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8th International Workshop on Offshore Geologic CO_2 Storage

A joint initiative of the GCCC at the University of Texas and IEAGHG
20th – 21st April 2026 - Bergen, Norway

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IEAGHG

About the IEAGHG

Leading the way in carbon management with advanced CCS research. IEAGHG are at the forefront of cutting-edge carbon, capture and storage (CCS) research. We advance technology that reduces carbon emissions and accelerates the deployment of CCS projects by improving processes, reducing costs, and overcoming barriers. Our authoritative research is peer-reviewed and widely used by governments and industry worldwide. As CCS technology specialists, we regularly input to organisations such as the IPCC and UNFCCC, contributing to the global net-zero transition.

About the International Energy Agency

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate is twofold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy. The IEA created Technology Collaboration Programmes (TCPs) to further facilitate international collaboration on energy related topics.

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Organising Committee

This work reports on the 8th in a series of international workshops on the offshore geological storage of CO_2 which was hosted in Bergen, Norway by Equinor. With thanks to our additional sponsors Equinor and Gassnova.

This report was written by Frank Thomas and Nicola Clarke, and edited by Tim Dixon, Katherine Romanak, Tip Meckel with input from the workshop presenters.

IEAGHG would like to thank the Steering Committee for their efforts in facilitating this workshop:

- Tim Dixon, IEAGHG (Chair)
- Tip Meckel, BEG (Co-chair)
- Katherine Romanak, BEG (Co-chair)
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- Jonathan Bull, University of Southampton
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Executive Summary

The 8th International Workshop on Offshore Geologic CO_2 storage was held in Bergen, Norway on April 20th-21st 2026, hosted by Equinor and co-organized by the University of Texas and the IEAGHG. There were around 100 in-person attendees, with over 250 participants joining online over the two days.

This workshop was established 10 years ago to promote knowledge sharing about offshore CO_2 storage. The first workshop was held in 2016 in Austin, Texas, followed by workshops in Beaumont, Texas (2017), Oslo, Norway (2018), Bergen, Norway (2020), New Orleans, Louisiana (2022), Aberdeen, UK (2023) and Porth Arthur, Texas (2025). Over the years, the workshop has grown to involve over 38 international CO_2 storage projects from countries like Norway, the Netherlands, and the United States.

Storage potential in offshore sedimentary basins is plentiful and has distinct benefits and limitations compared to utilising storage onshore. This year's workshop was held in Bergen to allow participants to visit the operational Northern Lights facility.

The agenda brought together 43 presentations and dedicated discussion sessions, covering international project updates, basin-scale management, prospect development, injection, monitoring technologies, the evolution of monitoring programmes, and commercial, regulatory and social dimensions. The meeting concluded with key conclusions and recommendations. Copies of the presentations for this workshop and previous workshops can be found at https://gccc.beg.utexas.edu/research/goi.

Welcome

The 8th International Workshop on Offshore Geologic CO_2 Storage opened at Equinor's Bergen office with welcome remarks from Sveinung Hagen (Equinor), Tim Dixon (IEAGHG) and Katherine Romanak (University of Texas at Austin). This was the eighth workshop in the series, the third held in Norway and the second in Bergen, a particularly fitting location given the region's connection to major energy and CCS developments, including Northern Lights and the Kollsnes gas processing plant.

The workshop series is a collaboration between IEAGHG and the Gulf Coast Carbon Center at the Bureau of Economic Geology, University of Texas, and is focused on the practical delivery of offshore geological storage. Hosted and sponsored by Equinor, with additional sponsorship from Gassnova, the 2026 meeting marked ten years since the first workshop in Austin, Texas, when offshore CO_2 storage was still at a much earlier stage of development. The scale of this year's participation, with around 100 delegates attending in person and more than 500 registered online, reflected how significantly the field has matured.

The opening remarks placed the workshop in the wider history of offshore storage development, recognising early leadership from Norway and Brazil, as well as the systematic building of CCS expertise in the United States through the Department of Energy's Regional Carbon Sequestration Partnership programmes. Northern Lights was highlighted as a global milestone for offshore CO_2 transport and storage, supported in part by the 2019 London Protocol Export Amendment, and provided a strong local context for the workshop and the planned field trip to its receiving facility.

Session 1a: International Project Roundup – The Americas and Europe

Gulf Coast, USA

Alex Bump, GCCC

In October 2024 in the Gulf Coast region there were 55 publicly announced storage projects and >45 publicly announced capture projects with over 12Gt in claimed storage capacity and ~330 Mtpa planned injection, a shortfall against the ~525 Mtpa emissions of this region. Over the past year a backdrop of reactionary politics has existed alongside industrial momentum, with the US pulling back on clean energy grants and the release of the One Big Beautiful Bill (which gives tax credit parity to CO_2-EOR). Importantly, despite this uncertainty, key language terms have emerged from Congress, spend the money as we have allocated it i.e. the CarbonSAFE program is clear to proceed as intended, and DOE has now sent a list of 'retained' projects to Congress.

However, some (capture) projects have been cancelled in the meantime but more have been retained. Storage projects are mostly still in the permitting process, which has been slow. Two projects have permits to construct Class VI wells, none have permit to inject as yet, and many projects have drilled stratigraphic test wells.

Permitting pace, commercial cost cutting pressure and counter-party risks, even with CO_2-EOR, are slowing projects. However, despite the political backdrop, progress is being made. In the offshore, the Federal offshore CCS regulations are now drafted with release imminent, albeit 4 years overdue, and have mild administrative support.

Petrobras' CCUS projects in the offshore scenario, Brazil

Lucas Pedroni, Petrobras

Petrobras operates the offshore pre-salt project, the largest CCUS project in the world and in 2025 re-injected 17.6 million tons of CO_2 using 24 FPSOs[1], this comprises >25% of total CO_2 injected globally. The project is now mature having been in operation for over 10 years, and further reduction in Scope 1 emissions are being targeted on the FPSOs e.g. and

[1] Floating Production Storage and Offloading vessel

installing capture units on the power generation units to capture and then re-inject the CO_2.

Petrobras has a full-chain CCUS R&D portfolio with several projects underway, the pilot at Sao Tome (also called the Cabiunas CCS Pilot) took FID in 2025 and is the first CO_2 injection into a saline reservoir in Brazil and will support the development of CCUS regulation in Brazil. CO_2 is derived from the Cabiunas Gas processing plant (gas derived from pre-salt gas fields) and transported via a re-purposed 70km pipeline (40 bar, in gas phase) to be injected in the Sao Tome reservoir at Barra do Furado (onshore injection into a largely offshore reservoir with a composite seal). The main objective is to test monitoring solutions and how the plume develops and migrates, monitoring both the onshore and offshore environment. Injection will start in 2028.

The injection well is larger and more expensive than conventional onshore injection wells, so that it can be fully instrumented to test more monitoring techniques (including fibre optics in the injection string and behind the casing). A single injector is complemented with three monitoring wells. The monitoring plan intends to down select tools to end up with a cost-effective monitoring plan.

Norway

Sveinung Hagen, Equinor

From Norse mythology (Sleipner – an eight-legged horse) to a fairy tale (Snøhvit – Snow White) to a natural phenomenon (Northern Lights), Norway's offshore CO_2 storage story spans over 30 years, with roots stretching back to the late 1970s when carbon capture was first proposed in Italy.

Some 30 Mt of CO_2 has been stored in the Norwegian offshore to date. Sleipner has operated for 30 years with almost 20 Mt stored from natural gas processing. Snøhvit has operated for 18 years, storing ~10 Mt transported via a 150 km pipeline from LNG export processing. Northern Lights, operational for six months, is the world's first open-access commercial cross-border CO_2 transport and storage service.

Eight storage licence rounds have been held on the NCS since 2019, yielding 14 licences across five operators: Var Energy, Aker BP, Equinor, Harbour Energy, and Northern Lights. Each licence includes a four-year work programme to de-risk the site ahead of FID. As most CO_2 will originate from Europe, transport infrastructure is critical – emerging options include ship-to-terminal (Northern Lights), direct ship injection, and the CO_2HE trunk pipeline from Europe. The pipeline offers unit cost reductions at sufficient volumes; permitting across six jurisdictions and site surveying are underway, but customers willing to commit are needed.

The three projects collectively represent a range of injection settings: Sleipner in shallow, high-quality reservoirs; Snøhvit in deeper, fault-bound reservoirs requiring corrective measures; and Northern Lights as a fully subsea, platform-free operation.

Finally, Equinor is involved in the onshore CO_2 Kalundborg project, where the reservoir extends offshore. Following a seismic campaign in August 2025, an exploration well is about to be spudded to test the Hansa structure.

Northern Endurance Partnership (NEP), UK

Susie Daniels, NEP

The Northern Endurance Partnership (NEP) is the transport and storage provider for the UK's Track 1 East Coast Cluster — the UK's first saline aquifer CO_2 storage project — and was awarded the UK's first carbon storage permit and economic licence in December 2024. Detailed engineering, procurement, surveys, and equipment qualification have since been completed, with construction now underway. A rig is in place in the Southern North Sea with drilling commenced February 2026, and construction is progressing at the Teesside base. Start-up is targeted for 2028. The other Track 1 project is HyNet, storing CO_2 in a depleted field complex. Track 2 projects are Acorn (Scotland) and Viking.

NEP is a phased development. Phase 1 serves the Teesside power station and region via a 28" offshore pipeline to the Endurance storage site, comprising 5 injection wells and 1 monitoring well (drilling commencing Q3 2026), licensed to inject 4 Mt/yr for 25 years. Phase 2 extends to the Humber region via an additional offshore pipeline and further storage sites currently under appraisal.

Endurance is one of four storage licences within the same high-quality Bunter Sandstone saline aquifer, sealed by up to 1 km of halite and muds — offering good capacity and low containment risk. The four stores likely share a hydraulic unit spanning over 13,000 km^2, requiring pressure monitoring across licences, though there is high confidence this can be managed.

Monitoring combines established and emerging methods. Novel approaches include seabed landers deployed for year-long water column variability measurements, though biofouling and baseline variability present practical challenges.

Poseidon, UK

Nick Terrell, Carbon Catalyst

Poseidon CCS is a joint venture between Perenco, Carbon Catalyst, and Harbour Energy. Since the last offshore workshop, the well workover and injection test have both been completed, and the project is now progressing from pre-FEED towards FEED.

Perenco is a major UK E&P operator seeking to leverage existing gas infrastructure for carbon management services. Poseidon is centred on the Leman gas field — one of the UK's largest (14.5 Tcf) — with 15 platforms and 200 wells available for CCS repurposing. The ultra-depleted, thick, high net-to-gross reservoir is highly compartmentalised, enabling staged segment-by-segment development, and benefits from an extensive historical gas production dataset.

Phase 1 involves recompleting 2 of 7 available gas wells and repurposing an existing platform to deliver up to 1.5 Mtpa via 7,500-tonne ships. Initial CO_2 supply is expected to originate from UK Energy from Waste emitters. The injection test confirmed that limited heating and conditioning are required, validating a direct offshore unloading medium-pressure shipping solution using ambient seawater to heat CO_2 to 0–5°C.

The long-term potential is substantial: total field capacity of 840 Mt with peak injection rates of 40 Mtpa, supported by a highly skilled existing workforce. A storage permit application is planned for around the end of the year, with FID targeted in late 2027, paving the way for Phase 1 commercial injection start-up in 2030 and subsequent expansion to serve European emitters via shipping and pipeline connection to the UK and Europe.

