

Guidance for States & Provinces on OPERATIONAL & POST-OPERATIONAL Liability of Carbon Geologic Storage



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Acknowledgement

This material is based upon work supported by the U.S. Department of Energy Award Number DE-FC26-05NT42592.

Reporting Period

September 1, 2012 through September 30, 2014

Guidance for States and Provinces on **OPERATIONAL AND POST-OPERATIONAL** Liability in the Regulation of Carbon Geologic Storage

Principal Authors:

IOGCC Task Force on Carbon Capture and Geologic Storage (CCGS)
Lawrence E. Bengal, Director, Arkansas Oil and Gas Commission
Kevin Bliss, Esq., Washington, D.C.
Kevin Connors, CCS Supervisor, North Dakota Industrial Commission,
Department of Mineral Resources, Oil and Gas Division

Submitted to:

National Energy Technology Laboratory

Submitted by:

Interstate Oil & Gas Compact Commission through the
Energy & Environmental Research Center's Plains Carbon Dioxide (CO₂) Reduction (PCOR) Partnership

Published September 2014

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Participants & Observers

Anderson, A. Scott^{1,2}
Senior Policy Advisor
Environmental Defense Fund
Austin, TX

Bengal, Lawrence E.¹
Director
Arkansas Oil & Gas Commission
Little Rock, AR

Bioletti, Rob²
Director, CCS Policy
Alberta Energy
Edmonton, Alberta

Bliss, Kevin J.^{1,2}
Task Force & Subgroup Coordinator
Bliss Consulting
Washington, D.C.

Botnen, Lisa^{1,2}
Research Manager
Energy & Environmental Research Center
University of North Dakota
*Plains CO₂ Reduction (PCOR)
Partnership*
Grand Forks, ND

Childers, Amy
Federal Project Manager
Interstate Oil & Gas Compact Commission
Oklahoma City, OK

Coddington, Kipp^{1,2}
Partner
Mowrey Meezan Coddington Cloud LLP
McLean, VA

Connors, Kevin C.^{1,2}
CCS Supervisor
North Dakota Industrial Commission
Department of Mineral Resources
Oil & Gas Division
Bismarck, ND

Dhupar, Ankush
Legal Intern
Los Angeles, CA

Eames, Frederick¹
Partner
Hunton & Williams LLP
Washington, D.C.

Fernandez, Mike¹
Director, Market Diversification
Alberta Energy
Edmonton, Alberta

Finley, Robert J.¹
Illinois State Geologic Survey
*Midwest Geological Sequestration
Consortium (MGSC)*
Champaign, IL

Fredrick, Kevin³
Administrator
Wyoming Department of
Environmental Quality
Water Quality Division
Cheyenne, WY

Harju, John¹
Associate Director for Research,
Energy & Environmental Research Center
University of North Dakota
*Plains CO₂ Reduction (PCOR)
Partnership*
Grand Forks, ND

Helms, Lynn¹
Director
North Dakota Industrial Commission
Department of Mineral Resources
Oil & Gas Division
Bismarck, ND

Hill, David¹
Texas Railroad Commission
Oil & Gas Division
Carbon Capture Program
Austin, TX

Ladd, Laura⁴
Principal
Hewitt Ladd, Inc.
Jackson Hole, WY

Melzer, Stephen¹
Consulting Engineer
Melzer Consulting
Midland, TX

Rogers, Marvin²
Legal Counsel
Alabama Oil & Gas Board
Tuscaloosa, AL

¹ Task Force Participant

² Subgroup Participant

³ Task Force Observer

⁴ Subgroup Observer

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LIST OF ACRONYMS

AoR	Area of Review
BACT	Best Available Control Technology
CAA	Clean Air Act
CCEMC	Climate Change and Emissions Management Corporation
CCEMF	Climate Change and Emissions Management Fund
CCGS	Carbon Capture and Geologic Storage
CDM	Clean Development Mechanism
CEPA 1999	Canadian Environmental Protection Act (1999)
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CGS	Carbon Geologic Storage
CO₂	Carbon Dioxide
CO₂-EOR	Carbon Dioxide Enhanced Oil Recovery
CSP	Carbon Dioxide Storage Project
DEQ	Department of Environmental Quality
EIA	Environmental Impact Assessment
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
EPCs	Emission Performance Credits
FA	Financial Assurance
GHG(s)	Greenhouse Gases
GS	Geologic Sequestration
IOGCC	Interstate Oil and Gas Compact Commission
LBG	Leggette, Brashears, & Graham
MRV	Monitoring, Reporting and Verification
NETL	National Energy Technology Laboratory
NSPS	New Source Performance Standards
PCOR	Plains CO ₂ Reduction Partnership
PSD	Prevention of Significant Deterioration
RCRA	Resource Conservation and Recovery Act
RCSP	Regional Carbon Sequestration Partnership Program
SDWA	Safe Drinking Water Act
UIC	Underground Injection Control
USDW(s)	Underground Source(s) of Drinking Water
VERs	Voluntary Emission Reductions

EXECUTIVE Summary

This report is the product of the Interstate Oil and Gas Compact Commission (IOGCC) Task Force on Carbon Geologic Storage (CGS). It represents the work product of the IOGCC CGS Task Force in its fourth iteration since formation in 2002. With this writing, the Task Force now has produced reports in each of the three phases of the U.S. Department of Energy's Regional Carbon Sequestration Partnership program. Taken together, all of the reports in 2005, 2007, 2010 and now 2013, constitute IOGCC guidance to U.S. states and Canadian provinces on the formation of legal and regulatory frameworks for the storage of carbon dioxide (CO₂) in non-hydrocarbon-bearing geologic formations.

This Phase III effort of the Task Force, of which this report is the primary component, began in July 2012. Under the terms of the agreement with the U.S. Department of Energy and its National Energy Technology Laboratory through the Plains CO₂ Reduction (PCOR) Partnership, the IOGCC Task Force focuses upon issues of liability in all of the phases of a CGS project related to CGS in non-hydrocarbon-bearing formations. It does not, except cursorily, address CGS in the context of enhanced oil recovery.

In this report, the Task Force discusses liability broadly under federal, state or provincial, and common law, from the perspective of the state or provincial regulator of CGS. The most relevant of these liability concerns likely are to be those liabilities that arise out of the state or provincial and, in the United States, federal laws that deal directly with CGS.

Since the last IOGCC guidance in 2010, the Environmental Protection Agency (EPA) in the U.S. promulgated regulations (Class VI) under the Safe Drinking Water Act (SDWA) and its Underground Injection Control (UIC) Program to govern CGS. Addressed in detail in the body of this report, the new regulations by EPA address many but not all aspects of CGS project.

To better illustrate the divisions in federal/state regulation and jurisdiction within a CGS project, the Task Force did two things in this report. First, it posited a CGS project as being comprised of five phases: (I) Exploratory; (II) Permitting (Pre-Storage); (III) Storage (Operational); (IV) Closure; and (V) Post-Closure. Five phases rather than the four identified in previous IOGCC Task Force guidance better captures the limited federal jurisdiction under the SDWA.

Second, the Task Force produced a CGS Project Framework and Risk Analysis. The analysis, by activity over the five phases of a CGS project, identifies the risks posed by each activity, the regulatory jurisdiction (federal or state) over the activity, and the recommended Financial Assurance (FA) to cover the regulatory risks of the activity. In the report the Task Force discusses FA and the various mechanisms available to the states to protect their interests related to a CGS project.

One of the major conclusions of this report is that in the U.S., states must play a role in the regulation of CGS. EPA jurisdiction does not cover all of the state's regulatory interests in a CGS project. (This conclusion is not relevant to Canadian provinces as there is no comparable provincial-federal regulatory overlap in Canada.) The EPA regulatory mandate under the SDWA begins and ends with the protection of underground sources of drinking water. The report will discuss how state interests extend well beyond this important but limited mandate. Those state interests include protecting the state from associated liability from what would otherwise be non-regulated CGS-related activity under the UIC Class VI Rule.

Prime examples of these include all of the CGS Phase I (Exploratory) and Phase V (Post-Closure) activities, as well as activity involving surface facilities, including pipelines, in Phases II, III and IV of a CGS project. None of these are regulated by EPA jurisdiction under the SDWA.

In addition to the recommendation that states play a regulatory role alongside EPA in regulation of CGS, the Task Force encourages states to secure Class VI "primacy" jurisdiction from EPA. By securing Class VI primacy, a state concurrently will exercise both its regulatory jurisdiction and the federal SDWA regulatory jurisdiction. (The SDWA allows a state to be granted primacy if it meets certain conditions set forth in the act.)

The situation in Canada with regard to CGS development is quite different as CGS almost entirely is regulated at the provincial level. Except in a few instances, such as if a project is receiving federal funding, which would trigger a federal environmental impact assessment (EIA) in addition to a potential provincial EIA, there is minimal overlap between federal-provincial regulatory jurisdiction.

Given the regulatory complexities of CO₂ storage dealing with property rights, pore space management, and environmental protection issues, the Task Force strongly recommends that states and provinces regulate CO₂ storage utilizing a resource management philosophy, first introduced by the Task Force in conjunction with its 2007 Guidance. A resource management philosophy allows these issues to be regulated in a way that balances these activities within an all encompassing regulatory framework. Waste management frameworks do not adequately address pore space ownership and consequently cannot effectively manage the efficient use of the pore space resource.

The Task Force concluded that in order to facilitate the orderly development of CO₂ storage projects within state and provincial boundaries that a state or province should embrace two basic principles enumerated in previous Task Force efforts.

These principles are: (1) that it is in the public interest to promote the geologic storage of CO₂ in order to reduce anthropogenic CO₂ emissions; and (2) that the pore space of the state or province should be regulated and managed as a resource under a resource management framework. This should be done by the state or province prior to storage occurring within the state or province.

In this report the Task Force once again recommends, as it did in 2007 and 2010, that states and provinces are best situated to assume responsibility for the "caretaking" (monitoring and maintenance) responsibility in the final Post-Closure (Long-Term Storage) Phase of a CGS project when that project has been deemed to have stabilized.

It also once again is recommending that these long-term state and provincial responsibilities be financed by an industry-funded and state/province administered trust fund financed by a tax or fee on each ton of CO₂ injected for storage along the lines set forth in 2007 and 2010 IOGCC Model CGS Statute. (The Model Statute also detailed the “caretaking” activities covered by the trust fund.)

The report further observes that in the United States under the SDWA, EPA is unable to release the operator from federal liability in the Post-Closure Phase of CGS project.

Noting that perpetual federal liability has been cited as a threat to the viability of a CGS industry in the United States, the Task Force suggests two general responses, one state, the other federal.

Expressed in its broadest form, under the state response the state would, after issuance of the Certificate of Closure, assume complete responsibility for the CGS storage site. The state concurrently also would assume near-complete liability from the operator under federal and state law, to be financed by a Long-Term State Trust Fund that would be funded by an appropriately greater tax or fee on each ton of CO₂ injected. This “remediation trust fund” could be the same as or distinct from the trust fund. The Task Force recommends it be established to address long-term site care (monitoring and maintenance). This option and the breadth of its potential exercise by a state would be totally within the control of the state.

The federal response could take a myriad of forms. At its broadest, the federal response could involve amending existing federal environmental legislation, including the SDWA, to authorize transferral of liability when a site is deemed to no longer pose a potential environmental risk. Variations of a federal response also could include a federal trust fund, to which post-closure liability could be transferred, or other public-private sector options for the Post-Closure Phase of a CGS project.

While the Task Force was unable to go beyond its recommendation of 2007 and 2010 concerning the Long-Term Trust Fund and its focus on monitoring and maintenance, it sees merit to a state actively considering the assumption of broader responsibility and liability in the Post-Closure Phase.

As it stands, there is a relative dearth of commercial projects for active CGS development in the United States due in part to the fact that the business case for CCGS does not yet exist and a rigorous regulatory environment has discouraged early adoption of the technology.

No doubt the issue of long-term liability is another important factor. One conclusion that appears clear is that states that are willing to adopt legal and regulatory frameworks along the lines suggested in the state solution described above likely will have an advantage when it comes to securing CGS project development in their jurisdictions.

SECTION 1

Introduction

1.1 BACKGROUND

In July 2002, the Interstate Oil and Gas Compact Commission (IOGCC) began a multi-year effort to ensure that U.S. states and Canadian provinces would have the legal and regulatory capacity to oversee the storage of carbon in geologic formations. The effort, a part of the U.S. Department of Energy (DOE) Regional Carbon Sequestration Partnership Program (RCSPP), has encompassed all three phases of the program.

In Phase I, the IOGCC Carbon Capture and Geologic Storage (CCGS) Task Force in 2005 produced a report that broadly examined “the issues — legal, policy and regulatory — related to the safe and effective geologic storage of Carbon Dioxide (CO₂) for both enhanced recovery and long-term CO₂ storage.”¹

In Phase II, the Task Force in 2007 produced a document titled “Storage of Carbon Dioxide in Geologic Structures: A Legal and Regulatory Guide for States and Provinces” (Task Force 2007 Guidance).² The primary components of that guidance document were both a Model Statute and Model Rules and Regulations for geologic storage of CO₂. In conjunction with the Task Force 2007 Guidance the IOGCC produced an additional publication that summarized the guidance.³ It was in this publication that the Task Force first articulated its Resource Management Philosophy.⁴

As a further part of its work in Phase II the IOGCC CCGS Task Force three years later, in September 2010, produced a “Biennial Review of the Legal and Regulatory Environment for the Storage of Carbon Dioxide in Geologic Structures” (Biennial Review).⁵ A primary component of that review was “An Update on IOGCC Legal and Regulatory Guidance for States and Provinces” (Task Force 2010 Guidance).⁶

¹ INTERSTATE OIL & GAS COMPACT COMM’N TASK FORCE ON CARBON CAPTURE AND GEOLOGICAL STORAGE, A REGULATORY FRAMEWORK FOR CARBON CAPTURE AND GEOLOGICAL STORAGE (2005), *available at* <http://iogcc.publishpath.com/Websites/iogcc/PDFS/2008-CO2-Storage-Legal-and-Regulatory-Guide-for-States-Full-Report.pdf>.

² INTERSTATE OIL & GAS COMPACT COMM’N TASK FORCE ON CARBON CAPTURE AND GEOLOGICAL STORAGE, STORAGE OF CARBON DIOXIDE IN GEOLOGIC STRUCTURES: A LEGAL AND REGULATORY GUIDE FOR STATES AND PROVINCES (2007), [hereinafter TASK FORCE 2007 GUIDANCE], *available at* <http://iogcc.publishpath.com/Websites/iogcc/PDFS/2008-CO2-Storage-Legal-and-Regulatory-Guide-for-States-Full-Report.pdf>

³ INTERSTATE OIL & GAS COMPACT COMM’N TASK FORCE ON CARBON CAPTURE AND GEOLOGICAL STORAGE, ROAD TO A GREENER ENERGY FUTURE: CO₂ STORAGE: LEGAL AND REGULATORY GUIDE FOR STATES (2008), *available at* <http://iogcc.publishpath.com/Websites/iogcc/pdfs/Road-to-a-Greener-Energy-Future.pdf>.

⁴ *Id.* at 3.

⁵ INTERSTATE OIL & GAS COMPACT COMM’N TASK FORCE ON CARBON CAPTURE AND GEOLOGICAL STORAGE, PHASE II BIENNIAL REVIEW OF THE LEGAL AND REGULATORY ENVIRONMENT FOR THE STORAGE OF CARBON DIOXIDE IN GEOLOGIC STRUCTURES (2010) [hereinafter BIENNIAL REVIEW], *available at* <http://groundwork.iogcc.org/topics-index/carbon-sequestration/iogcc-whitepapers/iogcc-ccgs-task-force-phase-ii-biennial-review>.

The document also contains “A Review of State and Provincial Action to Create a Legal and Regulatory Infrastructure for Storage of Carbon Dioxide in Geologic Structures” that updates (through September 2010) state and provincial actions to create laws and regulations to govern CGS. BIENNIAL REVIEW at 12.

⁶ *Id.* at 38 - 50, Appendix I-1 to I-5 & Appendix II-1 to II-15 [hereinafter TASK FORCE 2010 GUIDANCE]. The Introduction is also important to understanding the guidance. BIENNIAL REVIEW, *supra* note 5, at 6

This guidance document included an updated Model Statute and Model Rules and Regulations. Importantly, the updated model documents included innovations from states that already had begun to create their own laws and regulations for CO₂ storage based on the Task Force 2007 Guidance model documents.

This 2010 Guidance should be considered, in conjunction with commentary contained with the Task Force 2007 Guidance, as the current IOGCC Guidance to States and Provinces on Carbon Geologic Storage (CGS).

The Phase III effort, of which this report is the primary component, began in July 2012. Under the terms of the agreement with DOE/NETL through the Plains CO₂ Reduction (PCOR) Partnership, the IOGCC Task Force, renamed the CGS Task Force, focuses upon issues of liability in all of the phases of a CGS project related to the storage of CO₂ in non-hydrocarbon-bearing formations.⁷ This report will therefore constitute supplementary guidance to states and provinces on the issues of liability in a CGS project. This has been the focus of the work undertaken by the Task Force in this 14-month effort.

1.2 CO₂ ENHANCED OIL RECOVERY

It is important to make clear that the IOGCC Task Force, in both its Phase II efforts to produce guidance, including model documents, and this Phase III effort, has focused solely upon issues related to the legal and regulatory framework for storage of CO₂ in non-hydrocarbon-bearing subsurface formations and not the incidental storage (i.e., geologic retention of CO₂ in the reservoir) of CO₂ that occurs during enhanced oil recovery (EOR) using CO₂ (CO₂-EOR). This is because CO₂-EOR and incidental CO₂ storage already are considered to be covered under existing state, federal, and provincial legal and regulatory frameworks.

A further discussion of this is included in the guidance below. Additionally, any reference to CGS in the pages that follow is to CGS in non-hydrocarbon-bearing subsurface formations unless otherwise noted.

1.3 CHANGES SINCE TASK FORCE 2010 REPORT

A useful starting point in this updated guidance document is a description of how the playing field for CGS has changed for U.S. states⁸ since release of the Task Force 2010 Guidance in September 2010.

At the time of that report, the Task Force observed that while much work remained to be done by states and provinces in enacting the legal and regulatory infrastructure for the storage of CO₂ in geologic formations, “an important core group of states — North Dakota, Washington, Wyoming, Kansas, Louisiana, Montana, Ohio, Oklahoma and Texas — has put legislation and/or regulations into place to govern

⁷ Among non-hydrocarbon-bearing subsurface formations, the most likely candidate for CO₂ storage is likely to be deep saline reservoirs. It also is possible that fully depleted natural gas reservoirs may be appropriate for CO₂ storage where the injection of CO₂ would not result in incremental hydrocarbon recovery. Other commentators also have suggested the potential for storage in unminable coal seams, basalts, limestone formations, fractured karst, and other formations.

⁸ While this report generally will be addressed to both U.S. states and Canadian provinces, the discussion that follows concerns changes in U.S. environmental law that does not affect Canadian provinces.

[such storage]”⁹ largely based on the IOGCC model documents. The Task Force also noted that a number of additional states were engaged in processes to study, then formulate draft legislation.¹⁰

What changed in the CGS playing field for U.S. states contemplating CGS was EPA’s release in December 2010 of a new rule governing CGS under the Underground Injection Control (UIC) Program¹¹ of the Safe Drinking Water Act (SDWA).¹² It was titled “Final Rule for Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO₂) Geologic Sequestration (GS) Wells” (UIC Class VI Rule or Class VI).¹³ This rule established minimum federal requirements under the SDWA for the injection of CO₂ for sequestration purposes. Although there were existing regulations for other types of underground injections, the rule was considered necessary by the EPA to address what it regarded as the unique nature of carbon dioxide injection for long-term storage.

When the IOGCC released the 2010 Guidance in September, the Task Force was aware of the EPA’s “Proposed Rule for Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO₂) Geologic Sequestration (GS) Wells” (UIC Class VI Proposed Rule (2008)),¹⁴ which was released by the EPA in July 2008. In the 2010 Guidance the Task Force recommended states “continue to proceed expeditiously to develop and adopt CCGS regulatory frameworks based on the IOGCC model documents and that states not wait for finalized EPA regulatory action under the SDWA. As noted, the IOGCC model documents are in general alignment with the draft EPA Storage Rule and, therefore, any divergence in regulatory methodologies that might arise from adoption of the IOGCC model should be easily reconciled.”¹⁵ The Task Force made this recommendation with the intention of eliminating regulatory uncertainties and to encourage commercial development of CCGS projects. As such, IOGCC, IOGCC member states, and other groups¹⁶ submitted comments to EPA during the public comment period on the UIC Class VI Proposed Rule (2008).

⁹ BIENNIAL REVIEW, *supra* note 5, at 7.

¹⁰ *Id.* at 12 for a detailed review of state legal and regulatory activity.

¹¹ Underground Injection Control Program (UIC), 42 U.S.C § § 300h (1974) [hereinafter UIC]. The regulations issued pursuant thereto can be found at 40 C.F.R. Parts 144-147; *See also* U.S. Environment Protection Agency, *Underground Injection Control Program*, EPA.GOV, <http://water.epa.gov/type/groundwater/uic/index.cfm> (last updated Sept. 12, 2012).

¹² Safe Drinking Water Act (SDWA), 42 U.S.C § § 300h (1974) [hereinafter SDWA]; *see also* U.S. Environment Protection Agency, *Safe Water Drinking Act* (SDWA), EPA.GOV, <http://water.epa.gov/lawsregs/rulesregs/sdwa/index.cfm> (last updated Mar. 6, 2012).

¹³ Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO₂) Geologic Sequestration (GS) Wells; Final Rule. 75 Fed. Reg. 77230 (December 10, 2010) (codified at 40 C.F.R. Part 144.) [hereinafter references to the “UIC CLASS VI RULE PREAMBLE” will cite to page numbers in the Federal Register, whereas references to the rule as embodied in code will be referenced as “UIC CLASS VI RULE” and refer to section numbers within the C.F.R.]. *See also* U.S. Environment Protection Agency, *Geological Sequestration Regulations*, EPA.GOV, <http://water.epa.gov/type/groundwater/uic/class6/gsregulations.cfm> (last updated July 30, 2012).

¹⁴ Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO₂) Geologic Sequestration (GS) Wells; Proposed Rule. 73 Fed. Reg. 43492 (July 25, 2008). *See also* U.S. Environment Protection Agency, *Federal Register Environmental Documents*, EPA.GOV, <http://www.epa.gov/fedrgstr/EPAWATER/2008/July/Day-25/w16626.htm> (last updated Oct. 30, 2009).

¹⁵ BIENNIAL REVIEW, *supra* note 5, at 9.

