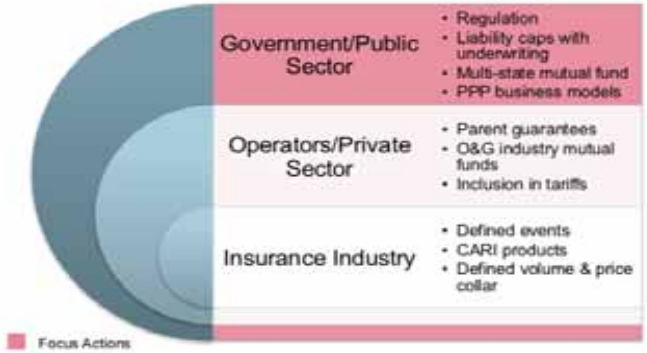
Dealing with the Financial Security

Some Unresolved Issues:

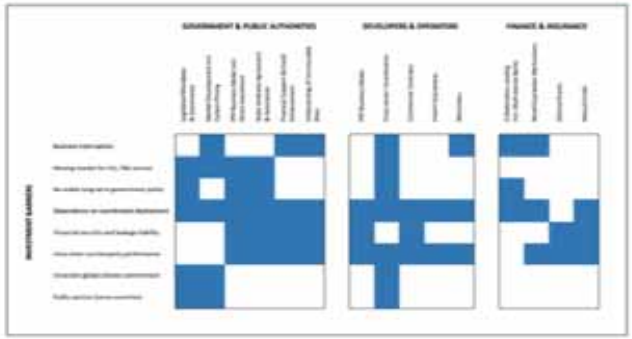
- Guidance Document 4 states: "Amounts should not be adjusted by multiplying with an estimated probability to calculate an expected value".
- Different approaches will be required at different stages of CCS deployment: FOAK, transitional, market-driven.
- The portfolio of projects will be initially too small for sensible mutualisation in a central industry fund.
- The insurance industry can only provide cover for defined quantifiable events.

Dealing with the Financial Security

Finding the Solution:



ZEP TWG-WS2 Collaboration Matrix



Summary and Next Steps

The 3 morning sessions form the basis for:

- Determining preferences and priorities for business models that remove investment barriers utilising collaboration between the public and private sectors.
- Discussing the need for policies to support market development and the link between these and business models such as PPPs and RAB
- Reviewing the limitations of private sector insurance for geological storage leakage risk
- Discussing how to make a joint business case that works for both public and private sector stakeholders

Joint ERA-NET ACT/ZEP Workshop

Geological Storage Leakage Liability and Limitations of Insurance

Brussels, 14th March 2019

European Zero Emission Technology and Innovation Platform

EU CO_2 Storage Directive Requirements

Total liability of permit site holder comprising the "Financial Security":

Decommissioning
- Cost of decommissioning

Monitoring
- Cost of monitoring of the storage site and corrective measures based on a 20 year period between closure of the store and handover to the competent authority.

Leakage Liability
- Contingent liabilities for leakage of CO_2 to the atmosphere. Operator must surrender EU allowances.

Transfer Payment
- A financial mechanism required prior to transfer is to cover most of the authorities' expenses and liabilities. There is a claw-back option if the operator has acted negligently or with fault prior to transfer.

2

Key ClimateWise Conclusions

"ClimateWise (2012) Managing Liabilities of European Carbon Capture and Storage"

"For the CCS-specific liabilities identified by the EU CCS Directive, 'off the shelf' insurance solutions do not exist."

"Ultimately, neither insurers nor storage operators will be able to bear unlimited liabilities, so where liabilities are not limited in size, risk sharing with government will be required to develop CCS at scale in Europe."

ClimateWise is a global insurance industry leadership group to drive action on climate change risk, facilitated by the Cambridge Institute for Sustainability Leadership.

