OCS Study
BOEM 2018-004

Best Management Practices for Offshore Transportation and Sub-Seabed Geologic Storage of Carbon Dioxide

US Department of the Interior
Bureau of Ocean Energy Management
Headquarters (Sterling, VA)

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Developing Environmental Protocols and Monitoring to Support Ocean Renewable Energy and Stewardship, Topic No. 5: Sub-Seabed Geologic Carbon Dioxide Sequestration Best Management Practices

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DISCLAIMER

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List of Acronyms, Abbreviations, and Symbols

2-D, 3-D, 4-D	two-, three-, and four-dimensional, in reference to seismic surveys
ALARP	as low as reasonably possible
AMP	Adaptive Management Plan
AOR	area of review
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
AUV	autonomous underwater vehicle
BEG	Bureau of Economic Geology
BLEVE	boiling liquid expanding vapor explosion
BMP	best management practices
BOEM	Bureau of Ocean Energy Management
BSEE	Bureau of Safety and Environmental Enforcement
CAA	Clean Air Act
CCS	carbon capture and storage (or sequestration)
CCUS	carbon capture, utilization, and storage
CF	Certification Framework
CFR	Code of Federal Regulations
CH_4	methane
CO_2	carbon dioxide
CO_2CARE	CO_2 Site Closure Assessment Research
COST	Continental Offshore Stratigraphic Test
CSA	Canadian Standards Association
DHS	Department of Homeland Security
DNV	Det Norsk Veritas
DNV OSS	DNV Offshore Service Specification
DOE	US Department of Energy
DOI	US Department of the Interior
DOT	US Department of Transportation
EC	European Commission
EEZ	Exclusive Economic Zone
EI	Energy Institute
EIA	Environmental Impact Assessment
EOR	enhanced oil recovery
EOR-GS	enhanced oil recovery–geologic storage
EPA	US Environmental Protection Agency
ERM	Environmental Resources Management
ERT	electrical resistance tomography
EU	European Union
FEED	Front End Engineering Design
FERC	US Federal Energy Regulatory Commission
FF	fluid flow
G&G	geological and geophysical
GF	geologic framework
GHG	greenhouse gas
GHGRP	Greenhouse Gas Reporting Program
GLO	Texas General Land Office
GOM	Gulf of Mexico
GS	geologic storage
Gt	billion metric ton
H_2S	hydrogen sulfide
HSE	Health, Safety, and Environmental
IEA	International Energy Agency

IEAGHG	International Energy Agency Greenhouse Gas R&D Programme
IEA/OECD	International Energy Agency, Organisation for Economic Co-operation and Development
IPCC	Intergovernmental Panel on Climate Change
IRGC	International Risk Governance Council
MPE	Ministry of Petroleum and Energy
MPRSA	Marine Protection, Research, and Sanctuaries Act
MRV	monitoring, reporting, and verification
MVA	monitoring, verification, and accounting
NETL	National Energy Technology Laboratory
NOAA	National Oceanic and Atmospheric Administration
O&G	oil and gas
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
OSHA	Occupational Safety and Health Administration
P&A	plugged and abandoned
P-wave	primary-wave
PENS	Predicting Engineered Natural Systems
PHMSA	Pipeline Hazardous Materials Safety Administration
PIG	pipeline inspection gauge
PISC	post-injection site care
PSIG	pounds per square inch gauge
QICS	Quantifying and Monitoring Potential Ecosystem Impacts of Geological Carbon Storage
RCSP	Regional Carbon Sequestration Partnership
RFA	Regulatory Framework Assessment
RISCS	Research into Impacts and Safety in CO_2 Storage
ROAD	Rotterdam Opslag en Afvang Demonstratie
ROW	right of way
RP	Recommended Practice
RRC	Railroad Commission of Texas
SACS	Saline Aquifer CO_2 Storage Project
SDWA	Safe Drinking Water Act
SEMS	Safety and Environmental Management Systems
TAC	Texas Administrative Code
UIC	Underground Injection Control
UK	United Kingdom
USACE	US Army Corps of Engineers
USDW	underground source of drinking water
USGS	US Geological Survey

Summary

The purpose of this report is to inform the US Department of the Interior (DOI) Bureau of Ocean Energy Management (BOEM) about potential best management practices (BMPs) for offshore sub-seabed geologic storage of carbon dioxide (CO_2) on the US Outer Continental Shelf (OCS). The BMPs pertain to activities associated with CO_2 transport and storage in offshore settings and are organized into nine topical areas, shown in Table ES-1. The offshore CO_2 storage infrastructure considered includes pipelines, platforms, and wells. Environments that may be impacted by CO_2 leakage are coastal, nearshore, and marine habitats and biota and sub-seafloor geologic strata that may contain at-risk resources.

The BMPs herein were developed by (1) reviewing international regulatory frameworks and technology applications; (2) reviewing existing US DOI policy and regulations, especially those of the BOEM and its sister agency the Bureau of Safety and Environmental Enforcement (BSEE); (3) reviewing, compiling, and summarizing of the most relevant literature; (4) where possible, developing BMPs for the nine subtopics; and (5) analyzing gaps in information needed to fully develop BMPs to further sub-seabed enhanced oil recovery–geologic storage (EOR-GS) and geologic storage (GS) on the OCS.

Table ES-1. BOEM Best management practices subtopics

Subtopic	Title
1	Site Selection and Characterization
2	Risk Assessment
3	Project Planning and Execution
4	Monitoring
5	Mitigation
6	Safety Inspection and Performance Assessment
7	Reporting Requirements
8	Emergency Response and Contingency Planning
9	Decommissioning and Site Closure

Carbon capture and storage (CCS) is an emerging technology that entails capturing CO_2 from industrial sources and compressing and transporting it to suitable storage sites for injection into deep geologic formations. The goal is to reduce emissions of industrial CO_2 to the atmosphere by isolating them within deep geologic formations. Carbon capture, utilization, and storage (CCUS), which has been taking place onshore in the US since the early 1970s, uses captured CO_2 for enhanced oil recovery (EOR). Only within the past decade has CCUS been recognized (e.g., Hill et al. 2013) as a method to reduce CO_2 emissions to the atmosphere (as long as the source of CO_2 being utilized is captured from industrial facilities and not produced from naturally occurring geologic reservoirs). CO_2 EOR-GS and GS both isolate anthropogenic CO_2 from the atmosphere, resulting in reduced emissions.

The BMPs consider both the CCUS and CCS options for the offshore environment: (1) EOR-GS, a type of CCUS, and (2) geologic storage of CO_2 without EOR (GS), a type of CCS. Currently, commercial-scale, offshore CO_2 EOR is not taking place anywhere in the world. However, for nearly two decades, GS has been underway offshore of Norway, where both onshore and offshore CO_2 and hydrocarbon fluid-stream-separation have been utilized.

A key finding of this research is that much of the knowledge gained from onshore transport and storage of CO_2 can be applied offshore. As with onshore CO_2 storage, the aim offshore will be to inject CO_2 thousands of feet below the seafloor into geologic systems, which are fluid reservoirs overlain by confining strata that have sufficient integrity and capacity to contain CO_2 without impacting other sub-seafloor resources, the ocean environment, or the atmosphere. However, because many aspects of offshore CO_2 EOR-GS and GS technologies are emerging, there are information gaps where more knowledge is needed through offshore pilot-scale projects and additional offshore industry experience to fully develop BMPs.

Currently defined BMPs for onshore CCS (CO_2 GS) and CCUS (CO_2 EOR-GS) range from technical guidance based on knowledge gained from pilot-scale projects (e.g., DOE NETL 2013c) to methodologies that have been proven through large-scale industry practice (e.g., API 2009, 49 CFR 195). The US Department of Energy (DOE) has funded tremendous CCS research conducted by governmental, academic, and private entities for more than ten years. Much of this research (and associated BMPs) is for onshore settings that may be applicable to offshore settings, as appropriate. In addition, offshore-specific research under this program has resulted in the delineation of vast areas for potential suitability for CO_2 EOR-GS and GS, especially in the northern and western Gulf of Mexico (GOM; DOE NETL 2015), and further offshore research is ongoing.

In 2010, the US Environmental Protection Agency (EPA) published regulations for onshore CO_2 GS. This rulemaking defined a new class of injection well, Class VI, specifically for CO_2 GS. The Class VI well rules are part of the Underground Injection Control (UIC) program under the US Safe Drinking Water Act of 1974. The primary purpose of Class VI well rules is to protect underground sources of drinking water, which are virtually non-existent on the OCS. However, some aspects of the UIC program can be applied to offshore sub-seabed CO_2 storage.

Our review of existing international policy indicates that CO_2 EOR-GS and GS can be conducted on the OCS in compliance with international regulatory frameworks, such as the London Convention and London Protocol. Since at least 2005, it has been recognized that storage of CO_2 in offshore sub-seabed geological formations will use many of the same technologies developed by the oil and gas (O&G) industry (IPCC 2005). BOEM and BSEE have authority, through the US Outer Continental Shelf Lands Act (OCSLA), to regulate offshore O&G exploration and production, including secondary and tertiary recovery. Under the OCSLA, they may also authorize certain types of projects on the OCS for sub-seabed GS of CO_2.

BMPs Summary

ST1: Site Selection and Characterization

The first BMPs subtopic (ST), site selection and characterization, is most critical to the success of sub-seabed CO_2 storage. Objectives of other phases of offshore CO_2 storage, such as risk analysis (ST2), monitoring (ST3), mitigation (ST5), and site decommissioning and closure (ST9) will be aimless if site characterization and selection are not completed in sufficient detail. Components of site characterization include data availability and acquisition, capacity assessment, and predictive numerical modeling.

Given that the same methods used for O&G exploration can be used to characterize CO_2 storage sites, the greatest density of available data in the US is found in the GOM. Reconnaissance-level characterization has also been completed in the Atlantic, and, to a lesser degree, on the Pacific OCS. However, data from intervals above deep sub-seabed reservoir horizons and below the seafloor, referred to as the overburden, are lacking throughout the OCS nationwide. Successful risk assessment and monitoring plans cannot be completed without detailed information on overburden geologic strata and pore fluids.

Different methods for calculating capacity of a geologic formation to hold a specified volume have been used by governmental, academic, and industry groups, and there are different methods used for EOR-GS and for GS. Attention to methodology, scale, and local pressure and temperature regimes (especially geopressure or geothermal zones) will be critical to accurately estimate CO_2 capacity. Studies show that, in general, the smaller the area assessed for CO_2 storage capacity, the smaller the estimated volume. In other words, basin-scale estimations cannot consider local conditions that impact site-specific CO_2 storage capacity; therefore, basin-scale calculations may estimate larger storage capacities than site-specific estimates.

ST1 and ST2 will need to be iterative as monitoring data, especially those collected during CO_2 injection testing and/or early stages of injection operations, are obtained and analyzed. Static geologic and dynamic fluid flow models used for site characterization need to be augmented with new data as they become available, and applied to risk assessment, monitoring, mitigation, and site closure planning.

ST2: Risk Assessment

The BMPs for risk assessment (ST2) associated with CO_2 transportation and storage operations on the OCS are focused on impacts to human health and safety and the environment. Economic, legal, or climatic risks are beyond the scope of this study.

The focus of storage risk assessment (ST2), which is intertwined with monitoring (ST4), mitigation (ST5), and site closure (ST9), is the potential leakage of CO_2 to shallower resource-bearing strata, the seafloor, the water column, and/or the atmosphere. Defining CO_2 leakage should be the first stage in risk assessment of a CO_2 storage site. Leakage is discussed in terms of the volume qualified for CO_2. In some geologic settings, this volume may only include the reservoir zone. In other settings, it may be acceptable for CO_2 to buoyantly migrate into strata overlying the reservoir zone, but remain isolated from the seafloor (e.g., as observed at the Sleipner field in the Norwegian North Sea). Consensus within the CCS research community is that the greatest risk to deep subsurface containment of CO_2 (onshore or offshore) is pre-existing well bores. If not properly constructed or plugged and abandoned, well bores may be potential leakage pathways through which CO_2 may escape to overlying resource-bearing formations or the seafloor. The risk of leaking wells may be lower on the OCS where well density is lower and horizontal wells are more common than in onshore settings.

Structural integrity risks associated with pipelines will be minimized if the CO_2 stream is as free as possible of chemical impurities (e.g., hydrogen sulfide) and water.

ST3: Project Planning and Execution

A standard industry model for project planning, construction, and operations, and numerous existing regulations and standards (e.g., ASME 2012, 2016; API 2009; DNV 2013; DOT 2014; Eldevik 2008) may be applicable to offshore pipeline transport of CO_2. The example standard industry model was applied to the recently cancelled Shell Peterhead-Goldeneye CCS project, which was to be located in eastern Scotland and the North Sea.

A critical aspect of planning for offshore CO_2 EOR-GS will be fluid separation for recycling of CO_2 co-produced with oil. Therefore, multiple modes of offshore transportation of CO_2 should be considered for both CO_2 EOR-GS and GS. Transportation of CO_2 will be more complex for EOR-GS, because a post-production, mixed-fluid stream (hydrocarbons plus CO_2) will need to be transported to a fluid separation facility before CO_2 is re-injected (recycled) for further EOR operations. Options are to build subsidiary offshore platforms (e.g., the Sleipner project in the Norwegian North Sea) or pipe a combined fluid stream to an onshore separation facility before returning the CO_2-stream offshore for re-injection (e.g., Snøhvit project in the Barents Sea). Ship-based transport of CO_2 to offshore sites is also considered. Section 3.3 provides example workflows for storage components of sub-seabed CO_2 EOR-GS and GS projects. Stages in the storage workflows are iterative (i.e., future operators are advised to update risk assessment and predictive fluid flow models with data from CO_2 injection testing and early CO_2 injection operations).

ST4: Monitoring

Directly applicable research ongoing in both onshore and offshore, along with detailed information of the types of sub-seabed monitoring tools and how they can be utilized in offshore settings, are covered extensively in Section 3.4. A thorough example of how the European CCS Directive (European Commission 2011a, 2011b, 2011c, 2011d) was applied to planning for many aspects of the offshore Shell Peterhead project, including monitoring, is presented in Shell 2014b.

To achieve an effective monitoring plan design, quantitative metrics must be set and linked to what is defined as leakage for a particular site. Metrics avoid the vagueness of broad statements about protecting sub-seabed and marine resources. For example, the threshold of activities (storage reservoir pressure increases, CO_2 leakage, induced seismicity, impact on seawater, etc.) that are considered unacceptable must be stated in terms such as mass, area, and time. Only when such quantitative goals are set will it be possible to make measurements to show that a CO_2 EOR-GS or GS project is performing acceptably. Results from monitoring at depths close to the injection-reservoir zone will provide the earliest and least ambiguous results in terms of CO_2 containment and avoidance of environmental risk. The lower density of wells and the abundance of horizontal completions in offshore settings, as well as the complexities of offshore operations, will most likely result in reliance on seismic and other geophysical methods for sub-seabed monitoring, both in deep geologic strata and relatively shallow sub-seabed sediments.

Offshore tests focused on environmental monitoring research near the seafloor include:

- Controlled release in the Quantifying and Monitoring Potential Ecosystem Impacts of Geological Carbon Storage (QICS) Project (Blackford et al. 2014, IEAGHG 2015, Mabon et al. 2015)
- Research into Impacts and Safety in CO_2 Storage (RISCS) Project (Pearce et al. 2014)

- Sub-seabed CO_2 Storage: Impact on Marine Ecosystems (ECO_2) Project (ECO_2 2015)

Quantitative leakage detection monitoring at the seafloor and in the water column might only be needed if an anomalous signal is clearly attributed to CO_2 leakage from the deep sub-seabed or for the purpose of EPA CO_2 injection and storage reporting requirements (EPA 2010a, 2010b).

Regulations and standards for monitoring offshore O&G pipeline construction and operations are well established in the US and internationally and have been undergoing recent updates to include specifics for transporting CO_2 fluid streams (e.g., DOT 2014, DNV 2013).

ST5: Mitigation

As with risk assessment and monitoring, CO_2 EOR-GS or GS site mitigation (ST5) will require definition of what constitutes a leak and what volume or rate of leakage is significant (i.e., action level). Action levels will need to be defined by regulators based on CO_2 storage objectives. There appear to be multiple uses of the term "mitigation" associated with CO_2 transport and storage across the industry standards. The Energy Institute of London describes mitigation measures to minimize potential impacts from failure of various components (e.g., pipelines and associated equipment, risers, and injection well components) of the CO_2 storage chain. These measures may be included as project design criteria, such as clearly marking offshore pipelines on marine maps, carefully selecting riser pipe material, and installing protective structures around riser pipes to minimize rupture potential (EI 2013). Det Norsk Veritas (DNV) defined mitigation as a method to reduce consequences of unplanned events, and it is used in conjunction with risk prevention (DNV 2010l).

CO_2 dissolves in water at high pressure and low temperature but will form bubbles in seafloor-water column settings at CO_2 storage sites on continental shelves. Depending on local and seasonal conditions, CO_2 will either become stratified in the water column or freely exchange with the atmosphere (ECO_2 2015). Hence, it will not be possible to use physical barriers to remove CO_2 as is done for oil spills (e.g., DNV 2010l). Mitigation measures for CO_2 leakage from injection or production wells include standard oil company techniques of injecting cement into selected zones within well casings, or plugging and abandonment. Options for mitigation related to CO_2 EOR-GS or GS sites are most likely limited to cessation of injection and/or injection of brine through nearby wells to create vertical or horizontal pressure barriers. Use of pressure barriers is also common practice in EOR operations to increase production of oil.

ST6: Inspection and Performance Assessment, ST7: Reporting Requirements, and ST8: Emergency Response and Contingency

There is limited data and information regarding these topics with respect to offshore CO_2 EOR-GS and GS as the technologies are emerging. Fully developed BMPs for these subtopics will require more knowledge gained through offshore pilot-scale projects and additional offshore industry experience.

Most of the information available for safety, inspection, performance assessment (ST6), reporting (ST7), and emergency response and contingency (ST8) for sub-seabed storage of CO_2 is specific to offshore hydrocarbon pipeline and platform operations. The Energy Institute and DNV documents provide much information that can be used as technical guidance on performance assessment requirements for CO_2 EOR-GS and GS on the OCS (e.g., DNV 2003, 2012b, 2012d, 2013; EI 2013). In the US, many

BOEM/BSEE regulations for O&G operations (e.g., 30 CFR 250.919 to 250.921) can be directly applied to aspects of ST6, ST7, and ST8 for CO_2 activities.

The most critical factor related to all three of these subtopics is the purity of the CO_2 stream for (1) prevention of corrosion of piping material used for offshore transport, platform operations and injection wells or (2) degradation of seal elastomers. The relevance of corrosivity and other critical properties of CO_2 to the BMP subtopics is presented.

ST9: Site Closure

These BMPs suggest that monitoring during a long post-injection site closure period (ST9) is not a best practice for assuring either the effectiveness of storage security or protection of the environment. If a CO_2 EOR-GS or GS site undergoes sufficient characterization before selection, there may not be a need for post-closure monitoring. Identification of potential problems should be thoroughly investigated during characterization phase because, after emplacement of much of the CO_2, it will be too late to manage or mitigate problems, and the highest reservoir pressures will have already been surpassed. Significant uncertainties about the long-term performance of the storage site should be constrained to an acceptable level prior to injection of large volumes of CO_2; if uncertainties cannot be resolved, injection should be stopped. A process of long-term risk assessment and identification of potential post-closure environmental impacts should be designed during the early stages of project planning or soon after injection begins while mitigation (e.g., plugging an abandoned wellbore or avoidance of injection of large CO_2 volumes) could still be effective.

Gaps Analysis Summary

There are two categories of knowledge gaps for offshore CO_2 sub-seabed storage: regulatory and technical, as discussed in detail in Section 5. US regulatory gaps are primarily a result of the current focus on offshore resource recovery and sparsity of monitoring requirements related to fluid injection on the OCS. There are also gaps in regulations related to the corrosive and potentially harmful characteristics of wet or impure streams of CO_2. The biggest technical gaps are associated with lack of data for shallower sub-seabed intervals in active O&G areas (overburden above the injection and confining intervals) or throughout the sub-seabed stratigraphic column for areas in which O&G activity is absent. In Section 5, we outline an approach (i.e., adaptive management) that should allow BOEM to determine the effectiveness of future regulatory frameworks, recognize regulatory gaps, and allow further development of BMPs as offshore CO_2 EOR-GS and GS technologies mature. The first step will be to encourage offshore pilot-injection projects with collaboration between government, academia, and industry.

Section 6 offers conclusions and recommendations regarding issues to be addressed during formulation of future regulations for CO_2 EOR-GS and GS on the OCS. The major categories of issues are corrosion management, characterization and qualification of storage sites, injection operations planning, risk management and monitoring, quantification of storage, and site closure planning.

1 Introduction

The purpose of this project is to compile and evaluate relevant information to generate best management practices (BMPs) for offshore transportation and sub-seabed geologic storage (GS) of carbon dioxide (CO_2) on the Outer Continental Shelf (OCS). The results may support the US Department of the Interior (DOI) Bureau of Ocean Energy Management (BOEM) in the potential future development of informed policy and regulatory frameworks.

Carbon capture and storage (CCS) is an emerging technology that entails capturing CO_2 from industrial sources, compressing it, and transporting it to suitable storage sites for injection into deep subsurface (onshore) or sub-seabed (offshore) geologic strata. The goal of CCS is to reduce emissions of industrial CO_2 to the atmosphere, and hence the oceans, by isolating the CO_2 within deep geologic formations. Carbon capture, utilization, and storage (CCUS), which has been taking place onshore in the US since the early 1970s, uses captured CO_2 for enhanced oil recovery (EOR). Only within the past decade has CCUS been recognized (e.g., Hill et al. 2013) as a method to reduce CO_2 emissions to the atmosphere (as long as the source of CO_2 being utilized is captured from industrial facilities and not produced from naturally occurring geologic reservoirs). The BMPs consider both the CCUS and CCS options for the offshore environment: (1) EOR with associated geologic storage (EOR-GS) (after McCoy et al. 2011) (a type of CCUS), and (2) geologic storage of CO_2 without EOR (GS), a type of CCS. CO_2 EOR-GS and GS isolate anthropogenic CO_2 from the atmosphere resulting in reduced emissions (Figure 1-1).

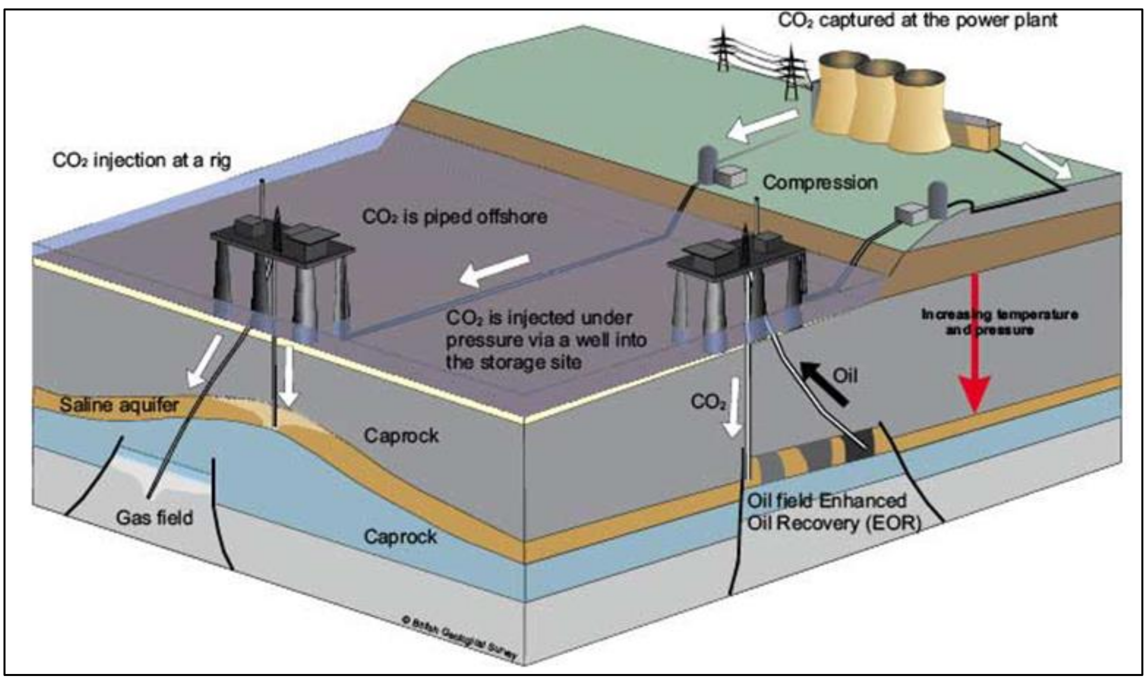

Figure 1-1. Schematic of offshore injection for CO_2 EOR and GS
Source: The Scottish Government, Scottish Centre for Carbon Storage 2009

The BMPs address activities associated with the CO_2 transport and storage components of CCS and CCUS in offshore settings. Much of what has been learned from onshore transport and storage of CO_2 can be applied to offshore settings. The aim of US offshore storage will be to inject CO_2 thousands of feet below the seafloor into geologic systems (i.e., fluid reservoirs overlain by confining strata) that have sufficient integrity and capacity to contain CO_2 without impacting other sub-seafloor resources, the ocean environment, or the atmosphere.

Multiple modes of offshore transportation of CO_2 are considered for both CO_2 EOR-GS and GS. Transportation of CO_2 will be more complex for EOR-GS because a post-production, mixed-fluid stream (i.e., hydrocarbons plus CO_2, and possibly hydrogen sulfide [H_2S]) will need to be transported to a fluid separation facility before CO_2 is re-injected (recycled) for further EOR operations. If CO_2 is recycled as a mixed-fluid stream (i.e., not having been separated from the hydrocarbon gases), its usefulness as an EOR solvent may be limited (Ogbuabuo 2015). Currently, commercial-scale offshore CO_2 EOR is not taking place worldwide, but GS has been underway for nearly two decades offshore of Norway, where both onshore and offshore CO_2 and hydrocarbon fluid-stream-separation have been used.

Both CO_2 EOR-GS and GS storage involve injection of CO_2 into the deep sub-seabed (thousands of feet below the seafloor). CO_2 GS can take place within depleted hydrocarbon reservoirs, in deep sub-seabed, brine-bearing geologic strata separated vertically (above or below) from oil-bearing strata, or in areas not associated with O&G production. CO_2 storage in areas separated from O&G activity is also referred to as saline or brine formation GS.

What is not considered here is the injection of CO_2 into the water column (e.g., as discussed in IPCC 2005) nor storage of CO_2 in shallow sub-seabed sediments as more recently proposed by several groups (i.e., House et al. 2006, Schrag 2009, Eccles and Pratson 2013). Discharge of CO_2 directly into the water column, or as a cold, compressed, dense phase emplaced in shallow sub-seafloor sediments, were formerly considered potentially viable storage methods. However, direct injection of CO_2 into seawater is considered ocean dumping and violates international treaties. Shallow sub-seabed CO_2 storage in deep water settings produces dense phase CO_2. This is proposed to be a theoretically effective mechanism of storage, however the mechanics and performance of this process remain untested and speculative, so the shallow injection methods is not further considered.

Despite the current lack of US economic incentive to reduce emissions of CO_2 to the atmosphere, private industry is investing in monitoring programs to verify permanence of CO_2 GS associated with EOR. This effort is not only to satisfy requirements for US Department of Energy (DOE) financial subsides for CO_2 capture and storage projects but also to be ready to take advantage of and future US CO_2 emissions reduction credits. These efforts provide assurance that long-term CO_2 storage goals, including those for incidental storage associated with CO_2 EOR, are realistic.

2 Existing Legal and Regulatory Frameworks

The objective of CO_2 EOR-GS and GS is the same onshore and offshore: to inject CO_2 into deep geologic systems that have sufficient integrity and capacity for safe and effective storage. As with onshore CO_2 storage, offshore regulations need to be developed such that (1) storage sites are carefully chosen, and (2) sufficient monitoring is conducted to assure that injected CO_2 remains confined in the deep sub-seabed for long periods of time. The purpose of developing BMPs for sub-seabed GS of CO_2 on the OCS is to provide technical information to BOEM in support of policy and regulatory development. Similarities among components of CO_2 EOR-GS and GS, and existing offshore oil and gas (O&G) operations, may allow some of the existing BOEM and Bureau of Safety and Environmental Enforcement (BSEE) regulations to be adapted, or even directly applied, to future offshore sub-seabed CO_2 storage activities. In addition, regulations for both onshore pipeline transports of CO_2 and offshore transport of natural gas may be applicable to offshore transport of CO_2. Below is an examination of existing onshore and offshore CCS-CCUS legal and regulatory frameworks (US and international) and discussion of how onshore frameworks may apply offshore.

2.1 The US Outer Continental Shelf

The OCS consists of 1.7 billion acres of submerged lands, subsoil, and seabed lying between the seaward boundaries of coastal States' submerged lands and the seaward extent of Federal jurisdiction. For most areas, Federal jurisdiction begins 3 nautical miles from the coastal baseline. However, for Texas and the Gulf Coast of Florida, Federal jurisdiction begins 9 nautical miles from the coastal baseline. For Louisiana, Federal jurisdiction begins 3 imperial nautical miles from the baseline. In most areas, the seaward extent of the OCS is the Exclusive Economic Zone (EEZ), which is 200 nautical miles from the coastal baseline[1]. Figure 2-1 shows (1) OCS Planning Areas, (2) location of a Congressional drilling moratorium for the Eastern GOM Planning Area (expires June 30, 2022), and (3) locations where offshore characterization studies of CO_2 GS potential have been completed, at least on a reconnaissance level.

The following characteristics of the Western and Central GOM Planning Areas make this a potential target for offshore CO_2 GS to begin on the OCS:

- Large storage potential (e.g., DOE NETL 2015, pg. 31)
- Extensive existing O&G production infrastructure and technical expertise
- Concentration of onshore CO_2 emissions sources
- Absence of moratoria

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[1] For a description of the state and Federal jurisdictions, see "Outer Continental Shelf" on the BOEM webpage. Available at http://www.boem.gov/Oil-and-Gas-Energy-Program/Leasing/Outer-Continental-Shelf/Index.aspx. Accessed 08 Nov 2017.

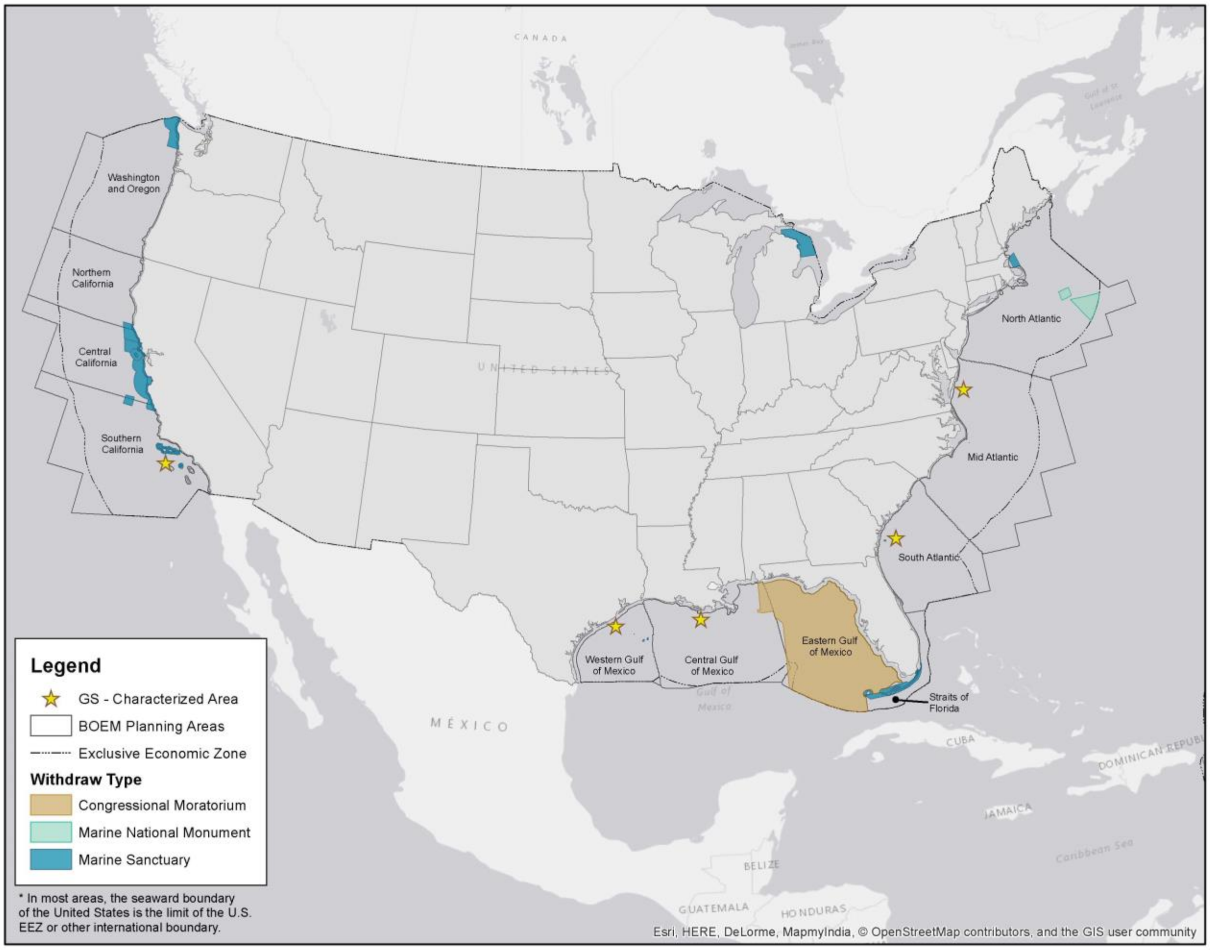

Figure 2-1. Extent of OCS relative to contiguous continental US, status of drilling moratoria within DOI planning areas, and location of areas where CO_2 GS potential has been characterized

2.2 US Legal and Regulatory Framework

In the US, the Legislative and Judicial branches of the Federal government pass relevant laws and issue judgements over legal disputes, respectively. Entities under the Executive Branch of the US government include regulatory agencies (e.g., Environmental Protection Agency [EPA], DOI, and US Department of Transportation [DOT]) and agencies conducting CCS research (e.g., DOE, US Geological Survey [USGS]) (Figure 2-2). The EPA, one of over 30 agencies under the Executive Branch, currently regulates onshore CO_2 injection activities (EOR-GS and GS) through the Office of Air and Radiation and the Office of Water. Future regulation of CO_2 storage in State submerged lands will also fall under the jurisdiction of the EPA. The DOE, one of 15 cabinets of the Executive Branch, does not have a regulatory role, but continues to fund CCS research being conducted by governmental (e.g., USGS), academic, and private entities (Lityenski et al. 2011). Onshore transport of CO_2 and offshore transport of O&G are regulated by the DOT.

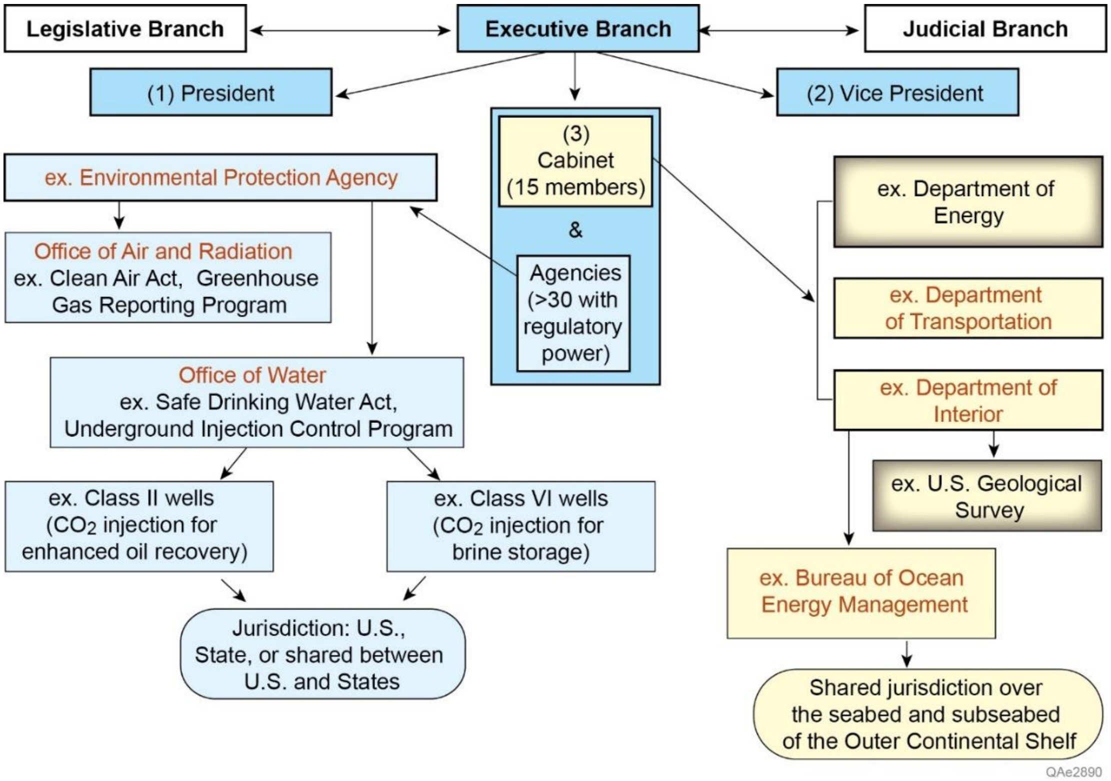

Figure 2-2. Select US governmental entities involved in CCS regulation and research
Note: Red text = CCS regulation, shaded boxes = CCS research

In 2010, the Presidential Interagency Task Force on Carbon Capture and Storage (CCS) examined the existing US regulatory framework and recommended the development of a comprehensive US framework for leasing and regulating sub-seabed CO_2 storage operations on the OCS that addresses the broad range of relevant issues and applies appropriate environmental protections. However, this comprehensive framework has yet to be established; therefore, the existing regulatory framework is shared across multiple Federal agencies, including DOI and the EPA, and may have jurisdictional gaps, including the transition from CO_2 EOR to sub-seabed GS of CO_2. Below, we discuss the existing EPA regulations for onshore CO_2 GS (Section 2.2.1) and the legal framework under which DOI may authorize offshore sub-seabed CO_2 EOR-GS and GS on the OCS (Section 2.2.2). A thorough review of other Federal agency rules that may apply to future CO_2 EOR-GS and GS on the OCS is included in Tew et al. (2013).

2.2.1 EPA Regulation of Onshore CO_2 GS

The EPA has jurisdiction over GS of CO_2 in onshore settings, where attention has been focused, through two Federal laws, the Clean Air Act (CAA) and the Safe Drinking Water Act (SDWA). Through its Office of Air and Radiation, EPA regulates air pollution under the authority of the CAA. In 2007, the US Supreme Court included CO_2 as an atmospheric pollutant that must be regulated by EPA. As a result, EPA established the Greenhouse Gas Reporting Program (GHGRP) and in 2009 published regulations for industrial emitters of CO_2[2]. The association of this program to offshore CO_2 GS is primarily through rules in Subpart RR, Geologic Sequestration of Carbon Dioxide[3]. Subpart RR requires the reporting of CO_2 injection and geologic sequestration of CO_2 in both onshore and offshore settings. Certain Subpart RR rules require operators seeking to avoid future CO_2 emissions penalties through GS to follow an approved plan for monitoring, reporting, and verification (MRV). Subpart UU, Injection of Carbon Dioxide, requires greenhouse gas (GHG) reporting from facilities that inject CO_2 into the subsurface onshore or offshore for EOR or any other purpose other than GS. Facilities that report under Subpart RR for a well or group of wells are not required to report under Subpart UU for that well or group of wells (EPA 2010b). Future operations located on State submerged lands could be subject to EPA GHGRP, Subparts RR or UU. In addition, for certain areas on the OCS, EPA has jurisdiction over emissions from offshore platforms (Tew et al. 2013).

The EPA Office of Water regulates protection of underground sources of drinking water (USDWs) by authority of the SDWA. The SDWA program that regulates CO_2 EOR and CO_2 GS operations on State lands is Underground Injection Control (UIC)[4]. UIC has defined multiple classes of injection wells, each with their own set of rules. For example, EPA UIC Class I well rules apply to industrial and municipal waste disposal wells. Injection of CO_2 for EOR falls under EPA UIC Class II. In 2010, EPA promulgated regulations for newly established UIC Class VI wells, which are wells used to inject CO_2 for long-term GS without EOR. Class VI well rules include (1) specific requirements for site selection, well design and construction, and monitoring, verification, and accounting (MVA) of injectate-CO_2, and (2) long-term monitoring after CO_2 injection has ceased[5]. The purpose of EPA's UIC program is to protect drinking water resources. The EPA has also developed guidance to support the Class VI regulatory requirements. Under the UIC regulations, operators of Class II (EOR) wells are required to apply for Class VI (CO_2 GS) permits when there is an increased risk to USDWs from Class VI compared to Class II operations. The EPA also published a memo (April 23, 2015) that discusses six key regulatory considerations when transitioning from Class II to Class VI wells.

Because the SDWA jurisdiction applies to State lands, the Class VI regulations apply to CO_2 GS in State submerged lands underlain by, or in hydraulic connection with, USDWs. Jurisdiction of the SDWA ends at the seaward extent of State-owned submerged lands.

2.2.2 DOI Regulatory Framework for Offshore CO_2 EOR-GS and GS

Under the OCSLA, DOI (BOEM and BSEE) may authorize and regulate the development of mineral resources (including O&G) and certain other energy and marine related uses on the OCS. Under this

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[2] See "Greenhouse Gas Reporting Program" on the EPA webpage. Available at: http://www.epa.gov/ghgreporting/. Accessed 08 Nov 2017.
[3] See Subpart RR of the GHGRP. Available at: https://www.epa.gov/ghgreporting/subpart-rr-geologic-sequestration-carbon-dioxide. Accessed 08 Nov 2017.
[4] See "Underground Injection Control Program" on the EPA website. Available at: http://water.epa.gov/type/groundwater/uic/index.cfm. Accessed 08 Nov 2017.
[5] See "Class VI - Wells used for Geologic Sequestration of CO2" on the EPA website. Available at: https://www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-CO2. Accessed 08 Nov 2017.

authority, with respect to CO_2 EOR and GS, DOI may permit the use and sequestration of CO_2 for EOR activities (secondary and tertiary) on existing O&G leases on the OCS and authorize the sequestration of CO_2 GS for certain types of projects. Although O&G EOR operations occur on the OCS, none to date have used CO_2. DOI does not currently have regulations specific to CO_2 EOR or GS.

2.3 International Legal and Regulatory Frameworks

To date, the global approach to CO_2 GS regulation has been for governments to begin by amending resource extraction regulations to expedite demonstration projects while simultaneously developing independent regulations for commercial-scale CO_2 GS (e.g., IEA/OECD 2010a, 2012). Australia, the European Union, China, and the US (onshore CO_2 GS regulations only) have already established CO_2 GS regulations. Canada, Norway, and Japan are in the process of writing CO_2 GS regulations. Furthermore, the International Energy Agency/Organisation for Economic Co-operation and Development (IEA/OECD 2012) stated that depleted O&G fields should not be treated differently from CO_2 saline storage areas when it comes regulating for CO_2 GS.

2.3.1 The London Convention and 1996 London Protocol

The 1972 Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter (London Convention), developed under the auspices of the International Maritime Organization, is a treaty to regulate the disposal of wastes and other matter at sea. The London Convention prohibits the dumping of all wastes, except those listed in Annex 1, which must be permitted under the conditions of Annex 2. Currently, 87 countries are party to the treaty, including the US, which became a party in 1975. The London Convention was implemented in the US under the Marine Protection, Research, and Sanctuaries Act (MPRSA) in 1972. The objective of the London Convention and MPRSA is to prevent dumping of waste streams into the sea (water column). Injection of CO_2 into deep (> 3,000 m) ocean waters or near-surface seabed sediments may be considered ocean dumping (e.g., Weeks 2007).

The 1996 Protocol to the London Convention (London Protocol) was adopted to modernize and eventually supersede the London Convention. It fundamentally shifts the approach to regulating waste materials disposed at sea by prohibiting all dumping, except for potentially permissible wastes on the "reverse list" (Annex 1). The London Protocol entered into force in March 2006. Currently, 47 countries are party to the Protocol; the US is not a party. The US signed the treaty in 1998, but because Congress has not ratified it, it has not been implemented into US law.

In 2006, Annex 1 (Sections 1.8 and 4) of the London Protocol was amended to include “CO_2 streams from CO_2 capture processes for sequestration” in sub-seabed geological formations (London Protocol 2006a), making the London Protocol the only international treaty relevant to worldwide sub-seabed storage of CO_2 captured from industrial and energy-related sources (e.g., Dixon et al. 2009; London Protocol 2012). The 2006 amendment to the London Protocol allows that disposal of captured CO_2 follows international law if it (1) is injected into a sub-seabed geologic formation, (2) is relatively pure, and (3) contains no other waste streams (London Protocol 2006a). According to Dixon et al. (2009), the scientific advisory group for the London Protocol did not to set specific numerical standards for CO_2 stream purity (original injectate-CO_2 or that recycled during CO_2 EOR) in order to allow for minor impurities introduced by industrial capture processes—which could improve project economics, pipeline materials, or geologic formations.

In 2006, the “Risk Assessment and Management Framework for CO_2 Sequestration in Sub-Seabed Geological Structures” (London Protocol 2006b) was developed. The aim of the Framework (which is not legally binding) is to aid parties in performing the assessments required under the London Protocol. The Framework addresses problem formulation, site selection and characterization, exposure assessment, effects assessment, risk characterization, and risk management.

In 2007, the London Protocol adopted a set of “Specific Guidelines for Assessment of Carbon Dioxide Streams into Sub-Seabed Geological Formations” (London Protocol 2012). The Specific Guidelines (which are also not legally binding) were updated in 2012 and supplement the Assessment Framework. They are intended to guide national authorities in evaluating applications for storage of CO_2 into sub-seabed geological structures. The guidelines include sections addressing (1) the conduct of a waste prevention audit, (2) consideration of waste management options, (3) consideration of the chemical and physical properties of the CO_2 stream, (4) site selection and characterization, (5) assessment of potential effects, monitoring and risk management, and (6) the issuance of permits according to particular developmental conditions. According to the guidelines, a properly selected and managed CO_2 GS site should retain captured CO_2 for as long as millions of years (London Protocol 2012). This duration is also supported by statements in the IPCC 2005 report on CCS (IPCC 2005).

In response to the Presidential Memorandum–A Comprehensive Federal Strategy on Carbon Capture and Storage (February 3, 2010), 14 Executive Branch departments and Federal agencies established an Interagency Task Force on Carbon Capture and Storage (CCS Task Force). In August 2010, the CCS Task Force recommended in their report (DOE/EPA 2010) the development of a comprehensive US framework for leasing and regulating CO_2 GS operations on the OCS that addresses the broad range of CO_2 GS issues and applies appropriate environmental protections.

2.3.2 Other International Legal and Regulatory Frameworks

Some countries are basing their offshore policy and regulations for CO_2 GS on existing O&G laws. According to Environmental Resources Management (ERM 2010), gaps in or issues with existing O&G regulations with respect to CO_2 injection are:

- Consideration of CO_2 GS and O&G permits in the same area and protection of O&G resources
- Transition from O&G production or CO_2 EOR to saline or brine storage (pure GS)
- Simultaneous permitting of CO_2 GS and CO_2 EOR
- Discovery of O&G while characterizing and drilling for CO_2 GS
- Reasonableness of storage permit application

Regardless of these issues, CO_2 GS regulations in Australia, Canada, and Norway are based on amendments to existing O&G laws (ERM 2010, Kjarstad et al. 2011a). Below we highlight existing regulations for offshore CO_2 GS in Australia, Canada, the EU, and Norway.

2.3.3 Australia

Australia has the most detailed existing offshore CO_2 GS regulations, which originated with previously existing O&G regulations. The Australian government published Offshore Petroleum and Greenhouse Gas Storage Act 2006 and the State of Victoria published Offshore Petroleum and Greenhouse Gas Storage Act 2010. According to IEA/OECD (2014), Victoria has already granted one permit for offshore GHG assessment (CarbonNet CCS Flagship). The Victorian regulations are similar to the Australian Federal Act. Of note, (1) the Act does not mention monitoring to assure safe storage of CO_2, and (2) the Act stipulates that exploration for a GHG storage site may not take place in an area that already has a petroleum permit, lease, or license (ERM 2010). The Australian CO2CRC (2008) considers capacity for CO_2 storage, which they identify as available pore space, as a resource.

2.3.4 Canada

The Canadian Standards Association (CSA) has developed, in cooperation with US entities, a draft standard on onshore geological storage of CO_2 (CSA Group 2012). However, Alberta is the only province in Canada that has established enforceable GS rules (i.e., the Carbon Capture and Storage Statutes Amendment Act, 2010). They have issued a draft CCS Quantification Protocol to grant emission reduction credits (Dixon 2015), probably because Alberta hosts the first post-combustion coal-fired CCS facility, the Boundary Dam project. The CO_2 from Boundary Dam is used for CO_2 EOR in Alberta. The Alberta rules are clearly O&G-based, because the mineral rights lease holder by default holds the CO_2 storage rights (ERM 2010). The regulatory working group of the Alberta Regulatory Framework Assessment (RFA) considers pore space to be a resource (Alberta Energy 2012b). Another fact pertinent to development of BOEM regulations for sub-seabed CO_2 storage is that the Alberta rules are modeled after acid-gas disposal regulations (Alberta Energy 2012b). An effort to establish an international standard for CCS is under way but is still in the beginning phases[6].

2.3.5 European Union

Many of the regulations for CO_2 GS in Europe pertain to offshore, because (1) much of their suitable geologic storage is offshore, and (2) public opposition to onshore storage has been widespread. The EU CO_2 GS policy is two-fold in that O&G-based and non-O&G-based approaches and permits are required. The O&G exploration permit holder has priority for issuance of a CO_2 storage permit. There is a lengthy Environmental Impact Assessment (EIA) requirement that must involve public consultation (ERM 2010).

The European Commission (EC) CCS Directive 2009/31/EC, dated 23 April 2009 (EC 2009), has been followed by many subsidiary documents. European Union (EU) decisions and regulations are the laws that enact EU Directives. Subsidiary EU CCS documents include:

1. EC Monitoring and Reporting Guidelines (e.g., EC 2010)
2. Four EU CCS guidance documents published in 2011:

[6] See International Organization for Standardization. "ISO/TC 265 Carbon dioxide capture, transportation, and geological storage." Webpage. Available at https://www.iso.org/committee/648607.html Accessed 08 Nov 2017.

- CO_2 Storage Life Cycle Risk Management Framework (EC 2011a)
- Characterisation of the Storage Complex, CO_2 Stream Composition, Monitoring and Corrective Measures (EC 2011b)
- Criteria for Transfer of Responsibility to the Competent Authority (EC 2011c)
- Financial Security and Financial Mechanism (EC 2011d)

3. Report on the implementation of the EU CCS Directive 2009/31/EC (EC 2014)

The EU CCS regulations apply to all member countries, and decisions only apply to specific groups for specific cases. For example, according to information from the Oslo-based Zero Emissions Research Organization (ZEROCO$_2$.NO), an environmental non-profit organization in Norway supported in part by industry, the EU Directive will be implemented in the Netherlands by amending the Mining Act and the Environmental Management Act and making a minor change to the Water Act.

2.3.6 Norway

Although Norway is not a member of the EU, it is using the EU Directives as a guideline for development of their offshore CCS regulations. Implementation of the draft regulations will be the responsibility of both the Ministry of Petroleum and Energy (MPE) and the Ministry of Climate and Environment (Kjarstad et al. 2011a). Because Norway lacks suitable onshore reservoirs, offshore sub-seabed storage is the only option for disposal of CO_2 generated by onshore industrial facilities (Agerup 2014). Norway has taxed CO_2 emissions since 1991 (IEA/OECD 2014), which is one of the reasons why companies such as Statoil have re-injected CO_2 co-produced with natural gas into the Norwegian North Sea sub-seabed since 1996. According to Agerup (2014), licensing of offshore CO_2 injection operations includes transfer of post-closure responsibility to the MPE. A thorough review of how offshore CO_2 GS is regulated in Norway is included in Tew et al. (2013).

3 Discussion of Best Management Practices Development

BMPs that have already been developed for CCS (CO_2 GS) and CCUS (CO_2 EOR-GS) range from technical guidance based on knowledge gained through pilot-scale injection projects (e.g., WRI 2008a, DOE NETL 2013c) to methodologies that have been proven through large-scale industry practice (e.g., API 2009). However, because many aspects of offshore CO_2 EOR-GS and GS technologies are emerging, there are information gaps; more knowledge is needed through offshore pilot-scale projects and additional offshore industry experience to fully develop BMPs (e.g., monitoring, inspections, auditing, reporting requirements, and emergency response). Topics with the greatest information gaps for BMPs development of offshore sub-seabed storage of CO_2 are (1) characterization of overburden intervals (i.e., geologic strata above an intended CO_2 reservoir and below the seafloor) and (2) sub-seabed and seafloor monitoring, which will be needed to demonstrate effectiveness of injectate-CO_2 isolation from the seafloor and oceans.

However, much industrial knowledge and experience related to onshore transport and injection of CO_2 can be applied in offshore settings. As a result, much of the discussion of storage BMPs presented below is based on the current state of knowledge as presented in available literature (see Appendix A for discussion of relevant documents and a literature database compiled for this study). BMPs discussion about CO_2 transport contains many references to existing regulations and standards, which are also included in the literature database and accompanying report (Appendix A).

General categories of BMPs development discussed here are technical operations, environmental concerns, and health and safety of workers. The following discussion of BMPs development is organized according to nine subtopics (Table 3-1) that reflect critical considerations needed for effective planning of CO_2 transportation and storage operations on the OCS.

Table 3-1. Best management practices subtopics

Subtopic	Title	Report Section
1	Site Selection and Characterization	3.1
2	Risk Analysis	3.2
3	Project Planning and Execution	3.3
4	Monitoring	3.4
5	Mitigation	3.5
6	Safety Inspection and Performance Assessment	3.6
7	Reporting Requirements	3.7
8	Emergency Response and Contingency Planning	3.8
9	Decommissioning and Site Closure	3.9

All of the nine BMPs subtopics overlap, influence, and/or build on each other. Site selection and characterization (Section 3.1) is the most important component of sub-seabed CO_2 storage, because it sets the stage for successful project implementation. Characterization of a CO_2 storage site needs to be an ongoing process that continues after site selection. For example, characterization models will need to be updated with new testing, operations, and monitoring data as CO_2 injection proceeds to more accurately interpret the geologic setting and its control on sub-seabed fluid migration. Refined geologic characterization through iterative fluid flow modeling will be of high value in predicting CO_2 migration, providing assurance that CO_2 will remain isolated from the atmosphere for at least hundreds of years, and will minimize the need for post-injection site monitoring. These are examples of the overlap in BMPs development for site characterization (Section 3.1), risk analysis (Section 3.2), and environmental monitoring (Section 3.4).

All types of wells must be considered during risk analysis (Section 3.2) and project planning and execution (Section 3.3), including:

- CO_2 injection wells
- Active O&G production wells
- Fluid disposal wells
- Plugged and abandoned (P&A) or legacy wells (knowing the location, construction, and condition of legacy wells is critical for both monitoring [Section 3.4] and mitigation [Section 3.5])

Directional wells are prevalent offshore; this could influence practices for many aspects of an offshore CO_2 sub-seabed GS project, i.e., site characterization and capacity estimation (Section 3.1), risk analysis, (Section 3.2), project planning (Section 3.3), monitoring (Section 3.4), and possibly mitigation (Section 3.5). The potential impact from corrosivity of CO_2 in the presence of water will also influence practices for many components of CO_2 storage technology, such as pipelines, facility equipment and associated infrastructure, and well casing and tubing. The potential for CO_2-stream corrosivity is addressed in Section 3.2 (risk analysis), Section 3.3 (project planning and execution), Section 3.6 (safety inspection and performance assessment), Section 3.8 (emergency response and contingency planning).

In Sections 3.1 through 3.9, each BMPs subtopic includes:

- Existing regulations and/or standards that might be utilized directly, or adapted, to address specific aspects of the sub-seabed CO_2 storage technology chain
- Considerations for the development of BMPs gleaned from project experience, or through review of documents summarizing CO_2 GS and EOR-GS research, limited industrial operations, and other relevant literature

See Appendix A for a through compilation of relevant literature.

3.1 Site Selection and Characterization

Site selection and characterization are presented here as a combined subtopic, because a CO_2 storage site cannot be confidently selected unless geologic and other types of characterization have been completed. Factors, such as proximity to CO_2 sources and existing pipeline right of way, will influence economic considerations weighed by industry during offshore sub-seabed CO_2 GS or EOR-GS site selection. Results of early monitoring data collected during site-specific injection testing and early-stage monitoring will also control site selection. Overall site development and monitoring BMPs are discussed in Sections 3.3 and 3.4.

The first criterion is to have a storage site that is geologically suitable; sufficient geologic characterization of sub-seabed strata is critical to offshore CO_2 site selection. Sufficient geologic characterization is the best way to ultimately assure long-term isolation of CO_2. The focus here is on the selection of a storage site with a geologic reservoir that is suitable for the injection of large volumes of CO_2, and that is overlain by geologic strata with fluid trapping properties sufficient to retain CO_2 deep (> 1,000 ft) below the seafloor.

Best practices for the geologic characterization of offshore storage sites were first developed by the British Geological Survey and Statoil as part of the Saline Aquifer CO_2 Storage Project (SACS) (Chadwick et al. 2004, 2008). Existing guidance documents include an updated manual prepared by DOE NETL (2013b), which covers many aspects of onshore CO_2 GS site selection. Much of what is contained in DOE NETL (2013b) can be applied to offshore settings. The components of site selection and characterization discussed below are data collection, capacity assessment, and modeling. In addition to the documents cited above, there are many other existing references on data collection, capacity assessment, and modeling requirements for selection and characterization of onshore GS sites, including manuals, guidance documents, standards, recommended practices, and regulations. Much of the information can be directly applied to characterization of offshore sub-seabed CO_2 storage reservoirs.

3.1.1 Data Collection

A difference between offshore sub-seabed O&G exploration and CO_2 storage site characterization is the need to collect data from the interval above the confining zone that overlies the CO_2 reservoir and below the seafloor; some refer to this interval as the overburden. Onshore, this interval is most commonly characterized using borehole data (geophysical logs and cores). Logging of the overburden interval is conducted to ensure protection of drinking water resources but may not be necessary on the OCS due to the lack of freshwater aquifers.

Shallow sub-seafloor geophysical surveying can obtain information on the geologic strata lying below the seafloor and above the reservoir interval. An example is the high-resolution three-dimensional (3-D) seismic system (P-Cable™) described in Meckel and Treviño (2014a, 2014b) and Meckel and Mulcahy (2016). P-Cable is a relatively new technology for collecting high-resolution 3-D marine seismic data within the upper few kilometers below the seafloor. Seismic data collection is also the primary way to characterize the deeper sub-seabed geologic intervals and is a critical tool for sub-seabed monitoring as discussed further in Section 3.4.2.3. Highlights of seismic data collection for offshore CO_2 sub-seabed storage site characterization include:

- Two-dimensional (2-D) seismic profile data can be used for reconnaissance-level site characterization. Although 2-D offshore data tend to be good quality, it will be difficult to conduct a detailed site assessment where the spacing between 2-D profiles is large.
- Three-dimensional (3-D) seismic data can be used to reach preliminary conclusions about seismic evidence of vertical migration paths and fault complications across sites considered for CO_2 storage.
- Collecting seismic data acquisition is often less expensive offshore than onshore, and the resolution of data products may be higher. Specific seismic applications that are routinely

used in offshore O&G exploration, which are equally effective for CO_2 GS site characterization, include the examination of legacy and newly acquired seismic data for evidence of the following:

- **Primary-wave (P-wave) wipeout zones:** Loss of P-wave reflectivity across shallow stratigraphic intervals is widely accepted by the O&G industry as compelling evidence that gas and fluids from deep reservoirs can rise to the seafloor via vertical migration paths (Heggland 1998). The importance of gas migration from deep geologic strata and seafloor seepage for CO_2 GS projects is discussed further in Sections 3.2 and 3.4.
- **Bright seafloor reflectivity:** An increase of a factor of two or more in seafloor P-wave reflectivity in water depths appropriate for hydrate stability has been established across the GOM as having approximately a 90 percent correlation with the presence of a sub-seafloor hydrate system (Roberts et al. 2006). Because GOM hydrates tend to be more dependent on deep thermogenic gas than on shallow biogenic gas, an increase in seafloor reflectivity can usually be assumed to indicate a flow path exists by which deep gases and fluids reach the seafloor (Hovland 2007).
- **Faults:** No measurement surpasses seismic data for identifying and mapping subsurface or sub-seafloor faults. The identification of sub-seafloor faulting will not necessarily exclude a site from consideration for CO_2 storage. However, if identified, it will be important to assess if the fault(s) are transmissive along all or portions of their extent, or if local stress fields could allow movement along fault planes if they become over-pressured and/or saturated (i.e., lubricated) with injected CO_2.

Other types of data (other than geophysical data) needed for CO_2 storage site characterization are referenced in the following Section 3.1.1.1 and discussed further in Section 3.1.3.

Existing BOEM and BSEE O&G regulations for geological and geophysical (G&G) data collection on the OCS have the potential to be adapted to offshore data collection for CO_2 EOR-GS and GS. The regulations address geophysical methods of sub-seabed characterization and shallow and deep stratigraphic testing.

3.1.1.1. Examples of Data Availability

Sites that can most readily and assuredly be characterized for offshore CO_2 GS are those where extensive sub-seabed geological data are already available. Consequently, basins with existing O&G fields will take less effort to characterize (e.g., Bachu et al. 2007). Below we provide examples of how existing geologic data in the Gulf of Mexico (GOM), the Atlantic continental margin, and the Pacific Ocean offshore from southern California will aid CO_2 storage site characterization in these areas.

Gulf of Mexico

The BOEM Gulf of Mexico OCS Region in New Orleans, Louisiana, has extensive 2-D and 3-D seismic data covering approximately 80 percent of the US portion of the GOM; however, it is important to note that the majority of the data, especially the 3-D data, is not available to the public due to regulations covering propriety terms. BOEM also maintains online databases containing drilling records, well-test data, and litho- and bio-stratigraphic information on oil- and gas-bearing sands in the GOM. This sands database will be of great value in characterizing possible future sub-seabed CO_2 storage sites in the GOM. For example, DiPietro et al. (2015) discussed how the BOEM sands database can be used to identify COM sites are suitable for CO_2 injection; however, their emphasis was on CO_2 EOR.

Additional sub-seabed geologic characterization data can be obtained from commercial sources, such as IHS Energy and DrillingInfo. The abundance of well data available for the GOM is apparent from Figure 3-1 and is outlined in detail in Appendix B. Another good source of geologic data for the GOM is the Gulf of Mexico Basin Depositional Synthesis project reports by The University of Texas Institute for Geophysics.

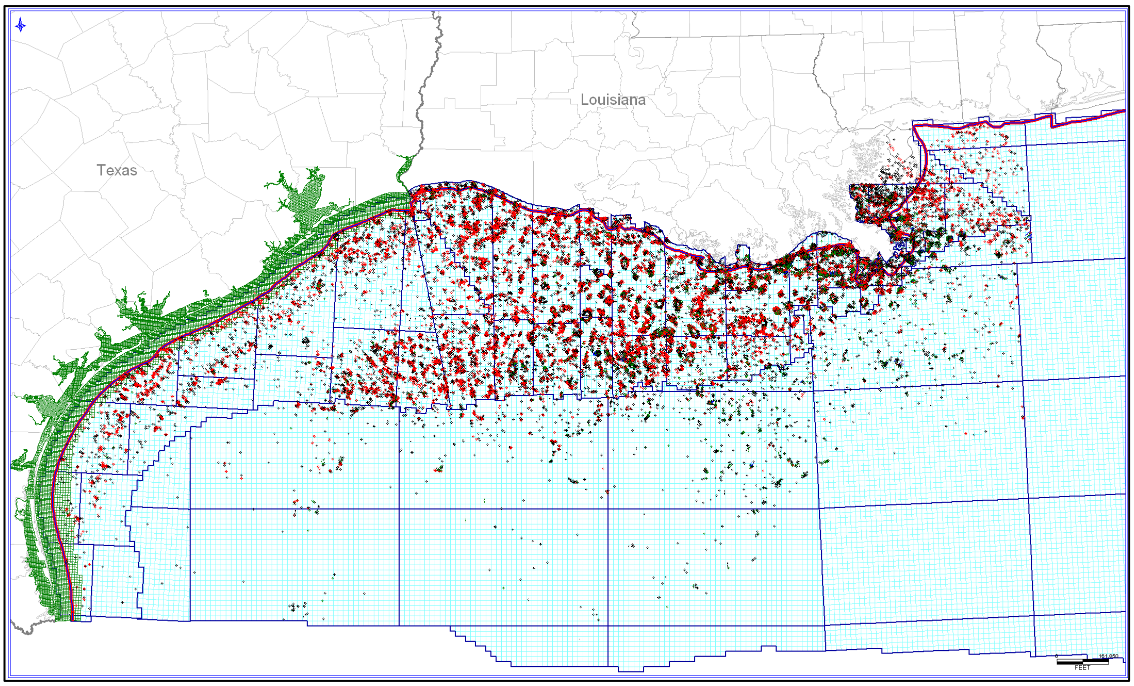

Figure 3-1. Example of well data coverage in the GOM from BOEM and IHS databases
Key: red dots = gas wells, green dots = oil wells, and black dots = dry holes

Atlantic Ocean
In comparison to the GOM, 2-D and 3-D seismic and well-based geophysical data are limited in the Atlantic OCS. Reports by BOEM and USGS show that many seismic surveys have been completed on the Atlantic OCS (Figure 3-2); however much of the data collection technology (2-D only) and data sets are outdated (1980s and older). Little well-based information, except for a few Continental Offshore Stratigraphic Test (COST) wells, is available for the Atlantic OCS, especially for deeper geologic reservoirs that will be more suitable for sub-seabed CO_2 storage. USGS has compiled reports of seismic and borehole data coverage in the Atlantic OCS (e.g., Hutchinson et al. 1995, 1997); review of these documents is a best first step in assessing site suitability in that area. Examples of reconnaissance-level site studies completed using available data on the Atlantic OCS can be found in Smyth et al. (2008, 2011).

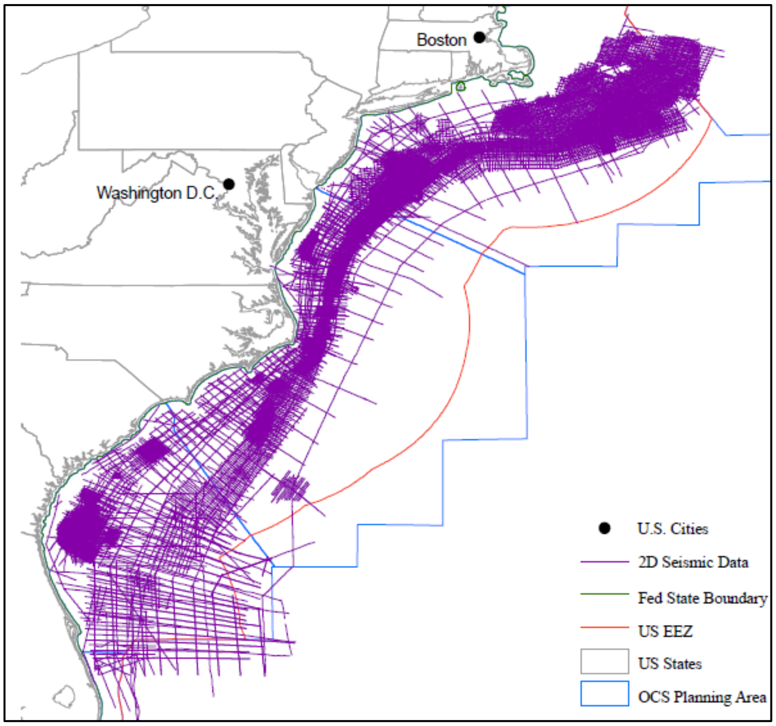

Figure 3-2. Seismic data coverage in the Atlantic OCS
Source: BOEM 2013b

Pacific Ocean: Los Angeles Basin

The DOE National Energy Technology Laboratory (NETL) has funded a study to characterize the potential for offshore CO_2 GS at Wilmington Graben (DOE NETL 2015). The Wilmington Graben is a geologic feature located approximately 10 miles offshore from Long Beach, California. Childers et al. (2012) and Bruno et al. (2014) provided a description of the methodology used to characterize the Wilmington Graben site. They noted that the Los Angeles basin is one of the most prolific O&G producing regions in the US, and that the area has also been used for underground storage of natural gas. This study is another example of how the characterization of offshore CO_2 GS sites tends to be coupled with areas of existing and historic O&G activity due to data availability. The Wilmington Graben DOE NETL results demonstrate both onshore and offshore basin-scale suitability for CO_2 GS in southern California but highlight the advantages of using offshore storage sites. In the DOE NETL-funded study of the Wilmington Graben, researchers estimated on the basis of modeling more than 100 million metric tons of CO_2 storage capacity for that area (Arra Site Characterization Projects [date unknown]).

3.1.2 CO_2 Storage Capacity Assessment

In a DOE NETL Best Practices document (DOE NETL 2013b), CO_2 storage capacity is presented as a qualified estimate of CO_2 storage resource. The term “storage resource” implies that the volume of pore space available for CO_2 storage is a natural resource. The consideration of pore space as a natural resource could have implications for development of CO_2 storage regulations as reported by the regulatory working group of the Alberta RFA (Alberta Energy 2012b).

There are no existing regulations or widely accepted standards for CO_2 storage resource and capacity estimations in onshore or offshore settings. According to DOE NETL, storage capacity is initially based on the calculation of storage resource and is then adjusted to compensate for geologic, economic, and regulatory limitations (DOE NETL 2013b, Appendix 1). Our interpretation of the distinction between storage resource and storage capacity is that the storage resource is a regional estimate, whereas storage capacity is a calculation based on site-specific or well-specific data. The difference in scale of the calculations is analogous to the basin-wide and site-specific levels of capacity estimation discussed further in Section 3.1.2.2.

There are many existing manuals, guidelines, and published papers on various ways to estimate CO_2 storage capacity of geologic strata in different locations. Among these is a report by the Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC 2008), which makes an important point that capacity assessment is always an estimate until after CO_2 injection begins. The report stresses the importance of a consistent methodology for estimating CO_2 storage capacity, especially once global CO_2 emissions trading is established.

DOE NETL has reported several accepted methods of resource estimation (more widely known as capacity estimation) for different types of geologic environments (e.g., DOE NETL 2013b; DOE NETL 2015 and preceding versions of the Atlas). Formulas used for volumetric estimates in O&G reservoirs and saline formations (i.e., brine storage) are similar in that both include:

- Area-plan view or x-y (A)
- Thickness (h)
- Porosity (ϕ)
- CO_2 density (ρ)
- Efficiency factor (E)

Variations in these parameters for O&G reservoirs and brine formations respectively include (1) net (h_n) compared to total (h_t) interval thickness and (2) average effective porosity (ϕ_e) compared to total porosity (ϕ_t). Additional factors included in estimates for O&G reservoirs are related to O&G saturation in the reservoir and a reservoir volume factor that is tied to in situ pressure and temperature (see DOE NETL 2013b, Appendix 1, Table 1). In both estimation approaches, the CO_2 density (ρ) term accounts for fluid and fluid-rock interactions.

The dimensionless efficiency factor (E) is an estimate of the percentage of pore space that can be filled by injectate-CO_2. E is the most variable and debated input parameter in CO_2 storage capacity estimation equations; part of the controversy is whether different E-values should be used for different types of reservoirs. There is also ongoing debate over other critical limiting factor(s) for CO_2 storage capacity estimation for various types of geologic reservoirs. Gorecki et al. (2012) provide an overview of variations in application of the capacity calculation, including the range of storage efficiency factors that are used in capacity estimation calculations. An example application of storage capacity estimation is provided in Appendix C.

Capacity estimation is a critical aspect for screening potential CO_2 GS sites; it varies in scope and scale. These and other aspects of capacity estimation are discussed in Sections 3.1.2.1 through 3.1.2.3.

3.1.2.1 Scope of Capacity Estimation

The following concepts need to be considered when estimating the CO_2 storage capacity of sub-seabed geologic strata:

- Closed and open deep subsurface fluid flow boundaries, which can be controlled by the presence or absence of structural closure, including transmissive and non-transmissive bounding faults, stratigraphic pinch-outs, irregular patterns of digenetic alteration in reservoir rocks, and facies changes in either reservoir or confining systems.
- Types of trapping can vary in space and time and are controlled by properties of geologic media and fluids, basin or continental margin stress regimes, fluid chemistry, and availability of ions for mineralization. Bachu et al. (2007) discussed different types and time scales of trapping in onshore settings; these parameters are also applicable to offshore sub-seabed strata. Hermanrud et al. (2009) provided in-depth discussion of the different types of CO_2 trapping observed at Sleipner.
- Density of CO_2 at reservoir pressure and temperature
- Petrophysical properties of the reservoir and confining system rocks
- Limiting CO_2 injectivity to some fraction of the fracture pressure of low-permeability layers (also called confining zones, seals, or caprock) needed to impede buoyant migration of CO_2
- Increased pressure within pore spaces occupied by CO_2 and in zones outside of a CO_2 plume (updip or vertically), potentially displacing brine updip or vertically to damage other sub-seabed resources

3.1.2.2 Scale of Capacity Estimation

The continuum endpoints for scale of capacity estimations are basin-wide to a single CO_2 injection well site. Early basin-scale estimates of the capacity available to store CO_2 in the State and OCS sub-seabed are reported in DOE NETL atlases (DOE NETL 2015). Ranges of values for CO_2 storage capacity for the OCS are shown on page 111 the DOE NETL atlases (DOE NETL 2015). The primary purpose of the atlases is to demonstrate that there is sufficient capacity in the US to move forward with CCS technology. Goodman et al. (2011) stated that capacity assessment for saline formations must be conducted on a basin scale, whereas a field-scale approach is appropriate for O&G reservoirs. The rationale behind this assumption was that the lower density of subsurface data in areas outside of O&G fields will only allow basin-scale capacity assessments to be made. Inherent in Goodman et al.'s (2011) assumption is that saline storage will take place in areas distant from O&G operations. Bachu et al. (2007) also recognized differences in scale of capacity estimation (i.e., basin to site scale) but stated that CO_2 storage capacity in existing O&G reservoirs is simply the amount of estimated recoverable reserves. It has since been recognized that saline aquifers underlying hydrocarbon reservoirs can also be included in capacity estimation in an area with existing O&G operations. Going one step further, Nicot and Hovorka (2009) discussed how open-boundary, saline reservoirs underlying Gulf Coast hydrocarbon reservoirs can provide additional CO_2 storage capacity, and they added assurance of retention by injecting deeper than the base of nearby O&G wells.

Wallace (2013) and Wallace et al., (2014) provide an example of how capacity estimation decreases with (1) decreasing scale of investigation (from basin to site scales), (2) modeling of site-specific CO_2 density, and (3) existing sub-seafloor pressure regime. This work focused on a 36,000 km^2 (14,000 mi^2) area in GOM State waters, within ~10 mi offshore from Bolivar Peninsula in Texas. Results from this work and that of another study (Nicholson 2012) include definition of upper and lower bounds on feasible injection depths below the seafloor. The shallowest depth at which CO_2 could be stored in supercritical state at this location is 1,006 m (3,300 ft). Estimated deepest depths for CO_2 storage range between 1,767 and 3,688 m (~5,800 and 12,100 ft). The deeper depth is where regional sub-seabed hydrostatic pore pressure is exceeded. This example illustrates the importance of knowing local conditions and their impact on CO_2 capacity estimation. CO_2 GS operators in other OCS basins will need to pay attention to sub-seabed pressure and temperature conditions, and their impact on CO_2 density, when calculating offshore storage capacity.

3.1.2.3 Examples Capacity Estimation Studies

In 2009 and 2010, controversial articles published in the journal of the Society of Petroleum Engineers (e.g., Economides and Economides 2009) stated that subsurface capacity for injection of CO_2 is too limited for the technology ever to be possible. The response published by Cavanagh et al. (2010) refuted this claim and reviewed how results of studies conducted in Australia, Europe, and North America show tremendous volume for storage of CO_2 exists, even if only a small volume of appropriate geologic formations is utilized. A point also made by Cavanagh et al. (2010) is that basin-scale estimates of CO_2 storage capacity are too large, because gross formation rather than net sand thickness has been used in calculations.

Examples from the Atlantic OCS demonstrate ways in which regional scale CO_2 storage capacity can be overestimated. In Smyth et al. (2008) and the NatCarb Atlas (DOE NETL 2015 and previous version of the Atlas), total unit thickness was used to estimate CO_2 storage capacity for two Cretaceous-age sub-seabed units offshore from the Carolinas. The estimate of more than 175 billion metric tons (Gt) for the deeper, more widespread lower Cretaceous unit is very likely too large, because gross unit rather than net sand thicknesses were used in the calculations. Another reason for over estimating capacity is that the 15,000 km^2 (~ 6,000 mi^2) area considered extends off the edge of the continental shelf in water deeper (> 200 m) than will likely be considered for CO_2 GS operations. In an updated version of CO_2 storage capacity estimation for the South Georgia Basin, which extends into the Atlantic OCS, Smyth et al. (2011) used net sand thicknesses, multiple E-factors, and site-specific CO_2 densities to come up with relatively smaller capacities (111 to 305 Gt) for a much larger area (191,000 km^2, or ~ 73,000 mi^2). Appendix C contains an excerpt from Smyth et al. (2011) showing the capacity estimation methodology used for the South Georgia Basin adjacent to the Atlantic OCS.

A DOE NETL project in progress (Hosseini and Kim 2014) is developing the Enhanced Analytical Simulation Tool (EASiTool). EASiTool uses a Monte-Carlo statistical simulation approach to estimate CO_2 injectivity, number of wells needed, and an alternative to storage efficiency coefficients (same as E described above) for specified geologic formation properties.

3.1.3 Modeling

There are currently no regulations or standards that specifically address modeling for offshore CO_2 storage site characterization. However, the IEAGHG coordinates an international research network on modeling associated with CO_2 storage. Two active participants in the IEAGHG research network, Statoil and Permedia Research Group Inc., have established a sub-seabed reservoir benchmark model with the aim of improving the understanding of CO_2 flow dynamics. Detailed results of the modeling are available to research group members only.

The best application of modeling is to use the same approach, or even the same set of models for site characterization, risk assessment, monitoring design, and monitoring verification to best support the ultimate step of site operations, which is site closure. Following is discussion on types and applications of models and examples of existing models that have been used in early stages of offshore CO_2 storage site characterization.

3.1.3.1 Types and Applications of Models

The types of models used for CO_2 storage site characterization are static geologic framework (GF) and dynamic fluid flow (FF) models for both onshore and offshore settings. Ideally, models will be populated with actual site data, more of which will become available as an offshore CO_2 storage project matures. For models constructed in offshore areas with sparse data, a stochastic approach will be needed, at least in earlier stages of a project. Stochastic approaches to modeling may also be necessary in risk analysis (Section 3.2) and monitoring plan design (Section 3.4).

Static GF modeling requires input of the most accurate interpretation of the stratigraphic correlations and structural geometries using all available data (see discussion in Section 3.1.1; Appendices B and C; and data elements A, B, and C in Table 3-2). Onshore, it is common for O&G site operators to use wireline geophysical logs, rock samples (continuous core or cuttings), fluid samples collected during borehole drilling and after well completion, and seismic data as input for static geologic models. Due to lower well densities, predictive models for offshore CO_2 GS may be based more on seismic or other geophysical data than on borehole or well data.

Table 3-2. Example data elements needed for sub-seabed storage models

Data element	Data description
A	Top and bottom elevations and other geometric characteristics of sub-seabed geologic units from regional or local-scale borehole geophysical logging
B	Permeability/porosity estimates of geologic units from borehole geophysical logs and cores (if available)
C	Petrographic information on injection/production and confining system rocks
D	Historical data on fluid production and injection volume and rates, pressure and temperature history
E	Fluid distribution history (oil-water contacts, gas cap, etc.)

Data element	Data description
F	Regional environment (water drive, etc.) and other boundary conditions
G	Results from reservoir zone hydraulic testing—interference, shut-in, and/or swab tests
H	Multi-phase flow parameters (relative permeability, capillary pressure) including experimental data if available
I	PVT data for oil and CO_2-injection stream (type of impurities if any)
J	Brine chemical analyses
K	Reservoir zone well completion history including records on plugging and abandonment
L	Method of operation for EOR flood (CCUS only)

Dynamic FF modeling, using measured or predicted fluid properties such as proportion of liquid and gas in pore spaces, is conducted to simulate fluid distribution within the static GF. Types of data needed for comprehensive FF models include elements D through L in Table 3-2. More work will be required to incorporate geochemical conditions and reactions and geomechanical parameters (e.g., Hosseini and Kim 2014) into dynamic FF models.

Appendix D contains an example workflow for constructing static GF and dynamic FF CO_2 storage site characterization models. The workflow starts at the basin or regional scale and moves to the site-specific scale. The outlined approach is analogous to identification of O&G plays followed by more site-specific prospect development. Most static and dynamic modeling have focused on deep subsurface, reservoir zone intervals and ignored the overburden zone (i.e., strata between the reservoir/seal and land surface/seafloor). A notable modeling approach to onshore capacity estimation and risk assessment that considers all depth intervals—reservoir zone to surface—is the Certification Framework (CF) (Oldenburg et al. 2009a, 2009b). CF modeling is discussed further in Section 3.2.

3.1.3.2 Existing CO_2 Site Characterization Models

All CO_2 storage site modeling must be iterative with observations from pre-perturbed systems (e.g., before primary oil production from a reservoir) with operational CO_2-injection monitoring being used to calibrate, update, and otherwise create more realistic models. This process is common knowledge among subsurface modelers and is demonstrated in work by the Australian CO2CRC (Kaldi et al. 2009) and research conducted at the In Salah CO_2 injection site in Algeria (i.e., Cavanagh and Ringrose 2011, Ringrose et al. 2013). The scale of model grids is also critical with the smaller grid-size models yielding more accurate results. DOE NETL (Goodman et al. 2011) used 10 km by 10 km 2-D grids in a capacity estimation model, whereas Cavanagh and Ringrose (2011) illustrated the utility of reducing grid cell size to 10 m by 10 m by 2 m.