¹⁶ One such other group was the Underground Injection Technology Group, an association of underground injection well operators. In its comments on the UIC Class VI Proposed Rule (2008), the group expressed concern as to “the overall level of stringency of the proposed requirements for Class VI injection wells. Carbon dioxide is among the most innocuous materials injected under the UIC program, and yet the proposed rules for carbon dioxide injection would be among the most elaborate and burdensome in the entire UIC program. UNDERGROUND INJECTION TECHNOLOGY GROUP, COMMENTS OF THE UNDERGROUND INJECTION TECHNOLOGY GROUP ON EPA’S PROPOSED GEOLOGIC SEQUESTRATION RULE 3 (Dec. 24, 2008)) [hereinafter UIT GROUP COMMENTS], available at <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OW-2008-0390-0246>.

When the UIC Class VI Rule was released in December 2010, it differed in many respects from the rule the IOGCC Task Force and most of the IOGCC member states had anticipated. In the opinion of many states, the UIC Class VI Rule had created a new category of well (Class VI) with requirements that in a number of respects met or exceeded the requirements for the UIC program's most rigorous class of well: Class I hazardous waste disposal wells.¹⁷ The Task Force had anticipated that EPA would create a Class VI well classification and that the rule promulgated for Class VI would fall, in terms of stringency, somewhere between the UIC Class II (Oil and Gas Related Injection Wells) requirements and the Class I requirements¹⁸ and be relatively consistent with the requirements contained in the IOGCC model documents. As it is, the UIC Class VI Rule in a number of significant respects went beyond the stringency of the Class I requirements. Among the particular concerns are Class VI monitoring requirements that go well beyond what is required for Class I wells.¹⁹

Nonetheless, as of September 7, 2011, EPA became the acting authority for Class VI injection wells in all states.²⁰ In order for a state to gain primary enforcement responsibility, or primacy,²¹ for CO₂ injection wells under Class VI, a state must demonstrate to EPA that its Class VI UIC program is no less stringent than the federal standards.²² Given the stringency of the UIC Class VI Rule noted above, the IOGCC model rule contained in the Task Force 2010 Guidance (2010) would need to be amended by a state so as to conform to the standards set forth in the UIC Class VI Rule.

Since the adoption of the EPA Rule, very few U.S. states have moved to develop or implement laws and regulations for CGS and only a very small number of states are moving to secure primacy for regulation of CGS.²³ Those states in primacy discussions with EPA are realizing that the process of obtaining primacy is complex and time-consuming. Also influencing states in this regard is the assumption that the UIC Class VI Rule will not be extended to CO₂-EOR and the apparent lack of significant commercial interest in pursuing CGS.²⁴

¹⁷ Class I wells are classified in four categories: (1) Hazardous Waste Disposal Wells; (2) Non-Hazardous Industrial Waste Disposal Wells; (3) Municipal Wastewater Disposal Wells; and (4) Radioactive Waste Disposal Wells. EPA contends that the construction, permitting, operating, and monitoring requirements for Class I hazardous waste disposal wells are more stringent than for the other types of injection wells. See U.S. Environment Protection Agency, *Classes of Wells*, EPA.GOV, <http://water.epa.gov/type/groundwater/uic/wells.cfm> (last visited May 15, 2013); U.S. Environment Protection Agency, *Industrial & Municipal Waste Disposal Wells (Class I)*, EPA.GOV, http://water.epa.gov/type/groundwater/uic/wells_class1.cfm (last updated March 6, 2012).

¹⁸ U.S. Environment Protection Agency, *Class II Wells – Oil and Gas Related Injection Wells (Class II)*, EPA.GOV, <http://water.epa.gov/type/groundwater/uic/class2/index.cfm> (last updated May 9, 2012).

¹⁹ See UIT GROUP COMMENTS, *supra* note 16, at 3-4.

²⁰ As no states applied for primacy during the time set forth, EPA assumed Class VI primacy in all states 270 days following its promulgation of the EPA Class VI Final Rule Federal on December 10, 2010. See UIC Class VI Rule, *supra* note 13, at 77242 (commenting upon 40 C.F.R. §145.21(h)).

²¹ For a general description of UIC program primacy see U.S. Environment Protection Agency, *UIC Program Primacy*, EPA.GOV, <http://water.epa.gov/type/groundwater/uic/Primacy.cfm> (last updated Aug. 12, 2012).

²² See SDWA, *supra* note 12, at § 1422. To gain authority over all classes of wells or Class I, III, IV, V, and VI state programs must be as stringent as the federal program and show that their regulations contain effective minimum requirements (e.g., inspection, monitoring, and recordkeeping requirements that well owners and operators must meet). State regulations must be as stringent as the federal requirements, but may be more stringent. Such states are authorized under section 1422 of the SDWA.

To gain authority over Class II wells only, states with existing oil and gas programs may make an optional demonstration that their program is effective in protecting USDWs. Such states are authorized under section 1425 of the SDWA.

To gain authority over Class VI wells only, states may apply for Class VI primacy under section 1422 of the SDWA for managing UIC CGS projects under the Class VI Program.

²³ The following states are known to have expressed interest in securing primacy for Class VI: North Dakota, Montana, Wyoming, Kansas, Mississippi, and Alabama.

²⁴ Other than EOR-related CGS, which will be discussed in Section 2 in more detail.

1.4 STAGES OF A CGS PROJECT

As noted above, the focus of this updated Task Force Guidance is on issues of liability that can be expected to arise in the phases of a CGS project. In previous guidance the Task Force had identified four basic stages in a CGS project: (I) Pre-Operational; (II) Operational; (III) Closure; and (IV) Post-Closure (Long-Term Storage).

The Task Force in this guidance has concluded that a more accurate depiction of the activities in a CGS project requires five phases: (I) Exploratory; (II) Permitting (Pre-Storage); (III) Storage (Operations); (IV) Closure; and (V) Post-Closure (Long-Term Storage).²⁵ It was decided that five phases better illustrated the U.S. federal/state regulatory and jurisdictional divisions in a CGS project from start to finish.²⁶ Figure 1-1 (CGS Project Flow) is a diagram showing the flow of a CGS project through each of the five phases. The Task Force will address this U.S. federal/state regulatory and jurisdictional division of authority in greater detail in both Sections 2.2 and 3.

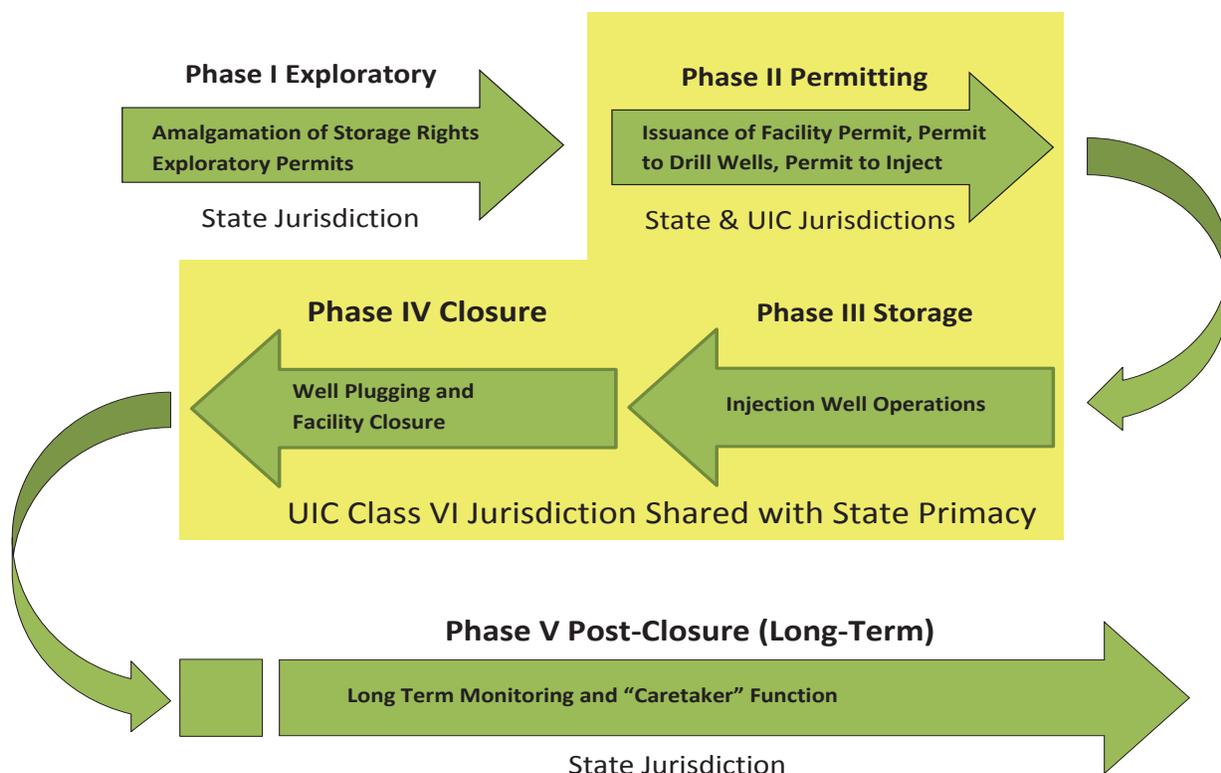


Figure 1-1 CGS Project Flow Diagram

(Yellow boxes show concurrent state and UIC Class VI jurisdiction in Phases II, III, IV. Phase I and V show exclusive state jurisdiction.)

²⁵ EPA identifies four phases of a CGS Project with important differences. EPA's four stages are: 1. Pre-Injection Phase: Prior to Construction (Permit application, site characterization, AoR delineation & corrective action, financial responsibility demonstration, proposed activities and project plans, injection depth waivers, and well transitioning from Class II to Class VI); 2. Pre-Injection Phase: Prior to Injection (Final AoR & corrective action status, site characterization, and injection well construction & testing); 3. Injection Phase (Injection well operation, testing & monitoring and AoR re-evaluation & phased corrective action); and Post-Injection Phase (Injection well plugging, post injection site care & site closure, and AoR re-evaluation). U.S. ENVIRONMENTAL PROTECTION AGENCY, GEOLOGIC SEQUESTRATION OF CARBON DIOXIDE DRAFT UNDERGROUND INJECTION CONTROL (UIC) PROGRAM CLASS VI RECORDKEEPING, REPORTING, AND DATA MANAGEMENT GUIDANCE FOR OWNERS AND OPERATORS, at 4, available at <http://water.epa.gov/type/groundwater/uic/class6/upload/epa816p13001.pdf>.

²⁶ While perhaps more descriptive of the stages of a CGS project, the addition of the fifth phase is less relevant in Canada.

This report is comprised of four sections. In Section 2, which follows immediately, the Task Force takes a broad look at “liability” in a CGS project. Section 3 examines liability more specifically in each of the five phases of a CGS project. Finally, in Section 4, the Task Force discusses in some detail a number of enacted laws and common law theories that may have relevance to CGS Operations. The report also contains two appendices:

Appendix 1: Examples of Interest to States and Provinces

Appendix 2: Bibliography

Appendix 1 contains four examples that the Task Force believes may help illuminate states and provinces on the range of options open to them in creating legal and regulatory frameworks for CGS. Specifically, Examples 1 and 2 explain how one Canadian province and one U.S. state, Alberta and Wyoming, respectively, are managing long-term liability for CGS in their jurisdictions.

Example 3 explains how the State of North Dakota responded to a massive large volume subsurface diesel spill in creation of the Mandan Remediation Trust. Example 4 sets forth a “Layered” Federal Risk Management Proposal to handle liability for CGS.

Appendix 2 is a bibliography that contains all of the documents referenced in this report, as well as other documents generally deemed relevant to liability and risk assurance and of potential value to states, provinces and companies contemplating CGS.

SECTION 2

General Discussion of Liability (Pertaining to all stages of a CGS Project)

2.1 LIABILITY IN THE CONTEXT OF CGS

This report is focused on liability and the potential risks associated with CGS operations. An important starting point is therefore a discussion of what the Task Force means by liability.

As with any industrial activity, liability for CGS operations will arise in one of two ways: (1) violation of laws enacted by a government — federal or state/province; or (2) under common law theory, such as negligence, trespass, or nuisance. The Task Force in this report will identify and discuss potential pathways of liability for CGS in three categories: federal statutes, state and provincial statutes, and common law.

For explanatory purposes, it also may be useful to think of potential liabilities in terms of these types: (1) liabilities for cleaning up after an incident, which would include both the cost of fixing the facility so future incidents do not occur, and the cost of remediating environmental damage that may occur, such as groundwater contamination; (2) penalties imposed by the government; and (3) liabilities to neighbors and others for property damage or other injuries.

From the perspective of the state or provincial regulator of CGS, the foremost “liability” concerns will be with those liabilities that arise out of the state/provincial and, in the U.S., federal laws that deal directly with CGS, most notably the SDWA and state laws. This includes the regulations promulgated by a state, province or federal government under those laws, and the permits and approvals issued. Playing an important role in this is “financial assurance” (FA), a regulatory requirement that assures that financial resources are available to the regulator should the CGS project operator fail to carry out a regulatory obligation.

This report in Section 2.6 will identify and discuss the common FA mechanisms used to handle these liabilities and in Section 3 will identify the risks inherent in the various activities that would be undertaken by a CGS project operator in each of the identified five phases of a CGS project. Some of those risks, but not all, will be covered by FA.

To the extent the identified risks are of a nature appropriate for FA — for example most environmental risks — the Task Force in Section 3 also identifies those FA mechanisms that the Task Force regards as most appropriate for the particular risk so as to cover the liabilities that would ensue from that risk event should the operator fail to remedy the problem in a timely manner on its own.

Although the state and provincial focus will be on the above, it is important that states and provinces administering a CGS regulatory regime also understand how their state or provincial CGS-specific laws and regulations fit into the broader liability framework.

In Section 4, the Task Force will discuss in some detail a number of enacted laws and common law theories that may have relevance to CGS operations. In the U.S., these include the SDWA²⁷, which has become the linchpin for all federal and state CGS regulation in the U.S., the Resource Conservation and Recovery Act (RCRA)²⁸, the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA or Superfund)²⁹, and the Clean Air Act (CAA)³⁰. States typically also have laws that track each of the laws above and may add additional requirements.

Much more will be said of the SDWA and its impact on state laws and regulations governing CGS, particularly in Sections 2.2 and 3. There may be other applicable state laws as well. At common law in the U.S. and Canada, there is the potential for trespass³¹, nuisance³², negligence³³, and strict liability.³⁴ These will be discussed in more detail in Section 4.4. Section 4.4 also includes a discussion of Canadian federal statutes.

2.2 Jurisdiction over CGS — State/Federal in the U.S. and Provincial/Federal in Canada

The discussion that follows addresses the situations in the U.S. and Canada separately.

United States. In the U.S., for a CGS project to be licensed and operated, a CGS owner or operator will have to comply with a mix of state and federal law. The CGS Project Flow Diagram (Figure 1) indicates those stages where states have sole regulatory jurisdiction (Phases I and V) and those stages where the states and the federal government share jurisdiction (Stages II, III and IV). The federal jurisdiction exercised in Stages II, III, and IV is under the SDWA and specifically the UIC Class VI Rule. Where a state has obtained Class VI primacy, the state will exercise this authority by enforcing its own rules and regulations, which will have been amended and adjudged by EPA to be at least as stringent as the UIC Class VI Rule.³⁵

The “default” position under the SDWA is that this federal jurisdiction will be exercised directly by the EPA. That is, unless a state applies to EPA and is approved to run the program, EPA will administer the Class VI program in the state. No state has received primacy under Class VI as of the date of this report.

²⁷ SDWA, *supra* note 12.

²⁸ Resource Conservation and Recovery Act (RCRA), 42 U.S.C § 6903.

²⁹ Comprehensive Environmental Response, Compensation, and Liability Act, 42 U.S.C. § 9606. [hereinafter CERCLA]

³⁰ Clean Air Act, 42 U.S.C. § 7401.

³¹ Should a CGS facility operator wrongfully interfere with a property owner’s possessory rights and the interference causes damage, the operator may be liable for trespass.

³² Should a CGS facility operator substantially interfere with a property owner’s use or enjoyment of their property, the operator may be liable for nuisance.

³³ A CGS facility operator will owe a duty of care to neighbors and others to operate the facility in a manner not likely to cause property damage or other injuries.

³⁴ It is possible that a court could find a CGS facility operator liable for damages to property or other injuries, even if the operator was neither at fault or negligent.

³⁵ See *supra* text accompanying note 22 for explanation of Class VI Primacy. Alternatively, a state may also adopt the UIC Class VI Rule by reference or verbatim.

One important take-away from the Task Force’s analysis of regulatory jurisdiction is, in a non-primacy state with EPA directly implementing the SDWA and the Class VI Rule, that it would be highly unlikely that a CGS project could move forward without state legislation and regulations in place to enable both Phase I activities (amalgamation of storage rights),³⁶ ensuring protection of mineral and correlative rights, and a Phase V arrangement that protects the state after closure of the site.

In addition, the analysis in Section 3 shows the necessity of active state involvement in Phases II, III, and IV. This reinforces the need for a non-primacy state to ensure appropriate legislation and regulations are in place to ensure the interests of the state and subsurface rights owners are being protected in all phases.

Additionally, note that the UIC Class VI Rule is not as broad as the IOGCC Model Rule (2010). EPA’s jurisdiction under the UIC Class VI Rule is limited to protection of “underground source[s] of drinking water” (USDW)³⁷, whereas the IOGCC Model Rule extended to all aspects of the project.

In the Section 3 discussion, the limited breadth of EPA jurisdiction is specifically identified in each of the five phases of a CGS project.

Thus, even in a state with no interest in obtaining primacy from EPA for CGS, any CGS development in the state likely also will require a state legal and regulatory framework.

Given all of the above, the Task Force strongly recommends that any state with potential for CGS adopt legislation and promulgate regulations for the geologic storage of CO₂ along the general lines of the Task Force 2010 Guidance combined with the UIC Class VI Rule.³⁸ It states that are best positioned to administer a combined regulatory system that meets the stringency requirements necessary to obtain Class VI primacy while at the same time implementing a resource management philosophy³⁹ articulated in conjunction with the Task Force 2007 Guidance.

³⁶ TASK FORCE 2007 GUIDANCE contained a conclusion that as part of the initial licensing of a storage project that an operator must control the reservoir and associated pore space to be used for CGS in order to allow for orderly development and maximum utilization of the storage reservoir. See TASK FORCE 2007 GUIDANCE, *supra* note 2, at 27. With exception of federal lands, the acquisition of these storage rights, which are considered property rights, generally are functions of state law.

³⁷ Underground source of drinking water (USDW) is defined as “an aquifer or its portion: (a)(1) Which supplies any public water system; or (2) Which contains a sufficient quantity of ground water to supply a public water system; and (i) Currently supplies drinking water for human consumption; or (ii) Contains fewer than 10,000 mg/l total dissolved solids; and (b) Which is not an exempted aquifer.” UIC, *supra* note 11, § 144.3.

Exempted aquifer is defined as “an ‘aquifer’ or its portion that meets the criteria in the definition of “underground source of drinking water” but which has been exempted according to procedures in § 144.7.” *Id.*

Aquifer is defined as “a geological ‘formation,’ group of formations, or part of a formation that is capable of yielding a significant amount of water to a well or spring.” *Id.* See also U.S. Environment Protection Agency, *Underground Injection Control Program – Selected Terms*, EPA.GOV, <http://www.epa.gov/region1/eco/drinkwater/terms.html> (last updated Dec. 12, 2012).

³⁸ As a few states obtain primacy jurisdiction from EPA for Class VI wells, there will be examples of legislation and rules and regulations that meet the Class VI requirements that could become, in essence, new model documents for states. Provinces will remain unaffected by this and may still rely on existing IOGCC guidance supplemented by this guidance in the area of liability. There also soon will be provinces with fully developed regulatory frameworks that also will be worthy of study or emulation.

³⁹ INTERSTATE OIL & GAS COMPACT COMM’N TASK FORCE ON CARBON CAPTURE AND GEOLOGICAL STORAGE, *supra* note 3, at 3.

2.3 RESOURCE MANAGEMENT PHILOSOPHY

Given the regulatory complexities of CO₂ storage dealing with property rights, pore space management and environmental protection issues, the Task Force strongly recommends that CO₂ storage be regulated utilizing a resource management philosophy.

A resource management philosophy allows these issues to be regulated in a way that balances the public benefits from development of natural resources with property rights and environmental protection within a multi-faceted set of regulations.

Waste management frameworks do not start with a recognition of the benefits of resource development, nor can they address property rights. Consequently, they cannot effectively manage the efficient use of the pore space resource.

The Task Force further recommends that in order to facilitate the orderly development of CO₂ storage projects within state and provincial boundaries, a state or province should embrace two basic principles enumerated in previous Task Force efforts.

A Resource Management Philosophy⁴⁰

Geological storage of CO₂ is one of several viable methodologies for reducing emissions of anthropogenic CO₂ into the atmosphere. Because the production of CO₂ is a consequence of the public's demand for and use of fossil fuels, it is arguably in the public interest to actively participate along with industry in efforts to reduce CO₂ emissions through geologic storage.

Given the regulatory complexities of CO₂ storage including environmental protection, ownership and management of the pore space, maximization of storage capacity and long-term liability, geologically stored CO₂ should be treated under resource management frameworks as opposed to waste disposal frameworks. Regulating the storage of CO₂ under a waste management framework sidesteps the public's role in both the creation of CO₂ and the mitigation of its release into the atmosphere and places the burden solely on industry to rid itself of "waste" from which the public must be "protected." Such an approach lacking citizen buy-in with respect to responsibility for the problem as well as the solution could well doom geological storage to failure and diminish significantly the potential of geologic carbon storage to meaningfully mitigate the impact of CO₂ emissions on the global climate.

A resource management framework, as proposed by the Task Force, allows for the integration of these issues into a unified regulatory framework and proposes a "public and private sector partnership" to address the long-term liability, given that the release of CO₂ into the atmosphere is a societal problem and the mitigation of that release is likewise a societal responsibility.

⁴⁰ *Id.*

These principles are: 1) that it is in the public interest to promote the geologic storage of CO₂ in order to reduce anthropogenic CO₂ emissions; and 2) that the pore space of the state or province should be regulated and managed as a resource under a resource management framework. This should be done by the state or province prior to CO₂ storage occurring within the state or province.

These principles will allow for the exercise of state and provincial authority so as to facilitate and regulate CGS projects within the state or provincial borders.

As to the first principle above, a declaration that CO₂ storage is in the public interest is important to enable the state or province to utilize its powers of eminent domain, or similar authorities, so as to amalgamate the necessary property rights.

