# BRIDGING THE GAP:

## AN ANALYSIS AND COMPARISON OF LEGAL AND REGULATORY FRAMEWORKS FOR $CO_2$–EOR AND $CO_2$–CCS

**A REPORT TO THE GLOBAL CCS INSTITUTE**

OCTOBER 2013

GLOBALCCSINSTITUTE.COM

**DISCLAIMER**

This research paper was prepared for the Global Carbon Capture and Storage (CCS) Institute. The views expressed herein are the personal views of the author. The report makes use of information gathered from a variety of sources that is believed to be accurate, but the author gives no representation or warranty as to the accuracy or completeness of the information or conclusions provided herein and specifically disclaims all implied warranties including, but not limited to, the implied warranties of merchantable quality or fitness for a particular purpose. In particular, the author states that the report is intended to provide a general overview only of the legal and regulatory frameworks governing $CO_2$–EOR operations and non-EOR related $CO_2$ transport and storage in selected jurisdictions, and does not constitute legal advice.

The research was completed in June 2012, but has been selectively updated through to 19 September 2013.

Paper prepared by:

Philip M. Marston, Esq.
Marston Law
Alexandria VA 22314
+1 703–548–0154
www.marstonlaw.com

**ACKNOWLEDGEMENTS**

The author gratefully acknowledges the review and comments of all those that he has spoken with in the preparation of the paper. Ian Havercroft of the Global CCS Institute was instrumental in setting the terms of reference for the project and providing guidance and comment throughout the process. The Institute's Tom Russial provided valuable review as the paper moved to completion. In addition, the author has benefited from comments from many experts in the US, Canada and Europe that he contacted on various broad or narrow issues. The author gives particular thanks to Sean McCoy of the International Energy Agency, Bruce Kobelski of the US Environmental Agency, Prof. Richard Macrory and Chiara Armeni of University College London's Carbon Capture Legal Programme, Prof. Owen Anderson of the University of Oklahoma College of Law, Prof. Martha M. Roggenkamp of the University of Groeningen, Jason Golder of The Crown Estate, Steve Melzer of Melzer Consulting, Cecilia A. Low, and Patricia Moore of Denbury Resources, Inc. Errors or omissions remaining in the final work are, of course, the responsibility of the author.

# Contents

## PART III

## LIST OF FIGURES



## LIST OF TABLES



## APPENDIXES

# INTRODUCTION

A

# The Two Cultures: Bridging the gap

> The clashing point of two subjects, two disciplines, two cultures—of two galaxies so far as that goes—ought to produce creative chances. In the history of mental activity that has been where some of the break-throughs came. The chances are there now. But they are there, as it were, in a vacuum, because those in the two cultures can't talk to each other.
>
> **C. P. Snow, The Two Cultures**[1]

C.P. Snow was a British physicist and man of letters in the mid-20th century. In the aftermath of the Second World War, he penned a remarkable essay, *The Two Cultures*, in which he lamented the separation that had arisen between the scientific and the literary cultures of his time.[2] For Snow, these had become distinct and essentially parallel universes with little communication between them. He viewed this as a loss for both, and indeed as posing a risk to the formation of sound public policy on a host of issues.

Today, one sees a somewhat analogous cultural and knowledge gap between those focused on the injection and incidental storage of large quantities of carbon dioxide ($CO_2$) in subsurface geologic formations during enhanced oil recovery (EOR) operations and those focused on the injection and storage component of carbon capture and storage (CCS) for the primary purpose of reducing $CO_2$ emissions released into the atmosphere. Bridging this knowledge and communication gap is particularly important, however, in assessing the potential for integrating supplies of captured anthropogenic $CO_2$ into profitable EOR operations as one part of a long-term strategy for developing widespread deployment of CCS technology.

This paper seeks to assist policymakers in evaluating that option.

- **Part I** reviews the existing legal and regulatory frameworks governing $CO_2$ transactions, transport, injection and storage in the context of EOR operations. The focus is on the United States (US) and Canada, because those are the jurisdictions where the great bulk of $CO_2$–based EOR operations (including injections in the US of more than 800 million tonnes of $CO_2$) have taken place over the past 40 years. These are the jurisdictions where the legal and regulatory framework for this activity is most fully developed. Part I also reviews briefly some of the important aspects of the underlying legal rules in the European Union (EU) upon which a CCS–based framework is in the process of being overlaid. The approach is *thematic* in that the discussion reviews the applicable legal or regulatory framework that governs the $CO_2$ component of each of the major aspects of a $CO_2$–EOR operation: commercial purchase and sale of the $CO_2$; acquisition of the subsurface property rights needed for injection; transportation via pipeline (including acquiring right of way for pipeline construction); injection and well closure.
- **Part II** reviews the changes to this existing EOR–based framework that are in various stages of adoption in order to allow for CCS–based storage. This section reviews the EU's Carbon Capture and Storage Directive (EU CCS Directive), which is perhaps the single most comprehensive, standalone legislative framework in the world today for $CO_2$ storage in the context of CCS activities. The CCS Directive applies exclusively to storage of $CO_2$ that is *captured from an emission source* and injected *for disposal* in the subsurface. The section then reviews the recent changes in the US and Canada (principally in Alberta) that are aimed largely at allowing supplies of captured, anthropogenic $CO_2$ to supplement—and eventually substitute for—naturally occurring $CO_2$ in EOR operations. As with Part I, the approach is thematic and follows the changes as they apply to $CO_2$ at each of the principal steps of the $CO_2$–CCS storage operation.

1 C. P. Snow, *The Two Cultures* (2nd ed. 1960), Cambridge University Press, 1998, at 16.

2 *Id.*

- **Part III** builds on these two prior sections to summarise issues that need to be addressed, and to set forth conclusions and recommendations for steps that may be taken by jurisdictions looking to harness the potential value of $CO_2$–based EOR as part of a long-term strategy of using CCS technology as an emissions reduction tool.

The principal barrier to capturing $CO_2$ from combustion and many other industrial sources, of course, is the cost of deploying the capture technology. Hence, a great deal of discussion among policymakers and commentators has focused on addressing this issue through various incentive mechanisms (e.g. imposing a carbon emissions price, creating feed-in tariffs for sale of electricity produced by low–emissions generation, government co-funding of demonstration projects, etc,). While these issues are of fundamental importance to the ultimate viability of CCS as a policy option for reducing atmospheric emissions of $CO_2$, they are not discussed here because this paper is limited to discussing the legal and regulatory frameworks only, not potential funding mechanisms to encourage deployment of capture technology. The funding or incentive mechanisms are mentioned only to the limited extent of how the regulatory framework may affect qualification under the funding mechanisms (e.g. qualification of $CO_2$ as 'not emitted' under the EU's Emissions Trading System (ETS), requirements to demonstrate quantity of $CO_2$ stored under government funding documents, etc.).

B

# Brief overview of the regulatory models

The legal and regulatory frameworks for $CO_2$–EOR and $CO_2$–CCS operations present two quite different models. The $CO_2$–EOR model is commercially–based and anchored principally in oil and gas law and regulation. It presupposes that $CO_2$ is one input among many in a chain of activities aimed at producing valuable oil. The model contemplates that the $CO_2$ may be injected and re-used multiple times. In contrast, the $CO_2$–CCS model is based on the premise that $CO_2$ is a waste to be injected a single time for permanent disposal and so is based largely on regulatory models for managing industrial wastes (including hazardous wastes). These two contrasting models might thus be summarised as follows.

### $CO_2$–based EOR—the commercial oil and gas model

This is the current regime for $CO_2$–based EOR operations in the US and Canada, as it has evolved with the industry over the past four decades. Geologic storage of the injected $CO_2$ is a necessary incident of hydrocarbon recovery operations (according to industry estimates, storing in excess of 95 per cent of $CO_2$ supplied to the site—more than 99.99 per cent for some operations), but is not itself an objective. The regulatory model is built on a hoary foundation of the law governing real property, the commercial law governing the exchange of goods and services, and the regulatory framework governing drilling for and producing oil, natural gas and other minerals, as well as land use generally. With a few recent additions, this existing template addresses the principal legal and regulatory questions raised by the injection of large quantities of $CO_2$ into subsurface geologic formations for use in EOR operations. Standards for maintaining storage integrity are largely comparable to industry standards that have developed over the past century for the underground storage of $CH_4$ (*i.e.* natural gas). This framework includes rules governing:

a. the acquisition of necessary rights to subsurface pore space and ownership of the injected CO2;
b. siting and regulation of $CO_2$ pipelines, as well as standards for safe construction and operation;
c. a permitting regime for drilling and production operations (including injection of various fluids that will remain in subsurface formations following oil or gas production); and
d. liability of parties conducting the operations and arrangements for post-closure stewardship that are not as broad as current geologic storage regimes.

This legal and regulatory regime exists to a large degree in all jurisdictions with relatively mature oil and gas production operations, even where there are no $CO_2$–based EOR operations that presently make use of it. Because the purpose of the $CO_2$ injections is to produce oil and the storage that occurs is an incident of oil recovery operations rather than an end in itself, there has traditionally been no need to develop standards for measuring, verifying or monitoring the $CO_2$ injections or for reporting such data on a standardised basis to verify permanence.

### CCS–based $CO_2$ injections and storage—the waste disposal model

In $CO_2$–CCS operations, the object is to ensure reductions in the amount of anthropogenic $CO_2$ emitted into the atmosphere. The presumption is that each molecule of captured $CO_2$ will be injected a single time for permanent disposal. The legal and regulatory regimes for such storage operations are still in their infancy or under development, but are progressing rapidly. The principal components are based, to a significant degree, on pre-existing waste disposal regulations, including regimes governing disposal of hazardous waste. Because there is no withdrawal of reservoir fluids to provide a pressure equalising function comparable to that provided during $CO_2$–EOR operations, there is more of a concern with subsurface pressure–related issues (including plume migration) than in the $CO_2$–EOR model. The standards adopted or being considered for adoption are, or may be, considerably more prescriptive and extensive than those applied to otherwise comparable $CO_2$ injections in EOR operations.

The $CO_2$–based EOR model is reviewed in Part I, while the emerging $CO_2$–CCS frameworks are the subject of Part II.

## TERMINOLOGY

**A-$CO_2$ and N-$CO_2$:** The treatment of a $CO_2$ stream under the law may differ based on whether it is naturally occurring or has been captured from an anthropogenic emission source, even where the chemical content is essentially identical. To make the distinction, this paper refers to naturally occurring $CO_2$ as 'N-$CO_2$' and to $CO_2$ captured from an anthropogenic emissions source as 'A-$CO_2$'. Thus, $CO_2$ that is captured from a facility where it would otherwise be vented to the atmosphere (such as a coal-to-methane or coal-to-liquids facility, a natural gas processing plant or an electricity generating plant) is designated here as A-$CO_2$. $CO_2$ that is produced from a geologic source that does not include commercial quantities of other gases (such as the geologic 'domes' that supply the bulk of naturally occurring $CO_2$ in the US) is designated 'N-$CO_2$'. About 75 to 80 per cent of $CO_2$ used in EOR operations in North America is N-$CO_2$.

**Source versus composition of a $CO_2$ stream:** The terms A-$CO_2$ and N-$CO_2$ are used here to distinguish between *sources* of a $CO_2$ stream, not to mark differences in chemical *composition* (such as the presence of combustion by-products produced by burning coal). The issues raised by variations in the chemical composition of particular $CO_2$ streams are addressed separately, in the discussion of specifications for composition of $CO_2$ streams.

**Natural gas does not include $CO_2$:** In some legal contexts, in both the US and Canada, the term 'natural gas' includes $CO_2$ while in others it does not. Clarity is important because naturally occurring minerals are rarely found in pure accumulations. A raw production steam produced to obtain CH4 (methane, the principal component of what is commonly called 'natural gas') may also include other naturally occurring gases, including $CO_2$, helium (He), nitrogen ($N_2$), hydrogen sulphide ($H_2S$), and various liquid or liquefiable hydrocarbons. For purposes of clarity, this paper uses the term 'natural gas' to refer only to a hydrocarbon heating gas, the principal component of which is CH4.

**CCS, CCUS, $CO_2$–EOR and $E^2R$:** CCS has become widely used to refer to capture and geologic storage of $CO_2$ acquired from various anthropogenic emissions sources. $CO_2$–EOR refers to the enhanced oil recovery technique of injecting $CO_2$ into an oil producing formation, a process by which additional oil is extracted from the reservoir while the injected $CO_2$ is effectively geologically stored as an incidental part of the oil recovery process. Where N-$CO_2$ is used in $CO_2$–EOR there is no reduction in emissions. Where A-$CO_2$ is used, however, it is effectively stored, as is the case with CCS. To distinguish the latter case, the term 'E2R' (E two R) has been suggested to designate specifically the use of A-$CO_2$ in EOR operations that results in geologic storage of the $CO_2$. Alternatively, the term 'CCUS' has begun to be used to designate carbon capture utilisation and storage. CCUS includes the use of A-$CO_2$ in EOR operations, but also includes other potential beneficial uses of captured $CO_2$.

# LEGAL AND REGULATORY REGIMES GOVERNING INJECTION *and* STORAGE OF $CO_2$ IN EOR OPERATIONS

PART I

Active $CO_2$–EOR operations to date have been conducted principally in the US and (to a much lesser extent) in Canada (although $CO_2$–EOR has also been practiced for several decades in Turkey[3] and Hungary,[4] and new projects are under various stages of development in Asia,[5] the Middle East[6] and the North Sea[7]). Accordingly, this section will focus in depth on the legal and regulatory rules in the North American jurisdictions, with some observations about salient aspects of the legal regimes in other jurisdictions as they would relate to $CO_2$–EOR operations in general. The approach here will be to examine the rules governing the principal stages of a $CO_2$–EOR operation, from acquisition and sale of the $CO_2$ supply through to well closure.

- **Acquiring a supply of $CO_2$: basic commercial law governing the exchange of goods and services:**

  This is the body of law that governs the purchase and sale of $CO_2$, whether it is severed from the real estate (in the case of N-$CO_2$)[8] or captured by an emissions source (in the case of A-$CO_2$). Commercial law also governs the off-take service provided to the capture source via a receiving pipeline.

- **Transporting the $CO_2$ supply to market:**

  Regulation of pipeline siting, construction and operation, including federal and state safety regulation and state regulation of pipeline access.

- **Acquiring and managing the property rights to the oil–bearing formation and preserving ownership of the $CO_2$:**

  This is the law of real property, including the special rules governing the division, conveyancing and management of mineral interests and the interrelationships of the various ownership interests (including subsurface trespass and rules setting priorities where these ownership interests may come into conflict).

- **Authorisation to drill wells and inject $CO_2$ and to manage obligations to protect public health and safety (including protections for underground sources of drinking water):**

  This is the body of regulation governing permitting of drilling and allowing injection of fluids to produce oil and to ensure the protection of health and safety. It includes rules governing liability for damage and requirements for financial reasonability to cover compensation for damage and costs of remediation.

- **Authorisation to plug and abandon injection and production wells and post-closure liability:**

  These are the rules governing how an operator obtains permission to effectively close an EOR operation by plugging and abandoning the various injection and production wells. These rules also govern release of financial security posted for such wells, and post-abandonment liability for any subsequent remediation steps that may be required.

Any jurisdiction with oil and gas operations that has well developed bodies of general law governing commercial transactions, pipeline transportation, oil and gas (or mining) codes, and environmental legislation already has much of the basic framework that could apply to $CO_2$–EOR, just as it applies to injection of other common injectates during oil and gas production operations.

---

3 This is the Bati Raman and related projects, where $CO_2$–EOR operations began in the mid-1980s.

4 See S. Doleschall, A. Szittar and G. Udvardi, *Review of the 30 Years' Experience of the $CO_2$ Enhanced Oil Recovery Projects in Hungary* (SPE-22362). Paper presented at a Society of Petroleum Engineers' International Meeting on Petroleum Engineering, Beijing, China, 24–27 March 1992.

5 See e.g. proposed CDM Methodology, reference # NM0167, *The White Tiger Oil Field Carbon Capture and Storage (CCS) project in Vietnam,* originally submitted 3 September 2005, (<http://cdm.unfccc.int/methodologies/PAmethodologies/pnm/byref/NM0167>) (viewed 17 January 2012) (storage of anthropogenic $CO_2$ in an oil reservoir off the coast of Vietnam, involving collection of $CO_2$ from combined cycle natural gas power plants and transport via a 144 km pipeline to the injection site at White Tiger Oil Field to result in net storage of approximately 30,000 t $CO_2$/day (9,000 t $CO_2$/day for phase 1 and 21,000 t $CO_2$/day for phase 2) and the recovery of an average of 50,000 barrels of crude oil per day with $CO_2$ exiting with the recovered oil to be separated and re-injected into the oil reservoir).

6 See e.g. projects proposed by Hydrogen Power (<http://www.globalccsinstitute.com/projects/16611>); Emirates Steel (<http://www.globalccsinstitute.com/projects/12711>); and Emirates Aluminum (<http://www.globalccsinstitute.com/projects/12716>).

7 See, e.g. 2Co Energy's Don Valley project (<http://www.globalccsinstitute.com/projects/12496>). See also 2Co Energy, Press Release, *2Co Energy's Model for a Successful UK Carbon Capture and Storage Project* (CCS project linked with EOR proposal in North Sea that would significantly reduce net cost) (<http://www.2coenergy.com/download.aspx?file=2Co_Energy_winning_business_model_for_successful_UK_CCS_project.pdf>) (viewed 17 January 2012).

8 Under the Uniform Commercial Code (UCC), as adopted by each of the 50 US states, transactions in 'goods', as that term is there defined, are governed by Article II of the UCC while transactions in "services" are left under other applicable law. Prevailing commercial practice in the US today is to structure agreements to receive A- $CO_2$ from a capture source as a service agreement (known as an 'off-take agreement'), rather than as a transaction in goods subject to the UCC.

A

# United States

## SUMMARY OF US $CO_2$–EOR FRAMEWORK

**State law and regulation**

State law governs most aspects of $CO_2$ injection and storage in EOR operations, including:

- purchase and sale of $CO_2$ are subject to general commercial law (for sale of produced $CO_2$ or off-take from to-be-constructed facilities) or real estate law (for mineral lease or sale of geologic reserves of $CO_2$ in the ground)
- pipeline construction and acquisition of needed rights of way
- oil and gas law and regulation by state oil and gas regulators that govern acquisition of property rights and landowner consents for subsurface injections during oil and gas operations (including the aggregation of rights into larger units), as well as financial security for compliance and liability for any damage caused by drilling and production operations.

**Federal regulation**

Federal regulation, while largely administered by the states, governs the design and construction standards of $CO_2$ pipelines and ensures protection of underground sources of drinking water.

- Safety standards for pipeline construction and operation are promulgated by the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA).
- Minimum standards for protection of subsurface drinking water are generally administered by the states via Class II well standards per the Underground Injection Control program promulgated by the Environmental Protection Agency (EPA).
- Standardised reporting of $CO_2$ production began in 2010 (per Subpart PP of EPA reporting rules), and reporting of $CO_2$ injections and emissions began in 2012 (per Subparts UU, RR and W of the EPA's rules).

When we talk about EOR we have to think about it as a sequestration tool, and when we think about sequestration we have to look at the business case.

**C. McConnell, former Assistant Secretary, US Department of Energy**

## 1 The US $CO_2$–EOR experience

### a. OVERVIEW

$CO_2$–EOR operations in North America comprise an active and growing industry that has been developing for more than 40 years. Recent annual injections have been estimated to run as high as 65 million tonnes per year[9] injected via more than 7,200 $CO_2$ injection wells.[10] By 2012, cumulative net injections in the US since $CO_2$–EOR operations began in the 1970s had reached 800 to 900 million tonnes.[11] The annual production rate for $CO_2$–EOR operations had reached more than 128 million barrels of oil[12] with an annual market value in the range of US$9 billion to nearly US$13 billion (assuming oil prices of US$80–100 per barrel). $CO_2$–EOR production now accounts for more than six per cent of total US domestic oil production, a fivefold increase since 1988.[13]

By 2011, cumulative oil production due to the injection and incidental storage $CO_2$ had totaled around 1.5 billion to 1.6 billion barrels, with production levels running in excess of 100 million barrels per year.[14] While oil prices have varied immensely over the past 40 years, at today's prices of US$80–100 per barrel this would represent an aggregate market value in the order of US$120–160 billion. Although these numbers are large by themselves, a June 2011 study conducted for the US Department of Energy (DOE) estimated that over the next 20 years oil production from $CO_2$–EOR could increase by more than an order of magnitude—to as much as four million barrels a day—if adequate supplies of low–cost $CO_2$ were available and if "'next generation' EOR techniques were broadly applied.[15]

Because of its role in this significant value chain, the use of $CO_2$ in EOR operations is viewed increasingly as the most likely transition pathway for encouraging commercial deployment of CCS technology.[16] The increasingly widespread recognition of the role of EOR is reflected in the wider use of the term 'CCUS' for carbon capture *utilisation* and storage, which is generally understood to include all beneficial uses of captured $CO_2$, including EOR.[17]

9 MIT, *Role of Enhanced Oil Recovery in Accelerating the Deployment of Carbon Capture and Sequestration: An MIT Energy Initiative and Bureau of Economic Geology. UT Austin Symposium* (23 July 2010) (available at <http://web.mit.edu/mitei/research/reports/110510_EOR_Report.pdf> [20 October 2011] (hereafter '*MIT $CO_2$–EOR Report*'). See also Report of the Interagency Task Force on Carbon Capture and Storage (August 2010) (hereafter '*White House CCS Task Force Report*'), at 39 (estimating around 50 million tonnes per year).

10 *2012 Worldwide EOR Survey*, Oil & Gas Journal, vol. 110, number 4 (2 April 2012) (Table C).

11 US National Energy Technology Laboratory (NETL), *Carbon Dioxide Enhanced Oil Recovery: Untapped Domestic Energy Supply and Long Term Carbon Storage Solution* (March 2010) (<http://www.netl.doe.gov/technologies/oil-gas/publications/EP/small_CO2_EOR_Primer.pdf>), at 13 (chart showing US $CO_2$ EOR production from 1972 to 2008). Injections had reached about 600 million tonnes by the end of 2006. James P. Meyer PhD., *Summary of Carbon Dioxide Enhanced Oil Recovery ($CO_2$EOR) Injection Well Technology* (prepared for the American Petroleum Institute), at 6 (available from the US Ground Water Protection Council at: <http://www.gwpc.org/e-library/documents/co2/API%20CO2%20Report.pdf>). Based on reported production of oil from $CO_2$–EOR operations since that time and on estimates of the amount of $CO_2$ that this level of oil production required, Dr Meyer has suggested that the cumulative quantity by 2011 might range from 800 to 905 million metric tonnes with a reasonable mean estimate of 825 million (correspondence with author).With adoption of $CO_2$ reporting by the US EPA under Subpart PP of the greenhouse gas reporting rules, systematic data on $CO_2$ supply is beginning to become available as of 2011. The initial public reports by Subpart PP respondents (not including various gas processing plants or the North Dakota coal gasification plant) indicate 48.4 million metric tonnes were produced and supplied to market in 2010. See <http://epa.gov/climatechange/emissions/ghgdata/index.html>. (viewed 15 January 2012). Assuming this figure for N-$CO_2$ supply continues to represent about 80 per cent of the US $CO_2$ supply, it would suggest a total $CO_2$ supply estimate for 2010 of about 60.5 million tonnes, the bulk of which would have been injected for EOR.

12 *2012 Worldwide EOR Survey*, *supra*, at 56 (daily $CO_2$–EOR production of 352,221 bbl/d, or more than 128 million bbl/year).

13 *Id.* For total US domestic oil production data for 2011 of 5,673,000 bbl, see US Energy Information Administration (<http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm>). Some published estimates for $CO_2$–EOR production have apparently erroneously included *non*-$CO_2$ based EOR production volumes (e.g. EOR operations using steam or thermal operations). The figures used here are based solely on reported $CO_2$–EOR production.

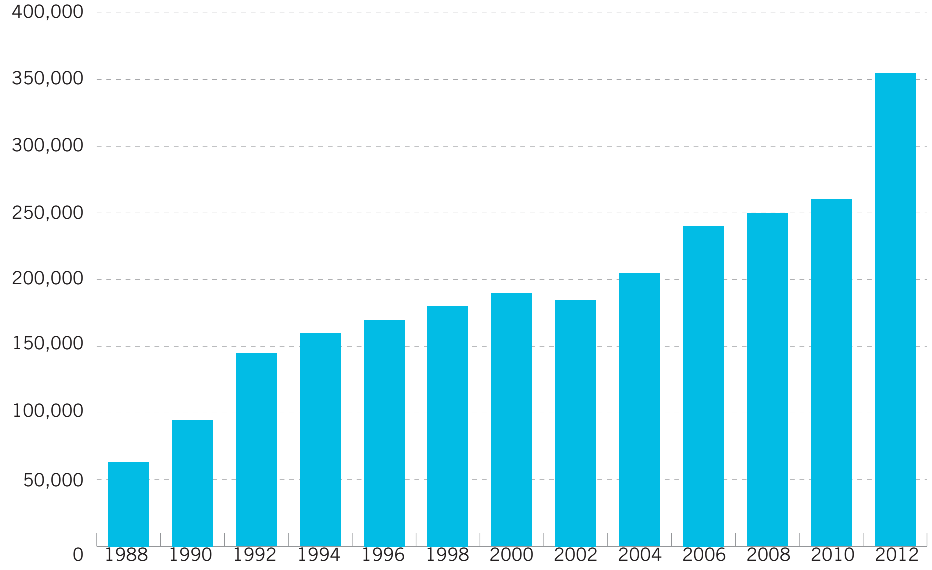
14 Melzer, '*Emergence Of Residual Zones, Price And Supply Factors Usher In New Day In $CO_2$–EOR*', American Oil and Gas Reporter (February 2011).

15 Vello A. Kuuskraa, Tyler Van Leeuwen, and Matt Wallace, *'Improving Domestic Energy Security and Lowering $CO_2$ Emissions with 'Next Generation' $CO_2$–Enhanced Oil Recovery ($CO_2$–EOR)'* (20 June 2011 (sponsored by US DOE/National Energy Technology Laboratory (NETL) and prepared by Advanced Resources International (ARI)) (available at <http://www.netl.doe.gov/energy-analyses/pubs/NextGen_CO2_EOR_06142011.pdf>) (viewed 28 January 2012).

16 *White House CCS Task Force Report*, *supra*, at 88–89 (showing EOR as target formation of large majority of DOE CCS Demonstration projects) and C–3.

17 In a 'Think Piece' published by University College London's Carbon Capture Legal Programme, the term '$E^2R$' has also been suggested to designate very specifically the use and incidental storage of captured, anthropogenic $CO_2$ in EOR operations. See Philip Marston, *From EOR to $E^2R$: Sequestering $CO_2$ while reducing dependence on imported oil* (May 2011) (published online only at: http://blogs.ucl.ac.uk/law-environment/files/2012/12/Think-piece-1-Marston.pdf ).

**FIGURE 1: Total US oil production for $CO_2$–EOR (bbl/d)**




About 80 per cent of the current $CO_2$ supply in the US comes from naturally occurring geologic sources of high purity $CO_2$ (above 90 per cent $CO_2$). The remaining 20 per cent is captured from emissions that would otherwise be vented to the atmosphere, including coal-to-natural gas and ammonia production, as well as natural gas separation and processing operations. It is interesting to note that when the US $CO_2$–EOR industry began in the early 1970s, *all* of the $CO_2$ was A-$CO_2$ captured from oil and gas processing operations. It was only after the production techniques had been proven with A-$CO_2$ that the industry sought out larger quantities of lower–cost $CO_2$ from naturally occurring sources of high quality $CO_2$. The long-lived nature of $CO_2$–EOR operations is illustrated by the fact that the $CO_2$–EOR production projects initiated in 1972 are apparently still in operation.

Reflecting the large scale of these commercial operations, a contractual and regulatory framework for $CO_2$–EOR operations has been developed by commercial law practitioners, multiple court decisions, regulators and legislation, the great majority of which has occurred at the state level. The property law governing $CO_2$–EOR operations is built on a legal foundation of oil and gas law that began developing with the drilling of the world's first oil well in 1859, and the birth in 1915 (in Canada) of geologic storage of $CH_4$ (*i.e.* methane, the principal component of natural gas).[18] In this world of EOR operations, injected $CO_2$ is merely one among a number of substances, including drilling 'mud', saltwater, polymers, additives, gases or fluids, that may be injected during drilling and production operations. Some are largely chemically inert (such as nitrogen or $N_2$), while others may be highly inflammable (such as methane ($CH_4$)), or corrosive (such as 'acid' or 'sour' gas streams that contain significant amounts of hydrogen sulphide ($H_2S$) as well as $CO_2$ and $CH_4$).[19]

Where it is not feasible or economic to deliver natural gas to a market, the natural gas produced with oil may be separated and then re-injected for pressure maintenance purposes. These natural gas streams may be principally $CH_4$, (methane), but are likely to include various other substances including nitrogen ($N_2$) and oxygen ($O_2$). Re-injected streams may also include the raw mix of liquid or liquefiable hydrocarbons where it is not economic to process the liquids from the natural gas stream to produce specification products such as propane ($C_2H_6$), butane ($C_4H_{10}$), and ethane ($C_3H_8$). For example, because there is no natural gas pipeline from the giant Prudhoe Bay field in northern Alaska, the operator there has for roughly four decades re-injected into the formation the natural gas separated from the oil.[20] A similar lack of natural

18 Federal Energy Regulatory Commission Staff Report, *Current State of and Issues Concerning Underground Natural Gas Storage* (30 September 2004), (issued in Docket No. AD04–11), at 4 (<http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=10265996>) (viewed 3 January 2012) (citing an underground storage operation in Ontario, Canada). See also 'Underground gas storage: worldwide experiences and future development in the UK and Europe' (Geological Society of London, Special Publication 313) (2009) (ed. D. J. Evans and R.A. Chadwick). For the history of underground storage, see Hans Plaat, 'Underground Gas Storage: Why and How', in Evans, at 25. See esp. discussion at 31–32.

19 Sam Wong, David Keith, Edward Wichert, Bill Gunter and Tom McCann, *Economics Of Acid Gas Reinjection: An Innovative $CO_2$ Storage Opportunity*, (vol. II of Gale, J. and Y. Kaya (eds) (2003) *Proceedings of the 6th International Conference on Greenhouse Gas Control Technologies,* 1–4 October 2002, Kyoto, Japan (Pergamon, New York) at 1661–1666 (paper available at <http://people.ucalgary.ca/~keith/papers/56.Wong.2003.EconomicsOfAcidGasReinjection.e.pdf>) (referencing 38 acid gas reinjection projects operating in Alberta, Canada, in 2002).

20 While proposals to build an Alaskan natural gas pipeline transportation system have been discussed and debated since the 1970s, none has been able to overcome concerns over the cost of the project and marketability of the natural gas. As a result, the natural gas continues to be re-injected into the subsurface.

gas pipeline infrastructure in some North Sea locations has led to the re-injection of natural gas (with added liquids or liquefiables) as the miscibility agent in an EOR operation at the Magnus Field.[21]

It is thus not surprising that a noted oil and gas law professor has concluded:[22]

> *That $CO_2$ is also injected for sequestration should be no different than injecting saltwater for EOR. When saltwater is injected, either partially or wholly for EOR or disposal purposes, permanent sequestration of the saltwater is contemplated, although, potentially, the saltwater could be withdrawn for use in another EOR project. The same would hold true with $CO_2$.*

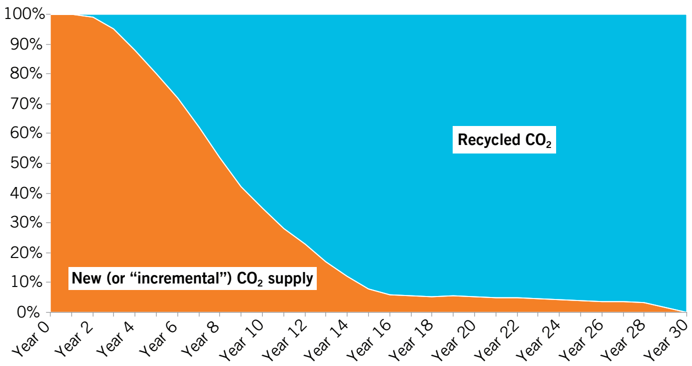
In addition, oil and gas are merely two of the native mineral resources that may be found in the subsurface formations into which $CO_2$ may be injected. Other valuable minerals may include salt and sulphur, sometimes separated from hydrogen sulphide gas ($H_2S$), that may occur separately or in combination with $CH_4$ and $CO_2$. Geothermal energy is another valuable resource that may be present in some cases and has begun to receive express legislative protection as well (as discussed in Part II).

In sum, the existing legal and regulatory frameworks governing $CO_2$ injections in EOR operations reflect the fact that *the subsurface is a complex world with multiple potential—and potentially competing—uses and with multiple ownership rights*. It is a world in which $CO_2$ is only one of various common injectates in oil and gas production operations. With regard to $CO_2$ injections, for example, operators may be more concerned with preserving good and clear title in the injected $CO_2$ than addressing the at-times metaphysical question of 'who owns the pore space?' (as discussed in Part II).[23]

## b. THE INCIDENTAL STORAGE OF $CO_2$ DURING EOR OPERATIONS (ALSO CALLED 'CONCURRENT' OR 'SIMULTANEOUS' STORAGE)

During $CO_2$–EOR operations, $CO_2$ accumulates in the oil–bearing formation during the injection and recycling of $CO_2$ in the production phase of an EOR operation. In normal operations, much of the $CO_2$ that is injected is mixed with the oil and other formation fluids (e.g. brine) and brought to the surface, where it is separated, dehydrated and then re-injected. On average, injections over the life of a $CO_2$ EOR operation total several times the quantity of $CO_2$ supplied to the site. This general pattern of recycled $CO_2$ gradually replacing new supplies of $CO_2$ at an EOR operation is illustrated in Figure 2.

**FIGURE 2: Illustrative ratio of new versus recycled $CO_2$ in EOR operations**




**Source:** Marston, *When once is not enough: Accounting for $CO_2$ recycling in EOR operations,* Greenhouse Gases: Science and Technology, Volume 1, Issue 4, pp. 320–323 (December 2011).

21 Project summary for Magnus EOR, UK in *Offshore Technology* (<http://www.offshore-technology.com/projects/magnus/>) (viewed 23 January 2012). See also Asset Portfolio: Magnus (<http://www.bp.com/liveassets/bp_internet/globalbp/STAGING/global_assets/downloads/U/uk_asset_magnus.pdf>) (viewed 23 January 2012).

22 Owen L. Anderson, *Geologic $CO_2$ Sequestration: Who Owns the Pore Space?*, 9 Wyo. L. Rev. 97, 102 (2009).

23 Many of the questions relating to 'who owns the pore space' can be avoided as a practical matter by simply negotiating the rights to use the pore space from all the relevant potential owners to the extent of their ownership without having to determine the precise boundaries thereof. The more pressing concern for the $CO_2$ injection project developer in the EOR context is preserving ownership of the $CO_2$ itself.

Except for very small amounts of fugitive emissions that may occur at joints and seals of the aboveground equipment or elsewhere in the injection and recycling process, essentially all of the injected $CO_2$ remains in the closed loop of the EOR–producing formation and the aboveground $CO_2$ handling facilities. Hence, the $CO_2$ is ultimately stored in the oil–producing formation unless it is extracted by the operator for use at another site.[24] The quantities of $CO_2$ retained in the reservoir at the end of an operation include both that portion of the $CO_2$ that has dissolved with immobile oil in the reservoir and cannot be recovered through normal producing operations as well as that portion that can (at least in principle) be recovered through a producing well, but is otherwise confined in the subsurface below the impermeable layers of superposing rock. Of course, where the $CO_2$ injected is N-$CO_2$, there is no reduction in atmospheric emissions because the $CO_2$ is simply transferred from one subsurface formation to another. Where $CO_2$ captured from an emissions source is injected for EOR, however, emissions are reduced as the captured $CO_2$ is isolated from the atmosphere in the oil–producing formation. Finally, where a *commingled stream* of both N-$CO_2$ and A-$CO_2$ is injected, the accounting protocols need to account for the relative proportions to ensure credit for storing the quantities of A-$CO_2$ without accidentally including the N-$CO_2$ present in the commingled stream. This point is addressed in Part III.

In the past, there has been no need to measure, verify or account for the $CO_2$ stored during such operations. Accordingly, there are apparently no industry wide data documenting these different categories of injected $CO_2$. Similarly, there has not been a mechanism for recognising the very large quantities of $CO_2$ that have been incidentally stored during EOR operations. The new regulatory certification procedures for incidental storage of A-$CO_2$ during EOR operations that are beginning to be adopted by US states are laying a regulatory foundation for addressing this issue. In addition, the federal reporting system being implemented by the US EPA is expected to begin providing industry wide data tracking these $CO_2$ flows.

An additional distinquishing aspect of $CO_2$-EOR operations is subsurface pressures are managed through balancing fluid injections ($CO_2$) with fluid withdrawals (oil, brine and recycling $CO_2$). This equilibrium between fluid input and output allows the operator to maintain a relatively constant subsurface pressure over the life of the operation.[25]

24 See, e.g. Society of Petroleum Engineers, '*$CO_2$ Geological Storage: Will we be ready in time?* (plenary session summaries) (Portugal 9–14 Oct. 2011) (estimate of $CO_2$ storage in subsurface reservoir of 99.9999 per cent); US Department of Energy, Office of Petroleum Reserves, *Fact Sheet: $CO_2$ Enhanced Oil Recovery* (<http://fossil.energy.gov/programs/reserves/npr/CO2_EOR_Fact_Sheet.pdf>), at 2 ($CO_2$ emissions are 'negligible' if injected $CO_2$ is stored in the reservoir when production is complete, not vented). See also US NETL, *Carbon Dioxide Enhanced Oil Recovery: Untapped Domestic Energy Supply and Long Term Carbon Storage Solution* (March 2010) (<http://www.netl.doe.gov/technologies/oil-gas/publications/EP/small_CO2_EOR_Primer.pdf>), at 24 (well selected, designed and managed sites likely to retain more than 99 per cent of injected $CO_2$ over 1,000 years; estimate for Weyburn project in Saskatchewan, Canada, likely to release less than one per cent in 5,000 years); and S. Hovorka, *EOR as Sequestration – Geoscience Perspective,* Appendix E of *MIT $CO_2$–EOR Report*, *supra*, at 5 (citing proprietary assessment from Kinder Morgan's West Texas operations showing losses during handling of less than one-half of one per cent of total $CO_2$ in the system). In 2010, one of the largest producers of naturally occurring $CO_2$ in the world (that also operates one of the largest $CO_2$ pipeline systems, as well as hundreds of $CO_2$ injection wells) surveyed its operations to estimate greenhouse gas emissions in preparation for EPA reporting and found that fugitive emissions and venting of $CO_2$ totalled 0.00021 per cent of total $CO_2$ processed. Denbury Resources Inc., *Emissions Disclosure Estimations: GHG Emission Survey* (at <http://www.denbury.com/emissions-disclosure-estimations.html>). See also L. Steven Melzer, *Constrained by Shortage of Carbon Dioxide Supplies*, American Oil and Gas Reporter (February 2012), at 128.

25 For further detail see Marston, *Pressure profiles for $CO_2$-EOR and CCS: Implications for regulatory frameworks*, Greenhouse Gases: Science and Technology, Volume 3, Issue 3, pp. 165–168 (June 2013)(available online at: <http://onlinelibrary.wiley.com/doi/10.1002/ghg.1348/full>) (viewed 18 September 2013).

## 2 Acquiring a supply of $CO_2$ for use in EOR—basic commercial law governing the exchange of goods and services and state law, not federal law, governs

### BUYING AND SELLING $CO_2$ AS A COMMODITY

- A state version of the Uniform Commercial Code (UCC) is likely to govern:
- sales 'into the pipeline' from $CO_2$ producing wells
  - sales of $CO_2$ 'out of the pipeline' to $CO_2$ users (e.g. industrial customers; EOR customers).
  - State commercial law governing services is likely to govern purchases from capture sources under off-take agreements.
- UCC and non-UCC law provide different legal rules (e.g. regarding contract performance, supplier warranties, and remedial provisions in the event of breach) that may be critically important in transactional planning and document drafting.

In the EOR context, $CO_2$ is a necessary resource that is acquired from suppliers and may be sold or exchanged like any other commodity. Accordingly, the law governing such transactions will be the applicable commercial law of the jurisdiction in question. In the US, the purchase and sale of commodities, provision of various services and the sale or transfer of real estate are governed principally by state, not federal, law.[26] While federal legislation affects commercial transactions in a variety of ways, the basic structure is very much a creature of state law. Hence, the legal framework governing the acquisition of $CO_2$ is the applicable state law governing the transaction (subject, of course, to the commercial parties' ability to include a 'choice of law' provision in the contract).[27]

This is true whether the transaction involves reserves of N-$CO_2$ in the ground (subject to the law governing real property), deliveries of N-$CO_2$ after severance from the real estate, or the provision of an off-take service by a pipeline receiving A-$CO_2$ after it has been captured from an emissions source (such as an ammonia plant, natural gas processing or separation facility, coal-to-liquids facility or electricity generating facility).

Where the $CO_2$ is sold as a discrete commodity, it is generally subject to the commercial law governing the sale of 'goods' as defined by the applicable state–enacted version of the Uniform Commercial Code (UCC). The UCC is a 'uniform' state statute initially developed in 1954 to replace the *Uniform Sales Act* that had been developed in the early part of the 20th century and adopted by individual states beginning in 1906. The statutory text and an accompanying commentary are developed by the National Conference of Commissioners on Uniform State Laws (established in 1892). This Commission develops and publishes suggested uniform texts that may then be adopted by individual state legislatures—ideally with as little change as possible.

26 In the famous phrase of Justice Brandeis, '[t]here is no federal general common law.' *Erie Railroad v. Tompkins*, 304 US 64, 78 (1938). See also Friendly, '*In Praise of Erie and the New Federal Common Law*', 39 NYU L. Rev. 383 (1964). Hence, except where their jurisdiction is founded on a federal statute, federal courts are *constitutionally* required to follow the law of the state in which they sit. As the Court held in *Erie*:

> *Except in matters governed by the Federal Constitution or by Acts of Congress, the law to be applied in any case is the law of the State. And whether the law of the State shall be declared by its Legislature in a statute or by its highest court in a decision is not a matter of federal concern. There is no federal general common law. Congress has no power to declare substantive rules of common law applicable in a State, whether they be local in their nature or 'general,' be they commercial law or a part of the law of torts. And no clause in the Constitution purports to confer such a power upon the federal courts.*

*Erie Railroad v Tompkins, supra*, 304 US at 78 (emphasis supplied). There are exceptions to this general rule. For example, where federal law supplies the basic legal rules governing a particular activity, the federal courts have evolved a body of judge-made law that is effectively a federal common law governing that activity under the particular federal statute. A classic example might be federal labour law under the National Labor Relations Act The point here, however, is that there is no federal *general* common law.

27 A choice of law provision in a contract is an agreement of the parties to be subject to the law of a given jurisdiction. Within certain limits, courts generally give effect to such private agreements.

The UCC has been generally adopted by all 50 states,[28] although there are some differences in the text as actually adopted by the states. These differences may be crucially important in particular cases and, indeed, determinative of the parties' rights, obligations and remedies. Hence, transactional documents should be drafted only by an attorney familiar with the applicable commercial law governing the transaction (including the relevant state rulings governing the use of 'choice of law' provisions in such contracts). The general discussion here of the applicable 'UCC' provisions refers to the UCC as the published uniform text, not to that of any particular state, as it is intended to provide a general overview of the commercial law framework, not to address the variation that might govern in a particular dispute.

As a general matter, the UCC governs the sale of 'goods', but not the sale of 'services'. The term 'goods' is defined generally in Section 2-105 as including in relevant part 'all things … which are movable at the time of identification to the contract for sale' while Section 2-107 more specifically addresses the sale of minerals or the like ("including oil and gas"), that are 'to be removed from realty'. Under Section 2-107, a contract for such a sale 'is a contract for the sale of goods' under Article 2 of the UCC 'if they are to be severed by the seller'. The Code does not address the case where the mineral is to be severed by the buyer, such that, as noted by the Official Comment, '[i]f the buyer is to sever, such transactions are considered contracts affecting land and all problems of the Statute of Frauds and of the recording of land rights apply to them'.

Hence, sales of $CO_2$ (whether N-$CO_2$ or A-$CO_2$) *delivered out of a pipeline* to EOR operators are likely to be governed largely by Article II of the UCC and, indeed, there is already case law, albeit in other contexts, that treats $CO_2$ as a UCC 'good'.[29] In these contexts, the UCC–based commercial law governing $CO_2$ is likely to be the same as for sales of $CH_4$ (*i.e.* "natural gas").[30]

Upstream, however, in transactions involving *receipt by the pipeline from the capture source* of A-$CO_2$, the legal situation is altered where the $CO_2$ transaction is part of a *service* of 'off-taking' the $CO_2$ from the capture source. The structuring of such off-take agreements is in fact the common contractual pattern around the world for agreements entered into for the future output of a variety of to-be-constructed facilities.[31] By providing a market for the future output—and therefore a cash flow—the off-take agreement can be a key part of financing the capture project. An off-take agreement for $CO_2$ may perhaps be more likely to be viewed by a US court as an agreement to govern a service, although the likely result in the event of a dispute is by no means crystal clear.

Perhaps, however, there could come a time when the $CO_2$ acquired as part of an off-take service agreement and injected for EOR (either by the off-taking party or after resale to others) may have been geologically stored for a sufficiently lengthy period after the wells are plugged and abandoned that a court might view a future sale as constituting a transaction in real estate (for example, following closure of an EOR operation or, conceptually, following closure of a CCS storage site). Here, the analogy might be to the law of 'fixtures', where a thing that was originally movable—and a 'good' within the meaning the of UCC) —has been affixed to a piece of real estate such that it is treated as having become part of the real estate (and thereby no longer subject to the UCC).

This distinction between the applicability of UCC and non-UCC law may have major consequences in particular disputes regarding $CO_2$ transfers because the UCC imposes on the seller various warranties (including an implied warranty of 'merchantability' of the goods sold) that may not be present under general non-UCC law. This is particularly the case in the event the seller is deemed a 'merchant with respect to goods of that kind'.[32] For example, if the UCC is applicable, $CO_2$ supplied by a capture source that failed to meet the applicable compositional standards for 'merchantable' $CO_2$ might be found to have breached an implied warranty of merchantability under the UCC, as well as any applicable contract standards for product quality. In addition, the legal rules governing termination of an agreement for failure to provide adequate assurances of performance in certain situations may also differ, depending on whether or not the transaction is subject to the UCC.

28 For a useful locator tool that provides links to the individual sections of the UCC as adopted by each of the states as of 2004, see <http://www.law.cornell.edu/uniform/ucc.html> (viewed 13 December 2011). The state of Louisiana adopted its version of the UCC only in 1990, a peculiarity attributable to Louisiana, having inherited the French Civil Code that was applicable prior to its sale to the US by the French Government in 1803.

29 *Rock Creek Ginger Ale Co. v. Thermice Corp.*, 352 F. Supp. 522, 523–530 (Dist. DC 1971) (court applied UCC provisions governing warranties in the sale of goods to dispute over sales of surplus $CO_2$ by beer brewer to a reseller for use by a soft drink bottler).

30 See, e.g. *Southern Natural Gas Co. v. Pursue Energy*, 781 F.2d 1079, 1081 n.3 (5th Cir. 1986) *citing* Miss. Code Ann. Sec. 75–2–107(1) (1972) (natural gas transactions at issue governed by Article 2 of the Mississippi Uniform Commercial Code). The case was a diversity case in federal court that applied Mississippi law. See also *Piney Woods Country Life School v. Shell Oil Co.*, 726 F.2d 225, 231–32 (5th Cir. 1984) (applying Mississippi version of UCC).

31 The Glossary of Project Finance Terms and Acronyms prepared by Benjamin C. Esty of the Harvard Business School defines an off-take agreement as '[a]n agreement to purchase all or a substantial part of the product produced by a project, which typically provides the revenue stream for a project financing.' (available online at: <http://www.people.hbs.edu/besty/projfinportal/glossary.htm>) (viewed 10 January 2012).

32 *See* UCC § 2–314 (1) (2004).

An example of the complexities is presented by a dispute during the 1990s in which the buyer of electricity under a long-term contract invoked UCC provisions that allow contract termination in the event a party (in this case the seller) fails to provide reasonable assurances of future performance under specific circumstances defined in the UCC. The seller claimed that the contract could not be terminated on those grounds because electricity was not a 'good' such that the UCC provisions did not even apply. It took multiple opinions from federal as well as the state courts before it was ultimately determined under the relevant state law that the electricity subject to the contract was not a 'good' and therefore not subject to UCC, but that a similar policy regarding the provisions of assurances should nonetheless apply under *non*-UCC law.[33]

In view of the uncertainty as to whether UCC or non-UCC law may apply in a particular case, one practical approach in drafting $CO_2$ off-take agreements is to include a 'UCC contingency clause' under which the parties agree that if the state whose laws govern the transaction were to determine that $CO_2$ is a 'good' for purposes of the UCC, then except as specifically otherwise provided, the agreement would be deemed subject to the UCC.[34] The parties could then, if they chose, include such an express disclaimer of warranties (in an appropriately "conspicuous" writing as required by the UCC for such disclaimers), including any warranty with respect to merchantability or fitness for any particular purpose. Under this approach, the parties are effectively treating the agreement as a non-UCC off-take service agreement, but planning for the possibility that some court in a future dispute may reach the contrary conclusion.

33 *Norcon Power Partners, L.P. v. Niagara Mohawk Power Corp.*, 92 NY 2d 458, (NY 1998).

34 An off-take agreement relating to an ethanol facility was at issue in a bankruptcy proceeding in the case *In re GOE Lima, LLC*, Case No. 08–35508 (Bankr. ND Ohio 3/12/2010) (Bankr. ND Ohio, 2010). There the court needed to apply the phrase 'adequate assurance of future performance' as it appeared (without a definition) in the US Bankruptcy Code and looked to how the identical phrase had been defined and interpreted in the UCC and UCC–based case law.

## 3 Transporting $CO_2$ to market—regulation of pipeline siting, construction and operation, including federal and state safety regulation and state regulation of pipeline access

### $CO_2$ PIPELINE REGULATION

- Regional networks have developed since 1970s.
- Since 1991, the federal government has set the safety standards for $CO_2$ pipeline construction.
- The states apply safety standards for in-state $CO_2$ pipelines.
- The states may regulate siting and provide for acquiring rights of way ('eminent domain').
- The states have the power to regulate access and rates where needed, but this power has rarely been called upon to date.

### a. OVERVIEW

The largest existing $CO_2$ pipeline networks in the world are presently found in the US, where there are roughly 4,000 miles of operating $CO_2$ pipeline. A 325–mile extension to the pipeline system linking Mississippi to Louisiana to Texas came into service in 2010 (at an approximate cost of US$884 million); additional expansions are under construction or planned in the US or Canada.[35] In all, $CO_2$ pipelines are found in nine US states, operated by about 21 companies. About a third of the total interstate pipeline mileage is located in Texas. Significant pipeline mileage is also located in New Mexico, Wyoming, Mississippi, Colorado, Oklahoma, North Dakota, Utah, and Louisiana, as shown on the map in Figure 3.

The regulatory status of these $CO_2$ pipelines has been detailed in a number of reports and articles over the past several years and will be summarised here briefly.[36]

### b. SAFETY REGULATION AND SAFETY RECORD

At the federal level, $CO_2$ pipelines are subject to safety regulation by the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the Department of Transportation (DOT). The existing federal safety standards for $CO_2$ pipelines were established in the early 1990s pursuant to a provision in the *Pipeline Safety Reauthorization Act of 1988* that directs the Secretary of Transportation to prescribe minimum safety standards for $CO_2$ pipelines, whether transported in a liquid or gaseous state.[37] The Secretary (acting through PHMSA) established regulations that applied only to the transportation of $CO_2$ by pipeline as a supercritical liquid (also termed a 'dense-phase gas') (effective 12 July 1992).[38] These regulations are now included in DOT's regulations at Title 49 of the Code of Federal Regulations (CFR), Part 195, entitled 'Transportation of Hazardous Liquids by Pipeline'.[39] In addition, although the PHMSA regulations for $CO_2$ pipelines are included in the same section as those for 'hazardous liquid' pipelines, PHMSA has made it clear that this was done for reasons of administrative convenience, not because supercritical $CO_2$ is a hazardous liquid.[40] See 49 C.F.R.§ 195.2.

35 See e.g. discussion of Alberta Carbon Trunk Line project of Enhance Energy, Inc. at <http://www.enhanceenergy.com/actl/> (viewed 17 January 2012).

36 See esp. Interstate Oil and Gas Compact Commission and Southern States Energy Board Task Force Carbon Dioxide Pipeline Transport, *A Policy, Legal, and Regulatory Evaluation of the Feasibility of a National Pipeline Infrastructure for the Transport and Storage of Carbon Dioxide* (10 September 2010). See also Marston and Moore, *From EOR to CCS: the Evolving Legal and Regulatory Framework for Carbon Capture and Storage*, 29 Energy L. J. 421, 449–461 (2008).

