CO_2 Storage from Lab to On-Shore Field Pilots Using CO_2 Foam for Mobility Control in CCUS

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Summary
This project included laboratory work and implementing a field pilot for CO2 storage. The project demonstrated how to realize global CO2 storage at volumes large enough to mitigate global warming by verifying a disruptive, new and more sustainable oil recovery technology for Carbon Capture Utilization and Storage (CCUS). The technology provides incentives for the industry to participate in CCUS by generating improved revenue in CO2 foam EOR utilizing mobility control and thus enabling industrial CCUS. In this project, the next generation petroleum engineers have integrated the entire value chain of CCUS in their education, including participation in upscaling from lab to field. By building long-term, interdisciplinary and international scientific networks, efficient industry-academia collaborations were generated. Determining scale-dependent foam mechanisms showed the applicability of foam to address CO_2 and climate challenges.

The NFR/CLIMIT Project at the Department of Physics and Technology, University of Bergen titled, "CO_2 Storage from Lab to On-Shore Field Pilots Using CO_2 Foam for Mobility Control in CCUS" has achieved the main goals within the budget and time frame. Industry support for the project was obtained as planned, resulting in a final budget of 14 278 KNOK: NFR: 10 018 KNOK (70%), UiB: 1 379 KNOK (10%) and industry: 2 881 KNOK (20%). A total of five PhD students and twenty master students have graduated in the project. Three of the PhD students graduated from UiB, before the project end date, and one graduated from Rice University and one from UiS. All PhD students were supervised or co-supervised by the project leader. A total of 101 papers have been published in international scientific journals and proceedings with peer review and as proceedings from international scientific conferences without peer review. A total of 72 scientific oral presentations have been given at International Scientific Conferences, for the oil industry, and for governments and universities; see enclosed list of all publications and talks. A total of 32 technical reports to industry have been issued. Extensive use of international scientific networks and industry collaborations were important for meeting the project objectives. International student exchange was a major part of the educational scheme in the project and was paid in full by the obtained industry funding.

Introduction
Global energy strategies need to reflect the current climate and societal challenges. Thus, petroleum production needs to become more sustainable while continuing to provide the much needed energy for the world's growing population. This energy strategy can be implemented through combining the utilization of anthropogenic CO2 for enhanced oil recovery (EOR) and CO2 storage. CO2 EOR is the only process that may store sufficient CO2 volumes to mitigate global warming while generating a revenue for the industry; a critical criteria for industry participation in Carbon Capture, Utilization, and Storage (CCUS).

The goals of the Paris agreement and the UN's sustainability goals cannot be achieved without significant global efforts to permanently store CO2. Carbon capture and storage (CCS) has been considered as a possible method to achieve these goals through capturing CO2 at industrial point sources and injecting it into deep, saline aquifers for permanent storage. However, the high cost has restricted its widespread implementation; most importantly because it has not been resolved how and by whom the costs will be covered, probably either by the tax payers or the end-users. Indeed, this scenario may be applicable in the western, well-developed world but it is unlikely to work in most of the world; especially not in developing countries where access to affordable energy is the main concern. The volumes of CO2 that must be stored in order to reduce anthropogenic climate change are so large that industrial participation is required. However, the industry will be reluctant to participate in CO2 storage unless revenues are generated during the process. Therefore, this project aims to demonstrate a disruptive new CO2 storage technology, which provides improved commercial revenues to industry while reducing CO2 emissions.

Objectives and Summary of Results

New technology developed at the University of Bergen utilizes anthropogenic CO2 together with mobility control foam in co-optimized EOR and CO2 storage processes. This approach is an economically sustainable solution for mitigating the high costs of CO2 capture and storage, while providing the world with much needed energy. Conventional CO2 EOR does not generate enough revenue, globally, to ensure industrial interest in CO2 storage. CO2 foam for mobility control is capable of increasing oil production more than in conventional CO2 EOR, while reducing operational costs and providing more efficient oil displacement. This EOR-technology, developed at University of Bergen, will increase CO2 sequestration and serve as an enabler of commercial CCUS. In general, water injection recovers 30-50% of the oil, CO2 EOR 5-10% more, while CO2 Foam EOR may provide 10-30% more oil recovery subsequent to waterflooding.

CCUS-contributions from the project:

- To realize global CO2 storage at volumes large enough to mitigate global warming, this project verifies a new and more sustainable oil recovery technology, both with respect to economy and environment, which provides incentives for the industry to participate in CCUS.

- In this project, the next generation of petroleum engineers have integrated the entire value chain of CCUS in their education, including participation in upscaling from lab to field.