With respect to the second principle, given that usable pore space is the major component of CGS storage, and is a finite resource within the state or province, it is in the interest of the state or province to manage this pore space resource so as to maximize the amount of CO₂, or some other future resource, that can be stored.

In this regard, there is one additional factor of which states need to be aware. It will be addressed in the next section after a review of provincial-federal jurisdiction in Canada.

Canada. In Canada, jurisdiction for regulating CGS projects lies primarily with the individual provinces, stemming from their jurisdiction over the direct ownership, management and regulation of most natural resources. This includes collecting royalties, land-use planning and allocation, and exploration, development, conservation, and use of natural resources within provincial boundaries.

The Federal Government holds jurisdiction over international and interprovincial issues, including transboundary pipelines; uranium and nuclear power; offshore areas and federal lands; and works declared to be for the general benefit of Canada (e.g. science and technology).

Responsibilities for environmental protection are shared between the federal and provincial governments. Certain aspects of CGS projects also may fall under other Canadian federal environmental laws such as the *Navigable Waters Protection Act*⁴¹, the *Canadian Environmental Protection Act, 1999*⁴² and the *Canadian Environmental Assessment Act 2012*⁴³.

In summary, regulation and permitting of CGS projects primarily will fall to the province, unless a project is transboundary in scope (e.g. pipeline crossing international or provincial borders) or the components of a CGS project occur in areas of federal jurisdiction (e.g. offshore CO₂ storage).

⁴¹ Navigable Waters Protection Act, R.S. 1985, c. N-22 (Can.), available at <http://www.tc.gc.ca/eng/acts-regulations/1985cN-22.htm>

⁴² Canadian Environmental Protection Act 1999, S.C. 1999, c.33 (Can.), available at <http://laws-lois.justice.gc.ca/eng/acts/C-15.31/>

⁴³ Canadian Environmental Assessment Act 2012, S.C. 2012, c.19, s.52 (Can.), available at <http://www.ceaa.gc.ca/default.asp?lang=En&n=9EC7CAD2-1>

2.4 CLASS II TRANSITION TO CLASS VI

At the time the Task Force 2010 Guidance was published in September 2010, the UIC Class VI Rule had not been promulgated. When it was released and became effective three months later, in December 2010, among the many provisions of the Rule that were not contained in the UIC Class VI Proposed Rule (2008), and therefore not anticipated by the Task Force and others, was a regulatory provision concerning the potential for conversion of a well from UIC Class II to Class VI.

The UIC Class VI Proposed Rule (2008) had stated that “Class VI requirements only would apply to injection wells specifically permitted for the purpose of [geologic sequestration]. Injection of CO₂ for the purposes of [EOR], as long as any production is occurring, will continue to be permitted under the Class II program.”⁴⁴

The UIC Class VI Rule specifically contains language bringing into question the continued regulation under Class II of CO₂-EOR.⁴⁵ Left in its place was language authorizing EPA, in states where Class VI primacy has not been granted to the state, to require a permit for transition from Class II to Class VI when the regional administrator finds that there is an increased risk to USDWs as compared to traditional EOR operations using CO₂.⁴⁶

The subject matter of this IOGCC guidance primarily is focused on the issue of liability in the storage of CO₂ in non-hydrocarbon-bearing formations. However, regarding this development, the Task Force will note the potentially serious economic and practical implications for the U.S., and particularly its CO₂ EOR industry.

It is the opinion of the Task Force that the distinct and likely consequence of such a transition requirement could be the impairment of currently active CO₂-EOR storage, due to widespread concerns in the EOR industry regarding the feasibility of complying with Class VI and regulatory risks associated with the uncertainty of compelled well conversion.

⁴⁴ *Supra* note 14, at 43502.

⁴⁵ As of the date of publication of the report, to the best of the Task Force’s knowledge no Class II to Class VI transition has occurred.

⁴⁶ UIC CLASS RULE, *Supra* note 13, §144.19. Section 144.19 reads as follows:

(a) Owners or operators that are injecting carbon dioxide for the primary purpose of longterm storage into an oil and gas reservoir must apply for and obtain a Class VI geologic sequestration permit when there is an increased risk to USDWs compared to Class II operations. In determining if there is an increased risk to USDWs, the owner or operator must consider the factors specified in §144.19(b).

(b) The Director shall determine when there is an increased risk to USDWs compared to Class II operations and a Class VI permit is required. In order to make this determination the Director must consider the following:

- (1) Increase in reservoir pressure within the injection zone(s);
- (2) Increase in carbon dioxide injection rates;
- (3) Decrease in reservoir production rates;
- (4) Distance between the injection zone(s) and USDWs;
- (5) Suitability of the Class II area of review delineation;
- (6) Quality of abandoned well plugs within the area of review;
- (7) The owner’s or operator’s plan for recovery of carbon dioxide at the cessation of injection;
- (8) The source and properties of injected carbon dioxide; and
- (9) Any additional site-specific factors as determined by the Director.

Likewise, operators of proposed EOR projects share the same concerns dealing with increased project costs. A June 2011 report by DOE outlined the potential economic and environmental benefits of CO₂-EOR.⁴⁷ According to that report:

- o “Next generation” CO₂-EOR can provide 137 billion barrels of additional technically recoverable domestic oil, with about half (67 billion barrels) economically recoverable at an oil price of \$85 per barrel. Technical CO₂ storage capacity offered by CO₂-EOR would equal 45 billion metric tons.
- o This volume of economically recoverable oil is sufficient to support nearly 4 million barrels per day of domestic oil production (1.35 billion barrels per year for 50 years), reducing oil imports by one-third. Production of oil from the residual oil zone would add to these totals.
- o Nearly 20 billion metric tons of CO₂ will need to be purchased by CO₂-EOR operators to recover the 67 billion barrels of economically recoverable oil. Of this, about 2 billion metric tons would be from natural sources and currently operating natural gas processing plants. The remainder of the CO₂ demand (18 billion metric tons) would need to be provided by anthropogenic CO₂ captured from coal-fired power plants and other industrial sources.
- o The market for captured CO₂ emissions from power plants created by economically feasible CO₂-EOR projects (projects that provide at least a 20% rate of return at an oil price of \$85 per barrel and a CO₂ cost of \$40 per metric ton) would be sufficient to permanently store the CO₂ emissions from 93 large one-gigawatt size coal-fired power plants operated for 30 years.

These concerns are notable for states with an active or prospective CO₂-EOR industry. Such states may wish to consider whether to adopt laws and regulations along the lines of the model documents contained in the Task Force 2010 Guidance and secure primacy under Class VI so the state has appropriate involvement in program implementation with respect to potential transition.

In addition, to the extent forced transition from Class II to VI impedes CO₂-EOR development, the requirement also is likely to conflict with state conservation principles that require that states maximize the economic recovery of its hydrocarbon resource.

New legal issues are likely to arise and be complex in a transition from Class II to Class VI. Class II is an established regulatory regime with an established implementation history and legal framework. Class VI is new and untested.

For instance, an EOR owner or operator required to transition operations under Class VI could face a

⁴⁷ U.S. DEPARTMENT OF ENERGY, IMPROVING DOMESTIC ENERGY SECURITY AND LOWERING CO₂ EMISSIONS WITH ‘NEXT GENERATION’ CO₂-ENHANCED OIL RECOVERY (CO₂-EOR) (June 20, 2011), available at http://www.netl.doe.gov/energyanalyses/pubs/storing%20co2%20w%20eor_final.pdf.

host of new and unanticipated potential liabilities and expenses related to pore space ownership for storage. The types of issues that may arise are discussed herein.

2.5 RISK ASSESSMENT

Risk assessment is a process that identifies adverse events and assesses the likelihood and potential consequences of those events. Some form of risk assessment may be needed in order to obtain an appropriate estimate of the risks associated with a CGS project and the potential costs associated with those risks.

Initial risk assessment is best completed during the permitting phase and should be re-evaluated periodically at the regulatory authority's discretion. It is understood that most operators would complete a preliminary risk assessment during the exploratory phase to assist in determining whether or not a site is suitable for CGS. Certain FA instruments may not be suited for a particular type of risk event or phase of a project (e.g. self-insurance may not be appropriate for the long-term storage phase of a project depending on the risk that the self-insuring entity will not be around throughout this phase). In jurisdictions where it is applicable, risk assessments may provide guidance for closure and transfer of liability.

There are a number of general contextual documents that provide information and background on appropriate risk assessment methodologies and realistic considerations that could inform a CGS project risk assessment.⁴⁸ There are also examples of risk assessments that have been modeled for specific projects and/or basins that also could inform a project's risk assessment.⁴⁹

2.6 FINANCIAL ASSURANCE

In the U.S. and Canada, most state and provincial governments have a long familiarity with FA. FA is required in multiple contexts to ensure that entities doing business within a state or province have financial resources available to carry out their statutory and regulatory obligations.⁵⁰

Certainly any state or provincial regulator of CGS will have extensive experience with at least some of the mechanisms that are widely available for FA. In this section of the report, the Task Force will

⁴⁸ See, e.g., CANADIAN STANDARDS ASSOCIATION, CSA Z741: GEOLOGIC STORAGE OF CARBON DIOXIDE (2012); DET NORSKE VERITAS, CO₂ QUALSTORE GUIDELINE FOR SELECTION AND QUANTIFICATION OF SITES AND PROJECTS FOR GEOLOGICAL STORAGE OF CO₂, Report Number 2009-1425, Rev 5 (2010); EUROPEAN COMMISSION, IMPLEMENTATION OF DIRECTIVE 2009/31/EC ON THE GEOLOGICAL STORAGE OF CARBON DIOXIDE, GUIDANCE DOCUMENT 1: CO₂ STORAGE LIFE CYCLE RISK MANAGEMENT FRAMEWORK, European Communities, (2011); QUINTESSA LIMITED, A GENERIC FEP DATABASE FOR THE ASSESSMENT OF LONG-TERM PERFORMANCE AND SAFETY OF THE GEOLOGICAL STORAGE OF CO₂ (June 2004); UNITED STATES DEPARTMENT OF ENERGY, BEST PRACTICES FOR: RISK ANALYSIS AND SIMULATION FOR GEOLOGIC STORAGE OF CO₂, National Energy Technology Laboratory, Publication DOE/NETL-2011/1459 (March 2011) available at

http://www.netl.doe.gov/technologies/carbon_seq/refshelf/BPM_RiskAnalysisSimulation.pdf.

⁴⁹ See, e.g., Chiara Trabucchi, Michael Donlan, Michael Huguenin, Matthew Konopka & Sarah Bolthrunis, Industrial Economics, Inc., *Valuation of Potential Risks Arising from a Model, Commercial-Scale CCS Project Site*, Industrial Economics (June 2012) [hereinafter INDUSTRIAL ECONOMICS VALUATION] available at <http://cdn.globalccsinstitute.com/sites/default/files/publications/40831/iec2012valuationofpotentialrisks.pdf>.

⁵⁰ See James Boyd, *Financial Responsibility for Environmental Obligations: Are Bonding and Assurance Rules Fulfilling Their Promise?*, RESOURCES FOR THE FUTURE (Aug. 2001), available at <http://ageconsearch.umn.edu/bitstream/10809/1/dp010042.pdf>.

attempt to discuss some of the various mechanisms that potentially will be available to ensure that a CGS operator meets its legal and regulatory obligations to the state or province.

We will end this section with the introduction of a CGS Project Framework and Risk Analysis Table that will suggest the mechanisms that the Task Force considers likely to be most appropriate for ensuring the performance of CGS operator activities and obligations in the five different phases of a CGS operation.

The Class VI regulations contain detailed requirements for FA, although they use the term “financial responsibility” instead.⁵¹ Owners or operators must demonstrate and maintain financial responsibility that meets specified requirements. The regulations list the types of qualifying instruments that may be used, and those instruments must cover the cost of: (1) corrective action; (2) injection well plugging; (3) post injection site care and site closure; and (4) emergency and remedial response.

To ensure that the risk management instruments will protect the public, the regulations set forth conditions regarding cancellation, renewal, and continuation provisions. The requirement to maintain adequate financial responsibility and resources is directly enforceable regardless of whether it is incorporated as a condition of the Class VI permit. Other requirements apply.

In addition to prescribing financial responsibility regulations, EPA also published interpretive guidance for the financial responsibility regulations for Class VI injection wells.⁵² A state with primacy under Class VI certainly would need to be familiar with the content of EPA’s guidance, although guidance is not mandatory.⁵³ A state’s interests in regulating a CGS operation are far broader than the EPA’s under Class VI, which are limited solely to the protection of USDWs.

⁵¹ UIC CLASS VI RULE, *supra* note 13, at § 146.85. Section 146.85 (1-3) reads as follows:

§ 146.85 Financial responsibility.

(a) The owner or operator must demonstrate and maintain financial responsibility as determined by the Director that meets the following conditions:

(1) The financial responsibility instrument(s) used must be from the following list of qualifying instruments:

- (i) Trust Funds.
- (ii) Surety Bonds.
- (iii) Letter of Credit.
- (iv) Insurance.
- (v) Self Insurance (*i.e.*, Financial Test and Corporate Guarantee).
- (vi) Escrow Account.
- (vii) Any other instrument(s) satisfactory to the Director.

(2) The qualifying instrument(s) must be sufficient to cover the cost of:

- (i) Corrective action (that meets the requirements of §146.84);
- (ii) Injection well plugging (that meets the requirements of §146.92);
- (iii) Post injection site care and site closure (that meets the requirements of §146.93); and
- (iv) Emergency and remedial response (that meets the requirements of §146.94).

(3) The financial responsibility instrument(s) must be sufficient to address endangerment of underground sources of drinking water.

⁵² UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, GEOLOGIC SEQUESTRATION OF CARBON DIOXIDE: UNDERGROUND INJECTION CONTROL (UIC) CLASS VI FINANCIAL RESPONSIBILITY GUIDANCE (2011), available at <http://water.epa.gov/type/groundwater/uic/class6/upload/uicfinancialresponsibilityguidancefinal072011.pdf>.

⁵³ For a state to have obtained primacy, it would have to have established to EPA’s satisfaction that its regulatory program for CGS is no less stringent than the UIC Class VI Rule. *See supra* notes 21 and 22. Therefore, the state’s regulatory provisions, in this case for FA, would control, not the UIC Class VI Rule per se or the EPA Financial Responsibility Guidance thereunder.

The extent of that broader liability is illustrated in the CGS Project Framework and Risk Analysis (Table 2-1) and in the discussion that follows in Part 3 where the Task Force addresses liability and the potential FA in each of the five phases of the CGS project lifecycle.

In its Task Force 2010 Guidance, the Task Force only specified three types of FA in its Model Rules and Regulations: “A CO₂ Storage Project (CSP) performance bond,” “well performance bonds,” and a state/provincial-controlled “trust fund” for the post-closure (long term storage) phase.

While the Task Force in its 2010 Guidance used the term “performance bonds,” it is clear, consistent with state practice⁵⁴, that the Task Force was using the term in its broadest context that included a multiple of FA instruments, including surety bonds, cash or certificates of deposit, escrow, letters of credit, insurance, or other mechanisms approved by the state regulatory authority. Therefore, the Task Force considers it appropriate in this report, focused as it is on “liability,” to address with more specificity the range of potential FA mechanisms that a state or province might want to consider as potentially acceptable.

The most common mechanisms for FA are: Cash; Private Trust Fund; Letter of Credit; Surety Bond; Insurance; Self-insurance; and Escrow Account. The Task Force suggests that it also would be advisable to give the state or provincial regulatory authority the discretion to accept any other instrument of FA that the regulatory authority deems to be satisfactory for the purposes proposed. This is consistent with the breadth of instruments contemplated under the EPA regulations.

If a state chooses not to obtain Class VI primacy from EPA, which results in EPA implementing the Class VI program in that state, a state still would need to regulate project-specific activities that lay outside of EPA authority.

The CGS Project Framework and Risk Analysis (Table 2-1) identifies specific activities in each phase, as well as the associated risks and the Task Force’s recommendation as to the best-suited FA for the mitigation of the risks for each activity. The identified FA has been used for decades by states in the regulation of oil and gas related activities and offer a proven history of risk mitigation and protecting the taxpayer from the costs associated with project risks. A summary of these common FA instruments follows.⁵⁵

Cash. Some states⁵⁶ allow an operator simply to post a certain amount of cash with the state regulatory agency. The agency utilizes the cash to ensure that the operator complies with the state laws and regulations. Should the operator be unable or unwilling to fulfill its obligations, the state can use the cash to fulfill the obligations.

⁵⁴ It is relatively common in state practice to refer to “performance bonds” but in application allow a variety of common FA instruments, including surety bonds, cash, certificates of deposit, escrow, letters of credit, insurance, or other alternate mechanism approved by the state regulator.

⁵⁵ See UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, *supra* note 55, at 9-18 for a discussion of the various instruments of FA; See also Lindene E. Patton & James L. Joyce, *Hazardous Waste Financial Assurance: A Comparison of Third-Party Risk Management Mechanisms—Suggestions for Reform*, BNA’s ENVIRONMENTAL DUE DILIGENCE (2008), available at <http://deq.state.wy.us/out/downloads/BNA%20ER%20231%20Pattonfinancialassure.pdf>; Richard A. Chancellor, Daniel M. Gillen & Paul R. Hildenbrand, *Commonwealth of Virginia-Uranium Study: Assessment of Financial Assurance Mechanisms* (Oct. 2012), available at http://www.uwg.vi.virginia.gov/pdf/Exhibit_I_Financial_Assurance_Final.pdf.

⁵⁶ Although the Task Force is using the term “state” or “states” in this subsection, the comments apply equally to Canadian provinces.

Cash deposited with the state is perhaps the best protection for the state because the state agency does not have to take action other than simply utilize the cash. Another advantage of cash deposited with the state is that there is no third-party involvement; the operator pays cash to the state rather than entering into a contract with a surety company or insurance company paying regular premiums.

The principal disadvantage of cash deposited with the state is that the operator reduces its assets that could be utilized in investing in and operating the storage facility.

Private Trust Fund. A trust fund is a mechanism under which a designated person or entity, or “trustee,” holds funds to conserve and spend on behalf of a third party, known as the beneficiary.

The trust may be a private trust fund established by the operator for use to ensure compliance with state laws and regulations.

The funds are accessible to the regulator by making the regulatory agency the beneficiary of the trust. The trust funds, or “corpus,” could be utilized for a specific activity. The trust fund has the advantage that monies have been set aside by the operator. A private trust fund can be an innovative approach to ensure that a site is cleaned up and restored properly. A private trust fund also might be utilized to protect the state when there is a concern that an operator has the potential for financial difficulty.

In utilizing a private trust fund as FA, the state may place restrictions or conditions on the trust fund either by agreement, statute, or regulation to ensure protection of the public.

The disadvantage of a private trust fund is that there is third party involvement and the event triggering transfer of the corpus to the beneficiary must be one specified within the trust document. Thus, it may take time for the state to secure funds beyond the time when they are needed.

Another disadvantage of trust funds is that if the money is permanently set aside it may be seen as being taken out of productive use in the economy, regardless of whether claims are made commensurate with the balance of the fund. This issue is less likely to be a concern in cases where the arising of expenses to be covered by the fund is somewhat predictable, such as monitoring and maintenance expense.

Trust funds under the UIC Class VI Rule allow for the option of “pay-in periods.”⁵⁷ The use and length of pay-in periods should be subject to the regulatory agency’s approval. A Private Trust Fund with pay-in periods allows the operator to make scheduled payments into the trust over a specific period of time to ensure sufficient funds will be available to carry out a defined activity for which the trust is designated. In order for pay-in periods to work to the advantage of the regulatory agency, a combined financial instrument approach should be considered to cover the designated activity (e.g. post-injection monitoring) FA during the pay-in period.

⁵⁷ Pay-in periods are discussed in the EPA Underground Injection Control (UIC) Program Class VI Financial Responsibility Guidance found in the Trust Fund discussion and in the Escrow Account discussion. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, *supra* note 52, at 26 and 34 (respectively). See also UIC CLASS VI RULE PREAMBLE, *supra* note 13, at 77268-77271 for a discussion of pay-in periods; UIC CLASS VI RULE, *supra* note 13, 146.85 (f), which requires the Director’s approval for the use and length of pay-in periods for trust funds or escrow accounts.

It is also of note that the Province of Alberta in its regulation of oil and natural gas in the province has allowed “transition periods” with both cash and letters of credit FA mechanisms. This allows the operator to make deposits into either or both over a number of years.

Throughout the pay-in period, the trust fund may not have sufficient FA to cover the designated activity until the pay-in period is complete. By combining financial instruments (i.e. insurance policy during the trust fund pay-in period), this assures that the regulator is not exposed to risk during the pay-in period, should an unforeseen event occur.

Letters of Credit. Letters of Credit are contracts or agreements by a bank to pay a specific sum on demand. In the context of regulation of CGS storage projects, the letter of credit would be issued by a bank for the benefit of the operator with the proceeds of the letter of credit being paid upon demand to the regulatory agency to ensure compliance with state laws and regulations.

The advantage to the state is that the state regulatory agency has access to the proceeds of the letter of credit to ensure compliance with state laws and regulations. The state regulatory agency collects the proceeds of the letter of credit when the conditions of the payment obligation have been met.

The disadvantage of the letter of credit is that a bank rarely issues a letter of credit for a long period of time. Commonly, when a letter of credit is issued to a state regulatory agency, the operator will have to arrange for the bank to renew the letter of credit, typically done annually and repeated throughout the life of the project.

The Task Force is aware that letters of credit (or other instruments providing for FA) may include certain language that places burdens on the state's regulatory agency; for example, letters of credit may require the agency to provide detailed proof and evidence concerning violations of statutes and regulations in order for the agency to collect the proceeds of the letter of credit.

The compilation and presentation of evidence and the potential for disputes and litigation over whether the agency has proved its case allowing the agency to collect the proceeds can be time-consuming and burdensome. The Task Force recommends that in drafting letters of credit, the state regulatory agency draft the letter of credit to allow the agency to collect the proceeds of the letter of credit simply upon demand by the agency or with few conditions placed on the agency.

Additionally, the bank upon which the letter of credit is issued should be adjudged by the regulator to be able to meet the obligations contained in the letter of credit.

Of note, the province of Alberta only accepts cash and letters of credit for FA in upstream oil and natural gas regulatory operations. Alberta believes that it represents the best of the FA mechanisms as the entirety of the FA provided is immediately available when needed, can be utilized at the regulatory agency's discretion within the boundaries of established regulation, and creates minimal administrative burden.

Alberta also has a separate industry-funded orphan well fund to address any costs in excess of the amounts covered by these other FA mechanisms.