Porthos, The Netherlands

Gloria Thürschmid, EBN

The Porthos project, located offshore Rotterdam, aims to inject 2.5 megatons of CO_2 annually for 15 years into depleted gas fields P18-2 and P18-4 with initial reservoir pressures of below 20 bar. The Bunter reservoir is 200m thick and of high quality, with several hundred meters of shale as a sealing horizon. 4 previous gas production wells will be reused as injectors. As of this year the well workover campaign has been completed. The pipeline has been finalized as well. The project has just finished revising the schedule and aims to start at the second half of 2027 (as opposed to Q3/4 2026).

The advantage of a later start allows for the continuous baseline monitoring program to continue until start-up. A chemical probe at the P18 site started last year, continuously monitoring sea water composition and parameters like pH. A self-sufficient passive seismic monitoring system is planned to be developed and deployed within a research project, comprising two buoys in the 500m exclusion zone, with an anchoring system. The conceptual design foresees solar panels and a data logger for real time monitoring (rtm) being attached to the buoys. Baseline seabed scans have been conducted. The interplay of the various components of the project, as well as external developments like delivery times, are taking more time and have set back some of the schedule. In the meantime, however, the first emitter (Shell CO_2 capture plant) has already been connected to the Porthos collective pipeline.

Greensands, Denmark

Kurt Jager Lykke, INEOS Energy Denmark

Following a successful 2023 pilot injection at the Nini West field — using CO_2 shipped from Antwerp in ISO containers — the Greensands project demonstrated viability and generated significant learnings. Despite a challenging business case driven by high costs relative to subsidies and carbon pricing, the project has developed a phased approach and is targeting first injection this summer (2026), positioning itself as the EU's first commercial CO_2 storage project. Initial customers are bio-methane emitters, who already capture CO_2, de-risking early operations ahead of scale-up to industrial emitters as the market matures.

The project builds on the pilot by establishing an intermediate storage facility at the Port of Esbjerg and direct ship-to-platform injection. The NA-5 well is being repurposed for initial injection, with NA-3 to follow this autumn. Four tanks are already installed at the port with tanks number 5–6 underway. The purpose-built ship, constructed in the Netherlands, was launched in May, with tanks installed and pre-conditioning and heating equipment to be fitted at Esbjerg. CO_2 is transported at medium pressure, then elevated in pressure and temperature ahead of injection. The injection system was installed in autumn 2025.

The commercial framework is now mature. The UK, Norway, and Denmark have broadly replicated the oil and gas licence model — exploration phase followed by storage phase. The project was sanctioned in November 2024 ahead of receiving the storage licence. A standard storage agreement has been established with the first emitters. Storage approvals were obtained in Q4 2025 (submitted February 2024), and a second storage application was submitted in January 2026 (targeting 2029/30). A baseline seismic survey will be completed in July.

Bifrost, Denmark

David Nevicato, TotalEnergies

TotalEnergies, Denmark's largest oil and gas producer, is leveraging its experience to develop the Bifrost CCS Hub, with two objectives: delivering CO_2 storage services to Europe and positioning Denmark as a CO_2 storage hub. Bifrost comprises three offshore exploration licences — Harald, Dagny, and Inez.

European market growth has slowed relative to expectations two years ago, largely due to delays in capture projects, prompting a phased development approach aligned to market ramp-up. Phase 1 covers the Harald and Dagny licences; Phase 2 will focus on Inez, awarded earlier this year. Harald comprises two depleted fields — Harald East (chalk) and Harald West (sandstone) — while Dagny is a deeper saline aquifer. Both licences are under appraisal, with current focus on Harald West, which offers greater capacity. The Dagny exploration well is due to spud by year-end. Storage licence applications are planned for 2027/28, with Phase 1 targeting operation in the 2030s.

Initial infrastructure plans centred on shipping CO_2 to Esbjerg port and transporting it via a repurposed pipeline to the Harald platform. However, a detailed assessment of technical and commercial risk has led to a preference for intermittent direct offshore injection (DOI), which streamlines the value chain and reduces costs — with greenfield assets assessed as preferable to brownfield reuse. DOI requires adding heaters and compressors to the vessel, offloading to a seabed pipeline end terminal (PLET), connected via a static pipeline and riser to a wellhead platform (WHP). A new WHP and new well are being considered in preference to reusing existing oil and gas infrastructure.

Intermittent DOI offers independence from third-party infrastructure, scalability, and flexibility to grow capacity as markets develop — with standardised design identified as essential to cost reduction.

PilotSTRATEGY, Portugal

Pedro Miguel Pereira, Universidade de Evora

PilotSTRATEGY is a five-year EC-funded R&D project (2021–2026) spanning seven countries, aimed at scaling up CO_2 storage across Western and Southern Europe through detailed characterisation of pilot storage sites.

The Portuguese site lies offshore, ~20 km from the coastline in the northern Lusitanian Basin. The proposed injection target — the Q4-TV1 prospect, 11 km southeast of the legacy Dourada exploration well — comprises ~300 m of lower Cretaceous siliciclastic deposits sealed by upper Cretaceous limestone and shales, at 85 m water depth and 860–1,200 m reservoir depth. Dynamic storage capacity exceeds 93 Mt CO_2 with excellent reservoir quality.

For the pilot phase, CO_2 captured from an onshore cement plant will be transported in 23.5-tonne cryogenic containers (15 bar, -29°C) by rail to the Port of Figueira da Foz, then by ship for direct offshore injection. Injected volumes will remain below 100 kt CO_2 to retain the project's research classification and comply with regulatory guidelines. Phase 2 commercial scale-up would involve high-pressure pipelines (8", 150 bar) from multiple capture facilities to port, and dense-phase pipelines (8", 120–140 bar) from port to the storage site.

The project timeline is: 2027–28, 3D seismic acquisition and environmental baseline; 2030, well construction; 2031–32, CO_2 injection up to 100 kt; 2031–33, monitoring, modelling validation, and FID; 2034, commercial deployment. The pilot phase is estimated at €98 million and is designed to de-risk future investment. Technical barriers are not the primary constraint — the pilot can proceed under current regulations — but scale-up beyond 100 kt requires political will and regulatory change, which remain the principal barriers to commercial deployment.

Prinos, Greece

Katerina Sardi, EnEarth

The Prinos project aims to convert a legacy Greek oil asset – operational since the 1980s – into a CO_2 storage site. The brownfield site features three existing rigs, onshore infrastructure, and four stacked, highly depleted fault-bound anticline reservoirs.

Due to the CAPEX burden of maintaining ageing infrastructure, new greenfield facilities have been designed to replace the existing Alpha, Beta, and Delta platforms. A new marine terminal and jetty will receive CO_2 by ship into onshore buffer storage, before processing (pumping, heating, compression) and export via subsea pipeline to the new OMEGA platform. OMEGA will inject 2.8 Mtpa through 6 injection wells, with 9 water production wells managing pressure and steering CO_2 to efficiently fill the storage volume – produced water will be returned onshore for treatment. The site is in shallow water (28–35 m) but requires drilling to 3–4 km with semi-horizontal wells.

The EU regulatory environment was slow to develop following the 2009 CCS Directive, but accelerated markedly after the 2021 Fit for 55 package. Fifteen regulations, decisions, and white papers have since been released, and in February 2026 the European Parliament adopted a revised Climate Law with binding 2040 targets.

EnEarth will conduct a market test in May 2026 to assess emitter appetite for 15-year contracts, with Prinos taking responsibility for CO_2 from jetty receipt onwards – whether from individual emitters or an aggregated hub. Non-binding MOUs covering ~6 Mtpa have been signed with emitters from Greece, Italy, France, and Croatia.

The project has received an environmental permit and a storage permit for 1 Mtpa – the third such permit in Europe after Porthos and Greensands. EU support totals ~€390 million (€270 million as a Project of Common Interest and €120 million via the Connecting Europe Facility) against a total project cost of ~€1 billion. A new competent person's report is being developed to assess total storage capacity. FID is scheduled for Q1 2027, with operations targeted by 2030.

Session 1b: International Project Roundup – Asia-Pacific

Indonesia

Grace Stephani, Pertamina

Indonesia is developing offshore CO_2 storage to support domestic emissions reduction and establish a wider role as a regional CCS hub in the Asia Pacific. Pertamina Hulu Energi is leading development through two main hubs, a West Hub and an East Hub in Sulawesi, supported by satellite sites across Indonesia. Total storage potential within the PHE area is estimated at around 7.3 Gt, with the full transport and storage value chain under consideration, including pipelines and liquid CO_2 shipping.

The Asri Basin is the most advanced project and is being positioned as a pioneer for cross-border CCS in the region. Located around 100 km offshore Jakarta in 30–35 m water depth, the basin covers approximately 848 km² and targets a saline aquifer with an estimated storage capacity of 2.9 Gt. Key technical challenges include reservoir heterogeneity, plume behaviour and containment uncertainty, requiring improved static and dynamic modelling, injectivity and conformance control, and fit-for-purpose monitoring.

The project has completed technical review and is now in pre-FEED, with FEED planned for 2026. Licensing is targeted for 2026, FID for early 2029 and first injection for 2032. Phase 1 is planned at 2.5 $MtCO_2$ per year, with potential expansion to 10 $MtCO_2$ per year and, longer term, up to 30 $MtCO_2$ per year depending on emitter demand. Under Indonesia's 2024 Presidential Decree, storage capacity is currently allocated 70% to domestic emitters and 30% to international emitters, although this may be adjusted subject to government discussion and domestic demand.

International market engagement is already underway with potential emitters in Japan, South Korea and Singapore, while Indonesia's domestic iron and steel sector could provide a market of up to 3.8 $MtCO_2$ per year.

Tomakomai, Japan

Daiji Tanasa, Japan CCS Co

The Tomakomai CCS Demonstration Project, operated by Japan CCS Co. under commission from NEDO and funded by METI, remains one of the most important offshore CO_2 storage demonstrations in Asia. The project is located at Tomakomai Port in Hokkaido, with CO_2 sourced from refinery hydrogen production, transported 1.4 km by pipeline to the capture facility, compressed and sent to two injection wells.

Injection began in April 2016 and ended in November 2019 after the target of 300,000 tonnes had been reached. The project is now in the post-injection monitoring phase. Two offshore reservoir intervals were originally targeted from onshore wellheads: the lower Moebetsu Formation sandstone at around 1 km depth and the deeper Takinoue Formation volcanic and volcaniclastic rocks at around 2.4 km. The full injected volume was ultimately stored in the Moebetsu Formation, which showed strong injectivity and reservoir pressures well below caprock protection limits. By contrast, the Takinoue Formation showed poor injectivity and rapid pressure build-up, so continuous injection into that interval was discontinued.

The monitoring programme includes downhole pressure and temperature sensors, observation wells, downhole seismic sensors, an ocean bottom cable, ocean bottom seismometers and coastal seismic monitoring. Repeat seismic surveys detected the evolution of the CO_2 plume in the Moebetsu Formation during and after injection. Microseismicity monitoring recorded only small events, all below magnitude 0.6 and occurring well below the storage interval.

Marine environmental monitoring is conducted under Japan's Act on Prevention of Marine Pollution and Maritime Disaster. Surveys include seawater and seabed sediment chemistry, plankton observation, pH sensor surveys and seismic monitoring. No indication of CO_2 leakage to the ocean has been detected to date. Beyond Tomakomai, nine new projects have been nominated for government financial support under Japan's Advanced CCS Project programme.