3

Requirements for Insurance Products

- Defined event – "proximal cause"
- Loss is beyond the control of the insured – "fortuity"
- Quantifiable probability of occurrence and consequence
- Commercially feasible – capital efficient risk transfer
- Can be a "class risk"

→ **Non-life insurance product**

1. The reimbursement of expenses paid by the insured
2. An indemnity covering the relevant loss, to re-instate the insured to the position they were in before the loss, and no better or worse

4

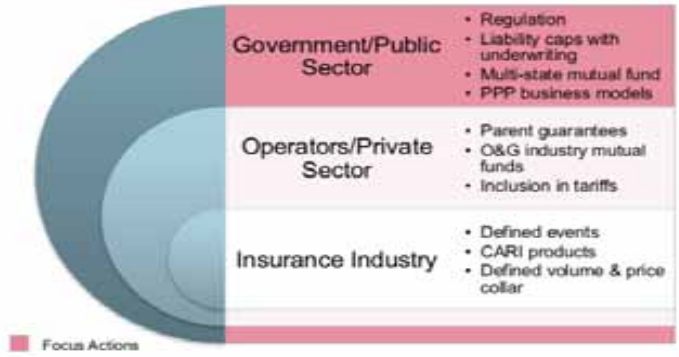
Post-Closure Insurability with Capping and Price Floor

- By linking the liability to the unknown future price of EUAs under the ETS, the EU CCS Directive **does not cap the size** of this liability for operators.
- Neither insurers nor storage operators are able to bear unlimited liabilities, so **risk sharing with government is required.**
- An innovative way of extending possible **'injection phase'** insurance products exists such that, under tightly defined criteria, they would provide cover for at least a subset of the total post closure liability.
- The insured is likely to need to declare the volume of stored CO_2 to be insured up front and the insurer and insured would need to agree the EUA price at which the policy would indemnify the insured following a leakage event, based on a **'ceiling and floor' price** or on a moving average based on the previous few years' price.

5

Dealing with the Financial Security

Finding the Solution:



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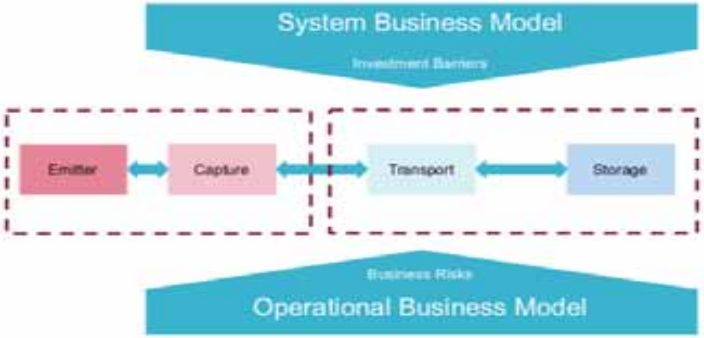
Options for Managing Liability in the Financial Security

- **Defined event liability cap similar to UK competition or risk-weighted based on probability and scale of event with fixed CO_2 price trajectory.**
- **Defined volume and price collar based on price setting mechanisms such as a moving average of previous few years' EUA price.**
- **New insurance product for carbon allowance reimbursement (CARI) requires capping of leakage liability and agreed trigger mechanism.**
- **A pan-European pooled mutual fund contributed to by both public and private sectors to cover the storage "class risk".**
- **Surety Bonds or CAT Bonds based on defined events or capped liabilities. CAT Bonds require competitive "investable" trigger criteria and returns.**

7

Business Models Allocate Risks



8

Leakage Liability Risk Sharing
Some Key Questions

- Is regulatory change feasible?
- Is a pan-European mutual fund feasible? How would it be created?
- Can we provide the insurance industry with sufficiently robust quantification of event probabilities?
- Is an annual insurance policy for a defined leakage volume commercially acceptable for investment decisions?