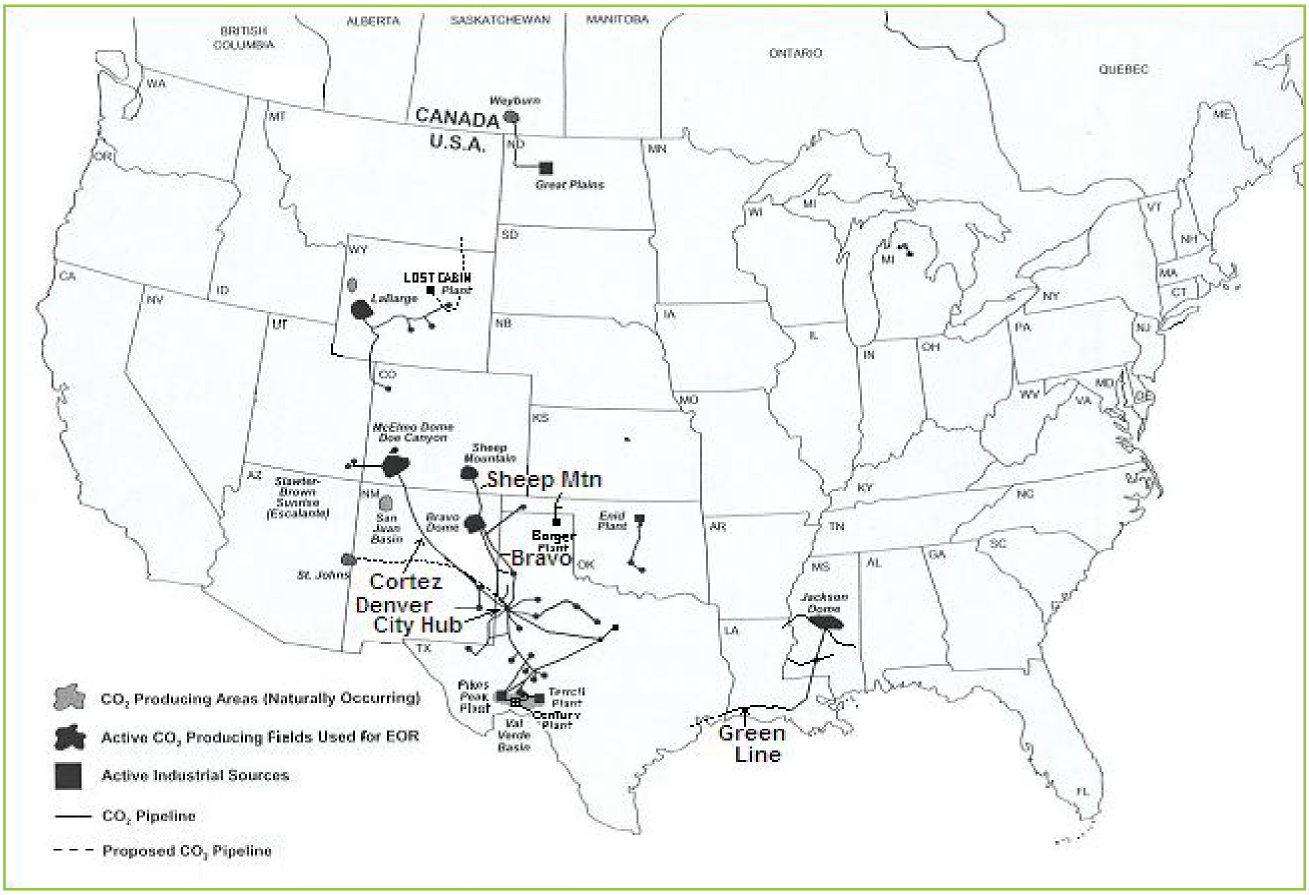
37 Codified at 49 USC § 60102(i).

38 *Final Rule: 'Transportation of Carbon Dioxide by Pipeline,'* 56 Fed. Reg. 26922, at 26923 (12 June 1991) (the '*Final $CO_2$ Pipeline Rule*').

39 *Id.*

40 In promulgating the rules in the early 1990s, the Department expressly recognised in response to comments that $CO_2$ is not a hazardous liquid, but decided to include the regulations governing $CO_2$ pipelines within the section addressing hazardous liquids for administrative convenience because changing the title heading 'would result in an awkward title.' Notice of Proposed Rulemaking: *Transportation of Carbon Dioxide by Pipeline*, 54 Fed. Reg. 41912 at 41914 (12 October 1989). Although $CO_2$ is listed as a Class 2.2 (non-flammable gas) hazardous material under DOE regulations (49 CFR § 172.101), it is not a 'hazardous liquid' included in 49 CFR § 195.2. The Department agreed that $CO_2$ 'should not be included in the definition of 'hazardous liquids,' but determined to apply the new regulation to $CO_2$ pipelines transporting dense phase or supercritical $CO_2$ 'without calling $CO_2$ a hazardous liquid'. *Id.* The final rule preserved the distinction between $CO_2$ pipelines and hazardous liquids pipelines. *Final $CO_2$ Pipeline Rule, supra.* See also 49 CFR § 195.0 providing that the regulation 'prescribes safety standards and reporting requirements for pipeline facilities used in the transportation of hazardous liquids *or* carbon dioxide.' *Id.* (emphasis added). See also discussion in *IOGCC/SSEB $CO_2$ Pipeline Report, supra*, at 24–25.

**FIGURE 3: Map of US $CO_2$ pipelines**




**Source:** $CO_2$ Pipeline Transportation Task Force of the Interstate Oil and Gas Compact Commission (IOGCC) and the Southern States Energy Board (SSEB), 2010.

The safety standards applied to these high pressure $CO_2$ pipelines are more comparable to those applicable to liquids pipelines than to natural gas pipelines and cover design, pipe, valves, fittings, flange connections, welding, breakout tanks, leak detection, inspection, pumps, compressors, etc.

*Interstate* $CO_2$ pipelines that transport $CO_2$ in a supercritical state are directly subject to the PHMSA safety standards, while pipelines that both start and stop within a state boundary are considered intrastate and are subject to regulation by a state authority, as long as the applicable state regulations are at least as stringent as the federally–prescribed standards (which is in fact generally the case).

$CO_2$ pipelines are also regulated by the states. For example, all Texas–regulated $CO_2$ pipelines must have a permit (Form T–4) that is issued by the Railroad Commission of Texas (RRC) that details the pipeline route and related information. State agencies are also responsible for safety regulation of $CO_2$ pipelines within the state.

In testimony before the legislature, the federal regulator has termed the safety record of $CO_2$ pipelines ‘particularly good’, noting that no fatalities had been reported for any of the incidents since the beginning of safey reporting for $CO_2$ pipelines in 1991.[41]

41 Prepared Statement of Krista L. Edwards, Deputy Administrator of PHMSA before the Senate Committee on Energy and Natural Resources Oversight Hearing on Construction and Operation of Carbon Dioxide Pipelines (31 January 2008), at 9 (providing details of safety record since 1991).

## c. REGULATION OF SITING, ACCESS, RATES AND TERMS AND CONDITIONS—FEDERAL REGULATION

$CO_2$ pipelines are not generally subject to federal regulation of siting or construction (other than the above-referenced standards for safety), nor do $CO_2$ pipeline operators have the power under *federal* law to invoke eminent domain for the acquisition of rights of way (except in certain cases crossing federally- owned land).[42] Both oil and $CO_2$ pipelines also differ from natural gas pipelines in that there is no prior federal permit required to construct a pipeline carrying either oil or $CO_2$, while a natural gas pipeline may not be constructed without a prior 'certificate of public convenience and necessity' from the Federal Energy Regulatory Commission (FERC).

In addition, the siting and construction of $CO_2$ pipelines (like oil pipelines) are subject to *state* law and the availability of eminent domain for acquiring rights of way for pipeline construction depends on applicable state law. In addition, the FERC certificate for natural gas pipeline construction confers a power of eminent domain, enforceable in state court, to condemn land for purposes of acquiring the necessary rights of way.[43]

Because there is no federal permitting for $CO_2$ pipelines (other than in the case where the pipeline crosses federal land) and therefore no 'major federal action' significantly affecting the human environment, there is normally no federal-level environmental review. Hence, in this respect the regulatory framework for $CO_2$ pipeline construction is similar to that for oil pipelines.[44]

## d. REGULATION OF SITING, ACCESS, RATES AND TERMS AND CONDITIONS—STATE LAW

Under state law, the regulatory situation is more complex. There is a vast body of state law (rooted in English law reaching back to the 14th century) applying the common law of common carriage to a host of activities, including transportation businesses.[45] In addition, states where $CO_2$ pipelines began to develop several decades ago have often addressed the carrier status of $CO_2$ pipelines by statute. Under several of those statutes, there is a state–granted power of eminent domain for $CO_2$ pipelines that meet the common carrier standard under that state's law. For example, in Texas, a prospective $CO_2$ pipeline may be either a common carrier or a private carrier. In the first case, the pipeline submits to the jurisdiction of the regulator and incurs an obligation to provide service to the public, but in exchange receives a power to acquire rights of way for the pipeline via eminent domain. If the pipeline chooses to remain a private carrier, it does not incur the regulatory obligation to provide carriage for third parties, but neither does it benefit from the ability to invoke eminent domain to acquire needed rights of way. Thus the statute sets out a choice of procedures under which a $CO_2$ pipeline developer may proceed.[46]

The states do not necessarily (or even typically) apply to common carrier pipelines a practice of requiring automatic pro-rata apportionment of existing capacity to those newly seeking a transportation service. As a result, the designation of common carrier status for $CO_2$ pipelines under these state statutes does not generally preclude the pipeline operator from effectively committing specified levels of pipeline capacity needed to provide potential $CO_2$ suppliers with firm contractual assurances of reliable long-term service. In this respect, state regulation of common carrier pipelines is quite different from the regulatory practice of the federal regulator (FERC) with respect to common carrier *oil* pipelines (but not natural gas pipelines, which are not 'common carriers', but open access *contract* carriers).

---

42 The two federal agencies that exercise regulatory responsibilities over certain other types of pipelines determined many years ago that their grants of regulatory authority under their respective statutes do not include the regulation of $CO_2$ pipelines. For detailed discussion of the rulings, *see IOGCC/SSEG $CO_2$ Pipeline Report, supra*, at 27–28.

43 15 USC § 717f (c) (requiring prior certificate from the FERC) and 15 USC § 717f (h) (granting certificate holder power of eminent domain to acquire right of way).

44 The recent much-discussed case involving a federal import permit for the Keystone XL oil pipeline is the exception that proves the rule. The permit at issue there is a presidential permit required to import the oil from Canada, not to site or construct the pipeline. The federal permit is thus required only because the oil to fill the pipeline was to be imported from Canada. The federal environmental review was conducted by the US Department of State because the issuance of the import permit was deemed the 'major federal action' triggering the federal environmental review procedure under the National Environmental Policy Act.

45 Mogel and Gregg, *Appropriateness of Imposing Common Carrier Status on Interstate Natural Gas Pipelines*, 4 Energy L. J. 155, 163–167 (providing short history of the common law of common carriage and contrasting it with contract carriage). See also *Marston and Moore, supra*, 29 Energy L. J. at 458–461 (discussing state standards for imposing common carriage).

46 Even where the developer follows the precise requirements of a state statute, however, the concern over the protection of private property (discussed in Part II) may lead a court to require more than the statutory *minima* to be considered a common carrier under the statute. See *Texas Rice Land Partners, Ltd. v. Denbury Green Pipeline-Texas, LLC*, 363 S. W. 3d 192 (2 March 2012) (ruling *inter alia* that state issued permit for $CO_2$ pipeline was merely *prima facie* evidence of common carrier status such that, if challenged in a condemnation action, the pipeline company has the burden in each action to prove it is actually a common carrier under Texas law).

The FERC's long-standing practice for common carrier oil pipelines is to require the pro-rationing or apportionment of capacity such that a new supplier may effectively force pre-existing suppliers off the pipeline to the extent of the prorated capacity.[47] If applied to $CO_2$ pipelines seeking to contract to provide off-take services for to-be-constructed facilities to capture $CO_2$, such a regulatory practice could raise an insurmountable barrier by precluding the proposed new $CO_2$ pipeline from being able to provide a capture source with binding contractual assurances that sufficient capacity will be reserved or dedicated in order to provide firm off-take service for the full contract term. This important point is discussed further in Part III.

## ACCESS TO THE SUBSURFACE FOR INJECTIONS

- The remaining oil belongs to the mineral interest owner and is likely to occupy the pore space in oil–bearing formations.
  - EOR operations will focus on this remaining oil in place for decades to come.
  - Defining pore space ownership will not settle the question of legal ability to inject $CO_2$ into the pore space of an oil–bearing formation because the space is occupied by remaining oil in place.
- Ownership is generally private and the surface owner owns the subsurface 'to the centre of the earth'.
- The mineral estate is the 'dominant' estate, with the right to reasonable use of the surface estate for mineral extraction.
- The 'rule of capture' generally provides the ability to draw oil or gas from under adjacent surface properties. The 'negative rule of capture' allows fluids injected for approved operations to migrate under adjacent properties where there is no actual damage.
- **From a legal standpoint, $CO_2$ injected in EOR operations is essentially the same as brine or other enhanced recovery injection fluids.**

With regard to the exercise of any power of eminent domain for purposes of acquiring rights of way for new pipeline construction, the matter is generally one for the individual state. Many states have traditionally provided for such land acquisition power for various types of carriers that serve a public interest (railroads, highways, pipelines, etc). A condemnation power to acquire right of way may also be granted in some states where the applicant is a common carrier under federal law, which includes interstate $CO_2$ pipelines under the *Interstate Commerce Act* where the permit granted for crossing federal land is granted under the *Mineral Leasing Act of 1920*.[48] Where available, the power typically may only be exercised in a judicial condemnation action. The details of each state's law and procedure must be consulted as individual state laws may vary substantially in these matters.[49]

47 For a detailed review of FERC's policy on allocating capacity on oil pipelines, see Christopher J. Barr, *'Unfinished Business: FERC's Evolving Standard For Capacity Rights On Oil Pipelines'* 32 Energy L. J. 563 (2011).

48 *Exxon Corp. v. Lujan*, 970 F.2d 757 (10th Cir. 1992) (upholding Bureau of Land Management's decision to grant authorisation under the Mineral Leasing Act rather than under another statute that would not have imposed a common carriage obligation).

49 For a detailed summary of the laws of the Midwest states in this regard, see Midwest Governors Association, *Legal and Regulatory Inventory for Carbon Capture and Storage & Analogues* (March 2009) (prepared by Jennifer Johnson, Great Plains Institute For the Midwestern Governors Association Renewable Electricity and Advanced Coal with Carbon Capture And Storage Advisory Group) (<http://www.midwesterngovernors.org/Publications/Inventory.pdf>) (viewed 27 January 2012).

## 4 Access to the subsurface—acquiring and managing property rights to the oil–bearing formation

In the US, the subsurface generally belongs to the surface owner. As a result, subsurface property interests can be at least as fragmented as surface rights. The relationships *among* the mineral interest owners may be dynamic over time as well, with differing types and levels of interest in a formation being modified to reflect the participants' changing interests, capital requirements or priorities. Hence 'oil and gas law' is to a large degree a sophisticated and complex form of conveyancing in which $CO_2$ injections for EOR operations are merely one more variable to be addressed. The following overview is intended to provide enough of an introduction to illustrate how $CO_2$ injections and incidental storage during EOR operations fit within this more encompassing legal regime. This discussion will set the stage for understanding the issues raised in Part II by the various statutory initiatives to promote CCS by addressing $CO_2$ injections following completion of EOR production operations, or in saline formations completely outside of the EOR context (what might be termed 'standalone' geologic storage).

### a. THE IMPORTANCE OF THE REMAINING OIL IN PLACE

In the EOR context, $CO_2$ is injected into the oil–bearing formation, where it mixes with the other reservoir fluids, including oil, in the subsurface pore spaces of the rock. What is often not recognised in discussions of pore space ownership and related subsurface property rights issues is that this subsurface pore space is almost *never empty*, but is, rather, filled with a fluid.[50]

In an oil–bearing formation, there will thus almost always be a portion of the original oil in place (OOIP) trapped in the pores mixed with other formation fluids (typically and principally, brine). In a non-oil-bearing saline aquifer, the pore space will be occupied typically by brine. The amount of oil remaining in an oil–bearing formation may not be economic to produce under current technology, in which case the formation is typically termed 'depleted'. This is more an economic or a technological reference than a physical description, however, for the entire EOR industry is built on re-entering these so-called 'depleted' fields and re-establishing production. Because an increasing portion of US domestic oil production (currently more than six per cent) comes from these 'depleted' fields, they might better be termed 'otherwise' or 'formerly' depleted. As one article put it:[51]

> *[T]here will be residual oil (and in some cases associated gas) remaining in the reservoir after the EOR project reaches its current economic state of depletion and this oil may become recoverable at a future time under future technology. After all, this is exactly what $CO_2$–based EOR has made possible for oil that was previously viewed as non-recoverable. This residual oil continues to belong to the mineral interest owner and could conceivably be reduced to future possession. The occupation of pore space by $CO_2$ at the end of a current EOR project thus in itself has a current value in the nature of an option for reserving the potential for that future oil production. In sum, the determination of the amount of pore space that is available for incremental storage for CCS purposes must recognize the existing property interests in the residual oil. ... When one ponders the technological accomplishments of the oil and gas industry in just the last twenty years, it is easy to realize how important it is for oil and gas attorneys to plan ahead for further potential advances a decade or two or three ahead … Under current technology there are always residual hydrocarbons that remain in the unitized formation at the time it becomes uneconomic to continue production. Hence, if technology, economics and the price of oil were to justify a return to oil and gas production, the operator could proceed to do just that—if he had planned ahead and obtained all the contractual owner approvals evidenced in his Unit Agreement and Unit Operating Agreement as well as the proper storage rights.*

Thus, in the EOR context, the storage 'space' is already occupied by a potentially valuable commercial commodity, whereas in the non-EOR context, the storage 'space' will be occupied principally by brine. The fact that oil will remain in the pore space of an oil–bearing formation—even when it has already been deemed depleted for commercial purposes—is a key fact to bear in mind in discussions of property rights for $CO_2$ storage. To the extent the pore space is already occupied by a mineral, the analysis of who controls the right to inject $CO_2$ into that space must address ownership of

50 An exception to this rule is the case of salt cavern storage, where an actual storage cavern is constructed by leaching and removing salt from the salt formation, thereby creating an actual empty space underground whose walls are constructed of the mineral itself.

51 Marston and Moore *supra*, at 482, 486.

those mineral rights as well.[52] The same holds true for all other subsurface mineral interests, whether they cover natural gas, sulphur, salt or other minerals or geothermal resources.

This fact affects much of the discussion in the US about access to, and aggregation of, subsurface pore space for geologic sequestration because of the fragmented and rather overlapping nature of the privately held property interests. Even where all the subsurface ownership interests are held by a single, governmental entity (as common in EU Member States), however, the same kind of conflict among potentially competing uses of the subsurface may come into play and must be addressed.[53] Owners of the mineral rights may be expected to seek to preserve potential future recovery of oil resources even if it may be decades before technological advances or market changes allow for their recovery. This is true of individual landowners and should be even more pronounced where the property in question is owned by a governmental entity which may be able to take an even longer-term view of optimal resource management.

### b. THE ROLE OF PRIVATE OWNERSHIP

In the US, the general rule is that the subsurface is owned by the surface owner and thus is privately held in most cases.[54] Property rights in the US derive from the success of the American Revolution. This is unlike the case of other former British colonies (including, of relevance here, Canada) that became independent nations through peaceful negotiations. This seemingly abstract observation has important and very practical consequences for potential legal regimes governing $CO_2$ injections (whether for EOR or for CCS) because that revolutionary impulse to protect ‘life, liberty and the pursuit of happiness’ was soon to be enshrined in the Bill of Rights as the Constitutional protection of ‘life, liberty, and property’. Hence, the approach to private ownership of the subsurface in the US over the past two centuries is not merely a legal construct, but a not-insignificant part of the American *political and constitutional* tradition. Any serious proposal to treat the subsurface for CCS purposes as some form of public resource is thus likely to be vigorously opposed by a host of long-established, sophisticated and politically powerful organisations devoted to the protection of private property rights.[55] This point is discussed further in Part II in connection with specific proposals for aggregating subsurface storage rights.

While the newly–founded states in the 18th century could presumably have stepped into the shoes of the British sovereign and treated subsurface rights (such as the right to extract minerals) as ‘regalian’ rights (i.e. pertaining to the Crown), they did not do so.[56] The state courts quickly adopted a common law rule that the property interest of the surface owner extends to the sky and to the depths, as captured in the Latin phrase c*ujus est solum, ejus est usque ad coelum ad infernos*, a principle in which American land policies and popular belief have manifested an ‘almost religious devotion’, as one scholar of the topic has put it.[57]

52 As Professor Anderson observes in discussing Texas law, ‘even though the surface owner may own the pore spaces, the mineral owner has broad rights to penetrate or otherwise use them in connection with mineral exploration and exploitation. Indeed, commercial deposits of oil and gas occupy pore spaces within geologic traps. Thus, the mineral owner may be able to enjoin $CO_2$ sequestration that prevents, greatly hinders, or endangers the capture of oil and gas.’ Owen L. Anderson, *Geologic $CO_2$ Sequestration: Who Owns the Pore Space?*, 9 Wyo. L. Rev. 97 (2009) (hereafter ‘Anderson—*Who Owns the Pore Space?*’).

53 For example, in the case of $CO_2$ storage in the UK portions of the North Sea where The Crown Estate is the effective property owner, the Crown Estate’s practice is that it will not grant a lease for $CO_2$ storage in a hydrocarbon field currently under a petroleum license ‘unless it is demonstrated that the prospective storage developer has entered into an agreement with the petroleum licence holder to allow the development of the site in a timely manner’, thereby protecting the lease rights of the current petroleum rights holder.

54 While the federal government owns about 28 per cent of the total surface acreage of the US, these holdings are highly concentrated in the western part of the country. For example, the US government owns nearly 80 per cent of the state of Nevada and nearly 68 per cent of Alaska. Congressional Research Service, ‘Major Federal Land Management Agencies: Management of Our Nation’s Lands and Resources’ (15 May 1995) (Report No. 95–599 ENR) (by Betsy A. Cody), at 1 and Appendix A (<http://www.cnie.org/nle/crsreports/natural/nrgen-3.cfm> (viewed 4 January 2012). In most of the rest of the country, the federal government’s land holdings are modest or minimal. For example, the federal government owns less than 1.5 per cent of the surface in Texas. *Id.*

55 The political reaction to the US Supreme Court decision in *Kelo v. New London*, 545 US 469 (2005) is instructive in this regard. There, a narrowly–divided court (voting 5–4) upheld as a ‘public use’ the taking of private property that was viewed as economically ‘distressed’ as part of a program of economic rejuvenation of an entire neighbourhood (including transfer of a portion for privately owned commercial development). The dissenters argued that the Court had effectively deleted the words ‘for public use’ from the Takings Clause of the Bill of Rights. The political reaction to the decision was swift, with several dozen states taking action by statute or referendum to modify their own state law. In effect, these states imposed greater protections for private property under state law than were available under federal law, as interpreted by the *Kelo* decision.

56 The history of the early development of US law involving subsurface mineral rights is told in Chapter 8 of Terence Daintith*, Finders Keepers: How the Law of Capture Shaped the World Oil Industry* (RFF Press, 2010) (hereafter ‘*Daintith, Finders Keepers*’).

57 *Id.* at 418. See also 2 Blackstone, Commentaries (Lewis ed. 1902) p. 18 (‘whatever is in a direct line between the surface of any land and the center of the earth, belongs to the owner of the surface; as is every day’s experience in the mining countries’). The principle entered American common law jurisprudence via multiple court decisions early in the history of the republic. See John G. Sprankling, *Owning The Center Of The Earth*, 55 UCLA L. Rev. 979 (2008).

That principle has long since been limited in a variety of ways, for example, where the arrival of aircraft led to a more limited legal rule with regard to ownership rights above the surface.[58] By 1946, the Supreme Court in *United States v Causby* (*Causby*) dismissed the *ad coelum* approach as an 'ancient doctrine' that simply 'has no place in the modern world'.[59] In essence, the courts decided that the surface owner had no legally protected property right to the air overlying the surface of his land unless he could show that the use of the airspace by a third party was damaging to the use of the surface.

With regard to the subsurface, however, the *ad infernos* portion of the traditional doctrine is still very much alive, as illustrated as recently as 2007 when the Illinois Supreme Court repeated the rule that '[t]he owner in fee owns to the center of the earth'.[60] The reason for the continued vitality of the *ad infernos* rule is due perhaps in part to the increasing technological ability to drill for, and develop, oil and gas resources from ever deeper geological formations as necessary to reach economically producible reserves and reduce them to possession. Well depths in the 1950s were generally around 3,900 feet and only exceeded 4,000 feet in a few years prior to the 1990s, but now range from around 4,500 to 5,000 feet for development wells, to 7,000 to 8,000 feet for exploratory wells.[61] For natural gas development wells, the average depth has nearly doubled from 1949 to recent years and is now running in excess of 6,500 feet.[62] But some wells go much, much deeper, with the current record held by an oil well drilled to 35,000 feet.[63] With specific regard to well depths of EOR operations, wells in the West Texas Permian Basin often produce oil from 5,000 to 6,000 feet, but $CO_2$–EOR wells in Mississippi typically produce oil from formations below 10,000 feet.[64]

As a result of this increasing ability to reduce to possession minerals from the deep subsurface, the common law rule of the surface owner's property extending *ad infernos*—even to the very deep subsurface—is unlikely to disappear in the foreseeable future. Note, however, that even states that still apply the *ad infernos* doctrine in general may take a more flexible approach in defining allowed regulation of that ownership in deeper formations:[65]

> *[T]hat maxim—cujus est solum ejus est usque ad coelum et ad infernos—'has no place in the modern world'. Wheeling an airplane across the surface of one's property without permission is a trespass; flying the plane through the airspace two miles above the property is not. Lord Coke, who pronounced the maxim, did not consider the possibility of airplanes. But neither did he imagine oil wells. The law of trespass need no more be the same two miles below the surface than two miles above.*

This ownership interest in real property may of course be 'sliced and diced' in a great variety of ways limited principally by economic needs and the legal imagination. The resulting fragmentation and multiplication of property rights involving various minerals (of which oil and natural gas are only two) has led over the past two centuries to a set of principles governing the interrelationship of the various ownership rights. While important parts of this body of law have been created (or confirmed) by statute, a great deal of the law remains judge-made law, evolving from rulings on individual disputes. Moreover, the specifics of this body of law vary from one state to another. What is presented here is an extremely simplified summary of a few principles that may have particular relevance to understanding the law governing $CO_2$ use in EOR operations and is based primarily on Texas oil and gas law.[66]

---

58 *Thrasher v. City of Atlanta*, 173 S.E. 817, 825 (Ga. 1934) (characterising the earlier cases citing the *ad coelum* maxim as involving airspace that was 'within the range of actual occupation'); *Hinman v. Pac. Air Transp.*, 84 F.2d 755, 757 (9th Cir. 1936) (rejecting *ad coelum dictum* with regard to airspace and noting '[w]e think it is not the law, and that it never was the law' and that the maxim 'simply meant that the owner of the land could use the overlying space to such an extent as he was able'). See also *State v. Layne*, 623 S.W.2d 629, 635 (Tenn. Crim. App. 1981) (noting that '[t]he maxim arose largely from dicta, since the early cases were limited to facts and conditions close to earth and did not require an adjudication of the title to the 'mansions in the sky'' (citing *Thrasher*, 173 S.E. at 825)).

59 *United States v. Causby*, 328 US 256 (1946).

60 *Kankakee County Bd. of Review v. Prop. Tax Appeal Bd.*, 871 N.E.2d 38, 52 (Ill. 2007) (quoting *Jilek v. Chi., Wilmington & Franklin Coal Co.*, 47N.E.2d 96, 100 (Ill. 1943)).

61 US Energy Information Administration, *Average Depth of Crude Oil and Natural Gas Wells* (sources identified as: 1949–65: Gulf Publishing Company, World Oil, 'Forecast–Review' issue; 1966–69: American Petroleum Institute, 'Quarterly Review of Drilling Statistics for the United States', annual summaries and monthly reports; 1970–94: Energy Information Administration (EIA) computations based on well reports submitted to the American Petroleum Institute; 1995 forward: EIA computations based on well reports submitted to the Information Handling Energy Group, Inc. (<http://www.eia.gov/dnav/ng/TblDefs/ng_enr_welldep_tbldef2.asp>) (viewed 7 January 2012).

62 *Id.* (average natural gas well depth increased from 3,412 feet in 1949 to 6,558 feet in 2008) (<http://www.eia.gov/dnav/ng/hist/e_ertwg_xwdd_nus_fwa.htm>) (viewed 7 January 2012).

63 <http://www.deepwater.com/fw/main/IDeepwater-Horizon-i-Drills-Worlds-Deepest-Oil-and-Gas-Well-419C151.html> (well drilled to 35,050 vertical depth while operating in 4,130 feet of water).

64 2012 Oil & Gas Survey, Table C, at 60–65.

65 *Coastal Oil & Gas Corp. v. Garza Energy Trust*, 268 S.W.3d 1, 11 (Tex. 2008) (footnotes omitted) (*citing United States v. Causby*, 328 US 256, 260–61 (1946)).

66 The classic treatise on US oil and gas law remains the eight–volume treatise of Williams and Meyers, *Oil and Gas Law*, Vols. 1–8 (currently edited by Patrick H. Martin and Bruce M. Kramer).

## c. BRIEF SUMMARY OF THE COMMON LAW BACKGROUND AFFECTING PORE SPACE OWNERSHIP

Legislatures in a few states have begun to explicitly address pore space ownership rights and property relationships in the context of $CO_2$ injections for CCS (as will be discussed in Part II). To the extent that these statutes speak to ownership of the pore space, they generally affirm the predominant (but not universal) law in US oil and gas case law that the pore space available for storage will usually be determined to belong to the surface owner unless the parties have explicitly provided otherwise. But determining ownership of the pore space is not the end of the matter, nor indeed is it necessarily the most relevant or pressing legal issue involving the ability to inject $CO_2$ into pore space for EOR purposes. Hence, some states' recent geologic storage statutes don't even bother to address pore space ownership and one state needed to amend its statute shortly after passage. Understanding why that is the case requires some understanding of the backdrop of the common law regarding the ownership of the subsurface on which these statutes were overlaid. Since this backdrop is the law governing $CO_2$–EOR operations (as well as oil and gas operations generally), it is discussed in this Part I. This will also set the stage for the discussion of how the recent geologic storage statutes address pore space ownership and the interplay among the differing ownership estates.

### i. Division of private ownership between the surface estate, the mineral estate and introduction to pore space issues

With regard to subsurface rights, the states have long recognised distinct 'estates' or ownership interests in subsurface minerals—generally termed the 'mineral estate'. The mineral estate can be 'severed' by lease or deed from the surface estate and may then be further divided (subject to any conditions imposed in the original instrument severing it from the surface estate).[67] While exploitation of the mineral estate is subject to state regulation, the underlying property interest is generally as freely transferable as any other property interest. Royalty interests also come into play. Not infrequently, tensions or conflicts may arise between (or among) these various property rights. Courts and the legislatures in the oil and gas (and other mineral producing) states have sought to develop rules for managing these at-times conflicting interests, frequently favouring economic development of the oil and gas resource.

### ii. The common law rule of capture, trespass—and the 'negative' rule of capture

As oil and gas development began in the 19th century, courts began to address property disputes where the owner of one plot of land asserted that oil from under his land was being drained by the owner of an adjacent or other nearby parcel. In those early days, the courts began to treat property in subsurface oil as the common law had long treated wild animals,[68] reasoning that he who 'captured' the oil and reduced it to possession was deemed the owner. As summarised by one oil and gas law treatise, this 'rule of capture' generally provided as follows:[69]

> *According to the law of capture, in general terms, the landowner may capture oil or gas by operations on his land. He owns the substance absolutely once it has been reduced to dominion and control. Before the instant of control, however, the ownership of the substance or the right to capture and control it is subject to the possibility of capture and control by another acting within his own rights as a landowner and producing from a common source of supply. The owner of the drained tract has no legal remedy but may protect his rights in the oil and gas by drilling on his own tract.*

The rule of capture has been called a 'cornerstone of the oil and gas industry' and 'fundamental both to property rights and to state regulation'[70] and even 'the most important single doctrine of oil and gas law'.[71] It is applied in some form or another in most of the major oil and gas producing states. It quickly produced adverse consequences as well, however. Because the only way a landowner could profit from oil under his land was to produce it, he was effectively forced to drill a well on his property, even if the oil reservoir could more profitably and efficiently be produced by a smaller number of more optimally located wells. This realisation led to the development of regulations governing well spacing, and the pooling and unitisation of producing properties, including in most states some form of compulsory unitisation (except in Texas, reflecting precisely the above-referenced concerns over the protection of private property).[72]

67 Judicial recognition of the severance of the estates is at least as old as the 1893 coal mining dispute addressed in the Pennsylvania case of *Chartiers Block Coal Co. v. Mellon,* 25 A. 597 (Pa. 1893) (noting that the surface of the land may be separated from the different strata beneath it, and there may be as many different owners as there are strata).

68 The celebrated case of *Pierson v. Post*, 3 Cai. 175 (NY 1805), known to generations of first year law students in the US, ruled that ownership of wild animals is acquired by occupancy and control.

69 E. Kuntz, *A Treatise on the Law of Oil and Gas,* vol. 1, § 4.1 (p. 88) (footnotes omitted).

70 *Coastal Oil & Gas v. Garza Energy Trust,* 268 S.W.3d 1, 13 (Tex., 2008).

71 1 Ernest E. Smith & Jacqueline Lang Weaver, *Texas Law Of Oil And Gas* § 1.1(A) (2nd ed. 1998).

72 *Daintith*, *infra*, at 437 (discussing unsuccessful legislative efforts to adopt compulsory unitisation in Texas).

There is a huge body of highly complex law dealing with the rule of capture as applied in the various states. The rule continues to apply in most US oil and gas producing jurisdictions, albeit long since subject to a host of legislative, regulatory or judicial modifications and refinements.[73] Its early presence helps to explain why oil resources that span state boundaries were able to be developed with as much ease as they were (e.g. the large Bradford Field underlying portions of both Pennsylvania and New York). As one scholar has explained, 'it was private, not public, property that was in play'.[74]

The rule of capture has been invoked in circumstances raising questions about the ownership of $CO_2$ injected and recycled in EOR operations. The 2011 case of *Occidental Permian Ltd. v. the Helen Jones Foundation* (hereafter *'Helen Jones Foundation'*)[75] involved the property status of certain $CO_2$ that had originally been produced from a geologic source in one state and was transported to another state for injection and use in $CO_2$–EOR operations. It was conceded that the original geologically occurring $CO_2$ had become personal property when it was initially produced (i.e. severed from the realty), consistent with the UCC analysis above. But the claim in this case was that the personal property $CO_2$ had been abandoned when it was injected for EOR operations such that (so it was claimed) the $CO_2$ again became subject to the rule of capture. In effect, the plaintiff argued that it should have been paid a royalty by the EOR operator each time the valuable injected $CO_2$ was produced from the EOR operation, separated from the oil, recycled and produced again.[76] The trial court adopted this approach and allowed a jury verdict for compensation from the EOR operator. While the Texas appeals court reversed, the case illustrates the concern EOR operators have for protecting the value of their investment in $CO_2$.

The simplified discussion is included here because the 'rule of capture' has led to some cases in Texas and elsewhere adopting a so-called 'negative rule of capture.' The best known case is *Railroad Commission of Texas v. Manziel*,[77] decided in 1962. There, some landowners challenged an order of the oil and gas regulator (in Texas a function discharged by, the Texas Railroad Commission) that allowed the operator of a well on an adjacent tract of land to drill a well near the boundary and to inject water for non-$CO_2$ based EOR operations. The landowners claimed that the injected water would migrate in the subsurface into their property, resulting in a trespass to their property and interfering adversely with the production of oil there. In the words of the *Manziel* court, the issue was 'whether a trespass is committed when secondary recovery waters from an authorised secondary recovery project cross lease lines'.[78] The court concluded that there was no trespass in such a case:

> *We conclude that if, in the valid exercise of its authority to prevent waste, protect correlative rights, or in the exercise of other powers within its jurisdiction, the Commission authorizes secondary recovery projects, a trespass does not occur when the injected, secondary recovery forces [sic] move across lease lines, and the operations are not subject to an injunction on that basis. The technical rules of trespass have no place in the consideration of the validity of the orders of the Commission.*

In reaching this conclusion, the *Manziel* court case quoted approvingly from the discussion in the Williams and Meyers treatise of an evolving negative rule of capture:[79]

> *What may be called a 'negative rule of capture' appears to be developing. Just as under the rule of capture a landowner may capture such oil or gas as will migrate from adjoining premises to a well bottomed on his own land, so also may he inject into a formation substances which may migrate through the structure to the land of others, even if it thus results in the displacement under such land of more valuable with less valuable substances …*

Even in a state that had not applied a distinct negative rule of capture, the court reached a similar result, foreclosing a claim unless the adjacent landowner could show special damages from the subsurface movement.[80] Subsequent Texas

73 For an excellent review of the history and potential future of the doctrine in the US context, see Bruce M. Kramer· and Owen L. Anderson, *The Rule Of Capture – An Oil And Gas Perspective*, 35 Environmental Law 899 (2005). For an exhaustive, but engaging, consideration of the Rule of Capture, its history, its theory and practice in various legal systems around the world (including in transboundary situations both across US state lines and across international boundary lines), the essential resource is Daintith, *Finders Keepers, supra*.

74 Daintith, *Finders Keepers*, *supra*, at 372.

75 333 S.W.3d 392 (Tex. App. 2011).

76 *Id.*, n.24.

77 *Railroad Commission of Texas v. Manziel*, 361 S.W.2d 560 (Tex. 1962).

78 *Id.*, 361 S.W.2d at 568 (Tex. 1962).

79 *Id.* (emphasis added).

80 See e.g. *Jameson v. Ethyl Corp*, 609 S.W.2d 346, 351 (Ark. 1980).

Supreme Court decisions have cast some doubt on the scope of the *Manziel* ruling, however, such that 50 years later, the full scope of the ruling is still somewhat unclear.[81]

Some commentators have opined that the case might provide legal protection from a claim of subsurface trespass in the event that $CO_2$ injected in a CCS project (or in an EOR operation) were to migrate outside the project's boundary (i.e. outside of the subsurface for which the operator had the appropriate ownership or lease rights). Further support for this view is found in the fairly recent case of *Coastal Oil & Gas v. Garza Energy Trust*, 268 S.W.3d 1 (Tex. 2008), where the Texas Supreme Court reaffirmed the rule of capture and held that subsurface hydraulic fracturing via subsurface injections was not an actionable trespass of adjacent property because the drainage of hydrocarbons by this means was protected by that rule.[82] As observed by Professor Anderson in commenting on the case:[83]

> *Presumably, the injection of $CO_2$ for enhanced recovery would be similarly protected. Some of the reasons cited by the court for its decision would also support protecting $CO_2$ sequestration from trespass actions. The court reasoned that trespass requires actual injury and that trespass injury should not be inferred when the physical invasion occurs far below the surface. The court noted that the ad coelum maxim 'has no place in the modern world' and that 'the law of trespass need no more be the same two miles below the surface than two miles above'. The court also reasoned that it should not usurp the lawful authority of the Texas Railroad Commission to decide to regulate, or not regulate, fracturing, should not allow the litigation process to determine the extent of harm (drainage) that is caused by fracturing, and should not allow an actionable trespass (by changing the rule of capture) when the oil and gas industry does not 'want or need the change'. Justice Willett, concurring, would have gone further and held that, not only was fracturing not an actionable trespass, it was not a trespass at all. His concurring opinion discussed the necessity of hydraulic fracturing for the recovery of hydrocarbons. As a matter of public policy, as with hydraulic fracturing, Texas courts should find that no trespass occurs if injected $CO_2$ crosses property lines. Because $CO_2$ injection, unlike hydraulic fracturing, will be subject to a regulatory permitting regime, the court should have even fewer concerns about $CO_2$ injection for enhanced recovery or $CO_2$ sequestration.*

### iii. The 'dominance' of the mineral estate over the 'servient' surface estate and the 'accommodation' doctrine

Another aspect of oil and gas law that is directly relevant to $CO_2$ injections for CCS is the concept of the 'dominance' of one estate over another. Because the owner of the mineral estate cannot normally exploit the minerals without some access to the surface, oil and gas law in the US has evolved a concept termed the 'dominance' of the mineral estate over the surface estate, which is deemed the 'servient' estate. What this means is that the owner of the mineral estate has in general a right to reasonable access to the airspace and surface that is reasonably necessary to explore for, and exploit, the minerals belonging to the mineral owner.[84]

---

81 See, e.g. *FPL Farming Ltd. v. Envtl. Processing Sys.L.C.*, 351 S.W.3d 306, (Tex. 2011) and the appellate court ruling on remand, *FPL Farming Ltd. V. Environmental Processing Systems LC*, ___ S.W. 3d ___, No. 09–08–00083–CV slip op. (Tex. App.—Beaumont, 13 September 2012) *app. pending sub nom. Environmental Processing Systems LC v. FPL Farming Ltd.* For an excellent review of the Texas law governing these issues as it stood following *Garza*, *see* Owen L. Anderson, *Geologic $CO_2$ Sequestration: Who Owns the Pore Space?*, 9 Wyo. L. Rev. 97 (2009), *supra*. See also Gresham and Anderson, 72 U. Pitt. L. Rev. 701, 733–750 (2011).

82 *Mission Resources v. Garza Energy Trust*, 166 S.W.3d 301 (Tex. App. 2005).

83 Anderson, *Who Owns the Pore Space?* (footnotes omitted). Professor Anderson offers a cogent, practical analysis of the ownership issue, based both on Texas oil and gas law (including the rule of capture, negative capture, dominance of the mineral estate and the accommodation doctrine, and the rule that the surface owner cannot unreasonably interfere with the interests of the mineral owner), as well as general principles of property law. He concludes that a CCS project developer should seek property rights from both the surface owner as well as the mineral estate owner. The recent Texas appellate case *FPL Farming*, *supra*, currently under review by the Texas Supreme Court, however, ruled that there is a property interest in the "'briny water underneath [a landowner's] property"' and that there is "'a cause of action for trespass at common law"' in order "'to protect the owner's right to the exclusive use of [that briny water] property"'. Slip op. at 11. While the injections in that case did not involve $CO_2$, it is likely to be followed with interest by practitioners involved with $CO_2$ injection and storage issues.

84 *Getty Oil Co. v. Jones*, 470 S.W.2d 618, 621 (Tex. 1971). See also *Ball v. Dillard*, 602 S.W.2d 521, 523 (Tex. 1980); *Humble Oil & Ref. Co. v. Williams*, 420 S.W.2d 133 (Tex. 1967) (discussing excessive use).

This ‘dominant’ right of the mineral owner is normally subject to the ‘reasonable accommodation’ doctrine. While it has been adopted in a number of US states and may be applied somewhat differently in each,[85] the accommodation doctrine has been rather extensively developed under Texas law (due to the many thousands of oil and gas wells). Thus, an examination of some of the Texas case law helps to illustrate how the courts have approached the issue.

In Texas, the landmark case was decided by the Texas Supreme Court in 1971 in *Getty Oil Co. v. Jones*, 470 S.W.2d 618 (Tex. 1971). There, the dispute involved the surface owner’s facilities for irrigation and the mineral’s owners mineral owner’s need to install and operate hydraulic pumps on the surface for oil production from the mineral estate. The court determined that the height of the hydraulic pumps would destroy the surface owner’s ability to use his irrigation equipment, whereas an alternative pumping system would allow the mineral owner to extract the oil without interfering with the surface owner’s facilities. The court ruled that there must be an ‘accommodation’ between the two estates, with the owner of the mineral estate giving ‘due consideration’ to the surface estate owner’s existing uses. In that case, the court found that there were other ‘reasonable means’ that were available to the mineral owner to produce the oil ‘without interfering’ with the surface owner’s existing use (basically installing pumps that were not as high such that the irrigation equipment could pass over top). The rights implied in favour of the dominant mineral estate ‘are to be exercised with due regard for the rights of the owner of the servient estate’, concluded the court (*Getty Oil*, *supra*, 470 S.W.2d at 621).

The following year, in *Sun Oil Co. v. Whitaker*, 483 S.W.2d 808 (Tex. 1972), the court held that the dominant mineral estate, even over the objections of the surface owner, could make use of water from the servient surface estate ‘as may be reasonably necessary to carry out the lessee’s operations under the lease’ (483 S. W. 2d at 811). This right to use the surface water included using it for waterflood oil production projects. The fact that the mineral estate owner could buy water from other sources off the leased premises was deemed to be irrelevant.

Some 20 years later, in *Tarrant County Water Control & Improvement District No. One v. Haupt, Inc.*, 854 S.W.2d 909 (Tex. 1993), the court said that although the mineral estate is the dominant estate, ‘the rights implied in favor of the mineral estate are to be exercised with *due regard* for the rights of the surface owner’, concluding that:[86]

> *Where there is an existing use by the surface owner which would otherwise be precluded or impaired, and where under established practices in the industry there are alternatives available to the lessee whereby minerals can be recovered, the rules of reasonable usage of the surface may require the adoption of an alternative by the lessee.*

These principles and the effort to balance the competing interests of surface and mineral estate owners have been applied on a case-by-case basis in various disputes. Among the various issues addressed was whether a court determining whether accommodation is required[87] (and the extent of impairment to the surface owner’s utilisation of the surface allowed before accommodation is required)[88] should consider the economics of possible alternatives the mineral owner might pursue. The case law regarding the dominance of the mineral estate also sheds light on key provisions of some of the recent geologic storage statutes (discussed in Part II) that speak to the *priority* of the mineral estate in the event of a conflict between the mineral estate and the pore space ownership estate. Since the mineral estate owner may make reasonable use of the surface estate even where that would interfere with uses by the surface owner, then it would seem to follow that the mineral owner would also have the right to make reasonable use of a *subsurface portion of the surface estate* i.e. the pore space.

### iv. Pore space ownership

It is in this context of the complex interplay of overlapping or competing property rights that one should approach the much-debated question of pore space ownership. Pore space ownership for storage purposes in the US (contrary to the

85 Cases where the accommodation doctrine has been applied in other states include cases from New Mexico (*Amoco Production Co. v. Carter Farms*, 703 P.2d 894 (N.M. 1985) (‘Amoco’s surface rights and the servitude it holds, however, must be exercised with due regard for the rights of the surface owner’)); North Dakota (*Hunt Oil Co. v. Kerbaugh*, 283 N.W.2d 131 (ND 1979) (‘…the owner of the mineral estate must have due regard for the rights of the surface owner and is required to exercise that degree of care and use which is a just consideration for the rights of the surface owner…’)); Utah (*Flying Diamond Corp. v. Rust*, 551 P.2d 509 (Utah 1976) (mineral owner and surface owner ‘each should have the right to use and enjoyment of his interest…’)); Arkansas (*Diamond Shamrock Corp. v. Phillips*, 511 S.W.2d 160 (Ark. 1974) (mineral owner must make reasonable usage of the surface and is liable for damages caused by any unreasonable use)); and West Virginia (*Buffalo Mining Co. v. Martin,* 267 S.E.2d 721 (W.Va. 1980) (mineral owner’s use of surface must be ‘reasonably necessary for the extraction of the mineral’ and ‘without substantial burden to the surface owner’)).

86 854 S.W.2d at 911 (emphasis in original).

87 *Haupt, Inc. v. Tarrant County Water Control and Imp. Dist. No. One*, 870 S.W.2d 350 (Tex. App. 1994) 870 S.W.2d 350 (Tex. App. 1994).

88 *Davis v. Devon Energy Production Co., L.P.*, 136 S.W.3d 419 (Tex. App. 2004).

general rule in Canada) is usually the property of the surface owner, unless it has been specifically conveyed.[89] This is the usual approach for subsurface storage of natural gas (although of course any natural gas remaining in the proposed storage formation would need to be acquired from whoever owns it). The logic is that a standard subsurface mineral lease conveys the *mineral* interests only (e.g. 'for the sole and only purpose of mining and operating for oil and gas' or the like) and thus does not convey the *pore space itself*, once the leased minerals have been extracted. As the court explained in *Emeny v. United States*: [90]

> *The surface of the leased lands and everything in such lands, except the oil and gas deposits covered by the leases, were still the property of the respective landowners ... This included the geological structures beneath the surface, including any such structure that might be suitable for the underground storage of 'foreign' or 'extraneous' gas produced elsewhere.*

This view was cited by the Texas Supreme Court in *Humble Oil & Refining Co. v. West*,[91] where the court cited *Emeny* for the proposition that it was the surface owner who retained 'the geological structures beneath the surface, together with any such structure that might be suitable for the underground storage of extraneous gas produced elsewhere'.

The frequently cited *Mapco* case[92] ruled that in a cavern created in a salt formation via leaching out, the salt belonged to the owner of the mineral interest (i.e. the owner of the salt). But the case would appear to be distinguishable on the grounds that the storage space at issue there was found *in the mineral itself*, rather than the usual case where the leased mineral is located *in the pore space*. In addition, the storage space was specifically *created by* the mineral interest owner through the salt mining operations.

In theory, of course, a conflict could arise where the mineral owner sought to use the surface estate's interest in the pore space for EOR operations while the surface estate owner sought to lease the pore space for long-term storage that would permanently foreclose other uses of the subsurface. This may not be a likely conflict, since the use in extracting a valuable mineral would presumably be more attractive to the surface/pore space owner than the one time, exclusive use for $CO_2$ storage. But the hypothetical illustrates that it is really more the *priority among competing rights* or interests that is at issue, rather than an abstract issue of naked legal title. There is law in Texas that would support a claim by the mineral owner—such as a $CO_2$–EOR operator—that the actions of the surface owner in the hypothetical would unacceptably foreclose potential production of the oil. This would be because a portion of any $CO_2$ required *for sequestration purposes* to have been permanently stored would necessarily return to the surface *in EOR operations*. To be sure, all the produced $CO_2$ would be re-injected in the EOR operation, but it may not always be clear whether the storage rules recognise such production and recycling of $CO_2$ permanently stored.[93] If that were the case, the decision of the surface owner/pore space owner to use the pore space for 'geologic storage purposes' may well be found to be unreasonable interference with the mineral owner's right to extract the mineral. As Professor Anderson has observed:[94]

> *[A] surface owner, by asserting a right of pore-space ownership and by engaging in subsurface $CO_2$ sequestration may not unreasonably interfere with mineral exploration or exploitation.*

In view of the remaining uncertainty, however, the practical approach has been to acquire the rights from *both* the surface interest as well as the mineral interest owners.[95]

89 The case law in several states is discussed in The Interstate Oil and Gas Compact Commission Task Force on Carbon Capture and Geologic Storage, *Storage of Carbon Dioxide in Geologic Structures: A Legal and Regulatory Guide for States and Provinces*, 25 September 2007) (Part I by David Cooney, *Analysis of Property Rights Issues Related to Underground Space Used for Geologic Storage of Carbon Dioxide*); see also Colorado CCS Task Force, *Briefing Paper For Discussion: Ownership Of Pore Space* (16 April 2010) (summarising various states' positions); and Elizabeth J. Wilson and Mark A. de Figueiredo, *Geologic Carbon Dioxide Sequestration: An Analysis of Subsurface Property Law*, 36 ELR 10114, 10122–10123 ((2006) (natural gas storage law largely affirms that the surface estate owner also owns the subsurface storage pore space and concludes that both surface and mineral estates need to be involved in geologic storage projects).

90 *Emeny v. United States*, 412 F.2d 1319, 1323 (Ct. Cl. 1969) (note that this was a federal court of claims case, but applying Texas law).

91 *Humble Oil & Refining Co. v. West*, 508 S.W.2d 812, 815 (Tex. 1974) (*citing Emeny*, 412 F.2d 1319). The *Humble Oil* case also found that a company owning natural gas did not lose its property interest in the natural gas when it was injected for storage.

92 *Mapco, Inc., v. Carter*, 808 S.W.2d 262 (Tex. App. 1991), *rev'd in part on other grounds*, 817 S.W.2d 686 (Tex. 1991).

93 As discussed in Part III, the EU's CCS Directive appears to address this issue by defining the geological 'storage site' to include the 'associated surface and injection facilities' such that $CO_2$ recycled for EOR would not leave the storage site.

94 Owen L. Anderson, *Geologic $CO_2$ Sequestration: Who Owns the Pore Space?*, *supra*, *mimeo* at 5.

95 Elizabeth J. Wilson & Mark A. de Figueiredo, *Geologic Carbon Dioxide Sequestration: An Analysis of Subsurface Property Law*, 36 ELR 10114, 11022–11023 (2006); Anderson, *Who Owns the Pore Space?*, *supra*, at 5 (advising that at this point, without an affirmative ownership declaration from the Texas courts, it is advisable to gain permission from both).

### d. CONCLUDING NOTE

The key "take-away" from this brief review of US oil and gas law, however, is that merely settling the question of 'who has title to the pore space' *doesn't settle the key issues* in the $CO_2$–EOR context. These are the legal ability of the operator to inject $CO_2$ into the pore space of an oil–bearing formation and to leave it stored there along with any other permissible fluids used during operations (e.g. brine) and extract it and re-use it in oil production where operationally feasible and economically desirable. This is where analogies to the law of natural gas storage simply miss the point. Where $CO_2$–EOR operations are involved, the pore space ownership of the surface owner is viewed by the operator as pertaining only to the actual *available* pore space, which is to say that which is not occupied by residual oil. What this means is that 'a large and significant portion of the pore space in an EOR project will in fact not be initially available [for $CO_2$ storage] at the end of an EOR project because of the presence of that residual oil, which may be potentially recoverable'.[96] This is an issue that will be revisited in the context of discussing the recent state geologic storage statutes in Part II.

Assessing these and related cases specifically addressing pore space and storage rights, a number of analyses have concluded that the law in this area is unsettled and that legislation is needed to clarify matters.[97] As will be seen in Part II, a few subsequent statutes have sought to determine that the pore space 'belongs' to the surface owner. However, the complexities of subsurface interests discussed above – including the concern over not introducing potential ambiguity in thousands of previously recorded conveyances of various property rights -- have led other leading states to forego speaking to the pore space ownership issue, while focusing instead on clarifying the priority among the various subsurface interests and preserving clear title to the injected $CO_2$ itself.