Taiwan

Cheryl Yang, ITRI

Taiwan adopted a 2050 net zero policy goal in 2021, with CCUS identified as one of twelve key strategies. Although Taiwan's current pilot sites are onshore, they were included in the workshop because of the country's wider CCS deployment plans. Deployment is planned in three phases: pilot projects from 2022 to 2030, demonstration from 2030 to 2040 and commercial deployment from 2040 to 2050.

Taiwan is currently developing two pilot sites. The Taichung Power Plant project, operated by Taipower, is a fully integrated capture and storage pilot designed to capture and inject 2,000 tonnes of CO_2 per year. CO_2 will be captured using chemical absorption, transported by truck over a short distance and injected at a nearby storage site, with baseline data collection currently ongoing.

The Tiehchenshan test site, operated by CPC at a natural gas storage field, is focused on storage testing. The project plans to inject 100 ktCO_2 per year for three years, a significant scale-up from earlier plans. The storage reservoir lies above the existing gas storage reservoir and is sealed by the Chinshui Shale caprock. The injection permit was obtained shortly before the workshop, and the monitoring programme includes downhole pressure and temperature gauges, DAS, DTS, VSP, seismic and microseismic surveys, and atmosphere, soil gas and groundwater monitoring.

Taiwan is also developing its regulatory framework following the 2023 Climate Change Response Act. Geological storage projects are now required to undergo Environmental Impact Assessment, and a draft regulation for the management of captured CO_2 storage is being prepared. ITRI is also advancing research on fibre optic sensing, deep learning for event detection, DAS-based surface wave imaging and high-temperature carbon reduction technologies.

CarbonNet, Australia

Scott Bailey, Govt of Victoria

CarbonNet is a Victorian State Government project jointly funded by the Victorian and Australian Commonwealth governments. Originally established in 2009 to capture CO_2 from coal-fired power plants in southeast Victoria, the project is now assessing alternative sources such as waste-to-energy and coal-to-products as the region's coal-fired power plants move towards closure.

CarbonNet holds two offshore assessment permits in the Bass Strait with a combined storage capacity of more than 350 $MtCO_2$. The Pelican site, offshore from Golden Beach, is the more advanced of the two, with 168 Mt capacity and a designed injection rate of 6 $MtCO_2$ per year. The project has completed FEED and drilled an offshore appraisal well. The original development concept includes an 80 km onshore and 20 km offshore pipeline from the Latrobe Valley to the storage site.

The project is now considering alternative execution strategies to reduce upfront capital exposure and phase development at lower initial rates. One option is extended-reach drilling from onshore, which could remove the need for offshore infrastructure while supporting an initial rate of around 2 $MtCO_2$ per year at a comparable tariff to the larger 6 Mtpa concept. This reflects lessons from projects such as Northern Lights and Moomba, which began at smaller scale with later expansion planned.

The second site, Kookaburra, lies further offshore and has an estimated capacity of 188 Mt. It is being developed as a ship-based receiving and injection concept, with options such as a Floating Storage and Injection Unit to be assessed.

CarbonNet also emphasised the importance of stakeholder engagement. The project works with traditional owners, industry, unions, regulators and government, and has secured support from 27 Victorian unions. A Community Reference Group chaired by the Victorian Chief Scientist has been in place since 2019, supporting direct two-way communication with the local community.

DeepC Store, Australia

Daein Cha, DeepC Store

Deep C Store is developing a transboundary CCS value chain between Japan and Australia, based on shipping liquefied CO_2 from Japanese emitters to offshore storage sites in Australia. The project is built around Australia's large storage capacity, accessible offshore acreage and established CCS legislation, including its position as a party to the London Protocol.

The company holds two offshore storage permits in around 100 m water depth, both in greenfield areas without legacy oil and gas interests. CStore1, in the Browse Basin around 200 km offshore Western Australia, targets a saline aquifer with gigatonne-scale potential. CStore2, in the Bonaparte Basin, targets a depleted oil field with an underlying saline aquifer and an estimated capacity of around 80 Mt.

The proposed development would receive low-pressure, low-temperature liquid CO_2 from Japan by ship and deliver it to a floating storage hub above the storage acreage. The hub would provide interim storage, compression or pumping, heating and injection, with a planned capacity of 3 $MtCO_2$ per year. Deep C Store is also undertaking R&D on the handling of low-pressure, low-temperature liquid CO_2 in collaboration with the Future Energy Exports CRC.

Several regulatory and policy issues remain central to the project. These include accelerating a bilateral agreement between Japan and Australia under the London Protocol, harmonising regulation across the transboundary value chain, defining the physical transfer point for regulatory responsibility, agreeing CO_2 specifications, clarifying carbon credit attribution, developing MRV regulations and calculating emission reductions on a net rather than gross basis. The project illustrates both the opportunity and complexity of cross-border offshore CO_2 storage.

Project Round Up, Global Progress

Frank Thomas, IEAGHG

The project roundup covered offshore CCS developments not represented by individual speakers.

In Australia, several projects are progressing across the Browse, Bonaparte and Pelican basins. Updates included Woodside Energy's withdrawal of environmental approvals for the Browse Basin GHG213/Angel CCS project in March 2026, with the intention to resubmit, and the cessation of production at Bayu-Undan in June 2025. Timor-Leste has formally committed to converting Bayu-Undan to CCS, with a proposed capacity of 10 $MtCO_2$ per year.

In China, offshore CCS activity includes Dongfang 1-1, Enping 15-1 and Daya Bay. Enping 15-1 has become China's first offshore CO_2 EOR project and is moving from pilot testing towards commercial application. The Daya Bay CCS project, involving Shell, ExxonMobil, CNOOC and Guangdong authorities, has signed an MoU targeting 10 $MtCO_2$ per year and is in the feasibility and policy development phase.

In Japan, additional projects are progressing under the Advanced CCS Project programme, including FEED-related work for the Tohoku West Coast CCS project and exploration drilling approval for the Metropolitan Area CCS project.

Malaysia is developing three offshore CCS clusters, northern, southern and eastern, supported by onshore hubs at Kerteh and Kuantan. These include the Kasawari CCS gas field, the M3 field, the Penyu saline aquifer, the Lawit field and the depleted Duyong field. Petronas has also received Malaysia's first offshore CCS assessment permit for the wider area.

In Thailand, PTTEP's Arthit CCS project reached FID in September 2025, with first injection targeted for 2028. The project will store CO_2 from the Rayong gas separation plant in a depleted gas reservoir.

In Europe, Spain's TarraCO_2 project, led by Repsol and supported by the EU Innovation Fund, is targeting natural cavity storage with a planned capacity of around 54 Mt and injection rate of 2 MtCO_2 per year. In the United Kingdom, offshore storage continues to advance through the cluster sequencing process, including HyNet, Acorn and Viking CCS, alongside earlier-stage projects such as Morecambe Net Zero, Medway Hub CCS, EnQuest CCS and Project Tellus.

Overall, the roundup showed the growing geographic spread of offshore CCS and the emergence of different development models, including domestic hubs, phased offshore developments, ship-based transport chains and cross-border storage services.

Session 2: Basin Scale Management

Basin management and pressure interference

Sarah Gasda, NORCE

Pressure interference is the primary constraint of large-scale CO_2 storage and must be actively managed. A recent paper[2] arose from researchers asking a fundamental question: what do we actually know about pressure? Storage opportunities are abundant, particularly in large saline aquifers, but scaling CCS requires multiple project operators developing within the same aquifers over long timeframes. Whether examined mathematically, physically, or economically, coordination and collaboration are essential in these shared resources — analogous to collaborative efforts on the capture side.

Ongoing simulation work on the Troll regional aquifer model[3] in the Horda Platform area of the Northern North Sea — encompassing licence blocks Luna, Aurora, and Smeaheia — illustrates this clearly. Two-year snapshots across a 500-year injection period of 500 Mt

[2] Ougier-Simonin, A., Tucker, O., Bump, A., Gasda, S.E., Otterlei, R.E., Lemgruber-Traby, A., Mackay, E., Ricard, L.P., Herrmann, F. and Imhof, M., 2026. The pressure balancing act in geological storage: sharing the subsurface for the common good. *International Journal of Greenhouse Gas Control*, *151*, p.104610.
[3] From the Norwegian Offshore Directorate.

CO_2 show slow growth of isolated CO_2 plumes but rapid pressure propagation. Critically, pressure footprints from CO_2 injection can extend 10–100× beyond the CO2 plume itself.

Multi-operator dynamics can be modelled to assess competing objectives and collective decision-making. Drawing on 60,000 reservoir simulations across three operators, the analysis shows that first-mover advantages reduce total resource capacity by 30%, with only marginal gains to the first mover. Physics ultimately determines total available resource; cooperative game theory and belief distributions can provide decision-making frameworks and quantify competition uncertainty in uncoordinated scenarios. Flexibility to redirect CO_2 between projects as storage performance becomes clearer offers significant optimisation potential.

Managing a CO_2 Storage Site Portfolio: A Regulator's View

Hilde Braut, SODIR

The Norwegian Offshore Directorate (NOD), sitting under the Ministry of Energy, is the expert body for oil and gas, seabed minerals, and CO_2 storage. Its functions include advising the Ministry, communicating knowledge of CO_2 storage potential on the NCS, and overseeing licence follow-up and regulatory development.

The NOD advises on pressure management and resource optimisation, targeting efficient storage resource management and predictable framework conditions for all operators. Pressure interference across licence and national boundaries is an active focus, with cross-border collaboration with Danish and UK regulators.

The 13 active licences on the NCS could collectively reach ~100 Mtpa injection capacity by 2040, though the maturation timeline from exploration licence application to first injection is 8–10 years. CO_2 supply remains the primary constraint on development.

To address resource optimisation and pressure management, the NOD has developed an aquifer model of the Frigg-Heimdal aquifer — a large area encompassing both potential CO_2 injection sites and existing oil and gas production, with Palaeocene reservoirs extending into the UKCS. Building on theoretical storage capacity estimates from the 2014 CO_2 Storage Atlas, the model assesses pressure development responses. Results are due for publication next year and are currently used internally with the Ministry.

The applicable Norwegian CO_2 Storage Regulations for pressure interference are: § 5-3C[4]; § 5-4[5]; § 5-11[6]. Regulations are intentionally flexible and guidance-oriented — mirroring the approach taken in the oil and gas sector — minimising the need for frequent revision.

[4] pressure interactions between licences may not compromise each site's ability to meet the requirements of the storage regulations
[5] the operator shall monitor the injection facilities and the storage complex
[6] co-ordinated storage of CO_2 when a hydraulic unit extends across multiple licences or national borders

Norway's open-door policy and subsurface data sharing further promote strong cross-sector collaboration.

Derisking composite confinement and implications for containment in layered systems

Alex Bump, GCCC, BEG

Containment is fundamental to safe and permanent CO_2 geologic storage. The oil and gas industry has demonstrated that buoyant fluids can be contained over geological timescales, with marine shales and evaporites forming highly effective seals. However, even in many offshore settings there are challenges, with sand horizons interrupting shale sequences (e.g. North Sea Palaeogene and Neogene sections) which can be problematic. Bump et al. (2023) proposed composite confining systems, where thick, multi-layered sequences of discontinuous barriers collectively confine CO_2, potentially removing a priori requirements for lateral continuity or capillary entry pressure familiar from hydrocarbon plays.

Despite growing research in this area, key practical questions remain: how do you de-risk composite confinement, and how do you convince regulators, investors, and internal teams?