Notable models specific to offshore CO_2 GS in the Norwegian North Sea include those by Estublier and Lackner (2009) and Singh et al. (2010). A scenario modeled for the Snøhvit site was 23 million tons injected in one well for 30 years (Estublier and Lackner 2009). The objective was to assess sealing capacity of faults and caprock above a saline formation. Results included differences in CO_2 migration with variations in fault permeability. Storage capacity was limited by large increases in reservoir zone pressure in simulations with non-transmissive or sealed faults. Alternate scenarios predicted that CO_2 would migrate up along faults assigned higher permeability even with a leaky overlying seal. CO_2 GS at Snøhvit was discontinued in 2012 when reservoir capacity was discovered to be lower than expected. Singh et al. (2010) demonstrated the importance of using site-specific geologic and fluid properties to accurately match monitoring data at Sleipner.

3.2 Risk Analysis

There are no existing regulations or BMPs for risk analysis of offshore sub-seabed storage of CO_2. There are, however, guidance documents, recommended practices (e.g., CO2RISKMAN, DNV 2010a), standards (e.g., API Standard 65-2), and published literature containing directly applicable information. Highlights from DNV documents, API standards, and other literature with information that can be applied to BMPs are presented below. Some view risk assessment as a process of evaluating model predictions by verifying them with monitoring data. Development of BMPs for risk analysis will most likely be iterative on a basin-by-basin or site-by-site basis.

Potential risks from offshore sub-seabed GS of CO_2 are multifaceted. This discussion of associated risks is limited to those that pose danger to human health and safety or the environment and does not consider economic, legal, or climate risks. Risk assessment for offshore CO_2 storage applies to physical components of the technological process and the potentially impacted environments. Physical components of offshore CO_2 storage technology considered here are pipelines, platforms, and wells. Environments that could be impacted by failure of the CO_2 storage technology (i.e., CO_2 leakage) include coastal, nearshore, and marine habitats and biota and sub-seafloor geologic strata.

CO_2 leakage from a storage reservoir via an injection well or a previously existing P&A well could pose risks to (1) other sub-seabed resources, (2) the ocean water column, (3) environmental resources in the water column and on the seafloor, or (4) platform workers, and result in emissions to the atmosphere. A question that needs to be answered is: what volume or rate of CO_2 leakage from a well or a storage reservoir is considered significant? Both temporal and spatial variability needs to be considered. Fast leakage will be more easily detected through abrupt changes in operations (e.g., significant change in well casing pressure) or possibly even catastrophic events. Slower leakage over longer time spans, even geologic time scales, could be difficult to detect, but could have negative consequences nonetheless (IPCC 2005, 2006). Factors influencing spatial variation in leakage scenarios, which are also tied to temporal variation, include migration of CO_2 through geologic strata, along transmissive faults, or along leaking well bores. Risk assessment for leakage of CO_2 from a storage reservoir needs to be realistic in perspective. GS may not have to be 100% effective to impact climate change mitigation; for example, work by Stone et al. (2009) shows storage reservoir retention time to be the most important factor in success of CO_2 GS.

There is much overlap between potential risks associated with offshore O&G activities and offshore CO_2 transport and storage. A difference between risk assessment for O&G operations and CO_2 storage is consideration of subsurface intervals included in models and monitoring programs. O&G operators usually only consider fluid migration within the reservoir/CO_2 injection zone. Risk assessment modeling for onshore CO_2 storage reservoirs also includes the following subsurface intervals: (1) the overlying confining systems (also referred to as caprock or seal), (2) all other subsurface strata up to base of USDW, which are also called overburden or intermediate zone (e.g., Wolaver et al. 2013), (3) the USDW, which is also called the freshwater or saturated groundwater zone, (4) the unsaturated/vadose/soil zone, and (5) the atmosphere. Zones of interest for risk assessment for offshore sub-seabed CO_2 storage, which are the same as for onshore, are the (a) reservoir zone, (b) confining system, (c) overburden, (d) water column, and (e) atmosphere. The approaches to risk analysis for onshore CO_2 GS, which include all the above zones of interest, and which can apply in offshore settings are:

- Features, events, and processes (FEPs), (e.g., Wildenborg et al. 2005, Stenhouse et al. 2005)
- The Australian sign post framework developed for the Gorgon project
- The CF approach developed by Lawrence Berkeley National Laboratory and The University of Texas at Austin (Oldenburg et. al. 2009b)
- The CO_2 Predicting Engineered Natural Systems (PENS) methodology developed by Los Alamos National Laboratory (Stauffer et al. 2008)

The primary risk assessment considerations for onshore CO_2 storage are health and safety of workers, protection of USDWs, and isolation of CO_2 from the atmosphere. In offshore settings, the primary considerations for risk assessment are health and safety of workers, protection of other sub-seabed resources, and isolation of CO_2 from the water-column and atmosphere. If CO_2 migrates from a sub-seabed reservoir and is released at the seafloor, it will quickly dissolve into seawater (e.g., Blackford et al. 2014, IEAGHG 2015). Increased ocean acidification is one of the major observable impacts of increased concentrations of atmospheric CO_2 (e.g., Dixon et al. 2009), and much work should go into prevention of seabed leakage of CO_2 from deep sub-seabed storage reservoirs. The following sections provide additional information on risk analysis of potential CO_2 leakage: (1) to the seafloor and water column (Section 3.2.1), (2) associated with CO_2 pipelines (Section 3.2.2), and (3) associated with wells (Section 3.2.3).

3.2.1 Risk Analysis of CO_2 Leakage at the Seafloor

The most recent and applicable work on the potential for CO_2 to impact marine ecosystems has been completed by ECO_2 and the Quantifying and Monitoring Potential Ecosystem Impacts of Geological Carbon Storage (QICS) project. ECO_2 is a European industrial and academic research consortium which has completed seabed characterization and monitoring near the Norwegian oil company, Statoil's Sleipner and Snøhvit sites, and at selected naturally sourced CO_2 seepage sites. ECO_2 also conducted controlled release experiments and numerical modeling to assess impacts to marine organisms.

The QICS project was conducted by a consortium of British, Dutch, Norwegian, and Scottish governmental and research institutions, and DNV. In the QICS in situ field injection experiment, 4 tons of CO_2 were injected into shallow sub-seabed sediments. Physical and biological monitoring of the induced seafloor leakage was conducted with results, including (1) large variations in signal detection due to tidal mixing, calcium carbonate buffering, etc., and (2) mixed impacts on marine organisms (see multiple papers in Blackford et al. 2015). Broad study conclusions were:

- It will be difficult to scale up results in a realistic way.

- "…Environmental impacts from small-scale leakage will be minimal and not ecologically significant, although in the unlikely event of larger leaks, impact could be locally more significant."
- "…Detection of small-scale leakage and monitoring of impact will be challenging due to the complexity of CO_2 flows and ecosystem heterogeneity but is tractable given development of existing tools, monitoring strategies and a comprehensive understanding of natural variability."

3.2.2 CO_2 Pipeline Risk Analysis

Environments at risk of impact from a potential CO_2 pipeline leak are nearshore and coastal habitats, the seafloor, and the ocean water column. A CO_2 pipeline risk analysis is needed in order to assess risk issues, develop acceptable pipeline route selection criteria, and identify additional measures to be taken during the CO_2 pipeline design, construction, and startup phase of the project. These risk assessments are currently performed by the pipeline industry for onshore and offshore pipelines.

Pipelines are generally designed to mitigate or control normal risk (e.g., corrosion, material integrity, controlled releases). However, when there are unusually high risks (e.g., high population density, wetland crossings, geohazards) additional risk mitigation may be warranted. The important outcome of any risk analysis is that the mitigation measures and long-term management of risk go beyond normal industry practices and regulations.

The risk analysis needs to address a broad scope of design, construction, operation and maintenance activities of the pipeline. Key objectives of performing the pipeline risk analysis are to (1) identify measures to mitigate the risks of hazards and product releases by minimizing the probability and consequences of such events, (2) protect employees and the public, and (3) minimize potential environmental impacts during project construction and operation.

Below are some of the primary concerns that should be addressed during a CO_2 pipeline risk analysis:

- Internal corrosion
- External corrosion
- Mechanical and material failure
- Operator and maintenance errors
- Unplanned product release
- Construction accidents and impact
- Natural disasters

By law, the responsibility for safety and minimum compliance with regulations lie with the pipeline operator.

Cole et al. (2011) is a literature review of risks from CO_2 pipelines in North America covering the:

- Compositional range of CO_2 streams
- Impact of impurities on pipeline corrosion based on limited laboratory studies

- Effect of varying pressure on CO_2 pipeline operations
- History of onshore CO_2 pipeline operations

They attribute safe operations of onshore CO_2 pipelines in North America to strict regulatory oversight, especially with respect to CO_2 stream purity. One needs to consider that most CO_2 currently being transported in the US is produced from in situ underground reservoirs, which contain as much as 99% pure CO_2 (Gilfillan et al. 2009). CO_2 that will be stored on the OCS will be captured from industrial sources and may contain impurities. Another source of impurities in CO_2 streams will be associated with recycling during offshore EOR operations. Impacts of potential impurities in CO_2 streams captured from industrial facilities or recycling of CO_2 in H_2S-bearing hydrocarbon reservoirs warrant further consideration of corrosion potential. For example, a laboratory study conducted at the University of Stavanger, Norway, of corrosion of steel pipe found that corrosion of a steel pipe from a fluid containing oil, H_2S, and CO_2 was greater than one with oil and H_2S only (Koteeswaran 2010).

Industry experts (e.g., personal communication with Michael E. Parker, Parker Environmental and Consulting, 2015) maintain that if a pipeline designer knows the characteristics of the fluid, the proper metallurgy for the pipe and associated equipment can be selected for safe operation. CO_2 EOR pipelines have been operated with mixtures of oil, gas, water, CO_2, and H_2S for over 40 years with a high degree of reliability.

3.2.3 Risk Analysis for Wells

There is widespread consensus that the highest risk for CO_2 migration from a reservoir zone to the shallow subsurface or atmosphere is associated with previously existing wellbores. If sufficient site selection procedures (Section 3.1) are followed to select a geologically suitable location, abandoned wellbores will also pose the greatest risk to CO_2 containment failure in offshore settings. In IPCC (2006), Table 5-3 "Potential Emission Pathways from Geological Reservoirs," the following statement is made: "Inadequately constructed, sealed, and/or plugged wells may present the biggest potential risk for leakage." Accordingly, DNV (2010b) and IPCC (2005) state that CO_2 storage is not risk-free, but it is a mature technology that should be safe if properly planned, constructed, and operated. DNV guidance on risk associated with handling of CO_2 streams in the CCS process is CO2RISKMAN (DNV 2013). Level 4 (part 4) of this four-volume series provides the most offshore-specific information.

The specific risks associated with wells are CO_2 leakage along wellbores, and impacts to other resources from migration of CO_2 out of the reservoir zone into overlying or laterally contiguous strata. These could occur at both fast and slow leakage rates.

Watson and Bachu (2009) discuss two potential CO_2 leakage pathways from surveys of onshore O&G well data: (1) surface-casing-vent-flow and (2) gas migration outside of casing. Either of these pathways could result from degraded wellbore cement, corroded casing, or improper well abandonment, and have been documented in wells not exposed to CO_2 (Watson and Bachu, 2009). However, completion of offshore O&G wells in the US must follow American Petroleum Institute (API) Standard 65-2, which could significantly reduce the risk of failure by these mechanisms (Parker 2015 personal communication).

Watson and Bachu (2009) contend that most leakage along wellbores is a result of cement failure, leaving steel pipe exposed to corrosive effects of subsurface fluids in newly constructed or abandoned wells. Effects of CO_2 on well materials are discussed in Sections 3.3 and 3.8 of this report. There has been much testing and consideration of CO_2 impacts on integrity of cement used to complete wells (e.g., Zhang et. al. 2011; Huerta et al. 2011; Connell et al. 2015). Of note is a finding by Huerta et al., (2011) that both dissolution and precipitation can occur along cement fractures in wellbores exposed to CO_2. Because of the uncertainty in risk associated with improperly cemented wells and potential chemical reactions between CO_2 and well bore cement, we suggest the following:

- Ensure that casing is properly centralized (API RP [Recommended Practice] 10D-2).
- Ensure that cement surface and production casings follow API Standard 65-2.
- Conduct some type of cement-verification testing on a representative sample of completed wells. Cement bond logging alone is not a very effective tool; the output interpretation is subjective and difficult to accurately interpret (Parker 2015, personal communication). It is more effectively used as a diagnostic tool when there is a known problem and less effectively as a preventative tool.

Zhang and Bachu (2011) provide a review of cement integrity from laboratory experiments and in existing wells that are exposed to CO_2. They conclude that more work is needed to determine the best way to formulate regulation regarding well integrity. There is uncertainty about current practice in abandonment of offshore O&G wells. According to van der Kuip et al. (2011), regulation for P&A wells are typically focused on preventing FF between different subsurface layers. As a result, there are wide variations in requirements for placement of plugs within wells (e.g., in deepest casing shoe or across perforations only) and plug lengths (15 to 100 m). They conclude from surveys of international regulations and literature reviews of laboratory experimental results that proper placement and mechanical integrity of cement plugs are more important to safe storage of CO_2 than chemical degradation of plugging cement. This publication contains a list of well abandonment regulations[7]and guidelines that were consulted during the study (van der Kuip et al. 2011, Table 2), including:

- US EPA plugging rules for UIC Class II wells
- API guidance documents
- State plugging rules from Alaska, California, and Texas
- London Convention (1972) and 1996 Protocol

Risk to other sub-seabed resources from unintended migration of CO_2 out of the storage reservoir is a concern. The Alberta RFA Regulatory Working Group considers pore space to be a natural resource that needs to be inventoried and managed. If there are competing interests in pore space utilization, the pore space owner would determine which uses have higher priority (Alberta Energy 2012a). Aldous (2013) refers to potential impact of CO_2 on hydrocarbon sources as “resource conflict.” As noted in Appendix D of the Alberta RFA (Alberta Energy 2012b, p. 29–31), there are two issues related to risk of CO_2 GS to other resources: stacking and joint pore space utilization. Stacking as used by Alberta RFA is similar to

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[7] BSEE also has regulations for well abandonment and testing procedures that can most likely be adapted to offshore sub-seabed CO2 storage on the OCS.

the concept of stacked CO_2 storage reservoirs discussed by Hovorka et al. (2013). From the perspective of risk of CO_2 injection to oil and natural gas resources, stacking refers to a hydrocarbon reservoir that is over or underlain by the geologic strata into which CO_2 injection is planned. This is the situation at Sleipner where CO_2 is being disposed in the Utsira formation that overlies the production reservoir.

3.3 Project Planning and Execution

Currently, there are no project planning and execution regulations specific to offshore CO_2 EOR-GS or GS. However, there are existing BOEM and BSEE O&G regulations that may be applicable to similar offshore CO_2 operations. O&G industry standards (e.g., API 2009) and well-established permitting processes for offshore pipelines (e.g., 49 CFR 195) may be applied, or modified, for use in future offshore CO_2 EOR-GS or GS regulation. Appendices E and F present a potential workflow models for CO_2 injection planning and operations that may become a best practice after testing.

Topics to be considered for project planning and execution for CO_2 EOR and GS on the OCS include:

- Location of the source of CO_2
- Mechanism of CO_2 transport to offshore injection sites
- Permitting and construction for offshore facilities (platforms, pipelines, etc.)
- Permitting drilling and injection operations
- Handling of produced and/or recycled fluids during EOR-GS (oil–CO_2–brine-separation will be conducted on the injection-production platform or an ancillary platform, or fluids will be piped to shore for separation)
- Monitoring and iterative updates to risk assessment to demonstrate retention of CO_2 in the deep sub-seabed
- Site closure

The following subsections discuss workflows (Section 3.3.1), permitting (Section 3.3.2), and special technical considerations (Section 3.3.3) for project planning, construction, and operations on the OCS.

3.3.1 Workflows for Project Planning, Construction, and Operation

As with any large-scale OCS O&G project, an offshore CO_2 EOR-GS or GS project may take 10+ years from conception to startup. An industry workflow and will consist of six distinct stages:

(1) Concept Development
(2) Pre-FEED (Front End Engineering Design)
(3) FEED
(4) Detailed Design
(5) Construction
(6) Startup

Although companies may use different terminology for these stages, the project execution sequence is generally the same whether onshore or offshore. A planning and operations workflow for offshore sub-seabed CO_2 storage is presented in Appendix F. Recommended steps for CO_2 GS site project planning and operation are shown in Table F-1 in Appendix F. Variations that will be needed if the site is a depleted hydrocarbon reservoir or will be used for CO_2 EOR (i.e., EOR-GS) are presented in Table F-2 in Appendix F. Other examples related to CO_2 EOR operations are presented by Cooper (2009) for the CO_2 Capture Project and Ren et al. (2011).

At the Concept Development, Pre-FEED, and FEED stages a company will review preliminary data and information to decide if the project should move forward to the next stage or be placed on hold until conditions (e.g., economic, regulatory) become more favorable. Determining if a project should proceed depends on return on investment, regulatory requirements, or operating necessity in relation to business goals of the company. If a company is confident in proceeding with the project, it may accelerate FEED stage steps that could ultimately impact the length of the total project (e.g., equipment and land acquisition, securing right of way, or submitting permit applications). In some cases, the Pre-FEED stage may be skipped. However, the objective of Pre-FEED is to further refine the project description and options available for execution, especially the economic analysis. The company may kick off engineering studies during Pre-FEED that will move the project forward through the remaining stages. As project planning moves from concept to detailed design, the forecasted return on investment and total installed cost become more reliable. Once the project reaches the detailed design stage the company is usually fully committed to executing through construction and startup stages.

Components of the six stages of a standard industry workflow model, which can be applied to an offshore CO_2 injection project are outlined in Appendix E. Included are examples of key work areas and deliverables to be executed during the various stages. As the project moves through each stage, additional work and deliverables are added; the ones that are repeated will be refined in order to achieve final design and construction. The timeline for an actual offshore CO_2 GS project, the Shell Peterhead-Goldeneye CCS project, which was planned to follow the standard industry workflow, is detailed in Appendix E:

- Conceptual plan introduced in 2005
- Cancelled in 2007 due to delay on government approval and concerns over long-term storage
- UK government elects to support CCS project(s) capital funding in 2011
- Pre-FEED phase started in 2012
- FEED phase started in 2014
- Onshore environmental planning application submitted in 2015
- Investment decision to proceed is forecast to occur sometime in 2015 / 2016
- Detailed Design start pending
- Construction start pending and anticipated to last approximately three years
- Start date forecast was 2020 but cancelled in 2015

A successful CO_2 EOR-GS or GS program will require coordinated site development, operations, and closure activities. During the pre-injection period, characterization, injection testing, modeling, and operational design will inform the risk assessment. This will help to reduce, manage, or mitigate risks in order to demonstrate effective, safe, and economically viable CO_2 storage, as well as meet other project goals. However, not all risks can be fully assessed prior to CO_2 injection; and therefore, must be further defined during planning and risk assessment. These potential risks will become the targets of monitoring during injection operations. Prioritizing target monitoring zones and iteratively assessing risks will allow site operations to continue with high confidence and will increase assurance of post-closure storage security. To achieve an effective monitoring design, quantitative metrics must be set. Metrics avoid the vagueness of broad statements about protecting sub-seabed and marine resources. For example, the threshold of activities (storage reservoir pressure increases, leakage, induced seismicity, impact on seawater, etc.) that are considered unacceptable must be stated in terms such as mass, area, and time. Only when such quantitative goals are set will it be possible to make measurements that show the project is performing acceptably.

3.3.2 Permitting for Offshore Site Planning and Construction

Many existing Federal and State laws, regulations, and standards will apply to offshore sub-seabed GS of CO_2 for pipelines, platform surface facilities, and injection well design and operations. Among the standards are those defined by the API. Potentially pertinent API guides, recommended practices, and standards are listed in Appendix G. In this section, we discuss permitting for nearshore settings followed by onshore-offshore pipelines and conclude with existing regulatory and permit considerations for future offshore storage complexes.

3.3.2.1 Nearshore Environments

One example of considerations for nearshore environments is provided by the Texas General Land Office (GLO), the State agency responsible (through the Coastal Zone Management Act of 1972, administered by the National Oceanic and Atmospheric Administration [NOAA]) for stewardship of State-owned lands in Texas, including coastal zones (bays and estuaries) and submerged lands. The GLO issues leases and easements for land owned by the State of Texas. Types of leases and easements that may be needed to support offshore GS from CO_2 sources in Texas are coastal structures, mineral (O&G), renewable energy, and miscellaneous (includes pipeline right of way [ROW]). A coastal structure lease would be required for infrastructure related to a pipeline transporting CO_2 from an onshore to an offshore facility or drilling rig or platform for CO_2 injection wells in Texas State waters. The GLO would also need to issue leases for a CO_2 pipeline ROW; however, the CO_2 pipeline permit would need to be issued by the Railroad Commission of Texas (RRC), if the CO_2 is going to be transported to offshore CO_2 EOR-GS operations. Examples of RRC pipeline permitting forms can be found on their website. Because the RRC has not applied for primacy for CO_2 GS under Class VI well rules, a CO_2 transport pipeline permit for this purpose may, under current circumstances, have to be issued by DOI, DOT, EPA, or others.

3.3.2.2 Existing Pipeline Regulations, Engineering Codes, and Permit Considerations

Some countries (e.g., Brazil, Norway, and Indonesia) produce large volumes of CO_2 during offshore hydrocarbon gas production (e.g., Korbøl and Kaddour 1995). Such impurities impact many aspects of pipeline operations and permitting. Hydrocarbons in the GOM do not bear large volumes of CO_2, and it is anticipated that US sources of CO_2 will be onshore industrial facilities. Transporting the CO_2 from onshore to offshore will require permits from both State and Federal entities that will likely require a CO_2 stream with few impurities.

There are many applicable laws, regulations, and engineering standards for onshore and offshore pipelines, including CO_2 pipelines; a few key ones are described below. A company beginning a CO_2

pipeline project will need to determine which regulatory agencies have jurisdiction, and agencies may have overlapping regulations. Understanding the applicable regulations and codes are critical to:

- Planning, designing, and constructing a new project
- Determining reporting requirements
- Addressing inspection requirements
- Developing emergency response plans

Because of the complexities, overlapping statues, and quantity of permits needed for an onshore to offshore pipeline, the pursuit of such permits is commonly supported by specialized engineering companies.

The onshore portion of the pipeline will need permits (Federal, State, and local), in the range of 10 to 20 (or more), from various agencies for construction and/or operations, with the quantity depending on the State and the pipeline routing involved. If the onshore pipeline is interstate, then permits from each of those applicable State agencies must also be obtained.

An extensive network of pipelines currently offshore of the GOM (Figure 3-3) is regulated under BSEE (BSEE regulations for OCS pipelines can be found at 30 CFR §§250.1000–250.1019) and US DOT jurisdiction. Even when regulated by BSEE or DOT (or a State agency having primacy), aspects of offshore pipelines, such as new construction or modifications, may also be regulated by other Federal agencies. Permits to construct and operate an offshore pipeline will be needed, as applicable, from States (coast activities per their coastal management plan), the US Army Corp of Engineers (USACE; nearshore permits), the US Coast Guard (pipeline crossings of waterways, shorelines, and navigation fairways), and other Federal agencies (e.g., DOT, EPA, BSEE, BOEM).

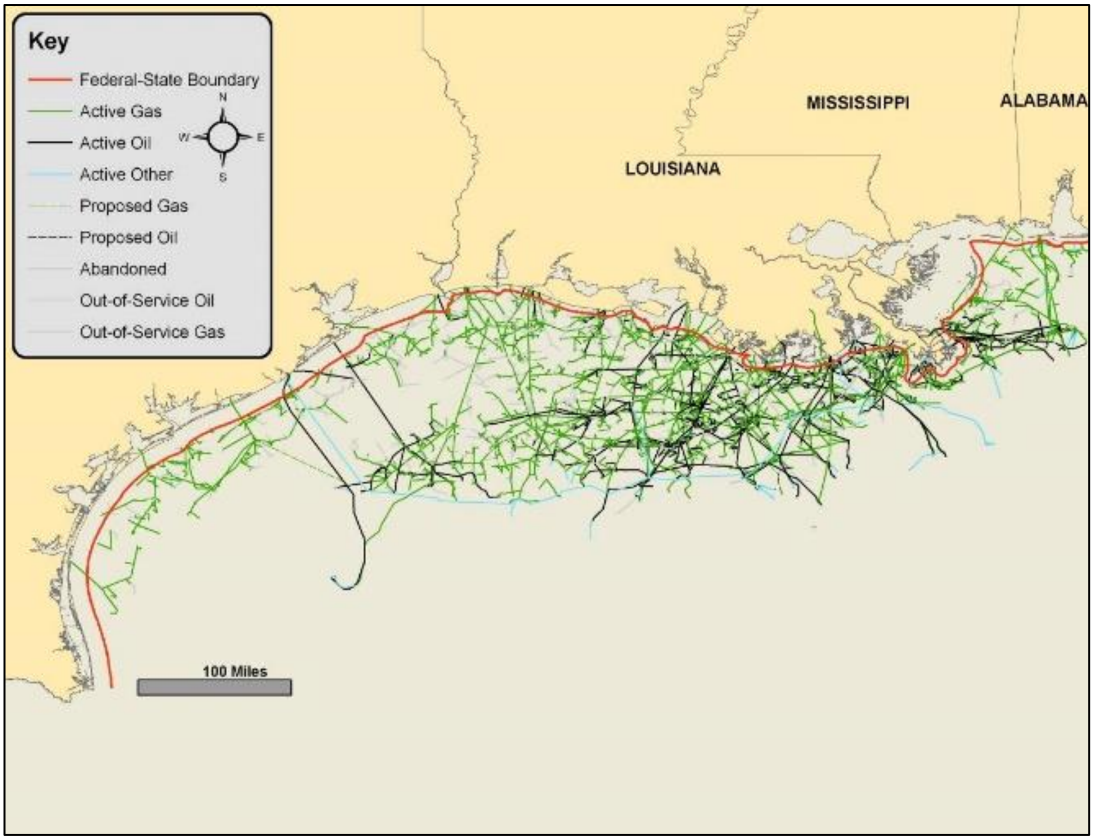

Figure 3-3. Locations and status of offshore northwestern GOM pipelines from BOEM database

Offshore pipelines in State waters are regulated by DOT or State agencies. For onshore interstate pipelines, DOT is the "primary" Federal regulatory agency, whereas State agencies that are authorized by DOT (through the Pipeline Safety Statute, 49 USC. § 60105–60106) are the "primary" regulators for intrastate pipelines. Individual States may enforce additional or more stringent pipeline safety regulations. Agencies such as the Federal Energy Regulatory Commission (FERC), EPA, Department of Homeland Security (DHS), BOEM, and BSEE have jurisdictions and responsibilities related to pipelines, as well as other Federal, State, and local agencies.

DOT regulations that apply to onshore and offshore CO_2 pipelines are in 49 CFR Part 195, which is under the US DOT Pipeline and Hazardous Materials Safety Administration (PHMSA). PHMSA is responsible for regulating and ensuring the safe and secure movement of hazardous materials and CO_2 to industry and consumers by all modes of transportation, including pipelines. DOT 49 CFR Part 195 prescribes safety standards and reporting requirements for pipelines and associated facilities used in the transportation of hazardous liquids or CO_2 in or affecting interstate or foreign commerce, including pipeline facilities on the OCS.

The American Society of Mechanical Engineers (ASME) B31.4 (National Code), Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids: The primary purpose of the ASME B31.4 code is to establish requirements for safe design, construction, inspection, testing, operation, and maintenance of liquid pipeline systems (offshore and onshore). This is for protection of the general public and operating company personnel, as well as for reasonable protection of the piping system against vandalism and accidental damage by others, and reasonable protection of the environment**.** ASME B31.4 is one of the primary applicable codes, and it has a section (Chapter X) specific to CO_2 pipelines. Other key codes used by US and international O&G industry in conjunction with ASME B31.4 include (1) additional ASME codes and standards, (2) National Electric Code, (3) National Fire Protection Agency, and (4) National Association of Corrosion Engineers, etc. These codes and standards are more detailed than DOT 49 CFR Part 195 in several areas.

Other applicable standards and permitting processes include:

- API publications (Standards and Recommended Practices): These documents are published by API to facilitate the broad availability of proven, sound engineering and operating practices and material and equipment standardization in the O&G industry. Examples include API 1111–Design, Construction, Operation, and Maintenance of Offshore Hydrocarbon Pipelines, API 14E–Design and Installation of Offshore Production Platform Piping Systems, API 14J–Design and Hazards Analysis for Offshore Production Facilities, API 5L–Specification for Line Pipe, and API 75–Development of a Safety and Environmental Management Program for Offshore Operations and Facilities.

- US Army Corps of Engineers: Issues permits for pipeline crossings of waterways, shorelines, and navigation fairways.

- State and local agencies: Issue permits (if applicable) for coastal activities, under their coastal zone management and other applicable plans. Texas has the largest pipeline infrastructure in the US and the Railroad Commission of Texas has good information relative to its various State-specific requirements.

- Company standards (specifications, procedures, guidelines, etc.): O&G companies commonly establish their own requirements that meet or exceed those of DOT 49 CFR Part 195 regulations, ASME B31.4, API publications, and other industry- or company-specific technical documents. Some companies may also reference DNV GL Recommended Practice documents, although these documents are not recognized by US DOT or ASME B31.4.

3.3.2.3 Existing Regulations and Permit Considerations for Offshore CO_2 Storage

Certain existing BOEM and BSEE OCS energy and mineral resources regulations may be applicable to offshore CO_2 EOR and GS operations; however, they will need revision to cover CO_2-specific requirements. Examples may include offshore O&G well drilling and completion operations as well as platform construction regulations.

Several States within the US have written regulations for onshore CO_2 GS in anticipation of applying for future Class VI primacy from EPA. The State of Texas has written regulations to protect USDWs from CO_2 injection, but they are not compliant with EPA UIC Class VI rules. The purpose of the Texas rules was to establish criteria for approval of a wellhead tax reduction for EOR operators utilizing anthropogenic CO_2 (CO_2–A). The State of Texas CO_2 GS regulations, under Title 16 of the Texas Administrative Code (TAC) Part 1–Railroad Commission of Texas (RRC), Chapter 5–Carbon Dioxide (CO_2), have three subchapters that cover (1) the definition and scope of CO_2–A storage and (2) requirements for certification of an EOR well operations as EOR-GS. Details follow:

1. GS of anthropogenic CO_2 (CO_2-A): describes permitting of CO_2-A injection wells (a) for which the primary purpose is GS, (b) that are currently permitted as CO_2 EOR (i.e., Class II) for which the operator also wants to simultaneously claim CO_2 emission reduction credits, and (c) previously permitted as a CO_2 EOR well that the operator wants to convert to a CO_2 GS-only well. Permit regulations for all three scenarios require that:
   - Existing O&G resources not be damaged
   - CO_2 injection wells are constructed to specified standards, and the tubing-casing annulus is filled with corrosion-inhibiting fluid
   - A monitoring and testing plan, including metering of injectate-CO_2, is approved and followed
   - Mechanical integrity testing and area of review procedures are followed

2. Certification criteria for conducting GS in a CO_2 EOR (i.e., EOR-GS) well include:
   - CO_2 is being injected for EOR.
   - The CO_2 stream may include any proportion of CO_2-A and naturally sourced CO_2.
   - A monitoring and testing plan must include:
     - chemical analysis of the injectate-CO_2 stream
     - mechanical integrity testing
     - corrosion testing of all well materials at a designated test site
     - annual injection zone pressure monitoring
     - continuous pressure monitoring in a monitoring well completed in a geologic unit that overlies the confining zone
     - geophysical monitoring techniques
     - a volumetric accounting of injected, produced, separated, and recycled CO_2-A
   - Annual reporting requirements must be satisfied.

3.3.3 Technical Considerations for Project Planning and Construction

This section provides technical information and BMPs for offshore CO_2 transport (Section 3.3.3.1) and platforms and injection well components of CO_2 sub-seabed storage (Section 3.3.3.2).

3.3.3.1 CO_2 Transport

The majority of CO_2 pipelines are found onshore in North America, where there is over 30 years of experience in transporting CO_2, mainly from natural deposits and gas processing plants for EOR. As discussed above in Section 3.3.2.2, existing onshore CO_2 pipeline regulations may be adapted for offshore settings. The only offshore pipeline constructed for transporting CO_2 is the Snøhvit pipeline (Oosterkamp and Ramsen 2008, DNV 2010a). Multiple modes of offshore transportation of CO_2 need to be considered for both CO_2 EOR-GS and GS. Transportation of CO_2 will be more complex for EOR-GS, because a post-production, mixed-fluid stream (i.e., hydrocarbons plus CO_2 and possibly hydrogen sulfide [H_2S]) will need to be transported to a fluid separation facility before CO_2 is re-injected (recycled) for further EOR operations. Commercial-scale offshore CO_2 EOR is not currently taking place worldwide, but GS has been underway for nearly two decades offshore Norway, where both onshore and offshore CO_2 and hydrocarbon fluid-stream-separation have been utilized.

Identifying the optimal model for onshore to offshore CO_2 transport is a complex process that should take into consideration a variety of site-specific conditions, both tangible and intangible. Several factors should be considered when deciding whether to transport CO_2 to offshore injection sites by ship or pipeline (Table 3-3).

Table 3-3. Offshore CO_2 transport considerations: pipeline compared with ship

Category	Discussion presented in reports and published literature
Stage of Project	In an evaluation of offshore CO_2 transport conducted by the Scottish Enterprise consortium, they favor transport by ship only during site assessment and testing phases of a project (i.e., FEED stage). Otherwise, they suggest that ship-based transport only be used during pipeline construction or repair (Element Energy 2014).
Distance to Injection Site	The major considerations are economics (e.g., Ozaki et al. 2005; Mallon, 2013, DNV 2010a) and presence of environmentally sensitive areas (Ozaki et al. 2013, Ozaki 2015).
CO_2 Injection Volume	Ships are favored when transporting small volumes of CO_2 (e.g., Neele et al. 2014).
Tectonic Setting	Ship transport of CO_2 may be safer in tectonically (seismically) active areas such as offshore Japan (e.g., Ozaki et al. 2013).

An additional consideration for offshore transport of CO_2 using ship or pipeline is thermodynamic constraints. The CO_2 stream will be transported at different temperatures and pressures in ships than it will in pipelines. According to the Energy Institute in London, offshore platforms will need to be equipped with pumps to boost CO_2 stream pressure to injection pressure if ships are used for transport (EI 2013). There is also an innovative plan for using liquefied CO_2 (LCO_2) ships equipped with dynamic positioning systems and onboard injection systems to inject into wells with flexible riser pipes (Ozaki et al. 2013, Ozaki 2015).

The literature shows that O&G industry experts have given much thought to the safe transfer of liquefied natural gas via ship (e.g., Newby and Pauw 2010). Also, as noted by ZEP (2011), ship transport of liquefied natural gas in the North Sea has a very good safety record.

There is much information on construction of onshore CO_2 pipelines, and much worldwide experience with constructing offshore pipelines for O&G industry. Available technical information ranges from small to large scale. It includes references from specific types of valves and manifolds needed for CO_2 handling in pipelines and on offshore platforms, to general topics on how to configure regional pipeline infrastructure to transport CO_2 to offshore platforms as efficiently as possible. Notable references on CO_2 pipeline construction include:

- Design and Operation of CO_2 Pipelines, DNV-RP-J202 (DNV 2010a) and Integrity Management of Submarine Pipeline Systems, DNV-RP-F116 (DNV 2009a).
- State-of-the-Art Overview of CO_2 Pipeline Transport with relevance to offshore pipelines (Oosterkamp and Ramsen 2008).
- Development of a CO_2 Transport and a Storage Network in the North Sea (Element Energy 2011).

Multiple DNV documents with technical specifications on onshore CO_2 pipelines exist. Several of these are not specific to CO_2 but are applicable (e.g., DNV 2003, 2008a, 2009a). A DNV project specific to CO_2 pipelines, CO_2PIPETRANS (described in Eldevik 2008) resulted in the development of the DNV Recommended Practice, DNV-RP-J202, Design and Operation of CO_2 Pipelines (DNV 2010a). These standards are intended to be a supplement to existing pipeline standards and are applicable to both onshore and offshore pipelines. Section 4 of DNV-RP-J202 includes recommendations related to design issues that are specific to CO_2 and that are considered during the project detailed design stage. Issues that need particular attention when designing CO_2 pipelines include:

- Pressure control and overpressure protection systems
- Dewatering
- Flow assurance
- Pipeline layout
- Pipeline routing
- CO_2 stream composition evaluation, and vent stations

DNV Recommended Practice (DNV 2004a, 2010a, and 2011a) and Offshore Standard (DNV 2010e) documents for offshore O&G, and onshore and offshore CO_2 pipelines, are recognized internationally but not widely used in the US.

Oosterkamp and Ramsen (2008) provide in-depth discussion on different technical requirements for onshore versus offshore CO_2 pipelines, including identification of three critical, short-term offshore CO_2 pipeline research and development needs:

- Assessment of the compatibility of non-steel materials for seals and gaskets if higher pressures and larger pressure variations are expected than commonly employed
- "Smart" pigging of long offshore pipelines
- Setting safe regimes for blow down of a long offshore pipeline

These three topics are discussed further in Sections 3.6, 3.7, and 3.8 of this report.

Another point made by Oosterkamp and Ramsen (2008) is that offshore pipelines will need to be constructed using longer segments than most onshore CO_2 pipelines. However, of the 14 existing "long" CO_2 pipelines, only one of these, Statoil's Snøhvit pipeline, extends offshore (Osterkamp and Ramsen, 2008, Table 3-1). Knowledge from long onshore pipelines will likely apply to offshore pipelines. A 2013 report by the Energy Institute of London (EI 2013) and IPCC (2005) both mention the possible need for intermediate compressor stations in offshore CO_2 pipelines due to long segments of inaccessible pipe.

Industrial CO_2 pipeline operators and materials engineers are familiar with specific requirements for supercritical CO_2 pipelines (e.g., Paul et al. 2010, Dugstad et al. 2011, Zhang et al. 2011). Additional information on valves, connectors, and manifolds needed for offshore CO_2 pipelines can be found in Cannistraci (2010), EI (2013), Alberta RFA, Appendix D (Alberta Energy 2012b).

For areas such as Japan or Europe, where the best or only option for storage of CO_2 from onshore industrial sources will be sub-seabed geologic strata, CO_2 pipeline hubs will be needed. Such hubs will most likely be onshore and are described in, for example, Chandel et al. 2010, Element Energy 2011, Morbee et al. 2011, and Neele et al. 2011a.

3.3.3.2 Platforms and Injection Wells

It has been recognized since at least 2005 that storage of CO_2 in offshore sub-seabed geological formations will use many of the same technologies developed by the O&G industry (IPCC 2005). However, CO_2 separation and re-injection equipment is something not commonly used in offshore O&G operations; exceptions are in the North Sea, and offshore Brazil and Indonesia (South China Sea). This following discussion includes information specific to planning and operation of offshore CO_2-injection platforms and wells, including consideration of (1) the need for corrosion-resistant materials, (2) well drilling, testing, and injection-site preparation, (3) well spacing, and (4) well instrumentation.

As described in CSA Group (2012), materials for pipelines, including those needed for onshore and offshore transport of CO_2, platform equipment, and well casing must be carefully selected due to the corrosivity of CO_2 in the presence of water or "wet CO_2." In addition to information included in Section 3.2 (risk analysis) and Section 3.8 (emergency response), documents with guidance on selection of CO_2-safe materials (i.e., specific metal alloys, types of elastomers, etc.) include CSA Group (2012), DNV (2013), and EI (2013). General guidance on construction of offshore platforms and associated equipment and other marine operations is contained in DNV-RP-H103, Modelling and Analysis of Marine Operations (DNV 2011a). Possible reuse of existing O&G platforms for subsequent CO_2 EOR or fluid (CO_2-oil-brine) separation infrastructure is discussed in Section 3.9 of this report.

According to EI (2013), the types of risers (pipe between the sea surface and base of platform) used in offshore O&G operations may not work for CO_2 operations because higher pressure fluctuation from unexpected phase changes of CO_2 may increase brittleness of the metal. The DNV CO2RISKMAN, Level 1 Guidance Document (DNV 2013), addressed a similar concern regarding the potential for pipe over-pressurization with small changes in temperature of fluid containing supercritical CO_2. General information on offshore flow lines and risers is contained in the following documents: DNV-0SS-301, Certification and verification of pipelines (DNV 2000) and DNV-0SS-302, Offshore riser systems (DNV 2012). A thorough list of failure modes and failure mechanisms for wells exposed to CO_2 is in DNV-RP-J203, Appendix B (DNV 2012b).

Offshore O&G operators have experience with blowout prevention and control, and in the time since the *Deepwater Horizon* oil spill in the GOM in 2010, US O&G regulations for blowout prevention have been strengthened. The potential impact to humans working near a CO_2 injection well is discussed in Aines et al., (2009), numerous DNV Guidance and Recommended Practice documents, and Section 3.8 of this report.

As noted in DOE NETL's *Best Practices for Carbon Storage Systems and Well Management Activities* (DOE NETL 2013c), CO_2 storage site planning and operations must be iterative, such that as new information is obtained, adjustments may be needed in operations. CO_2 injection testing to gauge capacity accessed by a specific well completed in a specific geologic formation is the next step in project planning after site characterization (Section 3.1). Some may consider well testing to be part of site selection, but it is a critical step nonetheless. Well testing could reveal drops in pressure, possibly indicating:

- Leakage through a nearby abandoned well bore that had not been properly plugged
- Other types of well integrity issues
- Permeability/porosity of the formation is higher than was originally assumed

An example of the need for well testing is the Snøhvit project where one zone of CO_2 injection project had to be abandoned after realization that the initially selected geologic formation could not accept the planned large rates of CO_2 injection without risk of exceeding the geomechanical maximum pressure. Significant additional financial investment was required to diagnose the problems and redevelop the well to inject into an alternative formation (e.g., Hansen et al. 2013).

Area of review (AOR) to identify improperly P&A wells is standard practice and part of permitting in onshore O&G industry. Onshore CO_2 EOR operators pay particular attention to P&A wells during field development so as not to lose their CO_2 a valuable commodity to their operations. These same practices should be followed in offshore settings; however, the analysis may be simpler offshore due to the lower density of existing wells.

DOE NETL has compiled the knowledge gained from Regional Carbon Sequestration Partnerships (RCSPs) (DOE NETL 2013c) and states that placement or spacing of CO_2 injection wells should be based on numerical modeling. Such models will need to be validated with results from CO_2 injection testing, and possibly even in response to early-stage post-injection monitoring activities as part of the iterative process noted above. Results from the Wilmington Graben project in the Los Angeles basin offshore from southern California include a recommendation that CO_2 injection wells be placed a minimum distance of 1,000 m (3,280 ft) away from any existing un-cemented wells or other injection wells. The later criteria are to prevent migration interference of CO_2 plumes and are probably dependent on the planned injection rate. A suggestion in DOE NETL (2013c) regarding CO_2 injection well placement in onshore settings is that a backup injection well be installed in case the primary injection well becomes inoperable, but this could be cost prohibitive. This suggestion could be especially pertinent for offshore CO_2 injection operations where CO_2 is being supplied via a long pipeline, because interruptions in CO_2 flow could cause exceedance of pressure limits resulting in the pipeline having to be shut-in. See Section 3.8 for further discussion.

A lesson learned by onshore CO_2 EOR operators and experience at RCSP sites, indicates that reuse of an existing well (e.g., primary or secondary production wells) for CO_2 injection is ill-advised. The concept of always drilling and completing new fit-for-purpose wells for CO_2 injection is also suggested in Zhang and Bachu (2011) and DOE NETL (2013c). It can also be problematic to use previously existing wells in CO_2 monitoring programs, a lesson learned at multiple RCSP sites.

3.4 Monitoring

Because offshore CO_2 GS is a developing technology, a mature list of recommendations or BMPs for offshore monitoring is not yet available, nor are there existing regulations specific to monitoring that can be adapted for offshore sub-seabed CO_2 storage. However, existing and planned projects for injecting commercial quantities of CO_2 into sub-seafloor geologic strata presented in the Literature Report (Appendix A) provide precedent. Experience has been gained through monitoring of Statoil projects in the Norwegian North Sea near the Sleipner gas field (Arts et al. 2005, 2008, Eiken et al. 2011; and many other publications) and in the Barents Sea near the Snøhvit gas field (Eiken et al. 2011). Plans under development for monitoring full-scale CO_2 GS projects, especially those located offshore, provide details on tools selected as technology and experience advance toward commercial application (reviewed in

Jenkins et al. 2015). One well-documented example of an offshore monitoring plan is Shell's development of the depleted Goldeneye gas field in the UK part of the North Sea as a sub-seabed CO_2 GS facility. Shell may eventually accept CO_2 from the Peterhead power station in the UK and has made public their project plan (Shell 2014b, Chadwick 2015). Monitoring plans are also being developed for offshore storage at the Rotterdam Opslag en Afvang Demonstratie (ROAD) project, where CO_2 captured from the Maasvlakte coal-fired power plant will be stored in a depleted gas reservoir in Block 18 of the Netherlands sector of the North Sea (e.g., Arts et al. 2012). Intermediate-volume injection experiments planned at the Tomakomai test in Japan provide further examples of monitoring plans (e.g., Tanaka et al. 2014). Offshore tests focused on monitoring research include: (1) the controlled release conducted at the QICS project (Blackford et al. 2014, IEAGHG 2015, Mabon et al. 2015), (2) the RISCS Project (Pearce et al. 2014), and (3) the ECO_2 (Sub-seabed CO_2 Storage: Impact on Marine Ecosystems) Project (ECO_2 2015). Lastly, the numerous monitoring tests, experiments, and demonstrations conducted onshore provide a wealth of information on monitoring objectives that apply if the differentiation of offshore risk and offshore cost and opportunity are considered.

A timely publication (Jenkins et al. 2015) focused on monitoring for CO_2 GS by authors with experience and knowledge from Australia, UK, and the US, documents progress made during the past decade and provides perspective on realistic technical objectives for regulatory programs. Highlights from this paper combined with knowledge gained through experience at experimental and applied-technology CO_2 injection sites are:

1. Results from monitoring at depths closer to the injection and reservoir zone provide the least ambiguous and most valuable information in terms of containment of CO_2 and avoidance of environmental risk.
2. Objectives of monitoring need to be clearly stated in monitoring regulations.
3. Quantification of CO_2 that migrates outside of a planned containment volume (e.g., reservoir and injection zone and overlying confining system) is probably not worth the effort unless there is clear indication that such migration has occurred, or if such quantification is needed for emissions reduction credits.

Topic 3 from the list above is similar to the concept presented in Section 3.2.

Though the following content has some similarity to the Jenkins et al. (2015) approach, there are also significant differences. Below, the purpose of monitoring (Section 3.4.1), monitoring approach (Section 3.4.2), and pipeline-specific monitoring (Section 3.4.3) are discussed.

3.4.1 Purpose of Monitoring

Major motivations for monitoring at CO_2 EOR-GS and GS sites are:

- Regulatory requirement (in some jurisdictions)—e.g., most O&G regulators require a program of testing injection wells for mechanical integrity
- Industry best practice for response to a specific concern (for example, optimizing the injection withdrawal ratio in secondary or tertiary oil recovery in CO_2 EOR operations)
- Evaluation of risk (see Section 3.2)

- Reduction of possible, but unlikely, modes and mechanisms of CO_2 containment failure (i.e., the impact hypothesis of the Specific Guidelines [London Protocol 2012], or simply "leakage")

Monitoring is conducted to confirm modeled predictions of secure or long-term CO_2 storage and to minimize the risk of environmental hazard. Identification of specific monitoring objectives is a critical first step in designing a monitoring program, so it can achieve the intended goals. Field monitoring goals are guided by the project objectives, the outcome of risk assessment modeling, and regulatory compliance. Categories of or approaches to CO_2 GS monitoring discussed here are conformance, containment, and environmental (after Jenkins et al. 2015).

3.4.1.1 Conformance Monitoring

Field-scale conformance monitoring is designed to test whether the reservoir zone response to CO_2 injection reasonably matches modeled predictions. A geologically justifiable match between different types of field observations with results from a predictive model is commonly considered evidence that the model can predict future system behavior. The robustness of this assumption depends on whether the observational data are designed to detect measurable impacts to the environment or other resources. The assumption can be tested by modeling various scenarios. For example, if CO_2 were to leak out of the reservoir to the seafloor, at what threshold (CO_2 leakage rate and duration) would leakage be detected? And, could modeled predictions of reservoir performance be sensitive enough to for the leakage to be detectable? Such evaluation of predictive modeling is presented in Azzolina et al. (2013). Monitoring and modeling uncertainty must be summed to identify the threshold at which measurable impacts can be detected. Although both uncertainties can be large, and because the role of modeling is smaller, monitoring design commonly focuses on containment of injected CO_2 rather than conformance or behavior of the reservoir.

3.4.1.2 Containment Monitoring

Containment monitoring is designed to focus on detection of CO_2 leakage by making targeted measurements above the storage reservoir interval. Favorable locations depend on the leakage scenario. The process is described in the "Specific Guidelines for Assessment of Carbon Dioxide Streams into Sub-Seabed Geological Formations" (London Protocol 2012, Section 8) as creating a "testable hypothesis" from the "impact hypothesis." For example, if well failure is a principal concern, the wells may be surveyed or instrumented to detect fluid leakage using physical (e.g., pressure, temperature, or noise) or chemical (e.g., introduced tracers that can be detected through casing) measurements. If at-risk wells are not accessible for monitoring, the focus may be on detecting leakage into permeable geologic strata in the overburden. Overburden monitoring should be designed to detect potential leakage. Modeling shows that a leakage signal is earliest and strongest in zones that are nearest (deepest) the injection zone, and that a leakage signal is greatly attenuated in shallower horizons (e.g., Porse 2013, Zhou et al. 2005).

3.4.1.3 Environmental Monitoring

Environmental monitoring is a third type of monitoring that may directly measure impacts or confirm the lack of impacts to the environment or other resources. In many cases, environmental damage may be a subtle or a delayed signal; however, monitoring may be required anyway because of regulation or stakeholder concern. Preparation for allegations of leakage may also be a driving force for environmental monitoring (Dixon and Romanak 2015). In this context, data on the ambient characteristics (sometimes referred to as “baseline”) of the environments of concern can be useful in determining if an allegation of damage has validity. Baseline data can also be of value should leakage occur and quantification or mitigation be needed.

3.4.2 Monitoring Approach

The monitoring approach requires careful planning to ensure goals are achieved through:

- Type of monitoring tools to be used (Section 3.4.2.1)
- Location of tools and monitoring targets (Section 3.4.2.2)
- Monitoring data collection specifics (Section 3.4.2.3)
- Application of monitoring data (Section 3.4.2.4)

The need for updates and iterations to the monitoring approach should be included in monitoring plans. Elements of the monitoring approach are discussed in detail below.

3.4.2.1 Types of Monitoring Tools

The type of tool(s) to be used for monitoring, as well as how they should be used, have been described by many workers (Table 3-4). A summary of offshore monitoring approaches using specific types of tools used by workers cited in Table 3-4 is presented in Appendix H. It is important to note that although selection of suitable tools is critical, other monitoring program considerations (e.g., location and frequency of monitoring) described in following subsections are equally important. The success of an excellent tool depends on (1) a good fit between intended purpose and result, (2) appropriate deployment and operation, and (3) high-quality data analysis.

Table 3-4. Examples of monitoring tool application

Scenario	Location	Citation
Monitoring required by regulation, structuring a monitoring program	Offshore	London Protocol 2012, Section 8
Structure of a monitoring program	Onshore	Chalaturnyk and Gunter 2005
Lifecycle cost, list of options	Onshore	Benson et al. 2005b
Tool inventory	Onshore	Benson et al. 2006
Tool inventory, analysis of monitoring approach	Offshore	Carroll et al. 2014
Probabilistic approach to monitoring design	Onshore	Condor and Ashari 2009
Overview of monitoring options tied to risk assessment	Offshore	Kirk 2011, ECO_2 2015
Reviews of nonseismic, crosswell seismic, and electromagnetic EM geophysical monitoring methods	Onshore	Hoversten et al, 2003, Hoversten and Gasperikova 2005
Review of best practices for GS monitoring and accounting	Onshore	DOE NETL 2012b
Review of 10 years of progress in monitoring GS	Both	Jenkins et al. 2015

Scenario	Location	Citation
Extensive review of current state of information about monitoring offshore CCS	Offshore	IEAGHG 2015
Risk inventory for offshore storage	Offshore	Pearce et al. 2014
Overview of quantification methods	Both	Korre et al. 2011
Overview of outcomes of Weyburn monitoring	Onshore	Preston et al. 2009
Monitoring techniques and program recommendations	Onshore	Quisel et al. 2010
Review of monitoring stages of an injection project	Onshore	Themann et al. 2009
Overview of the results of the Weyburn program	Onshore	Whittaker et al. 2011
Guidelines for several aspects of GS	Both	DNV 2010k
US EPA GS rules for the UIC program	Onshore	EPA 2010c, 2013c
EU GS rules	Both	European Commission 2009
Online tool for evaluation of monitoring programs	Both	British Geological Survey 2013
Review of detection and quantification techniques for CO_2 leakage	Both	IEAGHG 2012
Detailed monitoring plan for storage at depleted Goldeneye gas field to receive CO_2 from Peterhead Power Station	Offshore	Shell 2014b

Note: See Appendix H for approaches and tools used by workers cited here.

3.4.2.2 Location of Tools and Monitoring Targets

The location of tool deployment and monitoring target selection are two of the major decisions to be made in development of a monitoring program. Options for placement in the vertical dimension include:

- In the reservoir (in-zone)
- Within or above the confining system
- In shallow sediments
- At the seafloor
- In the water column
- At the sea surface
- In the atmosphere

Options for placement in a horizontal plane include in or above the area occupied by CO_2, in or above areas where pressure is elevated to a defined threshold, in selected locations (e.g., based on risk assessment), on a regular grid, or in linear arrays.

Some tools (e.g., pressure and temperature gauges, chemical samplers, and wireline logs) are deployed very near the location where data will be collected. This monitoring method is classified as direct data collection. For example, CO_2 bubble streams can dissolve into the water column within a few meters from the leakage point; therefore, any bubble detection method must survey close to the leakage point (McGinnis et al. 2011, Dewar et al. 2013).

Indirect data collection instruments target a remote location. For example, geophysical instrument arrays (acoustic, gravity, or electrical methods) can be deployed at the sea surface, on the sediment surface, at shallow burial depths, or in deep boreholes. Geophysical surveys are generally designed to collect data over a target volume. For example, a seismic survey designed to image the reservoir may not provide high-quality data in the shallow subsurface, nor will the inverse be true. In addition, the area to be seismically imaged can be much smaller than the area over which geophysical instrumentation is deployed. A typical seismic survey design will optimize locations and properties of the seismic sources and receivers. Modeling using rock physics is used to determine if CO_2 in the expected saturation and thickness is detectable at the relevant saturation and depth (see examples in Myer et al. 2003 and Ricarte et al. 2011). In addition, testing of tool response to site-specific geological conditions is common prior to a full-scale survey. The level of noise and repeatability of measurements need to be assessed to predict resolution of the survey before investment. Al-Jabri and Urosevic (2010) provided an example from the Otway Project of assessing the role of noise in seismic detection. Similar design approaches are also needed for other geophysics-based, as well as geochemically-based, surveys. For example, al Hagrey (2011) provided a model of electrical resistance tomography (ERT) sensitivity.

Monitoring objectives are tied to the target monitoring zone; they are also influenced by the background and experience of the monitoring team. Early monitoring at the Sleipner CO_2 storage project focused on four-dimensional (4-D) seismic monitoring, in part because this approach overlapped the interests and skills of the operator, who was already using this technique for surveillance of gas production. Only later and to a lesser degree was monitoring of the near surface implemented in this project. In contrast, an accounting framework that requires detecting or quantifying emissions that cross over the sediment-water column interface might motivate an approach targeted more to this horizon. An explicit statement of monitoring goals and a good risk assessment that highlights measurable impacts of those goals are critical for making the decision on where to focus monitoring (see examples in Kirk 2011). Forward modeling of measurable impacts may also be an important component in choosing where to monitor. For well integrity monitoring of a leakage path that would allow CO_2 to migrate to the seafloor through a damaged or unplugged well, a monitoring method targeting the seafloor or the base of the water column would be needed (e.g., see the technologies advised by Shitashima et al. 2013). However, if leakage involves transport through geologic media (such as a subsurface blowout or development of a gas chimney), the signal may be attenuated and not be detected at the seafloor for decades or even centuries (Porse 2013). This is a case where deep-focused monitoring may be essential for demonstrating proper site performance over the relevant time period.

3.4.2.3 Monitoring Data Collection Specifics

For monitoring to be successful, deployment and operational or sampling conditions required to attain the needed sensitivity must be determined. Frequency, scope, and duration of data collection are important aspects of a monitoring program. Approaches summarized in Appendix E should be assessed for tool operation and sensitivity, and variability of the environment being monitored. A tool that was highly successful in one horizon (or geologic setting) may not be useful in another; therefore, a full characterization and assessment of relevant parameters will be needed to match the tool and method of deployment with the site-specific conditions.

Time-lapse, 3-D analysis (4-D seismic) is especially useful for monitoring GS, because the introduction of CO_2 may provide a sharp change from pre-existing conditions. Comparison of pore-fluid characteristics prior to injection with those during and after injection will therefore be more powerful. Data collected before injection is referred to as "baseline," and repeated surveys generate "time-lapse" data. Repeat response can be subtracted from baseline (all the unchanged geologic complexity cancels out), and the remainder is assessed for evidence of fluid substitution and pressure increase. Sufficient data should be collected such that statistically significant deviations from normal variability can be recognized. Excellent examples of a reservoir response to CO_2 injection have been collected using a baseline and time-lapse repeats of 3-D seismic surveys (referred to as 4-D seismic) (e.g., Chadwick et al. 2009, Chadwick and Noy 2015). Change in seismic properties in response to increases in reservoir zone pressure has also been shown (e.g., Grude et al. 2013, Jenkins et al. 2015, White et al. 2015, for l0-bar increase in the reservoir pressure at Snøhvit). Chadwick et al. (2012) showed response to small pressure changes at Sleipner.

The value of 4-D seismic in monitoring for CO_2 has been demonstrated at multiple sites. At Sleipner, it was used to image CO_2 accumulations in shallower-horizon secondary traps, thereby serving as a confinement monitoring method (Arts et al. 2005, Chadwick et al. 2014). Its usefulness was also demonstrated in a well-constrained onshore study at Otway in Australia (Pevzner et al. 2011).

Other geophysical techniques show similar promise, such as (1) time-lapse gravity surveys (Sleipner), (2) electrical resistivity (onshore Ketzin vertical electrical resistivity array [VERA]) discussed by Girard et al. (2011), and (3) the array at the SECARB early test (Carrigan et al. 2013, Doetsch et al. 2013). It is critical to note that the time-lapse methods have implicit in them an assumption that the major change over time is the signal of interest.

Time-lapse seismic monitoring has been successful in deep sub-seafloor projects, because rock and fluid properties are static relative to injection, and the fluid substitution signal has been detectable above noise and repeatability error (Lumley 2010). Before application of a time-lapse method, characterization and analysis of the variability of the system with respect to the signal of interest are needed to determine if the change resulting from injection can be detected (e.g., see Pevzner et al. 2011, Meadows 2013a, Chadwick et al. 2014). Variability can be repeated—for example, tidal or seasonal—or have a trend that can be reduced by application of statistical methods (e.g., see onshore soil gas studies by Schloermer et al. 2013). Statistical methods to reduce random noise may also be applied in noisy, dynamic environments. In some cases, variability can be reduced by comparing a changed sample area with an area that remains unchanged. An especially difficult case is encountered in environmental monitoring, when the expected outcome is to make a strong statement that no leakage has occurred. It may be difficult to create an analysis strong enough to support a "non-detect" outcome in a complex system, such as a biologic or water column condition. Careful design is needed to document a negative outcome even in conditions where a positive outcome could be clearly shown.

Analytical methods needed to extract results from measurements are critical to a monitoring program in terms of both cost and quality of outcomes. Monitoring tools provide raw data in units native to the instrument or method. Processing is required to convert the raw data into units related to monitoring need. For example, seismic data record changes in acoustic velocity, amplitude (acoustic impedance), and spectral characteristics. Through a many-step workflow these data can be transformed into images of volumes where acoustic properties have changed. In many cases, additional laboratory and field tests must be combined with the survey, for example, to invert seismic data to saturation through a rock physics model (e.g., Carter and Spikes 2013). Further interpretation of the output may be needed to develop an outcome that meets a project's goals. For example, once seismic data have been fully interpreted, matching the data to an FF model may be needed to determine the significance of the results, as has been done for Sleipner, Snøhvit, Weyburn, Cranfield, and other sites. An onshore example of an integrated model-monitoring study is presented by Cavanagh and Ringrose (2011) for the fractured In Salah CO_2 storage project.

3.4.2.4 Application of Monitoring Data

Successful application or utilization of data is a hallmark of a mature, effective monitoring program. In many cases, the outcome of the monitoring activities will be confirmation of response expected from predictive modeling. In this case, the actions to be taken could be either to continue as before or, perhaps, to use the data to eliminate a material uncertainty and allow monitoring of that element to cease. Careful design can increase confidence and reduce costs of interpretation by assigning pre-assessed significance to various measurement outcomes. For example, the "traffic light" approach to seismic monitoring can classify data that have been only lightly processed to quickly separate "green-light" (project can continue) from "red-light" or "yellow-light" conditions where predetermined mitigation activities are required (Majer et al. 2012).

Modification of the monitoring program as injection progresses should be expected. Triggers for assessing the need for updates include changes in the injection plan, or refined geologic characterization, risk assessment, and modeling. In addition, relevance and results of the monitoring program should be reviewed and optimized if needed. The improved understanding of the influence of fractures on retention risk that was created by adding pressure to the system at the In Salah project (Mathieson et al. 2010, Smith et al. 2011, Gemmer et al. 2012) provides an example of what may be expected at other sites. As data were collected, it became apparent that the geomechanical response of the reservoir was more important than initially thought; this information motivated additional investment in analysis and data collection. Monitoring approaches that perform below the needed sensitivity should also be revised. It is likely that new and better technologies will become available during operation of a project; flexibility to substitute approaches should be planned. Last, it is likely that a well-designed monitoring program that validates predictive modeling results can sufficiently reduce concerns about leakage to the point that the program can be terminated before or as part of site closure. If modification is needed, the list of activities in Appendix F, Tables F-1 or F-2 should be reviewed to assure that the revised outcomes remain aligned with the project goals.

3.4.3 Pipeline-Specific Monitoring

Environmental issues and potential impacts on shallow sediments, at the seafloor, in the water column, at the sea surface, and in the atmosphere also need to be investigated and taken into consideration for an onshore and offshore CO_2 pipeline. This is to ensure regulatory compliance during construction and operations, determine mitigation measures, and optimize pipeline routing. Application documentation; facility site acquisitions; ROW, easements and grants; and permitting approvals can often take several years to obtain and thus need to be planned well in advance.

All pipeline construction projects crossing waters of the US are subject to EPA regulation and USACE permitting authority under Section 10 of the Rivers and Harbors Act (33 USC 403), and Section 404 of the Clean Water Act (33 USC §1251). Under Section 10, permitting is required before certain work in or affecting navigable waters of the US can occur. Section 404 requires permit approval for the discharge of dredged or fill materials into waters of the US.

Wetlands are considered US waters and also require Section 404 permits for crossings. Under USACE permits, pipeline projects must maintain erosion control over all crossings of US waters and the slopes which drain directly to the waterway. Wetlands are areas that are covered by water or have waterlogged soils for long periods during the growing season and generally include swamps, marshes, bogs and similar areas. A Wetlands Delineation Report and Permitting Requirement Plan are normally prepared during the FEED and/or the detailed design phase of a project.

Any applicable regulatory body having jurisdiction (e.g., DOT, EPA, BSEE, State, and local) can require facility (pipeline and other associated devices) and environmental monitoring and inspections both during construction and operations of the pipeline based on their applicable regulations. DOT 49 CFR Part 195 and ASME B31.4 stipulate that construction inspection must be conducted to ensure that the installation of the pipeline system complies with DOT regulations and codes.

Analysis of the potential environmental impacts of proposed onshore to offshore CO_2 pipelines will almost certainly be required in order to obtain the necessary environmental permit approvals. The final route of an onshore or offshore pipeline should be selected to minimize potential impacts to the public, the surrounding environment, and land and water resources.

For operational and safety reasons, for protection of the environment, and to meet regulatory requirements, pipeline operating companies often impose their own monitoring and inspection programs for onshore and offshore pipelines. In addition, operating companies generally provide manned control centers for continuous operational pipeline monitoring for detection of abnormal conditions and emergency situations in order to take immediate action to prevent and/or reduce an uncontrolled release of a product to the environment.

3.5 Mitigation

The purpose of mitigation is to avoid, minimize, reduce, rectify, or compensate potential project-specific environmental or operational impacts or risks associated with offshore CO_2 operations. Literature specific to mitigation for CO_2 operations is limited; however, selected BSEE, BOEM, and other regulations and O&G industry standards are applicable. Health and safety issues are discussed in Section 3.8.

Environmental research, analysis, and monitoring play key roles in identification and development of mitigation. Site selection and project planning and execution should incorporate design criteria that appropriately mitigate potential environmental impacts. EI (2013) describes mitigation measures to minimize potential impacts from failure of various components (e.g., pipelines and associated equipment, risers, and injection well components) of the CO_2 storage chain. These measures may be included as project design criteria, such as: (1) clearly marking offshore pipelines on marine maps, and (2) careful selection of riser pipe material and installation of protective structures around riser pipes to minimize rupture potential (EI 2013). In DNV (2010l), mitigation is defined as a method to reduce consequences of unplanned events, and is used in conjunction with risk prevention. There appear to be multiple uses of the term mitigation across the industry standards.

As with risk assessment, mitigation of risk requires definition of what constitutes a leak and what volume or rate of leakage is significant (i.e., action level). This threshold will need to be defined by regulators based on CO_2 storage objectives. Generic mitigation responses to risks from CO_2 operations in pipelines, platforms, wells, and storage reservoirs follow.

3.5.1 Pipeline Mitigation

Table 3-5 lists the principal concerns for CO_2 pipeline risks and current mitigation approaches considered by the O&G pipeline industry. The methodologies used to mitigate the risk for an onshore or offshore CO_2 pipeline are comparable, and in some areas identical, to the objective of reducing a tolerable risk to ALARP (as low as reasonably practical). All plans, programs, and processes associated with mitigation measures should be well documented to ensure consistency of implementation.

Table 3-5. Pipeline risk concerns and mitigation

Primary Pipeline Risk Concerns	Onshore, Offshore, Nearshore Pipelines Mitigation Consideration	Comments
Internal Corrosion	Product Control (e.g., fluid composition) Monitoring Dehydration Material Selection Operating Inspections Use of Chemical Inhibitors	Controlling water content in CO_2 is a critical aspect of mitigating internal corrosion and preventing formations of hydrates.
External Corrosion	External Coating Cathodic Protection Material Selection Monitoring Operating Inspections	
Mechanical and Material Failure	Design Route Selection and Mapping Material Selection Automation Controls Monitoring Regulatory Compliance Operating Inspections Maintenance Program Pressure Testing ROW Inspection Construction Inspection Burial	Pipe material selection is critical in controlling crack propagation in a CO_2 pipeline. Improperly selected elastomers can result in explosive decompression damage.
Excavation, Intrusion or Impact (e.g., 3rd party, company)	Route Selection and Mapping Planning and Communications Training and Operator Qualification Warning Markers and Signage Routine Patrols and Detection ROW Inspection	One Call (811) in advance to onshore digging is a law in each State.

Primary Pipeline Risk Concerns	Onshore, Offshore, Nearshore Pipelines Mitigation Consideration	Comments
Operating or Maintenance Error	Training and Operator Qualification Safety Procedures Automation Controls Operating Procedures Maintenance Procedures Controlled Dispersion Release Drug and Alcohol Testing	CO_2 pipeline operation and maintenance must take into account the very high operating pressures (1,200 to 2,200 PSIG plus).
Unplanned Product Release	Leak Detection and Response Route Selection and Mapping Automation Controls Public Education Valve Locations Emergency Response Plan Employee Training Routine Maintenance Operating Inspections Monitoring	Breathing elevated releases of CO_2 is very dangerous and can result in death. Densely populated and environmentally sensitive pipeline routes should be avoided.
Accidents and Environmental Impact During Construction	Design Constructability Route Selection Regulatory Compliance Execution Plans and Procedures Construction Inspection Construction or Execution of Compensatory Mitigation Actions	Several Federal and/or State regulations require inspections during construction.
Natural Disasters (e.g., hurricane, tornadoes, floods)	Advance Planning Procedures	

The consequences of not controlling and mitigating pipeline risks can result in:

- Harm to the surrounding environment
- Public endangerment
- Company personnel endangerment
- Loss of reputation
- Loss of assets
- Loss of revenue
- Loss of injection capacity and/or capability

3.5.2 Platform Equipment, Wells, and Storage Reservoir Mitigation

<u>Mitigation of leaking wells:</u> Well repair techniques and technologies are widely used in the offshore O&G industry, and should not be substantially different for an offshore CO_2 injection well. Standard well repair techniques include injecting cement into well annuli or casing, or zones within wells that are suspected of leakage. This process is termed “remedial squeeze” by the O&G industry. Such techniques, which are used in natural gas storage industry, are reviewed in IEAGHG (2007e).

CO_2 dissolves in water at high pressure and low temperature, but will form bubbles in seafloor-water column settings at CO_2 storage sites on continental shelves. Depending on local and seasonal conditions, CO_2 will either become stratified in the water column or freely exchange with the atmosphere (ECO_2 2015). Hence, it will not be possible to use physical barriers to remove CO_2 as is done for oil spills (e.g., DNV 2010l).

Mitigation of storage reservoir leakage: If monitoring data indicate CO_2 has migrated outside of an intended containment volume (vertically or laterally), the only mitigation measure possible or desirable may be cessation of injection. Again, this would require quantification of what rate of CO_2 migration constitutes mitigatable leakage, plus monitoring and modeling to determine if that threshold will be exceeded. A case of acceptable migration of CO_2 from one area to another is being observed at the Sleipner site in the Norwegian North Sea. Repeated seismic surveys provide monitoring data such that the long-term fate of CO_2 can be predicted through modeling. This is an example of how tracking migration can show that CO_2 is still well below the seafloor and hence remaining isolated from the atmosphere. IEAGHG (2007e) states that migration of CO_2 outside of a storage reservoir may not require mitigation. They also emphasize the need for up-front best practices for site selection and monitoring that will greatly reduce the need for mitigation.

In an overview of mitigation and remediation options for CO_2 GS presented to the California legislature, Kuuskraa (2007) suggested cessation of CO_2 injection as a first step in mitigation, followed by formation of pressure barriers through fluid injection (presumably brine) in targeted geologic interval(s) (e.g., overlying or laterally outside of the storage reservoir). Fluid barriers or pressure curtains are used by CO_2 EOR operators to restrict subsurface migration of CO_2 to increase oil recovery. Such barriers will likely be transient, because the pressure will attenuate and equalize. However, a sub-seafloor pressure curtain might retard migration sufficiently such that other trapping mechanisms (e.g., dissolution, capillary trapping, or mineral trapping) could be effective.

The extraction of large volumes of CO_2 is not likely to be a viable mitigation option since injected CO_2 enters a geologic system of pressurized pore spaces filled with other fluids. CO_2 extraction would be similar to natural gas production in that it would take a long time; the CO_2 would need to be separated from co-produced reservoir brine. Also, methods to modify defects in the reservoir or confining layers have generally not been proven.

3.6 Safety Inspection and Performance Assessment

Safety inspection and performance assessment will enhance safety, reliability, and uninterrupted operation of the entire CCS chain: capture, transportation, and storage. This subtopic covers selected aspects of safety inspection and performance assessment during design, construction, commissioning, operation, maintenance, and decommissioning of CO_2 pipeline transport infrastructure, and platform and injection well components of the CCS chain. Other than documents produced by DNV (e.g., DNV 2010e), literature on safety inspection and performance assessment for offshore CO_2 GS and CO_2 EOR is limited. However, applicable information is available from:

- Existing BSEE and BOEM O&G regulations
- Existing offshore O&G standards

- More than four decades of safe onshore CO_2 EOR
- Currently operating or planned offshore CO_2 GS projects

In the US, BSEE is responsible for annual pre-scheduled and periodic unscheduled (unannounced) inspections of all O&G operations on the OCS. The annual inspection includes all safety equipment designed to prevent blowouts, fires, spills, or other major accidents. Inspection-related BSEE regulations are contained in 30 CFR 250, Oil and Gas and Sulphur Operations in the OCS. Examples of specific inspection and enforcement O&G regulations that may be pertinent to offshore CO_2 transport and platform operations include:

- Subpart A–General
  - § 250.130 to 250.133: Inspections of Operations
  - § 250.135 to 250.136: Disqualification
- Subpart I–Platforms and Structures
  - § 250.919 to 250.921: Inspection, Maintenance, and Assessment of Platforms
- Subpart J–Pipeline and Pipeline Rights-of-Way (ROW)
  - § 250.1000 through 250.1008: Inspection Requirements for DOI Pipelines and ROW Permits

Parallel BOEM regulations are contained in 30 CFR 550, Oil and Gas and Sulphur Operations in the OCS. Below is specific information from existing regulations and industry practice for inspection and performance assessment of pipelines, platforms, and injection wells.

3.6.1 Pipelines

Although the Federal government is primarily responsible for regulating pipelines on the OCS, each State also assumes "intrastate" regulatory, inspection, and enforcement responsibilities in the territory of the State submerged lands.

Regulation 30 CFR 250 Subpart J-250.1005 applies to OCS O&G pipelines. Criteria for consideration in the development of an inspection and auditing program for OCS CO_2 pipelines include: (1) integrity of riser pipe and surrounding protective structures on platforms, (2) control and isolation valves, including fracture propagation control in pipelines, and (3) purity of CO_2 stream because impurities could lead to increased corrosivity (e.g., presence of water) and change in thermodynamic state (e.g., hydrate formation) (Cole et al. 2011).

An inspection and auditing program for OCS CO_2 pipelines should include inspections of pipeline routes at regular time intervals. For example, to ensure adequate corrosion control, pipelines protected by rectifiers or anodes, for which the initial life expectancy of the cathodic protection system either cannot be calculated or can be calculated but shows a life expectancy of less than 20 years, must be inspected annually. In addition, there should be a full-chain maintenance program for CCS equipment and facility integrity.

Specific inspections and performance assessments to be performed by the pipeline operator can be found in DOT 49 CFR Part 195, Subpart F, Operations and Maintenance. Some of the inspection requirements in ASME B31.4 (ASME 2016) are similar. Recommendations for frequency of inspections are available in both DOT 49 CFR Part 195 and B31.4. Selected inspection and performance assessment requirements from these sources that could be applied to an offshore CO_2 pipeline include but are not limited to:

- Inspect the seafloor conditions on or adjacent to each pipeline ROW.
- Conduct periodic underwater inspections in the GOM and its inlets in waters < 15 ft deep.
- Inspect each mainline valve.
- Inspect and test each pressure-limiting device, relief valve, pressure regulator, or other item of pressure control equipment.
- Test and verify an internal communication plan to provide adequate means for manual operation of the pipeline safely.
- Test any backup remote data communications systems.
- Identify points affecting safety, which have been identified in data streams, have had alarms inhibited, generated false alarms, or have forced values for extended periods.
- Verify safety-related alarm set-point values and alarm descriptions when associated field instruments are calibrated.
- Review the alarm management plan.
- Monitor content and activity being directed to and required of each controller.
- Establish controller training program, and review content to identify improvements.
- Conduct a periodic evaluation to assure pipeline integrity.
- Conduct cathodic protection tests on the protected pipeline.
- Identify when cathodic protection close-interval survey is practicable.
- Check cathodic protection rectifiers and other devices for proper performance.
- Examine corrosion coupons or other monitoring equipment.
- Inspect pipe removed from service for internal surface corrosion.
- Inspect pipe for external corrosion/damage.
- Review operations, maintenance, and emergency manuals.
- Review operator response to abnormal operations.
- Perform post-accident reviews.

Specific requirements for inspection of pipelines during construction are contained in DOT 49 CFR Part 195, Subpart D, Construction, and ASME B31.4, Chapter VI (onshore), Inspection and Testing, and Chapter IX (offshore), Inspection and Testing. Other Federal, State, and local agencies may also have specific requirements for inspection of pipelines during construction.

Construction inspections include

- Review of material and component design specifications
- Welding procedures and welder qualifications
- Non-destructive testing results
- Corrosion protection
- Installation and post-construction testing

If compliance violations are identified, then administrative, civil, and, in some cases, criminal charges can be filed.

In 2014, DOT pipeline safety personnel performed 1,071 Federal inspections of pipeline operators. Inspections included:

- Review of operator's documented processes, procedures, and records
- Observation of employees performing work
- Checking records to ensure the pipeline system is operating at or below the maximum parameters allowed by regulations
- Checking emergency preparedness for responding effectively to abnormal operating conditions or a pipeline failure (49 CFR 195)

The O&G pipeline industry performs routine inspection and auditing of their operating onshore and offshore systems not only to satisfy regulatory requirements but also to protect the public, environment, employees, and company assets. This same inspection practice for onshore CO_2 pipeline systems could be adapted to offshore CO_2 pipelines.

The operational inspections and performance assessment normally concentrate on the following categories:

- Material and Equipment Integrity (e.g., internal corrosion, external corrosion, damage, operability)
- Cathodic Protection Equipment and Effectiveness
- Critical Instruments, Controls, Safety and Emergency Devices
- Employee Personal Protection Equipment
- Route Surveillance and ROW Inspections
- Emergency Response Plan, Preparedness, Equipment and Training
- Employee Training and Qualifications (e.g., operators, maintenance)
- Employee Drug Testing and Employee HSE (Health, Safety, and Environmental) Compliance
- Operating, Emergency, and Maintenance Procedures
- Environmental and Regulatory Compliance
- Recorded Operations, Inspection, and Audit Documentation

According to DNV (2010a), a pipeline inspection gauge, or PIG, is one tool commonly used by industry for internal pipeline inspections; these tools are also known as smart PIGs or intelligent PIGs. A risk to be aware of during a PIG inspection of CO_2 pipelines is the dislodging of hydrates that may have formed inside of pipe (EI 2013). Remote visual external inspection will need to be performed using an autonomous underwater vehicle (AUV) or vessel-based system.

The goals of these company and regulatory inspections and audits are to ensure preventive measures are in place to reduce the likelihood of a hazardous event; to evaluate the effectiveness of the company's maintenance, safety, and response program; to manage the risks of the pipeline system; and to confirm compliance with regulatory and company requirements.

3.6.2 Platforms and Structures

As with other aspects of offshore O&G operations, existing regulatory and guidance documents on inspection and auditing also apply to platforms and associated structures. These documents include existing DOI regulations, DNV documents, and CO_2-specific manuals (e.g., EI 2013).

BSEE regulations in Subpart I–Platforms and Structures, under the Inspection, Maintenance, and Assessment of Platforms (30 CFR 250.919 to 250.921), schedules for offshore platform safety inspections are provided. These inspections include above- and below-water portions of fixed and floating platforms, as well as portions of pipelines, wells, and other equipment supported by the platform. Other equipment supported by a platform could include CO_2 separation facilities.

Several DNV documents address aspects of offshore platform safety (e.g., DNV 2003, 2012b, 2012d, 2013). In DNV's RP-H101 (DNV 2003), Section C.8 provides a general procedure for Inspection and Testing of marine operations. Appendix C of DNV OSS-300 has an exhaustive list of offshore installation components that should be considered during inspection and auditing (DNV 2012d). In the DNV (2013) document CO2RISKMAN, pages 175–178, causes of potential hazards on platforms, both non-CO_2- and CO_2-related, are tabulated. Entries in the non-CO_2-related list could be considered as additional inspection and auditing criteria.

Safety inspections of existing platforms that will be reused for CO_2 GS and EOR-GS will be needed, especially with regard to loading from equipment not considered in the original design (EI 2013, DNV 2012b); this will also need to be considered during the FEED process. Inspection of riser pipe for accumulation of hydrates is not routine for onshore CO_2 injection, but it will be needed in offshore settings. Because hydrate formation is not unique to offshore operations, technologies used in onshore operations can be applied.

Other specific components that will need to be included in inspection plans are:

- Emergency shut-down valves located between CO_2 supply pipeline and the riser to the platform
- CO_2-specific equipment seals
- Platform CO_2 compressors and pumps
- Platform isolating valves, especially given the "large liquid-to-gas expansion factor of CO_2" (EI 2013)

The EI (2013) report also considers "rupture in riser above the water line or between the low and high tide mark," thus creating the need for riser inspection in offshore CO_2 GS and EOR-GS. The EI (2013) suggests that highly concentrated CO_2 could be released onto the platform from a ruptured riser pipe. Existing risers used in offshore operations may not be suitable for CO_2 (EI 2013). Other safety measures to be included in inspection and performance assessment are records from injection volume and rate and downhole pressure monitoring; these may give early warning of a potential problem on the platform. Subsurface safety valves are a standard requirement for all offshore wells and could be expected for CO_2 wells too.

3.6.3 Injection Wells

Literature specific to safety inspection and performance assessment of offshore CO_2 injection wells is mostly limited to that produced by DNV. The most applicable documents are RP-E102–Recertification of Blowout Preventers and Well Control Equipment for the US OCS (DNV 2010d) (this would apply during well drilling only), CO_2WELLS (DNV 2011b), and RP-J203 (DNV 2012b). The biggest issues not already addressed in existing DOI OCS regulations are integrity of wellbore cements in the presence of CO_2 (e.g., Benge 2009) and potential for well failure from exposure to CO_2. Appendix B of DNV (2012b) contains an exhaustive list of potential failure modes and mechanisms for wells exposed to CO_2. The most applicable entries in this list should be included in inspection and auditing of an offshore well into which CO_2 is being injected or produced.

Existing BSEE regulations on casing and cementing requirements are in 30 CFR 250.420–250.428; API Standard 65-2 is adopted by reference in BSEE regulations. Industry operators confirm the quality of annular cement using cement bond and other types of downhole geophysical logging. Subpart H of the BSEE regulations covers O&G production safety systems (30 CFR 250.800–250.808).

3.7 Reporting Requirements

Record keeping and reporting requirements will be a key part of any regulatory framework (May 2007). As with inspection and performance assessment (Section 3.6), this section is only covers reporting of safety issues for offshore CO_2 transport and injection operations.