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Acknowledgements

European Commission
ZEP Secretariat
Weber Shandwick

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The CARI Injection Insurance Policy

KEY FEATURES OF CONCEPTUAL 'CARBON ALLOWANCE REIMBURSEMENT INSURANCE' (CARI) POLICY TO INDEMNIFY THE INSURED AGAINST THE COST OF SURRENDERING EUAS FOLLOWING A CO_2 LEAKAGE TO THE ATMOSPHERE.

Term: The CARI policy would be an annually renewable insurance policy.

Phase of CCS lifecycle: The CARI policy would apply to the injection phase in the first instance.

Proximate causes covered: Leakage events resulting from damage to operational wells, abandoned wells and the caprock seal over the well bores. In the insurance industry, this would best be termed 'all risks' by modifying other environmental insurance policies, it might be possible to cover gradual seepage through faults and fractures.

Exclusions:

- Defects in design, plan, specification, materials or workmanship.
- Normal wear and tear, gradual deterioration or normal corrosion.
- Earthquake (can be included, but could give rise to aggregation risk given the geographic focus of this market).
- Normal settling, normal shrinkage or normal expansion in land and/or caprock.

Limit of Liability: Precise limit TBC but the insured would need to declare the volume of stored CO_2 to be insured up front and the insurer and insured would need to agree the EUA price at which the policy would indemnify the insured following a leakage event. This could be based on a ceiling and floor (or cap and collar) price or on a moving average based on the previous few years' price. This approach is analogous to how future electricity prices are dealt with in other insurance policies.

Deductibles: A monetary deductible would need to be agreed as there would be an expectation that the insured would retain a primary portion of the risk.

"ClimateWise (2012) Managing Liabilities of European Carbon Capture and Storage"

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Joint ERA-NET ACT/ZEP Workshop

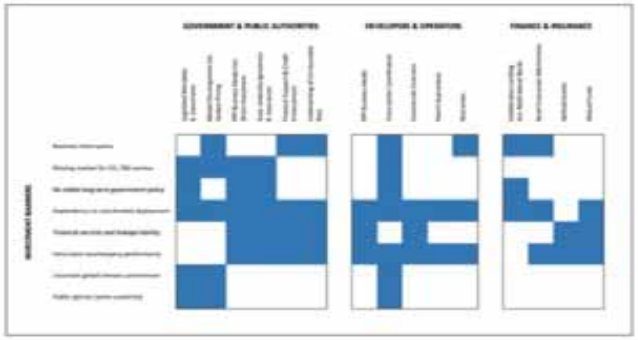
Public–Private Sector Collaboration: Making the Joint Business Case

Brussels, 14th March 2019

European Zero Emission Technology and Innovation Platform

ELEGANCY Business Case Structure & Dimensions

ZEP TWG-WS2 Collaboration Matrix



Public-Private Sector Collaboration

Some Key Questions

- Over the next 5+ years is it realistic to expect public buy-in to the need for CCS infrastructure during the transition to mid-century emissions targets?
- How do we foster collaboration between the public and private sectors to create the strategic rationale for a joint business case for CCS infrastructure and to overcome existing investment barriers?
- What is needed by the public and private sectors to create the market pull within the next 5+ years needed for low carbon industry, heat and transport beyond electrification and renewable technologies?
- Is multi-state or Pan-European collaboration and support feasible to create the FOAK infrastructure to support end-user market development in economic sectors that are difficult to decarbonise at scale?
- Do initiatives at the EC level (e.g. Innovation Fund, Mid-century zero emissions strategy, Connecting Europe Facility, Sustainable Finance Taxonomy etc.) address private sector CCS investment barriers?

A.3 Slide Pack – ELEGANCY Work Package 3 Presentations

ELEGANCY

Joint Elegancy-ZEP Workshop

A Framework For CCS Risk Sharing and Business Model Selection

Brussels/ 14th March 2019

WP3 team: Sustainable Decisions Ltd, First Climate AG, University of Oslo, Faculty of Law

ZEP TWG: Ward Goldthorpe

Overview of ERA-Net ACT ELEGANCY WP3

ACT – Accelerating CCS Technology (http://www.act-ccs.eu)

ELEGANCY - Enabling a Low-Carbon Economy via Hydrogen and CCS – led by Sintef (http://www.sintef.no/elegancy)

Work Package 3 - Formal Stated Objective:

- To develop a **business case framework** that comprises
  - **assessment tools** for the legal, market, policy and risk environment
  - a suite of optional **elements for business model selection**
- with the intention for users to apply this framework
  - **within ELEGANCY** in the WP5 case studies
  - **beyond ELEGANCY** in any other European country exploring H_2-CCS chain opportunities.