Project X, a real Gulf Coast case study, involves ~3,500 ft of heterogeneous deltaic sediments with no lateral seal overlying seven stacked Miocene injection targets. The top two injection systems were evaluated against the overlying composite system for a total injection of 18 Mt CO_2. The approach comprised statistical characterisation of 170 wells (defining mean, P50, and P90 values), followed by uncertainty testing against a base case — with zero leakage as the success criterion. A second stage defined an engineering safety factor by establishing the injection volume at which leakage first occurs.

Composite confinement relies on a low ratio of effective vertical to horizontal permeability. Darcy's law applied to a tortuous flow path governs vertical migration, incorporating average barrier length, barrier frequency, net-to-gross (NTG), and flow unit permeability — with any permeability reduction qualifying as a barrier.

Extreme well log values were validated and incorporated into models: permeability up to 1,600 mD, NTG of 60%, barrier length of 1,000 ft, and barrier frequency of 3 per 100 m. Multiple geological uncertainty scenarios, including a combined worst case, were tested. Across all cases, three-well injection of 18 Mt CO_2 followed by 200 years of post-injection monitoring produced CO_2 plumes with limited variation. Even the worst case showed only modest vertical rise above the plume top — less than 10% of the total confining system thickness. Safety factor testing at 5× and 10× injection volumes produced larger plumes but vertical migration reaching only 30% through the confining zone — equivalent to nuclear industry safety margins. Lateral migration remains the more probable and significant risk.

Offshore CCS Development for the Northeastern U.S. Atlantic Shelf

Neeraj Gupta & Joel Sminchak, Battelle

The US East Coast has limited onshore CO_2 storage but hosts significant industrial emissions. Building on prior screening work using reprocessed legacy seismic and well data, this study focuses on the southern continental shelf, evaluating CO_2 storage potential, onshore routing options, a pre-FEED development plan, and stakeholder engagement. Combined with regional carbon credit programmes and the 45AQ tax credit, offshore storage here could be economically viable.

A CO_2 storage common risk segment map was developed to identify optimal storage areas based on geology, operational constraints, cost, and environmental considerations along the NE Atlantic offshore. Three areas were selected: Indian River Shallow (a coastal setting suited to onshore injection); Indian River Deep; and Great Stone Dome, a deeper structure with prior hydrocarbon exploration history.

The basin contains Cretaceous sediments up to 3 km deep. A stratigraphic framework has been developed across the basin, revealing reservoirs more variable than previously modelled but with laterally continuous units >35 m thick with good reservoir-quality porosity and permeability. A stratigraphic test well and additional seismic acquisition would complement existing well and 2D seismic data and help verify findings.

Two areas have been modelled in detail. Great Stone Dome could support two platforms with four wells each, with modelled injection of 17 MMT/yr and 500 MMT total over 30 years. Indian River Shallow would require a single well delivering 2.5 MMT/yr and up to 75 MMT over 30 years, with careful well planning required to keep the plume from reaching shore.

Infrastructure options – combined pipeline or shipping from multiple emitters – will require substantial stakeholder support. Subsea infrastructure (central manifolds and clustered well pads) would minimise surface footprint compared to conventional oil and gas facilities.

The development roadmap prioritises permitting and community outreach ahead of stratigraphic well drilling, before progressing to FEED.

Discussion

The panel discussion provided a balanced discussion highlighting the interplay between geological uncertainty, containment behaviour, monitoring strategies, and basin-scale coordination.

A central theme was the role of wells as both valuable sources of subsurface data and potential containment risks. While they provide valuable data, they also introduce possible leakage pathways that must be carefully managed. Alex provided an example where analysis on 100 Gulf Coast fields with stacked pay, with an oil and water contact calculating buoyancy pressures and seal capacities showed that they were poor, but trapped oil in place (60-100Mt CO_2 equivalent) with composite systems.

The discussion probed the importance of geological heterogeneity and structure, particularly variations in permeability and the presence of fractures, in controlling CO_2 migration. Evidence from sites such as Sleipner and Frio suggest that even where vertical migration pathways exist, subtle intra-layer barriers and layered systems can still provide some containment, often diverting CO_2 laterally. The important factor was to derisk and characterise the system and try and make it fail – look at the response. This also can contribute to the appropriate design of a targeted monitoring plan. Also critical is the injection target, injections into synclines do not build column height in the same way that anti-clines or structural closures do. Discontinuous injection into composite systems, although modelled, were not anticipated to have an impact.

Uncertainty in subsurface parameters remains a key challenge, particularly in probabilistic modelling. However, progress is being made through large-scale aquifer models and increasing regulatory data availability. The panel agreed that monitoring strategies should evolve beyond leak detection to focus on understanding reservoir behaviour at scale, with collaboration offering both technical and cost advantages.

The Norwegian regulator reenforced their collaborative approach with regular meetings with the UK and Denmark, and further strategy discussions with the Netherlands, Belgium and Germany. The contrast of approach was acknowledged between aquifers and depleted fields. When asked about the types of data available, it was acknowledged that CO_2 storage needs different types of data, such as fall-off tests, to test the aquifer models and improve long-term storage confidence. The Northern Lights currently reports injection pressure data monthly to the NOD and they will need to verify what data will be publicly reported.

Potential projects near shore can raise concerns about pressure impact on outcropping or subcropping hydraulically connected units e.g. Humberside and elsewhere. In the Eastern US this is a factor they have considered and with few onshore wells, and injection targets that don't extend to the near shore they are confident this issue won't cause risks.

The discussion also underscored the importance of coordination across multiple operators and projects within a basin. A collaborative approach could enable optimisation of CO_2 injection and storage performance across sites, balancing operational efficiency with competitive dynamics. The NOD has loosely defined requirements for pressure requirements, for the Northern Lights is caprock strength. For adjacent projects cooperation forum are a requirement.

Session 3: Prospect Development

Cost-effective prospect screening of a CO_2 storage site

Gerardo Seri, Aker BP

The talk examined how CO_2 storage prospect screening on the Norwegian Continental Shelf has become more cost-conscious following the 2024 market correction. While the core technical and safety criteria remain unchanged, good reservoir quality, robust seals, large connected aquifers and proximity to CO_2 sources, project selection is now placing greater emphasis on legacy well risk, existing subsurface knowledge and portfolio diversification.

A key message was that prospects with previous oil and gas exploration history are increasingly attractive, as existing wells, seismic data and geological interpretation can reduce uncertainty and limit the need for costly new appraisal. In some cases, dry exploration wells may be valuable for storage screening, as they confirm water-bearing reservoir intervals while retaining useful subsurface data.

The talk also highlighted the growing importance of reusing existing oil and gas infrastructure, including subsea systems, umbilicals, power supply and platforms where remaining technical life allows. The main barriers may be commercial and regulatory rather than technical, particularly where oil and gas and CCS activities sit under different fiscal regimes.

Looking ahead, monitoring and other operating costs are likely to become the next major area for optimisation. Modular project designs, integrated transport and storage partnerships, and future cross-storage backup arrangements were identified as ways to reduce commercial risk and support phased CCS development.

Review of legacy well screening practice

Gwilym Lynn, Shell

The talk emphasised that legacy wells should be treated as a core part of CCS site characterisation, alongside reservoir quality, seals and containment. Legacy wells are one of the most common causes of late-stage project recycle, partly because the wells used to characterise a site can also become potential leakage pathways. This is especially important for wells abandoned under historical oil and gas standards, where barriers were not necessarily designed or verified for future CO_2 storage under increased reservoir pressure.

Several recurring issues were highlighted. Legacy well integrity is often considered too late, abandonment records may be incomplete or misleading, and changes to the development concept can alter the pressure footprint and invalidate earlier assumptions.

Storage site redefinition may also leave existing abandonment barriers in the wrong place relative to the final containment interval.

Good practice requires early, forensic and multidisciplinary screening of all wells within the affected area, involving subsurface, geomechanics and well engineering expertise. Screening should consider plug location, verification, pressure tolerance and potential cross-flow pathways. It should also extend beyond the CO_2 plume to the wider pressure plume, which may reach far-field wells and create risks such as hydrocarbon mobilisation or brine displacement.

The key recommendation was to assess legacy wells early enough to support "fail-fast" decisions across multiple candidate stores. Where problems are identified, options include adapting the development scheme, applying targeted monitoring or remediating wells, although remediation may not always be technically or economically feasible. AI tools may help accelerate initial screening, but strong quality control remains essential. The closing analogy was clear: a storage site should be treated like a pressure vessel, and the question is whether one would design such a system with holes in it.

Northern Endurance Partnership (NEP) aquifer models

Carwyn Adler, bp

The talk focused on how the Northern Endurance Partnership is modelling pressure interaction across multiple CO_2 storage licences in the Silver Pit Basin. NEP holds four licences, including CS001 for the Endurance store, where Phase 1 is planned at 4 $MtCO_2$ per year with start-up targeted for 2028. Other operators also hold licences in the same basin, meaning pressure headroom must be managed across a shared hydraulic system.

NEP uses a hierarchy of models, from well-scale injectivity models to site-scale plume models and regional pressure prediction. The regional model was the focus of the talk. Its main challenge is the large model area combined with sparse and uneven data, particularly limited core and dynamic pressure data.

Permeability was identified as the dominant control on pressure response. Lower permeability cases produce more localised pressure build-up around injection sites, while higher permeability cases create wider but lower-magnitude pressure plumes. The model is therefore being used to test development options and balance competing objectives: reducing CapEx by concentrating injection in fewer stores, while avoiding excessive pressure interference and storage risk.

The key message was that regional models provide the decision framework, but future expansion will depend on reducing uncertainty in permeability and connectivity through new dynamic data, including appraisal wells and pressure data from Endurance once injection begins.

Brine management for CCS practical challenges

Hans Sizoo, bp

The talk examined brine extraction as a possible way to manage pressure and increase storage efficiency in saline aquifers. For the Endurance store, previous work considered whether CO_2 injection could be increased from 4 to 10 $MtCO_2$ per year by producing brine from the reservoir flanks while injecting CO_2 at the top. This could raise storage efficiency but would also create a major brine management challenge.

A key issue is the composition of the produced brine. At Endurance reservoir depth, salinity is around an order of magnitude higher than seawater, with elevated potassium, chloride and metal concentrations. Studies therefore assessed whether offshore discharge could be acceptable, considering dilution behaviour, environmental impact and toxicity to marine organisms. Options such as engineered dispersion, onshore treatment and reinjection elsewhere were also considered.

The options were compared using a Best Practicable Environmental Option assessment, but no route was straightforward. Since NEP has gained access to additional storage licences, near-term capacity can now be expanded without relying on brine extraction, reducing the immediate priority of this option.

The broader takeaway was that maximising saline aquifer capacity is not simply a pressure-management problem, but a brine-management problem. In highly saline systems such as the Bunter Sandstone, brine extraction adds significant technical, environmental, regulatory and reputational complexity to the CO_2 storage project.

WELLFATE – gas provenance study, Tampen Spur

Stephane Polteau, IFE

The WELLFATE project is investigating fluid migration around decommissioned offshore wells in the Tampen Spur area of the Norwegian North Sea. With around 2,000 exploration wells already decommissioned in Norway and a similar number expected in coming decades, the project aims to understand how wells influence natural background seepage, and which wells may require monitoring.

Field campaigns in 2024 and 2025 acquired multibeam water-column data and ROV observations. Across the dataset, 1,810 acoustic gas flares were mapped, with the strongest flares commonly located close to wells. Of 241 wells observed, around 30% showed visible gas bubbles at the seabed.