Surety Bond. A surety bond is a promise to pay a sum of money upon occurrence of a particular event. In the context of CGS, the operator contracts with a surety company to execute the bond in favor of the state. The surety company pays the proceeds of the surety bond to the regulatory authority upon demand by the regulatory authority. The regulatory authority makes demand against the surety company when the operator fails to comply with state laws and regulations.

The advantage of surety bonds to the state is that the state regulatory agency has easy access to the proceeds of the surety bonds. The agency merely makes demand on the surety company, which pays the proceeds of the surety bond to the agency.

Another advantage is that surety companies are regulated by the state insurance commissioners helping to ensure that the surety company honors its obligations under the surety bond. A disadvantage of surety bonds is that the surety company may be reluctant to execute a surety bond where the length of time for the storage project potentially is unlimited.

As addressed above in the discussion of letters of credit, the Task Force recommends that the state regulatory agency draft language in the text of the surety bond to allow the agency to collect the proceeds of the surety bond simply upon demand with appropriate conditions (precedent) placed on the agency in collecting the proceeds.

Insurance. Insurance is an agreement by an insurance company to pay certain costs to a policyholder if certain defined events take place. A regulator may require as a condition of accepting insurance as FA that the policyholder relinquish any payments directly to the state if the policy is triggered. In the context of CGS, the operator would maintain insurance to cover fortuities that may occur during the storage, closure, or post-closure phases of a project. The advantages of insurance include that it can be a cost-effective means of managing the risk of potentially large remediation or other costs.

Also, the insurance market acts as an independent “regulator” of sorts, in that storage sites with favorable characteristics that are likely to be low-risk will see lower premiums than less favorable storage sites, some of which may not be insurable at all.

From the state’s perspective, it may be considered a disadvantage that insurance is not a “guarantee.” A policy may be canceled while the project is still active, and it may contain coverage limits that do not satisfy in full the FA requirements (though it may do so when used in combination with other instruments).⁵⁸

A caution is that as regulators seek to make insurance, or any FA product, as close to a guarantee as possible, costs likely will increase and availability may decrease.

For example, if regulatory requirements limit the cancellation of insurance policies, require that the insurance policy be paid directly to the regulator in conflict with policy terms that require payment to the policyholder, or require that any policy provision that is inconsistent with federal regulations be resolved automatically in favor of the regulations, insurers may not be willing to offer policies.⁵⁹

⁵⁸ The province of Alberta in its regulation of the oil and natural gas sector has concluded that the amount paid out by insurance companies may be different than what is requested and that the only means of addressing the discrepancy would be through litigation. Additionally, it is the province’s conclusion that insurance companies would not be willing to cover the costs associated with “unapproved activities” such as contamination. This is, of course, a huge issue as contamination is not “approved” but it is definitely a significant risk in oil and natural gas development and would likewise be a significant risk event (for which the state would want FA) in CGS.

⁵⁹ See generally CCA ALLIANCE, COMMENTS TO EPA CLASS VI UIC WELL FINANCIAL RESPONSIBILITY GUIDANCE (Feb. 8, 2011), available at http://www.ccsalliance.net/files/Uploads/Documents/ccsalliance/Comments_on_Financial_Responsibility_Guidance.pdf

The Task Force has done extensive research on the viability of insurance as an FA instrument for CGS projects. It is important to note that insurance for CGS likely is to evolve over time. Today, policies are available for the storage and closure phases, but not for the post-closure (long-term) phase. As the CGS industry matures, so will the overall understanding of risks that accompany projects. Terms and cost of insurance may change.

The market today shows that one- to three-year insurance policies with renewals likely will be available for CGS projects during the storage phase. This duration of insurance coverage is similar to what is available to the natural gas storage industry, which has a relatively low-risk profile with a proven case history.

Self-Insurance (i.e. financial test and corporate guarantee). An operator may be “self-insured” by meeting certain state and federal criteria for “self-insurance.” The operator does not enter into an agreement with an insurance company but agrees to pay monies depending on certain circumstances. In order for an operator to be self-insured, the operator must comply with strict financial tests to be allowed to enter into the corporate guarantee. The EPA Class VI regulations establish specific criteria for the owner or operator to qualify for self-insurance as a FA mechanism.⁶⁰

The self-insurance requirements include a tangible net worth and net working capital demonstration and a bond rating test or by meeting five financial ratio thresholds. If an owner or operator does not meet these financial test obligations then the UIC Class VI Rule allows for a corporate parent to make this demonstration as a corporate guarantee to satisfy the FA requirements for the owner or operator.⁶¹

There is an important consideration with self-insurance: the state’s regulatory authority has no direct access to the funds and it is not guaranteed.⁶²

Escrow account. An escrow account is an account of monies set aside for a specific purpose. In the context of CGS, an operator establishes an escrow account and the monies in the escrow account are payable to the regulator to ensure compliance with state laws and regulations should the conditions

⁶⁰ See generally UIC CLASS VI RULE, *supra* note 13, at § 146.85 (a)(6)(v). This provision states: “An owner or operator or its guarantor may use self insurance to demonstrate financial responsibility for geologic sequestration projects. In order to satisfy this requirement the owner or operator must meet a Tangible Net Worth of an amount approved by the Director, have a Net working capital and tangible net worth each at least six times the sum of the current well plugging, post injection site care and site closure cost, have assets located in the United States amounting to at least 90 percent of total assets or at least six times the sum of the current well plugging, post injection site care and site closure cost, and must submit a report of its bond rating and financial information annually. In addition the owner or operator must either: Have a bond rating test of AAA, AA, A, or BBB as issued by Standard & Poor’s or Aaa, Aa, A, or Baa as issued by Moody’s; or meet all of the following five financial ratio thresholds: A ratio of total liabilities to net worth less than 2.0; a ratio of current assets to current liabilities greater than 1.5; a ratio of the sum of net income plus depreciation, depletion, and amortization to total liabilities greater than 0.1; A ratio of current assets minus current liabilities to total assets greater than –0.1; and a net profit (revenues minus expenses) greater than 0.”

⁶¹ See *Id.* at § 146.85 (a) (6)(vi). An owner or operator who is not able to meet corporate financial test criteria may arrange a corporate guarantee by demonstrating that its corporate parent meets the financial test requirements on its behalf. The parent’s demonstration that it meets the financial test requirement is insufficient if it also has not also guaranteed to fulfill the obligations for the owner or operator.

⁶² While good for the short term, it is problematic from a long-term perspective. If a company becomes no longer able to be self-insured, it also no longer may have the financial capability to post replacement FA. Also, in the long term, it is likely that no company still will be operating in the sector as the sector will cease to exist and the backstop for the activity will have evaporated. This concern would be most relevant in the Post Closure (Long Term) phase.

triggering payment arise. The escrow account is used as depository for cash. See the discussion of the advantages and disadvantages of cash above.

Statutory Trust Fund. A trust fund could be established by statute that is under the authority of the state regulatory agency for use by the agency to ensure compliance with state laws and regulations. The principal advantage is that the state regulatory agency would have direct access to the fund.

From the state's perspective, such a trust fund could provide the most direct access to FA funds provided the fund is adequately structured to address the identified risks. The challenge will be in correctly estimating the size of the fund during the initial permitting of the project, however, the fund could be structured to allow for modifications to the funding levels as the project matured.

Disadvantages of a trust fund are that it may be considered by the operator to be more expensive than other options, and, if over-estimated, economically may not be efficient because increasingly large amounts are collected into the fund and kept there after risks begin to decrease, especially during the Closure Phase. Additionally, it takes time for funds to accumulate, so that the fund may not be capitalized sufficiently if an incident occurs early in the life of a project.⁶³

States and provinces also need to consider that site-by-site trust funds do not capture the economic efficiency of a large, pooled trust fund that covers risk at a number of sites (i.e. it is highly unlikely that all sites will have problems and therefore you can apply a discount rate to the amount contributed).

In Section 2.10 the Task Force will discuss a Post-Closure Phase statutory trust fund. Unlike the statutory trust fund just discussed, it is not a mechanism for FA, but rather a funding mechanism for the Post-Closure Phase activities.

2.7 CARBON CREDIT LIABILITY

United States. In some instances, the parties to a Carbon Capture and Geologic Storage (CCGS) transaction may endeavor to monetize the resulting CO₂ emission reductions through the generation and sale of what are known colloquially as "carbon credits."

This concept has no meaning under the United States CAA, but is presented here as it touches upon similar concepts.

For a CGS project, carbon credit liability theoretically could occur in several scenarios:

- (1) Generation of Certified Emission Reductions under the Clean Development Mechanism (CDM) of the Kyoto Protocol. While CCS is an eligible technology type under CDM, U.S.- and Canada-based projects are not eligible since neither country has agreed to abide by the Kyoto Protocol.

⁶³ Trust funds used in isolation also have been faulted for not providing specific motivation to operators to conduct their business in an appropriate way as, depending upon how the fund is set up, all operators may be charged the same rate (for example, per ton of CO₂ injected) regardless of their specific operations and practices.

- (2) Generation of offset credits under California's cap-and-trade program. This scenario is unlikely for several reasons. California law does not currently recognize CCS as a compliance technology. Furthermore, offset credits only could be generated by CO₂ sources that are not subject to GHG regulation, and such sources are unlikely to voluntarily deploy CCS technology for cost, liability and related reasons.
- (3) Generation of voluntary emission reductions (VERs) by non-California CO₂ sources that are not subject to any form of GHG emission limitation. These VERs may be transacted voluntarily on any of several climate change registries.

CGS-related carbon credit liabilities would arise under the relevant regulatory program if such program applied. For example, if the day arrives when CGS projects may generate offset credits under California's cap-and-trade program, the penalties and enforcement mechanisms of that program presumably would apply in the event of an atmospheric release of CO₂ from the storage site.

Conversely, carbon credit liabilities for VERs are more apt to arise under the commercial contracts through which the VERs were generated and thereafter transacted.

Canada. In Canada there is no federal mechanism for transfer of climate liability other than what is described in 2.1 for the United States. The province of Alberta does have a mechanism as described in Example 1 in Appendix 1.

2.8 LIMITING THE LIABILITY OF A STORAGE OPERATOR

The Task Force suggests that states and provinces consider whether to statutorily limit liability, particularly if the state or province has concluded that CGS is an important economic and environmental endeavor.⁶⁴

Governments have limited liability for various industries, such as the nuclear power industry,⁶⁵ and in many other situations, including the imposition of workers' compensation laws. In doing so, one or more of several justifications typically applies: the activity is important to the public interest and should be encouraged; the activity would not occur but for a governmental requirement; or the activity is a new one whose risks, while manageable, are not yet sufficiently characterized for the commercial risk management market to have fully emerged.

Any decision to statutorily limit liability must be done with great care and any such decision must be balanced against the perception, whether warranted or not, that this could undermine public confidence in CGS or have the potential to create a "moral hazard" — i.e., a situation where the operator's incentive is to engage in higher risk behavior.

⁶⁴ A discussion of "legislative limits to liability" can be found at Adam Gardner Rankin, *Student Article: Geologic Sequestration of CO₂: How EPA's Proposal Falls Short*, 49 NAT. RESOURCES J. 883, 934-938 (2009).

⁶⁵ Price-Anderson Act, 42 U.S.C. § 2210

2.9 CGS PROJECT FRAMEWORK & RISK ANALYSIS

In order to better understand the range of risks for which FA likely is to be required of a CGS operator by a state or province, the Task Force produced a CGS Project Framework and Risk Analysis.

By projected activity in each of the five phases of a CGS project, risks, damages, and best suited FA are identified. This analysis is presented in Table 2-1.

Table 2-1: CGS PROJECT FRAMEWORK & RISK ANALYSIS

ACTIVITY	ENVIRONMENTAL RISKS ASSOCIATED WITH THIS ACTIVITY	BEST SUITED FA TO MITIGATE ENVIRONMENTAL RISKS	REGULATORY FA REQUIRED BY ACTIVITY	RISKS AND OTHER CONSIDERATION (MAY BE COVERED BY FA AT STATE DISCRETION)
PHASE I: EXPLORATORY				
Amalgamation of property rights for storage project (CO ₂ plume area)	None	Not applicable	None Required	<ul style="list-style-type: none"> - Property rights may be infringed, possibly leading operator to incur legal costs - Project not permitted because property rights not acquired, resulting in negative economic impact to operator
Acquire permits to drill exploratory wells and conduct other geologic investigations	None	Not applicable	State issued Surety bond, Letter of Credit, Escrow Account (cash or CD)	None
Drilling exploratory wells and conducting geophysical (seismic) activities and other geologic investigations	Exploratory activities adversely impact public health, USDWs, surface waters or flora and fauna	State FA issued at time of well drilling permit issuance, remains in effect until well plugged	Not applicable	<ul style="list-style-type: none"> - Adverse economic impact to operator if exploratory activities determine the site is unusable - Adverse impact to adjacent or overlying mineral resources during exploratory activities

White: Activities covered by state authorities.

Yellow: Activities covered by UIC Class VI regs, separate state authorities also be involved for various aspects of permitted activity.

Green: Activities covered by UIC Class VI regs, state authorities involved only if state has primacy.

Table 2-1: CGS PROJECT FRAMEWORK & RISK ANALYSIS (continued)

ACTIVITY	ENVIRONMENTAL RISKS ASSOCIATED WITH THIS ACTIVITY	BEST SUITED FA TO MITIGATE ENVIRONMENTAL RISKS	REGULATORY FA REQUIRED BY ACTIVITY	RISKS AND OTHER CONSIDERATION (MAY BE COVERED BY FA AT STATE DISCRETION)
PHASE II: PERMITTING (PRE-STORAGE)				
Issuance of storage project permit (CO2 plume area)	Not applicable	Not applicable	Federal Trust Fund (private), Insurance, Escrow Account (cash or CD) staged or in combination as per project development	Adverse economic impact to operator if no permit issued
Issuance of surface facilities permit (if not included in storage project permit)	Not applicable	Not applicable	State Trust Fund (private), Insurance, Escrow Account (cash or CD) staged or in combination as per project development	Adverse economic impact to operator if no permit issued
Corrective action to plug or repair pre-existing wells	Wells not properly plugged or repaired resulting in adverse impact to USDWs	No FA necessary to plug or repair old wells as repair work or well plugging is required to be completed satisfactorily	No FA necessary to plug or repair old wells as repair work or well plugging is required to be completed satisfactorily for overall site approval	Adverse impact to adjacent or overlying mineral resources during well plugging or repair activities
Acquire permits to drill injection and monitoring wells	Not applicable	Not applicable	Surety bond, Letter of Credit, Escrow Account (cash or CD)	Adverse economic impact to operator if no permit issued
Construct and complete injection wells (includes logging, coring and injectivity tests)	Wells not properly constructed and/or completed resulting in adverse impact on USDWs	State FA issued at time of well drilling permit issuance, remains in effect until well plugged	Not applicable	None
Construct and complete monitoring well(s)	Wells not properly constructed and/or completed resulting in adverse impact on USDWs	State FA issued at time of well drilling permit issuance, remains in effect until well plugged	Not applicable	None
Acquire permit to inject (UIC Class VI or state primacy equivalent)	Not applicable	Not applicable	State FA issued at time of well drilling permit issuance may also meet UIC requirements. If not an additional Surety Bond, Letter of Credit, Escrow Account (cash or CD) FA will be issued with the injection permit	Adverse economic impact to operator if no permit issued

White: Activities covered by state authorities.

Yellow: Activities covered by UIC Class VI regs, separate state authorities also be involved for various aspects of permitted activity.

Green: Activities covered by UIC Class VI regs, state authorities involved only if state has primacy.

Table 2-1: CGS PROJECT FRAMEWORK & RISK ANALYSIS (continued)

ACTIVITY	ENVIRONMENTAL RISKS ASSOCIATED WITH THIS ACTIVITY	BEST SUITED FA TO MITIGATE ENVIRONMENTAL RISKS	REGULATORY FA REQUIRED BY ACTIVITY	RISKS AND OTHER CONSIDERATION (MAY BE COVERED BY FA AT STATE DISCRETION)
PHASE III: STORAGE (OPERATIONAL)				
Injection well operation	<ul style="list-style-type: none"> - Injecting over the authorized maximum injection pressure (MIP) compromising well integrity. - Failure to conduct required Mechanical Integrity Test (MIT) resulting in failure to identify well integrity problems. - Failure to maintain well corrosion inhibitor mechanisms, resulting in loss of well integrity. - CO₂ characteristics negatively impacts wellbore integrity. - Loss of well integrity in all above scenarios may result in leakage of CO₂ or formation. - Fluids adversely impacting USDWs or if to the surface endangering public health, flora and fauna and surface waters. 	State FA issued at time of well drilling permit issuance, remains in effect until well plugged	Not applicable	<ul style="list-style-type: none"> - Injecting over the authorized maximum injection pressure (MIP) compromising well integrity and adversely impacting overlying mineral resources - Failure to conduct required MIT resulting in failure to identify well integrity problems and adversely impacting overlying mineral resources - Failure to maintain well corrosion inhibitor mechanisms, resulting in loss of well integrity and adversely impacting overlying mineral resources
Injection into reservoir	<ul style="list-style-type: none"> - Storage reservoir does not perform as planned: <ul style="list-style-type: none"> • Upward migration of CO₂ plume beyond permit area, through old wellbore, fault, caprock failure, other geologic anomalies, and adversely impacting overlying USDWs. • Reservoir capacity not as modeled and CO₂ plume migrates laterally beyond permit area adversely impacting adjacent USDWs • Pressure front or fluids migrate outside of AOR, adversely impacting overlying USDWs • Formation fluids or CO₂ leak to surface adversely impacting public health, flora and fauna and surface waters 	FA issued at time of storage project permit issuance remains in effect through post-closure period	Not applicable	<ul style="list-style-type: none"> - Induced seismicity caused by injection of CO₂ potentially impacting public safety and causing damage to surface infrastructure. - Storage reservoir does not perform as planned: <ul style="list-style-type: none"> - Upward migration of CO₂ plume beyond permit area, through old wellbore, fault, caprock failure, other geologic anomalies, and adversely impacting overlying mineral resources - Reservoir capacity not as modeled and CO₂ plume migrates laterally beyond permit area adversely impacting adjacent mineral resources and CO₂ storage sites - Reservoir characteristics adversely impacted by injected CO₂ adversely impacting use of storage reservoir causing negative economic impact to operator - Pressure front or fluids migrate outside of AOR adversely impacting adjacent mineral resources and CO₂ storage sites

White: Activities covered by state authorities.

Yellow: Activities covered by UIC Class VI regs, separate state authorities also be involved for various aspects of permitted activity.

Green: Activities covered by UIC Class VI regs, state authorities involved only if state has primacy.

Table 2-1: CGS PROJECT FRAMEWORK & RISK ANALYSIS (continued)

ACTIVITY	ENVIRONMENTAL RISKS ASSOCIATED WITH THIS ACTIVITY	BEST SUITED FA TO MITIGATE ENVIRONMENTAL RISKS	REGULATORY FA REQUIRED BY ACTIVITY	RISKS AND OTHER CONSIDERATION (MAY BE COVERED BY FA AT STATE DISCRETION)
PHASE III: STORAGE (continued)				
Monitoring subsurface CO ₂ plume movement	Not applicable	Not applicable	FA issued at time of facility permit issuance remains in effect through post closure period	
Monitoring formation fluids and pressure front movement in subsurface	Not applicable	Not applicable	FA issued at time of storage project permit issuance remains in effect through post-closure period	
Monitoring surface for leak detection [legacy wells (plugged and abandoned), faults]	Not applicable	Not applicable	FA issued at time of storage project permit issuance remains in effect through post-closure period	
Monitoring and analysis of the CO ₂ stream's chemical and physical characteristics	Not applicable	Not applicable	FA issued at time of storage project permit issuance remains in effect through post-closure period	
Conduct and monitor surface facility operations including pipelines	<ul style="list-style-type: none"> - Facility equipment leaks - Facility equipment fails 	FA issued at time of surface facilities permit issuance remains in effect through post-closure period	Not applicable	<ul style="list-style-type: none"> - Negative economic damage due to project shutdown - Adverse impact to human health
PHASE IV: CLOSURE				
Monitoring subsurface CO ₂ plume movement	Not applicable	Not applicable	FA issued at time of facility permit issuance remains in effect through post closure period	
Monitoring formation fluids and pressure front movement in subsurface	Not applicable	Not applicable	FA issued at time of storage project permit issuance remains in effect through post-closure period	

White: Activities covered by state authorities.

Yellow: Activities covered by UIC Class VI regs, separate state authorities also be involved for various aspects of permitted activity.

Green: Activities covered by UIC Class VI regs, state authorities involved only if state has primacy.

Table 2-1: CGS PROJECT FRAMEWORK & RISK ANALYSIS (continued)

ACTIVITY	ENVIRONMENTAL RISKS ASSOCIATED WITH THIS ACTIVITY	BEST SUITED FA TO MITIGATE ENVIRONMENTAL RISKS	REGULATORY FA REQUIRED BY ACTIVITY	RISKS AND OTHER CONSIDERATION (MAY BE COVERED BY FA AT STATE DISCRETION)
PHASE IV: CLOSURE (continued)				
Closure period monitoring	Not applicable	Not applicable	FA issued at time of storage project permit issuance remains in effect through post-closure period	None
Secure closure/ completion certificate		Not applicable	FA issued at time of storage project permit issuance remains in effect through post-closure period. FA released when closure certificate approved	- Negative economic impact to operator if closure certificate not issued, resulting in extended operator liability
PHASE V: POST-CLOSURE (Operator no longer the responsible party)				
Monitoring	- Leakage incident or unanticipated plume movement is not detected resulting in adverse impacts to adjacent or overlying USDW's, flora and fauna, human health and surface waters	Trust Fund funded by: 1. Per ton injection fee 2. Lump sums based on layered approaches 3. Hybrid of 1. and 2.		- Leakage incident or unanticipated plume movement is not detected resulting in adverse impacts to adjacent or overlying mineral resources or CO ₂ storage sites
Corrective action (only if incident detected)	- Corrective action cannot resolve issue resulting in adverse impacts to adjacent or overlying USDW's, flora and fauna, human health and surface waters	Trust Fund funded by: 1. Per ton injection fee 2. Lump sums based on layered approaches 3. Hybrid of 1. and 2.		- Corrective action cannot resolve issue resulting in adverse impacts to adjacent or overlying mineral resources or CO ₂ storage sites
Plugging and reclaiming of any remaining monitoring wells and surface infrastructure	N/A	Trust Fund funded by: 1. Per ton injection fee 2. Lump sums based on layered approaches 3. Hybrid of 1. and 2.		

White: Activities covered by state authorities.

Yellow: Activities covered by UIC Class VI regs, separate state authorities also be involved for various aspects of permitted activity.