What we aim to achieve

- Creation of a structured framework (supported by a set of tools) for decision making, risk allocation and management
- Early identification and ongoing tracking of investment barriers and major business risks for private and public sectors
- Facilitate positive and effective engagement between public and private sectors:
  - To find risk management solutions applicable to the relevant H_2-CCS chain throughout the life cycle of the project
  - To define suitable business models and investment structures to allocate risk and reward.

ELEGANCY WP3

Business Model Selection Process and Key Drivers

Business Model Development Methodology

ELEGANCY

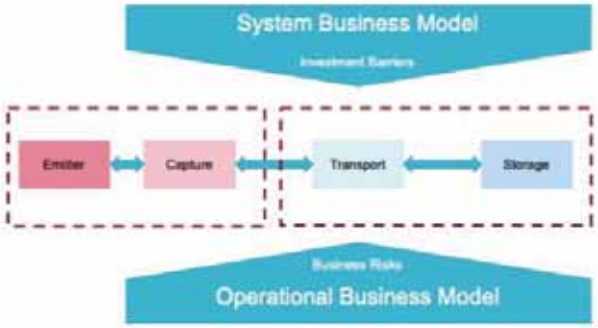
The framework facilitates the choice of business model to create an investable business proposition for public and private sector parties

What is Business Model?

- A way to organise and structure all the material elements of investment, market development, asset operation that will deliver the combined objectives of the public and private sector parties.
- The ELEGANCY framework differentiates between system scale business models and sector operational business models

Business Model Selection

System vs Operational Models



Investment Structures – Key Components

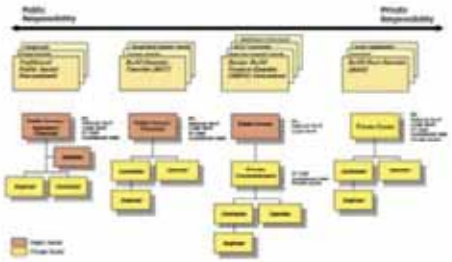
- Structures are classified by the degree of transfer of responsibility and risks from the public sector to the private sector.

- 4 Key Components:
  - Asset and Rights Ownership
  - Capital Sourcing
  - Market Development (and Remuneration)
  - Physical Delivery

- Large number of combinations to allocate risks and responsibility appropriately

No One Size Fits All

- Established historical models
- Regional/National Preferences influenced by a number of factors
- Allowing for innovation whilst appreciating complexity (and therefore risks) to set up and then manage and deliver
- Need for Collaboration and engagement with private sector



Illustrative Structures

ELEGANCY WP3

What is a Business Case and its key components?

Business Case Development

- What is a business case?
  - Structured rationale to justify a preferred investment to achieve specific objectives
  - Critical to justify why the project is necessary now, why it delivers the strategic objectives of the stakeholders, why it is a sound investment, why it should be preferred to alternatives
- Business Case Development
  - An iterative process with the business model selection
  - Driven by key factors from background assessment
  - Multiple dimensions for assessment
  - Tested against counterfactual scenarios

Business Case Development

The Link with Business Models

Public Business Case Assessment Protocols

- Guidance on appraising investment decisions for major projects is available from a number of bodies to ensure consistency with their objectives
- Multiple number of references with specific dimensions and preferences:
  - National Governments (e.g. UK)
  - European Commission
  - European Investment Bank
  - World Bank
  - Asian Development Bank