The key finding was that sampled gas from both wells and natural seeps is microbial in origin, sourced from the shallow subsurface rather than deeper reservoirs. Carbonate crusts at natural seep sites also indicate long-standing seepage over thousands of years, suggesting that gas migration in the Tampen Spur is a natural process, with wells sometimes acting as additional pathways for shallow gas.

Observed seabed expressions ranged from minor intermittent bubble streams to stronger discharges and well sites resembling natural seeps. Ongoing work includes fluid migration modelling, analysis of well design and cementing factors, and planned downhole camera observations to determine whether bubbles emerge from the well centre or from the side where casing was cut. The broader message was that gas provenance is essential for distinguishing shallow natural seepage from potential reservoir leakage at legacy wells.

Legacy well risk profile assessment based on lessons from methane leaks

Al Moghadam, TNO

The talk examined methane leakage from decommissioned offshore wells as an analogue for understanding potential legacy well risks in future CO_2 storage sites. Although no legacy well leakage has been observed in operational CCS projects, methane leakage in the North Sea provides useful evidence on why some wells leak other wells in the same geological setting do not

The study focused on shallow biogenic gas, where leakage is thought to occur along the cement sheath in the casing annulus. The central hypothesis is that cement sheath integrity above the shallow gas zone controls leakage. As cement hydrates, it can de-stress and shrink against the casing and formation, reducing its ability to act as a barrier. If residual stress falls below a critical level, gas may migrate through narrow gaps along the interfaces.

TNO tested this hypothesis using data from Dutch, Norwegian and UK wells. The results showed a clear relationship between lower cement sheath stress and leaking wells, with the model predicting most leaking cases. Non-leaking wells generally had higher cement densities and higher initial slurry pressures.

A striking comparison of two nearby Dutch wells with similar geology showed that the non-leaking well had two-stage cementing, a longer cement sheath and heavier cement, while the leaking well had single-stage, lighter cement. The conclusion was that leakage can often be explained by well construction and cement integrity, rather than more complex geological mechanisms. The study remains limited by sample size, but provides a practical basis for legacy well risk screening in CCS site assessment.

Discussion

The discussion returned first to the NEP regional model, confirming that pressure prediction must integrate multiple physical parameters, including compressibility and permeability, and be continually calibrated with new appraisal and dynamic data. The exchange reinforced that regional-scale storage modelling is not only a geological exercise, but a framework for managing pressure interaction across a shared hydraulic system.

Methane provenance and legacy well seepage were also major themes. Speakers noted that methane observed around Tampen Spur wells is microbial and shallow-sourced, rather than reservoir-derived, and that decommissioned wells contribute only a small fraction of wider North Sea methane emissions compared with natural seepage. The term “seepage” was preferred over “leakage” where shallow gas migration is natural and long-standing, although whether wells accelerate the release remains an important question.

Brine management discussion focused on the complexity of handling hypersaline formation water. The issue is not only volume, but composition, including elevated salinity, metals and, in some settings, entrained methane. NEP’s decision to expand storage acreage rather than pursue brine extraction illustrated how operators may avoid brine management where the added technical, environmental and regulatory burden outweighs the benefit.

Legacy well behaviour prompted strong discussion. Well integrity was seen as inseparable from geology, with uncertainty remaining around CO_2 reactions with old steel and cement, self-sealing versus self-enhancing leakage pathways, and microbiological effects in former hydrocarbon settings. Practical difficulties include inaccurate historical well coordinates, cut-off wellheads below seabed and, in some cases, wells that may be effectively unlocatable. Re-entry and remediation were viewed cautiously because of technical risk, cost, safety concerns and the potential emissions penalty of the intervention itself.

The discussion also pointed to possible future directions. TNO’s finding that two-stage cementing and longer, heavier cement sheaths correlate with non-leaking wells may help inform regulator engagement on CCS well construction standards. Biological remediation and ecosystem development around seep sites were raised as alternative ways to think about low-rate seabed seepage. Throughout the discussion, MMV was emphasised as a monitoring and decision-support tool rather than a physical barrier, with mitigation ultimately depending on development design and operational response.

Session 4: Injection

Lessons learned from early injection: Northern Lights

Farzad Zaker, Northern Lights

The talk presented early operational lessons from Northern Lights, which began injection in August 2025. Phase 1 has a capacity of 1.5 $MtCO_2$ per year, with CO_2 received at Øygarden and injected through one operational well. FID has been taken for Phase 2, expanding capacity to 5 $MtCO_2$ per year from 2028.

Commissioning was described as smooth, following extensive planning across Northern Lights, its owners, service providers and emitter operators. Since start-up, around 80,000 tonnes of CO_2 have been transported over 20–30 vessel cycles, with around 70,000 tonnes injected.

Early operations highlighted several practical lessons. The reservoir was sensitive to particulates, leading to temporary filtration during commissioning and permanent filters on the offloading and export lines. CO_2 quality monitoring has also been expanded to support plant integrity and customer assurance. Northern Lights has issued its first storage certificate, using an MRV framework that tracks CO_2 from capture through transport and injection while accounting for emissions across the value chain.

The wider lessons were clear: greater regulatory alignment is needed across jurisdictions; full-chain collaboration must begin early, especially around marine and terminal interfaces; and stakeholder expectations must be managed carefully, as oil and gas shipping standards do not automatically translate across the full CCS value chain.

Lessons learned from early injection: Greensands

Michael Larsen, INEOS

Project Greensand presented lessons from its phased CO_2 storage development in the depleted Siri Canyon area of the Danish North Sea. Led by INEOS with Harbour Energy and Nordsøfonden, the project completed an offshore pilot injection in 2023 and received its permanent storage permit in 2025. The development is ship-based, around 130 km offshore, and uses cyclic intermittent injection, starting with the Nina West segment before scaling to the wider field.

Nina West benefits from a well-characterised depleted oil reservoir, good porosity and permeability, a thick regional caprock, a proven trap and a large underlying aquifer for pressure support. Existing wells are being repurposed for injection and monitoring, supported by around 15 years of exploration and production history.

The pilot injected around 4,100 tonnes of CO_2 over seven cycles, fewer than planned due to weather and vessel issues. Pre-injection laboratory work tested core strength, relative permeability, CO_2 impurities, geochemical reactions, brine backflow, salt precipitation and pH changes. Monitoring included pressure measurements, interference monitoring through an old producer well and a focused seismic trial.

The main lessons were regulatory, operational and modelling-related. The pilot benefited from a faster scientific-project route, while the permanent storage permit was more complex and slower than expected. Operational issues included flow measurement problems, tank temperature increases and gas breakout during early cycles. Modelling also had to move beyond standard reservoir simulation, with CFD used to capture near-wellbore behaviour during cyclic injection. Overall, Greensand showed the value of small-scale injection for de-risking commercial storage and supporting public communication ahead of full-phase start-up, planned for mid-2026.

Lessons learned from early injection: Poseidon

Nick Terell, Carbon Catalyst

The Poseidon project, operated by Perenco with Carbon Catalyst and Harbour Energy, is targeting CO_2 storage in the depleted Leman gas field in the UK Southern North Sea. Leman is a highly depleted and compartmentalised legacy gas field, with thick reservoir intervals, strong sealing by the Zechstein salt, and extensive existing infrastructure. This allows a phased brownfield development, with CO_2 injection in some fault blocks while gas production continues elsewhere in the field.

The early-2025 injection test was designed to address the lack of UK offshore CO_2 injection data, particularly for depleted gas reservoirs. It aimed to confirm reservoir suitability, demonstrate commercial-scale injectivity, test reuse of existing wells and topsides, and trial MMV technologies including fibre optic DTS/DAS, gauges, DAS-VSP, spot seismic and passive seismic. CO_2 was imported from the Netherlands, shipped to the Leman site, and injected from equipment installed on a mobile jack-up adjacent to the platform.

The campaign injected CO_2 over 15 cycles, in gaseous, supercritical and dense phases. Stable dense phase injection was achieved up to 1.1 $MtCO_2$ per year, while the well capacity was assessed as exceeding 2 $MtCO_2$ per year, with the test rate limited by facility design rather than reservoir performance. Multiphase injection through gaseous, supercritical and dense liquid conditions was shown to be operationally feasible, and Jules-Thompson cooling effects were less severe than predicted.

The test confirmed that depleted gas fields can support commercial-rate CO_2 injection using repurposed infrastructure, while reducing offshore heating requirements and associated cost, energy use and emissions. The MMV technologies performed well and will inform the Phase 1 monitoring programme. The resulting dataset is now being used for reservoir and flow assurance modelling, with pre-FEED complete and FEED expected to follow ahead of a targeted late-2027 FID, subject to anchor emitter offtake agreements.

Lessons learned from early injection: Ravenna

Claudia Virno Lamberti, ISPRA

The Ravenna CCS Phase 1 project is Italy's first integrated CO_2 capture, transport and offshore geological storage project. Authorised in January 2023, it captures CO_2 from a gas processing plant on the Ravenna coast, transports it through a repurposed 9 km pipeline, and injects it into a depleted offshore gas reservoir in the North Adriatic at around 3,000 m depth.

The authorisation covered experimental injection of up to 50,000 tonnes of CO_2 over two years, with ISPRA providing technical support to the Ministry of Environment, particularly on environmental control and monitoring. Injection took place from August 2024 to August 2025, with around 11,000 tonnes injected, below the authorised maximum. Operations remained within safety limits, with injection pressures of around 150–160 bar and CO_2 purity above the required 95% threshold.

The monitoring programme covered well integrity, pressure, temperature, fluid composition, microseismicity, ground deformation, reservoir modelling and marine environmental conditions. Offshore monitoring included bathymetry, sub-bottom profiling, water and sediment analysis, biological investigations and dispersion modelling.

No evidence of CO_2 leakage was detected during the injection period. Well integrity and injectivity were confirmed, no abnormal ground deformation or reservoir-related seismicity was observed, and no marine environmental impact was identified beyond natural and seasonal variability. The pilot demonstrated the value of integrated, multi-parameter monitoring and provides an important baseline for future industrial-scale CCS development in the Ravenna area.

Discussion

The discussion highlighted the importance of knowledge sharing between early CO_2 storage projects. Poseidon drew directly on lessons from Greensand, particularly around vessel configuration and offshore CO_2 handling, while Northern Lights emphasised its role as a first commercial mover sharing operational experience through the wider Longship initiative. Speakers agreed that sharing lessons in this early phase is essential, while recognising the need to protect legitimate commercial confidentiality.

Cyclic and intermittent injection was another major theme. Greensand noted the need to manage start-ups carefully to avoid unnecessary reservoir stress, while Poseidon's test data suggested that intermittent injection and Joule-Thomson cooling can be managed in depleted gas reservoirs. Northern Lights reported no major issues from early operational stop-starts so far, although speakers cautioned that the operational evidence base remains limited.

CO_2 metering across the value chain was identified as a significant cost and complexity driver. Multiple regulatory regimes currently require measurement at several points between capture, transport and storage. Northern Lights described custody transfer measurement approaches adapted from LNG and LPG practice, but the wider message was that regulatory convergence and more efficient metering requirements will be needed as CCS scales.

The discussion also questioned whether some early engineering solutions may eventually prove overcautious, particularly around cooling, multiphase flow and continuous injection. Speakers agreed that caution is understandable at this stage, as first-wave projects cannot afford failures that damage confidence in CCS. The preferred balance was to maintain strict containment and safety standards while using early operational data to simplify designs where justified.

