New York State Energy Research and Development Authority

Carbon Sequestration Feasibility Study in the Chautauqua County, New York Area

Final Report

December 2011

No. 12-07

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Carbon Sequestration Feasibility Study in the Chautauqua County, New York Area

Final Report

Prepared for the

New York State Energy Research and Development Authority

Albany, NY
nyserda.ny.gov

John Martin
Senior Project Manager

Prepared by:
Ecology and Environment, Inc.

Robert Singer
Project Manager

NYSERDA
Report 12-07

NYSERDA 10498

December 2011

Project Overview

This project evaluated the feasibility of using geological formations for long-term storage of carbon dioxide (CO_2) derived from a proposed redevelopment of the Carlson Power Plant into an oxy-coal demonstration power plant in Jamestown, New York. The feasibility study was developed to evaluate selected geologic formations in Chautauqua County to determine capacity as a regional facility for carbon capture and long-term storage (sequestration) of CO_2 emissions from other existing and proposed projects in the area. In addition, the project studied regulatory, legal, and issues related to carbon capture and sequestration (CCS) throughout New York State.

The project team consisted of geologists, planners, ecologists, and attorneys. Sub-contracting, collaborative services, and cooperation were provided by Battelle (geology), Schlumberger Carbon Services (seismic survey, well bore data), GeoSeq (CCS), NYS Museum (geology), Unbridled Energy (well drilling), and NYS Department of Environmental Conservation (NYSDEC) (regulatory advice). The senior management team for Ecology and Environment, Inc. (E&E) included George Rusk, Esq., Robert Singer, Ph.D., Janine Whitken, and George Lukert.

The project was coordinated to take advantage of other research and planning efforts in western NY. The Jamestown Board of Public Utilities (JBPU), under the leadership of David Leathers, received a planning grant to conduct well drilling and feasibility studies from the NYS Legislature. The results of the JBPU work contribute to this study. Praxair, Inc., of Tonawanda, NY, provided planning services for JPBPU, and much of this design information was used to estimate the volume and composition of the product that was planned for CCS. Other cooperating entities included the proposed Lackawanna Clean Energy project and the State University of New York in Buffalo.

Work began on this project in June of 2008, and the final progress report covered activities through December, 2010. The project successfully summarized the legal, regulatory, and insurance issues relevant to the development of CCS on a state-wide level with a focus around the Jamestown area. The results of the geological studies indicated only a moderate potential for large-scale sequestration at the initial test site. In addition, the U.S. Department of Energy (DOE) declined to provide financial support under the Clean Coal Power Initiative to JBPU to build the proposed Carlson Power Plant that would utilize oxy-coal technology. A new application for support to DOE is currently pending, which would provide support for additional CCS exploration.

Project Deliverables and List of Appendices

Each of the reports prepared for this project were provided to NYSERDA in Draft and Final form. The final versions of these products are included in the Appendix. The following products were developed as part of this project.

Carbon Sequestration Permit Strategy

Completion of this task included a workshop bringing together industry and regulatory experts, establishing work groups to perform strategic and technical analyses. The results were compiled in two key documents:

> **Environmental Permitting of Carbon Sequestration**. A white paper was prepared to identify potential applicable federal, state, and local permits and requirements for CO_2 capture, transport pipeline and injection wells.
>
> **Carbon Dioxide Capture and Sequestration: Developing a CCS Regulatory Strategy for New York**. This comprehensive, 155 page report, describes the existing regulations that control the injection and transport of CO_2, and it proposes modifications to existing regulations and laws that could be adapted to consider CO_2. It reviews issues of liability and insurance, and makes recommendations how "early movers" can receive incentives to make the large investments required to implement CCS.

Geologic Carbon Sequestration Site Selection
The sequestration site evaluation process included background research of existing data and acquisition of additional geologic data to support development of a sequestration strategy. The results were compiled in the following reports:

> **Interim Geological Background Report.** The report described the site selection process through a surface constraints analysis, an initial background description of the geologic framework of the Jamestown, New York area, and a summary of the area's seismic activity history.
>
> **Geological Report: Miller 2 Well**. This report describes the exploratory drilling at the Miller 2 well north of Jamestown that was conducted as part of this project. This was a "piggyback well," which extended the depth of the Miller 2 well that was being drilled for shallow gas extraction by Unbridled Energy. Drilling extended 7,308 feet below the surface, but bedrock was not encountered, and the Potsdam formation, which is a likely saline storage stratum, was not encountered. Higher strata had restricted porosity, rendering this site unsatisfactory for CCS.
>
> **Seismic Report**. This report describes seismic testing conducted at a second site southwest of Jamestown. Strata appropriate for CCS were determined to be present, but permeability and porosity were not able to be assessed from these 2D data.

Evaluation of Costs and Potential Benefits
Based on literature reviews and data available for the redeveloped Carlson Power Plant, potential costs and benefits of sequestration were evaluated and summarized in the report:

> **Evaluation of Costs and Potential Benefits for Carbon Capture and Sequestration**. This study evaluated the added capital, operations and maintenance costs of a hypothetical 100 MW oxy-coal power plant that utilized CCS. The potential impacts of several proposed legislative initiatives to mandate CCS on the levelized cost of electricity was presented.

Presentations for Meetings. Two presentations were developed for professional meetings that are included in this final report. In addition, minor modifications of these presentations were made at several other venues. The first presentation is entitled CCS *Regulatory Options.* It was presented at the 2009 annual meeting of the New York Chapter of the Air and Waste Management Association. A similar presentation was made at the annual CCS conference in Pittsburgh in 2009. Another presentation, *Recent Attempts at Commercialization of CCS—Lessons Learned*, was made at 2009 EUCI conference in Atlanta, GA.

Summary

This project successfully evaluated the barriers and challenges that limit the widespread adoption of CCS in New York State. Implementation of CCS is hampered by costs, regulations, scientific uncertainty, and risk. Proposed changes were explored that would reduce risk, raise the confidence of the industries that produce CO_2, and protect first movers from liability. These changes would require legislative adoption of CO_2 standards, regulatory development, insurance vehicles, and more exploratory geology. In each case, the products of this project include specific proposals to overcome the barriers to implementation.

Appendices

1. **Environmental Permitting of Carbon Sequestration**
2. **Geological Report: Miller 2 Well**
3. **Seismic Report**
4. **Developing a CCS Regulatory Strategy for New York**
5. **Cost Benefit Report**

Appendix 1.

Environmental Permitting of Carbon Sequestration

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Environmental Permitting of Carbon Sequestration

January 2009

Prepared for:

NYSERDA
Agreement No. 10498
Natural Gas and Petroleum Exploration and Production, Emissions Reduction, and Carbon Sequestration

Prepared by:

ECOLOGY AND ENVIRONMENT, INC.
368 Pleasant View Drive
Lancaster, New York 14086

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The State of New York currently does not regulate the injection and storage of CO_2. Nevertheless, New York does regulate natural gas storage reservoirs and the injection of brine. The State is actively studying the existing sub-sections of §23 of the Environmental Conservation Law that regulate these activities. For planning purposes, this analysis assumes that the current regulatory framework for natural gas storage and brine injection will be applied to CO_2 injection and storage.

There is currently no federal regulation of siting and rates for CO_2 pipelines due in large part to the fact that many of them are intrastate and that they often transport CO_2 for the benefit of the pipeline's owners (so there are no rate or service disputes). The Natural Gas Act of 1938 (NGA) vests in FERC the authority to issue "certificates of public convenience and necessity" for the construction and operation of interstate natural gas pipeline facilities. FERC is also charged with extensive regulatory authority over the siting of natural gas import and export facilities, as well as rates for transportation of natural gas and other elements of transportation service. Given the reluctance of FERC and the STB to exercise jurisdiction over CO_2 pipelines the regulation of existing CO_2 pipelines (except pipeline safety) has been left to the regulatory structures of the states where they are located.

Historically, USEPA has allowed injection wells for the purposes of injecting CO_2 to be classified as either a Class II or Class V injection well. EPA anticipates pilot CO_2 injection projects will be put into operation and that the Class V experimental technology well permits will bridge the gap between pilot and commercial-scale projects. In July 2008, USEPA proposed new requirements for injection wells used for the geological sequestration of CO_2. Part of this proposal includes a new well classification (Class VI) for injecting CO_2, as well as meeting particular geologic site requirements.

A preliminary review has identified potential applicable federal, state, and local permits and requirements for the CO_2 pipeline and injection wells, as well as permit amendments for the CO_2 emission source. Table 1-1 summarizes these permits and the appropriate agency.

Table 1-1 Potential Permits, Approvals, and Consultations Applicable to the CO_2 Pipeline

Agency	Permits/Approvals/ Consultations	Applicability
FEDERAL		
Federal Energy Regulatory Commission	Federal Certificate of Public Convenience and Necessity	Not applicable to CO_2 pipelines; FERC has declined to take jurisdiction over CO_2
U.S. Army Corps of Engineers (USACE)	Clean Water Act Section 404 Permit Rivers and Harbors Act Section 10 Permit	NWP 12 required if pipeline crosses regulated water body or jurisdictional wetlands
U.S. Fish and Wildlife Services (USFWS)	Section 7 Endangered Species Act Consultation Section 7/10 Take Permit	Consultation required if project is required to obtain NWP12. A take permit would be required if there is a potential to take, or harass a T&E species
Advisory Council on Historic Preservation	Section 106, National Historic Preservation Act	Consultation required if project is required to obtain NWP12
U.S. Department of Transportation, Federal Highway Administration	Federal Highway Encroachment Permit	Required in pipeline crosses federal highway
NEPA lead Agency	EIS or EA	If project includes a non-exempt federal action
STATE		
New York State Public Service Commission	Article VII Certificate of Environmental Compatibility and Public Need	Not applicable to CO_2 pipelines
New York State Historic Preservation Office	Cultural Resources (Section 106/NHPA) Consultation/Clearance	Consultation required if state or federal approval is involved
New York State Department of Environmental Conservation	Threatened and Endangered Species Consultation Water Quality Certification (Section 401 Permit) State Pollution Discharge Elimination System (SPDES) Construction General Permit for Stormwater Discharges Article 15 Protection of Waters; Article 24 Freshwater Wetlands	Section 401 WQC required as part of the Section 404 permit process. Article 15, 24, and/or 25 Permits required if project crosses regulated wetlands or protected streams

Table 1-1 Potential Permits, Approvals, and Consultations Applicable to the CO_2 Pipeline

Agency	Permits/Approvals/ Consultations	Applicability
	Article 25 Tidal Wetlands	
New York State Department of Transportation	State Road Use Permits Highway Work/Utility/Non-utility Permits Consultation	Permits required if pipeline crosses a state highway
New York State Department of Agriculture and Markets	Consultation with respect to impacts to agricultural lands	Consultation required if project impacts Ag lands
SEQRA Lead Agency	EIS	If project requires a state or local action
LOCAL		
County Highway Department	road use permits	If project crosses town/county road
Town/County Planning Board	Building permits/ Zoning approvals	If town/County has enacted local requirements

Because neither FERC nor the PSC have jurisdiction over CO_2, no license comparable to what would be required for a natural gas pipeline is required for a CO_2 transmission project in NY. Instead, the project would be subject to a comprehensive environmental review under SEQRA/NEPA and federal, state and local resource/regulatory agencies permits would be required for discreet portions of the project subject to their jurisdiction. The SEQR process and the related key permits are described further below.

1.1 State Environmental Quality Review Act (SEQR)

For the purposes of SEQR, the project will include the CO_2 generation source, the CO_2 transport pipeline, and the CO_2 injection wells for long-term storage. For projects which oxidize a carbon based fuel, it is anticipated that the carbon dioxide produced will be purified and compressed for transport and beneficial reuse or sequestration (storage). The CO_2 will be stored in a supercritical (almost liquid) state, approximately 7,000 feet or more below the ground contained beneath a layer of solid cap rock. This roadmap focuses on the permitting associated with the pipeline and injection wells since most CO_2 generation sources are currently permitted and operating. The unique aspects of these project components in the SEQR process are discussed below.

1.1.1 Scoping

Although an optional part of the formal regulatory process, scoping is a critical first step in any application of SEQR, and particularly on a project that has the potential to be of significant interest to the community. Scoping also provides an opportunity to identify critical issues that may need to be addressed in community outreach efforts. Given the high level of public interest expected for implementation of a major new technology and regulatory applications, a corresponding level of commitment to public outreach should be part of any CCS permitting effort.

1.1.2 Preparation of Draft Environmental Impact Statement

The DEIS must include a description of the project, its purpose, public need and benefits, a discussion of alternatives, a description of the environmental setting of areas to be affected, an evaluation of the potential significant adverse environmental impacts, and a discussion of potential mitigation measures. For the purposes of this generic permitting roadmap for CCS, unique studies or considerations for the transport and injection of CO_2 are described in the applicable resource area below.

A strategic objective of the DEIS is to ensure that the project is defined and assessed not only in terms of its "impacts," which are commonly perceived as negative, but also in terms of the significant overall environmental benefits of the project. The net positive effect on the environment from reducing impacts to air quality, water resources, solid waste generation, and other resource areas should also be described and quantified for the decision-making agencies.

Air Quality

This analysis should include a Greenhouse Gas Impact Analysis that fully assesses impacts and mitigation of greenhouse gas emissions. The methodology for the analysis should be based on DEC guidance, resources, voluntary GHG reporting programs, and published literature on life cycle GHG analyses.

Water Resources

This analysis should include baseline information for water resources relevant to the CO_2 pipeline and injection site location, including wetlands and waterbodies. In addition, this analysis should identify the additional water use associated with CO_2 capture, compression, and transport.

Groundwater in the region of the anticipated CO_2 storage area will be characterized as part of the UIC Permit application. Short and long term impacts of CO_2 storage in saline aquifers should be described based on the anticipated volume of CO_2 storage.

Geology and Soils

This analysis should summarize the in-depth studies that will be performed for the UIC Permit Application.

Noise

This analysis should address impacts from the addition of CO_2 capture, compression, transport, and injection equipment.

Socioeconomics

This analysis should address the potential benefits to the project under federal or state CO_2 markets.

1.1.3 Public Outreach

The public outreach should be initiated early in the permitting process. This will serve to maximize public knowledge of the project, identify issues of concern, and build community acceptance. This PIP should include at least one Public Meeting or Open House in addition to scoping. Fact sheets and/or news articles should be prepared in advance. The preliminary topics are descriptions of the proposed project, environmental review process, project benefits, etc.

1.2 Air Permitting

Air Permit Modification

It is anticipated that a modification to any existing air permits will be required to address new emission control equipment, changes in operating scenarios, and changes in emissions.

The draft application will be prepared in accordance with Part 201 NYSDEC air pollution control.

Because emissions from the operating mode with CCS are anticipated to be extremely low or near zero, it is not anticipated that PSD review will be applicable for this operating scenario. The assumptions regarding the duration operating scenarios with and without CCS could avoid PSD applicability for the facility. For new projects, the regulatory applicability analysis should include the quantitative analysis to make this demonstration of PSD applicability.

BACT Review

On December 18, 2008 Stephen Johnson, USEPA Administrator issued a Memorandum Regarding EPA's interpretation of regulations that determine pollutants covered by the federal PSD Permit Program. The Memo clarified that CO_2 is not "subject to regulation" under the PSD program, including the requirement to install the best available control technology (BACT), because existing regulations currently only require monitoring and reporting but do not require control of emissions of CO_2. According to the Memo, the intent of the Clean Air Act and subsequent regulations have been implemented consistently for pollutants subject emission or other regulatory limits, not just monitoring or reporting requirements. EPA concludes that CO_2 is only subject to monitoring provisions, and therefore is not subject to BACT.

Modeling Protocol and Air Dispersion Modeling Analysis

It is anticipated that modeling of CO_2 emissions will be required to address potential releases from the CO_2 pipeline or sequestration site. A modeling protocol and air dispersion modeling analysis in accordance with NYSDEC requirements may be necessary.

1.3 Water Resources and SPDES Permit Modification

An existing CO_2 emission source is anticipated to be operating under a State Pollutant Discharge Elimination System Permit for industrial and stormwater discharges. The objective for the SPDES and related water quality permitting activities is to accurately characterize the existing and future conditions within the criteria of applicable regulations to demonstrate compliance with water quality standards.

1.3.1 SPDES Industrial Discharge Permit Modification

Depending on the design of the capture system, changes to the SPDES Permit may be necessary. Review of engineering data, including the proposed water balance and related water quality design data, will be necessary to characterize the type and volume of wastewater streams to be discharged. This review should include a summary of applicable Federal, state and local regulations that may affect design and compliance.

The application must include a demonstration that the discharges comply with all applicable technology-based and water quality-based effluent limits.

1.3.2 SPDES Construction and Operations General Stormwater Permit and Stormwater Pollution Prevention Plan

A completed Notice of Intent (NOI) for Stormwater Discharges from Construction Activities General Permit and a Stormwater Pollution Prevention Plan (SWPPP) will be required to address such discharges. The Storm Water Pollution Prevention Plan (SWPPP) must include Water Quality and Quantity Control and Erosion and Sediment Control (E&SC) plans in accordance with the NYS Stormwater Management Design Manual (NYSDEC 2003) and NYS Standards and Specifications for Erosion and Sediment Control (NYSDEC 2005).

Stormwater impacts may occur during construction or operation. Construction of the CCS system will include clearing, grading, and excavation, which have the potential to impact surface water through erosion from stormwater runoff. During operation, stormwater impacts include erosion from stormwater runoff, and the potential for spills of chemicals or petroleum stored on site.

1.4 CO_2 Pipeline and Injection Wells

1.4.1 UIC Permit

Historically, USEPA has allowed injection wells for the purposes of injecting CO_2 to be classified as either a Class II or Class V injection well. A Class II well is defined as used to inject brines and other fluids associated with oil and gas production, and hydrocarbons for storage beneath the lowermost underground source of drinking water (USDW). A Class V well is defined as all injection wells not included in Classes I-IV. In general, Class V wells inject non-hazardous fluids into or above USDWs and are typically shallow, on-site disposal systems. EPA anticipates pilot CO_2 injection projects will be put into operation and that the Class V experimental technology well permits will bridge the gap between pilot and commercial-scale projects.

In July 2008, USEPA proposed new requirements for injection wells used for the geological sequestration of CO_2. Part of this proposal includes a new well classification (Class VI) for injecting CO_2, as well as meeting particular geologic site requirements. The proposal is currently out for public comment.

USEPA guidance on the scope of the application intends to ensure that sound science is used to evaluate the fate and transport of CO_2. The UIC application must address potential acute and chronic health risks from the migration of CO_2. The application must characterize the CO_2 stream prior to permit issuance. Displacement of native fluids and chemical constituents, movement of possibly hazardous impurities in injected fluids, and potential leaching and mobilization of naturally occurring metals and minerals in the injection and confining formations associated with CO_2 injection must be evaluated for the potential to endanger USDWs. USEPA guidance recommends that regulatory agencies make these determinations based on their knowledge of the specific geology at the site.

Based on current USEPA guidance, the application will include the components described below.

Demonstration of the Appropriateness of Injection Sites

The appropriateness of injection sites selected for pilot CO_2 injection must be demonstrated with respect to the goals of the project. The application must present geological evaluations to demonstrate that an adequate receiving and confining system for a CO_2 injection site exists with sufficient depth, areal extent, thickness, porosity, and permeability; no major non-sealing faults; a confining system of sufficient regional thickness and competency; and a secondary containment system that could include buffer aquifers and/or thick, impermeable confining rock layers.

Other factors include potential reactions between injected CO_2 and the rocks and fluids in the injection zone may impact injectivity. Analytical or numerical models of CO_2 containment or transport must be used to make these demonstrations.

The area of review (AoR) and test modeling/monitoring of CO_2 movement must be based on a zone of pressure influence, which also will consider some or all of the following:

- Reservoir transmissibility
- Injection rate
- Duration of CO_2 injection
- Total injection volume
- Boundary conditions (e.g., pinchout or sealing fault)
- Pressure-volume-temperature (PVT) behavior, and
- Injection depth.

Description of Injection Well Construction

The applicant must prepare a description of the injection well construction, including construction materials, casing, and cement appropriate to the geologic environment, the properties of CO_2, and the anticipated life of the project.

Injection Well Operation and Monitoring Program

The applicant must prepare a description of the planned operating procedures and how USDWs will be protected. Monitoring parameters (e.g., injection pressure, volume, and rate) that help gather the data needed to understand the behavior and potential leakage of CO_2 and impacts of CO_2 injection on well materials and receiving formations will be defined.

Site Closure

As with other injection operations, CO_2 injection projects must be closed and abandoned in a manner that is protective of USDWs (40 CFR 144.12). The CO_2 produced from the project will be of relatively low volume and of food grade quality. In this case, EPA guidance indicates that remediation will not be an issue.

1.4.2 DOT Pipeline Permits

United States Department of Transportation-related permits may be required for the CO_2 pipeline defined above if the pipeline crosses federal highway. Similarly a NYSDOT permit may be required if the pipeline crosses a state highway.

The DOT also regulates the design and construction of interstate pipelines in the United States. The pipeline program is administered through DOT's Pipeline and Hazardous Material Safety Administration (PHMSA), Office of Pipeline Safety (OPS). OPS develops regulations and other approaches to risk management to assure safety in design, construction, testing, operation, maintenance, and emergency response of pipeline facilities. Regulations applicable to natural gas and CO_2 pipelines are found at 49CFR Part 195. While the federal government is primarily responsible for developing, issuing, and enforcing pipeline safety regulations, the pipeline safety statutes provide for state assumption of the *intrastate* regulatory, inspection, and enforcement responsibilities under an annual certification if their standards are compatible with minimum DOT standards. Where states have not adopted comparable programs the federal standards are enforceable by DOT. In New York, the PSC is the certified DOT partner agency and administers the 49 CFR Part 195 program for natural gas pipelines, however, the PSC definition of a regulated "gas pipeline" does not include pipelines that transport CO_2, and consequently PSC does not currently have express authority to enforce 49CFR Part 195 with respect to CO_2 pipelines.

1.4.3 Federal and State Wetlands Permitting

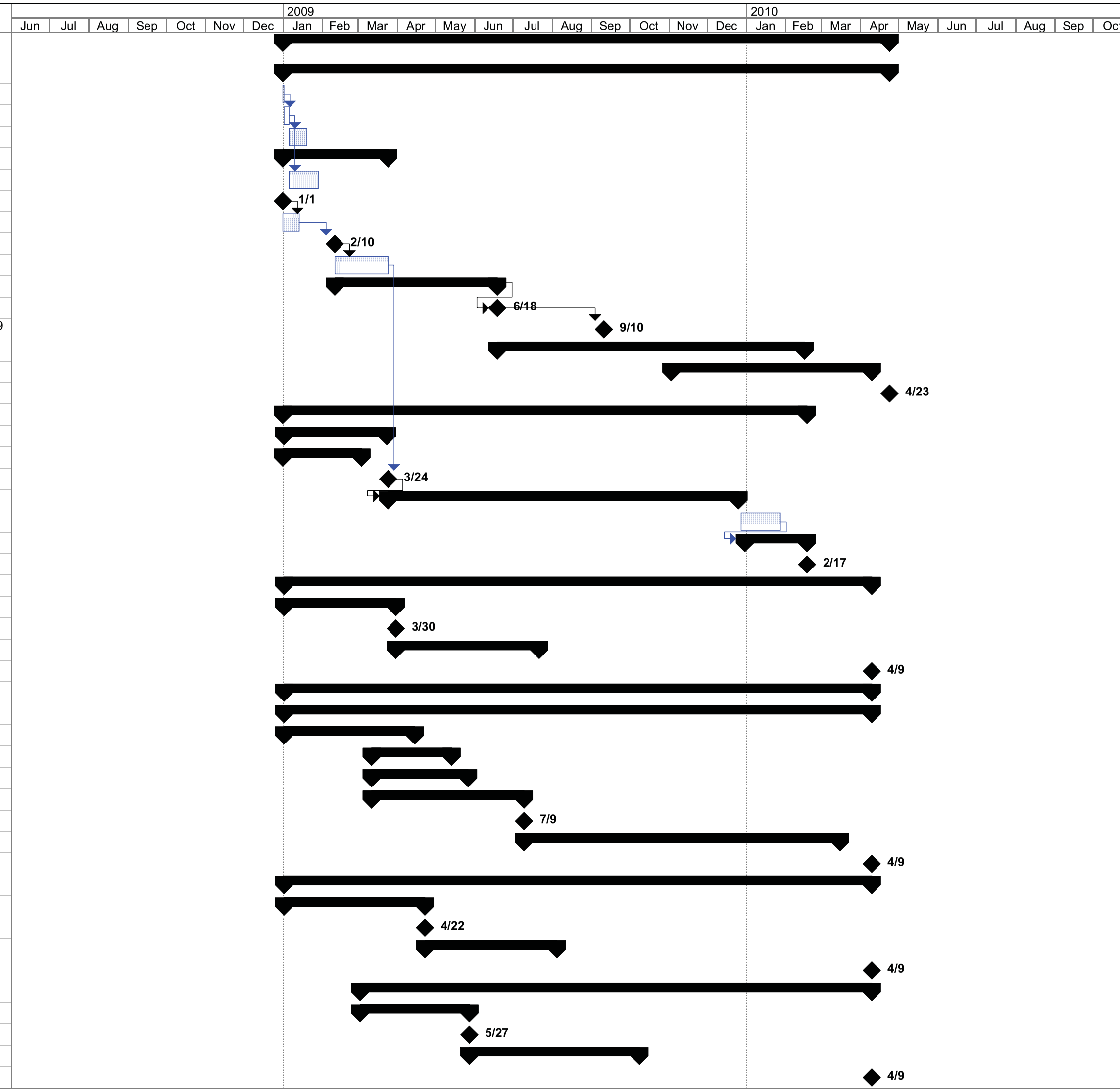
Most CO_2 pipelines are anticipated to cross or impact one or more wetlands. The applicant must address requirements for required state and federal wetland permits for the project, including required alternatives analysis. It is anticipated that most CCS projects will require a Joint Permit Application and NYSDEC jurisdiction under Article 24, Freshwater Wetland and Article 15, Protection of Waters. The Joint Application must include the application requirements of the United States Army Corps of Engineers, as well as NYSDEC

2 Anticipated Schedule for Permitting

Figure 1-1 (provided at the end of this section) illustrates the anticipated schedule for the environmental permitting described above. The schedule will depend on a number of site specific factors, including availability of engineering and design data and community interest.

ENVIRONMENTAL PERMITTING OF CCS
DRAFT GENERIC SCHEDULE

ID	Task Name	Work Days	Start	Finish	Predecessors
1	**ENVIRONMENTAL PERMITTING OF CCS**	**342 days**	**Thu 1/1/09**	**Fri 4/23/10**	
2	**Task 1: State Environmental Quality Review**	**342 days**	**Thu 1/1/09**	**Fri 4/23/10**	
3	Initiate Project	1 day	Thu 1/1/09	Thu 1/1/09	
4	***Agency pre-application meetings***	2 days	Fri 1/2/09	Mon 1/5/09	3
5	Prepare Environmental Assessment Form	10 days	Tue 1/6/09	Mon 1/19/09	4
6	**1.1 Scoping**	**59 days**	**Thu 1/1/09**	**Tue 3/24/09**	
7	Develop Draft Scoping Document	17 days	Tue 1/6/09	Wed 1/28/09	4
8	Submit Draft Scoping Document for Lead Agency review	0 days	Thu 1/1/09	Thu 1/1/09	
9	Lead Agency Review and Approval	9 days	Thu 1/1/09	Tue 1/13/09	8
10	***Scoping Meeting***	0 days	Tue 2/10/09	Tue 2/10/09	9FS+20 days
11	Compile and Review Scoping Comments	30 days	Wed 2/11/09	Tue 3/24/09	10
12	**1.2 DEIS**	**92 days**	**Wed 2/11/09**	**Thu 6/18/09**	
56	***Submit DEIS***	0 days	Thu 6/18/09	Thu 6/18/09	12
57	Open House(s) and Public Hearing	0 days	Thu 9/10/09	Thu 9/10/09	56FS+60 days,59
58	**1.4 Lead/Agency Review and Comment on DEIS**	**172 days**	**Fri 6/19/09**	**Mon 2/15/10**	
61	**1.5 Finalize EIS**	**114 days**	**Tue 11/3/09**	**Fri 4/9/10**	
66	***Final Decision***	0 days	Fri 4/23/10	Fri 4/23/10	64FS+20 days
67	**Task 2: PSD/NSR Construction Permit**	**295 days**	**Thu 1/1/09**	**Wed 2/17/10**	
68	**Air Quality Modeling Protocol**	**57 days**	**Fri 1/2/09**	**Mon 3/23/09**	
73	**Prepare Application**	**44 days**	**Thu 1/1/09**	**Tue 3/3/09**	
78	***Submit PSD/NSR Construction Permit Application***	0 days	Tue 3/24/09	Tue 3/24/09	11
79	**Agency Review, Comment, and Draft Permit**	**198 days**	**Wed 3/25/09**	**Fri 12/25/09**	**78**
86	***Pubic comment period / hearing***	**23 days**	**Mon 12/28/09**	**Wed 1/27/10**	**85**
87	**Response to comments**	**35 days**	**Thu 12/31/09**	**Wed 2/17/10**	**86FS-20 days**
90	***Final Permit***	0 days	Wed 2/17/10	Wed 2/17/10	88
91	**Task 3: Wastewater Discharge Permit Modification & Stormwater**	**331 days**	**Fri 1/2/09**	**Fri 4/9/10**	
92	**Prepare Application**	**62 days**	**Fri 1/2/09**	**Mon 3/30/09**	
97	***Submit Wastewater and Storm Water Applications***	0 days	Mon 3/30/09	Mon 3/30/09	96
98	**Agency Review, Comment, and Draft Permit**	**81 days**	**Tue 3/31/09**	**Tue 7/21/09**	
101	***Final permits issued***	0 days	Fri 4/9/10	Fri 4/9/10	100,65
102	**Task 4: Pipeline and Well Permits**	**331 days**	**Fri 1/2/09**	**Fri 4/9/10**	
103	**UIC Permit Application**	**331 days**	**Fri 1/2/09**	**Fri 4/9/10**	
104	**Demonstration of Appropriate Site**	**73 days**	**Fri 1/2/09**	**Tue 4/14/09**	
107	**Injection Well**	**45 days**	**Thu 3/12/09**	**Wed 5/13/09**	
110	**CO2 Fate and Transport Modeling**	**54 days**	**Thu 3/12/09**	**Tue 5/26/09**	
113	**Draft UIC Application**	**86 days**	**Thu 3/12/09**	**Thu 7/9/09**	
118	***Submit UIC Application***	0 days	Thu 7/9/09	Thu 7/9/09	117
119	**Agency Review, Comment, and Draft Permit**	**177 days**	**Fri 7/10/09**	**Mon 3/15/10**	
123	***UIC Permit issued***	0 days	Fri 4/9/10	Fri 4/9/10	122,65
124	**Pipeline DOT Application**	**331 days**	**Fri 1/2/09**	**Fri 4/9/10**	
125	**Prepare Application**	**79 days**	**Fri 1/2/09**	**Wed 4/22/09**	
129	***Submit Application***	0 days	Wed 4/22/09	Wed 4/22/09	128
130	**Agency Review, Comment, and Draft Permit**	**74 days**	**Thu 4/23/09**	**Tue 8/4/09**	
133	***Final permits issued***	0 days	Fri 4/9/10	Fri 4/9/10	132,65
134	**Pipeline Wetland Permits**	**289 days**	**Tue 3/3/09**	**Fri 4/9/10**	
135	**USACOE/NYS Application**	**62 days**	**Tue 3/3/09**	**Wed 5/27/09**	
141	***Submit USACE/NYS Applications***	0 days	Wed 5/27/09	Wed 5/27/09	140
142	**Agency Review, Comment, and Draft Permit**	**96 days**	**Thu 5/28/09**	**Thu 10/8/09**	
145	***Final permits issued***	0 days	Fri 4/9/10	Fri 4/9/10	144,65



Project: Jamestown OxyCoal CCS
Date: Thu 1/15/09

Task | Progress | Milestone | Summary

Appendix 2.

Geological Report: Miller 2 Well

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FINAL LETTER REPORT

JBPU Miller #2 CO_2 Piggyback Test Well
Data Analysis Report

Submitted to:

Ecology & Environment, Inc.

Project Manager:

Mr. George M. Lukert
Ecology & Environment, Inc.
368 Pleasant View Drive
Lancaster, NY 14086
glukert@ene.com

Prepared by:

Battelle Memorial Institute
505 King Avenue
Columbus, Ohio 43201

November 16, 2009

Battelle contact:
Joel Sminchak
614-424-7392
sminchak@battelle.org

EXECUTIVE SUMMARY

Overview. In Spring 2009, Jamestown Board of Public Utilities (JBPU) completed a "piggyback" test well with Unbridled Energy to explore carbon sequestration targets in the area. By drilling deeper and gathering detailed geologic information, this well provided a better understanding of the sequestration potential in the Jamestown area. The well was named Miller #2 and was located in Ellery Township, Chautauqua County, New York, near the JBPU landfill. Unbridled Energy originally planned to drill the well for gas production to the base of the Medina formation at a depth of approximately 3,600 ft. The piggyback effort allowed this well to extend to a depth of 7,312 ft into the Potsdam sandstone formation. In addition, a full program of mud logging, wireline logging, rock core collection, and geotechnical testing of rock cores was completed.

Drilling Summary. The JBPU/Miller #2 carbon dioxide (CO_2) Piggyback Test Well (API# 31-013-25737) was spudded on April 1, 2009, and reached a total driller's depth of 7,312 ft on May 2, 2009. A rotary drilling rig was used to construct the well using a combination of both air and mud circulation. Full cores and sidewall cores were collected at various selected depths. The well was completed with drilling runs to depths of 40, 500, 3,856, and 7,308 ft.

Mud Log. Mud loggers were on site from 3,880 to total depth to record geologic conditions through continuous observations of rig conditions and rock cuttings. Drill cuttings were collected once for every 10 to 20 ft of hole drilled throughout borehole advancement and more often in zones of interest. Cuttings provided nearly real-time information about the formations in contact with the drill bit and were valuable for defining a coring strategy. In general, the well tracked slightly shallower than expected, but the key formations were present as expected.

Wireline. Since the formations of interest have not been well characterized in the region, a comprehensive logging program was completed in the deep portion of the test well. Wireline logs provide a continuous record of the borehole conditions. The logging suite was especially selected for CO_2 storage parameters such as porosity, permeability, and mineralogy rather than typical information targeted by oil and gas exploration. Wireline logs included triple combo, elemental spectroscopy, resistivity image log, and sonic derived mechanical properties.

Core Collection and Testing Results. A total of 31 sidewall cores and 156 ft of whole core was recovered and analyzed from the well. Standard porosity, permeability and grain density tests were conducted on the samples. In addition, 20 thin sections that were prepared for key samples (thin sections were prepared for the other core samples and sent to NYSM for analysis). Ten samples from caprock zones were subjected to mercury injection for low permeability testing. Finally, six samples were taken for geomechanical testing.

Data Analysis. Neutron-density cross plots of wireline data, comparison of wireline data to core results, and hydraulic analysis were completed to evaluate the data collected in the Miller #2 well. Rose Run cross plots show a very mixed formation, either sandstone with carbonate cement or sandstone interbedded with carbonate. The porosity was mainly around 5% and ranged from about 2% up to about 7%. Wireline data were comparable to the core test results, verifying the accuracy of the logs. Some zones in the well were identified based on image logs that may contain secondary porosity that could have more injection potential, but it was difficult to evaluate these zones.

Conclusions and Recommendations. The Rose Run sandstone was 181 ft thick and the Potsdam sandstone appeared to be at least 108 ft thick in the Miller #2 test well. Therefore, the storage formations appear to have the overall physical dimensions desired for CO_2 storage. Both the Galway B-sand and the Galway C-sand were identified in the test well, but the formations were present as thin, sandy intervals. While the physical dimensions and lithology of the target formations were suitable for CO_2 storage, hydraulic parameters were lower than desired. Core test results generally showed porosity less than 3% and permeability less than 0.1 mD across all of the tested zones. These results match interpretation of wireline logs, visual core examination, and core thin sections. Several zones were identified that may have secondary or fracture porosity which may merit more consideration. Containment layers were over 2,500 ft thick in the test well with low permeability and porosity.

Recommendations to further define CO_2 storage options include a systematic regional assessment of CO_2 storage targets, reservoir stimulation/treatment tests, consideration of other targets in the region for CO_2 sequestration, and additional regional characterization of CO_2 storage targets.

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APPENDICES

Appendix A: Drilling Logs

Appendix B: Wireline Logs

Appendix C: Core Test Results

Appendices available at http://esogis.nysm.nysed.gov

Section 1.0: INTRODUCTION

1.1 Background

Capture and geologic storage of CO_2 from a proposed oxy-coal power generation project at Jamestown, New York, is being developed by Jamestown Board of Public Utilities (JBPU) with support from several companies and initial funding from the state of New York. In addition to engineering assessments of generation and CO_2 handling systems, the initial effort includes evaluation of the geology in the area to determine its suitability for geologic storage.

In Spring 2009, JBPU completed a "piggyback" test well with Unbridled Energy to explore carbon sequestration targets in the area. By drilling deeper and gathering detailed geologic information, this well provided a better understanding of the sequestration potential in the Jamestown area. The well was named Miller #2 and was located in Ellery Township, Chautauqua County, New York, near the JBPU landfill (Figure 1-1). Unbridled Energy originally planned to drill the well for gas production to the base of the Medina formation at a depth of approximately 3,600 ft. The piggyback effort allowed this well to extend to a depth of 7,308 ft into the Potsdam Sandstone formation. In addition, a full program of mud logging, wireline logging, rock core collection, and geotechnical testing of rock cores was completed.

This report summarizes results and analysis of characterization data from the Miller #2 test well. Information collected during drilling, logging, and testing of samples from the borehole is presented. In addition, data were analyzed to determine CO_2 sequestration potential in the test well. Both storage reservoirs and confining layers were evaluated. While this report focuses on the Miller #2 test well, information presented here may be useful for supporting CO_2 sequestration projects in other portions of southwestern New York State.

1.2 Objectives

The objective of this report is to present results of the characterization program and analysis of sequestration potential in the Miller #2 "piggyback" CO_2 test well in support of the JBPU oxy-coal project. The main targets being considered included the Rose Run/Theresa Sandstone and the Potsdam Sandstone. These formations are fairly unexplored in the area because they do not typically produce hydrocarbons. As such, a comprehensive program was developed to characterize the rock formation for CO_2 storage. Table 1-1 summarizes the overall test program planned for the test well.

For this effort, Battelle performed in an advisory role with respect to wireline data collection and rock core testing. Many of the decisions regarding collection of data were completed in the field in conjunction with Unbridled Energy, New York State Museum Reservoir Characterization Group, JBPU, and Ecology & Environment. The well was drilled into relatively unexplored rock formations, and there was some uncertainty to the rock character and extent. As such, the final test program was altered from the initial plan and some modifications were made to maximize information gained on the project.

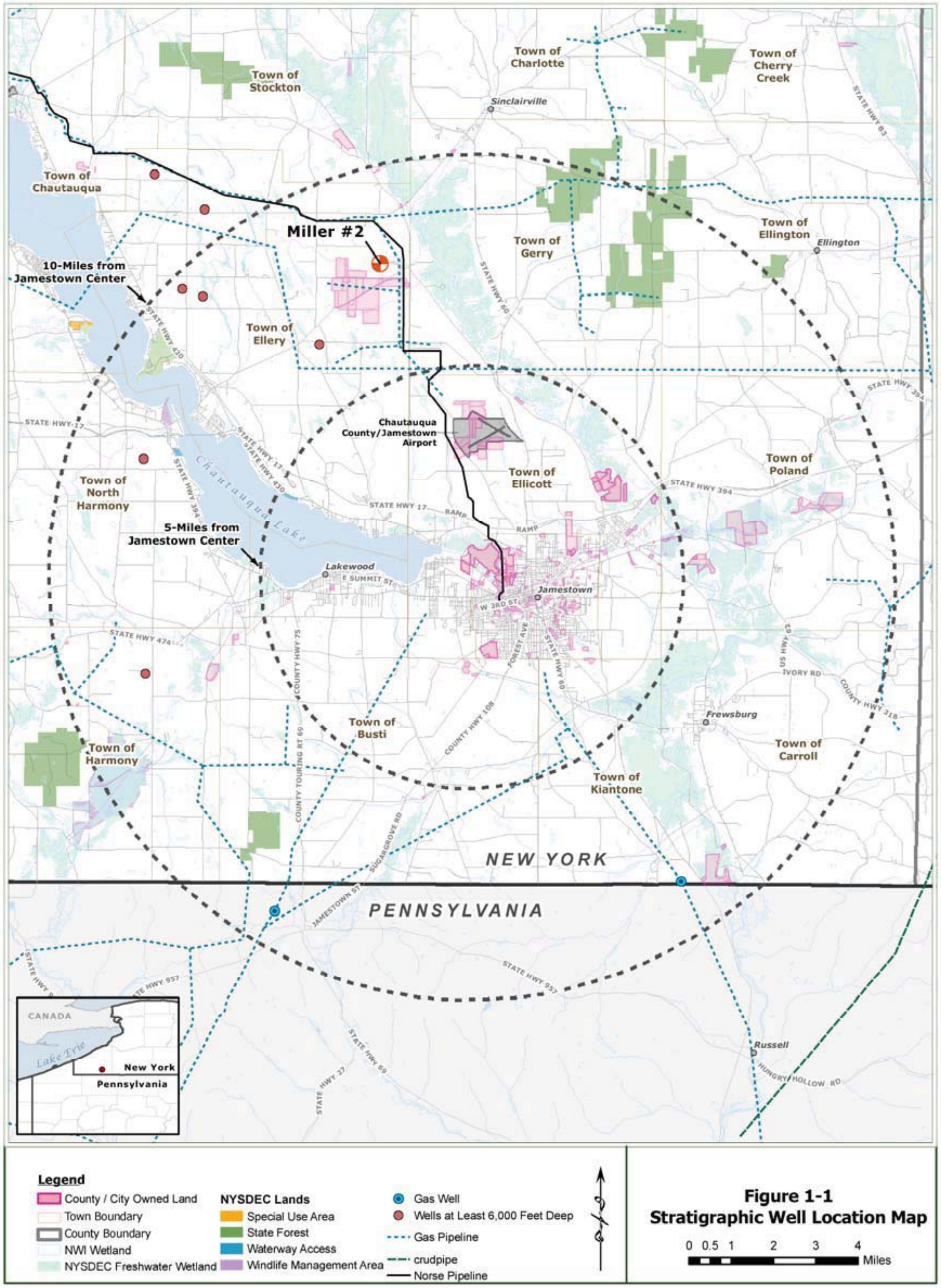


Figure 1-1. Site Location Map showing Miller #2 Location

Overall, the complete screening, site assessment, and sequestration design is a multiphase, multi-year effort (Benson et al., 2004). The current report covers only the work related to a single well in the region. The results of the analysis shall not be viewed as or interpreted as a definitive assessment of the presence (or absence) of suitable candidate geologic CO_2 storage formations, the presence of suitable caprocks, and sufficient injectivity to allow CO_2 sequestration to be carried out in an economic manner.

Table 1-1. Planned Site Characterization Activities for the Drilling Program

Test Item		Objective	Description
Mud Logging		Determine lithology	Continuous
Field Geologic Analysis		Characterize lithology, identify coring intervals	Continuous
Full Rock Coring		Characterize caprock and injection zones	~240 ft
Brine Analysis		Determine brine geochemistry	8 samples for cations, anions, O-isotopes
Rotary Sidewall Coring		Characterize/confirm caprock and injection zones	50 samples
Rock Core Testing		Determine hydraulic and geologic properties of caprock and injection zones	Permeability, Porosity, mineralogy, core scan (Hg injection, pulse decay, geomechanical tests on ~10 selected core)
Wireline Logging	Triple Combo	Delineate caprock and injection zones; log physical conditions	**X**
	Elemental Spectroscopy	Determine mineralogy and lithology	**X**
	Resistivity	Determine fluid composition, permeability, and lithology	**X**
	Nuclear Magnetic Resonance	Continuous log of porosity and permeability through caprock and injection zones	**X**
	Sonic	Determine seismic velocity, porosity, and anisotropy	**X**
	Image	Determine geomechanical properties, fractures, etc.	**X**
	Pulsed Neutron Capture	Determine baseline fluid saturation for MMV	---

Section 2.0: DRILLING SUMMARY

The JBPU/Miller #2 CO_2 Piggyback Test Well (API# 31-013-25737) was spudded on April 1, 2009 and reached a total driller's depth of 7,312 ft on May 2, 2009. Site preparation, which included spreading gravel, digging mud pits, and installing snow fences where necessary, was completed by April 1, 2009. A rotary drilling rig was used to construct the well using a combination of both air and mud circulation. Full cores and sidewall cores were collected at various selected depths to further characterize CO_2 sequestration potential in Chautauqua County, New York.

2.1 Well Description

2.1.1 Conductor Casing. Initial drilling was completed on April 1, 2009 with a 15 inch air-hammer bit. The borehole was drilled to 40 ft before 13-3/8 inch conductor casing was cemented in place to hold back unconsolidated sediments.

2.1.2 Surface Casing. The surface string went under construction on April 1, 2009 and was drilled using a 12-½ inch air-hammer bit. The borehole was advanced approximately 500 ft before surface casing was set on April 2, 2009. A total of 527 ft of 9-5/8 inch casing was cemented to surface using 215 sacks of Class A cement.

2.1.3 Intermediate Casing. The intermediate section of the well consisted of an 8-3/4 inch borehole drilled to a depth of 3,856 ft. Using a tricone bit, this section was drilled on air and reached the planned target depth (TD) in the Lockport Dolomite on April 7, 2009. A total of 3,829 ft of 7 inch casing was cemented into place with 130 sacks of Class A and 100 sacks of 50/50 POZ cement.

2.1.4 Deep Casing. On April 11, 2009 a 6-1/4 inch PDC bit was used to begin drilling the deepest section of the well. The interval from 3856 to 6254 ft was drilled on air before switching over to 9.5# fluid to begin coring operations.

On April 16, 2009, a 6-1/8 inch PDC coring bit was used to gather several planned whole cores in the Little Falls Dolomite and Rose Run Sandstone. The first 60 ft section core barrel was drilled from 6,254 to 6,308.15 ft and produced 54.15 ft of recoverable material from the Little Falls. Circulation problems followed this section and ultimately required a 6-¼ inch tricone bit to drill ahead approximately 20 feet to 6,328 ft. On April 19, 2009, the next section of whole core was drilled with a 6-1/8 inch PDC core bit and produced approximately 13 ft of material. Because of lower than expected penetration rates a 6-1/8 inch diamond coring bit replaced the PDC coring bit. The third coring run, from 6,342 to 6,372.6 ft, also encountered slow penetration rates and the coring program was stopped short of its intended depth. This last core did, however, accomplish to capture the transition from the Little Falls Dolomite to the Rose Run Sandstone.

On April 21, 2009, drilling operations continued with a 6-¼ inch tricone bit with the plan to drill ahead 650 ft to the next core point. However, the borehole was drilled to 6,437 ft before it was discovered that the bit had been smoothed off and was replaced with a stronger 6-¼ inch tricone bit. Penetration rates were still much lower than expected and it was discovered on April 23, 2009 that the weight indicator on the rig was not calibrated correctly. When corrected, drilling resumed as planned to a depth of 7,060 ft.

On April 29, 2009, a 6-1/8 inch diamond coring bit was used to cut the interval from 7060 to 7120 ft, the B Dolomite. On April 30, 2009, the core was tripped out and normal drilling operations continued with a 6-¼ inch tricone bit to total depth. The well reached total depth on May 2, 2009 at a depth of 7,312 ft in the Potsdam Sandstone. After total depth was reached, the well was turned over to Unbridled Energy for any further well completion work.

Section 3.0: MUD LOGGING

Mud loggers were on site from 3880 ft to total depth to record geologic conditions through continuous observations of rig conditions and rock cuttings. Drill cuttings were collected once for every 10 to 20 ft of hole drilled throughout borehole advancement and more often in zones of interest. Cuttings provided nearly real-time information about the formations in contact with the drill bit and were valuable for defining a coring strategy. Figure 3-1 shows a small section of the mud log for the JBPU/Miller #2 CO_2 Piggyback Test Well. The entire mud log is presented in Appendix A.

3.1 Mud Log

Mud log parameters included:

- Depth
- Rate of penetration
- Lithology: including mineralogy, texture, trace minerals, rock formation classification
- Continuous total gas
- Chromatograph percent volume of gas analyzed (optional)
- Hours on bit log
- Mud log (daily)
- Drilling remarks (WOB, rpm, pressure, drill method)

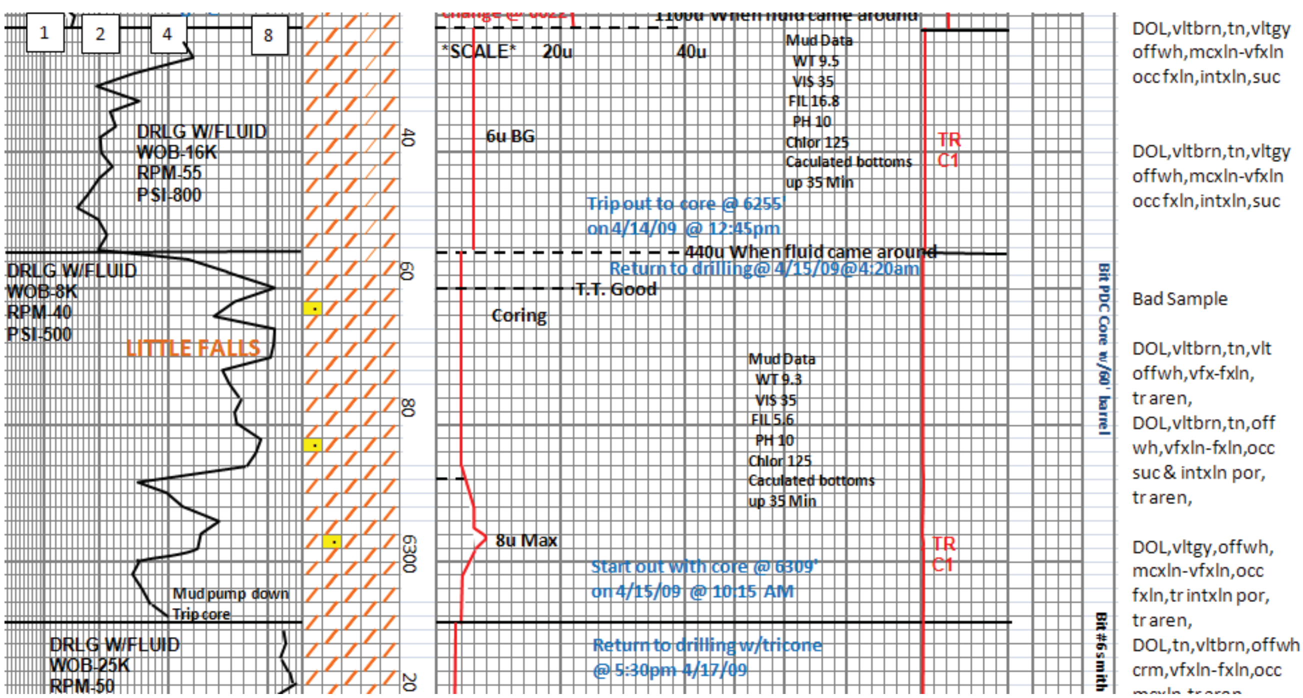


Figure 3-1. Section of Mud Log from JBPU/Miller #2 CO_2 Piggyback Test Well

The mud log for the JBPU/Miller #2 CO_2 Piggyback Test Well begins at a measured depth (MD) of 3,880 ft. Mud loggers were on site shortly after the 7 inch casing string was cemented in the borehole to 3,829 ft. The interval from 3,880 to 4,672 ft shows mostly red and brown shale samples with very little background gas, one to three units. Calcareous cement was reported in the shales occasionally although most were siliceous. This interval is regionally known as the Queenston Shale.

From 4,672 to 5,516 ft, siltstone stringers began to appear in the samples and background gas increased to 170 units. Connection gas measurements remained steady throughout the interval at 440 units. As depth increases, calcareous cement becomes increasingly evident. This interval is known as the Lorraine Formation.

The interval from 5,516 to 6,012 ft shows a dark brown to light grey crystalline limestone. This unit is known as the Trenton Limestone. The depths for this interval, along with rock type, match nicely with the expected depths from the well prognosis.

From 6,012 to 6,192 ft, microcrystalline dolomite becomes increasingly more apparent in the samples. This interval is called the Black River Group and sometimes contains calcareous shale or limestone and is interbedded with dolomite. As indicated on the log, some of the limestone can be fossiliferous or oolitic. Background gas jumped to 370 units at approximately 6,120 ft and the rig crew began circulating at each connection to prevent too much gas from accumulating in the mud.

The interval from 6,192 to 6,262 ft is dominated by microcrystalline dolomite but the upper 30 ft of this interval contains some interbedded shale. At a depth of 6,220 ft gas content circulating in the mud dropped off dramatically to 6 units. This unit is often called the Wells Creek Formation or the Little Falls Formation.

The Rose Run Sandstone, A-Dolomite, B-Sand, B-Dolomite, and Potsdam formations are below 6,262 ft. The Rose Run through B-Dolomite units are often grouped together into one package called the Galway Formation. For the JBPU/Miller #2 CO_2 Piggyback Test Well the Galway Formation extends to 7,186 ft. From 6,262 to 6,366 ft, microcrystalline to fine crystalline dolomite grades into sub-rounded and sub-angular sandstone. Gas content in the mud remained low at only 3 units through the sandstone interval, to 6,434 ft.

The interval from 6,434 to 7,186 ft consists of interbedded dolomite and sandstone in various percentages. The A-Dolomite, B-Sand, and B-Dolomite all exist on this interval although their respective contacts are gradational and therefore arguable. Hydrocarbon gases present in the mud were measured at a relatively constant 2 units for the duration of the well. The dolomite samples exhibited fine to microcrystalline textures and were brown to grey in color. Various minerals, including pyrite, are identifiable in the dolomite samples. The sandstone samples were mainly grey to translucent in color and generally had fine to medium and sub-rounded to sub-angular grains. Trace minerals such as glauconite were also present throughout the more sandy intervals.

From 7,186 ft to total depth the basal sandstone, referred to regionally as the Potsdam Formation, is present. It is believed that this sandstone was formed from weathered Pre-Cambrian formations because of its mineralogy. Abundant pyrite and feldspar littered the samples taken over this interval. The sand is mostly angular and arkosic although occasionally displays calcareous cement. Below 7,312 ft (TD) lies the Pre-Cambrian basement rock. It was not entirely clear whether Pre-Cambrian rock reached in this well.

Section 4.0: WIRELINE LOGGING

This section summarizes results of the wireline logging program. Since the formations of interest have not been well characterized in the region, a comprehensive logging program was completed in the deep portion of the test well. Wireline logs provide a continuous record of the borehole conditions. The logging suite was especially selected for CO_2 storage parameters such as porosity, permeability, and mineralogy rather than typical information targeted by oil and gas exploration.

4.1 Logging Sequence

For the Jamestown Miller #2 Well, Table 4-1 shows the logs that were run in the deep portion of the Miller #2 test well. Appendix B contains full wireline logs.

Table 4-1. Wireline Logging Program

Logging Run	Logging Tools	Start Depth (MD)	Stop Depth (MD)
Run 1	Triple Combo	7309	3825
Run 2	Elemental Spectroscopy	7306	3825
Run 3	Rotary Sidewall Cores	*	*
Run 4	Resistivity Image	7305	3875
	Sonic	7255	3875

*Sidewall cores taken at individually selected depth intervals.

The criple combo is the generic name for multiple measurements made together, which included gamma ray, resistivity, density and neutron. It was used to delineate caprock and injection zones into formations and to log physical conditions, such as net/gross reservoir sections and porosity. The elemental spectroscopy log was used to determine mineralogy and lithology. Side wall cores were taken to have representative rock samples of caprock and injection targets. The sonic log was used to determine seismic velocity, porosity, and to calculate geomechanical properties. The image log was used to determine geomechanical properties, fractures, faulting and to provide a resistivity "image" of the inside of the wellbore.

A total of 31 sidewall cores were collected for the project with good recovery, and an additional seven sidewall cores were collected by Unbridled Energy in other portions of the deep section. Core points were identified in the most promising intervals for CO_2 injection based on wireline logs and mud log data. Table 4-2 lists the rotary sidewall core points and rationale for collecting the samples.

Table 4-2. Rotary Sidewall Core Rationale

Core	Measured Depth	Targeted Formation	Explanation
1	7276	Potsdam	Core point chosen below the first Neutron reading
2	7255		Core point chosen below the first Neutron reading
3	7223		Core point had significant amount of crossover. Gamma Ray reading is moderate
4	7187	C-Sand	2 core points selected in anticipated C-sand. Selected interval had significant crossover with moderate Gamma Ray reading.
5	7186		
6	7155		Core point was selected from above where Gamma Ray and mud logger information became abnormal
7	6983	B-Sand	2 core points selected in region of density/neutron crossover, lower Gamma Ray, and a distinctive drop in Photoelectric Effect
8	6981		
9	6972		2 core points selected in region determined to be lower quality B sand
10	6958		
11	6952		2 core points selected in region of density/neutron crossover, lower Gamma Ray, and a distinctive drop in Photoelectric Effect
12	6950		
13	6944		Core point selected in region of high/hot Gamma Ray
14	6932		3 core points selected in large crossover section with high/hot Gamma Ray. There was no Photoelectric drop associated with the section.
15	6928		
16	6925		
17	6870		2 core points selected in area of high neutron, low photoelectric effect, and moderate Gamma Ray.
18	6868		
19	6542	Rose Run Sandstone	2 core points selected from the bottom Rose Run sand lobe.
20	6540		
21	6510		2 core points selected to represent poor quality Rose Run Sand
22	6502		
23	6490		Core point selected to represent moderate quality Rose Run Sand
24	6477		2 core points selected from the Middle Rose Run sand lobe.
25	6474		
26	6405		Cores 26 through 31 were selected in the top and largest lobe of the Rose Run Sandstone. This lobe shows very low Gamma Ray, a large amount of density/ neutron crossover and low photoelectric effect values.
27	6399		
28	6396		
29	6388		
30	6384		
31	6380		

Section 5.0: ROCK CORE COLLECTION AND TESTING RESULTS

In the Miller #2 well, both full core and sidewall core samples were collected. Full core was collected in advance of the boring based on the well prognosis across key caprock and storage intervals. After the well reached total depth and was logged, the rotary sidewall cores were collected from selected depths based on the wireline data. Core samples were then sent to a laboratory for hydraulic, petrographic, and geomechanical tests. Appendix C contains complete core test results.

5.1 Rock Coring Program

A total of 31 sidewall cores and 156 ft of whole core was recovered and analyzed from the well. Standard porosity, permeability and grain density tests were conducted on the samples. In addition, 20 thin sections were prepared for key samples (thin sections were prepared for the other core samples and sent to NYSM for analysis). Ten samples from caprock zones were subjected to mercury injection for low permeability testing. Finally, six samples were taken for geomechanical testing.

5.2 Core Testing Results

Full core was plugged on a 1-ft interval, or greater where warranted, and tested for standard permeability, porosity, and density (Table 5-1). A total of 175 plugs from full core were analyzed. In addition, all 31 rotary sidewall cores were analyzed. In total, tests were completed on 206 samples. These test results provide a key dataset for the region on relatively unexplored rock formations.

Core data from the Miller#2 well were tabulated and characterized using statistical analyses (Table 5-3). A full range of statistical functions were used to analyze porosity, permeability, and density data to ensure quality reservoir assessments were made. The results of these analyses showed that core data collected from Miller #2 were accurate and internally consistent.