ELEGANCY Business Case Structure & Dimensions

- Overview and Objectives
  - Project type, geography, market status, key actors…
  - Objectives and Key Metrics : Social, economic, financial, environmental, technical
- Structured in 6 Main Dimensions
- A number of tools exist to support assessment
  - Traditional Tools (NPV, Monte-Carlo, Real Options…)
  - Cost Benefit Analysis (CBA): Social, environmental, economic
  - Social Cost Effectiveness Analysis
  - ELEGANCY WP4 Techno-economic tool

Guidance for Dimensions

- Strategic Drivers and Rationale
  - List of key strategic issues to be addressed (see table)
- Economic Value and Benefits
  - Quantification of impact on wider economy
  - EER and ENPV
- Financial Cost and Benefits
  - Standard evaluation of cost and revenues
  - Standard metrics of Return on Investment (RoI), NPV
- Commercial Feasibility and Delivery
  - Business model selection
  - Commercial structuring and capital sourcing
- Technical Feasibility and Delivery
  - Physical delivery
  - Technology assessment and comparison
- Risk Assessment and Management
  - Risk assessment tool and heat map
  - Standard risk quantification and mitigation

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Examples of issues for key strategic rationale assessment

ELEGANCY WP3

The Elegancy Business Model Selection Tool

See screen

Key Principles for Tools/Processes

- Complex Business Environment
  - Designed for simple and impactful visualisation of critical investment issues
  - Designed to facilitate the engagement and conversations between private sector and public sector on key issues early
- Risk Management, Mitigation and Allocation is a Life Cycle process
  - Process/Tools should be designed to be flexible for various levels of project maturity – increased levels of detail
- Each case study/project is specific
  - Process/Tool should be flexible for the users to adapt to their own project conditions

ELEGANCy

Joint Elegancy-ZEP Workshop

A Framework For CCS Risk Sharing and Business Model Selection
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Market Development

The Critical Policy and Collaboration Dimension

Who is responsible will dictate the business model

Market Development

Drivers

- Market maturity (new, developing, established)
- Market structure and regulatory environment (monopoly, merchant, regulated)
- Market demand and outlook (growth/decline)
- Market failures
- Domestic or international

Market Development

End-use Markets to service with CCS Infrastructure

- Hydrogen
  - Domestic and commercial heat
  - Industrial heat and feedstock
  - Mobility
  - Centralised and decentralised electricity generation
- Fossil fuel electricity generation
- Industrial processes
- Industrial CO_2 use
- Direct Air Capture

Market Development

Some Key Questions

- Is government incentivisation instead of taxes/emissions penalties a feasible pathway in the next 5+ years?
- Is joint European, national and regional collaboration, investment and coordination for a first project feasible in the next 5+ years?
- Are state owned regulated entities the best organisations to be the early "market makers"?
- Is development of a low carbon "blue hydrogen" market a better route to CCS infrastructure than industrial decarbonisation or CCGT power generation with CCS?

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Regulated Asset Base Business Model

Characteristics (1)

- Usually natural monopoly e.g. infrastructure
- Revenue paid by end-users
- Corporate owners are licenced
- Regulated returns on capital and operating costs
- Prices are reviewed and set regularly by an economic regulator
- Construction of new assets may be supported by government
- Enhancements and innovation of asset base may be included in the returns model e.g. UK RIIO (Revenue=Incentives+Innovation+Outputs)

Regulated Asset Base Business Model

Characteristics (2)

- Consumers and tax-payers fill the gap between the fundamental investment profile of the underlying asset and the investment profile offered to investors.
- Typically used in mature markets and lower risk investments.
- Structure can be adapted to higher risk assets/operations and developing markets using additional publicly funded support mechanisms, capital return at construction phase, and revenue guarantees.