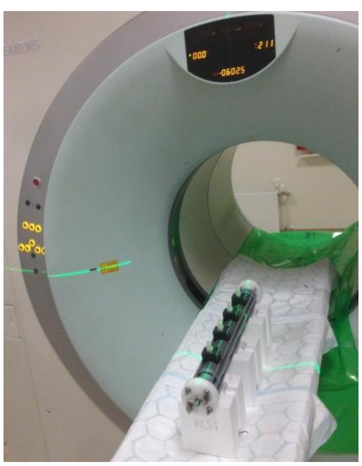
This international research collaboration between 6 universities and 6 oil companies in the US and Europe has demonstrated a more efficient method for CO2 storage using CO2 foam for mobility control in integrated EOR (IEOR). CO2 foam systems for mobility control have been developed within the project and were tested in an onshore US field pilot in a carbonate reservoir. Commercially available CO2 in the US, short interwell distances, and low costs in onshore pilot test, combined with long experience with CO2 EOR projects, made Texas a particularly good field pilot area. The field experience from the field pilots in Texas must be adapted to use on the Norwegian continental shelf. Upscaling from lab to onshore fields is part of a strategy for final upscaling to offshore reservoirs with large interwell distances. The international research team between academia and industry has ambitions to optimize the technology by performing several EOR field pilots with CO2 foam for mobility control in the US and then conducting an offshore field pilot, if funding becomes available. After three years of preparation, the foam pilot was started in an oil field in Texas in May 2019 and will last for 9-12 months. To date, 20 Master's students and 5 PhD students have graduated in the project.

Norway has more than 23 mature waterflooded reservoirs, both sandstone and chalk, with 2 400 million Sm3 residual oil after water injection as an EOR target. CO2 foam EOR can contribute to reaching this recovery target while simultaneously providing a positive synergy between the need for more energy and the requirement to reduce CO2 emissions through permanent, safe and affordable storage of CO2 in mature oil fields.

The primary objective of the project was to advance the technology of CO_2 foam mobility control to be a feasible option for EOR and aquifer storage on the Norwegian Continental Shelf (NCS). Secondary objectives aimed to develop and characterize CO_2 foam systems for CO_2 flooding of heterogeneous sandstone and carbonate reservoirs with a focus on the use of foam for mobility control in CO_2 storage and CO_2 EOR. The project also had additional goals to upscale the results from laboratory scale to reservoir scale by completing the design and implementation of a US field pilot to test and further develop foam system characterization. The project met the primary objective by establishing a robust, upscaling methodology by designing foam formulations in the laboratory and transferring them to the field-scale. The established methodology and results from the onshore field pilot advance the knowledge of multi-scale CO_2 foam mobility control for EOR and CO_2 storage and offer insight into its applicability on the NCS. The project also achieved the secondary objectives as described below.

The project developed and characterized CO_2 foam systems for mobility control during CO_2 flooding of heterogeneous reservoirs with a focus on CO_2 storage and CO_2 EOR. This included surfactant screening, determining the optimal foam formulation, and quantifying of CO_2 EOR and CO_2 storage potential with the optimized foam formulation at the pore- and core-scale. Surfactant screening studies identified the nonionic Huntsman L24-22 ($C_{12\text{-}14}EO_{22}$) surfactant for the field test based upon low adsorption on dolostone core material with and without CO_2 present. A scale inhibitor (SCALE INHIB-106 from CATALYST Co.) was also identified to be compatible with the surfactant. In addition, an oxygen scavenger was selected to prevent surfactant degradation due to oxygen exposure. No detrimental effect on foam was found when the oxygen scavenger and scale inhibitor was used in reservoir brine with surfactant. Finally, foam stability investigations demonstrated the effectiveness of the Huntsman L24-22 to stabilize liquid films, in the presence of S_{or}, providing reduced CO_2 mobility and increased fluid displacement.

A foam formulation for the pilot test was designed by evaluating surfactant concentration and foam apparent viscosity in reservoir core material. A surfactant concentration of 0.5 wt%, at a foam quality between 60 and 70%, was recommended for the field test based upon high foam apparent viscosity, incremental oil recovery by CO_2 foam, and CO_2 mobility reduction by foam. The optimal foam system was tested and verified through assessing CO_2 foam apparent viscosity, CO_2 mobility reduction, and incremental oil recovery. CO_2 foam EOR corefloods, using the optimal foam system, resulted in overall recovery factors of 80% OOIP and incremental recovery by CO_2 foam of 35% OOIP after waterflood. Foam also increased CO_2 performance by providing viscous displacement forces and recovering an additional 15% OOIP after CO_2 injection. In addition, high differential pressures during CO_2 foam injection indicated generation of stable foam with mobility reduction factors by CO_2 foam up to 340, over pure CO_2 at reservoir conditions.