Looking ahead, speakers suggested that future projects could benefit from hub-based configurations rather than single emitter-to-store chains, allowing larger vessels to serve multiple customers and reducing logistics costs. Further savings may also come from rightsized storage tanks, fewer testing requirements and better alignment between regulators as operational experience grows.

Session 5: Monitoring Techniques

Integration of seismic technologies for CCS monitoring – challenges and opportunities

Roya Dehghan Niri, Equinor

4D seismic is an established technology for offshore CO_2 monitoring, but can 4D acquisition and processing constraints be relaxed to reduce costs while maintaining effectiveness? This study examined sparse acquisition strategies and improved processing workflows for seismic monitoring optimisation. The approach remains under development but shows promise, with advances in Full Waveform Inversion (FWI) and computational algorithms.

A range of combined seismic solutions exists, though the integrity of an initial baseline dataset must not be compromised. Subsequent monitoring options include selected 2D lines, Ocean Bottom Nodes (OBN), Mini-Streamers (XHR), and Distributed Acoustic Sensing in wells (DAS-VSP). Each has distinct strengths and limitations; this study assessed whether an integrated multi-technology approach could deliver robust results.

Testing was conducted at Johan Sverdrup, a mature oil field with no CCS plans but with advanced infrastructure including a Permanent Reservoir Monitoring (PRM) system, in-well fibre optics, and accessible vessels. The test combined XHR mini-streamers, in-place OBN, and DAS-VSP, with the objective of evaluating integrated velocity model building and imaging.

Rather than constructing three separate seismic volumes for subsequent integration, all data were integrated into a single volume, with uncertainties handled within one model. FWI was selected as the integration method over co-migration. FWI was applied to XHR+OBN and DAS-VSP+OBN datasets using enhanced workflows. Key results include: decimated OBN combined with XHR improved shallow target imaging compared to OBN alone; DAS-VSP enhanced near-well velocity models from OBN data; and multi-parameter FWI resolved surface structures (including platforms) in detail despite absent source data at acquisition time.

While the methodology is still maturing, progressive improvements demonstrate the potential to optimise data type combinations and reduce monitoring costs without sacrificing imaging quality.

Insights from full waveform inversions (FWI) at Sleipner

Philip Ringrose, NTNU, Centre for Geophysical Forecasting

This PhD work by Ricardo Martinez demonstrates the benefits of applying full waveform inversion (FWI) to image multi-layer CO_2 plumes at Sleipner, where ~11 repeat seismic surveys have been acquired since 1994. 4D amplitude-difference data (2010 vs. 1994) show strong responses in the upper layers (6–9) but degraded resolution at depth due to interference and signal loss. Rather than processing this away conventionally, FWI exploits the full wavefield, including diving and refracted waves, to construct a complete earth model.

Results published in 2025 used 2010 marine-streamer data (6 km offset), providing improved imaging of lower layers (1–4) and vertical feeders. Subsequently, OBN data acquired by Veridian and TGS in 2023, processed through the same workflow, resolved all nine sand layers, vertical feeders, shallow gas, channels, and faults, with improved shallow resolution and reduced multiples. The resulting 3D velocity model, treated as an earth object with CO_2 mapped as low-velocity anomalies, clearly images the injection-point feeder, fault-influenced migration up to layer 2, and vertical containment across all nine layers. The number of identified feeders has increased from 10 to 15 or more.

Combined FWI and amplitude mapping enables detailed storage efficiency calculations and pore volume occupancy through time (1996–2020). Conventional metrics yield storage efficiencies of 1–6%, consistent with Norwegian Storage Atlas values. At mesoscopic scale, this workflow indicates ~50% saturation within structural closures. Layer-by-layer analysis of the 2010 FWI model shows layer 1 is compact and viscosity-dominated (~50% saturation); layer 2 is fault-controlled with significantly reduced efficiency; and layers 3–9 show decreasing efficiency upward as gravity-driven migration becomes dominant. FWI particularly illuminates vertical migration features not previously imageable.

Mass-in-place estimated from the 2023 OBN FWI dataset is 19.63 ± 4.05 Mt, comparing favourably with the reported injected mass of 19.1 Mt CO_2 by August 2023, providing independent verification at a reasonable level of accuracy.

An enLightening story – Fibre optics as a monitoring solution for CCS

Sondre Torset, Equinor

Fibre optic (FO) cables offer broad applications in offshore CCS monitoring. The two principal sensing modes are Distributed Acoustic Sensing (DAS) — the focus here — which measures strain or strain rate as seismic waves pass through the cable, and Distributed Temperature Sensing (DTS). Three case studies illustrate potential CCS applications.

Well integrity: Strain data collected in wells of known condition can be matched to well state, enabling confident interpretation in future wells and potentially reducing costs through fewer well interventions.

Passive seismic: TotalEnergies deployed a cable between the Troll and Oseberg platforms to detect naturally occurring seismic events. Integration into a holistic CO_2 monitoring plan requires further development (the CLIMIT demonstration project HNet is examining this[7]).

Active seismic (DAS-VSP): In-well fibre enables repeat seismic acquisition for 4D comparison. When benchmarked against a high-specification Permanent Reservoir Monitoring (PRM) system in the same well, DAS-VSP shows lower illumination and resolution but comparable structural results. Surface-deployed active fibre similarly produces lower data quality than PRM, though structural interpretation remains consistent.

A key consideration is the trade-off involved in substituting FO systems for conventional data types such as 3D seismic. There is a general industry aversion to accepting increased risk — in this case, reduced data quality and illumination range — in exchange for other advantages, and whether such trade-offs satisfy regulatory requirements remains an open question.

MMV challenges and options in a crowded offshore environment

Steve Oates, Marcella Dean-Elsener and Chris Willacy, Shell

Practical experience delivering risk-based MMV plans offshore highlights several key lessons. Operating in congested environments - navigating Environmental Protection Areas, pipelines, shipping lanes, and wind farms — demands a flexible, cooperative approach to designing both active and passive geophysical surveys.

CCS platforms must have adequate space and power for monitoring equipment; DAS/DTS energy requirements are frequently underestimated and should be assessed early. 3D seismic dominates MMV costs and must be integrated as a line item in project budgets from the outset.

Consortium projects HNET3 and ENSURE[8], have demonstrated the value of hybrid monitoring networks, combining complementary systems opportunistically. The new SAFE-C[9] project is testing buoy-based systems with data transmission and power supply

[7] CLIMIT demonstration project HNet is examining this topic https://hordanet.no/
[8] https://ensure.norsar.no/
[9] https://cetpartnership.eu/index.php/cetp-selected-projects-2024

to OBS arrays. Novel synergies — such as sensors embedded in wind farms or communication cables — represent attractive future options.

Passive monitoring options span surface and downhole deployment, each with cost, accessibility, and signal-to-noise trade-offs. OBS data collection approaches vary between continuous real-time cable transmission and periodic harvesting from autonomous units. Notably, onshore seismic receiver networks around the North Sea Basin provide reasonable passive coverage (down to M~2) of the near-offshore regions being considered for CCS projects.

Active monitoring options include time-lapse 2D/3D seismic, P-cable short streamer surveys, time-lapse DAS-VSP, and sparse "fence-line" surface seismic with dynamic positioning based on plume migration modelling. At the Sapphire prospect (Humberside, UK) — a significant storage opportunity near major UK emission clusters — a feasibility study using synthetic seismic data showed plume detectability to ~5% saturation, though a neighbouring wind farm may compromise longer-term plume tracking.

The central challenge is finding the optimal balance between acquisition cost and data quality. Sparse datasets reduce costs but risk interpretational ambiguity; AI-assisted interpretation is well suited to address this.

STEMM-CCS - Cseep technique for attribution in environmental monitoring

Katherine Romanak, GCCC and Abdirahman Omar NORCE

Attribution, determining whether an environmental anomaly represents leakage or natural variability, is not yet explicitly required by regulations, but this is changing, and rapid methods are essential. Seabed and water column baselines are problematic due to natural variability, creating false positive leakage signals. The marine environment is considerably more complex than the terrestrial, though the CO_2 respiration relationship does hold offshore, albeit with greater scatter. This relationship was applied at the Tomakomai project, where a single data point exceeding the threshold just one month into injection triggered a year-long shutdown pending investigation, highlighting the urgent need for more robust attribution methods.

The Cseep method addresses this through a process-based approach with three functions: characterising baseline dissolved inorganic carbon (DIC) at the site; attributing CO_2 seepage signals against natural variability; and quantifying excess dissolved CO_2 (as total flux or total dissolved). The method is flexible in implementation and areal coverage, suitable for automation, and mathematically straightforward. Total DIC is modelled as a function of the baseline, computed natural variability (driven by organic matter cycling, calcium carbonate cycling, water mass mixing, and air-sea exchange), and the Cseep seepage contribution.

Validated against the STEMM-CCS controlled release experiment and multi-year baseline cruises (2001–2019), the method identifies organic matter cycling as the primary driver of near-seafloor carbon variability. By comparing observed to computed values, natural variability is minimised and leak events are clearly distinguishable from background — offering a more reliable basis for regulatory decision-making and avoiding unnecessary project interruptions.

Discussion

The Q&A session opened with a discussion on potential synergies between offshore wind farms and storage projects. While the proximity of CCS infrastructure to wind developments was recognised as offering possible collaboration opportunities, speakers acknowledged that clear commercial or operational benefits for wind developers are not yet well defined. The emphasis was instead placed on the need for greater coordination, with organisations such as the NSTA encouraging collective thinking and cooperation—particularly around shared monitoring approaches. Beyond wind, participants noted that other offshore sectors could also offer partnership opportunities, especially those already deploying seabed infrastructure such as communications fibre, though this area remains under exploration.

A significant portion of the discussion focused on monitoring, measurement, and verification (MMV) strategies and how these should inform site selection and project design. Panellists stressed that monitoring approaches must be driven by a site-specific understanding of risk, flow physics, and reservoir behaviour. Rather than adopting prescriptive requirements, there was strong support for flexible, risk-based frameworks that allow operators to tailor monitoring tools to individual storage sites. It was also highlighted that FWI imaging techniques cannot capture all free-phase CO_2, underscoring the importance of integrating subsurface understanding with monitoring capabilities when designing CCS projects.

Emerging technologies, particularly fibre optic sensing, were discussed as promising tools for improving monitoring efficiency. Fibre installations could potentially reduce reliance on expensive repeated seismic surveys while providing valuable data such as temperature distributions within reservoirs. Surface distributed acoustic sensing (DAS) was considered sufficiently mature for offshore deployment, with evidence from recent projects and industry trials supporting its effectiveness. However, practical considerations remain, such as the need for suitable infrastructure to house interrogator units. Overall, fibre was seen as a versatile and increasingly compelling option, though deployment decisions will depend on cost-benefit considerations and project design choices.

Regulatory frameworks and carbon market requirements were another key theme. Participants highlighted the tension between the need for robust monitoring standards and the risk of overly prescriptive regulations, particularly as voluntary carbon markets begin to establish their own rules. There was consensus that regulators should focus on outcome-based frameworks supported by strong technical understanding, rather than mandating specific technologies. The role of international bodies such as the IPCC was noted as particularly important in shaping methodologies that balance credibility with flexibility, especially as updated guidance on CCS and carbon dioxide removal is developed.