Safety reporting requirements for O&G operations on the OCS are included in existing BSEE and BOEM regulations. From a general offshore perspective, these requirements could apply to sub-seabed CO_2 GS but with some limitations, because they do not specify technical requirements for CO_2 operations. For example, in 30 CFR 250.188, offshore operators are required to notify BSEE of the following incidents: fatalities, injuries that require evacuation of the injured person, loss of well control, fires and explosions, collisions that result in property or equipment damage of more than $25,000, incidents involving structural damage to an OCS facility, incidents involving crane operations, and incidents involving damage to safety systems and equipment.

US Occupational Safety and Health Administration’s (OSHA’s) rules in 29 CFR 1904, “Occupational Injury and Illness Recording and Reporting Requirements,” are intended to create employee and employer awareness of hazards associated with their operations through analysis of project records. Employers are required to prepare and maintain records of serious occupational injuries and illnesses. This information is important for employers, workers, and OSHA in evaluating the safety of a workplace, understanding industry hazards, and implementing worker protections to reduce and eliminate hazards. It should be noted if reported incidents were work related or non-work related.

Reporting requirements for onshore and offshore pipelines can be complex because of the number of permits involved to construct and operate, overlapping agency responsibility, and the challenge of keeping up with changing regulations. For a new pipeline, the reporting requirements of all Federal, State, local agency, and engineering codes need to be obtained, researched, addressed, and properly documented by the operator. Pipeline incidents and leaks may need to be reported to several different agencies. The following brief descriptions represent “some” of the regulatory reporting requirements for the pipeline industry; however, these may not be all inclusive.

BSEE: Decommissioning of an offshore pipeline requires a report be submitted to the BSEE regional supervisor within 30 days after the decommissioning. Other BSEE reports include the following: installation or relocation of a pipeline; conducting a pressure test; completion of construction; pipelines taken out of service; safety equipment taken out of service for more than 12 hours; details on the repair of any pipeline; corrective action plan for scouring, soft bottoms, or other environmental factors affecting the pipeline; results of any cathodic protection measurements of pipe to electrolyte potential measurements taken.

DOT 49 CFR Part 195: Regulated pipeline systems are subject to Annual, Accident, and Safety Related Condition Reporting (49 CFR 195, Subpart B). The following reports are required on a periodic schedule, and immediate notification is required in some cases:

- Annual Report
- Accident and Incident Reports
- Certain pipeline safety-related conditions
- Certain changes or environments that could impact the system
- Offshore Pipeline Condition Reports per completed inspections
- For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under, or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility.
- Drug and alcohol employee testing information
- Other reports based on compliance actions, special permits, etc.

Railroad Commission of Texas (RRC): RRC regulations for reporting related to Texas intrastate pipelines are provided as examples. All pipeline damage must be reported by the operator and the excavator involved.

Other States: As noted previously in this document, Texas is used as an example of State regulatory requirements. Depending on the location of the pipeline and facilities, other State(s) may have similar requirements. For example, about 75 percent of offshore operations occur off the Louisiana coast; their regulations would need to be researched and implemented for CO_2 projects involving that State.

One Call (811): The US DOT and each State require any plans for digging, including minor homeowner excavations, to be reported in advance in order for the area to be reviewed and marked for underground pipeline or utility obstructions. Texas 811 has recently purchased the GulfSafe database system that processes one-call notifications for the GOM offshore region.

The reporting of CO_2 atmospheric emissions from industrial facilities and CO_2 injection operations is described in Ritter et al. (2012) and by the US EPA on their GHGRP website. Reporting on or accounting of volumes of CO_2 that will be (1) received at offshore platforms, (2) injected for CO_2 EOR-GS or GS, and (3) separated and re-injected for CO_2 EOR-GS is discussed in Section 3.4.

3.8 Emergency Response and Contingency Planning

Well-planned and safely executed transport and storage operations for CO_2 GS and CO_2 EOR-GS should pose minimal risk of exposure to CO_2. DNV (2004b) lists “Emergency Response” as the last step in “Risk Reduction Measures” after inherent safety, prevention, detection, control, and mitigation. However, BMPs for emergency response must include requirements to establish and maintain emergency preparedness such that worst-case-scenario incidents are quickly identified and responded to by following an emergency response plan. The focus of this subtopic is emergency response and control for offshore CO_2 GS, not the likelihood of occurrence of a CO_2 incident. Existing BSEE regulations for offshore O&G operations are in 30 CFR 250, Subpart S–Safety and Environmental Management Systems, 250.1900–250.1933. Part 250.1918, specifically addresses emergency response and control of O&G operations on the OCS and requires emergency response plans to be ready for implementation, with periodic training and realistic drills. A variance on these regulations that could be required for CO_2 transport and injection operations is consideration of the properties of CO_2 or CO_2-mixed gas streams.

According to Zhou et al. (2014), properties of CO_2 and pressure variations during transport and injection pose the biggest health and safety threats in onshore or offshore operations. There are multiple sources with detailed descriptions of the thermodynamic properties of CO_2 and health and safety challenges in transport and storage of CO_2 (e.g., EI 2013; Tyndal et al. 2011; DNV 2010a, 2013; Zhou et al. 2014). Following are discussions of emergency preparedness guidelines and regulations related to CO_2 transport and storage for pipelines and platforms and wells.

3.8.1 Pipelines

Historically, the US O&G industry has been successful in responding to risks from onshore and offshore pipelines through established design practices and regulatory requirements, including onshore CO_2 pipelines that have been in operation for over 40 years. Transportation by pipeline is the safest and most economical way to transport large quantities of refined products, oil, gas, and CO_2.

The DOT reported that 20-year trend for “onshore” pipeline fatalities and injury requiring in-patient hospitalization for all DOT 49 CFR Part 195 regulated “hazardous liquid pipelines (including onshore CO_2 pipelines)” are (1) zero to five fatalities per year between 1995 and 2014 and (2) zero to 17 injuries in the same time frame. Data provided for “onshore CO_2 pipelines” indicate zero fatalities and only one injury in the same 20-year span. There are no US offshore supercritical CO_2 pipelines; however, there have been a few offshore liquid natural gas pipelines that will have similar risks as supercritical CO_2 pipelines.

Pipeline operating companies in the US provide emergency response planning for their pipeline systems. This is a requirement for onshore and offshore pipelines through regulations, codes, and local agencies (e.g., BSEE, DOT 49 CFR Part 195, ASME B31.4, and State). All regulations and codes pertaining to a new onshore to offshore CO_2 pipeline will need to be reviewed for emergency response planning, including how relevant agencies will participate in that response. Below we provide examples of applicable regulations and codes followed by recommended practices and information from published literature. The information presented below may not be all inclusive, and companies or agencies may have a different implementation interpretation.

BSEE: Regulations do not specifically address a spill response plan for offshore CO_2 pipelines. The BSEE, Subpart S, Safety and Environmental Management Systems (SEMS) Program requires that emergency response and control plans be in place and ready for immediate implementation. These plans must be validated by drills carried out in accordance with a schedule defined by the SEMS training program. The SEMS program must address the elements described in §250.1902 and the American Petroleum Institute's Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities (API RP 75).

DOT 49 CFR 195: Subpart F–Operations and Maintenance states each pipeline operator shall prepare a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. The operator shall conduct a continuing training program for emergency response personnel and develop and implement a written continuing public education program. The program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations.

Environmental Protection Agency: EPA has the authority to regulate emissions from pipelines and to create pipeline regulations aimed at preventing accidents that could result in releases of CO_2. EPA may also be involved in emergency management and responses to a pipeline accident.

American Society of Mechanical Engineers: In ASME B31.4, Chapters VII (onshore), IX (offshore), and X (Carbon Dioxide Pipeline Systems) state that an emergency plan is a requirement. ASME B31.4 requires communication be established with any residents along a pipeline ROW to educate them on how to recognize hazards and how to report an emergency to the company. For an offshore pipeline emergency plan, the code requires provisions for halting or diverting marine vessel traffic in the event of an emergency. Furthermore, Chapter X specifically requires the operator to maintain a liaison relationship with State and local civil agencies near a pipeline ROW on response, hazard mitigation, contact person, and what to do in the event of an emergency.

American Petroleum Institute RP 75: Development of a Safety and Environmental Management Program for Offshore Operations and Facilities (including pipelines), Section 10, Emergency Response and Control recommends

- Emergency response and control plans that are ready for immediate implementation
- Written action plans to assign authority for initiating emergency response and control Designated emergency control center(s)
- Training incorporating emergency response and evacuation procedures for personnel (including contractor's personnel)
- Conducting drills based on realistic scenarios

Publications with applicable information on emergency response to an offshore CO_2 pipeline leak include several DNV documents (i.e., 2009a, 2010a, 2010e, 2012b), the EI (2013) research report, and Zhou et al. (2014). From industry experience, the root causes of CO_2 pipeline incidents are relief valve failure, corrosion, weld-gasket-valve packing failure, external force (e.g., collisions), geologic hazards (e.g., slope failure), and natural disasters (e.g., hurricanes) (IPCC 2005).

The prevention and response to emergencies posed by hazards in offshore CO_2 pipelines could be problematic compared with those in onshore settings. Reasons for this include the inability to inspect and maintain safety apparatus in long sections of subsea pipelines (EI 2013). Several resources suggest that installation of rapid shut-off values at periodic distances along subsea pipelines may be the only way to respond to a large leak (e.g., DNV 2009a, EI 2013). Section 4.2.2.2 of EI (2013) discusses how emergency shut-down valves can be used to prevent additional loss of CO_2 from a source pipeline in case of problems on the platform.

CO_2 in an offshore pipeline that develops a leak has the potential to form hydrates, which could, among other things, block pressure-relief valves and cause false readings on safety-related instrumentation (EI 2013). Caution is advised against using pigging devices if a leak is suspected because they could dislodge hydrate formations and cause similar instrumentation and valve problems (DNV 2013, EI 2013). Cosham and Eiber (2008) discussed controls on fracture propagation in CO_2 pipelines, including the use of mechanical crack arrestors.

Modeled scenarios of offshore hazards due to a large-volume CO_2 release from subsea pipelines and platform conduits and vessels illustrate what could be expected and how an effective response might proceed (EI 2013, Section 3.7.4).

3.8.2 Platform and Injection Well

Existing BSEE regulations on emergency response for offshore O&G operations, industry standards, and literature produced before (e.g., DNV 2010d) and after the *Deepwater Horizon* explosion and spill in the GOM may apply to CO_2 offshore platform and injection well operations. However, specifics of CO_2 streams used in offshore CO_2 GS or CO_2 EOR necessitate additional considerations as discussed below.

3.8.2.1 CO_2 Properties

Although natural gas, which is less dense than air, will readily disperse into the atmosphere, a leak of dense phase CO_2 will upon contact with the atmosphere creates an ice fog that will hamper emergency operations. Large or small volumes of escaped CO_2 could also form invisible cloud-like accumulations and collect in confined or unventilated spaces of the platform (EI 2013). Aines et al. (2009) compiled examples of CO_2 well failures and quantified the safety hazard from release of CO_2 for different wind conditions in an onshore setting. An analogy to the offshore is release of CO_2 from a riser pipe out onto the platform with a similar potential to asphyxiate workers. A difference for offshore settings might be higher winds and quicker dispersion of a CO_2 plume.

3.8.2.2 Impurities in CO_2 Stream

Small amounts (a few parts per million to a few volume percent) of hydrogen sulfide (H_2S) are common in high-purity (98+%) supercritical CO_2 streams (Tyndal et al. 2011), especially for CO_2 captured from power plants or produced with oil during CO_2 EOR. Even though H_2S is toxic to humans in small concentrations, Tyndal et al. (2011) posed that in the case of a leak during GS or EOR operations, CO_2 would cause asphyxiation, possibly representing more of a hazard than the more toxic H_2S. Regulations could be developed for CO_2 contingency plans (e.g., TOTAL SAFETY Hydrogen Sulfide Contingency Plan for Anadarko Petroleum's RAPTOR prospect) like those currently in place for H_2S (i.e., 30 CFR 250.496).

3.8.2.3 BLEVE

A boiling liquid expanding vapor explosion (BLEVE) of CO_2 quickly transitioning from liquid or supercritical state to gas could result in a physical blast (EI 2013). Descriptions of CO_2 BLEVE are given in Section 5.11 of DNV's CO2RISKMAN, level 3 document (DNV 2013) and Annex F of EI (2013). Even though a CO_2 BLEVE is unlikely, it should be considered for a worst-case scenario event in offshore CO_2 GS operations.

3.8.2.4 Seal Elastomers

In Section 5 of CO2RISKMAN, level 3 (DNV 2013), material compatibility with liquid-phase CO_2, particularly supercritical CO_2, is noted as an important consideration in handling large volumes of CO_2. This phenomenon is well known by onshore CO_2 EOR operators, not only for equipment and pipeline seals, but also for types of pipe used. As discussed in EI (2013), a rapid change in pressure during an emergency response on an offshore platform could damage equipment seals and pose further risk if operations continue as usual after such an event.

Existing regulations (BSEE and BOEM) and industry practices for O&G wells on the OCS should apply to wells associated with CO_2 injection operations, especially with regard to blowouts (e.g., DNV 2010d). As discussed above for platforms, however, there are additional concerns with wells exposed to supercritical CO_2. Appendix B of CO_2WELLS, DNV includes a detailed list of modes and mechanisms for how CO_2 might cause wells to fail (DNV 2011b). Knowing what potential failures might occur will aid design of emergency response to hazards from CO_2 wells. Lynch et al. (1985) described multiple unsuccessful attempts to kill a well that blew out while producing from a natural CO_2 reservoir in southern Colorado. Multiple failed attempts provided lessons learned about what it finally took to get the well under control after almost a month.

3.9 Decommissioning and Site Closure

At the end of an offshore, sub-seabed CO_2 storage project, the components of the system—pipeline, platform, injection well(s), storage reservoir and overlying seabed—will need to be decommissioned. With minor adjustments for the equipment involved in the CO_2 handling, the first three components can follow O&G operations procedures. According to Kaiser and Liu (2014), decommissioning of offshore O&G-related infrastructure includes: (1) P&A of all wells, (2) removal of production-related structures, including platform(s) pipeline(s), and umbilical(s) and flowline(s) between production and manifold or separation structures, and (3) clearing seafloor of any debris left over from operations. A controversial topic is whether regulators should require offshore operators to remove platforms as quickly as is currently required. In addition, the storage component of decommissioning has become the topic of debate if a standard O&G project end is possible or if new procedures and protocols should be required. Decommissioning of each of the system components (pipeline, platform, injection well, and storage reservoir) is discussed further below.

3.9.1 Pipeline Decommissioning

The decommissioning plan for a CO_2 pipeline (onshore and offshore) will be similar to that for O&G pipelines and will also proceed according to regulations and industry standards. The pipeline should be designed and constructed in a manner that can reasonably accommodate decommissioning. A decommissioning plan should, at minimum, include:

- Methodology and schedule
- Equipment list
- Safety precautions
- Results of modeling studies (e.g., dispersion analysis)
- Permit details (i.e., identification of regulatory agencies and final documentation requirements)

Precautions must be taken to prevent rapid depressurization so that CO_2 does not solidify (form hydrates) along low points in the pipeline.

Existing BSEE regulations for O&G pipeline decommissioning, which may be applicable to CO_2 pipelines, are in 30 CFR 250.1750 through 250.1754. They are summarized as follows:

> § 250.1750 states a company may decommission a pipeline in place when the regional supervisor determines that it does not constitute a hazard (obstruction) to navigation and commercial fishing, unduly interfere with other uses of the OCS, or have adverse environmental effects.
>
> § 250.1751 requires that operators:

- Submit a pipeline decommissioning application for approval
- Pig the pipeline, unless approved otherwise
- Flush the pipeline
- Fill the pipeline with seawater
- Cut and plug each end of the pipeline
- Bury each end below the seafloor or cover each end with protective concrete mats
- Remove all pipeline valves and fittings that could interfere with use of the OCS

> DOT 49 CFR Part 195 does not specify pipeline abandonment procedures. ASME B31.4 requires the following for abandoning any pipeline:

- Have procedures for abandoning the system
- Disconnect it from all product and pressure sources
- Purge the system with an inert material (e.g., water, nitrogen) and seal the ends

3.9.2 Platform Decommissioning

No special considerations are needed to decommission a platform that has been in service for CO_2 injection as compared with other uses of a platform. Existing BSEE and BOEM rules should be suitable. Literature available on platform decommissioning includes DNV (2004), UK guidance (DECC 2011), energy and environmental assessment of O&G infrastructure (Elkins et al. 2005), cost savings for operators and "green" options (Lakhal et al. 2009), financial mechanisms in Brazil (Parente et al. 2006), and GOM options (Pulsipher 1996, Malone et al. 2014).

Malone et al. (2014) discussed the financial and technical advantage of leaving platforms in place after existing oil fields in the GOM become depleted. There is existing primary production infrastructure in shallow water of the GOM that could be used for CO_2 EOR operations. However, the current requirement is to remove platforms within one year of cessation of operations. Existing platforms could be reused for CO_2 injection wells or for offshore CO_2 separation facilities. Reusing these platforms could potentially benefit both operators and the public. For example, operators of fields transitioning from primary or secondary production to CO_2 EOR operations could benefit financially by using existing infrastructure (Malone 2014).

An alternative to decommissioning is conversion of platforms to artificial reefs, as described in Kaiser and Kasprzak (2008), Lakhal et al. (2009), and Alberta RFA, Appendix D (Alberta Energy 2012b), among others.

3.9.3 Injection Well Decommissioning

Most needs for closure of future OCS CO_2 injection wells are covered by the requirements for plugging and abandoning other types of wells under existing BOEM and BSEE regulations. Like all other wells, it is important that a CO_2 well be constructed and maintained to provide zonal isolation prior to abandonment. The critical issues of well integrity are addressed in the operational management of injection wells (Section 3.3). If a transmissive FF path along the well is left at abandonment, the flaw may be further enhanced and negative impact increased by FF and corrosion over the long term (CO_2CARE 2013a, 2013b). Work by Le Guen et al. (2009) emphasizes assessment of site-specific risks related to locating P&A wells; however, this should really be addressed during project planning and execution. RRC has recommendations for well plugging that include offshore and CO_2 injection wells. RRC in 16 TAC 1, Chapter 5, provides additional criteria for certifying P&A of wells used for CO_2 EOR-GS. Activities to be conducted before plugging an injection well under this rule include:

- Flush with a buffer fluid
- Measure to determine bottom hole reservoir pressure
- Perform final tests to assess mechanical integrity
- Ensure that the material to be used in plugging is compatible with the CO_2 stream and the formation fluids.

Research related to closure specific to CO_2 injection wells has focused on the corrosivity of CO_2 and water in contact with steel and cement (e.g., CO_2CARE 2013a, 2013b); however, no unique risks for long-term stability have been identified. Cement carbonation and steel corrosion reactions can cause porosity plugging in the rocks and wellbore annuli, tending to retard or prevent CO_2 migration along the well (Carey et al. 2007, Rochelle and Milodowski 2013).

3.9.4 Decommissioning of Storage Reservoir and Overlying Intervals

Opinions about how CO_2 storage reservoirs should be decommissioned (i.e., closure of storage sites) have evolved over the past decade (e.g., EPA, 2008, CCPSRP 2010a). The need for storage to be effective over a long time frame (e.g., Pacala 2003) has increased concern about the long-term performance of CO_2 storage sites. The properties of the CO_2, its buoyancy relative to brine at injection depths, the low viscosity that makes it relatively mobile compared to oil, and the increased pressure in the reservoir as a result of injection have all raised concerns about the long-term stability of CO_2 storage. The non-linear expansion of CO_2 to gas if it migrates to shallow depths, and the potentially corrosive interaction with steel casings and cement constructions of wells, also cause concern. This experience has primarily been gained through onshore CO_2 injection operations, but is also relevant to future sub-seabed storage of CO_2 on the OCS.

As part of a plan to incentivize industrial participation in CCS projects, some jurisdictions have agreed to assume ownership and any remaining liability after certain conditions have been attained for closure (EPA 2008). In the EU, the plan for site decommission and transfer to government responsibility has led to development of standards that must be met before the site can be closed, including a period of monitoring (EC 2009; Korre at al. 2011). A series of studies focused on closure in the European context were carried out by CO_2CARE. These studies recommend that a CO_2 storage site-abandonment period begin once CO_2 migration modeling predictions and safe storage of the CO_2 have been verified using site-monitoring data (CO_2CARE 2013a, 2013b). In the US, the EPA Class VI rules for protection of UIC have also required a prolonged “post-injection site care” (PISC) period of monitoring with a 50-year default duration. Activities to be conducted during the PISC are required to be defined in a plan prepared during site permitting.

Models of long-term fate of CO_2 are commonly prepared and monitoring during the period of injection can increase confidence that such models are correct. For example, Ketzer et al. (2005) showed stabilization of the CO_2 plume in the North 40s field of the North Sea was satisfactory in all reasonable outcomes. The consequences of failure can also be assessed (for examples, see the work of Kopp et al. 2010 on well leakage). Technical and policy considerations are needed to determine if such predictions are adequate; if they are not, what monitoring activities are needed over what period, and does this period include post-injection?

An extensive PISC period with long-term monitoring is not recommended as a best practice for assuring either the effectiveness of CO_2 containment or protection of offshore environments. It will be too late for effective mitigation if problems are not identification until after emplacement of the CO_2. Significant uncertainties about the long-term performance of a CO_2 storage site should be resolved prior to injection of large volumes of CO_2; if uncertainties cannot be resolved, injection should be stopped. A process of long-term risk assessment and identification of potential post-closure impacts should be designed during the early stages of the injection. Potential long-term consequences (e.g., seafloor leakage years after cessation of CO_2 injection), which may occur over the course of CO_2 injection, will need to be identified in early stages of the project. Then, if needed, targeted investigations will then need to determine the likelihood of potential impacts and associated mitigation strategies. If the potential for impacts to occur after site closure cannot be reduced to acceptably low consequences before the end of CO_2 injection, the project should not be permitted or allowed to continue to full duration.

It is likely that small volume injection will be needed to identify potential risks. In particular, risks related to pressure elevation and those related to uncertainties in multi-phase flow and CO_2 dissolution require a period of testing with relevant pressures and fluids in order to provide robust calibration for models. Probing conditions far from the injection well(s), in particular, may require innovative design. A test period of stabilization may also be needed to measure the FF under conditions where buoyancy and capillary processes dominate. However, if this uncertainty is material to the project success, conducting such a test should not be deferred to the end of a prolonged injection but should be conducted experimentally early in the project. Observation of stabilization of a small plume can be effective in confirming the physical processes relevant to the long term (Hovorka et al. 2006, Zhang et al. 2011). In addition, data on potential consequences should be factored in, as is done in risk assessment. For example, some remaining threat of long-term fluid leakage to the ocean water could be accepted if both the likelihood and the consequences are low.

Delaying evaluation of long-term risk to the PISC period will not support realistic mitigation options. More research should be focused on effective methods to test post-closure risk in the early stages of a project, so that mitigation and/or site closure can be effected long before the planned project ends. Should a CO_2 EOR-GS or GS project prove to have a containment flaw and need to be abandoned early, a contingency plan for one or more wells and parts of the site will be needed. Such an abandonment might not be able to meet the optimal standards for closure; however, early assessment would reduce net damage to the project since only modest injection would have occurred.

4 Legal Issues

Various legal commentators identify three impediments to implementation of CO_2 GS:

- Uncertain national policy and regulations
- Pore space ownership
- Long-term liability (e.g., Hawkins et al. 2009, Hoffman 2011, IEA/OECD 2014)

4.1 Uncertain National Policy and Regulations

The US has established regulations for the injection of CO_2 into geologic formations onshore and offshore under submerged lands within the territorial jurisdiction of States through EPA's UIC program. These regulations focus on protection of USDWs under the SDWA and reduction of CO_2 emissions to the atmosphere under the CAA.

As stated in Section 2, the 2010 Presidential Interagency Task Force on Carbon Capture and Storage (CCS) examined the existing US regulatory framework and recommended the development of a comprehensive US framework for leasing and regulating sub-seabed CO_2 storage operations on the OCS. However, this comprehensive framework has yet to be established; therefore, the existing regulatory framework is shared across multiple Federal agencies, including DOI and the EPA, and may have jurisdictional gaps.

4.2 Pore Space Ownership

The pore space of the OCS belongs to the US public; the Federal government has jurisdiction to manage both seabed surface and sub-seabed energy and mineral rights. Appropriate lease management of these OCS resources by the Federal government will be critical if different sub-seabed horizons are leased by different operators in the same geographic region or O&G "play" or other pertinent space-use conflicts exist.

The information paper by IEA/OECD (2010b) has a good review of subsurface pore space ownership (US and internationally), as do several articles in the Legal Issues category of the literature database (e.g., Duncan et al. 2009a, Zadick 2011), and Appendix D of the Alberta RFA (Alberta Energy 2012b). For example, the Alberta RFA Working Group considers pore space to be a natural resource that needs to be inventoried and managed. If there are competing interests in pore space utilization, the pore space owner would determine which uses have higher priority.

4.3 Long-Term Liability

The possibility of short- or long-term damage to O&G and other energy and mineral resources could be a liability concern to offshore CO_2 GS operators (see Section 3.2.3 for further discussion). The possible scenario for impacts would be from a release of CO_2 along a transmissive fault or leaking well bore. These liability risks can be reduced by careful subsurface characterization and site selection and proper site preparation and engineering, respectively. The worst-case scenarios for CO_2 leakage from a deep sub-seabed reservoir must be considered and protected against through regulations and insurance or bonding in the short term, and possibly governmental indemnity against long-term liability claims. Another idea put forward (e.g., Jacobs et al. 2009, Wilson et al. 2009, IEA/OECD 2014) is to establish a Post Closure Fund, that could be similar to Superfund, to cover possible future damages failing assignment of liability to a responsible party.

The acceptance of long-term liability, on the order of decades to 50 years, could prevent future CO_2 GS operators from entering the industry (Hawkins et al. 2009). On the other hand, if industry recognizes the burden of potential long-term liability, they may pay more attention to the quality of early operations (Ludwiszewski and Marsh 2013), or as per Hawkins et al. (2009), fewer projects may go forward. Others have suggested that the best approach is through development of private insurance and bonding institutions specific to offshore CO_2 storage (Shell 2014a). BOEM and BSEE require bonds for offshore O&G operations; a similar procedure may be appropriate for CO_2 GS. Kaiser and Pulsipher (2008) discuss formula development for bonding in the GOM. Australia has already addressed long-term liability risks by a schedule of governmental indemnification (IEA/OECD 2014); this legislation passed in 2011.

The International Energy Agency in cooperation with the Organisation for Economic Co-operation and Development (IEA/OECD) documents also provide guidance on long-term liability issues. For example, the Carbon Capture and Storage Model Regulatory Framework (IEA/OECD 2010b) is intended to assist governmental entities in developing regulatory frameworks for CCS using examples from Europe, Australia, and 15 States in the US (IEA/OECD 2010b).

Key examples from IEA/OECD (2012) concerning long-term liability are provided from the “Louisiana Geologic Storage of Carbon Dioxide Act” (their example 23) and “Offshore Petroleum and Greenhouse Gas Storage Act 2006” of Australia, which was amended in 2008 (their example 24).

5 Data Gap Analysis

A data gaps analysis was conducted to (1) identify gaps that may need to be addressed to facilitate offshore sub-seabed GS on the OCS (Section 5.1), and (2) define an adaptive management methodology to inform potential future policy and regulations and update BMPs as the technology advances (Section 5.2).

Broadly interpreted, "data gaps" for offshore CO_2 EOR-GS and GS include gaps in (1) existing US policy and regulations, and legal issues, and (2) current knowledge from existing offshore O&G operations, onshore and offshore CO_2 storage projects, and published literature. Sources of information and methods used to identify gaps in the technology needed to safely transport CO_2 and inject it into the sub-seabed include:

- Analysis of existing US regulations
- Literature compilation and review referenced in Appendix A
- Discussion included in the nine BMPs subtopics in Sections 3.1 through 3.9
- BEG research and experience gained through participation in multiple experimental and applied-technology CO_2 EOR-GS and GS projects
- Input from project subcontractors (primarily DNV and Wood Group industry participants) and external reviewers

Both categories of knowledge gaps are summarized in Table 5-1. An "x" in Table 5-1 denotes a knowledge gap for specified categories and subtopic. Discussion of knowledge gaps included in Table 5-1 follows in Section 5.1.

Table 5-1 **Gap summary**

	Site characterization ST1	Risk analysis ST2	Project planning ST3	Monitoring ST4	Mitigation ST5	Inspection/assessmer ST6	Reporting ST7	Emergency response ST8	Decommissioning ST9	Report sections
POLICY, REGULATORY & LEGAL GAPS										
CO_2 source		x						x		2.3, 3.8.1
pore space resources										2.2, 4.1
general oil and gas regulations		x	x	x	x	x	x		x	2.3.2, 3.3.3
well P&A	x	x	x	x	x					3.2.3
pipelines		x	x	x	x	x	x	x		3.3.4, 3.6.1
platform modification			x	x	x	x	x	x	x	3.6.2
CO_2 venting on platforms		x	x	x				x		3.8.2
emergency response								x		3.8
platform decommissioning	x		x						x	3.9
general liability										3.10
pore space ownership										3.10
TECHNICAL GAPS										
water depth	x	x	x	x	x					3.1.1
sub-seafloor data (geographic)	x	x		x						3.1.1
density of existing wells	x	x	x	x	x			x		3.3.4, 3.4.1, 3.1.1
scale of capacity estimation	x	x		x						3.1.2
sub-seabed data (stratigraphic)	x	x	x	x	x					3.1.3
storage site monitoring & mitigation		x	x	x	x					3.4.1, 3.4.3, 3.5.2
sub-seabed migration/leakage	x	x		x	x					3.2.3, 3.4
iterative well/site permitting	x	x		x	x	x				3.3, 3.4
CO_2 transport		x	x	x	x					3.3.2, 3.3.4, 3.8.1
production fluid handlng		x	x	x	x					3.3.4

5.1 US Policy, Regulatory, and Legal Gaps

A major gap in US policy regarding CO_2 storage, either onshore or offshore, is the lack of financial incentive to decrease industrial emissions of CO_2 to the atmosphere. The formulation of the Mandatory Greenhouse Gas Reporting Rules (EPA 2010a, 2010b) was one outcome of the 2006 US Supreme Court decision that required the EPA to regulate CO_2 emissions as an atmospheric pollutant. However, these rules are still facing legal challenges from industry and do not incentivize CO_2 capture. The American Clean Energy and Security Act passed in the US House in 2009, but not in the Senate. Resulting laws would have led the way for a cap-and-trade system for CO_2 emissions. If policy to limit US industrial CO_2 emissions is in place in the future, private industry located in areas where onshore CO_2 GS is not suitable may look to offshore sub-seabed storage. One example of such industry action was the PurGen One project in which CO_2 generated in New Jersey was to be stored ~1 mile below the seafloor on the North Atlantic OCS.

5.1.1 Policy/Regulatory Gaps

EPA has established regulations for onshore GS of CO_2. The next logical step in policy and regulatory preparedness for limits on industrial CO_2 emissions is development of offshore regulations that specifically address CO_2 transportation and sub-seabed storage. DOI has authority under OCSLA to authorize and regulate O&G primary, secondary, and tertiary recovery and certain sub-seabed CO_2 GS on the OCS when the source of CO_2 is “other than oil and gas” (e.g., coal-fired power plants) and could develop regulations that fully address all aspects of CO_2 EOR-GS and GS projects on the OCS.

The largest gap in existing BSEE and BOEM O&G regulations is the lack of monitoring requirements; these will be needed to demonstrate containment of CO_2 injected for EOR-GS and GS operations. If industrial CO_2 generators want to claim emissions reduction credits in the future, monitoring results will be needed.

Other specific topics for which existing BOEM and BSEE regulations may need to be adapted for sub-seabed CO_2 GS include:

- <u>Platforms.</u> Modification to accommodate CO_2 handling equipment, especially fluid separation facilities (see Section 3.6.2) and platform decommissioning (see Sections 3.3, 3.9).
- <u>P&A of legacy wells.</u> Current regulations and practices only address plugging of discrete depth intervals of old wells, because the objective is to keep fluids from migrating between different layers (van der Kuip et al. 2011). Based on surveys of international regulations and literature reviews of laboratory experimental results, proper placement and mechanical integrity of cement plugs are more critical to safe storage of CO_2 than chemical degradation of plugging cement (van der Kuip et al. 2011). Consideration of the potential for fluid migration to the seafloor will need to become more of a priority (see Section 3.2). Current BSEE and BOEM regulations for P&A of legacy wells will need to be adapted to address their potential as conduits for CO_2 migration.

- Pipeline inspection (see Sections 3.6.1, 3.8.1) and purity of CO_2 streams transported via pipelines. In order to provide uniformity within the CO_2 pipeline industry, and as the technical benchmarks become clearly established and/or more substantiated for onshore to offshore pipelines, ASME B31.4 Chapter X, Carbon Dioxide Pipeline Systems should be expanded to include:
  - More information on recommended fluid composition ranges
  - An algorithm, matrix, or combination thereof to further establish a wall thickness/toughness criteria for prevention of ductile fracture propagation
  - Guidance on acceptable water concentration limits in support of reducing the potential for internal corrosion of the pipe
  - Specification of a pipeline dryness level to satisfy industry-wide pre-commissioning startup prerequisites and ongoing pipeline operations
    - The alternative to expanding ASME B31.4 might be the development of a new API recommended practice document.
- Iterative well and site permitting. Jenkins et al. (2015) and other major published literature recognize the need for CO_2 storage site characterization, planning, operations, and monitoring to be iterative. However, this is not reflected in existing onshore (i.e., EPA Class VI) regulations. In Class VI regulations, a permit specifying monitoring details is issued before each CO_2 injection well is drilled. Valuable data could be gained from small volume CO_2 injections—after an initial well is completed—and these data could be used to refine the monitoring approach. Another related issue is whether new CO_2 injection wells will be routinely drilled in offshore settings or if old wells will be allowed to be repurposed. There may be an even greater need for an iterative approach to permitting if existing offshore oil or gas wells will be repurposed for CO_2 injection.

- General inspection and auditing regulations are present in BSEE 30 CRFR Part 250. The existing regulations are specific to O&G operations, but could be adapted to CO_2 transport and injection from a platform. However, there is no mention in the current BSEE or BOEM regulations of inspection, auditing, or reporting for monitoring of CO_2 in the deep sub-seabed, near seafloor, or water column. This significant gap will need to be addressed during formulation of future CO_2 EOR-GS and GS regulations on the OCS.

- CO_2 emissions from offshore platforms. It is not clear if this will be under jurisdiction of BOEM or EPA.

- Emergency response. 30 CFR 250.1918 will need to be adapted to account for properties of CO_2 gas or CO_2 mixed streams (Section 3.8). A health and safety consideration is the potential for CO_2 to interfere with helicopter engines that would be needed for emergency evacuations.

5.1.2 Legal Gaps

Work by de Figueiredo (2007a) and de Figueiredo et al. (2012) address many legal, regulatory, and organization issues with CCS. They state that gaps in most of these issues can be filled by consulting historical regulatory solutions that have been applied in other cases. An example could be to apply or adapt current regulations for offshore natural gas pipelines to offshore CO_2 transport. Three broad topics considered to be legal gaps in CO_2 storage issues are: (1) safety and environmental liability during injection, (2) long-term liability (i.e., post-injection liability), and (3) pore space utilization.

- Safety and environmental liability. Pfaff and Sanchirico (1999) discuss industry liability with respect to environmental auditing (i.e., monitoring). In 1986, EPA reduced fines on industry for discovery of violations through self-auditing. In Pfaff's opinion, this reduction should only apply after industry has corrected the cause of the violation. Industry is sometimes wary of sharing self-auditing results, because it may result in fines for violations that regulators may not have otherwise discovered (Pfaff and Sanchirico 1999). Questions are: (1) does higher awareness of violation aid improvement of regulations? and (2) do overly prescriptive regulations skew liability toward the regulator? The assumption for the latter being that only things being regulated are considered safety concerns. A thought is that regulations can be improved through results of industry-lead inspection, hopefully because industry has enough economic incentive and concern for public welfare to be exhaustive in their quest of potential safety and environmental hazards (Kallaur 1998).

- Long-term liability. Based on a literature review, this appears to be a common industry-governmental dilemma and is not isolated to CO_2 EOR-GS and GS. In EPA (2008), the International Risk Governance Council (IRGC) emphasized the importance of avoiding damage to industry credibility through public assumption of long-term liability. IRGC also stated that even though public assumption of long-term liability is probably inevitable, it should only happen after industry has clearly demonstrated environmental responsibility. An analogous example for CO_2 storage would be that operations-phase monitoring data would show risk from post-site closure to be minimal. BMPs to assure that risk of CO_2 leakage is minimized after a storage site has been closed are discussed in Sections 3.4 and 3.9.4. The best solution to long-term liability protection, without having to use public funds, may be to set up a post-closure stewardship fund (e.g., Jacobs et al., 2009, Wilson et al., 2009; IEA/OECD, 2014). Lessons could be learned from the US Superfund experiences.

- Pore space utilization. The regulatory working group of the Alberta RFA considers pore space to be a resource that needs to be inventoried and managed (Alberta Energy 2012b). The Australian CO2CRC (2008) also considers capacity for CO_2 storage (i.e., available pore space), to be a resource. The US President's CCS Task Force presented five options for aggregation of pore space under a section on property rights (DOE/EPA 2010, Appendix L).

5.2 Technical Gaps

According to Aldous et al. (2013), currently there are no major technology gaps in CCS science and engineering, and the major remaining tasks are to establish efficient operations, monitoring, and regulations. However, during this study we have identified some gaps or questions in current best practices documents, institutional reports, and published literature that could impact formulation of offshore regulations for sub-seabed CO_2 storage. Many of the informational, data, and knowledge gaps are pertinent to more than one of the subtopics covered in Section 3 of this report. For example, knowledge of geologic strata, fluid pressure and composition, and potential migration pathways in or through the overburden is important to site selection, risk assessment, and monitoring. To avoid redundancy, we discuss the technical gaps by category of information presented under Technical Gaps in Table 5-1.

5.2.1 Space-Use Conflicts

An aspect of site selection for CO_2 storage on the OCS that is not covered in Section 3.1 is potential space-use conflicts. Initial CO_2 GS projects may be more likely locate closer to the coast in the shallow water depths (i.e., < 200 m) of continental shelves. Although there may be logistical and financial benefits to locating closer to land, there may be greater potential for complex space-use conflicts than in deeper water depths farther from the coast. For example, presence of a wind farm, port, or harbor in close proximity may restrict site access. Another potential issue, identified at the Tomakomai site offshore Japan, was interference with seafloor operations and/or infrastructure from fishing or other maritime activities such as netting or anchors being towed or dragged along the seafloor (Tanaka et al. 2014).

5.2.2 Density of Existing Wells and Geographic Distribution of Sub-Seafloor Data

Sparse borehole-based information is available for the Atlantic OCS, especially for deeper geologic reservoirs that will be more suitable for sub-seabed CO_2 storage. This represents a gap in knowledge of potential offshore CO_2 GS sites; however, existing O&G exploration methodologies needed to fill this information gap are well established (see Section 3.1.1 for more information).

5.2.3 Scale of Capacity Estimation

There are gaps and disagreements in the best approach to CO_2 capacity estimation, especially when scaling down from basin to storage site scale. Geologic reservoir capacity for CO_2 injection at smaller scales is anticipated to always be lower than basin-scale estimates (see Section 3.1.2 for further discussion). This uncertainty is the same offshore as it is onshore.

5.2.4 Sub-seabed Stratigraphic Data

A difference between offshore O&G exploration and CO_2 GS site selection is the need to characterize the overburden. Most O&G fields in offshore settings are structurally or stratigraphically closed systems (e.g., salt structures) with multiple wellbores, at least in the western GOM. Because the aim is to extract resources rather than to retain injected fluid (CO_2), the character and lateral extent of the confining system (or in O&G terms, the type of trap) may not be known. The same is true for data from the overburden. Shallow sub-seafloor geophysical surveying could be the best way to fill in this knowledge gap for offshore storage sites.

5.2.5 Storage Site Monitoring and Mitigation

As with CCS BMPs and Standards for onshore (e.g., DOE NETL 2012b, CSA Group 2012), the largest gap in knowledge is how to effectively monitor CO_2 migration in the subsurface. Rather than tracking exactly where injected CO_2 has migrated, it could be more important to know where it has not reached (i.e., relatively shallow overburden sands above the confining zone). There needs to be a clear link between identified significant risks and quantifiable monitoring results.

Some aspects of the offshore environment that may require consideration when developing monitoring requirements include anthropogenic or environmental factors that may interfere with monitoring approaches and technologies. For example, the presence of a wind farm, port, or harbor in close proximity to a storage site may interfere with monitoring activities by creating "noise." Detection of bubble trains from a sub-seabed release of CO_2 would be difficult to detect in turbid or muddy water. Also, CO_2 bubbles rapidly dissipate as the released CO_2 dissolves in seawater, which will make tracking the migration of accidental releases of CO_2 and implementing effective mitigation difficult, if not impossible. Furthermore, algal blooms and anoxic zones associated with coastal runoff, like near the Mississippi River, could interfere with water column monitoring.

The need for subsurface mitigation for unexpected loss of containment of injected CO_2 in an offshore setting should be tied to risk. As the major impact of CO_2 loss is negation of the sum storage benefit without other major hazard, limited efforts to develop mitigation options may be sufficient. Modifications of operations such as limiting or ceasing injection operations or implementation of pressure barriers by injecting brine should be considered.

5.2.6 Sub-seabed Migration/Leakage

The biggest question with regard to monitoring and mitigation is how to define leakage that constitutes concern requiring a response (see Section 3.2 for further discussion). Knowing the answer will allow unambiguous monitoring objectives and clarify when mitigation will be needed. Monitoring at deeper horizons is preferred unless leakage into shallower intervals is detected, in which case contingency monitoring of shallower intervals may be needed.

5.2.7 Iterative Well and Site Permitting

Jenkins et al. (2015) and other major published literature recognize the need for CO_2 storage site characterization, planning, operations, and monitoring to be iterative. However, this is not reflected in existing onshore (i.e., EPA Class VI) regulations. In Class VI regulations, a permit specifying monitoring details is issued before each CO_2 injection well is drilled. Valuable data could be gained from small volume CO_2 injections—after an initial well is completed—and these data could be used to refine the monitoring approach. Another related issue is whether new CO_2 injection wells will be routinely drilled in offshore settings or if old wells will be allowed to be repurposed.

5.2.8 CO_2 Transport

There is some question as to whether CO_2 will be transported in the offshore by pipeline or ship. In the US, onshore pipelines have economically and safely transported large volumes of CO_2 up to 500 mi to onshore oil fields for EOR for over four decades (e.g., Cortez pipeline that feeds the Permian Basin). The purity of the naturally occurring and CO_2 transported through these pipelines is generally in the range of 95 to 99 percent, with trace volumes of nitrogen, helium, H_2S, water, and other hydrocarbons/impurities. Pumping and maintaining the CO_2 in supercritical phase is desired for economic reasons, and for higher efficiency and reliability. As demonstrated outside the US in recent years, pipeline transportation of CO_2 offshore is technically achievable. An informal comment, made by an operator in the Barents Sea, is that one of the problems with the extensive pipeline network used for the Snøhvit project was inflow of ocean water into the pipeline during construction.

As the US progresses toward offshore CO_2 pipelines sourced by multiple onshore industrial facilities, fluid compositions may no longer be as pure as naturally sourced CO_2. Thus, any resulting gaps in design, operations, and maintenance activities of these CO_2 pipelines will need to be reviewed and addressed. Some of the gaps identified pertain to:

- Dense phase CO_2 release: validation of dispersion models and consideration of cooler temperatures in offshore settings, especially since impurities can be less soluble at lower temperature
- Fracture arrest: theoretical model confirmation and recommended wall thickness/toughness
- Materials: elastomers and material compatibility for new or higher concentrations of impurities
- Corrosion: predictable corrosion rates and impact of various impurities on carbon steel
- Flow assurance: pipeline sizing, hydrate formation, compression/pumping arrangement; it might be necessary to have booster pumps installed in very long pipelines
- Fluid specification: identification of the allowable levels of impurities and water content

There is a large knowledge gap in emergency planning and response to a CO_2 pipeline leak in the offshore.

5.2.9 Production Fluid Handling

An unresolved issue for sub-seabed CO_2 EOR-GS is how production fluid streams will be handled. When CO_2 is injected for EOR, some volume (dependent on reservoir conditions and operations approach) is co-produced with oil, natural gas, and brine. Onshore fluid separation facilities require significant up-front investment. CO_2 will need to be recycled, allowing it to be separated from other fluids and re-injected for additional oil recovery.

Two options for offshore fluid separation facilities would be to (1) build facilities on auxiliary offshore platform(s), e.g., Sleipner project; or (2) transport the combined fluid stream from the offshore production platform to an onshore facility, conduct fluid separation, and then feed the recycled CO_2 back into whatever offshore CO_2 transport system (i.e., pipeline or ship) is being used for the project(s). This second option was utilized for Statoil's Snøhvit project. An industry-based study on merits of these two fluid handling options was undertaken by the Malaysian company Petronas, but we are not aware of the results.

5.3 Adaptive Management

An Adaptive Management Plan (AMP) can have different objectives for different governmental units, and for different environmental applications (Murray and Marmorek 2004). According to DOI:

- "An adaptive approach involves exploring alternative ways to meet management objectives, predicting the outcomes of alternatives based on the current state of knowledge…"
- "The distinguishing features of adaptive management are its emphasis on sequential decision making in the face of uncertainty and the opportunity for improved management as learning about the system processes accumulates over time"
- The true measure of adaptive management "is in how well it helps meet environmental, social, and economic goals, increases scientific knowledge, and reduces tensions among stakeholders." (National Research Council 2004)

It does not appear that there is enough knowledge to establish BMPs for all aspects of offshore sub-seabed storage of CO_2 on the OCS. Consequently, governmental oversight or adaptive management will need to proceed from general to specific as the technology matures. Presented below is a philosophy for how the resource management could proceed.

Adaptive management is most often used to sustainably manage ecosystems in the face of uncertainty (e.g., Murray and Marmorek 2004). One method of reducing atmospheric concentrations of CO_2 is to capture it from industrial facilities and store it in deep geologic strata—in this case, sub-seabed strata. However, the transport and storage of CO_2 have the potential to impact multiple ecosystems if not properly managed. Ocean waters are already being impacted by increased concentrations of atmospheric CO_2 (Dixon et. al. 2009), so it is imperative that transport and storage be done without causing additional environmental impacts. The sub-seabed, or more specifically, fluids within pore spaces of sub-seabed geologic strata, comprise another ecosystem that needs to be managed and/or protected.

Industry groups have made the furthest advances toward establishing BMPs for offshore CO_2 sub-seabed transport and storage. But much of this information is not publically available; especially CO_2 injection operations details. The best available plan for managing CO_2 pipeline transport at this point is to follow our previously stated suggestions for revision to ASME B31.4 in Section 4.1. Our suggestions for managing future offshore sub-seabed storage of CO_2 are for US government to:

- Encourage offshore CO_2 EOR-GS and GS pilot-injection projects with collaboration between government, academia, and industry. This may need to be sponsored by multiple governmental entities.
- Recognize the need for iteration in site characterization and selection

- Recognize the need for iterative approaches to risk assessment and monitoring, and understand that these are integral to operations design
- Understand the importance of proactive monitoring throughout injection operations to obviate the need for environmental mitigation or long-term monitoring after site closure

6 Conclusions and Recommendations

Despite the current lack of strong US regulatory incentive to reduce industrial emissions of CO_2 to the atmosphere, US and global private industry are investing in monitoring programs to verify the permanence of CO_2 GS associated with EOR. This effort is, in part, to satisfy requirements of US DOE programs for CCS and CCUS projects. It will also allow industry to take advantage of future US CO_2 emissions reduction programs. These private industry investments provide assurance that long-term CO_2 storage goals are realistic.

CCS is an emerging technology composed of CO_2 capture, transport, and GS components. US academic researchers and industry have been receiving significant funding from the DOE to perform CCS research and pilot projects for nearly a decade (Lityneski et al. 2011). CCUS has been ongoing in the US since the early 1970s as CO_2 EOR, but has only recently been recognized as having GS potential, when the source of CO_2 is captured from industrial facilities, and not when it is produced from naturally occurring geologic formations. Onshore CCS is regulated primarily by EPA (CO_2 capture and GS) and DOT (CO_2 transport).

DOI will be a primary Federal agency involved in the regulation of future CO_2 EOR-GS and GS on the OCS. BOEM and BSEE already regulate offshore O&G activity on the OCS, and there is much overlap between current O&G operations and those needed for CCS, and especially for CCUS. To avoid unnecessary rulemaking, future regulations for offshore CO_2 EOR-GS and GS should build upon current BOEM and BSEE regulations. This approach is reflected in the global approach to CO_2 GS regulation, which has been for governments to begin by amending resource extraction regulations to expedite demonstration projects while simultaneously developing independent regulations for commercial-scale CO_2 GS (e.g., IEA/OECD 2010b, 2012). Australia, the EU, China, and the US (onshore only) have already established CO_2 GS regulations. Canada, Norway, and Japan are in the process of writing CO_2 GS regulations. The International Energy Agency/Organisation for Economic Co-operation and Development state that depleted O&G fields should not be treated differently from CO_2 saline storage areas when it comes to regulating CO_2 GS (IEA/OECD 2012).

Future BOEM and BSEE regulations for CO_2 EOR-GS and GS should generally be performance-based; that is, they should only be specific enough to define how quantitative project goals will be met, while leaving flexibility in definition of details needed to meet performance goals. Overly prescriptive requirements may fail to:

- Satisfy site-specific goals
- Incentivize operations updates in response to monitoring observations or predictive numerical modeling results
- Inhibit evolution of GS best practices as the technology evolves (i.e., hinder adaptive management)

This recommendation for performance-based standards is in agreement with previous CO_2 GS reviews (i.e., WRI 2008a, CSA Group 2012, EC 2009). It also agrees with general opinions that environmental regulations should be less prescriptive, with emphasis on performance (e.g., Kallaur 1998), and that they should balance protection of the environment with economic viability, as noted by Koenig-Archibugi (2011).

Modification of the existing BOEM and BSEE regulations should be considered to include aspects of CO_2 EOR that are not related to resource recovery, most importantly monitoring and many aspects of CO_2 GS. Future regulations of CO_2 EOR-GS and GS on the OCS should ensure that (1) injection/storage sites are carefully chosen and (2) sufficient monitoring is conducted to ensure that injected CO_2 remains confined to deep sub-seabed strata for long periods of time. Otherwise, CO_2 EOR-GS and GS regulations may need only a few special considerations compared to offshore O&G activity.

Our recommendations regarding specific issues to be addressed during formulation of new regulations for offshore sub-seabed storage of CO_2 are outlined below. The information has been previously discussed in Sections 3 through 5 of this report. Major categories of offshore CO_2 transport and sub-seabed storage issues to be addressed are presented below: (A) corrosion management, (B) characterization and qualification of storage sites, (C) injection operations planning, (D) risk management and monitoring, (E) quantification of storage, and (F) site closure planning.

A. Corrosion management

a. The range of CO_2 compositions to be accepted into the CCS system should be specified. CO_2 stream compositions can vary in purity depending on the source and handling. Water dissolved in CO_2 is of special concern, as it impacts corrosivity of CO_2. Water can drop out of solution if pressure or temperature is lowered. Many other impurities can impact the handling of CO_2 and the material properties of components within the pipeline and well system. O_2 and SO_2 as well as other minor contaminants can come from CO_2 capture facilities. H_2S can come from natural gas processing. Engineered solutions can be found for these impurities; however, the range of compositions to be accepted must be measured and reported by all contributors.
b. Sources of CO_2 stream contamination (e.g., moisture, particulates) should be managed, with management strategy and outcomes being reported annually.
c. Materials throughout the pipeline, compression, recycling (CCUS only), and well systems should be designed for stability in contact with the CO_2 stream in the marine environment. Corrosivity of metal in contact with the CO_2 stream, including presence of dissolved water and water that may have become saturated with CO_2 and dropped out of solution, must be considered. Elastomers and other seals must be engineered and tested against CO_2 corrosivity. No special cement is required for well casing construction for CO_2 service. Although types of CO_2-resistent cements are on the market, the quality of emplacement of these specialty cements has not been widely tested in offshore settings, so use of them may add to overall project risk. Oil production wells handling wet CO_2 will require a corrosion inhibition program (CCUS only).
d. Purging of pipelines to prepare them for CO_2 service after installation in marine settings should create conditions to meet design standards.

e. All components of pipelines and wells should be tested for integrity on a program that is responsive to corrosion risk of each component.
f. Management strategy and outcome for each element of corrosion management and surface fluid handling system integrity should be reported annually. A program to bring lessons learned in handling CO_2 in offshore settings should be implemented and incorporated into best practices.

B. Characterization and qualification of storage sites

a. Additional G&G specifications. The 3-D volume of rocks and fluids in the subsurface to be occupied by injected CO_2 (volume qualified for CO_2) and the 3-D volume over which pressure will be significantly elevated (volume qualified for elevated pressure) should be specified using contoured maps supplemented by cross sections. The volume qualified for CO_2 will include the geologic reservoir zone, but could also extend laterally some distance away from the storage site or into strata overlying the reservoir.
b. Sufficient details about the volume qualified for CO_2 and the volume qualified for increased pressure should be provided to justify the expectation that injected CO_2 and displaced brine will be contained during the injection period and after the end of injection. The details should include the US EPA UIC program parameters (e.g., depth and thickness of volumes of strata, locations and characteristics of boundaries of each volume, locations and FF properties of permeable zones that will accept CO_2, locations and properties of zones that will limit migration of CO_2 [terms used include seals, caprock, and confining system], and characteristics of minerals and fluids in the volumes, especially with regard to reactions with CO_2). Features that may pose a risk to the quality of storage shall also be specified (e.g., the lateral and vertical transmissivity of fracture systems or faults, properties of the volumes that impact mechanical stability, including natural and induced seismic risks). The information provided should be in a format needed for input into static GF and dynamic FF numerical models. The characteristics of the site that provide secure storage of CO_2 shall be described and quantified in detail. Uncertainties in site characterization shall be quantitatively stated such that they can be assessed in risk models. The qualification of volumes can be associated with stages of a project such as stages of CO_2 plume growth or a post-injection stabilization period.
c. Properties of the overburden and seafloor activities should be defined in sufficient detail such that (1) any potential risks of negative consequences from the CO_2 injection can be assessed and (2) an effective monitoring program can be designed. Properties to be assessed include stratigraphy, rock and fluid properties of the overburden, characteristics of the shallow sub-seafloor in terms of mechanical stability, and potential/need for monitoring the water column. The assessments should consider uses for mineral extraction, fisheries, wind farms, shipping, pipelines, and dredging, which might conflict with CO_2 storage operations. Any other resources of value (e.g., archeological or biological preserves) should be mapped and descried in sufficient detail such that risk can be assessed.

d. Well characterization: All wells that penetrate the volume qualified for CO_2 and volume qualified for increased pressure should be inventoried and characterized. Required data include seabed and downhole location surveys or deviation logs, well construction and completion information, and available data on quality of well performance and isolation (i.e., results of mechanical integrity tests and cement bond logs, and casing pressure measurements).
e. Well qualification: All wells that penetrate the volume qualified for CO_2 and volume qualified for increased pressure should be assessed for quality of stratigraphic isolation and found fit, unfit, or uncertain. A program to evaluate the uncertain wells should be implemented; follow-up action could include further evaluation of target wells prior to beginning of CO_2 injection, or properly designed monitoring during injection to assess adequacy of well integrity.

C. Transport and injection operations planning

a. Pipeline transport of CO_2 should be permitted and operated according to other offshore pipeline requirements but should include refinements made to account for CO_2 properties that may be found in ASME B31.4 Chapter X, a new API standard practice, or onshore DOT regulations, etc.
b. Maximum injection pressure should be permitted in the same way that injection for O&G activities is permitted by BOEM, but it should be constrained by the mechanical strength of the reservoir and confining system strata, and the design strength of the well components. The maximum column height of CO_2 that will eventually accumulate over the volume qualified for CO_2 should be modeled and constrained to be less than that which would cause large-scale leakage of CO_2 through the confining system.
c. Prospective locations for all injection and production (CCUS only) wells and the planned injection and extraction (CCS only) rates should be provided for the life of project. Changes during CO_2 injection operations may be needed. The operations plan should encompass a range of options such that the overall project does not need redesign and re-permitting. Type of fluids to be handled during operations should be specified. Maximum (and minimum, if relevant) pressure at surface and bottom hole locations should be specified. The method and associated uncertainties for calculating bottom hole pressure should be specified. Well completion and construction details should be provided for all new wells.
d. Fluid handing is a critical component of CO_2 operations. Fluid handling regulations for CO_2 operations, especially for CCUS, are not currently addressed in BOEM or BSEE regulations. Fluids produced during EOR-GS will be the same as with CO_2 EOR operations. Caution is advised in handling high pressure CO_2 (e.g., freeze risk from Joule-Thomson cooling during pressure drop).
e. The full system (inclusive of reservoir zone and overburden) response to CO_2 injection should be modeled. This should include the evolution of the area occupied by CO_2, including the expected plume thickness and saturation, and the evolution of pressure elevation at the zone of maximum pressure. Uncertainties should be

included in predictive FF models, leading to multiple realizations. Special attention should be paid to outlier model outcomes that might not be acceptable under previously defined risk scenarios. The project shall specify the conditions that would be considered unacceptable in terms of CO_2 leakage.

D. Risk management and monitoring

a. Risk assessment should be conducted using all available data to (1) assess certainty of isolation of CO_2, (2) define leakage, (3) predict system response to elevated pressures including leakage risk, geomechanical risk, and seismicity risk, and (4) prevent risk to environmental and other resources. Updated risk assessment during operations may justify reduced monitoring, especially as containment certainty is increased and as site closure nears.
b. Design and operate a risk management strategy. This may include: (1) additional characterization to reduce uncertainties identified during injection testing and early stages of operations, and (2) additional fit-for-purpose monitoring to detect unacceptable system responses identified in the risk assessment during or after injection. Monitoring plan design shall specify via predictive numerical modeling how the monitoring approach will be able to detect and attribute signals before or during unacceptable events (e.g., CO_2 leakage, seismic event). The sensitivity of the system to unacceptable events shall be assessed and reported. A response protocol, including anticipated signal detection, associated mitigation, and quantification of CO_2 losses and potential environmental impacts, should be designed and implemented. This protocol should include a plan for cessation of operations for a failing project.
c. Report outcomes annually, to include the following tasks: (1) compare characterization data and modeled responses of the system to confirm the correctness of the prediction that the system is accepting and retaining CO_2 at the planned injection rate, (2) report outcomes of monitoring in terms of risk reduction, 3) report discrepancies and provide an attribution of conditions to a cause, 4) evaluate the significance of discrepancies in terms of established definition of leakage.

E. Quantification of storage. For some CO_2 EOR-GS and all GS projects, a statement of the effectiveness of the pipeline-well-sub-seabed storage system should be provided annually during the project period to the appropriate national accounting system. The equivalent onshore system is the EPA CAA CO_2 accounting system under the relevant subparts of the GHGRP (UU and RR) (EPA 2010b). Requirements for quantification of onshore storage include reporting (1) losses from diffuse sources and local release in pipeline, well, and CO_2 handling equipment (subpart UU), (2) losses from geosystem storage (report under CAA Subpart RR). Loss from geosystem storage includes all migration out of volume qualified for CO_2. Not all migrated CO_2 will reach the atmosphere, however the long-term fate any CO_2 out of the qualified volume will remain unknown and therefore may not be credited as stored.

F. Site closure planning. If the approach presented here is followed, the injectate-CO_2 in the volume qualified for CO_2 storage should have been shown to be isolated from the seabed or atmosphere. Any follow-up monitoring needed should have been conducted during injection operations.

In 2010, the EPA developed regulations for onshore CO_2 GS monitoring under the SDWA UIC program (i.e., Class VI CO_2 injection well rules [EPA 2010c]). The UIC program should be consulted during formulation of BOEM and BSEE offshore regulations. However, there are two reasons why the Class VI rules should not be used as a template for CO_2 EOR-GS and GS regulations on the OCS:

(1) The risk profile is different for onshore versus offshore settings. In onshore settings the primary objective of monitoring is to demonstrate that underground sources of drinking water are being protected. This objective is not as critical in US offshore settings, because freshwater aquifers, which sometimes extend beyond continental shorelines (e.g., Pettijohn et al. 1988), rarely extend seaward of State waters. In addition, concerns about impact on human populations and onshore ecosystems are less relevant in offshore settings. Potential environmental impacts specific to the offshore site are needed. However, studies showing potential impacts to marine organisms have widely differing results (e.g., Basallote et al. 2014, Blackford et al. 2014, IEAGHG 2015).

(2) Differences in costs and opportunities. It is more costly both to install and to access wells offshore than those onshore, resulting in a different cost/benefit ratio for each scenario. In offshore settings, the cost of drilling and platform construction design results in the probability that fewer wells would be constructed, which could limit well-based monitoring options. In contrast, in an offshore setting, geophysical methods can yield higher quality data than similar methods deployed onshore.

7 References

In addition to the references listed at the end of this report, we have compiled an extensive literature database in EndNote™ (v. X7) software by Thompson Reuters. The EndNote file is available on the US Department of the Interior, Bureau of Ocean Energy Management Data and Information Systems webpage (http://www.boem.gov/Environmental-Studies-EnvData/). Click on the link for the Environmental Studies Program Information System (ESPIS), and search on 20xx-xxx.

Note: The numbering for years matches the literature database for easier cross referencing.

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Appendix A: Literature Report

This appendix lists and summarizes documents found while searching for literature that is relevant to this study. These documents are also included in an EndNote™ (v. X7) library. The EndNote file is available on the US Department of the Interior, Bureau of Ocean Energy Management Data and Information Systems webpage (http://www.boem.gov/Environmental-Studies-EnvData/). Click on the link for the Environmental Studies Program Information System (ESPIS), and search on 2018-004.

Adelman, D. E. and I. J. Duncan (2013). "The limits of liability in promoting safe geologic sequestration of CO_2-Excerpt." The Environmental Law Reporter 43(8): 10646.

The article focuses on the limitation of liability in promoting safe sequestration of CO_2. It presents an overview of carbon capture and storage (CCS) and the evaluation of government policy and common law liability on carbon sequestration. Moreover, it proposes a hybrid legal framework which consists of a traditional regulatory regime that balances the principles of economic efficiency and political viability.

Agerup, M. K. G. (2014). "Norway: Legal and regulatory CCS framework."

This article is a presention that covers CCS operations in Norway, presented by the Assistant Director General of the Norwegian Ministry of Petroleum.

Aines, R. D., M. J. Leach, T. H. Weisgraber, M. D. Simpson, S. Julio Friedmann and C. J. Bruton (2009). "Quantifying the potential exposure hazard due to energetic releases of CO_2 from a failed sequestration well." Energy Procedia 1(1): 2421-2429.

Wells are designed to bring fluids from depth to the earth's surface quickly. As such they are the most likely pathway for CO_2 to return to the surface in large quantities and present a hazard without adequate management. We surveyed oil industry experience of CO_2 well failures, and separately, calculated the maximal CO_2 flow rate from a 5000 ft depth supercritical CO_2 reservoir. The calculated maximum of 20,000 tonne/day was set by the sound speed and the seven-inch well casing diameter, and was greater than any observed event. We used this flux to simulate atmospheric releases and the associated hazard utilizing the National Atmospheric Release Advisory Center (NARAC) tools and real meteorology at a representative location in the High Plains of the United States. Three cases representing a maximum hazard day (quiet winds <1 m s−1 near the wellhead) and medium and minimal hazard days (average winds 3 m s−1 and 7 m s−1) were assessed. As expected for such large releases, there is a near-well hazard when there is little or no wind. In all three cases the hazardous Temporary Emergency Exposure Levels (TEEL) 2 or 3 only occurred within the first few hundreds of meters. Because the preliminary 3-D model runs may not have been run at high enough resolution to accurately simulate very small distances, we also used a simple Gaussian plume model to provide an upper bound on the distance at which hazardous conditions might exist. This extremely conservative model, which ignores inhomogeneity in the mean wind and turbulence fields, also predicts possible hazardous concentrations up to several hundred meters downwind from a maximal release.

Alberta Energy (2012a). CCS Regulatory framework assesment. Summary Report of the Regulatory Framework Assessment. Edmonton, Alberta, Canada.

Alberta is committed to addressing climate change by reducing greenhouse gas emissions such as carbon dioxide (CO_2). Carbon capture and storage (CCS) will be a fundamental piece of the equation. Alberta's

Climate Change Strategy (2008) identifies CCS as a key mitigation technology, which will provide 70 percent of the province's targeted greenhouse gas emission reductions by 2050. Carbon capture and storage is a process that captures CO_2 from large industrial CO_2 emitters and injects it deep underground for permanent storage. Carbon capture and storage is the internationally recognized terminology for this process. However, this report refers to CO_2 sequestration to differentiate this process from other temporary underground storage activities. CCS is a key technology to advance the responsible and sustainable development of Alberta's energy resources while addressing greenhouse gas emissions from large CO_2 sources.

The oil and gas industry, and electricity production are important contributors to the economy and quality of life in Alberta. However, these industries emit about 60 percent of Alberta's total CO_2 emissions. CCS is one of the few ways to substantially reduce CO_2 emissions from these industries while ensuring that the economic benefits they create for Albertans continue. The Government of Alberta is taking action to deploy CCS and has committed over $1.3 billion to two commercial-scale CCS projects in the province. These projects will reduce Alberta's greenhouse gas emissions by approximately 2.76 megatonnes (Mt, or million tonnes) per year by 2016. They will also provide momentum for reaching the province's long term greenhouse gas reduction targets. To address regulatory barriers to the deployment of CCS, several legislative changes have been made, including the clarification of pore space ownership and disposition, and a procedure to enable the transfer of long term liability for CO_2 sequestration sites from industry to the Government of Alberta. In order to make sure that the right regulations are in place before full-scale CCS projects start operating, the Government of Alberta initiated a process called the Regulatory Framework Assessment (RFA) in March 2011. This process looked at the regulations that currently apply to CCS in Alberta as well as regulations and best practices in other parts of the world. It examined in detail the technical, environmental, safety, monitoring and closure requirements that apply to a CCS project. To ensure that the regulatory review was complete and balanced, many Canadian and international experts from industry, universities, research organizations, environmental groups and provincial and national governments participated. This multi-stakeholder process was guided by a steering committee and included an international expert panel, and four specialized working groups that examined various CCS-related issues in detail. The RFA concluded in December 2012. The CCS RFA process resulted in 71 individual recommendations and 9 conclusions, which can be combined into 25 actionable items for the Government of Alberta to consider.

Alberta Energy (2012b). "CCS Regulatory framework assesment: Appendix D."

This appendix contains the issue-specific recommendations as they were provided by the steering committee and working groups. The versions included in the main body of this report have been modified to improve readability and to increase consistency in wording across recommendations and conclusions.

Aldous, R., C. Anderson, R. Anderson and M. Gerstenberger (2013). "CSLF Technology Assessment, CCS Technology Development Gaps, Opportunities, and Research Fronts." Cooperative Research Centre for Greenhouse Gas Technologies (CO_2CRC): 117.

At the September 2011 CSLF Ministerial Meeting in Beijing, a Task Force was formed to investigate CCS Technology Opportunities and Gaps. The Task Force mandate was to identify and monitor key CCS technology gaps and related issues, to determine the effectiveness of ongoing CCS RD&D for addressing these gaps, and to recommend any RD&D that would address CCS gaps and other issues. This document is the Final Report from the Task Force. This report sets out some of the key technical issues and research fronts in CCS technology and identifies opportunities and gaps relevant to policy makers and technology development strategists. The report iscomplemented by a global listing of pilot plant projects in both capture and storage.

al Hagrey, S. A. (2011). "CO_2 plume modeling in deep saline reservoirs by 2D ERT in boreholes." The Leading Edge 30(1): 24-33.

Electrical resistivity tomography (ERT) techniques in boreholes are powerful in monitoring intrinsic property changes for storing the resistive (supercritical) CO_2 in conductive saline reservoirs. In this study, the mapping capability of various ERT techniques is studied for diverse wedge-like CO_2 plumes in a deep saline aquifer capped by an impermeable rock. Extensive, systematic 2.5D modeling studies (>100,000 models) were calculated to test the ERT sensitivity to multitude of parameters related to the subsurface setting, CO_2 plume reservoir, survey design, data acquisition, and modeling techniques. The new array optimization approach is applied to generate optimized data sets (opt) of only 4% of the comprehensive set but of almost similar resolution. Forward simulations was carried out to generate diverse synthetic data sets (>8000) as a function of plume scenarios (different dimensions and CO_2 saturations SCO_2 or resistivity, _), burial depths, electrode configurations, random noises, and aspect ratios (AR). The data quality (<3% noises) is confirmed by results of tests on a homogeneous model with constant _. This numerical study principally reveals the capability of ERT techniques to resolve the various deep subsurface scenarios with the CO_2 sequestration targets (plume, host reservoir, and cap rock).

Al-Jabri, Y. and M. Urosevic (2010). "Assessing the repeatability of reflection seismic data in the presence of complex near-surface conditions CO_2CRC Otway Project, Victoria, Australia." Exploration Geophysics 41(1): 24-30.

This study utilises repeated numerical tests to understand the effects of variable near-surface conditions on time-lapse seismic surveys. The numerical tests were aimed at reproducing the significant scattering observed in field experiments conducted at the Naylor site in the Otway Basin for the purpose of CO(2) sequestration. In particular, the variation of elastic properties of both the top soil and the deeper rugose clay/limestone interface as a function of varying water saturation were investigated. Such tests simulate the measurements conducted in dry and wet seasons and to evaluate the contribution of these seasonal variations to seismic measurements in terms of non-repeatability. Full elastic pre-stack modelling experiments were carried out to quantify these effects and evaluate their individual contributions. The results show that the relatively simple scattering effects of the corrugated near-surface clay/limestone interface can have a profound effect on time-lapse surveys. The experiments also show that the changes in top soil saturation could potentially affect seismic signature even more than the corrugated deeper surface.

Overall agreement between numerically predicted and in situ measured normalised root-mean-square(NRMS) differences between repeated (time-lapse) 2D seismic surveys warrant further investigation. Future field studies will include in situ measurements of the elastic properties of the weathered zone through the use of 'micro Vertical Seismic Profiling (VSP)' arrays and very dense refraction surveys. The results of this work may impact on other areas not associated with CO(2) sequestration, such as imaging oil production over areas where producing fields suffer from a karstic topography, such as in the Middle East and Australia.

Alnes, H., O. Eiken and T. Stenvold (2008). "Monitoring gas production and CO(2) injection at the Sleipner field using time-lapse gravimetry." Geophysics 73(6): Wa155-Wa161.

Thirty seafloor gravity stations have been placed above the carbon dioxide (CO_2) injection site and producing gas reservoir at the Sleipner Ost Ty field. Gravity and depth measurements from 2002 and 2005 reveal vertical changes of the permanently deployed benchmarks, probably caused by seafloor erosion and biologic activity (fish). The original gravity data have been reprocessed, resulting in slightly different gravity-change values compared with earlier published results. Observed gravity changes are caused by height variances, gas production and water influx in the Ty Formation, and CO(2) injection in the Utsira Formation. Simultaneous matches to models for these effects have been made. The latest simulation model of the Ty Formation was fitted by permitting a scale factor, and the gravity contribution from the CO(2) plume was determined by using the plume geometry as observed in 4D seismic data and varying the average density. The best-fit vertical gravity gradient is 1.80 mu Gal/cm, and the response from the Ty Formation suggests more water influx than expected in the presurvey simulation model. The best-fit average density of CO(2) is 760 kg/m(3). Estimates of the reservoir temperature combined with the equation of state for CO(2) indicate an upper bound on CO(2) density of 770 kg/m(3). The gravity data suggest a lower bound of 640 kg/m(3) at 95% confidence.

Alnes, H., O. Eiken, S. Nooner, G. Sasagawa, T. Stenvold and M. Zumberge (2011). "Results from Sleipner gravity monitoring: updated density and temperature distribution of the CO_2 plume." 10th International Conference on Greenhouse Gas Control Technologies 4: 5504-5511.

To help monitor the evolution of stored CO_2, we have made precision seafloor gravity measurements at 30 seafloor stations above the Sleipner CO_2 plume in the years 2002, 2005 and 2009. Each epoch of gravity data has an intra-survey repeatability of about 3 mu Gal (standard deviation), obtained using state-of-the-art instrumentation on top of pre-deployed seafloor benchmarks, with typically three visits on each location during a survey. We used three relative quartz-spring Scintrex CG-5 gravimeters in a unique offshore instrument package. Ocean tidal fluctuations and benchmark depths were determined using both pressure gauges on the gravity survey tool and stationary reference pressure gauges on the seafloor.

We analyzed and accounted for multiple sources of changes in gravity to obtain an estimate of in situ CO_2 density. First, the injected CO_2, 5.88 million tonnes during this time period, displaces denser formation water, causing a negative gravity change above the plume. This is the signal of interest for this study. At the same time, hydrocarbon gas production and water influx into the deep, nearby gas reservoir cause an increase in gravity of higher amplitude and longer wavelength. Finally, by observing vertical depth changes of the seafloor benchmarks between surveys to mm precision, we quantified vertical benchmark movements caused by sediment scouring. Some of the benchmarks have experienced more than 10 cm vertical movement over the 7 year duration of the experiment, and erosional topography can be seen in a > 10 m broad area around some of the benchmarks. The shifting sediment can also cause a change in the observed vertical gravity gradient. We inverted the gravity changes for simultaneous contributions from: i) injected CO_2 in the Utsira Formation, ii) water flow into the Sleipner gas reservoir, and iii) vertical benchmark movements. We estimate the part of the change in gravity caused by CO_2 injection to be up to 12 mu Gal. If we assume a geometry of the plume as seen in 4D seismic data, the best match to the 30 stations requires an average CO_2 density of 720 +/- 80 kg/m(3), neglecting dissolution of CO_2 into the formation water.

While the CO_2 in the Utsira Fm. at Sleipner is supercritical, it is fairly close to the critical point; therefore only a slight increase in temperature could lower the density significantly. Density is also sensitive to impurities, which make up 1-2 % of the injected material at Sleipner and reduce the density slightly. In the absence of down hole gauges in the injection well, we estimate the well-bottom CO_2 temperature to be 48 degrees C and pressure to be hydrostatic (similar to 105 bar). These conditions give a calculated density of 485 +/- 10 kg/m(3) at the perforation. Density is expected to increase away from the well as CO_2 cools down from contact with the cooler formation, up to a maximum of about 710 kg/m(3). The distribution of temperature and density within the plume is difficult to model exactly, but most of the CO_2 is expected to cool down to initial reservoir temperature (similar to 35.5 degrees C at the perforation) except for a central high-temperature region where CO_2 is still near the injection temperature. Because the undisturbed formation temperatures and the injection temperature are fairly well known, the 2002-2009 gravity change can be used to constrain the rate of dissolution of CO_2 into the formation water. Dissolved CO_2 is invisible in seismic data. The contribution from gravimetric data could therefore be highly valuable for monitoring this process, which is important for long-term predictions of the CO_2 stored in the Utsira Fm. We give an upper bound on the dissolution rate of 1.8% per year. (C) 2011 Published by Elsevier Ltd.

Annunziatellis, A., S. E. Beaubien, G. Ciotoli, M. G. Finoia, S. Graziani and S. Lombardi (2009). "Development of an innovative marine monitoring system for CO_2 leaks: system design and testing." Energy Procedia 1(1): 2333-2340.

A critical component of long term geological sequestration of anthropogenic CO_2 will be our ability to adequately monitor a chosen site to ensure public and environmental safety. Near surface monitoring is particularly important, as it is possible to conduct sensitive and direct measurements at the boundary between the subsurface and the biosphere (i.e. surface water or atmosphere). While discontinuous surface monitoring is often performed, continuous monitoring is preferable if one hopes to observe a leak in its early stages to allow for rapid remedial action. The geochemical signal that may result from a near-surface CO_2 leak might take the form of increased soil gas concentrations (on land) or changing pH, Eh, and aqueous chemistry (in groundwater or surface water), and thus continuous monitoring stations capable of analyzing for these parameters have great potential for early leak detection. In the framework of the EC-funded CO_2GeoNet and CO_2ReMoVe projects innovative monitoring systems have been designed and constructed for autonomous deployment in marine environments above geological CO_2 storage sites. The system developed within CO_2GeoNet was tested at a site in the Gulf of Trieste where there is no gas release; this site was chosen due to easy access and the presence of an existing oceanographic buoy onto which the monitoring station was mounted. Tests on this early prototype highlighted the various difficulties of working in marine environments, and this experience formed the basis for a new system developed for deployment at the Panarea test site within CO_2ReMoVe. This second site is located off the coast of Panarea Island, to the north of Sicily, where naturally produced CO_2 leaks from the seabed into the water column. The advantage of this site is that the leaks occur in a relatively near-shore environment (< 300 m) and in water that is not too deep (< 25 m), thereby allowing for easy access by SCUBA divers for system testing and maintenance. This location allowed the unit to be connected via cable, rather than a buoy, which makes power supply and data transfer simpler. The system developed for this site consists of three monitoring points that are connected to a land-based control unit. Each point, located 100, 200, and 300 m from shore in different CO_2 flux regimes, is able to measure dissolved CO_2 and CH4, conductivity, pH, and temperature using low cost but sensitive sensors. The complete system consists of flexible solar panels, a central control unit and three monitoring points, and data download is conducted using a GPRS connection and a web server. Difficulties with the initial deployment in early April of 2008 has necessitated further development work, with the second deployment planned for early November. The following paper discussed the experience gained with these stations, and presents data analysis and anomaly recognition from a land-based monitoring station that has been collecting dissolved CO_2 data for over 18 months.

API (2009). Design, construction, operation, and maintenance of offshore hydrocarbon pipelines (Limit state design), American Petroleum Institute.

This recommended practice (RP) sets criteria for the design, construction, testing, operation, and maintenance of offshore steel pipelines utilized in the production, production support, or transportation of hydrocarbons; that is, the movement by pipeline of hydrocarbon liquids, gases, and mixtures of these hydrocarbons with water. This RP may also be utilized for water injection pipelines offshore.

Arra Site Characterization Projects: Characterization of Pliocene and Miocene Formations in the Wilmington Graben, Offshore Los Angeles, for Large Scale Geologic Storage of CO2- Geomechanics Technologies. [date unknown]. USDOE, NETL. [accessed 2017 Nov 14]. http://www.netl.doe.gov/research/coal/carbon-storage/carbon-storage-infrastructure/sitechar-wilmington

Arts, R., A. Chadwick, O. Eiken, S. Thibeau and S. Nooner (2008). "Ten years' experience of monitoring CO_2 injection in the Utsira Sand at Sleipner, offshore Norway." First break 26(1).

Underground storage of carbon dioxide (CO_2) as a measure to reduce the amount of greenhouse gases in the atmosphere, and thereby to slow down global warming, has been studied and discussed widely over the last two decades (IPCC, 2005). Although considerable experience had been gained on CO_2 injection for enhanced oil recovery before the start of the Sleipner storage project, very little was known about the effectiveness of underground storage of CO_2 over very long periods of time. A number of demonstration sites have been initiated in the past few years, mainly for research purposes to investigate the feasibility of CO_2 injection in different types of reservoirs and to study the chemical and flow behaviour of CO_2 in the subsurface. The first, longest running and largest demonstration of CO_2 injection in an aquifer up to now is at Sleipner, in the central North Sea (Figure 1). Since October 1996, Statoil and its Sleipner partners have injected CO_2 into a saline aquifer, the Utsira Sand, at a depth of 1012 m below sea level, some 200 m below the reservoir top. The CO_2 is separated on the platform from natural gas produced from the deeper lying Sleipner Gasfield and injected into the aquifer through a deviated well at a lateral distance of about 2.3 km from the platform (Figure 2). This article outlines the experiences gained at this site, especially with respect to monitoring of CO_2 migration in the subsurface.

Arts, R.J., Vanderweijer, V.P., Hostee, C. Pluymaekers, M.P.D., Love. D. Koppe, A., Plug., W.J., 2012, The feasibility of CO_2 storage in the depleted P18-4 gas field offshore the Netherlands (the ROAD project). Int. J. Greenhouse Gas Control.

Near the coast of Rotterdam CO_2 storage in the depleted P18-4 gas field is planned to start in 2015 as one of the six selected European demonstration projects under the European Energy Programme for Recovery (EEPR). This project is referred to as the ROAD project. ROAD (a Dutch acronym for Rotterdam Capture and Storage Demonstration project) is a joint project by E.ON Benelux and Electrabel Nederland/GDF SUEZ Group and is financially supported by the European Commission and the Dutch state. A post-combustion carbon capture unit will be retrofitted to EONs' Maasvlakte Power Plant 3 (MPP3), a new 1100 MWe coal-fired power plant in the port of Rotterdam. The capture unit has a capacity of 250 MWe equivalent and aims to capture 1.1 million tonnes of CO_2 per year. A 20 km long insulated pipeline will be constructed to the existing offshore platform operated by TAQA and an existing well will be worked over and re-used for injection. Natural gas production in the P18-4 field is projected to end just before the start of the CO_2 injection. In this first phase a total storage of around 5 Mt CO_2 is envisaged with an injection timeframe of 5 years. This paper gives a description of the field and of the studies carried out to investigate the suitability of the field for CO_2 storage.

ASME (2102). Pipeline Transportation of Carbon Dioxide Containing Impurities. A. S. o. M. Engineers.

Pipeline systems are expected to play an increasingly important role in transporting carbon dioxide (CO_2) captured from flue stacks to distant fields for sequestration purposes or for Enhanced Oil Recovery (EOR). The phase diagram for a CO_2 stream is very sensitive to the level of impurities, and this in turn affects pipeline design and the boundaries within which CO_2 pipelines can be operated, without affecting the facilities design as well as delivery conditions. This book brings together the entire spectrum of design and operating needs for a pipeline and network of facilities that would transport CO_2 containing impurities safely, without adverse impact on people and the environment.

ASME (2016). Pipeline Transportation Systems for Liquids and Slurries. A. S. o. M. Engineers, ISBN: 9780791870242: 136.