Figure 5-4 illustrates the coring program and results. As shown, the full core obtained from the Little Falls and Black River was supplemented with a rotary sidewall core in Rose Run. The full core was collected from the C-sand, but only three rotary sidewall cores were collected from the Potsdam due to limited rathole available in the boring.

Table 5-1. Summary of Conventional Core Analyses Results.

SUMMARY OF CONVENTIONAL CORE ANALYSES RESULTS
Vacuum Dried at 180°F Net Confining Stress: 1200 psi

Unbridled Energy New York, LLC | Chautauqua County, New York
Miller No. 2 WO 287 Well | File: HH-43549
Date: 7-13-09

SUMMARY OF CONVENTIONAL CORE ANALYSES RESULTS
Vacuum Dried at 180°F Net Confining Stress: 1200 psi

Unbridled Energy New York, LLC | Chautauqua County, New York
Miller No. 2 WO 287 Well | File: HH-43549
Date: 7-13-09

Sample Number	Sample Depth, feet	Permeability, millidarcys		Porosity, percent		Grain Density, gm/cc
		to Air	Klinkenberg	Ambient	NCS	
1	6254.00	1.02	0.771	6.9	6.8	2.76
2	6255.00		+	11.8	11.7	2.83
3	6256.00		+	7.5		2.79
4	6257.00		+	8.3		2.81
5	6258.00		+	7.5		2.83
6	6259.00		+	5.6	5.5	2.81
7	6260.00	0.308	0.209	7.6	7.5	2.84
8	6261.00	0.0046	0.0013	5.9	5.8	2.86
9	6262.00	1.23	0.976	9.6	9.5	2.85
10	6263.00	0.0037	0.0010	5.5	5.3	2.85
11	6264.00	0.022	0.0095	8.0	7.9	2.81
12	6265.00	0.0015	0.0003	5.6	5.5	2.82
13	6266.00		+	10.6		2.85
14	6267.00	0.0066	0.0021	7.8	7.7	2.84
15	6268.00	0.0047	0.0013	7.1	7.0	2.86
16	6269.00	0.016	0.0062	6.5	6.4	2.86
17	6270.00	0.0049	0.0014	4.5	4.4	2.85
18	6271.00	0.022	0.0093	6.3	6.2	2.83
19	6272.00	0.0030	0.0007	4.5	4.4	2.75
20	6273.00	0.017	0.0069	6.6	6.5	2.81
21	6274.00	0.0065	0.0020	6.7	6.6	2.79
22	6275.00	0.0061	0.0019	6.6	6.5	2.80
23	6276.00	0.0052	0.0015	6.4	6.3	2.81
24	6277.00	0.0062	0.0019	6.7	6.6	2.81
25	6279.00	0.0040	0.0011	5.3	5.2	2.81
26	6280.00	0.0018	0.0004	4.5	4.4	2.80
27	6281.00	0.0012	0.0002	3.9	3.8	2.80
28	6282.00	0.0021	0.0005	3.5	3.4	2.81
29	6283.00	0.0010	0.0002	2.8	2.7	2.82
30	6284.00	0.010	0.0037	7.9	7.8	2.83
31	6285.00	0.0007	0.0001	2.4	2.3	2.81
32	6286.00	0.0009	0.0002	3.2	3.1	2.80
33	6287.00	0.016	0.0065	6.8	6.7	2.84
34	6288.00	0.0063	0.0020	6.5	6.4	2.84
35	6289.00	0.0036	0.0009	4.8	4.7	2.83
36	6290.00	0.0033	0.0008	4.6	4.5	2.82
37	6291.00	0.053	0.028	3.5	3.4	2.83
38	6292.00	0.0013	0.0002	3.2	3.1	2.81
39	6293.00	0.0021	0.0004	2.3	2.2	2.81
40	6294.00	0.022	0.0096	1.9	1.8	2.79
41	6295.00	0.042	0.021	2.1	2.0	2.81
42	6296.00	0.0047	0.0013	2.5	2.4	2.79
43	6297.00		+	2.6		2.78
44	6298.00	0.0020	0.0004	2.1	2.0	2.78
45	6299.00	0.0015	0.0003	4.1	4.0	2.79
46	6300.50	0.0070	0.0022	3.8	3.7	2.83
47	6301.00	0.0019	0.0004	3.6	3.5	2.80
48	6302.00	0.0042	0.0012	3.8	3.7	2.82
49	6303.00	0.0026	0.0006	3.2	3.1	2.82
50	6304.00	0.0029	0.0007	2.6	2.5	2.81
51	6305.00	0.0018	0.0004	2.0	1.9	2.82
52	6306.00	0.0034	0.0009	2.7	2.6	2.81
53	6307.00	0.0015	0.0003	1.8	1.7	2.81
54	6328.00	0.0068	0.0022	2.5	2.4	2.78
55	6329.00	0.0030	0.0007	3.3	3.1	2.75
56	6330.00	0.0077	0.0026	4.2	4.1	2.72
57	6331.00	0.022	0.0095	4.7	4.6	2.73
58	6332.00	0.017	0.0071	2.6	2.4	2.74
59	6333.00	0.0017	0.0003	1.3	1.2	2.78
60	6334.00	0.0016	0.0003	1.1	1.0	2.77
61	6335.00	0.0036	0.0009	1.8	1.7	2.77
62	6336.00	0.0034	0.0009	2.0	1.9	2.75
63	6337.00	0.0049	0.0014	3.0	2.9	2.63
64	6338.00	0.0031	0.0008	2.5	2.4	2.82
65	6339.00	0.270	0.180	5.9	5.7	2.74
66	6340.00	0.397	0.277	5.9	5.8	2.73
67	6341.00	0.020	0.0084	3.5	3.4	2.75
68	6342.00	0.011	0.0040	2.8	2.7	2.72
69	6343.00	0.332	0.227	9.0	8.8	2.62
70	6344.00	0.015	0.0059	5.3	5.2	2.69
71	6345.00	0.017	0.0069	3.1	3.0	2.78
72	6346.00	0.065	0.035	4.3	4.2	2.73
73	6347.00	0.016	0.0062	3.4	3.3	2.74
74	6348.00	0.0067	0.0021	2.4	2.3	2.64
75	6349.00	0.0044	0.0012	3.1	3.0	2.75
76	6350.00	0.0049	0.0014	3.2	3.1	2.72
77	6351.00	0.0062	0.0019	3.9	3.8	2.73
78	6352.00		<0.0001	1.4	1.3	2.70
79	6353.00	0.0005	0.0001	1.4	1.3	2.75
165	6353.50	0.0022	0.0005	2.6	2.5	2.75
80	6354.00	0.029	0.013	0.5	0.4	2.85
81	6354.50	0.0011	0.0002	0.6	0.5	2.81
82	6355.00	0.0003	<0.0001	2.0	1.9	2.82
83	6355.50		<0.0001	0.6	0.5	2.78
84	6356.00	0.0085	0.0029	2.7	2.6	2.67
85	6356.50	0.0037	0.0010	1.2	1.1	2.76
86	6357.00	0.0029	0.0007	2.1	2.0	2.71
87	6357.50	0.0071	0.0023	4.7	4.6	2.66
88	6358.00	0.170	0.107	6.6	6.5	2.64
89	6358.50	0.040	0.020	5.5	5.4	2.68
90	6359.00	0.039	0.019	6.3	6.1	2.64
91	6359.50	0.028	0.013	5.9	5.8	2.68
92	6360.00	0.0083	0.0028	3.9	3.8	2.67
93	6360.50	0.0076	0.0025	2.4	2.3	2.73
99	6361.00	0.015	0.0060	2.5	2.4	2.74
M2-6361.5	6361.50	0.0011	0.0002	1.3	1.2	2.76
M2-6362.0	6362.00	0.013	0.0050	2.7	2.6	2.82
95	6362.50	0.022	0.0096	3.3	3.2	2.76
96	6363.00	0.228	0.149	4.1	4.0	2.69
M2-6363.5	6363.50	0.172	0.108	4.2	4.1	2.74
M2-6364.0	6364.00	0.036	0.017	2.9	2.8	2.70
97	6364.50	0.023	0.010	3.0	2.9	2.75
98	6365.00	0.050	0.026	4.2	4.0	2.71
99	6365.50	0.041	0.020	3.5	3.4	2.71
100	6366.00	0.021	0.0090	3.2	3.0	2.69
101	6366.50	0.0019	0.0004	1.5	1.4	2.71
M2-6367.0	6367.00	0.0027	0.0006	1.5	1.4	2.66
102	6367.50	0.057	0.030	1.0	0.9	2.69
103	6368.00	0.0017	0.0004	0.9	0.8	2.74
104	6368.50	0.0008	0.0001	0.7	0.6	2.72
105	6369.00	0.020	0.0086	3.3	3.2	2.64
M2-6369.5	6369.50	0.020	0.0082	3.1	3.0	2.64
M2-6370.0	6370.00	0.039	0.019	3.4	3.3	2.66
M2-6370.5	6370.50	1.05	0.826	6.6	6.5	2.63
106	6371.00	0.182	0.116	3.4	3.3	2.63
M2-6371.5	6371.50	0.135	0.082	4.7	4.6	2.63
M2-6372.0	6372.00	0.227	0.148	5.6	5.5	2.63
107	7060.00	0.111	0.066	2.1	2.0	2.76
108	7061.00	0.0020	0.0004	2.0	1.9	2.84
109	7062.00	0.0027	0.0006	0.5	0.4	2.85
110	7063.00	0.0030	0.0007	0.8	0.7	2.83
111	7064.00	0.016	0.0065	2.3	2.1	2.83
112	7065.00	0.036	0.017	0.6	0.5	2.84
113	7066.00	0.0003	<0.0001	1.4	1.3	2.70
114	7067.00	0.0033	0.0008	1.5	1.4	2.78
115	7068.00		+	1.6	1.5	2.62
116	7069.00	0.0005	0.0001	0.9	0.8	2.80
117	7070.00	0.0009	0.0001	1.8	1.7	2.85
118	7071.00	0.0009	0.0001	1.3	1.2	2.85
119	7073.00	0.0002	<0.0001	1.1	1.0	2.83
120	7074.00		+	0.5	0.4	2.83
121	7075.00	0.0021	0.0005	2.4	2.3	2.64
122	7076.00	0.0090	0.0031	2.2	2.1	2.61
123	7077.00	0.0004	0.0001	2.4	2.3	2.61
124	7078.00	0.012	0.0044	3.7	3.6	2.59
125	7079.00	0.037	0.018	3.5	3.4	2.75
126	7080.00	0.0011	0.0002	1.4	1.3	2.82
127	7081.00	0.0018	0.0004	1.3	1.2	2.80
128	7082.00	0.0024	0.0006	2.1	2.0	2.82
129	7083.00	0.0005	0.0001	1.6	1.4	2.85
130	7084.00	0.0007	0.0001	0.6	0.5	2.85
131	7085.00	0.0074	0.0024	2.6	2.5	2.81
132	7086.00	0.0008	0.0001	0.6	0.5	2.85
133	7087.00		+	0.7	0.6	2.80
134	7088.00	0.0094	0.0033	1.3	1.2	2.80
135	7089.00	0.0025	0.0006	0.8	0.7	2.82
136	7090.00		+	0.9	0.8	2.83
137	7091.00		+	1.2		2.82
138	7092.00	0.0019	0.0004	1.5	1.4	2.80
139	7093.00	0.0047	0.0013	2.1	2.0	2.82
140	7094.00	0.0033	0.0008	1.1	0.9	2.82
141	7095.00	0.0042	0.0012	0.8	0.7	2.76
142	7096.00	0.0072	0.0023	1.8	1.7	2.72
143	7097.00	0.0093	0.0033	1.8	1.7	2.61
144	7098.00	0.0040	0.0011	1.7	1.6	2.62
145	7099.00	0.0038	0.0010	1.3	1.2	2.61
146	7100.00	0.0032	0.0008	1.3	1.2	2.63
147	7101.00		+	1.1	1.0	2.81
148	7102.00	0.0021	0.0005	1.7	1.6	2.83
149	7103.00	0.0020	0.0004	1.0	0.9	2.81
150	7104.00	0.0099	0.0035	1.1	1.0	2.79
151	7105.00	0.0041	0.0011	1.6	1.5	2.67
152	7106.00	0.020	0.0083	1.7	1.6	2.82
153	7107.00	0.0012	0.0002	0.6	0.5	2.79
154	7108.00	0.0071	0.0023	1.2	1.1	2.81
155	7109.00	0.0020	0.0004	2.2	2.1	2.80
156	7110.00	0.0074	0.0024	1.7	1.6	2.63
157	7111.00	0.0007	0.0001	1.0	0.9	2.82
158	7112.00	0.0047	0.0013	2.2	2.1	2.81
159	7113.00	0.018	0.0075	1.6	1.5	2.65
160	7114.00	0.025	0.011	1.8	1.7	2.74
161	7115.00	0.0008	0.0001	1.2	1.1	2.81
162	7116.00	0.0063	0.0020	1.1	1.0	2.81
163	7117.00	0.020	0.0085	1.2	1.1	2.80
164	7118.00	0.0067	0.0021	1.8	1.7	2.82

Table 5-2. Summary of Rotary Core Analyses Results.

SUMMARY OF ROTARY CORE ANALYSES RESULTS

Vacuum Dried at 180°F Net Confining Stress: 1200 psi

Unbridled Energy New York, LLC
Miller No. 2 WO 287 Well
Date: 7-13-09

Chautauqua County, New York
File: HH-43549

Run Number	Sample Number	Sample Depth, feet	Permeability, millidarcys to Air	Permeability, millidarcys Klinkenberg	Porosity, percent Ambient	Porosity, percent NCS	Grain Density, gm/cc	Lithological Descriptions
1	1-1R	6380.0	0.272	0.163	5.7	5.6	2.64	Ss fg wcmt
1	1-2R	6384.0	0.047	0.024	3.4	3.3	2.64	Ss fg wcmt
1	1-3R	6388.0	0.057	0.030	3.5	3.4	2.63	Ss fg wcmt
1	1-4R	6396.0	0.021	0.0089	4.1	4.0	2.64	Ss fg wcmt
1	1-5R	6399.0	0.012	0.0046	3.6	3.5	2.63	Ss fg wcmt
1	1-6R	6405.0	0.122	0.073	6.0	5.9	2.63	Ss fg wcmt
1	1-7R	6474.0	0.094	0.054	5.0	4.9	2.62	Ss fg wcmt
1	1-8R	6477.0	1.84	1.38	5.7	5.6	2.64	Ss mg-crs
1	1-9R	6490.0	0.054	0.028	4.6	4.5	2.67	Ss vfg-fg scalc wcmt
1	1-10R	6502.0	0.0008	0.0001	1.0	0.9	2.78	Ss vfg-fg sdol wcmt
1	1-11R	6510.0	0.016	0.0066	0.8	0.7	2.81	Ss vfg-fg dol wcmt
1	1-12R	6540.0	0.056	0.029	5.8	5.7	2.62	Ss fg wcmt
1	1-13R	6542.0	0.0004	<0.0001	0.8	0.7	2.58	Ss fg scalc wcmt
1	1-14R	6868.0	0.012	0.0046	5.6	5.5	2.63	Ss fg-mg wcmt
1	1-15R	6870.0	0.0003	<0.0001	2.5	2.4	2.67	Ss fg-vfg scalc
1	1-16R	6925.0	0.012	0.0047	3.8	3.7	2.59	Ss vfg-fg scalc wcmt
1	1-17R	6928.0	0.013	0.0051	6.2	6.1	2.61	Ss fg-vfg scalc spyr w/shly streaks
1	1-18R	6932.0	0.0091	0.0031	4.5	4.4	2.63	Ss vfg -fg scalc spyr w/shly streaks
1	1-19R	6944.0	0.0036	0.0009	2.1	1.9	2.65	Ss vfg -fg scalc spyr w/shly streaks
1	1-20R	6950.0	0.013	0.0050	4.5	4.4	2.63	Ss fg-mg wcmt
1	1-21R	6952.0	0.0026	0.0006	3.4	3.3	2.60	Ss vfg-mg wcmt
1	1-22R	6958.0	0.0004	<0.0001	0.4	0.4	2.79	Ss vfg-fg sshly sdol spyr
1	1-23R	6972.0	0.0004	<0.0001	1.4	1.3	2.81	Ss fg-vfg sdol wcmt
1	1-24R	6981.0	0.0060	0.0018	2.9	2.8	2.61	Ss vfg-fg spyr shly streak
1	1-25R	6983.0	0.0050	0.0015	3.1	3.0	2.60	Ss fg-mg wcmt
1	1-26R	7155.0	0.0069	0.0022	1.7	1.6	2.61	Ss vfg-fg scalc wcmt
1	1-27R	7186.0	0.0036	0.0010	2.6	2.5	2.62	Ss fg-vfg scalc wcmt
1	1-28R	7187.0	0.0062	0.0019	4.1	4.0	2.59	Ss vfg-mg wcmt
1	1-29R	7223.0		+	2.7		2.63	Ss vfg-crs wcmt frac
1	1-30R	7255.0	0.027	0.012	4.2	4.1	2.61	Ss fg-vfg spyr w/shly streaks
1	1-31R	7276.0	0.0035	0.0009	4.2	4.1	2.68	Ss mg-vfg scalc

Table 5-3. Statistical Analyses for the Miller#2 Well Near Jamestown, NY

Data	Mean	Standard Error	Geometric Mean	Median	Mode	Standard Deviation	Sample Variance	Range	Minimum	Maximum	Count	Formation
Permeability (mD), to air	0.1042	0.0592	0.0076	0.0051	0.022	0.3018	0.0947	1.2293	0.0007	1.23	26	Black River SH
Permeability (mD), Klinkenberg	0.0773	0.047	0.0023	0.0015	0.0002	0.2396	0.0574	0.9759	0.0001	0.976	26	
Porosity %, ambient	6.4	0.3756	6.0007	6.5397	4.5	2.1247	4.5145	9.4	2.4	11.8	32	
Porosity %, NCS	5.9	0.3859	5.5932	6.2432	4.4	2.0419	4.1694	9.4	2.3	11.7	28	
Grain Density, gm/cc	2.8	0.0047	2.8191	2.8137	2.81	0.0266	0.0007	0.1	2.8	2.9	32	
Permeability (mD), to air	0.0347	0.0097	0.0086	0.0068	0.022	0.0783	0.0061	0.3967	0.0003	0.397	65	Little Falls DOL
Permeability (mD), Klinkenberg	0.02	0.0064	0.0025	0.0021	0.0009	0.0528	0.0028	0.27695	0.00005 [1]	0.277	67	
Porosity %, ambient	3.3016	0.2027	2.8704	3.0302	N/A	1.6712	2.7929	8.4704	0.4926	8.963	68	
Porosity %, NCS	3.1949	0.2049	2.737	2.9621	N/A	1.6774	2.8137		0.4077	8.8462	67	
Grain Density, gm/cc	2.7553	0.0072	2.7546	2.756	N/A	0.0593	0.0035	0.2272	2.6196	2.8468	68	
Permeability (mD), to air	0.15	0.0704	0.0288	0.041	0.021	0.3791	0.1437	1.8396	0.0004	1.84	29	Rose Run SS
Permeability (mD), Klinkenberg	0.11	0.0536	0.0119	0.02	0.0004	0.2889	0.0835	1.37995	0.00005 [1]	1.38	29	
Porosity %, ambient	3.43	0.3356	2.8268	3.4462	N/A	1.8075	3.267	5.9191	0.7209	6.64	29	
Porosity %, NCS	3.32	0.3363	2.67	3.3485	N/A	1.8113	3.2807	5.9596	0.5804	6.54	29	
Data	**Mean**	**Standard error**	**Geometric mean**	**Median**	**Mode**	**Standard deviation**	**Sample variance**	**Range**	**Minimum**	**Maximum**	**Count**	
Grain Density, gm/cc	2.67	0.0099	2.6678	2.6431	N/A	0.0531	0.0028	0.23	2.58	2.81	29	

Table 5-4. Statistical Analyses for the Miller#2 Well Near Jamestown, NY (Continued)

Data	Mean	Standard Error	Geometric Mean	Median	Mode	Standard Deviation	Sample Variance	Range	Minimum	Maximum	Count	Formation
Permeability (mD), to air	0.01	0.0015	0.0035	0.0055	0.0012	0.0051	2.6428E 10^(-5)	0.0127	0.0003	0.013	12	B-Sand
Permeability (mD), Klinkenberg	0.0023	0.0006	0.0009	0.0017	0.00005	0.0021	4.3405E 10^(-6)	0.00505	0.00005 [1]	0.0051	12	
Porosity %, ambient	3.38	0.4874	2.8303	3.2595	4.5	1.6883	2.8505	5.8091	0.4291	6.2382	12	
Porosity %, NCS	3.27	0.4856	2.6915	3.1495	4.4	1.6821	2.8293	6.1028	0.0354	6.1382	12	
Grain Density, gm/cc	2.65	0.0206	2.6506	2.626	2.63	0.0714	0.0051	0.2131	2.592	2.8051	12	
Permeability (mD), to air	0.0138	0.0086	0.0025	0.0021	0.0009	0.0309	0.0009	0.1108	0.0002	0.111	13	B-Dolomite
Permeability (mD), Klinkenberg	0.0071	0.0051	0.0006	0.0005	0.0001	0.0183	0.0003	0.06595	.00005 [1]	0.066	13	
Porosity %, ambient	1.38	0.1643	1.2231	1.3623	0.5	0.6365	0.4051	1.87	0.48	2.35	15	
Porosity %, NCS	1.26	0.164	1.0853	1.2583	0.4	0.6351	0.4034	1.9	0.35	2.25	15	
Grain Density, gm/cc	2.79	0.02	2.79	2.8291	2.83	0.0776	0.006	0.23	2.62	2.85	15	
Permeability (mD), to air	0.0067	0.0012	0.0039	0.0042	0.0007	0.0075	5.5951E 10^(-5)	0.0366	0.0004	0.037	42	C-Sand
Permeability (mD), Klinkenberg	0.0024	0.0005	0.0011	0.0012	0.0001	0.0035	1.2365E 10^(-5)	0.0179	0.0001	0.018	42	
Porosity %, ambient	1.6258	0.1147	1.4697	1.5313	N/A	0.7776	0.6047	3.5064	0.6266	4.133	46	
Porosity %, NCS	1.5235	0.1167	1.3522	1.445	N/A	0.7832	0.6133	3.5363	0.4973	4.0336	45	
Grain Density, gm/cc	2.754	0.0133	2.7526	2.8038	N/A	0.09	0.0081	0.266	2.588	2.854	46	

Table 5-4. Statistical Analyses for the Miller#2 Well Near Jamestown, NY (Continued)

Data	Mean	Standard Error	Geometric Mean	Median	Mode	Standard Deviation	Sample Variance	Range	Minimum	Maximum	Count	Formation
Permeability (mD), to air	0.0153	0.0116	0.0097	0.0153	N/A	0.0166	0.0003	0.0235	0.0035	0.027	2	Potsdam
Permeability (mD), Klinkenberg	0.0065	0.0056	0.0033	0.0065	N/A	0.0078	6.1605E 10^(-5)	0.0111	0.0009	0.012	2	
Porosity %, ambient	3.6821	0.5009	3.6062	4.1823	4.2	0.0868	0.7527	1.5034	2.6803	4.1837	3	
Porosity %, NCS	4.0787	0.0086	4.0787	4.0787	4.1	0.0121	0.0001	0.0171	4.0702	4.0873	2	
Grain Density, gm/cc	2.64	0.0199	2.6399	2.6307	N/A	0.0344	0.0012	0.0669	2.6112	2.6781	3	

* Calculated mode for porosity measurements taken to one decimal place and grain density mode taken to two decimal places
* Several permeability measurements were below instrument's lower detection limit. In this case, one half of the lower detection limit was used as an approximation (marked [1])

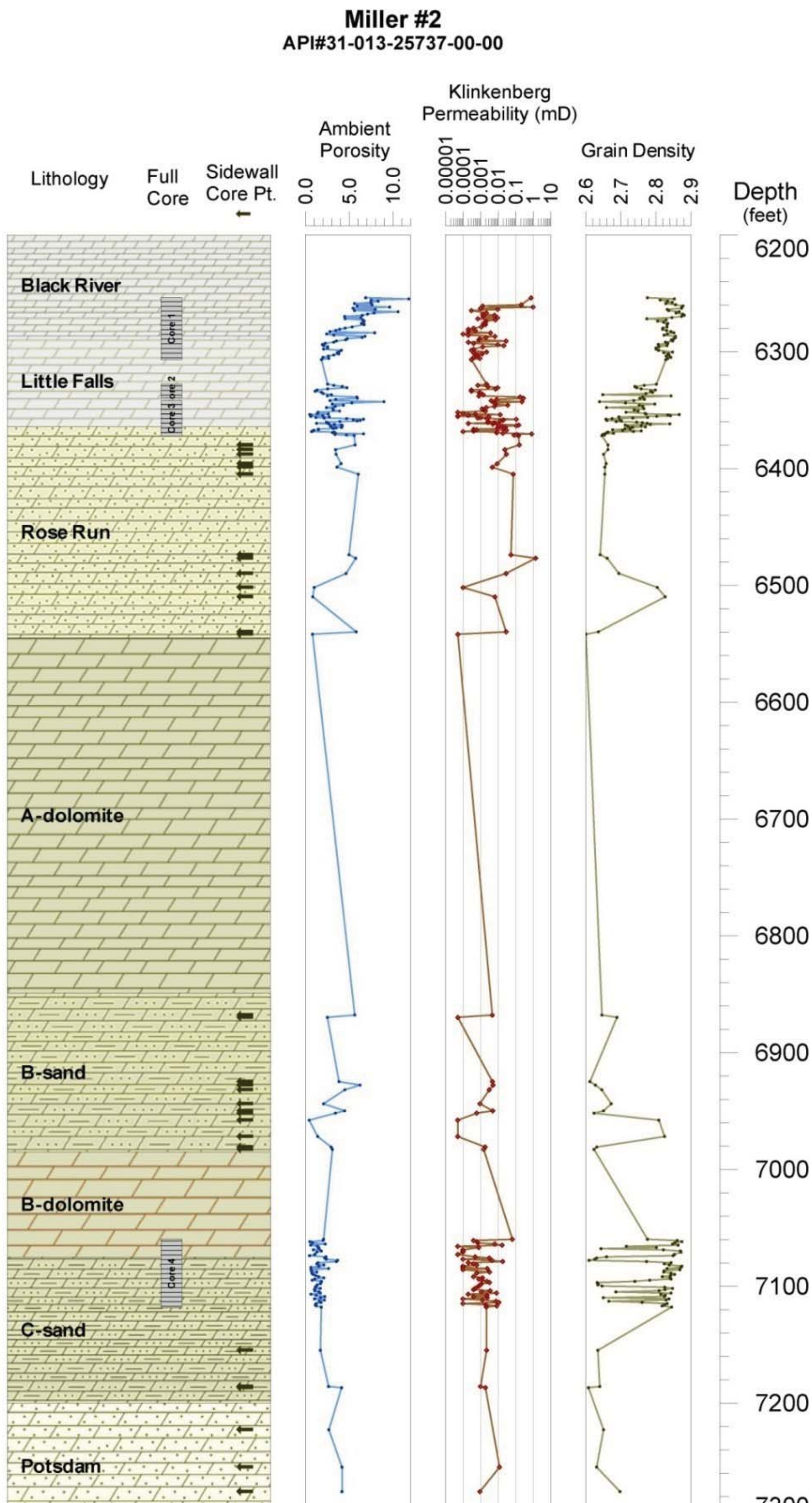


Figure 5-1. Summary of Full Core and Sidewall Core Program

5.3 Petrography/Mineralogy

Twenty rock core samples were identified for petrographic/mineralogical analysis. Samples were selected from key caprock and storage intervals (Table 5-5). Samples were analyzed for mineral composition, lithology, grain size, porosity type, and cement type. Samples selected for thin section analysis were prepared by first vacuum impregnating with blue-dyed epoxy. The samples were then mounted on an optical glass slide and cut and lapped in water to a thickness of 0.03 mm (30 microns). The samples were stained using Alizarin Red S for calcite and potassium ferricyanide for ferroan dolomite/calcite. When present, dolomite appears clear, ankerite appears turquoise blue, calcite appears red, and ferroan calcite appears purple. The prepared sections were then covered with index oil and temporary cover slips, and then analyzed using standard petrographic techniques.

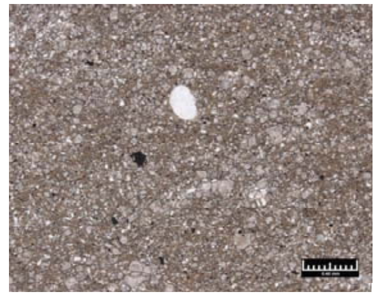
Table 5-5. Petrographic Analysis Samples

Sample Number*	Sample Depth (ft)	Formation
1	6,254	Black River
19	6,272	Black River
38	6,292	Little Falls
84	6,356	Little Falls
N/A	6,364	Rose Run
N/A	6,367	Rose Run
N/A	6,370	Rose Run
1-3R	6,388	Rose Run
1-6R	6,405	Rose Run
1-9R	6,490	Rose Run
1-13R	6,542	Rose Run
1-21R	6,952	Galway b-sand
1-22R	6,958	Galway b-sand
117	7,070	Galway b-dolomite
128	7,082	Galway c-sand
158	7,112	Galway c-sand
1-27R	7,186	Galway c-sand
1-29R	7,223	Potsdam
1-30R	7,255	Potsdam
1-31R	7,276	Potsdam

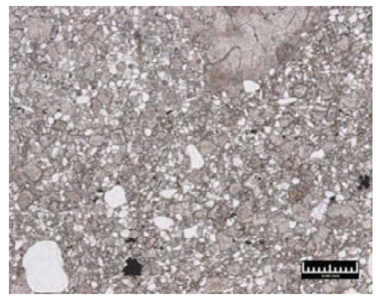
A complete mineralogy description is presented in Appendix A. Integrated results from the Black River-Little Falls caprock, Rose Run sandstone, Galway, and Potsdam formations are summarized as follows.

Black River-Little Falls Caprock. The Black River-Little Falls interval represents the immediate caprock above the Rose Run sandstone (Figure 5-2). The four thin sections from this interval are dolostone with little to no porosity visible in the samples. The Little Falls sample suggests gradation into a quartz sandstone. Overall, these thin sections suggest a very competent caprock interval.

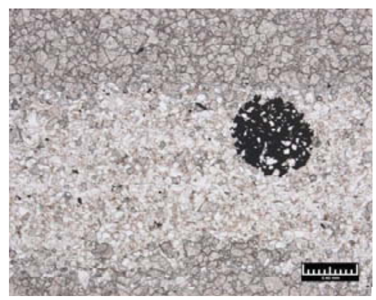
Black River- 6254 ft. Very abundant, sucrosic, crystalline dolomite . Minor detrital quartz . Minor authigenic pyrite cement . Very minor intercrystalline porosity present. Crystalline dolomite rhombs overlap, indicating several periods of crystallization and replacement of original carbonate and clastic sediments.



Black River- 6272 ft. Subrounded to rounded, detrital quartz grains. Very abundant, sucrosic dolomite and euhedral dolomite cement and rhombs. Minor intercrystalline porosity development in dolomite. Minor authigenic pyrite cement infilling intergranular pores and intercrystalline pores.



Little Falls- 6292 ft. Lamination of fine to very fine-grained quartz grains with sucrosic dolomite layers above and below. Authigenic pyrite nodule replacing original fossil material or primary grains. Interlayered, euhedral, sucrosic dolomite indicative of several episodes of replacement.



Little Falls- 6356 ft. Fine to medium grained, detrital quartz grains, are subrounded to rounded, with common quartz overgrowths on original grains. Common to minor dolomite cement , minor calcite cement, along with pyrite cement, are common pore reducers in this sample. Minor intergranular pores, and intracrystalline pores in dolomite.

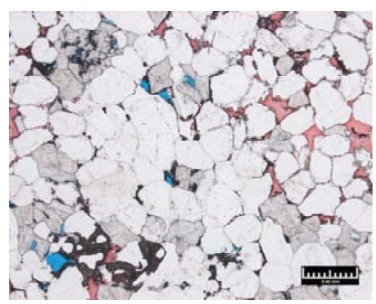
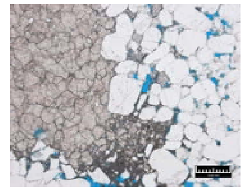


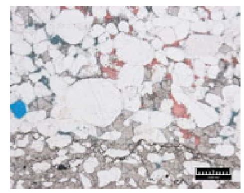
Figure 5-2. Petrographic Summary of Black River-Little Falls Caprock Interval

Rose Run Sandstone. The seven samples from the Rose Run sandstone are shown in Figure 5-3. As shown, the Rose Run formation was a quartz sandstone with varying amounts of quartz overgrowth and dolomite cement. Porosity in the samples appears fairly consistent with hydraulic test results at 1 to 4%. Samples from 6,405 and 6,490 ft appear to have much lower porosity than indicated in core tests, although this may be the result of variability of the unit.

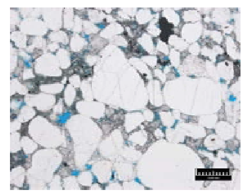
Rose Run 6364 ft. Sparry, crystalline dolomite cement , next to zone of subrounded to rounded, detrital quartz grains. Common quartz overgrowths on rounded detrital grains is significant pore reducer . Dolomite and pyrite cement in intergranular pores around quartz grains are significant pore reducers. Minor intergranular and intercrystalline pores are present .



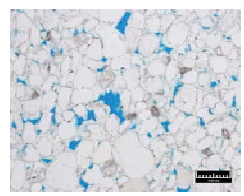
Rose Run 6367 ft. Bimodal distribution of detrital quartz grains is evident, with 0.14mm average size grains, and 0.80mm average size grains. Minor intergranular porosity is present , with common quartz overgrowths , common dolomite, and minor calcite cements all contributing to porosity reduction in this sample.



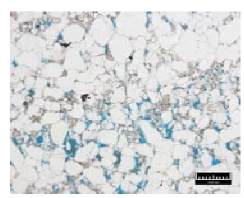
Rose Run 6370 ft. Detrital quartz grains are primarily rounded to subrounded, with common quartz overgrowths. Minor dolomite cement is a significant pore reducer in this sample. Minor detrital clay matrix material. Minor to rare pyrite cement . Minor intergranular porosity development.



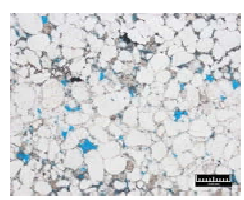
Rose Run 6388 ft. Well rounded to subrounded, detrital quartz grains, with common quartz overgrowths that significantly reduce porosity and permeability in this sample. Minor intergranular porosity development. Weathered feldspar grains with minor iron oxide and clay replacement.



Rose Run 6405 ft. Poorly developed laminations of larger quartz grains around finer grained lamination. Minor intergranular porosity development. Grain fractures have been healed and filled with secondary quartz and iron oxides. Detrital clay matrix material.



Rose Run 6490 ft. Rounded to well rounded, detrital quartz grains, with quartz overgrowths dolomite and pyrite as significant pore reducers. Minor intergranular pore development. Minor potassium feldspar and plagioclase feldspar grains have been partially weathered and replaced by authigenic clays.



Rose Run 6542 ft. Minor intergranular porosity development, and intercrystalline porosity development. Common quartz overgrowths, and authigenic dolomite are significant pore reducers in this sample. Detrital quartz grains are primarily rounded to subrounded and moderately well sorted. Euhedral dolomite rhombs on quartz grains are indicative of several episodes of replacement and cementation.

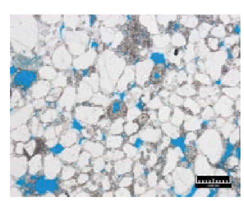
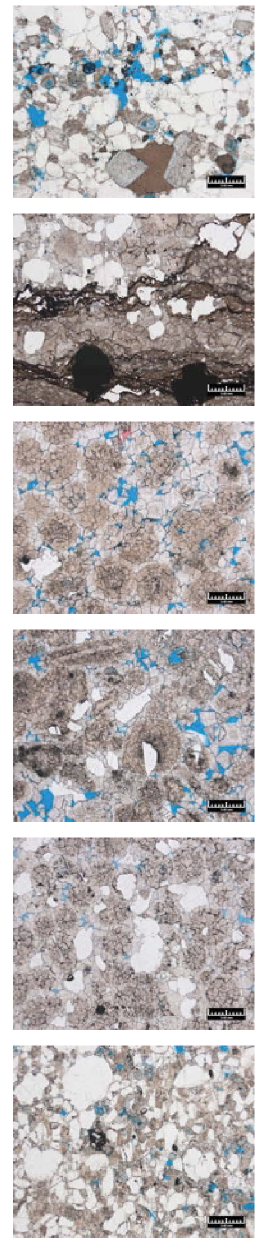


Figure 5-3. Petrographic Summary of Rose Run Sandstone

Galway Formation. Figure 5-4 shows the six samples from the Galway interval. As shown, there is a fair amount of variability within this formation. The rock formation is primarily a dolomitic sandstone. Samples from the B-dolomite and C-sand show evidence of replacement of oolites by dolomite. All samples suggest minor porosity less than 3%.



Galway b-sand 6952 ft. Several episodes of cementation are evident with formation of large, euhedral dolomite rhombs over micritic dolomite in large intergranular pore space. Minor, fair intergranular porosity development, and minor intracrystalline porosity development. Quartz grains have common quartz overgrowths that significantly reduce porosity and effective permeability in this sample.

Galway b-sand 6958 ft. Micritic dolomite laminae with high iron oxide content, and sparry dolomite laminae with detrital quartz grains. Authigenic pyrite as nodular replacement of original fabric. Detrital quartz grains are monocrystalline, nonundulatory, and rounded. Very little porosity is evident in this sample.

Galway b-dolomite 7070 ft. Original oolitic nature of dolostone is evident, with complete replacement of original calcite and aragonite oolites by crystalline dolomite. Minor intercrystalline and intracrystalline porosity development. Probable late-stage development of calcite cement. Quartz is present both as detrital grains and as authigenic quartz cement. Intercrystalline pore spaces have been infilled by sparry, euhedral dolomite.

Galway c-sand 7082 ft. Original oolitic nature of dolostone is evident, with complete replacement of original calcite and aragonite oolites by crystalline dolomite. Original grains oolites formed round was commonly quartz, which has been preserved in some oolites. Minor inter- and intracrystalline porosity development is present. Large, euhedral dolomite crystals are a common intercrystalline pore filling.

Galway c-sand 7112 ft. Original oolitic texture has been completely replaced by sucrosic dolomite and slightly iron-rich dolomite. Minor inter- and intergranular porosity is present. Quartz grains are primarily subrounded to rounded, nonundulatory, and have quartz overgrowths. Large, euhedral dolomite crystals are a common intercrystalline pore filling.

Galway c-sand 7186 ft. Common dolomite cement. Some detrital quartz grains have fractures healed by quartz overgrowths and iron oxides. Minor intergranular and intercrystalline pores. Minor authigenic pyrite and iron oxides. Euhedral dolomite rhombs on quartz grains suggests multiple periods of cementation and replacement.

Figure 5-4. Petrographic Summary of Galway Formation

Potsdam Sandstone Formation. Petrographic thin sections from the Potsdam sandstone are shown in Figure 5-5. The formation is described as a feldspathic, dolomitic quartz sandstone. There are some minor indications of porosity in the deepest sample. The Potsdam may not have been completely penetrated during drilling, so these samples likely reflect a portion of the rock formation.

Potsdam- 7223 ft. Bimodal nature of quartz grains is evident, with 0.12mm average grains, and 0.70mm average grains. Common quartz overgrowths and healed fractures in detrital grains are significant pore reducers. Minor intergranular porosity development. Minor detrital clay matrix and pyrite in sutures.

Potsdam- 7255 ft. Very minor intergranular and intercrystalline porosity development. Minor laminations filled primarily with micritic dolomite and with pyrite and iron oxides. Feldspar grains show minor weathering and alteration to clay and iron oxides. Quartz overgrowths are a common pore reducer in this sample.

Potsdam- 7276 ft. Fair intergranular and intercrystalline porosity development in this sample. Common authigenic dolomite cement, as both sparry dolomite and microcrystalline dolomite. Weathered feldspar grains, with minor pyrite and clay formation on grain surfaces. Detrital quartz grains contain minor, pore-reducing quartz overgrowths.

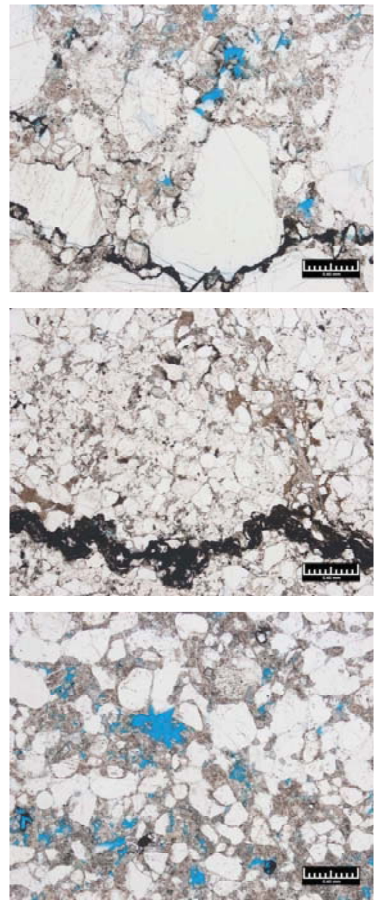


Figure 5-5. Petrographic Summary of Potsdam Formation

5.4 Geomechanical Parameters

Selected rock core samples were analyzed for geomechanical properties to provide information necessary to evaluate formation stimulation and hydraulic fracturing options. A total of six samples were identified for geomechanical tests (Table 5-6). The samples were selected from key confining layers and storage targets. The geomechanical tests can only be completed on full, competent rock core, because rotary sidewall cores are too small to be tested with standard methods. Consequently, there was a limited amount of core that could be tested.

Parameters were tested under static and elastic conditions at compressive pressure of 1,950 psi and saturated with synthetic 2% KCl brine. Table 5-7 summarizes results for static geomechanical analysis and Table 5-8 summarizes elastic test results. Overall, Young's modulus is on the higher end of values for carbonate rocks. Poisson's ratio is somewhat lower than typical carbonate rocks. The Poisson's ratio for sample 6370VRM (Rose Run) and 7076VRM (Galway C-sand) were notably lower than the other samples. Bulk modulus results were generally in the typical range for carbonate rocks. Samples 6370VRM (Rose Run) and 7076VRM (Galway C-sand) had lower Bulk Modulus results. These results suggest these formations are somewhat more compressible than other rocks tested. Shear modulus was within the typical range for carbonate rocks. Acoustic velocities are also within the expected range for carbonated rocks in the Appalachian Basin. These velocities are relatively fast for sedimentary rocks, and will factor into seismic applications that may be used to image CO_2 storage.

Table 5-6. Geomechanical Test Samples

Sample No.	Depth (ft)	Bulk Density (g/cc)	Formation
6272VRM	6272.09	2.68	Black River
6344VRM	6344.14	2.72	Little Falls
6367VRM	6367.56	2.68	Rose Run
6370VRM	6370.08	2.59	Rose Run
7069VRM	7069.45	2.80	Galway caprock
7076VRM	7076.31	2.57	Galway c-sand

Overall, geomechanical results suggest the presence of well-lithified, dense, sedimentary rock. Results were generally within the expected range for carbonate rocks in the Appalachian Basin. There was some indication of compressibility of the less dense samples from the Rose Run and Galway formations. Additional hydraulic fracture and geomechanical analysis would be required to determine well stimulation options.

Table 5-7. Summary of Static Triaxial Compressive Tests

Sample No.	Depth (ft)	Confining Pressure (psi)	Compressive Strength (psi)	Static Young's Modulus ($x10^6$ psi)	Static Poisson's Ratio
6272VRM	6272.09	1950	24786	5.59	0.42
6344VRM	6344.14	1950	42509	9.28	0.31
6367VRM	6367.56	1950	60443	11.45	0.27
6370VRM	6370.08	1950	74276	10.78	0.18
7069VRM	7069.45	1950	44327	10.45	0.31
7076VRM	7076.31	1950	89225	10.00	0.24

Table 5-8. Summary of Ultrasonic Velocities and Dynamic Elastic Parameters

Sample No.	Depth (ft)	Confining Pressure (psi)	Bulk Density (g/cc)	Ultrasonic Wave Velocity				Dynamic Elastic Parameter			
				Compressional		Shear		Young's Modulus	Poisson's Ratio	Bulk Modulus	Shear Modulus
				ft/sec	μsec/ft	ft/sec	μsec/ft	($x10^6$ psi)		($x10^6$ psi)	($x10^6$ psi)
6272VRM	6272.09	1950	2.68	16527	60.51	9253	108.08	7.86	0.27	5.74	3.09
6344VRM	6344.14	1950	2.72	20064	49.84	10730	93.20	10.96	0.30	9.12	4.22
6367VRM	6367.56	1950	2.68	18880	52.97	11510	86.88	11.54	0.20	6.50	4.79
6370VRM	6370.08	1950	2.59	17577	56.89	11550	86.58	10.43	0.12	4.58	4.66
7069VRM	7069.45	1950	2.80	21637	46.22	11477	87.13	12.97	0.30	11.04	4.97
7076VRM	7076.31	1950	2.57	17094	58.50	10948	91.34	9.57	0.15	4.59	4.15

5.5 Mercury Injection Core Permeability Tests

Mercury injection core permeability tests were completed on 9 selected samples to demonstrate low permeability properties of caprock zones (Table 5-9). A sample from 6352 ft was not suitable for testing. Mercury injection tests are useful to evaluate criteria like capillary entry pressures. The tests also have a lower detection limit for permeability and provide better confidence in caprock properties. As shown in the table, samples from the Wells Creek and upper Little Falls formations (6254, 6256, and 6292 ft) had very low permeability below 0.0001 mD and pore throat diameter less than 0.015 microns. Sample from the Little Falls at 6256 ft had higher permeability and pore throat diameter, suggesting this formation may be variable. The deeper samples also had low permeability. Samples from the Gallway were low permeability, but had larger pore throat diameters, likely related to dolomite grain size.

Table 5-9. Summary of Mercury Injection Core Permeability Tests.

Sample No.	Sample Depth, feet	Permeability to Air, millidarcys		Porosity, fraction		Grain Density, grams/cc		Median Pore Throat Radius, microns	Fluid Saturation at 200 psi Equivalent Gas-Water Capillary Pressure, fraction pore space
		Plug	Hg Inj*	Plug	Hg Inj	Plug	Hg Inj		
1	6254.00	1.02	0.000094	0.069	0.066	2.76	2.76	0.0032	1.000
3	6256.00	N/A	0.000082	0.075	0.065	2.79	2.80	0.0025	1.000
19	6272.00	0.0030	0.000066	0.045	0.043	2.75	2.75	0.0043	1.000
38	6292.00	0.0013	0.00017	0.032	0.031	2.81	2.81	0.0110	1.000
83*	6352.00	0.026	N/A	0.005	N/A	2.85	N/A	N/A	N/A
84	6356.00	0.0085	0.019	0.027	0.027	2.67	2.67	0.1790	0.097
117	7070.00	0.0009	0.0013	0.018	0.015	2.85	2.85	0.0820	0.623
128	7082.00	0.0024	0.0042	0.021	0.019	2.82	2.81	0.0087	0.432
155	7109.00	0.0020	0.0060	0.022	0.021	2.80	2.80	0.1200	0.317
158	7112.00	0.0047	0.0050	0.022	0.021	2.81	2.80	0.1130	0.402

*sample from 6352 ft not suitable for analysis due to insufficient pore volume.

Section 6.0: DATA ANALYSIS

This section presents an overall analysis of the results from the test well. Core test and wireline data were compared to determine the accuracy of the different methods. Petrographic analysis of the wireline data was also completed. Core test results were compared with data from other CO_2 injection test sites in the Midwest to provide a frame of reference for the test well data. Finally, hydraulic analysis of the injection targets was completed to estimate injection potential of the formations.

6.1 Wireline Analysis

Neutron and density porosities were calculated for each potential reservoir formation. Neutron porosity comes directly from the logging measurement and is related to the amount of hydrogen atoms in the formation and formation fluids. Neutron logging tools tend to overstate the amount of porosity in many formations due to the presence of hydrogen atoms within the crystal structure of the rock. Density porosity is defined by the following equation:

$$\Phi = \rho ma - \rho b / \rho ma - \rho fl$$

where

ρma = density of the matrix
ρb = bulk density
ρfl = fluid density.

Matrix density for sandstone is 2.644, 2.710 for limestone and 2.877 for dolomite. Bulk density is read from the wireline density log. Fluid density is assumed to be 1 for a fluid-filled system. For each potential reservoir formation, net to gross reservoir intervals were calculated by applying a gamma ray cutoff of 75 API and a porosity cutoff of 4%. Porosities were then averaged over both the gross and net intervals. Additionally, neutron-density crossplots were used to determine porosity and formation lithology.

Elemental spectroscopy refers to a log of the yields of different elements in the formation, as measured by capture gamma ray spectroscopy using a pulsed neutron generator. The main purpose of the log is to determine lithology. The principal outputs are the relative yields of Chlorite, Illite, Quartz, Orthoclase, Pyrite, Barite, Calcite and Dolomite. Additionally, the processing attempts to give relative volumes of water and hydrocarbons, which is of secondary interest in that the presence of free water can be an indication of porosity. These results are then compared to the core data.

As is expected for the Appalachian Basin, wave velocities indicate very fast rocks. The two-dimensional horizontal minimum stress gradient generally ranges between 0.8 and .97 psi/ft which can imply that the fracture pressure would be high. For confinement formations, high fracture pressures are favorable. The major exception of these values is in the Rose Run. The

Rose Run shows slightly slower formation velocities than what is seen in the rest of the well. The minimum horizontal stress gradient is also lower in the sand lobes and ranges between 0.68 and 0.78 psi/ft. This implies that the fracture pressure in the sand portions of the Rose Run is different from the formations above and below it. With further analysis, it may be possible to stimulate the Rose Run safely. The change in stress seen in the Rose Run in the Miller #2 well is consistent with what has been seen at elsewhere in the Appalachian Basin.

Compressional and shear wave velocities on the log generally match the values from the core measurement, with the exception of the core at 7076 ft. The geomechanical properties display a larger difference between the measured core values and the calculated log values. Data was collected for anisotropy analysis, however it was not processed.

In general, the sonic log provided good data that does not appear to have suffered from tool malfunctions. There are minor indications of wellbore integrity issues effecting the data, such as 4850 ft, however this is uncommon. Unusable sonic data due to zeroed out measurements starts at 7250 ft and extends to the bottom of the well. This data cannot be reliably used for assessing the characteristics of the rocks.

6.1.1 Rose Run Sandstone. Using a neutron porosity calculation, the Rose Run had 164 gross feet of reservoir and 10 feet of net reservoir. Porosity average for the entire interval was 2.2% and 6.1% for the net interval. Using a density porosity calculation, the Rose Run had 164 gross feet of reservoir and 33 feet of net reservoir. Porosity average for the entire interval was 3.4% and 5.2% for the net interval.

Rose Run crossplots show a very mixed formation, either sandstone with carbonate cement or sandstone interbedded with carbonate (Figure 6-1). The porosity is mainly around 5% and ranges from about 2% up to about 7%.

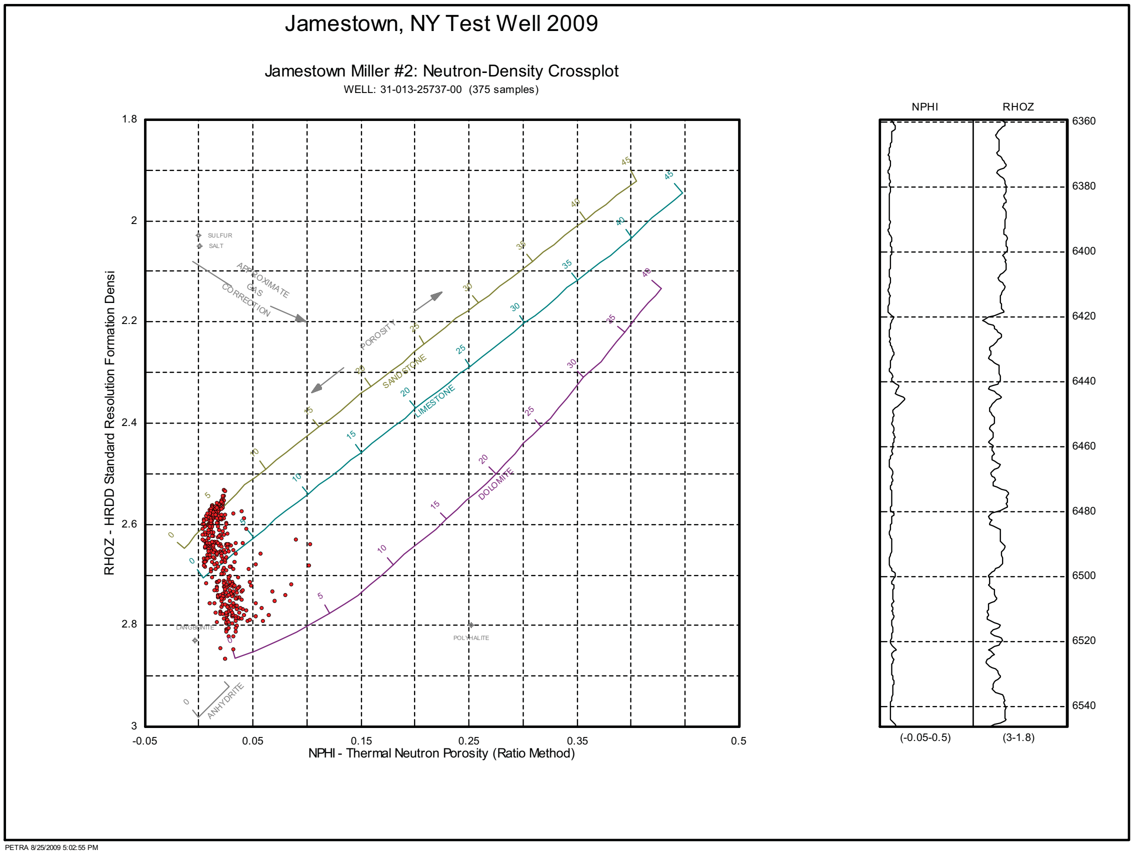


Figure 6-1. Rose Run Neutron-Density Cross Plot

6.1.2 A-Dolomite. Using a neutron porosity calculation, the A-Dolomite had a reservoir of 287 gross feet and 48 feet of net reservoir. The porosity average for the entire interval was 3.2% and 4.6% for the net interval. Using a density porosity calculation, the A Dolomite had a reservoir of 287 gross feet and 46 feet of net reservoir. The porosity average for the entire interval was 3.2% and 4.6% for the net interval.

The A Dolomite crossplots show a fairly clean dolomite with minimal amounts of limestone (Figure 6-2). The porosity is mainly around 3 to 4% and ranges from about 0% to about 5%.

6.1.3 B-Sand. Using a neutron porosity calculation, the B-Sand had a reservoir of 42 gross feet and 13 feet of net reservoir. The porosity average for the entire interval was 3.5% and 6% for the net interval. Using a density porosity calculation, the B-Sand had a reservoir of 42 gross feet and 1 feet of net reservoir. The porosity average for the entire interval was 2.7% and 5.3% for the net interval.

The B-Sand crossplots show a very mixed formation, either sandstone with carbonate cement or sandstone interbedded with carbonate (Figure 6-3). The porosity is mainly around 5% and ranges from about 2% to about 8 %.

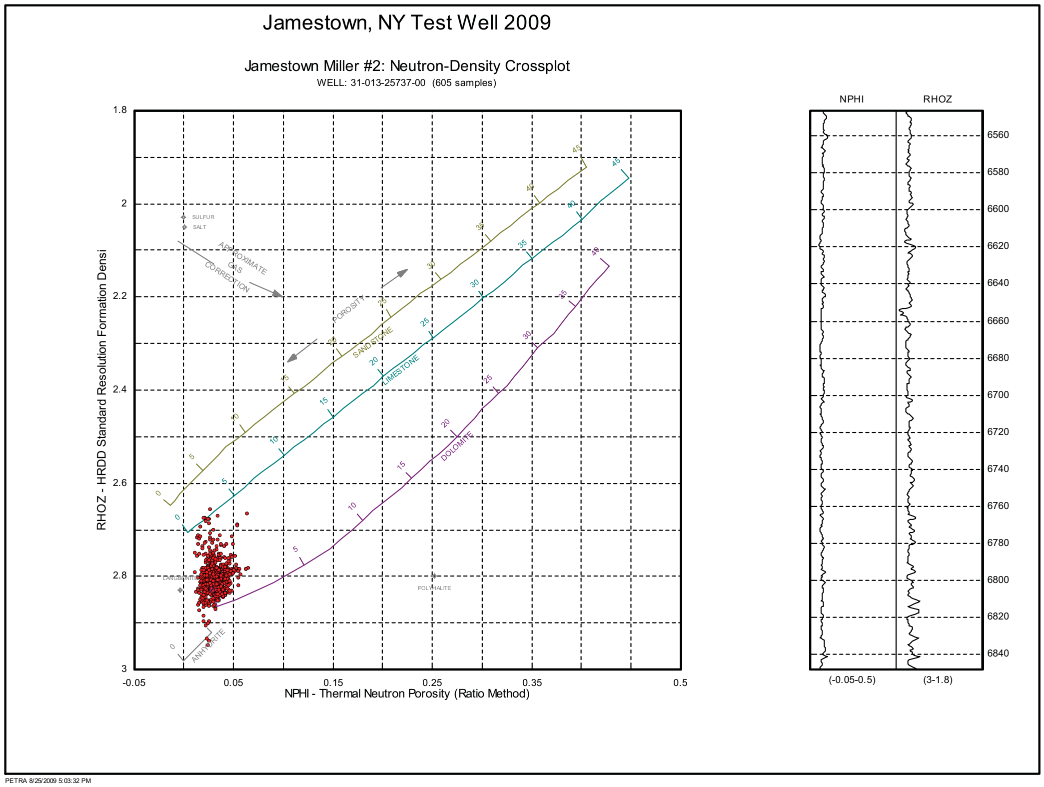


Figure 6-2. A-dolomite Neutron-Density Cross Plot

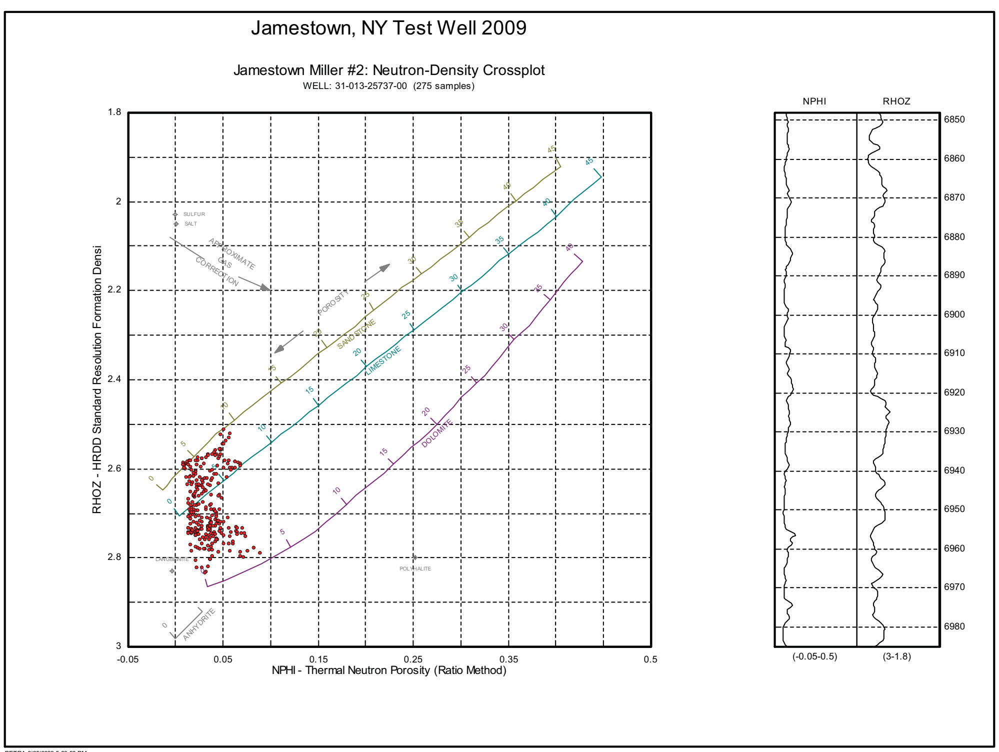


Figure 6-3. B-Sand Neutron-Density Cross Plot

6.1.4 B-Dolomite. Using a neutron porosity calculation, the B-Dolomite had a reservoir of 107 gross feet and 44 feet of net reservoir. The porosity average for the entire interval was 3.7% and 5.4% for the net interval. Using a density porosity calculation, the B-Dolomite had a reservoir of 107 gross feet and 13 feet of net reservoir. The porosity average for the entire interval was 2.3% and 5.4% for the net interval.