Finally, the session addressed the use of tracers for monitoring CO_2 movement. While tracers can be valuable for identifying and tracking injected CO_2, their practical application—especially in complex hub scenarios—were viewed with some caution. Challenges include overlapping signals from multiple sources and potentially high costs associated with artificial tracers. As a result, while tracers remain part of the monitoring toolkit, their utility may be limited in certain contexts, reinforcing the need for integrated, multi-method monitoring strategies.

Session 6: Monitoring – Evolution of Programs

Interactive Panel Discussion: From Baselines to Full Injection

Panellists: Cecilie Rosing Dybbroe (INEOS, Greensand), Jon Tarasewicz (bp, Northern Endurance Partnership), Gloria Thürschmid (EBN, Porthos), Matthieu Vinchon (Northern Lights).

The panel brought together operators at different stages of project maturity, including Greensand, Northern Lights, Porthos and NEP. Discussion focused on how monitoring plans evolve from early baselines to full injection, how projects balance subsurface and water-column monitoring, and how novel technologies can gain regulatory acceptance.

A clear message was that MMV plans change substantially through the project lifecycle. Northern Lights, Porthos and NEP have all revised or refined their monitoring strategies as new data and insights, project phases and regulatory requirements emerged. Established oil and gas monitoring methods are generally easier to implement, while newer approaches such as gravity monitoring, DAS and focused seismic require greater feasibility work, regulator engagement and supporting evidence.

The balance between subsurface and water-column monitoring was described as risk-based and site-specific. Projects without legacy wells, such as Northern Lights, place greater emphasis on subsurface conformance and containment, while projects with legacy well uncertainty, such as Greensand, require stronger seabed and water-column monitoring at specific locations. For Endurance, the thick sealing succession above the Bunter Sandstone provides containment confidence with seabed monitoring aimed at environmental assurance and vertical leakage detection.

The panel also highlighted practical constraints. Manual retrieval of seismic nodes is costly and requires substantial operational effort, creating interest in real-time data transmission through project infrastructure. Novel monitoring technologies can struggle to meet regulator expectations unless deployed alongside established methods and supported by published evidence. Early regulator engagement and sharing results from publicly supported pilots were seen as essential for building confidence.

The closing advice was to develop MMV plans early, alongside corrective measures plans, so that each monitoring element is linked to a clear operational response. Panellists also stressed the importance of non-technical risks, including public confidence and political acceptance. Monitoring must therefore be technically robust, cost-conscious and explainable to non-specialist audiences.

MMV – a regulator's view (Norway)

Jorge Sanchez Borque, SODIR

The talk set out The Norwegian Offshore Directorate (SODIR)'s approach to CO_2 storage monitoring, framed around enabling safe storage while trusting operators to develop fit-for-purpose solutions. Under the EU-derived framework, operators must show that CO_2 behaviour remains consistent with predictive models, that irregularities can be identified and addressed, and that the store remains stable through the post-injection period before liability transfer to the state.

The monitoring plan was presented as the tool for turning uncertainty into managed risk. SODIR expects operators to understand their licence area, identify key uncertainties, and design work programmes that reduce or manage those uncertainties. The requirement is not a standard template, but a credible plan matched to site-specific risks.

Norwegian experience shows why monitoring must be fit for purpose. Sleipner demonstrated the value of 4D seismic for tracking CO_2 movement, Snøhvit showed the importance of contingency planning when pressure behaviour differed from predictions, and Northern Lights has added induced seismicity monitoring with public data release.

SODIR also encourages cooperation between operators where storage reservoirs overlap, including shared seismic acquisition to reduce cost and improve regional understanding. The concluding message was that geological CO_2 storage can be safe, but residual risks must be actively managed through site-specific monitoring and early, continuing dialogue between operators and regulators.

MMV – a regulator's view (UK)

Ian Barron, NSTA

The talk set out the UK's North Sea Transition Authority's (NSTA) view of how monitoring plans should evolve across the lifecycle of a CO_2 storage project. The monitoring plan forms part of the approved storage permit, so operators are expected to deliver what they commit to. Monitoring should therefore be considered from the earliest appraisal stage, including technology opportunities, legacy well risks, monitorability and possible co-location issues such as overlap with offshore wind areas.

The Appraise Phase was described as a progression from Early Risk Assessment to the Containment Risk Assessment supporting the permit application. Monitoring design should follow this process, using site characterisation and dynamic modelling to define what needs to be measured, where and when. Where time-lapse seismic is being considered, expected 4D seismic response should be assessed early, with evaluation of other techniques such as gravity considered, particularly where seismic response may be limited or acquisition of 3D seismic is not feasible or desirable. Monitoring for natural and induced seismicity may be driven by stakeholder confidence as well as technical need.

For the Operational Term, monitoring plans must be updated at least every five years, although significant milestones such as injected volume or pressure thresholds may also be appropriate triggers for revision. Updates should reassess whether monitoring methods are delivering value, adjust deployment where needed, and allow new technologies to be introduced. Where novel methods are proposed, the NSTA encouraged early discussion between operators and vendors and parallel deployment alongside established techniques before substitution.

The closing message was that each store is different, and monitoring plans should remain risk-based, evidence-led and adaptable. Early engagement with regulators, cross-operator learning and collaboration across the sector will be important as UK CCS projects become more complex.

Discussion

The discussion emphasised the importance of starting risk assessment and regulator engagement early. Initial risk assessments should identify the broad risks to capacity, containment, injectivity and monitorability, before being progressively refined toward the storage permit application. Independent third-party review was described as a useful completeness check, while early engagement with technology vendors was encouraged so that novel monitoring methods can be assessed before they are committed to a project plan.

A key theme was the difference between factual and perceived risk. Technical risks require appropriate monitoring and mitigation, while perceived risks require communication and stakeholder engagement. Early agreement between operators and regulators on this distinction was seen as valuable, particularly as CCS regulators may need to become more visible in explaining how monitoring provides assurance.

The overlap between MMV and MRV was also discussed. Although they serve different purposes, metering data, injected volumes and CO_2 stream composition are relevant to both regulatory assurance and accounting. Better integration of these requirements could reduce complexity, although this is not yet a primary regulatory focus.

Several technical points were raised, including the limits of pressure gauges as substitutes for seismic or fibre-optic monitoring, the value of reusing oil and gas data where available, and the future need for cross-border data-sharing arrangements. Overall, the discussion reinforced that monitoring plans should be risk-based, adaptable and developed through early, continuous dialogue between operators, regulators and technology providers.

Session 7: Commercial. Regulatory & Social

2027 Methodology Report of Carbon Dioxide Removal Technologies, Carbon Capture, Utilization and Storage (Supplement to the 2006 IPCC Guidelines)

Tim Dixon, IEAGHG

Tim Dixon provided an update on the IPCC Task Force on National Inventories. The absence of a country-level methodology for Direct Air Capture has prompted a new CDR methodology report, due in 2027. The Terms of Reference — effectively a table of contents — were agreed following an October 2024 meeting, though two plenaries were required to reach consensus on several contentious issues, including whether to include marine CDR (ultimately excluded from the workplan). IEAGHG will contribute as experts throughout the two-year programme.

The methodology report will comprise six volumes covering all carbon removal techniques, including BECCS, land use, energy and industrial processes, and energy-from-waste. A chapter on direct CO_2 removal from water bodies was removed due to lack of agreement.

Volume 6 covers Carbon Capture, Transport, Utilisation and Storage, with new chapters on DAC and CCU alongside updates on point-source capture, transport, and storage. It will draw on the existing 2006 IPCC Guidelines for National Greenhouse Gas Inventories, which underpin regulations and site screening methodologies for CO_2 storage globally. The inclusion of DAC has necessitated a review of CO_2 storage methodology. Lead authors Tim Dixon and Katherine Romanak have prioritised preserving the established methodology's key elements to avoid disrupting existing regulations and permits in progress — a framework that regulators and operators are satisfied with and that functions well in practice.

Unlike an assessment report, which synthesises the latest science, this methodology report requires only a workable, practical framework.

Commercial aspects of the London Protocol

Ingvild Ombudstvedt, IOM Law

The talk provided an overview of a recent IEAGHG report on guidance for transporting CO_2 across national boundaries under the London Protocol, examining the issue from both government and commercial perspectives. It highlighted how CCS increasingly relies on cross-border value chains, raising questions about how countries negotiate agreements, what legal frameworks already exist, and where gaps remain. The London Protocol (LP), an international treaty aimed at protecting the marine environment, currently prohibits the export of waste for dumping under Article 6. Although a 2009 amendment allows CO_2 streams to be exported for storage, it has not formally entered into force. A 2019 resolution enables provisional application for countries that declare their participation, creating a partial pathway forward but leaving uncertainty, especially for collaboration involving non-contracting parties.

A key focus was the complexity of commercial agreements in CCS projects, particularly when crossing borders. As a relatively new industry, CCS lacks established contractual norms, although it can borrow elements from sectors like oil and gas. Even so, new challenges arise due to novel technologies and regulatory uncertainties. A central practical question for any project is whether the receiving country is a party to the London Protocol and, if so, whether bilateral agreements are already in place. Where they are not, significant government engagement is required to establish enabling frameworks. In practice, commercial projects are often driving which countries enter into negotiations, with differing business cases and levels of readiness across jurisdictions.

The talk also emphasised the importance of aligning bilateral agreements with broader frameworks, such as the Paris Agreement (notably Article 6), and, in some cases, carbon dioxide removal (CDR) strategies. In regions with established carbon markets, like the EU Emissions Trading System (ETS), additional complications arise: for example, CO_2 exported outside the ETS may not qualify for emissions credits. Differences in regulatory standards between countries further complicate matters, sometimes requiring reliance on international standards (e.g. ISO) to bridge gaps.

Finally, several technical and legal issues were highlighted as critical in contract design. These include defining CO_2 specifications, managing co-mingling of streams, determining the purpose (storage vs utilisation), and agreeing on applicable law and dispute resolution mechanisms. The treatment of CO_2 ownership and liability is particularly complex: in the EU ETS, responsibility may transfer to transport and storage operators once CO_2 is handed over, whereas in voluntary carbon markets, ownership and credit entitlement may remain with the emitter. Additional challenges arise with CDR, where differing methodologies, mixed CO_2 streams, and less mature market frameworks create further uncertainty—particularly in cases of leakage or accounting for emissions across jurisdictions.

ANGEA Cross Border CCS Study

Hanh Le, Ange association

Cross border CCS is complicated by an array of international guidelines and differing regulatory frameworks across countries in the Asia Pacific region (APAC). Key questions governments ask in considering cross border CCS, how does that influence our Nationally Determined Contribution (NDC) and for the receiving country, how do we avoid double counting?

The objectives of the study were to examine international guidelines, domestic regulations, and carbon accreditation mechanisms for certifying emission reductions from cross border CCS, and to review potential business models, and identify gaps and challenges that need to be addressed in future agreements. Two key areas needing resolution were: emission reduction credit generation and who held the rights to emission reduction, and leakage liability responsibility.

Five bilateral agreement recommendations on cross-border CCs projects came out of this study. Agree on ownership rights to the emission reductions. Agree on jurisdictional accountability for emissions from leakage and acceptable mechanisms for the adjustment of such emissions. Agree to share data for emission reduction certification. Agree on regulatory responsibility during CO_2 transportation. Agree on dispute resolution mechanism, including arbitration forums etc.