ASME B31.4 prescribes requirements for the design, materials, construction, assembly, inspection, testing, operation, and maintenance of liquid pipeline systems between production fields or facilities, tank farms, above or below ground storage facilities, natural gas processing plants, refineries, pump stations, ammonia plants, terminals (marine, rail, and truck), and other delivery and receiving points, as well as pipelines transporting liquids within pump stations, tank farms, and terminals associated with liquid pipeline systems. This Code also prescribes requirements for the design, materials, construction, assembly, inspection, testing, operation, and maintenance of piping transporting aqueous slurries of nonhazardous materials such as coal, mineral ores, concentrates, and other solid materials, between a slurry processing plant or terminal and a receiving plant or terminal. Piping here consists of pipe, flanges, bolting, gaskets, valves, relief devices, fittings, and the pressure containing parts of other piping components. It also includes hangers and supports, and other equipment items necessary to prevent overstressing the pressure containing parts. It does not include support structures such as frames of buildings, stanchions, or foundations, or any equipment.

Also included within the scope of this Code are:

a) primary and associated auxiliary liquid petroleum and liquid anhydrous ammonia piping at pipeline terminals (marine, rail, and truck), tank farms, pump stations, pressure-reducing stations, and metering stations, including scraper traps, strainers, and prover loops

b) storage and working tanks, including pipe-type storage fabricated from pipe and fittings, and piping interconnecting these facilities

c) liquid petroleum and liquid anhydrous ammonia piping located on property that has been set aside for such piping within petroleum refinery, natural gasoline, gas processing, ammonia, and bulk plants

d) those aspects of operation and maintenance of liquid pipeline systems relating to the safety and protection of the general public, operating company personnel, environment, property, and the piping systems

Key changes to this revision include a revised scope and updates to the stress section in Chapter II. A new paragraph has been added in Chapter III for material requirements in low-temperature applications. In addition, changes have been included throughout to reference minimum wall thickness requirements as permitted by manufacturing specifications.

Careful application of these ASME B31 standards will help users to comply with applicable regulations within their jurisdictions, while achieving the operational, cost and safety benefits to be gained from the many industry best practices detailed within these volumes.

Intended for liquid pipeline designers, owners, regulators, inspectors, and manufacturers. Primary industries served include those for carbon dioxide, liquid alcohol, liquid anhydrous ammonia, and liquid petroleum products.

Azzolina, N. A., M. J. Small, D. V. Nakles and G. S. Bromhal (2013). "Effectiveness of subsurface pressure monitoring for brine leakage detection in an uncertain CO_2 sequestration system." Stochastic Environmental Research and Risk Assessment 28(4): 895-909.

This work evaluates the detection sensitivity of deep subsurface pressure monitoring within an uncertain carbon dioxide sequestration system by linking the output of an analytical reduced-order model and first-order uncertainty analysis. A baseline (non-leaky) modeling run was compared against 10 different leakage scenarios, where the cap rock permeability was increased by factors of 2–100 (cap rock permeability from 10−3 to 10−1 millidarcy). The uncertainty variance outputs were used to develop percentile estimates and detection sensitivity for pressure throughout the deep subsurface as a function of space (lateral distance from the injection wells and vertical orientation within the reservoir) and time (years since injection), or P(x, z, t). Conditional probabilities were computed for combinations of x, z, and t, which were then used to generate power curves for detecting leakage scenarios. The results suggest that measurements of the absolute change in pressure within the target injection aquifer would not be able to distinguish small leakage rates (i.e., less than 50 × baseline) from baseline conditions, and that only large leakage rates (i.e., >100 × baseline) would be discriminated with sufficient statistical power (>99 %). Combining measurements, for example by taking the ratio of formation pressure in Aquifer 2/Aquifer 1, provides better statistical power for distinguishing smaller leakage rates at earlier times in the injection program. Detection sensitivity for pressure is a function of space and time. Therefore, design of an adequate monitoring network for subsurface pressure should account for this space–time variability to ensure that the monitoring system performs to the necessary design criteria, e.g., specific false-negative and false-positive rates.

Bachu, S., D. Bonijoly, J. Bradshaw, R. Burruss, S. Holloway, N. P. Christensen and O. M. Mathiassen (2007). "CO_2 storage capacity estimation: Methodology and gaps." International Journal of Greenhouse Gas Control 1(4): 430-443.

Implementation Of CO_2 capture and geological storage (CCGS) technology at the scale needed to achieve a significant and meaningful reduction in CO_2 emissions requires knowledge of the available CO_2 storage capacity. CO_2 storage capacity assessments may be conducted at various scales in decreasing order of size and increasing order of resolution: country, basin, regional, local and site specific. Estimation of the CO_2 storage capacity in depleted oil and gas reservoirs is straightforward and is based on recoverable reserves, reservoir properties and in situ CO_2 characteristics. In the case Of CO_2-EOR, the CO_2 storage capacity can be roughly evaluated on the basis of worldwide field experience or more accurately through numerical simulations. Determination of the theoretical CO_2 storage capacity in coal beds is based on coal thickness and CO_2 adsorption isotherms, and recovery and completion factors. Evaluation of the CO_2 storage capacity in deep saline aquifers is very complex because four trapping mechanisms that act at different rates are involved and, at times, all mechanisms may be operating simultaneously. The level of detail and resolution required in the data make reliable and accurate estimation of CO_2 storage capacity in deep saline aquifers practical only at the local and site-specific scales. This paper follows a previous one on issues and development of standards for CO_2 storage capacity estimation, and provides a clear set of definitions and methodologies for the assessment Of CO_2 storage capacity in geological media. Notwithstanding the defined methodologies suggested for estimating CO_2 storage capacity, major challenges lie ahead because of lack of data, particularly for coal beds and deep saline aquifers, lack of knowledge about the coefficients that reduce storage capacity from theoretical to effective and to practical, and lack of knowledge about the interplay between various trapping mechanisms at work in deep saline aquifers.

Basallote, M. D., M. R. De Orte, T. Á. DelValls and I. Riba (2014). "Studying the Effect of CO_2-Induced Acidification on Sediment Toxicity Using Acute Amphipod Toxicity Test." Environmental Science & Technology 48(15): 8864-8872.

Carbon capture and storage is increasingly being considered one of the most efficient approaches to mitigate the increase of CO_2 in the atmosphere associated with anthropogenic emissions. However, the environmental effects of potential CO_2 leaks remain largely unknown. The amphipod Ampelisca brevicornis was exposed to environmental sediments collected in different areas of the Gulf of Cádiz and subjected to several pH treatments to study the effects of CO_2-induced acidification on sediment toxicity. After 10 days of exposure, the results obtained indicated that high lethal effects were associated with the lowest pH treatments, except for the Ría of Huelva sediment test. The mobility of metals from sediment to the overlying seawater was correlated to a pH decrease. The data obtained revealed that CO_2-related acidification would lead to lethal effects on amphipods as well as the mobility of metals, which could increase sediment toxicity.

Benson, S. M., M. Hoversten, E. Gasperikova, M. Haines, E. S. Rubin, D. W. Keith, C. F. Gilboy, M. Wilson, T. Morris, J. Gale and K. Thambimuthu (2005b). Monitoring protocols and life-cycle costs for geologic storage of carbon dioxide. Greenhouse Gas Control Technologies 7. Oxford, Elsevier Science Ltd: 1259-1264.

In this study two scenarios are used to evaluate the applicability of the monitoring techniques and the costs of deploying them over the life-cycle of a storage project. Key assumptions underlying the cost estimates such as reservoir size and depth are provided and major cost dependencies are described. For each scenario a package of suitable monitoring techniques is proposed with a commentary on how the components were selected. For each monitoring scenario a basic and enhanced monitoring program is evaluated. Estimated costs for monitoring geologic storage over the full life-cycle of a project at a range from $0.05 to $0.10 per tonne of CO_2 (discounted at 10%/year, undiscounted cost range from $0.16 to $0.31 per tonne). This paper summarizes one part of a study performed for the International Energy Agency Greenhouse Gas R&D Programme (IEA GHG) to provide an overview of monitoring techniques for geologic storage of CO_2.

Benson, S. (2006). "Monitoring Carbon Dioxide Sequestration in Deep Geological Formations for Inventory Verification and Carbon Credits." SPE 102833.

Large scale implementation of CO_2 Capture and Storage is under serious consideration by governments and industry around the world. The pressing need to find solutions to the CO_2 problem has spurred significant research and development in both CO_2 capture and storage technologies. Early technical success with the three existing CO_2 storage projects and over 30 years experience with CO_2-EOR have provided confidence that long term storage is possible in appropriately selected geological storage reservoirs. Monitoring is one of the key enabling technologies for CO_2 storage. It is expected to serve a number of purposes – from providing information about safety and environmental concerns, to inventory verification for national accounting of greenhouse gas emissions and carbon credit trading. This paper addresses a number of issues related specifically to monitoring for the purpose of inventory accounting and trading carbon credits. First, what information would be needed for the purpose of inventory verification and carbon trading credits? With what precision and detection levels should this information be provided? Second, what monitoring methods and approaches are available? Third, do the instruments and monitoring approaches available today have sufficient resolution and detection levels to meet these needs? Theoretical calculations and field measurements of CO_2 in both the subsurface and atmosphere are used to support the discussions presented here. Finally, outstanding issues and opportunities for improvement are identified.

Bielinski, A., A. Kopp, H. Schütt and H. Class (2008). "Monitoring of CO_2 plumes during storage in geological formations using temperature signals: Numerical investigation." International Journal of Greenhouse Gas Control 2(3): 319-328.

Carbon dioxide (CO 2) injection into a storage formation is accompanied by non-isothermal effects. These are caused by a CO_2 injection temperature that does not correspond to the formation temperature, cooling of the carbon dioxide due to expansion (Joule–Thomson cooling) and heat of dissolution of CO_2 in brine. During flow in the subsurface, the carbon dioxide transports energy (advective heat transport) and undergoes an equilibrating process between temperature differences (heat conduction). These non-isothermal processes can be used for the purpose of monitoring the CO_2 plume propagation in the subsurface. Temperature sensors at monitoring wells at a certain distance from the injection well can detect temperature changes and give information about the CO_2 flow in the storage site. In this study, a numerical multi-phase simulation program is used to investigate the non-isothermal effects during CO_2 injection into a storage formation. The feasibility of using temperature measurements for the observation of the carbon dioxide plume in the reservoir is addressed. Various thermal processes and their dependency on the geological characterisation of the reservoir are discussed in detail.

Black, R. (2012). "Seabed Test Mimics Carbon Dioxide Release." BBC News: Science & Environment, from http://www.bbc.co.uk/news/science-environment-18045733.

"Scientists are beginning a month-long experiment in Scottish waters to study the impact of a possible leak from an undersea carbon dioxide storage site."

Blackford, J., H. Stahl, J. M. Bull, B. J. P. Berges, M. Cevatoglu, A. Lichtschlag, D. Connelly, R. H. James, J. Kita, D. Long, M. Naylor, K. Shitashima, D. Smith, P. Taylor, I. Wright, M. Akhurst, B. Chen, T. M. Gernon, C. Hauton, M. Hayashi, H. Kaieda, T. G. Leighton, T. Sato, M. D. J. Sayer, M. Suzumura, K. Tait, M. E. Vardy, P. R. White and S. Widdicombe (2014). "Detection and impacts of leakage from sub-seafloor deep geological carbon dioxide storage." Nature Clim. Change 4(11): 1011-1016.

Blackford, J. and e. al. (2015). Review of Offshore Monitoring Projects for CCS. IEAGHG, IEAGHG: 153.

A range of monitoring techniques are available for CO_2 geological storage offshore, both deep- and shallow-focused.

Boait, F., N. White, A. Chadwick, D. Noy and M. Bickle (2011). "Layer spreading and dimming within the CO_2 plume at the sleipner field in the north sea." Energy Procedia 4(0): 3254-3261.

The CO_2 plume at Sleipner has been imaged on 3D seismic surveys as a series of bright sub-horizontal reflections. Nine discrete CO_2 rich layers are inferred to have accumulated between a series of intra-reservoir mudstones beneath a substantial reservoir topseal. Time-lapse changes in reflectivity and in the lateral extent of these layers provide useful information about CO_2 flow within the reservoir. The deepest CO_2 layers within the growing plume have acoustically dimmed, stopped growing, and some have shrunk. Shallower layers have continued to grow. A combination of numerical flow models and analytical solutions of layer spreading yields useful insights into plume development. The observed seismic dimming and shrinkage of the deeper layers are, at least in part, caused by a reduction in the amount of CO_2 trapped in the deeper plume. This is probably due to increases in the effective permeability of thin intra-reservoir mudstones. These changes reduce net flux of CO_2 into the deeper layers of the plume with a corresponding increase of CO_2 flux towards the top of the reservoir

BOEM (2013a). Development of Mitigation Measures to Address Potential Use Conflicts between Commercial Wind Energy Lessees/Grantees and Commercial Fishers on the Atlantic Outer Continental Shelf. Report on Best Management Practices and Mitigation Measures. B. U.S. DOI, Office of Renewable Energy Programs: 71.

BOEM. 2013b. Gas hydrate resource assessment Atlantic Outer Continental Shelf. US Department of the Interior, Bureau of Ocean Energy Management. BOEM Report RED 2013-01.

Bohnhoff, M. and M. D. Zoback (2010). "Oscillation of fluid-filled cracks triggered by degassing of CO_2 due to leakage along wellbores." Journal of Geophysical Research-Solid Earth 115: 13.

We present evidence for a seismic source associated with degassing CO_2 during leakage along two wellbores instrumented with arrays of downhole seismometers. More than 200 microseismic events were detected in direct vicinity of the monitoring wells. The observed seismic waves are dominantly P waves and tube waves, with no (or extremely weak S) shear waves. The waveforms of these events indicate extremely rapid amplitude decays with distance across the arrays, consistent with the seismometers being in the near field of the seismic source. The frequency characteristics, first-motion polarities and S to P amplitude ratios suggest a single force source mechanism. Because the seismic arrays were located at the depth where the density of ascending CO_2 changes most rapidly, it appears that the transition of CO_2 from supercritical fluid to gas triggers an oscillation of fluid-filled cavities and fractures very close to the wellbores in which the monitoring arrays were deployed. In many aspects, the observed waveforms show a striking similarity to those modeled for degassing processes below volcanoes. We suggest that the single force represents bubble growth and resulting oscillations in cement cavities between the steel casing of the well and the rock adjacent to the wellbores and/or within fractures in the rock just outside the wellbores.

Bohnhoff, M., M. D. Zoback, L. Chiaramonte, J. L. Gerst and N. Gupta (2010). "Seismic detection of CO_2 leakage along monitoring wellbores." International Journal of Greenhouse Gas Control 4(4): 687-697.

A pilot carbon dioxide (CO_2) sequestration experiment was carried out in the Michigan Basin in which similar to 10,000 tonnes of supercritical CO_2 was injected into the Bass Island Dolomite (BILD) at 1050 m depth. A passive seismic monitoring (PSM) network was operated before, during and after the similar to 17-day injection period. The seismic monitoring network consisted of two arrays of eight, three-component sensors, deployed in two monitoring wells at only a few hundred meters from the injection point. 225 microseismic events were detected by the arrays. Of these, only one event was clearly an injection-induced microearthquake. It occurred during injection, approximately 100 m above the BILD formation. No events, down to the magnitude -3 detection limit, occurred within the BILD formation during the injection. The observed seismic waveforms associated with the other 224 events were quite unusual in that they appear to contain dominantly compressional (P) but no (or extremely weak) shear (S) waves, indicating that they are not associated with shear slip on faults. The microseismic events were unusual in two other ways. First, almost all of the events occurred prior to the start of injection into the BILD formation. Second, hypocenters of the 94 locatable events cluster around the wells where the sensor arrays were deployed, not the injection well. While the temporal evolution of these events shows no correlation with the BILD injection, they do correlate with CO_2 injection for enhanced oil recovery (EOR) into the 1670 m deep Coral Reef formation that had been going on for similar to 2.5 years prior to the pilot injection experiment into the BILD formation. We conclude that the unusual microseismic events reflect degassing processes associated with leakage up and around the monitoring wells from the EOR-related CO_2 injection into the Coral Reef formation, 700 m below the depth of the monitoring arrays. This conclusion is also supported by the observation that as soon as injection into the Coral Reef formation resumed at the conclusion of the BILD demonstration experiment, seismic events (essentially identical to the events associated with the Coral Reef injection prior to the BILD experiment) again started to occur close to a monitoring arrays. Taken together, these observations point to vertical migration around the casings of the monitoring wellbores. Detection of these unusual microseismic events was somewhat fortuitous in that the arrays were deployed at the depth where the CO_2 undergoes a strong volume increase during transition from a supercritical state to a gas. Given the large number of pre-existing wellbores that exist in depleted oil and gas reservoirs that might be considered for CO_2 sequestration projects, passive seismic monitoring systems could be deployed at appropriate depths to systematically detect and monitor leakage along them.

British Geological Survey (BGS) (2013) *Interactive Design of Monitoring Programmes for the Geological Storage of* CO_2, updated May 9, 2013, http://ieaghg.org/ccs-resources/monitoring-selection-tool1

The Monitoring Selection Tool has been created to identify and prioritise techniques that could form part of a monitoring programme. The tool will help users to design a monitoring programme to monitor a CO_2 storage project during all stages from site characterisation through to post-injection. It aims to select and rate monitoring techniques, based on a user-defined project scenario, and to identify the most appropriate techniques that should be evaluated for a given stage of project development. The tool should not be considered as being prescriptive but rather as a decision support tool that encourages evaluation of techniques by providing information on their applicability for a defined storage scenario. It is flexible enough to help design monitoring programmes for different storage scenarios and situations.

Bruno, M. S., J. Young, J. Diessl, K. Lao, N. White, B. Childers and J. Xiang (2014). "Characterization of Pliocene and Miocene formations in the Wilmington Graben, Offshore Los Angeles, for Large Scale Geologic Storage of CO_2." Energy Procedia 63(0): 4897-4917.

Geomechanics Technologies has completed a detailed characterization study of the Wilmington Graben offshore Southern California area for large-scale CO_2 storage. This effort has included: an evaluation of existing wells in both State and Federal waters, field acquisition of about 175 km of new seismic data, new well drilling, development of integrated 3D geologic, geomechanics, and fluid flow models for the area. The geologic analysis indicates that more than 100 million tons of storage capacity is available within the Pliocene and Miocene formations in the Graben. Combined fluid flow and geomechanical analyses indicates that injection and storage can be conducted without significant risk for caprock fracturing or fault activation, if injection pressures are limited to below 110% of hydrostatic pressure. Numerical analysis of fluid migration indicates that injection into the Pliocene Formation at depths of 5000 feet would lead to undesireable vertical migration of the CO_2 plume. Recent well drilling however, indicates that deeper sand is present at depths exceeding 7000 feet, which could be viable for large volume storage.

Butsch, R., A. L. Brown, B. Bryans, C. Kolb and S. Hovorka (2013). "Integration of well-based subsurface monitoring technologies: Lessons learned at SECARB study, Cranfield, MS." International Journal of Greenhouse Gas Control 18: 409-420.

An array of closely spaced wells at Cranfield, Mississippi, USA provided a field laboratory to test wirelinebased techniques for measurement of substitution of carbon dioxide (CO_2) for brine. Characterization of this moderate porosity–moderate permeability sandstone reservoir in the lower Tuscaloosa Formation was conducted using openhole logs. Cased-hole monitoring was conducted over the first year of injection using wireline tools including crosswell seismic, sonic, pulsed neutron, and resistivity logs. The wells were also instrumented with casing- and tubing-deployed instruments. The most quantitative wireline measurements were made using time-lapse pulsed neutron and crosswell seismic which documented evolution of the CO_2 plume. Theoretically, interpretation of fluid flow would be optimized by collection of as many types of data as possible, realistically in this setting interference among different measurements limited the amount of data collection possible. Complex well completions interfered with resistivity and sonic log quality. Changes in well bore fluids from brine to CO_2 can affect measurements of the pulsed neutron tool and additional processing may be required. Data collection with large diameter tools required displacing near well CO_2 with heavy brine, which perturbed the near well saturation and geochemistry. These observations provide pragmatic information for future tests to suggest (1) the need to optimize tools to maximize value and avoid interference and (2) suggest avenues of new tool development to avoid interference in CO_2 injection settings.

Cannistraci, L. (2010). In the Oceans' Depths, Valves Face Unique Challenges. Valve Magazine, Valve Manufacturers Association of America (VMA).

This is a magazine article featuring details on safety issues for offshore pipelines.

Caramanna, G., Y. Wei, M. M. Maroto-Valer, P. Nathanail and M. Steven (2013). "Laboratory experiments and field study for the detection and monitoring of potential seepage from CO_2 storage sites." Applied Geochemistry 30(0): 105-113.

Potential CO_2 seepages from geological storage sites or from the injection rig may affect the surrounding environment. To develop reliable detection techniques for such seepages a laboratory rig was designed that is composed of three vertical Plexiglas columns. The columns can be filled with sediments and water; CO_2 can be injected from the bottom. Two columns are used to simulate the impact of CO_2 on soils; while the third one, which is larger in size, simulates CO_2 seepage in aquatic environments. The main results of the laboratory experiments indicate that increased levels of CO_2 generate a quick drop in pH. Once the seepage is stopped, a partial recovery towards the initial values of pH is recorded. The outcomes of the laboratory experiments on the aquatic seepage are compared with observations from a submarine natural emission of CO_2. In this natural underwater seepage multi-parametric probes and laboratory analysis were used to analyze the composition and the chemical effects of the emitted gas; basic acoustic techniques were tested as tools for the prompt detection of CO_2 bubbles in water.

Caramanna, G., N. Andre', M. P. Dikova, C. Rennie and M. M. Maroto-Valer (2014). "Laboratory experiments for the assessment of the physical and chemical impact of potential CO_2 seepage on seawater and freshwater environments." Energy Procedia 63(0): 3138-3148.

This study focuses on a laboratory experimental injection of CO_2 through calcareous and siliceous sediments both in freshwater and seawater aimed to identify the physical and chemical effects of CO_2 seepage and to assess the ability of the system to return towards the original conditions once the CO_2 injection is stopped. A rapid acidification of the water column during the CO_2 injection and reduction in the dissolved oxygen concentration was measured as well as enhanced weathering of the sediments. A partial recovery towards the initial values of pH has been recorded following the stop of the CO_2 injection.

Carey, J. W., M. Wigand, S. J. Chipera, G. WoldeGabriel, R. Pawar, P. C. Lichtner, S. C. Wehner, M. A. Raines and G. D. Guthrie Jr (2007). "Analysis and performance of oil well cement with 30 years of CO_2 exposure from the SACROC Unit, West Texas, USA." International Journal of Greenhouse Gas Control 1(1): 75-85.

A core sample including casing, cement, and shale caprock was obtained from a 30-year old CO_2-flooding operation at the SACROC Unit, located in West Texas. The core was investigated as part of a program to evaluate the integrity of Portland-cement based wellbore systems in CO_2-sequestration environments. The recovered cement had air permeabilities in the tenth of a milliDarcy range and thus retained its capacity to prevent significant flow of CO_2. There was evidence, however, for CO_2 migration along both the casing–cement and cement–shale interfaces. A 0.1–0.3 cm thick carbonate precipitate occurs adjacent to the casing. The CO_2 producing this deposit may have traveled up the casing wall or may have infiltrated through the casing threads or points of corrosion. The cement in contact with the shale (0.1–1 cm thick) was heavily carbonated to an assemblage of calcite, aragonite, vaterite, and amorphous alumino-silica residue and was transformed to a distinctive orange color. The CO_2 causing this reaction originated by migration along the cement–shale interface where the presence of shale fragments (filter cake) may have provided a fluid pathway. The integrity of the casing–cement and cement–shale interfaces appears to be the most important issue in the performance of wellbore systems in a CO_2 sequestration reservoir.

Carrigan, C. R., et al. (2013). "Electrical resistance tomographic monitoring of CO_2 movement in deep geologic reservoirs." International Journal of Greenhouse Gas Control 18: 401-408.

Deep geologic sequestration of carbon dioxide (CO_2) is being evaluated internationally to mitigate the impact of greenhouse gases produced during oil- and coal-based energy generation and manufacturing. Natural gas producing fields are particularly attractive sites for sequestration activities owing to the assumption that the same geologic barrier or cap rock permitting the subsurface regime to act as a long term natural gas reservoir will also serve to permanently contain the injected supercritical CO_2. Electrical resistance tomography (ERT) can potentially track the movement and concentration of the injectate as well as the degree of geologic containment using time lapse electrical resistivity changes resulting from injecting the super-critical fluid into the reservoir formation. An experimental cross-well ERT system operated successfully for more than one year obtaining time lapse electrical resistivity images during the injection of approximately one million tons of CO_2 at a depth exceeding 3000 m in an oil and gas field in Cranfield, MS, representing the deepest application of the method to date. When converted to CO_2 saturation, the resultant images provide information about the movement of the injected CO_2 within a complex geologic formation and the development of the saturation distribution with time. ERT demonstrated significant potential for near real-time assessment of the degree of geologic containment and for updating risk analyses of the sequestration process. Furthermore, electrical resistivity imaging of the developing CO_2 distribution may provide crucial input about the developing reservoir pressure field that is required for active reservoir management to prevent the occurrence of cap rock-damaging seismic activity.

Carroll, A. G., R. Przeslawski, L. C. Radke, J. R. Black, K. Picard, J. W. Moreau, R. R. Haese and S. Nichol (2014). "Environmental considerations for subseabed geological storage of CO_2: A review." Continental Shelf Research 83(0): 116-128.

Many countries are now using or investigating offshore geological storage of CO_2 as a means to reduce atmospheric CO_2 emissions. Although associated research often focuses on deep-basin geology (e.g. seismic, geomagnetics), environmental data on the seabed and shallow subseabed is also crucial to (1) detect and characterise potential indicators of fluid seeps and their potential connectivity to targeted storage reserves, (2) obtain baseline environmental data for use in future monitoring, and (3) acquire information to facilitate an improved understanding of ecosystem processes for use in impact prediction. This study reviews the environmental considerations, including potential ecological impacts, associated with subseabed geological storage of CO_2. Due to natural variations in CO_2 levels in seafloor sediments, baseline CO_2 measurements and knowledge of physical–chemical processes affecting the regional distribution of CO_2 and pH are critical for the design of appropriate monitoring strategies to assess potential impacts of CO_2 seepage from subseabed storage reservoirs. Surficial geological and geophysical information, such as that acquired from multibeam sonar and sub-bottom profiling, can be used to investigate the connectivity between the deep reservoirs and the surface, which is essential in establishing the reservoir containment properties. CO_2 leakage can have a pronounced effect on sediments and rocks which in turn can have carryover effects to biogeochemical cycles. The effects of elevated CO_2 on marine organisms are variable and species-specific but can also have cascading effects on communities and ecosystems, with marine benthic communities at some natural analogue sites (e.g. volcanic vents) showing decreased diversity, biomass, and trophic complexity. Despite their potential applications, environmental surveys and data are still not a standard and integral part of subseabed CO_2 storage projects. However, the habitat mapping and seabed characterisation methodology that underpins such surveys is well developed and has a strong record of providing information to industry and decision makers. This review provides recommendations for an integrated and interdisciplinary approach to offshore geological storage of CO_2, which will benefit national programs and industry and will be valuable to researchers in a broad range of disciplines.

Carter, R. W. and K. T. Spikes (2013). "Sensitivity analysis of Tuscaloosa sandstones to CO_2 saturation, Cranfield field, Cranfield, MS." International Journal of Greenhouse Gas Control 18: 485-496.

The study of the seismic response of reservoirs containing injected CO_2 is important because it will improve monitoring and characterization of sites used for CO_2 utilization and storage. We investigated the sensitivity of the seismic properties to CO_2 saturation of the Cranfield injection site using rock physics modeling, fluid substitution, amplitude variation with angle (AVA), and statistical classification. Rock physics models quantitatively linked the elastic properties to variations of CO_2 saturation, lithology, and cement content. We modeled velocity and density logs with different fluid compositions. With seismic properties from to these different fluid compositions, we computed (1) AVA responses through Monte

Carlo simulations and (2) probability density functions for statistical classification. Rock physics modeling indicated that the upper reservoir is a cemented sandstone and the lower portion a poorly to well sorted mixed lithology sandstone. Consequently, AVA illustrated that the stiff reservoir masked the seismic response due to fluid changes. Statistical classification differentiated between CO_2 and brine, with the ratio of compressional to shear wave velocity (Vp/Vs) used as a discerning parameter. Accordingly, these seismic-based tools, applied to relatively high-resolution data, showed the sensitivity of the elastic properties of the Cranfield reservoir to modeled changes of CO_2 saturation.

Cavanagh, A. J., R. S. Haszeldine and M. J. Blunt (2010). "Open or closed? A discussion of the mistaken assumptions in the Economides pressure analysis of carbon sequestration." Journal of Petroleum Science and Engineering 74(1): 107-110.

The proposition by Economides and Ehlig–Economides (E&E) in 2009 and 2010 that geological storage of CO_2 is ‘not feasible at any cost’ deserves to be examined closely, as this is counter to the view expressed in the overwhelming majority of geological and engineering publications (IPCC, 2005; IEAGHG, 2009). The E&E papers misrepresent this work and suggest that: (1) CO_2 cannot be stored in reservoirs that have a surface outcrop; (2) CO_2 storage capacity in reservoirs without outcrops has been over estimated and (3) the potential for CO_2 storage in the deep subsurface is miniscule. We take issue with each of these, discussed in turn below. We also (4) review the evidence to date, which contradicts the Economides' analysis, and (5) describe common pressure management strategies that demonstrate a more realistic and rational assessment of the experience of CO_2 injection to date. We conclude that large-scale geological CO_2 storage is feasible.

Cavanagh, A. and P. Ringrose (2011). "Simulation of CO_2 distribution at the In Salah storage site using high-resolution field-scale models." Energy Procedia 4(0): 3730-3737.

The In Salah CO_2 storage site, Algeria, is an industrial-scale capture and storage project. CO_2 from several natural gas fields within the development is removed from the production stream and injected into a deep saline formation 1.9 km below the surface and several kilometers away from Krechba, one of the gas fields in production. The three horizontal injection wells have been actively monitored since the start-up in 2004. In particular, satellite surveys (InSAR), showing subtle surface deformation, and well data analysis (gas geochemistry and tracers) have been used to indicate the pressure and gas distribution. The 20 meter thick storage formation is pervasively fractured with the predominant joint set (NW-SE) in close alignment with the present-day stress field. The storage formation is also segmented by a number of strike-slip faults related to a regional mid-to-late Carboniferous basin inversion. The heterogeneous nature of the storage formation is a key influence on the distribution of stored CO_2. We use an invasion percolation modeling approach, assuming capillary limit conditions, to simulate the CO_2 migration process. The field-scale model involves 56 million cells with dimensions of 10x10x2 meters. This high-resolution model captures the reservoir heterogeneity with respect to both the fault and fracture distributions. The simulation results are reasonably consistent with the inferred CO_2 distribution after 5 years of injection, and indicate that the current distribution of CO_2 is principally related to the fracture network. Initial results for predictive simulations of the post-injection period are sensitive to, and principally constrained by, the fault distribution and the multiphase flow behavior. The simulation results highlight the role that high-resolution heterogeneous field-scale models can play in developing a comprehensive storage monitoring program.

Cavanagh, A. and N. Wildgust (2011). "Pressurization and Brine Displacement Issues for Deep Saline Formation CO_2 Storage." 10th International Conference on Greenhouse Gas Control Technologies 4: 4814-4821.

Deep saline formations are expected to store gigatonnes of CO_2 over the coming decades, making a significant contribution to greenhouse gas mitigation. At present, our experience of deep saline formation storage is limited to a small number of demonstration projects that have successfully injected megatonnes of captured CO_2. However, concerns have been raised over pressurization, and related brine displacement, in deep saline formations, given the anticipated scale of future storage operations. Whilst industrial-scale demonstration projects such as Sleipner and In Salah have not experienced problems, generic flow models have indicated that, in some cases, pressure may be an issue. The problem of modeling deep saline formation pressurization has been approached in a number of different ways by researchers, with published analytical and numerical solutions showing a wide range of outcomes. The divergence of results (either supporting or negating the pressurization issue) principally reflects the a priori choice of boundary conditions. These approaches can be summed up as either 'open' or 'closed': a) open system models allow the formation pressure to dissipate laterally, resulting in reasonable storage scenarios; b) closed system models predict pressurization, resulting in a loss of injectivity and/or storage formation leakage. The latter scenario predicts that storage sites will commonly fail to accommodate the injected CO_2 at a rate sufficient to handle routine projects. Our models aim to demonstrate that pressurization and brine displacement need to be addressed at a regional scale with geologically accurate boundary conditions. Given that storage formations are unlikely to have zero-flow boundaries (closed system assumption), the boundary contribution to pressure relief from low permeability shales may be significant. At a field scale, these shales are effectively perfect seals with respect to multiphase flow, but are open with respect to single phase flow and pressure dissipation via brine displacement at a regional scale. This is sometimes characterized as a 'semi-closed' system. It follows that the rate at which pressure can be dissipated (and CO_2 injected) is highly sensitive to the shale permeability. A common range from sub-millidarcy (10(-17) m(2)) to sub-nanodarcy (10(-22) m(2)) is considered, and the empirical relationships of permeability with respect to porosity and threshold pressure are reviewed in light of the regional scale of CO_2 storage in deep saline formations. Our model indicates that a boundary permeability of about a microdarcy (10(-18) m(2)) is likely to provide sufficient pressure dissipation via brine displacement to allow for routine geological storage. The models also suggest that nanodarcy shales (10(-21) m(2)) will result in significant pressurization. There is regional evidence, from the North Sea, that typical shale permeabilities at depths associated with CO_2 storage (1–3 km) are likely to favor storage, relegating pressurization to a manageable issue.

CCCSRP (2010a). Long-Term Stewardship and Long-Term Liability in the Sequestration of CO_2. Technical Advisory Committe Report, California Carbon Capture and Storage Review Panel.

This paper addresses some of the issues relating to long-term stewardship and liability that are sometimes viewed as barriers to timely Carbon Capture and Storage (CCS) development projects. The paper examines various approaches for addressing liability over the long-term post-closure phase. This phase is currently of an undetermined duration (i.e., after CO_2 injection wells are capped and permanently closed). Long-term liability is a complex subject that will almost certainly involve new and potentially intractable legal issues that require case-by-case resolution, which are beyond the scope of this paper. The issues related to monitoring, verification and reporting (MVR) during the post-closure phase are covered in companion white papers for the California Carbon Capture and Storage Review Panel.

Chadwick, R. A., et al. (2004). "Geological reservoir characterization of a CO_2 storage site: The Utsira Sand, Sleipner, northern North Sea." Energy 29(9-10).

The paper aims to draw some generic conclusions on reservoir characterization based on the Sleipner operation where CO_2 is being injected into the Utsira Sand. Regional mapping and petrophysical characterization of the reservoir, based on 2D seismic and well data, enable gross storage potential to be evaluated. Site-specific injection studies, and longer-term migration prediction, require precision depth mapping based on 3D seismic data and detailed knowledge of reservoir stratigraphy. Stratigraphical and structural permeability barriers, difficult to detect prior to CO_2 injection, can radically affect CO_2 migration within the aquifer.

Chadwick, R. A., et al. (2008). "Best Practice for the Storage in Saline Aquifers: Guidelines from the SACS and CO_2STORE Projects." Keyworth, Nottingham: British Geologic Survey Occasional Publication(14).

Carbon capture and storage is a subject around which there is a growing level of public awareness. A range of geological scenarios may be used for underground CO_2 storage; declining oil and gas fields, saline aquifers and coal seams. Saline aquifers are reckoned to offer the largest overall storage potential and this book offers key insights into aquifer storage issues. European collaborative projects between 1998 and 2006 have researched the potential for large-scale storage of CO_2 in underground saline aquifer formations. This book consolidates the findings of the SACS and the CO_2STORE projects into a manual of observations and recommendations, aiming to provide technically robust guidelines for effective and safe storage of CO_2 in a range of geological settings. A wide range of geological, environmental and planning issues are addressed, and it forms a sound basis for establishing recommended procedures for the planning and setting up of a potential CO_2 storage operation. It will be useful to commercial companies, regulatory authorities and NGOs in evaluating possible new CO_2 storage sites in Europe and elsewhere.

Chadwick, R. A., D. Noy, R. Arts and O. Eiken (2009). "Latest time-lapse seismic data from Sleipner yield new insights into CO_2 plume development." Energy Procedia 1(1): 2103-2110.

Since its inception in 1996, the CO_2 injection operation at Sleipner has been monitored by 3D time-lapse seismic surveys. Striking images of the CO_2 plume have been obtained, showing a multi-tier feature of high reflectivity, interpreted as arising from a number of thin layers of CO_2 trapped beneath thin, intra-reservoir mudstones. The topmost layer of the CO_2 plume can be characterized most accurately, and its rate of growth quantified. From this the CO_2 flux arriving at the reservoir top can be estimated. This is mostly controlled by pathway flow through the intra-reservoir mudstones. Flow has increased steadily with time suggesting that pathway transmissivities are increasing with time, and/or the pathways are becoming more numerous. Detailed 3D history-matching of the topmost layer cannot easily reproduce the observed rate of lateral spreading. Very high reservoir permeabilities seem likely, possibly with a degree of anisotropy. Other modelling variables under investigation include topseal topography, the number of feeder pathways and CO_2 properties. Detailed studies such as this will provide important constraints on longer-term predictive models of plume evolution.

Chadwick, R. A., G. A. Williams, J. D. O. Williams and D. J. Noy (2012). "Measuring pressure performance of a large saline aquifer during industrial-scale CO_2 injection: The Utsira Sand, Norwegian North Sea." International Journal of Greenhouse Gas Control 10(0): 374-388.

The Sleipner injection project has stored around 14 Mt of CO_2 in the Utsira Sand and provides a unique opportunity to monitor the pressure response of a large saline aquifer to industrial-scale CO_2 injection. There is no downhole pressure monitoring at Sleipner, but the 4D seismic programme provides an opportunity to test whether reliable indications of pressure change can be obtained from time-lapse seismic. Velocity–stress relationships for sandstones, calibrated against measured data from the Utsira Sand, indicate that pore pressure increases of <1 MPa should produce measurable travel-time increases through the reservoir. Time-lapse datasets were used to assess travel-time changes by accurately mapping the top and base of the reservoir on successive repeat surveys outside of the plume saturation footprint. Measured time-shifts are of the order of a very few milliseconds, with significant scatter about a mean value due to travel-time ‘jitter’. The ‘jitter’ is due to non-perfect repeatability of the time-lapse surveys and shows a Gaussian distribution providing a useful statistical tool for determining the mean. Observed mean time-shifts through the Utsira Sand were 0.097 ms in 2001 and 0.175 ms in 2006. These correspond to mean pressure increases of less than 0.1 MPa. An idealised noise-free reservoir ‘impulse response’ was computed, taking into account lateral reservoir thickness variation. Convolving this with the repeatability noise distribution gives a realistic predicted reservoir response. Comparing this with the observed time-shifts again indicates a pressure increase less than 0.1 MPa. Flow simulations indicate that pressure increases should range from <0.1 MPa for an uncompartmentalised reservoir to >1 MPa if strong flow barriers are present, so the results are consistent with the Utsira reservoir having wide lateral hydraulic connectivity.

Chadwick, R.A., Marchant, B.P., Williams, G.A., 2014. CO_2storage monitoring: leakage detection and measurement in subsurface volumes from 3D seismicdata at Sleipner. Energy Procedia 63, 4224–4239.

Demonstrating secure containment is a key plank of CO_2 storage monitoring. Here we use the time-lapse 3D seismic surveys at the Sleipner CO_2 storage site to assess their ability to provide robust and uniform three-dimensional spatial surveillance of the Storage Complex and provide a quantitative leakage detection tool. We develop a spatial-spectral methodology to determine the actual detection limits of the datasets which takes into account both the reflectivity of a thin CO_2 layer and also its lateral extent. Using a tuning relationship to convert reflectivity to layer thickness, preliminary analysis indicates that, at the top of the Utsira reservoir, CO_2 accumulations with pore volumes greater than about 3000 m3 should be robustly detectable for layer thicknesses greater than one metre, which will generally be the case. Making the conservative assumption of full CO_2 saturation, this pore volume corresponds to a CO_2 mass detection threshold of around 2100 tonnes. Within the overburden, at shallower depths, CO_2 becomes progressively more reflective, less dense, and correspondingly more detectable, as it passes from the dense phase into a gaseous state. Our preliminary analysis indicates that the detection threshold falls to around 950 tonnes of CO_2 at 590 m depth, and to around 315 tonnes at 490 m depth, where repeatability noise levels are particularly low. Detection capability can be equated to the maximum allowable leakage rate consistent with a storage site meeting its greenhouse gas emissions mitigation objective. A number of studies have suggested that leakage rates around 0.01% per year or less would ensure effective mitigation performance. So for a hypothetical large-scale storage project, the detection capability of the Sleipner seismics would far exceed that required to demonstrate the effective mitigation leakage limit. More generally it is likely that well-designed 3D seismic monitoring systems will have robust 3D detection capability significantly superior to what is required to prove greenhouse gas mitigation efficacy.

Chadwick, R. A. and D. J. Noy (2015). "Underground CO_2 storage: demonstrating regulatory conformance by convergence of history-matched modeled and observed CO_2 plume behavior using Sleipner time-lapse seismics." Greenhouse Gases-Science and Technology 5(3): 305-322.

One of the three key regulatory requirements in Europe for transfer of storage site liability is to demonstrate conformity between predictive models of reservoir performance and monitoring observations. This is a challenging requirement because a perfect and unique match between observed and modeled behavior is near impossible to achieve. This study takes the time-lapse seismic monitoring data from the Sleipner storage operation to demonstrate that as more seismic data becomes available with time, predictive models can be matched more accurately to observations and become more reliable predictors of future performance. Six simple performance measures were defined: plume footprint area, maximum lateral migration distance of CO_2 from the injection point, area of CO_2 accumulation trapped at top reservoir, volume of CO_2 accumulation trapped at top reservoir, area of all CO_2 layers summed, and spreading co-efficient. Model scenarios were developed to predict plume migration up to 2008. Scenarios were developed for 1996 (baseline), 2001, and 2006 conditions, with models constrained by the information available at those times, and compared with monitoring datasets obtained up to 2008. The 1996 predictive range did generally encompass the future observed plume behavior, but with such a wide range of uncertainty as to render it of only marginal practical use. The 2001 predictions (which used the 1999 and 2001 seismic monitoring datasets) had a much lower uncertainty range, with the 2006 uncertainties somewhat lower again. There are still deficiencies in the actual quality of match but a robust convergence, with time, of predicted and observed models is clearly demonstrated. We propose modeling-monitoring convergence as a generic approach to demonstrating conformance.

Chadwick, A. (2015). External Review of the Storage Plan for the Peterhead Carbon Capture and Storage Project. Confidential Report, CR/14/094. B. G. Survey. UK, Energy Programme.

This document summarizes the findings of an external independent review of the storage plan for the proposed Peterhead Carbon Capture and Storage project which aims to store up to 20 million tons (Mt) of CO_2 within the framework of the European Directive on the geological storage of CO_2. The Peterhead Carbon Capture and Storage Project proposes to capture carbon dioxide (CO_2) from an existing gas-fired power-station at Peterhead and to store this in geological strata at a depth of around 2600 m beneath the outer Moray Firth. The plan is to store 10–15 Mt of CO_2 over a ten- to fifteen-year period commencing around 2020, but the site is being qualified for 20 Mt to allow for potential extension of the injection period. Storage will utilize the depleted Goldeneye gas condensate field with the Captain Sandstone reservoir as the primary storage container. The Storage Site covers some 70 km^2, and comprises the Captain Sandstone and underlying strata of the Cromer Knoll Group, bounded by a polygon some 2 to 3 km outside of the original Goldeneye oil-water contact. The Storage Complex is larger, around 154 km^2, bounded some 2 to 7 km outside of the original oil-water contact, and extending upwards to the top of the Dornoch Mudstone at a depth of more than 800 m. The top-seal of the primary container is a proven caprock for natural gas and is formed by the mudstones of the Upper Cromer Knoll Group, the overlying Rødby and Hidra formations and the Plenus Marl. A number of additional seals are present in the overburden within the Storage Complex, as are a number of potential secondary containers which could also serve as monitoring horizons. The geological interpretation of the storage site is based on the comprehensive datasets acquired during the discovery, appraisal and development of the Goldeneye field, and also data from other wells, fields and seismic surveys in the surrounding area. The static geological model of the storage site and adjacent aquifer has been stress tested for the key uncertainties, and it is considered to be robust. The storage capacity of the Goldeneye structure has been calculated using both static (volumetric) methods and dynamic flow modelling together with uncertainty analysis. Total estimated capacity of the structural closure is in the range 25 to 47 Mt and so robustly exceeds the proposed injected amount.

Chalaturnyk, R. and W. D. Gunter (2005). Geological storage of CO_2: Time frames, monitoring and verification. Greenhouse Gas Control Technologies 7; E. S. Rubin, D. W. Keith, C. F. Gilboy, M. Wilson, T. Morris, J. Gale and K. Thambimuthu, eds. Oxford, Elsevier Science Ltd: 623-631.

This chapter explores that the scope, frequency, duration, and results of monitoring programs combined with interpretation of the monitoring results forms the key components of a monitored decision approach for verifying the integrity of a geological storage project. Monitoring provides the confidence that the CO_2 has been injected and stored in an environmentally sound and safe manner and provides the necessary accounting metrics for emissions trading scenarios based on geological storage. A monitored decision framework recognizes uncertainties in the geological storage system and allows design decisions to be made with the knowledge that planned long-term observations and their interpretation will provide information to decrease the uncertainties, as well as providing contingencies for all envisioned outcomes of the monitoring program. However, long-term monitoring requires integration with a “working hypothesis” of the storage mechanisms.

Chandel, M. K., L. F. Pratson and E. Williams (2010). "Potential economies of scale in CO_2 transport through use of a trunk pipeline." Energy Conversion and Management 51(12): 2825-2834.

A number of existing models for the transport of CO_2 in carbon capture and storage assume the CO_2 will be carried through isolated pipelines that connect each source to the nearest storage site. However storage costs will vary geographically, and it may be more economical to transport the CO_2 farther away to a lower cost storage site if the pipelines can be linked to the site via a primary trunkline. We evaluate this alternative by developing an engineering-economic model that computes the levelized cost of transporting captured CO_2 through pipes of different diameters and over varying distances. The model also computes the additional energy use and resulting CO_2 emissions involved in the transport and is used to arrive at a generalized correlation for estimating the cost of CO_2 transport ($/tonne/km) for different mass flow rates. Model results indicate that the cost for transporting CO_2 could be significantly reduced using a large-diameter trunkline networked to pipelines from individual CO_2 sources. This suggests that the design of CO_2 transport systems could be an important influence on the selection of storage sites, particularly where there is a tradeoff between nearby but high-cost sites and distant, low-cost sites.

Childers, W. E. (2012). Characterization of Pilocene and Miocene Formations in the Wilmington Graben, Offshore Los Angeles, for Large Scale Geologic Storage of CO_2. Carbon Storage R&D Project Review Meeting Developing the Technologies and Building the Infrastructure for CO_2 Storage August 21-23, 2012, U.S. Department of Energy, National Energy Technology Laboratory.

The Los Angeles Basin presents a unique and special combination of high need and significant opportunity for large scale geologic storage of CO_2. Terralog Technologies USA, Inc. was selected by the Department of Energy to manage a research project with the objective to characterize Pliocene and Miocene sediments within the Wilmington Graben, located offshore Los Angeles, for high volume CO_2 sequestration. These sediments are suspected to span more than 5000 feet of vertical interval, with an estimated capacity to store more than 50 million metric tons of CO_2.

CO_2CARE (2013a). CO_2 site closure assessment research: Best Practice Guidelines summary: 4. www.CO2care.org

This brochure summarizes the key findings from the CO_2CARE Best Practice Guidelines document which is available on the CO_2CARE website. The brochure is laid out as two parallel themes. The man white column summarizes best practice for risk management, well abandonment and post-closure reservoir management. The secondary ‘blue’ column summarizes key best practice issues associated with the three high level requirements of the Directive: no detectable leakage observed and modelled conformance and long term liability.

CO_2CARE (2013b). CO_2 site closure assesment research: Best Practices Guidelines. t. F. Programme, British Geological Survey: 52.

This report presents a set of pragmatic and workable generic procedures, suggested best practices and other recommendations and observations for the safe and sustainable closure of geological CO_2 storage sites. These have been distilled from the results of the CO_2CARE project and represent the most important messages that will be of benefit to Regulators, storage site Operators and other stakeholders. Best practice in well abandonment starts with ensuring the integrity of the well by its proper construction and safe operation. New wells in a CO_2 storage site should be constructed according to best practice for long-term integrity in a corrosive CO_2-rich environment. This means selecting appropriate materials and ensuring the long-term geomechanical and geochemical integrity of the wells. However, not all wells in CO_2 storage complexes will have been constructed and operated with CO_2 storage in mind. The risks associated with these older wells, including abandoned wells, should be assessed and, if necessary, remediation plans should be prepared for them. The main elements of managing the environmental and safety risks of CO_2 storage, namely risk assessment, monitoring and the application, if necessary, of corrective measures, are well embedded in the rules of the EU Storage Directive. CO_2CARE has developed a detailed scheme of milestones and procedures to be followed to ensure the safe and sustainable closure of CO_2 storage sites. It was observed that the EU Storage Directive and its associated Guidance Documents propose minimum periods to fulfil certain key criteria, which are not based on any scientific fundamentals. It is recommended that the EU Directive could be amended such that all decisions as to whether a criterion for the safety of a site has been met should be based on technical criteria only and should not be linked to prescriptive time spans.

CO_2CRC (2008). "Storage Capacity Estimation, Site Selection and Characterization for CO_2 Storage Projects." Research Centre for Greenhouse Gas Technologies, Canberra (2008) CO_2CRC(RPT08-1001).

This sixty page report by the COSCRC is relevant to the BOEMRE project b/c it represents an attempt to develop an appropriate and consistent protocol to assess the capacity and long-term integrity of geologic storage sites. The report is intended to outline capacity assessment and site characterization for Australia and New Zealand, but could provide pertinent insights toward the development of the necessary scheme for the U.S

Cole, I. S., P. Corrigan, S. Sim and N. Birbilis (2011). "Corrosion of pipelines used for CO_2 transport in CCS: Is it a real problem?" International Journal of Greenhouse Gas Control 5(4): 749-756.

The transport of carbon dioxide (CO_2) from capture to storage is a vital aspect of any CO_2 capture and storage (CCS) process – and it is essential that it is effective, safe and economical. Transport by pipelines is one of the preferred options and thus, for safe operations, such pipelines should not be subject to internal corrosion. Present CO_2 pipelines used for enhanced oil recovery (EOR) have suffered only minimal corrosion over the last 20 years, however, such pipelines operate under stringent regulations with regard to water and contaminant levels in the CO_2 stream. This paper reviews the literature on the range of potential compositions in CCS CO_2 streams and the likely phases that will be in such streams, the relevant history of CO_2 pipelines, and laboratory studies of CO_2 corrosion, with a view to understanding the corrosion threat to pipelines where CO_2 is the primary fluid.

Condor, J. and K. Asghari (2009). "An Alternative Theoretical Methodology for Monitoring the Risks of CO_2 Leakage from Wellbores." Energy Procedia 1(1): 2599-2605.

This paper proposes an alternative theoretical methodology to evaluate the risks of CO_2 leakage from reservoirs using a stochastic approach. The methodology suggested here makes use of three main concepts: – Features, Events and Processes (FEPs), Interaction Matrix, and Stochastic Representation. Both, FEPs and Interaction Matrix have been introduced by other researchers but for different objectives. The methodology that is proposed here modifies the original concept of Interaction Matrix in such a way that it may produce probabilistic results as outcome. A practical example is given at the end of this paper.

Connell, L., et al. (2015). "An investigation into the integrity of wellbore cement in CO_2 storage wells: Core flooding experiments and simulations." International Journal of Greenhouse Gas Control 37: 424-440.

An important issue for geological storage of CO_2 is the potential for wellbore cements to degrade in contact with the acidic formation waters resulting from CO_2 dissolution. Cement degradation is a two stage process; cement carbonation occurs as various cement phases react to form calcium carbonate. The key second stage is the potential for erosion of the cement as this calcium carbonate dissolves into the formation water. For significant erosion to occur there would need to be a flow of water, under-saturated in calcium and carbonate ions, across the cement to remove dissolved calcium carbonate. This paper, presents a program of work that investigates cement degradation at the cement-formation interface. Two core flooding experiments were conducted at pressures and temperatures representative of storage conditions using composite cement–sandstone core plugs using CO_2 saturated waters with chemistries representative of formation waters. The relatively high permeability of the sandstone allowed sufficient water flow rates for regular water samples to be collected and the chemistry analysed. As the sandstone simply provided a flow path for water, and did not impart any substantial chemical effect, the observations are applicable to a range of situations involving water flow in contact with cement. As the experiments, were structured such that the inflow water flowed across the cement plug surface before passing through the sandstone, each experiment provided two sets of observations with significantly different water flow velocities and chemistries. The measurements of water chemistry were combined with the flow rate observations to calculate the cumulative dissolution of the calcium carbonate and thus estimate the erosion of the cement. This compared well with direct estimates of the volume eroded by the flow across the cement plug surface. Using μXRD it was found that where the cement came into contact with the water it reacted to form calcium carbonate with none of the original cement phases detected. The erosion rate of the cement, when normalized by the water flow rate, had a clear relationship with respect to the difference between the inflow and outflow calcium concentrations. An empirical relationship was used to fit this data, thus providing a mathematical description of the cement erosion rate with respect to water flow velocity and the calcium solubility deficit. This was applied in a simulation model to a series of hypothetical case studies to investigate cement erosion at the cement-formation interface of a well, where there was an initial flow channel, across the geological seal in a CO_2 storage formation.

Cosham, A. and R. J. Eiber (2008). Fracture Propagation of CO_2 Pipelines. Atkins Boreas, Atkins Global.

THE FOURTH REPORT from the Intergovernmental Panel on Climate Change states that “Warming of the climate system is unequivocal…”. It further states that there is a “very high confidence that the global average net effect of human activities since 1750 has been one of warming.” One of the proposed technologies that may play a role in the transition to a low-carbon economy is carbon dioxide capture and storage (CCS). The widespread adoption of CCS will require the transportation of the CO_2 from where it is captured to where it is to be stored. Pipelines can be expected to play a significant role in the required transportation infrastructure.

CSA Group (2012) "Standard for Geologic storage of carbon dioxide." Z741

CCS is a process consisting of the separation of CO_2 from industrial and energy-related sources, transport to a storage location and long-term underground isolation from the atmosphere. Scientists estimate carbon capture units can be used to reduce emissions from industrial plants by 85 to 95 per cent.

The CSA Z741 Geological storage of carbon dioxide standard is a bi-national Canada-USA consensus standard, developed with a technical committee of more than 30 professionals representing industry, regulators, researchers and NGOs from both sides of the border. The genesis of the standard was a seed document developed by IPAC-CO_2 based on their research. It is intended that the new standard will also be used as a basis for the international CCS standards through the International Organization for Standardization (ISO).

"This standard will help instill public and regulator confidence in the geologic storage of CO_2 as an effective CO_2 mitigation option," said Carmen Dybwad, Chief Executive Officer of IPAC-CO_2 Research Inc. "The publication of this standard is a turning point for the CCS industry and in the quest to reduce greenhouse gas emissions in our fight against climate change." CSA Z741 Geological storage of carbon dioxide standard provides essential guidelines for regulators, industry and others around the world involved with scientific and commercial CCS projects. It establishes requirements and recommendations for the geological storage of carbon dioxide to help promote environmentally safe and long term containment of carbon dioxide in a way that minimizes risks to the environment and human health.

Dance, T. and A. Datey (2015). Monitoring CO_2 Saturation from Time-Lapse Pulsed Neutron and Cased-Hole Resistivity Logs. Carbon Dioxide Capture for Storage in Deep Geologic Formations - Results from the CO_2 Capture Project. K. Gerdes. UK, CPL Press, BP North American Corporation: 613-626.

Time-lapse well logging has long been a valuable petroleum reservoir management technique for monitoring relative changes in near-well bore hydrocarbons and formation fluid. As interest grows in the monitoring and accounting of Carbon Dioxide (CO_2) for enhanced recovery and sequestration, techniques such as pulsed neutron and cased-hole resistivity logging have been put to the test in the quantitative evaluation of CO_2. Despite this being beyond the original design purpose of the tools, and a lack of calibration specific to CO_2 injection conditions, results from demonstration projects and storage sites around the world have shown promise. In this chapter a case study is presented from the CO_2CRC Otway project, Australia, where time-lapse well logging was applied to monitoring of CO_2 storage in a depleted gas field. Not all of the interpreted products for the quantitative characterisation of CO_2 saturation were as definitive as hoped. This was due to a variety of factors related to timing of logging runs, low salinity of the formation water, high mud filtrate invasion, the presence of CO_2 inside the borehole, and existing residual hydrocarbons in the reservoir. Nevertheless, the more reliable log outputs were evaluated and corrected accordingly in order to produce a semi-quantitative evaluation of saturation post-injection. The results were used to verify that the CO_2 plume is contained above the structural spill point of the storage complex. The lessons learned from Otway show that these logging techniques can be used effectively as part of a monitoring portfolio at CO_2 storage sites provided the execution is carefully controlled and variables are well understood.

Dasgupta, S. N. (2006). Monitoring of Sequestered CO_2: Meeting the Challenge with Emerging Geophysical Technologies, Saudi Aramco.

A brief report outlining geological sequestration challenges, geophysical monitoring tools and CO_2 monitoring challenges. Use of fossil fuels is a major sources of excess CO_2 that contributes to the increased concentration of greenhouse gases in the atmosphere. There is a compelling need to reduce the concentration of CO_2; as a high concentration is likely to produce rapid climate change. Capturing and storing of CO_2 by injecting it in geologic formations is a mitigation option. Proven and emerging geophysical technologies could assess the reliability and long term stability of CO_2 storage to meet the challenge of monitoring CO_2 sequestration. Monitoring and verification are the other challenges in geologic CO_2 sequestration. Additional research and development efforts are needed in adapting currently proven and emerging geophysical tools applied for other applications and also in developing new innovative tools to CO_2 sequestration application. The optimum site selection for geologic storage requires thorough analyses of data, integration of results and fully characterizing the subsurface formations. This process requires years of preparation, feasibility studies, field data collection, data integration and interpretation of results.

DECC (2011). Decommissioning of Offshore Oil and Gas Installations and Pipelines under the Petroleum Act 1998. Offshore Decommissioning Unit, Department of Energy and Climate Change: 1-139.

The aim of these notes, which have been prepared by DECCS's Offshore Decommissioning Unit in Aberdeen, in consultation with other Government Departments, is to provide guidance to those engaged in preparing programmes for the decommissioning of offshore installations and pipelines. Account has been taken of views expressed by operating companies and other interested parties. These guidance notes, which were first issued in August 2000, provide a framework and are not intended to be prescriptive. They will be reviewed regularly and updated as necessary. We intend to make the process of submission and approval of a decommissioning programme as flexible as possible within statutory and policy constraints, allowing adequate time for full and considered consultation but without unnecessary delay.

We recognise that circumstances will vary from case to case and that differing approaches may be required. Furthermore, whilst these guidance notes are intended to provide fairly detailed guidance to those engaged in preparing decommissioning programmes, they should not be read in isolation from the relevant legislation.

de Figueiredo, M. A. (2007a). The liability of carbon dioxide shortage Thesis Ph. D. --Massachusetts Institute of Technology Engineering Systems Division 2007.

This research examines the liability of storing CO_2 in geological formations. There is a potential tortious and contractual liability exposure if stored CO_2 is not fully contained by the geological formation. Using a combination of case study and survey methods, this research examines the risks confronted by CO_2 storage, the legal and regulatory regimes governing these risks, and liability arrangements in other sectors where analogous risks have been confronted. Currently identifiable sources of liability include induced seismicity, groundwater contamination, harm to human health and the environment, property interests, and permanence. The risks of CO_2 storage are analyzed in the context of several case studies: acid gas injection, natural gas storage, secondary oil recovery, and enhanced oil recovery. Methods for containing liability are considered in the context of regulatory analogs. This research finds that the current public and private mechanisms that would govern CO_2 storage liability do not adequately address the issue. The analysis reveals six lessons learned: (1) the successful resolution of the CO_2 liability issue will require combining our understanding of physical and regulatory analogs; (2) the prospect of CO_2 storage liability will affect the implementation of predictive models and incentives to monitor leakage; (3) jurisdictional differences in liability exposure could affect where storage projects are eventually sited; (4) the development of liability rules is a function of an industry's emergence, but an industry's emergence, in turn, may affect the content of the liability rules; (5) regulatory compliance is not always a safe harbor for liability; and (6) statutes of limitation and repose mean that private liability is not necessarily "forever". A new liability arrangement is advocated where the current permitting regime is amended, long-term liability is managed by a governmental CO_2 Storage Corporation with backing from an industry-financed CO_2 Storage Fund, compensation for tortious liability occurs through an Office of Special Masters for CO_2 Storage in the U.S. Federal Court of Claims, and the permanence issue is addressed on an annual ex post basis during the injection phase of CO_2 storage operations and on an ex ante basis when sites are transferred to the CO_2 Storage Corporation.

de Figueiredo, M., et al. (2012). Greenhouse Gas Reporting for Geologic Sequestration of Carbon Dioxide. Carbon Management Technology Conference. Florida USA, Carbon Management Technology Conference.

Abstract In December 2010, EPA amended the regulatory framework for the Greenhouse Gas Reporting Program to create Subpart RR, Geologic Sequestration of Carbon Dioxide. Under Subpart RR, facilities that conduct geologic sequestration by injecting CO_2 for long-term containment in subsurface geologic formations are required to develop and implement an EPA-approved site-specific monitoring, reporting, and verification plan, and report basic information on CO_2 received for injection, the amount of CO_2 geologically sequestered using a mass balance approach and annual monitoring activities. This paper provides an overview of the Subpart RR greenhouse gas reporting requirements. Introduction Geologic sequestration (GS) is the long-term containment of a carbon dioxide (CO_2) stream in subsurface geologic formations and is a key component of a set of climate change mitigation technologies known as carbon dioxide capture and sequestration (CCS). CCS is a three-step process that includes capture and compression of CO_2 from power plants or industrial sources; transport of the captured CO_2 (usually in pipelines); and storage and monitoring of that CO_2 in geologic formations, such as deep saline formations and oil and gas reservoirs. CCS could play an important role in achieving national and global greenhouse gas (GHG) reduction goals. In December 2010, the U.S. Environmental Protection Agency (EPA) amended the regulatory framework for the GHG Reporting Program to create Subpart RR, Geologic Sequestration of Carbon Dioxide (EPA 2010c). EPA promulgated the rule under authorities provided in the Clean Air Act. The GHG Reporting Program, 40 CFR Part 98, requires reporting of GHG data and other relevant information from certain source categories in the United States. The purpose of the GHG Reporting Program is to collect accurate and timely GHG data to inform future policy decisions. Subpart PP of the GHG Reporting Program requires the reporting of CO_2 supplied to the economy. During the public comment period on the Part 98 rule establishing that requirement, EPA received comments that CO_2 geologically sequestered should be considered in the GHG Reporting Program. In the October 2009 final rule promulgating Subpart PP, EPA committed to taking action to collect such data in the near future (EPA 2009). EPA proposed GS reporting mechanisms on April 12, 2010 and finalized the rule on December 1, 2010, taking into account over 16,000 comments received during the 60-day public comment period. Data obtained under Subpart RR will, among other things, inform Agency decisions under the Clean Air Act related to the use of CCS for mitigating GHG emissions. The rule establishing the Subpart RR GHG reporting requirements was closely coordinated with EPA's December 2010 Safe Drinking Water Act rule establishing Federal requirements under the Underground Injection Control (UIC) program for Class VI injection wells (EPA 2010a). The UIC program is designed to prevent the movement of such fluid into underground sources of drinking water (USDWs) by addressing the potential pathways through which injected fluids can migrate and potentially endanger USDWs. Subpart RR fulfills a separate but complementary goal, which is to quantify the amount of CO_2 sequestered in geologic formations. EPA designed requirements under Subpart RR with careful consideration of UIC Class VI requirements to minimize overlap between the two programs.

Dewar, M., Wei, W., McNeil, D. and Chen, B. (2013). Small-scale modelling of the physiochemical impacts of CO_2 leaked from sub-seabed reservoirs or pipelines within the North Sea and surrounding waters. Marine Pollution Bulletin, 73 (2): 504-515

A two-fluid, small scale numerical ocean model was developed to simulate plume dynamics and increases in water acidity due to leakages of CO_2 from potential sub-seabed reservoirs erupting, or pipeline breaching into the North Sea. The location of a leak of such magnitude is unpredictable; therefore, multiple scenarios are modelled with the physiochemical impact measured in terms of the movement and dissolution of the leaked CO_2. A correlation for the drag coefficient of bubbles/droplets free rising in seawater is presented and a sub-model to predict the initial bubble/droplet size forming on the seafloor is proposed. With the case studies investigated, the leaked bubbles/droplets fully dissolve before reaching the water surface, where the solution will be dispersed into the larger scale ocean waters. The tools developed can be extended to various locations to model the sudden eruption, which is vital in determining the fate of the CO_2 within the local waters.

DiPietro, P., V. A. Kuuskraa and Malone Taylor (2015). "Taking CO_2 Enhanced Oil Recovery to the Offshore Gulf of Mexico: A Screening-Level Assessment of the Technically and Economically-Recoverable Resource " SPE 102833: 7.

This document summarises the findings of an external independent review of the storage plan for the proposed Peterhead Carbon Capture and Storage project which aims to store up to 20 million tonnes (Mt) of CO_2 within the framework of the European Directive on the geological storage of CO_2. The Peterhead Carbon Capture and Storage Project proposes to capture carbon dioxide (CO_2) from an existing gas-fired power-station at Peterhead and to store this in geological strata at a depth of around 2600 m beneath the outer Moray Firth. The plan is to store 10 - 15 Mt of CO_2 over a ten to fifteen-year period commencing around 2020, but the site is being qualified for 20 Mt to allow for potential extension of the injection period. Storage will utilise the depleted Goldeneye gas condensate field with the Captain Sandstone reservoir as the primary storage container. The Storage Site covers some 70 km2, and comprises the Captain Sandstone and underlying strata of the Cromer Knoll Group, bounded by a polygon some 2 to 3 km outside of the original Goldeneye oil-water contact. The Storage Complex is larger, around 154 km^2, bounded some 2 to 7 km outside of the original oil-water contact, and extending upwards to the top of the Dornoch Mudstone at a depth of more than 800 m. The top-seal of the primary container is a proven caprock for natural gas and is formed by the mudstones of the Upper Cromer Knoll Group, the overlying Rødby and Hidra formations and the Plenus Marl. A number of additional seals are present in the overburden within the Storage Complex, as are a number of potential secondary containers which could also serve as monitoring horizons. The geological interpretation of the storage site is based on the comprehensive datasets acquired during the discovery, appraisal and development of the Goldeneye field, and also data from other wells, fields and seismic surveys in the surrounding area. The static geological model of the storage site and adjacent aquifer has been stress tested for the key uncertainties, and it is considered to be robust. The storage capacity of the Goldeneye structure has been calculated using both static (volumetric) methods and dynamic flow modelling together with uncertainty analysis. Total estimated capacity of the structural closure is in the range 25 to 47 Mt and so robustly exceeds the proposed injected amount.

Dixon, T., A. Greaves, O. Christophersen, C. Vivian and J. Thomson (2009). "International Marine Regulation of CO_2 Geological Storage. Developments and Implications of London and OSPAR." Greenhouse Gas Control Technologies 9 1(1): 4503-4510

For the last four years a considerable amount of both legal and technical work on the storage of CO_2 in sub-seabed geological formations has been developed under the London Convention and its 1996 Protocol and the OSPAR Convention. The technical and legal work included consideration of the risks and benefits to the marine environment within the context of increasing atmospheric CO_2 absorption by the oceans. The conclusion of this work was that the Conventions should move to remove their prohibitions that applied to certain CO_2 geological storage project configurations, so as to facilitate and to regulate environmentally safe CO_2 geological storage. In timescales faster than most anticipated, the London Protocol was amended in Novemeber 2006 and OSPAR was amended in June 2007. The actual amendments include various provisions, conditions and restrictions so as to only allow environmentally sound CO_2 storage. These provisions and their implications for CCS regulation and projects are described in this paper. In this process, three detailed guidelines were produced for risk assessment and management of CO_2 storage. These guidelines and their implications for CCS regulation and projects are described. Some key principles from the London and OSPAR CO_2 developments are now being reflected in the European Commissions's proposed directive on geological storage of CO_2. These marine conventions are good examples of evidence-based regulatory development in a new area, which brought together environmental, climate and energy experts and regulators, and key principles established by them will have wider implications for future CCS regulation and projects.

Dixon, T. (2015). Blog Summary of IEAGHG Information Paper 2014-IP19, presented at 7th IEA CCS Regulatory Network meeting in Paris, France, 22-23 April.

The IEA CCS Unit held their 7th meeting of the International CCS Regulatory Network in Paris 22–23 April. Sessions looked at country updates from the EU, the USA, Canada and Korea, and on international standards, on project experiences, on CO_2 EOR, and on emission trading schemes. More information from the meeting will be found at http://www.iea.org/topics/ccs/.

Dixon, T. and K. D. Romanak (2015). "Improving monitoring protocols for CO_2 geological storage with technical advances in CO_2 attribution monitoring." International Journal of Greenhouse Gas Control 41: 29-40.

Existing monitoring protocols for the storage of carbon dioxide (CO_2) in geologic formations are provided by carbon dioxide capture and geological storage (CCS) specific regulations and bodies including the 2006 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories, the European Union (EU) CCS and Emission Trading Scheme (ETS) Directives, United States Environmental Protection Agency (US EPA) Final Rules, and the United Nations Framework

Convention on Climate Change (UNFCCC) Clean Development Mechanism (CDM) Modalities and Procedures (for developing countries). These protocols have varying levels of detail but similar principles and requirements for monitoring, and all include the need to quantify emissions and measure environmental impacts in the event of leakage to the surface. What they do not all include is the clarification that quantification monitoring should only be undertaken in cases where CO_2 has been attributed to leakage and not when leakage is only suspected. Quantifying suspected emissions is a significant monitoring challenge and undertaking, and may rely on acquiring large data sets over long time periods. This level of effort in monitoring would be unnecessary if the source of CO_2 detected at the surface is attributed to natural sources rather than from leakage, but a step to attribute CO_2 source is either missing from these protocols or is outdated in technical scope. Regulatory bodies call for protocols to be updated based on technical advances, and ongoing technical advances into leakage monitoring have now benefited from a first-ever public claim of leakage over a geologic CO_2 storage site in Saskatchewan, Canada, bringing more emphasis on the role of attribution monitoring. We present a brief update of some of the newest technical advances in attribution and suggest that CO_2 'attribution monitoring' could now be included in monitoring protocols to avoid unnecessary and costly quantification monitoring unless it is fully warranted. In this context, this paper describes an option to improve the existing protocols for monitoring CO_2 at geological storage sites made possible because of recent developments in near-surface attribution monitoring techniques.

DNV (2000). "DNV OSS-301 Certification and Verification of Pipelines." DNV OSS 301.

The objectives of this document are to: describe DNV's verification and certification services for submarine pipeline systems; describe DNV's approach to risk differentiated levels of verification involvement; provide guidance for the selection of the level of DNV verification involvement; provide guidance on how to establish a verification plan; provide a common communication platform for describing the extent of verification activities required for DNV certification of submarine pipelines.

DNV (2003). RP-H101, Recommended Practice: Risk Management in Marine - and Submarine Operations, Det Norske Veritas.

The overall objective with this Recommended Practice is to establish guidelines and recommendations for the process required to reach an acceptable and controlled exposure to risk during marine operations, for personnel, environment, assets and reputation. The Recommended Practice aim at zero accidents, incidents or losses through promoting safe, robust and efficient marine operations, and through application of the principles of ALARP. It is further the ambition that this document shall influence the overall awareness and consciousness of the exposure to risks during marine operations, as well as provide a basis for consistent and uniform understandings and applications of processes, tools and methods commonly used for managing and controlling these risks. A Risk Management Plan is recommended to describe, communicate and document the objectives, responsibilities and activities specified for assessing and reducing risk to an acceptable level.

This Recommended Practice should be used as a support document for the Risk Management Process required for Marine Operations. Marine Operations in this context are defined as: "Non-routine operations of a limited defined duration carried out for overall handling of an object at sea (offshore,inshore and at shore). Marine Operations are normally related to handling of objects during temporary phases from or to the quay side or construction sites to its final destination or installation site. Marine operations include activities such as load transfer operations, transport, installation, sub sea operations, decommissioning and deconstruction, rig moves and pipe laying". The Recommended Practice is considered applicable world wide, for simple single operations as well as larger complex development projects, from the need for a marine operation is realised, through the project period, until the operation is completed.

DNV (2004a). Marine operations during removal of offshore installations. Oslo, Norway, Det Norske Veritas.

The objective with this RP (Recommended Practice) is to establish technical guidelines and recommendations that would result in an acceptable low risk of failure for the marine operations needed during removal of offshore installations. This RP, including references and gives detailed requirements for: content of test and operational procedures, loads and load effects to be considered, strength and or capacity, condition and contingency or back-up of equipment and vessels, strength, quality and redundancy of temporary structures, and condition and strength verification of the object to be removed.

This is in order to ensure that the operation is planned and executed in a manner that fulfils the objective. By following the recommendations in this RP it is assumed that the safety of personnel and an acceptable working environment are ensured in general. However, specific personnel safety issues are not covered in any detail in this RP. Relaxations in the personnel HSE regulations applicable for marine operations during transport and installation of offshore structures shall not be allowed. If a removal operation involves risk of pollution, damage to live platforms or vessels not involved in the operation, additional requirements, i.e. not given in detail in this RP, will normally be applicable. This RP does not accept a lower safety level for removal operations than those for other marine operations. However, the structural strength acceptance criteria for the removed object can often be relaxed.

DNV (2004b). OSS-306, Offshore Service Specification: Verification of Subsea Facilities, Det Norske Veritas.

This document introduces a levelled description of verification involvement during all phases of an asset's life. It facilitates a categorisation into risk levels High, Medium and Low, assisting in an evaluation of the risk level. Assists in planning the verification through the making of a Verification Plan, and describes the DNV documentation of the process throughout. The document provides an international standard allowing transparent and predictable verification scope, as well as defining terminology for verification involvement. This document gives criteria for and guidance on verification of the integrity and function of parts or phases of subsea facilities.

DNV (2008a). RP-D101, Recommended Practice: Structural Analysis of Piping Systems, Det Norske Veritas.

This Recommended Practice is based on, and intends to, show the best from European industrial practice for structural analysis of piping systems intended for the offshore sector. Typical applications are Oil & Gas Platforms, FPSOs, Drilling Units and Subsea installations. Subsea installations are installations such as templates, manifolds, riser-bases and subsea separation and pump modules. There is no piping design code that fully covers these topics, and hence Engineering Companies have developed a variety of internal design philosophies and procedures in order to meet the requirements to structural integrity, safety, economical and functional design of piping systems. A number of references are given to below listed codes and standards from which equations for a large number of pipe stress relevant calculations can be found.

The objective of this recommended practice is to describe “a best practice” for how structural analysis of piping systems can be performed in order to safeguard life, property and the environment. It should be useful for piping structural engineers organizing and carrying out the piping design, and any 3rd party involved in the design verification, such as Class Societies, Notified Bodies etc. The proposed project documentation should provide the operator with essential design information and be useful during commissioning, maintenance, future modifications, and useful in order to solve operational problems, if and when they occur.

DNV (2009a). RP-F116, Recommended Practice: Integrity Management of Submarine Pipeline Systems, Det Norske Veritas.

This recommended practice provides requirements and recommendations for managing the integrity of submarine pipeline systems during the entire service life.

The objectives are to:

- Ensure that the operation of submarine pipeline systems are safe and conducted with due regard to public safety, environment and properties
- Present more detailed requirements based on these general requirements
- Present general requirements reflecting the parts of the DNV offshore standard DNV-OS-F101 that cover integrity management
- Provide guidance on how to comply with the requirements
- Serve as a guideline for operators and suppliers.

This recommended practice gives guidance on how to establish, implement and maintain an integrity management system. The main focus is on the Integrity Management Process; i.e. the combined process of threat identification, risk assessment, planning, monitoring, inspection, and repair. This recommended practice is applicable to rigid steel submarine pipeline systems, and its associated pipeline components. It focuses on structural/containment failures, and threats that may lead to such failures. The integrity management system described herein will also be applicable to rigid risers.

DNV (2010a). RP-J202, Recommended Practice: Design and Operations of CO_2 Pipelines, Det Norske Veritas.

This Recommended Practice(RP) has been developed in order to address the need for guidance for how to manage risks and uncertainties specifically related to transportation of CO_2 in pipelines. This document provides guidance and sets out criteria for the concept development, design , construction and operation of steel pipelines for the transportation of CO_2. It is written to be a supplement to existing pipeline standards and is applicable to both onshore and offshore pipelines. The RP is intended to assist in delivering pipelines in compliance with international laws and regulations. The pipeline operator will also have to ensure that the project is in compliance with local laws and regulations.

DNV (2010d). RP-E102, Recommended Practice: Recertification of Blowout Preventers and Well Control Equipment for the U.S. Outer Continental Shelf, Det Norske Veritas.

The purpose of this document is to describe DNV's recommendations for recertification of BOP and well control equipment used in drilling operations on the US Outer Continental Shelf. It is DNV's recommendation that a recertification of blowout preventers and well control equipment used for drilling, completion, workover and well intervention operations, should be performed at least every five years. The purpose of this recertification is to verify and document that the equipment condition and properties are within the specified updated acceptance criteria as well as recognized codes and standards, thus ensuring that documentation of the condition of the equipment is available at all times.

DNV (2010e). OS-F101, Offshore Standard: Submarine Pipeline Systems, Det Norske Veritas.

This standard gives criteria and guidance on concept development, design, construction, operation and abandonment of Submarine Pipeline Systems. The objectives of this standard are to:

- Ensure that the concept development, design, construction, operation and abandonment of pipeline systems are safe and conducted with due regard to public safety and the protection of the environment.

- Provide an internationally acceptable standard of safety for submarine pipeline systems by defining minimum requirements for concept development, design, construction, operation and abandonment
- Serve as a technical reference document in contractual matters between Purchaser and Contractor
- Serve as a guideline for Designers, Purchaser, and Contractors.

DNV (2010l). Key Aspects of an Effective U.S. Offshore Safety Regime, Det Norske Veritas.

As a consequence of the Deepwater Horizon blow-out accident in the Gulf of Mexico, DNV has prepared a position paper highlighting the key aspects of an effective US offshore safety regime. Major accidents tend to lead to a review and revision of current practices and regulations with the objective of avoiding other major accidents in the future. This also appears to be the case after the tragic Deepwater Horizon blow-out accident and subsequent oil spill. DNV´s views on key aspects of an effective offshore safety regime are presented in the position paper that has now been developed.

“The position paper is meant as input to the on-going discussion The white paper presented on the following pages has been on how to improve safety and environmental protection during off-prepared by Robin Pitblado and Peter Bjerager in Houston and shore oil and gas exploration, development and production,” says Eirik Andreassen in Oslo with input and suggestions received by a COO Elisabeth Tørstad, who has been in charge of the project. number of experts and managers in DNV.

DNV (2011a). RP-H103, Recommended Practice: Modelling and Analysis of Marine Operations, Det Norske Veritas.

The present Recommended Practice (RP) gives guidance for modelling and analysis of marine operations, in particular for lifting operations including lifting through wave zone and lowering of objects in deep water to landing on seabed. The objective of this RP is to provide simplified formulations for establishing design loads to be used for planning and execution of marine operations.

DNV (2011b). CO_2WELLS: Guideline for the Risk Management of Existing Wells at CO_2 Geological Storage Sites, Det Norske Veritas.

This document is a DNV guideline that describes a risk management framework for existing wells CO_2 storage sites, both onshore and offshore. It supplements the DNV CO_2QUALSTORE guideline(1) that was published in 2010 and is the final deliverable from the CO_2WELLS Joint Industry Project (April 2010 to June 2011). This guideline does not represent a standardized guidance for the design, operation and monitoring of new wells, although the qualification methodology described in Chapters 2 and 3 may be relevant to these activities. It is intended to support the development of CO_2 geological storage projects up to the point of final investment decision. The scope of work includes risk assessment of active and abandoned wells prior to storage site selection, and qualification of existing wells for abandonment, conversion or continued use at the storage site selected. It is consistent with current and emerging regulations for CO_2 geological storage and other supporting guidelines.

DNV (2012b). RP-J203, Geological Storage of Carbon Dioxide, Det Norske Veritas.

The main objective of this Recommended Practice (RP) is to provide a systematic approach to the selection, qualification and management of geological storage sites for CO_2. This RP specifies what, in DNV's opinion, is the best industry practice for that purpose and provides users with procedures and performance requirements for assessing and verifying the suitability of storage sites and projects for environmentally safe, long-term injection geological storage injected streams.This RP may be used for verification of monitoring and risk management plans and is considered applicable worldwide.

DNV (2012d). OSS-300, The DNV Offshore Service Specification: Risk Based Verification, Det Norske Veritas.

The document describes DNV's Risk Based Verification services and provides a common communication platform for describing the extent of verification activities, i.e. how to define a verification scope. It gives guidance to owners and other parties for selecting the level of involvement of the verifier and provides an opportunity to establish efficient, cost-effective, predictable, and transparent verification plans.

DNV (2013). CO_2RISKMAN, Guidance on CCS CO_2 Safety and Environment Major Accident Hazard Risk Management- Level 1,2,3 & 4, Det Norske Veritas.

This document forms one part of a DNV industry guidance that provides a comprehensive reference source to assist CCS projects and operations to appreciate, understand and communicate the issues, challenges and potential major accident hazards associated with handling CCS CO_2 streams. The CO_2RISKMAN guidance is structured to form a pyramid of four levels to allow it to be used to inform, educate and provide guidance to various levels of a CCS project or operation from senior management to hazard management specialist. The Guidance is not prescriptive, its goal is to help projects develop their competency in the subject area and their own integrated hazard management strategy that addresses the 'new' aspects associated with handling very large quantities of impure CO_2. The components of the reference are:

- Document Level 1 - Executive Summary
- Document Level 2 - Overview of level 3 & 4
- Document Level 3 - Generic information on hazard management, CCS, CO_2 which is applicable for use in major accident hazard management across the whole CCS chain
- Document Level 4 - CCS link specific guidance on hazard management and the application of this generic material into each main CCS chain unit.

The success of risk management will depend on the effectiveness of the management framework which provides the foundations and arrangements to embed it throughout the organisation at all levels. The framework assists in managing risks effectively through the application of the risk management process at varying levels and within specific contexts of the organisation. The framework also ensures that information about risk derived from the risk management process is adequately reported and used as a basis for decision making and accountability at all relevant organisational levels.