The B-Dolomite crossplots show a fairly clean dolomite with minimal amounts of limestone (Figure 6-4). There also appear to be a few interbeds of sandstone. The porosity is mainly around 3% and ranges from about 0 % to about 4%.

6.1.5 C-Sand. Using a neutron porosity calculation, the C-Sand had a reservoir of 9 gross feet and 1 feet of net reservoir. The porosity average for the entire interval was 2.1% and 3.1% for the net interval. The C-Sand did not correctly calculate average porosities using the density porosity calculation.

The C-Sand crossplots show a very mixed formation, either sandstone with carbonate cement or sandstone interbedded with carbonate, mostly limestone (Figure 6-5). The porosity is mainly around 3% and ranges from about 0% to about 5%.

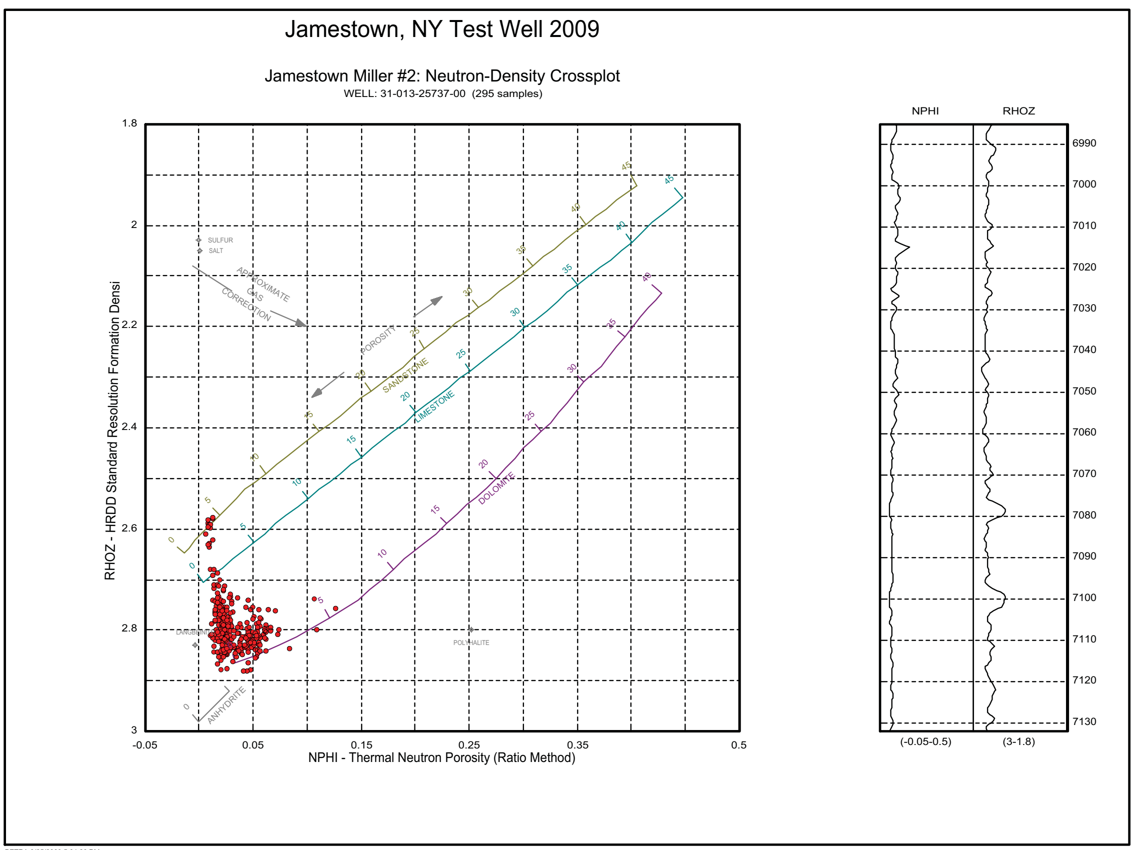


Figure 6-4. B-Dolomite Neutron-Density Cross Plot

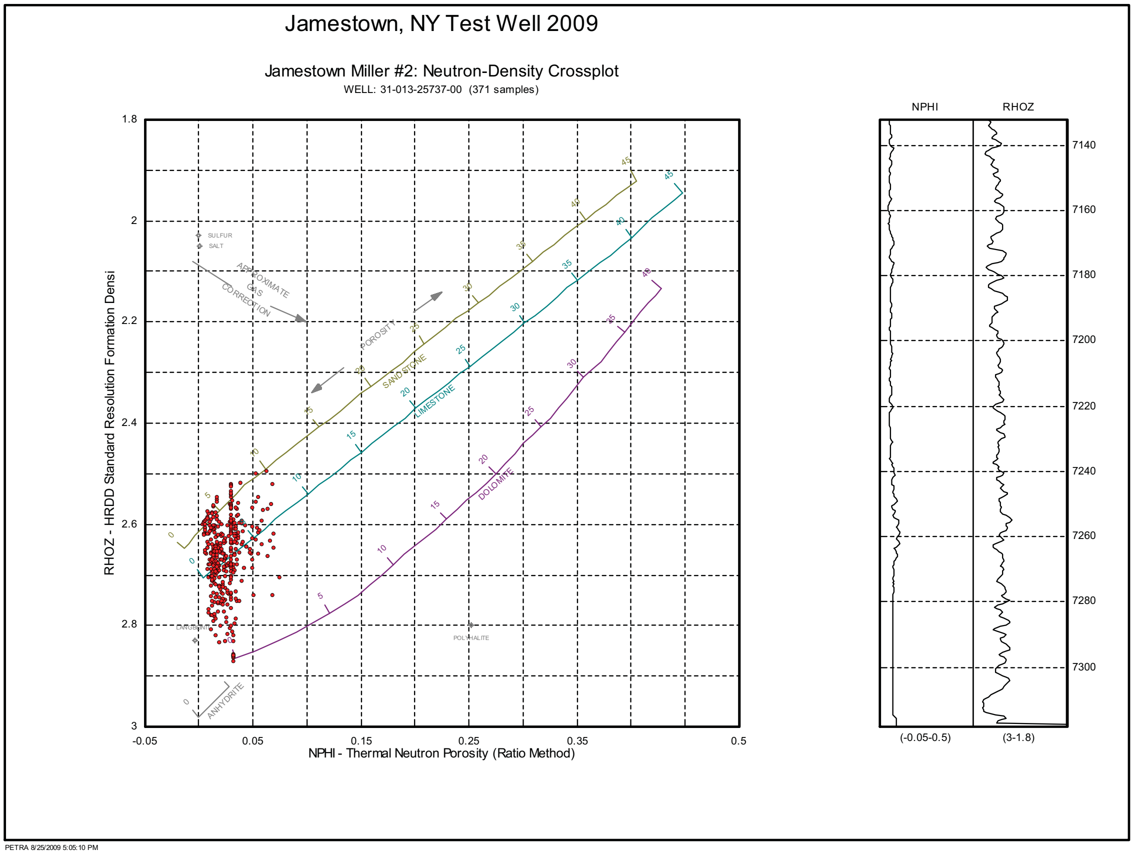


Figure 6-5. C-sand Neutron-Density Cross Plot

6.2 Core Test and Wireline Comparison

Wireline data is most useful when verified by actual core. Density measurements made by the wireline logs are compared to the values in the core samples. In additional, a comparison between the elemental spectroscopy results and the core lithology is made.

Figure 6-6 shows a graphical display of wireline density and core density, adjusted for depth. As indicated in the figure there is excellent agreement (generally <5% difference) between the two methods of measurement, which suggests the measured values are a close approximation to the true values. The range of values measured with core analysis is 0.28 (g/cm^3) while the range for the wireline values is 0.38 (g/cm^3). These values are in good agreement with each other as well as expected values.

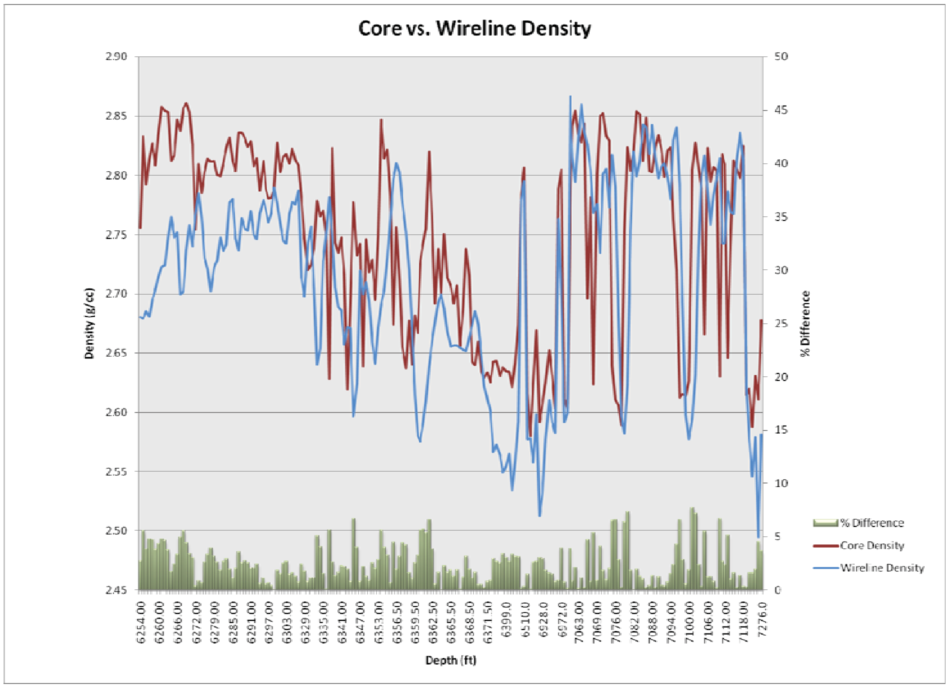


Figure 6-6. Graph Showing Measured Core Density Versus Measured Wireline Density for Miller #2 (in g/cm^3) and the Percent Difference between the Two Curves

Cores were not analyzed in the Utica or Trenton formations. Elemental spectroscopy shows the Utica Formation overall to be more or less equal parts quartz and illite, with some minor chlorite. The Trenton Formation is dominantly calcite, which grades into some minor dolomite in last 100 feet of the unit. There is an area of partial quartz and illite around 5600-5800.

The Tribes Hill Formation is overall as dominantly dolomite, with a few calcite rich streaks. There is also minor quartz, illite and chlorite. One core sample from the Tribes Hill at 6254 is described as a pyritic, quartzitic dolostone. The elemental spectroscopy for the same depth shows tiny amount of pyrite, but mainly quartz with illite.

The Little Falls interval is characterized as dominantly dolomite that grades into quartz with some minor calcite. The core at 6272 is a feldspathic, quartzitic dolostone, while the elemental spectroscopy shows mainly dolomite and minor quartz with illite and chlorite. The core at 6292 is a quartzitic, sparry dolostone and elemental spectroscopy shows mainly dolomite, minor calcite, and some quartz. The core at 6356 is calcareous, dolomitic, quartz sandstone and the elemental spectroscopy shows dominant quartz with calcite and dolomite.

Overall the Rose Run is characterized by the top 70 feet dominated by quartz, which grades into dolomite beds with minor calcite. The core at 6364 is a dolomitic, quartz sandstone, which agrees with the elemental spectroscopy assessment of overwhelming quartz with minor dolomite. The core at 6367 is a calcareous, dolomitic, quartz sandstone and the elemental spectroscopy shows overwhelming quartz with minor dolomite and minor calcite. The core at 6370 is argillaceous, dolomitic, quartz sandstone. However the elemental spectroscopy only shows quartz at this depth. The cores at 6388 and 6405 are feldspathic, quartz sandstones but the elemental spectroscopy only categorizes the quartz. The core at 6490 is a dolomitic, quartz sandstone and the elemental spectroscopy shows overwhelming quartz with minor dolomite and also minor calcite. The core at 6542 is a dolomitic, quartz sandstone, but the elemental spectroscopy only shows quartz.

Cores were not analyzed in the A Dolomite. The elemental spectroscopy shows a dominant dolomite lithology with very minor quartz and calcite.

Overall the elemental spectroscopy shows the B Sand to be quartz with high dolomite influence. There large amounts of orthoclase from 6880 to 6950 and minor illite throughout. The core from 6952 is a lithic, dolomitic, quartz sandstone, while the elemental spectroscopy shows overwhelming quartz with minor orthoclase. The core from 6958 is an argillaceous, pyritic, quartz dolostone with the elemental spectroscopy from that depth showing mainly dolomite with minor quartz and some orthoclase.

The elemental spectroscopy characterizes the B Dolomite Formation as dominantly dolomite with minor quartz and illite, with increasing amounts of quartz in bottom 50 feet. The cores from 7070 and 7082 are quartzitic, sucrosic dolostones and the elemental spectroscopy shows a dominant dolomite, with some quartz and orthoclase. The core at 7112 also shows a quartzitic, sucrosic dolostone. However the elemental spectroscopy shows dolomite, quartz and orthoclase as roughly equal.

The Potsdam is characterized by the elemental spectroscopy as an orthoclase rich quartz with minor dolomite. The cores at 7186 and 7276 are dolomitic, quartz sandstone, but the elemental spectroscopy shows quartz and orthoclase with no dolomite. The core at 7223 is an argillaceous, feldspathic, quartz sandstone and the elemental spectroscopy shows quartz and orthoclase. The core at 7255 is a feldspathic, dolomitic, quartz sandstone but the elemental spectroscopy shows quartz and orthoclase with no dolomite.

6.5 Potential Secondary Porosity

Image logs were reviewed to identify zones which may have secondary porosity and injectivity not revealed with other methods. The image log run on May 3, 2009 shows few, relatively minor indications of secondary porosity which sometimes are not accurately represented in core samples and wireline logs. Further investigation into these intervals may be warranted if other testing, such as reservoir testing, could support the indications on the image log. The Rose Run Sandstone seems to contain natural partial fractures throughout the formation including two open fractures. Additionally, indications of vugular porosity exist on a small interval (net ~5 ft) in the B-Dolomite.

The Rose Run formation exhibits relatively low porosities (5 to 10%) in both wireline and core data. However, the image log clearly shows several fractures which intersect the borehole that could be indicative of higher than expected porosity at a depth near 6395 ft (Figure 6-10). It is difficult to quantitatively describe this type of porosity without further investigation into the condition, such as hydraulic testing. It is possible that injectivity is increased in this interval due to the fracturing and that the Rose Run could be a potential reservoir candidate for sequestration in the future.

Another type of secondary porosity is recognized in the image log as being vugular. Over an interval of approximately 28 ft in the B-Dolomite (7042 to 7070 ft) there appear to be dark, electrically conducive circles on the borehole wall (Figure 6-11). Sometimes, this is an effect caused by vugs, small gaps in the formation created by dissolution. However, the net total thickness of these potentially vuggy intervals is approximately 5 ft over the 28 ft section. Additionally, it is possible that this vugular porosity does not translate into good permeability which could occlude the B-Dolomite as a potential reservoir.

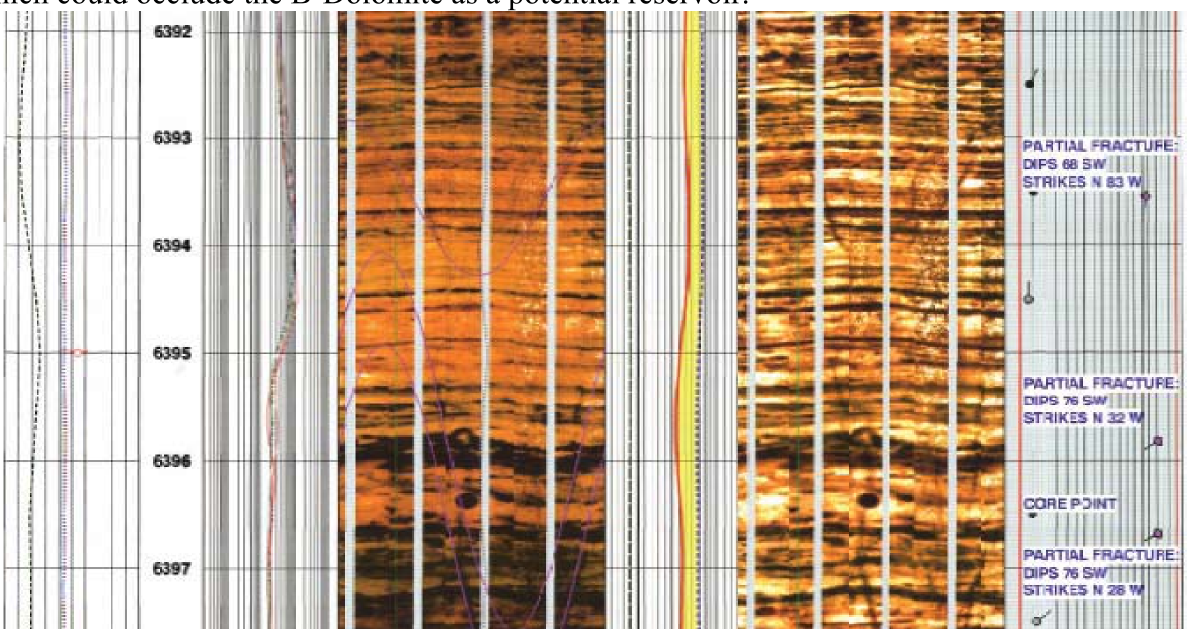


Figure 6-10. Image Log Section Showing Fractures in the Rose Run Sandstone

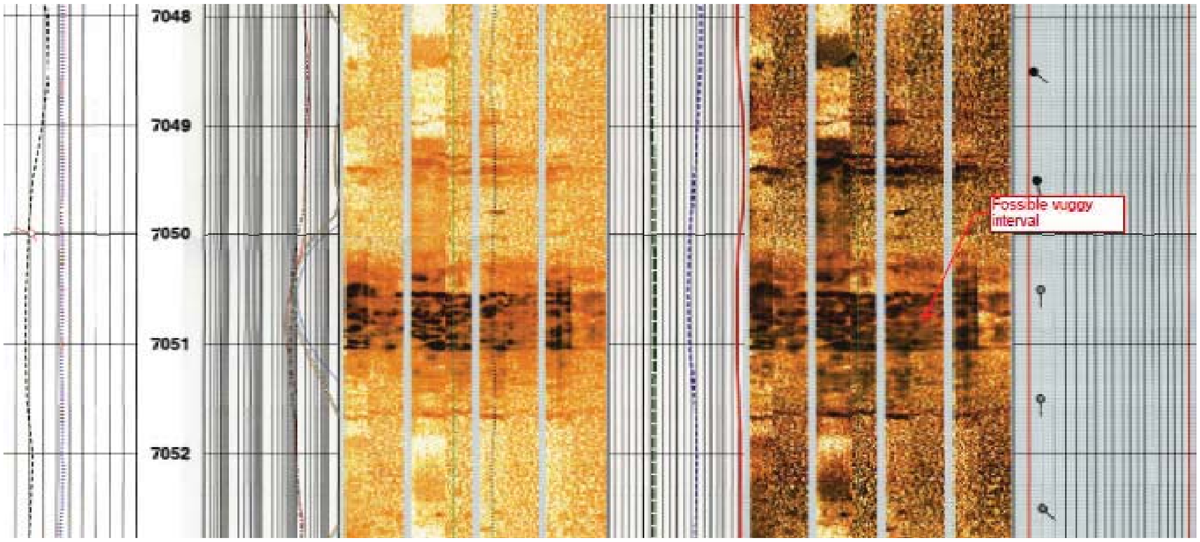


Figure 6-11. Image Log Section Showing Potential Vugular Porosity in the B-Dolomite

Section 7.0 CONCLUSIONS AND RECOMMENDATIONS

This section summarizes the conclusions and recommendations that can be made based on the Miller #2 test well results. The current report addresses only a single well point. Overall, the complete screening, site characterization, and CO_2 storage design is a multiphase, multi-year effort. This preliminary assessment should not be viewed as or interpreted as a definitive assessment of the presence (or absence) of suitable CO_2 storage formations, caprocks, sufficient injectivity to allow CO_2 sequestration to be carried out in an economic manner, etc.

The Miller #2 test well drilled into relatively uncharacterized rock formations. As experienced in other areas of the Appalachian Basin, the deeper rocks presented some drilling challenges such as low penetration rates, poor circulation, and rapid drilling bit wear. While this is likely attributable to the nature of the rocks, it may be beneficial to invest more time in selecting drilling fluids and drilling bits to limit drilling time. Mud logs provided useful feedback on the rock formations; although some debate exists as to the nomenclature of the deeper formations because they are not commonly drilled. Full rock core was collected in 60 ft runs with acceptable recovery.

A total of 156 ft of full core and 31 rotary sidewall core plugs were collected from the test well. The well was logged with a complete suite of geophysical logs. This data set provides a fairly thorough characterization of the deep rock formations in the Miller #2 test well.

Key caprocks penetrated in the test well included the Queenston, Lorraine, Utica, Black River, and Little Falls. Together, these formations represent over 2,500 ft of containment layers. Log and core test data demonstrate that the formations have low permeability and porosity.

Overall, it appears that the targeted storage formations had suitable thickness for CO_2 storage as suggested by previous regional studies on CO2 storage potential for the region (Wickstrom et al., 2006). The Rose Run sandstone was 181 ft thick and the Potsdam sandstone appeared to be at least 108 ft thick. Both formations were slightly thicker than predicted in the well prognosis. Therefore, the storage formations appear to have the overall physical dimensions desired for CO_2 storage. Both the Galway B-sand and the Galway C-sand were identified in the test well, but the formations were present as thin, sandy intervals.

While the physical dimensions and lithology of the target formations were suitable for CO_2 storage, hydraulic parameters were lower than desired. Core test results generally showed porosity less than 3% and permeability less than 0.1 mD across all of the tested zones. Several zones were identified that may have secondary or fracture porosity which may merit more consideration.

The lithology of the Rose Run and Postdam formations was mostly a dolomitic quartz sandstone. There were only minor amounts of clay and iron-oxide minerals that might result in CO_2 dissolution/precipitations reactions. The Galway sand zones were mostly dolomite with minor detrital quartz. Dolomite may be susceptible to minor amounts of dissolution by carbonic acid.

Recommendations to further define CO_2 storage parameters include the following:

- **Systematic regional assessment of CO_2 storage targets**. Given results from the Miller #2 test well, it would be valuable to complete a systematic geologic assessment of the CO_2 storage options in deep saline formations in the region overall. This study would integrate existing geologic information to generate maps, geologic cross-sections, and estimated parameters relevant to sequestration potential in the area. Information of interest includes deep well locations, formation thickness, geophysical logs, well construction details, formation pressure, permeability, porosity, location and availability of core samples, location and availability of brine/formation fluid samples, and mineralogy. This study would help define trends in CO_2 storage targets like the Rose Run and Potsdam formations, and help determine areas which may be more suitable for CO_2 storage.
- **Reservoir stimulation/treatment tests**. Additional tests in the Miller #2 test well may be useful to evaluate the feasibility of reservoir stimulation/treatment. Many formations in the Appalachian respond to hydraulic fracturing for gas production, but there is not much experience with enhancing injectivity with these methods. It is also difficult to delineate secondary porosity zones in carbonate rocks, which may be suitable for injection. Consequently, some additional testing in the Miller #2 well may be useful for investigating CO_2 storage. These tests would be considered well treatment and not require underground injection. The tests may consist of short brine injection tests, mini-frac tests, and other tests.
- **Consideration of other targets in the region for CO_2 sequestration**. Other rock formations in the Jamestown area may be targets for CO_2 storage. Enhanced recovery of oil and gas using CO_2 injection is an option for this particular location, but the potential for injection into hydrocarbon deposits requires further analysis. This study would identify and map oil and gas fields in the area of review in respect to their potential for CO_2 sequestration and EOR. Available seismic data and geophysical well log information would also be reviewed for the project area. Other shallow units may also be of interest, such as the Bois Blanc, Akron/Bass Island, Oriskany, and Lockport.
- **Additional Regional Characterization of CO_2 Storage Targets**. More deep wells in the region would clearly aid in defining the geological framework for CO_2 storage. These wells may be piggyback wells or dedicated exploratory wells. The wells should focus on the injection target parameters because it appears that containment layers are well defined in this study.

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APPENDIX A: DRILLING LOGS

APPENDIX B: WIRELINE LOGS

APPENDIX C: CORE TEST RESULTS

(Appendices available at http://esogis.nysm.nysed.gov)

Appendix 3.

Seismic Report

Schlumberger
Carbon Services

Final Report - Seismic Survey Results & Interpretation

Jamestown BPU Oxy-Coal Project
Jamestown, NY
Project No. 002595.NY13.05

Prepared by:
Schlumberger Carbon Services
14090 SW Freeway, Ste 300
Sugar Land, TX 77478

Project Manager
Eric Berlin berlin1@slb.com

Geoscientists
Kathryn Tamulonis KTamulonis@slb.com
Valerie Smith VSmith2@slb.com
Marcia Couëslan MCouselan@slb.com

www.slb.com/carbonservices

February 14, 2011

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1.0 Introduction and Project Scope

Ecology and Environment, Inc. (E & E) has commissioned Schlumberger Carbon Services (Schlumberger) to acquire a high resolution 2D seismic survey and review/interpret the results of this survey along with other pertinent existing seismic and wellbore data in the study area. The scope of services is part of a project being conducted by E & E on behalf of New York State Energy Research and Development Authority (NYSERDA) and the Jamestown Board of Public Utilities (Jamestown BPU). E & E under contract with NYSERDA (Project No. 10498 Carbon Sequestration Feasibility Study in the Chautauqua County, New York Areas) has been tasked with identifying potential areas suitable for geologic carbon sequestration in the Chautauqua County area. Based on surface constraints, E & E has identified the Wellman Multiple Use Area (MUA) in southeast Chautauqua County as a potential site. The goal of the seismic survey was to acquire data to evaluate the geologic conditions at the site and identify the presence of seismically discernible faults, reservoir continuity, and general frame work of the deep rock layers in the vicinity of the Wellman MUA. Data collection, processing, and interpretation of results were performed by Schlumberger Carbon Services and WesternGeco, a business segment of Schlumberger.

Schlumberger Carbon Services provides comprehensive deep geological storage solutions for CO_2 consistent with care for health, safety, and environmental protection. Technical expertise, project management, and technology are leveraged from more than 80 years of proven subsurface evaluation experience in the oil and gas industry and our recent involvement in nearly every geologic carbon storage and sequestration (CCS) demonstration project in the United States and abroad.

WesternGeco, a business segment of Schlumberger, is the world's leading geophysical services company, providing a full range of services to the oil and gas industry.

The primary tasks involved with this project are as follows:

1. Design & Permitting of Seismic Survey
2. Data collection (acquisition)
3. Data processing
4. Interpretation
5. Reporting and Deliverables

The purpose of this report is to summarize the subsurface geology at the study site, seismic acquisition, and data processing, as well as to provide an interpretation of the seismic survey results. The report is to also provide an estimation of depths of formation tops and whether indications of faulting (or other flaws) exist in the study area.

2.0 Site Description

2.1 Basin Location, Regional Description, and Characteristics

Chautauqua County is located in western New York in the north-eastern portion of the Appalachian Basin (Figure 1). The bedrock geology is primarily composed of Cambrian through Devonian clastic and carbonate rocks and is underlain by Proterozoic basement rock. The surficial bedrock of Chautauqua County is Devonian carbonates, sandstones, and shales. The rocks in this portion of the Appalachian Basin were deposited in environments that fluctuated between non-marine to deep marine settings during the Taconic and Acadian Orogenies. Specifically for this study, the Upper Cambrian subsurface stratigraphy is being targeted for CO_2 storage evaluation (Figure 2).

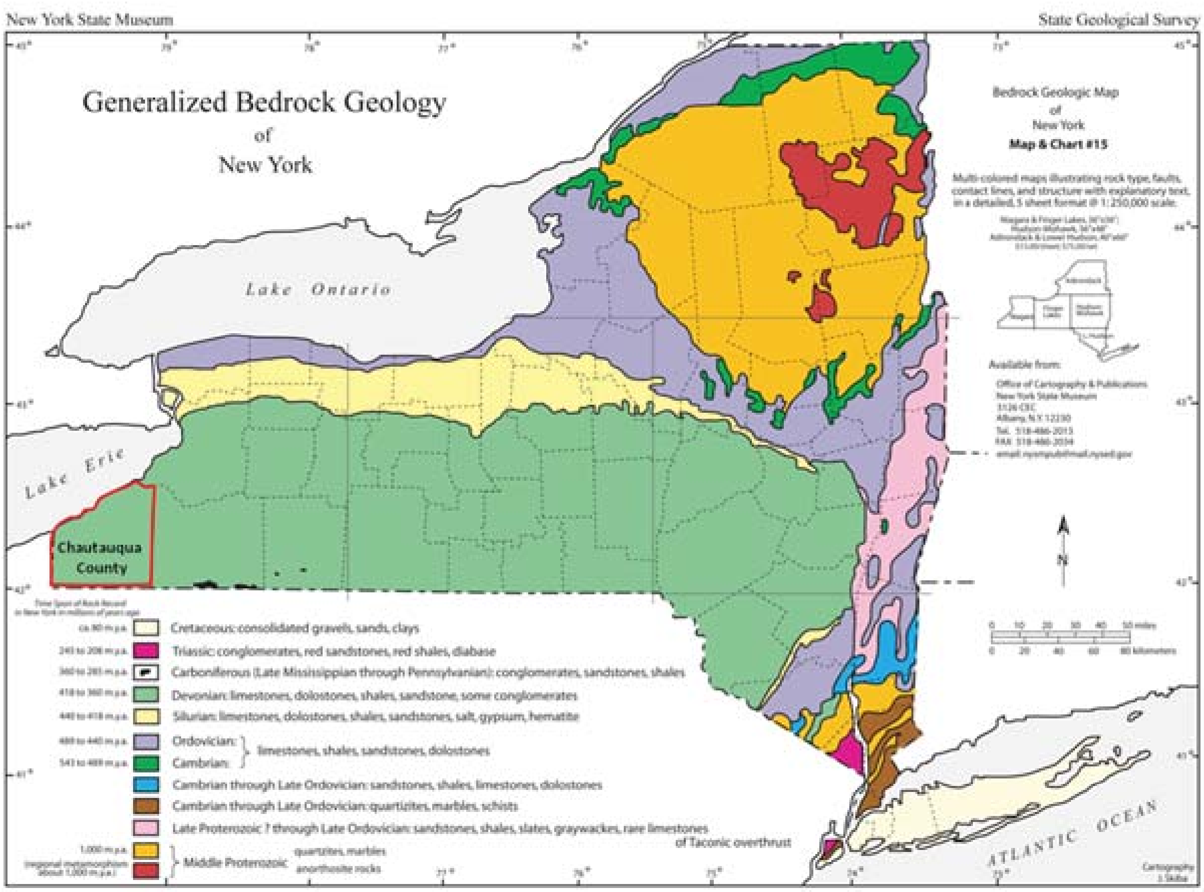


Figure 1: Bedrock geologic map of New York State with Chautauqua County outlined in red. Surficial bedrock geology of the study area is Devonian strata of the Appalachian Basin. Modified from Fisher (1970).

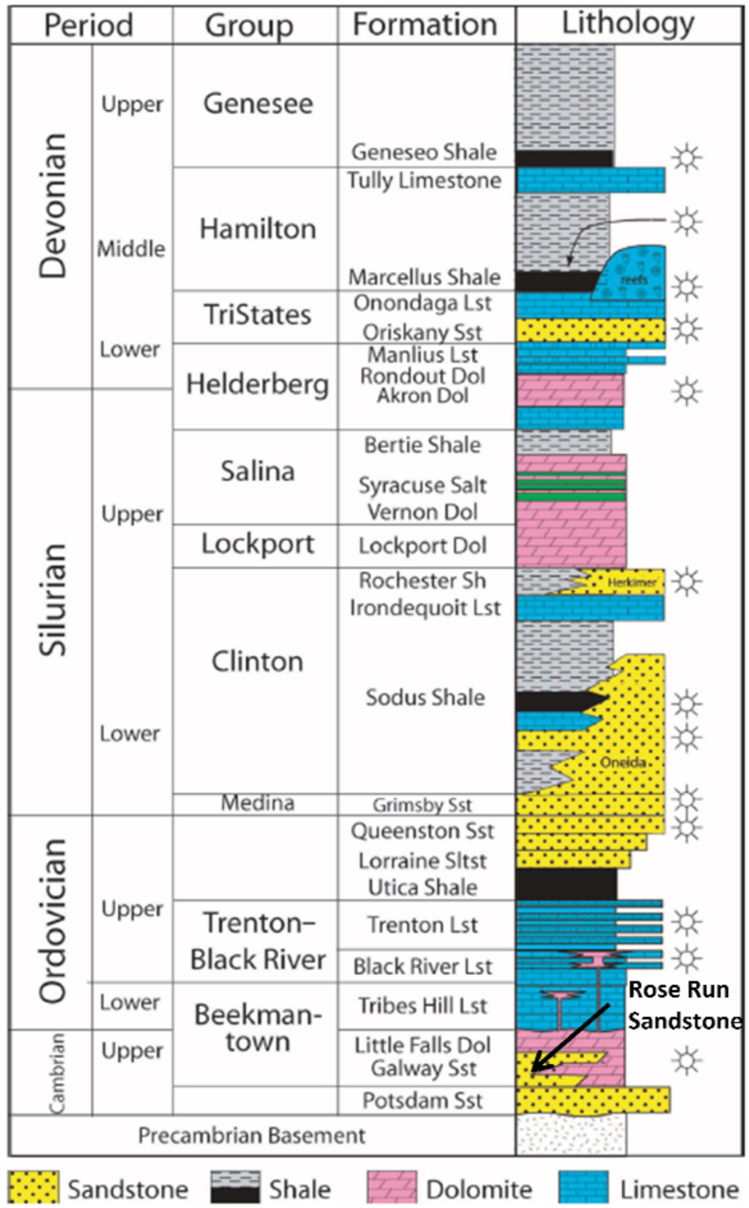


Figure 2: Generalized stratigraphy of central and western New York. The Upper Cambrian Rose Run Sandstone Member, Galway Formation, and the Potsdam Formation are being assessed for carbon sequestration potential at the Jamestown site. Modified from Smith (2006), Figure 3.

2.2 Interface between Site, Surface Features, and Land Use

Chautauqua County is located in the southwest corner of New York State. The total population of the county is approximately 140,000, and two cities exist within the county: Jamestown (population 32,000) and Dunkirk (population 13,000). Chautauqua County has six lakes and nearly 50 miles of Lake Erie shoreline. Surface topography ranges from relatively flat along the shores of Lake Erie to rolling hills. Most of Chautauqua County is considered rural, as farming is the primary land use, and most land is privately owned (www.co.chautauqua.ny.us).

3.0 Geologic Summary

The Proterozoic Grenville Basement underlies the Paleozoic sedimentary strata of New York State and generally dips southward during Paleozoic sediment deposition. During the Cambrian through Upper Ordovician, New York State was situated on a passive margin south of the equator, and in the Late Ordovician, an island arc collided with proto-North America creating the Taconic Orogeny. Following a period of quiescence after the Taconic Orogeny, a second mountain building event, the Acadian Orogeny, occurred during the Devonian through Mississippian periods. This cycle of quiescence and mountain-building is recorded as a complex pattern of deposition, erosion, and facies change in the strata of New York State.

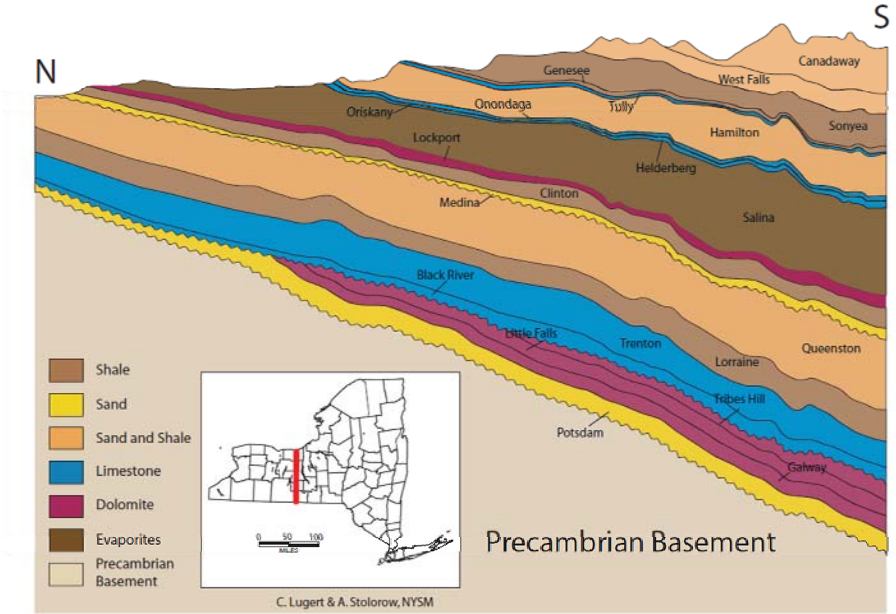
Specifically during the Upper Cambrian period in New York State, the Potsdam and Galway Formations were deposited in a shoreface to shallow marine transgressive environment (Kolkas, 1998). During this time, the two primary structures influencing sedimentation in the Appalachian Basin were a tectonic high that extended NE-SW from New York to Alabama (perhaps an early peripheral bulge expression) and the extent of exposure of the Canadian Shield (Smith et al., 2010).

4.0 Regional Surface and Subsurface Geology

Throughout western and central New York State, formations generally shallow and thin to the north and west and have a regional 1-2°SE dip, which tends to decrease in the younger rocks (Figure 3). Two regional unconformities, the Knox Unconformity (underlying the Black River Formation) and the Cherokee Unconformity (underlying the Medina Formation), represent periods of erosion within the sediment package.

Numerous proposed fault systems have been mapped in Chautauqua County, New York from outcrop, gravity gradient, lineament, stratigraphic, well, and proprietary seismic data, including the Bass Island (NE- striking), Mayville (NE- striking), and Charlotte Center (N- striking) faults (Jacobi, 2002; Figure 4). The Bass Island trend is a series of northwesterly directed Alleghanian thrusts, and it is hypothesized that the Mayville fault system follows a similar trend. Little is known about the Charlotte Center fault system except that magnetic data suggest that the fault extends into the Precambrian basement (Jacobi, 2002). Throughout northwestern Pennsylvania, numerous Cambrian and Early Ordovician basement-rooted growth faults have been mapped by Wagner (1976), and basement rooted faults are also documented to have created the hydrothermal dolomite reservoirs in the Upper Ordovician Trenton Formation in New York, Ohio, Indiana, and Michigan (Smith, 2006). These basement-rooted faults are hypothesized to potentially affect porosity of the Cambrian formations as well.

A) Schematic North-South Cross Section of New York State



B) Schematic East-West Cross Section of New York State

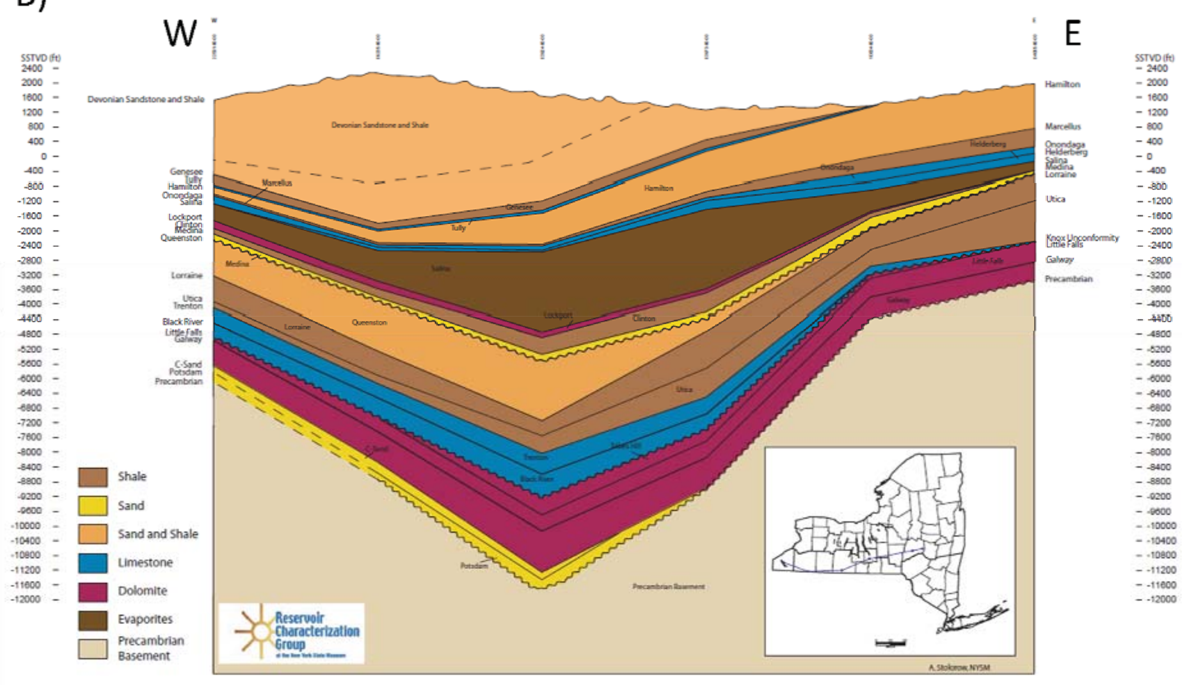


Figure 3: A) Regional North-South cross section displays dip to the south. B) Regional West-East cross section displays the basement-controlled strata dip toward the central New York. Modified from New York State Museum Reservoir Characterization Group cross sections (http://esogis.nysm.nysed.gov/esogis/mapsState.cfm).

Devonian sandstones and shales comprise the surface bedrock of western New York (Figure 2). Overlying these sandstones and shales, the Pleistocene geology of western New York is dominated by glacial deposits and erosional features. Ice sheets advanced and retreated over western New York bedrock between 1.6 million and 11,000 years ago, carving the bedrock and depositing moraines, drumlins, glacio-lacustrine sediment, and gravel (Rogers, 1991). Thick packages of fluvial sediment were deposited as the glaciers retreated and continue to be deposited today.

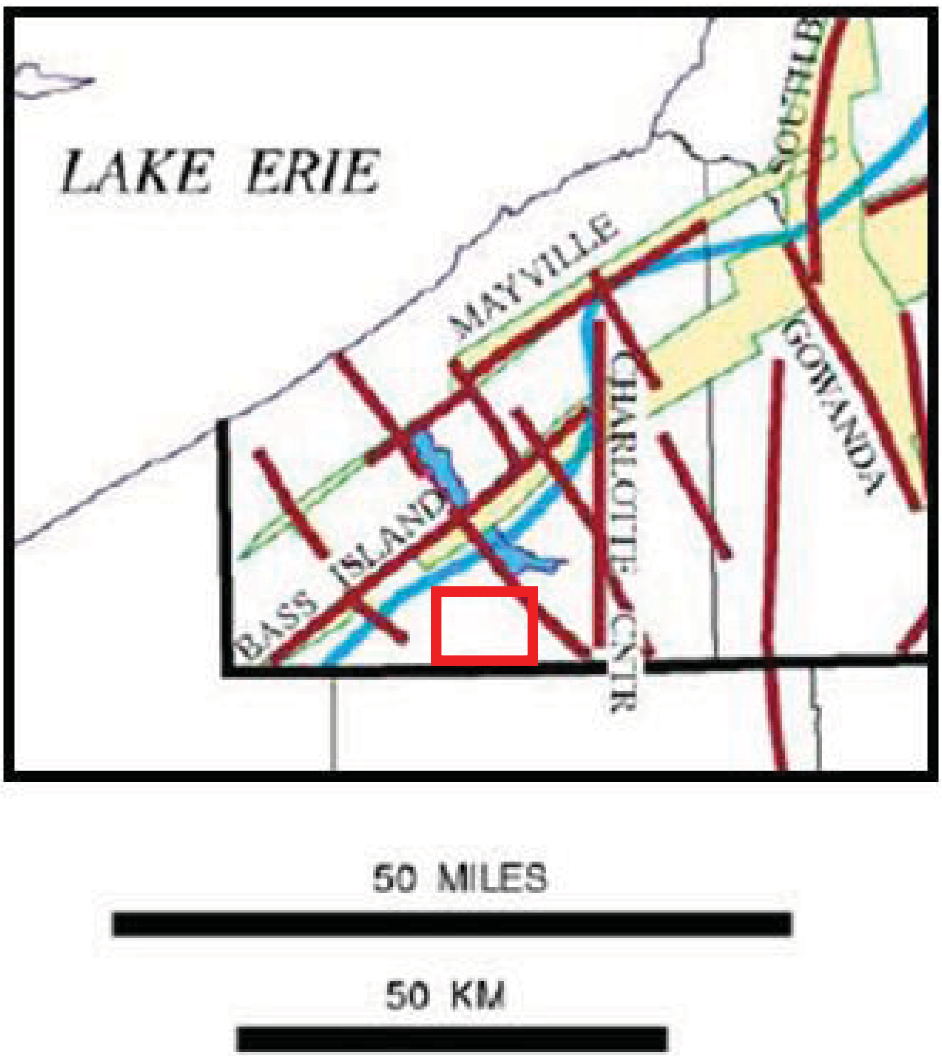


Figure 4: Location of Chautauqua County fault systems (from Jacobi (2002), Figure 5). Red box locates approximate study area.

4.1 Summary and Description of Stratigraphic Units beneath Study Area

Cambrian through Devonian sandstones, shales, carbonates, and evaporates comprise the sedimentary section beneath the Chautauqua County study area (Figures 2 and 3). The following section describes these strata in chronological order with particular attention paid to the Upper Cambrian Potsdam and Galway target formations.

Cambrian

The **Potsdam Formation** is the lower-most sedimentary formation in the New York State portion of the Appalachian Basin and onlaps the underlying Grenville Basement. It is composed of a basal feldspathic member and an upper clean sandstone member in western New York, but it is unclear if this formation extends beneath the study area. This formation is interpreted to have been deposited in a tidally-influenced shallow-marine environment. The formation is thickest in south-central New York (>200 feet) and pinches out to the north, east, and west (Smith et al., 2010). This formation has been identified as a potential carbon dioxide sequestration reservoir by the New York State museum (Smith, 2007), and the presence of the Potsdam Formation at the Jamestown site is being investigated in this report.

The transition from sandstones to carbonates occurs in the **Beekmantown Group** (Tribes Hills, Little Falls, and Galway Formations). The Tribes Hills Formation is primarily limestone except where it was dolomitized near faults, and the Little Falls Formation is a dolostone with vuggy porosity and breccias (Smith, 2006). The **Galway Formation** overlies the Potsdam Formation and also onlaps basement where the Potsdam Formation does not exist. This formation has been subdivided into several informal members, including (in stratigraphic order):

1) the basal sandstone with thin beds of sandy dolomite
2) a sandstone and sandy dolomite beds
3) a thick dolomite interval
4) an interbedded sandstone/dolomite
5) a massive, clean sandstone in some areas (Smith, 2010).

The **Rose Run Sandstone** Member of the Galway Formation is defined to be the upper interbedded sandstone/dolomite and the massive clean sandstone members of the Galway Formation (Smith, 2010) and is interpreted to have been deposited in a tidally-influenced to sub tidal environments with associated tidal flat and sub tidal channel deposits (Nwaodua, 1998). The Galway Formation has also been identified as a potential carbon dioxide sequestration reservoir by the New York State museum (Smith, 2007), and its extent and reservoir quality at the Jamestown site are being investigated in this report.

Ordovician

The **Trenton and Black River Formations** overlie the Beekmantown Group and grade upward from the finer-grained shallow marine carbonates of the Black River Formation to deeper water, argillaceous limestones and calcareous shales of the Trenton Formation. Gas fields in central New York occur along hydrothermally dolomitized, fault-bounded structural lows in the Black River Formation, which are sealed vertically by the Trenton Formation and laterally by unaltered limestone (Smith, 2006). The Knox Unconformity separates the Black River Formation from underlying Cambrian rocks.

The **Utica Formation** is primarily a deepwater black shale that is currently being explored for natural gas potential in Ontario, Canada and Ohio. This formation grades upward into the overlying Queenston Delta Complex.

The Queenston Delta Complex was deposited during the Taconic Orogeny and is a regional redbed complex that extends throughout the Appalachian Basin. In New York, this complex is composed of the **Lorraine**, **Oswego**, and **Queenston Formations**, which are a clastic foreland basin wedge deposited westward during the Taconic Orogeny. Generally, these formations grade upward from the deep water shales of the Lorraine Formation to the fluvial, coastal plain and shallow marine deposits of the Queenston Formation (Brett et al., 1996).

Silurian

The Knox Unconformity separates the **Medina Group** from the underlying Queenston Formation. The Medina Group is composed of shale and sandstone. In central New York, this group is primarily fluvial redbeds, which transition to marine white sandstones and grey shales in western New York (Woodrow et al., 1989).

The Clinton Group is composed of marine shales, shell rich carbonates, and iron-ore beds. This group generally grades eastward from fine-grained siliciclastics and carbonates to well-sorted sandstone and conglomerates (Woodrow et al., 1989).

The Upper Silurian Lockport Group is composed of dolomitic carbonates with some interbedded shales and records a shallowing upward succession (Woodrow et al., 1989).

The Salina Group contains numerous evaporite deposits, including anhydrite, gypsum, and halite. This group commences with siliciclastic mudstones of the Vernon Formation, which is succeeded thick halite and anhydrite deposits of the Syracuse Formation (Woodrow et al., 1989).

Devonian

The **Hamilton Group** (Tully Limestone, Marcellus Shale) is part of the Catskill Delta Complex and was deposited during an active phase of the Acadian Orogeny. It is composed primarily of non-marine and marine sandstone, siltstone, and shale with sparse interbedded carbonates. The Marcellus Formation is the marine black shale that is the lowest member of the Hamilton Group and contains a largely untapped natural gas reserve.

The **TriStates Group** (Onondaga Limestone, Oriskany Sandstone) was deposited at the initiation of the Acadian Orogeny and is composed of marine sandstone and limestone. This group was deposited during a quiescent time of the Acadian Orogeny known as the Onondaga Tranquillity.

The **Helderberg Group** is composed primarily of limestone and dolostone, which include shallow reef, intertidal, and lagoon deposits.

4.2 Discussion of Wells near the Study Area

The New York State Museum's Empire State Oil and Gas Information System (www.esogis.com) reports that there are approximately 6,220 gas wells drilled in Chautauqua County. However, only three of these wells extend deeper than the Trenton Formation because most of the wells produce natural gas in the Medina Group. Warren County, Pennsylvania, which abuts Chautauqua County to the south, has only two wells that are at least 7,000 feet deep. The closest well drilled into the Galway Formation is the Miller #2 well in Chautauqua County, which was completed in April 2009 and is located approximately 12 miles northeast of the seismic survey area. The Miller #2 well was drilled by Unbridled Energy. The dataset for this well consists of an extensive suite of petrophysical logs and was partially funded by New York State Energy Research and Development Authority (NYSERDA).

4.3 Evaluation of Key Formations based on Miller 2 well

Formation tops were picked in the Miller 2 well based on previous interpretations and the well log signatures (Figure 5). The Galway Formation and what is possibly the Potsdam Formation were examined in further detail. The top of the Rose Run Member (equivalent to the top of the Galway Formation) is at approximately 6,322 feet depth. It extends to the top of the Galway A Dolomite at 6,545 feet and has a thickness of 223 feet. It is believed that this well almost hit the Precambrian basement, and it is possible that the Potsdam Formation is represented in the bottom 25 feet of the logged interval. Using the sonic and density logs, a seismic synthetic gather was generated to help with the interpretation of the 2D seismic survey (Figure 5).

ELAN is an advanced multi-mineral log analysis program developed by Schlumberger that computes the most probable formation mineralogy, pore fluid volumes, and porosity using a multi-log, least-squares inversion technique. An ELAN analysis was performed on the Miller 2 well, for which volumes of quartz, calcite, dolomite, illite, chlorite, and effective porosity were calculated from the available well logs. Figures 6 through 9 display the ELAN analysis for the Gull River and Wells Creek Members of the Black River Formation, Little Falls Formation, Galway Formation (Rose Run, dolomite, and sand Members), and possibly the Potsdam Formation. Table 1 displays ELAN mineralogy for the subsurface Cambro-Ordovician geology near the Jamestown site. In general, the Gull River and Wells Creek Members of the Black River Formation and the Little Falls Formation are dominated by carbonates. The members of the Galway Formation primarily have interbedded quartz and carbonate lithologies, and orthoclase content increases in the C Sand Member of the Galway Formation and in what may be the Potsdam Formation.

Effective porosity values calculated for the Gulls River Member of the Black River to the bottom of the logged interval are shown in Table 2. The Gull River and Wells Creek Members of the Black River Formation have the highest average porosity values (5-6%) over relatively thick intervals (35 feet and 41 feet, respectively). Within the Galway Formation, the thickest interval with effective porosity occurs in the Rose Run Sand (36 feet with and an average effective porosity of 4%). The Potsdam Formation also has a relatively thick, porous zone (36 feet with and an average effective porosity of 4%). Intervals within the above formations with less than 3% effective porosity are not accounted for in Table 1.

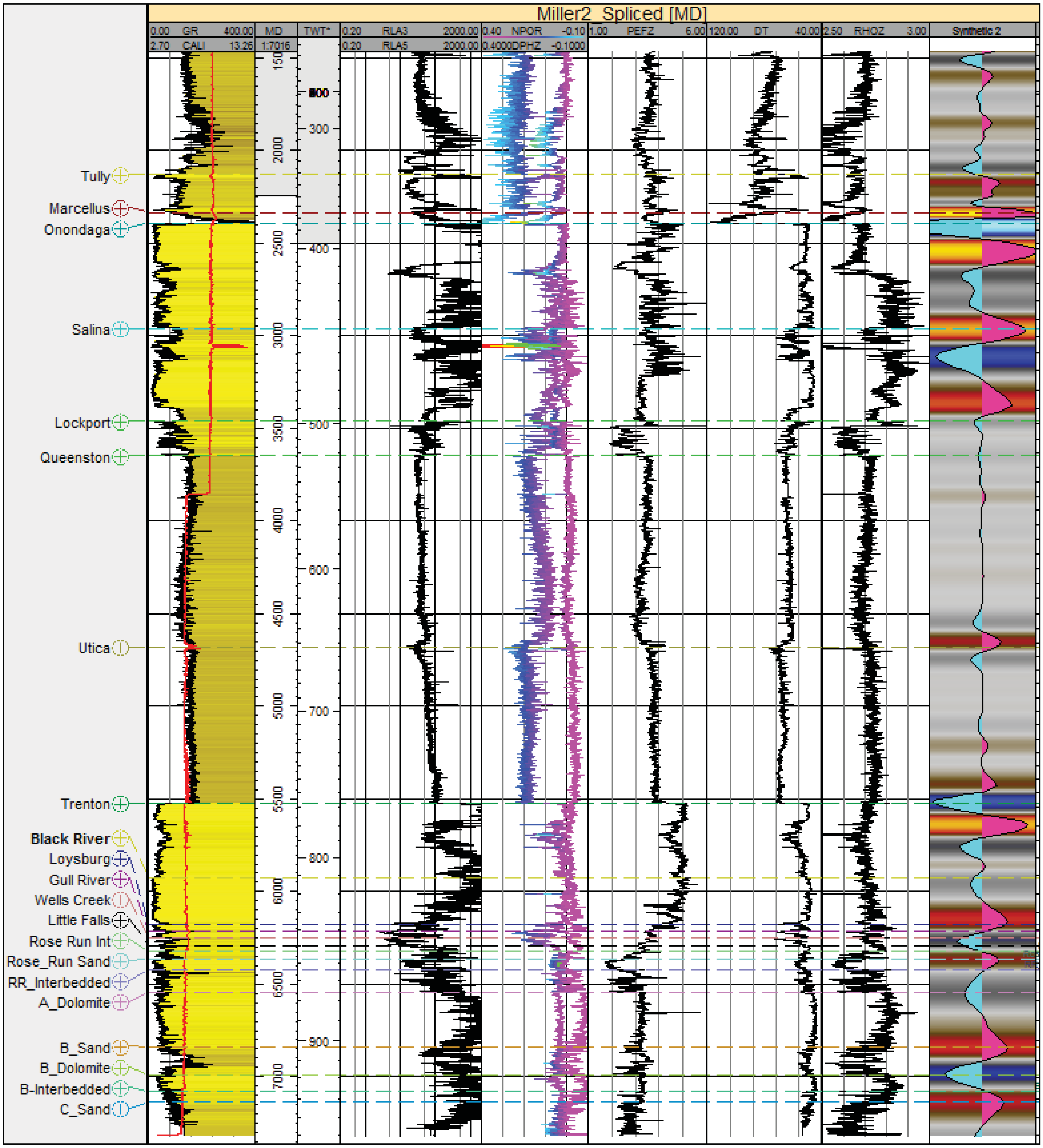


Figure 5: Logs for the Miller 2 well, including gamma (GR), caliper (CALI) resistivity (RLA3, RLA5), porosity (NPOR, DPHZ), photoelectric (PEFZ), time (DT), and density (RHOZ) tracks and a seismic synthetic. The synthetic was generated by calculating a reflection coefficient from the sonic and density logs and then multiplying that by a specified wavelet. In this figure, Rose Run Member is equivalent to the top of the Galway Formation.