Green: Activities covered by UIC Class VI regs, state authorities involved only if state has primacy.

2.10 Long-Term Liability

In the Task Force 2007 Guidance, the Task Force proposed “the creation of an industry-funded and state-administered trust fund as the most effective and responsive ‘care-taker’ program to provide the necessary oversight during the Post-Closure Period. The trust fund would be funded by an injection fee assessed to the CSP Operator and calculated on a per ton basis, at the point of custody transfer of the CO₂ from the generator to the CSP Operator.”⁶⁶

The Task Force in its 2010 Guidance reiterated this proposal.⁶⁷ The trust fund’s purpose would be to fund necessary Post-Closure activities. This would replace the UIC Class VI Program FA that would be released when the closure certificate is issued in the Closure Period.

The Task Force in this report again believes that an industry-funded and state/province administered trust fund is the most appropriate solution available to states and provinces for the Post-Closure phase (Phase V). The proposed trust fund is identical to the trust fund suggested by the Task Force in the Model Statute proposed in the Task Force’s 2007 and 2010 Guidance.

This trust fund, as initially proposed, would be “utilized solely for long-term monitoring of the site, including remaining surface facilities and wells, remediation of mechanical problems associated with remaining wells and surface infrastructure, repairing mechanical leaks at the site, and plugging and abandoning remaining wells under the jurisdiction of the State Regulatory Agency for use as observation wells.”⁶⁸

The extent to which this trust fund, as initially proposed, could be expanded by states to cover additional liabilities beyond those originally envisioned, is discussed in Section 3. Other potential solutions for the Post-Closure phase were considered by the current Task Force, including a federal trust fund,⁶⁹ private insurance and a “layered” risk management proposal.⁷⁰

⁶⁶ TASK FORCE 2007 GUIDANCE, *supra* note 2, at 30. This guidance also sets forth the rationale behind the Task Force’s conclusion and the likely scope of the activities that would be covered by such a fund. In the Model Statute, which also was a part of the 2007 guidance, the Task Force included a “Section 6. Establishment of Carbon Dioxide Storage Facility Trust Fund.” *Id.* at 34.

⁶⁷ In its guidance in 2010, the Task Force updated the Model Statute, including the language pertaining to the trust fund. TASK FORCE 2010 GUIDANCE, *supra* note 6, at Appendix I-4. That section reads as follows:

Section 6. Establishment of Carbon Dioxide Storage Project Trust Fund. There is hereby established the Carbon Dioxide Storage Project Trust Fund to be administered by the State Regulatory Agency. There is hereby levied on the storage operator a tax or fee equal to \$----- on each ton of carbon dioxide injected for storage for the purpose of funding the Carbon Dioxide Storage Project Trust Fund. The trust fund shall be utilized solely for long-term monitoring of the site, including remaining surface facilities and wells, remediation of mechanical problems associated with remaining wells and surface infrastructure, repairing mechanical leaks at the site, and plugging and abandoning remaining wells under the jurisdiction of the State Regulatory Agency for use as observation wells. The trust fund shall be administered by the State Regulatory Agency.

⁶⁸ *Id.*

⁶⁹ At the present time in the U.S., the prospect of a federal trust fund in the Post-Closure Phase of a CGS project seems remote. Were legislation to pass Congress granting the federal government such a role in the Post-Closure Phase, it could pre-empt the need for a state trust fund.

⁷⁰ See Example 3 (“Layered” Federal Risk Management Proposal) in Appendix 1. This example presents an interesting potential option in the future and contains a federal component.

At this time, the Task Force believes that an industry-funded and state/province-administered trust fund still is likely to be viewed by many states and provinces as the most appropriate framework to fund the long-term facility oversight activities enumerated above. It is noted that both North Dakota and the province of Alberta⁷¹, two jurisdictions in North America that have moved rapidly in developing legal and regulatory frameworks for CGS, have opted in favor of a state/province administered trust fund for the Post-Closure Phase.

For a state or province that opts for such an industry-funded and state/province-administered trust fund, its terms and existence, including the eventual release of the operator from project responsibility, as well as the operator cost for the fund over the lifetime of the project need to be clear at the onset of a project. All will be critical factors to an operator in assessing the economics of a prospective CGS project.

⁷¹ See Example 2, Managing Long-term Liability for CGS in Alberta in Appendix 1.

SECTION 3

Discussion of Liability by Phase of CGS Project

Following is a discussion of the five basic phases (See Figure 1-1) of a CGS project defined by the Task Force: (I) Exploratory; (II) Permitting, (III) Storage (Operations); (IV) Closure; and (V) Post-Closure (Long Term).

The five phases are portrayed more specifically in the CGS Project Framework and Risk Analysis set forth in Table 2-1, that enumerates the risks associated with each activity and the best suited FA to mitigate those risks. Given that much of the discussion in this section concerns the inter-relationship of U.S. federal and state jurisdiction, this discussion may be of less utility to Canadian provinces.

As was discussed in Section 2.3, the Task Force strongly recommends that a state or province explicitly enumerate in statutory or regulatory language two principles: (1) that it is in the public interest to promote the geologic storage of CO₂ in order to reduce anthropogenic CO₂ emissions; and (2) that the state's pore space should be regulated and managed as a resource under a resource management philosophy.

These principles allow for the exercise of the state's authority to facilitate and regulate CGS projects within the state's borders, so as to ensure that available pore space is effectively managed to maximize CO₂ storage capacity within the state.

In reviewing the associated risks in each of the five phases of a CGS project, the Task Force determined there were both environmental and other (generally non-environmental) risks. These other risks may or may not be suited to mitigation by required regulatory FA, such as discussed in Section 2.6 above. Environmental risks are best suited to being addressed by FA, as these risks generally will fall to the state or federal regulator to mitigate, utilizing the required regulatory FA. The other risks generally are attributable to economic risk assumed by the project operator and not usually covered by the required regulatory FA should the operator fail to perform as required.

These would be similar to risks undertaken in most commercial endeavors and particularly those in the analogous resource extraction sector. Various commercial instruments and other contractual arrangements would mitigate these risks.

With respect to the environmental FA, the UIC Class VI Rule⁷² lists numerous types of FA acceptable under the UIC Class VI Program. The Task Force is suggesting herein only those FA mechanisms it believes best suited. This suggestion is based on the flexibility of the FA to mitigate the enumerated risks and state experience with various FA for analogous regulatory programs.

⁷² UIC CLASS VI RULE, *supra* note 13, at § 146,85(a)(1)(i-vii) .

In addition, Figure 1-1 shows the regulatory jurisdiction of the state and the federal government (Class VI) with respect to regulatory oversight throughout the CGS project.

In this report, the Task Force has recommended that states with any potential for CGS secure Class VI primacy: 1) to incentivize project development 2) to ensure a streamlined permit process covering all aspects of the project, and 3) to ensure the state's active involvement in any decision concerning transition of regulatory oversight of CO₂-EOR projects from Class II to VI.

Should states decide against seeking primacy, the Task Force has recommended that they nonetheless be active participants in a CGS project to ensure that their interests are protected. It is important to reiterate that even states that never may seek and secure Class VI primacy will have a necessary role in the regulation of a CGS project within their boundaries.

Phase I - Exploratory

The Exploratory Phase is the phase in which a prospective CGS operator undertakes the process of determining the suitability of the proposed CGS site for CGS operations and the acquisition of the necessary property rights. The activities undertaken during the Exploratory Phase are under the regulatory jurisdiction of the state. There is no federal jurisdiction in this phase under the UIC Class VI Rule.

Entities contemplating the development of a CGS project almost certainly will elect to engage in exploratory activities well in advance of the application for a UIC Class VI permit as the data collected during the Exploratory Phase may be used during the UIC application process. These early project development activities include exploratory well drilling, geophysical and other types of geologic investigations.

An entity may undertake these exploratory activities for the purposes of defining a potential storage project area. Generally, these exploratory type activities already are regulated in states with existing oil and gas regulatory frameworks. However, these regulations may need to be developed in states without such existing frameworks.

The Exploratory Phase also includes the amalgamation of storage rights as previously discussed in the Task Force 2007 Guidance and included in both the 2007 and 2010 versions of the IOGCC Model Statute and Rules and Regulations.

In the Task Force 2007 Guidance, the Task Force concluded that control of the reservoir and associated pore space used for a CGS project is necessary to allow for the orderly development of the project. The right to use reservoirs and associated pore space generally is considered a private property right in the United States, and must be acquired from the owner.

The control of the storage rights is necessary prior to issuance of the initial CGS project permit, not only to promote orderly development, but also to maximize utilization of the pore space resource. In the U.S., with the exception of federal lands, the acquisition of these storage rights, which are considered property rights, generally are functions of state law.

If these property rights cannot be acquired voluntarily, the operator can request the use of state authorities to acquire the rights necessary to control the CGS project area.

To streamline procedures, the state may allow for a property right amalgamation process to occur in conjunction with the CGS project permit application submitted in accordance with Class VI requirements during Phase II.

In Canada, the amalgamation of personal property rights may need to occur in certain limited circumstances, but given that pore space rights are generally controlled by the province, as is the case in Alberta⁷³, (notwithstanding federal jurisdiction over federal Crown lands within a province) the amalgamation process would be less complex before tenure has been granted in a certain geographic area.⁷⁴

If an evaluation permit or sequestration lease already has been issued, commercial agreements are the preferred approach for granting third-party access to pore space, although the government is recommending that regulatory mechanisms should be developed to mandate third-party access.⁷⁵

As enumerated in the CGS Project Framework and Risk Analysis table, the risks that may be incurred by the state or province during the Exploratory Phase are minimal due to limited activity during this phase.

The other major risks primarily are related to the amalgamation of property right activities and would be incurred by the entities involved in conducting those activities and the affected property owners (surface, mineral, pore space).

Any such liabilities arising during this phase likely would arise under the common law theories of liability, which this report discusses in Section 4, among the affected parties. The operator generally would mitigate these risks arising during the property amalgamation process by the various risk management mechanisms used in any private sector commercial endeavor (various liability insurances and contractual agreements among the parties).

Other risks that may be incurred by the state during the Exploratory Phase occur during exploratory drilling and other associated activities, such as seismic operations. These exploration activities generally are covered by established state FA requirements during the permitting procedures for these activities, and would be sufficient to allow the state to correct any problems or issues should the operator be unable or unwilling to correct the problem.

The best-suited FA mechanisms for the exploratory well drilling and geophysical investigations likely are to be a surety bond, cash bond, or letter of credit, and states that have mineral resource exploration regulatory frameworks in place generally already have developed the necessary FA to address these risks.

These frameworks would have to be developed in states without mineral resource exploration regulatory frameworks in place.

⁷³ All pore space within the Province of Alberta has been declared by the province to be the property of the province. Mines and Minerals Act (Revised Statutes of Alberta 2000 cM-17), *available at* http://www.qp.alberta.ca/1266.cfm?page=m17.cfm&leg_type=Acts&isbncln=9780779772650&display=html.

⁷⁴ Carbon Sequestration Tenure Regulation, Alberta Regulation 68/2011, *available at* http://www.qp.alberta.ca/1266.cfm?page=2011_068.cfm&leg_type=Regs&isbncln=9780779772513&display=html.

⁷⁵ ALBERTA ENERGY, CARBON CAPTURE AND STORAGE – SUMMARY REPORT OF THE REGULATORY FRAMEWORK ASSESSMENT (2013), *available at* <http://www.energy.alberta.ca/Initiatives/3544.asp>

Phase II - Permitting

Entities which have acquired the necessary property rights, in accordance with applicable state laws and during the Exploratory Phase, and have determined to their satisfaction that a site is suitable for a CGS project, will initiate the process to acquire the necessary permits.

The CGS Project Framework and Risk Analysis table enumerates the general activities that will be undertaken in the Permitting Phase. The first identified activity is the “storage project permit.”

Functionally, that permit requires application of both federal law and state law. Federal law (UIC Class VI Rule) permits those aspects of a CGS project pertaining to the UIC program, including the required Class VI permit information⁷⁶ and the Area of Review (AoR),⁷⁷ which extends beyond the CO₂ plume area (outer edge of the pressure front caused by the displacing of formation fluids).

The UIC Class VI Rule is designed to protect USDWs and is limited with respect to the regulatory framework addressing all aspects of a CGS project. The UIC program jurisdiction focuses on the injection well (construction, monitoring, maintenance, and plugging and abandonment) and the lateral migration of the injectate (CO₂) with respect to the extent USDWs may be endangered.

The UIC Program does not provide a regulatory framework for the regulation of surface facilities and the protection of other resources or properties.

States have a much broader authority that provides for the protection of the state, its citizens, lands, and natural resources. Accordingly, states are best positioned to ensure that all aspects of a CGS project are properly regulated. State law would provide for a permit to cover a storage project in its entirety including the necessary surface facilities on the site (compressors, pipelines, well pad and drill pit construction, etc.)

Should a state have primacy and have adopted the necessary federal authority (the UIC Class VI Rule) into its own rules, it is possible that state could issue one “storage project permit” that encompasses both the federal UIC program and the federal and state permits.

The Task Force notes that although the UIC Class VI Rule has no jurisdiction over surface facilities, such as pipelines and compressor stations, states need to be aware that there is the potential for additional federal jurisdiction under both the Clean Air Act⁷⁸ and under U.S. Department of Transportation (DOT) programs.

Depending upon whether the state has primacy or a partnership relationship under these federal programs, the state potentially could include these facilities in the overall facility/project FA.

The primary FA for the overall CGS project will be issued during the Permitting Phase and likely will consist of a combination of instruments covering all aspects of the project. It should be noted that the FA issued at this time likely would be structured so as to allow modification due to changing circumstance, including changes in the risk assessment for the permitted activities.

⁷⁶ UIC CLASS VI RULE, *supra* 13, at § 146.82

⁷⁷ *Id* at § 146.84

⁷⁸ See the discussion in Section 4 herein on the Clean Air Act and particularly as concerns the Greenhouse Gas (GHG) Reporting Rule.

As discussed earlier, the UIC Class VI jurisdiction does not extend to the surface facilities and other risks. Consequently, additional state jurisdiction will be necessary to require FA to mitigate these risks.

With respect to the types of FA best suited for the overall project, the UIC Class VI Rule enumerates the FA that is acceptable. Should a state secure Class VI primacy, the federal FA could be adopted in total by the state or the state could request to expand upon or specify which FA would be used. States with primacy also may consider the use of an all-encompassing “storage facility” FA which would cover all contingencies in both the subsurface and surface facilities and could remain in effect through the Closure Phase.

For states without primacy, as the UIC Class VI Rule does not deal with surface events, events dealing with pipelines or other surface facilities operations associated with the project will require that the state is involved, otherwise there would be no FA to cover these operations. Here the state likely would want to require separate FA to cover these facilities.

Given the staging of project development time frames requiring potentially different types of FA and of varying amounts, the Task Force recommends the FA be flexible to allow for seamless modifications and combinations of FA to address the differing levels of risk. The Task Force suggests the best suited facility or project FA are insurance, escrow account (cash or CD), or a private trust fund (funded and managed by the operator).

The project permit also includes corrective actions, primarily the plugging, replugging, or repair of previously abandoned wells, and the drilling and construction of injection and monitoring wells. Again, as shown in the CGS Project Framework and Risk Analysis, these additional Permitting Phase activities involve a combination of state and federal authorities. The major activities of this phase are primarily administrative dealing with permit review procedures.

As concerns corrective actions, the risks associated with these activities are primarily with the project operator, and involve an economic risk to the operator should the site not receive a permit. The environmental risks during this phase deal with the plugging of old wells identified during the project permitting process.

With respect to the permit review process for activities involving the identification of existing wells requiring corrective action (to plug or repair the wells), FA to mitigate the risks associated with the corrective actions would not be necessary, given that the project permit would not be issued unless the corrective actions were completed properly.

As concerns the drilling and completion of the injection and monitoring wells, a state permit normally is required to drill the wells, which will remain in effect until the well is plugged. The standards by which the wells must be constructed, completed and operated are dictated by the UIC Class VI Rule. A state with primacy will handle all of this. Without state primacy, EPA (under direct implementation) and each state will handle its permitting functions.

With respect to the FA best suited to mitigate risks associated with the drilling and completion of the injection wells, the FA will be similar to that required in Phase I for the exploratory wells.

Although the UIC Class VI Program requirements enumerate in detail the types of FA that have been approved as acceptable to mitigate the various individual well risks, the Task Force suggests that the best-suited FA for both injection and monitoring well drilling are surety bonds, cash bonds, or letters of credit.

States that have mineral resource exploration regulatory frameworks generally have developed the necessary FA to address these risks. States with no such frameworks will have to develop them.

The final permit required in the Permitting Phase is the Permit to Inject, which will be issued pursuant to the UIC Class VI Rule by either EPA (direct implementation) or a state with primacy. Where states have primacy, in some instances the permits to drill and inject may be issued at the same time and utilize the same FA for both permit functions.

In states where both the state and EPA share regulatory authority, both state and federal officials will need to be well-versed in each other's rules and regulations to ensure a streamlined permitting process.

Phase III - Storage

Phase III commences with the active injection of CO₂ into the reservoir and the storage of CO₂. The CGS Project Framework and Risk Analysis enumerates the activities during the Storage Phase, the potential risks, environmental and otherwise, and the FA that covers or could cover these risks. It is without question the phase with the greatest risk potential.

As was explained in the preceding discussion of the Permitting Phase, the FA issued in that phase is FA that provides coverage throughout the Storage Phase and is the FA that would cover all of the potential environmental risks identified should the CGS operator (the primary responsible party under that FA) fail to correct any project failures, deficiencies, or violations. Again, the FA likely will be modified periodically during this phase to account for changes in the project, including the risk profile parameters.

In the Phase II Permitting discussion above, the Task Force noted that additional regulatory programs dealing with federal air and pipeline programs also might be involved. These would become fully relevant during the Storage Phase.

It is also in the Storage Phase that the state or province would begin to collect the tax or fee "on each ton of carbon dioxide injected for storage for the purpose of funding the Carbon Dioxide Storage Project Trust Fund."⁷⁹

As was discussed in Section 2.10, details as to the amount of this fee or tax need to be established early in the life of a CGS project, no later than the Permitting Phase, as this will be an important factor for the operator and its financial backers in assessing the economics of a project. The IOGCC model language envisions a set tax or fee that would apply to all projects in the state or province.

⁷⁹ See *supra* text accompanying note 67 for Section 6 of the IOGCC 2010 Model Statute.

An alternate approach that has been adopted by the province of Alberta is to determine the tax or fee on a project by project basis.⁸⁰ Under this approach, sites with a higher risk profile will have higher taxes or fees assessed per ton of injected CO₂. Such an approach would offer an incentive to operators to propose only the best potential storage sites.

Under either the IOGCC Model approach or the Alberta approach, the state or province presumably will need access to risk assessments to guide them in setting the rate. The Task Force in Section 2.5 discusses Risk Assessment generally. While the Task Force considered developing guidelines for states and provinces in this regard, it was beyond the scope of this work product. The Task Force notes it is an area for further research.

The Task Force also notes that as more CGS projects are developed, the body of this type of information will increase. Of interest in this regard are both the fee created by the state of North Dakota by statute and rule⁸¹ and the valuation developed by Industrial Economics for a proposed FutureGen site in Jewett, Texas.⁸² North Dakota assessed a fee of 8 cents on each ton of CO₂ injected for storage (one cent for an administrative fund and 7 cents for the trust fund.) Interestingly, Industrial Economics estimated total damages over the life of the Jewett project at 15 to 37 cents per ton of CO₂ injected.⁸³

One form of CGS liability that has been discussed widely is commonly referred to as induced or triggered seismicity. Changing the state of stress in the earth's crust and causing slippage along pre-existing faults or other planes of weakness via dam building (reservoir filling)⁸⁴, mining⁸⁵, and fluid injection⁸⁶ has been linked to small earthquakes, generally of magnitude 4 or much less and very few at levels noticeable to the public (i.e., above magnitude 2.0).

Many of these events have magnitudes less than 0 and are often termed microseismic events. The risk of inducing or triggering an earthquake is almost always related to the activity in proximity to a fault or into a fault zone, or in the case of fluid injection, into a rock volume that critically is stressed (on the verge of breakage). The scale of injection anticipated by CGS will clearly be of large volumes, hence the broad discussion. But the counter argument is that many regions of the world have seen enormous injected volumes of water and/or CO₂ and not created any significant seismicity.⁸⁷

Site selection should address the proximity of faults and consider microseismic monitoring to understand any tendency of injection to induce seismicity and ensure that an understanding of the state of stress of the subsurface is not neglected. It is assumed that during the permitting process every

⁸⁰ Alberta proposal for a Post-Closure Stewardship Fund. See ALBERTA ENERGY, *supra* note 75 at Appendix D, 60-67.

⁸¹ In North Dakota there are two statutory provisions and one regulatory provision that pertain to the collection of fees by the state. See N.D. CENT. CODE § 38-22-14, 38-22-15 (2010); N.D. ADMIN. CODE 43-05-01-17 (2010; Amended 2013).

⁸² INDUSTRIAL ECONOMICS VALUATION, *supra* note 49.

⁸³ The Industrial Economics valuation states that the "range of damage estimates is highly sensitive to site-specific data." *Id.* at i.

⁸⁴ L. Chen & P. Talwani, *Reservoir-Induced Seismicity in China, Pure and Applied Geophysics*, 153, 133-149 (1999).

⁸⁵ D.W. Redmayne, *Mining induced seismicity in UK coalfields identified on the BGS National Seismograph Network*, GEOLOGICAL SOCIETY, ENGINEERING GEOLOGY SPECIAL PUBLICATIONS 5 405, 405-413 (London 1988).

⁸⁶ See J. H. Healy, W.W. Rubey, D.T. Griggs & C.B. Raleigh, *The Denver Earthquakes*, SCIENCE, 161, No. 3848, 1301-1310 (1968); Robert B. Herrmann, Sam-Kuen Park & Chien-Ying Wang, 1981, *The Denver Earthquakes of 1967-1968*, BULLETIN OF THE SEISMOLOGICAL SOCIETY OF AMERICA 71, No. 3, 731-745 (1968).

⁸⁷ See Board on Earth Sciences and Resources, *Induced Seismicity Potential in Energy Technologies*, NATIONAL ACADEMIES PRESS (Washington, D.C 2012).

effort will be made to identify the seismic risk and proceed accordingly with permit operating conditions to minimize that risk.

It also is assumed, that any induced seismic activity which may occur and results in property damage, that it will be the responsibility of the operator. Accordingly, this risk will need to be evaluated during the permitting process and the appropriate FA required to mitigate the potential risk should the operator fail to do so.