## 5 Authorisation to drill wells and inject $CO_2$—managing the obligations to protect public health and safety (including underground sources of drinking water)

This is the body of regulation governing permitting of drilling and allowing injection of fluids to produce oil and to ensure the protection of health and safety. It includes rules governing liability for damage and requirements for financial responsibility to cover compensation for damage and costs of remediation. Under the *Safe Drinking Water Act of 1974* (the SDWA),[98] the US EPA sets standards for all injection wells to protect underground sources of drinking water. These federal standards for oil and gas–related wells (including the thousands of $CO_2$ injection wells) are generally applied by state regulatory agencies. Generally speaking, as long as $CO_2$ injection (and incidental storage) is taking place as part of oil and gas production operations, the $CO_2$ injectate is treated the same as other fluids used in such operations while $CO_2$ injections that are *not* part of oil or gas production operations are subject to new rules that are discussed in Part III.

### a. INITIAL DEVELOPMENT AND APPLICABILITY OF INJECTION REGULATION UNDER EPA CLASS II

Well drilling and fluid injections during drilling operations are highly regulated by the states as well as under federal rules. About 13,000 or so $CO_2$ injection and/or production wells have been drilled in the US with more than 7,200 active $CO_2$ injection wells permitted as Class II $CO_2$ injection or production wells under the US EPA's Underground Injection Control (UIC) program.[99]

Prior to adoption of the federal SDWA in 1974, state governments were responsible for issuing permits to drill wells or inject substances into the subsurface. In early production operations, the saltwater that was produced in conjunction with oil (known as oil field brine) was typically discharged into surface water, although as early as the 1930s, oil producers in Texas had begun re-injecting it into the subsurface formation. This was done both to dispose of the saltwater that might otherwise contaminate surface water due to excess salinity, as well as to maintain reservoir pressures to assist in hydrocarbon production. These were the original *injection* wells and the injection and re-pressurisation technique used can be readily recognised as a forerunner of $CO_2$ injection for EOR operations.

96 Marston and Moore, *supra*, at 475.

97 See e.g. the report by the Interstate Oil and Gas Compact Commission Task Force on Carbon Capture and Geologic Storage in 2007 (concluding that the law was 'not clearly settled, highlighting the need for statutory and regulatory clarity').

98 Pub. L. 93–523, (16 Dec. 1974), codified at 42 USC § 300 *et seq.*

99 *2012 Worldwide EOR Survey*, Oil & Gas Journal, vol. 110, number 4 (2 April 2012) (Table C) (listing 7,259 injection wells). See also Marston & Moore, *supra*, at 424 (n.6). Note that wells may alternate between injectors and producers as the $CO_2$–EOR flood proceeds over many years.

With expanded operations, concerns grew in the 1950s over saltwater contamination. In 1967, the Texas regulator generally prohibited surface discharges and moved the industry to the use of injection wells as the preferred method for disposing of oil field brine. In the following years, other states took similar action and injection wells for disposal of oil field brine became standard practice.

The SDWA directed the US EPA to establish an Underground Injection Control (UIC) program for all subsurface injection wells. Of relevance here, it tasked the EPA to develop rules setting minimum standards for state underground injection programs that would 'prevent underground injection which endangers drinking water sources'.[100] Under the SDWA, the federal government thus sets minimum standards that state UIC programs must meet. States are free to adopt more stringent rules, but must at a minimum meet the federal standards effectively preventing the endangerment of drinking water sources.

The federal UIC permitting program is for *injection* wells only; $CO_2$ *production* wells that are not also injection wells thus remain exclusively under state oil and gas regulation along with oil and gas production wells.

The statute provided for states to obtain 'primacy', which is to say to retain day-to-day administration of their own UIC programs once the federal agency determined that the state program met the applicable federal minimum standards.[101] The initial rules adopting the UIC program were finalised in 1980, and have been amended numerous times since then.[102] Of particular relevance here is the fate of the statutory and regulatory provisions addressing oil and gas wells and, in particular, secondary or tertiary recovery operations. The original statute as adopted in 1974 contained provisions that specifically addressed secondary or tertiary recovery of oil or natural gas. The initial rules promulgated by the EPA in 1980 were viewed by many in oil and gas producing states as poorly adapted to the requirements of regulating oil and gas wells. In response, the Congress amended the SDWA in 1980, adding Section 1425.[103] That section creates an alternative avenue for states to acquire primacy for a state UIC program that relates to injections in connection with oil and gas production and natural gas storage as well as *'any underground injection for the secondary or tertiary recovery of oil or natural gas*'.[104] Over the past 30 years, it is Section 1425 that has primarily governed approval of state UIC programs for $CO_2$ injections in EOR operations as well as for a great many other oil and gas wells (which is to say 'Class II' wells).

The statute also provides that in the event the EPA disapproves a state–submitted plan, the EPA may develop its own plan, but with the proviso that it may not adopt a UIC program requirement that will 'interfere with or impede' the underground injection of brine or other fluids which are brought to the surface in connection with oil or natural gas production or natural gas storage operations, or any underground injection for the secondary or tertiary recovery of oil or natural gas, 'unless such requirements are essential to assure that underground sources of drinking water will not be endangered by such injection'.[105]

100 42 USC § 300h (b)(1).

101 42 USC § 300h (b)(3). The statute speaks in terms of the state having 'primary enforcement responsibility', a phrase that has become 'primacy' in regulatory shorthand. The rules governing a state's qualification for primacy in implementing their UIC programs are codified in 40 CFR Part 145.

102 The UIC program rules are codified at 40 CFR Part 146.

103 Section 1425 is codified at 42 USC Section 300h–4.

104 42 U.S.C. Section 300h–4(a) (emphasis added).

105 42 USC Section 300–h(b)(2).

## b. THE OVERALL UIC WELL CLASSIFICATION SCHEME

Under the UIC program, the EPA developed five classes of wells, identified by roman numerals I through V.[106] Class II wells are more specifically defined as wells that inject fluids:[107]

1. which are brought to the surface in connection with conventional oil or natural gas production;
2. which are used for enhanced recovery of oil or natural gas and;
3. which are used for storage of hydrocarbons which are liquid at standard temperature and pressure.

Nearly all oil and gas producing states have qualified for primacy for these Class II wells.[108] Accordingly, it is the Class II regulations adopted by the state UIC programs that govern injection and incidental storage of $CO_2$ in EOR operations today. In most states, the Class II well permitting program is administered by the oil and gas regulatory agency while permitting for the other well classes is the responsibility of a state environmental regulator. As will be seen in the Part II discussion of the recent geologic storage statutes in several states, this distinction in administration is generally maintained.

It should be noted that natural gas storage injections are statutorily excluded from the definition of 'underground injection' under the SDWA (pursuant to a 1980 amendment).[109] Thus, the SDWA does not govern the subsurface injection and storage of toxic, inflammable and potentially explosive $CH_4$ (natural gas), but does apply to the injection and storage of non-toxic, non-inflammable and non-explosive $CO_2$.

## c. DISTINCTION BETWEEN CLASS II AND CLASS VI PERMITTING

In 2010, completing a rulemaking process begun in 2008, the US EPA promulgated a final rule establishing a new category of Class VI regulations that are applicable to owners or operators of wells that will be used to inject $CO_2$ into the subsurface for the purpose of long-term storage.[110] The Class VI rule will be described in detail in Part II. However, it important here to note that the Class VI rule does not apply in the case of $CO_2$ injection for EOR operations, except where the operator elects to transition from EOR to pure storage operations or the relevant permitting authority determines that there is increased risk to underground sources of drinking water (USDW) as compared to Class II operations based on factors set forth in the regulation. The EPA explained why it preserved the traditional Class II treatment for $CO_2$–EOR wells, stressing the key difference in the risk profiles presented by the two activities:[111]

> *EPA believes that if the business model for E[O]R changes to focus on maximizing $CO_2$ injection volumes and permanent storage, then the risk of endangerment to USDWs is likely to increase. This is because reservoir pressure within the injection zone will increase as $CO_2$ injection volumes increase. Elevated reservoir pressure is a significant risk driver at GS [geologic sequestration] sites, as it may cause unintended fluid movement and leakage into USDWs that may cause endangerment. Additionally, increasing reservoir pressure within the injection zone as a result of [geologic sequestation] will stress the primary confining*

---

106 The EPA has summarised the five well classes as follows:

- Class I wells inject industrial non-hazardous liquids, municipal wastewaters, or hazardous wastes beneath the lowermost USDW. These wells are among the deepest of the injection wells and are subject to technically sophisticated construction and operation requirements.
- Class II wells inject fluids (e.g. $CO_2$; brine) in connection with conventional oil or natural gas production, enhanced oil and gas production, and the storage of hydrocarbons that are liquid at standard temperature and pressure.
- Class III wells inject fluids associated with the extraction of minerals, including the mining of sulphur and solution mining of minerals (e.g. uranium).
- Class IV wells inject hazardous or radioactive wastes into or above USDWs. Few Class IV wells are in use today. These wells are banned unless authorised under a federal or state approved groundwater remediation project.
- Class V includes all injection wells that are not included in Classes I–IV. In general, Class V wells inject nonhazardous fluids into or above USDWs; however, there are some deep Class V wells that are used to inject below USDWs. This well class includes Class V experimental technology wells including those permitted as GS pilot projects.

*Class VI rule, infra*, 75 Fed. Regs. 77243–77244.

107 US EPA, *UIC Program Primacy: Who currently has primacy* (<http://water.epa.gov/type/groundwater/uic/Primacy.cfm#who>) (viewed 27 January 2012).

108 For updated information on which states exercise primacy for Class II wells, see <http://water.epa.gov/type/groundwater/uic/Primacy.cfm> (viewed 9 January 2012).

109 42 USC 300h(d)(1) provides that the term 'underground injection' as used there excludes:

(i) the underground injection of natural gas for purposes of storage; and
(ii) the underground injection of fluids or propping agents (other than diesel fuels) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities.

110 US EPA, *Final Rule: Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide ($CO_2$) Geologic Sequestration (GS) Wells,* 75 Fed. Reg. 77230 (10 December 2010) ('Class VI rule').

111 *Id.* 75 Fed. Reg. at 77244. Some experts believe that the EPA conclusion would be factually inaccurate if it implied that reservoir pressure within an injection zone will necessarily increase if the EOR operator seeks to optimise the total quantity of $CO_2$ stored in conjunction with an EOR operation.

> *zone (i.e. geologic caprock) and well plugs to a greater degree than during traditional E[O]R (e.g., Klusman, 2003). Finally, active and abandoned well bores are much more numerous in oil and gas fields than other potential [geologic sequestation] sites, and under certain circumstances could serve as potential leakage pathways. For example, in typical productive oil and gas fields, a $CO_2$ plume with a radius of about 5 km (3.1 miles) may come into contact with several hundred producing or abandoned wells (Celia* et al.*, 2004).*

Accordingly, the EPA determined to apply the Class VI rule only when the risk profile changes and so created a transitioning mechanism for EOR operations to transition from incidental storage of $CO_2$ during EOR operations to 'pure' or non-EOR related storage. The applicability to 'pure' storage operations and the EPA's attempt to craft a transitional path for Class II wells to shift from EOR to CCS projects are discussed in Part II. For present purposes, it is enough to note that the EPA preserved the Class II classification for $CO_2$ injection wells in traditional EOR operations largely because the continued production of oil (and brine, and entrained $CO_2$) reduces and controls the subsurface pressure while additional quantities of $CO_2$ are injected at the injection sites:[112]

> *Traditional E[O]R projects are not impacted by this rulemaking and will continue operating under Class II permitting requirements. EPA recognizes that there may be some $CO_2$ trapped in the subsurface at these operations; however, if there is no increased risk to USDWs, then these operations would continue to be permitted under Class II.*

### d. INCREMENTAL $CO_2$ INJECTIONS FOR STORAGE GENERALLY PROHIBITED FOR CLASS II WELLS

One of the key characteristics of $CO_2$–EOR operations is that the governing rules effectively prohibit the geologic storage of more $CO_2$ than is used and incidentally stored in the EOR operations. The prohibition has not been couched in these terms. Rather it has been the necessary consequence of the fact that the authorisation of a Class II permit only extends to oil and gas operations. Hence, under the Class II UIC rules, $CO_2$ injection and storage operations must come to a close with the termination of the EOR operation. The EPA's new Class VI rule provides an option to transition to *incremental* storage in the same formation. The details of that regulatory option are discussed in Part II.

### e. REPORTING $CO_2$ SUPPLY AND INJECTIONS: SUBPARTS PP, UU, RR, AND W

While leaving the UIC rules governing traditional $CO_2$–EOR operations essentially unchanged, the EPA adopted reporting rules that do apply to traditional $CO_2$–EOR operations. These reporting obligations are part of the extensive rules the EPA has adopted under its Greenhouse Gas Reporting program. Under **Subpart PP** of the new rules, suppliers producing N-$CO_2$ will now report all $CO_2$ *production,*[113] while under **Subpart UU**, $CO_2$–EOR operators will now report net injections of $CO_2$ injections for purposes of $CO_2$–EOR operations.[114] Injections of $CO_2$ for purpose of long-term storage are to be reported under **Subpart RR**, discussed in more detail in Part II.

112 *Id.* 75 Fed. Reg. at 77245.

113 US EPA, *Final Rule: Mandatory Reporting of Greenhouse Gases*, 74 Fed. Reg. 5620 (30 October 2009) ('*General GHG Reporting Rule*').

114 US EPA, *Final Rule: Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide*, 75 Fed. Reg. 75060 (1 December 2010) ('*Subpart RR and UU Reporting Rule*').

**TABLE I: Summary of reporting of $CO_2$ production and injections by EPA subpart**

| EPA GREENHOUSE GAS REPORTING REGULATION SUBPART | WHO REPORTS | WHAT IS REPORTED | INITIAL REPORT YEAR |
|---|---|---|---|
| PP | Suppliers of $CO_2$, including producers of N-$CO_2$ from geologic formations and suppliers of captured A-$CO_2$ from various processes (ammonia, coal-to-liquids, gas processing, etc) | ▪ $CO_2$ supply (i.e. $CO_2$ captured from production process units or extracted from $CO_2$ production wells, as well as imports and exports) | 2010 |
| RR | ▪ Operators of geologic sequestration facilities via Class VI wells<br>▪ EOR operators of Class II wells where operator voluntarily chooses to 'opt-in' to Subpart RR reporting | ▪ Mass of $CO_2$ received, injected and produced<br>▪ Mass of $CO_2$ emitted from surface leakage and equipment leaks and vented $CO_2$ emissions<br>▪ Mass of $CO_2$ sequestered in subsurface geologic formations.<br>Additional information required includes:<br>▪ source of $CO_2$ received<br>▪ the cumulative amount of $CO_2$ geologically sequestered since the facility first reported under subpart RR<br>▪ class of UIC permit and well identification number<br>▪ $CO_2$ concentration, mass flow or volumetric flow<br>▪ a description of the monitoring program (including monitoring anomalies and surface leakage, if any). | 2011 |
| UU | All other subsurface injectors of $CO_2$ regardless of source of $CO_2$ (principally including operators of Class II wells used in EOR operations who do not opt in to Subpart RR) | ▪ Annual mass of $CO_2$ received (essentially injections for EOR net of recycle)<br>Additional information reported includes:<br>▪ the source of the $CO_2$<br>▪ concentration<br>▪ mass flow or volumetric flow. | 2011 |
| W | All oil and gas operators | ▪ $CO_2$ emissions from oil and gas operations | 2011 |

As explained by the EPA, the Subpart PP source category is focused on upstream supply:[115]

> *It does not cover: Storage of $CO_2$ above ground or in geologic formations; use of $CO_2$ in enhanced oil and gas recovery; transportation or distribution of $CO_2$; or purification, compression, onsite use of $CO_2$ captured on site, or processing of $CO_2$. This source category does not include $CO_2$ imported or exported in equipment, such as fire extinguishers.*

Further, the EPA made clear that it did not intend to characterise all $CO_2$ supplied to the economy as 'emissions' and recognised that with respect to EOR:[116]

115 *General GHG Reporting Rule*, *supra*, 74 Fed. Reg. 56349.
116 *Id.* at 56350.

> … *the geology of an oil and gas reservoir can create a good barrier to trap $CO_2$ underground. Because these formations effectively stored oil or gas for hundreds of thousands to millions of years, it is believed that they can be used to store injected $CO_2$ for long periods of time.*

The EPA determined that it needed to acquire the production data, however, to allow the agency to evaluate the appropriate action under its statutory responsibilities, to:

- inform its evaluation of possible regulation under the *Clean Air Act* of the supplier and/or recipient of the $CO_2$, and
- 'allow EPA to make a well informed decision about whether and how to use the [Clean Air Act] to regulate facilities that capture, sequester, or otherwise receive $CO_2$ as an end-user.'[117]

Subpart RR of the reporting rules applies to $CO_2$ injections for storage purposes. Accordingly, it is an integral part of the EPA's regulatory architecture for $CO_2$ injections for CCS and will be discussed in Part II, in conjunction with the Class VI injection rules.

For present purposes, it should be noted that all $CO_2$ injections other than those under Subpart RR must be reported under Subpart UU, because the EPA has defined the Subpart UU reporting category as a 'catch-all' category. It comprises 'all facilities that inject $CO_2$ underground' *except those* that report under Subpart RR for geologic sequestration, regardless of the amount of emissions from the facility or the amount of $CO_2$ injected.

As of 1 October 2012, there were no Class VI $CO_2$ injection wells, but more than 7,000 Class II $CO_2$ injection wells. No EOR operator had opted in to Subpart RR reporting. Hence, as a practical matter, all subsurface injections of $CO_2$ incidentally stored during $CO_2$–EOR operations in 2011 were reported pursuant to Subpart UU.

There is also no distinction in the Subpart UU reporting between naturally occurring $CO_2$ (N-$CO_2$) and anthropogenic $CO_2$ i.e. captured from an emissions source (A-$CO_2$). Under the rule, it is not the source of the $CO_2$ but the injection well class or the *purpose of the injection* that is the principal dividing line between Subparts UU and RR. Injections via Class VI wells must be reported under Subpart RR, while all other injections must be reported under Subpart UU unless the operator chooses to 'opt in' to reporting under Subpart RR. The Subpart UU reporting obligation is fairly straightforward, with the rules providing specific standards for measurement and reporting. The EPA attempts to address the recycling of $CO_2$ during EOR operations by defining the term '$CO_2$ received' to mean:

> *$CO_2$ received means the $CO_2$ stream that you receive to be injected for the* ***first time into*** *a well on your facility that is covered by this subpart. $CO_2$ received* ***includes,*** *but is not limited to, a $CO_2$ stream from a production process unit inside your facility and* ***a $CO_2$ stream that was injected into a well on another facility, removed from a discontinued enhanced oil or natural gas or other production well, and transferred to your facility***. (Emphasis added.)

It is not yet clear precisely how this will be interpreted. While it appears that the agency's intent is to gather data on net injections, the definition may cause some confusion. If the report is only for $CO_2$ to be injected 'for the first time into a well' at a facility, then the report will capture *incremental* supply of $CO_2$ that comes from offsite (and will therefore appropriately avoid the 'double-counting' that would result from simply reporting all injections, including re-injection of recycled $CO_2$). But the definition goes on to say that the term includes a '$CO_2$ stream that was injected into a well on another facility, removed from a discontinued enhanced oil or natural gas or other production well, and transferred to your facility'.

Read literally, this could be read to mean that recycled $CO_2$ could be counted once when it is injected 'for the first time' at an EOR facility and then may be counted a second (or third or fourth) time as $CO_2$ 'that was injected into a well on another facility' and 'transferred to your facility. Such a reading would seem contrary to the regulator's intention, however, and EOR operators have no interest in such double-counting of net injections. As the legal and regulatory framework develops, it should be made clear that re-injected $CO_2$ cannot be double-counted as greenhouse gas (GHG) abatement, regardless of its source.

117 *Id.*

The ***Subpart PP*** obligation to measure and report $CO_2$ production became effective for calendar 2010 operations.[118] The publicly available Subpart PP data for supply facilities located in Colorado, New Mexico and Mississippi in 2010 totalled 49.4 million tonnes. This appears to be for N-$CO_2$ production and supply only and does not include non-public data from other sources.[119]

Under ***Subpart UU***, the initial reporting year for $CO_2$ injections for EOR operations was 2011. Injections totaled about 64 million tonnes, the vast majority of which was for $CO_2$-EOR operations.[120] The ***Subpart RR*** regulations (discussed in Part II) apply to operations beginning in calendar year 2011. According to the EPA reports, no $CO_2$ injections were reported under Subpart RR for 2011. Presumably, there will be no injections reported under Subpart RR unless and until any wells are permitted under the new Class VI regime.

Atmospheric emissions of $CO_2$ from oil and gas operations will be reported under Subpart W. Thus, as reporting is phased in for all the relevant categories, it should become possible to have a fairly clear, industry wide picture of the quantities of $CO_2$ injected and emitted during EOR operations on an annual basis.

In sum, to date, the EPA has preserved unchanged the current permitting rules governing $CO_2$ injection and incidental storage during traditional EOR operations as long as there is no increased risk to USDWs as compared to traditional EOR operations, while adopting reporting rules for these operations. In addition, the EPA has adopted the new well classes and reporting rules for geologic storage that are discussed below.

## 6 Liability, closure, and post-closure remediation issues (including post-closure stewardship)

### LIABILITY, CLOSURE AND POST-CLOSURE REMEDIATION

**State law issues:**

- various grounds under common law for claiming liability for damage from subsurface injections (e.g. trespass, nuisance, negligence, etc)
- financial security (e.g. bonding) required for individual wells
- industry–funded stewardship regimes fund closure or remediation for improperly plugged wells (‘orphan well’ programs).

**Federal environmental liability issues:**

- Statutory exemption from the Comprehensive Environmental response, Compensation and Liability Act (CERCLA) for ‘federally permitted releases’
- EPA 1988 regulatory exemption of $CO_2$ under the Resource Conservation and Recovery Act (RCRA)

***The practical reality is that operators are likely to assume that anyone damaged by injections will impose liability under state and/or federal law.***

118 US EPA, Greenhouse Gas Reporting Program Data for Calendar Year 2010 (<http://www.epa.gov/climatechange/emissions/ghgdata/index.html>) (viewed 19 January 2012).

119 Author’s analysis of EPA 2010 reported data for Subpart PP.

120 Author’s analysis of reported data and personal communication from EPA staff for aggregate data..

These are the rules governing how an operator obtains permission to effectively close an EOR operation by:

- plugging and abandoning the various injection and production wells
- obtaining release of financial security posted for such wells, and
- governing post-abandonment liability for any subsequent remediation steps that may be required.

### a. COMMON LAW LIABILITY ISSUES

A great deal of legal analysis has been published regarding the potential common law liability of oil and gas operators (including $CO_2$–EOR operators) for any damage that may result from these operations. Theories of liability include negligence, nuisance, trespass, strict liability (normally reserved for unusually dangerous activities), as well as statutory claims under various environmental protection and surface damage acts.[121] Each one of these approaches may support a claim for compensation by one who has been damaged by another's actions. To take just one approach to common law liability – subsurface trespass -- a good many cases have addressed questions of subsurface trespass of injected fluids in a variety of circumstances.[122] Three examples will illustrate.

In *Crawford v. Hrabe*, 44 P.3d 442 (Kan. 2002), there was a claim of subsurface trespass where wastewater injected for secondary recovery was injected into the lessor's subsurface. The plaintiff claimed injury due to migration of water throughout their subsurface. The court, however, found no actionable trespass had occurred and noted that injecting wastewater for secondary recovery operations was a practical and efficient use of a potentially hazardous waste product.

In a California case, *Cassinos v. Union Oil Company of California*, 18 Cal. Rptr. 2d 574 (Ct. App. 1993), the court found actionable trespass in the case of wastewater injected into a petroleum reservoir that caused actual damage to production operations on neighbouring land. Similarly, in *Tidewater Oil Co. v. Jackson*, 320 F.2d 157 (10th Cir. 1963) the court found actionable trespass where injected wastewater for secondary recovery flooded the neighbouring oil wells, even though the operator had obtained a regulatory permit that authorised the injections. The court reasoned that the water flooder 'may not conduct operations in a manner to cause substantial injury to the property of a non-assenting lessee-producer in the common reservoir'.

These cases often turn on the specific facts presented and the nature of the real injury or damage claimed. In a 1950 Oklahoma decision, the court reviewed claims that saltwater injected into a well on one plot of land was forced through the porous stratum into which it was injected and carried into the stratum underlying the adjacent land.[123] The court noted the state Attorney-General's concern that characterising such injections during oil production as a prohibited trespass would make underground disposal of the brine 'practically prohibited'. But the court also stressed the fact that the plaintiff did not show any *actual damage* from the subsurface migration of the injectate:[124]

> *The applicable and governing principle in this case is the rule of reasonable use, that is, that a person may use his property in any lawful manner, except that he must not use it so as to injure or damage his* neighbor.

The need to show actual damage from the subsurface migration of injected fluids is a common theme in many of the cases and liability for trespass has been found where damages were present.[125] Reviewing the case law, Professor Anderson has concluded that:

- the courts should not allow subsurface trespass claims unless the plaintiff shows substantial and actual damages
- subject to limited exceptions, injunctive relief for subsurface trespass should not be granted.[126]

---

121 For a review of the actual case law involving claims of subsurface trespass in a host of circumstances, see Owen L. Anderson , *Subsurface 'Trespass': A Man's Subsurface Is Not His Castle*, 49 Washburn L. J. 249 (2010) (<http://washburnlaw.edu/wlj/49-2/articles/anderson-owen.pdf>) (viewed 20 January 2012) (hereafter '*Anderson—Subsurface Trespass*'). For a discussion of Surface Damage Acts and the Wyoming experience, see Kulander, *Surface Damages, Site-Remediation and Well Bonding in Wyoming – Results and Analysis of Recent Regulations*, 9 Wyo. L. Rev. 413 (2009). For discussion in specific context of storage of captured $CO_2$, see Jeffrey W. Moore, *The Potential Law Of On-Shore Geologic Sequestration Of $CO_2$ Captured From Coal–Fired Power Plants*, 28 Energy L. J. 443, 477–484 (2007) (<http://www.felj.org/journal_vol28-22007.php>). For a discussion of recent state statutes addressing long-term liability and proposing a model approach, see Allan Ingelson, Anne Kleffner, and Norma Nielson, *Long-Term Liability For Carbon Capture and Storage in Depleted North American Oil and Gas Reservoirs – A Comparative Analysis*, 31 Energy L. J. 431 (2010).

122 *Anderson—Subsurface Trespass, supra*.

123 *West Edmond Salt Water Disposal Ass'n v. Rosecrans*, 226 P.2d 965, 969 (Okla. 1950).

124 *Id.*

125 *West Edmond Lime Unit v. Lillard*, 265 P.2d 730, 732 (Okla. 1954) (allowed cause of action where injected saltwater had migrated beneath neighbouring land, harming ongoing petroleum operations).

126 *Anderson—Subsurface Trespass, supra*, at 282. See also *FPL Farming v. Environmental Processing Systems* discussed *supra*, note 81.

In addition, like all oil and gas operations, $CO_2$–EOR operations are subject to complex environmental and permitting regulations. These regulatory and permitting issues are not discussed here for the simple reason that they are part of the general legal framework that applies to all similar activity and are not unique to $CO_2$–EOR. They are noted only for reasons of completeness.

## b. STEWARDSHIP REGIMES FOR ‘ORPHAN WELLS’ ARE ALREADY IN PLACE IN MOST STATES, ALONG WITH FINANCIAL SECURITY REQUIREMENTS

The real issue, then, with regard to $CO_2$ injection and production/recycling wells for EOR operations is not whether or not there is some form of operator liability or the particular legal basis asserted, but the need for a *stewardship entity* that is sufficiently well funded to take corrective action. The current ‘orphan well’ initiatives typically do not have the resources or responsibility for compensating anyone who may suffer injury from an unplugged or improperly plugged well; the focus is on repair and remediation, not on compensation. While these state initiatives go only part way toward providing a model for post-closure stewardship for long-term storage of $CO_2$ from carbon capture projects (as explained in Part II), they are an important component of the existing regulatory regime because they do establish a form of post-closure stewardship by the relevant state jurisdiction.

Assuming that viable, operating companies may face liability for repair, remediation and compensation in the event of $CO_2$ leakage or other damage resulting from $CO_2$–EOR operations, the next question is how to assure properly funded stewardship when the otherwise responsible entity is no longer present. This is the problem presented by so-called orphaned wells, where there is no longer a viable entity to undertake the work (typically, to repair a leaking well). This can occur either because the problem has arisen many years after production has ceased and the responsible company is no longer in existence, or because the company is financially unable to bear the cost of the repair work (e.g. due to bankruptcy). While various states have specific definitions of the term, an orphaned well is generally defined as one that is ‘not producing or injecting, has not received state approval to remain idle, and for which the operator is unknown or insolvent’.[127]

The problem of orphaned wells is attributable in large part to the fact that standards for drilling, plugging and abandoning oil and gas wells were not as high in the earlier days of oil and gas production, which began more than 150 years ago.[128] As a result, there are perhaps as many as 150,000 wells for which no one is responsible that have not been properly plugged.[129] The majority of these wells were drilled and abandoned more than 50 years ago, before the establishment of a formal regulatory system. On average, about 60 years elapsed between the drilling of the first exploratory well and the establishment of a formal regulatory system. As explained by a recent survey of state efforts at finding and plugging these wells, the causes of problem are varied:[130]

> *Historically, factors that contribute to the development of orphan wells are a combination of technological capabilities of the era and the economic climate. During the earliest years of petroleum production, wells were literally abandoned. The wooden superstructure might have been salvaged for other uses and as metal replaced wood, the casings and superstructure were sometimes pulled for use in other wells or for salvage value, particularly during the two World Wars when steel was in short supply. The well hole itself was left either unplugged or plugged with tree stumps, logs, mud, or a variety of other readily available materials. Generally, wells drilled prior to the 1930s were shallow and lacked a cement plug. California was the first state to make plugging with cement mandatory, but by then, the state estimates nearly 30,000 wells had been drilled. Still, many wells pre-dating 1952 were probably plugged improperly. Early cement plugs were not always effective as their compounds lacked the chemical components to withstand down-hole temperatures and pressure, so failing to harden properly. This led to the establishment of industry standards in 1952.*

127 Interstate Oil and Gas Compact Commission and US DOE NETL, *Protecting Our Country’s Resources: The States’ Case Orphaned Well Plugging Initiative* (2008) (available at <http://iogcc.publishpath.com/Websites/iogcc/pdfs/2008-Protecting-Our-Country%27s-Resources-The-States%27-Case.pdf>) (viewed 20 January 2012) (‘*IOGCC Orphan Well Report*’), at 4.

128 For example, in Texas, plugging and abandonment procedures were initiated through state-wide rules in 1933, about 30 years after the beginning of large–scale oil production in Texas. Under chapter 89 of the Texas Oil and Gas Conservation Laws and Statewide Rule 14, the Texas Railroad Commission has the authority to require the plugging of abandoned oil and gas wells. In 1965, the RRC was authorised to use state funds for that purpose. The state created a dedicated well plugging fund in 1983, which was expanded in 1991. *Id.* at 57 (Appendix BB).

129 *Id.* at 7 (Figure 1).

130 *Id.* at 4.

To address the problem, beginning in the 1960s, oil and gas producing states (and several Canadian provinces) began establishing orphaned well funding programs. The funds are raised from taxes on production, fees or other assessments. Since the first Interstate Oil and Gas Compact Commission (IOGCC) survey of orphan well initiatives began in 1992, it is estimated that the states have spent $319.1 million to plug and remediate 71,618 wells nationally.[131]

These funds are principally raised now by requiring bonds from the operator prior to drilling. While there are very great variations among the state programs, a typical approach is to vary the size of the bond in part based on the depth of the well. States typically accept different types of financial security, including surety bonds, letters of credit, certificates of deposit and cashier's checks.

Notwithstanding the current requirement for all operators to properly plug and abandon wells, there may still be ways for less fastidious operators to effectively circumvent the plugging requirement and thereby add new wells to the inventory of orphans: [132]

> *An operator [in Texas] is allowed to treat an entire lease as a single entity. So, for example, if there are ten wells on a lease and only one is a producer, then the other nine holes need not be plugged until the one well stops producing. By the time that happens, the operating company may be bankrupt. The likelihood of bankruptcy increases as the production decreases over time because wells with dwindling production typically get sold down the company 'food chain' so that wells circling the drain of economic viability are common in the portfolio of financially unstable corporations. These companies often go out of business, orphaning a large group of wells in one fell swoop. In a few cases, unbonded operators intentionally accumulated inactive wells and strip[p]ed the wells of salvage. Then they went out of business, orphaning many wells at once.*

Responsible operators who do not engage in such tactics are of course also harmed by such a practice because the state wide funding costs will be borne by those who continue to operate, potentially creating a competitive disadvantage for the responsible operators. The Texas experience thus underscores the importance of *properly designing a stewardship program* so that those who are subject to it are not able to shift costs to others by such tactics.

$CO_2$–EOR operations tend to be long-lived, such that apparently none of the sites that began being developed in 1972 have been closed.

## c. FEDERAL ENVIRONMENTAL LEGISLATION—CERCLA AND RCRA

Of more particular relevance to $CO_2$–EOR projects (and potential migration to $CO_2$–CCS), however, are two federal statutes, most often known by their acronyms of 'CERCLA' (pronounced 'serk-lah', also known as the 'Superfund' legislation) and 'RCRA' (pronounced 'rick-rah').

### i. The Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA or Superfund)

CERCLA is a federal law designed to address releases or threatened releases of hazardous substances that may endanger human health or the environment. Under CERCLA, more than 800 substances are designated 'hazardous', and many more 'potentially hazardous'. CERCLA authorises the EPA to clean up sites that have been contaminated with hazardous substances and to seek compensation from those responsible parties or compel them to perform clean-ups themselves.

CERCLA specifically exempts from the definition of 'hazardous substance' or 'pollutant or contaminant': petroleum (including 'crude oil or any fraction thereof which is not otherwise specifically listed or designated as a hazardous substance' under the statute); and 'natural gas, natural gas liquids, liquefied natural gas, or synthetic gas usable for fuel (or mixtures of natural gas and such synthetic gas)').[133] $CO_2$ itself is not listed as a hazardous substance under CERCLA, as recognised by the EPA.[134] The concern has been raised, however, that $CO_2$ injections may mobilise native substances in the subsurface and bring them into contact with groundwater, and could produce listed hazardous substances (such as sulphuric acid).

131 *Id.* at 11.

132 Kulander*, supra*, 9 Wyo. L. Rev. at 440 (footnotes omitted). See also at 442–444. For further discussion of the experience with individual state initiatives, see *OGCC Orphan Well Report, supra*, at 14–15.

133 42 USC § 9601(14) (definition of 'hazardous substance') and § 9601 (33) (definition of 'pollutant or contaminant' (2000).

134 *Class VI rule*, 75 Fed. Reg. at 77260.

The statute also exempts from liability under the CERCLA certain 'federally permitted releases'.[135] This term specifically includes 'any injection of fluids authorised under Federal underground injection control programs or State programs submitted for Federal approval (and not disapproved by the Administrator of the Environmental Protection Agency) pursuant to part C of the Safe Drinking Water Act'.[136] Hence, the injection of $CO_2$ in connection with $CO_2$–EOR operations via Class II wells that have been permitted under the UIC program is not subject to liability under CERCLA. The exclusion from CERCLA explicitly does not 'affect or modify in any way' obligations or liability that may arise under other provisions of either state or federal law (including common law) for damages resulting from a release.[137]

The exclusion of 'federally permitted releases' is not necessarily the end of the matter, however, if a given $CO_2$ stream should contain a listed hazardous substance, release of which would take it outside of the permitted terms of the UIC permit. This has not been a significant issue to date for $CO_2$–EOR operations using $CO_2$ from non-combustion sources. This is much more of a potential issue, however, in the case of A-$CO_2$ to be captured from the combustion of coal in the context of $CO_2$–CCS operations for emissions reduction purposes and will be discussed in the context of $CO_2$–CCS in Part II.[138]

### ii. Resource Conservation and Recovery Act of 1976 (RCRA) and the EPA's exemption of $CO_2$

Pursuant to Subtitle C of RCRA, the EPA has adopted regulations that establish a 'cradle-to-grave' regulatory scheme over certain 'solid wastes' that are also 'hazardous wastes'. The statute defines 'solid waste' in relevant part (with emphasis added) as: [139]

> *… any garbage, refuse, sludge from a waste treatment plant, water supply treatment plant, or air pollution control facility and **other discarded material**, including solid, liquid, semisolid, or contained gaseous material. (Emphasis added.)*

Under the EPA's regulations, the agency has further defined the term 'solid waste' as inclusive of certain 'hazardous wastes'.[140] Under the regulations, a material first must be classified as a 'solid waste' before it can be considered a 'hazardous waste'. The generator of a solid waste must make a determination whether the waste is a 'hazardous waste'.[141] A 'solid waste' is a 'hazardous waste' under the regulations if it exhibits any of four specific characteristics, which are ignitability, corrosivity, reactivity, or toxicity,[142] or if it is a waste that is specifically listed in the regulations.[143]

In amendments to RCRA adopted in 1980, Congress conditionally exempted from the 'cradle-to-grave' hazardous waste management requirements of Subtitle C certain oil and gas exploration and production wastes (drilling fluids, produced waters, and other wastes 'associated with' exploration, development, and production of crude oil, natural gas and geothermal energy).[144] The 1980 amendments also directed the EPA to conduct a study of the issue and make a report to Congress.[145] Following that, the EPA was directed to either (a) promulgate regulations under Subtitle C of the RCRA or (b) make a determination that such regulation was unwarranted.[146]

135 42 USC § 9607(j).

136 42 USC § 9601(10)(G).

137 42 USC § 9607(j) (providing that recovery by any person for response costs or damages resulting from a 'federally permitted release' shall be 'pursuant to existing law in lieu of this section' and that '[n]othing in this paragraph shall affect or modify in any way the obligations or liability of any person under any other provision of State or Federal law, including common law, for damages, injury, or loss resulting from a release of any hazardous substance or for removal or remedial action or the costs of removal or remedial action of such hazardous substance').

138 *Id.* See also e.g. Apps, J. A., *A Review of Hazardous Chemical Species Associated with $CO_2$ Capture from Coal–Fired Power Plants and Their Potential Fate in $CO_2$ Geologic Storage* (Lawrence Berkeley National Laboratory) (2006) (available at <http://escholarship.org/uc/item/2162k9tn#page-6>) (viewed 21 January 2012).

139 RCRA § 1004(27), codified at 42 USC 6903(27).

140 40 CFR § 261.2.

141 40 CFR § 262.11.

142 40 CFR § 261.20–24.

143 40 CFR 261.30–33. The EPA notes that these include wastes from non-specific sources, such as spent solvents; by-products from specific industries and discarded, unused commercial chemical products.

144 Solid Waste Disposal Act Amendments of 1980 (Pub. L.94–580), adding provision now codified at 42 USC 3001 (b)(2)(A).

145 42 USC 8002(m).

146 42 USC 3001(b)(2)(A).

In 1988, having completed its study and report to Congress, the EPA made the determination that regulation of these substances was ‘not warranted’ and so determined to exempt them from Subtitle C of RCRA.[147] In particular, the EPA determined that produced water injected for enhanced recovery is ‘not a waste’ for purposes of RCRA regulation and therefore not subject to regulation under either Subtitle C or Subtitle D of RCRA. The EPA noted that produced water used in enhanced recovery ‘is beneficially recycled and is an integral part of some crude oil and natural gas production processes’ and already regulated under the UIC program under the SDWA.[148] The EPA determined that the Subpart C regulatory scheme was unnecessary for the safe management of oil and gas wastes. It determined not to promulgate Subpart C regulations for large volume and associated wastes generated by the exploration, development and production of crude oil and natural gas.[149] As a similar integral part of the oil production process, $CO_2$ injected for EOR has thus not been considered a waste within RCRA.

In sum, RCRA regulation has generally not been an issue for $CO_2$ injections for EOR operations. As with CERCLA, its potential for applicability to permanent geologic storage of $CO_2$ streams captured from combustion sources is another matter. The EPA has recently proposed a conditional exclusion from RCRA of $CO_2$ injections for geologic sequestration under certain circumstances. The EPA’s proposed rule will be discussed in Part II.

### d. TWO CONCLUDING THOUGHTS ON $CO_2$ INJECTIONS IN EOR OPERATIONS AND LIABILITY

In light of the long history of injecting various fluids into the subsurface during oil and gas operations, the $CO_2$–EOR operator views $CO_2$ injection as a fairly routine oil field procedure. It is perhaps not surprising that a noted oil and gas law professor views $CO_2$ injections for long-term storage as legally similar to injections of produced water:[150]

> *That $CO_2$ is also injected for sequestration should be no different than injecting saltwater for EOR. When saltwater is injected, either partially or wholly for EOR or disposal purposes, permanent sequestration of the saltwater is contemplated, although, potentially, the saltwater could be withdrawn for use in another EOR project. The same would hold true with $CO_2$.*

This fundamentally different experience of the $CO_2$–EOR industry thus brings a quite different perspective to the CCS debates than is found among those less familiar with the industry.

The second differing perspective relates to liability for injections. As a practical matter, anyone damaged by a $CO_2$ injection that leaks from the target formation is likely to seek compensation from the $CO_2$–EOR operator under one theory or another. The details of the theory of liability that is advanced in a particular claim or the particular defences that may be applicable will vary from case to case, and individual outcomes may differ. Those details will be crucially important to individual parties in individual cases. But for purposes of planning and executing operations generally—and for considering how to address liability questions in the context of possible CCS legislation—the operator is likely to assume that if something goes wrong in the transport, injection, recycling or storage of $CO_2$ in an EOR operation, any injured party will seek redress and compensation from the operator. After all, in light of the myriad avenues for asserting liability, plaintiffs will not lack for legal bases upon which to assert their claims. What this means is that, *for practical purposes*, the $CO_2$–EOR operator may well anticipate liability for compensating for damages resulting from $CO_2$ leakage, either on the surface or in the subsurface. As one representative from an environmental organisation put it:[151]

> *In a very real sense, there is no liability issue, or at least there should not be. A liability regime for CCS already exists. It consists of the existing state and federal laws and procedures pursuant to which actors can be held liable under certain circumstances for damages caused by their actions ... The existing liability regime applies to*

147 US EPA, *Regulatory Determination for Oil and Gas and Geothermal Exploration, Development, and Production Wastes*, 53 Fed. Reg. 25447 (6 July 1988), *codified at* 40 CFR 261.4(b)(5) (5) (including in the list of ‘solid wastes which are not hazardous wastes’; ‘Drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy’ (available at <http://epa.gov/osw/nonhaz/industrial/special/oil/og88wp.pdf> (viewed 21 January 2012) (hereafter ‘*1988 Regulatory Exemption*’). In 1993, the EPA issued clarification of the scope of the exemption particularly as it relates to crude oil reclamation, service companies, gas plants and feeder pipelines, crude oil pipelines, and natural gas storage and re-injection. US EPA, *Clarification of the Regulatory Determination for Wastes from the Exploration, Development and Production of Crude Oil, Natural Gas, and Geothermal Energy*, 58 Fed. Reg. 15284 (22 March 1993) (<http://www.epa.gov/osw/nonhaz/industrial/special/oil/og93wp.pdf>).

148 *1988 Regulatory Exemption, supra*, 53 Fed. Reg. at 25454.

149 *Id.* at 25456.

150 *Anderson—Who Owns the Pore Space? Supra*, 9 Wyo. L. Rev. at 102.

151 A. Scott Anderson, *Carbon Sequestration in Oil and Gas Fields (in Conjunction with EOR and Otherwise)*, at 18 (published in report of joint Symposium of the MIT Energy Initiative and Bureau of Economic Geology at University of Texas, Austin, *Role of Enhanced Oil Recovery in Accelerating the Deployment of Carbon Capture and Sequestration* (23 July 2010) (available at <http://web.mit.edu/mitei/research/reports/110510_EOR_Report.pdf>).

> *many industries, including industries that spend millions and even billions of dollars on projects that entail long-term risks that are much greater than the risks that are expected to be created by CCS. These industries are able to attract capital and make investments. Businesses in many industries routinely conduct operations that expose the owners to potential liability for indefinite periods or even permanently—these financial risks generally persist until statutes of limitation run (if there are applicable statutes of limitation) or companies receive bankruptcy protection. Steel mills and refineries do not enjoy 'liability relief' that allows them to escape this liability regime. Neither do the EOR business, the gas storage business, or the underground injection of industrial or hazardous waste businesses. Yet none of these industries have trouble attracting capital when prices for their goods and services are favorable. It is worth noting in this context that $CO_2$ does not explode or ignite, and that it is not considered a hazardous waste.*

In sum, corporate liability for operational negligence is not unusual and can generally be borne where the underlying activity—in this case, producing oil—has sufficient commercial value. Much of the difficulty raised by the spectre of civil liability in the $CO_2$–CCS world comes from the fact that the underlying storage activity does not itself generate commercial value, such that *any* liability tends to be viewed as too much. This is a key distinction with incidental storage of $CO_2$ during EOR operations and is discussed further in Part III.

B

# Canada

## CANADA

**Subsurface ownership:**

- subsurface may be privately held, but provincial governments own considerable majority of the subsurface mineral rights
- provinces have constitutional power to take land without compensation; Alberta has now exercised that power to take pore space for $CO_2$ storage.

**Pipeline transportation regulation:**

- the National Energy Board (NEB) has permitting and economic regulatory jurisdiction over interprovincial $CO_2$ pipelines
- provincial regulators have jurisdiction over intra-provincial $CO_2$ pipelines.

**Liability for closing and properly abandoning wells:**

- provincial oil and gas regulators regulate well drilling and abandonment
- liability for remediation may continue long after post-closure
- industry funded 'orphan well' fund for remediation work where responsible party cannot be found or is unable to undertake required work.

## 1 Overview

### a. THE CANADIAN $CO_2$–EOR EXPERIENCE

The Canadian $CO_2$–EOR industry is considerably smaller than in the US, with roughly 195 $CO_2$ injection wells reported active in the most recent industry survey. The vast majority are associated with the Weyburn project in Saskatchewan (about 175 wells).[152]

There are significant projects under construction or in development in both Alberta and Saskatchewan that would expand $CO_2$–EOR operations using $CO_2$ captured by new projects developed for emissions reduction purposes. In addition to $CO_2$–EOR operations, however, there are significant operations in Alberta and British Columbia for subsurface injection of a mix of $CO_2$ and hydrogen sulphide (generally referred to as 'acid gas'). This toxic acid gas has been injected in both EOR production operations as well as non-EOR disposal operations.[153]

152 2012 Oil & Gas Survey, *supra*, Table D.

153 For overview of acid gas EOR operations, see Steven A. Smith, *et al. Zama Acid Gas EOR $CO_2$ Sequestration and Monitoring Project*, paper presented at Sixth Annual Conference on Carbon Capture & Sequestration (Pittsburgh 2007) (available at <http://www.netl.doe.gov/publications/proceedings/07/carbon-seq/data/papers/tue_081.pdf>). For overview of non-EOR operations, see Stefan Bachu and William D. Gunter, *Overview Of Acid-Gas Injection Operations In Western Canada*, vol. I, Proceedings 7th Intl Conference on Greenhouse Gas Control Technologies (September 2004) (Vancouver Canada) (2005), at 443–448 (available at <http://uregina.ca/ghgt7/PDF/papers/peer/588.pdf>).

At the Weyburn facility in Saskatchewan, $CO_2$ that is captured at a 1980s' era coal-to-natural gas facility in North Dakota, US, is transported across the border to the site where it is injected for EOR operations. While the project is unique in using $CO_2$ that has been captured from a commercial–scale coal-to-natural gas facility, the EOR component of the operation is largely comparable to those elsewhere. Weyburn is also distinctive, however, with regard to the high level of monitoring conducted.

Public concerns were voiced in early 2011 that $CO_2$ injected at the Weyburn site might be leaking to the surface and into well water at a nearby farm. In December 2011, following an extensive investigation, the final report issued by the International Performance Assessment Centre for Geologic Storage of Carbon Dioxide in Saskatchewan concluded that the $CO_2$ levels were in fact normal and there was no evidence that the injected $CO_2$ had leaked as alleged.[154]

## b. GENERAL LEGAL AND REGULATORY RULES

The general legal and regulatory system in Canada as it relates to oil and gas matters generally has many similarities with the US, but some distinct differences as well. As in the US, Canada has a federal legal system in which the constitution divides legal and regulatory powers between the federal government and the provinces. Property law issues are generally a matter of provincial law, unless the case in question is on federal land or involves interprovincial or international property issues. [155]

There are important differences from the US legal framework, however. For example, while mineral rights can be privately owned, the federal government owns large amounts of land in the territories and lesser amounts in the provinces (typically parks) and the provincial governments have majority holdings of the mineral resources.[156] In addition, the provinces generally have a more important land holding and management role than do the states in the US. For example, some of the eastern provinces (New Brunswick, Quebec and Nova Scotia) vest natural gas storage rights in the Crown (i.e. the provincial government). In British Columbia, there is a mechanism for vesting storage rights in the Crown on a case-by-case basis. Further, the ownership of subsurface waters in aquifers is generally held by the federal or provincial government. In Saskatchewan, The *Crown Minerals Act 1985* (s. 27.2) provides that all 'spaces'—defined as 'spaces occupied or formerly occupied by a Crown mineral'—are the property of the Crown.

Perhaps the most distinctive difference from the standpoint of property issues affecting $CO_2$ storage, however, is that the government has a sovereign constitutional power to take real property without compensation if it is sufficiently clear in its intent to do so.[157] Unlike the American Constitution's prohibition of governmental taking of "'life, liberty or property' without due process of law or taking property for public use without just compensation, as discussed above, Section 7 of the Canadian Charter of Rights and Freedoms provides that:

> *Everyone has the right to life, liberty and security of the person and the right not to be deprived thereof except in accordance with the principles of fundamental justice.*

The limitations in Canada on the government's power to take property without compensation lie more in the political and judicial realms than in the nature of the property right itself. This legal distinction has considerable impact on defining the range of possible approaches to acquiring and aggregating pore space for possible $CO_2$ storage sites. As will be seen in Part II, at least one Canadian province has already exercised this power and deemed the relevant pore space to belong to the Crown, without further judicial procedure or payment of compensation.

As a general matter, mineral interests underlying land may be separated from the surface estate and further split with regard to the type of mineral estate held or conveyed (e.g. petroleum, natural gas, bitumen).[158]

154 International Performance Assessment Centre for Geologic Storage of Carbon Dioxide, '*International Team of Scientists Conclude No Carbon Dioxide ($CO_2$) Leaked On Kerr Farm*' (<http://www.ipac-co2.com/projects/kerr-investigation/news-release>); Dr George William Sherk, *et al. The Kerr Investigation Final Report: Findings Of The Investigation Into The Impact Of $CO_2$ On The Kerr Property* (December 2011).

155 As noted by Bankes and Gaunce: 'The determination of who owns storage rights (as between the Crown, mineral owners, and surface owners) is clearly a matter of property and civil rights and a part of provincial jurisdiction under section 92(13) of the Constitution Act, 1867.' Nigel Bankes and Julia Gaunce, *Natural Gas Storage Regimes In Canada: A Survey* (ISEEE Research Paper) (December 2009) (available at <http://www.iseee.ca/media/uploads/documents/pdfs/researchreports/Nat_gas_storage_cdn_survey.pdf>) (viewed 22 January 2012), at 118.

156 Given the likelihood that geologic storage of $CO_2$ in Canada is far more likely to begin in the oil and gas producing provinces, this paper focuses there, and does not address the frameworks applicable in the other provinces.

157 J. B. Cullingworth, *Urban and regional planning in Canada* (1987) at 174.

158 For a more detailed review of provincial legislation governing landholding rights, see the Carbon Capture Legal Programme materials, *Property rights: Canada*, at http://www.globalccsinstitute.com/networks/cclp/legal-resources/property-rights/canada.

Similar to the US, provincial oil and gas law in Canada has generally followed a form of the rule of capture, well-articulated in *Borys v. C.P.R.*:[159]

> *The substances are fugacious and are not stable within the container although they cannot escape from it. If any of the three substances is withdrawn from a portion of the property which does not belong to the appellant but lies within the same container and any oil or gas situated in his property thereby filters from it to the surrounding lands, admittedly he has no remedy. So, also, if any substance is withdrawn from his property, thereby causing any fugacious matter to enter his land, the surrounding owners have no remedy against him. The only safeguard is to be the first to get to work, in which case, those who make the recovery become owners of the material which they withdraw from any well which is situated on their property or from which they have the authority to draw.*

While speaking in somewhat different terms than some of the Texas cases, *Borys* also highlighted the impact of allowing one estate to be dominant over the other and the need to assess these competing rights:[160]

> *For the purpose of their decision their Lordships are prepared to assume that the gas whilst in situ is the property of the appellant even though it has not been reduced into possession, but the question is not whose property the gas is, but what means the respondents may use to recover their petroleum.*

One commentator summarises *Borys* as standing for the proposition that:[161]

> *… in split title cases, the person holding the gas rights may not prevent the holder of the oil rights from producing oil as long as that party's working activities are reasonable and in keeping with industry practice and even if, as a result of natural effluxion, some of the gas cap gas is produced with the oil by the oil rights holder.*

While Canadian courts in the oil and gas provinces adopted the rule of capture, the development of the industry largely post-dated its development in the US, allowing the legislatures to respond more quickly to the adverse effects of an unmodified version of the rule:[162]

> *In Canada, suffice it to say that by the time oil and gas exploration activity was gearing up, in Alberta in particular, Canadian policy- and law-makers had had the benefit of observing the free-for-all south of the border and the resultant waste. As a consequence, rules that had the effect of damping the effects of the rule of capture were introduced early on through conservation legislation.*

Of particular interest to the $CO_2$–EOR operations, the rule in Canada emerged largely in cases involving split estates (as opposed to adjacent surface estates). In other words, these were cases where the production of one mineral was alleged to have an adverse effect on another subsurface mineral interest (e.g. oil production adversely affecting natural gas or where the production of bitumen also produced separately owned natural gas). The cases highlight the competing potential uses and resources of the subsurface and the need for rules governing priority among competing rights. In the event of a single government owner of the subsurface, there is a need to establish priorities to govern licensing decisions and a concomitant need to reflect those priorities in any permits or licenses granted to private parties for development.