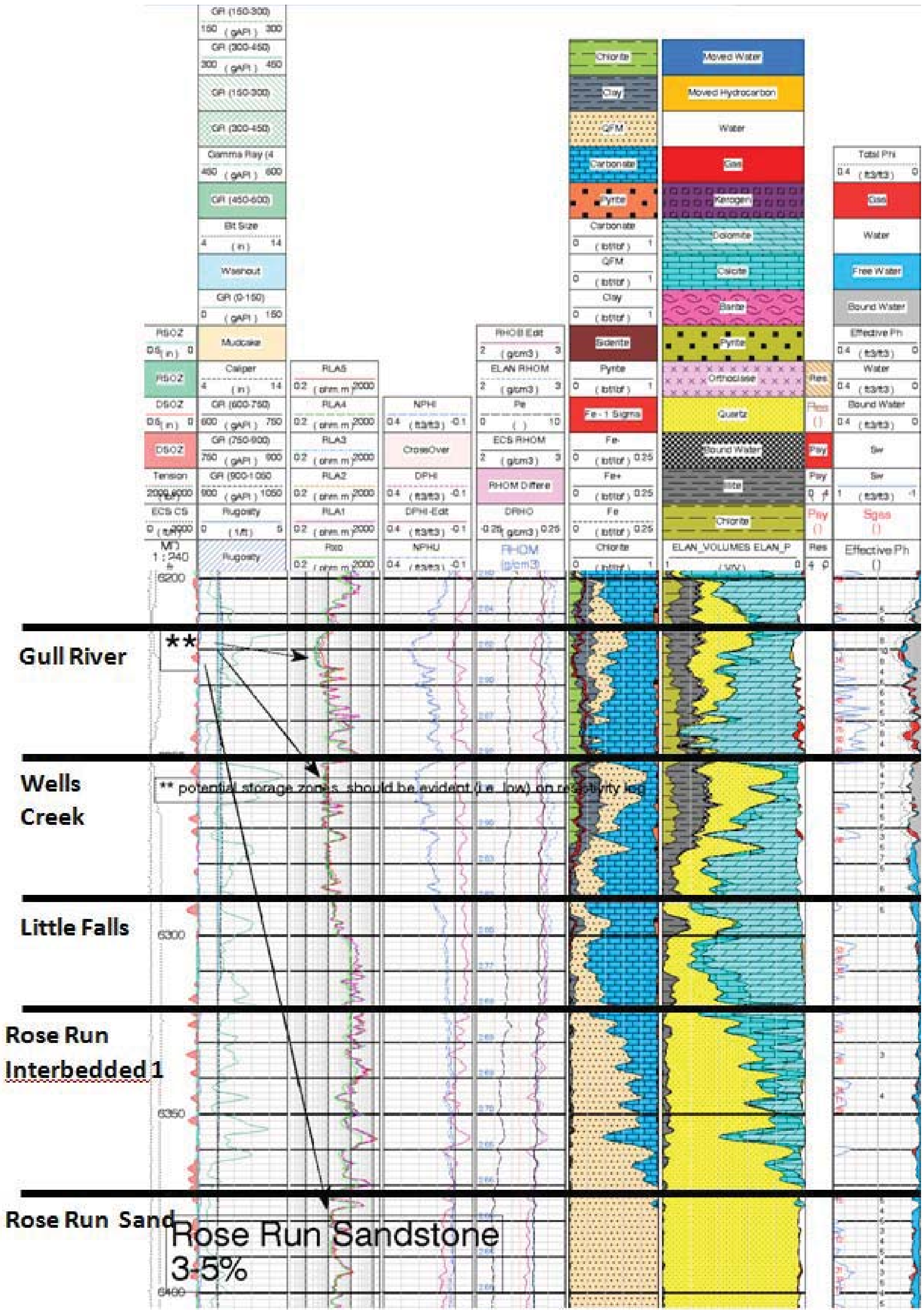


Figure 6: Miller 2 well ELAN analysis for the Gull River, Wells Creek, and Little Falls Members of the Black River Formation and the Rose Run Interbedded Member of the Galway Formation (6200 to 6400 feet).

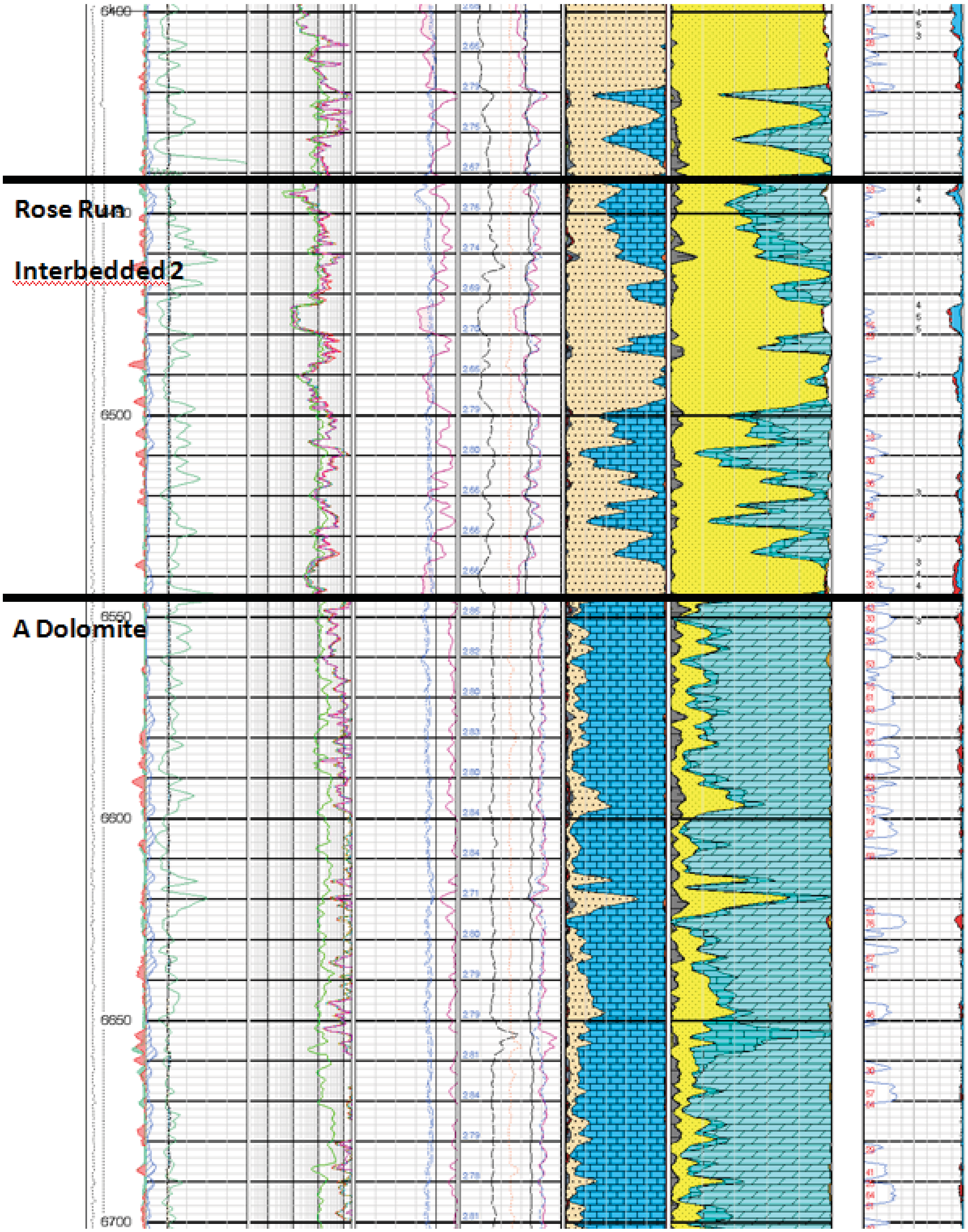


Figure 7: Miller 2 well ELAN analysis for the Rose Run Interbedded and A Dolomite Members of the Galway Formation (6400-6700 feet).

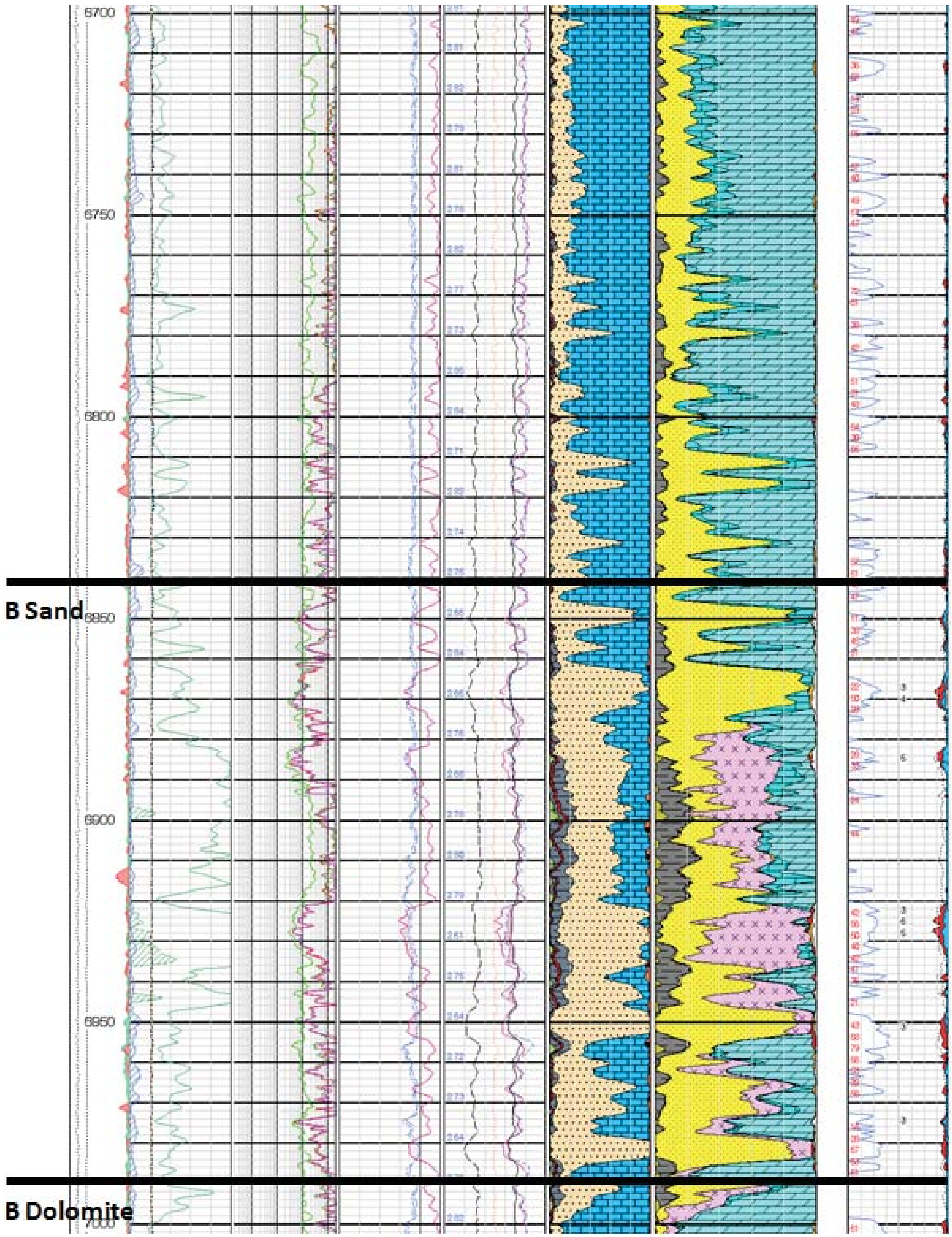


Figure 8: Miller 2 well ELAN analysis for the A Dolomite, B Sand, and B Dolomite Members of the Galway Formation (6700-7000 feet).

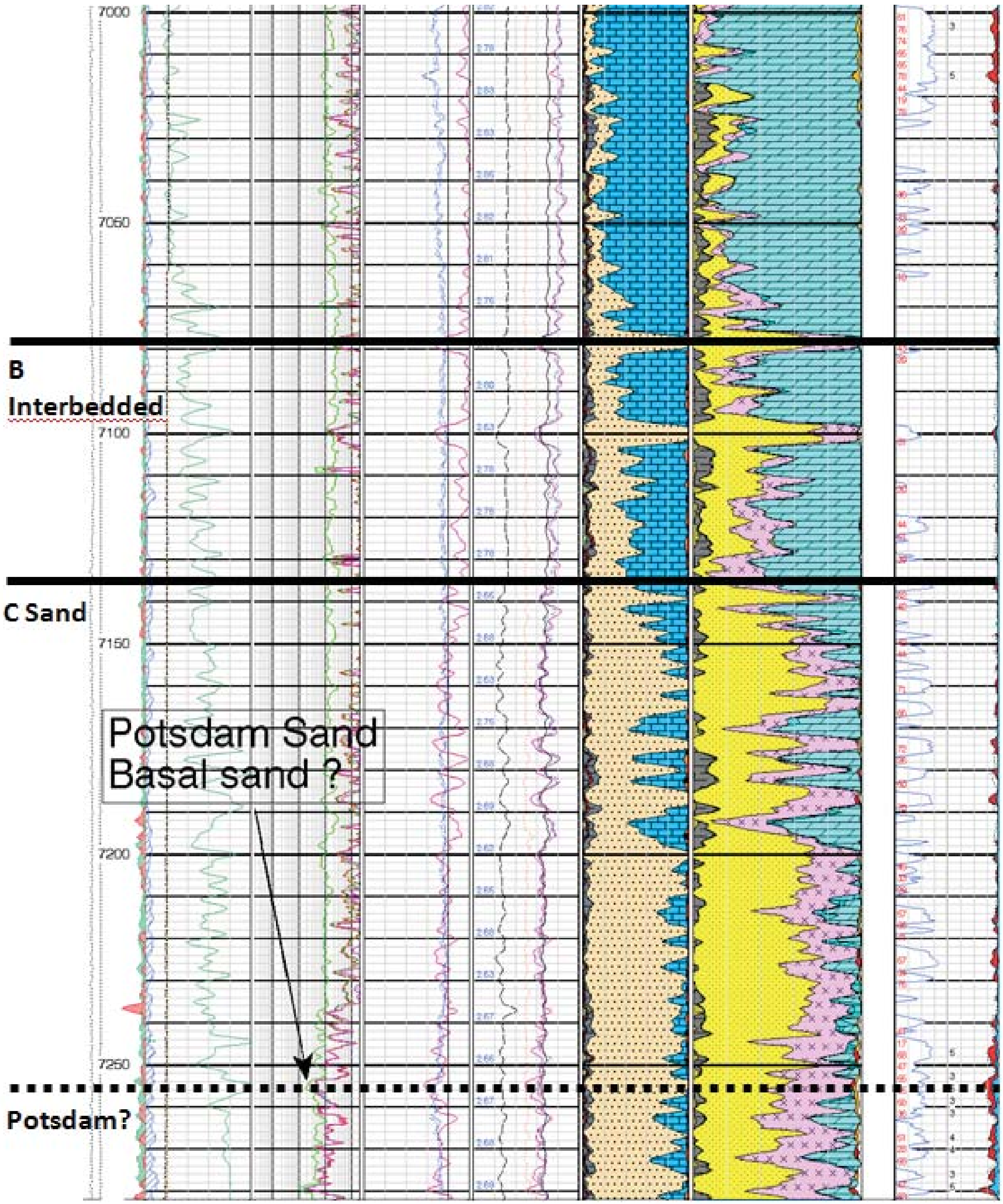


Figure 9: Miller 2 well ELAN analysis for the B Dolomite, B Interbedded, and C Sand Members of the Galway Formation and possibly the Potsdam Formation (7000-7300 feet).

Formation	Member		Depth (feet)	Porosity%	Dolomite%	Calcite%	Quartz%	Illite%	Chlorite%	Pyrite%	Orthoclase(%)
Black River	Gulls River	Range		3-14	0-80	0-30	0-38	0-26	0-18	0-3	0
		Average	6215-6251	8	50	4	16	12	9	1	0
		StDev		3	18	7	10	6	4	1	0
	Wells Creek	Range		3-10	0-70	0-20	6-60	0-28	0-13	0-3	0
		Average	6251-6292	8	40	5	26	15	6	1	0
		StDev		2	19	5	12	6	4	1	0
Little Falls		Range		1-5	0-70	0-36	15-55	0-19	0	0-2	0
		Average	6292-6321	3	42	7	40	5	0	1	0
		StDev		5	40	18	20	15	0	1	0
Galway	Rose Run Interbedded 1	Range		0-5	0-50	1-47	22-95	0-8	0-3	0-1	0
		Average	6321-6366	2	27	16	49	4	0.2	0.3	0
		StDev		1	22	9	22	4	0.5	0.4	0
	Rose Run Sand	Range		1-6	0-18	0-17	76-98	0-4	0-2	0-0.2	0
		Average	6366-6419	3	6	7	81	2	0.3	0.1	0
		StDev		1	11	10	16	2	0.5	0.1	0
	Rose Run Interbedded 2	Range		0.4-7	0-66	0-32	12-98	0-15	0-3	0-2	0
		Average	6419-6545	2	20	10	64	3	0.2	0.2	0
		StDev		1	20	8	24	3	0.5	0.3	0
	A Dolomite	Range		0-4	0-94	0-85	0-75	0-12	0-2	0-1	0
		Average	6545-6839	1	63	9	22	3	0.1	0.3	0
		StDev		0.6	20	9	16	3	0.3	0.3	0
	B Sand	Range		1-7	0-83	0-31	0-95	0-25	0-9	0-3	0-75
		Average	6839-6991	2	47	8	28	5	0.5	0.4	9
		StDev		1	9	8	21	5	1	0.4	16
	B Dolomite	Range		0.5-5	0-96	0-12	0-75	0-13	0-4	0-1	0-37
		Average	6991-7079	2	45	3	21	6	1	0.4	21
		StDev		1	32	5	19	6	1	0.4	18
	B Interbedded	Range		0.4-3	0-78	0-7	2-80	0-12	0-6	0-2	0-34
		Average	7079-7134	3	45	3	21	3	1	0.4	21
		StDev		1	32	5	19	5	1	0.4	17
	C Sand	Range		0.5-4	0-60	0-18	5-83	0-14	0-7	0-2	0-60
		Average	7134-7246	2	14	2	50	3	0.6	0.4	27
		StDev		0.8	17	3	18	3	1	0.5	9
Potsdam?		Range		2-7	0-32	0-11	23-72	0-10	0-4	0-2	14-55
		Average	7246-7325	3	8	1	47	2	1	0.3	36
		StDev		1	9	3	12	3	1	0.3	7

Table 1: ELAN mineralogy for the Miller 2 well Cambro-Ordovician subsurface geology.

Formation	Member	Interval with effective porosity (feet)	Thickness (feet)	Average Effective Porosity (%)	Effective Porosity Range (%)
Black River	Gull River	6216-6251	35	6	4-10
	Wells Creek	6251-6292	41	5	3-7
Little Falls		N/A	0		
Galway	Rose Run Interbedded 1	6334-6346	12	4	3-4
	Rose Run Sand	6372-6408	36	4	3-5
	Rose Run Interbedded 2	6444-6448	4	4	4
		6472-6478	6	5	4-5
		6520-6530	10	3	3
		6536-6542	6	4	3-4
	A Dolomite	6550-6560	10	3	3
	B Sand	6866-6870	4	4	3-4
		6885-6886	1	5	NA
		6922-6928	6	5	3-6
		6950-6951	1	3	NA
		6975-6976	1	3	NA
		7004-7005	1	3	NA
		7114-7115	1	5	NA
	B Interbedded	N/A	0		
	C Sand	N/A	0		
Potsdam?		7246-7282	36	4	3-5

Table 2: ELAN analysis effective porosity averages and ranges for the Black River, Little Falls, Galway, and Potsdam Formations. Intervals within each formation/member with calculated effective porosity are reported. N/A indicates the respective formation/member did not have effective porosity greater than 3%. For the one foot intervals reported, a single sample was collected, and thus there is no range.

5.0 Seismic Acquisition Summary

WesternGeco was contracted by Schlumberger Carbon Services to conduct a regional 2D seismic survey over the proposed Jamestown area to determine if the subsurface was suitable for carbon sequestration. The design of the project was developed in cooperation with WesternGeco and Schlumberger Carbon Services personnel in Calgary and Columbus.

WesternGeco crew 1752 performed the survey with Tesla-Conquest Inc. WesternGeco provided the proprietary Q-Land MAS Point Receiver acquisition system, processing equipment, and technical and managerial personnel. Conquest provided the vibrator trucks with technicians & operators, line movement vehicles, and necessary personnel to deploy and pickup the line equipment. The operation was supervised by a WesternGeco Operations Supervisor, Party Manager/Chief Observer, and Project and Chief Geophysicists.

The preparation for the project started in early October 2010. The survey permitting along the New York County and Pennsylvania DOT roads was performed by Tesla-Conquest Inc. The project program comprised the following:

- Securing the county roads in New York and PENNDOT permit to conduct vibrator truck operations on necessary roadwayss
- Surveying of GAC and vibrator point positions as per set parameters
- The acquisition of two – 2D surface seismic lines by WesternGeco (Figure 10)

The prospect area extends from Chautauqua County, NY into approximately two miles of Pennsylvania (north of Sugar Grove, PA). The survey consists two 2D lines that are each approximately 5 miles long. East/West Line 101 was along Co. Touring Route 12, and North/South Line 301 was along Wellman Roadin New York and extended onto Catlin Hill Rd. in Warren County, Pennsylvania.

The recording instruments were the point receiver WesternGeco Q-Land MAS system. The Digital Geophone String (DGS) is made up of 12 Geophone Accelerometers (GAC) with 10 ft spacing. Crew 1752 was equipped with 4 Hemi-44 truck mounted vibrators (Figure 11). Four sweeps were acquired per source point with a linear sweep range of 6 – 100 Hz. Source points were 120 ft apart. Detailed survey parameters can be found in Appendix A.

From an operational standpoint, the project was completed without any unexpected issues. Public interest in the project was high with many people stopping by to see the operations. All individuals were previously informed by client representatives using flyers and visiting individuals who lived along the affected roadways. There were houses along the roadways, but with close communications between the peak particle velocity (PPV) monitoring representatives on site, recording occurred near the houses without exceeding agreed specifications for PPV. Field brute stacks were generated each day after the day's production and overall data quality was very good (Figures 12 and 13). There were no lost time injuries on the project.

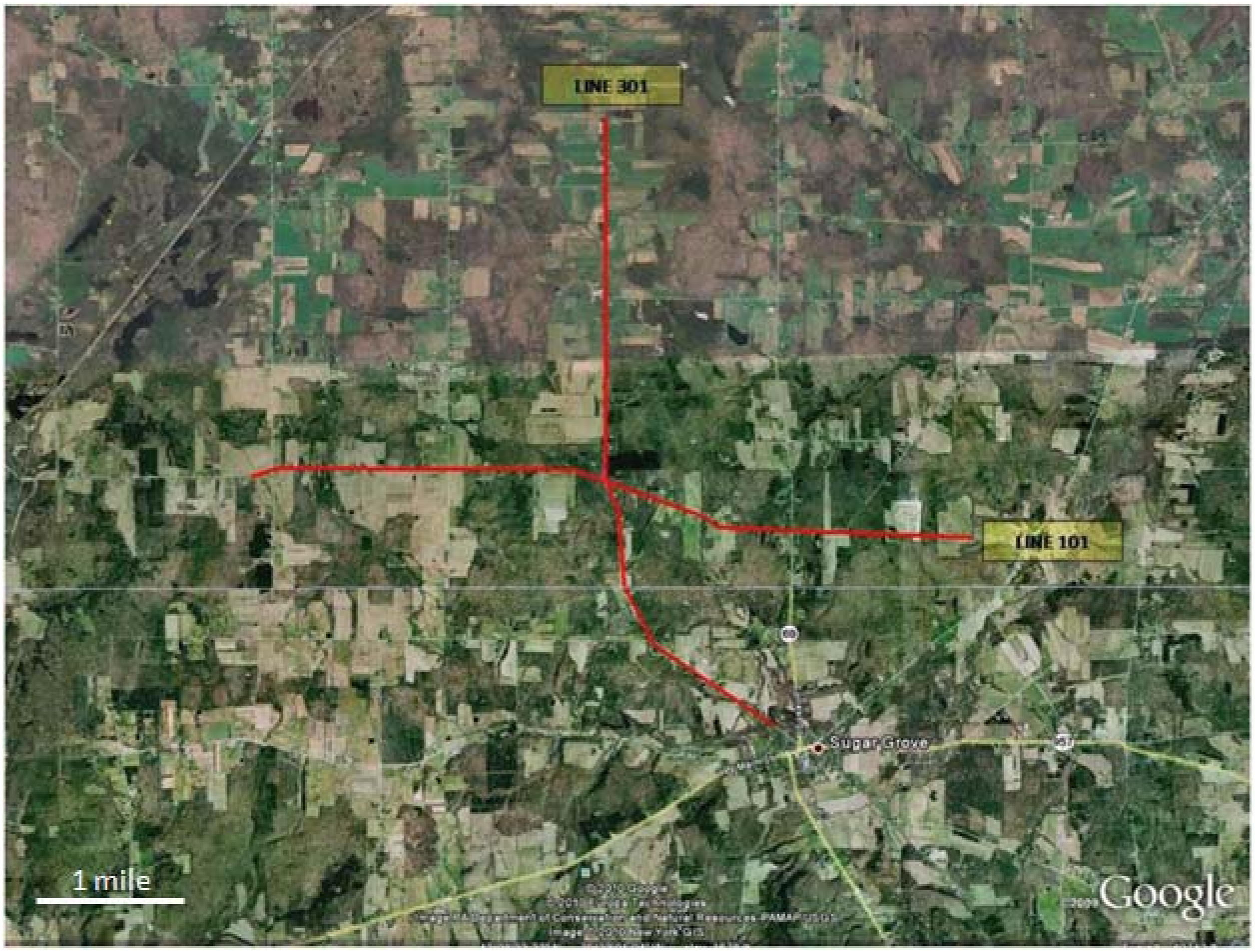


Figure 10: Location of Jamestown 2D Seismic Lines.

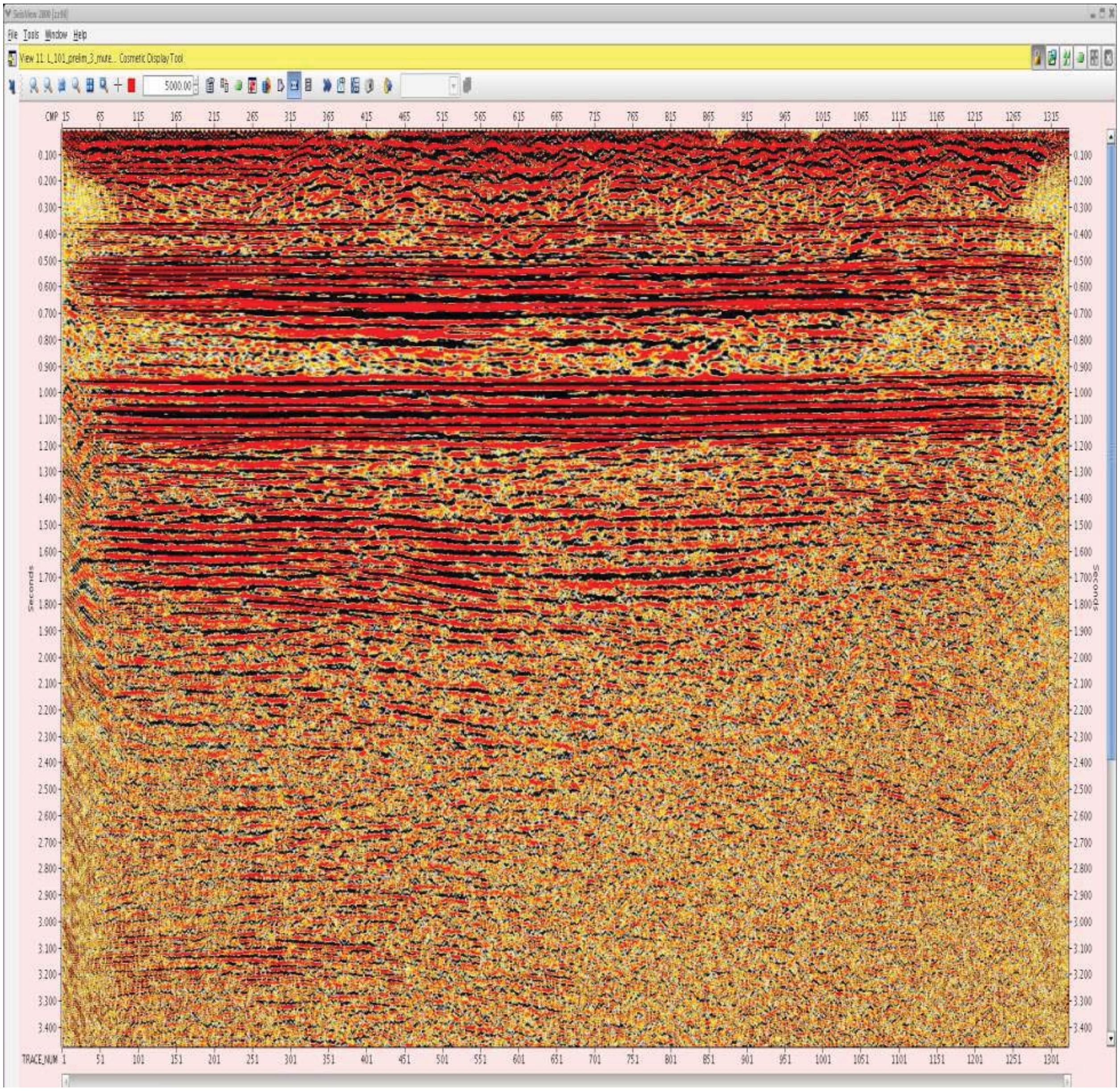
The main tasks of the field geophysics department could be split into two distinctive stages:

1. Pre-acquisition
   - Quality control (QC) of survey data
   - QC of source points placement

2. Post-acquisition
   - Geosupport
     - QC of vibrator positioning and performance
     - Processing and QC of instrument tests, hardwires and vibrator similarities
     - Generation of daily production report
   - In-field Data Processing (Appendix A)
     - Generate and QC correlated dat.
     - Test data pre-processing and display
     - Noise attenuation
     - Generation of in-field brute stacked volume (Figures 12 and 13)

For more detailed information on the surface seismic acquisition, please refer to Appendix A: Final Acquisition Report for Jamestown 2D Project that was completed by WesternGeco.

Figure 11: View of prospect area with vibrator trucks



Figures 12: Line 101 field brute stack

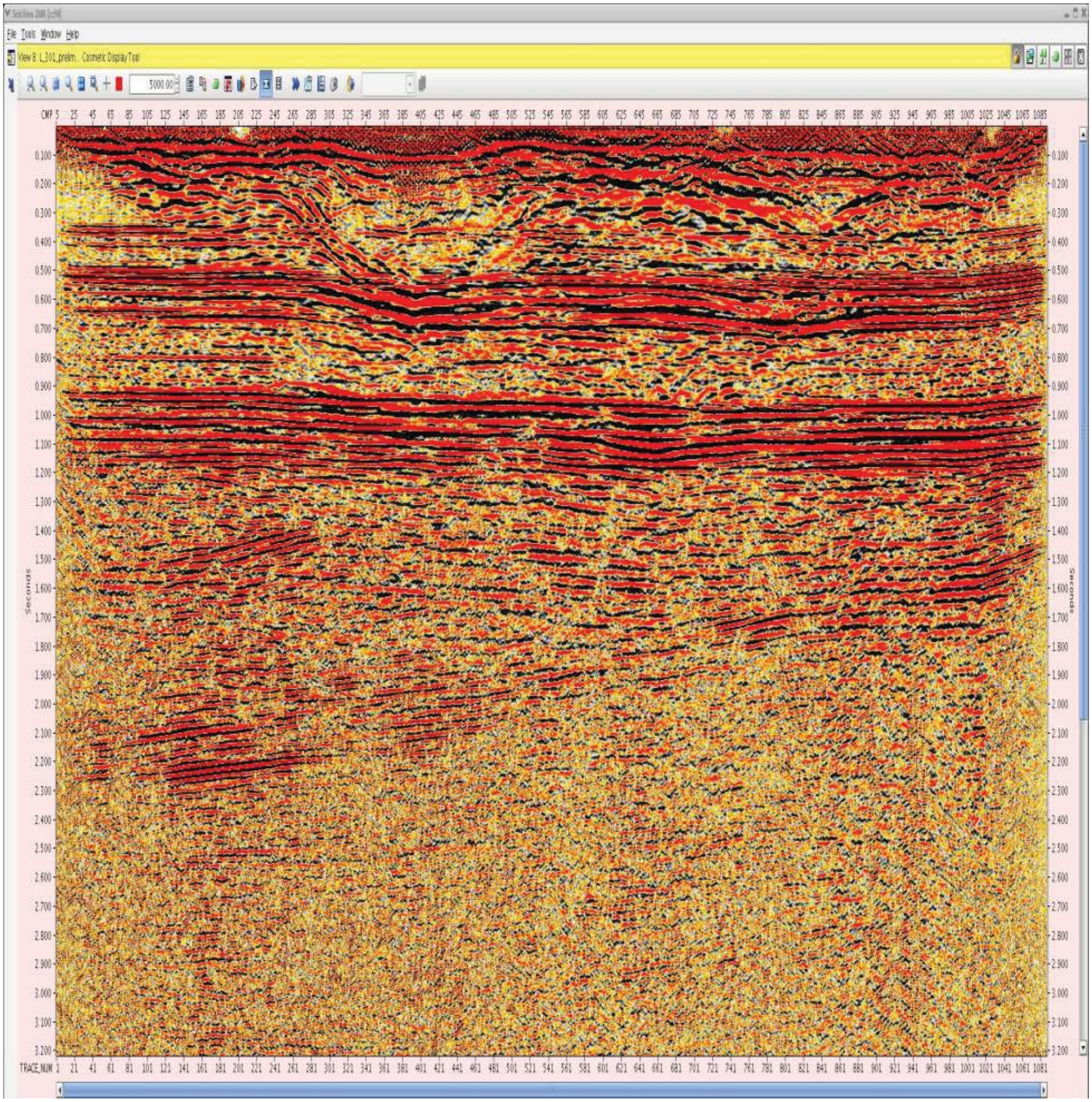


Figure 13: Line 301 field brute stack

6.0 Processing Summary

WesternGeco was also contracted by Schlumberger Carbon Services to process the Jamestown 2D seismic survey. There were two main processing challenges with this data:

1) There was an abundance of near-surface noise resulting from the receiver's close proximity to the vibrator trucks

2) There were multiple bends in the north-south line L301. The number of bends resulted in the Common Mid-Points (CMPs) between the sources and receivers to be widely distributed. As a result, the processing was not able to focus the energy in one two-dimensional plane and smearing can be observed in the stacks.

Table 3 details the processing flow used for the data. Please refer to Appendix B: for a more thorough discussion of the processing.

Processing Flow
Noise Attenuation (2 passes)
Surface Consistent Deconvolution
Surface Consistent Amplitude Compensation
Velocity Analysis
Residual Statics (2 passes)
Kirchhoff Post-stack Time Migration
Post Migration Processing

Table 3: Processing flow used for the Jamestown 2D seismic data

The aim of the noise attenuation was to attenuate random and coherent noise in the data. Noise sources can include electrical lines, traffic, and source generated noise. Noise needs to be removed early in the processing flow, as it can have a negative effect on other processing algorithms. Figure 14 shows the brute stack from Line 101 from the field prior to any noise attenuation. Figure 15 shows Line 101 after 2 passes of noise attenuation

Deconvolution is used to whiten or enhance some portions of the frequency spectrum. It generally enhances the resolution of the seismic data (Figure 16). However, it may also have the effect of boosting noise levels in the data.

Surface consistent amplitude compensation compensates for shot, detector, and offset amplitude variations that are caused by acquisition effects and are not a consequence of the subsurface geology. Velocity analysis was completed at 0.5 mile spacing along each line. The velocity analysis flattens the CMP gathers, improves the stacking power of the data, and provides a velocity model for migration and depth conversion.

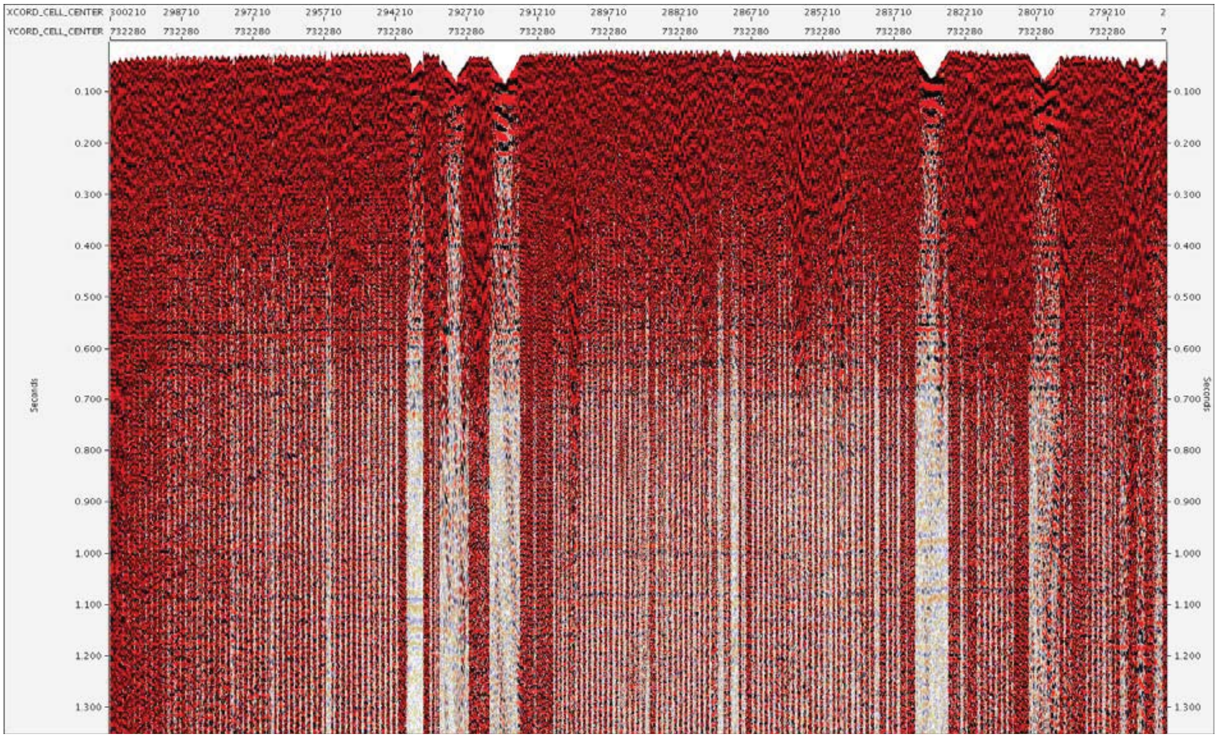


Figure 14: Line 101 brute stack from the field. West is on the left. Note that holes at the surface are related to infrastructure where source and receivers points could not be acquired.

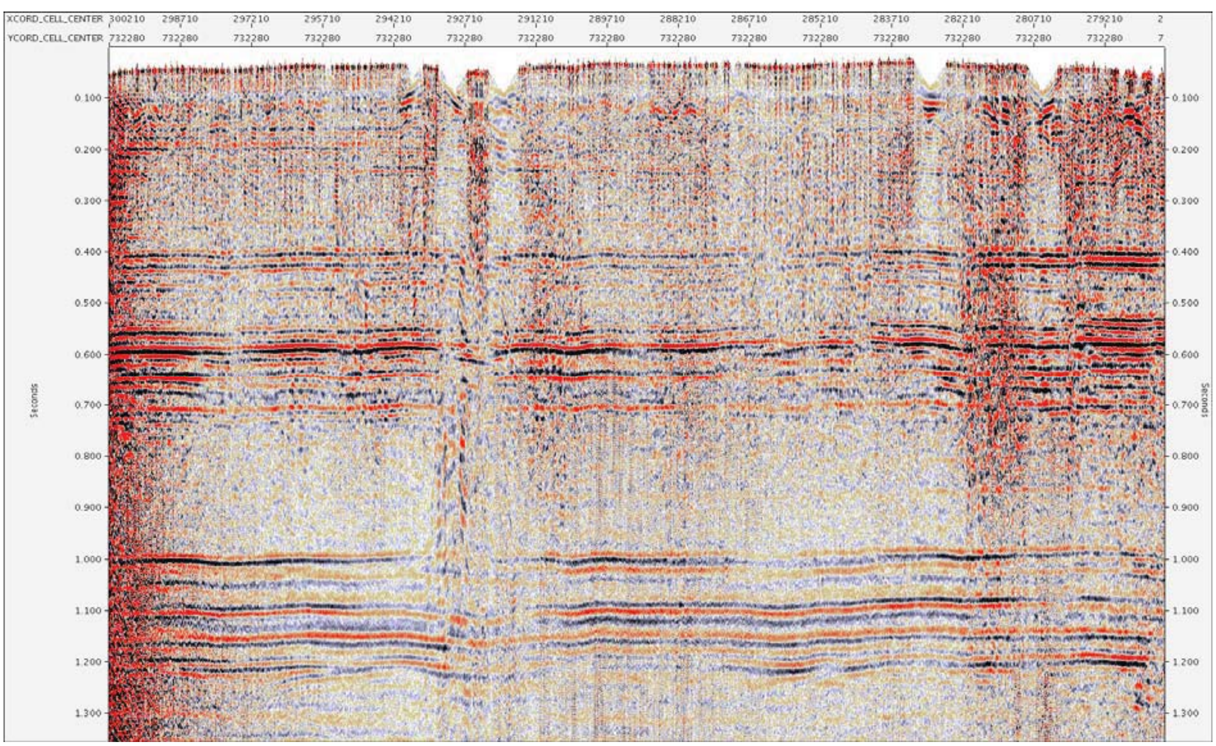


Figure 15: Line 101 after 2 passes of noise attenuation. West is on the left.

Schlumberger Carbon Services

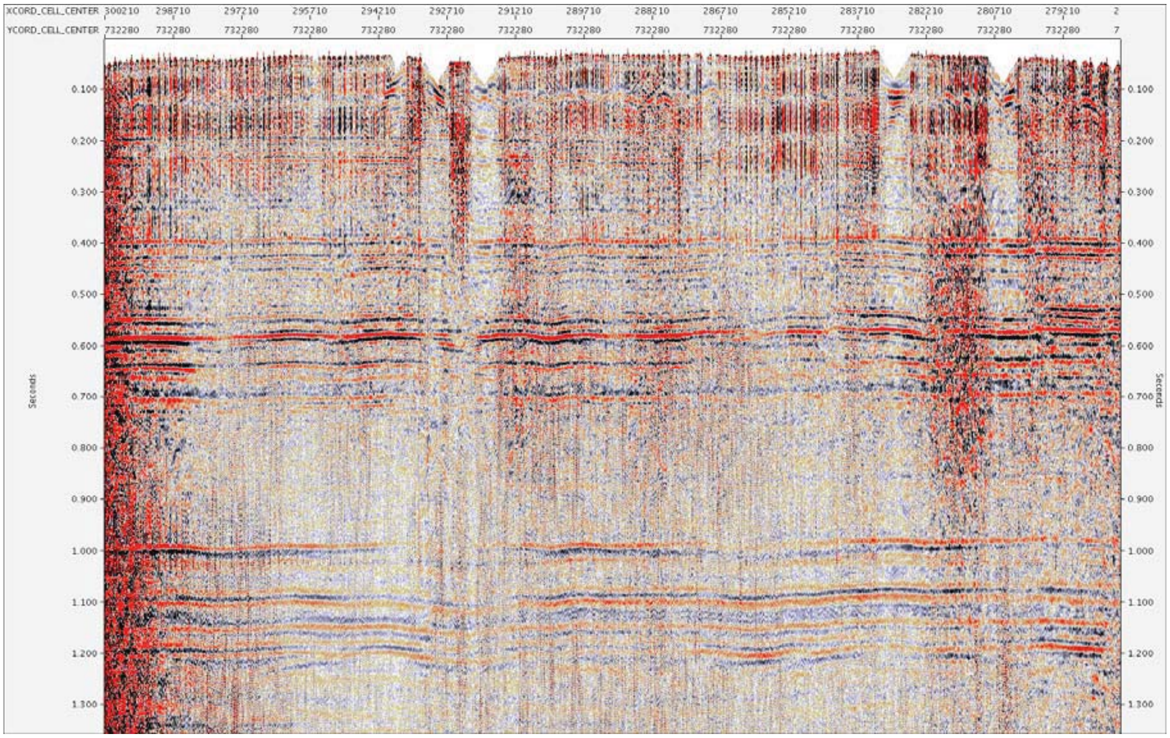


Figure 16: Line 101 after deconvolution. The major reflectors are now sharper and have higher resolution. West is on the left.

Residual statics are used to correct for velocity variations in the near surface that may be related to the weathering layer or glacial till. Generally, applying static corrections to seismic data has the effect of flattening reflectors and improving reflector coherency. Two passes of static corrections were applied to the Jamestown dataset.

A Kirchhoff post-stack time migration was used to migrate the data. Migration is used to collapse diffractions and move reflectors to their true subsurface locations. It is one of the important final steps in any processing flow. The data was filtered to zero phase and residual amplitude scaling was applied after migration to improve the final data display for interpretation. True amplitudes were not maintained. Figures 17 and 18 show Lines 101 and 301 after migration.

Finally, the seismic data was converted from time to depth so that it could easily be tied to the well data in the area.

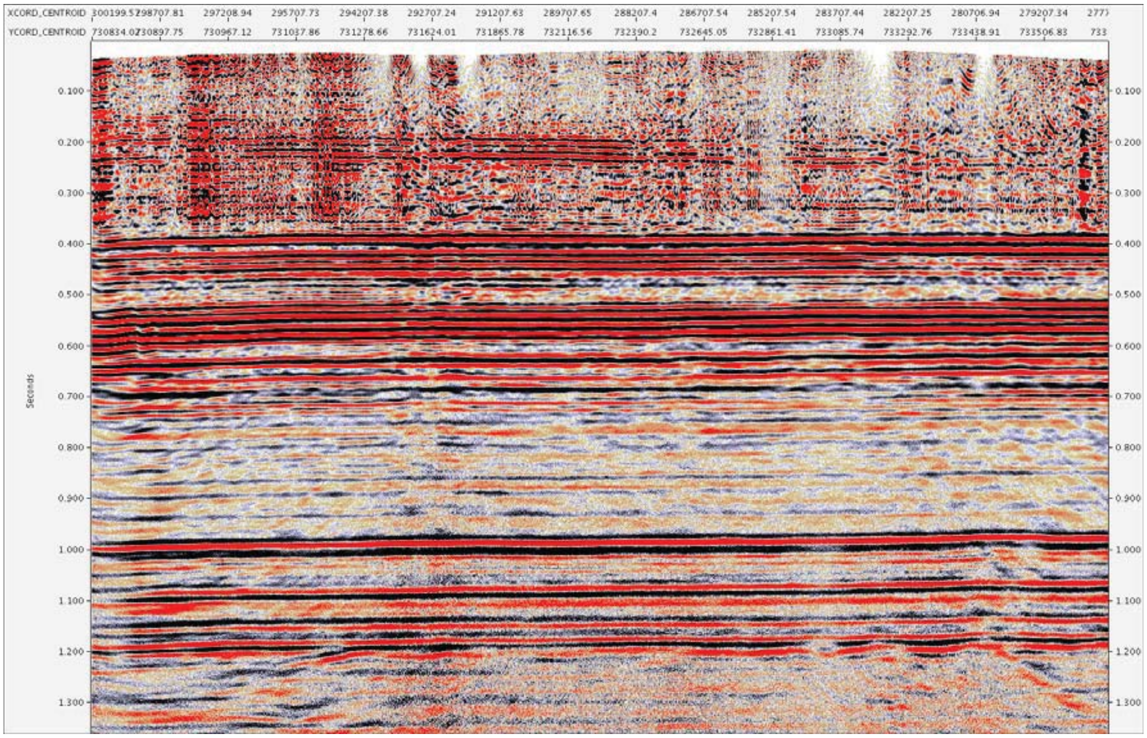


Figure 17: Line 101 after migration and with post-migration processing. Correcting for residual statics has flattened many of the reflectors. West is on the left.

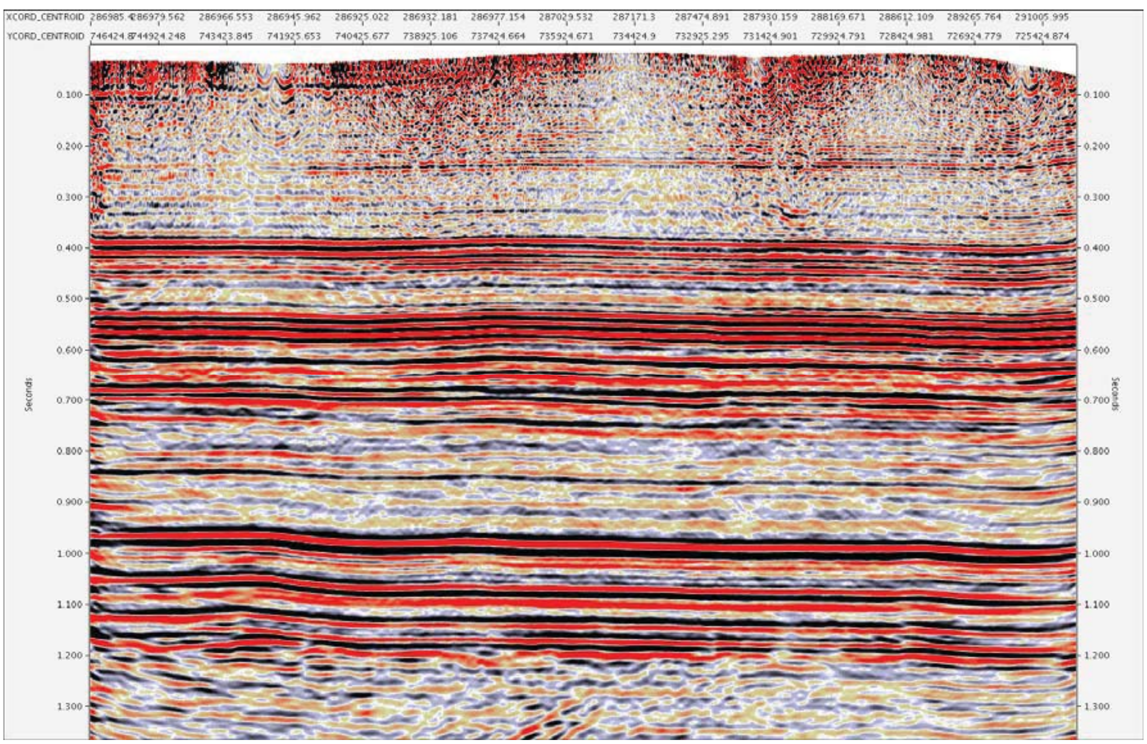


Figure 18: Line 301 after migration and with post-migration processing. Correcting for residual statics has flattened many of the reflectors. North is on the left.

7.0 Interpretation of Processed Results

The processed 2D seismic survey and a topographic map were loaded into Petrel, which is Schlumberger's "Seismic to Simulation" software (Figure 19). Using the synthetic data generated from the Miller 2 well, the tops of key formations, including the Precambrian basement up to the Devonian Tully Formation, were mapped on both 2D seismic lines (Figures 20 and 21). Surfaces were then generated from the seismic interpretation (Figure 22). It is important to note that the distance between the seismic survey and the Miller 2 well introduces uncertainty to the seismic interpretation.

The top of the Precambrian basement is at approximately 1.2 seconds (1200 milliseconds) and is defined by discontinuous, low amplitude reflectors with localized topography. The overlying sedimentary strata are dipping 1-2° SE. Faults resolvable at the scale of the seismic data are not observed. Generally, most reflectors are characterized by considerable lateral continuity, with variability in reflection frequency and amplitude among formations. Only reflectors immediately overlying the Precambrian basement appear to be locally discontinuous (Figures 20 and 21), with channel-fill and pinch-out geometries distinguishable. These reflectors may be the Potsdam Formation.

Table 4 displays the approximate depth to formation top and formation thickness at the intersection of Lines 101 and 301. These measurements were obtained from the depth converted seismic lines. The top of the Galway Formation (equivalent to the top of the Rose Run Member) is approximately at 6,500 feet depth, and this formation is 930 feet thick. The top of the Potsdam Formation is approximately at 7,430 feet depth, and this formation is 420 feet thick. The Precambrian Basement is at approximately 7,850 feet depth. Figures 23 and 24 show the non-interpreted seismic lines.

	Depth (Feet)	Thickness (feet)
Tully Formation	490	125
Marcellus Formation	615	100
Onondaga Formation	715	785
Salina Formation	1500	550
Lockport Formation	2050	1125
Queenston Formation	3175	1325
Utica Formation	4500	1030
Trenton Formation	5530	845
Black River Fm. (Gull River Member)	6375	125
Galway Formation	6500	930
Rose Run Interbedded	6640	440
Galway B Sand	7080	185
Galway B Interbedded	7265	165
Potsdam Formation?	7430	420
Precambrian Basement	7850	

Table 4: Approximate formation top depth and thickness at the intersection of seismic lines 101 and 301.

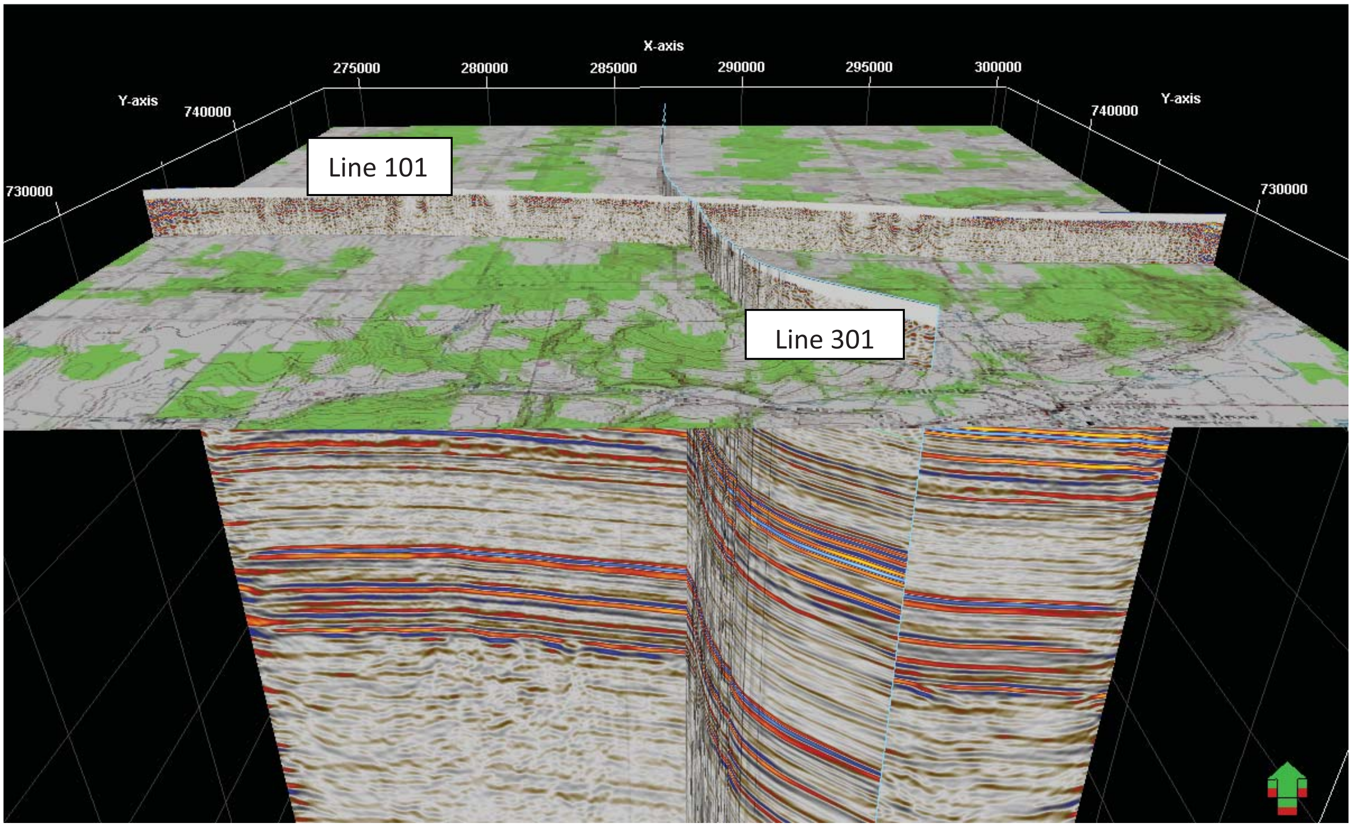


Figure 19: Petrel image of 2D depth converted seismic lines and topographic map. Green arrow is pointing north. Area is 5 miles by 5 miles with no vertical exaggeration.

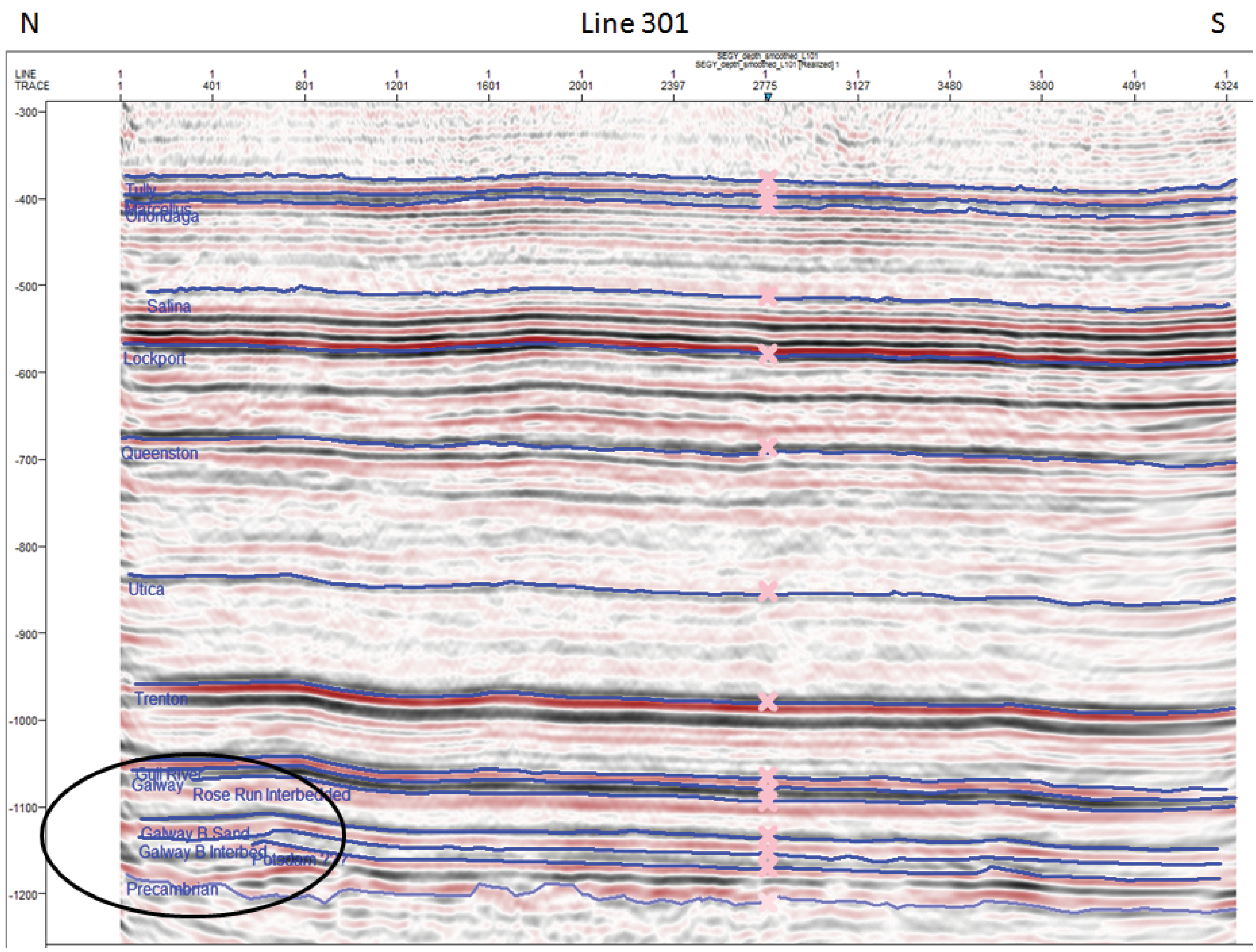


Figure 20: Line 301 in two-way travel time (TWT) and milliseconds (ms). This line is approximately 4.8 miles long. Formation tops are represented by blue lines, and the black circle indicates lateral discontinuity in the strata overlying the Precambrian basement. Note southward dip.