Build out of coastal and offshore Hubs in Brazil

Flavia Almada Horta Marques, Petrobras

Brazil's large population and land area contribute to significant emissions, primarily driven by agriculture and land-use change. However, its energy mix is already around 90% clean energy, which limits the role of carbon capture and storage (CCS) mainly to industrial processes. The country benefits from extensive sedimentary basins, some of which underly major emission sources, however most CCS expertise to date has been developed offshore. This creates challenges for high-emission regions such as São Paulo, where distance from offshore storage sites and only vintage legacy onshore seismic data constrain deployment. Bioethanol presents a promising opportunity for CO_2 capture due to its proximity to suitable basins, potentially enabling more cost-effective solutions.

Initial CCS hub strategies focused on well-characterized offshore pre-salt basins, but high costs have driven a recent shift toward onshore storage. Petrobras is advancing four hub projects (Bahia, Espírito Santo, Rio de Janeiro, and São Paulo) alongside a São Tomé pilot (FID in 2025) to support decarbonisation across sectors such as refining, hydrogen, sustainable aviation fuel, and steel production—particularly where exports face carbon border adjustments. Despite progress, significant barriers remain, including high capital costs, reliance on imported capture technology, immature business models, and regulatory uncertainty. Brazil introduced a CCUS regulatory framework in 2024 and is developing the details, including carbon market integration and emissions trading, but key issues—such as long-term liability, CO_2-EOR treatment, and fiscal stability—are still unresolved. Building public trust, strengthening cross-sector collaboration, and clarifying incentives will be critical to scaling CCS and achieving national climate targets

Monitoring solutions through Citizen Science

Katherine Romanak, GCCC

Public understanding of carbon capture and storage (CCS) is often limited, but communities consistently prioritise safety and environmental protection. Experience and research, including a 2024 study on the impact of monitoring complexity on stakeholder acceptance in the US Gulf region, show that simple, transparent environmental monitoring approaches can significantly improve public confidence. Crucially, involving stakeholders directly in project planning increases their willingness to accept CCS developments, as it builds trust and gives communities a sense of control over how risks are managed and communicated.

This dynamic was illustrated in the Lake Maurepas region of Louisiana, an area of high community value due to its role as a brackish tidal estuary supporting recreation and wildlife. Plans for a potential CCS project generated concern when seismic testing began without prior public consultation, contributing to local opposition and even proposed (though unsuccessful) legislation for a 10-year moratorium. Inspired by these events, students from Denham Springs High School engaged with the issue as part of Samsung's "Solve for Tomorrow" challenge. After identifying low levels of community awareness about CCS, they surveyed residents and found strong support for accessible monitoring solutions. With mentoring support, the students developed a community-focused CO_2 sensor and companion app, empowering residents to monitor local conditions and understand what actions to take if concerns arise. Through this process, the students themselves gained confidence in the safety of CCS and became effective communicators within their community—demonstrating the powerful impact of youth-led engagement in building trust and awareness.[10].

Discussion

Discussions highlighted the generally supportive stance of the London Protocol (LP) toward carbon capture and storage (CCS), recognising its role in reducing greenhouse gas emissions and mitigating ocean impacts. Ingvild noted that CO_2 in the atmosphere contributes significantly to ocean degradation, including acidification, and that impact

[10] [2024 - 2025 Solve for Tomorrow Student Video: Denham Springs High School, LA]

assessments under the LP have consistently found CCS to be favourable due to its emissions reduction benefits. Tim added that when amendments to the LP were first considered in the mid-2000s, emerging science on ocean acidification reinforced the urgency of action, with CCS offering a comparatively straightforward, closed-system solution. In contrast, marine geoengineering remains far more complex from both a technical and legal perspective, and continues to present significant challenges.

The discussion also emphasised the importance of stakeholder engagement in marine environments, which are often incorrectly assumed to have few or no stakeholders. In reality, coastal and marine ecosystems support livelihoods, recreation, and biodiversity, making public engagement essential. Practical approaches, such as involving students in STEM-based activities to explore CO_2 storage concepts (e.g. measuring pH and alkalinity), can help build understanding even without direct site access. Research from southern Europe suggests that public acceptance of CCS can in some cases be lower offshore than onshore, partly due to concerns about impacts on marine environments, highlighting the need for improved communication and education—particularly among younger, environmentally aware audiences.

On carbon markets, Tim explained that the relationship between voluntary and compliance systems remains uncertain. Voluntary markets are largely self-regulating and lack formal governance, although mechanisms under Article 6 of the Paris Agreement may enable some integration. Examples such as Singapore's carbon tax scheme, which allows companies to use internationally transferred mitigation outcomes, illustrate potential links between systems, while Japan's Joint Crediting Mechanism offers another model for structured offsets.

Finally, participants discussed the growing importance of cross-border CCS in the Asia-Pacific region. Many countries are exploring how to balance domestic needs with international opportunities, with some, such as Malaysia, establishing policies to receive imported CO_2. Japan, facing limited domestic storage capacity, is actively seeking such partnerships, while other countries—including Indonesia and Australia—are positioning themselves within an emerging regional market. Although regulatory alignment remains a challenge (particularly where countries are not parties to the LP), cross-border collaboration is widely seen as essential to scaling CCS and building viable value chains, demonstrating how developments that began in regions like Norway are now shaping global deployment

Session 8: Closing Wrap-up

Conclusions:

The two-day programme concluded with a plenary discussion synthesising key conclusions and recommendations. Participants — in-person and online — agreed that opening with project round-up sessions was valuable for both experienced practitioners and new entrants.

Across projects, clear progress was evident in storage type diversity, transport configurations, and monitoring innovation. A phased approach is increasingly common, with test injections informing staged scale-up aligned to emitter readiness — a reminder that projects need customers to progress. Direct ship injection is emerging as a flexible, lower-cost alternative to fixed pipeline infrastructure, and is being adopted across multiple projects as the preferred early-stage solution. Two projects have demonstrated and de-risked cyclic offshore injection; the Poseidon project's early model calibration through operational range and phase envelope testing was highlighted as a positive industry contribution. Early collaboration across stakeholders, regulators, communities, and supply chain partners was emphasised throughout, particularly for cross-border CO_2 transport contracting.

Composite confinement systems were recognised as expanding potential storage capacity opportunities and increasing confidence in storage security. Proactive operator collaboration and regulatory oversight are essential for basin-scale resource management, including pressure management and interference, with data sharing as an enabling foundation. The NEP's decision to increase storage acreage rather than produce brines was noted as a positive example of balancing resource and environmental considerations.

Wells remain critical to site screening and should be de-risked early, with the shallow section often the primary concern. AI tools show promise for well screening, but require expert verification. The Wellfate study demonstrated the ability to detect and characterise methane seeps, finding most to be biogenic and sourced from shallow strata.

Offshore monitoring is progressing towards cost-effective commercial solutions, with regulators remaining open to engagement including on commercially sensitive matters. There is significant activity around reducing MMV costs without sacrificing data quality. Operators are testing a range of low-cost technologies, fibre optics, short cables, OBS, sparse seismic, against established benchmarks. Thirty years of Sleipner data have enabled exceptional CO_2 fate tracking via FWI. Further innovation and collaboration with co-located infrastructure might unlock future solutions, especially in a crowded environment. Attribution methods are now being incorporated into regulations, helping avoid unnecessary project shutdowns.

The workshop was originally convened to learn from Norway's early offshore CCS projects and continue to demonstrate what is possible.

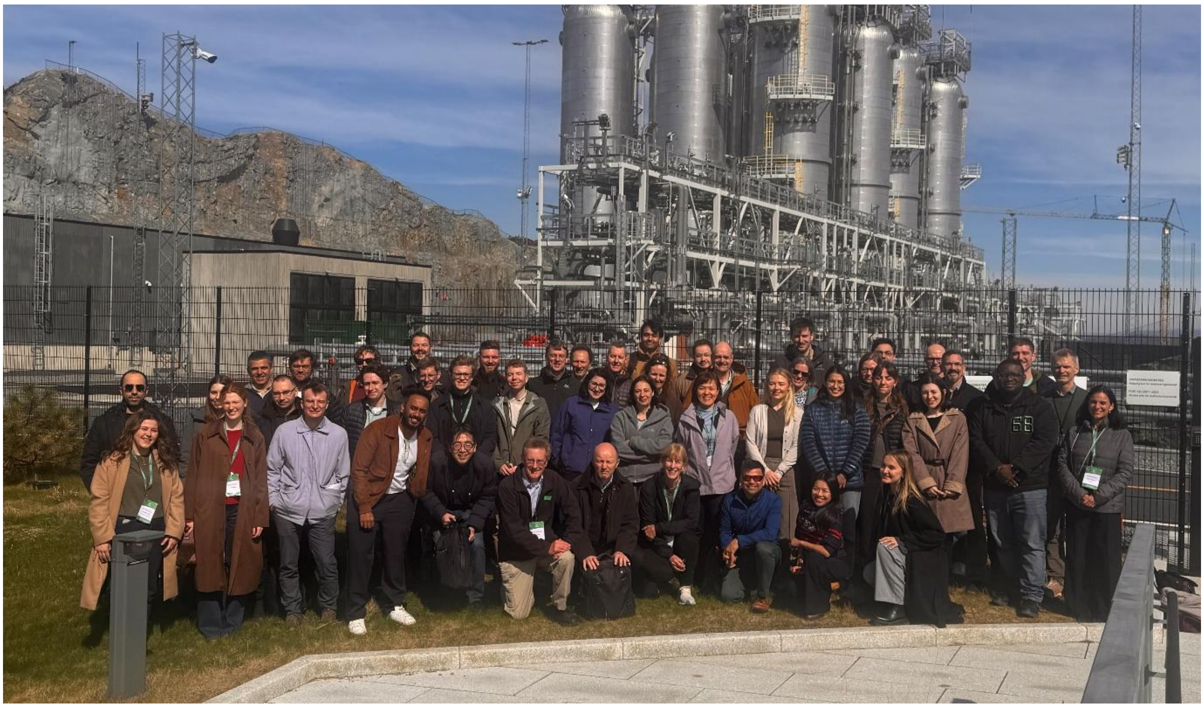
Recommendations:

The following recommendations resulted from the discussions:

- Learnings from projects are incredibly valuable, and data sharing is to be encouraged, where possible.
- A wealth of legacy research and outputs from projects are available in the literature that will shortcut the timeline of current projects and reduce costs. E.g. the IJGGC and the STEMM-CCUS reports.
- Keep an eye on how pressure might impact neighbouring projects and environmental impacts (legacy wells, onshore outcrops).
- Being vigilant to ensure regulations continue to advocate for non-prescriptive technologies and solutions for monitoring.
- Engaging stakeholders in monitoring helps elicit buy-in and project acceptance, don't overlook the young or old in that process. Use all methods of approach for outreach.

Field trip

Following the offshore workshop, 50 delegates were treated to a visit to the Northern Lights facility, where attendees enjoyed informed presentations from Geir Grottveit (Manager of Operations and Maintenance), Knut Mathias Vestbo (Project Director Northern Lights Phase 2), an inspiring talk from the Mayor of the Øygarden Municipality, and lastly a visit from Tim Heijn (MD of Northern Lights JV). Tim Dixon was able to present a glass globe gift on behalf of IEAGHG to Tim Heijn with the inscription "From IEAGHG to the Northern Lights Project, marking your achievement as a global milestone for CCS. Presented on the occasion of the 8th Offshore Workshop, 22 April 2026". Some 15,000 visitors have so far visited the Northern Lights visitor centre, and seeing really is believing.



Attendees of the 8Th International Workshop

Tim Dixon (IEAGHG) presents Tim Heijn (Northern Lights) an award that marks Northern Light's achievement as a global milestone for CCS.

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