With regard to a 'negative' or 'reverse' rule of capture, the Canadian courts have apparently not adopted such an approach.[163] However, if the owner of petroleum was allowed by the applicable rules to inject $CO_2$ in order to produce oil, those injections could presumably proceed even if they interfered with the ability of the other subsurface interest owners. This would presumably include the right to occupy with the $CO_2$ any pore space from which the oil was displaced. Hence, it is not so much the ownership of the pore space that is necessarily the key issue, but rather the *priority of the pore space interest* (regardless of who owns it) in relation to the other subsurface interests. To paraphrase *Borys*, even if one assumes that the pore space while *in situ* is the property of the surface owner and even though it has not been occupied

159 2 DLR 65 (PC) (1953) (*Borys*). For a detailed but concise summary of the history of the rule of capture in the US and its adoption in Canada, see Cecilia A. Low, *The Rule Of Capture: Its Current Status And Some Issues To Consider*, 46 Alberta L. Rev. 799 (2009) (available at <http://www.albertalawreview.com/index.php/alr/article/view/118>) (viewed 22 January 2012) (hereafter, '*Low, The Rule of Capture*'). For citations to some of the relevant legal literature examining the application of the rule of capture in the Canadian oil and gas context, see esp. articles cited at n.9).

160 *Borys, supra* at 77 (emphasis added).

161 Low, *The Rule of Capture*, *supra*, at 809.

162 *Id.* at 805–806 (2009) (footnote omitted).

163 Low, *The Rule of Capture*, *supra*, and personal communication with the author.

by the surface owner's operations, the question is *not whose property the pore space is, but what means the owners of the petroleum interest may use to recover their petroleum*.

With regard to pore space ownership, there was some difference historically with the US because its ownership for storage purposes in oil and gas formations generally followed the ownership of the mineral interest (in Alberta, for example). Recent legislative changes in Alberta and British Columbia have essentially resolved any legal questions over pore space ownership and use by assigning pore space for storage of $CO_2$ to the provincial governments, making a discussion of pre-existing law governing pore space a matter of historical interest only. Accordingly, a discussion of the currently applicable legal framework regarding property rights for storage in these jurisdictions is best considered in the context of the new legislation reviewed in Part II.[164]

**PIPELINE REGULATION IN CANADA**

- The National Energy Board has jurisdiction over interprovincial $CO_2$ pipeline construction
  - only one significant interprovincial line (serving the Weyburn EOR/storage project).
- Safety regulation is administered by the Canadian Transportation Safety Board (TSB).
- Provincial authorities have jurisdiction over $CO_2$ pipelines that are entirely within an individual province.

## 2 Transporting $CO_2$ supply to market—regulation of pipeline siting, constructing and operation, including safety regulation

At present, there is a single $CO_2$ pipeline in Canada, although significant projects are under active development in Western Canada. The existing pipeline is the Souris Valley $CO_2$ pipeline licensed by the federal National Energy Board (NEB) to carry $CO_2$ to EOR operations in Saskatchewan (the pipeline feeding the Weyburn project with $CO_2$ captured from the North Dakota coal gasification facility constructed in the 1980s).[165] The projects under active development are intraprovincial lines.

### a. FEDERAL REGULATION BY THE NEB

#### i. General

Prior to 1 July 1996, the NEB's jurisdiction was limited to pipelines transporting oil or gas. Under legislation that came into force on that date, however, jurisdiction over pipelines transporting commodities other than oil and gas (commodity pipelines) was transferred from the National Transportation Agency (now the Canadian Transportation Agency) to the

164 For additional detail on the property regimes in the Canadian provinces, see Carbon Capture Legal Programme materials, supra note 158. For reviews of the pre-existing ownership regimes and the issues the legislative draftsmen confronted in the recent legislation, see Nigel Bankes, *Legal Issues Associated with the Adoption of Commercial Scale CCS Projects* (November 2008); Nigel Bankes and Julia Gaunce, *Natural Gas Storage Regimes In Canada: A Survey* (ISEEE Research Paper) (December 2009) (available at (<http://www.iseee.ca/media/uploads/documents/pdfs/researchreports/Nat_gas_storage_cdn_survey.pdf>); and Nigel Bankes, *Developing a Legal Regime for Carbon Capture and Storage in Canada: Some reflections based upon a survey of natural gas storage regimes* (ISEEE Research Paper) (December 2009) (<http://www.law.ucalgary.ca/system/files/Bankes_CCS_regime_for_Canada_reflections.pdf>)(viewed 6 January 2012).

165 National Energy Board, *Reasons for Decision Souris Valley Pipeline Limited*, No. MH–1–98 (October 1998) (available at <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90464/90554/92820/92821/92823/1998-10-01_Reasons_for_Decision_MH-1-98.pdf?nodeid=92830&vernum=0>) (viewed 22 January 2012). More information on NEB regulation of commodity pipelines is available from the NEB's *Information Bulletin on the Regulation of Commodity Pipelines*, appended to document at: <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90463/334304/334294/A0L0L7_-_Letter.pdf?nodeid=334295&vernum=0> (viewed 22 January 2012). See also Office national de l'énergie, *Motifs de décision:Souris Valley Pipeline Limited* (MH–1–98) (Octobre 1998) (version en français) (<https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90464/90554/92820/92821/92823/1998-10-01_Motifs_de_d%E9cision_MH-1-98.pdf?nodeid=92827&vernum=0>) (viewed 22 January 2012).

NEB. Accordingly, interprovincial $CO_2$ pipelines must now obtain authorisation from the NEB under the *National Energy Board Act 1985* (NEB Act), which deals with the construction and operation of pipelines. Public hearings are required if the pipeline is to exceed 40 km in length, but the NEB may at its discretion conduct a hearing regarding shorter pipelines.

Under the *Canadian Environmental Assessment Act 2012* (CEAA), the NEB is required to conduct an environmental review of proposed commodity pipelines (including, as noted, $CO_2$ pipelines).

For safety regulation, $CO_2$ pipelines are within the purview of the *Canadian Transportation Accident Investigation and Safety Board Act 1989* and the Transportation Safety Board Regulations. Similar to the US Department of Transportation PHMSA safety regulation, the Canadian Transportation Safety Board (TSB) maintains a mandatory incident reporting system.

With regard to tariff and rate regulation (under Part IV of the NEB Act), shipper–owned pipelines are designated 'Group 2' pipelines. They are not subject to the cost recovery and related regulations that apply to oil and gas pipelines.

After receiving jurisdiction over commodity pipelines in 1996, the NEB determined that it would be more practical to regulate non-oil or gas pipelines on a case-by-case basis, rather than under its general regulations for onshore pipelines. As a result, interprovincial $CO_2$ pipelines (like other non-oil and gas commodity pipelines) are exempt from the provisions of the Onshore Pipeline Regulations (OPR–99) and are instead regulated on a case-by-case basis.[166]

### ii. The Souris Valley $CO_2$ pipeline authorisation

The Souris Valley Pipeline Ltd (Souris Valley Pipeline) is apparently the only $CO_2$ pipeline under the Board's jurisdiction at present. It was approved in 1998. The Board conducted a full investigation and a trial-type hearing on the proposal, including details of proposed construction design, safety standards for construction, environmental impact, etc. The Board issued its Reasons for Decision, approving the construction in October 1998. The pipeline was subsequently constructed and has been operating since then.

Unlike any of the existing US $CO_2$ pipelines, the Souris Valley $CO_2$ pipeline carries and injects $CO_2$ that is derived from a coal–gasification process. As a result, the composition of the $CO_2$ includes some substances that would be listed as hazardous substances in the US, including, in particular, hydrogen sulphide ($H_2S$), due to the amount of sulphur contained in the coal fed into the gasifier. The anticipated normal composition of the pipeline gas mixture at the time of the application was 97 per cent $CO_2$ and 0.8 per cent hydrogen sulphide, with not more than two per cent by volume of nitrogen or two per cent by volume of methane (natural gas). The maximum concentrations of $CO_2$ and hydrogen sulphide were not to exceed 98 per cent and two per cent, respectively. The NEB conducted a risk analysis of potential leaks of both materials in evaluating whether to approve construction.[167]

## b. PROVINCIAL REGULATION OF $CO_2$ PIPELINES

There are several significant $CO_2$ pipeline projects under development at the provincial level that will require authorisation from the relevant provincial regulator, with one project having now been authorised by the regulator. In Alberta, a license from the Energy Resources Conservation Board (ERCB) is required under the *Alberta Pipeline Act (Consolidated)* and Pipeline Regulation in order to construct and operate a pipeline, including a $CO_2$ pipeline within the province. Similarly, in British Columbia, the *Oil and Gas Activities Act* 2008 and Regulation requires a certificate from the provincial's Oil and Gas Commission before a pipeline may be constructed. In Saskatchewan, the Ministry of Energy and Resources (ER) has jurisdiction under the *Pipelines Act 1998* over the intraprovincial portion of the Weyburn project's pipeline (the portion running between the two fields).

The Alberta ERCB has established general requirements that must be met by $CO_2$ pipeline companies, which are included in its Directive 56. The licensing procedures for a $CO_2$ pipeline under Alberta's Directive 56 are more streamlined than those used by the NEB for the federally–approved Souris Valley Pipeline. On 26 April 2011, the ERCB issued a license for the construction and operation of the first $CO_2$ pipeline for $CO_2$–EOR in Alberta, the Alberta Carbon Trunk Line (ACTL), developed by Enhance Energy. The ACTL pipeline presents a somewhat unique situation with regard

166 *Id.* at 3.

167 *Souris Valley $CO_2$ Pipeline*, *supra*, at 7–14.

to sizing the pipeline in that the Alberta Government is providing significant funding for the project in part to allow initial construction to be designed for an eventual capacity of about 14.6 million tonnes a year.[168] This is considerably in excess of the anticipated initial commercial requirements of approximately 1.8 million tonnes a year.[169] Thus, the ACTL system is being designed as a 'trunk' line to accommodate $CO_2$ supply offered by multiple yet to be defined capture sources. In February 2011, the Alberta Government agreed to terms and conditions for the new pipeline, as well as to support construction of the industrial capture source (a bitumen refinery).

**POST CLOSURE LIABILITY AND FINANCIAL SECURITY**

- Indefinite and continuing liability at the provincial level of the well operator to properly 'abandon' (i.e. plug) all wells and conduct remediation in the event required, even years after production has terminated.
- 'Orphan well funds' created at the provincial level (funded by an annual levy) to provide funds for remediation where the responsible party is unavailable or unable to conduct remediation.

## 3 Post-closure liability and financial security for well remediation

In the oil and gas provinces of Canada, there is a complete existing framework governing well drilling, the injection of fluids (including $CO_2$) during operations, and the proper closure and abandonment of drilling sites. Professor Nigel Bankes *et al* has presented a review of each of the aspects of the Canadian legal and regulatory regime as it stood shortly before the major legislative changes adopted in 2010.[170]

The $CO_2$–EOR operator bears the risk of damage to human health and safety as well as damage to the surrounding environment (including underground sources of drinking water). The responsibility for remediating leaking wells may extend indefinitely, even after approved well closure (at least in Alberta). Well operators in the Canadian oil and gas provinces are required to 'abandon' wells upon completion of operations. In this context, the term abandon means to complete proper well plugging and related operations to ensure that the subsurface formation is isolated from the surface, and that there is no leakage of fluids from the oil or gas producing formation into drinking water sources. For example, the *Alberta Oil and Gas Conservation Act 2000* (OGCA) (RSA, c O–6 (1)(1)(a)) defines 'abandonment' generally as 'the permanent dismantlement of a well or facility in the manner prescribed by the regulations and includes any measures required to ensure that the well or facility is left in a permanently safe and secure condition'.[171] The OGCA, as implemented by the Board, requires the well operator to abandon a well when required by regulation.

Similar to the orphan well programs in the US, the Alberta framework establishes an 'Orphan Fund', financed by fees imposed on the industry to address cases where the well operator or working interest owners fail or are unable to complete proper abandonment of a well. The Board may in effect hire third-party contractors to undertake the proper remedial work to ensure that the well is left permanently in a safe and secure condition, with the cost borne by the Orphan Fund.[172] The operation of the orphan well funding mechanism is discussed extensively in the literature.[173]

168 Enhance Energy, Inc., *The Alberta Carbon Trunk Line Project Fact Sheet,* (available at <http://www.enhanceenergy.com/pdf/ACTL/actl_fact_sheet.pdf>) (viewed 10 February 2012).

169 Zero Emissions Resource Organisation, project database entry for Alberta Carbon Trunk Line (Enhance Energy) (<http://www.zeroco2.no/projects/alberta-carbon-trunk-line>).

170 Nigel Bankes, Jenette Poschwatta, and E. Mitchell Shier, *The Legal Framework For Carbon Capture And Storage In Alberta*, 45 Alberta L. Rev. 585 (2008).

171 The Oil and Gas Conservation Act is available at <http://www.canlii.org/en/ab/laws/stat/rsa-2000-c-o-6/latest/rsa-2000-c-o-6.html> (viewed 23 January 2012).

172 The programs of Alberta and Saskatchewan, in particular, are summarised in the *IOGCC Orphan Well Report*, *supra*, at 16.

173 See e.g. De Figueiredo, *The Liability of Carbon Dioxide Storage*, (PhD thesis 2007), pp. 257–259.

Moreover, under s. 29 of the OGCA, 'Continuing liability', the statute provides that:

> *Abandonment of a well or facility does not relieve the licensee, approval holder or working interest participant from responsibility for the control or further abandonment of the well or facility or from the responsibility for the costs of doing that work.*

The practical impact of that continuing liability was demonstrated rather pointedly in 2010 when the ERCB required the successor in interest to bear remediation responsibility for a well that was licensed in 1911, last produced oil in 1921, and was abandoned in 1926. The agency received a complaint of possible leakage from the well in 2005. Following inquiry, the ERCB eventually directed the successor in interest to conduct remedial work to 're-abandon' the well; the company failed to do so; and the ERCB carried out abandonment operations and invoiced the company for the roughly CA$500,000 cost (including a penalty for failure to pay). The Board concluded:[174]

> *The fact that the well had been abandoned 50 years earlier does not affect current liability for the additional abandonment work that later became necessary. It is not unusual for a well to require further abandonment after abandonment work has been completed. Section 29 of the OGCA addresses that very situation. It reads:*
>
> > Abandonment of a well or facility does not relieve the licensee, approval holder or working interest participant from responsibility for the control or further abandonment of the well or facility or from the responsibility for the costs of doing that work.
>
> *Section 29 prevents a licensee, approval holder or W[orking] I[nterest] P[articipant], as the case may be, from avoiding liability for control or further abandonment work of a well or from liability for the costs of such work. The Board interprets Section 29 as prohibiting such parties from using previous abandonment of a well as a shield to protect them from liability for future abandonment work or abandonment costs. The Board finds that Section 29 prevents the WIP in this well from avoiding liability for payment of costs merely because the well had previously been abandoned to a satisfactory condition. Section 29 ensures that Section 30 applies to further abandonment work, in addition to the initial abandonment.*

While the fairly evident implications of this ruling for liability frameworks for $CO_2$–CCS storage projects will be discussed later, Professor Bankes has concluded that:[175]

> *This decision demonstrates that in the conventional oil and gas business (and not just the conventional business because the ss. 28–30 OGCA obligations apply, for example to acid gas disposal wells), the industry in practice operates within a rule system that leaves liability on a long-term and ongoing basis firmly with owners and operators, and only secondarily with the industry fund; and only if that were to turn out to be under-capitalised would there then be recourse to general revenues (and then only as a matter of policy and discretion and not as a matter of law).*

174 ECRB Decision 2010–019, *Dalhousie Oil Company Limited*, S*ection 40 Review of Abandonment Cost Order No. ACO 2008–1 (Turner Valley Field*) (18 May 2010) (available at <http://www.ercb.ca/docs/documents/decisions/2010/2010-019.pdf>) (viewed 23 January 2012).

175 Nigel Bankes, *A Century of Liability for an Abandoned Well*, (20 June 2010), at 2 (<http://www.ablawg.ca>).

C

# European Union and its Member States

## EUROPEAN UNION

**No history of, or current, $CO_2$–EOR operations (except for Hungary)**

**$CO_2$ viewed as a waste, not a commodity**

**Limited $CO_2$ pipeline infrastructure:**

- short-haul pipelines for EOR in Hungary; non-EOR distribution lines in Netherlands; short pipeline in non-Member State Norway.

**Subsurface ownership:**

- generally owned by the Member State
- property rights issues far simpler than in the US
- must still address competing potential uses of the subsurface.

**Environmental limitations—cross-border transport and marine storage of waste $CO_2$:**

- the OSPAR Convention (pre-2007 changes) allowed $CO_2$–EOR, but prohibited $CO_2$–CCS
- the London Protocol applies to $CO_2$ injections as waste only; recent changes allow storage of waste $CO_2$ on national territory, but apparently still prohibits its cross-border movement

The state of play in the EU and its Member States regarding $CO_2$ injections and storage—whether in EOR or non-EOR projects—is quite different from that in North America in a number of important respects. Unlike in North America, $CO_2$–EOR operations in the EU to date are extremely limited. Other than projects in Hungary (which became an EU Member State in 2004), there have apparently been no $CO_2$–EOR operations in the EU Member States, although a number of projects are under active development.[176] The principal reason for the difference with the North American experience has been an unavailability of low–cost supplies of $CO_2$.[177] While there are various natural reserves of $CO_2$ in Europe, it has apparently not yet been economic to develop them for EOR (again, with the exception of Hungary).[178]

176 Tzimas, E., Georgakaki, A., Garcia Cortes, C. and Peteves, S.D. *Enhanced Oil Recovery using Carbon Dioxide in the European Energy System.* European Commission Directorate General Joint Research Centre Report EUR 21895 EN, Institute for Energy, Petten, Netherlands (2005), at 45 (footnotes omitted) (available at <http://science.uwaterloo.ca/~mauriced/earth691-duss/CO2_General%20CO2%20Sequestration%20materilas/CO2_EOR_Misciblein%20Europe21895EN.pdf>) (viewed 20 March 2012) (hereafter '*Tzimas, et al*').

177 *Id.* at 6 (noting that '[t]here are no applications of $CO_2$–EOR in Europe as the economic situation has not been favourable for investment in such projects' and citing as the major barrier the unavailability of low cost $CO_2$ at the injection site). See also Espie, Brand, Skinner, Hubbard, and Turan, *Obstacles To The Storage Of $CO_2$ Through EOR Operations In The North Sea* (GHGT–6 conference), at 207.

178 Pearce, Baker, *et al. Natural $CO_2$ Accumulations in Europe: Understanding Long-Term Geological Processes in $CO_2$ Sequestration*, (GHGT–6 conference), at 417.

Prior to the 2009 CCS Directive[179] and other recent changes specifically designed to address $CO_2$–CCS (discussed in Part II), there was generally little legislation in effect in Europe specifically designed to address onshore $CO_2$ injections for EOR. To the extent that produced incidental quantities of $CO_2$ may have been re-injected along with produced water at offshore installations, it was generally viewed, as in the US, as part of oil and gas production operations and subject to the various regulations governing such operations.

When project developers and policymakers began to consider potential geologic storage of $CO_2$ offshore (notably in the North Sea), they were quickly confronted by considerable legal concerns. Specifically, these related to whether environmental legislation prohibiting the dumping of waste would prohibit $CO_2$ injection, even in oil bearing reservoirs, if the injections were not associated with simultaneous oil recovery.[180] Indeed, there was a concern whether these instruments might be violated if a future $CO_2$–EOR operation should change *from minimising* $CO_2$ injections needed for the recovery of oil *to maximising* the amount of $CO_2$ in order to achieve emissions reduction objectives as well. In this respect, the practical issue was similar to that faced by $CO_2$–EOR operators in the US due to the limited scope of Class II well permits.

The adoption of the CCS Directive has set in motion major changes in the rules that will affect all Member States to the extent that they accept geologic storage of $CO_2$ in their national territory.[181] Nevertheless, as in the case of the recent legislative changes in the US states and Canadian provinces, the CCS Directive presupposes and builds upon portions of the pre-existing legal framework. Hence, some of the principal elements of that underlying legal and regulatory regime are addressed here.

## 1 Property rights and the regulation of drilling and fluid injections

With regard to the underlying framework for subsurface property rights, the general rule in European countries is that *minerals* and other subsurface formations and resources are publicly owned (although there are wrinkles in the ownership frameworks among the various jurisdictions). In addition, the legal regime governing the North Sea presents its own particularities under international laws and conventions.

Even though the mineral interest in the subsurface may be owned by a government entity, many of the same issues addressed in North American property rights cases are present, even if the legal rules used to address them are different (and can yield strikingly different results). Issues arise both from competing potential uses of the subsurface resources and competing production interests in the same resource. A few examples will illustrate.

### a. THE ‘AD INFERNOS’ DOCTRINE AND SUBSURFACE TRESPASS APPLIED TO ACCESSING NON-MINERAL STRATA

A recent case decided by the UK Supreme Court, quoting the same ancient Latin maxim as in the US cases, has affirmed the continuing viability under English (but not necessarily Scottish) law of the proposition that the surface owner owns the subsurface strata ‘unless there has been an alienation of them by a conveyance, at common law or by statute to someone else’ (*Star Energy Weald Basin Limited v Bocardo*[182]). In that case, an onshore oil and gas operator had obtained the appropriate consents from the Crown, as owner of the mineral resources, to extract certain petroleum. The petroleum deposits lay in part under one tract of land, upon which the operator had no facilities and from whose surface owner they had not obtained any consents. The operator located the surface facilities on an adjoining tract of land instead, for which they had obtained that surface owner’s consent. The well, however, was drilled at an angle that penetrated underneath the first tract and accessed and produced the oil as authorized by the government. Upon objection by the surface owner of the first tract, however, the court found that the operator had committed an actionable trespass against the surface owner of that first tract once the subsurface drilling penetrated the non-oil bearing strata on its way to the oil.

179 Directive 2009/31/EC of the European Parliament and of the Council of 23 April 2009 on the Geological Storage of Carbon Dioxide and Amending Council Directive 85/337/EEC, European Parliament and Council Directives 2000/60/EC, 2001/80/EC, 2004/35/EC, 2006/12/EC, 2008/1/EC and Regulation (EC) No. 1013/2006 OJ L,140/114, 5.6.2009.

180 Tzimas, *et al*, *supra*, at 44–46.

181 As discussed in Part III, the CCS Directive allows for each Member State to decide whether or not to accept geologic storage of $CO_2$.

182 *SA*, [2010] UKSC 35.

In the opinion of Lord Hope, the better view was to hold that the owner of the surface is the owner of the strata beneath it, including the minerals that are to be found there, 'unless there has been an alienation of them by a conveyance, at common law or by statute to someone else' (*Id.*, para 27). Lord Hope added:

> *There must obviously be some stopping point, as one reaches the point at which physical features such as pressure and temperature render the concept of the strata belonging to anybody so absurd as to be not worth arguing about. But the wells that are at issue in this case, extending from about 800feet to 2,800 feet below the surface, are far from being so deep as to reach the point of absurdity. Indeed the fact that the strata can be worked upon at those depths points to the opposite conclusion ... I would hold therefore that the appellant's title extends down to the strata through which the three wells and their casing and tubing pass.*

The case is instructive because it underscores the importance of focusing on the interaction of various subsurface rights that may be involved in storing $CO_2$ in either an EOR or a non-EOR context. In *Star Energy*, there was no dispute that the Crown owned the petroleum and had authorised the operator to extract it. But by affirming the subsurface ownership of the surface owner to the non-Crown owned strata, the case underlines the importance of properly identifying all of the potential ownership interests that may be affected by an operation, whether a $CO_2$–EOR operation or an geologic storage operation. Under *Star Energy*, the mere right to inject $CO_2$ for recovery of Crown–owned oil underneath a tract of land would not automatically convey the right to access the non-oil-bearing formations in order to come at the Crown–owned and licensed mineral. The necessary access rights would have to be procured either through negotiation or some form of compulsory acquisition of the underground wayleave (several approaches to which were discussed in the court's opinion). Under the *Star Energy* approach, the cost of the compulsory acquisition would probably be limited to the value of the property to the landowner, rather than to any portion of the value to be created through the execution of the project by the acquiring entity.[183]

This approach could open the door to a debate over the value of potential competing uses of the subsurface. For example, if an entity sought to acquire subsurface property rights as part of a $CO_2$ disposal project and the landowner argued that such a use of the subsurface would interfere with a potential future mining operation, the claim could be that the value to the landowner for that purpose was greater than the value to the $CO_2$ storage disposal site operator. While such disputes may not arise often, the *Star Energy* case emphasises the importance of carefully reviewing subsurface property issues even in jurisdictions where the state owns subsurface minerals.

### b. THE RULE OF CAPTURE

One scholar who examined the issues relating to the rule of capture in multiple jurisdictions around the world has concluded that it is 'impossible' to find clear rulings in most of them on whether the rule of capture would apply when a compulsory unitisation provision does not. An exception is The Netherlands, where in 2005 the highest court considered and explicitly rejected a claim that the rule of capture should apply in the Dutch offshore. There, two separate companies (Conoco and Unocal) had leases from the government on adjacent blocks. One company had a development well on its lease while the second company had not drilled on its own lease. The second company filed a civil action against the producing company seeking a civil remedy of compensation for the oil that had migrated from underneath its lease and been produced by the first company. The producing company cited US case law applying the rule of capture in federally owned and leased land in the offshore Gulf of Mexico and argued *inter alia* that the rule of capture should be applied in the Dutch offshore as well. The court determined to reject the claim and held that the rule of capture did not apply under Dutch law:[184]

> According to Conoco *… the Rule of Capture implies that the license holder is authorized to produce oil in its license area without any restriction derived from the (mere) provenance of the oil … The Rule of Capture in [this] sense … is not applicable as a valid rule of Dutch law to the production license granted pursuant to the* Mining Act Continental Shelf.

183 The judges' views on compensation were significantly divided. The majority of the Supreme Court judges took the position that compensation for the trespass should be based on the value to the landowner, rather than to the added value that might result from the acquisition of the property and the execution of the project making use of it. In this case, it implied an essentially nominal amount. Two of the judges focused more on the value to the acquiring party, which would have allowed the landowner a material share of the value of the produced oil. For discussion of the case, see Richard Macrory, '*Landowners lose out on oil extraction windfall*, ENDS Report 427 (26 August 2010), at 62.

184 Case C04/;127HR, 14 October 2005 (in Dutch) (available at <http://zoeken.rechtspraak.nl/detailpage.aspx?ljn=AT7537> (viewed 23 January 2012), at paras. 8.2.1, 8.2.2) (English translation in Daintith, *Finders Keepers, supra*, at 364. See also Hein Kernkam, Case law summary of *Unocal et alia v. Conoco et alia* (29 October 2005) (in English), available at <http://www.kernkamp.nl/case-law/2009/10/unocal-v-conoco/>. Daintith discusses the case at some length. *Finders Keepers, supra*, at 362–367.

The clear rejection of a rule of capture would seem to suggest that the Dutch court would be no more favourably inclined to a 'negative' or 'reverse' version of the rule. This would suggest that developers of $CO_2$–EOR operations would need to make fuller (or earlier) use of the rules governing pooling than was done in the Unocal–Conoco dispute to be certain that the injected $CO_2$ did not go outside the boundaries of the pooled or unitised interests. The lack of a workable version of the negative rule of capture would not preclude $CO_2$–EOR development, but would require greater planning and more involvement of the relevant government authorities than in a similar instance in most US jurisdictions.

### c. THE UK'S PROPERTY OWNERSHIP AND ENERGY LICENSING REGIME: THE CROWN ESTATE AS RESOURCE MANAGER; THE DEPARTMENT OF ENERGY AND CLIMATE CHANGE (DECC)[185] AS REGULATORY LICENSING AUTHORITY

A slightly different property ownership scenario is presented in the UK offshore. There, the relevant subsurface property interest in the offshore is owned by the Crown and managed by The Crown Estate, a private business established by an act of Parliament in 1961.[186] It is responsible for managing a diverse portfolio of commercial and retail properties, including agricultural land, parkland and forestry, shopping centres, business parks, farms and housing. Of relevance here, The Crown Estate is responsible for managing the UK seabed as far as the 12 nautical mile territorial sea limit and, under the *Energy Act 2008* (Energy Act), holds the rights for $CO_2$ storage within a broader zone (the Gas Importation and Storage Zone (GISZ)), which extends out to the continental shelf.[187]

In this role of resource manager, The Crown Estate is responsible for multiple resources that may be obtained offshore, including renewables (e.g. wind–, tidal– and wave–generated electricity), as well as carbon storage.[188] In the offshore, The Crown Estate is responsible for minerals *other than* oil and coal, which are directly managed by the government. The Crown Estate's permission, in the form of a lease or license, is required for the placement of structures on the seabed, which would include the construction of an offshore $CO_2$ pipeline. However, it is not responsible for offshore hydrocarbon resources, which are managed directly by the UK government.

Hence, the source of the $CO_2$ and the purpose of the injection project may affect the property consent required for the project. Three examples may help illustrate the interplay of the entities.

- *Agreements for Lease for $CO_2$ storage*. The Crown Estate has begun $CO_2$ storage leasing in the North Sea in both depleted hydrocarbon formations as well as a saline aquifer underlying petroleum licenses. In July 2012, The Crown Estate announced the UK's first agreement for lease for the permanent geological storage of $CO_2$, in certain petroleum license blocks at the offshore depleted Goldeneye gas field located in the North Sea. The second lease was agreed in February 2013 and covers an offshore saline aquifer that generally underlies certain petroleum license blocks, also in the North Sea, but about 70 miles east of the Yorkshire coast.[189]
- *Natural gas–based Magnus EOR project in the northern North Sea*. This project involves the re-injection in an offshore EOR operation of a natural gas stream also produced from the offshore (with natural gas liquids or liquefiables added). Since the project involves injections solely for recovery of petroleum, presumably only DECC approvals are required, and the property consent of The Crown Estate is not required.
- *A-$CO_2$ injected in the North Sea for both EOR and emissions reductions purposes*. If A-$CO_2$ were captured from an industrial or power plant source, it would presumably be for the purpose of sending it to a geologic facility that will qualify as a geologic sequestration site under applicable regulation (as discussed in Part II), whether or not it produces oil in an EOR operation in the process. Since the project would be conducted at least in part for long-term storage, the consent of The Crown Estate, as property owner, would be required for the use of the subsurface for storage purposes (as well as the placement of the $CO_2$ pipeline and any associated facilities on the seabed).

  If, however, the $CO_2$ were naturally occurring $CO_2$ being moved from one geologic formation to another for EOR purposes, then presumably The Crown Estate's consent, as property owner, would be required only for the placement of the $CO_2$

185 The DECC is successor to the Department of Trade and Industry (DTI).

186 The Crown Estate Act (1961) (available at <http://www.thecrownestate.co.uk/media/106150/crown_estate_act_1961_text.pdf>) (viewed 23 January 2012). For more detail concerning The Crown Estate in general, see <http://www.thecrownestate.co.uk/> (viewed 23 January 2012).

187 The Crown Estate, *Carbon capture and storage* (<http://www.thecrownestate.co.uk/energy/carbon-capture-and-storage/>) (viewed 23 January 2012).

188 Pursuant to the *Energy Act 2004* (and the *Energy Act 2008*), The Crown Estate is also responsible for development of natural gas on the UK continental shelf.

189 The Crown Estate, *First Agreement for UK Carbon Dioxide Storage*, (<http://www.thecrownestate.co.uk/news-media/news/2012/first-agreement-for-uk-carbon-dioxide-storage/>) (viewed 25 February 2013), and The Crown Estate, *Agreement for Lease for an Offshore $CO_2$ Storage Site Signed with National Grid* (<http://www.thecrownestate.co.uk/news-media/news/2013/afl-offshore-co2-storage-national-grid/>) (viewed 25 February 2013).

pipeline (or any other facilities) on the seabed, but not for the injection for EOR purposes. The EOR-related injection would require regulatory approvals from the DECC only.[190] In the case of geologic storage of $CO_2$, a development would require a *lease* from The Crown Estate as well as the necessary *regulatory license or permit* from the DECC.

In sum, even in legal regimes where the relevant subsurface interest is held by the state, there is a need for a manager to evaluate potentially competing uses or policy objectives.

## d. IMPACT OF THE INTERNATIONAL AGREEMENTS ON STORAGE—OSPAR CONVENTION AND THE LONDON PROTOCOL[191]

A good many analyses have been published on the effect of the OSPAR Convention and the London Protocol on $CO_2$ injections for storage purposes in the North Sea.[192] These agreements are both generally aimed at prohibiting the disposal of waste at sea. For purposes of $CO_2$ injections for EOR, however, the legal situation is altered. In this case, $CO_2$ is a valuable commodity, among others, and one of various fluids injected during routine oil and gas drilling and production operations. Hence, the status of a $CO_2$ injection under these agreements depends on the use. It may be noted that while the US and Canada are Contracting Parties, the focus of geologic storage efforts there has generally been onshore, not in the maritime environment, whereas some of the primary likely storage sites in Europe are in the North Sea. For this practical reason, this discussion is included in the context of other European legal and regulatory issues, although in principle it applies to the US and Canada as well.

### i. OSPAR Convention (pre-2007 changes): $CO_2$–EOR allowed; $CO_2$–CCS prohibited

The OSPAR Convention, which came into force in 1998, is focused on preventing and eliminating pollution affecting the northeast Atlantic, including the North Sea.[193] Parties include all the principal states in northern and western Europe, as well as the European Community as an entity.

In 2002, as interest was expressed in $CO_2$–CCS operations in the North Sea, the question of how $CO_2$ injections would be viewed was posed to a legal working group under the Convention. The *Report of the Group of Jurists and Linguists on Placement of Carbon Dioxide in the OSPAR Maritime Area* was released in 2004. It set out the initial views of the Group on the 'legal compatibility' with the OSPAR Convention of possible subsurface $CO_2$ injections (termed there, the 'placement' of carbon dioxide).[194] The report concluded, in substance, that *$CO_2$ injections for EOR operations* were allowable under the Convention, but that *$CO_2$ injections for geologic storage for climate mitigation purposes* were prohibited.

190 For example, the $CH_4$–EOR operation at the Magnus Field, to the north of Scotland, uses a natural gas stream from another offshore field as the miscibility agent, with some liquid or liquefiable hydrocarbons added to the stream. The project is under the DECC license only.

191 Transport of $CO_2$ under the 1989 Basel Convention and its 1999 Liability Protocol (not yet in force), although significant, will not be discussed in detail here. The Basel Convention governs the transportation of certain 'hazardous wastes' with categories and characteristics of 'hazardous wastes' listed in Annexes I to III to the Convention. $CO_2$ is not listed there and, accordingly, international transportation of $CO_2$ is not regulated under the Convention. Some commentators have noted, however, that $CO_2$ exhibits some of the hazardous characteristics listed in Annex III to the Convention (e.g. corrosivity when combined with water) and stated that it could be brought under the Convention. See e.g. Andy Raine, *Transboundary Transportation of $CO_2$ Associated with Carbon Capture and Storage Projects: An Analysis of Issues under International Law*, 4 Carbon & Climate L. Rev. 353, 358 (2008) (hereafter '*Raine*'). Mr Raine also points out that a substance is classified as 'hazardous waste' under the Convention if it is defined as, or considered to be, hazardous waste by the domestic legislation of the party of export, import or transit (article 1(b)). Hence, action by a *national* authority classifying $CO_2$ as a hazardous waste in domestic legislation could have an effect—intended or not—of raising *international* issues under the Basel Convention. The Convention website is at <http://archive.basel.int/index.html> (viewed 25 January 2012).

192 Raine, *supra;* Jürgen Friedrich, *Carbon Capture and Storage: A New Challenge for International Environmental Law*, 11 Heidelberg J. of Intl. Law 211, 223–226 (2007) (available at <http://www.zaoerv.de/11_1942_43/vol11.cfm>) (viewed 25 January 2012).

193 The website of the OSPAR Commission is found at <http://www.ospar.org/> (viewed 25 January 2012). The formal name of the agreement is 'The Convention for the Protection of the Marine Environment of the North-East Atlantic.

194 OSPAR Commission, Report from the Group of Jurists and Linguists on Placement of Carbon Dioxide in the OSPAR Maritime Area (ANNEX 12, Ref. § 11.7a for the Meeting Of The OSPAR Commission (OSPAR), Reykjavik: 28 June–1 July 2004.

The report first noted that $CO_2$ 'arising on' an offshore installation from its normal operation 'can be regarded as in the same position as produced water arising from such operations and can therefore be treated in the same way as produced water for the purposes of discharge or emission from an offshore installation'.[195] It then distinguished between $CO_2$ injections for EOR and non-EOR purposes, basically taking the position that:

a. offshore $CO_2$ injections in EOR operations would not be regulated or prohibited under the Convention instruments;
b. offshore $CO_2$ injections made for *both* EOR and disposal would similarly be outside the Convention prohibitions; but that
c. offshore injections of CO2 arising from other than an offshore source and injected 'for the purposes of climate mitigation' would be *prohibited under the Convention*.[196]

Thus, prior to changes adopted in 2007 (and discussed in Part II), the general view of the experts was that, under the Convention, offshore $CO_2$–EOR injections were allowed, at least where the injections were made 'in a genuine attempt' to facilitate or improve recovery of hydrocarbons, but that offshore $CO_2$ injections for the purpose of reducing emissions was prohibited. The report reflected what has been termed a 'general consensus' that the use of $CO_2$ in EOR projects would not come under the prohibitions designed to prohibit disposal of wastes.[197]

The net effect of this recommendation was to reproduce in the North Sea a similar state of affairs as under the US EPA's Class II regulation, where $CO_2$–EOR injections are allowed as long as oil is being produced, but prohibited when oil recovery operations cease.

Following the report and further deliberations, the OSPAR parties in 2007 adopted a formal decision approving $CO_2$ injections for emissions reduction purposes under certain terms and conditions (including compliance with risk management guidelines adopted at the same time).[198] These CCS–related requirements are detailed in Part II's discussion of the $CO_2$–CCS world.

### ii. London Protocol (pre-2006)—some movement on national storage of waste $CO_2$, but not on prohibition of export

The London Protocol (1996) is an anti-pollution agreement. It is the successor to an earlier agreement designed to prevent marine pollution by dumping of wastes 'and other matter'.[199] The agreement classified various materials into seven categories and established rules respecting each, essentially prohibiting the dumping at sea, except for certain listed materials. The Protocol effectively encourages the country that is the source of the waste material to endeavour to reduce the amount of waste at the source and consider other steps for reducing potential effects.

As with the OSPAR Convention, no effort has been made to apply the London Protocol provisions to existing $CO_2$ injections that (in the absence of any explicit treatment of $CO_2$ by the Protocol documents themselves) have been

195 *Id.* at ¶ 24.

196 *Id.*, ¶¶ 25–27. The document is carefully worded and based on various terms as specifically defined in the Convention instruments. The exact text of the summarised paragraphs (note omitted) reads as follows:

(25) In addition, where $CO_2$ is injected in a genuine attempt to facilitate or improve the production of hydrocarbons, it should be treated on the same basis as any other substance used for production purposes. This applies regardless of the source of the $CO_2$. It would, of course, be subject to meeting the requirements of any relevant decisions, and to taking into account any relevant recommendations, under the OSPAR Convention relating to the use and discharge of chemicals offshore.

(26) Placements of $CO_2$ in the marine environment for the purposes both of the disposal of offshore arisings of $CO_2$ (paragraph 24) and of enhancing hydrocarbon production (paragraph 25) can thus be regarded as part of the normal operation of an offshore installation. They are therefore not prohibited by the Convention, subject to meeting the requirements of the Convention and any relevant applicable decisions, and to taking into account any relevant recommendations.

(27) In contradistinction to such placements, however, the placement

- in the maritime area
- from an offshore installation
- of $CO_2$ not arising from an offshore source
- for the purposes of climate mitigation

*is prohibited by Annex III. Some participants in JL emphasise that this is the case whether it reaches the offshore installation by vessel or pipeline.*

197 *Tzimas, et al*, *supra*, at 44. For a detailed review, including discussion of the interplay between the OSPAR Convention and the London Protocol, see Friedrich, *Carbon Capture and Storage, supra,* 11 Heidelberg J. of Intl. Law at 223–226 (2007).

198 Decision 2007/2 on the Storage of Carbon Dioxide Streams in Geological Formations, (Annex 6) (Ref. § 2.10c) for the Meeting Of The OSPAR Commission (Ostend: 25–29 June 2007). See generally International Energy Agency, *Carbon Capture And Storage: Legal And Regulatory Review* (Edition 2) (May 2011), at 15–16 (<http://www.iea.org/Papers/2011/ccs_legal.pdf>) (viewed 27 January 2012) (hereafter '*CCS Legal and Regulatory Review*').

199 *CCS Legal and Regulatory Review*, *supra*, at 15.

viewed as oil and gas operations or industrial processes rather than prohibited waste disposal. Efforts have been made (beginning around 2006) to explicitly address $CO_2$ injections for storage purposes. In late 2006, agreement was reached to amend the Protocol to create a new category for $CO_2$ for geologic storage (an eighth category) and a permitting regime for subsurface storage (still considered a 'waste' under the Protocol). The new category consists of 'carbon dioxide streams from carbon dioxide capture processes for sequestration' i.e. A-$CO_2$ injected for emissions reduction purposes. The $CO_2$ stream must consist 'overwhelmingly' of $CO_2$ (an undefined term) but may contain 'incidental associated substances derived from the source material and the capture and sequestration processes used'. It may not include any 'wastes or other matter' that are added 'for the purpose of disposing of those wastes or other matter'.[200] The amendment entered into force on 10 February 2007 for all Contracting Parties to the Protocol, as no objection to the amendment was notified to the International Maritime Organization by the deadline provided by Article 22 (4) of the Protocol.

The effect of this change was to allow an individual Member State to allow for geologic storage of $CO_2$ in the subsurface *of its own territory*. However, in 2008, a legal and technical working group under the Protocol reached the conclusion that the prohibition of the *export* of wastes in Article 6 would prohibit $CO_2$ export from a Contracting Party, even though the recipient Contracting Party was in a position to authorise geologic storage under the 2006–07 amendment. A further amendment has been proposed to effectively allow export of $CO_2$ under defined circumstances, but as of early 2012, only one Contracting Party (Norway) had ratified the amendment and further ratifications are not deemed likely in the near future.[201]

The net effect appears to be that, at least at present, the export of $CO_2$, whether by pipeline or other means, from one of the London Protocol Contracting Parties remains prohibited *if it to be injected for storage purposes, but not if it is injected as part of EOR operations*. As a result, the International Energy Agency (IEA) has concluded that, pending further change, contracting parties 'will be constrained in their ability to cooperate on offshore storage' and further work is needed.[202]

## 2 Regulation of $CO_2$ pipelines

At present, there are apparently no large, high pressure $CO_2$ pipelines in EU Member States. There is, however, an 85 km line from the Rotterdam industrial area that feeds a distribution network of about 130 km of lines serving roughly 4,000 tonnes of $CO_2$ a day to a number of major greenhouse horticultural areas,[203] and some relatively short pipelines in Hungary carrying N-$CO_2$ to EOR projects. There is also an approximately 145 km pipeline that transports $CO_2$ captured from a raw production stream at a liquefied natural gas liquefaction facility in Norway (not an EU Member State) back to the Snøhvit field for storage in a subsurface brine formation.[204] Apparently, the Norwegian projects have been addressed on a case-by-case basis under existing Norwegian petroleum and pollution control legislation.[205]

Prior to the 2009 CCS Directive, there was a concern that if $CO_2$ were classified as a waste, then its transportation would be required to conform to the EU's regulatory regime governing wastes generally. This could have included the Landfill Directive,[206] Hazardous Waste Directive,[207] and Transfrontier Shipment of Waste Regulation.[208] Had this situation not been addressed, regulation as a 'waste' under this framework would have required the pipeline operator to obtain various additional authorisations that could have seriously delayed development. These issues were addressed by the 2009 CCS Directive by removing certain $CO_2$ streams transported for geologic storage from the applicable definitions of 'waste', discussed in Part II.

200 Annex 1, subsection 4.

201 *CCS Legal and Regulatory Review*, *supra*, at 15–16.

202 *Id.*

203 Roggenkamp and Haan-Kamminga, *$CO_2$ Transportation in the EU: Can the regulation of $CO_2$ pipelines benefit from the experiences in the energy sector?*, For a detailed review of legal issues affecting CCS in the EU and particularly in The Netherlands, see Martha M. Roggenkamp (ed.) and Edwin Woerdman (ed.), *Legal design of carbon capture and storage: developments in The Netherlands from an international and EU perspective* (2009).

204 The $CO_2$ produced as part of the raw production stream at the Sleipner field is captured at the offshore platform and re-injected without the need for a transport pipeline.

205 Laetitia Birkeland, *Burying $CO_2$ The New EU Directive on Geological Storage of $CO_2$ from a Norwegian Perspective* (The Bellona Foundation) (January 2009) (<http://www.bellona.no/filearchive/fil_Bellonas_paper_-_Burying_CO2-_The_New_EU_Directive_on_Geological_Storage_of_CO2_from_a_Norwegian_Perspective.pdf>) (viewed 25 January 2012), at 20.

206 Directive 1999/31/EC.

207 Directive 91/689/EC.

208 Regulation No. 1013/2006.

With regard to rules governing access to $CO_2$ pipelines prior to the CCS Directive, existing EU legislation addressing natural gas market liberalisation—which includes various provisions addressing access to natural gas pipelines—does not appear to apply to $CO_2$ pipelines. While the term 'natural gas' is not a defined term in the various directives and regulations from 2003 to 2009,[209] the entire context of the regulations addresses the markets and infrastructure for 'natural gas' as the term is used by the US FERC and in this paper, *viz.* a fuel principally comprising $CH_4$ (methane). Hence, while it is clear the EU generally favours open and non-discriminatory access to transmission networks for natural gas and electricity, prior to the CCS Directive there was no legislation addressing cross-border transportation of $CO_2$.

## 3 Conclusion for European Union

An extensive body of environmental, safety, and economic regulations applies to pipeline construction, transportation, and oil and gas operations. Presumably these regulations would have applied generally to $CO_2$ transport and injection for EOR purposes had the $CO_2$ supply been available. The legal and regulatory situation has changed radically in the past few years, such that any future $CO_2$ injections will be governed largely by rules crafted with $CO_2$ expressly in mind. Thus, more detailed consideration of the pre-reform rules is largely moot and attention is now turned to the newly evolving $CO_2$ regulatory regime.

209 See Directive 2003/55/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in natural gas and repealing Directive 98/30/EC, (15 July 2003) (2003 Directive); Regulation (EC) No. 1775/2005 of the European Parliament and of the Council of 28 September 2005 on conditions for access to the natural gas transmission networks (published 3 November 2005); Regulation (EC) No. 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No. 1775/2005 (published 14 August 2009); Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC (published 14 August 2009).

# EMERGING LEGAL *and* REGULATORY REGIMES FOR $CO_2$ STORAGE FOR CCS

PART II

There has been an enormous amount of change in the applicable legal and regulatory frameworks in both Europe and North America since 2006. While policymakers on both sides of the Atlantic have sought to enable $CO_2$–CCS, there are significant differences in the approaches adopted in the EU, the US and Canada.

- **European Union.** The CCS Directive adopted by the EU focuses principally on creating a comprehensive framework for standalone $CO_2$ storage operations, but has the flexibility to accommodate $CO_2$–EOR if a Member State chooses to do so. The Directive is largely based on the 'waste management' model and allows each Member State to prohibit geologic storage of $CO_2$ on its national territory. Member States that so choose may, during transposition of the Directive, include provision for $CO_2$–EOR projects that subsequently transition to storage–only facilities. The transposition process is still unfolding and many key aspects of implementation have not yet been determined by the respective national authorities. One particular concern is whether, or on what terms, an EOR operator may use a geologic storage facility permitted under the Directive to accommodate operational variations that will inevitably arise between the output of $CO_2$ captured from emitting facilities and the injection requirements of the EOR operation.
- **United States.** In the US, there has not been a comparable national framework adopted. Instead, the legislative changes have come principally *at the state level* in those states where there are CCS projects under construction or active development. Some state statutes are fairly comprehensive, while others are far more targeted (e.g. addressing $CO_2$ pipeline right of way acquisition only). In some cases, these state initiatives include a formal regulatory mechanism for verifying and certifying the quantity of anthropogenic $CO_2$ that is permanently stored during EOR operations. At the *federal* level, regulatory changes by the US EPA have addressed principally $CO_2$ injections for storage that occurs *outside* of EOR operations. The EPA's regulations lay the basis for standardised measurement and reporting of the amount of $CO_2$ produced from geologic sources and injected during EOR operations and, separately, the amount injected for long-term storage outside of EOR operations. The EPA's rules thus create a framework (under legislation for protecting water quality) for standalone geologic storage facilities. The rules also allow in principle for EOR operators to transition from *incidental* storage that occurs during EOR operations to *incremental* storage that may accompany or follow the close of an EOR operation (although the implementation of this transitional pathway is not yet complete). Hence, while there is no overarching national legal framework comparable to the EU's CCS Directive, the *net result* of recent changes is that the first commercial–scale capture project supported by the Department of Energy has come online. In addition, several other projects (including related pipeline construction) are moving ahead rapidly, with the $CO_2$ expected in most instances to be sold for use in EOR operations.
- **Canada.** The Canadian approach has been a little bit in between the supranational, comprehensive legislation in Europe and the more piecemeal approach observed in the US. As in the US, the principal changes have been at the provincial level. But the Canadian approach parallels the EU to the extent that the legislation adopted by the main oil and gas producing provinces has been more comprehensive than is the case with the US state legislation. It bears noting, moreover, that the largest $CO_2$ capture project under construction in Canada (SaskPower's Boundary Dam project in Saskatchewan) has been developed, and is proceeding, entirely under the pre-existing legal and regulatory framework.

This Part II examines recent changes, following the same general thematic organisation as Part I. This discussion sets the stage for evaluating the potential for transition from $CO_2$–EOR operations toward pure storage operations, with perhaps intermediate stages of optimising EOR operations for increased $CO_2$ storage either in oil bearing or nearby non-oil bearing formations.

[A]

# European Union and Member States

## EU CCS DIRECTIVE (ADOPTED 2009)

- Dedicated legislative framework for CCS.
- Governs all aspects of CCS permitting, including siting, $CO_2$ stream composition, competing subsurface uses, storage permitting and ultimate transfer of liability and stewardship to a government entity.
- Applies only to captured, anthropogenic $CO_2$ injected for storage purposes.
- Third-party access principles adopted for $CO_2$ pipelines and for storage sites.
- Amends ETS) Directive so that $CO_2$ stored under the CCS Directive is treated as 'not emitted'.
- Qualification under CCS Directive is required to access the NER300 Reserve funding.
- CCS Directive states that EOR is not in itself included, but that the Directive's provisions for environmentally safe storage of $CO_2$ should apply where $CO_2$–EOR is 'combined with' storage.

## 1 Overview

The state of play in the EU and its Member States has been completely redefined by 2009's CCS Directive.[210] The Directive reflects some of the fairly fundamental differences between the '$CO_2$ as a commodity' model and the '$CO_2$ as waste' model. It also reflects, of course, the publicly–owned nature of the subsurface prevalent in EU Member States, which is different from the privately held subsurface in the US. In addition, because the CCS Directive is basically a *framework* document, it can speak comprehensively to all aspects of the issues addressed.

Unlike an EU 'regulation',[211] an EU 'directive' does not (as a general matter) directly bind individuals. Rather, it imposes an obligation on Member State governments to transpose the principles of the directive into binding national laws. The question of *how* the principles enunciated in a directive should be turned into specific, binding national legislation is left in large measure to the transposition process, whereby Member State governments may adapt the principles to their own varying circumstances. Similarly, the question of *who* will discharge the various responsibilities and exercise the new licensing and regulatory roles contemplated by a directive is left primarily to the considered judgement of the individual Member States.

The overall result is a different process for policy formulation compared to the more fragmented approach currently employed in the US (and, indeed, the process that may prevail *within* various Member States). As a result, the thematic approach used to describe the framework in the US works less well for describing the CCS Directive framework. Instead, the Directive and the ongoing transposition process will be summarised on their own terms.

210 Directive 2009/31/EC of the European Parliament and of the Council of 23 April 2009 on the geological storage of $CO_2$ and amending Council Directive 85/337/EEC, European Parliament and Council Directives 2000/60/EC, 2001/80/EC, 2004/35/EC, 2006/12/EC, 2008/1/EC and Regulation (EC) No. 1013/2006) (hereafter 'CCS Directive' or 'Directive').

211 Treaty of Rome, Article 189 ('A regulation shall have general application. It shall be binding in its entirety and directly applicable in all Member States').

## 2 Removing $CO_2$ injections for storage (and upstream transport to storage) from the general waste and water regulations

Before looking at the new regulatory regime the CCS Directive creates, it is important to look at the steps taken to remove the transport and subsurface injection of captured $CO_2$ streams from existing, more general waste and water protection legislation. Under Articles 35 and 36 of the Directive, $CO_2$ captured and transported for the purposes of geological storage and geologically stored in accordance with the Directive are removed from the definition of 'waste' under the pre-existing EU waste legislation (Waste Framework Directive 2006/12/EC) and the Transfrontier Shipment of Waste Regulation (Regulation No. 1013/2006).[212] Similar steps were taken with regard to the Water Framework Directive (Directive 2000/60/EC).[213] Article 33 of the Directive also amended the Large Combustion Plant Directive (Directive 2001/80/EC) (which imposed a carbon capture 'readiness' requirement) to require Member States to ensure that large combustion plants (i.e. 300 megawatts or more) have assessed whether suitable storage sites are available for the potentially captured $CO_2$.[214]

### CCS DIRECTIVE (2009)

**Allows for Member State veto of storage within national territory:**
**Dedicated legislative framework for all phases of CCS**

- generally removes $CO_2$ from applicability of other European waste legislation
- applies only to captured, anthropogenic $CO_2$ injected for storage purposes
- does not apply to 'enhanced hydrocarbon recovery', but states that, where it is combined with CCS, then provisions for environmentally safe storage apply
- governs siting, $CO_2$ stream composition, competing subsurface uses, and storage permitting
- provides for MRV plans and corrective measures
- sets standards for closure, post-closure liability and stewardship and transfer of liability to Member States
- generally adopts third-party access principles for $CO_2$ pipelines; allows apparent priority for 'duly substantiated reasonable needs' of pipeline owner or other shippers; requires capacity expansions where shipper pays.