Phase IV - Closure

The potential risks arising during the Operational Phase are expected to be lessened significantly during the Closure Phase, as active injection operations cease and monitoring activities become the primary activity. As indicated on CGS Project Framework and Risk Analysis table, the potential risks are associated with well-plugging activities and any potential remediation that may be needed, expenses which would remain covered by the various FA put in place during the initial Permitting Phase.

The regulatory authority governing the activities during this phase continues to be the UIC Class VI Program. As is evident in the table, the exception concerns surface facilities and the reclamation of the site, which is not covered by the Class VI program and is therefore under exclusive state jurisdiction.

Entities that have reached a determination to cease injection activities, as defined under the UIC Class VI Program, will commence designated closure activities during the Closure Phase in accordance with the requirements of the Class VI Program.

As before, in states with primacy the state will have adopted the necessary federal authority into its own rules. This phase also includes the required post-injection monitoring activities necessary to demonstrate that the stored CO₂ has stabilized and no longer represents a potential danger to USDWs.

During the Closure Phase the individual well FA could be released, at the discretion of the state, as the wells are plugged. The overall Class VI storage project FA, however, would remain in effect until a final certificate of closure has been issued in accordance with the Class VI Program requirements.

The Task Force in its 2007 Guidance concluded that a 10-year time frame likely would be sufficient prior to release of the CGS operator and/or CO₂ generator from further project monitoring and maintenance responsibility as set forth in the IOGCC Model Statute.

The UIC Class VI Rule addresses post-injection site care and site closure,⁸⁸ requiring the owner or operator to “continue to conduct monitoring as specified by the Director-approved post-injection site care and site closure plan for 50 years or for the duration of the alternative timeframe approved by the Director.”⁸⁹

⁸⁸ UIC CLASS VI RULE, *supra* note, at § 146.93

⁸⁹ *Id.* at 146.93 (b)(1). The director is defined as “the Regional Administrator, the State director or the Tribal director as the context requires, or an authorized representative. When there is no approved State or Tribal program, and there is an EPA administered program, ‘Director’ means the Regional Administrator. When there is an approved State or Tribal program, ‘Director’ normally means the State or Tribal director. In some circumstances, however, EPA retains the authority to take certain actions even when there is an approved State or Tribal program. In such cases, the term ‘Director’ means the Regional Administrator and not the State or Tribal director.” UIC, *supra* note 11, at § 144.3.

The Task Force has in its past guidance discussed various time periods at which time the operator would be released from further responsibility ranging from three to ten years, as well as time frames longer than ten years. Ultimately, if a state has secured Class VI primacy, the determination of when a site is issued a certificate of closure is a state decision.

However, at whatever point a final closure certificate is issued, the regulatory jurisdiction under the UIC Class VI Program ends and the CGS storage project FA, put in-place in the Permitting Phase under the Class VI requirements, will be released. The Closure Phase has ended.

Phase V - Post-Closure

The Post-Closure Phase begins upon issuance under the UIC Class VI Rule, whether by EPA or a state with primacy, of a certificate of closure. In order for a certificate of closure to be granted to a CGS operator, the operator will have to have demonstrated that the CO₂ plume essentially has stabilized, that no additional monitoring is required, and that there is no longer any risk of endangerment to USDWs.

With the issuance of the certificate of closure, active federal jurisdiction under the SDWA and its UIC Class VI Rule ends. This statement contained in the EPA's UIC Class VI Financial Responsibility Guidance sums up the Post-Closure Phase under the SDWA and its UIC Class VI Rule:

Although the owners or operators are not required to demonstrate financial responsibility after the post-injection site care period has ended, owners or operators still are financially liable for the site. Safe Drinking Water Act (SDWA) does not provide EPA with the authority to indefinitely release owners or operators from long-term responsibility for potential impacts to USDWs after the post-injection site care period has ended (e.g., for unanticipated migration that endangers a USDW). Under current SDWA provisions, EPA does not have the authority to transfer liability from one entity to another.⁹⁰

Additionally, the CGS Operator presumably also will remain liable in the Post-Closure Phase for any potential liability that may arise under any other federal statute, as EPA similarly has no federal authority to release an operator from liability under those acts.⁹¹

The concern of states with this federal reality is twofold. First, many companies have expressed concern about taking on perpetual liability for CO₂ injections in North America in which the practice has not been tested at anywhere near the scale envisioned for commercial operation.

This greatly diminishes the potential for CGS as a CO₂ mitigation strategy. Second, should an operator agree to take on this unlimited liability, states know only too well from their experience with "orphaned" oil and natural gas wells in the U.S. that should an operator cease to exist, which is inevitable in the very long term, it would be government, and most likely state government, that would be left responsible for the site.

⁹⁰ UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, *supra* note 52 at 4.

⁹¹ EPA has proposed a conditional exclusion from RCRA for CGS in Class VI wells. This is discussed in Section 4.1.

The Task Force emphasizes that in establishing FA for the Post-Closure Phase, states should distinguish between costs that are certain or highly likely to arise, such as monitoring and periodic maintenance costs, and remediation costs, which diligent administration of Class VI regulation is designed to render unlikely.

Thus, from the state's perspective, at a absolute minimum there needs to be a long term financial mechanism that provides the necessary resources for a state to monitor and maintain the site in perpetuity.

A state would be prudent to insist on a long-term financial mechanism to insure that resources are available to pay for at least these long-term contingencies.

It is for this reason the Task Force once again recommends that a state or province undertake, at a minimum, the "caretaking" (monitoring and maintenance) responsibility of a stabilized project. This also would provide a backstop to address other liabilities should the operator no longer be in existence. As presented in Section 2.10 above, the Task Force therefore recommends, as it did in its 2007 and 2010 Guidance, that an industry-funded and state/province administered trust fund is as the best solution available to states and provinces for the Post-Closure phase (Phase V).

Financed by the trust fund, the state or province would assume responsibility for the continued monitoring and maintenance of the site. The state and province would release the operator of the CO² project from further obligation with respect to these long-term "caretaking" functions of the facility.⁹²

In addition, the state or province could release the operator from any potential liabilities for remediation (e.g., for unanticipated migration that endangers a USDW or other resources). A decision for the state would be the extent of the liability that the state or province is willing to assume. It is conceivable that a state or province could decide to assume all operator liability, federal, state or province, and common law, from the issuance of the certificate of closure into the future (excepting liability in cases such as gross negligence, malfeasance or fraud). In the interest of precision, legally the state cannot "release" the operator from liability under federal law, but it can enter an agreement to assume the operator's liability, should any arise.

If the state or province desires that the trust fund cover potential damages or liabilities related to the facility, beyond the caretaking responsibilities specified in the IOGCC Model Statute, the state or province would state this specifically in its enabling statutory language.

This could include a complete assumption of federal liability, including any potential liability under RCRA, CERCLA or the CAA.⁹³ A decision of this nature likely would result in a higher per ton tax or fee paid to the long-term trust fund to cover the potential increased risk.

⁹² Were the state to assume some or all federal liability, it would give an operator, still considered liable by the federal government, a cause of action against the state to the extent of the operator's federal obligation to the extent assumed by the state.

⁹³ Note that the SDWA, RCRA, and CERCLA all are statutes designed to provide the government authority to compel environmental remediation, which in the case of CGS is most likely to consist of groundwater contamination, if any environmental harm occurs at all. In other words, these three laws can all be thought of as covering the same potential problem, though with different triggering authorities for the government and different processes, some more burdensome than others.

In addition, there are concerns about the possibility that a state or provincial governing body might reprogram funds prematurely from a trust fund. In the U.S., the Task Force concluded that this might be difficult to prevent. However, it is noted that should funds be removed, and a state or province subsequently encounter a problem for which the remaining trust fund balance is inadequate, the state or province likely still would have to remedy the problem and find the necessary funding.

Given all of the above, the Task Force is left to conclude that unless a state is willing to go beyond the recommendation of the Task Force set forth in Section 2.10 and restated above, (concerning creation of an industry-funded and state/province administered trust fund covering the long-term “care-taking” — monitoring and maintenance — functions at the site and releasing the operator from such responsibility), the operator will remain liable in perpetuity to the state for remediation activities, should such prove necessary, and to the federal government for all federal liability under the SDWA and, if applicable, RCRA, CERCLA and the CAA. The Task Force, however, was unwilling to recommend a broader state approach, leaving it to states to decide whether to go beyond that recommended.

This reality has been cited as a threat to the viability of a CGS industry in the United States. Many find it hard to imagine a future where there are more than a handful of CGS projects in the U.S. The situation is different in Canada, but would remain an issue were a province to limit its assumption of liability to only cover monitoring and maintenance.

There appear to be two general responses.

The first is a state response. Expressed in its broadest form, under this response the state would, after issuance of the Certificate of Closure, assume complete responsibility for the site. The state also would concurrently assume near complete liability from the operator⁹⁴ under federal and state law, to be financed by a Long-Term State Trust Fund that has been funded by an appropriately greater tax or fee on each ton of CO₂ injected.⁹⁵

This option and the breadth of its potential exercise by a state is totally within the control of the state.

The second would be a federal legislative response that, at a minimum, would allow transfer of liability under all applicable federal laws from an operator to a state in the Post-Closure Phase. A more comprehensive federal response could involve amending the SDWA, RCRA, CERCLA and the CAA to authorize transferral of liability when a site is deemed to no longer pose a potential environmental risk. Variations of a federal response also could include a federal trust fund to which post-closure liability could be transferred or other public-private sector options.

⁹⁴The exception would be for liability arising from negligence, malfeasance or fraud on the part of the operator prior to site closure.

⁹⁵ Relying on a risk analysis of the broader assumption of liability, it would presumably be a higher tax or fee than that set for a trust fund covering simply monitoring and maintenance. It is worth noting that based on the valuation conducted by International Economics, the total potential liability (in all phases of a CGS project) may be relatively moderate. It is likely in the hundreds of millions of dollars rather than in the billions. See INDUSTRIAL ECONOMICS VALUATION, *supra* note 49.

While the Task Force was unable to go beyond its recommendation of 2007 and 2010 concerning the Long-Term Trust Fund and its focus on monitoring and maintenance, it sees merit to a state actively considering assuming broader responsibility and liability in the Post-Closure Phase.

As it stands, there is a relative dearth of commercial projects for active CGS development in the United States, due in part to the fact that the business case for CGS does not yet exist and a rigorous regulatory environment that has discouraged early adoption of the technology.

No doubt the issue of long-term liability is another important factor. One conclusion that appears clear is that if states that are willing to adopt legal and regulatory frameworks along the lines suggested in the state solution described above, those states likely will have an advantage when it comes to securing CGS project development in their jurisdictions.

SECTION 4

Discussion of Potential Liability for CGS Operations

As noted in Section 2, liability for CGS operations, as in any industrial activity, arises in one of two ways: violation of laws enacted by a government — federal or state — or under common law theory, such as negligence, trespass, or nuisance.

In this section, the Task Force will identify and discuss potential pathways of liability for CGS in three categories: federal statutes, state statutes, and common law.

It will be important that states and provinces administering a CGS regulatory regime understand how their state or provincial CGS-specific laws and regulations fit into the broader liability framework.

4.1 U.S. Federal Statutes

The statutes that have definite application to CGS are the SDWA and the reporting requirements under the CAA. The Task Force is including a broader discussion of the other federal statutes because as CGS is an emerging field, the applicability of other statutes has yet to be tested.

A. Safe Drinking Water Act. Given the central role that the SDWA⁹⁶ and its UIC program⁹⁷ play in the regulation of CGS in the United States, much already has been written about the SDWA in this report. The fundamental purpose of the Act's UIC program is to ensure that underground injections will not endanger USDWs.⁹⁸ The UIC program regulates the injection of CO₂ under three separate regulatory structures of relevance for this discussion, depending on the type of well. As noted previously, injections into oil and gas wells, which are done for purposes of EOR, are regulated under Class II regulations.⁹⁹

Experimental wells are subject to regulation under Class V.¹⁰⁰

Some of the demonstration projects conducted over the past several years through the Regional Sequestration Partnership Program (RCSPP) received Class V permits, but the EPA is no longer issuing Class V permits for CO₂ injections. Finally, as noted previously, EPA adopted in December 2010 a new

⁹⁶ SDWA, *supra* note 12.

⁹⁷ UIC, *supra* note 11.

⁹⁸ SDWA, *supra* note 12, at § 300h(b)(1). *See also supra* text accompanying note 37 for the definition of USDW.

⁹⁹ U.S. Environmental Protection Agency, *supra* note 18.

¹⁰⁰ More information on Class V wells may be found at U.S. Environmental Protection Agency, *Class V Wells*, EPA.GOV, <http://water.epa.gov/type/groundwater/uic/class5/index.cfm> (last updated May 24, 2012).

regulatory structure specifically for geologic storage of CO₂, designated as Class VI.¹⁰¹ This new injection well class covers CO₂ injections into formations other than oil and natural gas-bearing formations.

Additionally, as discussed in Section 2.4, Class II injections ultimately may be reclassified at a later point in a project's life as subject to Class VI regulation. In order for states to regulate these classes of injection wells under state laws and regulations, they must seek and be granted primacy from EPA under the SDWA.¹⁰² For primacy to be granted, the state program must meet federal requirements, including that it be no less stringent than federal regulations.

The act specifies penalties for violating regulations that have been established under it. The enforcing agency (a state agency or the EPA) may, for violations of UIC regulations:

- Issue an administrative order compelling compliance and assessing a civil penalty of up to \$10,000 per day (\$5,000 per day in the case of injections in connection with enhanced oil or gas recovery) up to a total of \$125,000.
- Bring a civil action in federal district court to compel compliance and seek penalties of up to \$25,000 per day per violation.
- Bring a criminal action in the case of willful violations for imprisonment of up to three years and seek fines in addition to those above.¹⁰³

Liability would arise for failure to comply with operating, reporting, closure or other requirements applicable to the well.

UIC regulations can be enforced not only by the administering agency (i.e., the state or the EPA), but also through citizen suits, if the administering agency has not filed suit for a violation.

B. Resource Conservation and Recovery Act. The Resource Conservation and Recovery Act¹⁰⁴ ("RCRA") applies to disposal of "solid wastes," a term defined in the statute. RCRA is a regulatory statute designed to protect land and water from waste disposal. It has a so-called "cradle to grave" regulatory structure applicable to wastes from their point of generation, through treatment, transport, storage and disposal. A far more stringent set of requirements applies to disposal of "hazardous wastes," a subset of solid wastes. The law sets requirements for "corrective action" when wastes leak from a facility. The law also sets forth a penalty regime for violating the act, including penalties of up to \$25,000 per day for infractions involving hazardous wastes.

A key issue is what is considered to be a "waste." First, it is well-established that the term "solid waste" can apply to materials in gaseous or liquid form, such as CO₂ for CGS. Specifically, it includes "discarded material, including solid, liquid, semisolid, or contained gaseous material resulting from ... industrial ... operations."¹⁰⁵

¹⁰¹ UIC CLASS VI RULE, *supra* note 13.

¹⁰² See SDWA, *supra* note 22; U.S. Environmental Protection Agency, *supra* note 21.

¹⁰³ See SDWA, *supra* note 12, at § 300h-2.

¹⁰⁴ RCRA, *supra* note 28. RCRA imposes liability for releases of hazardous substances that threaten human health or the environment. It is unclear that it will apply since CO₂ is not a hazardous substance.

¹⁰⁵ RCRA, *supra* note 28, at § 6903(27).

A key issue that has long been a focus of the Task Force is whether sequestered CO₂ is discarded material. In the past the Task Force has termed this issue as the “waste versus commodity” debate and advocated regulation of CO₂ under a resource management philosophy.¹⁰⁶

That being said, the Task Force reaffirms its view that CO₂ be treated as a commodity, with a growing list of potential industrial and commercial uses. RCRA regulation is fundamentally at odds with the concept of CO₂ as a commodity.

A hazardous waste is “a solid waste ... which, because of its quantity, concentration, or physical, chemical, or infectious characteristics may ... pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported, or disposed of, or otherwise managed.”

The only theory under which CO₂ itself could be conceived of as a hazardous waste is that in high concentrations it can be fatal to humans or animals. High concentrations above ground resulting from CO₂ storage are extremely unlikely to occur.

There is a compelling theory that CO₂ for Class VI injection should not be considered a solid waste at all. Instead it should be considered an “uncontained gas.” Uncontained gases are not solid wastes under RCRA, and therefore are not subject to that law.¹⁰⁷

EPA clarified some 20 years ago that material that is not “containerized in the narrower sense of being in an individual container such that the gas is amenable to shipment” is not a contained gas.¹⁰⁸ CO₂ that is stored in a geologic formation certainly is not “in an individual container.” EPA confirmed its interpretation of “uncontained gas” in 2011.¹⁰⁹

The end result of CO₂ injectate being considered a hazardous waste would be that its injection would be subject to regulation under Class I — Hazardous regulation under the UIC program, rather than under the Class VI program.

While Class VI regulation has some features that go beyond Class I, which EPA justified based on the unique circumstances of geologic sequestration of CO₂ (particularly the buoyancy and anticipated volume of the injectate), overall the regulation for Class I — Hazardous is the most stringent in the UIC program. Class I regulation contains features that make it unsuitable for geologic storage — for example, a requirement of no migration of injected fluids for 10,000 years.¹¹⁰ CO₂ injectate is highly buoyant and a substantial portion of the injectate may remain in mobile phase for years following injection making such a requirement inapt to CGS.

¹⁰⁶ See INTERSTATE OIL & GAS COMPACT COMM’N TASK FORCE ON CARBON CAPTURE AND GEOLOGICAL STORAGE, *supra* note 3, at 3. See also Section 2(3) herein.

¹⁰⁷ RCRA, *supra* note 28 at § 6903(27).

¹⁰⁸ BP Chemicals America, Inc., RCRA Appeal No. 89-4, 1991 WL 208971, 2-3 (E.P.A., August 20, 1991) (holding that uncondensable hydrogen cyanide “contained” within piping and other equipment of an acrylonitrile manufacturing plant is not a contained gaseous material and therefore not subject to RCRA. “[T]he Agency views gaseous material to be “solid waste” only when it is containerized.”).

¹⁰⁹ See letter from Suzanne Rudzinski, Director, Office of Resource Conservation and Recovery, to Tim Hunt, American Forest and Paper Association (May 13, 2011).

¹¹⁰ UIC, *supra* note 11, at § 144.12(b). See also Natural Resources Defense Council v. U.S. EPA, 907 F.2d 1146, 1158 (D.C. Cir. 1990).

The EPA's concern connecting CGS with RCRA has been that the capture process may result in CO₂ injectate that includes hazardous constituents that could cause the injectate to be a hazardous waste when stored or disposed.

However, such materials, if present at all, are expected to be present only in trace amounts. EPA also is concerned that hazardous wastes not intentionally be mixed into the injectate as a means of avoiding hazardous waste disposal regulation.

It is extremely unlikely that hazardous constituents could be present in CO₂ injectate in amounts large enough to cause environmental concern. Pipeline transportation standards limit the concentration at which any hazardous constituencies could be mixed with CO₂.

Furthermore, EPA's UIC regulations prohibit disposal of hazardous wastes into Class VI wells. EPA has recognized these facts and in 2011 proposed that CGS in Class VI wells be conditionally excluded from RCRA regulation.¹¹¹ A conditional exclusion is a recognized method to set aside RCRA regulation where its purpose is achieved via other regulation. As of this writing, EPA has sent its final RCRA exclusion to the Office of Management and Budget for review, the last review step before a regulation is made final. As of the publication of this document, EPA has finalized their regulation.¹¹²

C. Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA" or "Superfund")¹¹³ potentially could apply to CGS. Under Superfund, joint, strict, and several liability applies to owners, operators, generators, and transporters for the "release" of a "hazardous substance" where there "may be an imminent and substantial endangerment to the public health or welfare or the environment ..."¹¹⁴

CERCLA is not a regulatory statute. That is, it does not set forth requirements that facility owners and operators must follow when storing CO₂ or engaging in any other industrial activity. Instead, Superfund provides broad liability for hazardous substance releases, as set forth above.

A "hazardous substance" is a very broad term, incorporating by reference lists of not currently listed under any of those statutes, including RCRA. However, CERCLA does not by statute exclude releases of de minimis amounts of hazardous substances from liability, though as a matter of enforcement the EPA has done so. If CO₂ injectate includes trace elements of a hazardous substance, theoretically at least there could be liability under Superfund if the injectate later is released in a manner causing endangerment.

Practically speaking, liability is more likely to arise instead under the UIC permit issued by the State or EPA. Precedent suggests a court would consider whether it was physically possible and foreseeable that injection of CO₂ would cause a release of hazardous substances.¹¹⁵

¹¹¹ See 76 Fed. Reg. 48074 (Aug. 8, 2011).

¹¹² See 79 Fed. Reg. 350 (Jan. 3, 2014).

¹¹³ CERCLA, *supra* note 29. This statute imposes liability for releases of hazardous substances that threaten human health or the environment. It is unclear that it will apply since CO₂ is not a hazardous substance.

¹¹⁴ *Id.* at § 9606.

¹¹⁵ See, e.g., U.S. v. New Castle County, 769 F. Supp. 591, 596 (D. Delaware) ("[I]f a defendant's waste is a non-hazardous substance, a plaintiff must show that the defendant's waste is capable of generating or releasing a hazardous substance within the meaning of CERCLA.>").

A special concern with Superfund is its joint, strict and several liability, which might in some circumstances reach back up the chain of custody to CO₂ generators. An industrial source that generates CO₂ also may not run the CGS storage facility. Instead, they may rely on the expertise of the sequestration operator to properly sequester, manage, and monitor the CO₂ through post-closure.

Superfund includes an exemption from liability for a “federally permitted release.”¹¹⁶ Injection of CO₂ pursuant to a UIC permit, regardless of well class, would constitute a federally permitted release. However, that exemption has been applied narrowly and would not reach a case where a hazardous substance was not permitted to be released. If injection causes a hazardous substance to be released in a manner not provided for in a permit, it is unlikely to qualify as a federally permitted release.

The Task Force believes that CERCLA is unlikely to apply. However, federal liability certainly applies to CGS through the UIC program.

D. Clean Air Act. Largely, the Clean Air Act(CAA)¹¹⁷ does not apply to CGS facilities because they do not emit Greenhouse Gases (GHGs) to the atmosphere. However, some of its regulatory provisions do apply to those facilities, and others are discussed herein because of their significant relationship to and potential impact on CGS operations.