CO_2 foam injection in PET/CT at Haukeland University Hospital.

Field operations: CO_2 foam EOR field pilot in Texas, USA

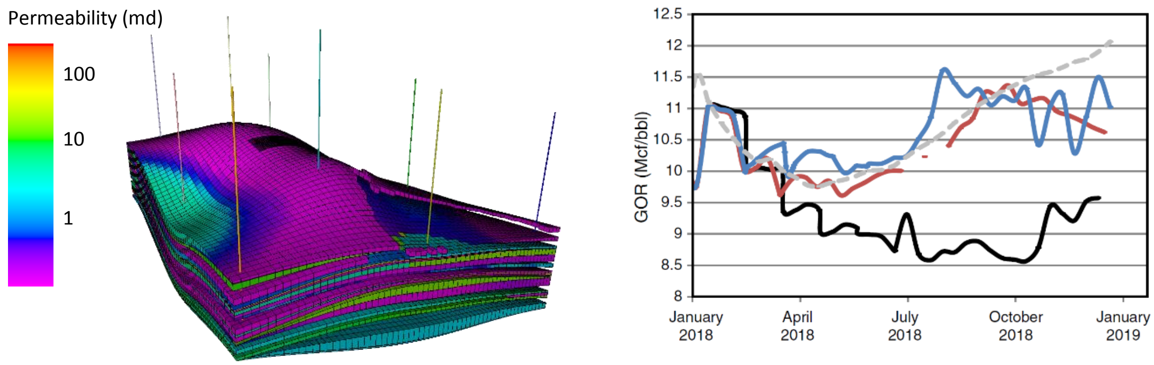
The project also had additional goals to upscale the results from laboratory scale to reservoir scale by completing the design and implementation of a US field pilot to test and further develop foam system characterization. These goals were met by selecting a site for the field pilot test, determining the injection strategy, and designing the surface facilities for the pilot test. An inverted 40 acre 5-spot well pattern was selected to demonstrate the applicability of the optimized laboratory foam system at the field scale. Criteria was followed for the selection of a well pattern within the field pilot location that established a best case scenario to maximize the chance of success for the foam treatment and minimized avoidable operational issues of selected wells (i.e. injectivity interruptions due to pressure buildup near the injection well). The following criteria were applied and met to select pilot wells for the CO_2 foam treatment:

- The chosen producer experienced rapid gas breakthrough from CO_2 injection, relative to surrounding production wells.
- A high gas-oil-ratio was observed in the selected producer relative to surrounding producers.
- The injection well head pressure is lower than comparable injection wells.
- The wells are in close proximity to minimize geological uncertainty and maximize interwell connectivity.

The selected well pattern consists of a central injection well and four surrounding producers. The selected well pattern provides a site to experimentally study the injection of CO_2 foam for analysis on incremental oil recovery, sweep efficiency, CO_2 utilization, and foam's impacts on CO_2 mobility.

The injection strategy was selected based upon modeling results, the desire to control foam quality, and maximize the chance of *in-situ* foam generation, while considering field constraints. A rapid surfactant-alternating-gas (SAG) was selected as the injection strategy for pilot injection. The rapid SAG consists of up to twelve cycles with 10 days of surfactant solution injection followed by 20 days of CO_2 injection. A foam quality of 70% is targeted at a surfactant concentration of 0.5 wt%. Pilot injection is planned to be up to 12 months, targeting a total of 0.1 HCPV injected. The SAG injection scheme provides better injectivity control, when operating close to formation fracture pressure. It is expected that the fast alternation between slugs will provide the most flexibility, should injectivity issues arise, through minimizing the risk of fracturing the formation potentially creating problems beyond the remediation by foam. Further, it was desired to achieve foam dry out near the injection well to provide a modest decrease in gas mobility near the well and a larger mobility reduction further into the reservoir.