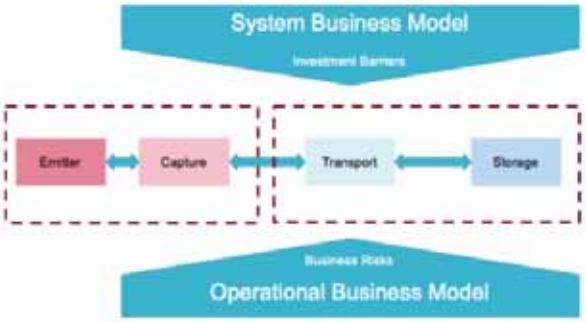
Regulated Asset Base Business Model

H_2/CCUS Examples Proposed

- Hydrogen distribution and retail
- Hydrogen transmission
- Hydrogen storage for demand management
- Hydrogen production with carbon capture
- Power generation with CCS (full chain)
- CO_2 intra-cluster gathering and/or distribution network
- CO_2 transport and storage (both separate and combined)

Regulated Asset Base Business Model

System vs Operational Models



Regulated Asset Base Business Model

Some Key Questions[1]

- Should the first "project" be integrated or split into separate emitter/capture plus T&S infrastructure components?
- Will public/society support deployment of CO_2 handling (T&S) infrastructure (i.e. the perceived hazard of continued used of fossil fuels in power or for heat and transport)?
- Should energy consumers/taxpayers take the financing, market development, and operational risks?
- Is delivery of a first split chain RAB business model politically and commercially feasible?

1. UKERC, 2018, CCS: New enthusiasm, old uncertainty, and the need for a Delivery Body

Regulated Asset Base Business Model

Business Model Drivers

Solution: Regulated coordination, market making and delivery.

There is no 'one size fits all'.
Public and private sector collaboration must be fit for purpose.

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A.4 Attendees

First name	Surname	Organisation	Status
Alice	O'Brien	University of Oslo	Attended
Brian	Murphy	Ervia (Cork project)	Attended
Chris	Gittins	TAQA	Attended
Christiaan	Gevers Deynoot	Weber Shandwick	Attended
Claudia	Vivalda	Vivalda Scientific Services	Attended
Eric	Cauquil	Total	Attended
Eric	De Coninck	ArcelorMittal	Attended
Fabrice	Devaux	Total	Attended
Filip	Neele	TNO	Attended
Han	Greijn	Energy Technology Europe	Attended
Il Shik	Sloover	Berenschot	Attended
Ivan	Srbulov	Business Energy and Industrial Stratgey Department, UK Government	Attended
James	Dobing	Business Energy and Industrial Stratgey Department, UK Government	Attended
Jan-Justus	Andreas	Bellona	Attended
John	Waldron	Business Energy and Industrial Stratgey Department, UK Government	Attended
Jon Magne	Johansen	SINTEF	Attended
Jonathan	Schwieger	First Climate Consulting	Attended
Keith	Whiriskey	Bellona	Attended
Lionel	Avignon	Sustainable Decisions	Attended
Maila	Puolamaa	European Commission, DG GROW, Resource Efficiency and Row Materials	Attended

Marijn	Van de Sande	The Netherlands Enterprise Agency (Ministry of Economic Affairs)	Attended
Marine	D'Elloy	Zero Emissions Platform	Attended
Paul	Moseley	Scottish Futures Trust	Attended
Paula	Coussy	IFP Energies Nouvelles (IFPEN)	Attended
Paul-Octave	Tollu	Total	Attended
Ragnhild	Rønnberg	ACT Coordinator	Attended
Robert	Maaskant	EBN (Porthos Project)	Attended
Ward	Goldthorpe	Zero Emissions Platform	Attended
Per	Sandberg	Equinor	Registered, not attended
Amélie	Carron	Air Liquide	Registered, not attended
Dominique	Rassool	GCCSI	Registered, not attended
Peter	Horvath	European Commission, DG ENER	Registered, not attended
Rob	Van der Meer	Heidelberg Cement	Registered, not attended
Thomas	Mikunda	TNO	Registered, not attended
Roman	Berenblyum	NORCE Norwegian Research Centre AS	Registered, not attended