**ETS Directive amended to treat $CO_2$ stored under the CCS Directive as 'not emitted', effectively valuing stored quantities at a level equal to the ETS price for allowances.**

212 CCS Directive, Article 35 and Article 36.
213 *Id.* art 32.
214 *Id.* art 33.

## 3 Scope and purpose of the CCS Directive

In terms of its affirmative scope, the CCS Directive relates to the 'geological storage of $CO_2$'. This is a defined term; it means 'injection accompanied by storage of $CO_2$ streams in underground geological formations'.[215] The term '$CO_2$ stream' is defined as 'a flow of substances that results from $CO_2$ *capture* processes'.[216] Hence the Directive applies only to $CO_2$ that is captured, i.e. 'A- $CO_2$' in the terminology of this paper. In addition, it applies only when the injection of A-$CO_2$ is 'accompanied by storage'. While the Directive does not define 'storage', the preamble describes 'carbon dioxide capture and geologic storage' as 'the capture of carbon dioxide ($CO_2$) from industrial installations, its transport to a storage site and its injection into a suitable underground geological formation for the purposes of *permanent* storage'.[217] Similarly, the Directive states that the purpose of environmentally safe geological storage of $CO_2$ is '*permanent* containment of $CO_2$ in such a way as to prevent and, where this is not possible, eliminate as far as possible negative effects and any risk to the environment and human health'.[218]

The preamble recognises in passing the possible development of $CO_2$–based EOR (there termed 'EHR' for 'enhanced hydrocarbon recovery'). It states that EHR 'is not in itself included in the scope' of the CCS Directive, but adds that 'where EHR is combined with geological storage of $CO_2$, the provisions of this Directive for the environmentally safe storage of $CO_2$ should apply'.[219] Hence, it would appear that (analogous to the position taken by the US EPA) the Directive would not include $CO_2$–EOR operations unless the operator effectively chose to opt-in to regulation under the Directive (and thereby benefit from the linkage with the EU ETS). Moreover, the CCS Directive only applies where the $CO_2$ has been injected 'for the purposes of permanent storage'; it does not appear to apply to the incidental storage of $CO_2$ (even A-$CO_2$) in EOR operations, even though essentially all of the injected $CO_2$ (i.e. more than 95 per cent) is, in fact, stored.[220]

The manner in which $CO_2$–EOR operations using captured $CO_2$ may be 'combined with' geological storage within the meaning of the Directive, and the details of the process, are thus left to be addressed by Member States during the transposition process. In the UK, section 33 of the Energy Act specifically contemplates the possibility of integrating $CO_2$–EOR into this system.

## 4 What can be injected—composition specifications

The CCS Directive does not define the term 'carbon dioxide' or seek to establish any particular compositional requirements for a $CO_2$ stream. The details are left to be addressed during the transposition process. Article 12(1), however, provides some guidance, stating that a $CO_2$ stream shall consist 'overwhelmingly' of carbon dioxide and that, to this end:

> *[N]o waste or other matter may be added for the purpose of disposing of that waste or other matter. However, a $CO_2$ stream may contain incidental associated substances from the source, capture or injection process and trace substances added to assist in monitoring and verifying $CO_2$ migration. Concentrations of all incidental and added substances shall be below levels that would:*
>
> a. *adversely affect the integrity of the storage site or the relevant transport infrastructure;*
> b. *pose a significant risk to the environment or human health; or*
> c. *breach the requirements of applicable Community legislation.*

215 Article 3(4).

216 Article 3(13) (emphasis added).

217 CCS Directive, recital at 4 (emphasis added).

218 Article 1(2) (emphasis added). The Directive then notes that:
*In that case, the provisions of this Directive concerning leakage are not intended to apply to quantities of $CO_2$ released from surface installations which do not exceed what is necessary in the normal process of extraction of hydrocarbons, and which do not compromise the security of the geological storage or adversely affect the surrounding environment. Such releases are covered by the inclusion of storage sites in [Directive establishing the European Emissions Trading System], which requires surrender of emissions trading allowances for any leaked emissions.*

219 CCS Directive, recital 20 (emphasis added).

220 See n.24, *supra*.

Article 12(3), however, provides that Member States must ensure that the operator of a storage site only accepts and injects $CO_2$ streams 'if an analysis of the composition, including corrosive substances, of the streams and a risk assessment have been carried out, and if the risk assessment has shown that the contamination levels are in line with' those conditions.

The preamble (para 27) notes that an environmental impact assessment has to be carried out in the capture permit process pursuant to Directive 85/337/EEC,[221] and advises that the operator of a storage site should only accept and inject $CO_2$ streams 'if an analysis of the composition, including corrosive substances, of the streams, and a risk assessment have been carried out, and if the risk assessment has shown that the contamination levels of the $CO_2$ stream are in line with the composition criteria referred to in this Directive'.[222]

## 5 Where $CO_2$ may be injected—site characterisation, competing uses and the Member State veto

Article 4, para 1 of the CCS Directive provides that each Member State has the right to determine the areas from which storage sites may be selected. This expressly includes the right to prohibit $CO_2$ storage in any part, or the whole, of the Member State's territory.[223]

Assuming that storage is not prohibited under this clause, the Directive provides that the suitability of a formation for storage will be determined through a characterisation and assessment process of the proposed site and the surrounding area (the 'storage complex'). The criteria that should be applied in the characterisation and assessment process are spelled out in Annex I to the Directive. They include data collection, construction of a model of the subsurface formation, and 'characterisation' of the formation, which involves assessing how the $CO_2$ injectate is likely to behave in the subsurface under various assumptions, together with an assessment of risks to the environment, and human health and safety issues. The preamble notes that a site should only be selected if there is 'no significant risk of leakage, and if in any case no significant environmental or health impacts are likely to occur'.[224]

The Directive recognises that there may be competing uses for the storage site or the surrounding area and advises that the power to prohibit storage includes the right to give priority to other uses of the subsurface:[225]

> *This includes the right of Member States ... to give priority to any other use of the underground, such as exploration, production and storage of hydrocarbons or geothermal use of aquifers. In this context, Member States should in particular give due consideration to other energy-related options for the use of a potential storage site, including options which are strategic for the security of the Member State's energy supply or for the development of renewable sources of energy.*

Similarly, Article 6(1) expressly provides that each Member State 'shall ensure that no conflicting uses of the complex are allowed during the permit procedure'.[226]

## 6 The exploration permit

The CCS Directive provides for exploration permits to be issued, on an exclusive basis, to obtain the information necessary for selecting suitable storage sites. No such exploration is to take place without an exploration permit, which should be open to all qualified entities on an open and non-discriminatory basis. Importantly, Article 5(4) provides that the holder of an exploration permit shall have the 'sole right' to explore the potential $CO_2$ storage complex (i.e. the proposed storage site and surrounding area) and that there shall be 'no conflicting uses of the complex' during the permit's validity.

221 Directive 85/337/EEC.

222 CCS Directive, recital 27.

223 CCS Directive, article (1).

224 *Id.* recital 19.

225 *Id.*

226 CCS Directive, article 6(3).

The exclusivity of the exploration permit is particularly important because, under Article 6(3), the holder of the exploration permit for a site 'shall' be given priority in the granting of a storage permit.[227] By providing a type of 'first in time, first in right' principle for obtaining a storage permit, the aim presumably is to create an incentive for companies to move quickly to explore for appropriate sites and so gain the priority for the storage permit itself.

## 7 Storage permitting

Articles 7 through 11 set out a straightforward storage site permitting process, detailing the information required to ensure an applicant is technically and financially capable of developing and operating the site safely and honestly. The process includes, for example, the critical issues of conditions for closure and monitoring, but the details are left to be addressed by the Member States in transposing and implementing the Directive.

Article 10 reflects the high level of concern the European authorities have for safety and security and the desire, at least in the early stages of implementation, to be able to take a 'second look' at permitting decisions. Hence, the article provides for all permit applications to be forwarded to the European Commission (EC), which is the EU's executive branch, along with all draft permits the Member State's competent authority plans to issue. The EC has four months from receipt of a draft permit to issue (if it chooses) a non-binding opinion on the draft, which may identify recommended changes or make other recommendations. As explained by the preamble (recital 25), this opportunity for review of draft permits is intended to ensure consistency in implementation of the Directive and enhance public confidence in CCS.[228] The Member State's competent authority does not have to follow the Commission's opinion, but must take the opinion 'into consideration' in its final permitting decision. It must also state the reasons if it departs from the Commission's opinion.

The first such EC opinion was issued on 28 February 2012. It reviewed the Dutch Government's draft permit for the ROAD project to store about 1.1 million tonnes of $CO_2$ a year for eight years in an offshore storage facility.[229] The EC's opinion reviewed the Dutch draft in detail for compliance with the principal requirements of the Directive. The opinion made several recommendations for points to be clarified or addressed in the final permit.

## 8 Monitoring, reporting, inspections, and corrective measures

During operations, the operator must monitor the 'storage complex' according to the approved plans. The CCS Directive provides for various reporting obligations, as well as routine and non-routine inspections of a storage site. The Member States are required to ensure that the operator notifies the competent authority immediately in the in event of a leakage or 'significant irregularities', and take necessary corrective measures.

## 9 Closure, post-closure, and transfer of responsibility and stewardship to the Member State

The Directive does not specify a standard for closure of a site, only that a site may be closed if the relevant conditions in the permit have been met.[230]

However, it is more prescriptive with regard to the ultimate transfer of responsibility for the site to the Member State. As a general rule, this may occur no earlier than 20 years after closure, unless the competent authority is 'convinced' that 'all available evidence indicates that the stored $CO_2$ will be completely and permanently contained'.[231] At that time, assuming

227 *Id.*

228 *Id.* recital 25.

229 *Commission Opinion of 28.2.2012 relating to the draft permit for the permanent storage of carbon dioxide in block section P18–4 of block section P18a of the Dutch continental shelf, in accordance with Article 10(1) of Directive 2009/31/EC of 23 April 2009 on the geological storage of carbon dioxide* (<http://ec.europa.eu/clima/policies/lowcarbon/ccs/implementation/docs/c_2012_1236_en.pdf>), (addressing the Rotterdam Capture and Storage Demonstration ('ROAD') project).

230 CCS Directive, article 17(1). The site may of course also be closed if the competent authority so decides after the withdrawal of a storage permit.

231 Article 18(1)(b).

all of the various post-closure obligations have been met, the storage site (including the injected $CO_2$) shall be transferred to the competent authority if the following conditions are met:[232]

a. all available evidence indicates that the stored $CO_2$ will be completely and permanently contained;
b. a minimum period, to be determined by the competent authority has elapsed;
c. the financial obligations referred to in Article 20 have been fulfilled;
d. the site has been sealed and the injection facilities have been removed.

The operator is required to prepare a report documenting that the stored $CO_2$ will be 'completely and permanently contained'. The report must demonstrate that the actual behaviour of the injected $CO_2$ complies with the modelled behaviour, there is no 'detectable leakage' and the storage site 'is evolving towards a situation of long-term stability'.[233] Following other procedures and reviews specified in Article 18, a transfer of responsibility shall be deemed to take place:[234]

> *… if and when all available evidence indicates that the stored $CO_2$ will be completely and permanently contained, and after the site has been sealed and the injection facilities have been removed.*

Assuming that there has been no fault by the operator (including deceit or negligence), there shall be 'no further recovery' of costs following the transfer of responsibility.

## 10 Getting to the site—third-party access to the $CO_2$ pipeline and storage site and dispute resolution

The CCS Directive seeks to ensure that all parties will have access to storage sites and $CO_2$ pipelines on a non-discriminatory basis. As noted in Part I, $CO_2$ pipelines are not included in the EU's requirement foropen access to natural gas pipelines (and electricity transmission networks). Article 21 of the CCS Directive sets out the general principle that potential users must be able to obtain access to transport networks and storage sites for the purposes of geological storage of the 'produced and captured' $CO_2$.[235] In applying the objectives of 'fair and open access', the Member State is to take into account:

a. the storage capacity which is or can reasonably be made available within the areas determined under Article 4, and the transport capacity which is or can reasonably be made available;
b. the proportion of its $CO_2$ reduction obligations pursuant to international legal instruments and to Community legislation that it intends to meet through capture and geological storage of $CO_2$;
c. the need to refuse access where there is an incompatibility of technical specifications which cannot be reasonably overcome;
d. the need to respect the duly substantiated reasonable needs of the owner or operator of the storage site or of the transport network and the interests of all other users of the storage or the network or relevant processing or handling facilities who may be affected.

Under paragraph 3, the operators of the pipeline (or 'transport network', in the terms of the Directive) and storage sites may refuse access on the grounds of 'lack of capacity', providing 'duly substantiated reasons' for any refusal. Moreover, the Member States are directed to ensure that any operator that refuses access on the grounds of lack of capacity or a lack of connection 'makes any necessary enhancements as far as it is economic to do so or when a potential customer is willing to pay for them, provided this would not negatively impact on the environmental security of transport and geological storage of $CO_2$'.[236]

232 Article 18(1).
233 Article 18(2).
234 Article 18(8).
235 Article 21(1). The phrase 'produced and captured' $CO_2$ does not appear anywhere else in the Directive, which does not explain whether this phrase is intended to mean something other than 'captured $CO_2$' used elsewhere in the document. It may be that it is referring to $CO_2$ that is produced by the original combustion or other potential emission source and captured at that point (which is a usage in some other EU–related documents).
236 Article 21(3)–(4).

Article 22 anticipates that disputes may arise over access issues, and hence requires Member States to ensure that they have in place 'dispute settlement arrangements'. These should include an authority that is independent of the parties to all disputes relating to access to transportation and storage facilities so that disputes can be settled expeditiously. For potential cross-border disputes, where more than one Member State covers the transport network or storage site concerned, the Member States concerned shall 'consult with a view to ensuring that this Directive is applied consistently'.[237]

## 11 The relationship between the CCS Directive and the ETS

### a. $CO_2$ STORED ACCORDING TO THE CCS DIRECTIVE IS DEEMED 'NOT EMITTED' FOR PURPOSES OF THE ETS DIRECTIVE

On the same day that it adopted the CCS Directive, the EU amended its directive governing the Emissions Trading System to effectively treat $CO_2$ captured and stored under the CCS Directive as 'not emitted'. This was accomplished by amending the ETS Directive to provide that an obligation to surrender allowances shall not arise 'in respect of emissions verified as captured and transported for permanent storage to a facility for which a permit is in force in accordance with' the CCS Directive.[238]

### b. MONETISATION OF THE 'NER300 ALLOWANCES' HAS BEGUN

It may be noted as well that the EU has determined to effectively allocate 300 million emissions allowances from what is known as the 'new entrant reserve' through to 2015 (frequently referred to as the 'NER300 allowance'). The revenues from the sale of these allowances are to be distributed among the Member States to co-finance up to 12 CCS demonstration projects. Importantly, the availability of a share of these funds serves as a key incentive for the Member States to complete transposition because the funds may only go to support projects that will store captured $CO_2$ pursuant to the CCS Directive. This means that no funds will be available for projects located in Member States that have not successfully transposed the Directive.

On 2 December 2011, the EC delivered the 300 million allowances to the European Investment Bank (EIB), which is responsible for monetising them. The bank was required to complete monetisation of the first tranche of 200 million allowances by 2 October 2012. Sales began during December 2011; they were expected to sell at an indicative rate of 20 million allowances a month.

In January 2012, the EIB began providing monthly standardised reports of overall sales volumes achieved and aggregated prices obtained.[239] Over the course of 2012 and into early 2013, the price of emissions allowances via the ETS fell, such that by February 2013 they were trading at around €4–5 a tonne, far below the levels expected in 2009. As a result, the ETS is not playing the originally hoped-for financing role. As 2013 began, various efforts were being undertaken to review aspects of the system in order to increase the funds available through it.

237 Article 22(2).

238 Article 11a(15) of the Directive 2009/29/EC of the European Parliament and of the Council of 23 April 2009 amending Directive 2003/87/EC so as to improve and extend the greenhouse gas emission allowance trading scheme of the community.

239 European Investment Bank, '*Frequently Asked Questions – EIB Role in NER300 Monetisation*' (available at <http://www.eib.org/attachments/ner-300_faq.pdf>).

# 12 Guidance, transposition and next steps

## a. GUIDANCE DOCUMENTS ISSUED IN 2011

In March 2011, the European Commission published four guidance documents that provide a considerable amount of additional detail (and complexity) to the storage permitting process.[240] They address four areas:

- the $CO_2$ storage lifecycle risk management framework
- characterisation of the storage complex, $CO_2$ stream composition, monitoring and corrective measures
- criteria for transfer of responsibility to the competent authority
- financial security and financial mechanism.

The guidance document on financial security and contributions generated the highest level of interest. A particular concern expressed by potential project developers is that the requirement for providing the full amount of financial security 'up front' may be prohibitively and unnecessarily costly.

## b. TRANSPOSITION—THE OVERALL STATE OF PLAY

The deadline for completing transposition of the CCS Directive into binding national legislation was 25 June 2011. However, transposition has been more difficult than might have been anticipated in view of the relative ease with which the Directive itself had been negotiated and approved. As of March 2012, the EC had initiated the first stage of infringement proceedings against 19 of the 27 Member States.[241] This is a rather informal process that is often resolved without further formal action.

One of the main issues identified as requiring further development in the transposition process is the potential for conflict with other intended uses of the subsurface. For example, Latvia has indicated that it intends to prohibit $CO_2$ storage due to a conflict with use of the subsurface for geothermal energy production and natural gas storage.

As previously noted, the CCS Directive specifically allows for a Member State to preclude $CO_2$ storage on its territory. By 2011, several Member States appeared to have decided (or were taking steps) to exercise this right. These include Austria, which has considered a draft bill that would ban commercial $CO_2$ storage; Germany,(which would allow the individual German states to exercise that power within their territory; Finland, which has announced plans to prohibit $CO_2$ storage by statute; Latvia, which is planning to prohibit $CO_2$ storage due to conflict with preferred uses of the subsurface for geothermal energy production and natural gas storage; and Denmark, which is deferring its decision while allowing for EOR operations offshore in the North Sea.

The availability of this Member State veto of storage adds a level of complexity to the transposition process because in some Member States this power may be exercised by a non-Member State level governing entity (e.g. *Länder* in Germany, Scotland in the UK, the various Spanish regions), requiring an additional level of inter-governmental coordination.

The storage veto provision has raised another issue in the transposition process. It is clear that the provisions concerning third-party access to pipelines and the requirements for capture and storage must be transposed. But given that the Directive does not require a Member State to provide for $CO_2$ storage—and indeed expressly allows it not permit storage on its national territory—the question of European law is whether a Member State that chooses not to allow storage or to restrict it (e.g. to demonstration plants only) must still transpose the whole Directive into its legal system. In these circumstances, a Member State may view transposition as a largely futile and costly gesture. One might argue that where a Member State (or an authorised sub-national entity) imposes a prohibition in law on storage (rather than simply having a policy against storage), this should exempt it from the need to transpose the Directive's provisions on storage.

240 The four guidance documents may be found at <http://ec.europa.eu/clima/policies/lowcarbon/ccs/implementation/documentation_en.htm>.

241 The EU's site for tracking the status of national transposition measures is found at <http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:72009L0031:EN:NOT> (viewed 6 March 2012).

However, the EC and European Court of Justice have generally taken the view that a Member State is obliged to transpose all the provisions in a directive, whatever its current policy. Governments and policies change; presumably a legal framework consistent across the EU should be in place to accommodate this eventuality. The only exception allowed by the Court to date is where it is physically impossible for a Member State to implement a directive. Hence, it seems unlikely that the EC would accept the argument that the presence of the Member State veto in the CCS Directive dispenses that Member State from the transposition obligation. The issue may eventually be tested before the European Court.

### c. TRANSPOSITION—UK, GERMANY AND THE NETHERLANDS.

The UK, Germany and The Netherlands represent contrasting approaches to transposing the Directive. In the case of the UK, much of the legislative framework for permitting $CO_2$ storage sites was actually adopted before the EU's CCS Directive had been finalised. Chapter 3 of the Energy Act establishes a licensing regime for the storage of $CO_2$ in the UK territorial sea and certain other defined offshore waters (in relation to its permanent disposal or as an interim measure prior to permanent disposal).[242] The UK essentially integrated CCS with its existing oil and gas legislation, rather than creating a separate new regulatory regime.[243] As of 23 February 2012, the UK has reported it is in full compliance with the CCS Directive.[244]

As part of its transposition effort, the UK conducted public consultations on regulations for several key issues, including terms of access to pipeline infrastructure and storage facilities and the offshore storage licensing regime.[245] The *Storage of Carbon Dioxide (Access to Infrastructure) Regulations 2011* were adopted in September 2011. They address in detail the terms under which infrastructure should be constructed, including the potential for sizing the project greater than that originally proposed and arrangements for payment of costs of capacity increases to meet future demand.[246]

Of particular relevance to the integration of EOR, section 33 of the Energy Act specifically contemplates the potential for EOR activities. It states that provisions of the Energy Act concerning $CO_2$ storage do not apply to EOR activities unless the Secretary of State makes an Order extending their application to EOR. This implies that $CO_2$–EOR operations could proceed (much as in the US) under existing oil and gas regulation, essentially independent of CCS regulation. Obtaining an order from the Secretary of State, however, would allow an EOR operator to obtain the benefits under the CCS Directive. In particular, it would allow them to qualify the stored $CO_2$ as 'not emitted' for purposes of the EU ETS Directive (as modified by the CCS Directive).

A further issue for integrating EOR with CCS relates to how the rules would treat the re-use of $CO_2$ during EOR operations. There is likely to be a need for operational buffering to smooth out mismatches that will arise from time to time between the supply of $CO_2$ from capture sources and the injection requirements of an EOR operation. The CCS Directive provides that EOR activities (there referred to as enhanced hydrocarbon recovery) can only be included within the Directive 'if combined with geological storage' of $CO_2$ and the term geologic storage is defined as 'permanently stored'. Moreover, the UK's CCS licensing Regulations effectively provide that stored $CO_2$ may not be extracted from a storage site except with the written consent of the Secretary of State.

Article 3(3) of the CCS Directive, however, specifically includes 'associated surface and injection facilities' in the definition of the term 'storage site'. This indicates that a permitted geologic storage site under the Directive could include the surface facilities used during EOR operations to separate the produced $CO_2$ from the oil and other formation fluids and then dehydrate, re-compress and re-inject the $CO_2$ into the productive formation. Hence, the CCS Directive effectively recognises that when EOR operations are combined with geologic storage, the $CO_2$ recycled during EOR operations remains in a 'closed loop'. Any atmospheric emissions during the recycling operation (e.g. fugitive emissions from the surface equipment) would, of course, have to be accounted for under the ETS Directive.

242 For a detailed review of the UK transposition experience, see C. Armeni, *Case studies on the implementation of Directive 2009/31/EC on the geological storage of carbon dioxide: United Kingdom* (November 2011) (available at <http://www.ucl.ac.uk/cclp/pdf/CCLPEUCaseStudiesProject-UnitedKingdom.pdf>).

243 *Id*. See esp. at 4, 14–16 and 34–35.

244 For a list of transposition measures communicated to the EU, see, <http://eur-lex.europa.eu/LexUriServ/LexUriServdo?uri=CELEX:72009L0031:EN:NOT#FIELD_UK>.

245 See e.g. UK Department of Energy and Climate Change ('DECC'), *Government response to the consultation on implementing the third party access provisions of the European Union Carbon Capture and Storage Directive* (8 April 2011) (<http://www.decc.gov.uk/assets/decc/Consultations/ccs-third-party-access/1666-gov-response-cons-third-party-eu-ccs.pdf>). See also DECC, *Government Response to the Consultation on the Proposed Offshore Carbon Dioxide Storage Licensing Regime* (August 2010) (<http://www.decc.gov.uk/assets/decc/Consultations/carbondioxidestorage%20licensing/422-govt-response-offshore-co2-storage.pdf>).

246 Statutory instrument (SI), number: 2011 No. 2305; Official Journal: Her Majesty's Stationery Office (HMSO), number: 2011 No. 2305, Publication date: 15/09/2011

This approach would allow for the incidental storage of $CO_2$ to be permitted in the context of $CO_2$–EOR operations, in effect allowing the oil–producing formation to be considered a permanent $CO_2$ storage site, similar to the approach being developed in several US states. Alternatively, one might link a non-storage $CO_2$–EOR formation with a permitted storage–only formation located below it (i.e. 'stacked' storage), where the operator could use the same surface facilities as part of the permitted storage site to support both operations, directing the $CO_2$ stream to the appropriate subsurface location as dictated by operational demands. Such co-located facilities would appear to come easily within the terms of the Directive, allowing for the eventual integration of $CO_2$–EOR operations with storage operations permitted under the CCS Directive.[247]

The German transposition experience has been strikingly different from that of the UK. Legislative proposals to transpose the Directive have faced considerable public opposition, even though they have provided for individual German *Länder* to be able to exercise the veto of $CO_2$ storage sites within their territories, as explicitly allowed by the Directive.[248] By mid-2012, legislation was finally adopted, but it is limited to allowing research, pilot and demonstration projects only and imposes volumetric limits such that it would only allow for three small-to-medium sized demonstration projects.[249] The law will be re-evaluated in 2018.[250] The EU commenced first stage infringement proceedings against Germany for failure to transpose by the June 2011 deadline; it is not clear whether the 2012 legislation will be viewed as satisfactory compliance.

In The Netherlands, the CCS Directive has been transposed by amending existing legislation, primarily the mining law. In July and August 2011, the Dutch Government submitted to the EC for review the first draft permit for a $CO_2$ storage site under the Directive. The EC issued its opinion in February 2012, following several meetings with Dutch authorities and submission of a revised draft permit in response to informal comment.[251] Following a point-by-point review, the EC generally found the Dutch draft permit to be in compliance with the Directive.

247 At some future point in the development of an EOR/storage complex, of course, there could come a time where the developer might seek to link an EOR production operation that is not itself permitted as a geologic storage site with a separately located storage site. From a textual standpoint, the surface and injection facilities at a separately located EOR location may not be deemed sufficiently 'associated' with the permitted geologic storage site so as to be considered a part of the storage site.

248 For example, the north German state (or 'Land') of Schleswig-Holstein took formal action in January 2013 to ban CCS within its jurisdiction.

249 See the Research, Pilot and Demonstration of Technologies Act (the original title is Gesetz zur Demonstration und Anwendung von Technologien zur Abscheidung, zum Transport und zur dauerhaften Speicherung von Kohlendioxid' (or 'KSpGEG')). The law was passed on 17 August 2012 and became effective on 24 August 2012. The geologic storage provisions are included in Article 1, designated the '$CO_2$ Storage Act' ('Gesetz zur Demonstration der dauerhaften Speicherung von Kohlendioxid' (or the 'KSpG')).

250 For a detailed case study of the early German transposition experience, see Professor Dr Ludwig Krämer, *Case studies on the implementation of Directive 2009/31/EC on the geological storage of carbon dioxide: Germany* (November 2011) (<http://www.ucl.ac.uk/cclp/pdf/CCLPEUCaseStudiesProject-GermanywithAnnex.pdf>). The law finally adopted in 2012 took effect on 24 August 2012.

251 *Commission Opinion of 28.2.2012 relating to the draft permit for the permanent storage of carbon dioxide in block section P18–4 of block section P18a of the Dutch continental shelf, in accordance with Article 10(1) of Directive 2009/31/EC of 23 April 2009 on the geological storage of carbon dioxide*, (<http://ec.europa.eu/clima/policies/lowcarbon/ccs/implementation/docs/c_2012_1236_en.pdf>).

B

# United States

Although still in development, the US has now put in place the principal components of a legal and regulatory framework for geologic storage or sequestration of $CO_2$ in many of those parts of the country where such activities appear likely to evolve.[252] Reflecting the large potential market that EOR presents for $CO_2$ capture sources in the US, the activity has mainly focused on making the changes needed to integrate new sources of A-$CO_2$ into the existing EOR–based infrastructure of pipelines, wells and target EOR formations. Hence, $CO_2$–EOR operations remain at the centre of analysis as the focus begins to shift to incorporating captured $CO_2$ into the supply mix. As will be discussed in Part III, it is not yet clear how successful the new rules will be.

The evolving legal and regulatory framework consists of action by *state* legislatures and regulators as well as by *federal* regulators under existing legislation.

- **State initiatives.** These include individual actions by states to address property rights issues, including protecting ownership of injected $CO_2$, acquisition and aggregation of pore space and defining the priorities between the mineral estate and the storage interest; permitting of storage sites, including post-closure stewardship issues; and right of way acquisition for pipelines to deliver $CO_2$ to the injection sites. The states (notably Texas and Mississippi) have also begun to adopt regulatory mechanisms to verify and certify the quantity of anthropogenic $CO_2$ that is permanently stored during the incidental storage phase of $CO_2$–EOR operations. Not all of the states that have acted have included each of these elements, and the manner in which the individual states have addressed a given element may vary. A summary table of legislative changes is provided at Appendix A.[253]
- **Federal initiatives.** Because so many of the legal issues relating to $CO_2$ storage involve property issues that fall within the legal competence of the states, it is not surprising that there is no storage permitting legislation at the federal level. And only minor federal legislative changes have been made regarding safety standards for some potential interstate $CO_2$ pipelines. At the regulatory level, however, there have been major changes by the US EPA in the rules governing subsurface $CO_2$ injections for storage purposes (including monitoring, verification and accounting for certain $CO_2$ storage injections), as well as in standardised, mandatory reporting of $CO_2$ production, injection and emissions. The EPA rulemaking process is not complete and many questions remain as to how its rules will be applied.

---

252 While some statutes use the term ‘sequestration’, others use ‘storage’. Others define the two terms as being synonymous. This paper follows that approach and uses the term interchangeably.

253 There have been several significant efforts to develop an online database for tracking legislative and/or regulatory developments among the various states. These include:

**US, EU, UK, Canada and Australia—Carbon Capture Legal Programme:** The most complete and up-to-date database for the US, EU, UK, Canada and Australia was developed by University College London’s Carbon Capture Legal Programme, and is now hosted and maintained by the Global CCS Institute. Available at http://www.globalccsinstitute.com/networks/cclp

Other useful reference tools for differing time periods or jurisdictions include:

**IEA Legal and Regulatory Review**—The IEA has published two editions of its *Carbon Capture and Storage Legal and Regulatory Review* to which principal jurisdictions and selected non-governmental organisations have submitted brief updates. They are found at <http://www.iea.org/ccs/legal/review.asp> (viewed 29 January 2012). The first edition is located at <http://www.iea.org/ccs/legal/regulatory_review_edition1.pdf> and the second edition (dated May 2011) is at <http://www.iea.org/Papers/2011/ccs_legal.pdf>.

**Earlier US state legislation—IOGCC:** The IOGCC, a Congressionally approved interstate compact of about 30 US oil and gas producing states and several Canadian provinces, has created a tracking database of state and provincial legislation affecting CCS. See <http://groundwork.iogcc.org/topics-index/carbon-sequestration/state-progress> (viewed 29 January 2012). See also the site (apparently no longer being updated) at <http://www.iogcc.state.ok.us/Websites/iogcc/Images/CO2-Update.pdf> (viewed 13 January 2012).

**US state legislation—CCS Reg:** For state legislation affecting $CO_2$ storage in the US, a useful site for developments to about May 2010 is that prepared by the CCS Reg Project. The map interface, with links to referenced legislation, is found at: <http://www.ccsreg.org/bills.php> (viewed 16 January 2012).

**Global coverage—CSLF:** The CSLF maintains an online registry of legislative and regulatory actions around the world affecting the regulatory framework for CCS. See <http://www.cslforum.org/incentivesregistry/IncentivesRegistry.xls> (viewed 13 January 2012). While the focus is on incentives for capture projects, the database has considerable information on other legislative or regulatory reforms.

Because the framework for $CO_2$ storage operations has not been constructed in a centralised fashion, it is less visible than might otherwise be the case. Nonetheless, by the end of 2012, the overall effect of the individual state initiatives combined with the federal regulatory changes put in place the principal legal and regulatory components for geologic storage of $CO_2$. Important questions remain, however, about how the new state storage permitting programs will be applied and how they will be integrated with the new federal rules. Questions remain, for example, about whether the EPA's proposed transition pathway for $CO_2$–EOR wells under Class II will in fact allow such wells to migrate to non-EOR storage operations. Similarly, it is not entirely clear how effectively the monitoring, reporting and verification aspects of the Subpart RR reporting rules will work. If the Class VI rule for $CO_2$–CCS is viewed by industry participants as unworkable, $CO_2$–EOR operators may find it necessary to continue to limit $CO_2$ injections and storage to those quantities required solely for EOR operations, thereby foregoing additional $CO_2$ storage operations that could otherwise have been undertaken for emissions reduction purposes.

## 1 Property law issues regarding ownership of injected $CO_2$

Since the bulk of $CO_2$ from new capture sources is expected to be purchased by EOR operators for injection and concurrent storage during EOR operations, the EOR operator has a strong incentive to protect ownership of the injected $CO_2$. In this context, two significant changes have been made to the recent state statutes that affect the underlying property law regarding $CO_2$ ownership and commercial transactions in $CO_2$.

- Most of the new statutes confirm or provide that an owner of $CO_2$ does not lose that property right when the $CO_2$ is injected, at least in circumstances defined in the particular statutes, and that liability therefore continues indefinitely.
- Most of the statutes contain some language stating that $CO_2$ is 'valuable', 'a commodity', 'a resource' or similar language.

The details and implications of these statutory provisions are discussed here.

### a. PRESERVATION OF TITLE TO INJECTED $CO_2$

Preserving title to, and ownership of, injected $CO_2$ is an important issue for $CO_2$–EOR operators. Because of the historical treatment of migratory subsurface fluids discussed in Part I, there may be a concern that a person injecting $CO_2$ could be deemed to have abandoned the injected $CO_2$ (in the sense of having disclaimed any ownership interest) even though there may still be the possibility of transporting it to another subsurface formation for further EOR purposes. There may also be a concern that the injected $CO_2$ could be captured by some other party and sold for their own account (conceivably even back to the original owner).

This is not a theoretical issue. A Texas trial court judgement allowed a claim that $CO_2$ was abandoned when it was injected for an EOR operation and it was only on appeal that the ruling was reversed, holding instead that the $CO_2$ remained the property of the EOR operator.[254] In addition, preserving ownership of the $CO_2$ injectate tends to confirm liability in the event of leakage to surrounding land unless, and until, the ownership interest is transferred or otherwise extinguished.

Accordingly, it is not surprising that most of the recently enacted statutes generally confirm that an operator who injects $CO_2$ into a subsurface formation does not by that act lose title to the $CO_2$. The scope of each statute is slightly different, for example in terms of whether it applies to all $CO_2$ or only to anthropogenic $CO_2$, and in how the term 'anthropogenic $CO_2$' is defined.[255] Hence, the precise applicability of the statutory provision will vary, and will need to be examined carefully by any potential project developer. Still, this greater statutory clarity that the injector of the $CO_2$ retains ownership will help encourage subsurface injections and incidental storage of applicable $CO_2$ during the operational phases of $CO_2$–EOR. In addition, it will help set the stage for potential transition to storage–only projects and the eventual potential transfer of ownership and liability to a stewardship entity (typically a state government).

254 *Occidental Permian Ltd. v. the Helen Jones Foundation, supra.*

255 For example, the recent Texas statute does not apply to A-$CO_2$ that is injected 'for the primary purpose of enhanced recovery operations.' Since the statute was adopted pending court litigation, the decision not to speak to title of $CO_2$ injected in EOR operations may have reflected a desire not to interfere with the normal operation of the courts in deciding such issues. After the Texas statute had passed, however, the *Helen Jones Foundation* case was decided, which makes it clear the injector of $CO_2$ in Texas (whether N-$CO_2$ or A-$CO_2$) does not lose title by injecting it in an EOR operation.

**TABLE II: Preservation of title to injected $CO_2$**

| STATE | STATUTE | REFERENCE | PROVISION ADDRESSING TITLE TO INJECTED $CO_2$ |
|---|---|---|---|
| Louisiana | HB 661 | § 1104 (E) | **Confirms ownership of injected $CO_2$:**<br>*The commissioner may issue any necessary order providing that all carbon dioxide which has previously been reduced to possession and which is subsequently injected into a storage reservoir* ***shall at all times be deemed the property of the party that owns such carbon dioxide****, whether at the time of injection or pursuant to a change of ownership by agreement while the carbon dioxide is located in the storage facility, his successors and assigns; and i****n no event shall such carbon dioxide be subject to the right of the owner of the surface of the lands or of any mineral interest therein*** *under which such storage reservoir shall lie or be adjacent to or of any person other than the owner, his successors, and assigns to produce, take, reduce to possession, waste, or otherwise interfere with or exercise any control there over, provided that the owner, his successors, and assigns shall have no right to gas, liquid hydrocarbons, salt, or other commercially recoverable minerals in any stratum or portion thereof not determined by the commissioner to constitute an approved storage reservoir.* |
| Mississippi | SB 2723 (§ 5) | MS Code § 53–11–9(2) | **Confirms ownership of $CO_2$:**<br>*Neither injection nor an order of the board shall affect ownership of the carbon dioxide or inhibit the voluntary conveyance of title to the carbon dioxide by the owner. The board may issue any necessary order to protect the title of an owner to carbon dioxide injected into a geologic sequestration facility. The carbon dioxide shall not be subject to the right of any person other than the owner of the carbon dioxide to produce, take, reduce to possession, or otherwise interfere with or exercise any control thereover. The owner of the carbon dioxide shall have no right to gas, liquid hydrocarbons, salt or other commercial minerals in any stratum or portion thereof not determined by the board to constitute an approved sequestration reservoir which are not otherwise owned or leased by the owner.* |
| Montana | SB 498 | | Storage operator retains title to $CO_2$ and liability, therefore, until transfer to state. |
| North Dakota | SB 2095 | Century Code § 38–20–16 | **Confirms ownership of $CO_2$:**<br>*The storage operator has title to the carbon dioxide injected into and stored in a storage reservoir and holds title until the commission issues a certificate of project completion. While the storage operator holds title, the operator is liable for any damage the carbon dioxide may cause, including damage caused by carbon dioxide that escapes from the storage facility.* |
| Texas | SB 1387 | § 120.002 | **Confirms ownership of A-$CO_2$ in storage operations; does not apply to A-$CO_2$ injections in EOR (emphasis supplied):**<br>"Sec. 120.002. OWNERSHIP OF ANTHROPOGENIC CARBON DIOXIDE.<br>(a) *This section* ***does not apply to anthropogenic carbon dioxide injected for the primary purpose of enhanced recovery operations.***<br>(b) ***Unless otherwise expressly provided*** *by a contract, bill of sale, deed, mortgage, deed of trust, or other legally binding document or by other law, anthropogenic carbon dioxide stored in a geologic storage facility is considered to be* ***the property of the storage operator*** *or the storage operator's heirs, successors, or assigns.*<br>(c) ***Absent a final judgment of wilful abandonment*** *rendered by a court or a regulatory determination of closure or abandonment, anthropogenic carbon dioxide stored in a geologic storage facility is* ***not considered to be the property of the owner of the surface or mineral estate*** *in the land in which the anthropogenic carbon dioxide is stored or of a person claiming under the owner of the surface or mineral estate.*<br>(d) *The owner, as designated by Subsection (b) or (c), of the anthropogenic carbon dioxide stored in a geologic storage facility, or the owner's heirs, successors, or assigns, may produce, take, extract, or otherwise possess anthropogenic carbon dioxide stored in the facility".* |
| Wyoming | HB 58 (2009) | § 1 adopting W.S. §. 34–1–153 | All carbon dioxide and other substances injected incidental to the injection of carbon dioxide that are injected into any geologic sequestration site for the purpose of geologic sequestration are 'presumed' to be owned by the injector, such that 'all rights, benefits, burdens and liabilities' of ownership belong to the injector. This presumption of ownership may be rebutted by a preponderance of the evidence in an action to establish ownership. |

### b. $CO_2$ DECLARED A 'COMMODITY', NOT A 'WASTE'

In 2007, a taskforce created by the Interstate Oil and Gas Compact Commission developed a model statute and implementing regulations for geologic storage.[256] The model statute included a legislative declaration that geologic storage of $CO_2$ will benefit the citizens of the state and the state's environment by reducing greenhouse gas emissions, and that $CO_2$ is a 'valuable commodity to the citizens of the state'.[257] A number of the recent statutes follow this Model Statute, either *verbatim* or in some variation. None has defined or treated $CO_2$ for injection purposes as a waste. The precise definition of 'carbon dioxide' varies from one statute to another. For example, the statutes that create a storage facility licensing system generally define the term 'anthropogenic $CO_2$' and may or may not include an intended use in the definition. Statutes granting eminent domain authority for $CO_2$ pipelines may include either A-$CO_2$ or N-$CO_2$ and use in EOR operations. Sometimes a compositional standard is included.[258]

These provisions of *state* law may or may not have legal consequences in the application of *federal* law. In some instances, they appear in prefatory clauses in the legislation that may or may not be treated as creating 'law'. In any event, in the exercise of its own responsibilities under such federal statutes as RCRA or CERCLA, the US EPA appears unlikely to defer on legal grounds to state legislative determinations. Instead, it will make its own determinations about classifying $CO_2$ streams for its own regulatory purposes.[259] State law declarations that $CO_2$ is a commodity may have some *persuasive* effect, however, by underlining the extent to which state governments recognise value in the injected $CO_2$.

These state legislative declarations may also have private law consequences. For example, a typical contract clause transferring title to $CO_2$ or tendering it for transportation in a third-party pipeline is likely to have a provision in which the seller agrees that it is subject to applicable law and that it warrants that the $CO_2$ will meet the contract specifications for quality. Those specifications will likely prohibit the inclusion of wastes or hazardous wastes or the like. Hence, the state statutory declarations (as well as a properly structured conditional exemption from the EPA under RCRA) may help lessen contractual uncertainty that could otherwise arise in these agreements.

**TABLE III: Statutory declarations of $CO_2$ as commodity or resource**

| STATE | STATUTE | REFERENCE | |
|---|---|---|---|
| Louisiana | HB 661 | § 1102(A)(2) | States that carbon dioxide is a "valuable commodity to the citizens" of the state. |
| Mississippi | SB 2723 | § 53–11–3 (1)(a) and (b) | Declares $CO_2$ a 'valuable commodity' to the citizens of the state |
| North Dakota | SB 2052 | Century Code § 38–20–01 | Declares $CO_2$ is a potentially valuable commodity. |
| Oklahoma | SB 1765 | § 2(A)(2) | Declares $CO_2$ a valuable commodity to the citizens of the state; states that capture recovery and geologic storage of $CO_2$ will benefit the citizens of this state |
| Texas | SB 1387 | | Not addressed |

256 The Interstate Oil and Gas Compact Commission Task Force on Carbon Capture and Geologic Storage, *Storage of Carbon Dioxide in Geologic Structures A Legal and Regulatory Guide for States and Provinces* (25 September 2007) (<http://groundwork.iogcc.org/topics-index/carbon-sequestration/executive-white-papers/co2-storage-a-legal-and-regulatory-guide-fo>) (viewed 14 June 2012) (hereafter '*IGOCC Model Statute*).

257 *Id.* at 32 (IOGCC Model Statute, Section 1(a).

258 Montana, HB 498, Section 12 (amending 82–11–101, MCA to define 'Carbon dioxide' as 'carbon dioxide produced by anthropogenic sources that is of such purity and quality that it will not compromise the safety of a geologic storage reservoir and will not compromise those properties of a geologic storage reservoir that allow the reservoir to effectively enclose and contain a stored gas.' The North Dakota statute, SB 2095 promulgating Code s. 38–20–02, is virtually identical.

259 Under Article VI of the US Constitution, the 'Supremacy Clause', federal laws trump (or 'pre-empt') state laws that are in direct conflict. There is a great body of case law where the courts define the boundaries between federal and state law. The issue is frequently one of determining whether or not an authorised federal regulatory scheme is intended to wholly occupy a given field or defining the extent to which differing state and federal regulatory schemes may co-exist.

### c. WITHDRAWAL AND RE-USE OF STORED $CO_2$

One of the interesting provisions common to a number of the new statutes is a legislative recognition that $CO_2$ that has been geologically stored under a storage statute may be withdrawn for re-use. A provision to this effect was part of the IOGCC Model Statute, explicitly providing that 'geologic storage of carbon dioxide gas may allow for the orderly withdrawal as appropriate or necessary, thereby allowing carbon dioxide to be available for commercial, industrial, or other uses, including the use of carbon dioxide for enhanced recovery of oil and gas (EOR).[260] This provision of the Model Statute has also been adopted nearly *verbatim* in several of the recent state statutes.[261] The Model Statute provision reflects the fact that injected $CO_2$ can be recycled and re-injected (whether in the same or a different subsurface formation) without leaving the closed system of piping to and from underground storage. This of course is a very different perspective than the idea of injecting $CO_2$ a single time for permanent storage. As will be seen below, the EPA's $CO_2$ reporting rules also recognize such reuse in some contexts and the reporting formulae are intended to avoid any double-counting.

## 2 Transporting the $CO_2$ supply to storage sites

### a. FEDERAL CHANGES—SAFETY STANDARDS TO BE SET FOR GASEOUS STATE $CO_2$ PIPELINES

As noted in Part I, the existing federal safety regulations for pipelines carrying dense phase or supercritical $CO_2$ (i.e. under high pressure as a *fluid*) have been in place since the early 1990s.[262] This is how all (or nearly all) $CO_2$ is transported in the major pipelines.[263] Under Section 15 of the *Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011*, signed into law on 3 January 2012,[264] the Secretary of Transportation is directed to establish minimum safety standards for the transportation of $CO_2$ by pipeline in a gaseous state as well. The statute directs the Secretary to consider whether the existing standards for transporting $CO_2$ (which the statute terms a 'liquid' state) would ensure safety. Implementing rules are likely to be adopted in due course.[265] It may be unlikely (for economic reasons) for long-line pipelines to transport $CO_2$ in a gaseous state, but the new standards do help to complete the overall framework for safety regulation.

### b. STATE LAW CHANGES

It is at the state level that the more significant changes in this area have been made. Principally, a procedure has been created by which the developer of a $CO_2$ pipeline may obtain a power of eminent domain to acquire property interests needed for the pipeline. There are variations in the details. In some states, a $CO_2$ pipeline operator may acquire the power of eminent domain by agreeing to become a 'common carrier' under existing state or federal law, thus becoming subject to requirements to provide service where capacity is available on a non-discriminatory basis (e.g. Montana,[266] Mississippi,[267] North Dakota[268] and Texas[269]). In other states, there is a procedure for the pipeline applicant to obtain a newly created certificate of authorisation from a state agency to construct and operate a $CO_2$ pipeline. The certificate carries with it the power to acquire the necessary rights of way through an eminent domain proceeding. This is the

260 IOGCC Model Statute, *supra*, Section 1(a).

261 Examples include Oklahoma and Mississippi, among others.

262 Dense-phase or supercritical $CO_2$ is a fluid; it is not a 'liquid'. Nonetheless, in some statutory or regulatory documents, it is referred to as a 'liquid'. To avoid legal confusion, it is highly preferable for the legislative or regulatory draftsman to be more precise and to use the term 'fluid' or, better yet, the terms 'dense phase' or 'supercritical' to describe the state $CO_2$ assumes at the pressures and temperatures typically used for long-line pipeline transportation or injection in typical $CO_2$ operations.

263 Some lower pressure field lines that move the produced $CO_2$ *to* compressors for reinjection as a supercritical fluid carry the $CO_2$ in a gaseous state.

264 The full text of the new statute is available at <http://www.govtrack.us/congress/billtext.xpd?bill=h112-2845> (viewed 27 January 2012).

265 Field facilities are not subject to the standards. Section 15 provides that the statute does not authorise the Secretary to regulate 'piping or equipment used in the production, extraction, recovery, lifting, stabilization, separation, or treatment of carbon dioxide or the preparation of carbon dioxide for transportation by pipeline at production, refining, or manufacturing facilities'.

266 HB 338 (2009), codified at 69–13–101 MCA (applies to pipelines transporting 'carbon dioxide produced in the combustion or gasification of fossil fuels').

267 Miss. Code Ann. § 11–27–1.

268 North Dakota. Century Code, 49–19–01 (available at <http://www.legis.nd.gov/cencode/t49c19.pdf>).

269 Texas Nat. Res. Code § 111.002(6).

approach adopted by Illinois,[270] Indiana,[271] Kentucky,[272] and Oklahoma.[273] Eminent domain is generally available for $CO_2$ pipelines in Colorado, Louisiana,[274] New Mexico,[275] and Wyoming, as well.

The precise terms of these statutes vary and the individual statutes must, of course, be consulted in evaluating a particular project. This includes, for example, requirements with regard to the source of the $CO_2$ to which eminent domain authorisation relates (N-$CO_2$, A-$CO_2$, or all $CO_2$); the location of the injection site (in-state, out-of-state); and/or the purpose for which it is to be transported (commercial or industrial use, EOR operations, and/or long-term storage). Despite the variations, there is now generally a legal mechanism for acquiring the necessary rights of way in most of the principal states in which such pipelines may be constructed in coming years.

## 3 Acquiring and managing the property rights to the target formation

### a. STATUTORY CHANGES AFFECTING PORE SPACE OWNERSHIP AND THE DOMINANCE OF THE MINERAL ESTATE

Providing clarity regarding pore space ownership (between the mineral interest owner and the surface owner) has been identified by many commentators as a key issue to be addressed under the US and Canadian legal regimes of private subsurface ownership. In response, a number of the recent state statutes address pore space ownership, either as part of an overall storage licensing scheme, or as separate legislation. They generally confirm what many believed was the case, that the pore space for storage purposes in the US belongs to the surface owner unless it has been clearly conveyed to another.[276] However, in other states, including some of the most active in $CO_2$–EOR operations, such as Texas and Mississippi, the recent statutes do not address the pore space issue, leaving the existing law in place.[277]

The legislative provisions confirming pore space ownership for storage in the surface estate owner has not been a particularly controversial issue in and of itself. As noted above, that is the general rule for natural gas storage; and providing legislative certainty in the case of $CO_2$ storage may be a positive step for potential project developers. However, a legislative declaration may also have the unintended consequence of creating confusion with regard to prior land records, making the process of assembling the necessary rights *more* difficult, not less.

The more significant point however, is that pore space cannot be *available* for storage unless or until it is no longer occupied by a previously severed mineral interest. This is a capital point that has not often been recognised in the literature, but it helps explain why nearly *all* of the recent state statutes that address geologic storage confirm or reaffirm the long-standing respective roles of the mineral and the surface estate (discussed in Part I). The issue may not arise in the case of non-EOR geologic storage sites in saline aquifers, where the pore space in the formation is occupied by brine

270 Illinois SB 1821 (enacted 2011) declares $CO_2$ pipelines to be: for a public use and service: in the public interest: a benefit to the welfare of Illinois: and necessary for sequestration, enhanced oil recovery, or other carbon management purposes. Thus, they are 'an essential component to compliance with required or voluntary plans to reduce carbon dioxide emissions'. The statute states that $CO_2$ pipelines are 'critical to the promotion and use of Illinois coal and also advance economic development, environmental protection, and energy security in the State'. The statute is limited to pipelines that transport and sequester certain A-$CO_2$, which is to say $CO_2$ 'produced by a clean coal facility, by a clean coal SNG [synthetic natural gas] facility, or by any other source that will result in the reduction of carbon dioxide emissions from that source'. The certificate procedure provides for conditioning the grant of the certificate upon compliance with various other governmental standards for safety, land use, etc.

271 Section 39 of Indiana SB 251 (2011) declares that the use of $CO_2$ transmission pipelines is a public use and service, in the public interest, and a benefit to the welfare and people of Indiana. It establishes a procedure to obtain a 'carbon dioxide transmission pipeline certificate authority' for pipeline used exclusively for the purpose of transporting $CO_2$ to 'a carbon management application, including sequestration, enhanced oil recovery, and deep saline injection, within or outside Indiana'.

272 Kentucky SB 50 (enacted 2011) provides procedure for eminent domain for $CO_2$ pipelines.

273 Under the Oklahoma Carbon Capture and Geologic Sequestration Act, the pipeline operator, 'after obtaining the required Oklahoma Corporation Commission and Department of Environmental Quality permits and certificates', may exercise the power of eminent domain to acquire property interests necessary for 'constructing, operating or modifying a storage facility or carbon dioxide transmission pipeline'.

274 LA Rev. Stat. § 19:2(10) (2007).

275 NM Stat. Ann. § 70–3–5.A.

276 These include Wyoming (HB 89) (ownership of all pore space in all strata below the surface lands and waters of this state is declared to be vested in the several owners of the surface above the strata); and Montana (HB 498) (presumption that the surface owner owns the storage reservoir if it cannot otherwise be determined from the relevant land instruments).

277 The collective wisdom of various Texas state agencies on the pore space question is set out in a report required by SB 1387. The report concluded that Texas statutory law does not address which estate, surface or mineral, possesses ownership of the pore space for storage purposes unless the contract severing the surface and mineral estates expressly specifies and that the case law (primarily cases involving natural gas storage) gives conflicting results, leaving the law uncertain. See *Injection and Geologic Storage Regulation of Anthropogenic Carbon Dioxide: A Preliminary Joint Report by The Texas General Land Office, The Railroad Commission of Texas, The Texas Commission on Environmental Quality, in Consultation with The Bureau of Economic Geology, Jackson School of Geosciences, The University of Texas at Austin* (1 December 2010).

that has no economic value and would not generally be subject to any prior mineral lease. But in the early decades of CCS deployment, it is far more likely that geologic storage sites will be located in a still producing or formerly producing oil or gas formation. Yet primary and secondary oil production techniques today typically leave unrecovered 50 per cent or more of the original oil in place (OOIP).[278] Thus, even after current $CO_2$–EOR techniques are applied, there will still remain in the formation perhaps one-third or more of the original oil. In general, this oil remains part of any severed mineral interest unless or until the mineral interest comes to an end (e.g. as may occur with lease termination due to termination of production).