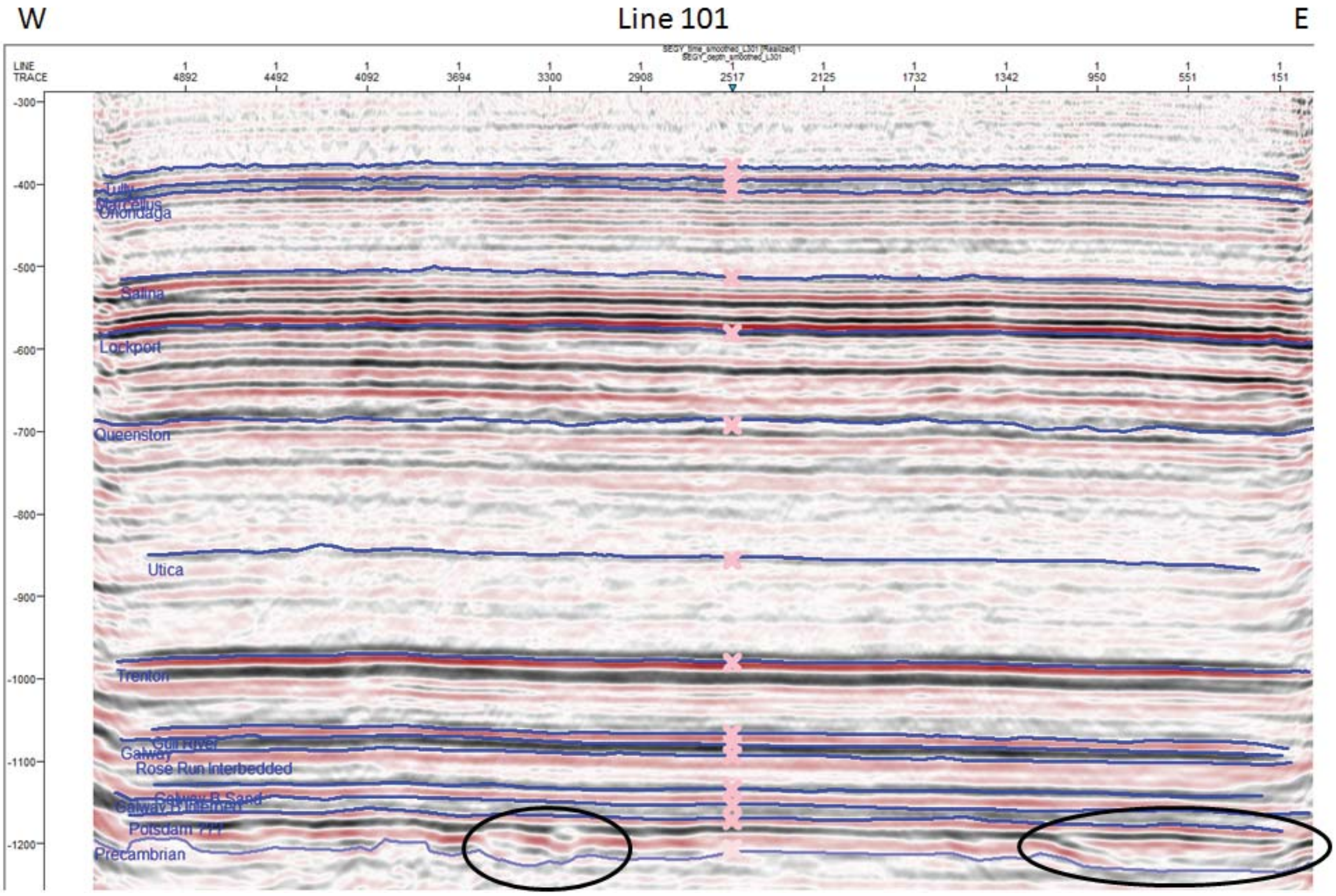


Figure 21: Line 101 in TWT (ms). This line is approximately 5.1 miles long. Formation tops are represented by blue lines, and each black circle indicates a lateral discontinuity in the strata overlying the Precambrian basement. Note eastward dip.

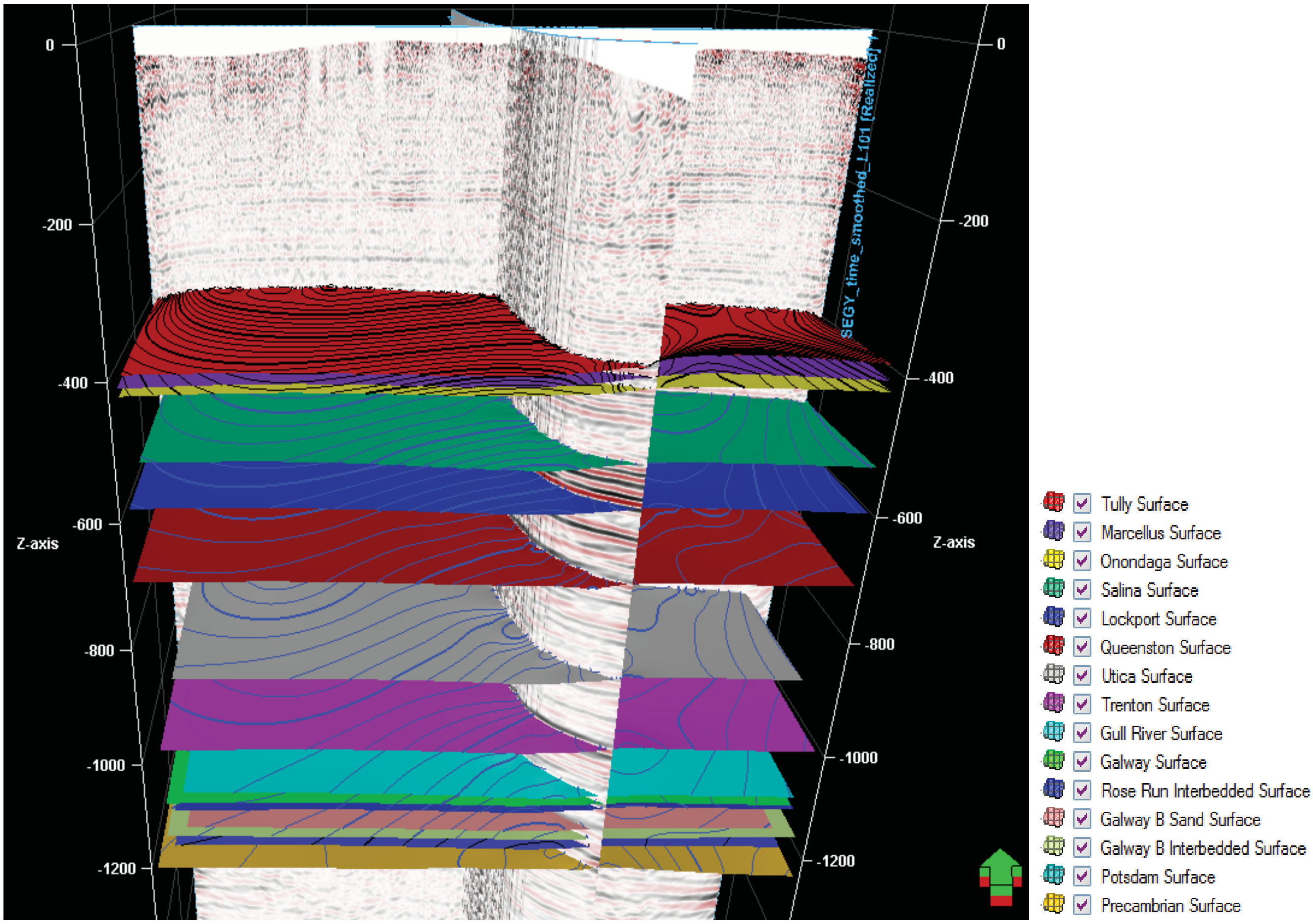


Figure 22: Formation top surfaces generated from seismic interpretation. Z axis is in TWT, green arrow is pointing north, and vertical exaggeration is x25. A southeastern dip is observed in these surfaces.

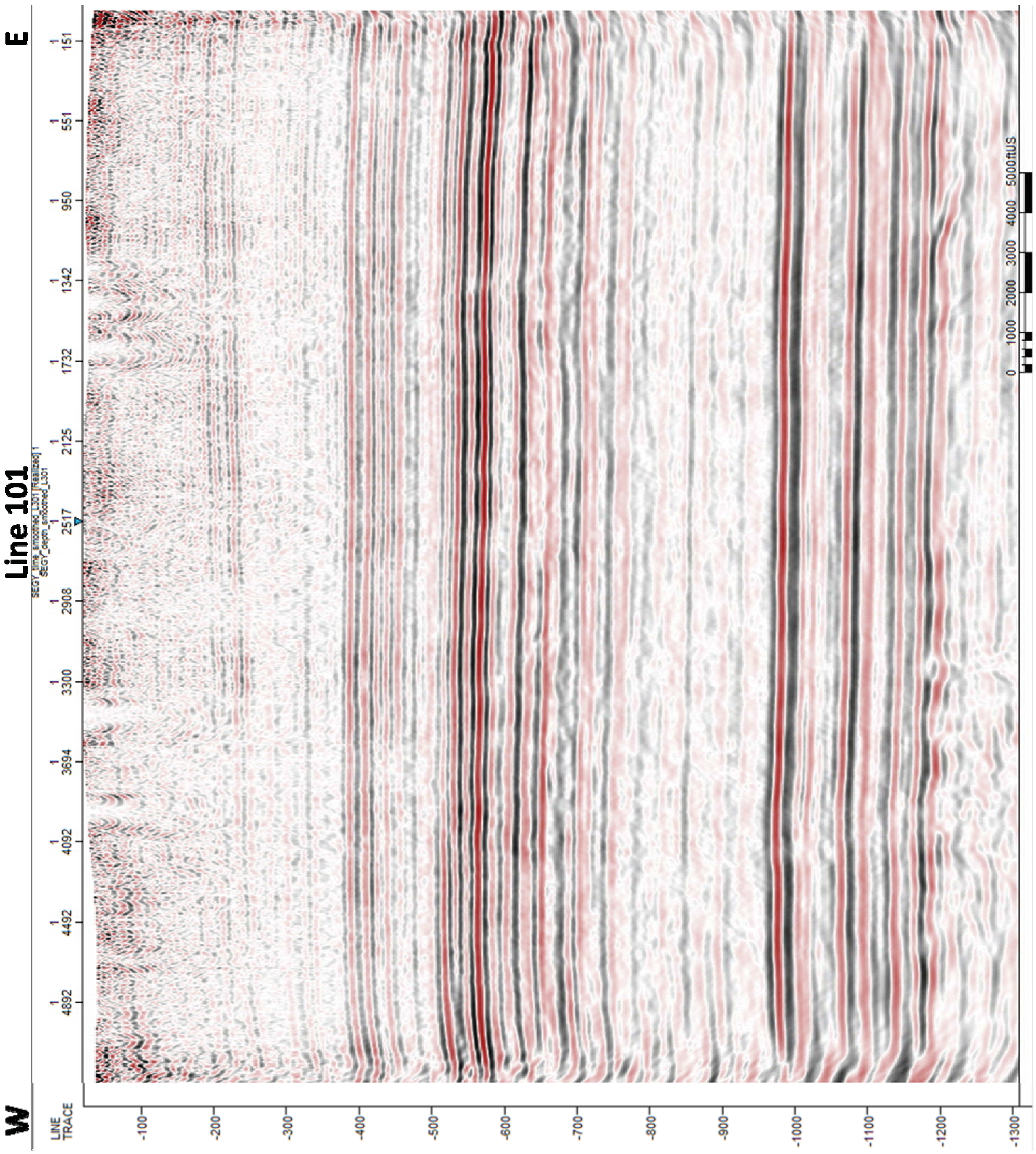


Figure 23: Seismic line 101 without interpretations. Scale is TWT (ms).

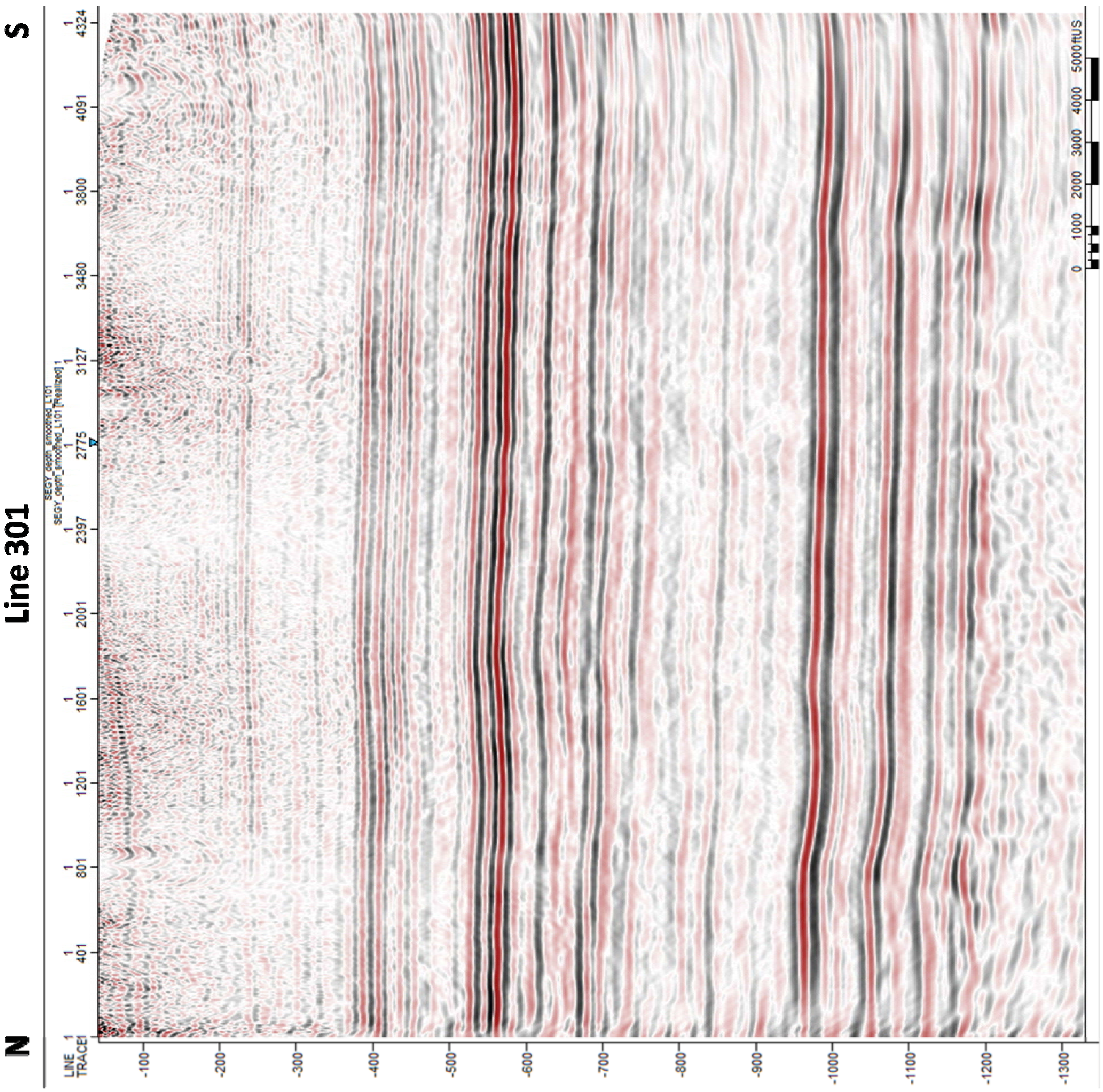


Figure 24: Seismic line 101 without interpretations. Scale is TWT (ms).

8.0 Conclusions

Seismic data from the Jamestown study area was successfully acquired and processed. Based on this seismic data, it is interpreted that the Galway Formation and its Rose Run Member are present in the study area. However, it is unclear whether the Potsdam Formation is present and an accurate interpretation cannot be made without a well drilled in the study area. Generally, most seismic reflections are sub-horizontal, laterally continuous, and dip to the southeast. Only reflectors immediately overlying the Precambrian basement are locally discontinuous. Faulting resolvable at the scale of the seismic data has not been observed. The continuous seismic reflections and the lack of any resolvable faulting are encouraging results regarding to CO_2 storage potential in the study area. Storage capacity and injectivity for the prospective storage zones, (i.e. porosity, permeability and thickness) cannot be assessed based on the work performed to date.

9.0 References

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10.0 Appendix A – Data Acquisition Report

10.1 Overview of Seismic Survey

WesternGeco was contracted by Schlumberger Carbon Services to conduct a regional 2D survey over the proposed Jamestown area to determine if the subsurface was suitable for carbon sequestration.

The design of the project was developed in cooperation between WesternGeco Integrated Services and Schlumberger Carbon Services personnel in Calgary and Columbus.

WesternGeco crew 1752 performed the survey with Tesla-Conquest Inc as the Alternative Business Model (ABM) subcontractor. WesternGeco provided our proprietary Q-Land MAS Point Receiver acquisition system and processing equipment, plus technical and managerial personnel. Conquest provided the vibrators with Technicians & Operators, line movement vehicles, and necessary personnel to deploy and pickup the line equipment. The operation was supervised by a WG Operations Supervisor, Party Manager/Chief Observer, Project and Chief Geophysicists.

The preparation for the project started in early October 2010, with the New York County and Pennsylvania DOT roads permitting performed Keith Uruski with Tesla-Conquest Inc. The survey and acquisition was performed between Oct 16, Oct 21. The program of the project comprised the following:

- Securing the county roads in New York and PENNDOT permit to conduct vibroseis operations on the necessary roadways.
- Surveying of GAC and vibrator point positions as per set parameters.
- The acquisition of surface 2D seismic data on two lines, performed by WesternGeco.

The Jamestown 2D program was permitted for 10 linear miles using strictly Vibrator for the source. Crew 1752 was temporally based in Jamestown, New York at the Comfort Inn, which was about 20 miles north of the project area. Due to the short term of this project, no long-term base was established for this project.

Project was recorded with the following sweep; x4 @ 12 sec sweep w/5 sec listen time, sweeping from 6-100Hz Linear with 300msec start and end tapers, utilizing 90 degree phase rotation between sweeps.

There were no lost time injuries on this project.

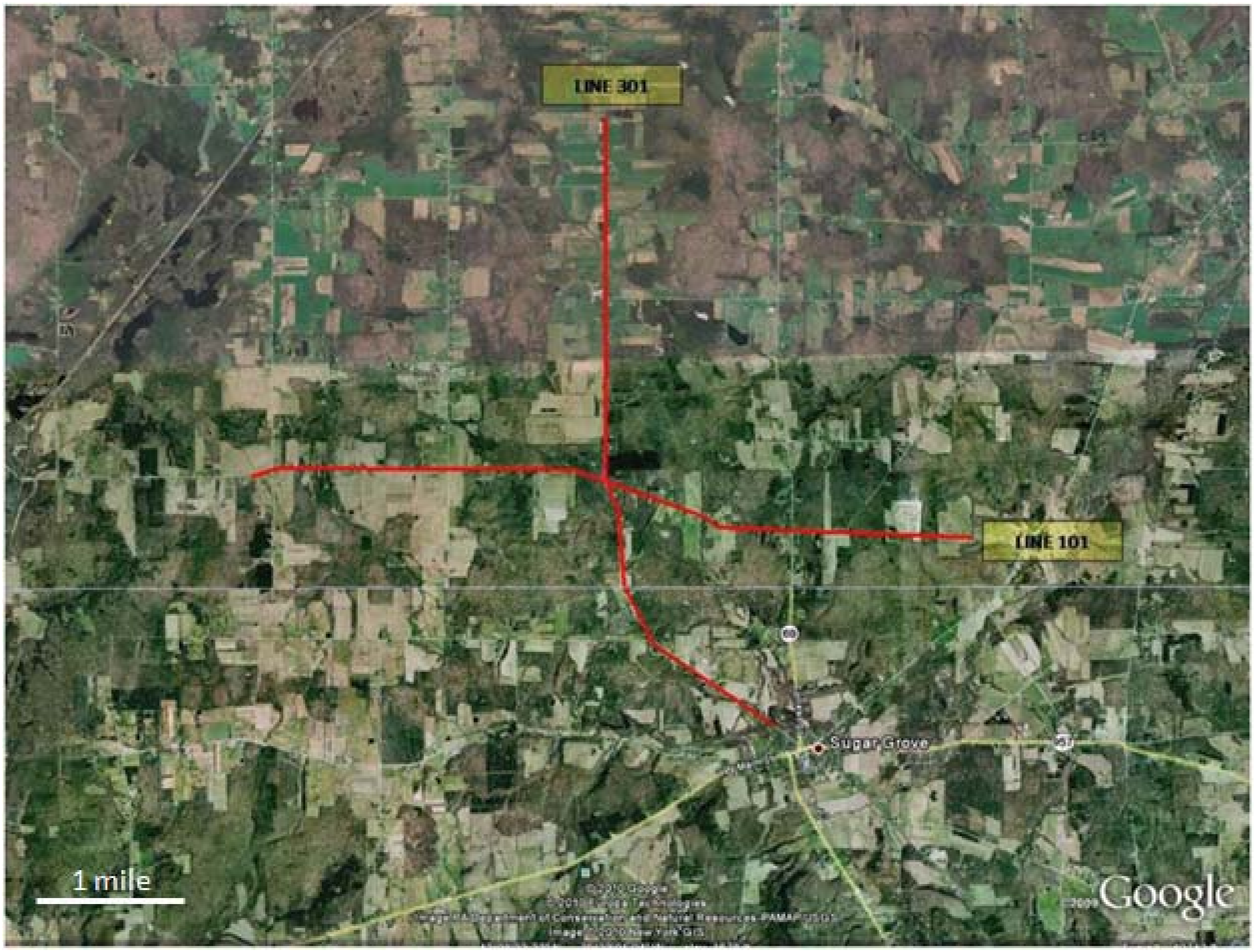


Figure A.1 Location of Jamestown 2D Seismic Lines

10.1.1 Area Description

The prospect area was located in Chautququa County, NY and extending approximately 2 miles into Pennsylvania north of Sugar Grove. The prospect area consisted of two 2D lines, each approximately 5 miles long. East/West Line 101 was along County Touring Route 12, and North/South Line 301 was along Wellman Road in New York, extending onto Caitlin Hill Road in Warren County, Pennsylvania.

The area is predominantly used for farming and is mostly private lands. Sparse oilfield infrastructure is present.

10.1.2 Weather

Throughout the project, temperatures varied during the day, ranging from lows of around 45°F in the morning to highs of 65°F in the afternoon. There was no lost time due to weather.

10.1.3 Crew Personnel

Over the course of the project the assigned personnel on WesternGeco Crew 1752 grew to a total of 17 members including subcontracted personnel. The WesternGeco personnel included:

- 1 Party Manager
- 1 Chief QC Geophysicist
- 1 Project Geophysicist

10.1.4 Subcontractors and Vendors

Surveying of GAC and Vibrator Points was conducted by Survey Technology Inc. (STI) from Katy, Texas.

Tesla-Conquest Inc from Denver, Colorado provided personnel for deploying and picking up line equipment, vibrator truck operators, and certified flagging personnel to control traffic flow around the vibrators.

Elexco Land Services Inc from Marysville, Michigan provided pipeline and dwelling Peak Particle Velocity monitoring throughout the vibration portion of the project to insure we were maintaining proper distances from houses and pipelines.

All subcontractors listed above have had a long term relationship with WesternGeco and are fully integrated and trained in the Schlumberger QHSE Management System.

10.1.5 Vehicles

Tesla-Conquest Inc provided 4 Hemi-44 truck mounted vibrators each rated at 46,700 lbs hold down weight. Six vehicles were also provided including F-350 jug trucks and F-250/F-350 pickups.

Tesla-Conquest Inc line trucks were equipped with special boxes fabricated for transportation of 3 LCU's of recording equipment: 30 DGS's and 6 ITO cables. MRU's and fiber optic cable, and batteries were transported by a regular pick-up truck.

WesternGeco managers used 2 F-250 pickups.

10.1.6 Chronology of the Project

01 August 2010 – Applications submitted for New York and Pennsylvania DOT road permits
20 August 2010 - Recording equipment mobilized to Elmira, NY from Hermiston, Oregon
01 October 2010 – New York and Pennsylvania DOT road permit approved for 180 day period
01 - 02 October 2010 – Survey crews Mobilized from Bradford, Pennsylvania to Jamestown, NY
03 October 2010 – Survey crews started production
12 October 2010- Survey crews completed project
12 – 15 October 2010 – Acquisition crew mobilizes from Elmira, NY and Denver, CO
16 October 2009 – Start-up meeting conducted with Acquisition crews and layout of line 301 started.
17-18 October 2010 – Completed recording line 301 and started layout on line 101
19 October 2010 – Completed layout and recording on line 101
21 October 2010 – Final pickup completed, all lines inspected for trash

22 October 2010 – Demobilization.

10.2 Operations

The Jamestown Q-Land MAS 2D project was done as part of the City of Jamestown Energy Site characterization project in the same area. The programs main goal was to determine if the subsurface formations were suitable for carbon sequestration.

From an operational standpoint, the project was completed without any unexpected issues.

Public interest in the project was high, with many people stopping by to see the operations, all having been well informed by the client representatives in the area regarding our operations.

There were houses along the roadways, but with close communications between the PPV Monitoring representatives on site, we were able to record alongside them without exceeding agreed specifications for PPV.

Field brute stacks were generated each day after the day's production and overall data quality was very good.

10.2.1 Survey Design and Project Parameters

10.2.1.1 Subsurface Zones of Interest

There are at least two potential storage formations. The Upper Cambrian basal Potsdam Formation and the Rose Run member of the Upper Cambrian Galway Formation may exist at the site. These formations are primarily siliciclastic intervals and were deposited in shallow marine environments in the Appalachian basin. Tectonic features such as basement highs and basement-rooted faults controlled dissolution and mineralization processes, which directly affect the textural properties and porosities of the target rock. The seismic survey portion of the feasibility study is structured to provide insight into two fundamental questions that directly affect CO_2 storage potential in the target formations: 1) Does the Potsdam Formation extend into the study area? *and* 2) How do basement-rooted faults affect the porosity?

10.2.1.2 Source Parameter Tests

Testing was deemed as not needed due to fixed budget for the project, so a broad band sweep was used with 4 sweeps to insure we have sufficient source energy.

10.2.1.3 Project Parameters

Table A.1: Project parameters

Surface geometry	
Source Line Interval	2D
Source Point Interval	120 feet
Source points / salvo	n/a
Receiver Line Interval	2D
Inline SS Interval	10 feet inline spacing with 120 feet ITO interval
Xline SS Interval	n/a
DGF Receiver Point Interval	40 feet, to be tested
SS Density per mi	528
DGF Density per mi	132, to be tested
Shot Density per mi	44
Source area	10 linear miles
Total number of source points	440
Total number of ITO points	440
Total number of SS points	5,280
Recording Parameters	
Spread type	2D, lines all live
Spread move	n/a
Total live channels	2,640 single sensors per 5 mile line
Recording Instrument	Q-Land MAS
Sample Interval	2ms
Low Cut Filter	3Hz., -3dB, 18 dB/Oct
High Cut Filter	Out
Notch Filter	Out
SBP (Anti-Alias Filter)	Nyquist. 198.5 Hz., -3dB (0.8 Nyquist Linear Phase) -130 dB Down @ 102%
Source Parameters	
Source Type	Vibroseis
Starting frequency	6 Hz
Ending frequency	100 Hz
Sweep Length	12 sec
Listening time	5 sec
Sweep type	Phase Rotated Sweep 0 – 90 – 180- 270
Force level	70%
Number of sweeps per VP	4

Number of vibs per group	3
Nominal array	Inline
Nominal vib spacing in array	Bumper to Bumper
Vibrator type	Hemi-44 Enhanced Trucks
Binning and Fold	
Bin size	20 feet, to be tested
Bin Density	264 per mi
Nominal Fold	110 post DGF
Minimum Offset	5 feet
Maximum Offset	13,200 feet (all live)

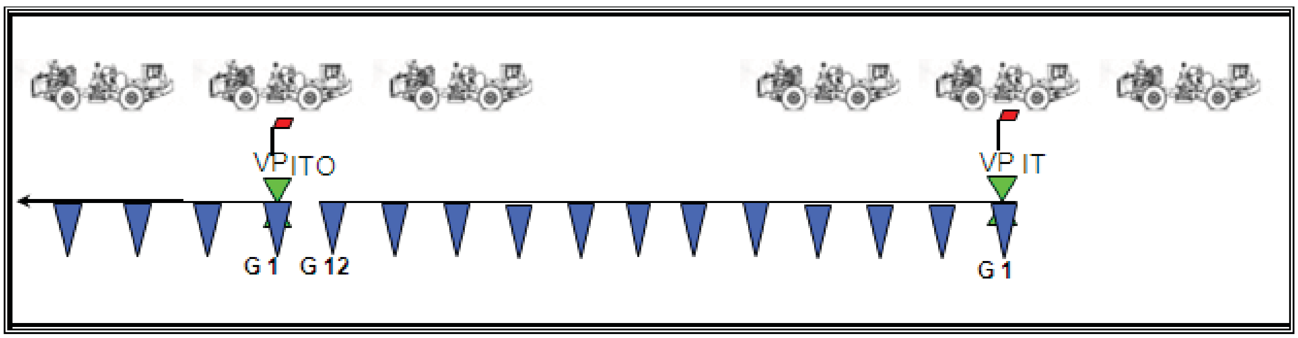


Figure A.2- Source - Receiver array scheme

The spread geometry was all receivers on each line recorded as live.

DGF filter dimensions anticipated at the design stage were 40 ft.

The theoretical coordinates of the sources and receivers were provided to the Survey department, which was responsible for physically locating and flagging these coordinates on the ground.

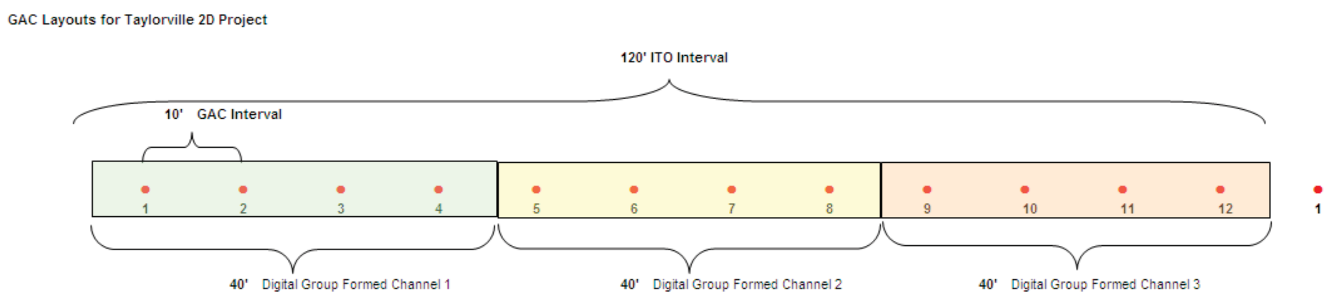


Figure A.3 GAC - IDF array scheme

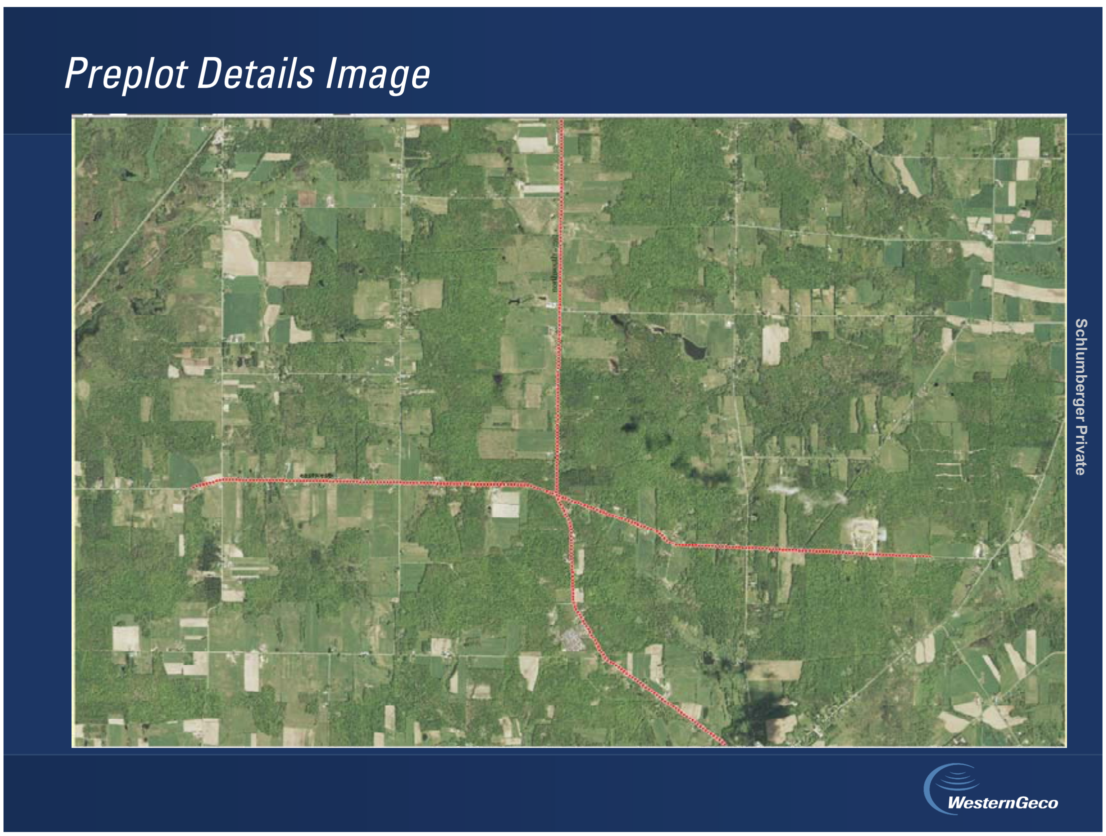


Figure A.4 - Preplot Map Image

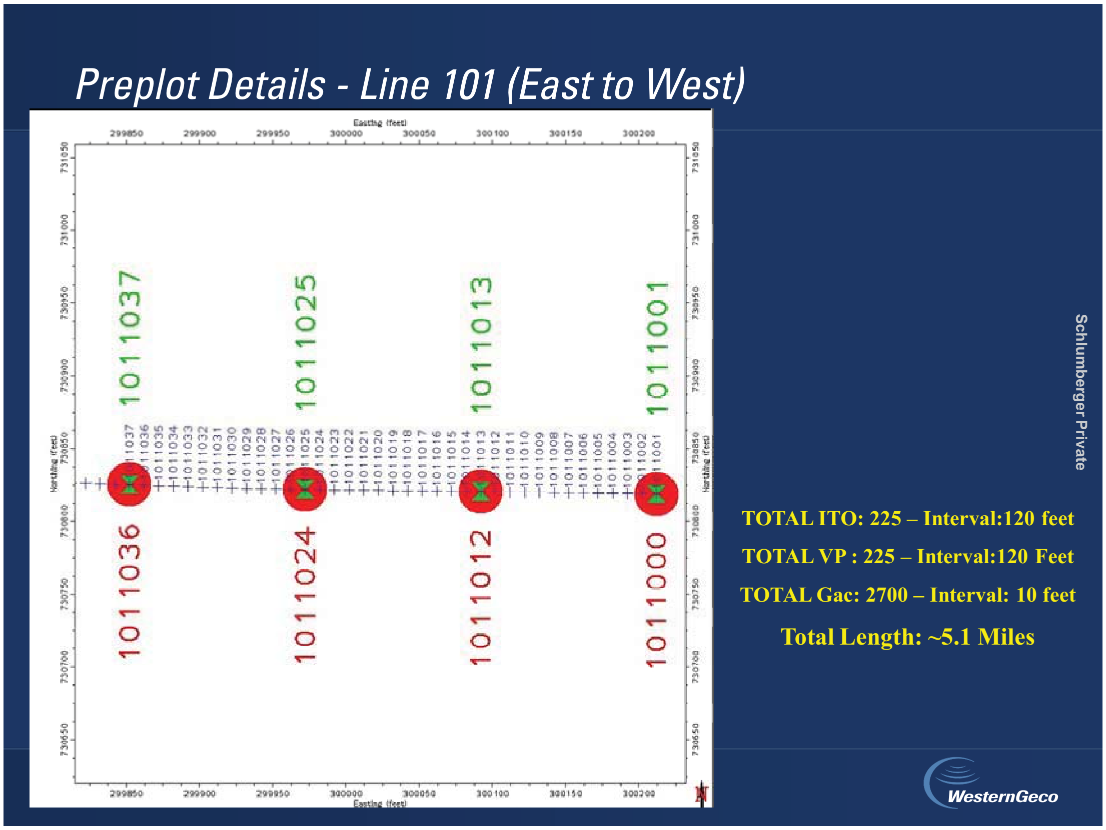


Figure A.5 - Preplot Details – Line 101

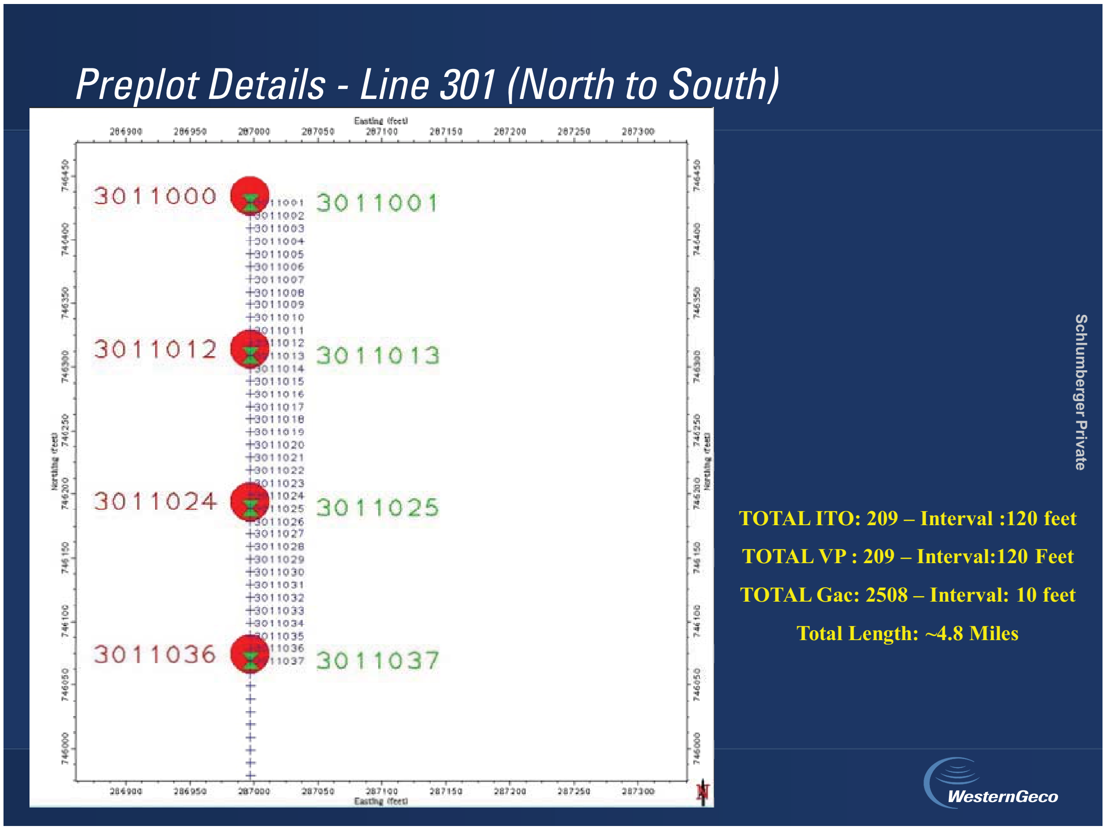


Figure A.6 Preplot Details – Line 301

10.2.2 Permit Summary

Tesla-Conquest Inc secured the county road permit and STI completed the One-Call for utilities and pipelines once the line locations were established. A total of 10 miles was permitted, consisting of one N-S line and one E-W lines between State Highways 12 and 315. The county road permit and DOT was valid for 180 days from October 01 2010, but can be renewed for future lines in the area.

Surface owners were all notified by flyers and knocking on each individual's door along the road lines we recorded.

There were no permit issues on the project.

Personnel– WesternGeco Permit Agents

Surface – Project was permitted by Keith Uruski of Tesla-Conquest Inc

Mineral – n/a

Permit research and applications began in early August 2010. DOT road permit was finalized on 1th October 2010.

10.2.2.1 Surface Permits

Only a DOT road permit was required, with flyers and verbal notification to each landowner along the road right of way. There were no permit fees paid.

10.2.3 Survey

The main volume of survey operations in the Jamestown 2D project were carried out between 03th October 2010 and 12nd October 2010 by STI survey crews. Geodetic control was established on 03th October 2010. Surveying commenced on 03th October. There were 2 crews active daily, plus a Field Supervisor.

An average production of 521 single sensor points per crew was achieved, with peak daily production of 1,098 positions. Project total was 5,209 single sensor points. The Survey crew did have 5 days of rain where minimum production each day was achieved.

The survey team was based out of Katy, Texas. It consisted of:

- 1 Chief Surveyor / data processor / mapper
- 2 rover pack operators
- 2 survey helpers
- Trimble R8 GPS receivers with Trimble Internal radio transmitters
  - matching the number of crews
  - + 1 used by chief surveyor
- 1 Trimble R8 GPS receiver base with Trimmark 3 radio transmitter
- 2 crew cab trucks

10.2.3.1 Survey Control

Static control survey was established prior to conducting the survey operations with 2-hour sessions at each station. The raw data was processed on the crew. Control information was converted to the local grid coordinates and heights, which were delivered to the crews. The Chief Surveyor converted this information to SEG-P1 format and combined both: control SP1 and pre-plot sp1 to create QLD file to run RTK survey.

Table A.2: Survey parameters used in Jamestown 2D project

Datum: NAD 1927 (NADCON CONUS)
Method: NADCON
Ellipsoid: CLARKE 1866
Semi-major axis: 6378206.400
Reciprocal of flattening: 294.97869820000
Shift file: conus.ncn
System: New York West 3103
Projection: TM
Origin latitude: 40° 00' 00.000" N
Origin longitude: 078° 35' 00.000" W

Origin/false easting (m): 152400.305
Origin/false northing (m): 0.000
Scale factor: 0.999937500

10.2.3.2 Real Time Kinematic Surveying

Source stations and ITO positions were marked with fluorescent paint spots on the roads: pink for receivers and orange for sources. For better visibility fluorescent flagging tape of matching color was used on stakes. The survey settings were as listed in Table A.3.

Table A.3: RTK Survey settings

Elevation Mask	13
Number of satellites tracked	5
PDOP	5
HDOP	3.5
VDOP	5
Epoch Interval	1 sec.
Point Occupation	1 epoch (initially – 3 epochs)
Max. Range from Base Station	10 km (~6.25 mi)
Horizontal staking out accuracy	1 ft
Max. inline single sensor offset	9 ft

The staking accuracy of 1 foot was maintained when laying out points, unless prevented by terrain or obstacles. Crossline offsets were not applicable in 2D mode on roads.

Both source and receiver offsets were mostly due to houses and pipelines, and their amount was minimal.

10.2.3.3 Processing Results & Quality control

The survey software used for daily quality control of RTK data was GPSeismic™ version 2006.4. The data acquired in the field was checked against the technical GPS (Table A.3) and offset criteria. Once the data quality was deemed satisfactory the data was incorporated into the survey database. In the database, additional analysis was run to determine the displacement against the pre-planned coordinates, as well as any missing station through a set of pre-defined queries. If the quality or differences from the pre-plot were out of acceptable range, field re-observations would be done.

The final data was exported in NAD27 values and local height and submitted to the Geosupport department. Maps were generated to facilitate recording and survey crew operations.

Elevation QC

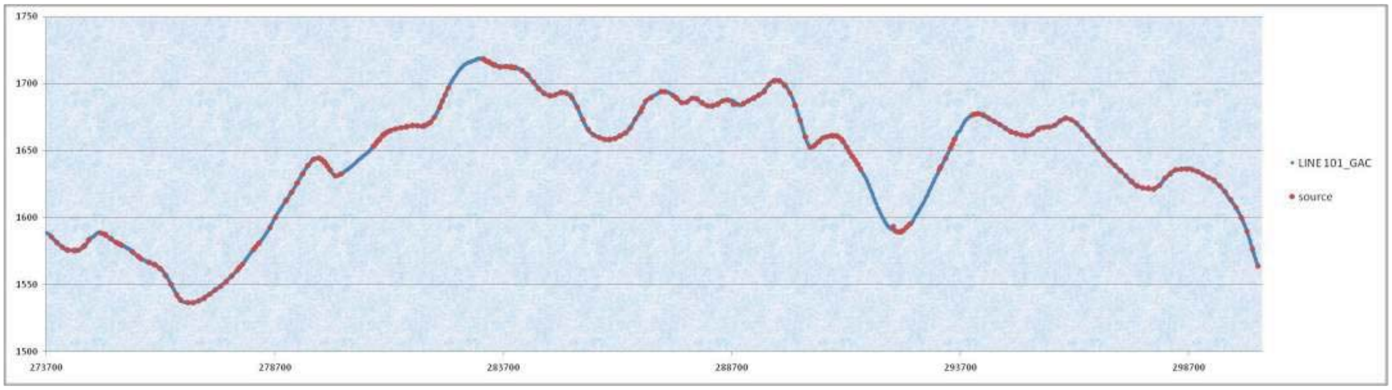


Figure A.7 Elevation Profile – Line 101

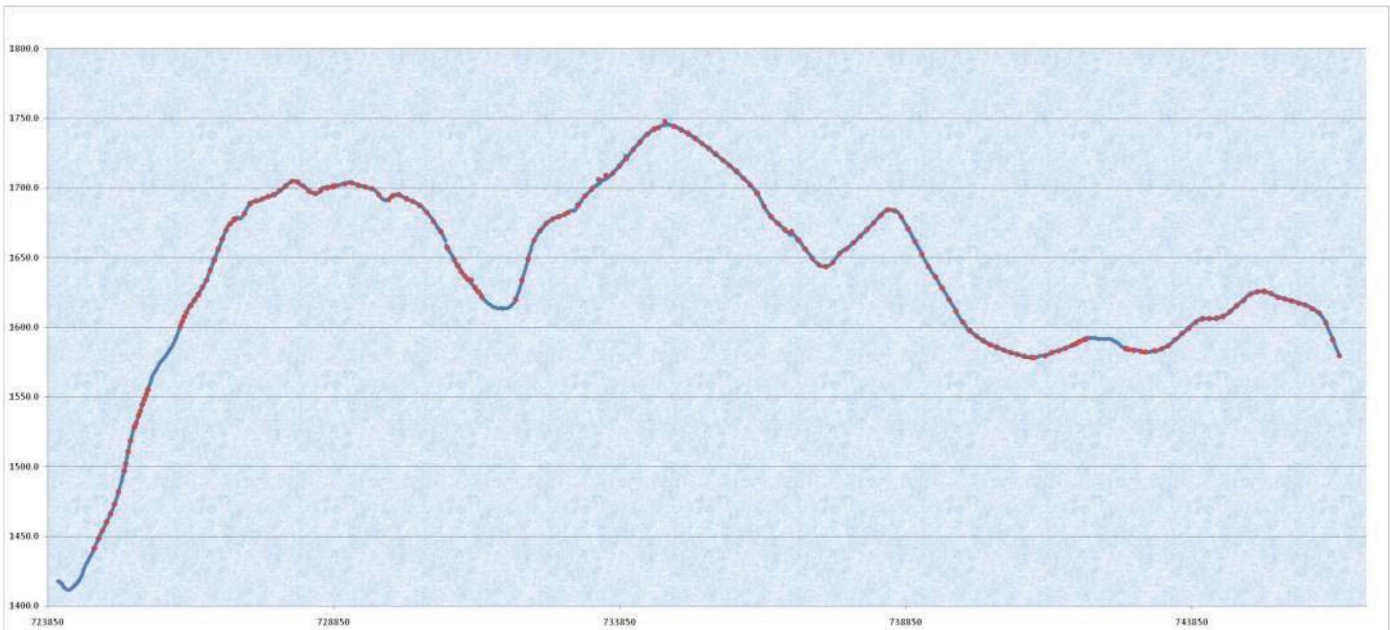


Figure A.8 Elevation Profile – Line 301

10.2.4 Archaeological Survey

Not applicable for this project.

10.2.5 Recording

10.2.5.1 Operations description

The Jamestown 2D line operations commenced on 16th October 2010. The line personnel were supplied by Tesla-Conquest Inc, and consisted of 1 cable team of 5 personnel, 3 traffic control persons, 2 trouble-shooters, and 1 Head Linesman.

The cable team was responsible for the layout and pick up of line equipment, and the trouble-shooters were responsible for the fiber optic backbones, replacing the bad equipment from the lines and for changing batteries.

Table A.4: Cable crew personnel

	Personnel	Total
Front and Back Crew (1)	5	5
Traffic Control	3	3
Trouble shooters	2	2
Head Lines men	1	1

Only minor damage was sustained by line equipment during the project during normal operations.

The amount of equipment brought to the project was sufficient to lay out entire lines and enable efficient rolling from one line to the next.

Line and recording operations were performed during light hours. At around 7:00am the crew would leave from Jamestown after the morning QHSE/Operations meeting (approx. 20 minute drive) via highway 104 for the prospect.

The Q-Land MAS recorder was set up in a custom built utility trailer, powered by a 7.5kVA electrical diesel generator, mounted in the rear of the trailer frame. One AC unit was providing the climate control. This trailer also served as a field office, QC control, Data Processing, and proved adequate for operational use.

Recording trailer was set up at line intersections of 101 and 301 to allow multiple lines to be recorded from each site.

Figure A.9 - Recording trailer - outside view

10.2.5.2 Analysis of Operations

The short duration of this project makes it difficult to draw conclusions from timing and production analysis, but all phases were completed within the time frame assumed in the bidding process.

Graph n/a for this project.

No line equipment downtime or power problems occurred and hardly any battery replacement had to be done during the project.

10.2.5.3 Recording Equipment

The recording instrument was the point receiver WesternGeco Q-Land MAS system.

The Digital Geophone String (DGS) is made up of 12 Geophone Accelerometers (GAC) which have the digitizer and acceleration coil element integrated in one case. A pre-amplifier amplifies the coil response to the earth's movement and then the signal is digitized at the sample rate.

WesternGeco Q-Land Crew 4 System

FAS Serial No: Q-Land MAS-001

FCI Serial No: 1240500399/ZA

Manufacturer: WesternGeco

Field Acquisition System

Model: Sun Microsystems V120 s/n TF61150948

Operating System: Solaris 2.8

Vibrator Control Equipment

1 Pelton VibPro (Encoder) Firmware Version 10 C

3 Pelton VibPro (Decoder) Firmware Version 10 C

Field Equipment

Table A.5: Line equipment calculation and counts

TOTAL ITO PTS: 440	ACTUAL Needed	20% EXTRA	30% EXTRA	EQUIPMENT TO BRING
ITO CABLES	**88**	**106**	**114**	**120**
LCU	**44**	**53**	**57**	**60**
BCU	**50**	**60**	**65**	**70**
DGS, 12 elements ea.	**440**	**528**	**572**	**600**
MRU	**5**	**6**	**7**	**7**
FO 950m	**5**	**6**	**7**	**7**
SPA	**150**	**180**	**195**	**200**
EBU	**150**	**180**	**195**	**200**

10.2.5.4 Source - Vibroseis

Crew 1752 was equipped with 4 Hemi-44 truck mounted vibrators. The vibrators were fitted with Pelton VibPro electronics version 10C software. The fundamental ground force was 32,690 lbs. (70% of maximum hold down). A three vibrator source array was chosen for the 2D project.

Table A.6: Hemi-44 Enhanced Vibrator specifications

Specification	Value
Type	P-wave
Peak hydraulic force (lbf)	43,620
Maximum hold-down weight (lb)	46,700
Usable actuator stroke (P-P) (in)	3.00
Effective reaction mass weight (lb)	5,970
Effective baseplate weight (lb)	4,720
Baseplate clearance (in)	24
Gross vehicle weight (lb)	48,000

The vibrators underwent a continuous program of quality control checks. On a sweep-by-sweep basis the vibrators were monitored by the QC status returns to the recording truck. Each day, 3 radio similarity tests were acquired for each vibrator. A set of hardwire similarity tests were recorded once the production sweep was determined. The table below gives the specifications that WesternGeco expects the vibrators to comply with. No variability in the vibrator performance was found related to the ground conditions because the vibrators were on paved road surface all the time, and specifications were not exceeded.

Table A.7: Vibrator Quality Control

Specification	Value
Average sweep phase not to exceed	5 degrees
Peak sweep phase not to exceed	10 degrees
Average sweep distortion not to exceed	25%
Peak sweep distortion not to exceed	35%
Variation of average sweep force from target force	20% in time, <2dB in FK domain

Vibrator performance details are illustrated in figure 11&12.

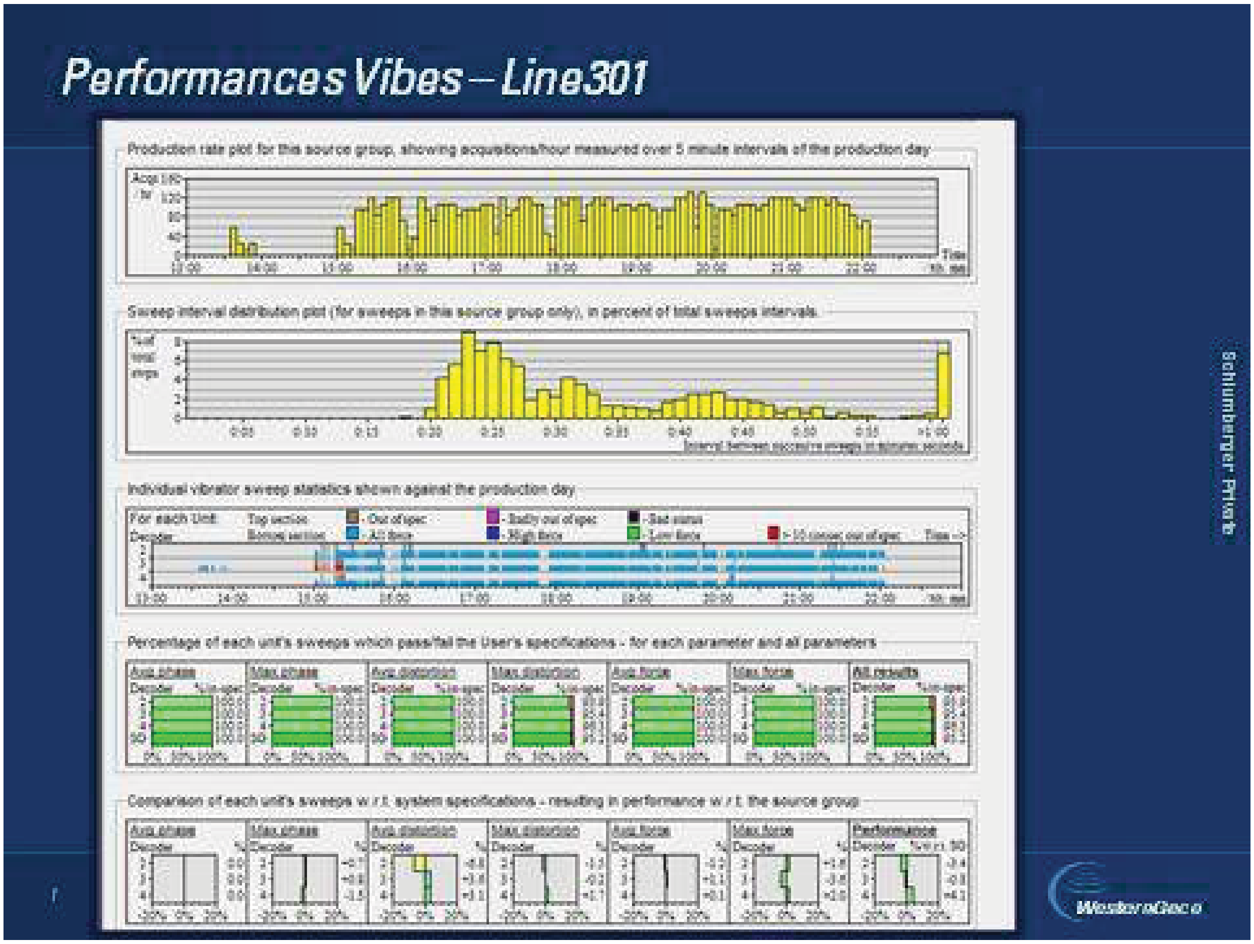


Figure A.10 - Vibrator Performance L301

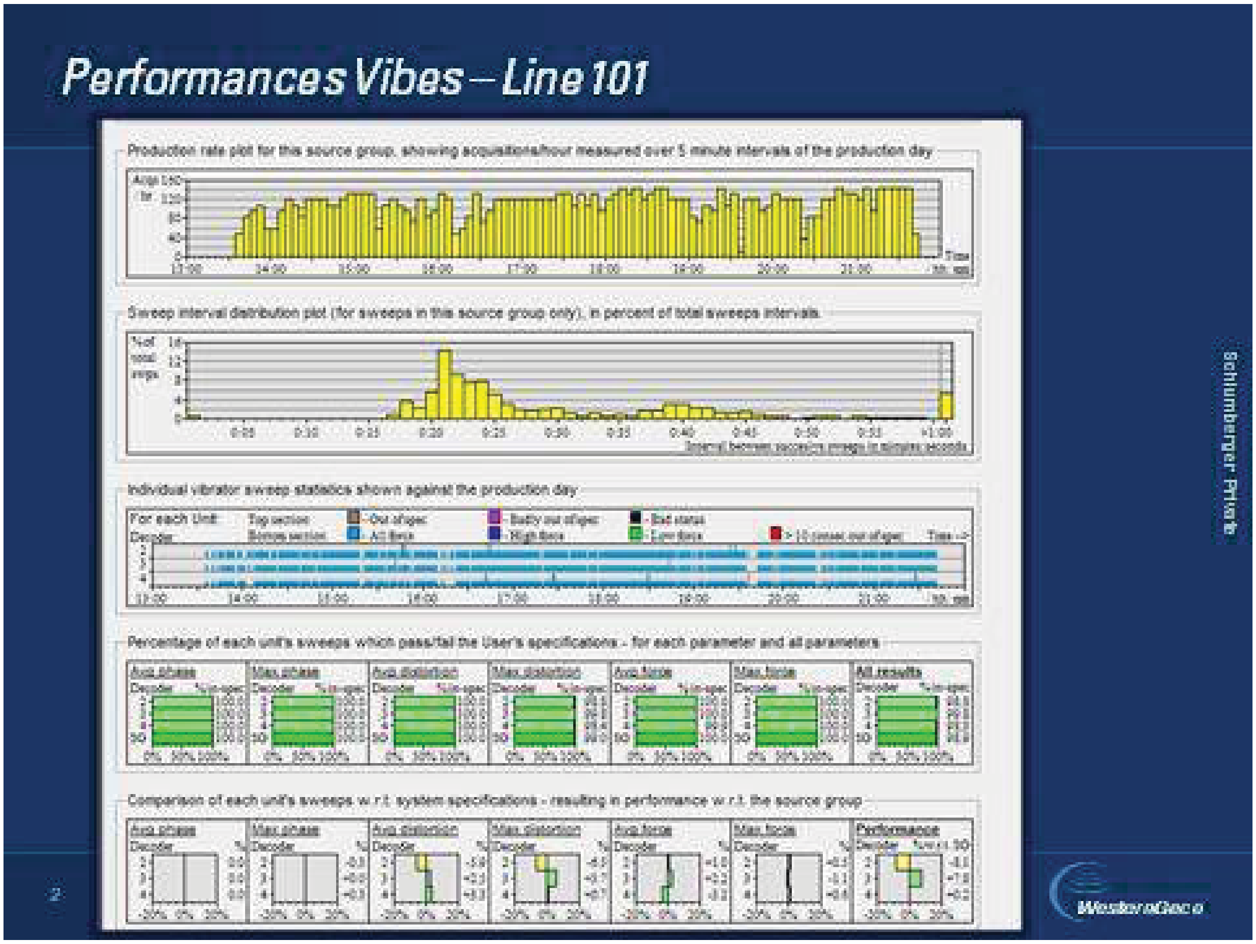


Figure A.11 - Vibrator Performance L101

10.2.5.5 Equipment Tests

Vibrator Testing

The following tests were performed as part of the start-up and acceptance tests for the WesternGeco Q-Land MAS and the Hemi-4 Vibrators, for the acquisition of the Jamestown 2D Survey.