Greenhouse Gas (GHG) Reporting Rule. Originally finalized in 2009 and 2010, EPA’s GHG Reporting Rule requires reporting of GHG emissions data and other relevant information from large sources and suppliers in the United States. Three sections of the rule are potentially relevant for CGS: (1) subpart PP¹¹⁸, which applies to suppliers of CO₂; (2) subpart RR¹¹⁹, which applies to the geologic storage of CO₂; and (3) subpart UU¹²⁰, which applies to the non-storage injection of carbon dioxide.

Compliance with subpart RR carries with it additional obligations. A key part of subpart RR is the requirement for the owner or operator of the CGS site to develop and submit to EPA a plan for monitoring, reporting and verification — a so-called MRV plan.¹²¹ EPA itself issues the final MRV plan, which is subject to administrative appeal.¹²² The administrative appeal process effectively subjects the final MRV plan to judicial review.

Unlike compliance with the preconstruction permits or operating permits under the Prevention of Significant Deterioration (PSD) program,¹²³ Title V program¹²⁴, and New Source Performance Standards (NSPS)¹²⁵ — all of which potentially apply to the CO₂ source — compliance with the GHG Reporting Rule (and subpart RR specifically) directly applies to the owner or operator of the CGS site. A violation of the GHG Reporting Rule is a violation of section 114 of the CAA, which deals with recordkeeping, inspections, monitoring, and entry.

¹¹⁶ CERCLA, supra note 29 at § 9607(j).

¹¹⁷ Clean Air Act, supra note 30.

¹¹⁸ 40 C.F.R. § 98.420.

¹¹⁹ 40 C.F.R. § 98.440.

¹²⁰ 40 C.F.R. § 98.470.

¹²¹ 40 C.F.R. § 98.448.

¹²² 40 C.F.R. § 98.448(c).

¹²³ 40 C.F.R. § 52.21.

¹²⁴ 40 C.F.R. part 70.

¹²⁵ 40 C.F.R. part 60.

Violations include but are not limited to failure to report GHG emissions, failure to collect data needed to calculate GHG emissions, failure to continuously monitor and test as required, failure to retain records needed to verify the amount of GHG emissions, and failure to calculate GHG emissions using specified methodologies. Each day of violation constitutes a separate violation.¹²⁶

NSPS. On April 13, 2012, EPA proposed new source performance standards (NSPS) for emissions of CO₂ for new affected fossil-fuel fired electric utility generating units (EGUs).¹²⁷ The proposed requirements, which strictly are limited to certain new sources, would require new fossil fuel-fired EGUs greater than 25 megawatt electric to meet an output-based standard of 1,000 pounds of CO₂ per megawatt-hour. New coal-fired or pet coke-fired units could meet the standard either by employing Carbon Capture and Storage (CCS) for approximately 50 percent of the CO₂ at startup, or through later application of more effective CCS to meet the standard on average over a 30-year period.

EPA has not finalized this proposal and on June 25, 2013, the Obama Administration stated in its new Climate Action Plan and related Presidential Memorandum that this proposal was being withdrawn but would be repropoed by September 20, 2013. Sources subject to other NSPSs, however, generally are required to perform an initial performance test to demonstrate compliance. To demonstrate continuous compliance some NSPSs require sources to utilize continuous emission monitors. Sources may also be required to monitor control device operating parameters to demonstrate continuance compliance. Further, NSPS-regulated sources that meet the CAA definition of “major source” generally receive a full compliance evaluation by state or regional regulators at least once every two years.

As above for the PSD and Title V programs, statutory compliance with the proposed NSPS presumably would rest with the CO₂ source not the owner or operator of the CGS site. However, this does not mean that the owner or operator of a CGS site would be immune from NSPS-related liabilities in the unlikely event of a containment failure. In such a scenario, it is conceivable that the CO₂ source would be deemed to be out of compliance with the NSPS. In turn, the CO₂ source may endeavor to pursue legal remedies against the owner or operator of the CGS site.

PSD Program/Title V Program. The PSD program imposes preconstruction permitting requirements on certain new major sources or major modifications at existing sources of air pollution. The Title V program similarly requires certain major stationary sources to obtain permits after they commence operations.

Both the PSD and Title V programs would apply to CO₂ sources. In regulations issued on June 3, 2010¹²⁸, and July 12, 2012¹²⁹, EPA specified that the PSD and Title applicability thresholds at 100,000/75,000 tons per year (tpy) in CO₂-equivalent (CO₂e) potential emissions.¹³⁰ A CO₂ source making use of CGS would almost certainly exceed these emission thresholds, thereby triggering PSD and Title V application for the source.

¹²⁶ 40 C.F.R. § 98.2.

¹²⁷ 77 Fed. Reg. 22392 (April 13, 2012).

¹²⁸ 75 Fed. Reg. 31514.

¹²⁹ 77 Fed. Reg. 41051.

¹³⁰ *Id.* at 41052.

Application of the PSD program in particular to the source would trigger a requirement that the source install Best Available Control Technology (BACT).¹³¹ BACT is defined as:

an emissions limitation ... based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant ...¹³²

For BACT purposes, EPA “classifies CCS as an add-on pollution control technology that is available for facilities emitting CO₂ in large amounts, including fossil fuel-fired power plants, and industrial facilities with high-purity CO₂ streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing.”¹³³ This does not necessarily mean that CCS will ultimately be determined to be BACT for a specific emission source, as other factors — to include technical feasibility and costs — may prove to be disqualifying. Still, CCS must be considered as part of the BACT analysis for large sources of CO₂ for PSD and Title V permitting purposes going forward.

It is unlikely that a CGS site itself would be subject to the PSD and/or Title V programs in the near future for several reasons.

First, even considering the possibility of fugitive CO₂ emissions or the failure of surface equipment, a CGS site is unlikely to trigger the PSD and Title V emission thresholds. EPA never has suggested that a CGS site would be subject to such programs. EPA also has taken the position that the PSD and Title V programs will not apply to stationary sources with a potential to emit of less than 50,000 tpy of CO₂e prior to 2016.¹³⁴

Second, even if a CGS site might in fact have air emissions that exceed the applicable PSD and Title V triggering thresholds, it is unclear if a CGS site would constitute the type of “stationary source” that EPA traditionally has regulated under the Clean Air Act. While the Clean Air Act definition of “stationary source” is broad, EPA historically has applied air emission requirements on discrete pieces of equipment or stacks.¹³⁵ EPA’s recent efforts to adopt a sweeping definition of “stationary source” in the analogous context of a geographically large oil and natural gas development was recently struck down by the courts.¹³⁶

¹³¹ The BACT requirement based on section 165(a)(4) of the Clean Air Act and applicable regulations. 40 C.F.R. §§ 51.166(j), 52.21(j).

¹³² 42 U.S.C. § 7479(3). The BACT analysis for a given emissions source is complex and beyond the scope of this report.

¹³³ UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, PSD AND TITLE V PERMITTING GUIDANCE FOR GREENHOUSE GASES 32 (Mar. 2011), available at <http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf>.

¹³⁴ 75 Fed. Reg. at 31522-525.

¹³⁵ 42 U.S.C. § 7602(z) (“The term ‘stationary source’ means generally any source of an air pollutant . . .”).

¹³⁶ W. Bumpers and P. Williams, *Sixth Circuit Pushes Back on Oil and Gas Aggregation under the Clean Air Act*, HARVARD BUSINESS REVIEW ONLINE 41 (2013).

Third and finally, given that a CGS site by purpose and definition is intended to prevent the source's CO₂ emissions from reaching the atmosphere, as a policy matter it might be awkward to envision and allow such sites to emit CO₂ in quantities that would require permits.

The potential liability of a CGS site under the PSD and Title V programs is uncertain. In the highly unlikely event that the owner or operator of a CGS site had to obtain a PSD and Title V permit for site construction and operations, the owner or operator presumably would become subject to the full weight of the Clean Air Act's compliance and enforcement mechanisms.

In the more likely scenario — i.e., the CO₂ source but not the CGS site is subject to PSD and Title V permitting — the potential liability, if any, of the CGS site is murky at best. If an atmospheric release of CO₂ were to occur at the CGS site, it is conceivable that environmental liabilities under the Clean Air Act still would attach to the CO₂ source despite the fact that the event occurred at the storage site.

As long as the CGS site does not hold a Clean Air Act permit itself, EPA presumably would lack legal jurisdiction to take enforcement action against the site owner or operator directly under the PSD and Title programs.

Interaction of Federal Laws

There is a concern among some that a confluence of legal obligations could, at least for the electric utility sector, which is the major source of anthropogenic emissions, create a situation in the case of a CGS facility leak that restricts entities from preventing liability. Electric utilities are obligated under state law and regulation to provide their customers with reliable service. If the power supply in a state relies on sources such as coal or natural gas that ultimately become subject to GHG emission limitations, the only choice to limit emissions may be to geologically store CO₂.

Note, for example, that the EPA's proposed GHG new source performance standard NSPS would establish a CO₂ emission rate limit of 1,000 lbs./MWh, applicable to both coal-fired and combined cycle natural gas units¹³⁷. Only through use of CCS technology would coal-fired units be able to meet that limit.

At that regulatory limit, CCS also may be needed for some gas units. If the CGS facility to which fossil-fueled generators are linked is not meeting regulatory requirements, because of a leak or otherwise, those generators may face the regulatory Hobson's choice of failing to meet their obligation to provide reliable electric service, emitting CO₂ into the air in violation of CAA regulatory limits, or contributing to violation of UIC regulatory requirements.

This is merely one example of potential regulatory and liability Catch-22s that may arise in connection with CGS. The Task Force recommends that ways to mitigate this risk be explored by state and federal agencies.

¹³⁷ Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77 Fed. Reg. 22392 (Apr. 13, 2012).

4.2 Canadian Federal Statutes

The *Canadian Environmental Protection Act, 1999* (CEPA 1999) is one of the Government of Canada's primary tools for achieving sustainable development and pollution prevention. One of CEPA 1999's major thrusts is the prevention and management of risks posed by harmful substances. It provides for the assessment and/or management of the environmental and human health impacts of new and existing substances. This includes products of biotechnology, marine pollution, disposal at sea, vehicle, engine and equipment emissions, fuels, hazardous wastes, environmental emergencies and other sources of pollution.

Under CEPA 1999, the Government of Canada recently passed the *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations* (Coal Regulations). These regulations apply a stringent performance standard to new and end-of-life coal-fired electricity generation units. Additional regulations are being developed as part of the government's sector-by-sector approach to address GHG emissions. While existing and any future emissions regulations would not apply directly to the permitting of CGS projects, a release of injected CO₂ that was captured at a federally regulated facility (e.g. a coal-fired generating unit) could lead to the facility being in non-compliance with the regulations.

In general, liabilities associated with CGS operations will fall under provincial jurisdiction. If the CO₂ was captured from a facility regulated by the Coal Regulations, the regulations do not address liabilities associated with stored CO₂ explicitly but recognize CO₂ emissions that are captured, transported, and stored in accordance with the laws of a province.

4.3 State Statutes

States have enacted laws similar to many of the major federal environmental laws, such as the SDWA, RCRA, and CERCLA. It is not possible to summarize those laws for the purposes of this report. A common principle is that federal environmental law typically requires that for states to gain administration and enforcement primacy, state programs must be no less stringent than federal requirements.¹³⁸ However, state laws may be more stringent than federal laws and may cause liabilities to arise under broader circumstances than those described above for federal laws. The states are often the implementing agencies for federal environmental laws, receiving delegated authority to implement federal laws via agreements with the EPA.

4.4 Common Law

Common law — law not set forth by statute but developed through court precedent — features a number of potential theories by which liability could develop for CGS operations. Most prominent among them are trespass, nuisance, and negligence or strict liability.

¹³⁸ States can apply for primacy in one of two ways for relevant purposes here.

To gain authority over Class VI wells only, states must apply for primacy under section 1422 of the SDWA, which requires state programs to be as stringent as federal law. States also must show that their regulations contain effective minimum requirements. State requirements may be more stringent than federal law.

To gain authority over Class II wells only, states with existing oil and gas programs may opt to demonstrate that their program is effective in protecting USDWs. Such states are authorized under section 1425 of the SDWA.

A threshold issue concerns ownership of the property that is being used for subsurface injection. Fee simple property ownership historically has extended the property right to the depths of the earth and the outer limits of the sky. Property ownership can be severed into parts. Subsurface mineral ownership often is divested from surface ownership. Indeed, geologic storage relies upon property owners (typically the surface owner) selling or leasing their pore space rights to a storage site developer. It is not necessary here to discuss the intricacies of various state laws regarding whether the pore space into which CO₂ will be injected is owned by the surface or the mineral owner, only to note that the extent of a permittee's property ownership affects some of the common law liability issues below.¹³⁹

The types of damages that could result in a claim would include personal injury, damage to surface property, or damage to subsurface resources.

Trespass. Subsurface injection of CO₂ may result in a CO₂ plume that over time spreads several miles in a radius from the injection well. The size of the plume will depend on a variety of site-specific factors, including the amount injected, the depth of the injection zone, and the rate and interplay of trapping mechanisms. A significant pressure front caused by brine mobilization may develop in addition to the spreading of the CO₂. Both the CO₂ and the brine may remain mobile for some time after the cessation of injection.

As previously recommended, the owners of a storage facility would be well-served to obtain the right to use a formation for CO₂ storage from property owners prior to receiving a storage facility permit.¹⁴⁰ In many states, the concept of "unitization" may apply. Under this concept, a permittee would not need to obtain rights to use all of the property into which the CO₂ will be injected. Instead, the permittee would need to acquire rights to use some percentage of the affected property, typically 50 to 85 percent, depending on state law. This bringing together of smaller parcels into common control so that an entire formation may be used for storage (or, more typically, resource extraction) is called unitization.

A trespass is the wrongful interference with a property owner's possessory rights. An element of trespass is that a harm must be caused. In the case of CO₂ migrating into pore space a mile or more below the surface, it is unclear whether a harm would be sustained. The Task Force concluded in the Task Force 2007 Guidance that subsurface trespass is "probably a cause of action,"¹⁴¹ but that the circumstances had yet to be defined.

Case law from activities similar to geologic storage might provide a guide to how the law of trespass may develop with respect to CO₂ injections.

EOR, being a form of geologic storage, is a suitable starting point. A body of law already has developed regarding EOR. Texas, for example, recognizes a principle called the "negative rule of capture,"

¹³⁹ See TASK FORCE 2007 GUIDANCE, *supra* note 2, at 15 (containing "Part 1: Analysis of Property Rights Issues Related to Underground Space Used for Geologic Storage of Carbon Dioxide" by David Cooney for a further discussion of this issue).

¹⁴⁰ Property rights are not required under the federal UIC program, because the Safe Drinking Water Act does not give the EPA authority over property rights issues, which are a matter of State law.

¹⁴¹ TASK FORCE 2007 GUIDANCE, *supra* note 2, at 20.

whereby “[j]ust as under the rule of capture a land owner may capture such oil and gas as will migrate from adjoining premises ... so also may [a landowner] inject into a formation substances which may migrate through the structure to the land of others. ...”¹⁴² The injection was justified because public policy favored production of oil and gas.

By contrast, hazardous waste disposal, an industrial activity regulated under a subclass of UIC Class I, shows a different history related to trespass. In an Ohio case, a valid hazardous waste injection permit did not preclude a cause of action for trespass.¹⁴³ Similarly, the Fifth Circuit Court of Appeals has held that a valid permit “does not necessarily bar claims of trespass when authorizing the disposal of waste through injection wells.”¹⁴⁴ While these hazardous waste cases may show that a claim is not barred, note that the plaintiffs had difficulty establishing in both cases that they used the subsurface and therefore were harmed by intrusion of hazardous wastes.

A key issue going forward is how courts will consider the issue of damages. It may be difficult to show trespass for mere occupancy of pore space of which the owner was making no active use, or no use supported by a public policy purpose, especially when injections of CO₂ for CGS are supported by the public purpose of reducing GHG emissions to the atmosphere. However, that may not be the fact pattern in all cases.

As a final note, in the case of injection into a non-hydrocarbon-bearing formation, trespass of CO₂ may be less likely to occur than trespass of brine. Permittees are required to calculate in advance the extent of the CO₂ plume over the life of the project. The extent of the pressure front and resultant brine intrusion may be beyond the project boundary, meaning brine intrusion is much more likely than CO₂ intrusion beyond the area where a permittee has assembled property rights. However, the brine in question may be of the same character as the brine already in place and thus the change in the pore space would be chemically indistinguishable.

Nuisance. Nuisance is a common law action similar to trespass. Where trespass involves intentional physical invasion of property, nuisance arises from substantial interference with the use and enjoyment of the property. CGS that harms nearby property or environmental resources or affects human health could constitute either a public nuisance or a private nuisance. A public nuisance is an “unreasonable interference with a right common to the general public” and generally would be asserted by a governmental body.¹⁴⁵ A private nuisance is a “nontrespassory invasion of another’s interest in the private use and enjoyment of land.”¹⁴⁶ A person with ownership of or interest in the land may assert the claim. A nuisance generally must either be intentional and unreasonable, or negligent, reckless, or subject to strict liability.

¹⁴² *Id.* at 21 (citing *R.R. Comm’n of Tex. v. Manziel*, 361 S.W.2d 560, 568 (Tex. 1962)).

¹⁴³ *Id.* at 22 (citing *Chance v. BP Chemicals, Inc.*, 670 N.E.2d 985 (Ohio 1985)).

¹⁴⁴ *Id.* at 22 (citing *Mongrue v. Monsanto Co.*, 249 F.3d 422, 433 (5th Cir. 2001)).

¹⁴⁵ Restatement (Second) of Torts, §§ 821B, 821C (1977).

¹⁴⁶ *Id.* at §§ 821D-828 (setting forth principles of private nuisance).

Subsurface injections have in the past resulted in nuisance claims. For example, nuisance claims have been raised for contamination of a private drinking water well from salt water injected for EOR.¹⁴⁷ This could result in damages being awarded even if the GS project is in compliance with state or federal permits.¹⁴⁸

Negligence. A reasonably prudent person owes a duty to use due care. If the person breaches that duty, and thereby causes an injury, they would be subject to liability for negligence. Thus, even if there were no federal or state laws requiring a permit to operate a geologic storage facility, an operator would still be liable for any action that caused a harm to others where due care was owed but not taken.

In a CO₂ storage context, a plaintiff would need to show that the CGS facility operator had a duty of reasonable care to the plaintiff, that the duty was breached by unreasonable conduct, and the result was harm to the plaintiff. “Reasonable” in the case of a specialized activity such as operation of a CGS facility means reasonable in light of the expertise to be expected in that context.

Strict Liability. Strict liability is a liability standard applied to activities that are of an inherently and abnormally dangerous nature. Strict liability means that an injured party may recover damages as long as the defendant is found to have caused the damage, regardless of whether the defendant perfectly was cautious. That is, it differs from negligence in that no deficiency in care must be shown. For example, in many jurisdictions a manufacturer of explosives would be liable strictly if his factory exploded and damaged neighboring property, even if perfect precautions were taken. In cases of strict liability, the burden of loss is on the actor who caused the damage, rather than harmed individuals who did not have the ability to protect themselves.

The presumption in common law historically has been in favor of negligence, that a standard of care is owed in the majority of cases, and that only in a minority of instances is an action sufficiently dangerous so that liability would attach even without negligence. Statutory law is different, often assigning liability without regard to negligence.

The Restatement (Second) of Torts lists six factors in considering whether an activity is “abnormally dangerous.” They include: (1) a high risk of harm to the person, chattel, or lands of others; (2) likelihood that the harm will be great; (3) inability to eliminate the risk by exercising reasonable care; (4) whether the activity is common usage; (5) inappropriateness of the activity where it is being conducted; and (6) extent to which the activity’s value to the community is outweighed by its dangerous attributes.¹⁴⁹

¹⁴⁷ See, e.g., *Gulf Oil Corp. v. Hughes*, 371 P.2d 81, 82 (Okla. 1962).

¹⁴⁸ See Michael D. Axline, *The Limits of Statutory Law and the Wisdom of Common Law*, in *CREATIVE COMMON LAW STRATEGIES FOR PROTECTING THE ENVIRONMENT*, 74-76 (Rechtschaffen & Antolini eds. 2007) (discussing how compliance with federal or State statutes or permits is not a defense to a common law claim for relief); Alexandra B. Klass, *Common Law and Federalism in the Age of the Regulatory State*, 92 *Iowa L. Rev.* 545, 583 & n. 215 (2007).

¹⁴⁹ Restatement (Second) of Torts § 520 (1977).

APPENDIX 1

Examples of Potential Interest to States & Provinces

APPENDIX 2

Bibliography

APPENDIX 1

Examples of Potential Interest to States & Provinces

Appendix 1.1 Example: Managing Long-Term Liability for CSG in Alberta

Greenhouse gas emissions are taken seriously in the western Canadian province of Alberta. With its oil and gas industry providing jobs for Albertans and royalties to the provincial government, innovative solutions were needed to secure Albertans' quality of life, protect the environment and maintain a healthy economy. Under the province's Climate Change Strategy, the Alberta government committed to reducing emissions below 2005 levels while at the same time allowing for growth within the oil industry.

Unveiled in 2008, Alberta's Climate Change Strategy takes a three pronged approach to reducing emissions. The strategy focuses on carbon capture and storage, conservation and energy efficiency and greening energy production. Together these initiatives are aiming for a 50 percent reduction in emissions by 2050 compared to business as usual, or a 14 per cent reduction below 2005 levels.

Specified Gas Emitters Regulation

Prior to this, Alberta became the first jurisdiction in North America to legislate a reduction in greenhouse gas emissions from large emitters in 2007. The Specified Gas Emitters Regulation requires all facilities in Alberta that emit more than 100,000 metric tons of carbon dioxide (CO₂) equivalent greenhouse gases per year to reduce their emissions intensity by 12 percent from an established baseline level. Facilities that exceed their emissions limit have three options to comply with the regulation, which include:

- **Paying a per tonne compliance fee.** Emitters that exceed their emissions limit pay \$15 into the Climate Change and Emissions Management Fund (CCEMF) for every tonne of CO₂ that they are over limit. The Alberta collects the funds, which are managed by the Climate Change and Emissions Management Corporation (CCEMC). An independent organization, CCEMC directs the funds collected toward innovative projects for reducing greenhouse gas emissions. Now in its fourth year of operations, CCEMC has contributed to 48 clean technology projects valued at more than \$940 million.
- **Purchasing Emission Performance Credits (EPCs):** EPCs are credits generated by regulated facilities achieving emission reductions beyond their mandatory 12 percent target. EPCs generated at a regulated facility can be banked for future use, or sold to other facilities that need to meet their reduction targets. EPCs offer incentive for regulated facilities to make emission reductions above and beyond their emissions target.