Moreover, the history of the oil businesshas been marked by technological advances allowing the economic production of resources that previous generations deemed uneconomic. The advances in information technology over the past 20–30 years have had a huge impact on the oil and gas industries, for example by allowing for horizontal drilling and 3–D seismic analysis, to name just just two innovations made possible in large part by advances in information processing capabilities. It may be no great exaggeration to say that 'Moore's Law' of exponential increases in processing capability of integrated semiconductor circuits[279] may play a more important role in the future development of geologic storage of $CO_2$ than federal or state law.

Knowing this, the owners of mineral interests will generally be unlikely to forego potential future resources where it can be avoided. As a result, the recently enacted statutory provisions regarding pore space ownership may have less of a practical impact for near-term storage opportunities in conjunction with or following EOR operations than might otherwise have been thought. The IOGCC's 2007 taskforce report on the Model Statute and Regulations for geologic storage discussed some of these complexities:

> *In the case of $CO_2$ enhanced oil recovery projects, the right to inject $CO_2$ into the subsurface oil reservoir generally is contained in and part of the oil and gas lease that would have been obtained to develop the project. During the operation of a $CO_2$ enhanced oil recovery project (EOR), a certain amount of the injected $CO_2$ remains in the oil reservoir, and should be considered stored $CO_2$. Consequently, the right to use an oil reservoir for the associated storage of $CO_2$ during the operational phase of a $CO_2$ EOR project would be permissible under an oil and gas lease. However, at the conclusion of a $CO_2$ EOR project when active oil production ceases and the remaining reservoir capacity is used for $CO_2$ injection for the purpose of long-term storage, the extension of the underlying oil and gas lease granting this authority has not been clearly enumerated in existing law or in associated case law. It's possible that at the time $CO_2$ EOR ceases and storage begins, the subsurface rights necessary for storage might need to be acquired if they had not already been acquired at the beginning of the project. In addition, the potential also could exist that the final $CO_2$ storage phase of a $CO_2$ EOR project might not necessarily end further oil production. A long-term $CO_2$ 'soaking' phase could be contemplated, followed by reactivation of another phase of oil production, before the final storage of $CO_2$ in the reservoir is initiated. This 'soaking' phase might be covered by the initial oil and gas lease; however, the necessary storage rights eventually will need to be acquired as part of the final storage phase.*

The issues are highlighted by the Wyoming legislative experience. The original legislation in 2008 addressed the pore space issue by declaring that the pore space in strata belonged to the surface owner above the strata. But in response to concerns that the pore space ownership provision could unintentionally and adversely affect owners of other subsurface interests—i.e. the existing mineral interests—the legislature in 2009 added a proviso expressly preserving the priority of the mineral estate: [280]

> *For the purpose of determining the priority of subsurface uses between a severed mineral estate and pore space as defined in subsection (d) of this section, the severed mineral estate is dominant regardless of whether ownership of the pore space is vested in the several owners of the surface or is owned separately from the surface.*

278 Vello A. Kuuskraa, Tyler Van Leeuwen, and Matt Wallace, *'Improving Domestic Energy Security and Lowering $CO_2$ Emissions with 'Next Generation' $CO_2$–Enhanced Oil Recovery ($CO_2$–EOR)'* (20 June 2011 (sponsored by US DOE/NETL and prepared by Advanced Resources Internationa) (available at <http://www.netl.doe.gov/energy-analyses/pubs/NextGen_CO2_EOR_06142011.pdf>) (viewed 28 January 2012).

279 See e.g. Intel Corp., '*Excerpts from A Conversation with Gordon Moore: Moore's Law*', (available at <ftp://download.intel.com/museum/Moores_Law/Video-Transcripts/Excepts_A_Conversation_with_Gordon_Moore.pdf?) (viewed 28 January 2012).

280 Codified at §34–1–152 (e).

Thus, a key part of understanding the ownership puzzle lies in understanding the *relationship among the ownership interests*. Since as a general matter the mineral estate is the dominant estate and the surface estate is the servient estate, the mineral interest owner may—subject of course to the accommodation doctrine—make use of that portion of the surface estate that is reasonably necessary for the extraction of the minerals. As applied in the context of $CO_2$ injections in an oil–bearing formation, this would seem to imply that the $CO_2$–EOR operator may make use of any pore space owned by the surface owner that is reasonably necessary for the EOR operation. As long as there is material oil production occurring—presumably even if the operation is conducted so as to maximise $CO_2$ injections for storage—the availability of the pore space for separate non-EOR related storage will be delayed. This would not appear to affect how much $CO_2$ is ultimately injected for storage, but rather who is responsible.

### b. AGGREGATING THE NECESSARY PROPERTY RIGHTS—PLANNING AHEAD, EMINENT DOMAIN AND UNITISATION PROVISIONS

Given the fragmented nature of property ownership in the US, there is a need for a mechanism to aggregate the storage rights. This does not necessarily require special legislation if a site is transitioning from an EOR operation, as explained in the 2007 IOGCC taskforce report.[281] This strictly commercial approach will not work in all cases, of course, and not at all in cases where there is no mineral lease, such as saline aquifers. The IOGCC taskforce report concluded that necessary storage rights should be required as part of the initial geologic storage licensing. It proposed that the states use eminent domain power to acquire the necessary surface and subsurface storage rights. This is generally the approach taken in a state when creating a storage certification procedure.

In addition, there may be a need for some form of unitisation where subsurface rights have already been granted for EOR operations but there is a need to amalgamate those rights in a larger unit for $CO_2$ storage. Unitisation provisions were included in the statutes in Mississippi, Montana, North Dakota, Oklahoma, and Wyoming. The percentages of the affected ownership interests that must consent in order to create the $CO_2$ storage unit varies from a simple majority (as is provided for natural gas storage fields in Mississippi), to two–thirds, to as much as 80 per cent (in Wyoming).

281 IOGCC's *Legal and Regulatory Guide for States and Provinces,* s*upra*, at 28–29. See also Marston and Moore, *supra*, 29 Energy L. J. at 481:

*This existing legal and institutional structure means that an operator planning ahead for future potential use of the reservoir for incremental storage of $CO_2$ need only take one more step than has been traditional in the past in preparing for unit operations. That additional step is to initially solicit and incorporate into the traditional EOR unitization documents the agreements of the working interest and mineral interest owners to the future potential use for CCS storage. This could be done by including in the Unit Agreement the extension of the oil and gas leases beyond termination of the Unit and through a future potential $CO_2$ storage term, which term would be until the $CO_2$ storage project itself were actually permanently terminated and sealed (comparable to the 'post-closure' period in the IOGCC report at which time ownership would transfer to a governmental or quasi-governmental entity). This action alone would allow the operator to later produce commercially available oil under future technology or produce oil that might be associated with produced $CO_2$ that could be withdrawn for other use. It could also provide the mechanism whereby the mineral interest owner consents to his residual pore space being utilized for $CO_2$ storage. Likewise, the Unit Operating Agreement could be expanded to include new definitions for a $CO_2$ storage Unit Operation post EOR, so that the operator would have early approval of those owners required by a regulatory agency for future approval of a $CO_2$ storage project. With the inclusion of the surface owner(s) in this early development planning, the progression of an EOR project into a carbon dioxide storage project can be handled reasonably seamlessly with only slight additions to, or tweaking of, current state oil and gas and property laws.*

## 4 Authorisation to drill wells, inject $CO_2$ and manage obligations to protect public health and safety (including underground sources of drinking water)

### a. OVERVIEW OF THE EPA RULES

Because there is no federal legislative framework for CCS similar to the EU's CCS Directive, there is no national permitting framework for developing a $CO_2$ geologic storage site. The US EPA's remit does not extend so broadly,[282] at least in direct terms. Under the Safe Drinking Water Act, it sets standards to protect underground sources of drinking water, while under the Clean Air Act it regulates the emission of 'air pollutants', [283] including reporting of emissions–related information. In addition, under the Resource Conservation and Recovery Act, the EPA has established a comprehensive framework for the management of certain solid wastes, as there defined (which includes solid wastes that are also hazardous wastes). .

The EPA has invoked these three statutory authorities in separate rulemaking proceedings to create important, yet limited, elements of an overall geologic storage regulatory regime.

- *Class VI well permitting rule*. This SDWA–based rule, finalised in 2010, established a new well classification under the Underground Injection Control Program (Class VI) for geologic sequestration wells.
- *$CO_2$ reporting from suppliers and injectors—Subparts PP, RR, and UU*. These Clean Air Act–based rules (two separate rules) were finalised in 2009 and 2010. They require reporting of $CO_2$ supply, including principally the production of $CO_2$ from naturally occurring sources for delivery into a transporting pipeline (Subpart PP) and of $CO_2$ injected into subsurface formations in $CO_2$–EOR operations (Subpart UU) and non-EOR storage sites (Subpart RR, which includes requirements for monitoring, reporting and verification activities ('MRV')).

Together, these Class VI and Subpart UU/RR rules contemplate the possibility of EOR–related operations (permitted under Class II and reported under Subpart UU) transitioning to storage–only operations by complying with certain additional requirements, including monitoring, verification and reporting, as detailed below.

- *Proposed conditional exemption of certain $CO_2$ streams from hazardous waste regulation under RCRA*. The third component of the EPA's geologic storage framework is a proposed rule expected to be finalised during 2013 that would exempt certain $CO_2$ streams that contain substances that would otherwise be defined as hazardous waste.

In essence, the EPA regulatory rules presuppose the recent state legislative initiatives addressing the property and storage facility certification procedures, and *vice versa*. The adequacy of the overall framework can thus only be evaluated by examining the federal and state initiatives in combination.

### b. THE CLASS VI WELL PERMITTING RULE FOR GEOLOGIC SEQUESTRATION WELLS.

#### i. Overview.

The US EPA promulgated its Class VI permitting rule in December 2010. As discussed in Part I, the new Class VI requirements apply to any well that is used 'to inject carbon dioxide specifically for the purpose of geologic sequestration, i.e. the long-term containment of a gaseous, liquid or supercritical carbon dioxide stream in subsurface geologic formations'.[284] The rule defines the term 'carbon dioxide stream' as:[285]

> *… carbon dioxide that has been captured from an emission source (e.g. a power plant), plus incidental associated substances derived from the source materials and the capture process, and any substances added to the stream to enable or improve the injection process. This subpart does not apply to any carbon dioxide stream that meets the definition of a hazardous waste under 40 CFR part 261.*

---

282 Indeed, in declining in its *Class VI rule* to try to address the issue of possible transfer of long-term liability, the EPA explicitly noted that 'under current SDWA provisions EPA does not have authority to transfer liability from one entity (i.e. owner or operator) to another'. *Class VI rule, supra*, 75 Fed. Reg. at 77272.

283 It was based on this phrase that the US Supreme Court's decision in *Massachusetts v. EPA* found that the US EPA had the legal authority to regulate $CO_2$ and other greenhouse gases as 'air pollutants' if it found that their atmospheric emissions 'endangered' human health. *Massachusetts v. EPA*, 549 U.S. 497 (2007). The EPA made that 'endangerment' finding in 2009, beginning the actual process of regulating $CO_2$ emissions. That ruling is now pending a decision by the US court of appeals, which heard argument on the case in February 2012. *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, 74 Fed. Reg. 66,496 (15 December 2009), *Denial of the Petitions to Reconsider the Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, 75 Fed. Reg. 49,556 (13 Aug. 2010), *pet. for rev. pending sub nom. Coalition for Responsible Regulation v. EPA*, D.C.Cir. Nos. 09–1332, *et al.*

284 40 CFR § 146.81 (b). See also 40 CFR § 144.3 (codifying definition of 'geologic sequestration' and adding that the term 'does not apply to carbon dioxide capture or transport'.

285 40 CFR § 146.81 (d) (found at 75 Fed. Reg. at 77292).

Hence, the Class VI rule applies only to the injection of A-$CO_2$ (logically enough because there is no reason for anyone to produce N-$CO_2$ merely for the purpose of injecting it in a storage facility).

The EPA believed that a new well class was appropriate because of what it viewed as unique risks to underground sources of drinking water from $CO_2$ injections outside of the EOR context. The EPA distinguished carefully between the *purposeful* storage of $CO_2$ under Class VI and the *incidental* storage of $CO_2$ under Class II during $CO_2$–EOR operations. The key differences in the agency's mind were: the scale of anticipated injections; the absence of the pressure relief provided by production wells of a $CO_2$–EOR operation, and the resulting higher subsurface pressure. Other factors in the EPA's determination that a separate well category was appropriate were: the potential presence of impurities in a $CO_2$ stream captured from a combustion source (not present in N-$CO_2$ or in A-$CO_2$ derived from non-combustion processes); the corrosivity of $CO_2$ in the presence of water; and the fact that $CO_2$ is less dense than water and hence would tend to migrate upward in the event the $CO_2$ plume encountered a migration pathway (e.g. a poorly plugged pre-existing well or a fault or fracture).[286]

Accordingly, the EPA developed detailed regulations governing all aspects of the siting and preparation of a geologic sequestration facility via the underground injection requirements for Class VI wells.[287] If VI implementation were to follow the Class II experience, most states in which geologic sequestration projects may develop would seek and obtain primacy under the SDWA and hence would need to demonstrate that their UIC program meets the Class VI federal requirements.[288]

Prior to drilling a proposed Class VI well,[289] the operator must submit an application that contains detailed site characterisation assessment and extensive supporting information on the proposed site. The information must cover the Area of Review (AoR) surrounding the project area, identify potential leakage pathways and describe corrective action being taken to address them. Acceptable forms of financial responsibility are spelled out.[290] The regulations detail specific requirements for injection well construction, testing, and well operations.[291]

The Class VI rule is designed in part to work with the Subpart RR reporting rule. Thus, some of the monitoring obligations under a Class VI UIC permit will satisfy certain of the requirements of a monitoring, reporting and verification plan under Subpart RR. But the focus of the MRV plan under Subpart RR is on *emissions to the atmosphere*, not subsurface movements. Hence, the reporting entity is required to include certain additional information regarding surface detection and quantification of $CO_2$.[292]

Well closure and post-injection site care are also addressed in detail. Following the cessation of injections, the owner or operator is required to continue monitoring the site as specified in the approved post-injection site case and site closure plan. The default rule is that such monitoring is required for 'at least 50 years' or such alternative time approved by the director of the UIC program (the state agency under primacy or the EPA itself if the state has not qualified for primacy).[293] The rule allows for the owner or operator to seek to demonstrate 'to the satisfaction of' the program administrator prior to the 50–year default period that the project 'no longer poses an endangerment to USDWs', in which case the program administrator may amend the plan and reduce the frequency of monitoring or authorise site closure at an earlier time.[294]

With regard to liability for SDWA noncompliance during the closure and post-closure periods, owners or operators of injection wells must ensure protection of USDWs from endangerment and are subject to liability for enforcement under the SDWA. Once the regulatory requirements have been met and site closure has been approved under 40 CFR § 146.93, the owner or operator will 'generally' no longer be subject to enforcement for non-compliance with the applicable regulatory requirements. However, an owner or operator may be held liable for regulatory non-compliance

286 *Id.* 75 Fed. Reg. at 77234.

287 The requirements are now codified at 40 CFR §§ 146.82 to 146.94.

288 The rules governing a state's application for primacy for Class VI are codified at 40 CFR § 145.21, *et seq.*

289 As codified at 40 CFR § 146.5(4) Class VI wells are specifically defined as:

*Wells that are not experimental in nature that are used for geologic sequestration of carbon dioxide beneath the lowermost formation containing a USDW; or, wells used for geologic sequestration of carbon dioxide that have been granted a waiver of the injection depth requirements pursuant to requirements at § 146.95; or, wells used for geologic sequestration of carbon dioxide that have received an expansion to the areal extent of an existing Class II enhanced oil recovery or enhanced gas recovery aquifer exemption pursuant to § 146.4 and § 144.7(d) of this chapter.*

290 40 CFR § 146.85.

291 40 CFR §§ 146.86 to 146.88.

292 *Class VI Rule, supra,* 75 Fed. Reg. at 77236. The rule includes a table (Table II–1) comparing the major reporting requirements in subpart RR with those of Class VI.

293 40 CFR § 146.93 (b)(1).

294 40 CFR § 146.93 (b)(2).

under certain circumstances, even after site closure is approved, for example where the owner or operator has provided erroneous data to support approval of site closure. In addition, an owner or operator 'may always be subject to an order' if there is fluid migration that 'causes or threatens imminent and substantial endangerment to a USDW'. This could take the form of a civil action seeking appropriate relief. After site closure, an owner or operator could remain liable under tort and other remedies, or under other statutes 'including, but not limited to', the Clean Air Act, CERCLA[295] and RCRA.[296]

It is, in sum, a comprehensive and detailed set of regulatory rules. Since issuing the Class VI rule in December 2010, the EPA has published a series of even more detailed guidance documents (either draft or final), including:

- Guidance for states in applying for Class VI well primacy[297]
- Well Site Characterization Guidance[298]
- Area of Review Evaluation & Corrective Action Guidance[299]
- Class VI Well Construction Guidance [300]
- Class VI Well Project Plan Development Guidance[301]
- Various Financial Responsibility Guidance and supporting documents.[302]

The EPA remains focused on the issue and may amend its rules and guidance documents as more experience becomes available.

### ii. Proposed transition pathway from EOR storage to non-EOR storage

Of particular relevance here, the EPA has crafted what it hopes will be a transition pathway for $CO_2$–EOR operators to transition sites over time to non-EOR, storage–only operations. The EPA fully recognised the role that $CO_2$ injections play in EOR operations, noting the extent to which the $CO_2$ acquisition cost has historically accounted for a very large share of the total cost of a $CO_2$–EOR project (between one-third to about two-thirds, according to EPA).[303] Accordingly, EOR operators carefully track $CO_2$ injection volumes at EOR sites and endeavour to recover, transport to other sites and re-inject as much $CO_2$ as is feasible at the end of an EOR operation.[304] While recognising that 'a certain amount' of the injected $CO_2$ remains in the original EOR production formation, the EPA noted a lack of documentation regarding the eventual migration of the unrecovered $CO_2$ (because there has never been a requirement to track the $CO_2$ in the EOR context). While industry sources indicate that 95 per cent or more of originally supplied $CO_2$ for EOR is stored (in excess of 99 per cent according to some industry sources),[305] there has in the past never been a reason to document or account for the exact percentages.

295 With regard to CERCLA, the 'Superfund' legislation providing federal authority to clean up releases or threatened releases of hazardous substances that may endanger human health or the environment, the EPA noted that $CO_2$ itself 'is not listed as a hazardous substance under CERCLA'. *Class VI rule*, *supra*, at 77–260. But as with RCRA, the EPA cautioned that a $CO_2$ stream (defined in the rule as captured $CO_2$) may contain a listed hazardous substance (such as mercury) or may mobilise substances in the subsurface that could react with groundwater to produce listed hazardous substances (such as sulphuric acid). Hence, whether such an included substance may result in CERCLA liability 'depends entirely on the composition of the specific $CO_2$ stream and the environmental media in which it is stored (e.g. soil or groundwater)'. *Id.* The EPA added, of course, that CERCLA exempts from liability under certain 'Federally permitted releases', which, it said, would include a permitted injectate stream 'as long as it is injected and behaves in accordance with the permit requirements'. *Id.* Exceeding those permit conditions could take the $CO_2$ stream outside the bounds of the federally permitted release and thus trigger liability under CERCLA.

296 *Class VI rule, supra,* 75 Fed Reg. at 77272. This sentence would seem intended to preserve potential private civil liability that might otherwise be deemed pre-empted by a comprehensive federal regulatory scheme that 'occupies the field'. In *American Electric Power Co. Inc. v. Connecticut*, __ U.S. ___ (decided 20 June 2011), the Supreme Court ruled that a nuisance action *under federal law* for atmospheric emissions of $CO_2$ was pre-empted by the federal regulatory scheme under the Clean Air Act. The Supreme Court did not decide whether such an action *under state law* was similarly pre-empted, on the grounds that the state law issue had not been decided by the court below. The Supreme Court thus remanded the case for further proceedings on whether the state law nuisance action was pre-empted or not holding only that 'the Clean Air Act and the EPA actions it authorizes displace any *federal* common law right to seek abatement of carbon dioxide emissions from fossil fuel–fired power plants'). Sl. op. at 14 (emphasis added).

297 US EPA, *Geologic Sequestration of Carbon Dioxide: Draft Underground Injection Control (UIC) Program Class VI Primacy Application and Implementation Manual for State Directors* (June 2011) (<http://water.epa.gov/type/groundwater/uic/class6/upload/primacy_application_and_impl_manual_508_compliant.pdf>).

298 US EPA, *Class VI Well Site Characterization Guidance for Owners & Operators* (<http://water.epa.gov/type/groundwater/uic/class6/upload/GS_Site_Char_Guidance_DRAFT_FINAL_031611.pdf>).

299 US EPA, *Class VI Well Area of Review Evaluation & Corrective Action Guidance for Owners & Operators* (<http://water.epa.gov/type/groundwater/uic/class6/upload/GS_AoR_CA_Guidance_DRAFT_FINAL_031611.pdf>).

300 US EPA, *Class VI Well Construction Guidance for Owners & Operators* (<http://water.epa.gov/type/groundwater/uic/class6/upload/GS_Well_Construction_Gudiance_DRAFT-FINAL-030911.pdf>).

301 US EPA, *Draft Class VI Well Project Plan Development Guidance for Owners & Operators* (<http://water.epa.gov/type/groundwater/uic/class6/upload/GS_Proj_Plan_Development_Guidance_DRAFT_FINAL_031111.pdf>).

302 US EPA, *Geologic Sequestration Guidance Documents* (<http://water.epa.gov/type/groundwater/uic/class6/gsguidedoc.cfm>).

303 *Class VI rule, supra,* 75 Fed. Reg. at 77244 (*citing* EPRI, 1999).

304 *Id.*

305 See sources identified n.24, *supra.*

In addition, the EPA recognised the potential role for EOR–related operations in developing geologic sequestration. It is anticipated that 'many' of the early geologic sequestration projects will be sited in depleted or active oil and gas reservoirs due to the fact that they have already been characterised for hydrocarbon recovery and infrastructure such as pipelines, wells and the like are already in place. The EPA believed that the future deployment of CCS could 'fundamentally alter' $CO_2$–EOR in the US as greater supplies of $CO_2$ become available.[306]

Accordingly, the EPA endeavoured to structure a transition pathway by which Class II wells could be re-permitted as Class VI wells for storage purposes when EOR operations come to an end.[307] The Class VI rule does not apply to Class II wells being used for EOR operation as long as any oil or gas production is 'simultaneously occurring' from the same formation. An operator who wants to continue to inject $CO_2$ in a formation after completion of the oil or gas operations will need to obtain a Class VI permit under a specific set of requirements.

The basis for the EPA's judgement is that there is an increased risk to USDWs in $CO_2$ injections—even in the same formation—when oil or gas production operations have ceased. Hence, while $CO_2$ injections via Class II wells for EOR operations may continue under the pre-existing regulations, the EPA was concerned that the $CO_2$–EOR business model could change in the future to focus on maximising $CO_2$ injection and storage rather than minimising them:[308]

> *EPA believes that if the business model for E[O]R changes to focus on maximizing $CO_2$ injection volumes and permanent storage, then the risk of endangerment to USDWs is likely to increase. This is because reservoir pressure within the injection zone will increase as $CO_2$ injection volumes increase. Elevated reservoir pressure is a significant risk driver at GS [geologic storage] sites, as it may cause unintended fluid movement and leakage into USDWs that may cause endangerment. Additionally, increasing reservoir pressure within the injection zone as a result of GS will stress the primary confining zone (i.e. geologic caprock) and well plugs to a greater degree than during traditional ER (e.g. Klusman, 2003). Finally, active and abandoned well bores are much more numerous in oil and gas fields than other potential GS sites, and under certain circumstances could serve as potential leakage pathways.*

The Class VI requirements do not apply to wells employed in traditional $CO_2$–EOR operations. They do apply to owners or operators that are injecting carbon dioxide 'for the primary purpose of long-term storage' into an oil and gas reservoir 'when there is an increased risk to USDWs compared to Class II operations'.[309]

> *Traditional E[O]R projects are not impacted by this rulemaking and will continue operating under Class II permitting requirements. EPA recognizes that there may be some $CO_2$ trapped in the subsurface at these operations; however, if there is no increased risk to USDWs, then these operations would continue to be permitted under Class II. EPA has developed specific, risk based factors to be considered by the Director in making the determination to apply Class VI requirements to transitioning wells. EPA believes this approach provides the necessary, site specific flexibility while providing appropriate protection of USDWs from endangerment. These risk-based factors for determining whether Class VI requirements apply are finalized in today's rule at § 144.19 and include:*
>
> 1. *Increase in reservoir pressure within the injection zone;*
> 2. *increase in $CO_2$ injection rates;*
> 3. *decrease in reservoir production rates;*
> 4. *the distance between the injection zone and USDWs;*
> 5. *the suitability of the Class II A[rea] o[f] R[eview] delineation;*
> 6. *the quality of abandoned well plugs within the AoR;*
> 7. *the owner's or operator's plan for recovery of $CO_2$ at the cessation of injection;*
> 8. *the source and properties of injected $CO_2$; and*
> 9. *any additional site-specific factors as determined by the Director.*

306 This view is consistent with a study conducted for the NETL of the US DOE in 2011 that indicated EOR operations in the US could expand the nation's domestic oil resource base and production very considerably over the next 20 years if sufficient supplies of $CO_2$ were available. Vello A. Kuuskraa, Tyler Van Leeuwen, and Matt Wallace, *Improving Domestic Energy Security and Lowering $CO_2$ Emissions with 'Next Generation' $CO_2$–Enhanced Oil Recovery ($CO_2$–EOR)* (20 June 2011) (estimating that such additional reserves could support nearly four million barrels per day of domestic oil production).

307 Codified at 40 CFR § 144.19.

308 *Class VI rule*, *supra*, 75 Fed. Reg. at 77244.

309 *Id.* 75 Fed. Reg. 77245.

Each of the factors is relevant to the EPA's review. The agency is developing guidance to help the state regulators (which, under primacy, are the principal on-the-ground regulators in this area) evaluate these factors and make the determination on when the Class VI requirements would apply.

The new rules allow for the relevant UIC program director (typically the state agency that administers the program under primacy) to make the determination that a well must move from Class II to Class VI in the absence of an application by the owner or operator. This would effectively require the submission of a complete application for a Class VI permit in order to continue injection operations (§ 144.19(a)).The EPA cautioned that if an operator changed operations, increasing the risk to USDWs, and failed to notify the relevant authority, it could be subject to enforcement and compliance actions.

While requiring re-permitting under Class VI in these circumstances, the rules provide the program Director the discretion to allow 'constructed components' of Class II EOR wells to be 'grandfathered' under specific requirements intended to ensure protection of USDWs.[310] The EPA intends to monitor any such transitioning wells and will review its assessment of the appropriate risk factors in light of experience. The rules may be modified as a result.

The EPA has indicated that it is preparing a draft guidance document on the transition pathway. As of 25 February 2013, the draft had not yet been published for comment. This guidance document is likely to be significant in determining the ultimate viability of the transition mechanism contained in the current Class VI rule.

It should be noted that, as of September 2013, only one state has formally applied to the EPA to exercise primacy for Class VI wells (North Dakota). Apparently only a handful of Class VI well applications have been filed directly with the EPA, none of which is for injection in conjunction with EOR operations, but rather for disposal of $CO_2$ in a deep saline formation in Illinois. As of mid-2013, no Class VI permit has been issued. Although the Class VI rule was finalised in 2009, it may still be premature to gauge how extensively they will be used since the EPA has not yet issued its guidance documents for the transition pathway for wells to move from EOR operations under II to geologic sequestration purposes under VI. The state regulators in the oil and gas producing states have historically been protective of exercising their jurisdictional prerogatives. The fact that few of these states has moved to seek primacy for VI wells suggests that they do not anticipate many filings for VI well permits in the foreseeable future.

### c. REPORTING—$CO_2$ PRODUCTION, INJECTION AND STORED AND PAIRING WITH UIC WELL CLASSES

The second component of the EPA's recent rules of particular relevance for $CO_2$–EOR and $CO_2$–CCS operations are the Subpart PP, RR and UU reporting rules discussed in Part I. As detailed there, Subpart PP requires suppliers producing N-$CO_2$ to report all $CO_2$ *production*;[311] Subpart UU requires $CO_2$–EOR operators to report *net injections* in EOR operations;[312] and Subpart RR requires reporting of $CO_2$ sequestered.

Now that the Class VI rule has been finalised, it is possible to see how the pieces will fit together in a world where quantities of capturedA-$CO_2$ are progressively introduced into existing transportation and injection infrastructure handling N-$CO_2$.

- *Class II/Subpart UU.* $CO_2$–EOR operators continuing oil production operations with current $CO_2$ supplies will inject via Class II wells and report total injections of $CO_2$ under Subpart UU (under rules intended to avoid double counting the re-injection of quantities of $CO_2$ that have been recycled at that facility) The Subpart UU report is of $CO_2$ injections regardless of source (whether N-$CO_2$ or A-$CO_2$) and regardless of the purpose of the injection. In this case, there is no *federal* quantification or verification of the amounts of $CO_2$ incidentally stored during the Class II EOR operation.
- *Class II/Subpart RR.* A $CO_2$–EOR operator of a Class II well that wishes to obtain a federal quantification and verification of the amounts stored during Class II EOR operations may elect to 'opt-in' to report injections under Subpart RR. In this case, the operator is required to file and obtain EPA approval of monitoring, reporting and verification plan (see 40 CFR § 98.448). If an operator chooses to report under Subpart RR, it may not 'opt-out' unless and until the EPA grants approval. A request to discontinue Subpart RR reporting must include either a copy of the authorisation of site closure under the UIC program or a demonstration that the injected $CO_2$ stream is not expected to migrate in a manner likely to result in surface leakage.

310 The rules for approving grandfathered Class II wells are codified at 40 CFR § 146.81(c).

311 US EPA, *Final Rule: Mandatory Reporting of Greenhouse Gases*, 74 Fed. Reg. 5620 (30 October 2009) ('*General GHG Reporting Rule*').

312 US EPA, *Final Rule: Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide*, 75 Fed. Reg. 75060 (1 December 2010) ('*Subpart RR and UU Reporting Rule*').

- *Class VI/Subpart RR.* A geologic storage facility operator would inject $CO_2$ through wells permitted under Class VI and report quantities sequestered under Subpart RR. The storage facility could either be a former EOR production facility converted to storage–only following completion of EOR production operations or a non-EOR reservoir (e.g. a saline aquifer) developed solely as a $CO_2$ storage site. The monitoring requirements of Subpart RR and Class VI are intended, among other things, to provide the quantity of $CO_2$ injected for the purpose of long-term, permanent sequestration. The intent presumably is that only captured A-$CO_2$ would be reported here (since there is no reason for anyone to produce N-$CO_2$ for the purpose of injecting it for long-term storage). However, since A-$CO_2$ is likely to be frequently commingled with N-$CO_2$ in pipeline infrastructure, and some may be cycled through EOR facilities before being sent to a Class VI storage facility, it is not entirely clear whether the current reporting protocols are sufficiently robust to address this level of complexity.

What is not addressed in this schema, however, is a mechanism for quantifying the injections of captured anthropogenic $CO_2$ (A-$CO_2$) that is commingled in a transporting pipeline with quantities of naturally-occurring $CO_2$ (N-$CO_2$) and then injected in Class II wells for the purpose of producing oil in $CO_2$–EOR operations. As widely recognised, including by the EPA's rules, $CO_2$ is incidentally stored during standard EOR operations through Class II wells. By early 2013, supplies of A-$CO_2$ captured from industrial facilities receiving significant financial support from the US DOE had begun to be commingled with N-$CO_2$ supplies in existing mainline pipeline infrastructure and injected via Class II wells in EOR operations, and incidentally stored in the process. While these captured quantities of A-$CO_2$ constitute emissions reductions, there is no place in the current EPA schema for the emitter to obtain an officially recognised quantification of the avoided emissions. The EPA's schema offers the possibility for an injector to 'opt-in' to Subpart RR reporting as 'geologic sequestration' for A-$CO_2$ that is stored in a Class II EOR project. This would be done by migrating from reporting under Subpart UU to Subpart RR (which would include obtaining EPA approval for an MRV plan for reporting emissions under the Clean Air Act). The cost of making that election is expected to be substantial, however. Moreover, while the supplies of A-$CO_2$ in a typical case may make up only a small fraction of the total amount of $CO_2$ used (and incidentally stored) in the EOR operation, the operator electing Subpart RR reporting would presumably have to comply with the requirements of Subpart RR *with respect to the entire commingled stream*. By substantially increasing the cost of using captured A-$CO_2$ compared to alternative supply sources, electing to report under Subpart RR puts A-$CO_2$ at a distinct competitive disadvantage and thus creates a regulatory disincentive to using (and incidentally storing) A-$CO_2$ in traditional $CO_2$–EOR operations. Accordingly, it is not yet clear how viable this option may be; the EPA's yet to be released transition guidance document may help to answer that question. In addition, this issue underscores the importance of developing state–based regimes for verification and certification of permanent storage in states exercising primacy for Class II well permitting.

### d. EPA'S PROPOSED CONDITIONAL EXEMPTION FOR $CO_2$ STORAGE UNDER WASTE LEGISLATION

In promulgating the Class VI rule in December 2010, EPA recognised that $CO_2$ is not itself a listed hazardous waste under RCRA, but the agency also was concerned about impurities that might be included in $CO_2$ streams captured from the combustion sources.[313] EPA indicated that it intended to consider the possibility of a conditional exemption from the RCRA requirements for $CO_2$ stored via Class VI wells.

313 *Class VI rule*, *supra*, 75 Fed. Reg. at 77260.

This proposed exemptive rule has been published for public comment and as of this writing action on a final rule remained pending.[314] The EPA stated that it had 'little information' upon which to conclude that $CO_2$ streams would be classified as RCRA hazardous wastes, but stated that this could be the case depending on the composition of a stream. The EPA stated in the preamble that a supercritical $CO_2$ stream injected into a Class VI well 'for purposes of' geologic sequestration 'is a RCRA solid waste' because it is a 'discarded material' within the terms of the statute.[315] Accordingly, the EPA concluded that a $CO_2$ fluid would become a 'solid waste' under RCRA if a decision were made to discard it, abandon it, or throw it away.[316] As a 'solid waste', the $CO_2$ injected in a storage facility could thus be considered a 'hazardous waste', depending on its physical characteristics. That would present a problem under the existing EPA well classification scheme because 'hazardous wastes' may only be injected in a Class I well.

Hence, the agency has proposed a rule that, if finalised, will allow $CO_2$ streams that would otherwise be classified as RCRA hazardous wastes to be managed in a Class VI well instead, provided that they meet the conditions of the rule.[317] The proposed rule would accomplish this objective by excluding from the definition of hazardous waste those $CO_2$ streams that would otherwise be defined as hazardous; the exclusion would apply to $CO_2$ streams managed under specified conditions (*i.e.* including transportation by a pipeline compliant with PHMSA regulations, disposal in a Class VI well, compliance with the MRV plan and reporting requirements; etc). The EPA has proposed adding a definition of the term 'carbon dioxide ($CO_2$) stream' to its hazardous waste regulations in 40 CFR 260.10 that would define a 'carbon dioxide ($CO_2$) stream' as 'carbon dioxide that has been captured from an emission source (e.g. a power plant), plus incidental associated substances derived from the source materials and the capture process, and any substances added to the stream to enable or improve the injection process'. This is the same definition adopted in the Class VI rule, except for the exclusion of $CO_2$ that meets the definition of a hazardous waste.

With regard to $CO_2$ injections and concurrent storage in $CO_2$–EOR operations, the EPA explicitly stated that $CO_2$ use and storage during $CO_2$–EOR operations would not be affected:[318]

> The proposed rule is not intended to affect the status of $CO_2$ that is injected into wells other than UIC *Class* VI wells. For example, $CO_2$ that is used for enhanced oil or gas recovery (EOR/EGR) in other than UIC *Class* VI wells, where some sequestration may occur in the process of recovering gas or oil, is beyond the scope of this proposal.

In sum, under the Class VI rule, it is prohibited to inject $CO_2$ that meets the definition of hazardous waste; but if the *RCRA Proposed Rule* is adopted, then certain streams that *do* meet that definition would nonetheless be able to be injected for storage in Class VI wells when managed under the conditions specified in the rule.

Last, it should be noted that the EPA indicated that the phrase 'substances added to the stream to enable or improve the injection process' refers to non-waste substances that serve the legitimate purpose as stated (i.e. to enable or improve the injection process), and does not include listed or characteristic hazardous wastes.[319]

---

314 US EPA, *Hazardous Waste Management System: Identification and Listing of Hazardous Waste: Carbon Dioxide ($CO_2$) Streams in Geologic Sequestration Activities*, 76 Fed. Reg. 48073 (8 August 2011) (hereafter '*RCRA Proposed Rule*').

315 *Proposed Rule: Hazardous Waste Management System: Identification and Listing of Hazardous Waste: Carbon Dioxide ($CO_2$) Streams in Geologic Sequestration Activities* , 76 Fed. Reg. 48073 at 48077–480078 (1 August 2011).

316 The EPA stated that a supercritical $CO_2$ stream (a fluid exhibiting some characteristics of both a gas and a liquid) could nonetheless be a 'solid waste' within the definitions of RCRA if it is a 'discarded material'. In the EPA's words, '[o]nce the decision is made that the supercritical $CO_2$ stream will be sent to a UIC Class VI well for discard, EPA considers this material to be a solid waste'.' *Id.* 76 Fed. Reg. at 48078. Under this interpretation, a supercritical $CO_2$ stream injected for the purpose of EOR is not a 'solid waste' because it is not 'discarded material", but if a decision is made to discard, abandon or throw away the supercritical stream, it thereby becomes a 'solid waste' under RCRA and hence may also be a 'hazardous waste' based on its characteristics. See *RCRA Proposed Rule*, *supra*, 76 Fed. Reg. at 48078. The state statutory provisions ensuring $CO_2$ title to injected $CO_2$ would suggest that $CO_2$ subject to those statutes is not abandoned or discarded unless, and until, a decision is made by the injector to do so.

317 *Id.* The proposed rule would not apply to $CO_2$ used and sequestered in EOR operations, but only to injections in Class VI geologic sequestration wells.

318 $CO_2$ in EOR operations is treated as a drilling fluid subject to the conditional exclusion from RCRA under the 1980 statute and the EPA's 1988 determination under that statute that regulation of drilling fluids and other identified substances was "'not warranted"' under Subtitle C of RCRA. *Proposed RCRA Rule*, *supra*, 76 Fed. Reg. at 48078 (n.16). See also at 48089 (EOR is "'outside the scope"' of the proposed rule). The proposed rule does not explain why the $CO_2$ would become a RCRA-–regulated "'solid waste"' when it is discarded via subsurface injection in a Class VI well but not when it is discarded via venting to the atmosphere. If finalised as proposed, the effect of the differential treatment could subject non-EOR sequestration of $CO_2$ to greater regulatory risk and cost than its bare venting to the atmosphere, thereby creating a regulatory *disincentive* to capture and geologic storage, a result that appears at odds with the EPA's intention.

319 *Id.* at 48088.

Comments were filed on the proposed rule in late 2011; many disagreed with the EPA's proposed view that a gaseous $CO_2$ stream could be a 'solid waste' as defined by RCRA and suggested alternative approaches for the EPA to achieve its objectives.[320] A final rule is expected to be issued during 2013.

### e. THE EPA'S INCLUSION OF CCS AS A 'BEST AVAILABLE CONTROL TECHNOLOGY' (BACT) UNDER THE CLEAN AIR ACT

While not directly affecting the EPA's rules governing geologic storage, there is one other EPA initiative that should be mentioned here. When $CO_2$ became a 'regulated N[ew] S[ource] R[eview] pollutant' on 2 January 2011 under the EPA's Clean Air Act regulation, applicants for new emission sources became subject to the requirement that they apply 'best available control technology' (BACT) to reduce $CO_2$ emissions.[321] In addition, the EPA included the BACT requirement in its rules governing approval of State Implementation Plans (SIPs) under the permitting program for certain existing sources,[322] as well as in various individual SIPs already in place.[323]

In March 2011, the EPA issued a (revised) guidance document intended to assist in implementing the BACT requirements.[324] While a BACT guidance document is not normally a binding rule,[325] it is a clear statement of the agency's views and policies. In the March 2011 *BACT Guidance*, the EPA concluded that CCS, comprising capture and/or compression, transport, and storage, must be included in the initial stages of the BACT review:[326]

> *For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is 'available' for facilities emitting $CO_2$ in large amounts, including fossil* fuel-fired *power plants, and for industrial facilities with high-purity $CO_2$ streams (e.g. hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). For these types of facilities, CCS should be listed in Step 1 of a top-down BACT analysis for GHGs.*

This does not mean that CCS necessarily should be selected and EPA made that plain. But the *Guidance* stated that:[327]

> for these types of facilities and particularly for new facilities, *CCS is an option that merits initial consideration and, if the permitting authority eliminates this option at some later point in the top-down BACT process, the grounds for doing so should be reflected in the record with an appropriate level of detail.*

The *BACT Guidance* noted further that where $CO_2$ transportation and sequestration opportunities already exist where the source is, or will be, located, or where other sources in the same source category have applied CCS in practice, then the project 'would clearly warrant a comprehensive consideration of CCS'.[328]

The practical effect of the *BACT Guidance* is that the EPA strongly encourages large $CO_2$ emission sources to consider add-on capture technology, but does not—at least at present—require its adoption.

320 Of relevance to this paper, comments objecting to the EPA's approach explained that it assumed a single stream of captured $CO_2$ would be injected in a single site, whereas it is more likely that there will be various complex scenarios in which streams of $CO_2$ captured from various sources will be commingled with N-$CO_2$ for delivery to multiple recipients and injected for various beneficial uses, including EOR. See e.g. comments filed in EPA Docket ID No. EPA–HQ–RCRA–2010–0695 by the Carbon Sequestration Council, the North American Carbon Capture and Storage Association, the Texas Carbon Capture and Storage Association, the American Petroleum Institute and the Edison Electric Institute. The agency has not yet replied to these comments.

321 The BACT requirement is set forth in the Clean Air Act at Section 165(a)(4), and in the implementing regulations at 40 CFR 52.21(j).

322 40 CFR 51.166(j).

323 40 CFR Part 52, Subparts A–FFF.

324 US EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases,* (EPA–457/B–11–001) (March 2011), (available at <http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf>) (viewed 27 January 2012).

325 But see *Natural Resources Defense Council v. EPA,* 643 F. 3d 311 (D.C. Cir. 2011) (finding that the 'guidance' there in fact bound the agency's Regional Directors, in effect changing the applicable law and was therefore a legislative rule that could only be adopted in compliance with the notice and public comment procedures of the Administrative Procedure Act).

326 *BACT Guidance*, at 32 (footnotes omitted) (emphasis added).

327 *Id.* at 32-–33.

328 *Id.* at 36. Similarly, the prohibitive cost of building a new pipeline to transport $CO_2$ might justify excluding CCS as a control option in Step 2 of the BACT analysis. *Id.* at 42 (for instance, 'when evaluating the cost effectiveness of CCS as a GHG control option, if the cost of building a new pipeline to transport the $CO_2$ is extraordinarily high and by itself would be considered cost prohibitive, it would not be necessary for the applicant to obtain a vendor quote and evaluate the cost effectiveness of a $CO_2$ capture system').

The EPA has also been moving forward with a proposed rule to set an emissions performance standard for new electric generating units.[329] A rule proposed in 2012 would generally allow power plants to use CCS to meet the emissions performance standard. It defined CCS in general terms only.[330] Some comments urged the EPA to modify the proposal in its final rule to limit the definition of qualifying storage to injections via Class VI wells with Subpart RR reporting, and exclude geologic storage that occurs in Class II EOR operations.[331] However, as noted previously, supplies of captured A-$CO_2$ are likely to be commingled in most early projects with supplies of N-$CO_2$ intended for use in EOR operations. Hence, were the EPA to preclude incidental storage during $CO_2$–EOR operations from qualifying as 'CCS' under a final Emissions Performance Standard, it would place these projects at a distinct and potentially insurmountable competitive disadvantage, depriving them of the potential revenue stream from EOR operations.

The proposal was withdrawn for further review in 2013 and a revised proposed rule was published for public comment in September 2013.

## 5 Storage site permitting, verification and certification of stored quantities, long-term liability and stewardship

Having addressed the *state law property rights* needed to acquire consents to inject $CO_2$ for storage as well as the rights of way needed for $CO_2$ pipelines construction, and the *federal regulatory* program governing the injections of $CO_2$ for storage and for transitioning from incidental storage during EOR to incremental storage in a post-EOR environment, it is now possible to see how the *state law certification programs* for geologic storage sites fit into the overall framework.

It should be noted in this context that there is no general $CO_2$ storage regulatory entity under US federal law. The EPA's Class VI UIC permitting program is limited to the protection of underground sources of drinking water, consistent with the scope of the SDWA under which it was promulgated. The EPA has noted repeatedly that it lacks the authority under existing legislation to address liability issues (other than liability for compliance with the statutes that it administers, of course), or to define the terms under which liability for potential damage from $CO_2$ injection and storage might be transferred from an operator to some other entity.[332]

The recently enacted state $CO_2$ storage statutes, however, are not so limited. In fact, they address in various ways the full range of storage permitting issues. By year end 2011, eight states had created a general storage site certification or permitting process for $CO_2$ storage.[333] These initiatives generally address liability during and after the injection period, including a mechanism for transferring or extinguishing that liability after a defined period. In most cases, the statutes establish a funding mechanism to provide at least some of the costs of long-term stewardship of the site following closure. In several cases, the statutes explicitly provide a mechanism for EOR operators to apply for a certification from the state regulator of the quantity of A-$CO_2$ that is permanently stored *during* EOR operations.

The basic pattern of these statutes is to: establish a permitting or certification process; allow geologic storage of $CO_2$ to proceed under specified terms and conditions; require assurances of financial security from the operator during the injection period; and provide for a post-injection period and review process to ensure that the stored $CO_2$ does not pose a

329 *Proposed Rule: Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, 77 Fed. Reg. 22392 (13 April 2012).

330 *Id.* (proposed Section § 60.5580).

331 See e.g. Comments of Natural Resources Defense Council (25 June 2012). The comment suggested, however, that the EPA commence a new rulemaking proceeding to establish conditions under which storage during $CO_2$–EOR operations might qualify. *Id.* at 5–6 (providing list of recommended minimum requirements for qualifying $CO_2$ injected during EOR operations). The comment further suggested (at 6) that the EPA add the term 'permanent' to its definition of qualifying storage. This change would raise the the EPA standard to that already adopted in the 2011 Texas certification rule, which requires a finding that the EOR–based storage quantities be 'permanently stored'.

332 See e.g. *Class VI rule*, *supra*, 75 Fed. Reg. at 77272 ('under current SDWA provisions EPA does not have authority to transfer liability from one entity (i.e. owner or operator) to another').

333 These are Kansas (HB 2419, adopted in 2007); Louisiana (HB 661, adopted in 2009); Mississippi (SB 2723, adopted in 2011); Montana (SB 498, adopted in 2009); North Dakota (adopting chapter 38–22 of the North Dakota Century Code in 2009), Oklahoma (SB 610, adopted in 2009) ; Texas (SB 1387, adopted in 2009); and Wyoming (HB 90, adopted in 2008). The present discussion does not address the statutes that were adopted for single, specific projects (which have not come to fruition), but focuses on those intended for more general use. Hence, the statutes adopted in Texas and Illinois during the competition for the 'Future Gen' project some years ago are not summarised here. Similarly, the discussion here does not address the issues related to possible sub-seabed storage, for example, in the Texas offshore. While there is some discussion of possible developments there, and the Texas Legislature has enacted law to govern such an offshore geologic storage repository, the interplay of property rights and state, federal and international regulation that are involved would deserve a more detailed treatment than available in this overview. The Texas offshore $CO_2$ repository statute (HB 1796) was adopted in 2009 and is available at <http://www.legis.state.tx.us/tlodocs/81R/billtext/pdf/HB01796F.pdf> (viewed 21 January 2012).

significant risk to health, safety or the surrounding environment, at which point the financial security instruments may be released. In some of the statutes, there is then a post-closure period during which the operator remains explicitly liable for any injury or damage the facility may cause.

It may be helpful to highlight several particularly interesting aspects of some of the storage facility permitting statutes.

### a. SCOPE

The statutes in the US are not merely for creating storage sites for permanent storage of captured $CO_2$ for emissions reductions, are conceived more broadly and, in some cases, deal with $CO_2$ injections associated with EOR operations as well. Hence, the definition of $CO_2$ and the reservoir formations subject to the statutes vary as well. Generally speaking, the certification statutes apply to A-$CO_2$. The precise definition of 'carbon dioxide' or 'anthropogenic carbon dioxide' differs. In some cases, the term refers to anthropogenic sources and is not limited to combustion sources, as in North Dakota (where the $CO_2$ produced by the coal gasification plant would meet the definition even though it is not from a combustion source).[334] In Texas, the definition generally includes $CO_2$ that would otherwise have been emitted to the atmosphere, while expressly excluding naturally occurring $CO_2$ that is recaptured, recycled and reinjected in EOR operations.[335]

### b. ACQUISITION AND AGGREGATION OF SUBSURFACE RIGHTS

The statutes generally provide that the authorisation for a storage facility allows the storage operator to exercise eminent domain powers (termed 'expropriation' in Louisiana) to acquire non-consenting pore space ownership.[336] In addition, except for Texas, the statutes generally also provide a mechanism for creation of a storage 'unit' using the existing unitisation procedures. The percentage of consenting property ownership required for formation of a unit varies from a majority of the affected ownership up to a high of 80 per cent.[337] In Texas, consistent with the traditional approach toward unitisation of production, the $CO_2$ storage law does not provide for any form of compulsory unitisation.

334 North Dakota Century Code Section 82–11–101 (3) defines 'carbon dioxide' as:

> *… carbon dioxide produced by anthropogenic sources that is of such purity and quality that it will not compromise the safety of a geologic storage reservoir and will not compromise those properties of a geologic storage reservoir that allow the reservoir to effectively enclose and contain a stored gas.*

335 In Texas, Section 1 of HB 138, adopting Section 27.002 (19) Water Code provides in part:

(19) 'Anthropogenic carbon dioxide':

(A) means:

(i) carbon dioxide that would otherwise have been released into the atmosphere that has been:
(a) stripped, segregated, or divided from any other fluid stream; or
(b) captured from an emissions source, including:
(1) an advanced clean energy project as defined by Section 382.003, Health and Safety Code, or another type of electric generation facility; or
(2) an industrial source of emissions;
(ii) any incidental associated substance derived from the source material for, or from the process of capturing, carbon dioxide described by Subparagraph (i); and
(iii) any substance added to carbon dioxide described by Subparagraph (i) to enable or improve the process of injecting the carbon dioxide; and

(B) does not include naturally occurring carbon dioxide that is recaptured, recycled, and reinjected as part of enhanced recovery operations.

336 See e.g. North Dakota Century Code Section 38–20–10:
*Amalgamating property interests. If a storage operator does not obtain the consent of all persons who own the storage reservoir's pore space, the commission may require that the pore space owned by nonconsenting owners be included in a storage facility and subject to geologic storage.*

337 In Mississippi, the legislature followed the existing rule for natural gas storage that requires a majority of the interest. In Wyoming, under HB 80, Section 35–11–316(c) of the Wyoming code was added to provide in part:

(c) No order of the Wyoming oil and gas conservation commission authorizing the commencement of unit operations shall become effective until the plan of unitization has been signed or in writing ratified or approved by those persons who have been allocated at least eighty per cent (80%) of the pore space within the unit area.

The Wyoming provision does not require the 80 per cent approval to be obtained prior to the issuance of the unitisation order, but rather within six months of the order (unless the time for gaining approval is extended under the procedure spelled out there). The North Dakota statute follows the same approach.

### c. STANDARDS FOR PERMITTING

All of these statutes require the applicant, in fairly general terms, to demonstrate the appropriateness of a formation for storage, taking into account not just the integrity of the formation for storing $CO_2$ but its impact on other resources. This effectively requires the regulator to make a public interest judgement about the best use of subsurface formations and resources. The Mississippi statute is illustrative. The statute requires a finding that a proposed reservoir is 'suitable and feasible' for long-term storage, that such use is in the public interest, and that a majority interest of the relevant ownership has consented in writing.[338] With regard to risk evaluation, the permitting board must find that there is 'no reasonable risk' of endangering human life or causing a 'hazardous condition to property'.[339] But the board is also directed to consider the impact on other subsurface resources. It must find that there is no reasonable risk that using the reservoir for $CO_2$ storage will 'injure or endanger other formations containing fresh water, oil, gas or other commercial mineral deposits'.[340] Then, in the case where a reservoir may contain oil, gas or other commercial minerals, the board must find either that the reservoir is 'substantially depleted' of those resources or that it has 'a greater value or utility as a reservoir for carbon dioxide storage than for the production of the remaining volumes of reservoir oil, gas, condensate or other commercial mineral, if any'.[341]

At bottom, this would appear to be fundamentally a *political* judgement. In the US, because property interests are privately owned, the political judgement to value long-term storage of $CO_2$ over other competing uses of the subsurface tends to come *toward the end* of the process, after the developer has put together all of the other pieces of the proposed storage project. In jurisdictions where the subsurface and the resources are owned by the government, this judgement could in theory be made much earlier in the process, for example, by designating a particular formation as reserved for storage purposes as part of a general land use plan. The advantage of the US approach, illustrated by the Mississippi statute, is that there is likely to have been a much greater airing of the competing interests and elucidation of the facts than might occur in a more 'top down' approach. The disadvantage, of course, is that there may be a waste of resources if the final political judgement determines that the requested formation has 'greater value or utility' for another purpose.

The Texas statute, in contrast, does not include an express requirement to compare the value of competing uses.[342] Given the absence of compulsory unitisation in Texas, however, there will presumably be a very high degree of support for a proposed storage project among the affected interest owners, such that considerations of impact on other resources will likely have already been made individually by the affected interest owners. Only projects with the consent of the affected interests are likely to come before the Texas regulator.