- Start Time adjusted for optimum +/- 20 µsec delay between all vibes and RT
- Radio Similarities
- Hardwire Similarities on production sweep

Instrument Testing

A full series of daily instrument tests were run and the results generated by the instrument were cross checked in the Quality Control section by independent third party software Testif-I version 2.0.2a. The tests performed included the following:

- Total Harmonic Distortion, recorded at 12 dB pre-amp gain, 2ms sample rate.
- Noise, recorded at 12 dB pre-amp gain; 2ms sample rate. Pulse Test, recorded at 12 dB pre-amp gain, 2ms sample rate.
- Gain Accuracy, recorded at 12 dB pre-amp gain, 2ms sample rate.
- CMRR, recorded at 12 dB pre-amp gain, 2ms sample rate.

10.2.6 Field Geophysics

The main tasks of the Field Geophysics department during the survey could be split into two distinctive stages:

- Pre-acquisition
  - Quality Control of survey data.
  - Quality control of source points placement.
  - Generation of shooting scripts for the Q recording system.
- Post-acquisition
  - Geosupport
    - Quality Control of vibrator positioning and performance.
    - Processing and Quality Control of instrument tests, hardwires and vibrator similarities.
    - Generation of SPS files.
    - Generation of daily production report.
  - In-field Data Processing
    - Generate and QC correlated data.
    - Test data pre-processing and display.
    - Noise attenuation
    - Generation of infield brute stacked volume

10.2.6.1 Pre-acquisition Quality Control

Original pre-plot positions of sources, and in exceptional cases – of receivers, were revised, based on updated infrastructure maps, satellite imagery and information coming from the survey and recording teams.

Offsets

Due to being in 2D mode, all points were confined to the road access. There were inline offsets due to skipped position (pipeline and houses) and were made up at 60’ intervals on each side of the relevant skipped area.

Source skips

On the end of Line 301 there were 9 skipped positions due to permit issues.

Figure A.12 - View of prospect area with vibrators

Shooting scripts

Scripts were generated from SPECS for each 2D line independently, and then modified manually to make them more efficient for observer's usage. When there was sufficient time, skipped VPs, identified during post-survey scouting, were removed from scripts. Updated scripts with scouting notes were passed on to observers.

10.2.6.2 In-field Processing

The main tasks of the In-Field Data Processing Group during the survey were:

- Convert to internal format.
- Correlation
- Update geometry headers.
- QC geometry
- Velocity filtering (FXIIR)
- Diversity sum 4 sweeps
- Velocity analysis and interpretation (every 0.5 mile)

- Grid data 20x20 (wide cell grid)
- Normal move-out correction (NMO)
- Mute (just on Line101)
- AGC (500 ms window)
- Stack

An example of shot correlated after sum:

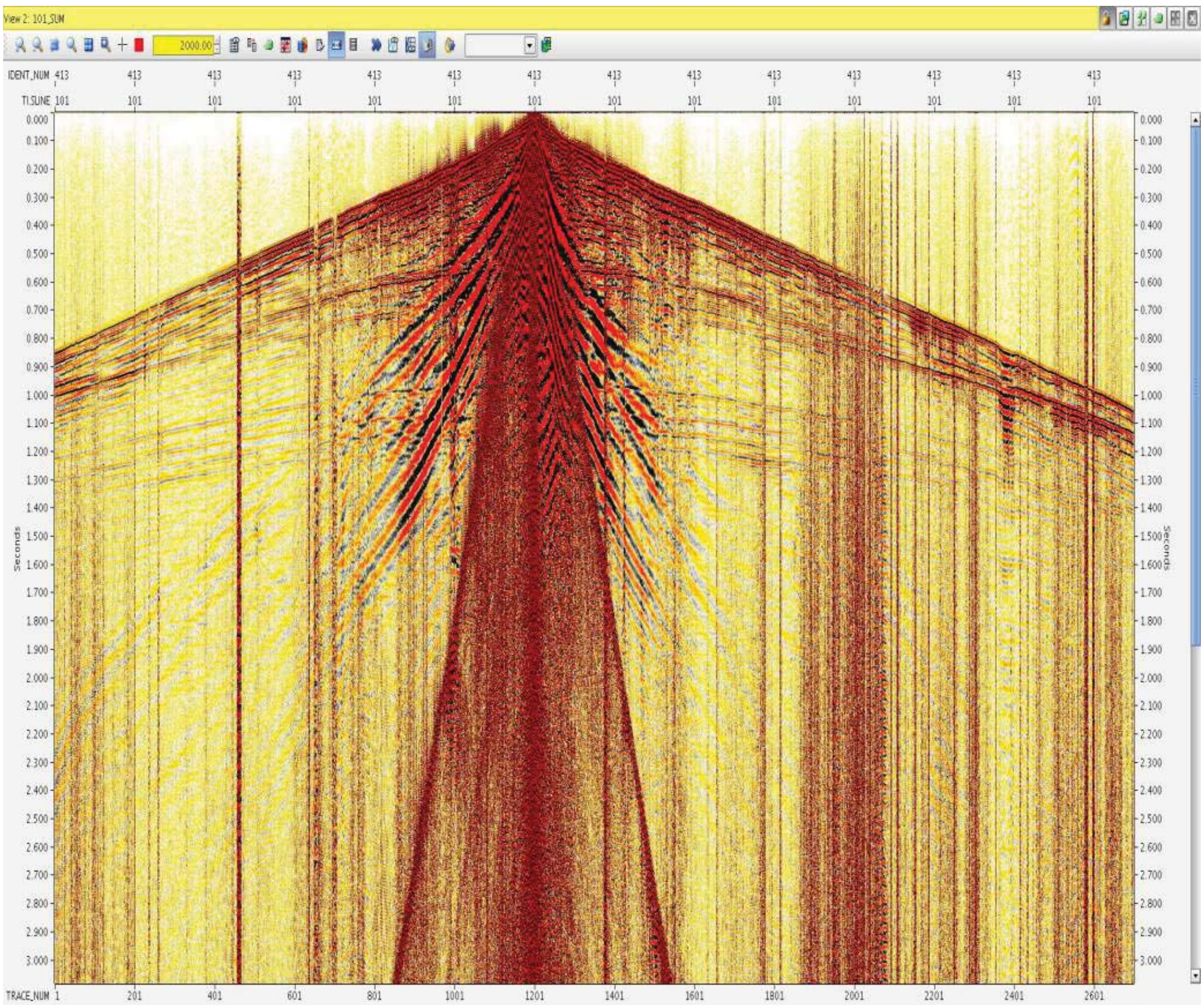


Figure A.13 - Shot correlated after sum – Line 101

Figure A.14: Shot correlated after sum – Line 301

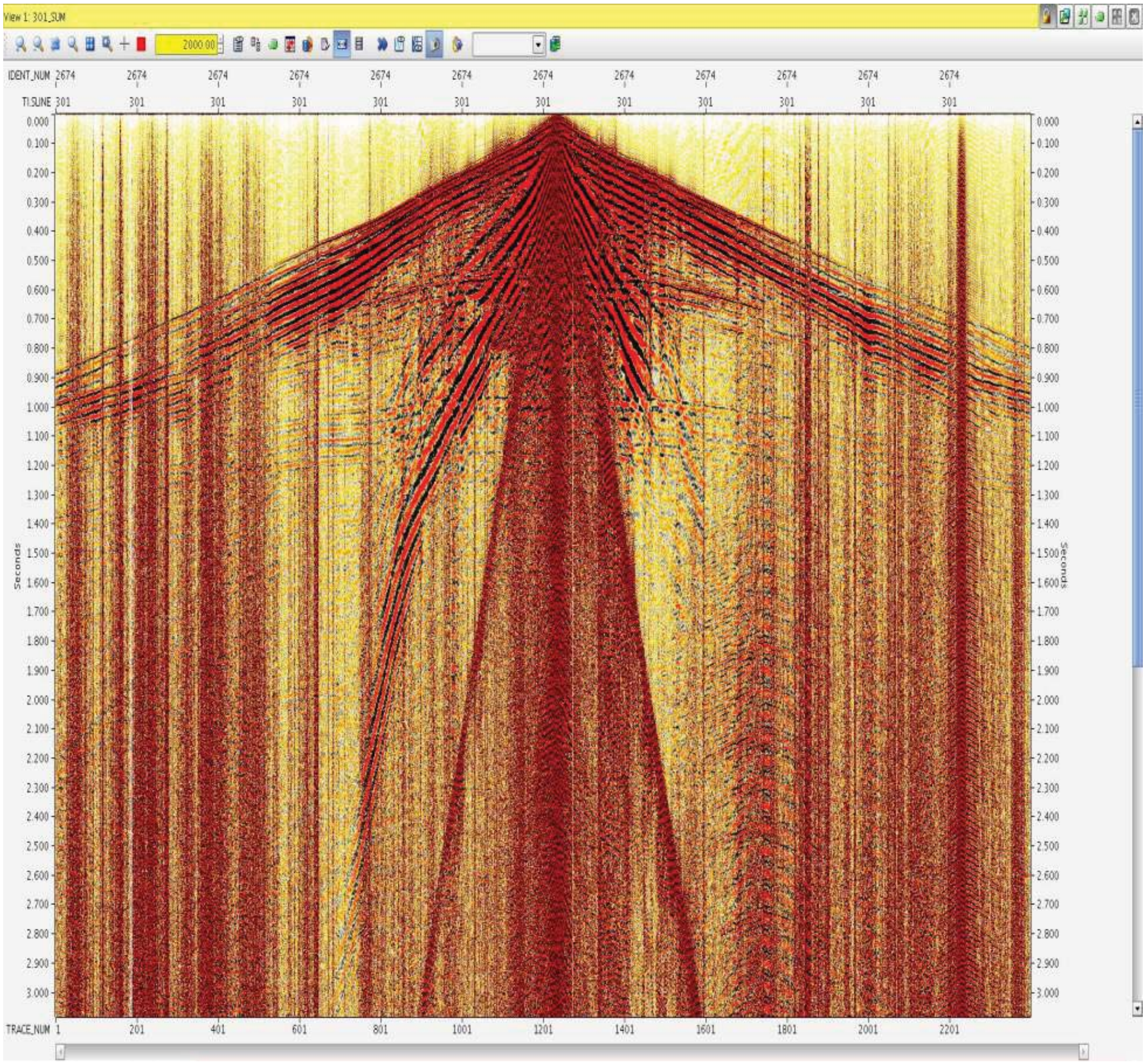


Figure 14 - Shot correlated after sum – Line 301

An example of brute stacks generated in the field:

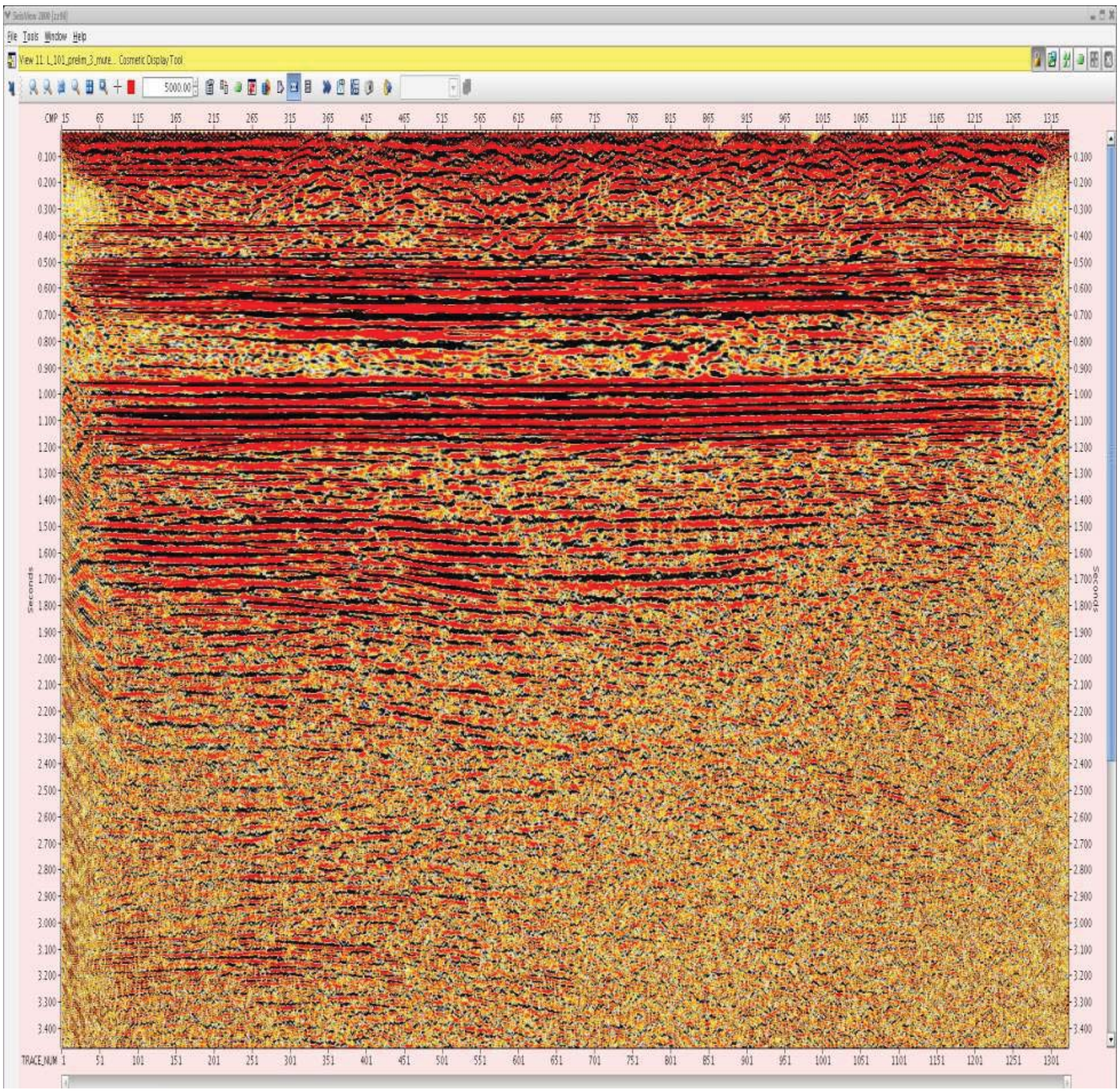


Figure A.15 - Field Brute Stack – Line 101

Schlumberger Carbon Services

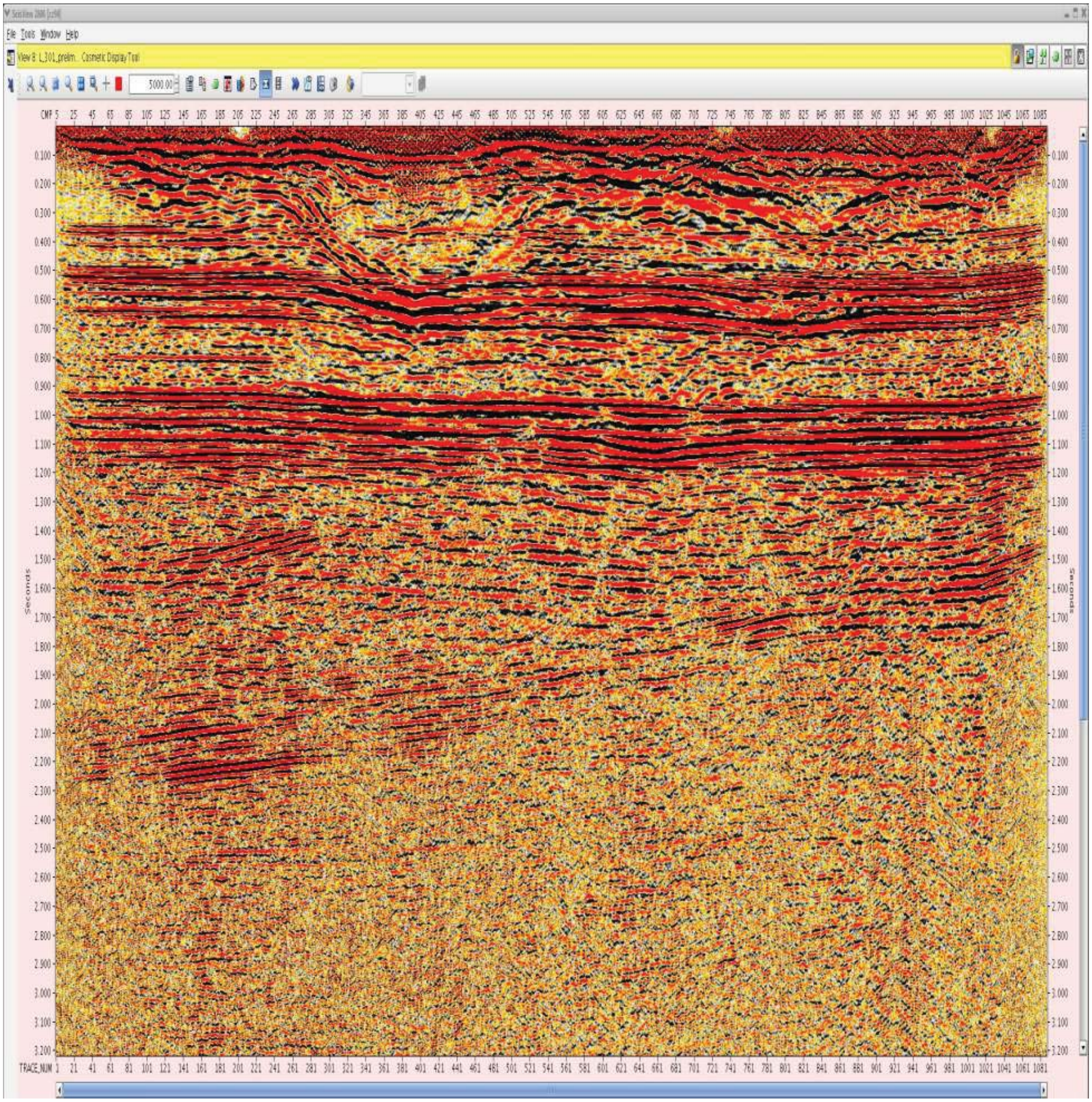


Figure A.16 - Field Brute Stack – Line 301

10.3 Production

10.3.1 Recording Production

Crew recorded 440 total VP's in 3 days of recording with an average of 146 VP's a day.

10.4 Quality, Health, Safety and Environmental Report

WesternGeco (WG) Crew 1752 and all subcontractors operated under the Schlumberger Quality, Health, Safety and Environment (QHSE) Management System (MS). All subcontractors have long term relationships working under this system with WesternGeco and have been pre-qualified through our auditing process.

10.4.1 Driving Risks

Local traffic and a weekend race track presented the added hazards of having a lot of traffic on the roads we were working on. Scheduling and insuring that all personnel related to the project were certified in Schlumberger's Driver SMARRT training program were key components in not having any vehicle related incidents on this project.

10.4.2 Environmental Risks

10.4.2.1 Climate and Heat Related Issues

Due to the time of year this project was being done there were no climate related risks. Temperatures ranged from the mid 40's to the upper 60's during the day.

10.4.2.2 Crops and Spraying

Most of the farm land in the area was hay fields, with no spraying being done.

10.4.1.3 Potential Energy

Attention to Handling, Stepping and Lifting activities, which are the most common cause for "low potential" lost time injuries during seismic operations. The risks related to potential energy were one of the main topics of the toolbox meetings. All personnel involved in field operations had valid SIPP (Schlumberger Injury Prevention Program) training.

11.0 Appendix B – Data Processing Report

Area: Jamestown, NY

WG Lawson Code/Job Number: cu31/3016

Date: 11/17/2010

WesternGeco

10001 Richmond Avenue, Houston TX 77042

Report Author

Michael McClimans

11.1 Introduction

11.1.1 Survey Description

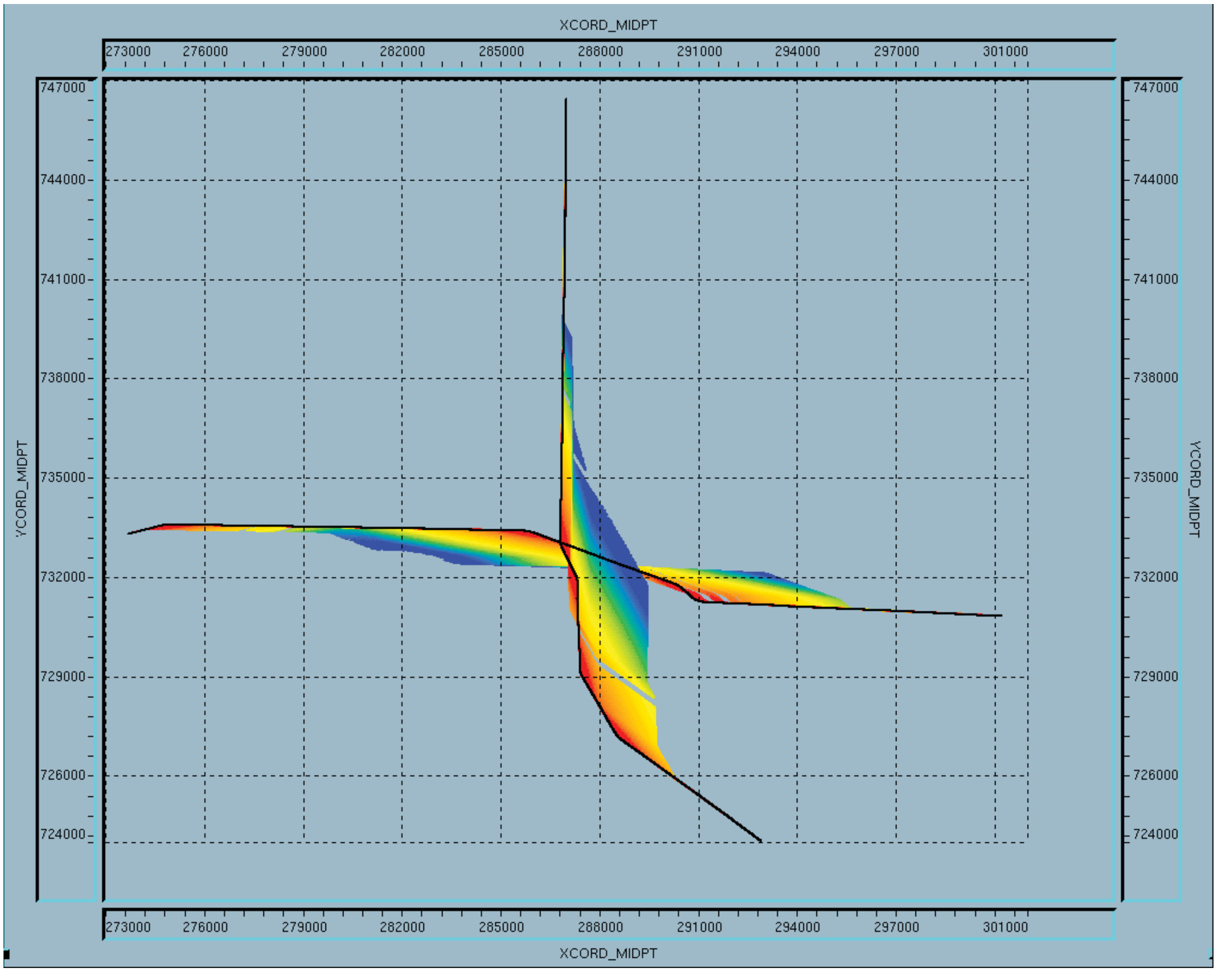
This survey, located in Jamestown NY, consists of two intersecting lines totalling ten miles. The field data was shot by WesternGeco. The north-south line has three bends, the last one being the greatest at 45°. The east-west line also has bends which are less severe than that of the north-south line.

11.1.2 Processing Objectives

- Produce a section suitable for structural interpretation
- Image any faults or fractures in the zone of interest (.5 - 1.2 s)

11.1.3 Processing Issues and Challenges

There were two main processing challenges with this data. The first challenge was an abundance of near-surface noise resulting from the receiver's close proximity to the vibrator trucks. The second more pressing issue was the multiple bends in the north-south line L301. The extensiveness of these bends resulted in the "Common Mid-Points, CMPs," between the source and receiver to be widely distributed. This inability to focus the energy in one two-dimensional plane caused a great deal of smearing in the stacks.



11.2 Acquisition Parameters

11.2.1 General Information

Client	
Contractor	WesternGeco
Survey Name	Jamestown 2D
Location	Jamestown NY
Type of Survey (2D or 3D)	2D
Heading / Azimuth	East-West source and detector lines

	North-South source and detector lines
Client	Schlumberger Carbon Services

11.2.2 Recording Parameters

Recording system	25-bit Q-Land MAS recording system
Recording format	SEG-D
Record length	5 sec
Sample rate	2 ms
Recording filter (Hi-Cut)	100 hz
Recording filter (Low-Cut)	6 hz
Nominal fold	60
Receiver type	GAC-C
Line geometry	Detector Interval = 10 ft.

11.2.3 Source Parameters

Source	Vibroseis
Source type	Hemmi-44 45,000 lbs
Shotpoint interval	120 ft.
Sweep number	4
Sweep start frequency	6 Hz.
Sweep end frequency	100 Hz.
Sweep length	12 sec.

11.3 Processing Flow

11.3.1 Reformat

The input seismic data were reformatted from SEGD to internal format.

11.3.2 Vibroseis Correlation

Input field tape data is correlated with a sweep recorded from the field.

11.3.3 Minimum Phase Conversion

As vibroseis data is output from the correlation process at zero-phase, it is generally recommended to convert to minimum phase prior to application of deconvolution to the data. The minimum phasing operator required is generally obtained by reading the sweep autocorrelation (the 'Klauder Wavelet') from the field tapes, then deriving the minimum phase equivalent of the Klauder, and then deriving the operator to convert from the zero-phase autocorrelation to minimum phase.

11.3.4 3D Grid Define

The seismic data was then mapped into a 3D grid coordinate system (primary and secondary ordinals). Grid Data Traces are assigned to cells (CMP) in the 3D grid based on their midpoint XY locations calculated from their source and receiver co-ordinates. With both lines as crooked as they are each line was placed on its own 3D grid. All surface consistent operations were performed on the 3D grid. Prior to stacking, each line had a wide cell grid applied

11.3.4.1 L101 Parameters

- MG1 Corner Point X-Y values: 300500 734000
- MG2 Corner Point X-Y values: 273500 734000
- MG3 Corner Point X-Y values: 300500 730500
- MG4 Corner Point X-Y values: 273000 730500
- Inline / crossline cell sizes : 5 x 5 ft
- Inline / crossline increment: 1, 1
- MG1 Primary Ordinal: 1
- MG1 Secondary Ordinal: 1

Wide Grid

- Inline / crossline cell sizes : 5 x 10,000 ft
- Inline / crossline increment: 1, 1
- MG1 Primary Ordinal: 1
- MG1 Secondary Ordinal: 320

11.3.4.2 L301 Parameters

- MG1 Corner Point X-Y values: 286500 746500
- MG2 Corner Point X-Y values: 286500 723500
- MG3 Corner Point X-Y values: 293000 746500

- MG4 Corner Point X-Y values: 293000 723500
- Inline / crossline cell sizes : 5 x 5 ft
- Inline / crossline increment: 1, 1
- MG1 Primary Ordinal: 1
- MG1 Secondary Ordinal: 1

Wide Grid

- Inline / crossline cell sizes : 5 x 10,000 ft
- Inline / crossline increment: 1, 1
- MG1 Primary Ordinal: 1
- MG1 Secondary Ordinal: 345

11.3.5 Anomalous Amplitude Attenuation (AAA)

Anomalous Amplitude Attenuation (AAA) aims to attenuate random noise by transforming the processing gather into the frequency domain and applying a spatial median filter. Frequency bands that deviate from the median amplitude by a specified threshold are either zeroed, or replaced by good frequency bands interpolated from neighboring traces. AAA is often run across all frequency bands to attenuate any high-frequency noise spikes as well as low frequency swell noise.

11.3.5.1 Shot Domain Parameters

- Processing Domain: Shot
- Frequency Range (Hz): 0 - Nyquist
- Window length (msecs): 300
- Threshold Range: 16-30

11.3.6 FXCNS

FXCNS is an approach to coherent noise suppression for 3-D shot or receiver data that can handle irregular spatial sampling and noise variability. This is accomplished internally by azimuthally binning the data prior to filtering. Data organized in common azimuths are irregularly sampled 2-D lines radiating from the source. Each azimuth bin is filtered independently. Using frequency-space (f-x) domain fan filters and a least-squares optimization scheme, noise is locally estimated at each receiver for a specified range of apparent velocities. The least-squares estimate is performed for each frequency independently over a specified portion of the bandwidth. Five passes were run.

11.3.6.1 Parameters – First Pass

- Low stop velocity: 1600 ft/sec
- Low pass velocity: 1800 ft/sec
- High pass velocity: 8800 ft/sec
- High stop velocity: 9000 ft/sec

- Low cut frequency: 1 Hz.

- Low pass frequency: 5 Hz.
- High pass frequency: 20 Hz.
- High cut frequency: 23 Hz.

11.3.6.2 Parameters – Second Pass

- Low stop velocity: 2200 ft/sec
- Low pass velocity: 2400 ft/sec
- High pass velocity: 4500 ft/sec
- High stop velocity: 4700 ft/sec

- Low cut frequency: 1 Hz.
- Low pass frequency: 5 Hz.
- High pass frequency: 45 Hz.
- High cut frequency: 50 Hz.

11.3.6.3 Parameters – Third Pass

- Low stop velocity: 300 ft/sec
- Low pass velocity: 400 ft/sec
- High pass velocity: 1800 ft/sec
- High stop velocity: 2000 ft/sec

- Low cut frequency: 1 Hz.
- Low pass frequency: 5 Hz.
- High pass frequency: 100 Hz.
- High cut frequency: 110 Hz.

11.3.6.4 Parameters – Fourth Pass

- Low stop velocity: 2200 ft/sec
- Low pass velocity: 2500 ft/sec
- High pass velocity: 6700 ft/sec
- High stop velocity: 7000 ft/sec

- Low cut frequency: 1 Hz.
- Low pass frequency: 5 Hz.
- High pass frequency: 100 Hz.
- High cut frequency: 110 Hz.

11.3.6.5 Parameters – Fifth Pass

- Low stop velocity: 300 ft/sec
- Low pass velocity: 400 ft/sec
- High pass velocity: 1800 ft/sec

- High stop velocity: 2000 ft/sec

- Low cut frequency: 1 Hz.
- Low pass frequency: 5 Hz.
- High pass frequency: 100 Hz.
- High cut frequency: 110 Hz.

11.3.7 Anomalous Amplitude Attenuation (AAA)

11.3.7.1 Receiver Domain Parameters

- Processing Domain: Receiver
- Frequency Range (Hz): 0 - Nyquist
- Window length (msecs): 200, 300
- Threshold Range: 14-30

11.3.8 Surface Consistent Spectrally Constrained Deconvolution

Spiking deconvolution typically whitens all frequencies within the spectrum, whether they are signal or noise. Spectrally constrained predictive deconvolution, on the other hand, allows the user to suppress the whitening effects in portions of the spectra, so restricting the level of noise resulting from the deconvolution process (that is, it acts as a colored-light rather than a built-in white-light process).

Following the application of the constraining filter to the data, spiking surface-consistent deconvolution was applied to the data. Log power spectra were generated from a window of constrained seismic data. These spectra were then decomposed in a surface-consistent manner into source, detector, offset, and, optionally, midpoint components using the Gauss-Seidel method. The minimum-phase inverse filter for each component was calculated and the appropriate operators were applied to the un-constrained data.

11.3.8.1 Parameters

- Total operator length: 250 ms
- Prediction distance: 2 ms
- Percentage white noise: 0.01
- Frequency range of constraining filter: 6 – 100 Hz.
- Window Start Time: 200 ms
- Window Stop Time: 1210 ms
- Window move-out velocity 12,000 ft/sec

11.4 Datum Correction Application

The Datum Correction Application step applies time corrections to seismic data to move the data to a desired datum. All datum correction time-shift values are obtained from the trace headers of the input data

11.4.1 Surface Consistent Amplitude Compensation

SCAC compensates for shot, detector and offset amplitude variations that are caused by acquisition effects and are not a consequence of the subsurface geology.

The amplitude of a given time window is determined for every trace using either a root-mean-square (RMS) or a mean-absolute amplitude criterion. The amplitudes measured can then be expressed as the product of surface-consistent Source, Receiver and Offset terms, and a subsurface-consistent geology (CMP) term. Taking the logarithm allows the amplitude to be expressed as a sum of the above terms, which in turn, allows the surface consistent terms to be computed using a Gauss-Seidel iterative decomposition.

Scaling factors are then computed and applied to each trace. In this computation the CMP term is ignored, the scaling factor being the ratio of the geometric mean of all the SCAC Source, Receiver and Offset terms to the individual trace's Source, Receiver and Offset term.

11.4.1.1 Parameters

- Amplitude Criterion: RMS
- Analysis Time Window: 200 - 1210 ms
- Compute Terms: Source, Receiver, Offset
- Apply Terms: Source, Receiver

11.4.2 Anomalous Amplitude Attenuation (AAA)

11.4.2.1 Receiver Domain 2 Parameters

- Processing Domain: Receiver
- Frequency Range (Hz): 0 - Nyquist
- Window length (msecs): 120
- Threshold Range: 8-26

11.4.2.2 CMP Domain Parameters

- Processing Domain: CMP
- Frequency Range (Hz): 0 - Nyquist
- Window length (msecs): 300
- Threshold Range: 4-10

11.4.3 Velocity Analysis

Velocity analysis was performed using WesternGeco's Interactive Velocity Analysis (InVa) package which displays all the relevant information on an X-terminal controlled by a UNIX- based workstation. This is an integrated velocity interpretation and QC system. This package has been designed to handle both 2D and large 3D surveys effectively.

NMO processed CMP gather data were input to velocity analysis. From these data Multi-velocity Function (MVF) stacks and velocity semblance displays were computed. For each velocity location the gathers, MVF data and semblances are displayed in separate windows on the workstation. Changes made to one window are automatically applied to all other windows. Velocities can be picked from either the MVF or semblance display. When velocities are interpreted at a location a velocity database is updated and the CMP gather is displayed with the NMO correction. To aid velocity picking, x and y co-ordinate information for each velocity location was loaded to InVa. This enables all the picks within a user-defined radius to be superimposed on the display. This is especially beneficial in areas where lines intersect, to ensure consistency in the velocity interpretation.

After the velocities had been interpreted they were QC'd using a range of tools available in InVa, including iso-velocity displays and horizontal contours. Interpreted velocities were then used to generate a velocity model for subsequent processing.

11.4.3.1 Parameters

- Fan Functions :

Time (ms)	Velocity (% input velocity function)
0	1.5
1500	2
3000	3.5
5000	4.5

- Number of Fan Functions : 21
- Analysis Spacing : .5 mi
- Number of CMPs per Analysis (MVF Stack) : 17
- Number of CMPs per Analysis (Semblance Display) : 1

11.4.4 First Pass Residual Statics

Surface consistent reflection residual statics were calculated from pre-processed CDP gathers. The process is split into two phases - the first (termed XPERT) picks the time shifts for each pre-stack trace and the second (termed MISER) computes surface consistent statics from these picks.

In the XPERT program, one or more time and space variant gates that contain reflection events are defined. A model trace is generated by performing a rolling average of the stacked traces within the time gate and then for each CMP gather, un-stacked traces are cross-correlated with the model trace. The peaks of these cross-correlations are picked and the differential times between the peak time and the zero lag computed. These represent the sum of the residual shot and receiver statics plus any structural and residual moveout terms.

In the MISER (Modular Iterative Statics Evaluation Routine) program, an iterative Gauss-Seidel decomposition technique is used to derive the individual components of the time shift, that is, Source, Receiver, Midpoint and

Residual NMO terms. The static values for each trace are written into that trace's header so that they are available for subsequent processing.

11.4.4.1 Parameters

- Model Window: 350 - 1300 ms
- Maximum Correlation Shift: 16 ms
- Inline and Crossline Model Extent: A stack volume was input as an exterior model

11.4.5 Second Pass Residual Statics

11.4.5.1 Parameters

- Model Window: 500 - 1270 ms
- Maximum Correlation Shift: 12 ms
- Inline and Crossline Model Extent: A stack volume was input as an exterior model

11.4.6 Time Variant Filter Pre-Stack (TVF)

A zero-phase TVF (Time Variant Filter) was applied to the data. The filter passbands were described by low- and high-cut frequencies and associated dB/octave cutoff slopes. The specified cutoff frequencies are located at the half-power (-3 dB in amplitude) response points and the slopes at these frequencies are equal to the respective dB/octave values. The slope is an approximate cosine squared function in the amplitude domain. The filters were normalized so that the output amplitudes were the same as the input amplitudes for frequency components within the band-pass.

11.4.6.1 Parameters

High-Cut Frequency (Hz)	High Cutoff slope (dB/Oct)	Filter Center Time (ms)
90	60	800
70	52	1600
40	40	3000
30	35	5000

Note: The times are those at the centre of the filter where the full effect of the filter is attained. The first filter was applied from the beginning of the trace to the first filter centre time. Intermediate filters were linearly tapered and blended with the preceding and succeeding filter between the filter centre times. The last filter was applied from the last filter centre time to the end of the data

11.4.7 Band Pass Filter

A band-pass filter was described by low- and high-cut frequencies and associated dB/octave cutoff slopes. The specified cutoff frequencies are located at the half-power (-3 dB in amplitude) response points and the slopes at these frequencies are equal to the respective dB/octave values. The slope is an approximate cosine squared function in the amplitude domain. The filter was normalized so that output amplitudes were the same as input amplitudes for frequency components within the band-pass.

11.4.7.1 Parameters

- Phase — Zero phase
- Low-cut frequency / slope — 6 Hz, 18 dB/octave

11.4.8 Kirchhoff Post-stack Migration

The Kirchhoff migration software performs pre or post stack time migration using the Kirchhoff summation method. The migrated image is constructed by summing weighted amplitudes along diffraction curves or curved surfaces for the 3D case. These diffraction curves are determined by two-way travel times from the surface to subsurface scatterers that are computed from the user-supplied velocity field. The trajectory for the summation curve can either be computed using the traditional double square root equation ("DSR") or in a mode that comprehends "ray bending". Ray bending becomes significant with velocity fields that generally increase with depth and at larger reflection angles and dips (typically greater than 40 - 50 degrees).

Theoretical Basis

Kirchhoff migration is based on Green's theorem, a mathematical equation that states a relationship between the observations of a wave field on a closed surface and the wave field at any point inside that surface (see Schneider, W.A., 1978). The name of Gustav Kirchhoff is associated with the method because of his work in 1882 on optical diffraction. The formula for migration that is derived from Green's theorem has the form of an integral (or a summation in the case of discretely sampled data) over observations made on the surface of the earth. The migrated image calculated by that summation represents the acoustic reflectance throughout a section of the earth beneath the surface observations.

Key parameters to the migration process are the maximum dip angle, maximum aperture limit and spatial anti-aliasing factors. Kirchhoff migration typically provides a better migration solution when velocities vary laterally and temporally. A feature of Kirchhoff migration is the ability to define an output location, line or volume independently of the input data. This provides the means to input a full 3D volume and output selected lines or locations that are fully migrated. This target output option is useful particularly in 3D pre-stack mode, for efficiently running migration passes producing a data selection suitable for velocity analysis, prior to running a full migration outputting all desired final data. Under such circumstances, the process does not waste computing resources migrating those input traces that do not contribute to the output profile.

11.4.8.1 Parameter values

- Dip limits — Max dip 60 deg
- Input bin size — 5 x 10,000 ft
- Output bin size — 5 x 10,000 ft
- Anti-alias bin size — 5 x 10,000 ft
- Aperture — 12,000 ft

11.4.9 Zero Phasing Filter

A zero-phasing filter operator was designed from the source signature. The instrument response and receiver and gun ghosts were convolved with the source signature to design the target wavelet present in the data after the signature deconvolution. A zero-phasing operator was modeled to this target wavelet and convolved with the seismic data.

11.4.10 Residual Amplitude Analysis/Compensation (RAAC)

Where true-amplitude information needs to be retained in the data, the application of data dependent scaling is undesirable; yet the failure to apply scaling can result in data which is difficult to display due to the range of amplitudes (dynamic range) present. The RAAC process uses statistical means to retain anomalous amplitude information, such as bright spots, while allowing the data to be scaled.

The analysis step of RAAC computes, for each trace, the amplitudes of multiple windows using a RMS-amplitude criterion. The Residual Amplitude Compensation (RAC) value of each window is then the reciprocal of this computed amplitude. The centre of each time window defines the position of its associated RAC value. Knowing the X-Y location and time of each RAC value allows both spatial and temporal smoothing to be applied to the RAC values.

The application step of RAAC takes the smoothed RAC values, interpolates to every sample, and applies the resulting scalars to the input traces.

11.4.10.1 Parameters

- Number of Windows 1
- Analysis Window Start Start Time
- Window Length 1200 ms
- Window Advance 0
- Amplitude Analysis Type RMS
- Temporal Smoothing at Top of Data 0
- Temporal Smoothing at Bottom of Data 0
- Spatial Smoothing Width 0

11.4.11 Time to Depth

A time-velocity function from an external file is used to convert a seismic time section to depth.

11.5 Results and Conclusions

11.5.1 Summary

The initial objectives were:

- Produce a section suitable for structural interpretation
- Image any faults or fractures in the zone of interest (.5 - 1.2 s)

These two objectives were achieved.

11.6 WG Personnel

Manager:	Rick Kania
Team Manager:	Vera Lansky
Area Geophysicist:	John Gilbert
Team Leader:	Michael McClimans

Appendix 4.

Developing a CCS Regulatory Strategy for New York

Carbon Dioxide Capture and Sequestration: Developing a Regulatory Strategy for New York State

June 10, 2009

Prepared for:

John P. Martin, Ph.D.
Senior Project Manager

NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY (NYSERDA)

Prepared by:

ECOLOGY AND ENVIRONMENT, INC.
368 Pleasant View Drive
Lancaster, New York 14086

Agreement Number: 10498

NOTICE

ABSTRACT

Carbon Dioxide Capture and Sequestration: Developing a Regulatory Strategy for New York State

The reduction of CO_2 emissions through the development of CO_2 capture and sequestration (CCS) technology is a critical component in the international efforts to battle global climate change. New York State has assumed a leadership role in this effort. This report summarizes the legal, permitting, and policy challenges that New York must address as it develops one of the first comprehensive CCS regulatory programs in the country. Among other things, it identifies evolving legal and regulatory precedents in other jurisdictions; summarizes the currently legal, regulatory and permitting issues in New York that are applicable to the full range of CO_2 capture, transportation, injection and long-term storage activities; and outlines available options and strategies for developing a CCS regulatory program that addresses key implementation issues involving property rights, financial impacts, and regulatory oversight.

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SUMMARY

1.0 INTRODUCTION

Carbon dioxide (CO_2) is the leading human-made green house gas (GHG), and significant efforts are occurring around the world to reduce CO_2 emissions into the atmosphere. New York is actively engaged in these efforts, and among other things, is exploring the development and deployment of Carbon Capture and Sequestration (CCS) technology as an important part of its CO_2 reduction strategy. This report summarizes the legal, permitting, and policy challenges that New York must address as it develops one of the first comprehensive CCS regulatory programs in the country.

2.0 DEVELOPING CCS PROGRAMS AND COMMON LAW PRECEDENT

There are various federal and state statutory and regulatory precedents and other proposed model rules that apply or could be modified to apply to the capture, transportation, and sequestration of CO_2. Following is a summary of those initiatives. To better understand the regulatory and policy options described in this report and to provide proper context for the recommendations that follow, the three phase sequence of CCS activities developed by the Interstate Oil and Gas Compact Commission (IOGCC) is used:

- The Operational Period is defined as the 30- to 40-year period that a power plant or industrial facility is in an operational mode. Operations would include all of the three CCS activities enumerated above;
- The Closure Period is defined as an intervening period (e.g., 10 or 29 years) immediately following the cessation of active operations and the plugging of injection wells. Each state has the right to determine the duration of the closure period and during this period the state is able to conduct further site evaluations, assess potential liability concerns, and impose additional precautionary or mitigation measures; and
- The Post Closure Period is defined as the long-term caretaking period following closure. During this period necessary CCS monitoring, verification, remediation, and mitigation measures are implemented.

Proposed EPA Underground Injection Control (UIC) Rule for Class VI Wells

Due to the importance of providing a regulatory framework for CCS, on July 29, 2008, the United States Environmental Protection Agency (EPA) published a Notice of Proposed Rulemaking (NOPR). The NOPR outlines the minimum requirements that must be met by any person or corporate entity seeking to inject CO_2 into geologic formations for long-term storage. The NOPR was proposed pursuant to the Safe Drinking Water Act (SWDA), which is a federal statute that is focused on establishing requirements to protect the nation's underground sources of drinking water. Among other things, it creates a new class of CO_2 injection wells that are referred to as Class VI wells, and establishes the minimum requirements for the safe construction and operation of these wells. It also establishes an EPA permit program to ensure that these requirements will be implemented in a consistent and environmentally sound and responsible manner.

It is important to note that states can make a "primacy" application to the EPA to take a lead role in implementing the UIC CO_2 program discussed in this section. If the state is able to show that it can administer and implement the UIC program, it will be approved as a primacy state. New York has not chosen to become a primacy state, and instead has adopted a policy of consulting with the EPA and deferring to the EPA on UIC permit and implementation issues. Consistent with this policy, New York could choose to independently legislate and/or regulate underground injection activities so long as the program would not impinge on the UIC program administered by the EPA.

Illinois and Texas. During the competition for the FutureGen Project, the states of Illinois and Texas passed legislation that provided for the transfer of title to the injected CO_2 to the state or a state commission, at no cost, either at the time the CO_2 is captured (Texas) or at the time that is injected (Illinois). The legal effect of these statutes is significant: based on public policy considerations, these states will assume potential long-term liabilities that otherwise would fall on owners or operators of the project.

Other States. There are several states that are in the process of developing their own regulatory program for CO_2 sequestration. As of May, 2009, the states of Alaska, California, Kansas, Montana, New Mexico, Ohio, Oklahoma, Utah, Washington, and Wyoming have enacted statutes or regulations for CCS or are reviewing the issue with the intent to establish a regulatory program.

IOGCC

The IOGCC Task Force on Carbon Capture and Geologic Storage included representatives from IOGCC member states (including New York), international affiliate provinces, state, and provincial oil and gas agencies, DOE-sponsored Regional Carbon Sequestration Partnerships, the Association of American State Geologists and independent experts. Its 2007 Phase II report was the culmination of a two-phase, five-year effort.[1]

The Task Force Report produced a model legal and regulatory regime for the geologic storage of CO_2. Among its conclusions the Task Force found that control of the reservoir and associated pore space used for CO_2 storage is necessary to allow for the orderly development of a storage project. The Task Force determined that control of the necessary storage rights should be required as part of the initial storage site licensing process including the acquisition of these storage rights and use of state natural gas storage eminent domain powers or oil and gas integration processes to gain control of the entire storage reservoir.

A major issue confronted by the Task Force was how to deal with long-term monitoring and liability issues. The creation of an industry-funded and state-administered trust fund was recommended by the Task Force as the most effective and responsive "care-taker" program to provide the necessary oversight and long-term care during the Post Closure Period.

The Task Force also considered the best approach to regulating geologic storage activities. It concluded that the federal UIC Program may be applicable at the discretion of a state program, but limitations of the program make it applicable only to the operational phase of a storage project. Given the proposed long-term "care-taker" role of the states, IOGCC recommended that the states were in the best position to provide the "necessary 'cradle to grave' regulatory oversight of geologic storage of CO_2"[1] and proposed that the states assume long-term legal responsibility for the sequestration fields following an evaluation period of 10 years or more.

Common Law Precedent

There are a number of common law precedents that are relevant to the property right issues associated with CCS activities. Though the common law doctrines are not unique to New York and were not developed to specifically address CCS activities in New York, some are applicable to situations that could very well arise in New York, while others could prove helpful in articulating new common law principles that are well suited to address CCS issues in New York. Each of the common law precedents listed below are presented from this perspective and to the extent possible, relevant provisions of New York common law are integrated into the discussion.

- The American Rule on Mineral Estate;
- Trespass;
- Nuisance;
- Abnormally Dangerous Activity;
- Negligence and Negligence *Per Se*;
- The Negative Rule of Capture;
- Limitations on the Boundaries of Property Ownership;
- Insufficiency of Claims and Inadequacy of Proof; and
- The English Rule on Mineral Estates.

Application of New York Common Law to CCS

Although there are no reported cases in New York directly dealing with CCS, because state case law is consistent with the "American Rule" the surface owner of real property owns the subsurface areas directly below his property. Applying this approach to CO_2 injection, the surface owner controls the surface access to his property and his permission would be required before an injection well could be located on his property. Similarly, the person or entity seeking to inject the CO_2 would also have to get permission to do so not only from the surface owner, who also owns the pore space, but also the mineral estate owner; in many cases, these parties may not be the same person. In addition, it may be difficult to acquire the rights of the mineral interest owner, who may claim that the formation is not depleted of minerals. Even if the mineral estate owner agrees to give up his rights, the compensation amount for the acquisition of storage rights might have to include the value of any recoverable minerals in the space. Typically a lease would be negotiated between (1) the person or entity drilling the well or injecting the CO_2, and (2) the surface owner and/or the mineral estate owner. The purpose of any such lease would be to ensure surface access, pore space injection access, and storage rights. Many leases currently in place for oil and gas exploration and extraction may not be specific enough to grant ownership rights in the pore space suitable for CO_2 storage and, therefore, a separate lease between the CO_2 injector and the surface owner/mineral estate owner(s) would be required that explicitly conveys access and storage rights.

Further, in this type of situation, absent any statutory direction to the contrary, the surface and pore space owner(s) may be entitled to compensation and it is likely that the negotiated lease would also specify the compensation to be provided. In addition, because mineral rights in New York and most states are considered dominant to the rights of the surface owner or lessee, if the CCS activity were to adversely impact the mineral rights of a party seeking to extract oil or gas, the CCS operator may be potentially liable for trespass or nuisance claims and associated damages. It would, therefore, be prudent in such situations to negotiate access and establish a fair means to assess damage and pay compensation to owners of the mineral rights that are adversely impacted by CCS activities.

Regarding New York common law liability, the owner of real property is typically held responsible for any injuries that occur on his property, based on traditional owner liability statutes and case law. If we apply these New York common law principles to CCS activities, the surface and/or mineral estate pore space owners could be held liable for any resulting injuries or damage if CO_2 were to escape from the owner's property, under any number of legal theories, including owner liability, abnormally dangerous activity, negligence or negligence *per se*. Similarly, if mineral right owners of oil or gas deposits are adversely impacted by the CO_2 sequestration activity, the mineral owners also would be entitled to hold the surface and/or mineral estate pore space owners liable under the American Rule.

3.0 REGULATORY FRAMEWORK FOR CCS IN NEW YORK STATE

Though a number of federal and state statutes and regulations touch on various aspects of CCS activities, at this time no comprehensive, focused CCS regulatory program has yet been developed in New York. The report discusses the provisions of the following federal and state laws and how they could be adapted to develop a comprehensive CCS regulatory program in the future:

- New York State Environmental Quality Review Act. (SEQRA);
- National Environmental Policy Act (NEPA);
- NYS Environmental Conservation Law (ECL), Article 19;
- Regional Greenhouse Gas Initiative (RGGI);
- Federal Clean Air Act;
- Federal Underground Injection Control (UIC) Program;
- Federal Resource Conservation and Recovery Act (RCRA);
- Federal Comprehensive Environmental Response Compensation and Liability Act (CERCLA);
- NYS Oil, Gas, and Solution Mining Law (OGL; codified as ECL, Article 23); and
- NYS Public Service Law.

4.0 POLICY ISSUES AFFECTING CCS IMPLEMENTATION IN NEW YORK STATE

A number of public policy issues should be addressed when establishing a CCS regulatory framework in New York State. To a large extent, how these critical policy issues are resolved will have a significant impact on the timely deployment of CCS technology in New York.

A number of precedents in New York State that are relevant to the development of a CCS regulatory framework are discussed in this section of the report, including Article 7 (electric and gas transmission siting) and Article 10 (energy facility siting-currently lapsed) of the Public Service Law, Title 5 (Environmental Restoration Projects) of the Clean Water/Clean Air Bond Act of 1996; Title 23 (Oil and Gas Exploration), Title 13 (State Superfund), and Title 14 (Brownfield Cleanup Projects) of Article 27 of the ECL; and the System Benefits Charge (SBC), Renewable Portfolio Standard (RPS) and Energy Efficiency Portfolio Standard (EEPS) orders of the Public Service Commission.

The uncertainty of successful development and the financial risk involved in undertaking a CCS demonstration project has deterred both the public and private sector from moving forward on any significant CCS projects in the United States. Complicating this potentially daunting financial and liability risk associated with the application of any new technology is the massive scale of infrastructure that CCS will require. To address these concerns a number of state and federal statutes have been proposed or enacted, but overall the statutory and regulatory framework for CCS is underdeveloped and rarely extend beyond basic, first-order issues. To potential operators and investors, this translates to uncertainty, and uncertainty often means shepherding investment capital to safer pastures.

There are three primary policy issues and ancillary concerns requiring resolution by New York State policymakers:

- Property Rights
  - Due process, and
  - Pore space ownership and compensation;

- Financial Impacts
  - Liability and indemnification,
  - Financial responsibility, and
  - Cost of operating CCS projects in the absence of mandatory limits on CO_2; and

- Regulatory Oversight
  - CO_2 pipeline construction and operation,
  - Risk Assessment and Mitigation, and
  - Hydraulic Fracturing.

These issues and policy options are discussed in detail in Section 4 of the report.

5.0 CONCLUSIONS

For New York State to move forward with the in-state development of CCS technology, a regulatory framework will need to be developed that provides for the protection of public health and safety as well as the environment while at the same time providing predictability for CCS developers. In addition, a number of issues confronting the deployment of CCS in New York as outlined in this report will need to be addressed by public policymakers.

The following policy options should be considered:

- A comprehensive CCS regulatory program that considers relevant New York State statutory and common law precedents in the context of new regulations;

- A statutory scheme similar to those endorsed by Wyoming and the IOGCC Model rule, which address property rights issues by identifying the surface owners as having ownership of subsurface pore spaces below their properties;

- Identification and creation of a regulatory scheme informed by programs in analogous industries—waste disposal, gas storage and oil, and gas extraction;

- A regulatory framework that builds on existing OGL natural gas extraction and storage programs that define spacing units to identify production areas boundaries; utilize an integration process to identify ownership interests with access and the injection rights; establish procedures to facilitate mineral storage in reservoir areas and buffer zones; utilize a unitization process to maximize mineral extraction efficiency; establish due process safeguards; establish minimum control thresholds of mineral ownership interests before state permits can be filed by project sponsors; and establish appropriate regulatory procedures (e.g., compulsory integration and eminent domain) that allow pore space owners to earn fair compensation for the use of their property;

- A detailed review of other statutes to identify those that should be amended to address CCS projects. For example, ECL §23-030, Declaration of Policy, is often cited as an appropriate rationale for legislation authorizing the extraction of oil and gas, underground storage of gas, solution mining of salt, and installation of brine disposal wells and geothermal and stratigraphic wells. It may prove helpful to amend the OGL statute to include CCS;

- The development of a fair and rational approach to providing compensation for access and use of surface lands for drilling and injection purposes, and the use of underlying pore spaces for CO_2 sequestration; and

- The development of new state and federal laws that use other proposed or existing laws as models. Illinois and Texas enacted statutes that address CO_2 ownership and liability issues and similar laws can be drafted in New York for "Early Movers," as an incentive to invest in CCS activities. Similarly, precedents from other jurisdictions can be used to limit rights to ownership and compensation, as appropriate.

In addition, it is well documented that CCS will add significant costs to power plant projects that could be so prohibitive as to prevent their commercial development and deployment. Some of the cost barriers to the implementation of a CCS program in New York include the following, regardless of whether the CCS is associated with a "Green-field" or retrofit project:

- Highly site-specific costs, varying from less than US $0.50 to more than US $30 per ton of avoided CO_2 capture and sequestration;
- Energy consumption to capture, compress, and sequester CO_2;
- Current lack of market incentives or regulatory certainty;
- Lack of knowledge about available and potential capacity of subsurface rock formations and long-term geographic sequestration suitability; and
- Difficulties associated with matching large CO_2 sources with suitable sequestration reservoirs and the inability to optimize an associated sequestration repository network.

While financial incentives can stimulate the demonstration of CCS, such incentives will not be enough to drive the widespread commercialization of these technologies unless the liability issues are addressed. Special consideration should be given to the "early movers" willing to engage in the first CCS demonstration projects as CCS regulatory programs develop, because they are the ones that will bear the greatest financial liability and technical risk and their successful development of these initial projects is critical for widespread, accelerated CCS project deployment.

Because of the important role that the private sector will play on CCS projects, it is important that public and private partnerships be encouraged by the CCS regulatory program. Both parties must be able to agree on the importance of sharing risk and to find a way to strike a balance between the risks that currently loom large, and the future goals and objectives that both are committed to achieve. The best use of incentives will require flexibility with respect to a range of terms and conditions. A single project may require more than one incentive, depending on the nature and importance of the risks the project faces and the capacity of a project's sponsors to manage them. If we are to meet the global climate change challenge before us, government agencies and private entities must be able to consider and accept a range of alternative approaches to address different risks and achieve their respective goals.