- **Purchasing Alberta-based emission offsets credits:** Large emitters can purchase credits from verified emission reductions and removals of greenhouse gases from unregulated offset projects within Alberta. This provides large emitters flexibility in compliance options and gives all sectors of the economy incentive to be innovative and invest in activities that reduce greenhouse gas emissions. Prices for Alberta offset credits are a function of supply and demand, and based on a negotiation between the buyer and seller.

Setting the Stage for Carbon Capture

The introduction of carbon capture and storage into the mix came at the time of booming growth in oil sands development. The combination of emissions from large industrial emitters (including oil sands, conventional oil and coal-generated electricity) and suitable geology for long-term storage of CO₂ provided an opportunity for more sizeable greenhouse gas reductions. While the emissions regulations were a way of meeting climate change goals in the near-term, the government of Alberta had to think longer term as it put in place a legislative and regulatory framework to enable carbon capture and storage in the province.

The first step to signal the government's commitment to emissions reductions through carbon capture and storage was passing the Carbon Capture and Storage Funding Act in 2009. This allocated up to \$2 billion to encourage and expedite the development of commercial-scale projects. Presently, \$1.3 billion has been allocated over 15 years to two projects that will reduce emissions from oil sands upgrading.

The first project is the Alberta Carbon Trunk Line, a 240 kilometre pipeline that will connect North West Upgrading's Sturgeon Refinery and the Agrium fertilizer plant with enhanced oil recovery projects in central Alberta. The Sturgeon Refinery, which will turn bitumen into diesel and other products, will be the first refinery in Canada to have built in carbon capture. The Quest project will see Shell's existing Scotford oil sands refinery retrofitted to capture 1.2 million metric tons of CO₂ each year, and then shipped 64 kilometres away for injection into a saline formation 1.2 miles deep.

The success of these projects relies heavily on the province having the right regulations in place. In 2010, the Alberta government passed a series of legislative amendments to enable carbon capture and storage. The most significant piece of this legislation was changes to the *Mines and Minerals Act* that defined ownership of pore space for the first time in Alberta, and allowed lease of that space to companies undertaking large scale carbon storage projects. [Reference: Mines and Minerals Act (Revised Statutes of Alberta 2000 cM-17), available at http://www.qp.alberta.ca/1266.cfm?page=m17.cfm&leg_type=Acts&isbn_cln=9780779772650&display=html].

The same act also was amended to take care of the long-term considerations of the transfer of post-closure liability to the Government of Alberta and the creation of the Post-Closure Stewardship Fund to manage the storage sites long after the projects' 15-year time frame.

While the amendments put the larger legislative pieces in place for carbon capture projects, a more thorough look was needed at the regulatory level. The Regulatory Framework Assessment was initiated in 2011 to make sure that the regulations needed to enable the day-to-day operations of the projects were in place. Working with government departments, the energy regulator, industry representatives and global experts, Alberta set out to examine what changes to its regulations were

needed to make sure that carbon capture and storage is conducted in the safest and most environmentally responsible way possible.

The final report of the Regulatory Framework Assessment is currently awaiting approval, and its recommendations will shape any changes to carbon capture and storage regulations in Alberta in the coming years.

Transferring Long-Term Liability for Carbon Capture Projects

The public needs to be confident that carbon capture and storage sites meet all of the closure requirements before the government assumes liability for them. The *Mines and Minerals Act* provides the Minister of Energy the ability to issue a closure certificate to a CCS project. Once this is done, the provincial government takes on long-term liability for the CO₂ stored underground, becoming the owner, operator and licensee of any remaining wells and facilities. Once this occurs, the original operator of the project is indemnified against any liability going forward with the site or the CO₂.

Currently, there is no assumption of climate liability pertaining to responsibilities under the *Climate Change and Emissions Management Act*. Under this act, Alberta has a regulated carbon offset market where offset credits can be purchased by large industrial emitters or other interested parties. CCS offers an opportunity to generate offset credits by sequestering CO₂.

The large industrial facilities that are regulated under Alberta's Specified Gas Emitters Regulation can then use the credits to meet their own compliance obligations or sell the credits that they generate to other industrial emitters who need to comply with reduction obligations. Offset credits would be generated for every tonne of sequestered CO₂ from eligible and participating projects. [Footnote: A draft Quantification Protocol for the Capture of CO₂ and Storage in Deep Saline Aquifers is currently being reviewed by the Government of Alberta.]

If there is loss of CO₂ containment from a sequestration site during the post-closure period, it will be necessary to account for the quantities of released CO₂ in order to ensure accurate greenhouse gas accounting and reporting in the province. As owner of the CO₂ in the post-closure period, the government of Alberta has recommended that it should accept liability for reconciling CO₂ credits or other climate change obligations that may be required [Reference: "Carbon Capture and Storage — Summary Report of the Regulatory Framework Assessment" Alberta Energy (2013) available at <http://www.energy.alberta.ca/Initiatives/3544.asp>].

Assumption of these liabilities will be important for building confidence in Alberta's climate change accounting and reduction program. The closure requirements outlined in the monitoring, measurement and verification and closure plans will benefit the ability for the government of Alberta to ensure that these liabilities will not be overly burdensome.

By issuing a closure certificate, the government of Alberta will signal that it is confident that the CO₂ permanently and safely has been sequestered at the site.

The Mines and Minerals Act outlines the specific terms under which a closure certificate can be issued. These include:

- the operator has abandoned all wells and facilities;
- the operator has met reclamation requirements;
- the closure period, which has not been defined, has passed;
- all requirements specified in the regulations have been met; and
- the CO₂ is behaving in a stable and predictable manner with no significant risk of leakage.

It has been suggested that the closure period be a minimum of 10 years after the injection of CO₂ concludes. Additional criteria that have been recommended for the list of closure criteria include:

- a decreasing risk profile; and
- the absence of significant adverse effects of CO₂ or affected fluids on health, the environment and other resources.

The creation of the Post Closure Stewardship Fund, paid into by industry, will help cover the obligations assumed by the province after closure. Carbon capture and storage operators will pay a per tonne rate into the fund during the injection period, and will be used to fulfill the obligations of long-term liability, including monitoring the injected CO₂ and paying for any reclamation activities required. Costs associated with indemnifying the former operator against damages cannot come from the Post Closure Stewardship Fund.

It has been recommended that the fund should be made up of three broad categories — monitoring and maintenance; unforeseen events; and administrative costs. It also is recommended that rates be risk-based and project-specific, and that contributions into the Post Closure Stewardship Fund be pooled so that they are available to cover costs from any carbon capture and storage project.

By the time projects begin injecting CO₂ in 2015, the combined output of Alberta's conventional oil and crude bitumen will equal three billion barrels per day. The province's existing emissions regulations and carbon capture and storage will help Alberta reduce its greenhouse gas emissions. It is anticipated that by 2016, the two projects will be capturing 2.76 million metric tons per year over 10 years, in what could be just the start for carbon capture and storage projects in the province.

Appendix 1.2 Example: State of Wyoming

In 2007, Wyoming policymakers foresaw the possibility of industrial scale development of CGS with the increasing commercial and federal interest in Integrated Gasification Combined Cycle and other technologies focused on sequestering carbon at the power generation source. Recognizing the importance of CGS to Wyoming's economy, and in particular, its continued productive use of its carbon-based resources, Wyoming's leadership embarked on an effort to develop a clear legal framework that would enable the development of CGS in Wyoming.

In 2008, Wyoming passed the first of several laws pertaining to geologic sequestration. House Bill 90 authorized the state geologist, oil and gas supervisor and the director of the Department of Environmental Quality (DEQ) to convene a working group for the purpose of developing an appropriate bonding procedure and other financial assurance methods to assure adequate financial resources were provided to pay for mitigation or reclamation costs that the state may incur as a result of default by the permit holder, which bond or other financial assurance requirement shall be required during the operating life and throughout the post-closure care period.

The working group also was asked to recommend the duration of the post-closure care period. In 2009, the legislature also passed three additional laws regarding ownership of the pore space, ownership of the material injected into a geologic sequestration site and unitization of geologic sequestration sites.

Wyoming's leadership recognized that without a financial assurance foundation to address liability issues, CGS would likely fail to advance. The legislature identified the need to develop a financial assurance regime which offers assurances to both the public and private sector and which appropriately manages the risks inherent to geologic carbon sequestration activities in Wyoming.

The working group sought to develop an integrated framework which provided a menu of financial instruments that ensure funds are adequate, if and when needed, and readily available to pay for site closure, post-closure and corrective activities, both now and in the future in the event of default by the permit holder or failure of the containment zone after the end of the permit term.

Geologic sequestration was broken into four phases, each of which was considered separately from a financial assurance standpoint. The phases included site characterization and permitting; operations including injection, monitoring and closure tasks; post-closure including monitoring until plume stabilization is confirmed; and long-term stewardship after bond release and permit termination, where the sequestration site still requires periodic monitoring.

Timeline estimates were developed for each of these phases. Notably, post-closure was assumed to be at least 10 years and long-term stewardship/monitoring was indefinite. After the release of Wyoming's report, EPA defined project phases; these phases mapped fairly closely to Wyoming's recommendations.

Risk levels were developed during each phase of the project to guide the assessment of financial assurance levels. The highest level of risk was perceived during the injection period, or the operating

phase, with a decline in risk after injection ceases and pressure reduces. Both the duration and the scope of long-term risk was considered likely small, though non-zero.

Major categories of risk were identified and include contamination of underground water, including potable water; trespass, specifically mineral rights infringement; atmospheric release of carbon dioxide; and property damage, including changes to surface topography and structures.

Special consideration was given to the potential effects of fluid displacement in saline aquifers and the potential need for pressure relief through brine removal along the hydraulic front.

To better understand and quantify risk and therefore appropriate financial assurance levels, Wyoming identified potential features, events and processes that could occur in each of the categories, then ranked the probability of occurrence in the post-closure and long-term stewardship phases.

The working group's recommendation for the duration of the post-closure period included both a timeframe and a requirement for monitoring data verifying plume stabilization. It suggested numerous characteristics for plume stabilization, such as acceptable reservoir pressure levels; stabilization of water chemistry in the reservoir zone; acceptable levels of pH, salinity, metals, etc.; no measurable surface subsidence; plume migration within acceptable limits; and acceptable levels of ambient CO₂ around abandoned wells.

The Wyoming legislature accepted the working group's recommendation and passed a state statute in 2010 requiring that the administrator certify that plume stabilization as defined by rule has been achieved without the use of control equipment based on a minimum of three consecutive years of monitoring data prior to issuing a release certificate.

Furthermore, closure shall not occur less than 10 years after the date when all wells excluding monitoring wells have been plugged appropriately and abandoned, all subsurface operations and activities have ceased, and all surface equipment and improvements have been removed or appropriately abandoned.

The administrator also shall certify that monitoring and remediation is sufficient to show that the carbon dioxide injection into the geologic sequestration site will not harm or present a risk to human health, safety or the environment, including drinking water supplies, consistent with the purposes of the statute and the rules and regulations adopted by the council. The Department of Environmental Equality is writing the rule referenced in this statute presently.

The working group evaluated financial assurance instruments and their applicability for each phase of a CGS project. It also endeavored to determine a range of financial assurance levels for a mid-sized project with a 60M ton/annum injection. It was clear that many of the traditional financial assurance vehicles would be appropriate for components of a CGS project.

For example, traditional forms of bonding are appropriate for well-capping, reclamation, and mitigation activities. However, the availability and applicability of traditional financial assurance in the post-closure and long-term stewardship phases was less certain.

The working group recommended, and the legislature adopted, a new statute which established a Special Revenue Account to fund monitoring, measurement, and verification by DEQ after site-closure

certification, release of all financial assurance instruments and termination of the permit.

The statute directs DEQ promulgate rules to collect funds.

While these rules are still in development, it is anticipated that the Special Revenue Account will be funded privately with fees collected through a per ton injection fee and/or a closure fee. The statute further states that the creation of the Special Revenue Account does not constitute an assumption of liability by the state for CGS sites or the carbon dioxide and associated constituents injected into those sites.

The working group also considered a Trust Fund concept to address long-term costs and liability post-closure for unexpected events. It believed that traditional financial assurance instruments or mechanisms might not be available or appropriate in the long-term stewardship phase. No statutory recommendations were made at that time and Wyoming as yet has not addressed financial assurance requirements in the long-term stewardship phase of a CGS project.

Wyoming's rule is in development but will seek to encourage good site selection, flexibility, and financial assurance levels that are set based on risk-based modeling. Overall cost estimates are likely to vary greatly based on specific site attributes, amount of CO₂ to be injected, and the duration of the project. The Special Revenue Account funding mechanism also will be established based on either a per-ton injection fee or a closure fee. The issue of financial assurance during the long-term stewardship phase remains open though is not within the scope of the rules being developed by DEQ.

Appendix 1.3 Example: Mandan Remediation Trust

The Mandan Remediation Trust was created as a result of the largest environmental settlement in North Dakota's history. It all began in 1985 with the discovery of diesel fuel in the subsurface during the construction of the Morton County-Mandan Law Enforcement Center.

Following subsequent investigations, the North Dakota Department of Health estimated that over a 30-year period, approximately three million gallons of diesel fuel were released into the ground as a result of fueling activities at the Burlington Northern rail yard. In 1985, the North Dakota Health Department ordered Burlington Northern to begin removing diesel fuel contamination from near the release site.

From 1985 to 2000 BNSF Railway recovered approximately 650,000 gallons of diesel fuel. The pollution led to a halt in new construction and ultimately an end to investment and lending for development of a 30-acre area in the heart of Mandan's central business district.

The Morton County–Mandan Law Enforcement Center basement was plagued with fuel odors, downtown Mandan lost businesses and investments due to the fear associated with potential clean-up costs, and local citizens expressed their concerns.

In 2000, BNSF Railway denied responsibility for any remaining fuel contamination or environmental damage and refused to conduct additional clean-up causing remedial efforts to cease. The North Dakota Department of Health was forced to take over clean-up efforts using funds from the leaking underground storage tank trust fund.

In 2002, the North Dakota Department of Health and the City of Mandan joined together in a lawsuit against BNSF Railway to accelerate the clean-up efforts. In addition, multiple private lawsuits against BNSF Railway for health impacts were settled confidentially.

In 2004, the North Dakota Department of Health and the City of Mandan agreed to settle the lawsuit with BNSF Railway for \$30.25 million, the largest environmental settlement in the North Dakota history. The Mandan Remediation Trust was created to pay for the clean-up of the diesel fuel contamination and \$24 million of the settlement was deposited in the trust.

Of the remaining settlement funds: \$2.5 million was placed in a Mandan supplemental Environmental Projects Trust, \$1 million was paid to the state as a penalty for violations of North Dakota laws, \$500,000 was paid to reimburse the state's Leaking Underground Storage Tanks trust Fund, \$1 million was paid to the City of Mandan as reimbursement for legal fees, and land and buildings valued at \$1.25 million were transferred to the City of Mandan.

The settlement also addressed BNSF Railway's continued responsibility for the contamination in the Mandan rail yard and the state's right to bring future enforcement actions for any new contamination. Settling the case allowed the parties to avoid a trial, the associated costs, and the uncertainty that accompanies litigation.

The Mandan Remediation Trust has three Trustees: a designee of the North Dakota Department of Health, a designee of the City of Mandan, and an additional Trustee chosen by mutual agreement of the Trustees designated by the North Dakota Department of Health and the City of Mandan. A majority vote of the Trustees is required to act for the Trust, except that a unanimous vote of the Trustees is required for decisions concerning project scope, selection of technology for remediation, selection of contractors for remediation projects, and public health and safety issues.

After the completion of the clean-up efforts, any remaining funds in the Mandan Remediation Trust will be transferred to the Mandan Supplemental Environmental Projects Trust to benefit the city.

In December 2004, environmental engineering firm Leggette, Brashears, & Graham (LBG) was awarded the Mandan Downtown Remediation Project, funded through the Mandan Remediation Trust to plan and implement the diesel fuel remediation. The plan provides for the extraction, treatment and disposal of diesel, contaminated groundwater, and soil vapor. The project included up to five years for active remediation, with several additional years for hot-spot remediation and follow-up monitoring.

The remediation strategies entailed soil-vapor extraction and a multi-phase extraction plan that included a gaseous phase, a free-phase diesel phase, and a ground-water phase. Installation of five miles of pipe south of Main Street began in 2005 to connect 75 extraction wells to the main treatment facility, which was built on a downtown site. Satellite treatment buildings were constructed near First Avenue NW and at a fire station which will be utilized as an additional truck bay at the completion of the remediation. The multiphase extraction plan called for drilling of 280 extraction wells an average of 25 feet down into the aquifers.

Many business owners agreed to have remediation wells drilled in their basements to keep sidewalks and streets intact. The wells removed the freephase diesel fuel by first separating the air from the fluid and then the fluids from the gas. The products collected were moved through pipes to the treatment building, where the diesel and vapors were separated from the water and air. The water and air were treated and released, and the diesel was recycled.

The soil-vapor extraction phase, which utilized the same wells installed for the multi-phase extraction, used bioventing methods that introduced oxygen into the soil to feed the bacteria, speeding up the soil scrubbing process. To date, more than two million pounds of hydrocarbons have been removed from the contaminated area.

The contamination has had a significant impact on the economic viability of Mandan's central business district. Fear of clean-up and health liabilities held back investment and made it nearly impossible for new businesses to get loans. During the 2005 North Dakota legislative session, liability protection legislation was enacted.

The legislation provides lender liability protection delegating authority to the North Dakota Department of Health to establish institutional controls, give site-specific responsibility exemptions, or regulatory assurances to owners, operators, or lenders for contaminated properties. The City of Mandan followed up the legislation with an ordinance creating an Environmental Institutional Control Zoning District. As a result, local financial institutions are becoming much more comfortable in accepting property as collateral on loans for building purchases, remodeling, or additions in downtown Mandan.

The Mandan project includes a very comprehensive outreach program intended to keep the local community fully informed of all ongoing remediation activities. The program includes public input and education interviews and a public relations campaign.

The project team has established a web site that is updated regularly and publishes a periodic newsletter. In addition, several special public information meetings have been held to solicit input and inform the public of the project's history, approach, and goals.

Considerations of Example. Consider the complexity of what was required to carry out the remediation efforts and if a private enterprise such as BNSF Railway would have been able to achieve what the Mandan Remediation Trust was able to accomplish. The Mandan Remediation Trust created a transparent working relationship between those affected by the diesel fuel contamination and those tasked with the clean-up of the contamination.

The clean-up efforts required streets to be torn up for the installation of pipelines, buildings to be bought and demolished, and additional buildings to have wells drilled in the basements. Local businesses, Mandan residents, local officials, the Mandan City Commission, LBG, and the Remediation Trust all had to agree on the best way to minimize disruption to businesses, residents, and visitors while getting installing the remediation system as quickly as possible. BNSF Railway almost certainly would have met resistance while attempting to implement the aggressive multi-phase remediation plan. The Mandan Remediation Trust is an example of a successful solution to a complex issue.

It is important to consider the Mandan Remediation Trust and how it can be applied to the states and provinces role in long-term monitoring and liability of CGS projects. North Dakota has established a Carbon Dioxide Trust Fund for the long-term monitoring and management of a closed CGS facility based on the logic and success of the Mandan Remediation Trust.

It is the position of the Task Force that the states and provinces that are best positioned at this time to administer a regulatory system, particularly given the ownership issue and the states and provinces proposed long-term "caretaker" role.

Appendix 1.4 Example: “Layered” Federal Risk Management Proposal

In 2010, a group of entities — including Southern Company, Duke Energy, Environmental Defense Fund, and Zurich — proposed a liability approach similar to the Price Anderson Act that covers liability for the domestic commercial nuclear energy fleet in that it allocates liability to parties in risk layers.

Under this layered proposal, the U.S. Secretary of Energy could enter cooperative agreements with a limited number of (roughly 80) storage facilities. The layers would apply with some variation during all phases — site operation, post-injection site care, and post-closure.

Under this approach, if damages were to occur related to a geologic storage facility, the facility owner/operator would be responsible for those damages up to a capped amount per incident. This amount is the “first layer.”

If the damages were greater than the capped amount, each facility that had a cooperative agreement with the Secretary would have to pay a pro rata share of the excess, again up to a capped amount. If the damages were still greater than this second layer, the federal government would be responsible for the excess, up to a capped amount.

If damages were greater than these three layers combined, the remainder would be the responsibility of the owner/operator. Again, the structure would be in place beginning with operation and would endure even after site closure, a distinction from other risk management ideas.

This proposal reflected a variety of policy considerations, not all of which were shared by all parties to the agreement. Perhaps most surprising to those who have looked at other risk management structures is that some commercial entities do not view long-term liability as an impediment to proceeding with geologic storage.

Another is that liability should be a shared responsibility. If geologic storage is being undertaken to serve a federal mandate for the benefit of society, the federal government should share in the responsibility for this policy choice. Nevertheless, companies should retain the primary risk.

Another thought was that it may not be economically efficient to establish a trust fund to cover a large future remediation bill that never may arise. A trust fund that grows over time will have the largest balance years in the future when the risks can be expected to be lowest. However, the proposal did include establishment of a trust fund to cover long-term costs that were likely to arise, such as post-closure monitoring and maintenance.

The parties devising the “layered” approach also considered that over time, industry and regulators would build experience with CGS. In part for this reason, the proposal is limited to the first 80 or so sites and later projects are eligible for lesser amounts of government indemnity than early projects. A successful learning period with CGS in a variety of different geologic formations and under a variety of conditions will provide confidence that should make it easier to resolve risk management issues when planning and developing a CGS facility. A similar proposal by former Senate Energy and

Natural Resources Committee Chairman Jeff Bingaman (D-NM) employed a limited approach for the same reason, but covered fewer sites.

This proposal may offer some useful concepts as states consider various options for addressing liability related to geologic storage.

APPENDIX 2

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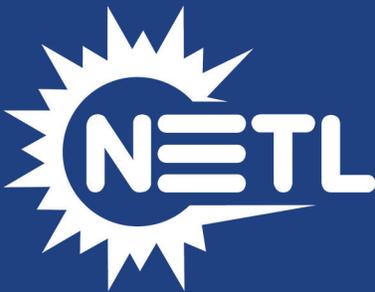
IOGCC

Interstate Oil and Gas Compact Commission
900 NE 23rd Street
Oklahoma City, OK 73105
(405) 525-3556
www.iogcc.ok.gov



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led by Energy and Environmental Research Center (EERC)
University of North Dakota
15 North 23rd Street, Stop 9108
Grand Forks, ND 58202
(701) 777-5000
www.undeerc.org



NETL

U.S. Department of Energy
National Energy Technology Laboratory
626 Cochrans Mill Road
Pittsburgh, PA 15236
(800) 553-7689
www.netl.doe.gov