In all the state statutes, the designated state regulatory body (or bodies) is directed to adopt more detailed rules. In some cases, such as in Texas, the legislation has designated the oil and gas regulatory body as the regulator for storage in productive hydrocarbon formations (or in saline formations directly above and below such formations).[343] Those implementing rules are beginning to be established in some jurisdictions and provide a highly detailed framework for $CO_2$ injections for long-term storage. The Texas and Wyoming rules, promulgated in December 2010, are illustrative.[344] Both detail the information the applicant must submit to meet the applicable statutory standards.

338 Sections 53–11–9 (a) and (b), Mississippi Code of 1972.

339 *Id.* Section 53–11–9 (d).

340 *Id.* Section 53–11–9 (c).

341 *Id.,* Section 53–11–9 (e).

342 Section 3 of SB 1387 and Section 27.051 (b–1), Water Code to allow the Railroad Commission to issue a permit if it finds:
(1) that the injection and geologic storage of anthropogenic carbon dioxide will not endanger or injure any oil, gas, or other mineral formation;
(2) that, with proper safeguards, both ground and surface fresh water can be adequately protected from carbon dioxide migration or displaced formation fluids;
(3) that the injection of anthropogenic carbon dioxide will not endanger or injure human health and safety;
(4) that the reservoir into which the anthropogenic carbon dioxide is injected is suitable for or capable of being made suitable for protecting against the escape or migration of anthropogenic carbon dioxide from the reservoir; and
(5) that the applicant for the permit meets all of the other statutory and regulatory requirements for the issuance of the permit.

343 SB 1387, adopting Section 27.041(a).

344 35 Tex. Reg. 11020 (17 December 2010) (adopting new chapter 5) (available through the IOGCC at <http://groundwork.iogcc.org/topics-index/carbon-sequestration/regulations/carbon-storage-regulatory-development-texas> (viewed 31 January 2012). The Wyoming rules are available via the IOGCC at <http://groundwork.iogcc.org/topics-index/carbon-sequestration/regulations/carbon-storage-regulatory-development-wyoming> (viewed 31 January 2012).

### d. STANDARDS FOR CLOSURE, TRANSFER OF LIABILITY AND RELEASE OF FINANCIAL ASSURANCE

The statutes set forth a standard that must be met for approving closure of a storage facility. This is usually a performance standard that requires the equipment to be in good condition and the $CO_2$ in the storage reservoir to be stable and unlikely to cross a reservoir boundary. For example, the Montana statute allows closure if the applicant:[345]

a. *is in full compliance with regulations governing the geologic storage reservoir pursuant to this part;*
b. *shows that the geologic storage reservoir will retain the carbon dioxide stored in it;*
c. *shows that all wells, equipment, and facilities to be used in the post-closure period are in good condition and retain mechanical integrity;*
d. *shows that it has plugged wells, removed equipment and facilities, and completed reclamation work as required by the board;*
e. *shows that the carbon dioxide in the geologic storage reservoir has become stable, which means that it is essentially stationary or chemically combined or, if it is migrating or may migrate, that any migration will not cross the geologic storage reservoir boundary;*
f. *shows that the geologic storage operator will continue to provide adequate bond or other surety after receiving the certificate of completion for at least 15 years following issuance of the certificate of completion and that the operator continues to accept liability for the geologic storage reservoir and the stored carbon dioxide.*

A more generalised performance standard is required by the Mississippi statute. Section 53–11–25 provides that the regulator may issue a certificate of completion upon a showing that 'the reservoir is reasonably expected to retain mechanical integrity, and that carbon dioxide will reasonably remain emplaced'.[346] In Texas, the standard is not in the statute but in the rules promulgated by the regulator, which require that:[347]

> *Following cessation of injection, the operator must continue to conduct monitoring as specified in the approved plan until the director determines that the position of the $CO_2$ plume and pressure front are such that the geologic storage facility will not endanger underground sources of drinking water.*

Upon completion of the regulatory requirements, the certificate of closure will be issued, at which time the operator is released from the requirement to maintain financial assurance.[348]

Some of the statutes allow for a post-closure monitoring period. For example, under the Montana statute, the certificate of closure may not be issued until at least 15 years after termination of injections.[349] The operator must continue to provide adequate bond or other surety for at least 15 years following issuance of the certificate of completion, and to accept liability for the geologic storage reservoir and the stored $CO_2$ during this period.[350] It is at this point—at least 30 years after injections have ceased —that the operator may transfer title to the state.[351]

With regard to the transfer of title and liability for $CO_2$to a government or government–supported entity at the end of this period, the statutes take different approaches. Section 38–22–17 of the North Dakota statute provides for the title to be transferred to the state at closure. In Montana, there is the option to retain title to the $CO_2$ rather than to transfer it to the state,[352] in which case the operator 'indefinitely' accepts liability.[353] The Texas statute is silent on the matter, leaving no statutory mechanism for transferring title and only the regulatory release of performance security.[354] Similarly, the

345 Section 4(4) of Montana SB 498 (2009).
346 Section 53–11–25, Mississippi Code of 1972.
347 16 TAC 5.206 (j)(2).
348 16 TAC 5.206 (j)(7).
349 Section 4(3) of Montana SB 498 (2009).
350 Section 4(4)(f) of Montana SB 498 (2009).
351 Section 4(7) of Montana SB 498 (2009).
352 Montana SB 498, Section 4(7()A) (operator 'may' transfer to the state title to the geologic storage reservoir and the stored carbon dioxide).
353 Montana SB 498, Section 4(9). Under the Montana statute, the operator may petition for transfer of liability to the state every 15 years after receiving a certificate of completion.
354 A project–specific Texas statute provided for a transfer of title to the state in a special purpose law intended to create a favourable environment for the federally–supported 'Future Gen' project. The project was awarded to a competing consortium and the Texas law therefore had no real applicability.

Mississippi statute[355] provides that nothing in the $CO_2$ storage law will create any liability or responsibility on the part of the state to pay any costs associated with facility restoration (other than out of the operator's performance bond, etc), and there is no provision for transfer of title or liability to the state. Indeed, it is the opposite: the statute is clear that release of the financial security after the certificate of completion has been issued 'shall not affect, either to enlarge or diminish in any way, any legal obligations of the owner of the carbon dioxide or an owner or operator of any carbon dioxide sequestration facility resulting from the actions authorised pursuant to this chapter'.[356]

Section 53–11–27 of the Mississippi code allows an operator to seek to cancel the performance bond on or after the third anniversary of the date the board issued a certificate of completion. The application must describe the status of $CO_2$ plume development or migration compared to models previously provided to the board. The operator is required to satisfy the financial assurance requirements of the federal SDWA and regulations promulgated thereunder. The board may begin to release the financial security if it is satisfied that 'plume migration has stabilized or is developing in the manner anticipated in models previously filed with the board and the geologic sequestration facility has met all necessary mechanical integrity requirements'.

### e. PURPOSES FOR WHICH REMEDIATION OR TRUST FUND MONIES MAY BE USED

Most of the statutes take a fairly limited approach to the trust fund they establish for $CO_2$ storage facilities, generally building on the orphan well funds approach discussed in Part I. Hence, the funds may be used for monitoring and well remediation (e.g. proper plugging). North Dakota's statute provides that monies collected in the fund may be used for 'long-term monitoring and management of a closed storage facility'.[357] The meaning of 'management' is not defined. Montana's statute provides that the funds may be used to pay the 'reasonable costs of properly plugging a well and either reclaiming or restoring, or both' the site if it has been abandoned and the responsible person cannot be located or fails or refuses to properly plug, reclaim or restore the site. The statute adds that, in the event the operator of a $CO_2$ well cannot be identified or located to pay for 'complete reclamation', the board may 'reclaim the disturbed land' with funds from the $CO_2$ storage program account. The provisions in the other statutes appear roughly analogous, with funds authorised for inspecting and monitoring the storage facility and injection wells, replugging wells, or repairing similar mechanism leaks.[358]

The Mississippi fund structure is much more focused on SDWA responsibilities. Section 53–11–23 provides for the creation of a Carbon Dioxide Storage Fund to be funded by a per ton fee to be paid by operators of geologic storage facilities. Monies from the fund may only be used for oversight of geologic storage facilities after cessation of injections and release of the facility's performance bond or other assurance of performance.[359] In addition, funds may be used:[360]

> *… as shall be necessary or appropriate to satisfy the requirements of the federal Safe Drinking Water Act, including, without limitation, matters with respect to closed facilities such as: .*

i. *inspecting, testing and monitoring of the facility, including remaining surface facilities and wells;*
ii. *repairing mechanical problems associated with remaining wells and surface infrastructure; and*
iii. *repairing mechanical leaks at the facility.*

Texas is similar.[361]

---

355 Section 53–11–25 of Mississippi Code of 1972.

356 Section 53–11–27(6) of Mississippi Code of 1972.

357 North Dakota Century Code Section 38–22–15.

358 It has been said that the recent statutes in Montana (SB 498, 2009) and North Dakota (SB 2095, 2009) include 'tort liability' and 'climate liability' among the approved uses for the funds collected. See presentation of Melisa Pollak, R. Lee Gresham, Sean McCoy, Sara Johnson Phillips, *Sequestration Regulatory Issues: State Regulation of Geologic Sequestration: 2010 Update* (10–13 May 2010, Pittsburgh) (<http://www.ccsreg.org/pdf/Pollak_Weds_178.pdf>). This author is unable to find such authorisation for expenditure of funds. The statutes appear much like the others in authorising funds to be used for 'long-term monitoring and management of a closed storage facility' (North Dakota) or for paying the 'reasonable costs of properly plugging a well' and for reclamation or restoration of the site (Montana). It is true that Section 38–22–17 of the North Dakota statute provides for the title acquired by the state at closure to include 'all rights and interests in, and all responsibilities associated with, the stored carbon dioxide' as well as taking on responsibility for 'monitoring and managing the storage facility'. But there is no authorisation in the statute for the fund collected during operations to be used for those broad and undefined purposes.

359 Section 53–11–23 (f) of Mississippi Code of 1972.

360 *Id.*

361 Section 120.003, Subtitle D, Title 3, of the Natural Resources Code provides that monies in the trust fund may be used only for: (1) inspecting, monitoring, investigating, recording, and reporting on geologic storage facilities and associated anthropogenic carbon dioxide injection wells; (2) long-term monitoring of geologic storage facilities and associated anthropogenic carbon dioxide injection wells; (3) remediation of mechanical problems associated with geologic storage facilities and associated anthropogenic carbon dioxide injection wells; (4) repairing mechanical leaks at geologic storage facilities; (5) plugging abandoned anthropogenic carbon dioxide injection wells used for geologic storage; (6) training and technology transfer related to anthropogenic carbon dioxide injection and geologic storage; and (7) compliance and enforcement activities related to geologic storage and associated anthropogenic carbon dioxide injection wells.

### f. APPLICABILITY TO $CO_2$–EOR STORAGE

Because of the extent of $CO_2$–EOR injections and storage in the US, it is not surprising that a number of the statutes expressly address the relationship between $CO_2$–EOR storage and non-EOR storage. For example, the Texas geologic storage statute is intended to create a framework for storage of A-$CO_2$. Accordingly, it applies to the storage of 'anthropogenic carbon dioxide', which explicitly excludes 'naturally occurring carbon dioxide that is recaptured, recycled, and reinjected as part of enhanced recovery operations'.[362] In addition, the statute makes clear that '[t]he storage of carbon dioxide incidental to or as part of enhanced recovery operations does not in itself automatically render a facility a geologic storage facility'.[363] Similarly, the provisions of the Texas Water Code governing geologic storage facilities do not apply to $CO_2$ injections via EPA Class II wells for the 'primary purpose' of EOR operations.[364]

In other words, while recognising that geologic storage occurs during EOR operations, the Texas statute distinguishes between the incidental storage that occurs when injections are for the 'primary purpose' of EOR, and injections and storage that may take place during a transition to storage facility status. Other provisions of the statute similarly contemplate the transition of EOR facility infrastructure, including wells, to use as a geologic storage facility.

With regard to potential transition of $CO_2$–EOR operations to pure storage operations, the Texas statute directs the oil and gas regulator to adopt rules for the geologic storage and associated injection of $CO_2$ 'in connection with' certain EOR operations. EOR operations that are excluded are those where there is a 'reasonable expectation of more than insignificant future production' as a result of A-$CO_2$ injections and where the operating pressures are 'not higher than reasonably necessary' to produce those results.

Mississippi's $CO_2$ storage statute makes it clear that it is not intended to affect $CO_2$–EOR operations. New Section 53–11–33 provides that 'notwithstanding anything to the contrary' in the new statute, nothing there makes a $CO_2$–based EOR or EGR project subject to the law unless it requests approval as a geologic sequestration facility.[365] In addition, an operator may also request that the regulator determine that injection activities constitute the sequestration of $CO_2$.[366]

### g. STATE CERTIFICATION OF PERMANENT STORAGE OF $CO_2$ INCIDENTALLY STORED DURING EOR OPERATIONS

The initial $CO_2$ capture facilities, supported by some form of public funding for CCS projects; need to be able to demonstrate that the $CO_2$ to be captured from the facility will be permanently stored. This means that the off-taking entity (e.g. an EOR operator or an entity planning to supply the $CO_2$ to EOR operators) needs some officially sanctioned mechanism for verifying and certifying that the $CO_2$ to be incidentally stored during an EOR operation is, in fact, permanently stored. As previously noted, there is no federal mechanism for performing this function in the context of Class II injections for EOR operations.

To address this issue, several states have now included among the legislative steps to encourage CCS deployment a mechanism to verify and certify permanent $CO_2$ storage. In Texas, acting under Senate Bill 1387, the Texas Railroad Commission (the oil and gas regulator) has adopted rules to provide for certification of permanent geologic storage of A-$CO_2$ that is incidental to EOR operations. This rule applies also to storage incidental to EGR and geothermal resources.[367] The Texas rule establishes the requirement for certification of injection and incidental storage of A-$CO_2$ into productive reservoirs 'for the purpose of enhanced recovery of oil, gas, or geothermal resources, and for which the operator requests certification from the Commission that the anthropogenic $CO_2$ is permanently stored.[368] The certification is a document issued annually by the agency that validates the geologic storage of A-$CO_2$ incidental to enhanced recovery at a facility that is registered under the rule.[369] The rule applies where there is a 'reasonable expectation of more than insignificant future production' as a result of the $CO_2$ injection and where operating pressures are not anticipated to be higher than reasonably necessary to produce the resource.[370]

---

362 See definition in note 335, *supra*.

363 Subdivision 23.

364 Section 27.042 of the Water Code (adopted by Section 2 of SB 1387) provides that:
*This subchapter does not apply to the injection of fluid through the use of a Class II injection well as defined by 40 CFR Section 144.6(b) for the primary purpose of enhanced recovery operations.*

365 Section 53–11–33 of Mississippi Code of 1972.

366 *Id.*

367 The rules are codified at 16 TAC §§ 5.301 to 5.308, published in 36 Tex. Reg. 4397 (8 July 2011).

368 16 TAC § 5.301(a).

369 16 TAC § 5.302(4) (defining 'certification').

370 16 TAC § 5.301(b).

Registration for certification under Texas' incidental storage rule is voluntary and is separate and distinct from any application as a geologic storage facility.[371] The requirements for registering a facility include extensive information about the facility and a testing, monitoring, and reporting plan ( which may be met by complying with the relevant EPA requirements under Subparts RR or UU).[372] Registrant applicants are required to use continuous recording devices to monitor injection pressure and the rate, volume and temperature of the $CO_2$ stream. Further detailed requirements are set out in the rule.[373] The rules vest considerable discretion in the agency staff tasked with implementing the rule to include measures to ensure permanence, in particular by providing that in issuing a registration, the director of the applicable office 'shall impose' the terms and conditions that are reasonably necessary to prevent the escape of $CO_2$.[374]

Also of note, the rules expressly allow for the potential commingling of A-$CO_2$ with N-$CO_2$, and thus provide for reporting A-$CO_2$ quantities on an allocated basis.[375]

The Mississippi statutory provision on recognising incidental storage during EOR operations is limited to unitised operations. As under the Texas law, the procedure is voluntary and separate from the procedure for certifying a geologic storage site. The Mississippi statute provides that the regulator may, upon application by the unit operator, make an order 'recognizing' the incidental sequestration of $CO_2$ that is occurring during EOR (or EGR) operations.[376] This procedure does not require the project to qualify as a geologic sequestration facility or otherwise be subject to the provisions of the new law.[377] The Mississippi regulator has not yet promulgated rules implementing this provision.

By creating a specific procedure to verify and certify the quantity of A-$CO_2$ that may be stored during a routine EOR operation – either supplmeneting or replacing supplies of N-$CO_2$ – these state certification initiatives may be expected to provide detailed information on the amounts of $CO_2$ permanently stored during first-stage EOR operations. They may also develop regulatory expertise in appropriate monitoring, accounting and verification protocols.

It is not clear at present how the EPA may view such certifications by state regulators exercising primacy over the thousands of Class II wells in the US. Logically, the state certification process would appear to synchronise smoothly with the existing state administration of the Class II permitting program under the federal UIC program. The details of federal–state coordination in this area remain to be developed.

371 16 TAC § 5.301(f) (registration is voluntary); and 16 TAC § 5.301(e) (separate and distinct procedure).

372 16 TAC § 5.305(3).

373 See esp. 16 TAC § 5.305 (setting out detailed requirements for monitoring, sampling and testing plan); 16 TAC § 5.306 (setting out standards for certification); and 16 TAC § 5.307 (imposing reporting and record keeping requirements).

374 16 TAC § 5.306(h).

375 16 TAC § 5.301(c) ($CO_2$ stream may include 'any proportion' of A-$CO_2$ and N-$CO_2$); 16 TAC § 5.306(b) (when A-$CO_2$ is commingled outside the facility with other $CO_2$, operator reports A-$CO_2$ quantities on an allocated basis).

376 MS Code Section 53–11–15(e)(2).

377 *Id.*

## h. PROVISIONS ALLOWING WITHDRAWAL AND RE-USE OF STORED $CO_2$

Several US state statutes follow the IOGCC Model Statute's approach of expressly providing for the potential withdrawal of $CO_2$ from a certificated geologic storage facility for use. This is perhaps not surprising, given the potential value of $CO_2$ in EOR operations. This aspect of the state storage statutes clearly highlights the difference between the '$CO_2$-as-commodity' approach generally followed in the US and the '$CO_2$-as-waste' approach in the EU's CCS Directive. The Texas statute expressly directs the regulator to adopt rules allowing A-$CO_2$ that has been stored to be extracted for commercial or industrial use.[378] The Texas regulator is also directed to adopt rules 'for the geologic storage and associated injection' of $CO_2$ 'in connection with' certain EOR operations.[379] Other states, such as Mississippi, simply follow the IOGCC Model Statute's approach of providing that nothing in the definition of the term 'geologic sequestration facility' shall prevent 'orderly withdrawal of the contained carbon dioxide as appropriate or necessary to allow carbon dioxide to be available for enhanced oil or gas recovery projects or other authorized commercial, and industrial uses'.[380]

378 Section 120.004 of the Subtitle D, Title 3, of the Texas Natural Resources Code, entitled 'Extraction of Stored Anthropogenic Carbon Dioxide', provides that:
(a) The commission shall adopt rules allowing anthropogenic carbon dioxide stored in a geologic storage facility to be extracted for a commercial or industrial use.
(b) The commission has jurisdiction over the extraction of anthropogenic carbon dioxide stored in a geologic storage facility.

379 Section 11 of SB 1387 provides as follows:
(a) The Texas Commission on Environmental Quality shall adopt rules under Section 27.046, Water Code, as added by this Act, as soon as practicable after the effective date of this Act.
(b) Not later than March 1, 2010, the Railroad Commission of Texas shall adopt rules under Section 27.047, Water Code, as added by this Act, for the geologic storage and associated injection of carbon dioxide in connection with enhanced recovery operations excluding enhanced recovery operations for which:
    (1) there is a reasonable expectation of more than insignificant future production volumes or rates as a result of the injection of anthropogenic carbon dioxide; and
    (2) operating pressures are not higher than reasonably necessary to produce the production volumes or rates described by Subdivision (1) of this subsection.
(c) Not later than September 1, 2010, the Railroad Commission of Texas shall adopt rules under Section 27.047, Water Code, as added by this Act, for the geologic storage of carbon dioxide in, and the injection of carbon dioxide into, a reservoir that is initially or may be productive of oil, gas, or geothermal resources.

380 MS Code Section 53–11–5(j)(iii)(defining term 'geologic sequestration facility'). See also Oklahoma SB 1765, Section 1 adopting provision to be codified at Oklahoma Statutes, Title 27A, Section 3–5–101(A)(3).

C

# Canada

In Canada, the recent legislative and regulatory change involving $CO_2$ storage has been at the provincial level, much as has been the case with state legislation in the US. This is true of Alberta, Saskatchewan and British Columbia, in particular, where there is considerable interest in both $CO_2$–EOR and geologic storage of captured $CO_2$.

## CANADA

There is no federal $CO_2$ storage regulator. Regulation has been developed instead at the provincial level where actual projects are being developed.

- **Alberta**
- Bill 24 (enacted in 2010) adopted a general $CO_2$ storage framework
- implementing regulations were adopted 2011 (Carbon Sequestration Tenure Regulation)
- $CO_2$ pipeline construction began 2012
- several $CO_2$ capture and EOR–based storage projects moving forward.

- **Saskatchewan**
- current projects were developed under pre-existing legal and regulatory framework:
  - Weyburn $CO_2$–EOR project begun in 1999
  - SaskPower Boundary Dam capture and $CO_2$–EOR storage project under construction; expected to be online in 2014
  - amendments to Crown Minerals Act adopted.

- **British Columbia** published natural gas strategy document in February 2012; reviewing $CO_2$ storage issues.

- **Canadian federal regulator** has adopted regulations in 2012 that treat captured and stored $CO_2$ as ‘not emitted’ (Reduction of Carbon Dioxide Emissions from Coal-fired–Fired Generation of Electricity Regulations)

## 1 Alberta

The *Carbon Capture and Storage Statutes Amendments Act 2010* (sometimes referred to as 'Bill 24') took effect in late 2010.[381] The statute builds on the existing framework for oil and gas regulation, comprehensively addressing most of the topics discussed earlier in this Part II, including pore space ownership, long-term liability, post-closure stewardship, and permitting agreements for site evaluation and geologic sequestration. The statute is built around the term 'captured carbon dioxide', which is defined as 'a fluid substance consisting mainly of carbon dioxide captured from an emissions source'.[382] Hence, the definition does not provide any compositional standard other than 'consisting mainly' of $CO_2$.

### a. ACQUISITION AND AGGREGATION OF SUBSURFACE RIGHTS

There are a number of striking differences between the Alberta statute and the recent US state statutes. The Alberta statute defines the term 'sequestration' as 'permanent disposal,'[383] suggesting that it may borrow more from the 'waste disposal' model of $CO_2$ injections than from the 'valuable commodity' model.

More profoundly, with regard to pore space the province chose, under s. 15.1(1) of the 2010 act, to exercise its sovereign power to take property without compensation (as discussed in Part I) and vest ownership of pore space for $CO_2$ storage in the Alberta provincial government ('the Crown'). The statute states that the pore space below the surface of all land in Alberta is vested in, and is the property of, the Crown in right of Alberta, and that no grant from the Crown of any land in Alberta, or mines or minerals in any land in Alberta, 'has operated or will operate as a conveyance of the title to the pore space contained in, occupied by or formerly occupied by minerals or water below the surface of that land'.[384] It is deemed that 'no expropriation occurs' as a result of the provision and that no person may claim damages or compensation as a result.

In addition, 54(1) of the statute prohibits the injection of any substance into a subsurface reservoir that is the property of the Crown in right of Alberta unless the person is authorised to do so under the act or by an agreement. The appropriate minister is authorised to enter into agreements for its use. This section thus provides a requirement for the government's consent as property owner that is separate from the regulatory approvals required from the Energy Resources Conservation Board (ERCB).

As a result of these provisions, the great bulk of property right issues have been resolved, or at least redefined. However, the resource management and priority of use questions are now internalised within the government. The statute addresses the issue of competing uses explicitly by providing that the ERCB may not approve a scheme for the disposal of captured $CO_2$ to an underground formation unless the lessee satisfies the Board that the injection of the captured $CO_2$ will not interfere with: (a) the recovery or conservation of oil or gas; or (b) an existing use of the underground formation for the storage of oil or gas.[385] Thus, while the legal regime governing ownership in Alberta is different from that of the US, the result is similar to that produced in the US by the dominance of a severed mineral estate. Indeed, under the 2010 act, the basic legal framework is analogous to that governing geologic storage operations in the UK North Sea. There is a dual regime in which the developer must obtain a consent from the property owner, similar to The Crown Estate's role in the North Sea, as well as regulatory approvals from the ERCB, akin to that required in the UK from the Department of Energy and Climate Change.

With Bill 24 having declared the subsurface pore space to be the property of the Crown, new regulations were subsequently adopted to establish the process for developers to lease pore space for the purpose of $CO_2$ storage. The new regulations, adopted in April 2011,[386] are similar to those governing the granting of lease for oil, natural gas, and other minerals.

The lease has a defined initial term of 15 years, with monitoring, measurement and verification (MMV) plans to be submitted every three years.

---

381 Carbon Capture And Storage Statutes Amendment Act 2010, available at <http://www.assembly.ab.ca/ISYS/LADDAR_files/docs/bills/bill/legislature_27/session_3/20100204_bill-024.pdf> (viewed 31 January 2012) (hereafter '*Bill 24*').

382 Bill 24, s. 2(2).

383 Bill 24, s. 2(2).

384 *Id.* s. 15.1(1).

385 Section 3(6), amending s. 39.

386 The Carbon Sequestration Tenure Regulation (AR 68/2011)('2011 Tenure Regulation'). The regulation has a 'sunset date' of 30 April 2016, at which point it expires unless re-promulgated. *Id.* s. 22.

### b. TRANSPORTING CAPTURED $CO_2$ TO THE STORAGE SITE

Once a $CO_2$ pipeline is licensed by the ECRB, the operator has the power to acquire the rights of way for construction and may proceed to acquire the necessary rights of way.

### c. STANDARDS FOR STORAGE SITE PERMITTING

Having acquired the appropriate lease for the pore space, the next step is to obtain a $CO_2$ storage permit from the regulator. The permitting provisions of the statute are simple. The lessee of pore space for a storage facility must apply for a well license and approval from the ERCB, submitting monitoring, measurement and verification plan for approval. The lessee must comply with an approved plan and provide compliance reports. The lessee must 'fulfil the work requirements with respect to the location of the agreement', submit a closure plan for approval, and comply with the approved closure plan. The details are left to the regulator.

### d. STANDARDS FOR CLOSURE, TRANSFER OF LIABILITY AND RELEASE OF FINANCIAL ASSURANCE

The standard for approving closure of a site is a general performance standard. In addition to finding that the applicant has met all the detailed conditions in the regulation, including having properly 'abandoned' i.e. plugged all the wells, the regulator must find that 'the captured carbon dioxide is behaving in a stable and predictable manner, with no significant risk of future leakage'.[387]

Upon issue of the closure certificate, the title of the injected A-$CO_2$ passes to the Crown, which assumes 'all obligations' of the lessee. These are defined as the fourfold obligations (i) as owner and licensee under the *Oil and Gas Conservation Act* of the wells and facilities covered by that agreement; (ii) as the person responsible for the injected captured $CO_2$ under the *Environmental Protection and Enhancement Act*; (iii) as the operator under Part 6 of the Environmental Protection and Enhancement Act in respect of the land within the location of the agreement used by the lessee in relation to the injection of captured $CO_2$; and (iv) under the *Surface Rights Act*.[388] The lessee is then released from the obligations with respect to the defined wells 'in relation to' the injection of captured $CO_2$.

### e. TRUST FUND AND PURPOSES FOR WHICH REMEDIATION OR TRUST FUND MONIES MAY BE USED

Like the US statutes, the Alberta regime builds on its existing orphan well fund model, creating a 'Post-closure Stewardship Fund'.[389] This is a fee per tonne of A-$CO_2$ injected into the storage lease set by the government.[390] The fund may be used for the purposes of monitoring the behaviour of captured $CO_2$ and 'fulfilling any obligations that are assumed by the Crown' under the act, as well as costs associated with ensuring the proper plugging of wells etc (suspension, 'abandonment' and related reclamation or remediation costs) at orphan facilities. The statute also provides for the designation of wells and related facilities as 'orphans' and for administering the program.[391]

### f. CARBON SEQUESTRATION TENURE REGULATION

In April 2011, the government adopted an implementing regulation that begins to fill in some of the implementing details under the statute. The Carbon Sequestration Tenure Regulation sets out the basic standards for addressing a number of key issues for obtaining and managing a geologic sequestration lease, including the MMV plan. The regulation does not actually set the details of the MMV plan; rather, it adopts some general standards for regulatory approval of an MMV plan. Recognising the importance of resolving potential competing uses of the subsurface, s. 15 effectively requires an analysis of the likelihood that the $CO_2$ storage operations 'will interfere with mineral recovery'. The regulation does not dictate how the relevant ministry should resolve the potential conflict, but merely seeks to ensure that the issue is properly considered in the governmental decision–making process.

---

387 Bill 24, s. 120(3).
388 Bill 24, s. 121.
389 Bill 24, s. 122.
390 2010 Tenure Regulation, s. 20.
391 *Id.* Section 123.

### g. CCS REGULATORY FRAMEWORK ASSESSMENT PROCESS

Alberta has also committed to a 'CCS Regulatory Framework Assessment' process to review the newly–created regulatory framework and consider various remaining issues. They include the criteria for closure; methodology for setting the fee-per-tonne for the stewardship fund; role of risk assessment; institutional roles and respective responsibilities of the Alberta regulators; and role of environmental impact assessments, including procedures for input from the public.

For example, under Bill 24, as enacted in 2010, it is not clear whether the stewardship fund may be used to cover potential civil liability assumed by the province, including compensation in tort or under other legal theories. Similarly, the existing legislation is not expressly clear on whether the fund may be used to compensate for eventual $CO_2$ leakage to the atmosphere (e.g. by purchasing carbon credits). These issues are addressed in the CCS Regulatory Framework Assessment and may result in subsequent legislative changes.

Recommendations from the CCS Regulatory Framework Assessment were submitted to the provincial government in late 2012. The final report was published on the Alberta Energy website in August 2013 and the public were invited to provide comment and feedback on the recommendations before the 3rd October 2013.

### h. ILLUSTRATION OF REGULATORY APPROVALS REQUIRED FOR THE ALBERTA CCS PROJECT

The following table, which is based on a table of regulatory approvals prepared for the Shell Quest CCS project in Alberta, illustrates how regulatory approval for the $CO_2$ storage component fits into the overall regulatory approvals scheme.[392]

392 Shell Canada Limited, *Quest Carbon Capture and Storage Project: Vol. I, Project Description*, (prepared by Stantec Consulting Inc.) (November 2010) pp. 1–13 available at <<http://www-static.shell.com/static/can-en/downloads/aboutshell/our_business/oil_sands/quest/01_quest_vol_1_main_report_project_description.pdf> (viewed 31 January 2012).

**TABLE IV: Regulatory approvals by project component for Shell Quest Project (from Table 1.2 of application)**

| RESPONSIBLE AGENCY | APPROVAL AND APPLICABLE LEGISLATION |
|---|---|
| **Project** | |
| Natural Resources Canada | ▪ Section 20 decision regarding the environmental assessment<br>▪ Canadian Environmental Assessment Act |
| Alberta Environment | ▪ Environmental Impact Assessment determination of completeness<br>▪ Environmental Protection and Enhancement Act |
| **$CO_2$ capture infrastructure** | |
| Alberta Environment | ▪ Amending Approval 49587–01–00 (as amended) for Scotford Upgrader<br>▪ Approval to construct, operate and reclaim a facility through AENV's Guide to Content of Industrial Approval Applications<br>▪ Environmental Protection and Enhancement Act |
| ERCB | ▪ Amending Approval 8522 (as amended) for Scotford Upgrader<br>▪ Approval to construct and operate a facility via ERCB *Directive 23: Guidelines Respecting an Application for a Commercial Crude Bitumen Recovery and Upgrading Project* (Directive 23)<br>▪ Oil Sands Conservation Act |
| **$CO_2$ pipeline** | |
| ERCB | ▪ Pipeline licence application in accordance with ERCB Directive 56<br>▪ Emergency Response Plan approval in accordance with ERCB *Directive 71: Emergency Preparedness and Response Requirements for the Petroleum Industry* (Directive 71)<br>▪ Oil and Gas Conservation Act<br>▪ Oil and Gas Conservation Regulations<br>▪ Pipeline Act<br>▪ Pipeline Regulation |
| Alberta Environment | ▪ Conservation and Reclamation Plan approval<br>▪ Conservation and Reclamation Regulation<br>▪ Environmental Protection and Enhancement Act |
| Canadian Transportation Agency | ▪ Railway crossing agreement authorisation<br>▪ Canada Transportation Act |
| **$CO_2$ injection wells** | |
| ERCB | ▪ Well licence application in accordance with ERCB Directive 56 and ERCB *Directive 51: Injection and Disposal Wells—Well Classifications, Completions, Logging, and Testing Requirements* (Directive 51) and ERCB *Directive 20: Well Abandonment* (Directive 20)<br>▪ Oil and Gas Conservation Act<br>▪ Oil and Gas Conservation Regulations |
| **$CO_2$ storage component** | |
| ERCB | ▪ Approval in accordance with ERCB *Directive 65: Resources Application for Oil and Gas Reservoirs* (Directive 65)—Unit 4.2 Acid Gas Disposal<br>▪ Oil and Gas Conservation Act<br>▪ Oil and Gas Conservation Regulations |

## 2 Saskatchewan

The current $CO_2$–EOR storage operations in Saskatchewan were developed under the pre-existing oil and gas framework without special consideration given to the $CO_2$ being A-$CO_2$ acquired from a coal–gasification facility in North Dakota. Similarly, the Boundary Dam CCS project currently under construction by SaskPower has been proceeding under the pre-existing legal and regulatory framework.

Revisions to the OGCA were adopted in 2011.[393] The new law provides for greater regulatory oversight, including oversight of $CO_2$–EOR operations. With regard to storage and sequestration of $CO_2$, the 2011 amendments provide specific regulatory authority to the government to oversee storage and sequestration of $CO_2$. The amendments also expand the scope of the pre-existing orphan well program. The legislative revisions took effect simultaneously with new implementing regulations on 1 April 2012.[394]

The new legislation and regulations are not focused particularly on $CO_2$ storage or $CO_2$–EOR operations, but apply generally to all oil and gas operations. They are notable here, however, because they do expand regulatory oversight to provide authority for regulating $CO_2$ injections.

## 3 British Columbia

As of mid-2012, the policy and regulatory framework for CCS was still under development in British Columbia. A natural gas strategy paper published in February 2012 stated that use of CCS in the provinces would be promoted.[395] In this context, the government stated that it would complete development of a regulatory framework for CCS and amend legislation, if required. The government indicated that it was working with the provincial Oil and Gas Commission to develop regulations.[396]

The effort to date has been on reviewing the existing oil and gas legal and regulatory framework to identify gaps and changes that may be required to facilitate CCS projects. Legislative amendments are being contemplated for introduction sometime in 2013.[397]

## 4 Federal $CO_2$ Emission Performance Standard incorporating CCS provisions

In August 2011, the Canadian Departments of the Environment and Health proposed regulations designed to reduce $CO_2$ emissions from coal–fired generators.[398] The new rules would set a $CO_2$ emissions performance standard for new coal–fired units and for those that have reached the end of their useful life. The intention is to phase out high emitting coal–fired generation and 'to promote a transition towards lower or non-emitting types of generation such as high efficiency natural gas, renewable energy, or fossil fuel–fired power with carbon capture and storage.'[399] In particular, the new performance standard would favour the incorporation of CCS technology by allowing a deferral of the compliance date under specified circumstances for certain existing generating units. The rules were finalised in August 2012, making the new performance standard effective 1 July 2015.[400]

393 The Oil and Gas Conservation Amendment Act 2010 (Bill 157).

394 The Oil and Gas Conservation Regulations 2012 (OGCR).

395 *British Columbia's Natural Gas Strategy: Fueling BC's Economy for the Next Decade and Beyond* (<http://www.gov.bc.ca/ener/popt/down/natural_gas_strategy.pdf>) (viewed 18 June 2012), at 19.

396 *Id.*

397 Presentation by Kathryn Gagnon, CCS Policy, Office of Energy Research and Development of Natural Resources Canada, *Canada Update: CCS Legal and Regulatory Developments* (presentation at International Energy Agency's 4th CCS Regulator Network Meeting) (Paris, France, 9 May 2012) (available at <http://www.iea.org/media/workshops/2012/ccs4thregulatory/new/Kathryn%20Gagnon.pdf>) (viewed 18 June 2012), at 15. Ms Gagnon's presentation provides recent information on CCS regulatory developments in several Canadian provinces.

398 See the Regulatory Impact Analysis Statement, *Reduction of Carbon Dioxide Emissions from Coal–Fired Generation of Electricity Regulations* Vol. 145 Canada Gazette, Part I, at 2779 (27 August 2011).

399 *Id.*

400 *Reduction of Carbon Dioxide Emissions from Coal–Fired Generation of Electricity Regulations*, SOR/2012/167, PC 2012–106 2012–08–30.

# ANALYSIS *and* CONCLUSIONS

PART

> The only existing and short term realistic use for large amounts of $CO_2$ is Enhanced Oil Recovery.
>
> **Günther Oettinger, EU Commissioner for Energy (12 December 2011)**

As recognised by EU Commissioner Günther Oettinger and documented above, large amounts of $CO_2$ are already being used in North America in EOR operations and being stored in the process. These $CO_2$ supplies are a necessary component of an oil- production value chain that is currently generating annual gross revenues in the order of roughly US$10–13 billion.[401] In addition, major $CO_2$–EOR operations are being considered in many other parts of the globe that will, if ultimately developed, require very large additional $CO_2$ supplies.

If policymakers wish to consider encouraging deployment of $CO_2$-CCS by leveraging off this $CO_2$-EOR value chain and harnessing the EOR-based infrastructure and storage capability, it will be necessary to assess avenues for integrating the two legal and regulatory models discussed above. This Part III seeks to aid in that assessment by:

- clearly identifying the different types of $CO_2$ storage that would need to be accommodated to allow EOR operators to incorporate A-$CO_2$ into the supply mix for EOR
- summarising the elements of the two legal and regulatory frameworks where the existing oil and gas framework appears generally sufficient to allow $CO_2$–EOR operations to incorporate supplies of A-$CO_2$ captured for emissions reduction purposes (or can become so with fairly modest changes)
- identifying the principal 'pressure points' where more extensive changes to the legal or regulatory framework may be appropriate
- suggesting a potential way forward to address the remaining challenges.

401 Based on $CO_2$–EOR production estimates from 2012 *Oil and Gas Survey* and a price range of US$80–100 per barrel.

A

# The storage scenarios: the EOR-to-CCS Continuum

There are essentially four different scenarios under which $CO_2$ can be stored during or following $CO_2$–EOR operations and a fifth scenario for standalone storage for $CO_2$–CCS projects. It is the last of these five scenarios that has been the model in most analyses of CCS regulatory regimes. A framework for integrating $CO_2$–EOR related storage into an emissions reduction scheme, however, needs to consider how it would apply to each of the different storage scenarios. In addition, in $CO_2$–EOR operations, supplies of A-$CO_2$ captured from industrial emissions sources have already begun to be commingled with N-$CO_2$; this model appears increasingly likely to be the most prevalent model for early mover CCS projects. Absent careful thought and drafting, rules developed with solely A-$CO_2$ injection operations in mind are unlikely to adequately account for the commingling of N-$CO_2$ and A-$CO_2$ or for the recycling of $CO_2$ that takes place during EOR operations. Such accounting is essential to ensure public confidence in the integrity of any system providing a financial benefit for emissions reductions via geologic storage of captured $CO_2$.

**The five potential storage scenarios are:**

## 1 The base storage scenario— *incidental* storage during EOR (also called 'concurrent' storage or 'simultaneous' storage)

This is the $CO_2$ that accumulates in the oil–bearing formation during the injection and recycling of $CO_2$ that occurs during the production phase of an EOR operation. While the $CO_2$ may be reproduced with the oil and re-injected several times, studies estimate that essentially all of the $CO_2$ originally injected in an EOR operation is ultimately stored in the oil–producing formation.[402] The vast majority of the roughly 800 million tonnes of $CO_2$ incidentally stored during EOR operations since 1972 come within this category.

In the case of N-$CO_2$, of course, there is no *reduction* in atmospheric emissions of $CO_2$ when it is incidentally stored during EOR because it has simply been transferred from one subsurface formation to another. But as additional supplies of captured A-$CO_2$ become available for use in EOR, the geologic storage of these A-$CO_2$ supplies during EOR operations achieves the same sequestration from the atmosphere and therefore the same reduction in atmospheric emissions as when the $CO_2$ is injected in a saline or other non-oil-bearing formation. Moreover, as recognised by the US EPA, it is done at lesser risk to drinking water sources because of the concurrent extraction of fluids from the reservoir during EOR operations, thereby presenting a lower risk profile than for $CO_2$ injections without concurrent fluid extraction.

Under this storage scenario, the supplies of captured A-$CO_2$ may be *commingled* with supplies of N-$CO_2$. Indeed, part of the value of integrating A-$CO_2$ with EOR operations comes from the ability to use much of the EOR–based transportation infrastructure.

Moreover, the injected $CO_2$ will be re-used after initial injection. There are two scenarios for re-use. First, the $CO_2$ injected at a particular EOR operation will be produced with the oil, separated, dehydrated and recycled through the formation several times on average—all the while staying within the closed loop of the site's surface and subsurface facilities (including the targeted producing formation). Second, $CO_2$ that is left in one field when the oil-producing wells are plugged and abandoned may in some instances be brought back into production at some later time (perhaps years later) and used as a $CO_2$ supply source for another EOR operation. While the likelihood that injected $CO_2$ will be used in this second manner will depend on many factors and will not occur in all cases, it is a distinct storage scenario that the regulatory framework should consider.

402 See sources cited at n. 24, *supra*. Again, the new EPA greenhouse gas reporting requirements (Subparts PP, UU, RR and W) may be expected to begin documenting these numbers industry wide in the US as the required reports begin to be submitted.

## 2 *Incremental* storage during EOR operations (or 'optimising for storage')

Where there is no commercial value to reducing atmospheric emissions of $CO_2$ (as is generally the case at present in the US), the $CO_2$–EOR operator will invariably seek to minimise the amount of (relatively expensive) $CO_2$ injected for the production of a given quantity of oil. There are alternative production techniques, however, that could be used to *maximise* the quantity of $CO_2$ injected for a given amount of oil production.[403] Any amount of $CO_2$ injected in an oil–bearing formation during EOR operations in excess of the minimal quantity normally required for oil production constitutes *incremental* $CO_2$ storage above and beyond the storage level that occurs as a natural incident of EOR production operation. The legal and regulatory framework should be able to recognise and account for this storage scenario.

Note that, as with the incidental storage scenario, the $CO_2$ stream injected in this case may also consist of a commingled stream of N-$CO_2$ and A-$CO_2$. Hence the accounting and measurement protocols must be sufficiently robust to accurately account for the respective proportions of the differently sourced $CO_2$ (both when initially injected and throughout the decades long recycling phases).

There may or may not be a material change in the risk profile presented by these operations depending on the specific circumstances of a given project (pressure management regime, percentage of fracture pressure reached, migration of the $CO_2$ plume, etc).

## 3 Incremental storage in an EOR site *following termination* of EOR operations

Eventually, the EOR operation will become uneconomic and recovery operations will be terminated even though substantial quantities of oil will remain in the reservoir (in the order of 30–50 per cent of the OOIP). Additional quantities of $CO_2$ could then be injected into the formation. At this point, injections should be attributable *only* to A-$CO_2$, because oil production operations will have ceased and there is no reason to continue injecting $CO_2$ other than for emissions reduction purposes. Note, however, that the actual $CO_2$ stream injected may still be a commingled stream of N-$CO_2$ and A-$CO_2$. This is because the upstream pipeline may still be carrying a commingled stream, even though the *incremental* amount of $CO_2$ injected for emissions reduction purposes would have to be clearly traceable to incremental supplies of captured A-$CO_2$.

With regard to the storage operation itself, the risk profile of the operation is more likely to change at this point under because there will no longer be the pressure relief effect from the oil production operations. Hence some of the regulatory requirements intended to protect drinking water sources (e.g. monitoring of plume migration) may well change.[404] There may still be injection of commingled supplies of N-$CO_2$ with A-$CO_2$ because of commingling in the upstream pipeline facilities (as in the prior storage scenario).

Incremental injections of $CO_2$ may well have the effect of foreclosing future potential recovery of the remaining, presently-uneconomic, oil. Hence incremental storage operations would only be undertaken where the operator believes that the present value of the incremental $CO_2$ storage exceeds the future value of the remaining, potentially-recoverable oil.

403 See e.g. Advanced Resources International and Melzer Consulting, '*Optimization of $CO_2$ Storage In $CO_2$ Enhanced Oil Recovery Projects*,' prepared for the UK DECC, Office of Carbon Capture & Storage (30 November 2010) (hereafter '*Optimization of $CO_2$ Storage*').

404 The issue of risk profile changes is discussed in more detail later.

## 4 Storage during buffering or balancing operations

As previously explained, there is an operational need to accommodate variations between $CO_2$ supply and injection operations, whether the $CO_2$ utilised is captured from an emissions source or is naturally occurring. This buffering function can be provided, for example, by using a form of 'stacked' storage in which the 'water leg' of a producing oil reservoir is used as a saline storage formation (allowing maximum use of pipeline and related facilities). Or it can be achieved simply by linking to another nearby saline formation that allows joint use of the mainline pipeline facilities and only requires a short extension line from the EOR formation. The expectation would be that when $CO_2$ supply is *in excess of* EOR requirements, the excess could be injected into the saline formation. Conversely when $CO_2$ supply *falls below* EOR requirements (e.g. when a $CO_2$ capture facility goes out of service for maintenance or repair), the supply deficit could be met by extracting $CO_2$ from the saline formation for use in the EOR operation.

If the policy objective is to maximise emissions reduction and geologic storage of the captured $CO_2$, there is no reason to discourage an EOR operator using captured A-$CO_2$ from linking the EOR operation with a saline formation for such operational buffering operations, as long as the $CO_2$ remains in the closed loop and is not emitted to the atmosphere (and as long as the measurement and accounting protocols are adequate to document these facts). This will encourage the more efficient and lower cost development of pipeline infrastructure to deliver $CO_2$ to the saline storage formation.

## 5 Standalone (i.e. non-EOR related) geologic storage as part of a CCS project

This storage scenario is the one that is most frequently in mind in discussions of non-EOR related storage in conjunction with CCS projects. It differs significantly from the other categories of EOR–related injections in three principal respects. First, it involves injection of A-$CO_2$ only, and the $CO_2$ is injected solely for the purpose of emissions reductions. Second, where the storage formation is a saline aquifer, it may frequently or typically lack a *lateral* boundary serving to limit lateral migration that would typically be present in all of the EOR–related storage scenarios. Last, since the oil–bearing formation fluids are not being removed as the $CO_2$ is being injected, there may be greater concern over avoiding undue increases in formation pressures.[405] Presumably, this storage scenario is much less likely to involve a commingled stream of A-$CO_2$ and N-$CO_2$. It might simply be based on a dedicated pipeline transporting captured $CO_2$ to a saline storage formation (although it might also still involve a commingled stream of N-$CO_2$ and A-$CO_2$ due to commingling in upstream transportation).

405 See further discussion in Marston, *Pressure profiles for $CO_2$-EOR and CCS: Implications for regulatory frameworks*, *supra*, n.25. To be sure, formation pressures can be managed in the standalone storage scenario by drilling additional wells that extract formation fluids (typically brine) in order to achieve a similar pressure management tool. The point here is that such a pressure reduction effect is an inherent part of the $CO_2$–EOR operations, but would have to be adopted as an add-on reservoir management tool in the non-EOR context, adding to the cost of operating the storage project.

These various storage scenarios are summarised in the following table.

**TABLE V: Potential storage scenarios**[406]

| STORAGE SCENARIO | DESCRIPTION | SOURCE OF $CO_2$ |
|---|---|---|
| 1. Base storage: storage that is incidental (also called 'concurrent' or 'simultaneous' | Storage of $CO_2$ as a normal incident of EOR operations; pressure management provided by production of oil and other formation fluids; formation typically has lateral trap. | May be **either** N-$CO_2$ or A-$CO_2$, or a commingled stream of both. |
| 2. Incremental storage during EOR operations (or 'optimising for storage') | Additional $CO_2$ storage in an EOR formation in excess of that required for oil production (i.e. optimising operations for $CO_2$ storage during oil production); most risk factors remain the same, but some may change. | Incremental $CO_2$ would be attributable to **A-$CO_2$ only**, but may be physically commingled with N-$CO_2$ also being used for EOR. |
| 3. Incremental storage in an EOR site following termination of EOR | Additional $CO_2$ storage in an EOR formation following completion of EOR operations and termination of oil production. Elimination of pressure management from oil production may alter risk profile. | Same as incremental storage during EOR. |
| 4. Storage during buffering or balancing operations | Injections in a **non**-oil-bearing storage formation that may be used in part for balancing supply of $CO_2$ from capture source with injection requirements during EOR operations. | When supporting EOR, may be either N-$CO_2$ or A-$CO_2$, or a commingled stream of both. When supporting CCS storage, would be A-$CO_2$ only. |
| 5. Standalone geologic storage as part of a CCS project | Injections in any appropriate formation solely for the purpose of emissions reduction; may typically lack lateral trap and pressure management tools. | A-$CO_2$ only (unless there is commingling during upstream transportation). |

To achieve full integration of $CO_2$–EOR into a $CO_2$–CCS regime across each of the potential steps, the framework should ideally accommodate operations under each of these different storage scenarios. The starting point, however, is to integrate into standard $CO_2$–EOR operations the initial supplies of A-$CO_2$ to be captured for emissions reduction purposes. Accordingly, this paper focuses next on the elements of the existing legal and regulatory frameworks that appear generally adequate for this purpose. Following this, the paper addresses the issues more generally, addressing the principal 'pressure points' or potential barriers, and suggesting ways to address the remaining issues.

Before proceeding, however, it is helpful to distinguish clearly between the purpose of a $CO_2$ generator in *capturing* the $CO_2$ and the purpose of an EOR operator *in injecting* the $CO_2$ into the subsurface. The operator of a power plant or industrial facility may install facilities to capture $CO_2$ for the primary or exclusive purpose *of reducing or avoiding atmospheric emissions,* while the EOR operator receives, transports and injects the captured $CO_2$ for the purpose *of enhancing recovery of otherwise stranded* oil.

The fact that A-$CO_2$ that is geologically stored during the EOR operation may meet one public policy objective (or a compliance obligation for the $CO_2$ generator) does not change the fact that for the EOR operator, the purpose of the injection is the production of otherwise stranded oil, which serves another important public policy objective of conserving a scarce natural resource. Similarly, the fact that the EOR operator injects $CO_2$ to produce oil does not alter the fact that for the $CO_2$ emitter, the purpose of capturing the $CO_2$ is to have it geologically stored to reduce atmospheric emissions of a greenhouse gas. The distinction is potentially important because some regulatory rules apply only when the 'primary purpose' is permanent geologic storage.

406 For further discussion of how risk factors may change in the various storage scenarios, see Philip Marston, *Are we there yet? Storing A-$CO_2$ in an EOR world* (presentation at the Eleventh Annual Conference on Carbon Capture, Utilization & Sequestration) (Pittsburgh 2012).

B

# Incorporating A-$CO_2$ into standard $CO_2$–EOR operations

By breaking down the storage scenarios, it becomes easier to see the extent to which a given legal and regulatory framework governing $CO_2$ injections and storage for the purpose of $CO_2$–EOR operations (whether using N-$CO_2$ or A-$CO_2$) may also support the injection and storage of A-$CO_2$ that has been captured for the purpose of reducing atmospheric emissions.

## 1 US and Canada—elements that accommodate integration of A-$CO_2$ in EOR

As of early 2012, and taking into account recent changes in the US and Canada, most aspects of the legal and regulatory regimes for $CO_2$–EOR allow for incorporation into standard $CO_2$–EOR operations of captured A-$CO_2$ in the base storage scenario. The adequacy of the legal and regulatory framework can best be judged by actual experience to date.

- In Canada, $CO_2$ captured from the Great Plains Synfuels Plant (located in the US) has been injected in EOR operations at the Weyburn–Midale project in Saskatchewan since 2000 under the pre-existing oil and gas regulatory framework. Also in Saskatchewan, the SaskPower Boundary Dam project is well under construction, with the captured $CO_2$ also contracted to supply EOR projects. In the province of Alberta, major projects are moving ahead with the support of the provincial government, including construction of the Alberta Carbon Trunk Line system and several major capture facilities, with the bulk of the $CO_2$ expected to be used for EOR.
- In the US, off-take agreements for A-$CO_2$ from various capture projects were signed as early as 2006; several of the initial projects are now well under construction. Indeed, the initial phase of a one million ton per year project supported by the US DOE was completed by year end 2012 and has begun supplying $CO_2$ into an existing pipeline, where it is commingled with N-$CO_2$ supply and injected for EOR operations. A commercial–scale IGCC project is scheduled for commercial operation in 2014;[407] and other projects are moving towards construction during 2012. Nearly all of these projects include EOR for the storage component.