The creation of a CCS Early Deployment Fund could play an important role in helping to reduce uncertainty about budget cycles and provide consistent, large-scale funding to enable critical early deployments of fully integrated CCS projects. Such a fund would help accelerate the deployment of CCS by: (a) covering the additional cost of CCS technologies, (b) protecting the ratepayers of the community(ies) hosting the first CCS projects, and (c) addressing the full range of CCS liability issues. Projects, not generating electric power, that use petroleum coke or other fossil fuels to produce energy, could also qualify for CCS incentives if they are able to commit to comparable, large-scale CCS activities.[1]

The CCS challenges facing New York are clearly stated in the *Operating Plan for Investments in New York under the CO_2 Budget Trading Program and the CO_2 Allowance Auction Program:*

> Given the level of sophistication of current and emerging power generation technologies, carbon capture and sequestration are the only means now available to permit continuing use of fossil fuels without releasing climate-changing GHGs into the atmosphere. Current U.S. DOE estimates put New York's onshore sequestration potential at more than three billion tons of CO_2, enough capacity to eliminate all of the state's power plant-generated emissions for nearly 50 years. By capturing and sequestering the lifetime emissions from one 600-megawatt integrated gasification combined-cycle power plant, the release into the atmosphere of more than 150 million tons of CO_2 could be avoided. Before these benefits can be realized, however, capture technologies need to advance and site-specific geological research needs to be conducted to determine the best methods and locations to sequester CO_2. Projects funded through this program will focus on assessing and demonstrating carbon capture, reuse, compression, and transport technologies, characterizing and testing the state's geological sequestration potential, and supporting development of carbon capture and sequestration demonstration projects in New York.

Section 1.0
INTRODUCTION

Carbon dioxide (CO_2) is the leading human-made green house gas (GHG) and significant efforts are occurring around the world to reduce CO_2 emissions into the atmosphere. New York is actively engaged in these efforts, and among other things, is exploring the development and deployment of Carbon Capture and Sequestration (CCS) technology as an important part of its CO_2 reduction strategy. The New York State Energy Research and Development Authority (NYSERDA) is participating in several research projects related to CCS through the Environmental Monitoring, Evaluation, and Protection Program (EMEP). In addition, New York recently joined the United States Department of Energy's (DOE's) Midwest Regional Carbon Sequestration Partnership as a member state and has convened a CCS working group, which includes scientists and other experts from the New York State Department of Environmental Conservation (NYSDEC), the Department of Public Service, NYSERDA, New York State Museum, New York Power Authority (NYPA), Empire State Development Corporation, the Office of the Attorney General, and the Office of the Governor. The working group has taken responsibility for assessing the feasibility of CCS in the state, advancing a regulatory framework, and implementing a statewide public outreach program.

CCS projects proposed in New York include Jamestown BPU Oxy-Coal in Jamestown, New York; Lackawanna Clean Energy, in Lackawanna, New York; and NRG Integrated Gasification Combined Cycle (IGCC) in North Tonawanda, New York. On June 6, 2008, Governor Paterson announced his support of the Jamestown BPU Oxy-Coal Project. In announcing his support, the governor stated:

> "There is no silver bullet to solving the twin threats of climate change and growing energy demand, and New York should have a comprehensive strategy to address both…As a state and a nation we need to be less dependent on foreign energy supplies. China is building one new, uncontrolled coal plant every week. Therefore, we must act immediately to find ways to generate electricity, use energy wisely, maintain energy diversity, and create jobs locally. This comprehensive strategy has the potential to drive technology and innovation, improve our energy security, reduce energy price volatility, and create clean-tech jobs throughout the state, particularly upstate.[1]"

As part the state's efforts to take on a leadership role in the successful deployment of CCS, NYSERDA has contracted with Ecology and Environment, Inc. (E & E), an international environmental consulting firm headquartered in western New York, to identify and evaluate different technical, legal, and regulatory issues that that have the potential to impact the development of CCS demonstration and commercial projects in New York. One of the specific tasks assigned to E & E is summarized in the following work scope description:

An Initial Permitting Strategy Report will be written for use by the regulatory agencies for CO_2 transportation and sequestration in general and for specific permitting. The report shall include a permitting roadmap to guide applicants through the permitting process for CO_2 transportation and sequestration. This report shall summarize information and model indemnification agreements from the oil and gas industry as well as the nuclear power industry. The report shall develop guidelines for the liability and ownership risks associated with the sequestration of CO_2.[2]

1.1 REPORT OBJECTIVES AND ORGANIZATION

In anticipation of the preparation of this report, four work groups, made up of members of the key CCS stakeholders in New York State (NYS), as well as public and private sector experts, were convened to address three critical CCS issues, together with a number of ancillary issues under each category:

- Property Rights
  - Due process, and
  - Pore space ownership and compensation;

- Financial Impacts
  - Liability and indemnification,
  - Financial responsibility, and
  - Cost of operating CCS projects in the absence of mandatory limits on CO_2; and

- Regulatory Oversight
  - CO_2 pipeline construction and operation,
  - Risk assessment and mitigation, and
  - Hydraulic fracturing.

The development of a CCS regulatory program that addresses these issues is critical to the deployment of CCS technology in NYS. The discussion and recommendations contained in this report were informed by the deliberations of these work groups and their significant contribution. E & E acknowledges its profound gratitude and thanks to all of those involved for their time and input. Appendix A provides a list of members participating in the work groups. Appendix B provides copies of the policy papers produced by the work groups.

The research conducted by E & E that is reflected in this report focuses on the three primary public policy issues referenced above and provides guidance on a number of options that appear to offer the greatest promise to effectively address these issues. In developing its options and recommendations, E & E has assumed that the successful deployment of CCS projects will require the state to provide a predictable regulatory process that both ensures the protection of the public health and the environment and clearly identifies specific measures that will ensure the timely implementation of this technology. By developing such a process, NYS will encourage the development of CCS technology and CCS projects throughout the state and allow NYS to maintain its prominent leadership role in the climate change arena.

Section 2 of the report identifies various federal and state statutory and regulatory precedents and other proposed model rules that apply or could be modified to apply to the capture, transportation, and sequestration of CO_2.

Section 3 discusses the existing statutory and regulatory framework for CCS in NYS. A permitting roadmap that describes the process for permitting a CCS project under current laws and regulations is provided as Appendix C.

Section 4 identifies issues and recommendations that NYS policy makers should consider, including statutory and regulatory actions, in order to foster the development of CCS in New York in a manner that protects the environment and health of its residents.

Section 5 provides a summary of the conclusions outlined in the report.

1.2 DESCRIPTION OF CARBON CAPTURE AND SEQUESTRATION

CCS represents one approach to reduce GHGs in the atmosphere and address global climate change concerns. It is typically associated with a CO_2 emission source that can be captured, such as a power plant or an industrial facility that generates power from the combustion of fossil fuels.

CCS consists of three primary activities: (1) the collection and concentration of the CO_2 produced at industrial facilities or energy generating power plants; (2) its transportation to a suitable storage location; and (3) the injection of CO_2 into deep subsurface repositories and indefinite long-term storage where it will be "sequestered" from the atmosphere. Because of the expense associated with implementing these CCS activities, as described below, CCS is often employed on new plant construction or retrofit projects where the required capture technologies required can be more readily integrated into existing operations. Figure 1 provides a schematic highlighting the three primary CCS activities that are involved in a CCS project, to frame the issues discussed in this report.

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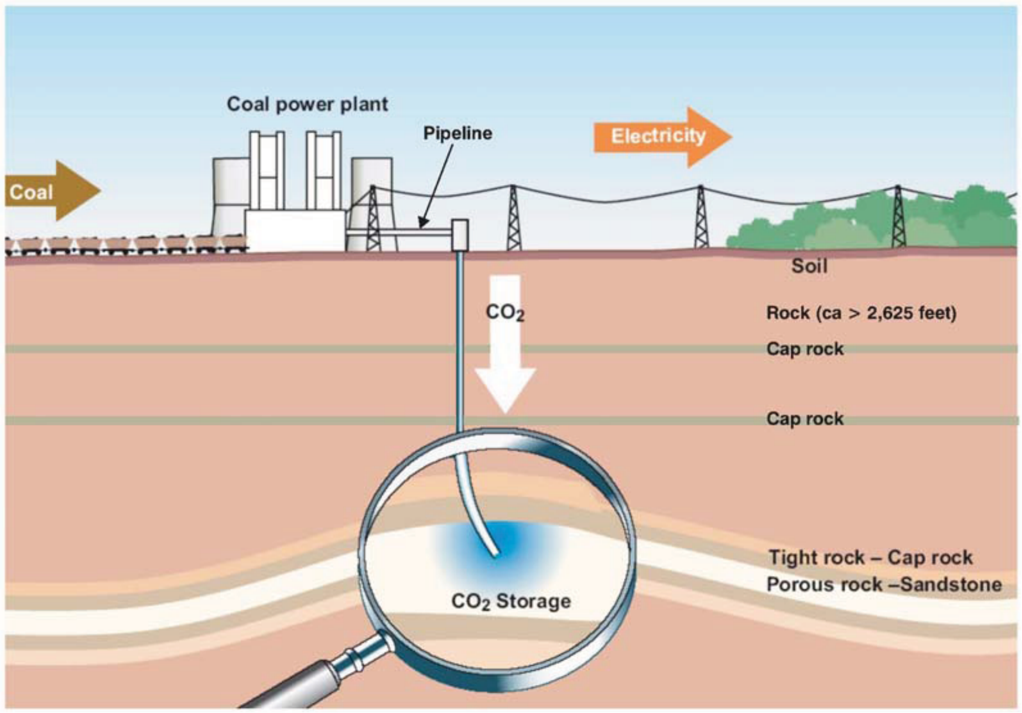

Operational Period (30-40 yrs)
- Capture, Compression
- Pipeline Transfer
- Injection
- Injection Well Plugging

Closure Period (10-29 yrs)
- Site Assessment
- Integrity Evaluation
- Liability Analysis
- Mitigation Programs

Post Closure Period (Indefinite)
- Storage
- Long term Monitoring

Figure 1 Carbon Dioxide Capture and Sequestration (CCS) Process Overview

To better understand the regulatory options outlined in this report, it is useful to understand the general time sequence during which the various CCS activities are likely to be implemented. For this purpose, we have adopted the three-phase sequence developed by the Interstate Oil and Gas Compact Commission (IOGCC) and incorporated in their model rule discussed in Section 2.4 of this report:

- The Operational Period is defined as the 30 to 40-year period that a power plant or industrial facility is in an operational mode. Operations would include all of the three CCS activities enumerated above;

- The Closure Period is defined as an intervening period (e.g., 10 to 29 years) immediately following the cessation of active operations and the plugging of injection wells. Each state has the right to determine the duration of the closure period and during this period the state is able to conduct further site evaluations, assess potential liability concerns, and impose additional precautionary or mitigation measures; and

- The Post Closure Period is defined as the long-term caretaking period following closure. During this period necessary CCS monitoring, verification, remediation, and mitigation measures are implemented.

Because power plants are one of the largest sources of CO_2, the first efforts around the country to employ CCS technology have focused on these facilities. Power plant emissions typically consist of no more than 14% CO_2. The relatively low CO_2 concentration requires significant additional processing to increase the concentration and enable cost effective capture, compression, and transport. Capture and compression processes increase CO_2 concentrations significantly, up to 80 to 90% depending on the capture mechanism. The CO_2 capture equipment requires a significant amount of electricity to operate and reduces the overall efficiency of power generation. The DOE estimates that the operating costs associated with operating a CCS project increase by 30%[3] over the costs of operating a conventional pulverized coal power plant, with much of these increased costs attributable to the additional power required (which is commonly referred to as "parasitic power") to operate carbon capture and compression equipment, such as oxygen separators, gasifiers, compressors, and injection systems. Nearly 80% of the increased cost of CCS is associated with CO_2 capture with the remaining 20% tied to transportation, injection, long-term sequestration, and post closure monitoring and verification.[4]

The CO_2 stream is maintained at pressures greater than 1,000 pounds per square inch (psi) and is converted to a supercritical fluid that can be transported like a liquid. Pipelines are the most common method that will be used for transporting large quantities of CO_2 over long distances at commercial scale and large pilot facilities. CO_2 pipelines are operated at ambient temperature and high pressure, with primary compressor stations located where the CO_2 is captured or injected and booster compressors located as needed farther along the pipeline. In overall construction, CO_2 pipelines are similar to natural gas pipelines, requiring the same attention to design, monitoring for leaks, and protection against overpressure.

The design of CO_2 injection systems is based on technologies that have been developed and refined by the oil and gas and chemical manufacturing industries over the past several decades. The CO_2 is injected to depths greater than 2,625 feet, such that a sufficiently high pressure and temperature would be maintained to keep the CO_2 in a supercritical state. CO_2 is sequestered by a combination of trapping mechanisms, including physical and geochemical processes. In the case of saline water bearing formations, which constitute the most suitable subsurface repositories for sequestration in New York, the CO_2 is trapped in the pore spaces of sandstone and carbonate rock formations. Provided the formations will accept the CO_2, it is anticipated that these saline formations will have adequate porosity to permanently store the entire volume of CO_2 generated during the operating life of a power plant emission source.

1.3 FEDERAL INVOLVEMENT

The federal DOE has undertaken a comprehensive program to encourage the research and development of CCS under its Fossil Energy program (see http://fossil.energy.gov/programs/powersystems/cleancoal/index.html). Nationally, the FutureGen project is the most prominently recognized proposed CCS project in the country. Though DOE funding and support is uncertain, the FutureGen project continues to move forward. If this project is implemented, the proposed site location will be in Mattoon, Illinois. In addition, the DOE has formed a nationwide network of regional partnerships to help determine the best approaches for capturing and permanently storing gases that can contribute to global climate change. The Regional Carbon Sequestration Partnerships are implementing pilot-scale CCS projects at selected power plants. The interest in CCS generated by these projects has already led a number of policymaking bodies to evaluate legal and regulatory issues that present challenges for CSS projects and consistent program implementation.[5]

Section 2.0
DEVELOPING CCS PROGRAMS AND COMMON LAW PRECENDENT

Set forth in this section are various federal and state statutory and regulatory precedents and other proposed model rules that apply or could be modified to apply to the capture, transportation, and sequestration of CO_2.

2.1 PROPOSED EPA UNDERGROUND INJECTION CONTROL (UIC) RULE FOR CLASS VI WELLS

Due to the importance of providing a regulatory framework for CCS, on July 29, 2008, the United States Environmental Protection Agency (EPA) published a Notice of Proposed Rulemaking (NOPR). The NOPR outlines the minimum requirements that must be met by any person or corporate entity seeking to inject CO_2 into geologic formations for long-term storage. The NOPR was proposed pursuant to the Safe Drinking Water Act (SWDA), which is a federal statute that is focused on establishing requirements to protect the nation's underground sources of drinking water.

The NOPR adds new provisions to the existing Underground Injection Control (UIC) regulatory program, since that program regulates the underground injection of most fluids, including liquids and gases, and therefore is well suited to regulate the injection of CO_2 for long-term, commercial-scale geologic sequestration. Among other things, it creates a new class of CO_2 injection wells that are referred to as Class VI wells, and establishes the minimum requirements for the safe construction and operation of these wells. It also establishes an EPA permit program to ensure that these requirements will be implemented in a consistent and environmentally sound and responsible manner.

The elements of the NOPR build upon the existing UIC regulatory framework, with modifications based on the unique nature of CO_2 injection for sequestration. The NOPR requires that there be geological site characterization to ensure that sequestration wells are appropriately sited, including a requirement that an "injection zone be of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream" and that the confining zone be "free of transmissive faults and fractures." The NOPR establishes requirements for well construction to ensure that injectate-compatible materials are utilized and that the wells are constructed in a manner that prevents fluid movement into unintended zones. Periodic (at minimum every 10 years and potentially more often) re-evaluation of the area of review around the injection well using computer modeling is required to incorporate monitoring and operational data and to verify that the CO_2 moves as predicted within the subsurface formations.

The NOPR sets out requirements for testing of the mechanical integrity of the injection well, ground water monitoring, and tracking of the location of the injected CO_2 to ensure protection of underground sources of drinking water. Extended post-injection monitoring and site care to track the location of the injected CO_2 and monitor subsurface pressures is required.

Important elements of the NOPR are EPA's proposed requirements for post-injection site care and financial assurance for operation of CO_2 injection wells. As part of their initial application, parties will be required to submit a post-injection site care and a site closure plan, which then will be subject to updates and periodic review requirements. Further, the owner or operator ultimately will be required to maintain post-injection site care measures for a 50-year period. This requirement could be shortened upon a finding that movement of a CO_2 plume has ceased and the injectate does not pose a risk to underground drinking water sources or lengthened if plume behavior is not as predicted. Further, owners or operators will be required to demonstrate and maintain financial responsibility for closure and remediation of a sequestration site. The NOPR includes the general requirement for maintenance of financial assurances to assure that funds will be available for well plugging, site care, closure, and emergency and remedial response. The EPA proposes that Class VI injection well permits would be issued for the operating life of the geologic sequestration project, which would include the proposed 50-year post-injection site care period. It is anticipated that these permits will be reviewed at least once every five years in accordance with the current practice relating to Class II and III wells under the UIC program.[6]

While the UIC NOPR is a first step to providing regulatory structure, there are, however, significant unresolved regulatory issues. The NOPR is only a proposed rule, and has not yet been finalized. The NOPR provides only certain minimal standards and general guidance; specific guidance will be developed after gaining case-by-case permit experience. There are a varieties of areas where the UIC NOPR provides general guidance but little in the way of specifics for a number of issues, including siting criteria, area of review, well construction, monitoring and well-plugging, and post-injection capping. Though this lack of specificity may have been intentional to allow sufficient flexibility to allow states that are familiar with the latter issues to exercise jurisdiction, the EPA also recognizes in the NOPR that anticipated Demonstration Projects funded by DOE will become a source of additional data "to support a decision in the Final Rule."

Under the EPA UIC proposal to establish the new Class VI CO_2 injection well program, CO_2 supercritical mixtures will be required to exclude hazardous wastes. It will be the responsibility of the owners and operators to characterize their individual CO_2 stream as part of the permit application and confirm that the injectate does not contain hazardous wastes, as defined in 40 CFR Part 261. If the injectate is determined to contain hazardous wastes, as defined and regulated under the Resource Conservation and Recovery Act (RCRA), then the more stringent UIC Class I requirements apply for injection of hazardous wastes. Hazardous waste disposal wells are regulated under the Safe Drinking Water Act (SDWA) and RCRA (see Section 3.1.4.1 of this report for discussion of RCRA and the state waste program) and will likely continue to be regulated under delegated state waste programs in New York when this program is finalized.[7]

It is important to note that states can make a "primacy" application to the EPA to take a lead role in the implementation of the UIC CO_2 program discussed in this section. If the state is able to show that it can administer and implement the UIC program, it will be approved as a primacy state. The EPA is aware that some primacy states are actively engaged in the process of developing their own regulatory frameworks for CO_2 sequestration. In some cases, these frameworks include capture, transportation, and injection requirements. It is important to note that states wishing to obtain UIC primacy status will need to promulgate regulations that are at least as stringent as those that will ultimately be finalized by the EPA when the UIC proposed rules are finalized. New York has not chosen to become a primacy state, and instead has adopted a policy of consulting with the EPA and deferring to the EPA on UIC permit and implementation issues. Consistent with this policy, New York could choose to independently legislate and/or regulate underground injection activities so long as the program would not impinge on the UIC program administered by the EPA. If it were to do so and establish well construction, CO_2 injection and long-term CO_2 monitoring and sequestration requirements also covered by the UIC program, as well as other CCS issues that are typically addressed by state law, this would require applicants seeking permits to inject CO_2 to adhere to the requirements of both the federal UIC and state CCS programs.[8]

2.2 ILLINOIS AND TEXAS

During the competition for the FutureGen Project, the states of Illinois and Texas passed legislation that provided for the transfer of title to the injected CO_2 to the state or a state commission, at no cost, either at the time the CO_2 is captured (Texas)[9] or at the time that is injected (Illinois).[10] The legal effect of these statutes is significant: based on public policy considerations, these states will assume potential long-term liabilities that otherwise would fall on owners or operators of the project. For purposes of this report, long-term liabilities are intended to refer to all potential legal claims for damages that could result from CO_2 releases to the surface or migration of the sequestered CO_2 in underground geologic formations.

More specifically, the Texas legislation passed in 2007 provides that Texas is to assume title to the CO_2 and that the owner and operator of the project will be relieved of liability for any act or omission related to the CO_2 injection location and the means of the CO_2 injection if the owner or operator complied with the terms and requirements of the issued injection permit. The law, however, does exclude from the scope of this liability exemption, "any liability for personal injury or death that results from construction of the site, or drilling or operation of the injection wells."

In 2007, Illinois passed similar liability protection legislation so as to be in a better position to compete with Texas for the FutureGen project. It specifically requires the state to indemnify and defend the operator from "public liability" actions (not separately covered by insurance), defined as civil liability arising out of the storage, escape, release, or migration of the sequestered gas, but excluding liability resulting from construction (which presumably would exclude all claims resulting from construction, regardless of whether the construction occurs before the injection or after the injection and, therefore, would exclude liability resulting from well drilling activities, such as replugging, remediation, restoration, etc.), operation, or other pre-injection activity. The only limits on the state's indemnity of the operator for public liability actions are losses resulting from: intentional or willful misconduct by the operator; the operator's failure to comply with applicable state or federal laws, rules, or regulations for the carbon capture and storage of the sequestered gas; or "pre-injection operation of the FutureGen project," which would include losses, such as those associated with capture, transportation, and pre-injection drilling activities (e.g., replugging, remediation, restoration). Illinois also agreed to pay for the cost of liability insurance associated with FutureGen and requires that those funds be expended before the state indemnity will be triggered; further, the statute provides that if federal indemnification is provided in the future, the state indemnification will be reduced proportionately.

The Illinois Attorney General, subject to timely notice, is required to defend actions against the FutureGen Alliance; if the Attorney General is conflicted, private counsel could be hired and the state would pay reasonable fees. The legislation provides for streamlined permitting and establishes state court jurisdiction for actions related to liability. The Illinois incentives package also included a $17 million direct grant from the Illinois Coal Development Fund, an estimated $15 million sales tax exemption on materials and equipment purchased through local enterprise zones, and $50 million for below-market rate loans through state finance agencies.

Further discussion of these statutory provisions and recommendations regarding the applicability of this approach in New York, are provided in Section 4 of this report.

2.3 OTHER STATES

There are several states that are in the process of developing their own regulatory program for CO_2 sequestration. As of May 5, 2009, the states of Alaska, California, Kansas, Montana, New Mexico, Ohio, Oklahoma, Utah, Washington, and Wyoming have either enacted statutes and regulations for CCS or are reviewing the issue with the intent to establish a regulatory program. A few of these state programs are summarized below to provide insight into how the various state programs are evolving.

2.3.1 New Mexico

In New Mexico, the governor issued Executive Order 2006-69 mandating seven executive agencies to implement 20 strategies for reducing GHG emissions in New Mexico. The agencies include the New Mexico Environment Department (NMED), Energy Minerals and Natural Resources Department (EMNRD), General Services Department (GSD), the Department of Transportation (DOT), Regulation and Licensing Department (RLD), the Department of Tax and Revenue (TRD), the Department of Finance and Administration (DFA) and the Department of Agriculture (DOA). The executive order creates a state government implementation team tasked with ensuring policies from the order are carried out.[11]

2.3.2 Wyoming

In March 2008, Wyoming became the first state to pass legislation addressing the issue of pore space ownership. Together with provisions enacted in early 2009, it has developed a fairly comprehensive CCS regulatory framework. In sum, the Wyoming statutes specify that ownership of all pore space in all strata below the surface lands and waters of the state is vested in the several owners of the surface above the strata. Any conveyance of the surface ownership includes the pore space below. Ownership of the pore space can be severed from the surface rights similar to how mineral rights can be severed, but such interest must be specifically conveyed with the associated rights to use the surface space and described in detail. Existing mineral rights are not affected by the statute and the injector of CO_2 is responsible for its long-term management. A more detailed discussion of the Wyoming statutory provisions follow.

House Bill 90 (enacted 2008; codified as W.S. 30-5-501 and 35-11-313) deals with landowner rights, albeit in a broad fashion. The statute requires state carbon sequestration permits to be obtained and permit applicants must demonstrate that they have “all legal rights, including but not limited to the right to surface use, necessary to sequester carbon dioxide and associated constituents into the proposed geologic sequestration site.” Further, applicants must, among other requirements, provide proof of notice to surface owners, mineral claimants, mineral owners, lessees, and other owners of record of the project and provide further notice within 30 days of when any excursion of CO_2 is discovered.

House Bill 89 (enacted 2008; codified as W.S. 34-1-152 and 34-1-202(e)) addresses the ownership of pore space. The law establishes that pore space is owned by the surface owner. In addition, a conveyance of the surface ownership constitutes a conveyance in all strata below the surface unless the ownership interest in the pore space has been previously conveyed or is explicitly excluded. Further, transfers of pore space after July 1, 2008 are null and void at the option of the owner of the surface if the transfer document does not contain a specific description of the pore space being transferred. The law does not affect the common law related to mineral estate dominance.

In February, 2009, House Bill 57 (codified as W.S. 34-1-152(e)) amended the provision relating to mineral deposit rights that was enacted the prior year, to clarify that mineral deposits constitute the dominant estate and if sequestration activities adversely impact mineral extraction activity, compensation will be owed to the mineral owner. This approach is a restatement of the general, mainstream approach currently referred to as the “American Rule,” which is consistent with the common law in New York (see Section 2.5.1 of this report).

A second provision enacted in 2009, referred to as House Bill 58 (codified as W.S. 34-1-153), addresses CO_2 injectate ownership and liability issues. This provision makes it clear that all CO_2 and other substances that are injected into any geologic sequestration site for the purpose of geologic sequestration, are presumed to be owned by the injector of such material and all rights, benefits, burdens, and liabilities of such ownership shall belong to the injector. Though not clearly stated, the implication of this new provision appears to be that Wyoming is distinguishing between pore space ownership and CO_2 ownership: it contemplates that the CCS injector must negotiate storage rights (which presumably would include some form of compensation) with the pore space owners (i.e., parties owning surface property above the pore spaces repositories or parties granted mineral rights that are broad enough to include pore space where CO_2 is to be sequestered) and that once this is done and the CO_2 is injected, the injector assumes long-term liability for the stored CO_2.

2.3.3 Montana

In November 2008 the DOE awarded $66.9 million, through its Regional Carbon Sequestration Partnership Program, to the Big Sky Regional Sequestration Partnership to conduct a large-volume test in the Nugget Sandstone formation to demonstrate the ability of a geologic formation to safely, permanently and economically store more than two million tons of CO_2.[12]

Montana is currently considering new legislation (passed by Montana senate on March 23, 2009) that establishes a CCS legal framework. It will make the project sponsor liable for CO_2 during the operating life and for a period of 20 years following closure, and contemplates that the state will take ownership 20 years following closure and be responsible for long-term post closure care.

2.3.4 Oklahoma

Despite a proposed bill, which would have required the development of a CCS permitting regime, the transfer of well ownership to the state, and a release from liability 10 years after closure; the version of the bill that became law only mandated a task force to the governor that was to provide permitting guidelines by December 2008.

2.3.5 Washington

In 2008 the state of Washington amended its laws regarding Class V wells to provide for specific requirements for wells used to inject CO_2 for permanent geologic sequestration. The legislation addressed a multitude of issues including geologic sequestration well standards and permit application requirements including the submittal of a map showing the boundaries of the project calculated to include an area containing 95% of the injected CO_2 mass 100 years after completion or the plume boundary at the point in time when expansion is less than 1% per year, whichever is greater or another method approved by the department.

Still, no provisions were included regarding pore space ownership or requirements to obtain surface and subsurface rights.[13]

Options and recommendations for the application of some of the foregoing regulatory approaches and initiatives, to a proposed New York regulatory framework are presented in Section 4.2 of this report.

2.4 INTERSTATE OIL AND GAS COMPACT COMMISSION (IOGCC)

In July of 2002, the IOGCC, with sponsorship from the DOE, convened a meeting of state regulators and state geologists. The purpose of the meeting was to decide whether oil and natural gas producing states, and in particular the oil and natural gas regulatory agencies in these states, might be able to play a meaningful role in the of sequestration of CO_2. The IOGCC established a Task Force on Carbon Capture and Geologic Storage, which included representatives from IOGCC member states (including New York), international affiliate provinces, state, and provincial oil and gas agencies, DOE-sponsored Regional Carbon Sequestration Partnerships, the Association of American State Geologists, and independent experts. The Task Force began an examination of the technical, policy, and regulatory issues related to the safe and effective storage of CO_2 in subsurface geological media (oil and natural gas fields, coal seams, and deep saline formations) for both enhanced hydrocarbon recovery and long-term CO_2 storage. Its 2007 Phase II report was the culmination of a two-phase, five-year effort.[14]

The Task Force Report produced a model legal and regulatory regime for the geologic storage of CO_2. Among its conclusions the Task Force found that control of the reservoir and associated pore space used for CO_2 storage is necessary to allow for the orderly development of a storage project. Therefore, the Task Force determined that control of the necessary storage rights should be required as part of the initial storage site licensing process. Its Model General Rules and Regulations proposes the required acquisition of these storage rights and contemplates use of state natural gas storage eminent domain powers or oil and gas unitization processes to gain control of the entire storage reservoir.

A major issue confronted by the Task Force was how to deal with long-term monitoring and liability issues. The creation of an industry-funded and state-administered trust fund was recommended by the Task Force as the most effective and responsive "care-taker" program to provide the necessary oversight and long-term care during the Post Closure Period.

The Task Force also considered the best approach to regulating geologic storage activities. It concluded that the federal UIC Program may be applicable at the discretion of a state program, but that limitations of the program make it applicable only to the operational phase of a storage project. Given the proposed long-term "care-taker" role of the states, IOGCC recommended that the states were in the best position to provide the "necessary 'cradle to grave' regulatory oversight of geologic storage of CO_2"[15] and proposed that the states assume long-term legal responsibility for the sequestration fields following a 10-year evaluation period.

Specific IOGCC recommendations follow:

- Following the Operational and Closure Periods, the storage operator will be released from liability. More specifically, the proposed IOGCC model rule provides that the state regulatory agency is required to issue a Certificate of Completion of Injection Operations, when active operations cease and a showing is made by the storage operator that the reservoir is reasonably expected to retain mechanical integrity and remain emplaced; once this is done, ownership to the remaining project including the stored CO_2 transfers to the state. After the Certificate of Completion of Injection Operations is issued, the operator and all generators of any injected CO_2 is released from all further state regulatory agency liability associated with the project. In addition, upon the issuance of the Certificate of Completion of Injection Operations, any performance bonds posted by the operator are released and continued monitoring of the site, including remediation of any well leakage, become the responsibility of the Carbon Dioxide Storage Facility Trust Fund.

- State agencies are granted authorization to enter into cooperative agreements with other governments or government entities for the purpose of regulating CO_2 storage projects that extend beyond state regulatory authority under the statute.

- After the Operational and Closure Periods expire, the state assumes liability for the stored CO_2.

- A CCS Trust Fund is established to address liabilities arising during the Post Closure Period. The Trust Fund is to be used, solely for the long-term monitoring of the site during the caretaker period after active operations cease and closure activities are completed. CCS Trust Fund monies are used to implement a variety of activities including, monitoring of the remaining surface facilities and wells, remediation of mechanical problems associated with remaining wells and surface infrastructure, repairing mechanical leaks at the site, plugging and abandoning remaining wells under the jurisdiction of the state regulatory agency for use as observation wells, and addressing third-party liability concerns should they arise. The model rule contemplates that the Trust Fund will be funded by a tax or fee on each ton of CO_2 injected for storage.

Options and recommendations regarding the application of these approaches to a proposed New York regulatory framework are provided in Section 4.2, 4.3, and 4.4 of this report.

2.5 COMMON LAW PRECEDENT

Set forth below is a general discussion of common law precedents that may have some bearing on the property right issues associated with CCS activities. Though the common law doctrines discussed below are not unique to New York and were not developed to specifically address CCS activities in New York, some are applicable to situations that could very well arise in New York, while others could prove helpful in articulating new common law principles that are well suited to address CCS issues in New York. Each of the common law precedents discussed below are presented from this perspective and to the extent possible, relevant provisions of New York common law are integrated into the discussion. Section 2.5.10 provides a summary of the various common law precedents and focuses specifically on how these precedents could be applied to address CCS in the state.

The common law discussion set forth in this section is intended to provide a legal basis and public policy rationale for limiting the scope of the regulatory program options set forth in Section 4 of the report. Additional detail on the common law principles that are discussed below are set forth in the Liability Work Group policy paper contained in Appendix B.

2.5.1 The American Rule on Mineral Estates

Most states have adopted the "American Rule" on mineral estates. Under this common law doctrine, the surface owner of real property owns the subsurface areas directly below his property. A surface owner may sever his mineral rights (i.e., rights to oil, gas, salt, or other minerals) but unless clearly and specifically stated otherwise in the conveyance, it is presumed that the surface owner retains ownership of the subsurface formation. In the case of a severed mineral estate, the surface owner's interest in the subsurface space is subject to the rights of the mineral owner. The mineral owner has exclusive use of the subsurface space until the mineral deposit has been exhausted or abandoned. As stated earlier, the CCS statute enacted in Wyoming, which is discussed in Section 2.3.2 of this report, is consistent with the American Rule.

New York case law is also consistent with the American Rule. The surface owner in New York may sever his mineral rights to oil, gas, salt and other minerals, and storage rights, provided that the conveyance of these rights clearly and specifically states the owner's intent to sever those interests; if he fails to do so, it will be presumed that the surface owner retains ownership of the subsurface formation.[16] It is also the case in New York, that if a mineral estate is severed, the surface owner's interest in the subsurface space is subject to the rights of the mineral owner and the mineral owner has exclusive use of the subsurface space until the mineral deposit has been exhausted or abandoned.[17]

To round out the discussion on mineral estates, the minority or "English Rule" is discussed in Section 2.5.9 of this report.

2.5.2 Trespass

Unauthorized entry onto another person's property may give rise to a claim of trespass by the property owner. In a CCS situation, if a party engaged in the drilling of an injection well were to rely solely on a UIC permit to justify the drilling of an injection well and injecting CO_2 in subsurface geological formations, by doing so that party may be vulnerable to a claim of trespass because the UIC permit does not convey property rights to the party granted the permit. The property owner raising such claim would likely base his claim on the trespassing party's failure to obtain owner consent. If this were the case, the trespassing party could also be held liable for monetary damages. These might include claims for damages for the diminution of property value; and/or damages equivalent to the costs necessary to restore damaged property.

Trespass claims of this type are authorized in New York if the trespass is intentional. Though in the case Phillips v. Sun Oil, 307 NY 328 (1954), the court dismissed a claim of trespass involving the leakage of gas from underground storage tanks into the drinking well of neighboring property, the court implied in dictum, that such a claim would be upheld if the trespassing party had "good reason to know or expect the subterranean and other conditions were such that there would be passage from defendant's to plaintiff's land."

Notably, the courts in several other states have held that a trespass is not even actionable in the absence of documented damage. For example, in the much anticipated decision of Coastal Oil & Gas v. Garza Energy, 05-0466, (Texas 2008), the Texas Supreme Court recently overturned a claim of trespass. The claim stemmed from the hydrofracing of a gas well, which resulted in the fracturing of the subsurface of the plaintiff's adjoining property. Plaintiff's sole claim of damages was for lost natural gas, which was drained from his property into the defendant's well. The Texas high court held that the rule of capture (i.e., a doctrine in Texas that allows the owner of an oil or gas well to "capture" what it is able to withdraw, without paying compensation to surface owners above the oil or gas reservoirs) precluded any damages and in the absence of damages, the trespass claim also fails.

2.5.3 Nuisance

Nuisance is the unreasonable interference with the enjoyment of one's property. Unreasonable interference and damages must be proven. A nuisance claim could arise from migrating or leaking CO_2 that adversely impacts nearby soil, surface water, groundwater, minerals, other resources, or human health. Nuisance claims are typically remedied through an injunction (a court order commanding or forbidding a party from taking an action) or monetary damages for property damage. In the case of CCS, an order to halt CO_2 injection could result.

2.5.4 Abnormally Dangerous Activity

The common law doctrine of strict liability allows for liability even where the defendant did not intend to interfere with a legally protected interest or did not act unreasonably or breach any duty of care in causing the harm.

An activity is "abnormally dangerous" and thus subject to strict liability based on a judicial balancing of several factors, some of which may make it more difficult for a plaintiff to establish strict liability for the release of stored CO_2.[18] In New York, the factors to be weighed include the following: (1) the existence of a high degree of risk of some harm to the person, chattel, or lands of others; (2) likelihood that the harm that will result from the activity will be great; (3) inability to eliminate the risk of harm by the exercise of reasonable care; (4) the extent to which the activity is not a matter of common usage; (5) the inappropriateness of the activity to the place where it is carried on; and (6) the extent to which the value of the activity to the community is outweighed by its dangerous attributes.[19]

Some examples of abnormally dangerous activities in New York include disposal of hazardous wastes at a landfill site,[20] hydraulic dredging and landfilling,[21] and allowing corroding tanks to hold significant quantities of hazardous waste.[22] In addition, the New York's Navigation Law, provides a cause of action for harm to public health and the environment for the release of petroleum or oil that contaminated groundwater.[23]

Whether courts will find the long-term storage of CO_2 associated with CCS to be subject to strict liability under the above enumerated criteria is unknown.

2.5.5 Negligence and Negligence *Per Se*

Plaintiffs can also establish negligence by traditional means or by employing a theory of negligence *per se*. Under negligence *per se*, a plaintiff can establish negligence if he or she can show that the defendant violated a statute or regulation designed to protect against the type of accident the actor's conduct causes and if the accident victim is within the class of persons the statute was designed to protect.[24] Plaintiffs harmed by stored CO_2 could look to violations of standards, such as the UIC regulations, to assert claims of negligence *per se* to obtain traditional common law relief that includes compensatory damages, punitive damages, and injunctive relief. For the UIC regulations, courts will have to address whether the regulations are limited to protecting drinking water impacts, or can also be used to set the standard of care for other harms.[25]

2.5.6 The Negative Rule of Capture

This rule provides that just as an owner may capture such oil or gas that migrates from adjoining property to a well on his own land under the "rule of capture," the converse is authorized as well. Under the "negative rule of capture" he is similarly authorized to inject substance into a geologic formation, even though those substances might migrate to the property of others. Under this rule, permission need only be sought from the owner(s) of the surface and subsurface of the land where the injection well is physically located. The consent of owners of land above the subsurface formation is not necessary, as they have no legal standing. Moreover, liability for migration of injected substances is virtually eliminated in exchange for public policy preferences that are supportive of the rule. In Texas, one of the public policies used to justify this rule is the encouragement of enhanced oil and gas recovery through the injection of CO_2. It is possible that in other jurisdictions, the public policy of encouraging carbon sequestration to mitigate climate change could be used as the justification for applying this rule.

It should be noted, however, that the negative rule of capture is not widely adopted; in addition, the case law in some states has resulted in limitations being placed on the rule even where it had been followed in the past. To date, this rule has not been applied in New York.

2.5.7 Limitations on the Boundaries of Property Ownership

An ancient Latin maxim of property law, *cujus est solum, ejus est usque ad coelum et ad inferos*, provides that "[t]o whomsoever the soil belongs, he owns also to the sky and to the depths." This doctrine has been modified by modern courts, including the United States Supreme Court, which concluded that the notion that land ownership extends infinitely upward, "had no place in the modern world" given the advent of air flight. Similarly, some courts have limited the depth to which subsurface rights exist in light of modern day of disposal wells.[26] The "center of the earth to the heavens" approach has also been limited by the public trust doctrine, which has been utilized to protect navigable waterways and tidal areas for the common use of the public.

If courts were to impose such "public trust" limitations on the boundaries of traditional property rights to conform with the complexities of the modern world, the injection and/or migration of CO_2 at deep depths or significant distances from the injections site, arguably would not violate any viable property rights and could significantly limit claims for compensation.

2.5.8 Insufficiency of Claims and Inadequacy of Proof

A CO_2 injection operator may attempt to defend a common law claim for damages based on the theory that the plaintiff's legal claim is legally insufficient or that the plaintiff is unable to provide adequate proof of ownership or damage.

Under common law doctrines in many jurisdictions, plaintiff landowners alleging injury must first prove that have an interest in the allegedly affected property. Further, landowners bear the legal burden and cost of proving a physical invasion -- that CO_2 from a specific project did in fact migrate to their properties and that its source was that of the project. Physical proof of migration may be difficult, given the depth of the injections, elapsed time, and the difficulty associated with gathering accurate geologic data. Further, admissible proof must often come in the form of experts hired to develop complex theoretical models that are normally developed after much expense and rest on assumptions that are likely to be subjected to extensive cross-examination.[27]

Landowners also bear the burden of proving that they were damaged. One prominent issue is whether subsurface voids have any legally recognized value. Under common law cases decided in New York, pore space may not have any recoverable value to a landowner absent a reasonably foreseeable expectation of using the deep pore spaces at the time of the invasion.[28] As the CCS industry develops, suitable pore space may be in higher demand with resultant recognition of market value, but until such a market value develops, it may prove difficult to support a claim for damages and claims for pore space damage could be summarily dismissed without trial or allow recovery for nominal amounts. As a practical matter, the potential of recovering only nominal damages may make the pursuit of claims cost prohibitive and/or simply unattractive to plaintiff attorneys. Further, in New York, Section 214 of the Civil Practice Law and Rules (CPLR) imposes a relatively short three-year statute of limitations for property damage claims, which may further reduce the likelihood that common law claims for CCS property damage pose a significant litigation risk. Nevertheless, it should be noted that if the injury is considered "latent," New York law allows the statute of limitations to be extended to three years from the date of actual discovery or the date that such discovery should have occurred. [29]

2.5.9 The English Rule on Mineral Estates

In contrast to the American Rule, which is discussed in Section 2.5.1, a minority of states hold that the mineral rights estate owns the geologic storage formation and pore space.[30] This view has been endorsed by the authors of an oft-cited oil and gas legal treatise:

> [The severance of the mineral estate from the surface estate] should be construed as granting exclusive rights to the subterranean strata for all purposes relating to minerals, whether 'native' or 'injected', absent contrary language in the instrument severing such minerals.[31]

The English Rule has not been adopted in New York.

2.5.10 Application of New York Common Law to CCS

The following discussion integrates the common law precedents in New York discussed in the preceding sections and evaluates how they could be applied to address CCS in the state.

Although there are no reported cases in New York directly dealing with CCS, because state case law is consistent with the "American Rule," the surface owner of real property owns the subsurface areas directly below his property. Applying this approach to CO_2 injection, the surface owner controls the surface access to his property and his permission would be required before an injection well can be located on his property. Similarly, the person or entity seeking to inject the CO_2 would also have to get permission to do so not only from the surface owner, who also owns the pore space, but also the mineral interest owner, which may not be the same person. It may be difficult to acquire the rights of the mineral interest owner, who may claim that the formation is not depleted of minerals. Even if the mineral interest owner agrees to give up his rights, the compensation amount for the acquisition of storage rights might have to include the value of any recoverable minerals in the space. Typically a lease would be negotiated between (1) the person or entity drilling the well or injecting the CO_2, and (2) the surface owner; the purpose of any such lease would be to ensure surface access, pore space injection access, and storage rights. Many leases currently in place for oil and gas exploration and extraction may not be specific enough to grant ownership rights in the pore space suitable for CO_2 storage, and therefore a separate storage lease between the surface owner and the CO_2 injector, explicitly conveying such rights, would be necessary.

Further, in this type of situation, absent any statutory direction to the contrary, the surface and pore space owner(s) may be entitled to compensation and it is likely that the negotiated lease would also specify the compensation to be provided. In addition, because mineral rights in New York and most states are considered dominant to the rights of the surface owner or lessee, if the CCS activity were to adversely impact the mineral rights of a party seeking to extract oil or gas, the CCS operator may be potentially liable for trespass (see Section 2.5.2) or nuisance claims (see Section 2.5.3) and associated damages. It would therefore be prudent in such situations to negotiate access and establish a fair means to assess damage and pay compensation to owners of the mineral rights that are adversely impacted by CCS activities.

Regarding New York common law liability, the owner of real property is typically held responsible for any injuries that occur on his property, based on traditional owner liability statutes and case law.[32] If we apply these New York common law principles to CCS activities, the surface and/or pore space owners could be held liable for any resulting injuries or damage if CO_2 were to escape from the owner's property, under any number of legal theories, including owner liability, abnormally dangerous activity (see Section 2.5.4), negligence or negligence *per se*. Similarly, if mineral right owners of oil or gas deposits are adversely impacted by the CO_2 sequestration activity, the mineral owner also would be entitled to hold the surface and/or pore space owner liable in accordance with the American Rule discussed above.

Options and recommendations for incorporating common law principles into a proposed CCS regulatory framework addressing pore space ownership, compensation, and liability issues are provided in Sections 4.2.1 and 4.2.2 of this report.

Section 3.0
REGULATORY FRAMEWORK FOR CCS IN NEW YORK STATE

Though a number of federal and state statutes and regulations touch on various aspects of CCS activities, at this time, no comprehensive, focused CCS regulatory program has yet been developed in New York.

Set forth in Section 3.1, is a description of those aspects of existing or proposed laws and regulations that play a role in the regulation of CCS activities in New York or that could play a role in regulating such activities in the future.

Section 4 completes the regulatory analysis by identifying the most significant policy issues that are not addressed by the existing regulatory framework, and proposing options to convert the patchwork of regulatory programs described in Sections 2 and 3 of this report, into a comprehensive CCS program for the state.

3.1 EXISTING ENVIRONMENTAL LAWS AND REGULATIONS GOVERNING CCS

This section provides a review of existing laws and regulations that are relevant to the development of a regulatory framework for CCS activities. In conducting this review, E & E has applied its best professional judgment and attempted to provide an objective and even-handed review of the legal concepts and concerns. That being said, E & E is mindful that all will not necessarily agree with the various legal interpretations and conclusions that follow and we welcome a dialogue on these matters so that the final CCS regulatory framework that is developed in New York will be robust and properly focused.

3.1.1 Environmental Review

3.1.1.1 State Environmental Quality Review Act. New York's State Environmental Quality Review Act (SEQRA) requires all state and local government agencies to consider environmental impacts during discretionary decision-making. This means these agencies must assess the environmental significance of all actions they have discretion to approve, fund, or directly undertake. SEQRA requires proponents of different types of "actions" to assess the environmental, social, and economic impacts that could result therefrom, as part of the permit approval process in New York. A project that could have significant environmental impacts is likely to constitute an "action" that triggers the SEQRA process and the preparation of an environmental impact statement (EIS).

The purposes of SEQRA are to identify environmental concerns associated with those projects; examine reasonable alternatives to avoid, reduce, or mitigate associated adverse environmental impacts; and establish appropriate permit conditions and mitigation measures that will protect human health and the environment to the maximum extent practicable. The SEQRA decision-making process encourages communication among government agencies, project sponsors, and the general public.

SEQRA is the state equivalent of the federal National Environmental Policy Act (NEPA). Once the SEQRA process is triggered, a coordinated review to assess environmental impacts is required. One of the state or local agencies from which a project approval is required is designated as the lead agency and that agency is responsible for evaluating project impacts in accordance with the requirements of SEQRA. The lead agency may either issue a negative declaration, or require a preparation of an Environmental Impact Statement (EIS;if there is a potential for a significant impact). The scope of the EIS must include all components of the project for which the approvals are required (i.e., capture, transport, and sequestration). If an EIS has been prepared under NEPA, a state agency has no obligation to prepare a separate EIS under SEQRA.

Because of the broad applicability of SEQRA, state regulatory agencies are able to evaluate all aspects of a CCS project, identify issues requiring attention, and impose permit conditions that will protect public health and the environment. NYSDEC has recently proposed regulatory guidance requiring that an EIS include a discussion of energy use or GHG emissions when it is the lead agency.[33] Other state or local agencies will likely consider this guidance when serving as lead agency.

It should be noted that, by its very nature, SEQRA provides a case-specific project evaluation and does not establish a coherent regulatory framework that addresses the broader policy issues raised in Section 4 of this report.

3.1.1.2 National Environmental Policy Act (NEPA). NEPA is the federal equivalent of SEQRA. If "major federal actions" are required (e.g., federal permit approvals under a federal statute) or federal funds are awarded for a particular project, NEPA requires federal agencies to integrate environmental values into their decision-making processes by considering the project's environmental impacts and identifying reasonable alternatives. In the case of a CCS project, NEPA compliance could be triggered by the issuance of a federal permit (e.g., a UIC permit) or the approval of a DOE Energy Clean Coal Power Initiative grants or loan guarantee for a CCS project. Because these programs are new, it is not well settled as to what specific NEPA compliance activities will be required; NEPA requirements could range from the preparation of an environmental questionnaire (which is currently required in the DOE CCPI grant application), to the development of a federal environmental impact statement. In the past, when New York has encountered situations where NEPA compliance has been triggered and these requirements are deemed by the New York lead agency to overlap with SEQRA requirements, the New York lead agency has either deferred to the federal NEPA process or worked with the lead federal agency to conduct a coordinated state/federal environmental impact review process.

It should be noted that NEPA has the same case-specific limitations as SEQRA that are not conducive to addressing broad CCS public policy issues in a comprehensive, consistent manner.

3.1.2 Air

3.1.2.1 Article 19 ECL. No NYS law or regulation currently requires CO_2 to be captured or sequestered. NYSDEC has taken the position that the existing statutory authority under Article 19 of the Environmental Conservation Law (ECL) is broad enough to allow the state to regulate CO_2. It is important to note, however, that initial NYSDEC regulatory efforts to regulate CO_2 are currently being challenged in court.[34]

Proposed limits on CO_2 emissions are being developed by NYSDEC. When promulgated, these regulations will likely be implemented throughout the state through the issuance of facility specific air permits. The draft emission standards will apply to fixed facilities emitting large volumes of CO_2, such as power plants and large industrial boilers.[35] State and federal proposed statutory initiatives suggest that these efforts are likely to be expanded to cover other CO_2 emission sources as appropriate.

3.1.2.2 Regional Greenhouse Gas Initiative (RGGI). In addition, the state of New York is a signatory to the Regional Greenhouse Gas Initiative (RGGI). RGGI is a cooperative effort by 10 Northeast and Mid-Atlantic states (i.e., New York, Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, Rhode Island, and Vermont) to limit GHG emissions via a cap-and-trade program. RGGI is the first mandatory, market-based CO_2 emissions reduction program in the United States. These 10 states will cap CO_2 emissions from the power sector, and then require a 10% reduction in these emissions by 2018.

RGGI is composed of individual CO_2 budget trading programs in each of the 10 participating states. These 10 programs are implemented through state regulations, based on a RGGI Model Rule, and are linked through CO_2 allowance reciprocity. Regulated power plants will be able to purchase CO_2 allowances issued by any of the 10 participating states to demonstrate compliance with the state program governing their facility. Taken together, the 10 individual state programs will function as a single regional compliance market for carbon emissions. It should be noted that the allowance price is being set by regularly scheduled auctions and the proceeds raised by New York will be managed by NYSERDA. The RGGI Operating Plan[36] is currently being finalized that will specify how RGGI allowance proceeds can be spent. Among other things, the plan is likely to allow a portion of these proceeds to be awarded to CCS projects. The draft plan states:

Projects funded through this program will focus on assessing and demonstrating carbon capture, reuse, compression, and transport technologies, characterizing and testing the state's geological sequestration potential, and supporting development of carbon capture and sequestration demonstration projects in New York. [37]

RGGI uses a phased approach so that reductions in the CO_2 cap will initially be modest, providing predictable market signals and regulatory certainty. Electricity generators will be able to plan for and invest in lower-carbon alternatives and avoid dramatic electricity price impacts.

New York's RGGI program has been implemented by regulations promulgated by NYSDEC and NYSERDA.[38] The first compliance period for each state's linked CO_2 Budget Trading Program began on January 1, 2009.[39]

3.1.2.3 Federal Clean Air Act. Under the Clean Air Act (CAA), in the 1990 Clean Air Act Amendments, Congress added Section 112(r) requiring owners and operators of "stationary sources" to identify hazards, and prevent and minimize the effects of accidental releases wherever extremely hazardous substances are present at their facility. Section 112(r) encompasses both the General Duty Clause of Section 112(r)(1) and the Risk Management Program (RMP) of Section 112(r)(7).

Because these Section 112(r) provisions are only applicable to stationary sources, such as power plants, it is possible that that these provisions do not extend to the regulation of underground injection wells. However, if we assume for purposes of discussion, that the General Duty Clause applies to any facility where extremely hazardous substances are present, it is necessary to further evaluate the requirements of both the General Duty Clause and as well as the RMP, since the RMP applies to a subset of these facilities where certain substances are determined to be present in quantities above a threshold level.

Regarding the General Duty Clause, this refers to the release of "extremely hazardous substances," but these substances are not defined in the statute. The EPA has adopted a broad interpretation of the term "extremely hazardous substances" that includes various lists of hazardous substances, toxic substances, and chemicals that it has identified in its regulations relating to the statute. Though CO_2 is not on any of these lists, by way of further guidance, the legislative history broadly describes the category as including any substance that has the capacity to cause death, injury, or property damage due to short-term exposure because of its toxicity, reactivity, flammability, volatility, or corrosivity. Pure CO_2, by itself, is not reactive, flammable, volatile, or corrosive. Still, the material safety data sheet for CO_2 provides toxicity information and, therefore, the possibility exists, though remote, that CO_2 could be considered toxic and subject to RMP requirements. This is likely an unintended consequence of the Section 112(r)(1) CCA provision and a clear exemption from General Duty requirements would be required to remove any uncertainty regarding the applicability of these requirements.

With regard to the RMP rule set forth at Section 112(r)7, this provision applies to facilities (both public and private) that manufacture, process, use, store, or otherwise handle hazardous air pollutants (HAP) at or above specified threshold quantities. The RMP is a regulatory program developed by the EPA, found at 40 CFR Part 68, which emphasizes hazard assessment, prevention, and response. Information on the RMP is available through The EPA's Chemical Emergency Preparedness and Prevention Office (CEPPO). There are 188 substances designated as HAPs for their effects on human health and ecosystems. CO_2 is not listed as one of 188 substances designated as HAPs.

The RMP rule requires all regulated facilities to prepare and execute a risk management program which contains the following elements:

- A hazard assessment to determine the consequences of worst-case scenario and other accidental release scenarios on public and environmental receptors and provide a summary of the facility's five-year accident history of accidental releases.

- An accidental release prevention program designed to detect, prevent, and minimize accidental releases.

- An emergency response program designed to deal with any accidental release in order to protect both human health and the environment.

- An RMP that summarizes the facility's risk management program and must be submitted to a central point that will be designated by the EPA. All RMPs will be made available to appropriate state and local agencies and the public.

In sum, it is unclear whether these provisions are directly applicable to CO_2 injection activities. Nonetheless, some of the approaches used in these programs to evaluate hazards and risks are relevant to the development of a CCS regulatory program and are further discussed in Section 4.3.1.3, Policy Options and Recommendations.

3.1.3 Water

UIC Program. CCS injection wells must be permitted pursuant to the federal UIC program of the SDWA. The SDWA provides the EPA with the authority to develop regulations to protect underground sources of drinking water, and as discussed in Section 2.1, the EPA does so via its UIC program. The UIC program currently establishes five classes of injection wells and sets minimal requirements for siting, testing, installing, operating, monitoring, reporting, and abandonment. The EPA has concluded that geologic sequestration of CO_2 through well injection meets the definition of "underground injection" of the SDWA, and CCS applications in several the EPA regions are currently being handled as Class V experimental injection wells.

See Section 2.1 of this report, regarding the proposed extension of the UIC program to create a new Class VI CO_2 injection well for the specific purpose of geologic sequestration.

Hydraulic Fracturing. Hydraulic fracturing is a "stimulation" technique used to increase the permeability of a geologic formation that may be appropriate in the development of geologic sequestration wells. Hydraulic fracturing is one form of stimulation. Acid treatment injection is another form of stimulation, used independently or in conjunction with hydraulic fracturing, in order to dissolve and enlarge pore spaces in carbonate bearing rocks and to clean carbonate based cement from well casing perforations. CO_2 or nitrogen may also be used as the hydraulic fluid to stimulate the geologic formation by causing fracturing.

In hydraulic fracturing, a "frac" fluid is pumped into the formation under high pressure and at a rate faster than the fluid can leak off into the rock, causing fractures typically in the vertical direction (specifically, the fractures occur along a plane perpendicular to the minimum compressive stress, which is typically in the horizontal direction). Because deep sedimentary rocks act in an elastic manner, the fractures induced by the frac fluid must be propped open. This is typically done by using a "proppant," such as sand that is added to the frac fluid once enough frac fluid has been injected to create a sufficiently wide fracture.[40]

Most of NYS's oil and gas bearing rocks are noted for their unusually low permeability and must be stimulated in order to produce.[41] It is estimated that as many as 90% of wells drilled in New York are hydraulically fractured.[42] Also, most new wells in NYS are cased along their entire length, with perforations across producing zones in order to prevent migration of water or gas between geologic layers.[43]

The environmental concern with high-volume hydraulic fracturing is primarily with regard to its potential impacts on water supplies and water quality. Specifically, the aspects of high-volume hydraulic fracturing identified in the Final Scope for Draft Supplemental Generic Environmental Impact Statement (DSGEIS)[44] are:

- Water withdrawals;
- Transportation of water to the site;
- Use of water additives;
- Requirements for proper handling of water and additives;
- Removal and disposition of spent fracturing fluid; and
- Potential impacts at sites with multiple wells.

This list is a reflection of concerns typically associated with standard hydraulic fracturing techniques. For example, impacts to groundwater can occur as a result of improper fluid handling, specifically when flow-back fluids are not properly contained, or where fluid collection pits are not properly lined, resulting in percolation into groundwater supplies. The potential for contamination of waterbearing groundwater formations is increased for shallower aquifers.[45] Based on evaluations conducted by NYSDEC to date, we have assumed for purposes of this report that such contamination is unlikely:

NYSDEC has no record of any documented instance of groundwater contamination caused by hydraulic fracturing for gas well development in New York, despite the use of this technology in thousands of wells across the state during the past 50 or more years (sic).[46]

3.1.4 Waste

For the purposes of this report, it is assumed that any captured, transported, or sequestered CO_2 material will consist primarily of CO_2 and advanced capture technologies will be used. Any contaminants captured and injected into the ground will contain constituents found in typical fossil fuel combustion air emissions and incompressible gases, including trace metals, oxides of sulfur, nitrogen, and argon. The extent to which waste laws apply to any of the contemplated CCS activities are addressed below.

3.1.4.1 Resource Conservation and Recovery Act (RCRA) and Article 27 ECL.

Solid Waste. RCRA and the delegated state solid waste program as provided in Article 27 of the Environmental Conservation Law and 6 New York Codes, Rules and Regulations (NYCRR) Part 360 sets forth applicable regulations for solid waste management facilities. These regulations establish solid waste disposal permit application requirements, recordkeeping requirements, and substantive operational requirements. In addition, owners of the waste or owners/operators of storage and disposal facilities can be held liable under Section 6973 of RCRA if those entities contribute to the handling of a RCRA-regulated waste that may present an imminent or substantial endangerment to human health or the environment.[47]

In addition, it is possible that CO_2 could meet the definition of solid waste as that term is defined in RCRA and the state solid waste regulations:

> The term "solid waste" means any garbage, refuse, sludge from a treatment plant, water supply treatment plant, or air pollution control facility and other discarded materials, including solid, liquid, semi-solid, or contained gaseous material, resulting from industrial, commercial, mining and agricultural operations, and from community activities…(42 USC 6903 (27) and 6 NYCRR 360-1.2).

CO_2 may not, however, be a waste if supercritical CO_2 is only being stored underground for later use, since RCRA does not regulate materials that are recycled, reclaimed or still useful. See 40 CFR Section 261.2 (2007). Also it should be noted that the EPA and NYSDEC have previously excluded a number of materials from the definition of solid waste, including certain oil and gas wastes. The EPA's rationale for excluding oil and gas waste from the definition was to "provide sufficient flexibility to consider costs and avoid the serious economic impacts that regulation would create" for industry.[48] It should be noted that if excluded from the definition of solid waste, it would also be excluded from the definition of hazardous waste.[49] Given the broad definition of solid waste, there is regulatory uncertainty in this area: unless CO_2 is specifically excluded from the federal and state definition of solid waste, there is a risk that it will meet the solid waste definition.