DOE/EPA (2010). Report of the interagency task force on carbon capture and storage. Washinton D.C., U.S. Government.

On February 3, 2010, President Obama sent a memorandum to the heads of fourteen Executive Departments and Federal Agencies establishing an Interagency Task Force on Carbon Capture and Storage. The goal was to develop a comprehensive and coordinated Federal strategy to speed the commercial development and deployment of clean coal technologies. The Task Force, co-chaired by the Department of Energy and the Environmental Protection Agency, was charged with proposing a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within 10 years, with a goal of bringing five to 10 commercial demonstration projects online by 2016. On August 12, 2010, the Task Force delivered a series of recommendations to the President on overcoming the barriers to the widespread, cost-effective deployment of CCS within ten years. The report concluded that CCS can play an important role in domestic GHG emissions reductions while preserving the option of using abundant domestic fossil energy resources. However, widespread cost-effective deployment of CCS will occur only if the technology is commercially available at economically competitive prices and supportive national policy frameworks are in place. The Task Force's recommendations included specific actions to help overcome remaining barriers and achieve the President's goals.

DOE/NETL (2012b). Mobility and Conformance Control for Carbon Dioxide Enhanced Oil Recovery (CO_2-EOR) via Thickeners, Foams, and Gels – A Detailed Literature Review of 40 Years of Research. National Energy Technology Laboratory, U.S. Department of Energy.

Carbon dioxide (CO_2) has been used commercially to recover oil from geologic formations by enhanced oil recovery (EOR) technologies for over 40 years. The U.S. Department of Energy Office of Fossil Energy and its predecessor organizations have supported a large number of laboratory and field projects over the past decades in an effort to improve the oil recovery process including investments to advanced reservoir characterization, mobility control, and conformance of CO_2 flooding. Currently, CO_2 EOR provides about 280,000 barrels of oil per day, just over 5 percent of the total U.S. crude oil production. Recently CO_2 flooding has become so technically and economically attractive that CO_2 supply, rather than CO_2 price, has been the constraining developmental factor. Carbon dioxide EOR is likely to expand in the United States in upcoming years due to "high?? crude oil prices, natural CO_2 source availability, and possible large anthropogenic CO_2 sources through carbon capture and storage (CCS) technology advances. Despite its well-established ability to recover oil, the CO_2 EOR process could be improved if the high mobility of CO_2 relative to reservoir oil and water can be effectively and affordably reduced. The CO_2 EOR industry continues to use water-alternating-with-gas (WAG) as the technology of choice to control CO_2 mobility and/or mechanical techniques (e.g., cement, packers, well control, infield drilling, and horizontal wells) to help control the CO_2 flood conformance. If the next generation CO_2 EOR target of 67 billion barrels is to be realized, new solutions are needed that can recover significantly more oil than the 10-20% of the original oil in place associated with current flooding practices. A recent literature review [Enick and Olsen 2011] concentrates on the history and development of CO_2 mobility control and profile modification technologies in the hope that stimulating renewed interest in these chemical techniques will help to catalyze new efforts to overcome the geologic and process limitations such as poor sweep efficiency, unfavorable injectivity profiles, gravity override, high ratios of CO_2 to oil produced, early breakthrough, and viscous fingering. This paper is a concise overview of the recent, comprehensive literature review available on the NETL website entitled "Mobility and Conformance Control for Carbon Dioxide Enhanced Oil Recovery (CO_2-EOR) via Thickeners, Foams, and Gels - A Detailed Literature Review of 40 Years of Research" [Enick and Olsen 2011] that focuses on attempts to enhance carbon dioxide mobility control (in-depth, long-term processes that cause CO_2 to exhibit mobility comparable to oil) and profile modification/conformance control (near-wellbore, short-term process primarily intended to greatly reduce the permeability of a thief zone) using CO_2 thickeners and CO_2 foams. In particular, this paper focuses on the history of CO_2 thickeners.

DOE/NETL (2013b). Site Screening, Selection, and Initial Characterization for Storage of CO_2 in Deep Geologic Formations. The Energy Lab.

This manual presents a systematic approach for selecting suitable locations for CO_2 GS projects based on an evolving set of science and engineering best practices as well as practical experience. The process begins with Potential Sub-Regions, identifies Selected Areas, and yields a prioritized list of Qualified Site(s). The approach draws on a number of existing reports and documents as well as industry practices. This manual builds on the experience of the RCSP Initiative as well as the body of literature and best practice guidelines developed by the research community and private industry from around the world. The manual is not intended as a guide to compliance with regulations but rather as a guide to considering the broader set of factors that determine the commerciality of a potential CO_2 GS site. Future editions are anticipated as experience gained through real-world commercial development of large, integrated CCS projects will help to inform and improve this manual and the proposed classification.

DOE/NETL (2013c). Best Practices for Carbon Storage Systems and Well Management Activities.

Carbon dioxide (CO_2) capture and storage (CCS) is one of several promising emission reduction strategies that can be used to help stabilize and reduce CO_2 emissions in the atmosphere while maintaining America's energy independence. The U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) has been actively researching and developing CCS technologies. The purpose of the DOE Carbon Storage Program is to demonstrate that CO_2 can be economically, successfully, and securely stored permanently in a manner that is compliant with the best engineering and geological practices; Federal, state, and local regulations; and in the best interests of local and regional stakeholders. In a typical CCS project, CO_2 is captured at an anthropogenic source, transported to a suitable location, and injected into deep geologic formations for permanent storage in saline and hydrocarbon bearing formations. Wells are a critical component of any CCS project; they will be drilled and completed for multiple purposes, including: exploring the suitability of geologic formations; injecting CO_2; monitoring the behavior and location of injected CO_2; and, in the case of CO_2 utilization through enhanced oil recovery (EOR), producing hydrocarbons from the injection zone. The purpose of this report is to share lessons learned regarding site-specific management activities for carbon storage well systems. This manual builds on the experiences of the Regional Carbon Sequestration Partnerships (RCSPs) and acquired knowledge from the petroleum industry and other private industries that have been actively drilling wells for more than 100 years. Specifically, this manual focuses on management activities related to the planning, permitting, design, drilling, implementation, and decommissioning of wells for geologic storage (GS) projects. A key lesson and common theme reiterated throughout the seven DOE Best Practice Manuals (BPMs) is that each project site is unique. This means that each CCS project needs to be designed to address specific site characteristics, and should involve an integrated team of experts from multiple technical (e.g., scientific and engineering) and nontechnical (e.g., legal, economic, communications) disciplines. Additionally, works during the characterization, siting, and implementation phases of projects are iterative; the results from previously completed tasks are analyzed and used to make decisions going forward. This means that as data comes in, the conceptual model of the site is revised and updated to allow better future decisions.

DOE/NETL (2015). Carbon Storage Atlas. U.S. Department of Energy, National Energy Technology Lab., Carbon Storage Atlas, fifth edition.

The U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) is proud to release the fifth edition of the Carbon Storage Atlas (Atlas V). Production of Atlas V is the result of collaboration among carbon storage experts from local, State, and Federal agencies, as well as industry and academia. Atlas V provides a coordinated update of carbon capture and storage (CCS) potential across the United States and other portions of North America. The primary purpose of Atlas V is to update the carbon dioxide (CO_2) storage potential for the United States and to provide updated information on DOE's carbon storage activities and field projects.

The Carbon Storage Atlas contains the following sections: (1) Introduction to CCS; (2) DOE's Carbon Storage Activities; (3) National Perspectives; (4) Large-Scale Field Projects; (5) Small-Scale Field Projects; and (6) American Recovery and Reinvestment Act (ARRA) Site Characterization Projects. The Introduction to CCS section is an overview of CCS. The DOE's Carbon Storage Activities section includes a summary of DOE's CCS activities, including information on DOE's Carbon Capture and Storage Programs, NETL's Office of Research and Development, systems analysis activities, DOE interagency and global collaborations, and knowledge sharing efforts. The National Perspectives section contains maps showing the number, location, and magnitude of CO_2 stationary sources in the United States, as well as the areal extent and estimated CO_2 storage resource available in DOE-evaluated geologic formations. The Large-Scale Field Projects, Small-Scale Field Projects, and Site Characterization Projects sections include a detailed background of each project, its objectives, a status update, and additional information.

Atlas V includes current and best available estimates of potential CO_2 storage resource determined by a methodology applied across all regions. A CO_2 storage resource estimate is defined as the fraction of pore volume of porous and permeable sedimentary rocks available for CO_2 storage and accessible to injected CO_2 via drilled and completed wellbores. Carbon dioxide storage resource assessments do not include economic or regulatory constraints; only physical constraints are applied to define the accessible part of the subsurface. Economic and regulatory constraints are included in geologic CO_2 capacity estimates.

The number of stationary CO_2 sources and CO_2 emissions reported in Atlas V is based on information gathered by the National Carbon Sequestration Database and Geographic Information System (NATCARB) as of November 2014. Likewise, the CO_2 storage resource estimates reported in Atlas V are based on information gathered by NATCARB as of November 2014. NATCARB is updated as new data are acquired and methodologies for CO_2 storage estimates improve. Furthermore, it is expected that, through the ongoing work of DOE/NETL, data quality and conceptual understanding of the CCS process will improve, resulting in more refined CO_2 storage resource estimates.

Doetsch, J., M. B. Kowalsky, C. Doughty, S. Finsterle, J. B. Ajo-Franklin, C. R. Carrigan, X. J. Yang, S. D. Hovorka and T. M. Daley (2013). "Constraining CO_2 simulations by coupled modeling and inversion of electrical resistance and gas composition data." international Journal of Greenhouse Gas Control(18).

This study investigates how model predictions of subsurface CO_2 migration can be constrained and improved with time-lapse electrical resistance tomography (ERT) data for a pilot experiment located at Cranfield, Mississippi. To this end, we first invert the time-lapse ERT dataset using structurally constrained and unconstrained inversions. With the ERT time-lapse inversions, we image the increasing supercritical CO_2 saturation in the reservoir and find that including the reservoir boundaries as structural constraints significantly improves the images. We then use ERT-derived changes in subsurface electrical resistivity along with gas composition data to constrain and calibrate hydrological models. We use the inversion framework iTOUGH2 and test several simplified conceptual models for the reservoir. Our analysis shows that the reservoir response cannot be adequately reproduced with a radial model; rather, the system exhibits 1D behavior. A model with three 1D layers, whose permeability values and width were estimated by inversion, is able to explain the ERT and gas composition data. Derived permeabilities agree with those from core measurements and a well test. Despite high noise levels, the ERT data provided crucial information in the inversion thanks to its high sensitivity at the inter-well scale, its stabilizing effect on the inversion, and the direct link it provides between electrical resistivity and CO_2 saturation.

Dugstad, A., B. Morland and S. Clausen (2011). "Corrosion of transport pipelines for CO_2-Effect of water ingress." Energy Procedia 4: 3063-3070.

Both field experience and lab data indicate that the corrosion rate of carbon steel in pure dense phase CO_2 is near zero if no free water is present. The question is whether this also applies when other contaminants like SOx, NOx, H2S and O2 are present in moderate amounts. In a pipeline network with different types of CO_2 sources, the commingling of streams with various impurities can give a very complex mixture, and side reactions like oxidation and decomposition of impurities can be foreseen. An important issue is how the contaminants partition between the various phases during pressure reduction and when free water is present. The corrosion mechanisms under these conditions are not well understood, and it becomes more and more uncertain what will happen when the concentration of contaminants including water increases. The paper addresses these issues and discusses recent corrosion flow loops and autoclaves results obtained in an ongoing sub-sea CO_2 transmission pipeline project.

Duncan, I. J., et al. (2009a). "Pore space ownership issues for CO_2 sequestration in the U.S." Energy Procedia 1(1): 4427-4431.

Previous assertions that the ownership of subsurface pore space in states in the US under common law are divided into a majority following the American Rule (surface rights owner owns pore space) and a minority following the English Rule (mineral rights owner owns the pore space) are shown to be inconsistent with case law precedents traced back to 1861. The mineral estate is not likely to “own” the pore space or to have the right to use the pore space for purposes other than extracting minerals. The exception will be where the original fee simple owner sells the surface rights but reserves the subsurface mineral rights. In all other circumstances it is likely that courts will find that the surface owner also owns the pore space under common law.

Dunk, R. M., E. T. Peltzer, P. M. Walz and P. G. Brewer (2005). "Seeing a Deep Ocean CO_2 Enrichment Experiment in a New Light: Laser Raman Detection of Dissolved CO_2 in Seawater." Environmental Science & Technology 39(24): 9630-9636.

We used a newly developed in situ laser Raman spectrometer (LRS) for detection of elevated levels of dissolved CO_2 in seawater. The experiment was carried out at 500 m depth, 6 °C, to examine new protocols for detection of CO_2-enriched seawater emanating from a liquid CO_2 source in the ocean, and to determine current detection limits under field conditions. A system of two interconnected 5 L chambers was built, with flow between them controlled by a valve and pump system, and this unit was mounted on an ROV. The first chamber was fitted with a pH electrode and the optical probe of the LRS. In the second chamber ∼580 mL of liquid CO_2 was introduced. Dissolution of CO_2 across the CO_2−seawater interface then occurred, the valves were opened, and a fixed volume of low-pH/CO_2-enriched seawater was transferred to the first chamber for combined pH/Raman sensing, where we estimate a mean dissolution rate of ∼0.5 (μmol/cm2)/s. This sequence was repeated, resulting in measurement of a progressively CO_2 enriched seawater sample. The rapid in-growth of CO_2 was readily detected as the Fermi dyad of the dissolved state with a detection limit of ∼10 mM with spectral acquisition times of 150 s. The detection of background levels of CO_2 species in seawater (∼2.2 mM, dominantly HCO3-) will require an improvement in instrument sensitivity by a factor of 5−10, which could be obtained by the use of a liquid core waveguide.

Eccles, J. K. and L. Pratson (2013). "Economic evaluation of offshore storage potential in the US Exclusive Economic Zone." Greenhouse Gases: Science and Technology 3(1): 84-95.

Drawing upon previously published results, we evaluate the offshore potential for storing CO_2 within marine sediments located inside the US Exclusive Economic Zone (EEZ). We then model the cost for transporting and injecting CO_2 into these strata, including into deep-marine (> 3000 m water depth) strata that we refer to as being ‘self-sealing' because pressure and temperature regimes would form an overlying gravitational seal. Finally, we compare the integrated transport and injection cost estimates for self-sealing and non-self-sealing offshore storage against the same integrated cost estimates for onshore storage in 15 deep saline sandstone aquifers located throughout the continental USA. The comparison is presented in the form of marginal abatement cost curves, which show that ocean storage is likely to be two or more times as expensive as onshore storage: 500 million tonnes of annual CO_2 emissions from coal-fired power plants in the USA is available for < $5/tonne in onshore DSAs, < $10/tonne in non-self-sealing offshore strata, and < $15/tonne in self-sealing offshore strata, with the cost differential between onshore and offshore storage increasing further up the supply curve. The higher total offshore costs are due to a combination of increases in transport and storage costs, with transport costs dominating total costs with increasing distance from shore. This suggests that CO_2 capture system operators would have to pay substantially more for offshore geologic storage over onshore options. The cost difference may be mitigated by certain advantages of offshore storage, which could include easier access to property rights, simplified regulation, and possibly lower monitoring, measurement, and verification (MMV) requirements.

ECO_2 (2015). Best Practice Guidance for Environmental Risk Assessment for offshore CO_2 geological storage. Sub-seabed CO_2 Storage: Impact on Marine Ecosystems. DNVGL: 49.

Carbon dioxide (CO_2) separated from natural gas has been stored successfully below the seabed off Norway for almost two decades. Based on these experiences several demonstration projects supported by the EU and its member states are now setting out to store CO_2 captured at power plants in offshore geological formations. The ECO_2 project was triggered by these activities and funded by the EU to assess the environmental risks associated with the sub-seabed storage of CO_2 and to provide guidance on environmental practices. ECO_2 conducted a comprehensive offshore field programme at the Norwegian storage sites Sleipner and Snøhvit and at several natural CO_2 seepage sites in order to identify potential pathways for CO_2 leakage through the overburden, monitor seep sites at the seabed, track and trace the spread of CO_2 in ambient bottom waters, and study the response of benthic biota to CO_2. ECO_2 identified a rich variety of geological structures in the broader vicinity of the storage sites that may have served as conduits for gas release in the geological past and located a seabed fracture and several seeps and abandoned wells where natural gas and formation water are released into the marine environment. Even though leakage may occur if these structures are not avoided during site selection, observations at natural seeps, release experiments, and numerical modelling revealed that the footprint at the seabed where organisms would be impacted by CO_2 is small for realistic leakage scenarios. ECO_2 conducted additional studies to assess and evaluate the legal framework and the public perception of CO_2 storage below the seabed. The following guidelines and recommendations for environmental practices are based on these experiences.

The legal framework that should be considered in the selection of storage sites and the planning of environmental risk assessments and monitoring studies includes not only the EU directive on CO_2 capture and storage (CCS) but related legislations including the EU Emission Trading Scheme, the Environmental Liability Directive, the London Protocol, OSPAR Convention, and Aarhus Convention. Public involvement in the planning and development of CCS projects is required by legislation. Based on its public perception studies, ECO_2 recommends that messages to be communicated should address the specific contribution of CCS to the mitigation of anthropogenic CO_2 emissions, its role within the context of other low carbon options as well as costs, safety and implementation issues at the local level. ECO_2 developed a generic approach for assessing consequences, probability and risk associated with subseabed CO_2 storage based on the assessment of i) the environmental value of local organisms and biological resources, ii) the potentially affected fraction of population or habitat, iii) the vulnerability of, and the impact on the valued environmental resource, iv) consequences (based on steps i – iii), v) propensity to leak, vi) environmental risk (based on steps iv and v). The major new element of this approach is the propensity to leak factor which has been developed by ECO_2 since it is not possible to simulate all relevant geological features, processes and events in the storage complex including the multitude of seepage-related structures in the overburden and at the seabed with currently available reservoir modelling software. The leakage propensity is thus estimated applying a compact description of the storage complex and more heuristic techniques accommodating for the large number of parameter uncertainties related to e.g. the permeability of potential leakage structures.

For site selection, ECO_2 recommends to choose storage sites that have insignificant risks related to i) geological structures in the overburden and at the seabed that may serve as conduits for formation water and gas release, ii) geological formations containing toxic compounds that can be displaced to the seabed, iii) low-energy hydrographic settings with sluggish currents and strongly stratified water column, iv) proximity of storage sites to valuable natural resources (e.g. Natura 2000 areas, natural conservation habitats, reserves for wild fauna and flora), v) areas in which biota is already living at its tolerance limits because of existing exposure to additional environmental and/or other anthropogenic stressors. Based on its extensive field programme ECO_2 recommends that overburden, seabed, and water column should be surveyed applying the following techniques: i) 3-D seismic, ii) high-resolution bathymetry/backscatter mapping of the seabed, iii) acoustic imaging of shallow gas accumulations in the seabed and gas bubbles ascending through the water column, iv) video/photo imaging of biota at the seabed, and v) chemical detection of dissolved CO_2 and related parameters in ambient bottom waters. Additional targeted studies have to be conducted if active formation water seeps, gas seeps, and pockmarks with deep roots reaching into the storage formation occur at the seabed. These sites have to be revisited on a regular basis to determine emission rates of gases and fluids and exclude that seepage is invigorated and pockmarks are re-activated by the storage operation. Baseline studies serve to determine the natural variability against which the response of the storage complex to the storage operation has to be evaluated. All measurements being part of the monitoring program, thus, need to be performed during the baseline study prior to the onset of the storage operation to assess the spatial and temporal variability of leakage-related structures, parameters, and processes.

Economides, M. J. and C. Economides (2009). Sequestering Carbon Dioxide in a Closed Underground Volume. SPE Annual Technical Conference and Exhibition. New Orleans, LA, Society of Petroleum Engineers.

The capture and subsequent geologic sequestration of CO_2 has been central to plans for managing CO_2 produced by the combustion of fossil fuels. The magnitude of the task is overwhelming in both physical needs and cost, and it entails several components including capture, gathering and injection. The rate of injection per well and the cumulative volume of injection in a particular geologic formation are critical elements of the process. Published reports on the potential for sequestration fail to address the necessity of storing CO_2 in a closed system. Our calculations suggest that the volume of liquid or supercritical CO_2 to be disposed cannot exceed more than about 1% of pore space. This will require from 50 to 200 times more underground reservoir volume than has been envisioned by many, and it renders geologic sequestration of CO_2 a profoundly non-feasible option for the management of CO_2 emissions. Material balance modeling shows that CO_2 injection in the liquid stage (larger mass) obeys an analog of the single-phase, liquid material balance, long-established in the petroleum industry for forecasting undersaturated oil recovery. The total volume that can be stored is a function of the initial reservoir pressure, the fracturing pressure of the formation or an adjoining layer, CO_2 and water compressibility values, and CO_2 solubility. Further, published injection rates, based on displacement mechanisms assuming open aquifer conditions are totally erroneous because they fail to reconcile the fundamental difference between steady state, where the injection rate is constant, and pseudo-steady state where the injection rate will undergo exponential decline if the injection pressure exceeds an allowable value. A limited aquifer indicates a far larger number of required injection wells for a given mass of CO_2 to be sequestered and/or a far larger reservoir volume than the former. Introduction According to the United Nations Intergovernmental Panel for Climate Change (IPCC, 2007), "the increases in atmospheric carbon dioxide (CO_2) and other greenhouse gases during the industrial era are caused by human activities,?? and the IPCC insists that anthropogenic greenhouse gas emissions are harmful to the planet and are causing global climate change evident as global temperature rise and local weather extremes. Although greenhouse gases include water vapor, carbon dioxide, and methane, that are emitted through various means, the focus of this paper is strictly on carbon dioxide emissions. In 2008 coal consumption for electric power generation in the United States was 1.04 billion short tons (tons) per year (EIA, 2009), and total carbon dioxide emissions in 2007 were 6.02 billion metric tons (tonnes) including 2.16 billion tonnes from coal fired electric power generation, 2.6 billion tonnes from petroleum consumption mainly for transportation, and 1.2 billion tonnes from natural gas consumption. By 2030 US carbon dioxide emissions are forecast to reach 6.41 billion tonnes according to the EIA. The Kyoto Protocol proposed for the US to reduce carbon dioxide emissions to 93% of the 1990 emission level, or to keep it at a level below 4.67 billion tonnes for every year from December 1997, the year of its enactment, and onward. To satisfy the Kyoto Protocol, carbon dioxide emissions should already be reduced and would have to be reduced by 1.75 billion tonnes per year by 2030. This task is enormous and will be exacerbated further by recent legislation that proposes even more stringent goals.

Eiken, O., P. Ringrose, C. Hermanrud, B. Nazarian, T. A. Torp and L. Høier (2011). "Lessons learned from 14 years of CCS operations: Sleipner, In Salah and Snøhvit." Energy Procedia 4(0): 5541-5548.

In the paper we share our operational experience gained from three sites: Sleipner (14 years of injection), In Salah (6 years) and Snøhvit (2 years). Together, these three sites have disposed 16 Mt of CO_2 by 2010. In highly variable reservoirs, with permeability ranging from a few milliDarcy to more than one Darcy, single wells have injected several hundred Kt of CO_2 per year. In the reservoirs, the actual CO_2 plume development has been strongly controlled by geological factors that we learned about during injection. Geophysical monitoring methods (especially seismic, gravity, and satellite data) have, at each site, revealed some of these unpredicted geological factors. Thus monitoring methods are as valuable for reservoir characterisation as they are for monitoring fluid saturation and pressure changes. Current scientific debates that address CO_2 storage capacity mainly focus on the utilization of the pore space (efficiency) and the rate of pressure dissipation in response to injection (pressure limits). We add to this that detailed CO_2 site characterisation and monitoring is needed to prove significant practical CO_2 storage capacity–on a case-by-case basis. As this specific site experience and knowledge develops more general conclusions on storage capacity, injectivity and efficiency may be possible.

Eldevik, F. (2008). "Safe Pipeline Transmission of CO_2." Pipeline & Gas Journal 235(11).

Together with major industry partners, Det Norske Veritas (DNV) is developing new guidelines for design and operation of onshore and offshore pipelines for the transmission of CO_2. The article provides a wider audience insight into the ongoing industrial collaboration on developing a new guideline for design and operation of onshore and offshore pipelines for transmission of CO_2. The reason behind this initiative is given in the article. The guideline will give provisions for specific issues related to transmission of dense CO_2, and these specific issues are also addressed.

Element Energy (2011). Development of a CO_2 Transport and a Storage Network in the North Sea. North Sea CCS Infrastrucutre: Report to the North Sea Basin Task Force, BERR: Department for Business Enterprise & Regulatory Refor.

The UK and Norwegian governments wish to examine the role that a pipeline infrastructure for carbon dioxide capture and storage (CCS) could play in reducing CO_2 emissions from both countries. The present study, commissioned by the UK Department of Business, Enterprise and Regulatory Reform (formerly the Department of Trade and Industry) on behalf of the UK, Norway and North Sea Basin Task Force, examines possible development pathways for a CCS pipeline infrastructure connecting large UK and Norwegian sources with appropriate sinks in the North Sea and reports on the implications for both countries. To examine these issues, the project team developed a comprehensive database of onshore CO_2 sources and offshore CO_2 sinks. A list of CO_2 tolerant pipelines in the North Sea was also developed and the potential for reuse of existing oil and gas infrastructure for CCS was explored. Making use of the above databases, a CCS network model was developed; permitting relatively rapid assessment of network configurations Simple user input is required to define pipeline configurations over a set of development phases. It calculates sizing, capacity requirements and costs for CO_2 capture sources, new pipelines and booster stations, and offshore infrastructure, to provide estimates of capital and ongoing expenditure, CO_2 captured and abated. Lifetime cost of carbon abated is used to measure the efficiency of networks.

Element Energy (2014). Scotland and the Central North Sea CCS Hub Study, Scottish Enterprise: 139.

The study begins with a critical review of the opportunities for CO_2 capture at new and existing industrial CO_2 sites in Scotland. Building on this and current projects plans, it identifies potential scenarios for CO_2 capture deployment in the UK and around the North Sea towards 2050. Next the study reviews storage capacity and the potential for CO_2-EOR in the Central North Sea, and identifies scenarios and opportunities for exploiting these storage and CO_2-EOR resources. Having identified source and storage configurations, the study identifies potential designs for the onshore and offshore infrastructure needed to collect CO_2 from sources and transport to stores, including the role of onshore and offshore clusters, existing infrastructure and hubs. Potential stakeholder interventions to overcome barriers to delivering the infrastructure that maximizes the opportunities for Scotland are reviewed. Finally the report makes several recommendations for both Scottish Enterprise and other stakeholders to facilitate opportunities for CCS and CO_2-EOR.

Elkins, P., R. Vanner, and J. Firebrace (2005). "Decommissioning of Offshore Oil and Gas Facilities: Decommissioning Scenarios: A Comparative Assessment Using Flow Analysis." Policy Studies Institute. Emberley, S., I. Hutcheon, M. Shevalier, K. Durocher, B. Mayer, W. D. Gunter and E. H. Perkins (2005). "Monitoring of fluid–rock interaction and CO_2 storage through produced fluid sampling at the Weyburn CO_2-injection enhanced oil recovery site, Saskatchewan, Canada." Applied Geochemistry 20(6): 1131-1157.

A material and energy flow analysis, with corresponding financial flows, was carried out for different decommissioning scenarios for the different elements of an offshore oil and gas structure. A comparative assessment was made of the non-financial (especially environmental) outcomes of the different scenarios, with the reference scenario being to leave all structures in situ, while other scenarios envisaged leaving them on the seabed or removing them to shore for recycling and disposal. The costs of each scenario, when compared with the reference scenario, give an implicit valuation of the non-financial outcomes (e.g. environmental improvements), should that scenario be adopted by society. The paper concludes that it is not clear that the removal of the topsides and jackets of large steel structures to shore, as currently required by regulations, is environmentally justified; that concrete structures should certainly be left in place; and that leaving footings, cuttings and pipelines in place, with subsequent monitoring, would also be justified unless very large values were placed by society on a clear seabed and trawling access.

Energy Institute (2013). Hazard Analysis for Offshore Carbon Capture Platforms and Offshore Pipelines.

The publication initially provides an understanding of the thermodynamics of pure CO_2, particularly liquid CO_2 (dense phase), since the majority of offshore applications will involve CO_2 in this state. In dense phase conditions, typical of those that would be expected in offshore pipelines and on platforms, the thermodynamic and physical properties of CO_2 are affected by impurities, and the implications of these impurities on the underlying properties are therefore addressed. The impact of the different properties of CO_2 on the hazards associated with carbon capture and storage applications are described. Some are hazards associated with CO_2 itself, whereas others are associated with impurities found within CCS CO_2 streams. However, designers can draw upon the considerable experience of both the offshore oil and gas industries worldwide to understand these hazards, and to minimise their impact. This publication provides guidance and references to assist with this.

There is an introduction to hazard analysis, and some of the hazards associated with CO_2 for offshore CCS applications are presented, together with how these can be used in conjunction with a hazard analysis. The potential hazards to personnel, both from CO_2 and the possible impurities likely to be found from the capture processes, are described. These are set in the context of how they might apply to offshore CO_2 transport and injection facilities. There is an example of the composition of captured CO_2, and the risks associated with operating outside of the limits described are outlined. The publication includes simplified examples of release modelling from a number of different possible offshore scenarios to demonstrate the use of an integral programme. The scenarios chosen are low-probability high-impact events, which demonstrate the capabilities of dispersion modelling. Overall, the majority of the release scenarios chosen indicate that the potential could exist for some degree of adverse impact either for persons on the platform deck or for those close to sea level (for example, ships or rescue vessels), but they also highlight the need for additional work to be carried out in some areas.

To enable the reader to understand typical design considerations for ensuring safe offshore CO_2 systems and the risk potential with respect to failure modes, some of the main system components associated with CO_2 transport, injection, offshore EOR processing of CO_2, and re-injection are described. This document also describes some typical mitigation techniques available to minimise the potential for failure.This publication should supplement rather than substitute regulatory requirements, many of which are referenced within the text. The intention is to allow project developers and designers to meet their statutory obligations with increased certainty.

The intention of this publication is to:

- Provide a basic guide for the health and safety hazard analysis for offshore management of CO_2 pipelines and platforms, where CO_2 will be present as a part of carbon capture and storage (CCS) installations

- Communicate existing knowledge on pipeline and offshore facility design and operation and identify areas of uncertainty where existing knowledge cannot be applied with sufficient confidence, considering the scale and nature of expected CCS operations in the future

- Allow engineers and project managers involved in CCS projects to widen their knowledge base to ensure that procurement of equipment and operational guidelines are using current knowledge

- Supplement the Technical Guidance on hazard analysis for onshore carbon capture installations and onshore pipelines which has previously been published

EPA (2008). Approaches to Geological Sequestration Site Stewardship After Site Closure, Office of Water.

This paper describes stakeholder-developed models for site stewardship at geologic sequestration (GS) sites, and summarizes examples of federal programs that may inform development of alternative models for stewardship of GS after site closure. EPA's proposed rulemaking, Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells, describes a new class of well and technical criteria for the geologic site characterization, fluid movement, area of review (AoR) and corrective action, well construction, operation, mechanical integrity testing, monitoring, well plugging, post-injection site care, and site closure to protect underground sources of drinking water (USDWs). As part of this proposal, EPA lays out general requirements for financial responsibility, and plans to clarify in guidance the types of financial mechanisms that owners or operators can use to meet financial responsibility requirements for new GS wells. The financial responsibility requirements would include provisions requiring that owners and operators demonstrate and maintain financial responsibility during operation, closure, and the post-injection site care period. This ensures that owners and operators have the resources to carry out activities related to closing and remediating GS sites if needed during injection or after wells are plugged, so that they do not endanger USDWs. Issues, such as the long timeframes anticipated for CO_2 sequestration, the absence of provisions in the Safe Drinking Water Act (SDWA) to allow transfer of liability to other government entities, and the requirement under SDWA that the responsibility for potential impacts to USDWs all have resulted in stakeholder requests for a discussion of alternative approaches to liability for GS sites. In addition, owners and operators may need to address liability related to potential impacts to air, ecosystems, and human health beyond the scope of the SDWA. These considerations, and the fact that the GS storage timeframe may exceed the lifetime of a typical owner or operator of a GS site, have led to requests that EPA provide information on site stewardship after site closure as part of its proposed rulemaking for GS wells. Accordingly, EPA has developed this paper to provide additional information on approaches to stewardship of carbon dioxide GS sites after site closure. Since the SDWA does not explicitly provide EPA the authority to transfer liability from the owner/operator to another entity, this paper is for informational purposes only.

EPA (2010a). Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide, Final Rule. EPA, Washington,D.C. 75: 31.

EPA is promulgating a regulation to require greenhouse gas monitoring and reporting from facilities that conduct geological sequestration of CO_2 and all other facilities that conduct injection of CO_2. This rule does not require control of greenhouse gases, rather it requires only monitoring and reporting of greenhouse gases.

EPA (2010b). General Technical Support Document for Injection and Geologic Sequestration of Carbon Dioxide: Suparts RR and UU. Greenhouse Gas Reporting Program. O. o. A. a. Radiation, U.S. Environmental Protection Agency: 98.

On November 22, 2010, the U.S. Environmental Protection Agency (EPA) issued a final rule that requires facilities that conduct geologic sequestration of carbon dioxide (CO_2) and all other facilities that inject CO_2 underground to report greenhouse gas (GHG) data to EPA annually. Subpart RR of this rule requires GHG reporting from facilities that inject carbon dioxide (CO_2) underground for geologic sequestration, and subpart UU requires GHG reporting from all other facilities that inject CO_2 underground for any reason, including enhanced oil and gas recovery.

EPA (2010c). Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS*) Wells 40 CFR* Parts 124, 144, 145, 146, and 147 77230 *Federal Register*; v. 75, no. 237.

This action finalizes minimum Federal requirements under the Safe Drinking Water Act (SDWA) for underground injection of carbon dioxide (CO_2) for the purpose of geologic sequestration (GS). GS is one of a portfolio of options that could be deployed to reduce CO_2 emissions to the atmosphere and help to mitigate climate change. This final rule applies to owners or operators of wells that will be used to inject CO_2 into the subsurface for the purpose of long-term storage. It establishes a new class of well, Class VI, and sets minimum technical criteria for the permitting, geologic site characterization, area of review (AoR) and corrective action, financial responsibility, well construction, operation, mechanical integrity testing (MIT), monitoring, well plugging, postinjection site care (PISC), and site closure of Class VI wells for the purposes of protecting underground sources of drinking water (USDWs). The elements of this rulemaking are based on the existing Underground Injection Control (UIC) regulatory framework,with modifications to address the unique nature of CO_2 injection for GS. This rule will help ensure consistency in permitting underground injection of CO_2 at GS operations across the United States and provide requirements to prevent endangerment of USDWs in anticipation of the eventual use of GS to reduce CO_2 emissions to the atmosphere and to mitigate climate change.

EPA (2013c). Underground Injection Control (UIC) Program Class Six Well Testing and Monitoring Guidance. Geologic Sequestration of Carbon Dioxide, Environmental Proctection Agency, Office of Water: 115.

The purpose of this guidance document is to describe the technologies, tools, and methods available to owners or operators of Class VI wells to fulfill the Class VI Rule requirements related to developing and implementing site-and project-specific strategies for testing and monitoring. The intended primary audiences of this guidance document are Class VI injection well owners or operators, contractors performing testing and monitoring activities, and Program Directors.

Eriksen, O. K., C. Berndt, S. Buenz, F. N. Eriksen and S. Planke (2012). Seismic characteristics of gas migration structures on the North Atlantic margin imaged by high-resolution 3D seismic. 74th EAGE Conference & Exhibition incorporating SPE EUROPEC 2012. Copenhagen, Denmark: 5.

We have acquired high-resolution P-Cable 3D data on five sites in the North Atlantic revealing a variety ofdifferent fluid migration characteristics. Both the Vestnesa and Nyegga areas offshore Svalbard and mid-Norway are characterized by pockmarks and vertical pipe structures. Gas hydrates are present in theseareas and a layer of free gas is trapped beneath the gas hydrate stability zone. Kilometer-sized mudvolcanoes have been imaged in the Gulf of Cadiz (Mercator Mud Volcano) and on the western Barents Seamargin (Haakon Mosby Mud Volcano) showing a circular crater with chaotic infill surrounded by inwarddipping reflections. The Barents Sea contains large accumulations of shallow gas. We have acquired datafrom two sites were shallow gas and gas hydrates are interpreted. However, no vertical pipe structures areidentified in the imaged regions. The surveys show that high-resolution 3D seismic data are very useful formapping shallow gas and gas hydrates, for increased offshore safety, and for understanding of fluid flow processes.

ERM (2010). Update on Selected Regulatory Issues for CO_2 Capture and Geological Storage. Environmental Resources Management (ERM).

As carbon capture and storage (CCS) is increasingly recognized by policy-makers as a key carbon abatement technology, legal and regulatory frameworks for CCS are emerging in several jurisdictions worldwide. Commercial investors in CCS project need to have a comprehensive framework which ensures that all aspects of the regulatory process are covered and can be understood when evaluating project risk. Governments should therefore continue to further develop regulatory frameworks and address the gaps that remain in the treatment of CCS projects, in order to accelerate demonstration and widespread deployment. Regulatory frameworks for CCS are at various stages of development and a number of important issues remain unresolved. In order to ensure that CCS projects are viable and successful, particular effort will be required by policymakers and regulatory agencies in all jurisdictions to ensure that:

- Licensing and permitting procedures do not present unnecessary delays to CCS deployment whilst also providing adequate assurance to the public that sites approved are safe and secure

- Authorities are able to assure CCS project developers that all regulatory requirements for a CCS project have been agreed by governments and can be communicated clearly to project sponsors

- Unresolved issues concerning long-term liability, transfer and financial provisions do not impose inordinate risk to commercial investment, thereby delaying widespread CCS deployment

- The development of legal frameworks at different levels of government (e.g., federal and state level) do not give rise to unaligned policy-making and regulation, thereby leading to uncertainty for CCS project investors and operators

This report provides an up-to-date review of a number of regulatory issues applicable to CCS projects identified as priority areas by the CCP3 team, and identifies potential barriers or gaps. The report also presents a survey of existing and emerging monitoring, reporting and verification (MRV) guidelines and requirements applicable to CCS, as well as perspectives from CCS project developers and regulators on key regulatory issues.

Estublier, A. and A. S. Lackner (2009). "Long-term simulation of the Snøhvit CO_2 storage." Energy Procedia 1(1): 3221-3228.

The purpose of this study is to simulate and evaluate the long-term (1000 years) consequences of carbon dioxide injection into a deep (2700 m) saline formation in the Snøhvit field located offshore in the northern Norwegian Sea. During the 30-year-lifetime of the project, which began in summer 2007, approximately 23 million tons of CO_2 are injected through one well. In order to analyse different possible CO_2 migration pathways, several scenarios have been assumed and simulated. They deal with the sealing capacity of the main faults and of the saline formation cap rock.

European Commission (2009). "Geological storage of carbon dioxide." Official Journal of the European Union, L 140/114 Directive 2009/31/EC of the European Parliament and of the Council of 23 April 2009

This Directive shall apply to the geological storage of CO_2 in the territory of the Member States, their exclusive economic zones and on their continental shelves within the meaning of the United Nations Convention on the Law of the Sea (Unclos). This Directive shall not apply to geological storage of CO_2, with a total intended storage below 100 kilotonnes, undertaken for research, development or testing of new products and processes. The storage of CO_2 in a storage site with a storage complex extending beyond the area referred to in paragraph 1 shall not be permitted. The storage of CO_2 in the water column shall not be permitted.

European Commission (2010). Monitoring and Reporting Guidelines for Greenhouse Gas Emission from the Capture, Transport and Geological Storage of Carbon Dioxide. European Union, 2010/345/EU.

This document is an official journal of the European Union which is am amedment document of Decision 2007/589/EC as regards the inclusion of monitoring and reporting guidelines for greenhouse gas emissions from the capture, transport and geological storage of carbon dioxide.

European Commission (2011a) Guidance Document 1: CO_2 Storage Life Cycle Risk Management Framework. Implementation of Directive 2009/31/EC on the Geological Storage of Carbon Dioxide Guidance Document 1, DOI: 10.2834/9801

The purpose of the set of four Guidance Documents is to assist stakeholders to implement Directive 2009/31/EC on the geological storage of CO_2 (so-called CCS Directive) in order to promote a coherent implementation of the CCS Directive throughout the European Union (EU). The guidance does not represent an official position of the Commission and is not legally binding. Final judgments concerning the interpretation of the CCS Directive can only be made by the European Court of Justice.

Guidance Document 1 (GD1) addresses the overall framework for geological storage in the CCS Directive for the entire life cycle of geological CO_2 storage activities including its phases, main activities and major regulatory milestones. Other issues addressed in the document include the high-level approach to risk assessment and management which is intended to ensure the safety and effectiveness of geological storage, and the processes by which the Competent Authority or Authorities1 (CA or CAs) in each Member State can interact with the operators at key project stages, particularly with regard to risk management. This document provides/describes: 1) an introduction to the legislative context relating to the life cycle and risk management; 2) a detailed framework for the life cycle of CO_2 storage projects 3) the geological context for CO_2 storage in Europe, 4) the nature of risks in geological storage, 5) risk management of storage including risk identification, risk ranking and risk management, and 6) a summary of key issues.

European Commission (2011b) Guidance Document 2, Characterization of the Storage Complex, CO_2 **Stream Composition, Monitoring and Corrective Measures. Implementation of Directive**

2009/31/EC on the Geological Storage of Carbon Dioxide Guidance Doument 2, DOI: 10.2834/98293

The purpose of this set of Guidance Documents is to assist stakeholders to implement Directive 2009/31/EC on the geological storage of CO_2 (so-called CCS Directive) in order to promote a coherent implementation of the CCS Directive throughout the European Union (EU). The guidance does not represent an official position of the Commission and is not legally binding. Final judgments concerning the interpretation of the CCS Directive can only be made by the European Court of Justice. This Guidance Document 2 (GD2) builds on the first Guidance Document (GD1) that has laid out the overarching framework and nomenclature for the entire life cycle of geological storage activities including its phases, main activities and major regulatory milestones. This non-legally binding document provides guidance on: 1) Site selection, 2) Composition of the CO_2 stream, 3) Monitoring, and 4) Corrective measures. It is important to recognize that the scientific basis for CCS is evolving, as more information is gained through the ongoing global research and development efforts. Thus, the scientific knowledge base on issues such as mapping technologies for evaluating storage locations, injection technologies, monitoring technologies, significance of various components in a CO_2 stream, and application of corrective measures will improve over time.

European Commission (2011c) Guidance Document 3: Criteria for Transfer of Responsibility to the Competent Authority. Implementation of Directive 2009/31/EC on the Geological Storage of Carbon Dioxide Guidance Document 3, DOI: 10.2834/21150

The purpose of this set of Guidance Documents is to assist stakeholders to implement Directive 2009/31/EC on the geological storage of CO_2 (so-called CCS Directive) in order to promote a coherent implementation of the CCS Directive throughout the European Union (EU). The guidance does not represent an official position of the Commission and is not legally binding. Final judgments concerning the interpretation of the CCS Directive can only be made by the European Court of Justice. This Guidance Document 3 (GD3) addresses the issue of transfer of responsibility for all legal obligations from a site operator to the Competent Authority or Authorities (CA or CAs). Article 18 of the CCS Directive specifies the conditions under which all legal obligations can be transferred to the CA of the Member State. It is important to recognize that the scientific basis for CCS is evolving, as more information is gained through the ongoing global research and development efforts. Thus, the scientific knowledge base on issues associated with transfer of responsibility will improve over time.

European Commission (2011d) Guidance Document 4: Article 19 Financial Security and Article 20 Financial Mechanism. Implementation of Directive 2009/31/EC on the Geological Storage of Carbon Dioxide Guidance Document 4, DOI: 10.2834/99563

This Guidance Document (4 of 4) addresses Article 19 (Financial Security) and Article 20 (Financial Contribution) of the CCS Directive. The guidance provides information and options that MS may choose to use in establishing an effective system for FS, including options for defining FS instruments or acceptable equivalents, determining amounts of FS for site operators' obligations under the CCS Directive, criteria for issuers of FS instruments and procedures for establishing, maintaining, and releasing FS. The guidance also describes options for determining the amount of the financial contribution to be made available by operators prior to transfer of their storage sites to their CAs, including similarities and differences with methods described for determining amounts of FS. The guidance encourages MS to secure the payment of the FC through the instruments and procedures described for FS. For both Article 19 and Article 20, the guidance describes the legislative context and the relevant obligations from the CCS Directive. The Guidance recommends options that are simple, established, and low risk. Complex financial arrangements should be avoided as outside the core competencies of CAs; arrangements that appear to flout financial principles (e.g., more certainty and higher return) may contain hidden risks. The intent of FS and FC is to protect the taxpayers and these programmes should not be used for financial speculation.

European Commission (2014). The implementation of Directive 2009/31/EC on the geological storage of carbon dioxide. Brussels, THE EUROPEAN PARLIAMENT AND THE COUNCIL.

This report from the European Commission to the European Parliament and Council addresses the general progress in implementation and specific implentation issues of the Directive on geologic storage of carbon dioxide (Directive 2009/31/EC) in the member states. The specific implementation issues are: permitting of CO_2 storage, obligations for operations of the storage sites, closure and post-closure obligations, financial guarantees, and trans-boundary issues.

Freifeld, B. M., T. M. Daley, S. D. Hovorka, J. Henninges, J. Underschultz and S. Sharma (2009). "Recent advances in well-based monitoring of CO_2 sequestration." Greenhouse Gas Control Technologies 9 1(1): 2277-2284

Recent CO_2 sequestration pilot projects have implemented novel approaches to well-based subsurface monitoring aimed at increasing the amount and quality of information available from boreholes. Some of the drivers for the establishment of new well-based technologies and methodologies arise from: (1) the need for data to assess physical and geochemical subsurface processes associated with CO_2 emplacement; (2) the high cost of deep boreholes and need to maximize data yield from each; (3) need for increased temporal resolution to observe plume evolution; (4) a lack of established processes and technologies for integrated permanent sensors in the oil and gas industry; and (5) a lack of regulatory guidance concerning the amount, type, and duration of monitoring required for long-term performance confirmation of a CO_2 storage site. In this paper we will examine some of the latest innovations in well-based monitoring and present examples of integrated monitoring programs.

Gasperikova, E. and G. M. Hoversten (2008). "Gravity monitoring of CO_2 movement during sequestration: Model studies." Geophysics 73(6): Wa105-Wa112.

The aim of this paper is to determine the effectiveness of gravitational monitoring of the CO_2 plume in EOR, deep saline and coal-bed sequestration projects as a low-cost alternative to seismic monitoring. The study found that for EOR projects surface gravity measurements needed to be supplemented with measurements from boreholes just above the reservoir in order to observe changes in Gz as CO_2 injection preceded. The detection of the CO_2-brine front was more successful, but in this study gravity monitoring required 30% CO_2 and 70% brine saturations. There were no detectable measurements for coal-bed monitoring for a pilot scale project. Overall, the authors seem confident that gravity monitoring can provide a low-cost alternative to seismic monitoring, with the use of the seismic method only during the initial reservoir characterization and risk assessment. However, the gravity inversion data only provided the general position of density changes cause by CO_2 and not an absolute value of change. Sequestration/enhanced oil recovery (EOR) petroleum reservoirs have relatively thin injection intervals with multiple fluid components (oil, hydrocarbon gas, brine, and carbon dioxide, or CO_2), whereas brine formations usually have much thicker injection intervals and only two components (brine and CO_2). Coal formations undergoing methane extraction tend to be thin (3–10 m) but shallow compared to either EOR or brine formations. Injecting CO_2 into an oil reservoir decreases the bulk density in the reservoir. The spatial pattern of the change in the vertical component of gravity (G(z)) is correlated directly with the net change in reservoir density. Furthermore, time-lapse changes in the borehole G(z) clearly identify the vertical section of the reservoir where fluid saturations are changing. The CO_2-brine front, on the order of 1 km within a 20 m thick brine formation at 1900 m depth with 30% CO_2 and 70% brine saturations, respectively, produced a -10 mu Gal surface gravity anomaly. Such an anomaly would be detectable in the field. The amount of CO_2 in a coal-bed methane scenario did not produce a large enough surface gravity response; however, we would expect that for an industrial-size injection, the surface gravity response would be measurable. Gravity inversions in all three scenarios illustrate that the general position of density changes caused by CO_2 can be recovered but not the absolute value of the change. Analysis of the spatial resolution and detectability limits shows that gravity measurements could, under certain circumstances, be used as a lower-cost alternative to seismic measurements.

Gemmer, L., O. Hansen, M. Iding, S. Leary and P. Ringrose (2012). "Geomechanical response to CO_2 injection at Krechba, In Salah, Algeria." First Break 30(2): 79-84.

The authors discuss the geomechanical modelling of the rock mechanical response to CO_2 injection at the Krechba gas field in Algeria arguing that key factors to understanding are the sensitivity of the model to the initial stress field and the rock-mechanical properties of the fault/fracture zones.

Gilfillan et.al (2009). "Solubility trapping in formation water as dominant CO_2 **sink in natural gas fields." Nature 458: 614–618.**

Injecting CO_2 into deep geological strata is proposed as a safe and economically favourable means of storing CO_2 captured from industrial point sources. It is difficult, however, to assess the long-term consequences of CO_2 flooding in the subsurface from decadal observations of existing disposal sites. Both the site design and long-term safety modelling critically depend on how and where CO_2 will be stored in the site over its lifetime. Within a geological storage site, the injected CO_2 can dissolve in solution or precipitate as carbonate minerals. Here we identify and quantify the principal mechanism of CO_2 fluid phase removal in nine natural gas fields in North America, China and Europe, using noble gas and carbon isotope tracers. The natural gas fields investigated in our study are dominated by a CO_2 phase and provide a natural analogue for assessing the geological storage of anthropogenic CO_2 over millennial timescales. We find that in seven gas fields with siliciclastic or carbonate-dominated reservoir lithologies, dissolution in formation water at a pH of 5–5. 8 is the sole major sink for CO_2. In two fields with siliciclastic reservoir lithologies, some CO_2 loss through precipitation as carbonate minerals cannot be ruled out, but can account for a maximum of 18 per cent of the loss of emplaced CO_2. In view of our findings that geological mineral fixation is a minor CO_2 trapping mechanism in natural gas fields, we suggest that long-term anthropogenic CO_2 storage models in similar geological systems should focus on the potential mobility of CO_2 dissolved in water.

Girard, J. F., N. Coppo, J. Rohmer, B. Bourgeois, V. Naudet and C. Schmidt-Hattenberger (2011). "Time-lapse CSEM monitoring of the Ketzin (Germany) CO_2 **injection using 2×MAM configuration." Energy Procedia 4(0): 3322-3329.**

This paper deals with the electrical resistivity monitoring of the Ketzin CO_2 injection pilot (CO_2ReMoVe EC project) through time-lapse CSEM measurements. There, 3 boreholes about 800 m deep have been especially designed for current injection at reservoir (sandstone) depth. CO_2 is directly injected in a saline (~240 g/l) aquifer. Prior modelling results indicated that the increase of electrical resistivity generated by the CO_2 plume (gaseous and liquid CO_2 phases) supposed to be highly resisitive, would generate measurable changes in the EM fields on the surface, when injecting current directly inside the reservoir. In order to highlight and follow these expected resistivity changes, 3 CSEM surveys were performed in August 2008 (baseline prior to injection), June 2009 and August 2010. Each time, 13 EM stations have been recorded during current injection of a square wave at 3 frequencies (0.125 Hz, 0.5 Hz and 4 Hz) in two configurations (“double mise à la masse” (2×MAM) and “mise à la masse–surface” (MAM-Surface)). This paper only presents results of the 2×MAM configuration at 0.5 Hz. In spite of a very noisy area (gas pipes, high voltage power lines), we measured signal amplitude 10 times higher than noise amplitude. We show that EM fields vectors (both inphase and quadrature components) measured on the surface are very similar to the forward modelling EM responses computed with COMSOL Multiphysics®. Models also show that electric field spatial distribution is strongly affected by a thin and resistive layer (35 m–200 Ωm) of anhydrite above the reservoir, making E field diverging from the boreholes whereas a dipolar pattern was expected for the dipole current injection used here. Moreover, while June 2009 survey highlighted the expected strong increase of electric field (increase of resistivity), August 2010 survey showed electric field amplitudes similar to the 2008 baseline survey, revealing therefore major changes of the reservoir properties. Finally, the directional sensitivity of the 2×MAM array is tested through modelling residuals computed for five CO_2 plume spatial distributions. Results show that a north-eastward migration of the CO_2 plume is expected to fit field data.

Goodman, A., A. Hakala, G. Bromhal, D. Deel, T. Rodosta, S. Frailey, M. Small, D. Allen, V. Romanov, J. Fazio, N. Huerta, D. McIntyre, B. Kutchko and G. Guthrie (2011). "U.S. DOE methodology for the development of geologic storage potential for carbon dioxide at the national and regional scale." International Journal of Greenhouse Gas Control 5(4): 952-965.

A detailed description of the United States Department of Energy (US-DOE) methodology for estimating CO_2 storage potential for oil and gas reservoirs, saline formations, and unmineable coal seams is provided. The oil and gas reservoirs are assessed at the field level, while saline formations and unmineable coal seams are assessed at the basin level. The US-DOE methodology is intended for external users such as the Regional Carbon Sequestration Partnerships (RCSPs), future project developers, and governmental entities to produce high-level CO_2 resource assessments of potential CO_2 storage reservoirs in the United States and Canada at the regional and national scale; however, this methodology is general enough that it could be applied globally. The purpose of the US-DOE CO_2 storage methodology, definitions of storage terms, and a CO_2 storage classification are provided. Methodology for CO_2 storage resource estimate calculation is outlined. The Log Odds Method when applied with Monte Carlo Sampling is presented in detail for estimation of CO_2 storage efficiency needed for CO_2 storage resource estimates at the regional and national scale. CO_2 storage potential reported in the US-DOE's assessment are intended to be distributed online by a geographic information system in NatCarb and made available as hard-copy in the Carbon Sequestration Atlas of the United States and Canada. US-DOE's methodology will be continuously refined, incorporating results of the Development Phase projects conducted by the RCSPs from 2008 to 2018. Estimates will be formally updated every two years in subsequent versions of the Carbon Sequestration Atlas of the United States and Canada.

Gorecki, C. D., J. A. Hamling, R. J. Klapperich, E. N. Steadman and J. A. Harju (2012). Integrating CO_2 EOR and CO_2 Storage in the Bell Creek Oil Field. Carbon Management Technology Conference. Orlando, Florida, USA, 7-9 February 2012, CMCT.

The Plains CO_2 Reduction Partnership is working with Denbury Resources to evaluate the efficiency of large-scale injection of carbon dioxide (CO_2) into the Bell Creek oil field for simultaneous CO_2 enhanced oil recovery (EOR) and long-term CO_2 storage. Discovered in 1967, the Bell Creek Field in southeastern Montana has produced approximately 133 million barrels (MMbbl) of oil from the Cretaceous Muddy Formation sandstone. The original oil in place (OOIP) for the field was estimated to be approximately 353 MMbbl of oil. Through primary and secondary production, about 37.7% of the OOIP has been produced, leaving an estimated 220 MMbbl of oil in the reservoir. It is estimated that CO_2 flooding will produce an additional 35 MMbbl of incremental oil, while simultaneously storing large volumes of CO_2 in the deep subsurface.

Approximately 50 million cubic feet of CO_2 a day will be captured at the ConocoPhillips Lost Cabin gas-processing plant in central Wyoming and transported via a 232-mile pipeline to the Bell Creek Field. Plans are under way to build compression facilities adjacent to the Lost Cabin gas plant to compress the CO_2 from 50 to 2200 psi, allowing for injection-ready pressures at the project site. The CO_2 will then be injected through multiple injection wells into the Muddy Formation at a depth of approximately 4500 feet.

A baseline CO_2-monitoring program is currently under development to establish preinjection CO_2 concentrations at the surface and in the shallow subsurface. Additionally, pressure and fluid saturations will be measured in the reservoir to establish preinjection conditions, so that repeat measurements can be used to better quantify the amount and location of the injected CO_2.

The Bell Creek integrated CO_2 EOR and storage project provides a unique opportunity to develop a set of cost-effective monitoring techniques for large-scale (> 1 million tons a year) storage of CO_2 in a mature oil field with EOR. The results of the Bell Creek project will provide insight regarding the impact of large-scale CO_2 injection on sink integrity, monitoring techniques, and regional applicability of implementing successful CO_2 storage projects within the context of EOR.

Grude, S., et al. (2013). "Time-lapse pressure–saturation discrimination for CO_2 storage at the Snøhvit field." International Journal of Greenhouse Gas Control 19: 369-378.

At the Snøhvit field, Barents Sea, the produced gas contains 5–8% CO_2. This is separated from the sales gas at the Melkøya LNG plant, piped back and re-injected into the saline aquifer Tubåen formation. The injected CO_2 is monitored by time-lapse seismic data. Pressure and saturation changes are estimated by using near and far offset amplitude changes. The inverted pressure and saturation are used to predict expected time-shifts. The predicted time-shifts are then compared to conventional time-shifts estimated directly from the time-lapse seismic data. Empirical rock physics parameters linking pressure and saturation to the seismic parameters are estimated assuming linear relationships. The pressure effect dominates the time-lapse seismic data, except in the near well area where a fluid effect is also estimated. The pressure increase is strong in the near well area (up to 15 MPa) and decreases rapidly with distance from the well. However, a continuous pressure buildup (4–5 MPa) is estimated terminating against the faults approximately 1–2 km away from the well. A CO_2 saturation of 0.15–0.5 is estimated in the near well area, depending on the fluid distribution in the pores (uniform to patchy). There is a good correlation between predicted and conventional time-shifts. The empirical rock physics parameters indicate a CO_2 saturation between 0.2 and 0.5, a patchy fluid distribution in the pore space is most likely. A pressure sensitivity corresponding to a Hertz–Mindlin exponent of 1/4 to 1/6 is estimated. This is clearly to high, and show that the uncertainties in the inverted rock physics parameters are high.

Han, W. S., et al. (2012). "Modeling of Spatiotemporal Thermal Response to CO_2 Injection in Saline Formations: Interpretation for Monitoring." Transport in Porous Media 93(3): 381-399.

We evaluated the thermal processes with numerical simulation models that include processes of solid NaCl precipitation, buoyancy-driven multiphase $SCCO_2$ migration, and potential non-isothermal effects. Simulation results suggest that these processes—solid NaCl precipitation, buoyancy effects, JT cooling, water vaporization, and exothermic $SCCO_2$ reactions—are strongly coupled and dynamic. In addition, we performed sensitivity studies to determine how geologic (heat capacity, brine concentration, porosity, the magnitude and anisotropy of permeability, and capillary pressure) and operational (injection rate and injected $SCCO_2$ temperature) parameters may affect these induced thermal disturbances. Overall, a fundamental understanding of potential thermal processes investigated through this research will be beneficial in the collection and analysis of temperature signals collectively measured from monitoring wells.

Hansen, O. and et.al. (2013) "Snøhvit: The history of injecting and storing 1 Mt CO_2 in the fluvial Tubåen Fm." Energy Procedia.

The Snøhvit CO_2 injection into the Tubåen Formation ended in April 2011. This paper summarizes the Statoil experiences from the injection regarding operational aspects, monitoring and simulation of the CO_2 flow in the reservoir. The use of down-hole pressure measurement, in combination with repeated surface seismic data, improved the understanding of the injection process. Detailed interpretation of fall-off pressures in combination with good and updated reservoir models and thorough investigations into the rock mechanical strength of the reservoir rock lead eventually to the abandonment of the original injection reservoir. The storage capacity of the Tubåen Formation is not reached, but the well and the near well reservoir could not receive the necessary volume rate. A PLT-log was run during abandonment confirming pressures and flow scenario and thereby the previous interpretations. The CO_2 injection at Snøhvit continues at normal levels in a fallback reservoir. No CO_2 has been or will be vented to the atmosphere.

Haszeldine, S., et al. (2014). "Sleipner CO_2 securely stored deep beneath seabed, in spite of unexpected Hugin fracture discovery."

Summary: General readers of Nature may now think that the proposition to store carbon dioxide in deep geological strata is doomed to fail (Monastersky 2013). This is far from the case, as a more balanced review could easily have pointed out. It is now important to provide an alternative perspective, based on published information, that geological storage of CO_2 by deep injection for CCS is both sufficiently secure, and knowable in its environmental impacts. Furthermore, research has shown that there is good support from many parts of the public, although qualified, for CCS as an essential part of a response to the threat of global climate change and ocean acidification.

Hawkins, D., G. Peridas and J. Steelman (2009). "Twelve years after Sleipner: Moving CCS from hype to pipe." Energy Procedia 1(1): 4403-4410.

Climate change is a global problem that requires decisive action. While numerous low-carbon solutions are available for immediate deployment, the world's largest economies' deep commitment to fossil fuels and the need for swift emission reductions dictates the use of CCS at fossil-based power plants and other large sources. While CCS technology is ready to be used today in large-scale projects, several barriers still stand in the way of deployment. We assert that these are mainly economic and regulatory barriers that can readily be addressed with well-crafted and targeted public policy. We outline the critically needed steps and assess their prospects for adoption in the near term.

Heggland, R. (1998). "Gas seepage as an indicator of deeper prospective reservoirs. A study based on exploration 3D seismic data." Marine and Petroleum Geology 15(1): 1-9.

Three periods of sustained gas seepage in geological time have been revealed in Danish block 5604/26 in the North Sea by the use of exploration 3D seismic data. The most recent period is indicated by a cluster of seismic chimneys which ties in to buried craters near the seabed, and possible present gas escape through the seabed, along with amplitude anomalies indicating a shallow gas sand charged by gas migrating from a deeper level. The cluster of seismic chimneys indicative of vertical gas migration is visible down to 1.5 s TWT (1500 ms), and therefore the gas is interpreted as migrating from a deeper stratigraphic horizon. Below this level it becomes difficult to see the chimneys due to complex faulting. The faults may work as gas migration pathways. The geometry of the cluster of seismic chimneys indicates that the gas has been migrating from one point. The nearest possible source of the gas is an underlying prospect where an oil and gas discovery has been made. Two earlier periods of gas seepage are indicated by mounds, possibly carbonate buildups over gas seepages in Pliocene time, and,similarly, buried craters formed by gas seepages in an earlier period in Pliocene time. The results of this study are that gas seepage is a periodical process in geological time and that its presence and associated features can be used as an indicator of deeper prospective reservoirs.

Hermanrud, C., T. Andresen, O. Eiken, H. Hansen, A. Janbu, J. Lippard, H. N. Bolås, T. H. Simmenes, G. M. G. Teige and S. Østmo (2009). "Storage of CO_2 in saline aquifers–Lessons learned

from 10 years of injection into the Utsira Formation in the Sleipner area." Energy Procedia 1(1): 1997-2004.

The ongoing CO_2 injection at Sleipner has demonstrated that 2/3 of the injected CO_2 has not reached the top of the Utsira Formation, but has instead migrated laterally below imperfect intra-reservoir seals. The CO_2 trapping below the structural spill point in the Utsira Formation is due to local mini traps, capillary flow resistance, and the hydrodynamic drive of the injection. About 40% of the CO_2 that has entered the pore systems will remain as residually trapped CO_2, whereas an unknown fraction of the remaining CO_2 will migrate towards the top of the reservoir.

Hill, B., S. Hovorka and S. Melzer (2013). "Geologic Carbon Storage Through Enhanced Oil Recovery." Energy Procedia 37(0): 6808-6830.

The advancement of carbon capture technology combined with carbon dioxide (CO_2) enhanced oil recovery (EOR) holds the promise of reducing the carbon footprint of coal-fired power plants and other industrial sources, while at the same time boosting production of oil. CO_2 injection in deep formations has a long track record. Tertiary EOR with CO_2 has its origins in West Texas in the 1970's, when CO_2 was first used at large scale at the SACROC field to produce stranded oil following primary and secondary production (water flooding). Because CO_2 mixes with oil and changes oil properties, CO_2 floods are effective at producing additional oil following water flooding. Carbon dioxide is a valuable commodity both because of its ability to stimulate oil production from depleted reservoirs, and because of the limited volumes of naturally sourced CO_2 in the U.S. Therefore, during large-scale commercial floods, CO_2 that is produced with oil during EOR is separated, compressed and re-injected and recycled numerous times. Venting to the atmosphere is a rare event, quantifiable, and constitutes an insignificant fraction of the injected CO_2. The CO_2 purchased mass, net any venting during EOR activity is sequestered in the reservoir by a combination of capillary, solution and physical trapping mechanisms. Approximately 600 million metric tonnes of purchased CO_2 have been utilized in the southwest U.S. Permian Basin (PB) alone, the rough equivalent of 30 years worth of CO_2 from a half dozen medium-sized coal-fired power plants. Although CO_2 EOR technology is mature in the U.S., many reservoir targets have not been flooded because of limited CO_2 supply. Moreover, very large newly discovered EOR resources, known as “residual oil zones” (ROZs) occur in naturally water-flooded intervals below the oil-water contact in reservoirs that possess pore space containing immobile oil. ROZs are also now being documented in geologic settings without overlying conventional oil and gas accumulations. ROZ exploration and production using CO_2 promises the supplemental capacity to accept very large volumes of CO_2 in order to access and produce the remaining immobilized oil. Many existing EOR sites may be ideal for sequestration because they: 1) provide known traps that have held hydrocarbons over geologic time, 2) provide existing CO_2 transportation and injection infrastructure, 3) occur in areas where the general public widely accepts injection projects, 4) provide CO_2 commoditization capability for capturing companies, 5) facilitate management of underground CO_2 plumes, 6) have proven reservoir injectivity, 7) may offer additional stacked storage potential, and, 8) are advantageous for monitoring because of available well infrastructure, experienced service company presence, and dense pre-injection data. Despite these advantages, in order to assure long-term containment of CO_2 for atmospheric purposes and related CO_2 reduction credits, the following best practices will ensure credit for captured and sequestered CO_2: 1) demonstrate the appropriateness of the reservoir and existing wells for long term CO_2 storage (integrity of the reservoir and seal, and identifying/remediating existing penetrations that are historically documented as the highest risk for unexpected pathways for CO_2 to the surface), 2) evaluate well construction practices to ensure they are compatible with long-term exposure to low pH fluids (carbonic acid), 3) account for the net CO_2 volumes stored separately from the volumes purchased and recycled, and 4) demonstrate the long-term “permanence” of the CO_2 plume in the subsurface through flood surveillance, monitoring and careful site closure. EOR provides a readily available pathway to large volume storage though oil production offsetting major capital costs of capture facility and pipeline construction, boosting public acceptance through experience and community benefits. Moreover, after completion of EOR operations, sequestration activities can be continued via maximizing CO_2 storage in the depleted field, and by injection into qualified and associated brine formations.

Hoffman, N. R. (2011). "The Emergence of Carbon Sequestration: An Introduction and Annotated Bibliography of Legal Aspects of CCS." Pace Environmental Law Review 29(1: Article 5).

This article decribes the emergences of carbon sequestration. The burning of fossil fuels results in significant carbon dioxide emissions into the atmosphere. Carbon capture and storage (CCS) offers a way of safely storing emissions produced by large-scale industrial operations such as power plants, petroleum refineries, oil sands facilities, and manufacturing plants on or beneath the earth's surface. Many corporations and governments are interested in CCS as it allows for the continued use of fossil fuels while reducing harmful carbon dioxide emissions. Consequently, CCS has become an emerging, burgeoning industry. Terms used to describe the CCS process include carbon sequestration, biosequestration, geosequestration, carbon dioxide geosequestration, ocean sequestration, terrestrial sequestration, carbon dioxide sequestration, carbon dioxide storage, and carbon capture and disposal. Most commonly, this technique is referred to as carbon capture and storage or carbon capture and sequestration. CCS is used in this article to refer to all of these terms generally; authors in the annotated articles may use more specific terms depending on the process or location of the sequestered carbon dioxide being discussed.

CCS research and collaboration is underway in a wide range of disciplines, including law, economics, political science, science, and engineering; many larger collaborative projects are multidisciplinary. Research and development is necessary for the CCS industry to be successful in combating climate change in the short-and medium-terms. Many authors of articles referenced in this annotated bibliography suggest that governments and industry need to work together in order to combat climate change. This collaboration is necessary to ensure that CCS becomes a viable option to reduce greenhouse gas emissions and to help decrease their future effects in climate change.

Hornafius, J. S., D. Quigley and B. P. Luyendyk (1999). "The world's most spectacular marine hydrocarbon seeps (Coal Oil Point, Santa Barbara Channel, California): Quantification of emissions." Journal of Geophysical Research-Oceans 104(C9): 20703-20711.

We used 50 kHz sonar data to estimate natural hydrocarbon emission rates from the 18 km2 marine seep field offshore from Coal Oil Point, Santa Barbara, California. The hydrocarbon gas emission rate is 1.7 ± 0.3 × 105 m3 d−1 (including gas captured by a subsea seep containment device) and the associated oil emission rate is 1.6 ± 0.2 × 104 Ld−1 (100 barrels d−1). The nonmethane hydrocarbon emission rate from the gas seepage is 35±7 td−1 and a large source of air pollution in Santa Barbara County. Our estimate is equal to twice the emission rate from all the on-road vehicle traffic in the county. Our estimated methane emission rate for the Coal Oil Point seeps (80±12 td−1) is 4 times higher than previous estimates. The most intense areas of seepage correspond to structural culminations along anticlinal axes. Seep locations are mostly unchanged from those documented in 1946, 1953, and 1973. An exception is the seepage field that once existed near offshore oil platform Holly. A reduction in seepage within a 1 km radius around this offshore platform is correlated with reduced reservoir pressure beneath the natural seeps due to oil production. Our findings suggest that global emissions of methane from natural marine seepage have been underestimated and may be decreasing because of oil production.

Hosseini, S. A. and S. Kim (2014). "Enhanced analytical simulation toot (EASiTool) for CO_2 storage capacity estimation and uncertainty quantification."

An analytical-based Enhanced Analytical Simulation Tool (EASiTool) will be developed for technical and non-technical users with minimum engineering knowledge. The purpose of EASiTool is to produce a fast, reliable estimate of storage capacity for any geological formation. EASiTool will include closed-form analytical solutions that can be used as a first step for screening of geological formations to determine which formation can best accommodate storage needs over given period of time.

EASiTool will be developed with a highly user-friendly interface, however the analytical models behind the EASiTool will be cutting-edge models that incorporate effects of rock geomechanics, evaporation of brine near the wellbore, as well as deployment of brine extraction in the field to enhance the storage capacity. A net present value (NPV) based analysis will be implemented to devise the best field development strategy to maximize the stakeholder's profit by optimizing the number of injection/extraction wells. This highly user-friendly tool will provide a unique strategy for CO_2 injection combined with brine extraction to optimize any CO_2 project by maximizing the project's NPV. Benefits of this project include:

- Application of the advanced closed-form analytical solutions to estimate CO_2 injectivity into geological formations
- Estimation of the number of injection/extraction wells necessary to reach the storage goal
- Improving current static storage efficiency coefficients by instead using dynamic closed-form analytical solutions

House, K. Z., D. P. Schrag, C. F. Harvey and K. S. Lackner (2006). "Permanent Carbon Dioxide Storage in Deep-Sea Sediments." Proc Natl Acad Sci U S A 103(33): 12291-12295.

Stabilizing the concentration of atmospheric CO_2 may require storing enormous quantities of captured anthropogenic CO_2 in near-permanent geologic reservoirs. Because of the subsurface temperature profile of terrestrial storage sites, CO_2 stored in these reservoirs is buoyant. As a result, a portion of the injected CO_2 can escape if the reservoir is not appropriately sealed. We show that injecting CO_2 into deep-sea sediments > 3,000 m water depth and a few hundred meters of sediment provides permanent geologic storage even with large geomechanical perturbations. At the high pressures and low temperatures common in deep-sea sediments, CO_2 resides in its liquid phase and can be denser than the overlying pore fluid, causing the injected CO_2 to be gravitationally stable. Additionally, CO_2 hydrate formation will impede the flow of CO_2(l) and serve as a second cap on the system. The evolution of the CO_2 plume is described qualitatively from the injection to the formation of CO_2 hydrates and finally to the dilution of the CO_2(aq) solution by diffusion. If calcareous sediments are chosen, then the dissolution of carbonate host rock by the CO_2(aq) solution will slightly increase porosity, which may cause large increases in permeability. Karst formation, however, is unlikely because total dissolution is limited to only a few percent of the rock volume. The total CO_2 storage capacity within the 200 mile economic zone of the U.S. coastline is enormous, capable of storing thousands of years of current U.S. CO_2 emissions.

Hoversten, G. M., R. Gritto, T. M. Daley, E. L. Majer, L. R. Myer, J. Gale and Y. Kaya (2003). Crosswell Seismic and Electromagnetic Monitoring of CO_2 Sequestration. Greenhouse Gas Control Technologies - 6th International Conference. Oxford, Pergamon: 371-376.

The quantitative estimation of changes in water saturation (Sw) and effective pressure (P), in terms of changes in compressional and shear impedance, is becoming routine in the interpretations of time-lapse surface seismic data. However, when the number of reservoir constituents increases to include in situ gas and injected CO_2, there are too many parameters to be determined from seismic velocities or impedances alone. In such situations, the incorporation of electromagnetic (EM) images showing the change in electrical conductivity (σ) provides essential independent information. The purpose of this study was to demonstrate a methodology for jointly interpreting crosswell seismic and EM data, in conjunction with detailed constitutive relations between geophysical and reservoir parameters, to quantiatively predict changes in P, Sw, CO_2 gas saturation (SCO_2), CO_2 gas/oil ratio (RCO_2), hydrocarbon gas saturation (Sg), and hydrocarbon gas/oil ration (Rg) in a reservoir undergoing CO_2 flood.

Hoversten, G. M. and E. Gasperikova (2005). Chapter 23 - Non-Seismic Geophysical Approaches to Monitoring. Carbon Dioxide Capture for Storage in Deep Geologic Formations. Amsterdam, Elsevier Science: 1071-1112.

This chapter considers the application of a number of different geophysical techniques for monitoring geologic storage of CO_2. The relative merits of the seismic, gravity, electromagnetic (EM) and streaming potential (SP) geophysical techniques as monitoring tools are examined. An example of tilt measurements illustrates another potential monitoring technique, although it has not been studied to the extent of other techniques in this chapter. This work does not represent an exhaustive study, but rather demonstrates the capabilities of a number of geophysical techniques on two synthetic modeling scenarios. The first scenario represents combined CO_2 enhance oil recovery (EOR) and storage in a producing oil field, the Schrader Bluff field on the north slope of Alaska, USA. The second scenario is of a pilot DOE CO_2 storage experiment scheduled for summer 2004 in the Frio Brine Formation in South Texas, USA. Numerical flow simulations of the CO_2 injection process for each case were converted to geophysical models using petrophysical models developed from well log data. These coupled flow simulation-geophysical models allow comparison of the performance of monitoring techniques over time on realistic 3D models by generating simulated responses at different times during the CO_2 injection process. These time-lapse measurements are used to produce time-lapse changes in geophysical measurements that can be related to the movement of CO_2 within the injection interval.

Hovland, M. (2007). "Discovery of prolific natural methane seeps at Gullfaks, northern North Sea." Geo-Marine Letters 27(2-4): 197-201.

The Gullfaks and Kvitebjrn fields are located on the North Sea Plateau (135 m water depth), and on an ancient beach (135–190 m) deposited during the sea-level lowstand during the Last Glacial Maximum (LGM). There are several continuous seeps of mainly methane gas, where large patches of Beggiatoa bacterial mats occur. The ‘Heincke’ seep area, which is named after the German research vessel Heincke, has been targeted by scientists studying seep-associated processes and microbiology. The Gullfaks area has a long history of shallow gas and seepage. In 1980, well no. 34/10–10 had a blowout from a reservoir located 230 m below seafloor. The active Heincke seep location has no topographic expression, probably because the seabed consists of dense sand and gravel. Extensive bacterial mats (Beggiatoa sp.) are found on the seafloor at this seep site. Organisms such as hermit crabs were seen ingesting pieces of such mat, indicating ‘trophic bypass,’ where carbon derived directly from seeping methane is evidently feeding directly into higher trophic organisms. Ongoing and future research at this seep location in the North Sea can answer some important questions on the environmental impact of natural methane seeps on continental shelves.

Hovorka, S. D., S. M. Benson, C. Doughty, B. M. Freifeld, S. Sakurai, T. M. Daley, Y. K. Kharaka, M. H. Holtz, R. C. Trautz, H. S. Nance, L. R. Myer and K. G. Knauss (2006). "Measuring permanence of CO_2 storage in saline formations: the Frio experiment." Environmental Geosciences 13(2): 105–121.

If CO_2 released from fossil fuel during energy production is returned to the subsurface, will it be retained for periods of time significant enough to benefit the atmosphere? Can trapping be assured in saline formations where there is no history of hydrocarbon accumulation? The Frio experiment in Texas was undertaken to provide answers to these questions.

One thousand six hundred metric tons of CO_2 were injected into the Frio Formation, which underlies large areas of the United States Gulf Coast. Reservoir characterization and numerical modeling were used to design the experiment, as well as to interpret the results through history matching. Closely spaced measurements in space and time were collected to observe the evolution of immiscible and dissolved CO_2 during and after injection. The high-permeability, steeply dipping sandstone allowed updip flow of supercritical CO_2 as a result of the density contrast with formation brine and absence of a local structural trap.

The front of the CO_2 plume moved more quickly than had been modeled. By the end of the 10-day injection, however, the plume geometry in the plane of the observation and injection wells had thickened to a distribution similar to the modeled distribution. As expected, CO_2 dissolved rapidly into brine, causing pH to fall and calcite and metals to be dissolved.

Postinjection measurements, including time-lapse vertical seismic profiling transects along selected azimuths, cross-well seismic topography, and saturation logs, show that CO_2 migration under gravity slowed greatly 2 months after injection, matching model predictions that significant CO_2 is trapped as relative permeability decreases.

Hovorka, S. D., et al. (2013). "Monitoring a large-volume injection at Cranfield, Mississippi-Project design and recommendations." International Journal of Greenhouse Gas Control 18: 345-360.

Injection and storage of 4 million metric tons of CO_2 have been monitored to observe multiphase fluid flow, to test technologies, to document permanence of storage, and to advance techniques for capacity estimation. The injection interval is the 3,000 m deep fluvial Tuscaloosa Formation at a structural closure that defines the Cranfield oilfield. Tests were conducted in the oil-producing area as well as in the downdip brine aquifer. These tests assessed the feasibility, operation, and sensitivity of monitoring using a selection of tools in the vadose zone, in the shallow groundwater, above the injection zone, and within the injection zone. Although each monitoring approach merits a separate, detailed analysis, this paper assesses the success of the overall strategy for monitoring and presents an overview of conclusions from multiple data sets. Comparisons of modeled to observed reservoir response highlight the difficulties encountered in uniquely explaining measured pressure and fluid saturation measurements at interwell and field scales. Results of this study provide a cautionary note to regulatory and accreditation end users about the feasibility of obtaining unique and quantitative matches between fluid flow models and field measurements.

Huerta, N. J., et al. (2011). "Dynamic alteration along a fractured cement/cement interface: Implications for long term leakage risk along a well with an annulus defect." Energy Procedia 4: 5398-5405.

The long term fate of wells proximal to CO_2 sequestration operations remains poorly understood. To date, experiments have shown that total degradation of well cement is unlikely and that severe, uniform degradation of a conductive pathway can lead to self-healing of a fracture. However these experiments did not carry out the degradation reactions while the (fractured) cement was under mechanical load comparable to subsurface conditions. A new experiment procedure that couples reactive flow through a fracture in cement with confining pressure has shown reaction along well defined flow channels along the fracture face. Injection of acidic ($2<pH<3$) aqueous solutions yielded effluent pH histories with a characteristic spike of rapid neutralization followed by a slow approach toward inlet pH. In all experiments, the effective hydraulic aperture after acid injection was smaller than the initial hydraulic aperture. This indicates that in a system with a slow leak of brine saturated with CO_2 along a defect in a wellbore, the leakage rate would decrease over time.

Hutchinson, D. R., C. Poag, A. H. Johnson, P. Popenoe and C. Wright (1997). Geophysical database of the East Coast of the United States; southern Atlantic margin, stratigraphy and velocity in map grids, US Geological Survey Open-File Report 96-55

This report describes the gridding of digital stratigraphic and lithologic information and the calculation of derivative acoustic information for the U.S. Atlantic continental margin between Florida and Cape Hatteras. It complements an earlier report describing the profile data on which the gridding is based (Hutchinson et al., 1995). The area to the north, between Cape Hatteras and Georges Bank has been summarized in Klitgord and Schneider (1994) and Klitgord et al. (1994). In summary (1) Two of the large offshore post-Middle Jurassic sedimentary basins are included in this compilation: the Blake Plateau basin, which is the widest, most equidimensional, and most carbonate-rich of the U.S. Atlantic offshore basins, and the Carolina trough, which is the narrowest, most linear basin and is transitional between carbonate deposition to the south and more clastic, terrigenous regions to the north, (2) Digital maps for 17 post-Middle Jurassic units (18 horizons) are developed using a grid-node spacing of 5 minutes (9.23 x 7.96 km). The units consist of the water column plus 7 Cenozoic, 5 Cretaceous, and 5 Jurassic units. Maps are included for isochron, interval velocity, thickness, lithology, and structure maps in both travel time and depth, (3) Spatial aliasing occurs because the sample rate along lines (250 m) is much greater than the distance between lines (30–40 km). Because of this under sampling, and the rather large grid interval, features such as large discontinuities (Blake Escarpment), certain non-two dimensional features (Blake Spur), narrow linear features (faults or reefs), and point source features (diapirs) are not always properly imaged in the gridding process, (4) The strategy adopted to minimize the editing during gridding and also realistically to present the data and geology, was to grid layer thicknesses, then sum grids to estimate depths to horizons. This strategy resulted in short-wavelength anomalies along the axis of the Carolina Slope and Blake Escarpment that are not geologically probable, and these are most noticeable for middle Cretaceous and older horizons. (5) From the digital stratigraphic, velocity, and thickness information, derivative calculations of density, shear-wave velocity, and compressional- and shear-wave attenuation were made.

Hutchinson, D. R., C. W. Poag and P. Popenoe (1995). Geophysical database of the east coast of the United States; southern Atlantic margin, stratigraphy and velocity from multichannel seismic profiles, US Geological Survey Open-File Report 95-27.