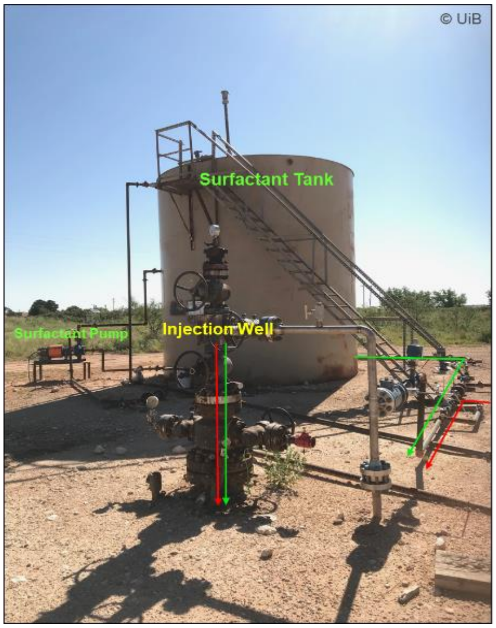
The injection strategy was also selected based upon modeling results and field constraints. A sector level model was set up and history matched for the historical waterflood and CO_2 injection periods. The waterflood was matched to monthly production and injection data, whereas the CO_2 injection period was matched to daily allocated oil and water production rate and CO_2 breakthrough. The model was calibrated to reduce uncertainties through identification of key performance indicators before being used for pilot design. Foam model parameters were derived from laboratory experiments and included in the forecasting stage. The forecasts were initialized from the pressures and saturations from the last step of the CO_2 history match. A surfactant component was added to the aqueous phase to model foam behavior. The aqueous phase only had the water component present during CO_2 injection match. Before using a particular model for making predictions, regions were assigned depending upon updated permeability after history match, using a script. The simulator was found to lack reliable modeling of dry-out effect during SAG. A local grid refinement (LGR) was introduced around the pilot injector, where grid cells were refined areally from 50 ft x 50 ft to 10 ft x 10 ft. In order to model foam dry-out during SAG near injector, the innermost cells (within LGR) connecting to injector were assigned an fmmob of 0 to mimic foam absence within a radius of 5 ft around injector. The 12 uncertainty parameters (UPs) that were introduced to model foam behavior were combined with 58 UPs from history matching phase, and Latin hypercube (LHC) sampling was used to generate 100 cases under two scenarios. Foam (SAG) forecast showed increased CO_2 retention, compared to WAG, and incremental oil recovery in the range of 2,000-5,000-8,000bbl based upon the low injection rate scenario during 1, 2 and, 3 years production, respectively. It may take 4-6 months for oil bank to reach producers.



Left: Permeability distribution in the sector-scale reservoir model of the pilot pattern and peripheral wells. Right: Simulation results showing reduction in producing GOR during rapid SAG injection (black curve) compared to WAG (blue curve), single cycle SAG (red curve), and continuous CO_2 injection (gray curve).

A field-scale data collection and monitoring program was also established to verify *in-situ* foam generation, CO_2 mobility reduction, and increased CO_2 storage and displacement. The data collection program includes a tracer program, daily measurements of rate and pressure, collection of downhole pressure data, and injection profiles at baseline and pilot stages. The aim was to collect sufficient data during the baseline (pre-pilot) stage for comparison to repeat surveys and tests during, and after, the pilot phase. Results from the baseline tracer indicate CO_2 breakthrough in 22 days. A repeat survey will be ran at the end of the pilot to investigate CO_2 mobility reduction by foam. It is expected from simulation results that foam will increase the CO_2 breakthrough time to at least 2 months, thereby increasing reservoir sweep and displacement.

Since the start of the pilot in May 2019, the downhole pressure gauge has been pulled from the well twice. The pressure results revealed reduced injectivity during surfactant slugs compared to CO_2 slugs and reduced injectivity for each CO_2 slug, compared to baseline CO_2 injectivity values. Injection profiles recorded during the pilot phase show potential diversion of flow by foam from a high permeability streak in the injection well, indicating improved reservoir sweep efficiency. In addition, this increases CO_2 storage efficiency as foam selectively generates in high permeability regions allowing diversion of CO_2 into low permeability regions, previously uncontacted by CO_2. Production response is expected to be seen in about 6 months.



Ongoing Large Scale Experiment: CO_2 Foam EOR as CCUS in Field Pilot at East Seminole, TX, USA

In addition to meeting the project objectives, the results have also contributed to the CCUS research community and the energy industry. The field pilot test verifies the applicability of an advanced CO_2 EOR technology which recovers additional oil while simultaneously storing CO_2. This seeks to enable wide-spread application of CO_2 foam technology to increase oil recovery and CO_2 storage potential, thus generating more revenues and attracting industry to participate in CCUS. Moreover, the project facilitated in-depth experience for the next generation of petroleum engineers by integrating whole value chain CCUS into their education.

List of Academic Partners

- Stanford University (T. Kovscek)
- U. of Texas at Austin (K. Johnston)
- Rice University (G. Hirasaki)
- TU Delft (B. Rossen)
- U. of Stavanger (M. Madland)

Acknowledgements

The authors acknowledge the Research Council of Norway CLIMIT program for support under grant number 249742 – ‘*CO2 Storage from Lab to On-Shore Field Pilots Using CO2-Foam for Mobility Control in CCUS’* to Petroleum and Process Technology Research Group at Univ. of Bergen. The authors acknowledge the industry partners – TOTAL E&P, Shell E&P and Equinor ASA; and the field operator, Tabula Rasa, for support.