The elements of the legal and regulatory framework that support integration of these new supplies of A-$CO_2$ into EOR operations include:

- The well-settled commercial law framework governing off-take agreements
- recognition of the value of $CO_2$ as a commercial commodity and the protection of property interest in injected $CO_2$
- the property law regime of the various states governing the acquisition and aggregation of relevant subsurface property rights used in oil and gas production operations (including the role played by the remaining oil, priority of the mineral estate, and acceptance of non-damaging subsurface migration of fluids injected during various oil and gas production operations pursuant to appropriate regulatory approvals)
- rules governing the siting and construction of new $CO_2$ pipeline capacity to receive the captured $CO_2$ output and carry it to $CO_2$–EOR sites for injection, recyle, re-use, and gradual accumulation and storage in the target formation

407 The adequacy of the ruling of the state utility regulator in approving construction of the capture facility project has been challenged in court, but the approval subsequently reconfirmed by the regulator. Construction of the project is continuing. See Order of the Mississippi Public Service Commission, issued 30 March 2012, in *Mississippi Power Company*, Docket No. 2009–UA–14 (authorising continued construction and operation of the project in question during further litigation on remand of earlier orders from the Mississippi Supreme Court).

- state oil and gas permitting rules governing EOR exploration and development operations generally
- the beginnings of a regime (e.g. in Texas and Mississippi) for the verification and certification of the quantity of A-$CO_2$ that will be incidentally stored during such EOR operations
- legislative recognition and approval in several states of withdrawal and re-use of stored $CO_2$
- the existence of a post-closure monitoring regime of the state oil and gas regulators responsible for overseeing plugging and abandonment operations generally, including closure of $CO_2$ injection and production wells. The state regulators can ensure that corrective action is taken in the event of leakage; this remediation mechanism is financially supported by the existing industry–funded orphan well fund
- the US EPA's Class II UIC injection well permitting program under the SDWA going back several decades, as administered by relevant state regulatory agencies that have long since qualified for primacy as provided for under the applicable statutes. The EPA has determined that as long as the risk profile of EOR operations does not change materially (e.g. $CO_2$ injections take place only in conjunction with oil recovery operations), there is no need for additional monitoring or other regulatory changes to the Class II framework
- the current RCRA and CERCLA rules. These are generally adequate, but it is important for the EPA to complete the pending RCRA rulemaking in a manner that does not introduce uncertainty or risk with regard to the use of $CO_2$ injectate streams captured from combustion sources.

## 2 European Union—elements that accommodate integration of A-$CO_2$ in EOR

Because no $CO_2$–EOR industry has ever developed in the EU (other than the use of N-$CO_2$ in Hungary), one cannot have the same degree of confidence in evaluating how the current legal and regulatory framework might govern what are largely hypothetical transactions. Still, it is fair to say that many elements of the existing legal and regulatory framework for oil and gas operations in EU Member States could accommodate the use of $CO_2$ in EOR operations—except to the extent that $CO_2$ is classified as a waste. The provisions of the CCS Directive that exclude $CO_2$ storage from the scope of the general EU waste legislation are limited, of course, to $CO_2$ that is stored pursuant to the permitting scheme of the Directive and do not apply to injection of $CO_2$ in $CO_2$–EOR operations.

The $CO_2$ injected during EOR operations could, of course, be viewed as a product used during oil or gas recovery operations, much the same as other substances injected during routine oil and gas production operations similar, for example, to the injection of $CH_4$ in an existing EOR operation in the North Sea or to routine injection of oilfield brine during oil and gas operations. In these circumstances, the $CO_2$ is not injected for disposal as a waste and would presumably therefore not be subject to the waste legislation in the first place. As noted above, this kind of analysis was reflected in the general consensus of experts that the OSPAR Convention and the London Protocol would not preclude the injection of $CO_2$ in EOR operations in the marine environments subject to those agreements. A similar line of analysis could perhaps be applied to use of $CO_2$ during EOR operations in the onshore as well.

C

# Identifying the 'pressure points': barriers inhibiting or precluding storage of A-$CO_2$ in EOR and non-EOR formations and crafting a way forward

While much of the existing framework can accommodate the integration of captured A-$CO_2$ into EOR operations, challenges remain, some of which, particularly in Europe, may pose an insurmountable barrier unless changes are made. This section seeks to identify the 'pressure points' at which issues arise and propose potential ways to address them.

## 1 Incorporation of A-$CO_2$ during base storage during EOR operations

### a. US AND CANADA—THE NEED TO CERTIFY THAT $CO_2$ STORED IN EOR OPERATIONS IS SECURELY AND PERMANENTLY STORED

Supplies of A-$CO_2$ are already injected and concurrently stored during EOR operations in Canada and are in the process of being so used in the US. To be sure, various parties could wish for greater clarity, or for legal and regulatory provisions that are better adapted to $CO_2$ storage during EOR operations. For example, the absence of some form of compulsory unitisation of subsurface mineral rights in Texas may hinder oil or gas development generally (and not just $CO_2$–EOR operations), but to date there has not developeted a political consensus that such a change in subsurface property law is warranted. Another example, in some states, might be the unavailability of some form of eminent domain for the acquisition of pipeline rights of way for $CO_2$ pipelines. In some states, an existing eminent domain statute may be limited to pipelines carrying oil, gas, or other enumerated commodities, and fail to include pipelines carrying $CO_2$ (presumably because the question of eminent domain for $CO_2$ pipelines had not arisen previously). In other instances, there may be implementation issues relating to the actual application of an existing eminent domain statute for $CO_2$ pipelines. There could certainly be improvements in the existing framework, but EOR–associated projects are moving forward in any event.

A key issue that is just beginning to be addressed in the US is the development of some form of recognition that $CO_2$ stored during EOR operations is, in fact, permanently and securely stored, including verification or certification of the specific quantities stored. Texas has adopted rules to that effect and the Mississippi statute contemplates the development of a rule by the regulator there. Such a certification mechanism may become increasingly important for companies planning capture projects that receive some form of funding assistance. Hence, the assurance that such a certification mechanism will be in place *in the state in which the $CO_2$ is to be used for EOR* is likely to be an essential prerequisite to finalise capture projects that plan to sell the $CO_2$ for use in EOR operations, even where the capture project is located in another state. It is possible that such a regulatory mechanism may, as a practical matter, only need to be implemented by those relatively few oil and gas producing states that expect to become preferred locations for $CO_2$–EOR operations (as is the case today).[408]

408 Presumably the same basic assurance will be required in some form as part of the documentation for public financial support for the Canadian projects.

### b. EUROPEAN UNION

Apparently no EU Member State is developing a certification mechanism under the CCS Directive, separate from permitting, for recognising the incidental storage of $CO_2$ during an EOR operation as permanent geologic storage. Qualification for permitting under the CCS Directive is the key under the EU structure for accessing financial assistance for initial commercial–scale capture projects. For example, unless a proposed EOR operation is approved as a storage site under the terms of the CCS Directive, a $CO_2$ generator capturing $CO_2$ to send to EOR operations would not explicitly be authorised to treat the captured $CO_2$ as 'not emitted' under the EU ETS Directive. Similarly, the capture project would not qualify for any share of NER300 Reserve funding, nor, presumably, would any power generated by the project qualify in the UK for the Contract for Difference Feed-in Tariff. Thus, even if the existing mining code or oil and gas regulatory framework allows for use of $CO_2$ in EOR operations, the ability to qualify base storage of $CO_2$ during standard EOR operations as 'geologic storage' under the Directive will be essential to the financing of the capture project.

## 2 Moving from incidental to incremental storage during EOR

This storage scenario begins to move away from the standard operations of $CO_2$–EOR operations as they have been conducted over the past four decades. With regard to North America, the bulk of the above analysis would generally appear to apply to operations under this storage scenario. With regard to the US, however, there is at least one key question mark that turns on the factual question of whether the change in operations to optimise or maximise $CO_2$ storage materially changes the risk profile presented by the operation. As explained by the US EPA in the Class VI rule, the principal difference it found between $CO_2$ injections for EOR and $CO_2$ injections for CCS lies in the difference in the respective risk profiles of the two activities. In incidental or concurrent storage during 'business as usual' $CO_2$–EOR operations, there is the concurrent extraction of reservoir fluids (e.g. oil, brine, injected $CO_2$) as the $CO_2$ is injected. This means that, generally speaking, there is less stress on the equipment, on the confining formation and on any potential leakage pathway (e.g. old wellbores) as compared to $CO_2$ injection that is not accompanied by EOR operation. It was largely for this reason that the US EPA determined to leave $CO_2$ injection wells for EOR operations under the existing Class II and to apply the new Class VI standards only to $CO_2$ injection wells not operated in conjunction with oil production (or wells that transition from Class II to Class VI as the risk profile changes).[409]

In the case of optimising EOR operations for $CO_2$, the operator would be injecting more $CO_2$ than might otherwise be required by its oil recovery plan. Thus, while the EPA stated clearly that 'traditional' $CO_2$–EOR projects are 'not impacted' by the new Class VI rule and will continue operating under Class II permitting requirements,[410] the regulatory situation may change if the EOR operator focuses on maximising $CO_2$ injection volumes and permanent storage. The EPA indicated that such a change is 'likely' to increase the risk of endangerment to underground sources of drinking water because it believed that the reservoir pressure within the injection zone would increase as $CO_2$ injection volumes increase and an elevation in reservoir pressure is a significant risk driver.[411] Whether there is, in fact, a change in the risk profile in a particular operation, however, is site-specific and depends on various factors.

Actual operations under some 'optimisation' or 'incremental' storage scenarios may be closer to traditional EOR operations than in other cases. The EPA left the matter initially with the operator to make the determination, but reserved the ability of the regulator to make that determination as well:[412]

> *Owners and operators of Class II wells that are injecting carbon dioxide for the primary purpose of long-term storage into an oil and gas reservoir must apply for and obtain a Class VI permit where there is an increased risk to USDWs compared to traditional Class II operations using $CO_2$. EPA expects that, in most cases, the EOR owners or operators will use these same factors to evaluate whether there is an increased risk to USDWs. When an increased risk is identified, the owner or operator must notify the Director of their intent to*

409 The EPA cites other factors present in $CO_2$–EOR operations that reduce risks to underground drinking water sources as compared to $CO_2$–CCS operations, including the presence of well-defined and characterised subsurface sites with extensive geologic and geophysical information and the presence of proven confining zones. One aspect of $CO_2$ injections in oil field operations tends to increase the risk of leakage as compared to injections in a deep saline formation, however, which is the presence of multiple well penetrations in producing areas, which if not properly plugged and managed may present possible leakage pathways.

410 *Class VI rule*, *supra*, 75 Fed. Reg. at 77244.

411 *Id.*

412 *Id.* 75 Fed. Reg. at 77245 (citation omitted).

*seek a Class VI permit. Today's rule clarifies that the Director has the discretion to make this determination in the absence of an owner or operator notification and, in doing so, require the owner or operator to apply for and obtain a Class VI permit in order to continue injection operations.*

As seen in the different storage scenarios, determining the risk profile of a particular operation may depend on more factors than merely whether or not oil is being produced and thus may vary depending on the storage scenario being pursued. In the event that an operator concludes that a change in operations changes the risk profile, an application for a Class VI permit could be required. In this case, the operator would become subject to the extensive additional monitoring and verification requirements under Class VI.

Depending on how the EPA's rules governing the transition from Class II to Class VI are interpreted and applied, the costs of making that transition may be prohibitive. If that were the case, the operator examining the option of increasing the amount of $CO_2$ storage during EOR operations would presumably decline to do so and limit $CO_2$ injections and storage to the quantities incidentally stored during standard $CO_2$–EOR operations.

The US experience thus suggests a framework for encouraging increased storage of $CO_2$ during EOR operations beyond that required by what the EPA terms 'traditional' $CO_2$–EOR operations, should provide clarity to operators as to whether or when changes in EOR operations to help meet emissions reduction objectives may trigger additional compliance obligations. If the integration of A-$CO_2$ into traditional EOR operations carries a risk of imposing additional costs on the EOR operator, then those supplies of captured A-$CO_2$ will be placed at a competitive disadvantage compared to naturally occurring sources. This result would presumably be directly opposite to any policy of encouraging deployment of CCS technology. In addition, the legislator or regulator should carefully consider the respective environmental benefits to be achieved by reducing greenhouse gas emissions via incremental storage during EOR operations with other applicable public policy objectives (e.g. protecting drinking water, or encouraging greater development of non-imported energy sources).

## 3 Incremental storage in an EOR site following termination of EOR—property issues and addressing implications of changing risk profiles

When EOR operations come to a close, a number of aspects of the legal and regulatory framework change. From a property law standpoint, the operator would presumably no longer have a right under traditional mineral leases to continue any operations other than properly closing and abandoning the wells under the applicable oil and gas regulations. In addition, from the standpoint of EPA regulation in the US, with the termination of oil production operations, the injection wells would plainly no longer qualify as Class II wells.

### a. PROPERTY RIGHTS ISSUES

#### i. Separately identifying the pore space to be used for storage

Where $CO_2$ is injected into an oil–bearing formation for EOR operations, it is typically the right to inject fluids ancillary to the extraction of the oil that provides the legal right to store the $CO_2$ concurrently with the EOR operation. In the non-EOR context, the right to available pore space must be separately acquired from the surface owner; pore space that remains occupied by a mineral is not available for separate $CO_2$ storage unless the mineral interest is acquired as well.

Because of the value of the potential future production of remaining oil, even after the field is deemed 'depleted' under current production techniques, the property rights to access the oil may, as a practical matter, convey the necessary storage right in a great many $CO_2$–EOR storage situations (depending, of course, on the terms of the specific leases involved, etc). The law governing subsurface property rights for oil and gas production should allow for the acquisition of property rights or owner consents for each of the potential storage scenarios described.

#### ii. Mechanisms for aggregating the necessary storage rights.

In the US EOR context, mineral interests are acquired from the (typically private) owners and include the right to inject $CO_2$ as part of mineral recovery operations. State law generally recognises the dominance of the mineral estate, such that the operator may make reasonable use of the surface owner's interest—including the subsurface portion of the surface owner's interest—that is used in the EOR operation. This dominance of the mineral estate has been re-affirmed in nearly all the recent US statutes discussed. The existing property acquisition practices in the US appear generally adequate for acquiring necessary storage rights in those scenarios where oil continues to be produced. At some point along the EOR-to-CCS storage continuum, however, standard oil leases will become inadequate to cover the storage rights needed and additional rights will need to be acquired. The practice of acquiring rights from both the surface owner and the mineral owners may address the issue. More generally, it will be helpful to have some legal mechanism available for compulsory acquisition of rights, as for example is done under the various recent US state statutes.

### b. ADDRESSING PERMANENCE

#### i. Defining the level of assurance and term required (monitoring and verification issues)

There has never been a need for EOR operators to measure $CO_2$ flows other than for operational purposes. While the $CO_2$ stored in a closed EOR operation does not leak during normal operations, there has not previously been a need to document that experience nor has a millennial time frame been applied in operational planning. However, because the purpose of subsurface storage in the CCS context is the reduction of atmosphere emissions of $CO_2$, legislators and regulators generally seek a higher degree of assurance that no appreciable quantity of the injected $CO_2$ will return to the atmosphere for a lengthy period. Meeting the desired level of assurance of permanence over the time frame selected by legislators or regulators will normally require additional monitoring and accounting protocols.

An additional level of complexity in accounting and documentation arises in storage scenarios that involve the use of commingled streams of N-$CO_2$ and A-$CO_2$. Regulatory changes in the $CO_2$–EOR regime may be required to ensure that measurement, monitoring and accounting protocols accommodate the use of commingled streams of $CO_2$. Disagreement may be expected to arise over the need, usefulness, and costs and benefits of particular additional monitoring requirements. If the anticipated additional monitoring costs of transitioning from the 'incidental storage' scenario are viewed as prohibitively high, however, $CO_2$–EOR operators will not proceed with the transition. Since continued successful experience with $CO_2$–EOR operations may enhance regulators' confidence that drinking water sources can be protected and greenhouse gas emissions reduced at lower cost, it is important to allow for these rules to be adapted to reflect increasing operational experience.

#### ii. Ensuring the ability to use and re-use $CO_2$ in a closed system and accommodating buffering and linking saline formations with oil–bearing formations

The $CO_2$ requirements of an EOR operator are not constant, but vary with a host of operational factors, both planned and unplanned. Thus, in the EOR context, it is essential to be able to re-use injected $CO_2$. This is required first to allow for recycling $CO_2$ that is returned to the surface with produced oil. It is also required to allow for operational buffering to address inevitable mismatches that will arise between the A-$CO_2$ supply acquired by off-take agreements from industrial sources and the injection requirements and/or capabilities of the EOR operations. The legal and regulatory framework for $CO_2$–CCS should thus address the terms under which $CO_2$ may be re-used while still meeting the requirements for storage integrity and permanence.

The pace of development of a $CO_2$ flood changes over time with the drilling of new $CO_2$ injection wells and oil production wells. In addition, under some common $CO_2$ flooding techniques, injections of $CO_2$ are alternated over a period of days, weeks or months with injections of saltwater (a technique known as 'water-alternating-gas' or 'WAG' operations). In other operations, a given quantity of $CO_2$ is injected in the target formation and allowed to 'soak' for a period of weeks, months or even years before oil production operations begin.[413] In all of these cases, the requirements for $CO_2$ at the site thus vary sharply with normal operations. Even where the operator uses continuous injections of $CO_2$, the actual quantities injected will vary, although more modestly, with operational changes.

Where the operator uses $CO_2$ that is produced from a naturally occurring source, it is a relatively simple matter to match receipts and injection requirements by reducing the upstream production of $CO_2$ to match the EOR injection requirements. However, where the $CO_2$ is captured from the output of a combustion emissions source such as a coal–fired power plant, the situation is altered. In the case of electricity generating facilities, the amount of $CO_2$ to be captured and stored will reflect electricity output at the facility, which itself will vary with the electricity load it must serve. While capture technology may initially be deployed on base-load plants that run at a relatively constant level, there will still be variations in output and there will still be a requirement to buffer variations in $CO_2$ output with variations in EOR input

413 Michael E. Parker, P.E., James P. Meyer, PhD., and Stephanie R. Meadows, *Carbon Dioxide Enhanced Oil Recovery Injection Operations Technologies*, Energy Procedia 1 (2009), 3141–3148, at 3143. For example, press reports indicate that $CO_2$ injections in one major new flood in east Texas continued for about a year before initial oil production began.

requirements. Moreover, future deployment of CCS technology will, of necessity, move increasingly to emissions sources that will be operated at lower load factors, increasing the need for flexible takeaway capacity.

One fairly straightforward way to provide this buffering capability would be to co-locate a saline storage formation adjacent to, or 'stacked' directly underneath, the oil–producing formation (or using the so-called 'water leg' of the target oil formation). The EOR operator would then direct the $CO_2$ that is in excess of current EOR requirements to the saline storage formation. Similarly, when EOR operating requirements exceed the available supply of $CO_2$, additional $CO_2$ could be withdrawn from the saline storage formation for injection in the oil–producing formation. In this case, the $CO_2$ stored in the saline formation would serve much the same role as the vast system of underground storage formations of natural gas ($CH_4$), smoothing out operational differences between supply and demand. Equivalent quantities of the $CO_2$ pulled from the saline formation for injection in the EOR operation would thus continue to be stored in the oil formation, either incidentally (during EOR operations) or incrementally (following completion of EOR operations), or returned to the saline formation.

Policymakers considering a legal and regulatory framework for integrating $CO_2$–EOR with $CO_2$–CCS should understand these operational considerations and ensure that the rules allow for the extraction and re-use of $CO_2$ that has been injected in a storage formation, so long as it remains in the closed system and is not vented to the atmosphere. Similarly, the tracking, and accounting protocols must be sufficiently robust to accurately track the various permutations of expected $CO_2$ flows.

It would appear that some of the regulatory frameworks in the US are well suited for addressing this issue. For example, the IOGCC Model Statute published in the US includes a provision that has been adopted by several of the recent US state statutes that explicitly contemplates subsequent withdrawal and re-use of sequestered $CO_2$.[414] The EU's CCS Directive, in turn, would appear to allow re-use by allowing for the facilities used for recycling and re-injecting $CO_2$ produced during an EOR operation that is part of a permitted geologic storage site to be treated as part of the storage site itself. This approach to implementing the Directive should allow for the use of saline storage buffering in combination with enhanced hydrocarbon recovery, as contemplated by the Directive.[415]

However the matter is handled by the EU or the individual Member State authorities, providing for operational buffering that links operations for EOR–based storage with non-EOR storage will eventually be essential to integrating the two $CO_2$ storage models and leveraging CCS deployment with the potential revenue stream from $CO_2$–EOR operations.

Of course, in order for an EOR operator to re-use $CO_2$ during operations, it is important to allow the EOR operator the ability to preserve ownership of injected $CO_2$, as is generally the case in the US. A number of the statutory storage regimes, however, assume that the injector of the $CO_2$ will want to disclaim ownership of injected $CO_2$ (together with any liability that may go with ownership). In the EOR context, that assumption may be misplaced and the operator may insist on the right to retain ownership or the exclusive right to use (or at least retain an option to do so) precisely so that the injected $CO_2$ may be re-used in EOR operations.

## 4 Third-party access rules—simultaneously ensuring access to infrastructure as well as the dedication of committed capacity required for reliable service under pre-existing off-take agreements

With regard to pipeline sizing and access issues, the approach being pursued by Alberta is to provide provincial support for sizing the Alberta Carbon Trunk Line system using larger dimensional pipe than would otherwise be commercially justified by anticipated use in the early years. In the US, pipelines are being developed based on commercial considerations. The Interstate Oil and Gas Compact Commission's taskforce report on potential $CO_2$ pipeline regulation discussed various potential approaches for addressing the at-times competing objectives of providing access for potential future projects while ensuring reliability of service for previously constructed capture facilities. The taskforce report found that at the present time no federal involvement was required to facilitate the development of $CO_2$ pipelines:[416]

414 See MS Code s. 53–11–5(j)(iii), which provides that '[n]othing in this definition [of geologic sequestration facility] shall prevent orderly withdrawal of the contained carbon dioxide as appropriate or necessary to allow carbon dioxide to be available for enhanced oil or gas recovery projects or other authorized commercial, and industrial uses'.

415 CCS Directive, *supra*, recital 20.

416 *IOGCC $CO_2$ Pipeline Task Force Report*, *supra*, at 2.

> *To the degree there is a place for expanded regulation of $CO_2$ pipelines, such regulation must preserve the contractual basis of $CO_2$ transport and avoid marginalizing states and their involvement.*

In the event that federal regulation  were deemed necessary at some future time, the taskforce report recommended that any such regulatory model closely follow the contract–based natural gas pipeline regulatory model.[417]

Because storage of captured $CO_2$ for emissions reduction purposes is intended to serve a public benefit, there is a greater public interest in assuring open access to the transportation and storage facilities than when purely private commercial interests are at stake. While this may argue in favour of some form of non-discriminatory open access to transportation and storage facilities, it is just as important to ensure reliability of service for capture facilities that have been constructed in reliance on contractual assurances of firm, long-term off-take service. In other words, it is as important to protect the reliability of service for *initially constructed* capture facilities as it is to ensure access for *subsequently constructed* capture facilities.

Where pipeline or storage facilities are developed to receive $CO_2$ from a to-be-constructed capture source, it will be necessary for the parties to be able to enter into long-term contracts that will assure each party that it will be able to perform its obligations over the contract term. This will be true regardless of how the contracts are structured and regardless of who owns or operates a given facility (i.e. whether the contract is an off-take agreement in which the pipeline operator commits to take the captured output of the emissions source or the pipeline is owned in whole or in part by the same entity that generates the captured $CO_2$). Meeting this objective may require some careful consideration of any regulatory rules proposed for ensuring access to transportation or off-take service.

The potential problem is explained in detail in the IOGCC/SSEB taskforce report addressing the integration of $CO_2$–CCS operations in the US:[418]

> *[C]$O_2$ pipelines for CCS purposes will almost certainly be built to link a relatively small number of large output sources of $CO_2$ (power plants and other large stationery [sic] sources) with a relatively small number of injection sites, which are likely to begin with EOR fields and gradually expand to include free-standing geological storage facilities. Movement in this direction has been underway for the last several years with regard to current pipeline construction and feasibility planning. The phenomenon can be illustrated by a simple example. Take the case of a 500 megawatt (MW) power plant that produced 3 million metric tons per year and captured 80% of the $CO_2$. This would produce approximately 2.4 million metric tons available for off-take. If this amount were delivered ratably on a daily basis, it would amount to about 6,575 metric tons per day, or, in volumetric terms, approximately 125,000 Mcf of dense-phase gas available for transport. The output of just eight such plants would fill the largest existing 30–inch $CO_2$ pipeline, which has a capacity of approximately 1 billion cubic feet per day (Bcf/d) ...*
>
> *Accordingly, rather than the 'many-to-many' set of network receipt and delivery points that characterizes the natural gas industry, the $CO_2$ pipeline network is unlikely over the next half-century to develop beyond a 'few-to-few' type network. Under that scenario, a handful of large $CO_2$ sources feed pipelines whose capacity is specifically dedicated to those sources and that carry the gas to a select number of large EOR injection sites that have contracted for long-term supply. The remainder would be delivered to free-standing geologic storage facilities that receive surplus $CO_2$ that cannot be marketed for use in EOR operations. The rate at which $CO_2$ supply captured from anthropogenic sources may come to exceed EOR demand is a major uncertainty in evaluating potential pipeline network development ...*
>
> *These underlying realities may have major implications for potential legal and regulatory structures. New capture sources will require pipeline off-take capacity that is specifically dedicated to receive the plant's $CO_2$ output. Failure to accommodate the requirement to ensure the availability of designated amounts of capacity for very lengthy periods could pose a significant regulatory barrier to wide-scale commercial deployment of CCS technologies.*

Applying this analysis to the US regulatory models, the IOGCC/SSEB taskforce found the contract–based regulatory model of open access to natural gas pipelines in the US to be more compatible with the needs of a CCS–oriented $CO_2$ pipeline

417 *Id.* at 3.

418 *IOGCC/SSEB $CO_2$ Pipeline Task Force Report, supra*, at 35–36 (footnotes omitted).

network than the pro-rationing of available capacity among current shippers (the methodology generally applied in the US for interstate oil pipelines, where there is insufficient capacity for all shippers):[419]

> *An effective $CO_2$ pipeline regulatory framework will recognize and accommodate these differences in network purpose and design. The failure to accommodate the requirement to ensure the availability of designated amounts of capacity for very lengthy periods could pose a significant regulatory barrier to wide-scale commercial deployment of CCS technologies. Apportionment creates challenges to assured off-take capacity for a given facility's $CO_2$ output and therefore makes the oil pipeline model a less desirable regulatory option.*

The Obama Administration's interagency taskforce on barriers to CCS deployment recognised the same point, noting that:[420]

> *Regulators may consider the impacts that common carrier laws will have on the future CCS industry. Power plants and other sources of $CO_2$ will likely need the flexibility to reserve capacity on the pipeline system. Power plants may need to cycle power production to meet demand, resulting in changes of emissions from the source, as well as bringing sources on and off line for maintenance. Under existing common carrier structures for natural gas transmission line, there exists the risk that another company could consume excess capacity during a period of reduced emissions from an emissions source, essentially stranding the source from access to a storage site. Regulators ought to carefully consider allowing sources to reserve capacity on dedicated pipelines once a source is in operation, or consider the entire CCS system (capture, transport, and storage) as an integrated system which would not be subject to the typical common carriage requirements.*

With regard to $CO_2$ pipelines under the EU's CCS Directive, a similar observation was made by Roggenkamp and Haan-Kamminga,[421] who noted that $CO_2$ pipelines are likely to link a limited number of producers with a limited number of consumers, forming a 'dedicated' or 'direct' pipeline.[422] In analogising to the classification of natural gas pipelines under the EU's open access directive for natural gas networks, they suggest considering $CO_2$ pipelines as some sort of 'reversed upstream pipeline' system, with the reservoir being viewed as the *terminus* of the chain (i.e. the 'consumer' or 'receiver' of the $CO_2$).[423]

Article 21 of the EU's CCS Directive appears to generally address this issue by recognising the need to respect 'the duly substantiated reasonable needs of the owner or operator of the storage site or of the transport network and the interests of all other users of the storage or the network or relevant processing or handling facilities who may be affected', and by allowing the refusal of access on the grounds of lack of capacity (while making provisions for expanding capacity where a potential customer is willing to pay for it). It would seem that these general principles in the CCS Directive should be adequate to allow a $CO_2$ pipeline developer to offer customers adequate contractual assurances of the ability to perform.

An alternative approach that has been discussed is to 'oversize' the pipeline's capacity, by designing it in excess of current and near-term foreseeable demand to accommodate new capture sources if, and as, they are constructed, and provide potentially for a lower unit transportation cost if or when throughput on the pipeline reaches a sufficiently high level of utilisation. This approach, however, implies a large amount of unused capacity in the early years of the pipeline, and perhaps in later years as well, if the hoped-for capture projects do not come to fruition. It therefore requires someone (presumably a government–backed entity) to assume the potentially significant risk of future underutilisation in the event the hoped-for capture projects are not constructed.

From the standpoint of a commercial pipeline, this is a recipe for serious financial problems because the fixed costs

419 *Id.* at 54. For a discussion of potential $CO_2$ pipeline regulation, see Philip Marston, *A Regulatory Framework for Migrating from Enhanced Oil Recovery to Carbon Capture and Storage: the USA Experience*, (Paper presented at 10th Greenhouse Gas Control Technologies conference (GHGT–10)) (Amsterdam 2010) (available at <http://ac.els-cdn.com/S1876610211008757/1-s2.0-S1876610211008757-main.pdf? tid=582baa5e82d1568424f614484d966a9b&acdnat=1340118876_9ea8f2ebff4a991f4d5aa99b7467f5cb>).

420 *White House CCS Task Force Report*, *supra*, at M–5 (emphasis added).

421 M. Roggenkamp and A. Haan-Kamminga, '*$CO_2$ Transportation in the EU: Can the regulation of $CO_2$ pipelines benefit from the experiences in the energy sector?*' (hereafter '*Roggenkamp/Haan-Kamminga*').

422 With regard to natural gas pipelines, the term 'direct pipeline' is defined by the EU's open access directive for natural gas pipelines as 'any pipeline or network of pipelines operated and/or constructed as part of an oil or gas production projection, or used to convey natural gas from one or more such projects to a processing plant or terminal or final coastal landing terminal'. Directive 2009/72/EC, article 2. That directive further distinguishes 'upstream' pipelines as well.

423 *Roggenkamp/Haan-Kamminga.*

(predominantly associated with recovery of, and on, invested capital) are usually very high in relation to costs that vary directly with throughput (e.g. variable costs of energy for compressing $CO_2$ to dense phase for transportation and pumping the dense phase gas to the injection site). The *unit* cost of transportation service is typically a matter of spreading the fixed costs for a given period (e.g. a year) plus variable costs over the throughput for that period. The fixed costs represent the lion's share of total costs. The unit cost calculated in this manner will increase sharply with a decline in throughput. This means that the unit cost of reserving capacity for potential future shipments or off-takes can be very high. The financial risk can be evaluated in the same manner as is done whenever a government supports an infrastructure project for public policy reasons. Once the risk is quantified, an informed political judgement may be made by the responsible authorities about whether or at what level to support the project and how the risks and benefits of future throughput should be shared.

It should be noted, however, that while this approach may make it less *likely* there will be capacity constraints facing future capture projects, it does not necessarily solve the project developer's problem, which is the need to ensure that all relevant contracting parties will be able to perform their respective contact obligations. Firm contractual assurances may be required to support private financing for a capture facility as well as a pipeline facility, since a firm off-take commitment will likely be an essential prerequisite for closing. To the extent that regulatory rules governing the allocation of pipeline capacity introduce additional uncertainty as to the parties' ability to perform, they will tend to increase the cost of the project and may preclude it all together.

This tension between the competing desires of ensuring access to infrastructure on the one hand, and reliability of service for those that contract for the service on the other, can be addressed by conducting an 'open season' process prior to initial construction or major expansions of capacity. Under an open season approach, the developer would offer an opportunity to potential customers to contract for a defined level of service, sometimes using an iterative process to test market demand before proceeding to binding precedent agreements. As described by the UK DECC:[424]

> *An open season is an obligation on a developer to make its plans known to other parties prior to finalising design and applying for consent. There is limited opportunity for other parties to make their interest known in joint developments as part of the existing pipeline consenting arrangements. However, the opportunity available to those that might have an interest in joint ventures is relatively constrained.*

In this fashion, as each new tranche of capacity is planned, there is an opportunity for parties to contract for service. At the same time, however, this approach protects the reliability of service commitments made for each tranche. This is the approach that the Federal Energy Regulatory Commission has applied successfully in the US for roughly 25 years or more in the permitting of many thousands of miles of new natural gas pipeline capacity. If regulation were found to be necessary, some variant of this approach would appear to lend itself readily to $CO_2$ infrastructure.

## 5 Post closure responsibility: funding and stewardship

### a. FUNDING FOR COMPENSATION AS WELL AS FOR WELL REMEDIATION AND REGARDLESS OF FAULT

In the EOR world, there is typically a funding mechanism in most jurisdictions to address 'orphan well' problems. The orphan well fund provides a funding source from which the oil and gas regulator may draw for well remediation in future years if the originally responsible operator is unavailable (either unwilling or unable to undertake the work or no longer in existence). In addition, operators are likely to face liability in the event of negligent operations (i.e. a fault–based compensation scheme rather than an insurance–based scheme).

There are two key differences, however, with the liability regimes typically discussed in CCS frameworks. First, policymakers in the CCS context generally seek to create a liability and stewardship framework that is *insurance–based rather than fault based*. Second, there is generally a desire to expand the stewardship responsibilities beyond remediation (e.g. re-plugging a leaking cement plug) to *include compensation* to anyone damaged as a result of the storage operation. The potential extent of financial liability for such a no-fault compensation scheme is significantly broader than the

424 DECC, *Developing Carbon Capture and Storage (CCS) Infrastructure: Consultation on Implementing the Third Party Access Provisions of the CCS Directive and Call for Evidence on Long Term Development of CCS Infrastructure* (December 2010), para 3.18.

fault–based common law system for addressing liability. Expanding the orphan well funding mechanism beyond well remediation responsibilities will also expand the cost considerably, as may uncertainty about the scope and details of operation of a non-fault based compensation scheme.

### b. DEVELOPING EXPLICIT INSTITUTIONAL ARRANGEMENTS FOR A STEWARDSHIP ENTITY

In the EOR world, in the event of damage after a well has been properly plugged and abandoned, the only explicit institutional arrangement in place for repairing leaking wells damage is the state or provincial entity responsible for managing the orphan well fund. But, as noted, these institutional arrangements are typically limited to well remediation issues and do not address general compensation for anyone who might have suffered actual damage from the injection activity. These damage compensation issues are generally left to the common law system of civil responsibility (e.g. nuisance, tort). Nor are there institutional arrangements for monitoring the site following closure. While the oil and gas regulator will respond to complaints of leaking wells and may require re-plugging or other remediation (which may be paid for from the orphan well fund), there is no general monitoring system for closed oil and gas wells.

In the CCS environment, there appears a general desire among policymakers to take a much more 'proactive' approach for $CO_2$ storage sites and establish some type of institutional arrangement both to ensure an appropriate level of post-closure monitoring and to take responsibility for taking remediation action in the event it should be required, even if the original operator is no longer in existence.

Institutionally, it is a rather simple matter to adapt an orphan well funding mechanism to expand funding to include general compensation claims, although the cost of the latter approach could be many times the cost of the existing systems. The real issue therefore is a political judgement call of whether, or to what extent, operators should be liable for post-closure damage even absent negligence or other fault i.e. whether to adopt a no-fault insurance scheme for covering compensation for injury claims potentially reaching many decades into the future. Since $CO_2$ injections for emissions reduction purposes will for the foreseeable future be funded in material part through some incentive mechanism (due to the cost of constructing the capture facilities), it could be argued that imposing a no-fault liability to be funded by the operator simply increases the amount of the public incentive that will be required in the first instance. If this analysis is correct, it might be less costly simply to have the government bear the cost and the risks directly. This is presumably the rationale for legislative provisions that provide for transfer of ownership and liability to a government entity at some point.

## 6 Liability—adapting the extent of liability to the benefits achieved

In the commercially-based, EOR world, an operator is generally free to reap the financial benefits of $CO_2$ injections and incidental storage but must bear all of the liability for compensating any parties damaged as a result of its negligence. If an operator concludes that the risks of a particular operation are too great in view of the anticipated benefits, the project will simply not be undertaken. In the case of $CO_2$–CCS injections and storage, however, the storage activity is undertaken to advance a public policy benefit of greenhouse gas emissions reduction. Various financial benefits have been created to provide incentives to companies to undertake $CO_2$–CCS projects. These include $CO_2$ being treated as 'not emitted' under the ETS; contracts for differences/feed-in tariff provisions; tax credits under Section 45Q of the US tax code; and qualification under the Clean Development Mechanism. While these incentive mechanisms are intended to reduce costs and risks, they can be negated if the public policy simultaneously imposes risks of long-term liability considered by the operator as too great or merely too uncertain.

To persuade EOR operators to implement storage scenarios that incorporate supplies of captured A-$CO_2$, it will be important to avoid *increasing* the risks beyond those to which the EOR operator would be subject if it confined its operations to traditional $CO_2$–EOR without an emissions reduction component. More generally, it is important to ensure that the risks imposed on a project developer are appropriately adapted to the public benefit expected to be achieved by the capture and storage effort.

## 7 Defining the parameters to be used in lifecycle emission analyses

Lifecycle emission analysis has been a topic of discussion in association with $CO_2$–EOR and GHG accounting and opinions vary as to the net effect on atmospheric emissions of $CO_2$–EOR operations. It is clear that the storage of 6–12 Mcf of $CO_2$ per incremental barrel produced during EOR operations (typical for the industry) sharply reduces the $CO_2$ footprint of that barrel of oil compared to a barrel of oil produced without $CO_2$ injections and storage. Hence $CO_2$–EOR can be viewed as the least carbon intensive form of oil production.

Whether a particular $CO_2$–EOR project is net emissions negative or not, however, depends on the specifics of the project and the way the 'boundaries' of the analysis are drawn. For example, continuous injection techniques use and store more $CO_2$ per barrel of oil produced than WAG techniques. Conversely, analyses that include emissions 'upstream' and 'downstream' of the $CO_2$–EOR operation or assume that the oil produced from $CO_2$–EOR supplements rather than supplants an alternative oil supply, view $CO_2$–EOR operations as providing less of an emissions reduction benefit than those that view the less carbon–intensive oil produced by $CO_2$–EOR as displacing some other, more carbon–intensive barrel.[425] Scenarios that maximise the amount of $CO_2$ used in an EOR operation present yet a different situation and may result in a net $CO_2$ emission–negative result, even after including emissions from combustion of the incremental barrel of oil.[426]

Given the complexities of international oil markets, arguments can be made for including and excluding downstream emissions in the scope of lifecycle assessments for $CO_2$–EOR.

A lifecycle emissions assessment is one analytic tool that can help inform broader public policy decisions regarding how $CO_2$–EOR fits into an overall emissions reduction policy. Such assessments are not necessarily tools for emissions accounting, however. In the actual accounting processes for evaluating $CO_2$ emissions and emissions–reduction policies, the appropriateness of including or excluding upstream or downstream emissions will depend in significant part on the overall architecture of a particular emissions reduction policy. For example, individual jurisdictions may elect to regulate downstream emissions at the emission source and not attribute those emissions to the upstream processes. There is no 'one-size-fits-all' answer to the correct scope of lifecycle assessment.

Once legislative or regulatory policymakers in a given jurisdiction define the scope to be considered in a lifecycle analysis for $CO_2$–EOR (and all other relevant alternatives), the various stakeholders should be able to reach a general consensus as to the emissions impact based on that particular set of assumptions and alternatives. Hence, while a lifecycle assessment may help inform policymakers in evaluating alternative emissions reduction or economic development policies, it is not a substitute for making the underlying policy judgements.

425 For a discussion of these issues, see Jaramillo, Griffin, and McCoy, '*Life Cycle Inventory of $CO_2$ in an Enhanced Oil Recovery* System', 43 Environmental Sci. Technol. 8027–8032 (published on Web 09/30/2009) (American Chemical Society).

426 See e.g. *Optimization of $CO_2$ Storage, supra.*

D

# Conclusion: the way forward

Most elements of a traditional legal and regulatory framework governing EOR operations can be adapted without great difficulty to allow the integration of supplies of A-$CO_2$ captured for emissions reduction purposes. There is a limited number of areas where there may be significant differences between or among regulatory authorities and the various affected stakeholders (including $CO_2$–EOR industry participants, landowners and residents in local communities, and citizen organisations).

Various studies and reports have sought to identify regulatory issues that need to be addressed for standalone CCS projects. The purpose of this concluding section is not to substitute for those analyses. Rather, it is to focus on the principal points of contention likely to require particular attention in any jurisdiction seeking to integrate the $CO_2$–EOR storage option into a broader policy for promoting CCS. These include:

- **Acceptance of the concept of re-using injected $CO_2$.** Re-use of $CO_2$ is essential for $CO_2$–EOR operations. Such re-use may, however, be viewed as unacceptable by some stakeholders in the context of $CO_2$–CCS operations, even where the recycled $CO_2$ remains in a closed loop from the underground formation through the piping and back to the subsurface formation where it is ultimately (and demonstrably) stored. There may be somewhat of a philosophical division of views between those who accept the production and re-injection of $CO_2$ during geologic storage operations and its use to produce petroleum, and those who do not. Greater familiarity with the $CO_2$–EOR experience may facilitate development of a consensus on this point, as may closer examination and better documentation of the integrity of the storage operations that occur during EOR operations. Better understanding of lifecycle analysis of $CO_2$ emissions from $CO_2$–EOR operations may also help policymakers make more informed judgements in this area. Ultimately, however, if there is no agreement on terms for re-use of $CO_2$, it may not be possible to integrate the two regulatory regimes.
- **Agreement on the proper basis and scope of liability.** If the scope or term of liability is not appropriately adapted to the perceived benefits to be gained, projects may not be developed to make use of the new framework. Greater familiarity with actual oil field experience in safely storing more than 800 million tonnes of $CO_2$ as a normal part of EOR operations over the past 40 years may help inform the development of liability rules that are well adapted to policymakers' key objective of safely reducing atmospheric emissions of $CO_2$. If the liability rules are too uncertain or too open ended, however, the project may prove unfeasible. In addition, a policy of imposing no-fault liability on $CO_2$ injections for emissions reduction in place of a fault–based approach for $CO_2$ injections for EOR purposes will likely raise project costs materially. The no-fault, insurance approach would hold the operator liable for events beyond its control and regardless of the degree of care and skill it applies. A liability policy that increases the costs borne by the EOR operator if it works with a $CO_2$ capture source to integrate A-$CO_2$ into an EOR operation may be expected to discourage EOR operators from incorporating A-$CO_2$ into their operations. Moreover, a liability policy that increases project costs is likely to require a commensurate increase in outside funding assistance. However, if the reason for incremental $CO_2$ injections is to achieve the public benefit of reduced $CO_2$ emissions, it would seem appropriate that the public bear the cost of insuring against damages suffered by any member of the public.
- **Adapting an existing well closure and post-closure management regime to provide for post-closure stewardship for the chosen term.** The existing procedures in most oil and gas jurisdictions are limited. The post-closure responsibilities of the regulator are focused primarily on responding to complaints about improperly plugged or leaking wells, frequently dealing with 'orphan' wells that may have been improperly plugged many decades before modern plugging procedures were implemented. Because policymakers are likely to set a lengthier term for closure and post-closure management of a $CO_2$ storage site, there may be a need to adjust the responsibilities of the regulator and expand the size of the stewardship fund. The experience of Alberta and the US states under the recently enacted $CO_2$ storage statutes is likely to be helpful in implementing working examples for the funding and operation of stewardship entities with such expanded responsibilities.

- **The extent and cost of well construction standards and additional monitoring.** There are a great many tools that may potentially be used to provide information regarding the movement of injected $CO_2$ in the subsurface. Among others, these tools include tracers, mechanical integrity testing of wells, air and soil monitoring, computer modelling of anticipated plume migration, and monitoring wells into formations above the injection/storage formation (and in some cases into the injection formation). Deploying some of these oilfield management tools can actually create additional risks of their own, however. For example, while monitoring wells can provide additional information about plume migration, they also constitute potential additional leakage pathways for the injected $CO_2$. Similarly, mechanical integrity testing provides information about the state of well materials, but stresses the various components being tested. Thus, tool selection should be site specific, requiring sound engineering judgement in the application of best practice. The regulatory rules should therefore try to avoid 'one-size-fits-all' requirements and allow instead for site specific, 'fit for purpose' techniques to ensure integrity of the storage operation. A regulatory framework for harnessing the $CO_2$–EOR value chain may not succeed if regulators and industry participants cannot agree on the appropriate types and degree of monitoring for transitioning progressively to increased $CO_2$ storage using $CO_2$–EOR infrastructure.
- **Ensuring that rules governing acquisition of pipeline rights of way apply to pipelines carrying $CO_2$.** Some statutes authorising the acquisition of wayleaves or rights of way for pipelines or other important carriers (e.g. railways) may be narrowly drawn and specific and not include pipelines carrying $CO_2$. Legislative revisions may be required in some instances to set appropriate terms under which $CO_2$ pipelines that are in the public interest may be sited and constructed.
- **Verifying the quantity of A-$CO_2$ stored during EOR operations.** Successful integration of A-$CO_2$ into EOR operations will require an officially acceptable mechanism for verifying the quantity of A-$CO_2$ that is stored. If N-$CO_2$ is also used in EOR operations, the mechanism must be constructed to separately account for A-CO2 in a commingled stream and the recycling and re-use of $CO_2$ in EOR operations. At the same time, it is important to avoid unnecessary administrative costs or complexity that could discourage EOR operators from substituting captured A-$CO_2$ for other supplies that do not provide an emissions reduction benefit. The procedures in the process of being adopted by several US states may provide useful models.
- **Avoid creating a competitive disadvantage for A-$CO_2$ in $CO_2$–EOR operations.** Because of the relatively high cost of capture, supplies of A-$CO_2$ captured for emissions reduction purposes are likely to bear a higher cost than alternative supplies. Hence, where these A-$CO_2$ supplies are to be integrated into an existing portfolio of $CO_2$ supplies, it will be critically important for regulators to avoid creating additional costs or uncertainty for potential purchasers (whether for $CO_2$–EOR use, industrial processing, food and beverage use or other beneficial uses that may develop in coming years). Treating A-$CO_2$ differently from N-$CO_2$ when it is used and stored in a commingled operation could lead EOR operators to avoid integrating A-$CO_2$ supplies into their portfolio.

More broadly, in evaluating proposed changes to any specific legal and regulatory framework intended to achieve such integration, policymakers may find it particularly helpful to review the following checklist of questions.

- Are all relevant property rights identifiable and practical mechanisms in place to allow acquisition and management of these property interests?
- Is there a mechanism for establishing priorities among competing interests in using the subsurface and for resolving conflict that may arise (either via legal rules where rights are privately held or institutional arrangements for resolving competing resource management priorities among governmental entities where the subsurface rights are state–owned or managed)?
- Do the rules allow for $CO_2$ injections in EOR operations to retain qualification as permanently stored even when the $CO_2$ is recycled during oil production operations or re-used in buffering operational variances in supply and demand?
- Can stored $CO_2$ be re-used in subsequent EOR operations (always assuming of course that the $CO_2$ demonstrably remains isolated from the atmosphere and does not endanger underground sources of drinking water)?
- May the EOR operator retain title to the injected $CO_2$ intended for future re-use?
- Do the accounting and monitoring protocols allow for the commingling of captured A-$CO_2$ with supplies of N-$CO_2$ while ensuring the integrity and accuracy of the calculations of the amount of A-$CO_2$ that is stored?
- Do the drilling and permitting rules appropriately reflect the varying risk profiles that may be presented by each of the potential storage scenarios?

- Are the rules governing liability for potential post-closure damage appropriately adapted to the value expected to be achieved from the storage operations?
- Are stewardship arrangements in place to address post-closure maintenance and management responsibilities?
- Do the rules governing access to pipeline and storage infrastructure protect over time the reliability of service for already constructed projects as well as ensuring reasonable access for capture projects that are yet to be constructed?

The integration of A-$CO_2$ into $CO_2$–EOR operations as part of a broader policy of reducing atmospheric emissions of $CO_2$ is clearly feasible with appropriate modifications to the oil and gas regulatory framework. The North American experience was already moving in that direction even absent binding national rules limiting $CO_2$ emissions. That experience underscores the potential for harnessing the additional value chain and infrastructure capability of $CO_2$–EOR to leverage deployment of carbon capture technologies.

# Appendix 1

## Abbreviations and acronyms

| | |
|---|---|
| **A-$CO_2$** | anthropogenic carbon dioxide |
| **ACTL** | Alberta Carbon Trunk Line |
| **AOR** | Area of Review |
| **ARI** | Advanced Resources International |
| **BACT** | best available control technology |
| **BBL/D** | barrels per day |
| **$C_2H_6$** | ethane |
| **$C_3H_8$** | propane |
| **$C_4H_{10}$** | butane |
| **CSLF** | Carbon Sequestration Leadership Forum |
| **CCS** | carbon capture and storage |
| **CCUS** | carbon capture utilisation and storage |
| **CEAA** | Canadian Environmental Assessment Act |
| **CERCLA** | Comprehensive Environmental response, Compensation and Liability Act (also called the 'Superfund') (US) |
| **CFR** | Code of Federal Regulations |
| **CFGER** | Canadian Federal Greenhouse Gas Emission Regulations |
| **$CH_4$** | methane (natural gas) |
| **$CO_2$** | carbon dioxide |
| **DECC** | Department of Energy and Climate Change (UK) |
| **DOE** | Department of Energy (US) |
| **DOT** | Department of Transportation (US) |
| **DTI** | Department of Trade and Industry (UK) |
| **$E^2R$** | use of anthropogenic carbon dioxide in enhanced oil recovery operations that results in geologic storage of the $CO_2$. |
| **EC** | European Commission |
| **EGR** | enhanced gas recovery |
| **EHR** | enhanced hydrocarbon recovery |
| **EIA** | Energy Information Administration (US) |
| **EIB** | European Investment Bank |
| **EOR** | enhanced oil recovery |
| **EPA** | Environmental Protection Agency (US) |
| **EPRI** | Electric Power Research Institute (US) |
| **ER** | (Saskatchewan Ministry of) Energy and Resources |
| **ERCB** | Energy Resources Conservation Board (Alberta) |
| **ETS** | Emission Trading System (EU) |
| **EU** | European Union |
| **FERC** | Federal Energy Regulatory Commission (US) |
| **GHG** | greenhouse gas |

| | |
|---|---|
| **GISZ** | Gas Importation and Storage Zone (UK) |
| **GS** | geologic storage |
| **$H_2S$** | hydrogen sulphide |
| **HMSO** | Her Majesty's Stationery Office |
| **IEA** | International Energy Agency |
| **IOGCC** | Interstate Oil and Gas Compact Commission (US and Canada) |
| **L. REV** | Law Review |
| **MCA** | Montana Code Annotated (US) |
| **MCF** | thousand cubic feet |
| **MMV** | monitoring, measurement and verification |
| **MRV** | monitoring, reporting and verification |
| **$N_2$** | nitrogen |
| **N-$CO_2$** | naturally occurring carbon dioxide |
| **NEB** | National Energy Board (Canada) |
| **NER** | New Entrants' Reserve |
| **NETL** | National Energy Technology Laboratory (US) |
| **NRDC** | Natural Resources Defense Council |
| **NSR** | New Source Review |
| **$O_2$** | oxygen |
| **OGCA** | Oil and Gas Conservation Act 2000 (Alberta) |
| **OGCR** | Oil and Gas Conservation Regulations 2012 |
| **OOIP** | original oil in place |
| **OSPAR** | The Convention for the Protection of the Marine Environment of the North-East Atlantic. |
| **PHMSA** | Pipeline and Hazardous Materials Safety Administration |
| **RCRA** | Resource Conservation and Recovery Act |
| **ROAD** | Rotterdam Capture and Storage Demonstration |
| **RSA** | Revised Statutes of Alberta |
| **RRC** | Railroad Commission (Texas, US) |
| **SDWA** | Safe Drinking Water Act of 1974 (US) |
| **SI** | statutory instrument |
| **SIP** | state implementation plan |
| **SNG** | synthetic natural gas |
| **SSEB** | Southern States Energy Board (US) |
| **TON** | Two thousand pounds (avoirdupoids) (roughly 0.9091 tonnes) |
| **TONNE** | One metric tonne, equal to 1,000 kilograms (roughly 2,200 pounds) |
| **TSB** | Transportation Safety Board (Canada) |
| **UCC** | Uniform Commercial Code (US) |
| **UK** | United Kingdom |
| **UIC** | underground injection control |
| **US** | United States of America |
| **USDW** | underground sources of drinking water |
| **WAG** | water-alternating-gas |

# Appendix 2

## Legislation referenced in this report

| LEGISLATION | JURISDICTION |
|---|---|
| *Alberta Oil and Gas Conservation Act 2000* | Alberta |
| *Alberta Pipeline Act* | Alberta |
| *Canada Transportation Act* | Canada |
| *Canadian Environmental Assessment Act 2012* | Canada |
| *Carbon Capture and Storage Statutes Amendments Act 2010* | Alberta |
| *Clean Air Act* | US |
| *Comprehensive Environmental Response, Compensation, and Liability Act of 1980* | US |
| *Crown Minerals Act 1985* | Saskatchewan |
| *Energy Act 2008* | UK |
| *Environmental Protection and Enhancement Act* | Alberta |
| *Interstate Commerce Act* | US |
| *Mineral Leasing Act of 1920* | US |
| *Mining Act Continental Shelf* | Netherlands |
| *National Energy Board Act* | Canada |
| *Oil and Gas Conservation Act 2000* | Alberta |
| *Oil Sands Conservation Act* | Canada |
| *Pipeline Act* | British Columbia |
| *Pipelines Act 1998* | Saskatchewan |
| *Pipeline Safety Reauthorization Act 1988* | US |
| *Pipeline Safety, Regulatory Certainty, and Job Creation Act 2011* | US |
| *Resource Conservation and Recovery Act* | US |
| *Safe Drinking Water Act 1974* | US |
| *Surface Rights Act* | Alberta |
| *CanadianTransportation Accident Investigation and Safety Board Act 1989* | Canada |
| *Uniform Sales Act* | US |