This report presents one part of a program to develop a geophysical database for the East Coast of the United States, specifically to describe the digital seismic and velocity horizons interpreted from multichannel seismic-reflection profiles across the continental margin south of Cape Hatteras. A companion paper (Hutchinson et al., 1996) describes the spatial, gridded data base for each horizon. The data base for the continental margin north of Cape Hatteras has been described by Klitgord and Schneider (1994) and Klitgord et al. (1994). In summary (1) 18 multichannel seismic lines, consisting of 42 line segments totalling about 7,600 km, were used to develop the digital stratigraphic and velocity information. The stratigraphic interpretations used in the database follow the stratigraphy of Poag (1991), (2) A total of 17 seismic discontinuities were interpreted for both stratigraphic and velocity information. Each horizon was assigned an arbitrary, but successively larger number starting at the sea floor and ending at the deepest postrift unit. The stratigraphic numbering scheme is identical to that used by Klitgord et al. (1994) for the region north of Cape Hatteras, (3) Even though the multichannel data were acquired using roughly similar equipment and source size, a large variation in data quality exists. Uncertainties can be assigned based on many criteria: e.g., the duration of the observed wavelet, frequency of the processed data, display scales, digitizing resolution. None of these uncertainties, however, is as large as the uncertainty in interpretation that arises from the lack of well-dated samples throughout the study region. Two end-member interpretations show that depths to Lower Cretaceous and Jurassic horizons differ by as much as 0.9 s, or up to 2–3 km. Depths to the younger Cenozoic and Upper Cretaceous units are more consistent because of more abundant shallow boreholes and surface samples. The uncertainty in age does not affect the velocity or depth estimates associated with each horizon, (4) Velocities for the study area are best constrained in the northern Carolina trough, and uncertainties are estimated at about 10-20 %. Data quality in the southern Carolina trough and Blake Plateau is compromised by poor, low-resolution velocity scans. Comparison of the poorly constrained multichannel velocities with recent and old refraction information suggests velocity uncertainties In the southern Carolina trough and Blake Plateau are probably no better than 20 -30 %. Because of the velocity smoothing process, velocities for the landwardmost 20-30 km of each line are probably high by up to 20 %.

IEA GHG (2007e). Remediation of Leakage from CO_2 Storage Reservoirs, IEA Greenhouse Gas R&D Programme (IEA GHG).

The aim of this study was to assess what remediation techniques and approaches are available if seepage of CO_2 is identified from a geological storage formation. The objective of the study was to develop a report that can act as a reference manual for IEA Greenhouse Gas R&D Programme (IEA GHG) members in their discussions with policy makers. The report sets out the remediation plan that can be adopted in the event of any seepage being detected upon the different types of seepage event and their associated remediation methods. This report also estimates the cost of different remediation measures. This study was undertaken by Advanced Resources International, USA.

IEAGHG. (2012). Quantification Techniques for CO_2 Leakage. 2012/02, January, 2012: from http://ieaghg.org/docs/General_Docs/Reports/2012-02.pdf.

This document summarizes and incorporates a multi-author report by Korre et al. (2011), which is also included in this EndNote database.

IEAGHG, (2015), Review of offshore monitoring for CCS projects, IEA/CON/14/223 Compiled and edited by Hannis, S., Chadwick, C., et al., 153 p.

Key messages: Deep-focused operational monitoring systems have been deployed for a number of years at Sleipner, Snohvit and also at the pilot-scale K12-B project in the offshore Netherlands, and conclusions regarding the efficacy of key technologies are starting to emerge. Shallow-focused monitoring systems are being developed and demonstrated. Monitoring strategies need to be devised to cover large areas, typically tens to hundreds of square kilometers and also achieve accurate measurement and characterisation possibly over lengthy periods. Limited spatial coverage could lead to the risk that anomalies remain undetected or are only detected after a lengthy period of time.

IEA/OECD (2010a). Carbon Capture and Storage: Legal and Regulatory Review. Edition 1, Organisation for Economic Co-operation and the International Energy Agency.

The International Energy Agency (IEA) considers carbon capture and storage (CCS) a crucial part of worldwide efforts to limit global warming by reducing greenhouse-gas emissions. The IEA has estimated that the broad deployment of low-carbon energy technologies could reduce projected 2050 emissions to half 2005 levels – and that CCS could contribute about one-fifth of those reductions. Reaching that goal, however, would require around 100 CCS projects to be implemented by 2020 and over 3 000 by 2050. Such rapid expansion raises many regulatory issues, so in 2008 the IEA established the International CCS Regulatory Network.2 In response to a suggestion that the IEA produce a regular review of CCS regulatory progress worldwide, made at the network's second meeting (Paris, January 2010), the IEA is pleased to now be launching the IEA Carbon Capture and Storage Legal and Regulatory Review (CCS Review). This publication aims to help countries develop their own CCS regulatory frameworks by providing a forum for sharing knowledge on CCS legal and regulatory issues. It also identifies steps taken towards the legal and regulatory goals in the 2009 IEA Technology Roadmap: Carbon capture and storage. The IEA intends that the CCS Review be produced every six months.

The CCS Review gathers contributions by national, state, provincial and regional governments, at all stages of CCS regulatory development. The first half of each contribution provides an overview of CCS advances over the preceding six months and those expected to occur in the following six months, with links provided to publicly available documents. The second half addresses a particular CCS legal and regulatory theme, such as long-term liability. Each contribution is limited to two pages to ensure the information is concise and easy to consult. Where CCS legal and regulatory development has not begun or is still at an early stage, contributors might provide an update on broader CCS progress. To introduce each edition, the IEA provides a brief analysis of key advances and trends. It is based only on the information in the contributions, but the themes discussed may be relevant beyond the jurisdictions mentioned. In addition to contributions from public authorities, the CCS Review also includes contributions from leading international organisations engaged in CCS regulatory activities. Each contributor is given the opportunity to comment on the IEA analysis before the CCS Review is released on the IEA CCS website (www.iea.org/ccs).

IEA/OECD (2010b). CCS Model Regulatory Framework, Information Paper, 127p.

This publication seeks to deal with the reality that rapid expansion and scale-up of CCS technology raises a number of regulatory issues that need to be addressed in parallel with ongoing efforts to demonstrate the technical, safety and environmental viability of industrial CO_2 storage sites over the long term, the protection of public health and the environment, and the security of CCS activities.

The model framework is structured to provide guidance to authorities around the world, operating in diverse legal and regulatory environments, and in the context of varying existing resource extraction or environmental impact frameworks. The model framework address 29 key issues identified as being critical to the regulation of CCS activities.

This model framework addresses all stages of the CCS chain, including CO_2 capture, transportation and geological storage. It focuses primarily, however, on the regulatory issues associated with CO_2 storage, which are commonly accepted as presenting the most novel and complex challenges in elaborating regulatory frameworks for CCS.

IEA/OECD (2012). Carbon Capture and Storage. Legal And Regulatory Review. Edition 3, International Energy Agency and Organisation for Economic Co-operation.

The International Energy Agency (IEA) considers carbon capture and storage (CCS) a crucial part of worldwide efforts to limit global warming by reducing greenhouse-gas emissions. The IEA estimates that emissions can be reduced to a level consistent with a 2°C global temperature increase through the broad deployment of low-carbon energy technologies – and that CCS would contribute about one-fifth of emission reductions in this scenario. Achieving this level of deployment will require that regulatory frameworks – or rather a lack thereof – do not unnecessarily impede environmentally safe demonstration and deployment of CCS, so in October 2010 the IEA launched the IEA Carbon Capture and Storage Legal and Regulatory Review.

The CCS Review is a regular review of CCS regulatory progress worldwide. Produced annually, it collates contributions by national and regional governments, as well as leading organisations engaged in CCS regulatory activities, to provide a knowledge-sharing forum to support CCS framework development.

Each two page contribution provides a short summary of recent and anticipated CCS regulatory developments and highlights a particular, pre-nominated regulatory theme. To introduce each edition, the IEA provides a brief analysis of key advances and trends, based on the contributions submitted.

The theme for this third edition is stakeholder engagement in the development of CO_2 storage projects. Other issues addressed include: regulating CO_2-EOR, CCS and CO_2-EOR for storage; CCS incentive policy; key, substantive issues being addressed by jurisdictions taking steps to finalise CCS regulatory framework development; and CCS legal and regulatory developments in the context of the Clean Energy Ministerial Carbon Capture, Use and Storage Action Group.

IEA/OECD (2014). Carbon Capture and Storage. Legal And Regulatory Review. Edition 4, International Energy Agency and Organisation for Economic Co-operation.

The International Energy Agency (IEA) considers carbon capture and storage (CCS) a crucial part of efforts to limit global warming by reducing greenhouse-gas emissions. The IEA estimates that carbon dioxide emissions could be reduced to a level that would limit long-term global temperature increases to 2°C through broad deployment of low-carbon energy technologies, including CCS. In the IEA's Energy Technology Perspectives 2012 2°C Scenario (2DS), CCS contributes about one-seventh of cumulative emissions reductions from a business-as-usual scenario through 2050. Achieving this contribution requires appropriate policy frameworks to both promote demonstration and deployment of CCS and ensure it is undertaken in a safe and environmentally responsible manner.

The IEA Carbon Capture and Storage Legal and Regulatory Review aims to help countries develop their own regulatory frameworks by documenting and analysing recent CCS legal and regulatory developments from around the world. It was first published in 2010, and a new edition is released annually to provide an up-to-date snapshot of global CCS regulatory developments.

Each edition includes short contributions from national, regional, state and provincial governments that review recent and anticipated CCS regulatory developments and highlight a particular, pre-nominated regulatory theme. To introduce each edition, the IEA provides a brief analysis of key advances and trends, based on the contributions submitted. The theme for this fourth edition of the CCS Review is policy measures to promote CCS demonstration and deployment. Other issues that have been highlighted include storage assessment and the Alberta Regulator Framework Assessment (RFA) process. Contributions from 22 governments and 6 international CCS organisations are presented in the fourth edition.

IPCC (2005). Carbon dioxide capture and storage : IPCC special report. Cambridge, Cambridge University Press.

This Special Report on Carbon dioxide Capture and Storage (SRCCS) has been prepared under the auspices of Working Group III (Mitigation of Climate Change) of the Intergovernmental Panel on Climate Change (IPCC). The report has been developed in response to an invitation of the United Nations Framework Convention on Climate Change (UNFCCC) at its seventh Conference of Parties (COP7) in 2001. In April 2002, at its 19th Session in Geneva, the IPCC decided to hold a workshop, which took place in November 2002 in Regina, Canada. The results of this workshop were a first assessment of literature on CO_2 capture and storage, and a proposal for a Special Report. At its 20th Session in 2003 in Paris, France, the IPCC endorsed this proposal and agreed on the outline and timetableb. Working Group III was charged to assess the scientific, technical, environmental, economic, and social aspects of capture and storage of CO_2. The mandate of the report therefore included the assessment of the technological maturity, the technical and economic potential to contribute to mitigation of climate change, and the costs. It also included legal and regulatory issues, public perception, environmental impacts and safety as well as issues related to inventories and accounting of greenhouse gas emission reductions. This report primarily assesses literature published after the Third Assessment Report (2001) on CO_2 sources, capture systems, transport and various storage mechanisms. It does not cover biological carbon sequestration by land use, land use change and forestry, or by fertilization of oceans. The report builds upon the contribution of Working Group III to the Third Assessment Report Climate Change 2001 (Mitigation), and on the Special Report on Emission Scenarios of 2000, with respect to CO_2 capture and storage in a portfolio of mitigation options. It identifies those gaps in knowledge that would need to be addressed in order to facilitate large-scale deployment.

The structure of the report follows the components of a CO_2 capture and storage system. An introductory chapter outlines the general framework for the assessment and provides a brief overview of CCS systems. Chapter 2 characterizes the major sources of CO_2 that are technically and economically suitable for capture, in order to assess the feasibility of CCS on a global scale. Technological options for CO_2 capture are discussed extensively in Chapter 3, while Chapter 4 focuses on methods of CO_2 transport. In the next three chapters, each of the major storage options is then addressed: geological storage (chapter 5), ocean storage (chapter 6), and mineral carbonation and industrial uses (chapter 7). The overall costs and economic potential of CCS are discussed in Chapter 8, followed by an examination of the implications of CCS for greenhouse gas inventories and emissions accounting (chapter 9).

The report has been written by almost 100 Lead and Coordinating Lead Authors and 25 Contributing Authors, all of whom have expended a great deal of time and effort. They came from industrialized countries, developing untries, countries with economies in transition and international organizations. The report has been reviewed by more than 200 people (both individual experts and representatives of governments) from around the world. The review process was overseen by 19 Review Editors, who ensured that all comments received the proper attention. In accordance with IPCC Procedures, the Summary for Policymakers of this report has been approved line-by-line by governments at the IPCC Working Group III Session in Montreal, Canada, from September 22–24, 2005. During the approval process the Lead Authors confirmed that the agreed text of the Summary for Policymakers is fully consistent with the underlying full report and technical summary, both of which have been accepted by governments, but remain the full responsibility of the authors.

IPCC (2006). 2006 IPCC Guidelines for National Greenhouse Gas Inventories. Hayama, Japan, Institute for Global Environmental Strategies (IGES). VOL 2: Energy.

Carbon dioxide (CO_2) capture and storage (CCS) is an option in the portfolio of actions that could be used to reduce greenhouse gas emissions from the continued use of fossil fuels. At its simplest, the CCS process is a chain consisting of three major steps: the capture and compression of CO_2 (usually at a large industrial installation), its transport to a storage location and its long-term isolation from the atmosphere. IPCC (2005) has produced a Special Report on Carbon Dioxide Capture and Storage (SRCCS), from which additional information on CCS can be obtained. The material in these Guidelines has been produced in consultation with the authors of the SRCCS. Geological storage can take place in natural underground reservoirs such as oil and gas fields, coal seams and saline water-bearing formations utilizing natural geological barriers to isolate the CO_2 from the atmosphere. A description of the storage processes involved is given in Chapter 5 of the SRCCS. Geological CO_2 storage may take place either at sites where the sole purpose is CO_2 storage or in tandem with enhanced oil recovery, enhanced gas recovery or enhanced coal-bed methane recovery operations (EOR, EGR and ECBM respectively). These Guidelines provide emission estimation guidance for carbon dioxide transport, injection and geological storage (CCGS) only. No emissions estimation methods are provided for any other type of storage option such as ocean storage or conversion of CO_2 into inert inorganic carbonates. With the exception of the mineral carbonation of certain waste materials, these technologies are at the research stage rather than the demonstration or later stages of technological development IPCC (2005). If and when they reach later stages of development, guidance for compiling inventories of emissions from these technologies may be given in future revisions of the Guidelines. Emissions resulting from fossil fuels used for capture, compression, transport, and injection of CO_2, are not addressed in this chapter. Those emissions are included and reported in the national inventory as energy use in the appropriate stationary or mobile energy use categories. Fuel use by ships engaged in international transport will be excluded where necessary by the bunker rules, whatever the cargo, and it is undesirable to extend the bunker provisions to emissions from any energy used in operating pipelines.

Jacobs, W. B., L. Cohen, L. Kostakidis-Lianos and S. Rundell (2009). Proposed Roadmap for Overcoming Legal Obstacles to Carbon Capture and Sequestration, Belfer Center for Science and International Affairs.

The Harvard Environmental Law and Policy Clinic supports the development of carbon capture and geological sequestration (CCGS) as part of a larger national effort to address climate change and promote economic growth. President Obama's commitment to reduce greenhouse gas emissions and to deploy CCGS as one mechanism for achieving emissions reductions provides impetus for realizing this goal. The urgency posed by climate change combined with the time needed for obtaining project financing and permits and for demonstration of large scale CCGS projects requires that the United States develop the necessary support structure for CCGS immediately.

Given the urgent need to slow climate change, it is not appropriate to wait for national restrictions to be imposed on emissions of carbon dioxide (CO_2) or for the establishment of a national cap-and-trade system, or national CCGS legislation before proceeding to demonstrate the technology necessary for commercial deployment. Apart from reducing CO_2 emissions, the development of CCGS technology in the United States also has the potential to provide large economic and energy security benefits by creating high quality jobs and reducing reliance on foreign imports of fossil fuels. Despite both the need and the emerging political will, few specific proposals for achieving the rapid development of CCGS have been put forward to date. Many existing proposals either lack sufficient concreteness to make CCGS operational or fail to focus on a comprehensive, long term framework for its regulation, thus failing to account adequately for the urgency of the issue, the need to develop immediate experience with large scale demonstration projects, or the financial and other incentives required to launch early demonstration projects. We aim to help fill this void by proposing a roadmap to commercial deployment of CCGS in the United States.

The proposed roadmap is a work in progress, and we look forward to receiving your feedback. This roadmap focuses on the legal and financial incentives necessary for rapid demonstration of geological sequestration in the absence of national restrictions on CO_2 emissions. It weaves together existing federal programs and financing opportunities into a set of recommendations for achieving commercial viability of geological sequestration. Part I provides a brief summary of the obstacles and disincentives to large scale deployment of CCGS and an overview of our recommended solutions. Part II presents the principles underlying this proposed roadmap. Part III includes a more detailed discussion of key milestones under the roadmap and the related rationales.

Jenkins, C., Chadwick, A, and Hovorka S.D. (2015). The state of the art in monitoring and verification—Ten years on; International Journal of Greenhouse Gas Control, http://dx.doi.org/10.1016/j.ijggc.2015.05.009

In the ten years since publication of the IPCC Special Report on CCS, there has been considerable progress in monitoring and verification (M&V). Numerous injection projects, ranging from small injection pilots to much larger longer-term commercial operations, have been successfully monitored to the satisfaction of regulatory agencies, and technologies have been adapted and implemented to demonstrate containment, conformance, and no environmental impact. In this review we consider M&V chiefly from the perspective of its ability to satisfy stakeholders that these three key requirements are being met. From selected project examples, we show how this was done, and reflect particularly on the nature of the verification process. It is clear that deep-focussed monitoring will deliver the primary requirement to demonstrate conformance and containment and to provide early warning of any deviations from predicted storage behaviour. Progress in seismic imaging, especially offshore, and the remarkable results with InSAR from In Salah are highlights of the past decade. A wide range of shallow monitoring techniques has been tested at many sites, focussing especially on the monitoring of soil gas and groundwater. Quantification of any detected emissions would be required in some jurisdictions to satisfy carbon mitigation targets in the event of leakage to surface: however, given the likely high security of foreseeable storage sites, we suggest that shallow monitoring should focus mainly on assuring against environmental impacts. This reflects the low risk profile of well selected and well operated storage sites and recognizes the over-arching need for monitoring to be directed to specific, measureable risks. In particular, regulatory compliance might usefully involve clearer articulation of leakage scenarios, with this specificity making it possible to demonstrate “no leakage” in a more objective way than is currently the case. We also consider the monitoring issues for CO_2-EOR, and argue that there are few technical problems in providing assurance that EOR sites are successfully sequestering CO_2; the issues lie largely in linking existing oil and gas regulations to new greenhouse gas policy. We foresee that, overall, monitoring technologies will continue to benefit from synergies with oil and gas operations, but that the distinctive regulatory and certification environments for CCS may pose new questions. Overall, while there is clearly scope for technical improvements, more clearly posed requirements, and better communication of monitoring results, we reiterate that this has been a decade of significant achievement that leaves monitoring and verification well placed to serve the wider CCS enterprise.

Johnson, J. W. and W. G. R. Team (2011). "Geochemical assessment of isolation performance during 10 years of CO_2 EOR at Weyburn." Energy Procedia 4(0): 3658-3665.

The Final-Phase Weyburn geochemical research program includes explicitly integrated yet conceptually distinct monitoring, modeling, and experimental components. The principal objectives are to monitor CO_2-induced compositional evolution within the reservoir through time-lapse sampling and chemical analysis of produced fluids; to document the absence (or presence) of injected CO_2 within reservoir overburden through analogous monitoring of shallow groundwater and soil gas; to predict intra-reservoir CO_2 migration paths, dynamic CO_2 mass partitioning among distinct trapping mechanisms, and reservoir/seal permeability evolution through reactive transport modeling; to assess the impact of CO_2-brine-rock reactions on fracture flow and isolation performance through experimental studies that directly support the monitoring and modeling work; and to exploit a novel stochastic inversion technique that enables explicit integration of these diverse monitoring data and forward models to improve reservoir characterization and long-term forecasts of isolation performance.

Kaiser, M. J. and R. A. Kasprzak (2008). "The impact of the 2005 hurricane season on the Louisiana Artificial Reef Program." Marine Policy 32(6): 956-967.

The 2005 hurricane season in the Gulf of Mexico was the worst in the history of offshore production, with Hurricanes Katrina and Rita destroying 110 oil and gas structures and eight mobile offshore drilling units. Infrastructure destroyed by accident or natural catastrophe are decommissioned according to the same federal regulations that guide normal decommissioning operations, but depending on the nature of the destruction and the market conditions in the months following the event, special conditions and delays may occur. Historically, offshore infrastructure destroyed by hurricanes or other unusual circumstances have been considered for inclusion in the Louisiana Artificial Reef Program (LARP) under the Special Artificial Reef Site (SARS) category. The purpose of this paper is to review the impact of the 2005 hurricane season on the LARP and the current status of the SARS program. We examine the criteria employed in project evaluation and approval as well as aggregate program statistics. The characteristics and risks associated with decommissioning destroyed infrastructure are also described. At the end of 2006, 10 projects representing 35 platforms destroyed in the 2005 hurricane season have been approved as SARS in the Gulf of Mexico, effectively doubling the number of sites and structures classified as SARS.

Kaiser, M. J. and M. Liu (2014). "Decommissioning cost estimation in the deepwater U.S. Gulf of Mexico – Fixed platforms and compliant towers." Marine Structures 37: 1-32.

Decommissioning is the final stage in the life cycle of an offshore structure, where all wells are plugged and abandoned, the platform and associated facilities are removed, and the seafloor cleared of all obstructions created by the operations. From 1989 to 2012, 15 structures in water depth greater than 400 ft were decommissioned in the U.S. Gulf of Mexico, but none of the project cost have been publicly released. The purpose of this paper is to apply work decomposition algorithms developed by ProServ Offshore to estimate cost for well plugging and abandonment, conductor severance and removal, pipeline abandonment, umbilical and flowline removal, and platform removal for the 53 deepwater fixed platforms and compliant towers in the Gulf of Mexico circa January 2013. Decommissioning cost estimates are presented by stage and operator. Bullwinkle and Pompano are expected to be the most expensive fixed platform decommissioning projects in the Gulf of Mexico estimated at $265 million and $203 million, respectively. Total undiscounted decommissioning liability for the asset class is estimated to be $2.4 billion.

Kaiser, M. J. and A. J. Pulsipher (2008). "Supplemental bonding in the Gulf of Mexico: the potential effects of increasing bond requirements." International Journal of Oil, Gas and Coal Technology 2(3): 262-279.

The Minerals Management Service (MMS) requires offshore oil and gas operators to procure surety bonds to ensure that they meet their decommissioning obligations. According to recent estimates developed by the authors, the total undiscounted cost of decommissioning structures and wells in the Gulf of Mexico in less than 500 ft. water depth is estimated to range between $18–63 billion. The MMS is currently reviewing and updating their supplemental bonding requirements, and in this paper, we discuss the potential impacts of an increase in the bond levels required. While the size of the increase will depend on the amount of risk MMS will assume, the average cost of plugging and abandonment and structure removal operations are between two and eight times greater than the current bond formula. We analyse the surety market, the companies involved in writing bonds and the approximate market share of organisations. This information is neither widely known nor well understood outside a few individuals specialising in the area. We conclude that the largest impacts of increased supplemental bonding requirements would be for exploration and production companies with approximately $10 to $20 million in current liabilities.

Kaldi, J. G., C. M. Gibson-Poole, and T. H. D. Payenberg,, (2009). Geological input to selection and evaluation of CO_2 **geosequestration sites. AAPG Studies in Geology J. C. P. M. Grobe, and R. L. Dodge, eds., . 59: 5-16.**

Coal, oil, and natural gas currently supply about 85% of the world's energy needs. Unfortunately, the burning of these fossil fuels is the major source of anthropogenic carbon dioxide, which is also the main greenhouse gas released to the atmosphere. One promising means by which to reduce CO_2 emissions, and so the atmospheric buildup of CO_2, is geosequestration. Geosequestration, also known as carbon capture and storage (CCS), involves the long-term storage of CO_2 in deep subsurface geological reservoirs. Geosequestration comprises several steps that include the capture of CO_2, the transport of CO_2, the injection of CO_2 into suitable reservoirs, and finally, the storage and monitoring of the CO_2 that has been introduced into the reservoir.

Geological input into the evaluation of storage sites, including injection, storage, and monitoring and verification of volumes and movement of CO_2 plumes, is critical for acceptance of CCS technologies. Detailed characterization and realistic modeling of reservoir and seal properties, as well as of rock and fault integrity, will permit a more viable analysis of risks associated with the subsurface containment of injected CO_2. Geosequestration can be a significant factor in the portfolio of CO_2 emissions reduction strategies because by reducing CO_2 emissions while still allowing for the continued use of fossil fuels, geosequestration buys time for the transition to renewable energy sources.

Kallaur, C. U. (1998). A Performance-Based Approach to Offshore Regulation SPE International Conference on Health, Safety, and Environment in Oil and Gas Exploration and Production. Caracas, Venezuela

The way in which the United States, through the Minerals Management Service (MMS) of the U.S. Department of the Interior, regulates its Outer Continental Shelf oil and gas program is at an important crossroads. During much of the 50+ year history of this program, a prescriptive approach was adopted for assuring safe and environmentally sound operations. As the next millenium nears, a clear shift towards performance-based regulation is taking place. This shift is occurring at a time when the Gulf of Mexico is once again being viewed as a world class production province, where technological records are being set routinely.

A high level of environmental and safety performance is a key to assuring that the significant energy and economic benefits tied to this development can be realized. The MMS recognizes that the majority of the companies who operate on the U.S. Outer Continental Shelf have alternative investment opportunities and that investment dollars will not only go where the prospects are, but also where the regulatory regime is the most rational.

Kazemeini, S. H., C. Juhlin and S. Fomel (2010). "Monitoring CO_2 response on surface seismic data; a rock physics and seismic modeling feasibility study at the CO_2 sequestration site, Ketzin, Germany." Journal of Applied Geophysics 71(4): 109-124.

An important component of any CO_2 sequestration project is seismic monitoring for tracking changes in subsurface physical properties such as velocity and density. Reservoir conditions and CO_2 injection quantities govern whether such changes may be observable as a function of time. Here we investigate surface seismic response to CO_2 injection at the Ketzin site, the first European onshore CO_2 sequestration pilot study dealing with research on geological storage of CO_2. First, a rock-physics model was built to evaluate the effect of injected CO_2 on the seismic velocity. On the basis of this model, the seismic response for different CO_2 injection geometries and saturation was studied using 1D elastic modeling and 2D acoustic finite difference modeling. Rock-physics models show that CO_2 injected in a gaseous state, rather than in a supercritical state, will have a more pronounced effect on seismic velocity, resulting in a stronger CO_2 response. However, reservoir heterogeneity and seismic resolution, as well as random and coherent seismic noise, are negative factors that need to be considered in a seismic monitoring program. In spite of these potential difficulties, our seismic modeling results indicate that the CO_2 seismic response should be strong enough to allow tracking on surface seismic data. Amplitude-related attributes (i.e., acoustic impedance versus Poisson's ratio cross-plots) and time-shift measurements are shown to be suitable methods for CO_2 monitoring.

Ketzer, J. M., B. Carpentier, Y. LeGallo and P. Le Thiez (2005). "Geological sequestration of CO_2 **in mature hydrocarbon fields - Basin and reservoir numerical modelling of the Forties Field, North Sea." Oil & Gas Science and Technology-Revue D Ifp Energies Nouvelles 60(2): 259-273.**

Numerical modelling is likely the only available tool to evaluate and predict the fate of CO_2 injected in deep geological reservoirs, and particularly in depleted hydrocarbon fields. Here we present a methodology which aims at evaluating the geological leaking risk of an underground storage using a depleted oilfield as the host reservoir. The methodology combines basin and reservoir scale simulations to determine the efficiency of the storage. The approach was designed for the study of the reservoir after the injection of CO_2 and then does not take into account any CO_2 injection period. The approach was applied to the Forties field (North Sea) for which CO_2 behaviour was simulated for a 1000 y time period. Our findings suggest that local geological conditions are quite favourable for CO_2 sequestration. Possible residence time of CO_2 will be it? the order of thousands of years and, thus such geological depleted hydrocarbon fields storage is probably a good alternative for a long term CO_2 sequestration. Additionally, results of this work can help to establish criteria to identify other mature hydrocarbon fields aimed for CO_2 sequestration.

Kharaka, Y. K., J. J. Thordsen, S. D. Hovorka, H. S. Nance, D. R. Cole, T. J. Phelps and K. G. Knauss (2009). "Potential environmental issues of CO_2 storage in deep saline aquifers: Geochemical results from the Frio-I Brine Pilot test, Texas, USA." Applied Geochemistry 24(6): 1106-1112.

Sedimentary basins in general, and deep saline aquifers in particular, are being investigated as possible repositories for large volumes of anthropogenic CO_2 that must be sequestered to mitigate global warming and related climate changes. To investigate the potential for the long-term storage of CO_2 in such aquifers, 1600 t of CO_2 were injected at 1500 m depth into a 24 m thick "C" sandstone unit of the Frio Formation, a regional aquifer in the US Gulf Coast. Fluid samples obtained before CO_2 injection from the injection well and an observation well 30 m updip showed a Na-Ca-Cl type brine with similar to 93,000 mg/L TDS at saturation with CH4 at reservoir conditions; gas analyses showed that CH4 comprised similar to 95% of dissolved gas, but CO_2 was low at 0.3%. Following CO_2 breakthrough. 51 h after injection, samples showed sharp drops in pH (6.5–5.7), pronounced increases in alkalinity (100–3000 mg/L as HCO3) and in Fe (30–1100 mg/L), a slug of very high DOC values, and significant shifts in the isotopic compositions of H2O. DIC, and CH4. These data, coupled with geochemical modeling, indicate corrosion of pipe and well casing as well as rapid dissolution of minerals, especially calcite and iron oxyhydroxides, both caused by lowered pH (initially similar to 3.0 at subsurface conditions) of the brine in contact with supercritical CO_2.

These geochemical parameters, together with perfluorocarbon tracer gases (PFTs), were used to monitor migration of the injected CO_2 into the overlying Frio "B", composed of a 4 m thick sandstone and separated from the "C" by similar to 15 m of shale and siltstone beds. Results obtained from the Frio "B" 6 months after injection gave chemical and isotopic markers that show significant CO_2 (2.9% compared with 0.3% CO_2 in dissolved gas) migration into the "B" sandstone. Results of samples collected 15 months after injection, however, are ambiguous, and can be interpreted to show no additional injected Cot in the "B" sandstone. The presence of injected CO_2 may indicate migration from "C" to "B" through the intervening beds or, more likely, a short-term leakage through the remedial cement around the casing of a 50 year old well. Results obtained to date from four shallow monitoring groundwater wells show no brine or CO_2 leakage through the Anahuac Formation, the regional cap rock. Published by Elsevier Ltd.

Kirk, K. (2011). Natural CO_2 flux literature review for the QICS project: 38, British Geological Survey, CR/11/005, 38p.

Carbon dioxide (CO_2) separated from natural gas has been stored successfully below the seabed off Norway for almost two decades. Based on these experiences several demonstration projects supported by the EU and its member states are now setting out to store CO_2 captured at power plants in offshore geological formations. The ECO_2 project was triggered by these activities and funded by the EU to assess the environmental risks associated with the sub-seabed storage of CO_2 and to provide guidance on environmental practices. ECO_2 conducted a comprehensive offshore field programme at the Norwegian storage sites Sleipner and Snøhvit and at several natural CO_2 seepage sites in order to identify potential pathways for CO_2 leakage through the overburden, monitor seep sites at the seabed, track and trace the spread of CO_2 in ambient bottom waters, and study the response of benthic biota to CO_2. ECO_2 identified a rich variety of geological structures in the broader vicinity of the storage sites that may have served as conduits for gas release in the geological past and located a seabed fracture and several seeps and abandoned wells where natural gas and formation water are released into the marine environment. Even though leakage may occur if these structures are not avoided during site selection, observations at natural seeps, release experiments, and numerical modelling revealed that the footprint at the seabed where organisms would be impacted by CO_2 is small for realistic leakage scenarios. ECO_2 conducted additional studies to assess and evaluate the legal framework and the public perception of CO_2 storage below the seabed. The following guidelines and recommendations for environmental practices are based on these experiences. The legal framework that should be considered in the selection of storage sites and the planning of environmental risk assessments and monitoring studies includes not only the EU directive on CO_2 capture and storage (CCS) but related legislations including the EU Emission Trading Scheme, the Environmental Liability Directive, the London Protocol, OSPAR Convention, and Aarhus Convention. Public involvement in the planning and development of CCS projects is required by legislation. Based on its public perception studies, ECO_2 recommends that messages to be communicated should address the specific contribution of CCS to the mitigation of anthropogenic CO_2 emissions, its role within the context of other low carbon options as well as costs, safety and implementation issues at the local level. ECO_2 developed a generic approach for assessing consequences, probability and risk associated with subseabed CO_2 storage based on the assessment of i) the environmental value of local organisms and biological resources, ii) the potentially affected fraction of population or habitat, iii) the vulnerability of, and the impact on the valued environmental resource, iv) consequences (based on steps i – iii), v) propensity to leak, vi) environmental risk (based on steps iv and v). The major new element of this approach is the propensity to leak factor which has been developed by ECO_2 since it is not possible to simulate all relevant geological features, processes and events in the storage complex including the multitude of seepage-related structures in the overburden and at the seabed with currently available reservoir modelling software. The leakage propensity is thus estimated applying a compact description of the storage complex and more heuristic techniques accommodating for the large number of parameter uncertainties related to e.g. the permeability of potential leakage structures.

For site selection, ECO_2 recommends to choose storage sites that have insignificant risks related to i) geological structures in the overburden and at the seabed that may serve as conduits for formation water and gas release, ii) geological formations containing toxic compounds that can be displaced to the seabed, iii) low-energy hydrographic settings with sluggish currents and strongly stratified water column, iv) proximity of storage sites to valuable natural resources (e.g. Natura 2000 areas, natural conservation habitats, reserves for wild fauna and flora), v) areas in which biota is already living at its tolerance limits because of existing exposure to additional environmental and/or other anthropogenic stressors.

Based on its extensive field programme ECO_2 recommends that overburden, seabed, and water column should be surveyed applying the following techniques: i) 3-D seismic, ii) high-resolution bathymetry/backscatter mapping of the seabed, iii) acoustic imaging of shallow gas accumulations in the seabed and gas bubbles ascending through the water column, iv) video/photo imaging of biota at the seabed, v) chemical detection of dissolved CO_2 and related parameters in ambient bottom waters. Additional targeted studies have to be conducted if active formation water seeps, gas seeps, and pockmarks with deep roots reaching into the storage formation occur at the seabed. These sites have to be revisited on a regular basis to determine emission rates of gases and fluids and exclude that seepage is invigorated and pockmarks are re-activated by the storage operation. Baseline studies serve to determine the natural variability against which the response of the storage complex to the storage operation has to be evaluated. All measurements being part of the monitoring program, thus, need to be performed during the baseline study prior to the onset of the storage operation to assess

Kjarstad, J., D. Langlet, D. Johansson, J. Sjoblom, F. Johnsson and T. Berntsson (2011a). "CCS in the Skagerrak/Kattegat-region -- Assessment of an intraregional CCS infrastructure and legal framework." Energy Procedia 4: 2793-2800.

This paper provides some initial results from the project "CCS in the Skagerrak/Kattegat-region" which is an intraregional CCS project partly funded by the EU. The project assesses the prospects for Carbon Capture and Storage (CCS) from industry and power plants located in the Skagerrak region which comprises northern Denmark, south-east coast of Norway and the west coast of Sweden. The project is a joint cooperation between universities, research institutes and industries in the region. The methodology used in one of the project work packages is presented together with some initial results on legal aspects.

CCS in the Skagerrak region may potentially account for a third of combined emission reduction commitments by 2020 in the three countries involved in the project. Yet, much of the emissions in the region occur from industry (in addition to power plants) and it is still not clear how these industries will be treated under the ETS. Based on current knowledge, a good storage option would be in the Hanstholm aquifer on Denmark's northwest coast. The phasing-in of capture plants over time is central to the development of a cost efficient CCS infrastructure. However, many of the sources in the region are located at a port facilitating use of boat transport through the build up period. The initial legal analysis show that significant regulatory uncertainties exist in the region with regard to CCS and it is not obvious that the implementation of the EU CCS directive into national law by June 2011 will alleviate these uncertainties. Finally, the project may provide a significant test case for what type of political and regulatory cooperation that will be required if CCS is to be deployed in a transboundary context under conditions of sufficient public acceptance and well-designed regulation.

Koenig-Archibugi, M. (2011). Global governance. The Handbook of Globalisation. J. e. Michie. Cheltenham, Edwards Elgar Publishing, Ltd.: 393-406.

The chapter addresses the topic of global governance and it's distinction from global government. Disparate issues in governance include the role of business in environmental policy. Governance implies the possibility of "order without hierarchy', and includes the adoption of rules, codes, and regulations.

Kopp, A., R. Helmig, P. J. Binning, K. Johannsen and H. Class (2010). "A contribution to risk analysis for leakage through abandoned wells in geological CO_2 storage." Advances in Water Resources 33(8): 867-879.

The selection and the subsequent design of a subsurface CO_2 storage system are subject to considerable uncertainty. It is therefore important to assess the potential risks for health, safety and environment. This study contributes to the development of methods for quantitative risk assessment of CO_2 leakage from subsurface reservoirs. The amounts of leaking CO_2 are estimated by evaluating the extent of CO_2 plumes after numerically simulating a large number of reservoir realizations with a radially symmetric, homogeneous model. To conduct the computationally very expensive simulations, the 'CO_2 Community Grid' was used, which allows the execution of many parallel simulations simultaneously. The individual realizations are set up by randomly choosing reservoir properties from statistical distributions. The statistical characteristics of these distributions have been calculated from a large reservoir database, holding data from over 1200 reservoirs. An analytical risk equation is given, allowing the calculation of average risk due to multiple leaky wells with varying distance in the surrounding of the injection well. The reservoir parameters most affecting risk are identified. Using these results, the placement of an injection well can be optimized with respect to risk and uncertainty of leakage. The risk and uncertainty assessment can be used to determine whether a site, compared to others, should be considered for further investigations or rejected for CO_2 storage.

Korbøl, R. and A. Kaddour (1995). "Sleipner vest CO 2 disposal-injection of removed CO 2 into the Utsira formation." Energy Conversion and Management 36(6): 509-512.

Production from the Sleipner Vest Field, containing up to 9,5% CO_2, starts October 1, 1996. The Sleipner Vest gas will be delivered under the Troll Gas Sales Agreements, and hence has to meet the sales specification of maximum 2,5% by volume CO_2 in the gas. The amount of removed CO_2 would be approximately 1 million metric ton per year. For environmental reasons the CO_2 will be injected into an underground aquifer.

Korre, A., C. E. Imrie, F. May, S. E. Beaubien, V. Vandermeijer, S. Persoglia, L. Golmen, H. Fabriol and T. Dixon (2011). "Quantification techniques for potential CO_2 leakage from geological

storage sites." 10th International Conference on Greenhouse Gas Control Technologies 4: 3413-3420.

The objective of this document is to discuss the European and international regulations covering carbon dioxide storage and specially the site abandonment period starting after the end of CO_2 injection. According to these regulations, the liability for the storage site can be transferred to the licensing authority/government once the safety and conformity of monitoring with model predictions has been demonstrated. In the EU the CO_2 storage Directive 2009/31/EC set out the regulatory regime and guidance for permitting CO_2 storage and while a few EU countries have already transposed this directive to national law, most are still tasked with formulating their own national regulations. Around the world, relevant bills and regulations have been introduced in recent years too. In addition, regulations originating from the oil and gas sector concerning well abandonment are also relevant to CO_2 storage well abandonment.

Koteeswaran, M. (2010). CO_2 and H2S corrosion in oil pipelines Master's, M. Koteeswaran.

This study has been conducted to find the corrosion behavior and corrosion rates of carbon steel in the presence of CO 2 and H2S at various pH levels using classical electrochemical techniques. It was found that in a galvanic coupling, the metal in the sulfide environment gets protection even at pH 3, and the bare metal which is in neutral pH was corroding sacrificially. The linear polarization resistance measurements and potentiodynamic scan of the metal without the galvanic coupling show a high degree of corrosion at pH 3. The corrosion rate generally was higher for CO_2/H2S system than for H2S system.

Kuuskraa, V. A. and A. R. International (2007). Overview of Mitigation and Remediation Options for Geological Storage of CO_2. AB1925 Staff Workshop - California Institute for Energy and Environment. Sacramento, CA.

This is a brief technical paper on comprehensive strategy for leak prevention and remidiation for CO_2 storage contained in five main elements.

Lakeman, B., W. D. Gunter, S. Bachu, R. Chalaturnyk, D. Lawton, D. van Everdingena, G. Lim and E. Perkins (2009). "Advancing the deployment of CO_2 monitoring technologies through the Pembina Cardium CO_2 Monitoring Project." Energy Procedia 1(1): 2293-2300.

CO_2-enhanced oil recovery projects have been the initial areas of focus for advancing geological storage of CO_2 as a key greenhouse gas mitigation option. Canada has provided international leadership through the IEA GHG Weyburn CO_2 Monitoring and Storage Project. In late 2004, a CO_2 EOR flood pilot within the Cretaceous Cardium Formation within the Pembina oil field in Central Alberta was selected as the site for a comprehensive CO_2 monitoring program. This pilot, completed in 2008 has tested the deployment of new CO_2 flood monitoring tools, allowing for a better understanding of the behaviour of CO_2 in the largest conventional reservoir in Canada and one of the largest in North America. The Pembina Cardium pilot has resulted in scientific advances related to the integration of different CO_2 monitoring technologies (reservoir surveillance, geochemistry, geophysical, environmental, reservoir simulation). The project's findings will inform new protocols concerning the deployment of downhole technologies in observation wells used for the monitoring and verification of CO_2 movement in the subsurface.

Lakhal, S. Y., M. I. Khan and M. R. Islam (2009). "An "Olympic" framework for a green decommissioning of an offshore oil platform." Ocean & Coastal Management 52(2): 113-123.

Oil and gas offshore platform and installations have a limited life of operations. When oil runs out, many terms are used to describe the situation: abandonment, removal, disposal, decommissioning, etc. Even the issue of decommissioning is now at the forefront of deep water oil drilling for many reasons (the enormous costs required for disposal, the increasing number of rigs which required removal, the need to

protect the marine environment, legal frameworks), yet there are very few published researchers studying the problem according to its different facets (legal, environmental, economical etc.). In this paper, we apply the concept of an "Olympic" supply chain developed by Lakhal et al.

Lakhal, SY, H'Mida S, Islam R. Green Supply Chain parameters for a Canadian Petroleum Refinery Company. International Journal of Environmental Technology and Management, IJETM 2007:7:56-67.

Le Guen, Y., O. Poupard and M. Loizzo (2009). "Optimization of plugging design for well abandonment- Risk management of long-term well integrity." Greenhouse Gas Control Technologies 9 1(1): 3587-3594

A part of MOVECBM EU project is dedicated at evaluating the long-term wellbore integrity on the basis of a risk perspective. This i mplies, among others, to optimize the plugging strategy, in order to mitigate risk associated to CO_2 migration inside the well during the abandonment phase (i.e. post injection). The role of containment of well's components has to be ensured for hundreds of years, despite degradation mechanisms (i.e. ageing) that affect their properties. To mitigate risk associated to CO_2 leakages, a probabilistic study was dedicated to casing corrosion in order to support the design of the plugging strategy and its optimization. This was achieved with calculations based on in-situ data and taking into account uncertainties. Results of this study enable to get objective criteria to support the decision process for efficient plugging design for the MS-3 well (vs. wellbore integrity perspective).

Litynski, J. T., et al. (2011). Carbon Capture and Sequestration: The U.S. Department of Energy's R&D Efforts to Characterize Opportunites for Deep Geologic Storage of Carbon Dioxide in Offshore Resources. Offshore Technology Conference, 2–5 May 2011. Houston, TX. London Protocol (2006a). Protocol to the Convention of the Prevention of Marine Pollution by Dumping of Wastes and other Matter, 1972. London, Australian Treaty Series 2006:11.

The United States Department of Energy (DOE) is the lead federal agency for the research, development, demonstration, and deployment (RDD&D) of carbon sequestration technologies. This effort is being implemented through several activities, including applied research and development (R&D), demonstration projects, and technical support to loan guarantee and tax incentives programs. The sequestration program started in 1997 and has grown significantly. In Fiscal Year 2010, $145 million in federal funding was received to support carbon capture and storage (CCS) related R&D. The Sequestration Program also received $80 million in funding from the 2009 American Recovery and Reinvestment Act (ARRA) to support the development of resources for geologic storage of CO_2. The goal of the program is to develop a suite of technologies that can support the implementation of commercial CCS projects by 2020.

Part of the program funding is being used to assess the potential for storing CO_2 in offshore geologic formations. This paper presents an overview of projects awarded to assess the potential for geologic storage in state and federal waters in the Gulf of Mexico (GOM), the Atlantic and Pacific Oceans, and in Texas and California state territorial waters, as well as research efforts DOE is supporting world-wide. These efforts are aimed at capacity assessments; monitoring and modeling of sub-seabed storage projects; characterization of projects that are drilling wells and conducting seismic surveys; and assessment of regulatory gaps relative to storing CO_2 in offshore formations. The results are expected to provide a summary of basin-scale suitability and will identify and prioritize potential offshore CO_2 geological storage opportunities.

London Protocol (2006b). Risk Assessment and Management Framework for CO_2 Sequestration in Sub-Seabed Geological Structures. London Convention. London. LC/SG-CO_2 1/7, annex 3:

This Risk Assessment and Management Framework for CO_2 Sequestration in Sub-Seabed Geological Structures (CS-SSGS) is developed to ensure compatibility with Annex 2 to the London Protocol, identify relevant gaps in knowledge, and reach a view on the implications of CS-SSGS for the marine environment. This Framework aims to provide generic guidance to the Contracting Parties to the London Convention and Protocol in order to characterize the risks to the marine environment from CS-SSGS on a site-specific basis and collect the necessary information to develop a management strategy to address uncertainties and any residual risks.

London Protocol (2012). "2012 Specific guidelines for the assessment of carbon dioxide for disposal into sub-seabed geological formations."

Carbon dioxide sequestration in sub-seabed geological formations is a process consisting of separation of carbon dioxide from industrial and energy-related sources, transport to an offshore geological formation, and long-term isolation from the atmosphere. This process is one option in a portfolio of mitigation actions for stabilization of atmospheric greenhouse gas concentrations with the potential for significant benefits at the local, regional and global levels over both the short and long-terms. The intent of carbon dioxide sequestration in sub-seabed geological formations is to prevent release into the biosphere of substantial quantities of carbon dioxide derived from human activities. The aim is to retain the carbon dioxide streams within these geological formations permanently.

Lu, J., Y. K. Kharaka, J. J. Thordsen, J. Horita, A. Karamalidis, C. Griffith, J. A. Hakala, G. Ambats, D. R. Cole, T. J. Phelps, M. A. Manning, P. J. Cook and S. D. Hovorka (2012). "CO_2–rock–brine interactions in Lower Tuscaloosa Formation at Cranfield CO_2 sequestration site, Mississippi, U.S.A." Chemical Geology 291(0): 269-277.

A highly integrated geochemical program was conducted at the Cranfield CO_2-enhanced oil recovery (EOR) and sequestration site, Mississippi, U.S.A.. The program included extensive field geochemical monitoring, a detailed petrographic study, and an autoclave experiment under in situ reservoir conditions. Results show that mineral reactions in the Lower Tuscaloosa reservoir were minor during CO_2 injection. Brine chemistry remained largely unchanged, which contrasts with significant changes observed in other field tests. Field fluid sampling and laboratory experiments show consistently slow reactions. Carbon isotopic composition and CO_2 content in the gas phase reveal simple two-end-member mixing between injected and original formation gas. We conclude that the reservoir rock, which is composed mainly of minerals with low reactivity (average quartz 79.4%, chlorite 11.8%, kaolinite 3.1%, illite 1.3%, concretionary calcite and dolomite 1.5%, and feldspar 0.2%), is relatively unreactive to CO_2. The significance of low reactivity is both positive, in that the reservoir is not impacted, and negative, in that mineral trapping is insignificant.

Ludwiszewski, R. B. and K. B. Marsh (2013). "A comment on the limits of liability in promoting safe geologic sequestration of CO_2." The Environmental Law Reporter 43(8): 10656.

The authors discuss the paper by David Adelman and Ian Duncan entitled, "The Limits of Liability in Promoting Safe Geologic Sequestration of CO_2." They say that the author of the study consider the lack effective regulatory and liability policies in consideration to the long-term legal liabilities of mitigation to be one of the major hindrance to the application of carbon capture and storage (CCS). They explore the argument on the impact of long-term and latent tort of liabilities.

Lumley, D. (2010). "4D seismic monitoring of CO_2 sequestration." The Leading Edge 29(2): 150-155.

We are about to face a surge in the need for geophysical characterization and monitoring of subsurface reservoirs and aquifers for CO_2 sequestration projects. Global energy demand is rising significantly, expected to double over the next 20–30 years, driven by world population increase and the rapid growth of emerging economies. At the current rate of development of alternate energy sources, it is possible that the world may have to rely even more heavily on carbon-based fuels than at present to meet the impending energy demand (Figure 1). With global oil production near its peak or perhaps already in decline, this will place an increased emphasis on coal and LNG (liquid natural gas) in the carbon-based energy mix, and on unconventional hydrocarbon resources like tight gas, coal-bed methane, and heavy-oil tar sands. All of these carbon-based energy sources, especially coal-fired power plants, LNG, and tar-sand operations, will create a growing supply of excess CO_2. Irrespective of whether man-made CO_2 emissions are a significant cause of global climate change, or simply well-correlated with global temperature rise, there will be increasing pressure from world governments to reduce the amount of CO_2 emissions to the atmosphere, via policy change (e.g., Kyoto, Copenhagen) or via financial measures (e.g., carbon tax, cap and trade). Capturing industrial CO_2 at its various sources and injecting it into deep geologic formations for long-term storage (sequestration) appears to be one of the most promising methods to achieve significant reductions in atmospheric CO_2 emissions.

Lynch, R. D., E. J. McBride, T. K. Perkins and M. E. Wiley (1985). "Dynamic Kill of an Uncontrolled Well." Society of Petroleum Engineers 37(No. 7): 1267-1275.

In March 1982 a CO_2 well in the Sheep Mountain Unit, CO_2 blew out. This well was brought under control in early April 1982 by the dynamic injection of drag-reduced brine followed by mud. This paper discusses the events and field activities that followed the blowout and led to the successful kill operation. Also included is a discussion of two initial, unsuccessful kill attempts, associated mechanical problems, and the understanding gained therefrom. Analyses of wellbore and reservoir hydraulics led to an understanding of the freely flowing well. Injection of kill fluid down the drillpipe was possible, but the small pipe diameter, particularly that of the heavy wall drillpipe. pipe diameter, particularly that of the heavy wall drillpipe. significantly limited the rate of kill-fluid injection. The kill operation was further complicated by the high flow capacity of CO_2 from the reservoir. The high CO_2 flow rate efficiently gas-lifted the kill fluid up the annulus and thus tended to maintain a low bottomhole pressure (BHP). Further analysis of the hydraulics of the system suggested two alternatives for dynamically killing the well: (1) use of highly drag-reduced fluids of moderate density such as water or brine, and (2) use of non-drag-reduced mud with a density greater than about 18 Ibm/gal [2100 kg/m3]. The well was killed successfully with 10.5 lbm/gal [1260 kg/m3] brine, which exhibited 72% drag reduction in surface lines and drillpipe at an injection rate of 60 bbl/min [570 m /h].

Mabon, L., et al. (2015). "Local perceptions of the QICS experimental offshore CO_2 **release: Results from social science research." International Journal of Greenhouse Gas Control 38: 18-25.**

This paper explores the social dimensions of an experimental release of carbon dioxide (CO_2) carried out in Ardmucknish Bay, Argyll, United Kingdom. The experiment, which aimed to understand detectability and potential effects on the marine environment should there be any leakage from a CO_2 storage site, provided a rare opportunity to study the social aspects of a carbon dioxide capture and storage-related event taking place in a lived-in environment. Qualitative research was carried out in the form of observation at public information events about the release, in-depth interviews with key project staff and local stakeholders/community members, and a review of online media coverage of the experiment. Focusing mainly on the observation and interview data, we discuss three key findings: the role of experience and analogues in learning about unfamiliar concepts like CO_2 storage; the challenge of addressing questions of uncertainty in public engagement; and the issue of when to commence engagement and how to frame the discussion. We conclude that whilst there are clearly slippages between a small-scale experiment and full-scale CCS, the social research carried out for this project demonstrates that issues of public and stakeholder perception are as relevant for offshore CO_2 storage as they are for onshore.

Majer, Ernie; Nelson, James, Robinson-Tait, Savy, Jean, and Wong. Ivan, 2012, Protocol for addressing induced seismicity associated with enhanced geothermal systems, DOE/EE-0662

This report is focused on geothermal energy operators and regulators, but outlines methodologies for seismic data analysis that can be applied to offshore sub-seabed CO_2 storage monitoring.

Malone, T., V. Kuuskraa and P. DiPietro (2014). CO_2**-EOR Offshore Resource Assessment. E. Lab.**

The Gulf of Mexico accounts for about 20 percent of total domestic crude oil production. Since reaching a peak of 1.54 million barrels a day in 2003, Gulf of Mexico's OCS oil production has declined to 1.23 MMB/D, as of mid-2013. While there is optimism that new discoveries in the deep and ultra-deep waters of the GOM OCS will reverse this decline, another option seems to offer even more promise—the application of CO_2 enhanced oil recovery. The CO_2-EOR assessment for the GOM OCS starts with a Base Case that assumes: (1) an oil price of $90/per barrel (B) ($2012 real, WTI); (2) CO_2 costs of $50 per metric ton (mt), delivered to the oil field at pressure (CO_2 purchase price of $30/mt (at plant gate) and $20/mt for offshore transportation); and (3) Current CO_2-EOR Technology. The study then examines how use of "Next Generation" CO_2-EOR Technology would impact the offshore GOM resource assessment. As important, the analysis shows that the GOM OCS oil fields provide sufficient long-term CO_2 storage capacity for all of the CO_2 emissions generated from large point sources along the Gulf Coast. Lower delivered costs of CO_2 enable more of the offshore oil resource to become economic under "Next Generation" CO_2-EOR. Table 1-4 and Table 1-5 provide the analysis of incremental oil recovery and CO_2 demand (storage) to changes in CO_2 costs. Even though "Next Generation" CO_2-EOR Technology provides higher volumes of oil recovery, offshore CO_2-EOR is still a high cost option that would benefit from higher oil prices, Table 1-6. At an oil price of $135/B ($CO_2$ costs of $70/mt), the incremental oil recovery more than doubles to 38,060 MM barrels compared to 14,920 MM barrels under a $90/B oil price. Similarly, with an oil price of $135/B ($CO_2$ cost of $70/mt), the demand (storage) for CO_2 more than doubles to 10,700 MMmt compared to 3,910 MMmt under a $90/B oil price.

Mathieson A., J. M., K. Dodds, I. Wright, P. Ringrose, and N. Saoul (2010). "CO_2 **sequestration monitoring and verification technologies applied at Krechba, Algeria." The Leading Edge 29(2): 216–222.**

The In Salah project in Algeria is an industrial-scale CO_2 storage project that has been in operation since 2004. CO_2 from several gas fields, which have a CO_2 content of 5–10%, is removed from the production stream to meet the sales gas-export specification of 0.3% CO_2. Rather than vent that separated CO_2 to the atmosphere (as was normal industry practice for such gas plants), BP and its joint venture (JV) partner, Sonatrach, invested an incremental US$100 million in a project to compress, dehydrate, transport, and inject that CO_2 into a deep saline formation downdip of the producing gas horizon. Statoil then joined the JV at production start-up in August 2004.

May, P. J. (2007). "Regulatory regimes and accountability." Regulation & Governance 1(1): 8-26.

This research considers accountability issues for new forms of regulation that shift the emphasis from prescribing actions to regulating systems or regulating for results. Shortfalls at various levels of accountability are identified from experiences with these regimes in the regulation of building and fire safety, food safety and nuclear power plant safety. These experiences illustrate how accountability shortfalls can undermine regulatory performance and introduce a potential for subtle forms of regulatory capture. These concerns underscore the importance of finding the right fit between regulatory circumstances and the design of regulatory regimes.

Mayer, B., M. Shevalier, M. Nightingale, J.-S. Kwon, G. Johnson, M. Raistrick, I. Hutcheon and E. Perkins (2013). "Tracing the movement and the fate of injected CO_2 **at the IEA GHG Weyburn-**

Midale CO_2 **Monitoring and Storage project (Saskatchewan, Canada) using carbon isotope ratios." International Journal of Greenhouse Gas Control 16, Supplement 1(0): S177-S184.**

Stable isotope data can assist in successful monitoring of the movement and the fate of injected CO_2 in enhanced oil recovery and geological storage projects. This is demonstrated for the International Energy Agency Greenhouse Gas (IEA-GHG) Weyburn-Midale CO_2 Monitoring and Storage Project (Saskatchewan) where fluid and gas samples from multiple wells were collected and analyzed for geochemical and isotopic compositions for more than a decade. Carbon isotope ratios of the injected CO_2 (−20.4‰) were sufficiently distinct from median δ13C values of background CO_2 (δ13C = −12.7‰) and HCO3− (δ13C = −1.8‰) in the reservoir to reveal the movement and geochemical trapping of injected CO_2 in the reservoir. The presented 10-year data record reveals the movement of injected CO_2 from injectors to producers, dissolution of CO_2 in the reservoir brines, and ionic trapping of injected CO_2 in conjunction with dissolution of carbonate minerals. We conclude that carbon isotope ratios constitute an excellent and cost-effective tool for tracing the fate of injected CO_2 at long-term CO_2 storage sites with injection rates exceeding 1 million tons per year.

McCoy, S. T., M. Pollak and P. Jaramillo (2011). "Geologic sequestration through EOR: Policy and regulatory considerations for greenhouse gas accounting." Energy Procedia 4(0): 5794-5801.

The objective of carbon capture and sequestration (CCS) is to reduce emissions to the atmosphere through the sequestration of carbon dioxide (CO_2) in deep geologic formations. Recent studies of life-cycle emissions from CCS projects that sequester CO_2 captured from coal-fired power generation through EOR show that net emissions from this process are positive due to the CO_2 emissions embodied in produced oil. For geologic sequestration through enhanced oil recovery (GS-EOR) to be effective, life cycle GHG emissions from the system must be small and consumption of the energy produced should not result in larger emissions than would otherwise happen in the absence of the GS-EOR project. In the best case, where relatively high emissions intensity oil and electrical generation are being displaced, the emissions reduction potential is greater than the amount of CO_2 purchased by the project; however, where a relatively light crude and carbon free marginal generation is being displaced, the GS-EOR project results in an emissions increase. As a matter of public policy, if reducing emissions of CO_2 is of great importance, encouraging GS-EOR will not be as effective as geologic sequestration in deep saline aquifers, or other means of reducing emissions that do not result in increased production of fossil fuels. Nonetheless, it is likely that GS-EOR projects will happen in the absence of emissions reduction incentives because they bring other benefits. The nature and scope of a GHG reduction program will determine the accounting approach needed to accurately estimate the emissions from GS-EOR, but in general, components that do not fall under an emissions cap will need to be accounted for via life cycle assessment. While further study is needed, it appears that allocating the emissions reduction to an electric power generator would be less complex and more effective that allocating it to the oil or fuels producer.

McGinnis, D. F., M. Schmidt, T. DelSontro, S. Themann, L. Rovelli, A. Reitz and P. Linke (2011). "Discovery of a natural CO_2 **seep in the German North Sea: Implications for shallow dissolved gas and seep detection " Journal of Geophysical Research-Oceans 116(C03013).**

A natural carbon dioxide (CO_2) seep was discovered during an expedition to the southern German North Sea (October 2008). Elevated CO_2 levels of ∼10–20 times above background were detected in seawater above a natural salt dome ∼30 km north of the East-Frisian Island Juist. A single elevated value 53 times higher than background was measured, indicating a possible CO_2 point source from the seafloor. Measured pH values of around 6.8 support modeled pH values for the observed high CO_2 concentration. These results are presented in the context of CO_2 seepage detection, in light of proposed subsurface CO_2 sequestering and growing concern of ocean acidification. We explore the boundary conditions of CO_2 bubble and plume seepage and potential flux paths to the atmosphere. Shallow bubble release experiments conducted in a lake combined with discrete-bubble modeling suggest that shallow CO_2 outgassing will be difficult to detect as bubbles dissolve very rapidly (within meters). Bubble-plume modeling further shows that a CO_2 plume will lose buoyancy quickly because of rapid bubble dissolution while the newly CO_2-enriched water tends to sink toward the seabed. Results suggest that released CO_2 will tend to stay near the bottom in shallow systems (< 200 m) and will vent to the atmosphere only during deep water convection (water column turnover). While isotope signatures point to a biogenic source, the exact origin is inconclusive because of dilution. This site could serve as a natural laboratory to further study the effects of carbon sequestration below the seafloor.

Meadows, M. A. (2013a). "4D rock and fluid properties analysis at the Weyburn Field, Saskatchewan." International Journal of Greenhouse Gas Control 16, Supplement 1(0): S134-S145.

This paper presents an analysis of CO_2 rock and fluid properties and 1D seismic modeling from the Weyburn Field, Saskatchewan. Dry frame properties of the Marly and Vuggy units were computed using data from ultrasonic core measurements, and the fluid physics of oil/brine/CO_2 mixtures was analyzed using established empirical relations and a multi-phase compositional simulator. The complex properties of supercritical CO_2 and miscible oil systems were taken into account for the range of reservoir pressures and fluid saturations expected at Weyburn. These dry rock and fluid properties were combined to obtain saturated P- and S-velocities and densities that were used directly in generating 1D synthetic seismograms from well logs modified to simulate production-related changes in pressure and saturation. It was found that pressure effects at Weyburn are at least as large as, and often larger than, saturation effects. 1D modeling results confirm the sensitivities of rock properties to pressure and saturation changes found in the rock physics analysis, but they also include the complexities of spatially varying properties and wavelet effects, which can significantly alter the seismic response. This analysis is an important first step in successfully implementing CO_2 monitoring and verification for enhanced oil recovery and long-term sequestration.

Meckel, T., N. Bangs and R. Trevino (2013). "Determining Seal Effectiveness and Potential Buoyant Fluid Migration Pathways using Shallow High-resolution 3-D Seismic Imaging: Application for CO_2 Storage Assessment on the Inner Texas Shelf." AAPG 2013 Annual Convention and Exhibition.

"Determining Seal Effectiveness and Potential Buoyant Fluid Migration Pathways using Shallow High-resolution 3-D Seismic Imaging: Application for CO_2 Storage Assessment on the Inner Texas Shelf." AAPG 2013 Annual Convention and Exhibition. Typically seal prediction focuses on wireline log and petrophysical flow properties that can be measured on cored seal specimens (i.e. capillary fluid threshold entry pressure).The lateral continuity of seals is difficult to predict. One way to overcome the spatial limitation is to observe long-term fluid history behavior by investigating overburden. Such analysis relies on the premise that prior or current migration of buoyant fluids has ‘tested' a more extensive area of seal coverage and variability, including faults. Indications of shallow migration and/or re-accumulation are suggestive of poor seal quality, and such indications may be helpful in identifying likely migration pathways, further delineating the mechanism or process of seal failure. Such analyses have been used to predict seal risk for hydrocarbon prospects and seem appropriate for understanding seal risks for CO_2 storage prospects. Typically the near-surface interval is poorly imaged in commercially available seismic data given acquisition and processing optimized for deeper reservoir systems. We present recently-collected shallow high-resolution 3-D seismic data and describe how they can be used to assess seal integrity and potential migration in inner Texas shelf, northern GOM offshore CO_2 storage prospects. For this study ~1,100 line km of 3-D seismic data were collected using the "P-Cable" acquisition system (12 25 m long streamers with 12.5 m spacing) focused on upper 1 sec TWTT over a prospective storage area. The site is offshore southern Galveston Island, adjacent to the San Luis Pass salt dome, in Texas state waters. The region has both commercial gas accumulations and abundant dry holes. Criteria were developed for identifying potential natural (hydrocarbon) fluid migration systems over geologic time, with an emphasis on how that understanding can be used to demonstrate effective (or alternatively leaking) seals and for identifying the likely migration pathways that may limit or render unsuitable a specific storage target. Collecting such data prior to initiating a storage project may also serve as a baseline for future time-lapse (4-D) surveys to demonstrate containment or identify non-containment. Several lines were shot twice for evaluating repeatability; perspectives on this application will be provided.

Meckel, T. and R. H. Trevino (2014a). "The offshore Texas miocene CO_2 storage project."

The Texas Offshore Miocene Project is a substantial five-year effort undertaken by the Gulf Coast Carbon Center at the Bureau of Economic Geology to investigate the regional geologic potential of Miocene-age rocks of Texas State Submerged Lands to store CO_2 for geologically significant periods of time. Such geologic storage provides current and future emitting industries with a viable environmental alternative to the current practice of atmospheric release. The results of this study should provide the next step in making permanent geologic storage of CO_2 a commercial reality.

Meckel T.A., Trevino. R. (2014b). High-resolution 3D seismic investigations of the overburden above potential CCS sites of the inner Texas shelf, Gulf of Mexico, U.S.A. B. o. E. G. Gulf Coast Carbon Center, University of Texas at Austin.

Much CCS research has focused on the injection interval (storage reservoir) and the immediately overlying primary seal. Considerations related to potential long-term leakage have turned attention toward the geologic overburden between the primary seal and shallow intervals containing protected groundwater. Typically the near-surface interval is poorly imaged in commercially available seismic data given acquisition and processing optimized for deeper reservoir systems. Recent advances in high-resolution 3D (HR3D) seismic imaging have allowed for more thorough investigation of this critical interval in marine settings, and are well-suited for evaluating potential leakage pathways for prospective CCS sites. Such analyses can serve to reduce risks of project development. A multi-year study characterizing prospective CO_2 storage sites in the inner Texas shelf utilized the high-resolution “P-Cable” marine seismic acquisition system to complement existing commercial 3D data by linking the shallow and deep geologic systems for unified interpretation. Three surveys have been conducted in 2012, 2013, and 2014 (totally over 150 sq. km.). Acquisition utilized twelve 25 m long streamers with 12.5 m lateral spacing, each with 8 receivers at 3 m spacing (total 96 channels). Dominant frequencies of 100–150 Hz allow vertical resolution of approximately 3 meters. Such HR3D data can be used to: 1) characterize any shallow (~1km depth) storage formations prior to initiating a project; 2) characterize the overburden above storage formations by providing stratigraphic and structural information for risking long-term storage and avoiding unintended migration, and 3) may also serve as a baseline for future time-lapse (4D) surveys to demonstrate containment or identify non-containment. Interpretation of the shallow seismic data highlights the ability to map structural discontinuities from depth (potential storage intervals) toward the seafloor as well as the stratigraphic complexity that various depositional systems leave in the geologic record. The former may serve as conduits for focused and relatively rapid vertical migration, whereas the latter will serve to disperse and otherwise retard or arrest vertical migration. A thorough understanding of the relationship among these two is critical for evaluating long-term potential for migration to the seafloor, thus reducing project risks. Fault expression in the seismic data changes vertically in the stratigraphy, likely as a result of increased lithification with depth. The implications this has for fluid flow are being assessed, and simplified 2D models of fluid migration on these features highlights the importance of the contrast in flow properties between the adjacent host stratigraphy and the fault zone itself. While many of the largest-scale faults in the study area can now be mapped to intersection with the near seafloor sediments, no examples of seafloor expression of fluid flow at fault locations are observed, suggesting the fluid system is currently inactive on the inner shelf. At relatively shallow stratigraphic depths (<500 m below seafloor), many readily recognizable depositional systems are seismically mapped in great detail in the HR3D volumes (e.g. fluvial channels, strand plains, estuaries, etc.). Mapping of these depositional systems suggests that any potentially upward migrating CO_2 would encounter a veritable geologic labyrinth, allowing for effective stratigraphic titration (geochemical reaction) of migrating CO_2 (Cathles & Schoell, 2007). Prior interpretations of the diagenetic history of the inner shelf of the Gulf of Mexico suggest this has been the case for natural CO_2 in the basin through geologic time (Lundegard and Land, 1986;Milliken, 2003). These considerations further reduce risks to project development.

Meckel, T. A. and F. J. Mulchay (2016). "Use of novel high-resolution 3D marine seismic technology to evaluate Quaternary fluvial valley development and geologic controls on distribution of shallow gas anomalies, inner shelf, Gulf of Mexico." Interpretation, AAPG/SEG 4(1): SC35-SC49.

The first deployment of the P-Cable™ high-resolution 3D (HR3D) seismic acquisition system in the Gulf of Mexico has provided unprecedented resolution of depositional, architectural, and structural features related to relative sea-level change recorded in the Quaternary stratigraphy. These details are typically beyond conventional 3D seismic resolution and/or excluded from commercial surveys, which are generally optimized for deeper targets. Such HR3D data are valuable for detailed studies of reservoir analogs, sediment delivery systems, fluid-migration systems, and geotechnical hazard assessment (i.e., drilling and infrastructure). The HR3D survey (31.5 km2) collected on the inner shelf (<15 m water depth) offshore San Luis Pass, Texas, imaged the upper 500 m of stratigraphy using peak frequency of 150 Hz and 6.25 m2 bin size. These data provided an exceptionally well-imaged example of shallow subsurface depositional system and stratigraphic architecture development during a lowstand period. The system evolved from a meandering channel with isolated point-bar deposits to a transgressive estuary characterized by dendritic erosional features that were eventually flooded. In addition, HR3D data have identified a previously unidentified seismically discontinuous zone interpreted to be a gas chimney system emanating from a tested (drilled) nonproductive, three-way structure in the lower Miocene (1.5 km depth). Within the shallowest intervals (<100 m) and at the top of the chimney zone, seismic attribute analysis revealed several high-amplitude anomalies up to 0.5 km2. The anomalies were interpreted as reaccumulated thermogenic gas, and their distribution conforms to the stratigraphy and structure of the Quaternary interval, in that they occupy local fault-bounded footwall highs within remnant coarser-grained interfluvial zones, which are overlain by finer grained, transgressive deposits.

Mito, S. and Z. Xue (2011). "Post-Injection monitoring of stored CO_2 **at the Nagaoka pilot site: 5 years time-lapse well logging results." Energy Procedia 4: 3284-3289.**

Monitoring is the major challenge in CO_2 geological sequestration. At the first Japanese pilot CO_2 injection site (Nagaoka), CO_2 was injected into a thin permeable zone at a depth of 1100 m and the total amount of injected CO_2 was 10,400 tons during the injection period from July 2003 to January 2005. After ceasing of CO_2 injection, well loggings which mainly consist of neutron logging, sonic logging and induction logging have been continued for 5 years. The Nagaoka site may provide the first field data set of post-injection monitoring and essential information on long-term CO_2 behaviour in a saline aquifer. In this paper reports the results of formation pressure, well logging and fluid sampling aiming to improve understanding of CO_2 long term behaviour in the reservoir. The results of time-laps well logging provide the evidences of the solubility trap and residual trap in progress at Nagaoka, suggesting CO_2 is stored safely in a complex sandstone reservoir.

Morbee, J., J. Serpa and E. Tzimas (2011). "Optimal planning of CO_2 **transmission infrastructure: The JRC InfraCCS tool." Energy Procedia 4: 2772-2777.**

Successful large-scale deployment of CCS will require the build up of commensurate infrastructure to transport CO_2 from sources (e.g., power plants) to sinks (e.g., mature oil and gas fields). Research so far has mostly dealt with the techno-economic assessment of pre-defined CO_2 value chains, which are typically country-specific and each connect a limited set of sources to a limited set of sinks. By contrast,

our paper presents the JRC's InfraCCS model, a tool that is capable of finding the optimal pipeline-based CO_2 transmission network for a given set of sources and sinks. The InfraCCS model is herein applied to the case of CCS in Europe, in order to estimate the strategic benefits of joint optimisation at pan-European level compared to optimisation at the level of individual countries.

Murray, C. and D. R. Marmorek (2004). Adaptive management: a spoonful of rigour helps the uncertainty go down. Proceedings of the 16th Annual Society for Ecological Restoration Conference, Victoria, BC, Citeseer.

Adaptive management is a rigorous approach to environmental management designed to explicitly address and reduce uncertainty regarding the most effective on-the-ground actions for achieving management goals and objectives. Unfortunately the term "adaptive management" has been widely misused, diluting both the concept and its application. This paper briefly clarifies what adaptive management really is, and what it can offer to the field of ecological restoration. This is done using several case studies, including habitat restoration in the Columbia River Basin, ecosystem restoration in the Trinity River in California, and recovery of Garry oak and associated ecosystems in British Columbia.

Myer, L. R., G. M. Hoversten, E. Gasperikova, J. Gale and Y. Kaya (2003). Sensitivity and Cost of Monitoring Geologic Sequestration Using Geophysics. Greenhouse Gas Control Technologies - 6th International Conference. Oxford, Pergamon: 377-382.

Monitoring of geologic sequestration projects will be needed in order to manage the process of filling the reservoir, verify the amount sequstered in a particular volume, and detect leaks. The sensitivity of geophysical methods depends, first of all, on the contrast in geophysical properties produced by introduction of CO_2. Rock physics models were used to calculate anticipated contrasts in seismic velocity and impedance in brine saturated rock when CO_2 is introduced. The phase behavior of CO_2 has large effects on property contrasts over the depth and temperature range of interest in geologic sequestration projects. Detectability depends critically on the spatial resolution of the method. Numerical simulations were performed to evaluate how small a volume of CO_2 could be detected in the subsurface by seismic methods. Results from a model based on Texas Gulf Coast geology showed that a wedge of CO_2 in a 10 m thick sand could be detected. The size of the Fresnel zone was about 320 m. Costs of performing 3-D land seismic surveys were estimated for a hypothetical project in which the CO_2 produced by a 1000 MW coal fired power plant is sequestered. Results indicate monitoring costs may be only a small percentage of overall geologic sequestration costs.

Neele, F., M. Koenen, J. van Deurzen, A. Seebregts, H. Groenenberg and T. Thielemann (2011a). "Large-scale CCS transport and storage networks in North-west and Central Europe." Energy Procedia 4: 2740-2747.

Carbon Capture and Storage (CCS) is one of the measures that can be used to reduce CO_2 emissions to the atmosphere in Europe. Of the total CCS chain the transport infrastructure may be the most planning and guidance-intensive part during the development of large-scale CCS. The EU FP7 CO_2 Europipe project aims to pave the road towards large-scale, Europe-wide infrastructure for the transport and injection of CO_2 from large point sources. The study presented here is part of that project and presents an assessment of the North-west and Central European sources and sinks of CO_2; matching of the sources and sinks is performed in order to identify likely future transport routes and the volumes that can be expected to be transported. The results are presented in maps with major transport corridors. The matching shows that, theoretically, sufficient storage capacity is available up to 2050, with the main part located in the North Sea. Aquifers are to play an important part in the storage and thus require early exploration activities. Infrastructure networks will be extensive and pipeline construction will need to be performed at a fast pace between 2020 and 2050 to make sure that transport can occur between the source clusters and the storage fields in time. To achieve this, international co-operation is required since cross-

border transport will be inevitable if the EU is to achieve its GHG emission reduction target. Also, necessary legal frameworks for CCS need to be in place in each affected country to allow this process to go ahead.

Neele, F., H. A. Haugen and R. Skagestad (2014). "Ship transport of CO_2 – breaking the CO_2-EOR deadlock." Energy Procedia 63(0): 2638-2644.

The North Sea contains the larger part of the storage capacity in North West Europe. Countries around the North Sea currently focus their attention on developing that capacity for the CCS demonstration projects. It is generally assumed that a second wave of CCS projects will further develop storage in the North Sea. However, a major hurdle is the development of long-distance pipelines. A requirement for the construction of a 'backbone' pipeline is the availability of a sufficient volume of CO_2, with a firm commitment on the duration of supply of CO_2. Especially for EOR purposes a CO_2 pipeline is not attractive, due to continuously decreasing demand for CO_2 after an initial peak. Transport by ship can provide a solution, because of its inherent flexibility in combining CO_2 from several sources, each too small to warrant a pipeline, to one or more storage locations. This paper describes the case for ship transport of CO_2 to North Sea oil fields, especially in the early phases of the development of CCS in Europe, providing the cross-benefit that will increase the lifetime of oil fields and, at the same time, provide the required commercial case for CO_2 capture and transport. This will help develop CCS industry, which will help EU Member States to meet their CO_2 emission reduction targets.

Newby, M. A. and W. H. Pauw (2010). Safe Transfer of Liquefied Gas in the Offshore Environment. Offshore Technology Conference, 3-6 May 2010. Houston, Texas.

In order to capture value from stranded gas reserves, operators are looking to offshore gas production from FPSOs and also from platforms stripping liquids and exporting through FSOs. This is a relatively new area for F(P)SO operations. In order for this to be carried out safely, there was a need to capture important lessons learned from the successful operations and ensure other operators apply the lessons at the feed engineering stage. The value of modeling in order to establish important parameters must also be considered. This paper outlines the development of the new OCIMF guideline on the "Safe Transfer of Liquefied Gas in the Offshore Environment" (STOLGOE) primarily for Side by Side transfer of LPG. The industry experience was used to develop the guideline. Important safety factors that need to be taken into account when doing side-by-side (SBS) transfer operations for LPG include:

- Mooring layout and release capability
- Heading ControlUse of hoses / hard arms
- Emergency release capability of hoses / hard arms
- Fendering systemsCrane operations

ConocoPhillips is leading the way with 2 LPG FSOs conducting SBS operations. "Liberdade" is the 3 product LPG FSO operating in the Timor Sea on the Bayu Undan Field and has achieved more than 130 SBS offloading operations. This facility has become industry benchmark for safe transfer operations of LPG in the offshore environment. In order to achieve such a safe and successful operation, modeling of parameters was vital to being able to determine mooring layout, tug assistance, heading control and operational limits. Modeling for design purposes and check with reality is necessary in order to improve the quality of models. It is important to get feedback from experienced personnel and to conduct full scale measurements to help ensure the success of future designs. The operating experience of Liberdade is being used to help act as a reality check of the software and model tests. This real life experience with design and operation is being used to give feedback on design tool developed through the Offloading Operability JIP and will be able to be applied to any transfer of LPG from an F(P)SO to a conventional LPG Gas Carrier using SBS method and can be used as the basis for transfer of LNG from an F(P)SO to a conventional LNG Gas Carrier.

Nicholson, A. J. (2012). Empirical Analysis of Fault Seal Capacity for CO_2 Sequestration, Lower Miocene, Texas Gulf Coast. Unpublished Masters Thesis, The University of Texas at Austin: 88.

The Gulf Coast of Texas has been proposed as a high capacity storage region for geologic sequestration of anthropogenic CO_2. The Miocene section within the Texas State Waters is an attractive offshore alternative to onshore sequestration. However, the stratigraphic targets of interest highlight a need to utilize fault-bounded structural traps. Regional capacity estimates in this area have previously focused on simple volumetric estimations or more sophisticated fill-to-spill scenarios with faults acting as no-flow boundaries. Capacity estimations that ignore the static and dynamic sealing capacities of faults may therefore be inaccurate. A comprehensive fault seal analysis workflow for CO_2-brine membrane fault seal potential has been developed for geologic site selection in the Miocene section of the Texas State Waters. To reduce uncertainty of fault performance, a fault seal calibration has been performed on 6 Miocene natural gas traps in the Texas State Waters in order to constrain the capillary entry pressures of the modeled fault gouge. Results indicate that modeled membrane fault seal capacity for the Lower Miocene section agrees with published global fault seal databases. Faults can therefore serve as effective seals, as suggested by natural hydrocarbon accumulations. However, fault seal capacity is generally an order of magnitude lower than top seal capacity in the same stratigraphic setting, with implications for storage projects. For a specific non-hydrocarbon producing site studied for sequestration (San Luis Pass salt dome setting) with moderately dipping (16°) traps (i.e. high potential column height), membrane fault seal modeling is shown to decrease fault-bound trap area, and therefore storage capacity volume, compared with fill-to-spill modeling. However, using the developed fault seal workflow at other potential storage sites will predict the degree to which storage capacity may approach fill-to-spill capacity, depending primarily on the geology of the fault (shale gouge ratio – SGR) and the structural relief of the trap.

Nicot, J.-P. and Hovorka S. (2009a). Leakage pathways from potential CO_2 storage sites and importance of open traps: Case of the Texas Gulf Coast. AAPG Studies in Geology J. C. P. M. Grobe, and R. L. Dodge, eds., , AAPG. 59: 321-334.

The Texas Gulf Coast is an attractive target for carbon storage. Stacked sandstone and shale layers provide large potential storage volumes and defense-in-depth leakage protection. Two types of traps are important in the initial sequestration stages: (1) closed structural and stratigraphic traps analogous to oil and gas traps, and (2) open traps where the residual saturation trail of capillary trapping is the main active mechanism. Leakage pathways of primary concern are wellbores and faults. Both could produce a direct connection to the atmosphere. However, most faults do not reach the surface, leaving abandoned wellbores the main focus of a risk analysis. Other leakage pathways, such as a closed trap overflowing through spill points or a seal failure, can be accommodated by the capillary trapping mechanism. The effectiveness of this mechanism depends on the level of heterogeneity of the formations. Determining formation heterogeneity is the second emphasis of any risk analysis in the Texas Gulf Coast. This chapter focuses on the Tertiary section of the Texas Gulf Coast and describes statistics on the hundreds of thousands of boreholes (age, depth, status) drilled in the area and on the shape and size of closed and open traps, which were measured from proprietary structural maps. The chapter also incorporates information about growth-fault distribution and discusses efficiency of capillary trapping. The implications for carbon storage are then derived (e.g., stay away from salt domes and their capture zone; inject mostly deeper than the majority of abandoned wells).

Nightingale, M., G. Johnson, M. Shevalier, I. Hutcheon, E. Perkins and B. Mayer (2009). "Impact of injected CO_2 on reservoir mine ralogy during CO_2 -EOR." Energy Procedia 1(1): 3399-3406.

An investigation of the impact of injected CO_2 on reservoir mineralogy was completed as part of the geochemical monitoring and modelling of the Pembina Cardium CO_2 Monitoring Project southwest of Drayton Valley, Alberta, Canada. Oil production at the pilot is primarily from the upper two of three stacked sandstone units of the Cardium Formation in the Pembina field. Core analyzed included samples

from each of the three sandstone units, and encompassed three distinct time periods: pre-water flood (1955), pre- CO_2 flood (2005), and post- CO_2 flood (2007). The results of whole rock analysis (XRF, ICP, and XRD), and microscopy (polarizing and electron microprobe) suggest the three separate sandstone units are both texturally and compositionally similar regardless of when the core was recovered. Framework grains are predominately sub-angular to sub-rounded quartz/chert (up to 90.0 wt%), and include smaller amounts of lithic fragments (shale), feldspar (k-feldspar, and albite), mica (muscovite and chlorite), and fluor-apatite. Authigenic pyrite is found as finely disseminated rhombs throughout the formation. Clay minerals present are predominantly kaolinite and illite. Kaolinite appears as fine discrete pore filling books, and is considered to be authigenic. Illite occurs as a major constituent of shale fragments, as well as fine pore bridging strands. The sandstone's irregular pores are cemented to varying degrees by silica and/or carbonate minerals (calcite and siderite). Dissolution features associated with formation diagenesis, including the degradation of detrital grains (quartz and feldspar), the partial and/or complete removal of carbonate cements, and the presence of residual clays, are found in core from each of the three time periods. Attributing dissolution features in post-CO_2 flood core to the interaction of minerals and carbonic acid is difficult due to the geologic history of the formation.

Offshore Energy Today. 2014. Shell moves ahead with Peterhead CCS project. [accessed 2017 Nov 3]. http://www.offshoreenergytoday.com/shell-moves-ahead-with-peterhead-ccs-project/.

Ogbuabuo, P. (2015). Energy and Earth Resources. Austin, Texas, The University of Texas at Austin. M.S.: 59.

Data from the US Department of Interior Bureau of Ocean and Energy Management 2012 Offshore Gulf of Mexico Atlas were analyzed to (i) compute reconnaissance-level estimates of CO_2 volumes for storage in sub-seabed offshore Gulf of Mexico (GoM) oil sands before and after carbon dioxide (CO_2) enhanced oil recovery (EOR), (ii) investigative technical and economic impacts of CO_2 injection in gas-rich offshore GoM hydrocarbon fields, and (iii) analyze legal issues and framework associated with offshore geologic sequestration or storage (GS). Part (i) of this study, Reconnaissance-level estimation of CO_2 sub-seabed GS potential in offshore GoM, builds on a similar study conducted by The University of Texas at Austin, Bureau of Economic Geology on potential onshore CO_2 GS in the GoM region, published in Nunez-Lopez et al. (2008). Part (ii) focuses on the use of two screening methodologies to investigate the impact of native methane (CH_4) in recycled CO_2. The impact of CH_4 on the effectiveness of CO_2 as a solvent for EOR is defined by: Calculating minimum miscibility pressure (MMP) of pure CO_2 for each oil sand (conventional oil reservoirs), Computing impure CO_2 MMP for each oil sand considering only native CH_4 as an impurity and neglecting other trace gas components in the oil reservoir. Five to 50 mole percent CH_4 impurity factor was computed as a function of the pseudocritical temperature (T[subscript pc]) of the CH_4-CO_2 mixture. Plotting miscibility against sub-seabed depth, total depth, play type, and API gravity. Part (iii) analyzes existing US outer continental shelf (OCS) regulations under the authority of the US Department of the Interior stated in Title 30 CFR Part 250 and Part 550 to determine their applicability to carbon capture, offshore GS, and CO_2 EOR. The study results show a potential storage capacity of approximately 3.5 billion metric tons of CO_2 after CO_2 EOR for the 3,598 offshore GoM individual oil sands assessed in Part (i). For Part (ii), results indicate that deeper reservoirs are most tolerant to miscible impure CO_2 EOR. Of the play types defined by the BOEM, fan and fold belt plays are most tolerant to impure CO_2 flooding. Further study on the impact of impure CO_2 on MMP resulted in a definition of 18 mole percent as the cutoff for economic and technically viable CO_2 flooding in offshore GoM oil fields. When a hypothetical CO_2 injection stream exceeded 18 mole percent CH_4 contamination, 72% of the case study oil reservoirs became immiscible. In Part (iii), policies that address offshore CO_2 GS, CO_2 EOR, and both price based and non-price based mechanisms in the OCS would accelerate a shift towards implementing GS and CO_2 EOR in offshore GoM.

Oldenburg, C. M., J.-P. Nicot and S. L. Bryant (2009a). "Case studies of the application of the Certification Framework to two geologic carbon sequestration sites." Energy Procedia 1(1): 63-70.

We have developed a certification framework (CF) for certifying that the risks of geologic carbon sequestration (GCS) sites are below agreed-upon thresholds. The CF is based on effective trapping of CO_2, the proposed concept that takes into account both the probability and impact of CO_2 leakage. The CF uses probability estimates of the intersection of conductive faults and wells with the CO_2 plume along with modeled fluxes or concentrations of CO_2 as proxies for impacts to compartments (such as potable groundwater) to calculate CO_2 leakage risk. In order to test and refine the approach, we applied the CF to (1) a hypothetical large-scale GCS project in the Texas Gulf Coast, and (2) WESTCARB's Phase III GCS pilot in the southern San Joaquin Valley, California.

Oldenburg, C. M., S. L. Bryant and J. P. Nicot (2009b). "Certification framework based on effective trapping for geologic carbon sequestration." International Journal of Greenhouse Gas Control 3(4): 444-457.

We have developed a certification framework (CF) for certifying the safety and effectiveness of geologic carbon sequestration (GCS) sites. Safety and effectiveness are achieved if CO_2 and displaced brine have no significant impact on humans, other living things, resources, or the environment. In the CF, we relate effective trapping to CO_2 leakage risk which takes into account both the impact and probability of leakage. We achieve simplicity in the CF by using (1) wells and faults as the potential leakage pathways, (2) compartments to represent environmental resources that may be impacted by leakage, (3) CO_2 fluxes and concentrations in the compartments as proxies for impact to vulnerable entities, (4) broad ranges of storage formation properties to generate a catalog of simulated plume movements, and (5) probabilities of intersection of the CO_2 plume with the conduits and compartments. We demonstrate the approach on a hypothetical GCS site in a Texas Gulf Coast saline formation. Through its generality and flexibility, the CF can contribute to the assessment of risk Of CO_2 and brine leakage as part of the certification process for licensing and permitting of GCS sites around the world regardless of the specific regulations in place in any given country. Published by Elsevier Ltd.

Oosterkamp A. and Ramsen. J (2008). State-of-the-Art Overview of CO_2 Pipeline Transport with relevance to offshore pipelines.

This report provides the results of a study of the existing experience regarding the design and operational aspecs of CO_2 transport by pipeline with relevance to future application on the Norwegian Continental Shelf. The effect of expected new conditions like higher pressures, offshore environment and impurities present in the CO_2 mixture are taken into account. The report concludes by summarizing the remaining uncertainties and R&D needs that were identified in this study. In addition, an overview of competence holders is given.

Ozaki, M., J. Davison, J. Minamiura, E. S. Rubin, D. W. Keith, C. F. Gilboy, M. Wilson, T. Morris, J. Gale and K. Thambimuthu (2005). Marine transportation of CO_2. Greenhouse Gas Control Technologies 7. Oxford, Elsevier Science Ltd: 2535-2539.

For the large scale transportation of CO_2 between capture and storage sites, ship transport is the alternative to pipelines, particularly in cases where the distance across the sea is quite long, very deep water is traversed, ect. This paper summarizes a study on the CO_2 marine transportation system, which consists of CO_2 liquefaction, intermediate storage and loading facilities, CO_2 ships and receiving facilities. Case studies are carried out assuming that the amount of captured CO_2 is 20, 000 tonne/day and the transport distance is widely changed from 200km to 12, 000km. The cost of CO_2 marine transportation and the additional emissions of CO_2 from the system are assessed. Influences of parameters such as ship size, ship speed and CO_2 condition before liquefaction are investigated.

Ozaki, M., T. Ohsumi and R. Kajiyama (2013). "Ship-based Offshore CCS Featuring CO_2 Shuttle Ships Equipped with Injection Facilities." Energy Procedia 37: 3184-3190.

Transport of CO_2 is a key component in the CCS chain for commercial projects, and CO_2 shipping is being reconsidered as an alternative to pipeline transport even when the distance across the sea is not so quite long. The ship-based transport will make it possible to couple CO_2 recovery plant and storage site without being limited to a single sink-source match, and decoupling and moving to another sink can be done with relative ease when necessary. It also removes the pipeline construction and removal activities in coastal zone where the social activities like fishery are often high. In this paper, the technical and economic feasibility of shuttle-type shipping and offshore operation for CO_2 injection from the ship to the well(s) are studied. The main components needed for the proposed system are liquefaction of CO_2, temporary storage at port, offloading, shuttle ship with Dynamic Positioning System and injection equipments onboard, flexible riser pipe whose end is connected with the wellhead on the sea floor, and pickup system at site.

Ozaki, M., et al. (2015). Ship-Based Carbon Dioxide Capture and Storage for Enhanced Oil Recovery. Offshore Technology Conference. Houston, TX.

This report presents details of a proposed ship-based carbon dioxide capture and storage (CCS) method. CCS is one of the key technologies essential to achieve greenhouse gas reduction. This technology can also contribute to enhanced oil recovery (EOR) efforts by increasing oil production in mature fields. The liquified CO_2 (LCO_2) to be sequestered is injected directly into subseabed geological formations through a flexible riser pipe using injection facilities contained onboard an LCO_2 carrier ship. The primary characteristics of this LCO_2 subseabed injection system are as follows: the presence of LCO_2 injection equipment onboard the LCO_2 carrier ship, a direct injection into subseabed geological formations through a flexible riser pipe, and the absence of any stationary sea surface structures at the offshore CO_2 injection site. The advantage of ship-based transportation is flexibility in regard to i) multiple CO_2 shipping locations and storage sites, ii) multiple injection sites from a larger CO_2 storage port, and iii) relocation of the injection site resulting from either termination of oil production or the site becoming filled with CO_2. That is, ships can easily alter their shipping ports and routes to the offshore injection site(s), depending on requirements.

Pacala, S. W. (2003). Global Constraints on Reservoir Leakage. Greenhouse Gas Control Technologies - 6th International Conference. J. G. Kaya. Oxford, Pergamon: 267-272.

Publisher’s Summary: One possible solution to the problem of greenhouse warming is to sequester the carbon from fossil fuel in geologic reservoirs, such as depleted oil and gas reservoirs, coal beds, and deep (1000m) saline aquifers. Geologic sequestration relies on proven and cost-effective technology, and suitable formations may have sufficient capacity. Environmental concerns about sequestration in geologic formations center on the possibility that some of these reservoirs may leak. Problems associated with leaking reservoirs could occur on two distinct spatial scales. At local scales, leaking CO_2 could mobilize contaminants of drinking-water aquifers or, in a worst-case scenario, reach toxic concentrations in a basement. This chapter focuses on the global-scale problem and uses models of carbon storage reservoirs and natural carbon sinks to calculate constraints on reservoir leakage. It assumes fossil fuel consumption at a level that would that would lead to an atmospheric CO_2 concentration of 750 ppm and then calculates the sequestration and leakage limits that would reduce the maximum concentration to 450 or 550 ppm. The surprising result is that leakage limits are much less severe than expected because of heterogeneity among reservoirs. In some cases, the reduction from 750 to 450 ppm would be possible even with a mean leakage rate of 1% per year or more. The results imply that economic considerations or local risks are likely to constrain allowable leakage rates more tightly than impacts of leakage on global atmospheric CO_2.

Parente, V., D. Ferreira, E. M. dos Santos and E. Luczynskic (2006). "Offshore decommissioning issues: Deductibility and transferability." Energy Policy 34(15): 1992-2001.

Dealing with the decommissioning of petroleum installations is a relatively new challenge to most producer countries. It is natural to expect that industry's experience in building platforms is much greater than the one of dismantling them. Even if manifold and varied efforts are underway towards establishing international "best practices" standards in this sector, countries still enjoy rather extensive discretionary power as they practice a particular national style in the regulation of decommissioning activities in their state's jurisdiction. The present paper offers a broad panorama of this discussion, concentrating mainly on two controversial aspects. The first one analyses the ex ante deductibility of decommissioning costs as they constitute an ex post expense. The second discussion refers to the assignment of decommissioning responsibility in the case of transfer of exploration and production rights to new lessees during the project's life. Finally the paper applies concepts commonly used in project financing as well as structures generally used in organising pension funds to develop insights into these discussions. (c) 2005 Elsevier Ltd. All rights reserved.

Paul, S., R. Shepherd, A. Bahrami and P. Woollin (2010). Material Selection for Supercritical CO_2 Transport. The First International Forum on the Transportation of CO_2 by Pipeline. Gateshead, UK, 1-2 July 2010.

Understanding materials' behaviour and assessing their integrity when in contact with supercritical CO_2 is crucial to the success and sustainable implementation of carbon capture and sequestration plans. Of critical importance for the successful and cost-effective operation of existing and new-build, infrastructure components, is quantifying materials' integrity in representative high pressure and supercritical CO_2. This will enable confident materials selection, safe operation and accurate remaining life assessment to avoid the consequences of unexpected failure, as well as removal and replacement. One of the most critical technical issues is quantifying degradation of different transport components, including pipes, pumps and valves, in CO_2 as a high pressure gas or as a supercritical fluid, particularly in the presence of impurities. Although there is considerable experience of testing materials in lower pressure CO_2, there are no standard test methods and few data for supercritical CO_2. This paper explores the state-of-the-art in this field and highlights the areas of technology gap.

Pearce J, Blackford J, Beaubien S, Foekema E, Gemeni V, Gwosdz S, Jones D, Kirk K, Lions J, Metcalfe R, et al. 2014. Research into impacts and safety in CO2 storage (RISCS): a guide to potential impacts of leakage from CO2 storage. British Geological Survey. 70 p.

This report summarises the conclusions and recommendations developed by the RISCS Consortium, based on four years of research into the potential impacts of leakage from CO_2 storage sites. The report has been developed in parallel with the experimental research, field-based investigations, modelling studies and analysis undertaken during the RISCS project. The research programme, from which these recommendations have been formed, was designed to assess the nature and scale of potential impacts on a range of reference environments, should leakage occur from storage sites located in both terrestrial and marine environments. Dispersion of CO_2 in the onshore near-surface environment and in seawater has been simulated. Potential impacts have been assessed on representative examples of plants, mainly agricultural crops, groundwaters and on individual marine species and communities. Evidence to date indicates that leakage is of low probability if site selection, characterisation and storage project design are undertaken correctly. In Europe, the Storage Directive (EC, 2009) provides a legislative framework, implemented by Member States, which requires appropriate project design to ensure the storage of CO_2 is permanent and safe. The work undertaken in the RISCS project, including comparisons with other published results, allows us to draw the following high-level conclusions: Impacts from CO_2 leakage are expected to be small compared to impacts caused by other stressors. These additional stressors include, but are not limited to, changes in land use, extreme onshore weather events, periods of abnormal weather and activities such as bottom trawler fishing, as well as the impacts that CCS seeks to mitigate such as climate change and ocean acidification.

It is recommended that storage operators and relevant Competent Authorities demonstrate that an appropriate level of understanding has been developed of the potential impacts that might arise if a leak did occur from the specific site being considered for CO_2 storage. Evaluation of risks of leakage and potential impacts should be undertaken at each site, since each will have specific characteristics which will influence the nature and scale of the environmental response. The context of what specific impacts mean for a particular storage site (e.g., selection of crops) is fundamental and should be explained where relevant. The research undertaken in RISCS, and reviewed research published elsewhere, indicates that there are no reasons why a storage project could not be sited within any of the large-scale environmental types that have been studied here. Potential impacts will be further reduced by careful site selection and appropriate monitoring and mitigation plans. All monitoring programmes should use ecosystem evaluation techniques. Monitoring technologies and assessment methodologies have been developed and tested that allow the impacts of CO_2 in terrestrial and marine environments to be assessed. Indicator species that occur within specific onshore sites have been identified that can be monitored in conjunction with other environmental factors to assess the scale of an impact and the efficacy of any remediation.

Furthermore, it is concluded that: Carefully selected reference sites, both onshore and offshore, could be a powerful tool for providing ongoing baseline data against which storage sites can be compared. They would allow changes related to factors other than CO_2 leakage to be assessed. Sites managed via joint industry initiatives may be a suitable approach to enable a smaller number of reference sites to be developed for use by several storage projects. Evidence indicates that areas that might be affected by leakage will be localised. Individual seeps can be up to a few tens of metres across, and groups of these seeps might occur along fault zones. However, the total area of these seeps would still be a very small proportion of the area that might be used for CO_2 storage. This applies to onshore and offshore sites and includes potential impacts on groundwaters. This implies that monitoring techniques able to detect leaks at these small scales over large areas should be deployed if leakage is suspected. Monitoring a number of parameters in addition to those directly indicative of CO_2 levels will help to separate natural variations in CO_2 content from leakage, such as measuring nitrogen, oxygen and isotopic contents of soil gas or recording temperature and dissolved oxygen in marine systems. Baseline surveys will be required and are a fundamental part of demonstrating site performance. Ecosystem baseline surveys should be carried out at proposed storage sites to ascertain changes resulting from any leakage. These will also assist in Environmental Impact Assessments. It would also be beneficial if reference sites were similarly assessed and monitored so that any ecosystem changes attributed to CO_2 leakage can be compared to results from the non-injection site. Specific recommendations for operators and regulators to consider are: Site-specific monitoring will aid confidence building and demonstrate that the duty of care for safe, permanent storage has been met appropriately. Baseline surveys should be designed to account for a full range of natural variation, which may occur over more than one year. Changes at the storage site due to other external factors should also be taken into account, for example through the use of reference sites. Communication of these baseline results to the local stakeholders (such as residents and NGO’s) is advisable to create dialogue and increase knowledge of the natural system and its variability. Investigations for storage sites should include an assessment to determine whether the Conservation Objectives of Natura 2000 sites and any other protected areas are significantly affected by the project Leaks may have a cumulative, additional impact on ecosystems already stressed by other factors, such as low salinity marine environments, existing contaminated areas or marginal systems that are already restricted in their development. The timing and duration of the exposure will influence the scale of the impact. Timing is important because the stage of development of plants and animals affects their response, whilst the ecosystem in its entirety may be able to cope with enhanced CO_2 for a short duration. The scale of the likely impacts examined in the RISCS project means that they are considered manageable both by the ecosystem and by relevant stakeholders (operators and regulators). Offshore sites where mixing in the seawater column would allow dilution of CO_2 would be preferred because if a leak were to occur the natural mixing processes in the seawater could enhance dispersion and thereby minimise impacts. Similarly, onshore sites that avoid potential build up of CO_2 in confined areas would also be preferred, as under normal conditions light winds can quickly disperse any leaking CO_2. Natural recovery in dynamic marine systems is expected to be relatively rapid i.e. mostly within one 'growing cycle' or season, due to the large pool of ecosystem resources and small scale of the impacted area, although this may not apply to all scales of leakage. In terrestrial systems, replanting of crops should be possible in affected areas once leakage has ceased, as no long term effects are expected based on experiments on crops. However the longer term recovery of pasture land has not been fully evaluated.

Pennell, V., D. W. Christopher, N. Bise, B. Veitch, K. Hawboldt, T. Curtis, D. E. Perrault, S. O'Young, Mukhtasor, R. Sadiq, T. Husain, J. Ferguson, G. Eaton and P. Reedeker (2001). Innovative approaches to environmental effects monitoring using an autonomous underwater vehicle. 1st International Workshop on Underwater Robotics for Seanvironmental Monitoring Conference. Rio de Janeiro, Brazil, NRC Institute for Ocean Technology; National Research Council Canada.

An overview is given of a project to develop autonomous underwater vehicle (AUV) technology for environmental effects monitoring (EEM) in the offshore oil and gas industry. This project is a joint venture between the Institute for Marine Dynamics of the National Research Council Canada (NRC-IMD) and the Ocean Engineering Research Centre at Memorial University of Newfoundland (MUN-OERC), with the support of several Canadian companies and universities. With the offshore oil and gas industry growing rapidly, it is important that new and innovative methods for EEM be considered. The paper reports on results from the project "Offshore Environmental Risk Engineering using Autonomous Underwater Vehicles" (OERE-AUV). The results include: (a) the development of a new general-purpose test-bed AUV called "C-SCOUT", (b) the planning for a series of sea trials using an existing vehicle to determine the effectiveness of an AUV to delineate a near-shore ocean outfall, (c) the characteristics and performance of several candidate sensors for EEM, and, (d) the development of hydrodynamic dispersion models for discharges into a marine environment. The ultimate application of the research is for the EEM of discharges of produced water, drilling cuttings and drilling muds from offshore oil and gas production facilities.

Pettijohn et al., 1988, Distribution of dissolved solids concentrations and temperature in ground water of the gulf coast aquifer systems, south-central United States, U.S. Geol. Surv. Water Res. Inv. Report 88-4082, http://pubs.er.usgs.gov/publication/wri884082

The distribution of dissolved solids concentrations and temperature in waters of 10 of the aquifers comprising the gulf coast aquifer systems of the Gulf Mexico Coastal Plain are mapped at a scale of 1:3,500,000. Dissolved solids concentration in the aquifers of the Tertiary System ranges from less than 500 mg/L at the outcrop and subcrop areas to as much as 150,000 mg/L at the downdip extent of these aquifers. A distinct band of sharply increasing concentration of dissolved solids occurs at about middip of each aquifer of the Tertiary System. Dissolved solids concentration in younger aquifers ranges from less than 500 mg/L in outcrop and subcrop areas to about 70,000 mg/L at the downdip extent of these aquifers. Temperature of waters in permeable Tertiary deposits ranges from about 18 C at the outcrop and subcrop areas to 90 C at the downdip extent of these aquifers. Temperature of waters in younger deposits ranges from about 14 C at the outcrop and subcrop areas to 30 C at their downdip extent

Pevzner, R., V. Shulakova, A. Kepic and M. Urosevic (2011). "Repeatability analysis of land time-lapse seismic data: CO_2**CRC Otway pilot project case study." Geophysical Prospecting 59(1): 66-77.**

Time-lapse seismics is the methodology of choice for remotely monitoring changes in oil/gas reservoir depletion, reservoir stimulation or CO_2 sequestration, due to good sensitivity and resolving power at depths up to several kilometres. This method is now routinely applied offshore, however, the use of time-lapse methodology onshore is relatively rare. The main reason for this is the relatively high cost of commercial seismic acquisition on land. A widespread belief of a relatively poor repeatability of land seismic data prevents rapid growth in the number of land time-lapse surveys. Considering that CO_2 sequestration on land is becoming a necessity, there is a great need to evaluate the feasibility of time-lapse seismics for monitoring. Therefore, an understanding of the factors influencing repeatability of land seismics and evaluating limitations of the method is crucially important for its application in many CO_2 sequestration projects. We analyse several repeated 2D and 3D surveys acquired within the Otway CO_2 sequestration pilot project (operated by the Cooperative Research Centre for Greenhouse Technologies, CO_2CRC) in Australia, in order to determine the principal limitations of land time-lapse seismic repeatability and investigate the influence of the main factors affecting it. Our findings are that the intrinsic signal-to-noise ratio (S/N, signal to coherent and background noise levels) and the normalized-root-mean-square (NRMS) difference are controlled by the source strength and source type. However, the post-stack S/N ratio and corresponding NRMS residuals are controlled mainly by the data fold. For very high-fold data, the source strength and source type are less critical.

Pfaff, A. and C. W. Sanchirico (1999). "Environmental Self-Auditing: Setting the Proper Incentives for Discovering and Correcting Environmental Harm." SSRN eLibrary.

Many firms have instituted a policy of conducting their own "environmental audits" to test compliance with a complex array of environmental regulations. Yet, commentators suggest that self-auditing is still not as common as it should be because firms fear that the information they gather will be used against them. This paper analyzes the two-tiered incentive problem raised by self-auditing-viz., incentives to both test for and effect compliance. We find that conventional tort remedies fail to produce an efficient amount of self-auditing. To fix the problem we propose three separate solutions, each with differing informational requirements and efficiency benefits, and each distinct in its own way from current EPA policy. First, we propose that punitive fines be reduced for firms that conduct their own investigation, whether or not the firm has "fixed" the harm that its investigation uncovers. Importantly, we argue that the nature of the self-auditing incentive problem makes conditioning on investigation informationally feasible, since it is the potential observability of investigative effort that produces the disincentive to investigation in the first place. Our second solution conditions on firm disclosure. While this solution allows for additional savings in government enforcement costs, it raises serious informational issues regarding the verifiability of disclosure. Lastly, we consider a solution that we call "inverse negligence," wherein firms are fined additionally for harms that they would have fixed, had they learned about them through investigation. This solution requires neither verifiable disclosure, nor observable investigation effort, but does require additional information about the firm's private cost of fixing harms.

Porse, S. L. 2013, Using analytical and numerical modeling to assess deep groundwater monitoring parameters at carbon capture, utilization, and storage sites, University of Texas at Austin masters thesis, 144 p.

Carbon Dioxide (CO2) Enhanced Oil Recovery (EOR) is becoming an important bridge to commercialize geologic sequestration (GS) in order to help reduce anthropogenic CO2 emissions. Current U.S. environmental regulations require operators to monitor operational and groundwater aquifer changes within permitted bounds, depending on the injection activity type. We view one goal of monitoring as maximizing the chances of detecting adverse fluid migration signals into overlying aquifers. To maximize these chances, it is important to: (1) understand the limitations of monitoring pressure versus geochemistry in deep aquifers (i.e., >450 m) using analytical and numerical models, (2) conduct sensitivity analyses of specific model parameters to support monitoring design conclusions, and (3) compare the breakthrough time (in years) for pressure and geochemistry signals. Pressure response was assessed using an analytical model, derived from Darcy's law, which solves for diffusivity in radial coordinates and the fluid migration rate. Aqueous geochemistry response was assessed using the numerical, single-phase, reactive solute transport program PHAST that solves the advection-reaction-dispersion equation for 2-D transport. The conceptual modeling domain for both approaches included a fault that allows vertical fluid migration and one monitoring well, completed through a series of alternating confining units and distinct (brine) aquifers overlying a depleted oil reservoir, as observed in the Texas Gulf Coast, USA. Physical and operational data, including lithology, formation hydraulic parameters, and water chemistry obtained from field samples were used as input data. Uncertainty evaluation was conducted with a Monte Carlo approach by sampling the fault width (normal distribution) via Latin Hypercube and the hydraulic conductivity of each formation from a beta distribution of field data. Each model ran for 100 realizations over a 100 year modeling period. Monitoring well location was varied spatially and vertically with respect to the fault to assess arrival times of pressure signals and changes in geochemical parameters. Results indicate that the pressure-based, subsurface monitoring system provided higher probabilities of fluid migration detection in all candidate monitoring formations, especially those closest (i.e., 1300 m depth) to the possible fluid migration source. For aqueous geochemistry monitoring, formations with higher permeabilities (i.e., greater than 4 x 10-13 m^2) provided better spatial distributions of chemical changes, but these changes never preceded pressure signal breakthrough, and in some cases were delayed by decades when compared to pressure. Differences in signal breakthrough indicate that pressure monitoring is a better choice for early migration signal detection. However, both pressure and geochemical parameters should be considered as part of an integrated monitoring program on a site-specific basis, depending on regulatory requirements for longer term (i.e., > 50 years) monitoring. By assessing the probability of fluid migration detection using these monitoring techniques at this field site, it may be possible to viii extrapolate the results (or observations) to other CCUS fields with different geological environments.

Preston, C., S. Whittaker, B. Rostron, R. Chalaturnyk, D. White, C. Hawkes, J. W. Johnson, A. Wilkinson and N. Sacuta (2009). "IEA GHG Weyburn-Midale CO_2 monitoring and storage project–moving forward with the Final Phase." Energy Procedia 1(1): 1743-1750.

Since the end of First Phase of the IEA GHG Weyburn CO_2 monitoring and storage research project in 2004, the leading sponsors, PTRC, and the project team have been moving forward with the Final Phase. International interest in this project has remained strong, with new industry sponsors and continued support from First Phase sponsors. This paper highlights the key activities undertaken and issues encountered during the transition period between the conclusion of the First Phase and the start of the Final Phase. A detailed overview is provided of the proposed Final Phase technical work program, progress on ongoing technical research activities and other key activities planned. The technical research program consists of four main technical themes: 1. Site Characterization-Geological Integrity 2. Wellbore Integrity 3. Storage Monitoring Methods-Geophysical & Geochemical 4. Risk Assessment. A key deliverable from this Final Phase is development of a Best Practises Manual to help guide implementation of CO_2 geological storage in conjunction with enhanced oil recovery and to provide learnings extracted from the project that are generally applicable to other geological storage projects.

Pulsipher Allan G (1996). An International Workshop on Offshore Lease Abandonment and Platform Disposal: Technology, Regulation, and Environmental Effects, Center for Energy Studies, Louisiana State University.

This proceedings volume includes papers prepared for an international workshop on lease abandonment and offshore platform disposal. The workshop was held April 15, 16, and 17, 1996, in New Orleans, Louisiana. Included in the volume are several plenary speeches and issue papers prepared by six working groups, who discussed: Abandoning Wells; Abandoning Pipelines; Removing Facilities; Site Clearance; Habitat Management, Maintenance, and Planning; and Regulation and Policy. Also included are an introduction, an afterword (reprinted with the permission of its author, John Lohrenz), and as Appendix C, the complete report of the National Research Council Marine Board's An Assessment of Techniques for Removing Fixed Offshore Structires, around which much of the discussuion at the workshop was organized. Short biographies of many speakers, organizers, and chairpersons are included as Appendix A. Appendix B is a list of conference participants.

Quisel N., R. N., Thomas S. (2010). Environmental Assessment of CO_2 **Storage Site. Canadian Unconventional Resources & International Petroleum Conference. Alberta, Canada.**

Ensuring societal acceptance of Carbon Capture and Storage (CCS) projects is strongly linked to the environmental impact assessment of projects. CCS implementation should not only be considered a technical solution to the carbon emissions issue as societal issues play at least an equal role in the full acceptance of the technology. CCS projects should be designed to minimize environmental impacts to the highest degree possible and prove that the environmental issues can be monitored during development and operational phases. As a consequence, CCS projects must integrate appropriate monitoring programs and develop environmental studies in order to gather and analyse required information and to communicate with stakeholders. This paper proposes to prioritize processes and techniques that can be implemented to monitor environmental impacts of CO_2 storage sited. The first part of the paper focuses on the key monitoring techniques and assesses monitoring programs that can be used to gather required information. The second part of the paper presents the importance of the additional studies needed to assess environmental, health, and safety impacts in the event of a leak from the storade site that should be recommended as part of the environmental methodaology. This study can be viewed as the starting point for the decision analysis related to CCS projects and provides some guidance in establishing a specific monitoring program and an environmental assessment plan. It could be considered as an important step in the identification of the development options and optimization of the investment strategy that is required at the front end of any large and complicated project.

Ricarte, P., M. Ancel, M. Becquey, R. Dino, P. S. Rocha and M. C. Schinelli (2011). "Carbon dioxide volume estimated from seismic data after six years of injection in the oil field of Buracica, Bahia." Energy Procedia 4: 3314-3321.

Carbon dioxide has been injected since 1991 in the oil field of Buracica in the Recôncavo Basin in Brazil for EOR purposes. The CO_2 gas is injected into the upper oil reservoirs, a 13 m thick sandstone layer, at a depth of about 550 m. The reservoir is included in a tilted block dipping at an angle of 5 to 6° toward the south-east. A 3D seismic survey was carried out six years after the beginning of CO_2 injection. Sensitivity studies concluded that the gas-invaded and the oil-filled parts of the reservoir show only a weak contrast between their mechanical properties so that their interface might not appear in the seismic sections. Directional dip filtering of the seismic data underlines horizontal events crossing the dipping layer interfaces. Some of them can be interpreted as the gas/oil contact. A careful picking and mapping of these events reveal two accumulations of carbon dioxide on each side of a system of N-S faults, with slightly different gas/oil contact levels. Estimation of the gas volume and of the density leads to a rough estimate of the mass of CO_2 in place, indicating that about one third of the CO_2 injected was stored in the reservoir.

Riding, J. B., E. S. Rubin, D. W. Keith, C. F. Gilboy, M. Wilson, T. Morris, J. Gale and K. Thambimuthu (2005). The IEA Weyburn CO_2 Monitoring and Storage Project - Integrated results from Europe. Greenhouse Gas Control Technologies 7. Oxford, Elsevier Science Ltd: 2075-2078.

The IEA Weyburn CO_2 Monitoring and Storage Project has analysed the effects of a miscible CO_2 flood into a carbonate reservoir rock at an onshore Canadian oilfield. Anthropogenic CO_2 is being injected as part of an enhanced oil recovery operation. The European research was aimed at analyzing long-term migration pathways of CO_2 and the effects of CO_2 on the hydrochemical and mineralogical properties of the reservoir rock. The long term safety and performance of CO_2 storage was assessed by the construction of a Features, Events and Processes (FEP) database which provides a comprehensive knowledge base for the geological storage of CO_2. The pre-CO_2 injection hydrogeological, hydrochemical and petrographical conditions in the reservoir were investigated in order to recognise changes caused by the CO_2 flood and assessing the fate of the CO_2. The Mississippian aquifer has a salinity gradient in the Weyburn area, where flows are oriented SW-NE. The baseline gas fluxes and CO_2 concentrations in groundwater and soil were also researched. The dissolved gas in the reservoir waters has allowed potential transport pathways to be identified. Experimental studies of CO_2-porewater-rock interactions in the Midale Marly unit have indicated slight dissolution of carbonate and silicate minerals, but relatively rapid saturation with respect to carbonate minerals. Equivalent studies on the overlying and underlying units show similar reaction processes, but secondary gypsum precipitation was also observed. Carbon dioxide flooding experiments on samples of the Midale Marly unit demonstrated that porosity and gas permeability increased significantly and calcite and dolomite were shown to have undergone corrosion. Hydrogeological modelling indicates that if any dissolved CO_2 entered the main aquifers, it would be moved away from Weyburn in an E-NE direction at a rate of c. 0.2 m/year due to regional groundwater flow. Analysis of reservoir fluids proved that dissolved CO_2 and CH4 increased significantly in the injection area between 2002 and 2003 and that solubility trapping accounts for the majority of the injected CO_2, with little apparent mineral trapping. Twelve microseismic events were recorded and these are provisionally interpreted as being possibly related to small fractures formed by injection-driven fluid migration within the reservoir. Pre- and post-injection soil gas data are consistent with a shallow biological origin for the measured CO_2. Isotopic (δ13C) data values are higher than in the injected CO_2 and confirm this interpretation. No evidence for leakage of the injected CO_2 to ground level has so far been detected.

Ringrose, P., A. S. Mathieson, I. W. Wright, F. Selama, O. Hansen, R. Bissel, N. Saoula and J. Midgley (2013). "The In Salah CO_2 storage project: lessons learned and knowledge transfer." Energy Procedia.

The In Salah CCS project in central Algeria is a world pioneering onshore CO_2 capture and storage project which has built up a wealth of experience highly relevant to CCS projects worldwide. Carbon dioxide from several gas fields is removed from the gas production stream in a central gas processing facility and then the CO_2 is compressed, transported and stored underground in the 1.9 km deep Carboniferous sandstone unit at the Krechba field. Injection commenced in 2004 and since then over 3.8Mt of CO_2 has been stored in the subsurface. The storage performance has been monitored using a unique and diverse portfolio of geophysical and geochemical methods, including time-lapse seismic, micro-seismic, wellhead sampling using CO_2 gas tracers, down-hole logging and core analysis, surface gas monitoring, groundwater aquifer monitoring and satellite InSAR data. Routines and procedures for collecting and interpreting these data have been developed, and valuable insights into appropriate Monitoring, Modelling and Verification (MMV) approaches for CO_2 storage have been gained. We summarize the key elements of the project life-cycle and identify the key lessons learned from this demonstration project that can be applied to other major CCS projects, notably the:

- Need for detailed geological and geomechanical characterization of the reservoir and overburden
- Importance of regular risk assessments based on the integration of multiple different datasets
- Importance of flexibility in the design and operation of the capture, compression, and injection system
- In Salah project thus provides an important case study for knowledge transfer to other major CCS projects in the planning and execution phases

Ritter, K., S. L. Crookshank, M. Lev-On and T. M. Shires (2012). Carbon Capture and Storage (CCS): Context and Contrasts of Voluntary and Mandatory Reporting in the US, Carbon Management Technology Conference.

Carbon capture and geological storage (CCS) is a core element in the global strategy to reduce greenhouse gas (GHG) emissions. This paper characterizes and contrasts the emission quantification methods associated with CCS projects from the perspective of voluntary emission reduction initiatives and recent regulatory reporting requirements under the U.S. Environmental Protection Agency (EPA) Greenhouse Gas Reporting Program (GHGRP). From the regulatory perspective, the U.S. EPA is addressing the mandatory GHG reporting for CO_2 injection and potential geological storage, providing a different approach for facilities that supply CO_2 to the market, those that inject CO_2 for purposes of enhanced oil and gas recovery, and those that are engaging in long-term geological storage. Information gathered under the GHGRP will enable EPA to track the amount of CO_2 supplied to the market, injected, and/or stored by U.S. facilities. In addition, where the CO_2 injection facilities are also associated with other oil and gas operations, the GHGRP requires quantifying and reporting GHG emissions from those operations where the facilities meet specified regulatory thresholds. This information will be a key element in providing baseline data and activity information for the development of future emission standards and control techniques for GHG emission mitigation in the U.S. In addition to reporting initiatives, industry is providing guidance to support voluntary GHG reduction initiatives. The American Petroleum Institute (API) and the International Petroleum Industry Environmental Conservation Association (IPIECA) have collaborated on a guideline document to promote the credible, consistent, and transparent quantification of GHG emission reductions from CCS projects (IPIECA/API, 2007). This document emphasizes that the entire range of activities associated with CCS—capture, transport, injection and storage—must be considered in quantifying emissions and emission reductions from CCS operations. This paper will examine common aspects and notable differences between the mandatory reporting programs and voluntary GHG emission reduction activities. It will specifically emphasize collateral characteristics such as the scope of emission sources, accuracy of quantification methods, reporting and monitoring requirements. Introduction to CCS CCS applies established technologies to capture, transport and store CO_2 emissions from large point sources. Wide deployment of CCS techniques is viewed as essential for addressing climate change, while also providing energy security, creating jobs, and economic prosperity. The International Energy Agency (IEA) states that CCS could reduce global CO_2 emissions by 19%, and that without CCS, overall costs to reduce emissions to 2005 levels by 2050 would increase by 70% (IEA, 2009). CCS refers to the chain of processes that are designed to collect or capture a CO_2 gas stream, transport the CO_2 to a storage location, and inject the CO_2 into a geological formation1 for long-term isolation from the atmosphere (See Figure 1). CCS involves avoiding the release of CO_2 emissions to the atmosphere by injecting CO_2 and ultimately storing it in a geological formation. The assessment of GHG emission reductions from CCS projects should address all of these elements.

Roberts, H. H., B. A. Hardage, W. W. Shedd and J. Hunt Jr (2006). "Seafloor reflectivity—an important seismic property for interpreting fluid/gas expulsion geology and the presence of gas hydrate." The Leading Edge 25(5): 620-628.

A bottom-simulating reflection (BSR) is a seismic reflectivity phenomenon that is widely accepted as indicating the base of the gas-hydrate stability zone. The acoustic impedance difference between sediments invaded with gas hydrate above the BSR and sediments without gas hydrate, but commonly with free gas below, are accepted as the conditions that create this reflection. The relationship between BSRs and marine gas hydrate has become so well known since the 1970s that investigators, when asked to define the most important seismic attribute of marine gas-hydrate systems, usually reply, “a BSR event.” Research conducted over the last decade has focused on calibrating seafloor seismic reflectivity across the geology of the northern Gulf of Mexico (GoM) continental slope surface to the seafloor. This research indicates that the presence and character of seafloor bright spots (SBS) can be indicators of gas hydrates in surface and near-surface sediments (Figure 1). It has become apparent that SBSs on the continental slope generally are responses to fluid and gas expulsion processes. Gas-hydrate formation is, in turn, related to these processes. As gas-hydrate research expands around the world, it will be interesting to find if SBS behavior in other deepwater settings is as useful for identifying gas-hydrate sites as in the GoM.

Rochelle, C. A. and A. E. Milodowski (2013). "Carbonation of borehole seals: Comparing evidence from short-term laboratory experiments and long-term natural analogues." Applied Geochemistry 30: 161-177.

It is crucial that the engineered seals of boreholes in the vicinity of a deep storage facility remain effective for considerable timescales if the long-term geological containment of stored CO_2 is to be effective. These timescales extend beyond those achievable by laboratory experiments or industrial experience. Study of the carbonation of natural Ca silicate hydrate (CSH) phases provides a useful insight into the alteration processes and evolution of cement phases over long-timescales more comparable with those considered in performance assessments. Samples from two such natural analogues in Northern Ireland have been compared with samples from laboratory experiments on the carbonation of Portland cement. Samples showed similar carbonation reaction processes even though the natural and experimental samples underwent carbonation under very different conditions and timescales. These included conversion of the CSH phases to CaCO3 and SiO2, and the formation of a well-defined reaction front. In laboratory experiments the reaction front is associated with localised Ca migration, localised matrix porosity increase, and localised shrinkage of the cement matrix with concomitant cracking. Behind the reaction front is a zone of CaCO3 precipitation that partly seals porosity. A broader and more porous/permeable reaction zone was created in the laboratory experiments compared to the natural samples, and it is possible that short-term experiments might not fully replicate slower, longer-term processes. That the natural samples had only undergone limited carbonation, even though they had been exposed to atmospheric CO_2 or dissolved HCO3 in groundwater for several thousands of years, may indicate that the limited amounts of carbonate mineral formation may have protected the CSH phases from further reaction.

Rodríguez-Romero, A., M. D. Basallote, M. R. De Orte, T. Á. DelValls, I. Riba and J. Blasco (2014). "Simulation of CO_2 leakages during injection and storage in sub-seabed geological formations: Metal mobilization and biota effects." Environment International 68(0): 105-117.

To assess the potential effects on metal mobilization due to leakages of CO_2 during its injection and storage in marine systems, an experimental set-up was devised and operated, using the polychaete Hediste diversicolor as the model organism. The objective was to study the effects of such leakage in the expected scenarios of pH values between 8.0 and 6.0. Polychaetes were exposed for 10 days to seawater with sediment samples collected in two different coastal areas, one with relatively uncontaminated sediment as reference (RSP) and the other with known contaminated sediment (ML), under pre-determined pH conditions. Survival and metal accumulation (Al, Fe, Mn, Cu, Zn, As and Hg) in the whole body of H. diversicolor were employed as endpoints. Mortality was significant at the lowest pH level in the sediment with highest metal concentrations. In general, metal concentrations in tissues of individuals exposed to the contaminated sediment were influenced by pH. These results indicate that ocean acidification due to CO_2 leakages would provoke increased metal mobilization, causing adverse side effects in sediment toxicity.

Schloemer, S., M. Furche, I. Dumke, J. Poggenburg, A. Bahr, C. Seeger, A. Vidal and E. Faber (2013). "A review of continuous soil gas monitoring related to CCS – Technical advances and lessons learned." Applied Geochemistry 30(0): 148-160.

One of the most vigorously discussed issues related to Carbon Capture and Storage (CCS) in the public and scientific community is the development of adequate monitoring strategies. Geological monitoring is mostly related to large scale migration of the injected CO_2 in the storage formations. However, public interest (or fear as that) is more related to massive CO_2 discharge at the surface and possible affects on human health and the environment. Public acceptance of CO_2 sequestration will only be achieved if secure and comprehensible monitoring methods for the natural habitat exist. For this reason the compulsory directive 2009/31/EG of the European Union as well as other international regulations demand a monitoring strategy for CO_2 at the surface. The variation of CO_2 emissions of different soil types and vegetation is extremely large. Hence, reliable statements on actual CO_2 emissions can only be made using continuous long-term gas-concentration measurements. Here the lessons learned from the (to the authors' knowledge) first world-wide continuous gas concentration monitoring program applied on a selected site in the Altmark area (Germany), are described.

This paper focuses on the authors' technical experiences and recommendations for further extensive monitoring programs related to CCS. Although many of the individual statements and suggestions have been addressed in the literature, a comprehensive overview is presented of the main technical and scientific issues. The most important topics are the reliability of the single stations as well as range of the measured parameters. Each selected site needs a thorough pre-investigation with respect to the depth of the biologically active zone and potential free water level. For the site installation and interface the application of small drill holes is recommended for quantifying the soil gas by means of a closed circuit design. This configuration allows for the effective drying of the soil gas and avoids pressure disturbance in the soil gas. Standard soil parameters (humidity, temperature) as well as local weather data are crucial for site specific interpretation of the data. The complexity, time and effort to handle a dozen (or even more) single stations in a large case study should not be underestimated. Management and control of data, automatic data handling and presentation must be considered right from the beginning of the monitoring. Quality control is a pre-condition for reproducible measurements, correct interpretation and subsequently for public acceptance. From the experience with the recent monitoring program it is strongly recommended that baseline measurements should start at least 3 a before any gas injection to the reservoir.

Schrag, D. P. (2009). "Storage of Carbon Dioxide in Offshore Sediments." Science 325: 1658-1659.

The battle to reduce greenhouse gas emissions and prevent the most dangerous consequences of climate change will be waged across multiple fronts, including efforts to increase energy efficiency; efforts to deploy nonfossil fuel sources, including renewable and nuclear energy; and investment in adaptation to reduce the impacts of the climate change that will occur regardless of the actions we take. But with more than 80% of the world's energy coming from fossil fuel, winning the battle also requires capturing CO_2 from large stationary sources and storing that CO_2 in geologic repositories. Offshore geological repositories have received relatively little attention as potential CO_2 storage sites, despite their having a number of important advantages over onshore sites, and should be considered more closely.

Sellami, N., M. Dewar, H. Stahl and B. Chen (2015). "Dynamics of rising CO_2 bubble plumes in the QICS field experiment: Part 1 – The experiment." International Journal of Greenhouse Gas Control(0).

The dynamic characteristics of CO_2 bubbles in Scottish seawater are investigated through observational data obtained from the QICS project. Images of the leaked CO_2 bubble plume rising in the seawater were captured. This observation made it possible to discuss the dynamics of the CO_2 bubbles in plumes leaked in seawater from the sediments. Utilising ImageJ, an image processing program, the underwater recorded videos were analysed to measure the size and velocity of the CO_2 bubbles individually. It was found that most of the bubbles deform to non-spherical bubbles and the measured equivalent diameters of the CO_2 bubbles observed near the sea bed are to be between 2 and 12 mm. The data processed from the videos showed that the velocities of 75% of the leaked CO_2 bubbles in the plume are in the interval 25–40 cm/s with Reynolds numbers (Re) 500–3500, which are relatively higher than those of an individual bubble in quiescent water. The drag coefficient Cd is compared with numerous laboratory investigations, where agreement was found between the laboratory and the QICS experimental results with variations mainly due to the plume induced vertical velocity component of the seawater current and the interactions between the CO_2 bubbles (breakup and coalescence).

Shell (2014a). Peterhead CCS Project, Insurance Plan, Shell U.K. Limited.

Coverage may be very expensive and/or restricted for the “novel” aspects of the project (CCSliability, financial risks of repurchase of carbon credits, subsurface migration/pollution, etc.). At present, no requirement for re-purchase of credits or financial penalties is expected in case of accidental CO_2 release from the reservoir. Protection against repayment of carbon credits (European Union Allowances (EUAs)) is currently uninsurable.

Shell, 2014b, Peterhead CCS project offshore environmental statement; http://www.shell.co.uk/energy-and-innovation/the-energy-future/peterhead-ccs-project.html 592 pages

The Goldeneye Field is a condensate and gas field located in the Outer Moray Firth, ~100 km north-east of the Peterhead Power Station, mainly in UK Continental Shelf (UKCS) Blocks 14/29a and 20/4b but also straddles Blocks 14/28b and 20/3b. Shell, with the support of SSE, is planning to develop the world’s first full chain gas fired Carbon Capture Storage (CCS) demonstration Project at the existing SSE power station in Peterhead, Aberdeenshire, Scotland (Figure 1). The project is part of the UK Government’s CCS Commercialisation Competition being run by DECC Office of Carbon Capture Storage (OCCS). The Project broadly consists of three main components:

1. Constructing and operating a CO_2 Capture Plant at the existing Peterhead Power Station which will capture CO_2 that would otherwise be released to the atmosphere from the exhaust gases from one of the station’s existing gas turbines. It will then compress and dry the captured CO_2 in preparation for onward transportation.
2. Transportation of CO_2 to the Goldeneye Platform via a combination of new and existing pipelines. A section of new pipeline between 15 and 26 km in length will transport the CO_2 from the power station and tie into the existing Goldeneye to St Fergus export pipeline for transport to the Goldeneye field for storage.
3. Injection of CO_2 in to the depleted Goldeneye gas reservoir for geological storage. The Goldeneye reservoir has the key geological features required for storing CO_2: a body of high quality porous rock overlain and surrounded by layers of impermeable rock, which provide effective barriers to keep the CO_2 securely contained deep beneath the seafloor.

This document provides details of the Environmental Impact Assessment (EIA) that has been undertaken to support Shell’s application for project consent in relation to the offshore aspects of the Peterhead CCS Development. EIA has been a legal requirement for offshore developments since 1998. Current requirements are set out in the Offshore Petroleum Production and Pipelines (Assessment of Environmental Effects) (Amendment) Regulations 1999 (as amended 2007 and 2010), hereafter referred to as the EIA Regulations. The purpose of the Regulations is to require the Secretary of State (SoS) for Energy and Climate Change to take into consideration environmental information before making decisions on whether or not to consent certain offshore activities. As of 2010 the EIA Regulations include CCS developments under the Energy Act 2008 (Consequential Modifications) (Offshore Environmental Protection) Order 2010. This process includes a period of public consultation and a comprehensive review by the regulator, the Department of Energy and Climate Change (DECC), and its statutory consultees, including Marine Scotland and the Joint Nature Conservation Committee (JNCC).

Shevalier, M., M. Nightingale, B. Mayer, I. Hutcheon, K. Durocher and E. Perkins (2013).

"Brine geochemistry changes induced by CO_2 injection observed over a 10 year period in the Weyburn oil field." International Journal of Greenhouse Gas Control 16, Supplement 1(0): S160-S176. The Weyburn oil field is hosted in a Mississippian carbonate formation that has experienced continuous anthropogenic CO_2 injection for enhanced oil recovery since September 2000. A baseline geochemical survey and regular geochemical monitoring occurred in two parts, Part 1 from 2000 to 2004 and Part 2 from 2008 to 2010 resulting in 17 sampling events where wellhead fluid and gas samples were collected.

Solubility trapping, i.e. the formation of H2CO3, was observed within six months of the onset of CO_2 injection and is an important process for geochemical trapping of injected CO_2. Dissolved calcium and total alkalinity concentrations also increased implying that significant ionic trapping, i.e. the reaction of CO_2 with carbonate minerals, had occurred commencing within one year of CO_2 injection. Over the 10 year observation period the significant changes in the downhole pH suggest that both ionic and solubility trapping were occurring simultaneously. Brine resistivity shows that over the 10 year period of study there was significant movement of injected CO_2 and brines from injector to producer wells. The results show that geochemical monitoring provides valuable information for identifying the time scales required for solubility and ionic trapping of injected CO_2.

Shitashima, K., Y. Maeda and T. Ohsumi (2013). "Development of detection and monitoring techniques of CO_2 leakage from seafloor in sub-seabed CO_2 storage." Applied Geochemistry 30(0): 114-124.

Carbon dioxide capture and storage (CCS) in sub-seabed geological formations is currently being studied as a potential option to mitigate the accumulation of anthropogenic CO_2 in the atmosphere. To investigate the validity of CO_2 storage in the sub-seafloor, development of techniques to detect and monitor CO_2 leaked from the seafloor is vital. Seafloor-based acoustic tomography is a technique that can be used to observe emissions of liquid CO_2 or CO_2 gas bubbles from the seafloor. By deploying a number of acoustic tomography units in a seabed area used for CCS, CO_2 leakage from the seafloor can be monitored. In addition, an in situ pH/pCO_2 sensor can take rapid and high-precision measurements in seawater, and is, therefore, able to detect pH and pCO_2 changes due to the leaked CO_2. The pH sensor uses a solid-state pH electrode and reference electrode instead of a glass electrode, and is sealed within a gas permeable membrane filled with an inner solution. Thus, by installing a pH/pCO_2 sensor onto an autonomous underwater vehicle (AUV), an automated observation technology is realized that can detect and monitor CO_2 leakage from the seafloor. Furthermore, by towing a multi-layer monitoring system (a number of pH/pCO_2 sensors and transponders) behind the AUV, the dispersion of leaked CO_2 in a CCS area can also be observed. Finally, an automatic elevator can observe the time-series dispersion of leaked CO_2. The seafloor-mounted automatic elevator consists of a buoy equipped with pH/pCO_2 and depth sensors, and uses an Eulerian method to collect spatially continuous data as it ascends and descends.

Hence, CO_2 leakage from the seafloor is detected and monitored as follows. Step 1: monitor CO_2 leakage by seafloor-based acoustic tomography. Step 2: conduct mapping survey of the leakage point by using the pH/pCO_2 sensor installed in the AUV. Step 3: observe the impacted area by using a remotely operated underwater vehicle or the automatic elevator, or by towing the multi-layer monitoring system.

Singh, V., A. Cavanagh, H. Hansen, B. Nazarian, M. Iding and P. Ringrose (2010). Reservoir Modeling of CO_2 Plume Behavoir Calibrated Monitoring Data from Sleipner, Norway. SPE Annual Technical Conference and Exhibition, Florence, Italy, 19-22 September 2010, Society of Petroleum Engineers.

Sleipner is a commercial CO_2 storage site in the North Sea with good constraints from monitoring data, but also with some significant uncertainties regarding temperature, pressure and gas/brine behavior. At Sleipner, we have used high-quality repeated seismic and gravimetric surveys for monitoring and calibrating the reservoir uncertainties. To model the CO_2 behavior we have used two main approaches: a) traditional reservoir simulations, using black oil and compositional fluid descriptions; and b) invasion percolation simulations, using threshold pressure and fluid density descriptions that assume the dominance of capillary and gravity forces. The key findings from the study are:

- The invasion percolation simulation gave the best initial match to observed data, leading us to reassess the input assumptions for the black oil and compositional simulations.

- By taking into account gravity segregation and modifying the reservoir simulation input data, we were able to get a much better match for the black oil and compositional simulations.
- There is still scope for further optimization and history matching, however, this study has reduced the range of domain variables leading to an improved understanding of the flow processes involved in geological storage of CO_2 in saline formations.

The study has led us to conclude that we can make realistic and predictive CO_2 storage models provided that the site-specific conditions are honored, including reservoir and fluid property characterization. The necessary tight constraints on input parameters are achieved by calibration against monitoring data.

Our study illustrates both a rather novel approach to modeling CO_2 storage and the need for improved input to conventional simulators. Application of our approach to other CO_2 storage sites will help in achieving more realistic understanding of CO_2 storage, thereby contributing to the maturation of CO_2 storage technology worldwide.

Skarke, A., et al. (2014). "Widespread methane leakage from the sea floor on the northern US Atlantic margin." Nature Geosci 7(9): 657-661.

Methane emissions from the sea floor aect methane inputs into the atmosphere, ocean acidification, and de-oxygenation, the distribution of chemosynthetic communities and energy resources. Global methane flux from seabed cold seeps has only been estimated for continental shelves at 8 to 65 Tg CH_4 per year.

Smith, J., S. Durucan, A. Korre, J.-Q. Shi and C. Sinayuc (2011). "Assessment of fracture connectivity and potential for CO_2 migration through the reservoir and lower caprock at the In Salah storage site." Energy Procedia 4(0): 5299-5305.

Fractures are thought to strongly affect the flow of CO_2 at the In Salah storage site. In the work presented here, fracture networks at In Salah are characterised and modelled to assess percolation. Available fracture data is considered in the context of general characteristics of other fracture networks and this data is then used to model potential realisations of fracture networks within the In Salah reservoir and lower caprock. Horizontal percolation of fracture networks is highly dependent on fracture length, the proportion of cemented fractures and the properties of the uncharacterised disperse fracture set. However, largely open fractures with length distributions exceeding calculated values will percolate within the reservoir and lower caprock. Injection induced stress changes are assessed with a coupled flow geomechanical model. Both tensile and shear failure of fractures are found to be unlikely but possible given certain combinations of conditions.

Smyth, R. C., D. L. Carr, S. D. Hovorka, S. Coleman, C. Breton and E. N. Miller (2011). Continued Evaluation for Geologic Storage of Carbon Dioxide in the Southeastern United States. Gulf Cost Carbon Center, Bureau of Economic Geology- The University of Texas at Austin.

The need to reduce atmospheric emissions of carbon dioxide (CO_2) from industrial sources is now recognized internationally. As a result, companies operating coal-fired and other types of power plants in the southeastern U.S. (SE US) have been seeking information on the potential for long-term storage of CO_2 in nearby subsurface geologic formations. Previous studies have shown there to be little to no capacity for onshore subsurface storage of CO_2 in deep saline reservoirs in the Carolinas and northern Georgia (GA) (Smyth et al., 2008). However prior to this study, southern GA had not been assessed for geologic sequestration (GS) capacity potential. It is currently not known if extensive petroleum reserves exist below the continental shelf of the Atlantic Ocean offshore from SE US but, potential offshore capacity for storage of CO_2 is large.

The objectives of this study have been to (1) assess the potential for GS of CO_2 in areas of SE US not previously characterized (i.e. southern GA coastal plain between the panhandle of Florida (FL) and the Atlantic Ocean) and (2) refine capacity estimates for portions of offshore geologic units present below the nearby Atlantic continental shelf. We primarily focused on geographic areas where CO_2 can be stored in deep saline reservoirs at depths great enough to keep it in supercritical phase, but also had to consider surrounding areas in order to better solve the geological puzzle. Maintaining CO_2 in supercritical phase requires temperature greater than 31.1 °C (88 °F) and pressure greater than 7.39 MPa (72.9 atm), which corresponds to depth below ground surface of ~800 m (2600 ft). Results of this detailed study of the regional subsurface geologic units are timely for operators of coal-fired power plants in the SE US because technologies to separate, capture, and concentrate CO_2 from industrial emissions are ready for commercial-scale demonstration.

Smyth, R. C., S. D. Hovorka and T. A. Meckel (2008). Potential Saline Reservoir Sinks for Geological Storage of CO_2 Generated in the Carolinas. Sixth Annual Conference on Carbon Capture & Sequestration: Expediting Deployment of Industrial Scale Systems, Pittsburgh, PA, The University of Texas at Austin, Bureau of Economic Geology.

Saline reservoirs are one type of geologic CO_2 “sink.” These require depth sufficient to maintain CO_2 at or near supercritical phase, integrity of overlying seal, and capacity sufficient to prevent displacement of saline water into freshwater zones. Large areas of the southeastern U.S. either are unsuitable or have low potential for geologic storage of CO_2. Assessment completed for DOE-sponsored SECARB Partnership shows that the Carolinas are underlain by (1) fractured crystalline rocks that lack overlying seals or (2) sequences of sediment not thick enough to store CO_2 at sufficient density and they contain freshwater aquifers in most horizons. This leaves few options for onshore geologic storage of CO_2 within North and South Carolina. Alternatives include transporting CO_2 via pipeline from power plants to sinks underlying nearby states or to potential Atlantic margin subseafloor sinks. Potential onshore sinks outside of the Carolinas are in Upper and Lower Cretaceous and Triassic units in the South Georgia Basin, Upper Cretaceous in southeastern Alabama and the Florida panhandle, Mt. Simon Formation in Tennessee, and Knox Formation in Kentucky and West Virginia. Cretaceous-age strata, 25–175 km offshore in the western Atlantic, show promise for subseafloor (>1km depth) CO_2 storage. Water column height (50–1000 m) overlying the seafloor enhances suitability of the potential subseafloor sinks because of added pressure. The CO_2 storage potential for the subseafloor Atlantic margin could be significant along the entire U.S. eastern seaboard. Costs associated with transporting CO_2 from power plants in the Carolinas to potential geologic sinks are not trivial.

Stauffer, P. H., H. S. Viswanathan, R. J. Pawar and G. D. Guthrie (2008). "A System Model for Geologic Sequestration of Carbon Dioxide." Environmental Science & Technology 43(3): 565-570.

In this paper we describe CO_2−PENS, a comprehensive system-level computational model for performance assessment of geologic sequestration of CO_2. CO_2−PENS is designed to perform probabilistic simulations of CO_2 capture, transport, and injection in different geologic reservoirs. Additionally, the long-term fate of CO_2 injected in geologic formations, including possible migration out of the target reservoir, is simulated. The simulations sample from probability distributions for each uncertain parameter, leading to estimates of global uncertainty that accumulate through coupling of processes as the simulation time advances. Each underlying process in the system-level model is built as a module that can be modified as the simulation tool evolves toward more complex problems. This approach is essential in coupling processes that are governed by different sets of equations operating at different time-scales. We first explain the basic formulation of the system level model, briefly discuss the suite of process-level modules that are linked to the system level, and finally give an in-depth example that describes the system level coupling between an injection module and an economic module. The example shows how physics-based calculations of the number of wells required to inject a given amount of CO_2 and estimates of plume size can impact long-term sequestration costs.

Stenhouse, M., M. Wilson, H. Herzog, B. Cassidy, M. Kozak, W. Shou and J. Gale (2005). Regulatory Issues Associated with Deep (Geological) CO_2 Storage. Proceedings of 7th Greenhouse Gas Control Technologies Conference 1: 961-969.

In response to the potential developing industry associated with deep (geological) CO_2 storage and recognising the need for some form of regulatory guidance or control, the IEA Greenhouse Gas R&D Programme recently commissioned a study to identify and discuss potential regulatory issues associated with deep (geological) CO_2 storage. This paper presents a summary of the findings from this study. Regulatory issues are discussed in the context of relevant timeframes. Most industry standards and codes relate principally to an operational period for engineering projects of up to several decades, perhaps as much as one hundred years. In contrast, CO_2 stored in geological reservoirs should remain there for at least several hundreds, and possibly thousands of years. Thus, the focus of this study has been on the long-term framework for CO_2 storage. Two independent timeframes are identifiable, according to the specific responsibilities of a regulatory system. The first relates to reservoir storage performance, or permanence and the second timeframe relates to local environmental impacts (health and safety consequences). Issues were discussed in terms of these two timeframes under six main topic areas: liability, economics, record keeping, wellbore integrity, reservoir leakage, and monitoring. Clearly, such issues are inter-related and there is considerable overlap among/between the individual topics.

Stenhouse, M. J., J. Gale and W. Zhou (2009). "Current status of risk assessment and regulatory frameworks for geological CO_2 storage." Energy Procedia 1(1): 2455-2462.

A briefing document was prepared two years ago as the basis for dialogue with regulators with responsibilities in the area of CCS. Risk assessment was discussed under a number of headings, in particular assessment timeframes, acceptable leakage rates, risk assessment methodologies, modelling and uncertainty, monitoring, and the role of natural and industrial analogues. These topics are re-visited, taking into account developments that have occurred since the original document was prepared. In addition, developments in regulatory activities and how they are responding to the growth of CO_2 storage projects, both pilot and large-scale, are examined.

Stone, E. J., et al. (2009). "The impact of carbon capture and storage on climate." Energy & Environmental Science 2(1): 81-91.

Carbon capture and storage (CCS) is being widely discussed as a possible mitigation option for limiting the emissions of carbon dioxide (CO_2) from fossil fuel burning power plants. The implementation of CCS requires the resolution of a number of difficult policy, engineering and economic issues. Here we address the efficacy of CCS from the perspective of climate science. Implementation of CCS makes power stations less efficient, in the sense that they produce more CO_2 for a given output of electricity, a feature which is characterised by the so-called energy penalty. The captured CO_2 is then stored in, for example, geological storage reservoirs, from which some small fraction is expected to leak back into the atmosphere each year. We use a set of relatively simple models of carbon capture, the atmospheric carbon cycle and climate, to quantify, for a range of CCS engineering and implementation parameters, the amount of leakage from these reservoirs that can be tolerated to ensure that CCS leads to less, rather than more, climate change. We demonstrate that up to the year 2100, for almost all the parameters that we consider, application of CCS is beneficial. However, in some cases the benefit might be small. We also consider a much longer time horizon (out to the year 2500). We find that while many parameter combinations still lead to a benefit, there are some cases for which application of CCS leads to greater warming than had it not been applied at all. The largest single controlling factor is seen to be the storage reservoir retention time. Many previous studies focused on the use of those storage reservoirs with very long retention times, but we demonstrate that the use of less resilient reservoirs might also provide a climate benefit during the 100 to 500 year time horizon. The largest absolute benefits of CCS to global temperature are found for high future emission scenarios. These absolute benefits also increase as the climate sensitivity of the model is increased.

Sun, A. Y., J.-P. Nicot and X. Zhang (2013). "Optimal design of pressure-based, leakage detection monitoring networks for geologic carbon sequestration repositories." International Journal of Greenhouse Gas Control 19(0): 251-261.

Monitoring of leakage at geologic carbon sequestration (GCS) sites requires the capability to intercept and resolve the onset, location, and volume of leakage in a timely manner. Pressure-anomaly monitoring represents one of the few monitoring technologies that possess such capabilities. To fully leverage the strength of pressure monitoring while meeting cost constraints, optimization of network design is necessary. This study presents an optimization method for designing cost-effective GCS monitoring networks under model and parameter uncertainty. A binary integer programming problem (BIPP) is formulated to minimize both the total volume of leakage and the number of uncovered potentially leaky locations. The BIPP is demonstrated for selecting optimal monitoring locations in both homogeneous and heterogeneous formations. The sensitivity of monitoring design to a number of model and design parameters is investigated, while model structure and parameter uncertainties are incorporated through user-specified scenarios. Results suggest that the BIPP is a viable approach for identifying optimal sensing locations even when the number of design variables is relatively large (∼105). The BIPP is general and can be readily used to facilitate the design of performance-based GCS monitoring networks.

Sweatman, R., E. Samson, E. Davis, G. McCopin and S. Marsic (2012). New Technology for Offshore CO_2 Reservoir Monitoring and Flow Control. Carbon Management Technology Conference, Orlando, Florida, USA, 7-9 February 2012, Carbon Management Technology Conference.

A novel, cost-saving approach combining advanced electronic and chemical technologies for rapidly acquired reservoir flow measurements and early-alteration of flows is described. The combined technologies improve CO_2 injection, leak detection, and reservoir flow management in offshore CO_2 enhanced oil recovery (EOR) and carbon capture and storage (CCS) projects. The approach is based on old and new technologies that have been field proven in land-based operations. It employs reservoir flow-induced micro-deformation measurements by tiltmeters and absolute seafloor position monitoring using global positioning systems combined with underwater acoustic distance measurements from the sea surface to instruments installed in the seafloor over offshore reservoirs.

These systems can acquire micro-deformation data, which allows for geomechanical inversion analysis to provide 3-D reservoir flow images. Real-time temperature, pressure, and other data from fiber-optic sensors may also be needed to better characterize some CO_2 flows. New flow-controlling and leak-sealing chemical systems and placement methods combined with conventional ones have improved the options for management of flow paths both inside and outside of offshore reservoirs.

The paper includes a discussion on how the monitoring technology has evolved from similar methods proven in EOR projects, and more recently in CCS projects, to identify reservoir flows and pinpoint abnormal ones. An example of normal CO_2 flow results is presented to show how operators can calibrate flow-prediction software models and make fast decisions to apply flow enhancing methods that improve CO_2 sweep efficiency, increase oil production, and better utilize reservoirs' CO_2 storage capacity. Another example shows the early identification of an abnormal-flow path location that enables operators to make timely selections of sealing methods and materials to eliminate unwanted flows inside or outside of reservoirs and ensure planned CO_2 plume movement and containment within reservoirs.

The CO_2 flow controlling and remediation technology's history of field-proven success is described along with the recently developed versions. Generic case histories of conventional methods on land vs. the

proposed offshore systems are compared to show how the new approach creates synergy that can improve the performance of offshore CO_2 EOR and CCS projects while reducing operating costs.

Talman, S., E. Perkins, A. Jafari and M. Shevalier (2013). "Geochemical tracers applied to reservoir simulation of the Weyburn CO_2 EOR field." International Journal of Greenhouse Gas Control 16, Supplement 1(0): S216-S225.

The results of integrating processes affecting selected geochemical tracers into a model of fluid flow and phase behaviour at the Weyburn CO_2 EOR Field are presented. Flow patterns, and phase behaviours are obtained from a reservoir model, which had been history matched to fluid (oil and water) production rates as part of the IEA GHG Weyburn-Midale CO_2 Monitoring and Storage Project. The reservoir model was updated by including tracer components with properties similar to those measured in produced fluids as part of the same project. The modelling results are compared with field values of chloride in produced water and the carbon isotope ratio of ethane, δ13C(C2H6), in produced gases. An accurate representation of the processes responsible for generating these, relatively simple, signals is a prerequisite for any future simulations incorporating reactive transport, such as would be needed to quantify rates of reactions between the injected CO_2 and the host-rock. Modelling runs based on the previously developed history-matched single-porosity reservoir model failed to reproduce the variability seen in produced fluids for either a conservative major ion or δ13C(C2H6). Modifications incorporating fracture flow through use of a dual-porosity reservoir description lead to calculated chemical signals that were more compatible with the field observations.

Tanaka, Y., M. Abe, Y. Sawada, D. Tanase, T. Ito and T. Kasukawa (2014). "Tomakomai CCS Demonstration Project in Japan, 2014 Update." Energy Procedia 63(0): 6111-6119.

A large-scale CCS demonstration project is currently being undertaken by the Japanese government in the Tomakomai area, Hokkaido prefecture, Japan. The project is scheduled to run for the period JFY 2012–2020 to demonstrate the viability of CCS system from CO_2 capture through to injection and storage. 100,000 tonnes per year or more of CO_2 derived from an industrial source will be injected and stored in two different saline aquifers under the seabed in the offshore area of the Tomakomai Port. Construction of ground facilities and preparation of monitoring systems are progressing on schedule for planned CO_2 injection startup in 2016.

Taylor, P., H. Stahl, M. E. Vardy, J. M. Bull, M. Akhurst, C. Hauton, R. H. James, A. Lichtschlag, D. Long, D. Aleynik, M. Toberman, M. Naylor, D. Connelly, D. Smith, M. D. J. Sayer, S. Widdicombe, I. C. Wright and J. Blackford (2015). "A novel sub-seabed CO_2 release experiment informing monitoring and impact assessment for geological carbon storage." International Journal of Greenhouse Gas Control(0).

Carbon capture and storage is a mitigation strategy that can be used to aid the reduction of anthropogenic CO_2 emissions. This process aims to capture CO_2 from large point-source emitters and transport it to a long-term storage site. For much of Europe, these deep storage sites are anticipated to be sited below the sea bed on continental shelves. A key operational requirement is an understanding of best practice of monitoring for potential leakage and of the environmental impact that could result from a diffusive leak from a storage complex. Here we describe a controlled CO_2 release experiment beneath the seabed, which overcomes the limitations of laboratory simulations and natural analogues. The complex processes involved in setting up the experimental facility and ensuring its successful operation are discussed, including site selection, permissions, communications and facility construction. The experimental design and observational strategy are reviewed with respect to scientific outcomes along with lessons learnt in order to facilitate any similar future.

Taylor, P., A. Lichtschlag, M. Toberman, M. D. J. Sayer, A. Reynolds, T. Sato and H. Stahl (2015b). "Impact and recovery of pH in marine sediments subject to a temporary carbon dioxide leak." International Journal of Greenhouse Gas Control(0).

A possible effect of a carbon dioxide leak from an industrial sub-sea floor storage facility, utilised for Carbon Capture and Storage, is that escaping carbon dioxide gas will dissolve in sediment pore waters and reduce their pH. To quantify the scale and duration of such an impact, a novel, field-scale experiment was conducted, whereby carbon dioxide gas was injected into unconsolidated sub-sea floor sediments for a sustained period of 37 days. During this time pore water pH in shallow sediment (5 mm depth) above the leak dropped >0.8 unit, relative to a reference zone that was unaffected by the carbon dioxide. After the gas release was stopped, the pore water pH returned to normal background values within a three-week recovery period. Further, the total mass of carbon dioxide dissolved within the sediment pore fluids above the release zone was modelled by the difference in DIC between the reference and release zones. Results showed that between 14 and 63% of the carbon dioxide released during the experiment could remain in the dissolved phase within the sediment pore water.

Themann, S., H. M. Schmidt and D. Esser (2009). "Measurement, Monitoring, and Verification of CO_2 **Storage: An Integrated Approach." (SPE 129127).**

Carbon capture and storage (CCS) is an increasingly important tool for mitigating global climate change [1]. Pilot scale activities for the deposition of CO_2 include depleted oil and gas reservoirs and saline formations, as well as the use of CO_2 in enhanced oil and gas recovery (EOR). In these situations, CO_2 is deposited in highly mobile gaseous or supercritical state. Effective CCS requires zero tolerance for leakage at, or in the surrounding area. This emphasizes the need for precise Measurement, Monitoring & Verification (MMV); from deep strata up to the seafloor and beyond into the water column. Leak detection systems must detect even the smallest, slowest leaks and seepage of gas and fluid from the seabed, as well as from the injection facilities (e.g. manifolds, trees and templates). Compliance with currently known and future needs of regulators and government worldwide require an integrated and field-proven approach to this demanding MMV task. Monitoring of the injection facilities focuses on potential threats identified during risk assessment (i.e. pipe connections at manifolds, trees and templates). Storage site monitoring, in contrast, covers the surrounding area above the storage site (hundreds of square kilometers!). Such large areas and uncertain timescales require innovative detection and monitoring methods:

- Pre-Site Studies to establish the baseline (Background Values)
- Injection monitoring
- Post-Injection Surveys

Tyndal, K., et al. (2011). When is CO_2 **more hazardous than H2S. Hydrocarbon Processing. Houston, TX, Gulf Publishing Company. Special Report, Gas Processing Developments: 45-48.**

Many different types of facilities produce or use streams containing a high carbon dioxide (CO_2) content with low hydrogen sulfide (H2S) concentrations. Examples include CO_2-flood enhanced oil recovery, pre-combustion carbon capture and sequestration, natural gas conditioning, and agricultural manufacturing. In all industry examples, the potential exists for release of CO_2 from a pipeline during transport. The health effects and dangers of H2S are known, but those of CO_2 are not commonly understood. It is uncertain if industry realizes that CO_2 is a mildly toxic gas and not just a simple asphyxiant like nitrogen. Because CO_2 itself is toxic at higher concentrations, the high-purity CO_2 streams can actually be more hazardous that the H2S. In such cases, the presence of H2S may actually allow easier dectection of teh CO_2 danger. The article reviews the hazards of H2S and CO_2 and compares the effects of these acid gases on humans. Concentration levels corresponding to the immediately dangerous to life and health (IDLH) levels of the two gases are used to illustrate conditions where both H2S and CO_2 are present, and the CO_2 is the predominant concern.

van der Kuip, M. D. C., T. Benedictus, N. Wildgust and T. Aiken (2011). "High-level integrity assessment of abandoned wells." Energy Procedia 4: 5320-5326.

Potential migration of CO_2 from subsurface reservoirs along wells is generally recognized as the major hazard associated with long-term storage of CO_2 in geological formations due to possible chemical and mechanical impact on wellbore cement or casing steel. Many storage projects involve the presence of pre-existing wellbores, penetrating the prospective storage container. Because of their inaccessibility, the main risk is associated with previously abandoned wells. The actual operations at the time of abandonment determine the suitability of these wells for future CO_2 storage operations. Past and present oil and gas well abandonment regulations, prescribing minimum requirements for the use of cement plugs to prevent inter-zonal communication, form a good proxy to assess the general status of abandoned wells. A high-level review of current abandonment regulations showed that required plug lengths vary greatly between different regions, from a minimum of 15 m in Alberta to 100 m in some European countries. Many experimental studies have been performed on degradation of wellbore cement under influence of aqueous CO_2. Considering that diffusion of CO_2 in the cement matrix forms the rate-controlling step in cement degradation, extrapolation of the results of these studies shows that up to a few meters of cement may be affected in 10,000 years. In spite of the significant variation between the evaluated regulations, currently prescribed plug lengths seem appropriate for safe storage of CO_2 with respect to reported laboratory degradation rates. This implies that mechanical integrity of cement plugs and the quality of its placement probably is of more significance than chemical degradation of properly placed abandonment plugs.

Wallace, K. J. (2013). Use of 3-Dimensional Dynamic Modeling of CO_2 Injection for Comparison to Regional Static Capacity Assessments of Miocene Sandstone Reservoirs in the Texas State Waters, Gulf of Mexico. Master's Thesis, The University of Texas at Austin.

Geologic sequestration has been suggested as a viable method for greenhouse gas emission reduction. Regional studies of CO_2 storage capacity are used to estimate available storage, yet little work has been done to tie site specific results to regional estimates. In this study, a 9,258,880 acre (37469.4 km^2) area of the coastal and offshore Texas Miocene interval is evaluated for CO_2 storage capacity using a static volumetric approach, which is essentially a discounted pore volume calculation. Capacity is calculated for the Miocene interval above overpressure depth and below depths where CO_2 is not supercritical. The goal of this study is to determine the effectiveness of such a regional capacity assessment, by performing refinement techniques that include simple analytical and complex reservoir injection simulations. Initial refinement of regional estimates is performed through net sand picking which is used instead of the gross thickness assumed in the standard regional calculation. The efficiency factor is recalculated to exclude net-to-gross considerations, and a net storage capacity estimate is calculated. Initial reservoir-scale refinement is performed by simulating injection into a seismically mapped saline reservoir, near San Luis Pass. The refinement uses a simplified analytical solution that solves for pressure and fluid front evolution through time (Jain and Bryant, 2011). Porosity, permeability, and irreducible water saturation are varied to generate model runs for 6,206 samples populated using data from the Atlas of Northern Gulf of Mexico Gas and Oil Reservoirs (Seni, 2006). As a final refinement step, a 3D dynamic model mesh is generated. Nine model cases are generated for homogeneous, statistically heterogeneous, and seismic-based heterogeneous meshes to observe the effect of various geologic parameters on injection capacity. We observe downward revisions (decreases) in total capacity estimation with increasingly refined geologic data and scale. Results show that estimates of storage capacity can decrease significantly (by as much as 88%) for the single geologic setting investigated. Though this decrease depends on the criteria used for capacity comparison and varies within a given region, it serves to illustrate the potential overestimation of regional capacity assessments compared to estimates that include additional geologic complexity at the reservoir scale.

Wallace, K. J., T. A. Meckel, D. L. Carr, R. H. Treviño and C. Yang (2014). "Regional CO_2 sequestration capacity assessment for the coastal and offshore Texas Miocene interval." Greenhouse Gases: Science and Technology 4(1): 53-65.

Estimating regional geologic storage capacity potential for carbon dioxide will play an important role in determining the feasibility of widespread carbon capture and storage (CCS) programs in the United States and worldwide. The sandstone reservoirs of the Miocene Age located off the Texas coast in the northern Gulf of Mexico are a promising target for CCS due to favorable geologic properties (high porosity/permeability, effective traps and seals, etc.) and proximity to high carbon dioxide emission sources. The common method for regional storage capacity estimation involves the calculation of a pore volume which is modified by some discount or efficiency factor. Though efficiency factors have a large effect on calculated capacity, little work has been done to validate the use and effectiveness of these terms. In this paper we aim to provide an estimate for the storage potential of the coastal and offshore Texas Miocene interval using a common calculation methodology and to begin expanding on this calculation by developing and incorporating an additional sand picking refinement step. This step allows for an initial investigation into the accuracy and utility of typical efficiency factors and regional storage calculations. We find that in our study area, capacity that is calculated using the actual net sand thickness, or 'net capacity', is ∼25% less than capacity that is calculated using the total interval thickness, or 'gross capacity', though, ideally, the two should be equal. Discrepancies between the two calculations emphasize the large uncertainty inherent in efficiency factors and highlight the need for further investigation.

Watson, T. L. and S. Bachu (2009). "Evaluation of the Potential for Gas and CO_2 Leakage Along Wellbores."

Implementation of carbon dioxide (CO_2) storage in geological media requires a proper assessment of the risk of CO_2 leakage from storage sites. Leakage pathways may exist through and along wellbores, which may penetrate or be near to the storage site. One method of assessing the potential for CO_2 leakage through wells is by mining databases that usually reside with regulatory agencies. These agencies collect data concerning wellbore construction, oil and gas production, and other regulated issues for existing wells. The Alberta Energy Resources Conservation Board (ERCB), the regulatory agency in Alberta, Canada, collects and stores information about more than 315,000 oil, gas, and injection wells in the province of Alberta. The ERCB also records well leakage at the surface as surface-casing-vent flow (SCVF) through wellbore annuli and gas migration (GM) outside casing, as reported by the industry. The evaluation of a leakage pathway through wellbore casing or annuli and what causes these wellbore leaks are the first step in determining what factors may contribute to wellbore leakage from CO_2-storage sites. By using available data, major factors that contribute to wellbore leakage were identified. Data analysis shows that there is a correlation between these SCVF/GM and economic activity, technology changes, geographic location, and regulatory changes regarding well completion and abandonment. Further analysis indicates a relationship between low-annular-cement top, external corrosion, casing failure, and wellbore leakage (SCVF/GM). Other factors that could affect the presence of wellbore leakage, such as wellbore deviation, surface-casing depth, and wellbore density, were also investigated. This paper presents the findings of the data analysis and a method to evaluate the potential for leakage along wells in an area where CO_2 storage is intended. This information is useful not only for future operations of CO_2 storage in geological media, but also for current operations relating to the exploration and production of hydrocarbons.

Weeks, A. B. (2006). "Subseabed carbon dioxide sequestration as a climate mitigation option for the Eastern United States: A preliminary assessment of technology and law." Ocean & Coastal LJ 12: 245.

The recently released Summary of the Fourth Assessment Report of the Intergovernmental Panel on Climate Change starkly asserts that climate change is "unequivocal" and primarily caused by human activity. In particular, carbon dioxide emissions are the "most important anthropogenic greenhouse gas," and "past and future anthropogenic carbon dioxide emissions will continue to impact warming and sea level rise for more than a millennium," due to the long periods of time required for natural cycles to remove carbon from the atmosphere. While the Panel "expressly avoided recommending courses of action," experts noted the report "powerfully underscores the need for a massive effort to slow the pace of global climatic disruption before intolerable consequences become inevitable." In short, actions must be taken now to reduce future carbon dioxide emissions and also to isolate and sequester carbon dioxide from existing sources to prevent its release into the world's atmosphere. Among the near-term options for removing long-lived carbon dioxide from the atmosphere is the development and deployment of systems for capturing this gas from industrial facilities and electric power plants. While carbon capture is only one option among many that must be explored if we are to achieve stabilized or climate-safe levels of these emissions, it has received much technical attention.

This article decribes seabed sequestration of CO_2 and discussed current experince with this technology. It describes briefly some very preliminary technical assessments about its potential for global and U.S. development as one piece of a relatively near-term climate mitigation strategy. The international legal framework in ocean dumping, including the recent London Protocol amendments, is presented and compared with the U.S domestic law governing ocean dumping, the 1973 Marine Protection Research and Sanctuaries Act (MPRSA). The question whether CO_2 sequestration activities are prohibited "dumping" of "industrial wastes" under the MPRSA is evaluated, considering the purpose of the "sequestration" namely the very long-tem isolation of CO_2 from atmospheric release. Unfortunately, the MPRSA can be read either to ban sequestration outright, if CO_2 is found to be an "industrial waste," or to allow it, with a permit. Futhermore, the very limited relevant case law related to the Act's dumping ban contains a cautionary tale.White, D. (2011). "Geophysical monitoring of the Weyburn CO_2 flood: Results during 10 years of injection." Energy Procedia 4(0): 3628-3635.

White, D. (2013). "Seismic characterization and time-lapse imaging during seven years of CO_2 flood in the Weyburn field, Saskatchewan, Canada." International Journal of Greenhouse Gas Control 16, Supplement 1(0): S78-S94.

3D time-lapse seismic monitoring has been conducted over a seven year period of CO_2 injection within the Weyburn field, Saskatchewan, as part of an enhanced oil recovery operation. 3D monitor seismic volumes, acquired in 2001, 2002, 2004 and 2007, were processed in parallel resulting in good data repeatability with global NRMS values of 0.30–0.34. Time-lapse amplitude and travel time difference maps that include the reservoir interval depict changes that exceed background noise levels. Comparison with reservoir flow simulations show good correlation with injection-related reservoir changes, and demonstrate that the CO_2 plume outline can generally be tracked. Pressure changes within the reservoir are inferred to have a limited contribution to the time-lapse signal based on qualitative comparison with flow simulations. Lateral heterogeneity within the reservoir and injection procedures affect the observed seismic response due to CO_2 in the subsurface, emphasizing the need to combine seismic observations with reservoir simulations, calibration and an appropriate rock physics model in order to achieve robust semi-quantitative CO_2 quantity estimates.

White, D. J. and J. W. Johnson (2009). "Integrated geophysical and geochemical research programs of the IEA GHG Weyburn-Midale CO_2 monitoring and storage project." Energy Procedia 1(1): 2349-2356.

CO_2 monitoring activities within the IEA GHG Weyburn-Midale CO_2 Monitoring and Storage Project have been ongoing since 2000. Time-lapse seismic data provide the primary geophysical monitoring tool supplemented by passive microseismic monitoring. Here, we highlight results from seismic monitoring and the analysis methods applied to these data. Formal inversion methods (both prestack seismic inversion and model-based stochastic inversion) are being applied to optimize the geological model used to predict the storage behaviour of the reservoir. Seismic amplitude versus offset and azimuth analysis has been applied to identify areas of the caprock that may contain vertical fractures. Injection-related deformation of the reservoir zone has been modelled using coupled fluid flow-geomechanical modeling constrained by the observed low levels of microseismicity. Finally, we present results from a feasibility study on the use of electrical resistivity tomography for CO_2 monitoring at Weyburn using existing steel well casings as electrodes.

White, J.C., Williams, G.A., Grude, S., Chadwick, R.A., 2015. Using spectral decomposition to determine the distribution of injected CO2 and pressure at the Snøhvit field. Geophys. Prospect. 63(5):1213–1223. http://dx.doi.org/10.1111/1365-2478.12217.

Time-lapse 3D seismic reflection data, covering the CO_2 storage operation at the Snøhvit gas field in the Barents Sea, show clear amplitude and time-delay differences following injection. The nature and extent of these changes suggest that increased pore fluid pressure contributes to the observed seismic response, in addition to a saturation effect.

Spectral decomposition using the smoothed pseudo-Wigner–Ville distribution has been used to derive discrete-frequency reflection amplitudes from around the base of the CO_2 storage reservoir. These are utilized to determine the lateral variation in peak tuning frequency across the seismic anomaly as this provides a direct proxy for the thickness of the causative feature.

Under the assumption that the lateral and vertical extents of the respective saturation and pressure changes following CO_2 injection will be significantly different, discrete spectral amplitudes are used to distinguish between the two effects. A clear spatial separation is observed in the distribution of low- and high-frequency tuning. This is used to discriminate between direct fluid substitution of CO_2, as a thin layer, and pressure changes that are distributed across a greater thickness of the storage reservoir. The results reveal a striking correlation with findings derived from pressure and saturation discrimination algorithms based on amplitude versus offset analysis.

Whittaker, S., B. Rostron, C. Hawkes, C. Gardner, D. White, J. Johnson, R. Chalaturnyk and D. Seeburger (2011). "A decade of CO_2 injection into depleting oil fields: Monitoring and research activities of the IEA GHG Weyburn-Midale CO_2 Monitoring and Storage Project." Energy Procedia 4(0): 6069-6076.

Injection of CO_2 into the Weyburn Oil Field, Saskatchewan, Canada, began October 2000 and 10 years later approximately 18 MT of CO_2 will have been stored in the geological reservoir. The CO_2 injection is part of an ongoing enhanced oil recovery effort that will extend to 2035 and likely beyond. Both Weyburn and the adjacent Midale oil field are highly suitable for CO_2-EOR and it is expected that, combined, more than 40 MT CO_2 will eventually be stored in these carbonate reservoirs. Currently about 2.4 MT and 0.4 MT CO_2/year are being stored in the Weyburn and Midale fields, respectively, which now represent the largest site of monitored geological storage of CO_2 globally. The Weyburn Field is operated by Cenovus Energy and the Midale Field by Apache Canada. The anthropogenic CO_2 used at Weyburn-Midale is a by-product of coal gasification at the Great Plains Synfuels Plant in North Dakota, USA. The compressed CO_2 is delivered to the oil fields through a 323 km pipeline that crosses the international boundary. The IEA GHG Weyburn-Midale CO_2 Monitoring and Storage Project was established prior to the onset of CO_2 injection at Weyburn to assess monitoring methods and subsurface processes associated with the injection of CO_2 into geological storage sites. This research program is now in its second phase of research. Baseline 3D seismic surveys were performed over the Weyburn Field before injection and subsequent repeat 3D seismic surveys have been taken during the course of injection spanning multiple years and have indicated that CO_2 distribution within the reservoir can be imaged seismically. Similarly, repeat reservoir fluid sampling surveys have monitored a range of chemical and isotopic parameters to help identify processes associated with CO_2-rock interaction. In addition, multiple soil gas and shallow hydrology surveys have been performed during the past 10 years with no indication of CO_2 reaching the surface. The current research program is building on many of the results obtained during the first phase of work on the Weyburn Field. For example, some of the current research includes applying stochastic methods to relate fluid chemistry to the seismic data to better characterize the distribution of CO_2 in the subsurface. Additional methods of modeling CO_2 distribution post-injection are also being demonstrated and integrated into several risk assessment methodologies. A detailed well database has been developed to catalogue characteristics associated with wells drilled at various stages of field development using different cementing practices and completion methods to assist with providing parameters for long-term modeling of well behaviour. In addition, a downhole well integrity testing program to examine cement sheath characteristics will be implemented in two wells in each of the fields. In summary, more than 30 research studies are being performed within this phase of the program to examine aspects of site characterization, well integrity, geochemical and geophysical monitoring methods and risk assessment. One of the goals for the work from this research program is to provide a best practices manual for the transition of CO_2-EOR sites into storage sites. This paper provides an overview of the studies and results developing from the research program.

Wildenborg, T., J. Gale, C. Hendriks, S. Holloway, R. Brandsma, E. Kreft, A. Lokhorst, E. S. Rubin, D. W. Keith, C. F. Gilboy, M. Wilson, T. Morris, J. Gale and K. Thambimuthu (2005). Building the Cost Curves for CO_2 Storage: European Sector. Greenhouse Gas Control Technologies 7. Oxford, Elsevier Science Ltd: 603-610.

Taking all storage options into consideration, close to 100% of the 20-year emissions (≈ 30 Gt CO_2) can be transported and stored less than 20 Euro/tonne CO_2, 20 Gt of which can be transported and stored for up to 4 Euro/tonne CO_2. The total costs amount to 120 billion Euro. No cost-reducing effect of the central pipeline infrastructure (backbone) was seen. Not all emitted CO_2 can be stored when storage is restricted to the hydrocarbon fields: 76% without backbone and 85% with backbone. The costs per tonne CO_2 are higher, viz. 6.17 Euro without backbone and 7.73 Euro with backbone. The central transport infrastructure becomes cost effective when storage is restricted to offshore hydrocarbon fields (North Sea region). The costs amount to 9.74 Euro/tonne CO_2 without backbone and equal 4.48 Euro/tonne CO_2 with backbone.

Williams, G. and A. Chadwick (2012). "Quantitative seismic analysis of a thin layer of CO_2 in the Sleipner injection plume." GEOPHYSICS 77(6): R245-R256.

Time-lapse seismic reflection data have proved to be the key monitoring tool at the Sleipner CO_2 injection project. Thin layers of CO_2 in the Sleipner injection plume show striking reflectivity on the time-lapse data, but the derivation of accurate layer properties, such as thickness and velocity, remains very challenging. This is because the rock physics properties are not well-constrained nor are CO_2 distributions on a small scale. However, because the reflectivity is dominantly composed of interference wavelets from thin-layer tuning, the amplitude and frequency content of the wavelets can be diagnostic of their temporal thickness. A spectral decomposition algorithm based on the smoothed pseudo Wigner-Ville distribution has been developed. This enables single frequency slices to be extracted with sufficient frequency and temporal resolution to provide diagnostic spectral information on individual CO_2 layers. The topmost layer of CO_2 in the plume is particularly suitable for this type of analysis because it is not affected by attenuation from overlying CO_2 layers and because there are areas in which it is temporally isolated from deeper layers. Initial application of the algorithm to the topmost layer shows strong evidence of thin-layer tuning effects. Analysis of tuning frequencies on high-resolution 2D data suggests that layer two-way temporal thicknesses in the range 6 to 11 ms can be derived with an accuracy of c. 2 ms. Direct measurements of reflectivity from the top and the base of the layer permit calculation of layer velocity, with values of around 1470 ms−1, in reasonable agreement with existing rock physics estimates. The frequency analysis can, therefore, provide diagnostic information on layer thicknesses in the range of 4 to 8 ms. The method is currently being extended to the full 3D time-lapse data sets at Sleipner.

Williams, B. K., et al. (2009). Adaptive Management: The U.S. Department of Interior Technical Guide. Washington D.C., U.S. Department of Interior.

The purpose of this technical guide is to present an operational definition of adaptive management, identify the conditions in which adaptive management should be considered, and describe the process of using adaptive management for managing natural resources. The guide is not an exhaustive discussion of adaptive management, nor does it include detailed specifications for individual projects. However, it should aid U.S. Department of the Interior (DOI) managers and practitioners in determining when and how to apply adaptive management.

Wolaver, B. D., et al. (2013). "Greensites and brownsites: Implications for CO_2 sequestration characterization, risk assessment, and monitoring." International Journal of Greenhouse Gas Control 19: 49-62.

Proposed CO_2 sequestration storage sites will require different approaches in characterization, risk assessment, and monitoring, given prior site history and land use. Those sites lacking previous subsurface development are defined as greensites, whereas sites where the subsurface is developed, particularly for hydrocarbon production, are defined as brownsites. Greensite CO_2 injection is specifically for storage of CO_2. Most CO_2 enhanced oil recovery operations using incidental storage would be characterized as a brownsite. Application of monitoring approaches developed for greensites is inadequate when applied to brownsites because intrinsically different uncertainties may lead to investment in ineffective monitoring. Subsurface data are sparse at greensites. Characterization and monitoring must ensure that the subsurface can accept and retain CO_2 in large volumes and that the confining system will isolate CO_2 from the atmosphere over extended time frames. Brownsites will have extensive data on capacity, injectivity, and fluid retention from past operations. However, brownsite confining system integrity may be compromised by the nature of past development. Greensite pore fluids are typically unperturbed and relatively stable, providing a simpler environment for characterization and monitoring. Brownsite reservoir fluids, however, may have been modified by resource recovery. Geologic processes commonly have introduced trace hydrocarbons into the shallow subsurface. At the surface, brownsite legacy infrastructure and contamination must be evaluated so that preinjection transients do not mimic or mask leakage signals. To be effective, policies and regulations need to recognize inherent differences between greensites and brownsites during CO_2 storage project development.

WRI (2008a). CCS Guidelines for Carbon Dioxide Capture, Transport, Storage. Washington, D.C., World Resources Institute (WRI).

The CCS Guidelines focuses a group of experts on specific issues in order to examine, describe, and explain best practices for the implementation of specific projects. In addition, the Guidelines introduce some larger policy issues that go beyond the regulatory frameworks proposed by federal and state governments. Appendices B, C, and D categorize the Guidelines according to the intended implementing audiences: Appendix B presents information intended for Congress, Appendix C presents information intended for regulators, and Appendix D presents information intended for operators. The purpose of the

CCS Guidelines is to develop practical considerations for demonstrating and deploying CCS technologies. The starting point for the CCS Guidelines stakeholder discussions was that CCS will most likely be needed to achieve the magnitude of CO_2 emissions reduction required to stabilize and reduce atmospheric concentrations of greenhouse gases (GHGs). These Guidelines represent current understanding of how to implement CCS technologies. Discussions of the Guidelines were predicated on the following principles:

- Protect human health and safety
- Protect ecosystems
- Protect underground sources of drinking water and other natural resources
- Ensure market confidence in emission reductions through regulatory clarity and proper GHG accounting
- Facilitate cost-effective, timely deployment

To develop the CCS Guidelines, theWorld Resources Institute (WRI) convened a diverse group of over 80 stakeholders, including representatives from academia, business, government, and environmental nongovernmental organizations (NGOs). Business participants included those most likely to be involved in CCS projects: fossil energy, electric utility, insurance and service providers. These experts represent a variety of disciplines, including engineering, finance, economics, law, and social science. To have the technical discussions needed to arrive at a robust set of guidelines, all stakeholders agreed to focus the discussions and guidelines on how and not whether to implement a CCS project. These Guidelines reflect the collective agreement of the contributing stakeholders, who offered strategic insights, provided extensive comments on multiple iterations of draft guidelines and technicalguidance, and participated in workshops. The authors and editors strived to incorporate these sometimes diverse views. In so doing, they weighed conflicting comments to develop guidelines that best reflect the views of the group as a whole, and acknowledged diverging opinions among stakeholders.

Zeidouni, M., M. Pooladi-Darvish and D. W. Keith (2011a). "Leakage detection and characterization through pressure monitoring." Energy Procedia 4: 3534-3541.

Characterization of the CO_2 leakage pathways from the storage formations into overlying formations is required. We present a flow and pressure test to locate and characterize the leaks. The flow test is based on the injection (or production) of water into (or from) a storage aquifer at a constant rate. The pressure is measured at one or several monitoring wells in an aquifer overlying the storage aquifer, which is separated by an aquitard. The objective of the test is to locate and characterize any leakage through the separating aquitard. We present an inverse procedure to obtain the leakage pathway transmissibility and location, based on the pressure measurements in the presence of noise. A single monitoring well allows good determination of the leak magnitude but provides limited constraints on location. Adding a second monitoring well provides two-dimensional location of the leak location in the presence of noise/uncertainty in pressure measurements. It seems plausible that the use of multiple monitoring wells could enable cost-effective and sensitive detection of leakage over a large area. Unlike seismic imaging which only detects leakage when CO_2 penetrates the leak, these methods are able to test for leaks before CO_2 injection, or during injection but before the CO_2 plume reaches the leak.

Zeidouni, M., M. Pooladi-Darvish and D. W. Keith (2011b). "Analytical models for determining pressure change in an overlying aquifer due to leakage." Energy Procedia 4: 3833-3840.

Various methodologies are proposed to reduce CO_2 emissions that are believed to be the main drivers of the climate change. CO_2 capture and storage in deep underground formations is one of the promising methods that allow reducing the emissions while continuing the use of fossil fuels. Injection of immense quantities of CO_2 is required to make a reasonable cut of the emissions. Deep saline aquifers can provide the capacity to accommodate the storage of such huge amounts of CO_2. However, one of main challenges in deployment of CO_2 storage is the risk of CO_2 leakage through pathways in the cap rock overlying the target aquifer. The sealing capacity of the cap rock must be evaluated to ensure the safety of the storage. Therefore, characterization of the cap rock is required to find the potential leakage pathways even before the CO_2 storage begins. Methods to characterize the leakage pathways are proposed at two different scales: 1) by point sampling of the cap rock and testing the potential pathways such as abandoned wells, and 2) by analysing geophysical (e.g., 3-D seismic) data to estimate paths of upward migration of the injected CO_2. Flow based methods have the potential for bridging the large gap that exists between the length scale of these two approaches. The aquifer could be tested for the leakage pathways before CO_2 storage. This will allow finding proper storage aquifers and locations for the injection wells. In this work we present an analytical model to evaluate the pressure variation in the overlying aquifers due to leakage from the storage aquifer. In a companion paper, this model will be used along with an inverse modelling approach to locate and characterize the leakage pathways based on pressure data. This paper introduces two new analytical solutions: 1) exact solutions for the pressure variation in an overlying aquifer due to leakage (obtained in Laplace-transformation domain), and 2) time-domain approximations for the exact solutions to make the inversion possible. In deriving the analytical solutions two aquifers are considered: storage and monitoring. The aquifers are separated by an aquitard and are in communication through a leakage pathway. In departure from previous works the leakage pathways are not required to be line source/sink. Such consideration allows incorporation of large pathways such as stratigraphic and structural heterogeneities in the cap rock. We consider a single-phase 1-D radial flow system in the storage and monitoring aquifers. Both of the aquifers are considered as homogeneous, isotropic, and infinite-acting with constant thickness. The injection (or production) rate is taken as constant. The analytical solution are applied to a base case and corroborated versus numerical solution.

ZEP (2011). The Costs of CO_2 Transport: Post-demonstration CCS in the EU. Zero Admissions Platform, Advisory Council of the European Technology Platform for Zero Emission Fossil Fuel Power Plants.

Founded in 2005 on the initiative of the European Commission, the European Technology Platform for Zero Emission Fossil Fuel Power Plants (known as the Zero Emissions Platform, or ZEP) represents a unique coalition of stakeholders united in their support for CO_2 Capture and Storage (CCS) as a critical solution for combating climate change. Indeed, it is not possible to achieve EU or global CO_2 reduction targets cost-effectively without CCS – providing 20% of the global cuts required by 2050. Members include European utilities, oil and gas companies, equipment suppliers, national geological surveys, academic institutions and environmental NGOs. The goal: to make CCS commercially available by 2020 and accelerate wide-scale deployment. ZEP is an advisor to the EU on the research, demonstration and deployment of CCS. Members of its Taskforce Technology have therefore now undertaken a study into the costs of complete CCS value chains – i.e. the capture, transport and storage of CO_2 – estimated for new-build coal- and natural gas-fired power plants, located at a generic site in Northern Europe from the early 2020s. Utilizing new, in-house data provided by ZEP member organizations, it establishes a reference point for the costs of CCS, based on a "snapshot" in time (all investment costs are referenced to the second quarter of 2009). Three Working Groups were tasked with analyzing the costs related to CO_2 capture, CO_2 transport and CO_2 storage respectively. The resulting integrated CCS value chains, based on these three individual reports, are presented in a summary report. This report focuses on CO_2 transport.

Zhang, M. and S. Bachu (2011). "Review of integrity of existing wells in relation to CO_2 geological storage: What do we know?" International Journal of Greenhouse Gas Control 5 5(4): 826–840.

Carbon dioxide storage in geological media is a climate change mitigation technology that is based on the ability of certain geological media to retain CO_2 in supercritical phase or dissolved in formation water and to prevent its return to the atmosphere for very long periods of time. However, in certain cases there are flow pathways, natural or manmade, conducive to CO_2 leakage. Depending on their condition, existing oil and gas wells may provide such leakage pathways due to either mechanical defects developed during well drilling, completion and/or abandonment, or to chemical degradation of well cements and/or casing. In the case of CO_2 storage, there is a concern that well cement in existing wells will degrade in the presence of water-saturated CO_2 and/or CO_2 saturated formation water/brine, thus creating new leakage pathways and compromising the integrity and security of CO_2 storage. In this paper we review the status of knowledge in regard to the failure of existing wells, with special attention to the laboratory experiments, field investigations and numerical simulations carried out in the last several years in attempts to elucidate the behavior of well cements in the presence of CO_2. Extensive carbonation has been observed in well cements in both laboratory and field studies. However, in CO_2-rich environments, severe cement degradation is associated with the dissolution of calcite from the carbonated cement. This is not expected under typical geological storage conditions because CO_2-saturated brine is likely in equilibrium with carbonate minerals that are present in virtually all formation rocks.

Zhang, Y., X. Pang, S. Qu, X. Li and K. Gao (2011). "The relationship between fracture toughness of CO_2 corrosion scale and corrosion rate of X65 pipeline steel under supercritical CO_2 condition." International Journal of Greenhouse Gas Control 5(6): 1643-1650.

Corrosion experiments were performed with X65 pipeline steel under static supercritical carbon dioxide (SC CO2) conditions at 50, 80, 110 and 130 °C. The morphology, structure, chemical composition and fracture toughness of CO_2 corrosion scales formed on the surface of X65 pipeline steel at various temperatures were investigated by means of Scanning Electron Microscopy (SEM), X-ray Diffraction (XRD) and Energy Dispersive X-ray Spectroscopy (EDS). The corrosion rates were measured using weight-loss method. The fracture toughness of CO_2 corrosion scale formed at different temperatures was investigated by means of nanoindentation and Vicker's indentation on a polished cross-section of the CO_2 corrosion scale. The results showed that the corrosion rates increased from 50 °C to 80 °C and then decreased from 80 °C to 130 °C. As the temperature increased, the fracture toughness of CO_2 corrosion scale first decreased and then increased, and the lowest fracture toughness was found at 80 °C. The corrosion rate (CR) has a quantitative relationship with the fracture toughness (KIC)CR=(3.25/KIC3/2)−0.908.

Zhou, W., et al. (2005). The IEA Weyburn CO_2 monitoring and storage project -- Modeling of the long-term migration of CO_2 from Weyburn. Greenhouse Gas Control Technologies 7. Oxford, Elsevier Science Ltd: 721-729.

The subject of this report is a large-scale commercial pilot project in Weyburn, Saskatchewan, Canada, where CO_2 is injected into a mature oil reservoir and stored underground. Essentially, the project is a field demonstration of carbon storage in the subsurface, which has been made possible by adding a research component to a CO_2 enhanced oil recovery programme. Chapter 1 introduces the principles of underground storage and the practice of enhanced oil recovery. Chapter 2 covers the origins and location of the Weyburn project. The four research themes are described in Chapter 3. The results that have been identified are relayed in Chapter 4. In the final chapter the conclusions are reported and the results and implication of Phase 1 of the Weyburn Project are put in context.

Zhou, D., Zhang, Y., Haszeldine, S. (2014). Engineering Requirements for Offshore CO_2 Transportation and Storage: A Summary Based on International Experiences. Guangzhou, China, UK-China (Guangdong) CCUS Centre.

This paper details the models and results of the assessment of the long-term fate of CO_2 injected into the Weyburn field for Enhanced Oil Recovery (EOR) operations. A System Model was established to define the spatial and temporal extents of the assessment. The Base Scenario was developed to identify key processes, features, and events (FEPs) for the expected evolution of the storage system. A compositional reservoir simulator with equations-of-states (EOS) was used as the modeling tool in order to simulate multiphase, multi-component flow and transport coupled with CO_2 mass partitioning into all three phases. We apply a deterministic treatment to CO_2 migration in the geosphere (natural pathways), whereas the variability of abandoned wells (man-made pathways) necessitates a stochastic treatment. The results show that the geosphere is able to contain the injected CO_2 for at least 5000 yrs, i.e., no CO_2 enters the potable aquifers through natural pathways and media. The well results show that the likely cumulative leakage via all the existing wells in the field is less than 0.001% of the CO_2-in-place at the end of EOR.

Appendix B: Types of Geological Data Available for the Gulf of Mexico OCS

Large and rich data sets have been gathered during the six decade history of extensive petroleum exploration and production in the offshore Gulf of Mexico Basin. These data are widely available through public and commercial sources. Comprehensive data and information—much of it free—is available from the BOEM "Data Center" website (https://www.data.boem.gov/). Users can access public information and data pertaining to the appropriate subject matter. Data are available via online queries, as well as downloadable PDF reports and ASCII files. Older documents have been scanned and are also available in PDF format. Some files are available for purchase on CD/DVD media. Information may be cross referenced among different subjects. Subject matter categories are:

Well: Basic well data, including header information, total depth, and latitude-longitude locations, from approximately 53,000 wells in the GOM federal OCS can be obtained free of charge from BOEM's download page (http://www.data.boem.gov/homepg/data_center/well/well.asp). Well information includes information on borehole activities such as drilling activity, counts on the number of boreholes completed, and number of shut-ins. Additional information includes the lease number, well name, spud date, the well class, surface area/block number, and statistics on well status summary. Other downloadable data includes:

- Directional Surveys (ASCII and PDF)
- Completion Reports (PDF)
- Well Test Reports (PDF)
- Velocity Surveys (ASCII)

Field & Reserves: Reserves information includes information on active and expired fields and leases in the Gulf of Mexico. Field data available includes leases assigned to each field, Energy Information Administration (EIA) field code number, and cumulative field production. Lease data available includes OCS blocks, operators, effective date of lease in field, expired lease status, and date and portion of lease within the field. (ASCII)

Paleontologic: Paleontologic information and data includes publicly releasable biostratigraphic and paleobathymetric summary information on active and expired fields and leases in the Gulf of Mexico. The foraminiferal and coccolith biostratigraphic markers are placed in their proper chronologic, chronostratigraphic and chronozonal context as determined by the BOEM Resource Evaluation Paleontologic Group. In May 2003, a revised Biostratigraphic Chart of the Gulf of Mexico Offshore Region was published. Using standardized global stratigraphic concepts, this new version of the chart (download from BOEM, *Atlas of Gulf of Mexico Gas and Oil Sands Data* webpage at https://www.data.boem.gov/Main/GandG.aspx) incorporates the latest information currently used as biostratigraphic datum markers by industrial paleontologists for the Mesozoic and Cenozoic geologic sections. (ASCII and PDF)

Geological and Geophysical Studies: Detailed information on reservoir properties, plays, and Chrono zones also downloadable from the BOEM at http://www.boem.gov/Oil-and-Gas-Energy-Program/Resource-Evaluation/Geological-and-Geophysical-Data-Acquisition/GGData-Gulf-of-Mexico.aspx.

Mapping: Includes GIS cultural data, such as lease lines, blocks, and political boundaries. (ASCII, E00, DXF and SHP)

Leasing: Leasing information includes information on the status of leases, along with the geographic locations, effective date, surface acreage and other data elements specific to the lease. Lease Owner details lease ownership by percentage and includes the company who is the designated lease operator. (ASCII and PDF)

Pipeline: Pipeline information includes information specific to each segment number, such as origination and destination locations, approval, authority, size and product codes as well as approval, test, and construction dates. (ASCII, E00, DXF and SHP)

Platform/Rig: Platform/rig information includes information on a complex with specific information on the structure and/or abandonment of a complex, production equipment and gas, oil, water and condensate status. This dataset provides information on the complex as to availability of a heliport and whether the complex is in the production status and manned or not. (ASCII and PDF)

Production: These files include information on oil and gas production by Lease, Well (API No.), or Lease Operator. Additional files are also available on historical Gulf of Mexico production from the Public Information Office. (ASCII and PDF)

Seismic: Seismic information includes CD/DVD sets with scanned images of 2D seismic line film, SEG-P1 navigation files, SEG-Y files by permit area (including Atlantic Offshore, Louisiana OCS, Texas OCS, MAFLA OCS), protraction maps and seismic permits. Additional scanned images of public documents related to applications and permits for Geophysical prospecting for mineral resources and scientific research.

Appendix C: Excerpt of BEG 2011 Contract Report

Continued Evaluation of Potential for Geologic Storage of Carbon Dioxide in the Southeastern United States

By:

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Prepared for:

Southern States Energy Board

Duke Energy

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Bureau of Economic Geology

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October 2011

NOTE: ONLY THE CONTENT HIGHLIGHTED IN BLUE TEXT IS INCLUDED FROM THE ORIGINAL REPORT

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Executive Summary

The need to reduce atmospheric emissions of carbon dioxide (CO_2) from industrial sources is now recognized internationally. As a result, companies operating coal-fired and other types of power plants in the southeastern U.S. (SE US) have been seeking information on the potential for long-term storage of CO_2 in nearby subsurface geologic formations. Previous studies have shown there to be little to no capacity for onshore subsurface storage of CO_2 in deep saline reservoirs in the Carolinas and northern Georgia (GA) (Smyth et al., 2008). However prior to this study, southern GA had not been assessed for geologic sequestration (GS) capacity potential. It is currently not known if extensive petroleum reserves exist below the continental shelf of the Atlantic Ocean offshore from SE US but, potential offshore capacity for storage of CO_2 is large.

The objectives of this study have been to (1) assess the potential for GS of CO_2 in areas of SE US not previously characterized (i.e. southern GA coastal plain between the panhandle of Florida (FL) and the Atlantic Ocean) and (2) refine capacity estimates for portions of offshore geologic units present below the nearby Atlantic continental shelf. We primarily focused on geographic areas where CO_2 can be stored in deep saline reservoirs at depths great enough to keep it in supercritical phase, but also had to consider surrounding areas in order to better solve the geological puzzle. Maintaining CO_2 in supercritical phase requires temperature greater than 31.1 °C (88 °F) and pressure greater than 7.39 MPa (72.9 atm), which corresponds to depth below ground surface of ~800 m (2600 ft). Results of this detailed study of the regional subsurface geologic units are timely for operators of coal-fired power plants in the SE US because technologies to separate, capture, and concentrate CO_2 from industrial emissions are ready for commercial-scale demonstration.

Two areas with thick accumulations of coastal plain sediment underlie the southwest and southeast GA embayment. It is in thicker sections of the embayment, both onshore and offshore, that nonmarine, clastic (i.e., gravel-, sand-, and silt-bearing) strata have the highest potential for deep geologic storage of CO_2 generated in the SE US.

To battle the complexity of Georgia's deep subsurface geology, Carr used the concepts of sequence stratigraphy to define the large-scale distribution of two potential CO_2 geologic sequestration units (GSUs). The sequence stratigraphic method focuses on tracing correlative time surfaces in cross sections that are made up of individual well logs and/or descriptions of rock core collected from wellbores. The advantage of the sequence stratigraphic method is that applied correctly, it captures architecture of rock units more accurately and at scales that affect subsurface fluid flow.

After many iterations of correlation and cross section construction, Carr identified the following major stratigraphic packages within our area of interest:

1. Pre-Tuscaloosa sandstones/conglomerates of upper Jurassic (?) to Early Cretaceous age
2. Tuscaloosa (or equivalents) sandstones of early Late Cretaceous age
3. Post- Tuscaloosa sandstones and limestones of Late Cretaceous age

The two intervals with sufficient thicknesses of net permeable clastic strata, at depths deep enough to store CO_2 in supercritical phase, are Pre-Tuscaloosa and Tuscaloosa (fig. 1).

Estimates for the capacity of subsurface geologic units to store CO_2 depend on, among other variables, the thickness of permeable sand present in a reservoir. We estimated CO_2 storage capacity of the two GSUs by (1) establishing geologic framework and determining porosity in Petra geologic modeling software (2) exporting data to ArcGIS, and (3) using the methodology developed primarily by researchers at the Massachusetts Institute of Technology (MIT, 2010) and reported in the U.S. Department of Energy, National Energy Technology Laboratory National Carbon Sequestration Atlas (NETL, 2010) for saline reservoir capacity.

The total capacity for the Pre-Tuscaloosa GSU, using an efficiency factor (E) of 2 percent, is ~111 Gt over an area of ~74,000 mi^2 (191,000 km^2). The total capacity for GS of CO_2 in the Tuscaloosa GSU, using E = 2 percent, is ~31 Gt over an area of ~65,000 mi^2 (168,000 km^2). Areas with higher capacity are in offshore portions of the SW and SE GA embayment, which is where the thickest accumulations of permeable sands and highest estimated porosities lie.

Capacity Estimates

The methodology used to estimate CO_2 storage capacity and the resulting capacity estimates for each of the two GSUs is described below. Estimates for the capacity of subsurface geologic units to store CO_2 depend on the thickness of permeable sand present. After identifying units with enough permeable sand in locations appropriate for GS of CO_2, we followed a series of additional steps to come up with the capacity estimations for the Pre-Tuscaloosa and Tuscaloosa GSUs. As previously detailed, the steps we took to select the GSUs included delineation of structural tops and bottoms, summation of net permeable sands, and estimation of porosity for each unit. All of this work was completed in IHS Petra© software and exported to Geographic Information Systems (GIS) shape files for further analysis using ESRI ArcGIS (ArcMap©) software.

Work completed in ArcMap for each GSU included:

- Interpolated Petra-generated depth, area, and thickness contours to generate Arc-grids (metric units)
- Adjusted depth below sea level grids (top and bottoms of units) to depth below surface for onshore areas by adding ground surface elevation (fig. 10)
- Defined GSU area polygons by (1) trimming northern edge of grid along 2, 600 ft. (800 m) depth below ground surface contour, (2) trimming eastern edge along 400 m bathymetric contour, which approximates the seaward extent of the continental shelf (fig. 10).
- Calculated mid-point depths below ground surface for each grid cell within each polygon to use in CO_2 density calculation. For the Pre-Tuscaloosa GSU this is the mid-point between the top of basement and the base of the Tuscaloosa Fm. For the Tuscaloosa GSU this is the mid-point between the top and bottom of the Tuscaloosa Fm.
- Interpolated Petra-generated net sand and porosity contours to generate Arc-grids
- Performed grid algebra within each 2.3 km^2 grid cell (number of grid cells within the Pre-Tuscaloosa GSU = 82,369; number of grid cells within the Tuscaloosa GSU = 72,314) using a formula that defines mass resource estimate potential of CO_2 in saline formations (MIT, 2010; NETL, 2010):

Eqn. 4. $$G_{CO_2} = A_t \, h_g \, \phi_t \, \rho_{CO_2} \, E_{saline}$$

Where:

GCO_2 = mass of CO_2 stored (kg)

A_t = geographical area defining region of CO_2 storage (m^2)

h_g = gross formation thickness (m)

ϕ_t = total porosity

ρCO_2 = density of CO_2 estimated at temperature and pressure of anticipated storage (reservoir) conditions (kg/m^3)

E_{saline} = CO_2 storage efficiency factor (we used E_{P50} = 0.02, and 0.004, 0.055)

We calculated CO_2 density for each grid cell midpoint-depth using the Winprop© routine (an equation solver) within CMG (Computer Modeling Group LTD.) reservoir simulation software to solve the Peng-Robinson equation of state (Peng and Robinson, 1976). Simply stated, Peng-Robinson is an equation that calculates molar volume of a fluid at specified temperature and pressure, and also using other input values such as the universal gas constant, R, critical temperature, T_c, etc. Then by knowing the molecular mass of CO_2, one can calculate the density because volume = mass/density. The steps taken to get to the point of solving for CO_2 density included:

- Assigned a temperature for specific mid-point depths in GSUs assuming a surface temperature of 59 °F and a gradient of 1.5 F/100 ft. (Griffin et al., 1969; Reel and Griffin, 1971), changing temperature every 30 ft.
- Increased pressure with depth according to a hydrostatic pressure gradient of
- Calculated CO_2 density for tabulated mid-point depths using the Peng-Robinson equation described above.
- Converted resulting density values in lb./ft^3 to kg/m^3 and interpolated to Arc-grid format.

Results of the capacity calculations (using **Eqn. 4**) for both the Pre-Tuscaloosa and Tuscaloosa GSUs are shown in figures 18 and 19, and Table 4. The color scale for capacity is the same for both the Pre-Tuscaloosa and the Tuscaloosa GSUs (figs. 18, 19); thus it is more obvious that there is much higher capacity for GS of CO_2 in the deeper Pre-Tuscaloosa than in the shallower Tuscaloosa GSU. In both images, grid cells shaded gray mark areas of zero capacity.

The total capacity for the Pre-Tuscaloosa GSU, using an efficiency factor (E) of 2 percent, is ~111 Gt over an area of ~74,000 mi^2 (191,000 km^2) (Table 4). Capacity estimates for this unit over the same area using E = 0.4 and 5.5 percent are included in Table 4. The maximum capacity (for E = 2 percent) within a single 2.3 km^2 grid cell in the underlying Pre-Tuscaloosa GSU is just over nine million tons (0.009 Gt); the highest capacity grid cells are shaded in blue (fig. 18). Note that areas with higher capacity (yellow-green-blue range) are in offshore portions of the SW and SE GA embayment (fig. 3), which is where the thickest accumulations of permeable sands and highest estimated porosities (e.g. figs. 13, 14) lie. We are most confident in capacity estimates for areas covered by the seven cross sections shown in fig. 4. The reason being that areas outside of those covered by the cross sections are outside of our area of geophysical log coverage (Recall this was discussed in detail in the Methodology section). So of the Pre-Tuscaloosa GSU areas with higher capacity, we are most confident in the onshore portions of the SW GA embayment, and SE GA embayment strata offshore below the Atlantic continental shelf. It makes sense that in central portions of the study area where post-rift sediments are thin, capacity estimates are low; this is the Suwannee saddle (FL/GA uplifts) area (figs. 3, 4, 11).

We are less confident in the Pre-Tuscaloosa GSU highest capacity estimates (blue shaded areas) offshore below the eastern Gulf of Mexico (GOM) continental shelf (fig.18), and consider results for this area to be only reconnaissance level. Using results for E = 2 percent, this ~4,600 km^2 area accounts for ~13 Gt of the total capacity estimate for the Pre-Tuscaloosa GSU. In other words, 2.4 percent of the Pre-Tuscaloosa area accounts for 12 percent of the capacity. However the area is worth including here, especially since results of other reconnaissance level studies have suggested that offshore portions of the SW GA embayment may contain large thicknesses of permeable sands (e.g. Mancini et al., 1987).

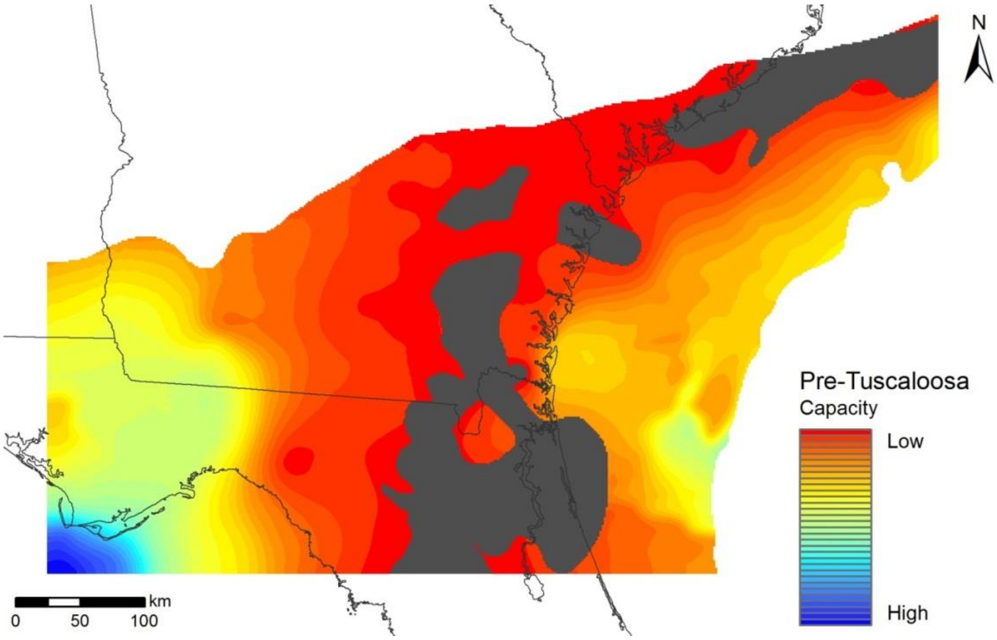

Figure 18 Tuscaloosa GSU capacity ranges from zero (gray areas) to over nine million tons (dark blue areas) per 0.9 mi2 (2.3 km2) grid cell using an efficiency factor (E) of two percent.

Table 4 Summary of capacity information for Pre-Tuscaloosa and Tuscaloosa GSUs.

	Tuscaloosa GSU	Pre-Tuscaloosa GSU
Area (mi^2)	64,892	73,915
Area (km^2)	168,070	191,440
for E = 0.02		
Mass (kg)	30,576,708,605,597	110,774,300,000,000
Mass (tonnes)	30,576,708,606	110,774,300,000
Mass (Gt)	31	111
for E = 0.004		
M (kg)	6,115,342,149,255	22,154,852,585,700
M (tonnes)	6,115,342,149	22,154,852,586
M (Gt)	6	22
for E = 0.055		
M (kg)	84,085,950,138,676	304,629,200,000,000
M (tonnes)	84,085,950,139	304,629,200,000
M (Gt)	84	305

The total capacity for GS of CO_2 in the Tuscaloosa GSU, using E = 2 percent, is ~31 Gt over an area of ~65,000 mi^2 (168,000 km^2) (Table 4). Capacity estimates for this unit over the same area using E = 0.4 and 5.5 percent are included in Table 4. The maximum capacity within a single 2.3 km^2 cell in the overlying Tuscaloosa GSU, using E = 2 percent, is just over two million metric tons (0.002 Gt) (fig. 19). So the capacity for GS of CO_2 in the Tuscaloosa GSU is only ~28 percent of that estimated for the Pre-Tuscaloosa GSU. As with the Pre-Tuscaloosa GSU, the highest capacity estimates fall within the SW GA embayment. In contrast to the Pre-Tuscaloosa results, most of the capacity in the Tuscaloosa GSU is onshore.

Reasons for differences in the distribution of capacity between the two GSUs are related to depositional processes taking place during the two respective geologic time periods. From middle Jurassic to lower Cretaceous time, nearshore deposition was dominantly continental clastic sediments with carbonate deposition being limited to areas farther offshore near the Blake Plateau. By upper Cretaceous time when sea level was rising, most of the rocks being deposited in the SE GA embayment were carbonates (Buffler et al., 1978; Frazier and Schwimmer, 1987). This pattern of deposition matches the results of net sand distribution documented herein.

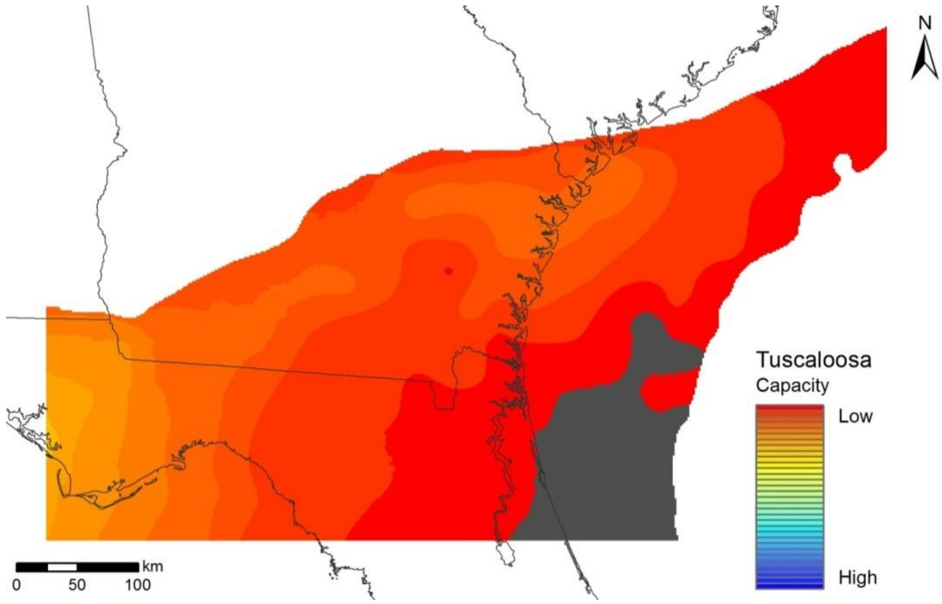

Figure 19 Tuscaloosa GSU capacity ranges from zero (gray areas) to over two million tons (yellow-orange areas) per 0.9 mi^2 (2.3 km^2) grid cell using an efficiency factor (E) of two percent.

Conclusions

This work surpasses the scope of previous individual studies through identification of two GSUs that span the GA coastal plain, parts of adjacent FL and SC, and extend out onto the offshore continental shelf of the Atlantic Ocean and a small area of the eastern Gulf of Mexico. Delineation of the subsurface geologic units was accomplished using sequence stratigraphic methods, which allow interpretations that should more accurately predict reservoir properties.

Even though the results presented here provide more accurate capacity estimates than previously calculated in the SE US (Smyth et al., 2008), they will still need to be refined by site-level investigations. The method for calculating capacity (MIT, 2010) is meant to be used for regional assessments without refined estimates of specific intervals into which the CO_2 will be injected. For example permeability is not considered so inter-well heterogeneity (connectedness of sands identified in individual wells) is not taken into account.

The potential to store CO_2 in deep (greater than 2,600 ft.) subsurface geologic strata underlying southern GA and offshore below the Atlantic seafloor is significant. Here we present two new geologic sequestration units (Pre-Tuscaloosa and Tuscaloosa) identified in this area that are capable of storing up to 15 giga tonnes (billon metric tons) (Gt) of CO_2 within clastic sedimentary strata.

Previous estimates for areas surrounding and slightly overlapping our two new GSUs were based on limited and generalized data sets, which were primarily from research reports and published literature (Smyth et al., 2008). However given the information available, these previous estimates are still valid.

Maps and cross sections generated during this study are consistent with earlier research results in terms of (1) gross vertical and lateral distribution of major geologic strata and (2) patterns of deposition of sedimentary strata being controlled by the following regional structural features: Southwest Georgia Embayment, Southeast Georgia Embayment, and the Central Georgia uplift/Florida Pennisular arch (referred to by some researchers as the Suwannee Saddle.

Operators of coal- and natural gas-fired power plants, and other types of industrial facilities, that release significant volumes CO_2 to the atmosphere have options for GS in the SE US.

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Appendix D: Example of CO_2 EOR-GS and GS Geologic Framework Modeling Workflow for Site Characterization

I. General database assembly and management (continues throughout)
   a. Well-related data
      i. Determine data sources
         1. Governmental
         2. Industry (vendors)
      ii. Acquire data
         1. QC data
         2. Select interpretation software package(s)
         3. Load data
   b. Seismic data (2-D and 3-D)
      i. Determine data sources
         1. Governmental
         2. Industry (vendors)
      ii. Acquire data
         1. QC data
         2. Select interpretation software package(s)
         3. Load data

II. Regional assessment
   a. Regional geologic interpretation
      i. Literature review
         1. Understand basin history
         2. Understand fluid systems (e.g., petroleum system as an analog)
      ii. Determine time-stratigraphic framework (Incorporate regionally significant bio-chronozones)
      iii. Select a time-stratigraphic model
         1. Sequence stratigraphy
         2. Genetic stratigraphy
         3. Combination?
         4. Other?
      iv. Determine tectonic and structural framework
         1. Dominant tectonic trends
            a. Active vs. passive margin
            b. Compressional vs. extensional stress terrain
            c. Mobile substrate present? If so, type is:
               i. Salt?
               ii. Fine-grained clastic (“shale”)?
         2. Dominant deformation type
            a. Folding (type and prominence)
            b. Faulting (type and prominence)
      v. Identify / analyze prospective regional units
         1. Reservoirs (regional saline aquifers)
            a. Below supercritical CO_2 depth?

        b. Above over-pressure depth?
            i. Analyze reservoir data
                1. Porosity
                2. Permeability
                3. Salinity
        c. Calculate regional static capacity
    2. Confining systems (also called seals or caprock)
        a. Identify available rock samples
        b. Analyze samples
            i. Capillary pressure properties (mercury intrusion capillary pressure analysis
            ii. Scanning electron microscopy (e.g., argon-ion milled)
            iii. Clay alignment (e.g., high-resolution X-ray texture goniometry)

b. Determine potential "play" types
    i. If available, use petroleum fields as analogs
        1. Trap styles
            a. Structural
            b. Stratigraphic
            c. Combination
            d. Fluid drive types
                i. Open system (preferable)
                ii. Closed system (capacity-limiting parameter)
        2. Field sizes
            a. Statistically analyze fluid accumulations and production history (if available)
    ii. If no petroleum production history, determine why
        1. Frontier area / lack of exploration?
        2. Lack of kerogen source?
        3. Lack of confining system? (capacity-limiting parameter)
        4. Lack of reservoirs? (capacity-limiting parameter)
        5. Breaching of traps? (potentially capacity-limiting parameter)
            a. Post petroleum migration trap breaches—subsequently "healed?"
            b. Identify leads (areas with good potential for CO_2 GS)
            c. Select sites (prospects) from most promising leads

III. Site-specific assessment (analogous to prospect development in O&G)

a. Identify risks (iterative tasks with geologic characterization of site, below)
    i. Environmental
        1. Top seal
        2. Fault seal
        3. Injectivity
        4. Other resources
    ii. Infrastructure
        1. Pre-existing well bores
        2. Quality of cement in existing wellbores
        3. Pipelines

b. Interpret local well data
    i. Stratigraphic
        1. Digitize geophysical well logs if not available in LAS format (log ASCII standard)
        2. Incorporate biostratigraphic data
        3. Identify time-stratigraphic surfaces

a. Sequence boundaries
b. Marine condensed section / maximum flooding surfaces
4. Iterate with seismic interpretation (if available)
ii. Structural
1. Identify fault cuts in wells
2. Iterate with seismic interpretation (if available)
c. Interpret local seismic data (time domain)
i. Pick / map significant seismic reflections
1. Generate time horizons
ii. Identify / define faults
iii. Iterate with geophysical well log interpretations
1. Digitize well logs if not available in LAS format (log ASCII standard)
2. Identify well-based time-depth data (purchase if necessary)
a. Acoustic (sonic) well logs
b. Check-shot data
c. VSP (vertical seismic profiles)
3. Generate time-depth tables
a. Associate with wells of utilized geophysical logs
b. Extrapolate time-depth data to nearby wells
4. Import well logs into time domain.
a. Compare well-based time-stratigraphic horizons (sequence boundaries & maximum flooding surfaces) with seismic dataset.
b. Iterate - adjust well-based time-depth tables to match seismic-based with well-based interpretations.
d. Convert seismic (time data) to depth data
i. Generate velocity model – utilize well-based time-depth data
ii. Apply to time volume – generate depth volume
iii. Iterate
1. View original (depth domain) geophysical well log data
2. Adjust or discard data with obvious data busts
3. Update velocity model until satisfied.
e. Generate volumetric (depth volume)
i. Map top and base of potential reservoirs
ii. Determine area and porosity
iii. Map projected CO_2 densities at reservoir depths.
f. Generate static geologic framework (GF) model using all the geological data sources described above
g. Generate dynamic fluid flow (FF) model using static GF model
h. Determine local capacity (according to preferred models / algorithms)
i. Static: in local area use methodology of Wallace et al. (2014)
ii. Dynamic: determine pressure regime, fluid drive, open/closed system

IV. Approve or reject site for further consideration
a. Meets capacity requirements?
b. Acceptable risk profile?

V. Follow up with permits for well drilling and injection testing.

Appendix E: Industry Workflow for Project Planning and Construction

Components of the six stages presented below show the typical planning and execution sequence for a large-scale onshore/offshore project as outlined by Wood Group Mustang engineering contributors. Included are examples of key work areas and deliverables that are executed during the various stages. As the project moves through each stage, additional work and deliverables are added; the ones that are repeated will be refined in order to achieve final design and construction. The six stages presented below are: Concept Development, Pre-FEED (Front End Engineering Design), FEED, Detailed Design, Construction, and Startup.

<u>Concept Development</u>

- Project Objectives and Stakeholder Identification
- Project Description and Options Established (e.g., identification of CO_2 sources and potential sub-seabed geological sinks)
- Project Execution Plan
- Project Risk Assessment
- Desk-Top Studies (e.g., Major Facility / Platform Locations and Pipeline Routings)
- Economic Analysis
- Project Schedule Timeline
- Environmental, Legal, Social, and Regulatory Concern Identification
- Permitting Constraints

<u>Pre-FEED</u>

- Project Objectives and Stakeholder Identification
- Project Description and Options Development
- Project Execution Plan
- Project Risk Assessment
- Desk-Top Studies (e.g., Major Facility / Platform Location Options, Pipeline Routing Options, Metocean)
- Economic Analysis
- Project Schedule Timeline
- Environmental, Social, Legal, and Regulatory Plan
- Permitting Constraints and Action Plan
- Land and Site Acquisition Research
- Preliminary Engineering Studies and Reports (e.g., flow assurance, design basis, process, site investigations, reservoir, major equipment lists, power loads, seismic, environmental, regulatory, plan and profile, and crossings)
- Operating Philosophies
- Capital and Operating Cost Estimates
- Preliminary Process Flow Diagrams
- Contractors Plan and Selection

FEED

- Project Scope of Work, Objectives, Stakeholder Identification
- Project Description – Final Selection
- Project Execution Plan
- Project Risk Assessment and Management Plan
- Quality Plan and Audits
- Major Facility / Platform Locations and Pipeline Routings Determined
- Economic Analysis
- Project Schedule
- Environmental, Social, Regulatory, and Legal Execution Plan
- Permitting Application Implementation
- Land and Site Acquisition Implementation
- Refined Engineering Studies and Reports (e.g., flow assurance, design basis, process, site investigations, reservoir, major equipment lists, power loads, seismic, metocean, environmental, regulatory)
- Philosophies (e.g., operating, control, cathodic and corrosion protection, fire protection, utilities)
- Capital and Operating Cost Estimates
- Construction Cost Estimates
- Preliminary Geotechnical Reports
- Preliminary Surveys and Mapping
- Environmental Impact Analysis
- Health, Environmental and Safety Plan
- Preliminary Hazard and Operability Study
- Preliminary Hazard Identification Study
- Specialized Studies (e.g., stress, pipeline buckling, 3D evaluations, lifts, reservoir management)
- FEED Design Drawing and Document Development
    - Process Flow Diagrams
    - Process and Instrument Diagrams
    - Plot Plans and Layouts
    - Route Maps and Plans
    - 3D Models
    - Building Layouts
    - Preliminary Plan and Profile and Crossing Drawings
    - One-Line Diagrams
    - Equipment Lists
    - Automation / Telecommunication Control Block Diagram
    - Equipment Specifications and Data Sheets (to begin major equipment procurement)
    - Project Specifications (e.g., cathodic protections)
    - Material and Coating Selection Criteria
- Selection of Engineering and Construction Contractor(s) (detailed design / procurement / construction)
- Preliminary Procurement Plan
- Logistics Plan
- Preliminary Constructability Review
- Preliminary Construction Execution Plan

Detailed Design

- Project Scope of Work, Objectives, and Stakeholder Identification
- Project Description – Final Selection
- Project Execution Plan
- Project Risk Assessment and Management Plan
- Quality Plan and Audits
- Major Facility / Platform Locations and Pipeline Routings Determined
- Economic Analysis
- Project Schedule
- Environmental, Social, and Legal Execution Plan
- Permitting Implementation
- Land and Site Acquisition Implementation
- Final Engineering Studies and Reports (e.g., flow assurance, design basis, process, site investigations, 3D evaluations, major equipment lists, power loads, seismic, metocean, environmental, regulatory)
- Philosophies (e.g., operating, control, cathodic and corrosion protection, fire protection, utilities, spare parts)
- Capital and Operating Cost Estimates
- Construction Cost Estimates
- Geotechnical Reports
- Surveys
- Environmental Impact Analysis
- Health, Environmental, and Safety Plan
- Hazard and Operability Study
- Hazard Identification Study
- Technical Safety Studies (e.g., dispersion, egress/ingress, safety equipment)
- Specialized Studies (e.g., stress, pipeline buckling, 3D evaluations, lifts, reservoir management)
- Detailed Design Drawing and Document Development
    - Process Flow Diagrams
    - Process and Instrument Diagrams
    - Plot Plans and Layouts
    - Route Maps and Plans
    - 3D Models
    - Building Layouts and Detailed Drawings
    - Plan and Profile and Crossing Drawings
    - One-Line Diagrams
    - Equipment Lists
    - Equipment Specifications and Data Sheets (not already purchased)
    - Automation / Telecommunication Control Block Diagram and Detail Drawings
    - Isometrics
    - Piping Plans and Detail Drawings
    - Pipeline and Riser Detail Drawings
    - Electrical and Instrument Detail Drawings
    - Civil and Structural Detail Drawings
    - Project Specifications (e.g., cathodic and corrosion protection, minor equipment, control system)
    - Specifications for Piping, Material, and Coatings
    - Discipline Supporting Calculations

- Bulk Material Take-Offs
- Cathodic Protection Scope of Work and Detail Drawings
- Construction Scope of Work

- Select Remaining Construction Contractor(s) Needed
- Procurement and Vendor Inspection Plan
- Implement Procurement and Expediting
- Preliminary Construction Execution Plan
- Logistics Plan
- Preliminary Construction Execution Plan
- Constructability Review
- Construction Detailed Design Support Established
- Decommissioning Plan

Construction

- Project Scope of Work and Stakeholder Identification
- Construction Execution Plan
- Construction Permits Implemented
- Environmental and Social Issues Action Plan
- Project Health, Safety, and Environmental Plan
- Construction Schedule
- Subcontractor Contracts
- Third-Party Inspection Contract
- Quality Plans and Audits
- Material and Equipment Handling Procedure
- Logistics Plan
- Vendor Support Established
- Lift Plans
- Welding Procedures
- Pre-qualification of Welders
- Surveys
- Mobilization of Equipment and Personnel
- Procurement of Bulk Material
- Piping and Structural Fabrication
- Installations (e.g., piping, civil, structural, electrical, telecommunications, instruments, pipelines, automation, cathodic protection, equipment, jackets, platforms)
- Hydrotest Plans and Implementation
- Material and Testing Documentation
- Completion of Discipline Punch List
- As-built Drawings and Documentation
- Construction Records Handover
- Inspection Records Handover
- Project Books Handover
- Demobilization of Equipment and Personnel

Startup

- Operational Permits Completed
- Regulatory Reporting Requirements Established

- Project Books in Place
- Inspection Program Established
- Operation and Maintenance Procedures
- Operator and Maintenance Personnel Training
- Emergency Plan
- Pre-commissioning and Commissioning Procedures
- Pre-commissioning
- Commissioning
- Start-up
- Operational Handover
- Close-out

Appendix F: Proposed Project Planning and Operations Workflows for Sub-Seabed Geologic Storage of CO_2

In the following Table F-1 and Table F-2, we present workflows for sub-seabed CO_2 storage planning and operations for GS (Table F-1) and EOR-GS (Table F-2) on the OCS.

Table F-1. Stages of CO_2 GS project planning and operations in offshore settings

Stage	Task	Purpose	Timing
A	Formulate quantitative project monitoring goals	Establish project metrics: voluntary, in response to regulation, best practice, or stakeholder-driven. Metrics define impacts that could cause the project to close prematurely. Potential impacts become risk assessment criteria (step D) and then the focus of the monitoring program.	Initial step that defines all subsequent activities.
B (see Section 3.1)	Collect quantitative site data (reservoir, confining system, interval between confining system and seafloor, and water column)—Input to monitoring program	Input into models (step D); need statistical data including uncertainty and temporal and special variability	Mostly completed prior to detailed monitoring plan design, but characterization is iterative: additional data may be needed in steps D and E. Statistical definition of noise may be needed in step H; pre-injection data may be required in step I.
C (see Section 3.3)	Establish operation plans including injection schedule—Input to monitoring program	Use data in step D, model planned injection	Initial operations plans follow shortly after development of project goals but may be modified throughout the project.

Stage	Task	Purpose	Timing
D (see Section 3.1)	Model injection effects such as evolution of reservoir zone fluid composition and pressure	Evaluate perturbation of the geosystems resulting from injection. This is the core activity for evaluating risk and drives the needs for risk assessment (step E).	Initial models follow shortly after development of project goals but may be modified throughout the project. After a model update, repetition of steps E, F, G, and H will be needed.
E (see Section 3.2)	Perform risk assessment—Input to monitoring program	Inventory and describe risks or threats that lead to potential impacts to environment or other resources.	Follows initial iteration of steps A, B, C, and D; e.g., risk mitigation can be accomplished by more characterization (B) or operations change (C). Completed in preparation for step F.
F	Inventory monitoring needs	Include activities prescribed by regulation, project team requirements, risk mitigation, and activities in response to other stakeholder needs.	Completed before initiation of monitoring
G	Model the array of risk scenarios—Input to monitoring program	Conceptualize and simulate (analytical or numerical) conditions or events that could lead to impacts. Quantify signals from geosystems that could precede or indicate containment failure. This can be highly effective under conditions where optimization is favored.	Preparation for step H, but not needed if prescribed tests are required.
H	Design monitoring program	Compare possible tools that could be used to meet monitoring needs, defined in step E, with models developed in step G. Modeling tool response[1] is used to determine if monitoring approach is adequately sensitive to the signals that precede or indicate material impact. This is the core of the monitoring program and is discussed in detail below.	Designed after initial completion of steps F and G, but plans for iteration updates and cession of activities should be included in the program.

[1] Will need to use sensitivity analyses to determine acceptable ranges of monitored parameters or action levels that are outside of acceptable ranges.

Stage	Task	Purpose	Timing
I	Conduct monitoring program during CO_2 injection operations	Conduct plans developed in step H; analyze results and report outcome.	Data collection may be a follow-on from characterization or pre-injection testing. It may also be modified in response to steps J and K, or as the project matures.
J (see Section 3.5)	Perform iterative adjustments to model inputs	Expect deviation from initial plan due to uncertain response of geosystems receiving multiphase fluids. Update model inputs and monitoring program in response to observations.	Occurs throughout project
K (see Section 3.9)	Close site	Cessation of CO_2 injection. A prolonged period of post-injection monitoring is required by some regulations or guidance frameworks. Our concept is that material uncertainties are reduced during the life of the project such that adequate certainty of secure retention is reached long before project end, and the site should be able to be closed without additional monitoring.	Closure is an initial goal supported by data collection and analysis, and modification of operations throughout the project. After injection stops, the well will be plugged and abandoned, and permission will be sought to end monitoring. Analysis of monitoring data may indicate additional data needs; e.g., to constrain the rate and geometry of plume stabilization.

Table F-2. Stages of CO_2 EOR-GS project planning and operations in offshore settings (note similarity to table in Appendix H)

Stage	Task	Purpose
A	Formulate quantitative project monitoring goals	In CO_2 EOR, the principal goal is oil recovery and efficient use of CO_2; CO_2 storage is a secondary goal. The activities will most likely be subject principally to oil and gas laws; any greenhouse gas rules will be additional.
B	Collect quantitative site data (reservoir, confining system, overburden, and water column)—Input to monitoring program	Much of the reservoir data will come from existing characterization and analysis of production history. Analysis of the confining system is greatly decreased because the trapped oil increases certainty compared with a saline site. Data on overlying zones will need to be collected. Complexities from petroleum accumulation at depth and pressure perturbations from oil production will need to be considered. Natural or introduced geochemical anomalies should be taken into account during characterization and monitoring design.
C	Establish operation plans including injection schedule—Input to risk assessment model and monitoring program.	This will include schedule of CO_2 or other fluid injection and withdrawal of produced fluids. Fluid production impacts the project through engineered control on the CO_2 plume and extent and magnitude of pressure elevation.
D	Model injection effects such as evolution of reservoir zone fluid composition and pressure	Computationally intensive modeling that represents CO_2-oil interaction may be conducted for only a representative volume of the field; the response of the whole field may be extrapolated or simplified. Examples: Bourgeois et al. (2012)
E	Perform risk assessment—Input to monitoring program	Risk profile will be adapted to CO_2-EOR. Control of CO_2 migration and pressure elevation through fluid production reduces risk. Out-of-pattern migration must be considered.
F	Inventory monitoring needs	This step similar to saline (CO_2 GS) project.
G	Model the array of risk scenarios—Input to monitoring program	This step similar to saline (CO_2 GS) project.
H	Design monitoring program	Harmonization of monitoring needs with EOR operations may provide opportunities; e.g., oil production response serves as monitoring data. Monitoring options may be limited; e.g., where wells are in production.
I	Conduct monitoring program during CO_2 injection operations	This step similar to saline project. Data on the response to CO_2 injection (incremental oil recovery) will be monitored.
J	Perform mitigation or corrective action—Input to monitoring program	This step similar to saline (CO_2 GS) project.
K	Close site	Oil resource remaining at project end may impact the long-term site management, in that the option to later bring new technologies to extract additional resource may be considered.

Appendix G: American Petroleum Institute Guides, Recommended Practices, and Standards Potentially Relevant to CO_2 EOR-GS and GS Operations

The materials listed here are seen as potentially being directly relevant to offshore carbon capture and storage (CCS) operations with little or no modification from their intended application to oil and gas operations.

RP 2A-WSD – *Planning, Designing, and Constructing Fixed Offshore Platforms, Working Stress Design*
Provides design and construction requirements for new platforms and relocation of existing platforms for drilling, development, production and storage of oil and gas in offshore areas. Included are guidelines for assessment of existing platforms when it becomes necessary (a use not originally anticipated when the structure was designed) to make a determination of "fitness for purpose" of the structure.

SPEC 5CRA, ISO 13680:2010 – *Specification for Corrosion Resistant Alloy Seamless Tubes for Use as Casing, Tubing and Coupling Stock*
Specifies the manufacturing requirements for corrosion resistant alloy seamless tubulars used in oil and gas wells. This specification does not apply to threaded connections.

SPEC 5CT – *Specification for Casing and Tubing*
Specifies the manufacturing requirements for carbon steel tubulars used in oil and gas wells. This specification can be applied to tubulars with connections not covered by API Standards.

SPEC 5L – *Specification for Line Pipe*
Specifies the manufacturing requirements for seamless and welded pipe used in oil and gas production and transportation systems.

RP 5LC – *Specification for CRA Line Pipe*
Specifies the manufacturing requirements for a variety of corrosion resistant alloy pipes used in oil and gas production and transportation systems.

SPEC 5LD – *Specification for CRA Clad or Lined Steel Pipe*
Specifies the manufacturing requirements for steel pipe with corrosion resistant alloy layer inside the pipe used in oil and gas production and transportation systems.

SPEC 6A, ISO 10423:2009 – *Specification for Wellhead and Christmas tree Equipment*
Specifies the manufacturing and performance requirements for dimensional and functional interchangeability, design, materials, testing, inspection, welding, marking, handling storage, shipment, repair and remanufacture of wellhead and Christmas tree equipment for use in oil and gas production operations.

Bull 6J – *Testing of Oilfield Elastomers*
Provides guidance on the evaluation of elastomer seal materials intended for use in oil and gas operations.

SPEC 10A, ISO 10426:2009 – Specifications for Cements and Materials for Well Cementing

Specifies requirements for six classes of well cements, including their chemical and physical requirements and procedures for physical testing.

RP 10D-2, ISO 10427:2004 – *Recommended Practice for Centralized Placement and Stop Collar Testing*
Provides calculation methods for determining centralizer spacing based on centralizer performance (see SPEC 10D) and desired standoff to improve cement placement.

TR 10TR1 – *Cement Sheath Evaluation*
Provides principles and practices regarding the evaluation and repair of primary cementation of casing strings in oil and gas wells.

SPEC 14A, ISO 10432:2004 – *Specification for Subsurface Safety Valve Equipment*
Provides the minimum acceptable material and performance requirements for subsurface safety valves.

RP 14B, ISO 10417:2004 – *Design, Installation, Repair, and Operation of Subsurface Safety Valve Systems*
Provides recommendations for configuration, installation, test, operation and documentation of subsurface safety valve systems.

RP 14C – *Analysis, Design, Installation and Testing of Basic Surface Safety Systems on Offshore Production Platforms*
Provides a standardized method to design, install and test surface safety systems on offshore production platforms.

RP 14J – *Recommended Practice for Design and Hazard Analysis for Offshore Production Facilities*
Provides recommendations on planning, designing and arranging offshore production facilities, performing hazard analyses for offshore facilities.

SPEC 16A, ISO 13533:2001 – *Specification for Drill-Through Equipment*
Provides specification for performance, design, materials, testing, inspection, welding, marking, handling, storing and shipping drill-through equipment for oil and gas drilling operations. Drill-through equipment includes:

- Ram blowout preventers
- Ram blocks, packers and seals
- Annular blowout preventers
- Hydraulic connectors
- Drilling spools
- Adapters
- Connections and clamps

SPEC 16C – *Choke and Kill Systems*
Provides specifications for functionally interchangeable surface and sub-sea choke and kill system equipment used for drilling oil and gas wells.

SPEC 16D – *Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment*
Provides specifications for BOP and Diverter control Systems.

STD 53 – *Blowout Prevention Equipment Systems for Drilling Wells*
Provides requirements for the installation and testing of blowout prevention equipment systems on land and marine drilling operations.

RP 59 – *Recommended Practice for Well Control Operations*
Provides recommended practices for safe well control operations (influx control, circulation and well kill).

RP 65-2 – *Isolating Potential Flow Zones during Well Construction*
Provides recommendations for zone isolation (primarily through cement design and placement) in wells to prevent annular pressure and/or flow through or past pressure containment barriers installed and verified during construction.

RP 68 – *Recommended Practice for Oil and Gas Well Servicing and Workover Operations Involving Hydrogen Sulfide*
Addresses personnel training, protective equipment, contingency planning and emergency procedures.

RP 75 – *Development of a Safety and Environmental Management Program for Offshore Operations and Facilities*
Provides guidance on preparing safety and environmental management programs for offshore oil and gas operation.

Appendix H: Example Approaches and Tools Proposed for Offshore Monitoring

See also reviews included in papers in Table 3-4, many of which have more detailed information than what is presented here.

Approach	Physics	Deployment	Target zone(s)	Option	Analysis	Citation
Imaging substitution of CO_2 for brine or reservoir pressure increase using seismic surveys	Change in acoustic response of a zone containing CO_2 and/or elevated pressure compared with normally pressured water-bearing zones	Receivers on streamers and sources towed by boat; receivers on cables on seafloor or buried in sediment. Permanently installed sources are also under consideration are vertical seismic profiling.	Flexible, depending on geometry of array and frequency and energy content of sources: may target reservoir, secondary accumulations in overburden (P-cable). Images free-phase CO_2	Numerous options; e.g., single surveys may image CO_2 under favorable circumstances, but detection is greatly enhanced by time-lapse measurements. 3-D surveys improve imaging over 2-D.	Processing is a major part of work flow; mature and flexible. Requires optimization for application. Large volume of data collected, delay between collection and results. Powerful data set also has significant limitations.	Sleipner: Boait et al., 2011; Williams and Chadwick et al, 2012; Snøhvit: Dasgupta, 2006; Hansen et al., 2013. Numerous onshore examples, such as White and Johnson, 2009; Kazemeini et al., 2010; Herbert et al., 2011; White, 2011, 2013; Meadows et al., 2012b. Novel use of ocean-bottom cable proposed to Tomakomai demonstration, Japan (Tanaka et al., 2014)
Quantifying substitution of CO_2 for brine using gravity difference	Supercritical or gas-phase CO_2 is lower density than brine; replacement produces a small but detectable change in gravity	Instrument is placed on seafloor monuments, time-lapse measurements with good relocation ability are essential, downhole tools available	CO_2 accumulations in reservoir or overlying zones	Evolving tool for diverse uses	Needs significant data processing	Gasperikova and Hoversten (2008) provided a theoretical assessment of sensitivity; measurements were successfully made at Sleipner: Alnes et al., 2008, 2011

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Imaging substitution of CO_2 for brine using electrical and EM methods	Conductivity of CO_2 is much lower than that of brine	Time-lapse measurements needed; limited lateral depth of investigation if deployed from wellbores	CO_2 accumulations in reservoir or overlying zones (free-phase CO_2)	Evolving and flexible technologies, using diverse electrical and magnetic tools deployed on the seafloor and in wells	Needs significant data processing	Gasperikova and Hoversten (2006) provided theoretical assessment of sensitivity. Electrical resistance tomography (ERT) deployed at two CO_2 sites onshore (Girard et al., 2011; Doetsch et al., 2013).
Detecting pressure change at depth using seafloor tilt meters	Deformation of the reservoir zone by pressure increase (CO_2 and brine) may be seen in sediments up to the seafloor	Requires repeat measurements of change over time. Seafloor-based measurements require pedestals that allow instrument relocation.	Pressure increase in reservoir or overlying zones (brine or free-phase CO_2)	Satellite-based measurements of deformation used on land are not possible in subsea settings.	Requires coupling surface deformation measurement with geomechanical model.	No offshore deployment. Strong onshore example for out-of-zone fluid leakage at In Salah, discussed by Gemmer et al. (2009); Mathieson et al. (2010). Proposed method for subsea tilt described by Sweatman et al. (2012)
Detecting CO_2 using borehole petrophysical/geo-physical methods	Substitution of CO_2 for brine with wireline-deployed instruments: pulsed neutron capture (PNC), resistivity, acoustic, or other tools that measure pore-fluid substitution	Instruments currently too expensive or too fragile to be installed in wells are lowered on wireline.	Fluid change (free-phase CO_2) in reservoir or overlying zones	Diverse technologies can be deployed on wireline. Issues such as interference (with casings) and access through horizontal well segments must be considered.	Analysis of tools response requires conversion to saturation, then additional analysis to extrapolate results away from well-based measurement point.	Widely used onshore, e.g., Sakutai et al. (2005); Freifeld et al. (2008); Al Hagray (2011); Mito and Xue (2011); Butsch et al. (2013); Dance and Datey (2015). Less commonly deployed offshore because of costs.

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Detecting CO_2 using fluid sampling and geochemical methods	Direct sampling of CO_2 confirms geophysical methods; may be most needed where CO_2 is injected into gas reservoirs.	Sampling bias is strong in multiphase fluids as they enter the wellbore and are transported through the well system. Depressurizing and reaction may alter mixed fluid chemistry as samples are brought to surface pressure and temperature. Downhole sampling devices available.	Fluid change in reservoir or overlying zones, dissolved or free-phase CO_2 can be detected.	Fluids are fractionated during migration from reservoir to wellbore. May be important to produce fresh fluids; CO_2 and hydrocarbons can self-lift; but brine may need to be pumped. Fluids may lose integrity because of separation and reaction during production from reservoir to well head. Downhole samplers are commercially available. Many of these techniques may be too costly offshore.	Sample collection and preservation must be closely coordinated with laboratory analysis, as fluids will be out of equilibrium once removed from depth. Quality control and detection thresholds at the laboratory are needed. Data analysis to interpret trend and significance may be significant.	No known offshore examples; onshore extensive study at Weyburn field (Emberley et al., 2005; Riding et al., 2005; Shevalier et al., 2005, 2013; Nightingale et al., 2009; Raistrick et al., 2009; Johnson et al., 2011; Mayer et al., 2013; Talman et al., 2013); other onshore fields (Kharaka et al., 2009; Lakeman et al., 2009; Johnson et al., 2011; Lu et al., 2012; Nowak et al., 2013) and case studies at natural analogs (Hovorka et al., 2006; Gilfillan et al., 2009)

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Detecting pressure change using gauges in wells; also thermal changes	Injection increases pressure in the reservoir interval. Buoyant migration of fluid from reservoir will increase pressure in overlying zones. Monitoring fluids in overlying zones could detect change.	The classic completion is pressure gauge installed in a well and connected by a tubing and packer system to a perforated zone; tubing-deployed instruments available.	Reservoir in injection well, distant from injection well, and in overlying zones. Impact of horizontal well should be considered.	Pressure gauges can be placed at well head, in the well at an intermediate depth, or in the perforated interval. In each case, the impact of well construction on the measurement must be considered.	Relatively direct measurement can be interpreted rather simply by trend analysis, or input into numerical models.	Zeidouni et al., 2011a, 2011b; Sun et al., 2013; thermal effect (Bielinsk et al., 2008)
Wellbore integrity testing	Wellbores provide the most direct pathways for mass transfer from reservoir to surface; however, a great deal of effort is placed into correct installation and management. Failure can be detected by anomalous pressure and temperature, noise, and anomalous fluid chemistry.	Detection of failure is straightforward if well is accessible. If the well has been plugged and abandoned, re-entry is required, which is costly; hence, effective remote methods are preferred.	With the well long string casing, within the surface-casing/long string casing annulus; or within the rock-casing annulus.	Many technologies are in regular use, for both inspection of well materials (cement and casing integrity logs and imaging, materials stability assessment using coupons) and assessment of fluid flow or fluid composition change (pressure surveillance on annuli, temperature surveillance, logs to detect fluid composition or introduced tracers)	Analysis of tool output is needed; further interpretation of results or follow-up testing may be required to reach a conclusion.	Many commercial tools in the oil field management service companies; noise-based method: Bonhoff (2010); Bonhoff and Zoback (2010); modeling the basis for thermal method: Han et al. (2010)

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Shallow sediment imaging	Because offshore settings are actively collecting sediments, near-surface sediment and fluid accumulations can be used to assess active processes.	Shallow seismic data collection tools, including the short stringer array known as the P-cable or CHIRP	Shallow sediments	Numerous tools can be used to image shallow sediments. P-cable technologies are being applied to GS sites and prospects in the North Sea and Gulf of Mexico.	Needs same type of interpretations as deeper seismic data.	Eriksen et al. (2012); Meckel et al. (2013); Skarke et al. (2014) described cold methane seeps, which may be analogous.
Seafloor imaging	The surface of the seafloor can reveal fluid release (e.g., fissures, pits, pockmarks, and mud volcanoes).	Towed along sea-surface or in water column; autonomous vehicles towing or placing instruments on seafloor or surveying seafloor from within water column	Sediment-water interface, of particular concern in some reporting requirements	Various types of sonar are most common (backscatter, multi-beam bathymetry), video with light source may produce highest resolution.	Moderate effort to reduce primary data. Images can be interpreted visually; automated approaches are available; follow-up analysis may be needed to interpret significance.	North Sea natural analog described by Heggland (1998); California oil seep example Hornafius et al. (1999); Carroll et al. (2014); Pennell et al. (2001): development of autonomous underwater vehicles; Shell (2014): Peterhead-Goldeneye project.

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Sediment geochemical sampling	Fluids that reach the sediment surface may displace ambient fluids and be detected by analysis; reaction products of introduced fluids with sediment may be important.	Sediment samples can be collected by surface- and in-water-column-deployed towed or autonomous vehicles or at shallow depths by divers	Sediment-water interface, of particular concern in some reporting requirements. Need to sample near leakage point.	Various types of samples are available from dredges to coring apparatus that preserve fluid nearly intact. The depth of sampler penetration may be important. Mature technologies available	Sample collection and preservation must be closely coordinated with laboratory analysis, as fluids and biota will be out of equilibrium once removed from depth. Laboratory quality control and detection thresholds needed. Natural variability and dynamic processes may complicate interpretations.	Laboratory tests: Caramanna et al. (2013, 2014); controlled-release experiment monitored response of geochemistry of shallow sediments (Taylor et al., 2015a; 2015b)
Sediment and seafloor biologic sampling	Biota within sediment column and at the sediment-water interface may respond to fluid leakage.	Biotic samples can be collected by surface- and in-water-column-deployed towed or autonomous vehicles or at shallow depths by divers; images can also be used.	Shallow sediment column, at the sediment-water interface, near leakage point	Approaches to assessment of biologic populations and their response to ecosystem change are diverse and mature and readily applied to assessment of leakage threats.	Analysis of the data collected may be variable, depending on type of fauna. Strong statistical approaches from biologic disciplines are available and should be deployed to extract signal related to injection from other possible trends in the ecosystem.	Black (2012); Blackford et al. (2014, 2015); laboratory tests Rodriguez-Romero et al. (2014); planned for the Shell (2014) monitoring project above Goldeneye field

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Bubble stream imaging	Gases leaking from the subsurface can form bubbles, which, in aggregate, form bubble streams that can be detected. Visual and active sonar techniques or passive detection of acoustic signals are common detection methods. Bubbles may dissolve as they migrate in the water column.	Surface-, in-water-column-, or bottom-deployed towed or autonomous vehicles, or installed instruments or can be used.	Lower part of water column, near leakage point	Visual and active sonar techniques image the bubble stream; passive acoustic methods detect the noise made by the bubbles as they form.	After signal is analyzed, significant effort is needed to attribute the signal to leakage from depth. Follow-up sampling may be needed.	McGinnis et al. (2011) studied a North Sea natural analog CO_2 seep. Sellami et al. (2015) used videos of a controlled release at the QICS project to validate models of bubble behavior. See also Blackford et al. (2015).

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Seawater geochemistry	Leaking fluids may contain dissolved CO_2, or CO_2 bubbles may be dissolved in the water column.	Seawater samples can be collected by surface- and in-water column deployed towed or autonomous vehicles or at shallow depths by divers.	Water column, with strongest signal close to leakage point		Sample collection and preservation must be closely coordinated with laboratory analysis, as fluids will be out of equilibrium once removed from depth. Quality control and detection thresholds at the laboratory are needed. Data analysis to interpret trend and significance may be important.	Annunziatellis et al. (2009) reported on studies of natural analog sites in the Gulf of Trieste; Dunk et al. (2005); instrumental options are discussed by Shitashama et al. (2013).
Seawater biologic sampling	Biota within the seawater column may respond to fluid leakage.	Biotic samples can be collected by surface- and in-water colum deployed towed or autonomous vehicles or at shallow depths by divers; images can also be used.	In the water column near leakage point. Strong attenuation by mixing may make this a localized or transient response.	Approaches to assessment of biologic populations and their response to ecosystem change are diverse and mature and readily applied to assessment of leakage threats.	Data analysis may depend on type of fauna. Statistical approaches from biologic disciplines are available and should be deployed to extract injection signal from other possible trends in the ecosystem.	

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