To address potential RCRA and state solid waste regulatory and liability concerns, adjustments to both the federal and state equivalent programs would be required. See Appendix B for a more in-depth review of liability concerns raised by RCRA and New York waste laws and Section 4.3 of this report.

Hazardous Waste. RCRA and the delegated NYS Part 370 series hazardous waste programs provide "cradle to grave" regulatory controls governing all aspects of hazardous waste generation, treatment, storage, and disposal. The trigger for the applicability of these regulatory requirements is whether the compound of concern qualifies as a hazardous waste as defined by statute and regulation: in order to qualify, it must be a solid waste that exhibits a specific hazardous characteristic, or be specifically listed.

A pure CO_2 stream is unlikely to qualify as a hazardous waste. CO_2 is not a listed hazardous waste and, because available CO_2 capture technologies are sufficiently advanced and flexible, it is assumed for purposes of this report, that the air control systems at the capture plants will remove contaminants and/or reduce contaminant levels so that the resulting CO_2 will not exhibit hazardous waste characteristics that otherwise would subject the CO_2 material to hazardous waste regulatory requirements. This conclusion regarding the inapplicability of the hazardous waste definition is reinforced by the exemption provided in Section 371.1(e)(2)(iv) and the analogous federal provision set forth at 40 CFR 261.4(b)4, which specifically excludes from hazardous waste regulation "fly ash waste, bottom ash waste, slag waste and flue gas emission control waste generated primarily from the combustion of coal and other fossil fuels." EPA's draft UIC rule discusses the potential corrosiveness of CO_2 in the presence of water. Injected CO_2 could be defined as hazardous since the combination of water and CO_2 can be corrosive. CO_2 mixed with water forms carbonic acid, which can corrode well materials and piping.

Corrosivity; along with ignitability, reactivity, or toxicity; is a characteristic that can define a waste stream or injectant as hazardous.

To address potential RCRA and state hazardous waste regulatory and liability concerns, adjustments to both the federal and state equivalent programs would be required. See Appendix B for a more in-depth review of liability concerns raised by RCRA and New York waste laws and Section 4.3 of this report. Since New York has been delegated authority to operate the RCRA program in New York, federal amendments of the RCRA statute and regulations would be required before the state conforming amendments could be made.

3.1.4.2 Comprehensive Environmental Recovery Compensation and Liability Act (CERCLA). Primary Comprehensive Environmental Recovery Compensation and Liability Act (CERCLA) liability results from "releases" of "hazardous substances" as those terms are defined at 42 USC 9601 (14) and 9602. Under 42 USC 9607, such a release can result in the joint, several, and strict liability of all persons engaged in the generation, transportation, or disposal of hazardous substances or the "arrangement" of the transportation or disposal of those substances. Fortunately, as indicated in the previous section of this report, because "pure" CO_2 is not likely to qualify as a RCRA hazardous waste, it would not qualify as a hazardous substance and, therefore, a release of CO_2 alone is unlikely to trigger primary CERCLA liability.

However, the presence of trace metals or other contaminants in the CO_2 injectate material could potentially trigger primary CERCLA liability. It should be noted in this regard that the EPA, in its proposed UIC rulemaking, (see Section 2.1 of this report) expressed this concern by suggesting that the presence of such contaminants in the injectate material could trigger CERCLA liability.[50] Nonetheless, there are a number of factors that would perhaps make it less likely to consider these trace contaminants as qualifying as hazardous substances:

- Court cases have determined that CERCLA liability may not result if the hazardous substances are sold as "useful products." Given the fact that CO_2 injectate has been routinely used for enhanced oil and gas recovery for over 30 years it could qualify as a "commodity" rather than a waste[51] and CERCLA liability may not apply;

- CCS permit conditions are likely to establish numerous safeguards to ensure that the CO_2 is permanently sequestered in a safe manner;

- CO_2 injection for enhanced oil recovery purposes has not raised any significant health and safety concerns; and

- Public policies favoring the development of CCS to address climate change concerns would be significantly undermined if primary CERCLA liability were to attach to CO_2 injectate material.

A final point is worth noting with respect to CERCLA liability in light of the recent United States Supreme Court case, Massachusetts v. the Environmental Protection Agency. Because that case specifically identifies CO_2 as an "air pollutant" under the federal CAA, it is possible that secondary liability for reimbursement of agency response costs under 42 USC 9604 of CERCLA, could result from the injection of CO_2 that would subject CCS generators, transporters, disposers and arrangers to claims for reimbursement of government clean-up costs. Though nowhere in that decision did the court determine that CO_2 is a pollutant for purposes of 42 USC 9604 of CERCLA, it remains a potential concern.[52]

In summary, while the risk of triggering CERCLA liability may be relatively small, uncertainty remains with regard to CERCLA liability and its implications for CCS activities. Furthermore, because CERCLA is a federal statute that raises significant legal concerns for the implementation of CCS activities throughout the nation, it is important to amend CERCLA on the federal level so that the issues discussed above in this section of the report are properly addressed. See Appendix B for a more in-depth review of liability concerns raised by CERCLA, and Section 4.3 of this report for recommendation to address CERCLA concerns.

3.1.5 Other Environmental Requirements

Set forth below are summaries of other existing or proposed laws, regulations and model rules that are relevant to the development of a CCS regulatory framework in New York.

3.1.5.1 NYS Oil, Gas, and Solution Mining Law. The NYS Oil, Gas, and Solution Mining Law (OGL) codified as Article 23 of the New York Environmental Conservation Law (ECL), grants NYSDEC the authority to regulate the drilling of oil and natural gas wells, solution mining wells, and the underground ,storage of natural gas, among other well types. Environmental policy objectives relevant to the development of oil and gas resources in New York are set forth in the OGL:

> It is hereby declared to be in the public interest to regulate the development, production and utilization of natural resources of oil and gas in this state in such a manner as will prevent waste; to authorize and to provide for the operation and development of oil and gas properties in such a manner that a greater ultimate recovery of oil and gas may be had, and that the correlative rights of all owners and the rights of all persons including landowners and the general public may be fully protected, and to provide in similar fashion for the underground storage of gas, the solution mining of salt and geothermal, stratigraphic and brine disposal wells (ECL §23-0301).

Under this program, NYSDEC administers a regulatory permitting program to mitigate potential environmental impacts associated with conducting drilling, mineral extraction and gas storage activities in the state. Some of the key provisions of the OGL that are relevant to the development of a CCS regulatory framework are summarized below.

Regarding the development of oil and gas reserves, pooling, and integration provisions provide NYSDEC with the statutory framework needed to maximize production, prevent waste and manage potentially difficult and contentious property ownership issues:

- A single well can drain an area that extends far beyond the boundaries of the parcel where the drilling pad is located. If such is the case, land may be pooled or combined with adjacent lands into a "spacing unit" until enough is held by the well operator to satisfy state rules and regulations regarding well spacing. The dimensions of the spacing unit are determined by OGL criteria, based on the geologic formation and/or the depth of the mineral "pool;" the largest of the specified spacing units is 640 acres, which is roughly 1 square mile in size. See ECL §23-0501.

- The OGL specifies that NYSDEC is the designated state regulatory agency charged with the approval of all spacing units (ECL §23-0501). NYSDEC also has authority to review and approve pooled oil and gas reserves if requested by interested persons (ECL §23-0701). Among other things, by providing NYSDEC the authority to review and approve spacing units and voluntary pooling agreements, NYSDEC is able to protect the correlative rights of holders of mineral rights in the spacing unit. If a mineral rights holder owns rights in the spacing unit, then he or she is entitled to receive the benefits (working interest share or royalties) of drilling in that spacing unit. If the mineral rights owner enters into a lease, the royalty paid is based on the share he owns in the spacing unit. See ECL §23-501 and §23-0701, setting forth the statutory due process procedures governing the well permit and well spacing approval process and voluntary integration and unitization procedures.

- Sometimes the land that is pooled includes mineral right holders that have not entered into leases with the well operator. If the well is productive and the lease agreement provides for a royalty payment, a well operator can proceed to drill as long as it controls 60% of the spacing unit and controls the oil and gas rights in the target formation to be penetrated by the wellbore. Nevertheless, the unleased rights must be dealt with. In those cases, the unleased rights can be joined into the spacing unit by a process known as compulsory integration. The compulsory integration provisions establish a number of statutory legal rights, due process safeguards and hearing requirements to ensure that all parties to the process are treated in a "just and reasonable" manner. In exchange for being integrated into the spacing units, the unleased mineral right owners are given various options to either participate in the costs and potential profits from the well or to not participate and simply receive royalties or accept a "buyout" should a well prove to be productive. See ECL §23-0901.

The ECL provides a different regulatory framework in the area of underground gas storage. There an operator must submit an affidavit that it has acquired at least 75% of the storage rights in the reservoir and buffer zones, calculated on the basis of surface acreage. The applicant must further agree as a condition to the issuance of the permit that it will acquire the remaining 25% of the storage rights in the reservoir and buffer zone by negotiation or file and proceed with eminent domain acquisition proceedings within two years of first injection of gas, unless an extension is granted by NYSDEC. See ECL §23-1303.

Options and recommendations for applying the foregoing provisions of the OGL to a proposed CCS regulatory framework, are provided in Sections 4.2 and 4.3 of this report.

3.1.5.2 Public Service Law. In NYS, Article VII of the Public Service Law (PSL) is the statute under which the construction and operation of major utility transmission facilities is licensed. A "major utility transmission facility" is defined as a) an electric transmission line of 125 kilovolts (kV) or more and of a mile or more in length; and b) a fuel gas transmission line of 1,000 feet or more in length used to transport fuel gas at pressures of 125 pounds per square inch (psi) and above PSL § 120(2). Because CO_2 is not a fuel gas, Article VII does not give the Public Service Commission (PSC) jurisdiction over CO_2 being transported to a sequestration site. Instead, the construction and operation of CO_2 lines in New York is regulated by multiple federal, state, and local resource and regulatory agencies that have general authorities over discrete portions of a project.

Under the PSC Article VII process, the PSC acts as the sole state licensing entity for a project. The PSC is required to make a determination of environmental compatibility and public need for a project and coordinate with state and local resource and regulatory agencies to ensure that the substantive requirements of laws and regulations administered by those agencies are met. Once a certificate is obtained from the PSC, the project sponsor is not required to obtain individual project permits from any state or local agencies, although acquisition of permits from federal agencies (e.g., United States Army Corps of Engineers) is still required. The Article VII process supersedes and exempts a Project from needing a separate SEQRA review. Unlike the authority issued through Federal Energy Regulatory Commission (FERC) approvals, approval through the PSC does not provide applicants for pipeline systems with eminent domain authority.

Because neither FERC nor the PSC have jurisdiction over CO_2, no state or federal license comparable to those required for other types of natural gas transmission is required for a CO_2 transmission project in New York. Instead, the CO_2 pipeline component of the project would be subject only to the comprehensive environmental review under SEQRA/NEPA and any federal, state and local resource/regulatory agency permit requirements that might apply to discrete elements of the project subject to their respective jurisdiction (e.g., USACE and/or NYSDEC wetland permits; State Historic Preservation Office archaeology approvals; Department of State coastal zone consistency approvals; United States Fish and Wildlife Service Endangered Species Act Section 7 consultations). A number of these permitting agencies could act as the lead agency for purposes of the SEQRA/NEPA review.

The existing permitting structure outlined above provides a workable permitting approach for an applicant considering constructing a CO_2 project in the near term. Still, in the long term, a statewide permitting program administered by the PSC that is coordinated with the SEQRA process may be preferable to ensure that the state agency with the most experience over pipelines has authority to regulate a CCS pipeline during its construction and operation. Options and recommendations on how to address the current gap in state regulatory jurisdiction and better coordinate and expedite the CO_2 permit approval process and enable the state to provide uniform and consistent oversight of pipeline operations, are provided in Section 4.4.1 of this report.

Section 4.0

POLICY ISSUES AFFECTING CCS IMPLEMENTATION IN NEW YORK STATE

A number of public policy issues should be addressed when establishing a CCS regulatory framework in NYS. To a large extent, how these critical policy issues are resolved will have a significant impact on the timely deployment of CCS technology in New York. A number of these issues have been addressed in the enacted and proposed state and federal statutes and regulations and the model rules discussed in Section 2 of this report. In addition, the stakeholder workgroups described in Section 1 that were convened in the preparation of this report made a number of recommendations that helped to inform the policy options provided in this section.

Section 4 completes the regulatory analysis by identifying the most significant policy issues that are not addressed by the existing regulatory framework and proposing options to convert the patchwork of regulatory programs described in Sections 2 and 3 of this report into a comprehensive CCS program for the state.

4.1 PUBLIC POLICY CONSIDERATIONS

Establishing a just and reasonable CCS regulatory framework in NYS requires a careful balancing of interests on a number of public policy issues. For purposes of this report, we have grouped these public policy issues into three (3) primary areas and subcategories:

- Property Rights
  - Due process, and
  - Pore space ownership and compensation;

- Financial Impacts
  - Liability and indemnification,
  - Financial responsibility, and
  - Cost of operating CCS projects in the absence of mandatory limits on CO_2; and

- Regulatory Oversight
  - CO_2 pipeline construction and operation,
  - Risk assessment and mitigation, and
  - Hydraulic fracturing.

This section of the report discusses these key public policy concerns and develops proposed options for addressing them in a reasonable manner that is respectful of the historic legal, statutory and policy precedents that exist in NYS.

To a large extent, relevant state policy precedents have been codified in a number of NYS statute and guidance documents governing the implementation of environmental initiatives. Specifically, these include the Article 7 (electric and gas transmission siting) and Article 10 (energy facility siting-currently lapsed) of the Public Service Law, Title

5 (Environmental Restoration Projects) of the Clean Water/Clean Air Bond Act of 1996; Title 23 (Oil and Gas Exploration), Title 13 (State Superfund), and Title 14 (Brownfield Cleanup Projects) of Article 27 of the ECL; and the System Benefits Charge (SBC), Renewable Portfolio Standard (RPS) and Energy Efficiency Standard (EES) orders of the Public Service Commission.

As was stated in the *World Resources Institute Guidelines for Carbon Dioxide Capture Transport and Storage*:

> Because of the public good benefits of early storage projects and the potential difficulty of attracting investment, policymakers should carefully evaluate options for the design and application of a risk management framework for such projects. This framework should appropriately balance relevant policy considerations, including the need for financial assurances, without imposing excessive barriers to the design and deployment of CCS technology.[53]

The uncertainty of successful development and the financial risk involved in undertaking a CCS demonstration project has deterred both the public and private sector from moving forward on any significant CCS projects in the United States. Complicating this potentially daunting financial and liability risk associated with the application of any new technology is the massive scale of infrastructure that CCS will require. There are currently over 600 coal-fired power plants operating in the United States that provide over 51% of U.S. domestic energy needs. To impose CCS at even a fraction of these sites will require massive and expansive investment in infrastructure, including integrated carbon capture and gas compression systems; pipeline construction; deep well drilling and CO_2 injection; and long-term sequestration monitoring. To spur on this type of widespread and expansive development, clear public policies encouraging this type of investment are critical.

In order to address these concerns a number of state and federal statutes have been proposed or enacted. In Illinois and Texas, statutes were enacted specifically for the proposed FutureGen project. Other states, including Wyoming and Washington, have enacted statutes that are intended to encourage the development of CCS. At the federal level, a number of proposals have been introduced in Congress, including some as part of Cap and Trade Climate Change legislation, which provide both funding and address liability concerns. Here in NYS, Governor Paterson has taken the lead in encouraging the development of CCS technology by initiating a process that includes funding, public outreach, and an interagency CCS Working Group to address the various regulatory issues.

While CO_2 has been injected underground for enhanced oil or gas recovery for over 30 years, sequestration for large-scale and long-term storage is a relatively new technology with only a limited number of commercial operations around the world. Further, though a number of projects are in planning stage, to date there are few, if any, integrated CCS systems being implemented at power plants anywhere in the world. Legal statutes, relevant common law, and regulatory framework are underdeveloped and rarely extend beyond basic, first-order issues. There may be legal trends among certain jurisdictions and analogous industries, such as oil and gas and natural gas storage, from which to draw comparisons. But, to potential operators and investors, this translates to uncertainty, and uncertainty often means shepherding investment capital to safer pastures.

In 2008 the Midwestern Governors Association's Energy Security and Climate Stewardship Platform conducted seven interviews with project developers and industry experts. Areas identified as top priorities included:

1. The need for a regulatory framework to address climate change issues, so industry can adapt to the rules and avoid being in a position of implementing a CCS project in an uncertain regulatory environment; and

2. The need for a legal and regulatory framework that addresses issues related to pore space ownership and mechanisms for acquiring property rights.[54]

Based on a review of the various issues recited above and discussed in Section 2 and 3 of this report, this section of the report focuses on the three primary policy issues referenced earlier in this section that require resolution by NYS policymakers.

Each discussion concludes with a summary of specific options that E & E recommends for consideration by NYS policymakers as they develop a comprehensive statewide CCS regulatory framework. The options are presented in relative order of preference, based on E & E's best professional judgment.

4.2 PROPERTY RIGHTS

4.2.1 Due Process

4.2.1.1 Overview. In developing any comprehensive regulatory program, fundamental concepts of fairness and reasonableness must be evaluated and integrated. In addition, to ensure that the program can accomplish its objectives, it is important to establish a mechanism to resolve disputes and ultimately force a final resolution of critical issues if an impasse is reached.

The right to use reservoirs and associated pore space for sequestration of CO_2 is considered a private property right in New York and the rest of the country. It, therefore, follows that a reasonable process to establish the legal right to conduct sequestration activities should be integrated into the sequestration permitting process to promote orderly development and maximize utilization of the sequestration field. In New York, given the success of the existing approach currently adopted by NYSDEC under the OGL, it would be appropriate to ensure that any sequestration regulatory program granting authority to inject CO_2 into subsurface saline formations employs a similar approach. In implementing a CCS project, project sponsors will need to gain legal rights of access to surface lands where injection and monitoring wells will be placed, as well as to subsurface formations and "pore space" where drilling is to occur and into which CO_2 is to be injected. In addition, a fair system of determining appropriate compensation must be established. It is, therefore, essential that procedures be put in place to address the inevitable disputes that will arise when conflicting property interests clash. Section 4.2.1 focuses only on the procedural safeguards that are essential to an effective CCS program. The property ownership issues that are also critical to this discussion are separately discussed in Section 4.2.2

4.2.1.2 Precedent. The due process safeguards that allow New York to effectively regulate mineral extraction and storage under the OGL are described in Section 3.1.5.1. The key concepts of that law that are directly relevant to the injection and sequestration of CO_2 and applicable to a CCS regulatory program are the following:

- NYSDEC review of proposed subsurface activity plans;
- Voluntary integration of multiple tracts into a single, integrated spacing unit area with properly spaced wells(ECL §23-0701);
- A statutory procedure to provide to mineral owners a fair procedures (e.g., notice, hearing rights over) to resolve disputes;
- The right of owners and/or NYSDEC to seek unitization of a mineral pool to allow efficient well operation (ECL §23-0701 and §23-0901(3);
- Establishing minimum statutory threshold requirements for operator control of property ownership rights before allowing NYSDEC to issue a well permit in a spacing unit (60%: ECL §23-0501); an integration order pursuant to ECL§23-0501 or §23-0701(60%); or an underground storage permit (75%: ECL §23-1301(1)C); and
- Issuance of state NYSDEC permits establishing permit conditions.

An alternative approach is to adopt the recommendation of the IOGCC model rule. Some of the procedural safeguards specified in the IOGCC program include the following:

- Public notice requirements prior to initiating unitization and eminent domain proceedings (Section 4.1, General Rules and Regulations);
- A procedure for "amalgamating" subsurface rights to operate a geologic sequestration unit, characterized by public notice requirements and a public hearing convened by the state regulatory agency for the purpose of joining necessary property ownership rights (Section 5, General Rules and Regulations);
- Sequestration well permit application procedures and operational standards (Sections 6 and 7, General Rules and Regulations); and
- Reporting and closure requirements (Sections 8 and 9, General Rules and Regulations).

4.2.1.3 Policy Options and Recommendations. The following policy options should be considered for inclusion in the New York CCS regulatory program. It is anticipated that considerable discussion will be required to assess and evaluate these options and that additional refinement will be required as experience is gained through the implementation of demonstration scale projects.

1. One option is to amend the OGL by granting NYSDEC jurisdiction over CO_2 and developing new CCS provisions that expand the existing due process and eminent domain procedures to cover CO_2 injection activities. Because the existing OGL program is well established and working effectively in New York, its expansion to cover CO_2 injection activity is likely to be viewed in a positive manner, will provide certainty in the industry and can be implemented in a "just and reasonable" manner. All of the precedents specified in Section 4.2.1 would be adopted, with the following suggested modifications:
    a. For CCS, the spacing unit where the injection wells are to be installed and any adjacent unitized area required to maximize efficient operations, would be based on the projected dimensions of an "injection pool" of CO_2, as opposed to the oil and gas mineral spacing unit that is currently regulated in terms of extraction or storage. As is currently provided in the OGL, the dimensions of the spacing unit/injection pool would be defined by statute based on geologic formation and depth; given the relatively limited available historic data on CCS, it may be appropriate to allow greater flexibility in the definition of spacing units, that allows NYSDEC a greater role in defining the spacing unit/injection pool on a case by case basis and granting it authority site specific modeling data. Given the volume of CO_2 to be injected and the depth required to maintain the CO_2 in a semi-critical state, it is anticipated that the spacing unit/injection pool will be at least 640 acres, which represents the largest spacing unit currently specified in ECL §23-0501. Because of public safety concerns, it may be advisable to expand the concept of unitization by specifically authorizing and requiring NYSDEC to review all proposed operational units not only from an efficiency perspective, but from a safety perspective as well; it may also be advisable to expand the definition of "interested persons" authorized to request and/or participate in a unitization review, to include persons who could be potentially impacted by a release of CO_2 from the sequestration repository.

    b. Due process safeguards (e.g., hearings, notice) to address disputes over ownership, compensation, and other relevant issues could be modeled after the existing OGL provisions. A minimum threshold ownership control percentage (e.g., 60 or 75%) should also be considered, consistent with existing OGL requirements, as a prerequisite to NYSDEC having authority to issue a well permit in a spacing unit; an integration order; or an underground storage permit. Upon issuance of the permit, injection activities could be commenced, which is consistent with the manner in which oil and gas permits are currently used to regulate oil and gas extraction activities under the OGL.

    c. Appropriate consideration should be given to the coordination of the expanded state CCS regulatory program discussed above and in Section 4.3 and 4.4, with the existing and the proposed EPA UIC program discussed in Sections 2.1 and 3.1.3. Both the EPA and the NYSDEC should be involved as participating agencies during all permit reviews addressing sequestration issues; this coordination is needed to ensure that the federal and state permits are consistent, and protective of human health and the environment. Coordination is also essential to ensure that the permit application and review processes are not unduly burdensome on project sponsors/permit applicants.

2. A second option is to integrate useful elements of the due process procedures codified in the IOGCC model rule, into the state regulatory program described in paragraph 1, above. In addition, NYSDEC could consider applying for state primacy for either UIC authority generally or specific authority to administer and enforce the new Class VI program components only.

3. A third option is to develop new procedures for CCS that are based on the IOGCC model rule and to integrate appropriate changes to that rule based on implementation experience under the OGL program.

4.2.2 Pore Space Ownership and Compensation

4.2.2.1 Overview. Common law real property rights impact several aspects of CCS:

- Surface owner rights to control access. There is no dispute that the surface owner has the legal right to control site access. In situations where mineral rights have been severed, the mineral owner may also have equivalent rights to control access (e.g., oil an gas development rights may have been granted to control access for the limited purpose of oil and gas or mineral development). The surface owner and/or the mineral owner that have access rights are the proper parties with whom to negotiate an easement and are entitled to compensation for said access.

- Owner rights to drill injection wells. The party who controls injection rights include the surface owner; and may include the mineral right owner that controls mineral deposits through which the well is to be drilled; and any third party to whom the surface owner sells an interest that allows well drilling in subsurface lands.

- Owner rights to control subsurface pore space and sequester CO_2. As mentioned in Section 2.5.1, any conveyance of such an interest by deed or lease must be specific and convey the right to sequester CO_2 in subsurface pore space formations. The party who controls this right includes the surface owner; any person with mineral rights pursuant to a deed or lease that specifically conveys CO_2 sequestration rights; and any third party to whom the surface owner conveys an interest authorizing the long-term sequestration of CO_2 in subsurface rock formations or pore space.

4.2.2.2 Precedent. Absent an explicit statutory program governing this area of the law, common law principles will control. Unfortunately, common law is not well equipped to address the number of controversies likely to arise from CCS activities. For example, under New York common law, it is difficult to predict how a number of situations would be addressed:

- If a surface owner above a sequestration field objects to the injection, does that owner have the right to prevent the drilling of an injection well and/or the injection of CO_2 into the saline aquifer?

- Who owns the CO_2 once it is injected into the pore space?

- If the CO_2 migrates under ground, do all owners of the pore space also own the CO_2?

- Once ownership is decided, does this entitle all owners, regardless of the distance from the injected CO_2, to compensation?

- How is compensation to be determined?

- In the event of a release, is liability to be limited to the original surface owners or pore space owners that have been granted leases; and/or "new" surface owners of surface property above the sub-surface areas and/or pore space holding CO_2 leases to sub-surface areas where the CO_2 has migrated?

A summary of key common law principles are provided in Section 2.5.

As stated in that section, New York case law is consistent with the "American Rule" and, therefore, it is the surface owner who owns the pore pace and subsurface geological formations. The mineral estate owner, if any, is limited to mineral interests and unless there is interference with his mineral deposits, is not entitled to compensation. This is consistent with the statutory program enacted by Wyoming that is discussed in Section 2.3.2 and could prove helpful in addressing state pore space ownership issues and compensation rights.

Any attempt in New York to convey rights to sequester CO_2 in pore spaces must be explicitly stated in a deed or lease document. Further, under common law doctrines, a number of states have limited ownership and compensation rights based on public policy rationales that are based on de minimis impacts and the "negative rule of capture."

Without a more complete CCS regulatory program, CCS is unlikely to take hold in New York or any other jurisdiction. Some policy recommendations that integrate basic common law principles into a fair and robust CCS regulatory program follow.

4.2.2.3 Policy Options and Recommendations. A number of options exist to address pore space ownership and compensation issues:

1. One option is to include in an amended provision of the OGL, a clear statutory restatement of the law governing CCS activities, based on existing New York common law principles and drawing from approaches incorporated in the IOGCC Model Rule and the Wyoming CCS statute.

a. A separate New York CCS statute and regulatory program should be considered that would clarify ownership and owner liability issues, stating that the surface owner is the owner of all pore space absent a grant by lease to a third party; recognizing that mineral right owners own the dominant estate and are entitled to injunctive relief and/or compensation if those rights are interfered with; stating that owner liability lies with the surface owner unless expressly assumed by a lessee; and establishing a reasonable compensation formula taking into account the risks assumed, the degree of ownership interest, and other relevant factors, such as the volume of CO_2 injected.

b. To address concerns about specificity, an OGL provision would state that any conveyance of CO_2 sequestration ownership or lease rights must specifically state that the lease or deed conveys rights to sequester CO_2 in subsurface formations and pore space.

c. Regarding pore space owner compensation, as currently contemplated by the OGL voluntary negotiation of compensation among the spacing unit owners would be preferred. In the event that compensation cannot be negotiated on a voluntary basis, a mechanism is needed to resolve compensation issues. One option that would build on precedent already established in New York would be to establish a two-tiered compensation program: one for the spacing unit injection area (e.g., 640 acres or larger); and another for the outlying buffer zone located beyond the spacing unit/injection pool. It may also be appropriate to consider placing some geographic limits on the adjacent buffer zone areas entitled to compensation based on the public policy justifications discussed in Sections 2.5.6 and 2.5.7 of this report. For example, anyone owning pore space rights outsides a defined distance (e.g., 3 miles, 5 miles, from spacing unit/injection pool boundary) could be considered to have a *de minimis* interest and not entitled to compensation.

    i. Primary Compensation: Compulsory Integration. Within the spacing unit, owners unable to agree on compensation would be able to elect one of three options for compensation, similar to those already in place under the OGL. These options would build on the compensation formula set forth in the existing OGL and could be based on the ownership risks assumed and the volume of CO_2 injected (ECL §23-0901). This compensation approach assumes for purposes of this report that a market based system for valuing CO_2 will emerge and that injected CO_2 will have a market value that will produce a revenue stream for the operator. To put this in perspective, many commentators are currently projecting that the CO_2 market value will reach \$30 per ton; a demonstration-scale plant can generate 400,000 tons per year and a full-scale plant could generate ten times the volume or more. At these volumes, the income stream generated from a CO_2 sequestration field could be significant. To simplify the compensation formula, it may be worth considering whether an objective standard might be appropriate to establish market value of the sequestered CO_2; for example, this could be based on based on net revenues generated by the sale of CO_2 credits, RGGI auction prices, or the value of federal cap and trade credits when a federal cap and trade system is adopted. However, because this market is unproven with no historic track record to establish a fair expectation of revenue, an alternative would be to use the eminent domain construct (see paragraph 1(c)ii below that could use historic values established for underground gas storage pore space to arrive at a reasonable compensation figure for CCS pore space.

ii. Secondary Compensation: Eminent Domain. Outside the primary spacing unit, a relatively large buffer zone area could be impacted by a CO_2 injection field. Reasonable estimates for a full-scale power plant project are in the 640,000-acre per 1,000-square-mile range (i.e., 32 by 32 miles) over a 40-year operating period.[55] As discussed above, the Public Trust doctrine could be used to limit the areas in which owners would be entitled to compensation, but the number of parties entitled to compensation would still be anticipated to be large. This is a significant issue since compensation from oil and gas storage in some areas of the country is currently in the $20 per acre per year range.[56] Under this option the project sponsor would be granted eminent domain authority to allow the sponsor to purchase the pore space ownership rights from all pore space owners in the secondary compensation buffer zone. This approach of relying on eminent domain authority to compensate pore space owners is consistent with the approach outlined in ECL §23-1303 and the IOGCC recommendations. It should also be noted that under eminent domain precedent, the compensation paid is unrelated to the revenue generated and tied only to the reasonable value of the property adversely impacted by the condemnation. Given that the compensation value could decrease dramatically as the injection depth and distance from the injection site increase -- this approach of tying compensation to the value of the impacted areas in remote buffer zones, may provide a sound basis for a realistic compensation formula.

d. NYSDEC, in its approval of the sequestration/injection permit, would be obligated to identify on a map, specific areas impacted by the sequestration activity subject to the boundary limitations specified in subparagraph (c) above. This map will define CO_2 impact areas and provide the means to readily determine what surface/pore space owners are entitled to compensation.

2. A second option would be to allow common law to develop in New York without statutory controls. This would allow pore space market prices to be established over time through the negotiation of leases and allow individual surface owners over all areas above the CO_2 plume or pore space owners that have been granted CO_2 sequestration rights, to negotiate a price for sequestration rights with the CCS developer, on a case by case basis. Still, an obvious problem with this approach may be that it will be cumbersome and slow in its development and implementation. Surface/pore space owners would be forced to rely on the courts to resolve property disputes; it would likely result in significant litigation, which by its very nature is a slow process that moves in fits and starts until the appeal process is concluded. It is also likely to encourage costly “battles of experts” that will be characterized by opposing experts playing a critical role in defining plume migration and determining which surface or pore space owners will be able to secure fair compensation for the sequestration of CO_2 on their property. (See Section 2.5.6 of this report.)

3. A third option is to adopt the IOGCC model rule approach and require compensation to be paid to all surface owners above the CO_2 plume locations. Again the CO_2 impact area determinations provided as part of the NYSDEC injection/sequestration permit approval would provide a basis for determining who is entitled

to compensation. The amount of compensation would be negotiated on a case by case basis in the same manner that well access leases or easement rights-of-way are currently negotiated.

4.3 FINANCIAL IMPACTS

Addressing the many financial impacts of CCS in a project context is difficult. As indicated in Section 1.2 of this report, CCS projects are expensive. The current construction and development cost estimate for a full-scale 600-megawatt power plant that includes advanced CO_2 capture and compression, CO_2 pipeline transportation, and CO_2 sequestration is between \$1 and \$2 billion with between 25 and 40% of that cost attributable to the CCS components of the project.[57] This is in addition to the 30% increase in operating costs of a CCS power plant discussed in Section 1.2 of this report for parasitic power needed to operate carbon capture and compression equipment, such as oxygen separators, gasifiers, compressors, and injection wells.

Because of the size and complexity of these financial impacts, there are a large number of parties associated with a CCS a project that face financial challenges:

- Project sponsors are concerned about securing adequate financing to fund the construction and earning sufficient revenues to cover projected operating, closure, and post closure costs;

- Project sponsors as well as vendors, suppliers, and other third parties providing CCS technologies, services or CO_2 injectate materials are concerned about being drawn into disputes and litigation that could be expensive to resolve if CO_2 were to escape from a storage reservoir;

- Insurance companies providing bonds or liability insurance for a project are concerned about the safe implementation of CCS activities to avoid financial exposure;

- Residents and landowners are concerned about potential risks to health and potential damage to their property and mineral interests, keeping their electricity cost/rates as low as possible, and avoiding disproportionate rate increases to cover CCS construction and operating costs; and

- The state will need to evaluate fiscal impacts related to staffing and resources needed to review proposals and monitor CCS activities over the life of the project, including the Post Closure Period, and that ratepayers will not be adversely impacted by the implementation of CCS activities.

This section looks at all of these potentially significant and inter-related financial impacts and presents options for addressing through the development of a comprehensive CCS statutory and regulatory framework.

4.3.1 Liability and Indemnification

Set forth below is a discussion of available options to address potential liability concerns associated with CCS projects. As indicated in Section 2.2, the term “long-term liability” refers to all potential legal claims for damages that could result from CO_2 releases to the surface or migration of the sequestered CO_2 in underground geologic formations.

The complementary regulatory recommendations that would address the potential CCS financial impacts on the project sponsor, the state, and nearby residents through financial security products, such as insurance, bonds, letters of credit, and trust funds, are discussed in Section 4.3.2; and recommendations to address operating cost shortfalls are set forth in Section 4.3.3 of this report.

4.3.1.1 Overview. A significant concern that could adversely impact the broad and rapid deployment of CCS is the possibility that CCS project sponsors and third parties engaged in CCS support activities could one day face massive claims for damages as a result of a release of CO_2 from the geologic sequestration reservoirs. This long-term liability concern is reflected in the very thorough liability assessment set forth in the liability workgroup report included in Appendix B.

This concern is particularly troubling for "early movers" who currently have little prospect of recovering the added costs of engaging in CCS activities through the sale of generated electricity and have no regulatory framework in place that can offer them certainty or protection. In addition, early movers involved in CCS demonstration projects not only face the long-term liabilities associated with CCS, but also must be able to withstand the added financial uncertainties resulting from the use of new CCS technologies and equipment; the implementation of untested geologic characterization and assessment techniques to determine CO_2 reservoir suitability and integrity; and first generation attempts to integrate CO_2 transportation, injection, modeling and monitoring systems. These unique problems facing early movers and recognition of the important role they play in developing and deploying CCS technology, provides a public purpose justification for a separate Early Mover CCS Regulatory Program. Illinois and Texas have recognized the need for such a program in their enactment of the CCS legislation discussed in Section 2.2 of this report.

Similarly, any Comprehensive CCS Regulatory Program that follows must address the long-term liability issue as well if the CCS is to be successfully deployed in NYS. It should be noted that for purposes of addressing the foregoing liability concern discussed in this section of the report, distinctions have been made between an early mover CCS regulatory program that is designed to provide incentives to commit to CCS technology and address global warming issues (hereinafter referred to as the "Early Mover CCS Regulatory Program"); and a more mature, comprehensive CCS regulatory program that anticipates private sector market developments which could reduce the need for government incentives and statutory liability protection (hereinafter referred to as the "Comprehensive CCS Regulatory Program").

Early Mover CCS Regulatory Program Liability Considerations. The significance of long-tem liability for early movers and need for a separate Early Mover Regulatory Program to promote CCS development is summarized below.

New York has faced similar situations in the past, most notably with the early development of the Voluntary Clean up Program (VCP).[58] In 1994, NYS sought to encourage the revitalization of contaminated urban areas by cautiously encouraging cleanups though the case by case review of voluntary cleanup applications. If approved, volunteers that were not responsible for the contamination were allowed to enter into “covenants not to sue” that precluded the state from commencing suit for further cleanup activities ad imposed limited “re-opener” restrictions on the state. Unfortunately, this program was unable to achieve its overall program objective of encouraging the cleanup of hundreds of industrial sites in urban areas so that the development of these sites could compete effectively with the development of “Greenfield” sites. It became evident that the limited incentives offered by the VCP program did not adequately motivate private sector development of contaminated sites:

> While the cleanup of more heavily contaminated properties is driven by the need to abate a hazard to public health and the environment, Brownfield sites will generally be cleaned up only if incentives are provided to encourage their reuse and redevelopment. Failure to provide these incentives will primarily hurt the economically disadvantaged and racial minorities who cannot afford to move to the suburbs or chase after higher paying jobs. It will also hurt the state’s older cities, towns, and villages that are already straining to maintain aging infrastructure and more costly community services in the face of a rapidly declining tax-base. If the right incentives are not provided to stimulate the cleanup and reuse of Brownfields, it will not hurt the wealthy or land developers. They will simply go to the suburbs or to “greenfield” areas not yet marred by urban decay or pollution.[59]

Recognizing the lack of incentives as a fundamental problem, in 2003, New York enacted a more ambitious incentive program through the Brownfield Cleanup Program (BCP).[60] Though this program has also had some implementation problems stemming from state fiscal constraints, the significant tax incentives offered under the program have provided a much needed jump start to the cleanup of Brownfield sites. By providing both strong monetary incentives, as well as broad protections against liability, the BCP is making good progress in the redevelopment of urban areas.

Comprehensive CCS Regulatory Program Liability Considerations. Regarding the specific liability concerns facing CCS project sponsors, technology vendors and pore space owners sequestering CO_2, many have already been discussed in Section 3 of this report:

- Potential RCRA and/or equivalent NYS solid and hazardous waste law liability stemming from unlawful disposal and/or imminent hazard claims;

- Potential CERCLA Section 9607 liability that could result from the release of reportable quantities of hazardous substances contained in sequestered CO_2 injectate material and/or for potential CERCLA Section 9604 response costs[61] incurred to address releases of CO_2 that could result from its status as a regulated “pollutant.”

- Common law trespass, nuisance, negligence, negligence per se and ultra-hazardous activity claims that could result in from CO_2 injection and/or the release of CO_2 from subsurface pore space formations.

If a health or environmental incident were caused by the release of CO_2, regardless of whether the activity were duly permitted under state or federal law, there is little doubt that absent some sort of statutory protection, the CCS project sponsor would face significant litigation costs and damage claims.

4.3.1.2 Precedent.

Illinois and Texas Project Specific Assumption of Liability/Indemnification. As stated in Section 2.2 of the report, the states of Texas and Illinois have sought to encourage early mover development of CCS projects by giving the sponsors of the proposed FutureGen project statutory protections that transferred long-term liability for the release of CO_2 , from private parties to the respective states.

If a decision were made to extend similar protections to early movers in New York, constitutional sensitivities would have to be considered. Section 8, subdivision 1 of Article VII of the Constitution of New York contains the following constraints on state assistance:

> The money of the state shall not be given or loaned to or in aid of any private corporation or association, or private undertaking; nor shall the credit of the state be given or loaned to or in aid of any individual, or public or private corporation or association, or private undertaking, but the foregoing provisions shall not apply to funds or property now held or which may hereafter be held by the state for educational, mental health or mental retardation purposes.

This provision has been interpreted by the legislature and New York courts, to allow indemnification by the state only if the indemnification provided is broadly conferred to a class of persons and not a single private person or corporate entity. Relevant indemnification precedents in New York that are consistent with this constitutional provision are discussed below and the liability recommendations that follow are consistent with that precedent.

NYS Brownfield Limited Liability and Indemnification. The limited liability and indemnification provisions set forth in Article 56 of the ECL offers useful New York precedent that could be integrated into the framework of a longer-term CCS regulatory program.[62]

New York's 1996 Clean Water/Clean Air Bond Act (Article 56 of the ECL) provides funding to assist municipalities with the completion of Environmental Restoration Projects (ERP). The ERP law provides funding, limited liability and indemnification to the municipality, successors in title, lessees and lenders in order to promote the clean up and redevelop contaminated sites.

The ERP limited liability provision set forth at 56 ECL 0509(1) provides that municipalities, successors in title, lessees, and lenders:

> …shall not be liable to the state upon any statutory or common law cause of action, or to any person upon any statutory cause of action arising out of the presence of any contamination in or on property at any time before the effective date of a contract entered into pursuant to this title.[63]

A separate ERP indemnification provision in 56 ECL 0509(3) provides that:

> The state shall indemnify and save harmless any municipality, successor in title, lessee, or lender identified in paragraph (a) of subdivision one of this section in the amount of any judgment or settlement, obtained against such municipality, successor in title, lessee, or lender in any court for any common law cause of action arising out of the presence of any contamination in or on property at anytime before the effective date of a contract entered into pursuant to this title.

The Legislature determined that the preservation, enhancement, restoration and improvement of the quality of the state's environment is one of the government's most fundamental obligations - therefore, the Legislature, by passing the 1996 Bond Act, authorized a number of incentives to promote this objective:

- State financial assistance to develop and implement ERP projects;
- Limits to liability associated with such projects; and
- Indemnification for any legal actions brought against the municipality, successor in title, lessee, or lender associated with the cleanup of the subject property.

In support of this action, the Legislature stated that it believes that NYS has a responsibility toward future generations and to encourage "pollution reducing technologies." The Senate and Assembly Memorandum in Support of the 1996 Bond Act states that:

> This Bond Act will help fulfill our responsibility to the future of our state's environment and the health of future generations. A tremendous opportunity exists for the state to set an example for the twenty-first century by making an investment in air quality projects. There are many important initiatives that New York State can undertake that will simultaneously serve to address ongoing environmental degradation while encouraging the development of pollution reducing technologies.[64]

The key point to recognize from the foregoing is that New York precedent exists for the state to limit the liability of public and private sector entities and to indemnify them to achieve environmental objectives, based on public policy considerations. Recognition of the value of implementing CCS could provide the same public purpose justification for limiting liability and providing indemnification, as has already been recognized by New York under the Environmental Bond Act for promoting the cleanup of contaminated sites.

Federal CCS Indemnification Initiatives. At the federal level, there have been efforts to encourage the development of CCS through the enactment of significant limitations on liability for harm associated with the long-term storage of CO_2. Recent efforts to do so are instructive and show recognition of the importance of liability in the development of this new technology.

In 2006, the U.S. House of Representatives considered a bill to authorize and appropriate funds for the FutureGen project "to demonstrate the feasibility of the commercial application of advanced clean coal energy technology, including carbon capture and geological sequestration, for electricity generation."[65] One of the failed amendments to that bill was to allow the Secretary of the DOE to "indemnify the consortium and its member companies for liability associated with the first-of-a-kind sequestration component of the project," with indemnity extending to any legal liability arising out of "the storage or unintentional release, of sequestered emissions."[66] The proposed indemnification contained exceptions for gross negligence and intentional misconduct, and limited the United States Government's aggregate liability to $500,000,000 for a single incident.[67]

IOGCC Model Rule. As indicated in Section 2.4 of this report, the IOGCC model rule proposes to transfer legal responsibility over the CO_2 to the state during the Post Closure Period. The delay on the transfer of legal responsibility during the closure period is intended allow sufficient time for the state to verify that the CO_2 sequestration is secure and allow additional precautionary or mitigation measures to be developed that will allow the state to better protect the state treasury against future long-term liabilities:

At the conclusion of the CO_2 Storage Project (CSP) closure period, the CSP performance bond maintained by the CSP operator shall be released, and continued monitoring of the site, remediation of any well leakage, including wells previously plugged and abandoned by the CSP operator, shall become the responsibility of designated state or federal agency programs and the CSP operator and generator of the CO_2 shall be released from further state regulatory agency regulatory liability relating the CO_2 facility. [95]

NYSDEC Plugging and Abandonment Permits. It is the longstanding policy of NYSDEC to require operating companies to apply for plugging and abandonment permits (hereinafter referred to as " P&A Permits") when a well drilled for oil or gas production comes in "dry" or is depleted over time. General authority for the regulation of this activity with respect to oil and gas wells is set forth at ECL §23-0305 (8)(d), (e) and (k); authority to regulate these activities with respect to solution mining wells is set forth at 23 ECL 0305 (9). Regulations implementing the P&A permit program are set forth at 6 NYCRR Part 555. Among other things, the P&A permit process consists of the following activities:

- The permit applicant files a notice of intent to plug and abandon a well;

- Following NYSDEC review of the notice, NYSDEC will issue a permit that specifies well plugging and abandonment requirements;

- The permittee implements the plugging requirements and submits a completed plugging report form to NYSDEC confirming the activities performed and any additional reclamation work to be performed; and

- NYSDEC conducts a field inspection and signs off on the plugging report.

Typically any well drilling bonds previously posted by the permittee are authorized for release by NYSDEC when it signs off on the plug report or when any significant restoration work specified in the plugging report is completed. At this point the permittee is able to "abandon" the well, but it retains responsibility indefinitely, for any replugging or associated restoration work that may be required. NYSDEC has general statutory authority to protect and safeguard the environment and specific authority under the OGL to hold permittees responsible for any "pollution to the land" and to engage in "replugging of wells" and the "reclamation of surrounding land" as needed to:

> … prevent or remedy the escape of oil, gas, brine or water out of one stratum into another; the intrusion of water into oil or gas strata other than during enhanced recovery operations; the pollution of fresh water supplies by oil, gas, salt water, or other contaminants; and blowouts, cavings, seepages, and fires. [68]

The New York approach outlined above is similar in many states where oil and gas drilling activities are regulated. For example, the Illinois long-term liability transfer statute discussed in Section 2.2 of this report, focuses on claims relating to an escape of the sequestered CO_2 and any costs associated with the repair or replugging of a well or the remediation or restoration of areas damages by releases from a well would likely remain the responsibility of the permittee.

4.3.1.3 Policy Options and Recommendations.

1. One option is to develop a bifurcated approach that addresses the liability concerns of both an Early Mover CCS Regulatory Program, as well as the Comprehensive CCS Regulatory Program.

   a. Early Mover CCS Regulatory Program Liability Provisions
   To address the policy concerns discussed above, the sponsors of early mover projects would be entitled to broader liability protection than will be available to those parties in the future when CCS projects become commercially available and a comprehensive CCS regulatory framework is developed. A proposed definition of "Early Mover projects" is those projects located in New York that receive substantial funding as Demonstration Projects through federal DOE funding awards granted on or before December 31, 2011. Specific early mover liability recommendations follow:
      i. For early mover projects meeting this definition, project sponsors would either be:

(1) indemnified by NYS against all third party claims arising from the release of sequestered CO_2/injectate materials (see Illinois FutureGen Statute, described in Section 2.2.) and/or

(2) insulated from liability for all third party claims arising from the release of sequestered CO_2/injectate materials, by having the state assume title to the CO_2/injectate materials upon injection (see Texas FutureGen statute referenced in Section 2.2 of this report).

To ensure consistency with the OGL P&A permit precedent, said indemnification/transfer of title would in no way absolve the project sponsors from addressing any and all plugging, replugging, remediation and restoration responsibilities as may be required by NYSDEC to address any release of CO_2/injectate from the injection well or movement of other gas, oil or fluid from one stratum into another; and complying with all EPA and NYSDEC permit requirements. Intentional or willful misconduct would be excluded from state liability protection (see Illinois FutureGen statute), as would any claims resulting from pre-injection activities (see Illinois and Texas FutureGen statutes).

ii. Building on the precedent established under 56 ECL 0509(1), for early mover projects meeting this definition, the statute would expressly provide that project vendors, suppliers and other third parties providing CCS technologies, services or CO_2 injectate materials would be granted a statutory exemption from liability; more specifically these parties would remain legally responsible for injuries or damages resulting from their own negligent acts or omissions, but otherwise exempt from all liabilities arising out of the injection and sequestration of CO_2 by the project sponsor.

iii. The statute would also clearly state that any claims brought in New York under state equivalent laws governing hazardous and solid waste or air emissions or state common law for abnormally dangerous activity, negligence or negligence per se would be governed by the following clarifying interpretation of these provisions or state equivalent provisions:

(1) Captured CO_2/injectate materials do not qualify as a solid or hazardous waste;

(2) These materials are not subject to any state equivalent of the RCRA imminent endangerment liability provisions;

(3) These materials are not “extremely hazardous substances” under any state provisions equivalent to Section 112(r) of the CAA; and

(4) CCS activities engaged in pursuant to a valid NYSDEC permit will be presumed to not constitute abnormally dangerous activity, negligence or negligence per se unless the complaining party can demonstrate that the project sponsor engaged in intentional misconduct.[69]

To further address this issue, the state should also consider participating in national efforts to amend RCRA, CAA, and CERCLA to clarify that these materials are not hazardous substances subject to CERCLA Section 9607 liability; and are not “pollutants” subject to CERCLA Section 9604 cost recovery.

iv. In addition, to protect surface/pore space owners who are not project sponsors or operators, a provision similar to the Wyoming statute (see Section 2.3.2) would be added holding surface/pore space owners exempt from liability for the effects of CO_2 injection for geologic sequestration purposes, solely by virtue of their ownership interest or by their having given consent to the injection.

v. To protect the interests of oil and gas mineral owners, a provision similar to the Wyoming statute (see Section 2.3.2) could be added confirming that the severed mineral estate is dominant regardless of whether ownership of the pore space vests with the surface or other owners; and

vi. As a means of preserving the state treasury, the new law would provide that to the extent that the state indemnification or transfer of title is superseded by any federal indemnification or title transfer provisions benefiting the project sponsors of early mover projects under federal laws that may be enacted in the future, the federal provisions shall replace any state indemnification or title transfer protections provided to those parties (see Illinois FutureGen statute).

b. Comprehensive CCS Regulatory Program Liability Provisions

The new law would offer more limited protections to project sponsors, in anticipation of the development of market based insurance and financial responsibility mechanisms along the lines discussed in Section 4.3.2 of this report. In addition, different provisions would be specified for each of the three periods of CCS activities envisioned by the IOGCC Model Rules.

1. Operational Period

i. During the 30 to 40-year period of active CCS operations, the statute would clearly state that the project sponsor would be responsible for adhering to all permit conditions and will be potentially liable for any damages resulting from their activities, subject to the limited indemnification provisions set forth in Section b(1)iii below. To address financial risks, the project sponsor will be responsible for complying with applicable financial responsibility requirements during the operational period and these requirements could include insurance, bonds, and/or letters of credit. These requirements would be similar to those currently established by RCRA and are discussed in Section 4.3.2 of this report.

ii. The project sponsors would be required to work with the state to establish a project CCS trust fund and collect revenues based on the volume of CO_2 injected in the CCS reservoirs it operates.

iii. The project sponsors would receive a limited indemnity from the state during the operational period against all claims arising from any releases of sequestered CO_2/injectate materials from areas not occurring at the injection well provided that they were:

(a) injected in compliance with EPA and NYSDEC permits , and

(b) were caused either by: (i) an act of god and/or (ii) resulted from acts or events that could not have been reasonably foreseen.

Further, the limited indemnification would only be applicable to address the above specified liabilities and only to the extent that said liabilities are not otherwise covered by private insurance, bonds, letters of credit, and project trust funds. This approach is generally consistent with historic state indemnity precedent; as well as the current provisions of the OGL relating to P&A permits since it holds the operator responsible for all well installation, plugging, replugging, and restoration requirements associated with the well injection location.

As a final point, to make clear the limitations of this indemnification provisions and the ongoing responsibilities of the project sponsor, the statute would explicitly state that said limited indemnification would in no way absolve the project sponsors from addressing any and all plugging, replugging and restoration responsibilities as may be required by NYSDEC to address any release of CO_2/injectate from the injection well or movement of other gas, oil or fluid from one stratum into another; and its obligation to comply with all EPA and NYSDEC permit requirements.

iv. The new law would provide the same exemption from liability to vendors, suppliers, and other third parties providing CCS technologies, services or CO_2 injectate materials as specified in item 1(a)ii above.

v. In addition, the new law would provide the same clarification of statutory scope and intent as specified in item1(a)iii above; the protections offered to the pore space and mineral estate owners as specified in items 1(a)iv and 1(a)v above; and the treasury safeguard provisions set forth in item 1(a)vi above.

2. Closure Period

i. All financial responsibility requirements applicable during the operational period as specified in paragraph 1(b)1(i) above would apply.

ii. The project sponsor limited indemnity provisions outlined in paragraph 1(b)1(iii) would be extended to project sponsors during the Closure Period.

iii. In addition, the new law should provide the same exemption from liability to third parties as specified in item 1(a)ii above; the clarification on statutory scope and intent as specified in item 1(a)iii above; the protections offered to the pore space and mineral estate owners as specified in items 1(a)iv and 1(a)v above; and the treasury safeguard provisions set forth in item 1(a)vi above .

3. Post Closure Period

i. The new law would adopt the IOGCC approach of transferring CO_2 title to the state at the conclusion of the closure period and after NYSDEC has confirmed that all required closure activities have been completed and grants approval for all required closure bonds and well plugging releases. Upon transfer of title, the state would be responsible for implementing the monitoring program and providing assurance to the public that the long-term site management programs required by the facility permits, are continuing to be implemented. It is anticipated that funding for these activities will be provided by the CCS trust fund and financial assurance mechanisms established during the operating and closure periods. See Section 4.3.2 of this report. In addition, the new law could clarify that all costs incurred by the state are fully reimbursable.

ii. In addition, the new law would provide the same protections to third parties as specified in item 1(a)ii above; the clarification on statutory scope and intent as specified in item 1(a)iii above; the protections offered to the pore space and mineral estate owners as specified in items 1(a)iv and 1(a)v above; and the treasury safeguard provisions set forth in item 1(a)vi above.

iii. It would be appropriate to determine whether compensation is required to be paid to pore space owners during the closure and/or post closure periods. The state should consider whether it is reasonable, prudent, and consistent with public policy and common law property ownership precedent to discontinue such payments after active CCS operations are completed at the conclusion of the operational period. If it is determined that payments are to continue to be paid to pore space owners for CO_2 storage by the former operator/state during the closure and post closure periods, a state lien provision similar to ECL§23-0901(3) (c) 1(ii) D (allowing a well operator to place a lien on well owner production revenues) could be adapted to ensure that any costs incurred by the state are reimbursed or deducted from revenues earned by the pore space owners. If it is determined that such payments to pore space owners are not appropriate, the money saved would continue to be aggregated in the CCS trust fund to address future contingencies.

2. A second option is to provide early mover protection as specified in 1(a) above; and for the long-term program make the following modifications:
   i. Retain the same provisions set forth in 1(b)1 during the Operational Period above but delete the indemnity referenced in 1(b)1(iii) above; and/or
   ii. Retain the same provision set forth in 1(b)2 during the Closure Period above but delete the limited indemnity referenced in 1(b)2(ii) above.

3. A third option is to provide the early mover protection as specified in 1(a) above; and for the long-term program, make the following modifications:
   i. Retain the same provisions set forth in 1(b)1 and 2 above, for the Operational and Closure periods, but delete the transfer of title provisions during the Post Closure Period referenced in 1(b)3(i) above.

4. A fourth option is to take no action to address liability concerns and allow private sector market forces to play out, subject to the financial responsibility requirements addressed in Section 4.3.2 of this report. Note that this option poses the potential risks of reducing the likelihood of having an early mover project successfully sited in NYS and increasing the potential for exporting CCS technology to another state offering more favorable liability protections.

4.3.2 Financial Responsibility

4.3.2.1 Overview. As discussed earlier in Sections 1.2 and 4.3, CCS activities add significant cost to a power plant project and the implementation of financial responsibility requirements can play a significant role in addressing the myriad financial impacts identified in Section 4.3 of this report.

Even though the risk of a release of CO_2 for subsurface reservoirs may be low, if an environmental incident were to occur during the implementation of any of the various CCS activities, public policy demands that the CCS sponsor and owner/operator of various project components have the financial means to complete the project in accordance with permit requirements; pay for operation and maintenance costs as they arise; pay for proper closure and long-term monitoring activities that will be required by state and federal regulatory agencies; and address anticipated and unknown contingencies that may develop over the operating life of the project and over the long-term post closure period during which CO_2 will continue to be sequestered in deep saline aquifers.

Because CCS projects have not been implemented on the scale currently contemplated, financial responsibility requirements for CCS should build on other relevant precedents as described in Section 4.3.2. Likely financial responsibility requirements will include such things as bonds to guarantee payment and continued operations, the plugging of wells and the implementation of closure activity; letters of credit; insurance policies; and post closure trust funds. The purpose of requiring these types of products is to mitigate potential project risks. On a CCS project, the risks fall into two categories. The first are insurable risks for property type issues such as equipment failures (pipe leaks, machinery breakdown), or liability type issues, such as third party bodily injury, subsidence liability (the ground moves due to the gas pressure) or pollution liability. These risks are normally covered by an insurance product. The second types of risks are financial. These financial risks include such things as plugging of wells, reclaiming the site and, if required, monitoring the sequestration reservoir during the Post Closure Period to insure there is no CO_2 leakage. These risks would normally be covered by a surety bond, a letter of credit or a trust fund.

Sequestration Insurance. While the risks across the industry associated with sequestration may be small, for each individual plant the impacts of liability are potentially significant. See Section 4.3.1 for discussion of potential CCS liability risks. An analogy to the CCS liability risk and the need for insurance is the risk associated with driving an automobile. Statistically, each day of driving an automobile presents a tiny risk of an accident. As a percentage of annual miles driven in the United States, only a very small number of cars are involved in accidents. Nevertheless, the damages from even one accident could exceed the financial capability of a given driver to pay. In order to address this liability we have liability insurance for cars. The liability insurance premium is low due to the safety of driving cars with a lot of drivers paying the premiums.

Similarly, liability insurance is needed to protect the owner/operator, and the technology and service providers, against the above potential liabilities that may arise from CCS. While the likelihood of an event arising causing personal injury, property damages, or environmental harm arising from CCS will be quite small, the injuries or damages that might result could be significant.

The state of Illinois addressed this issue, in part, in its FutureGen legislation by requiring their Department of Commerce and Economic Opportunity to procure an insurance policy, if available, that insures the operator against certain losses, including any public liability arising from post-injection escape of the sequestered gas. If no commercial insurance can be obtained, or only certain aspects of the CCS facilities are eligible for insurance because they are risks not underwritten by any carrier even with reinsurance, uninsured risks may be a risk to bond holders. Bond holders would not be paid or have their bonds redeemed from available funds if there is a failure of the CCS facilities to function properly or if liability from injury or property damage would cause money revenues to be materially reduced. A standard default provision for bonds is the failure to maintain insurance once obtained and in force at bond closing. Failure to maintain insurance may cause an early extraordinary redemption of all outstanding bonds.

There are three main options for insuring the pollution risks that would be associated with CCS: property, general liability, and environmental insurance. Property coverage is first party only and would cover physical loss or damage to the pipeline transporting the CO_2. Still, it would have a low pollution sublimit. General liability pollution coverage is third party only and may extend to sudden and accidental, time element, and named perils. Environmental insurance provides the most extensive coverage to first and third parties, with no time element, all perils coverage. Traditional environmental markets also have more experience covering similar risks based on a long history of underwriting subsurface gas storage and waste disposal facilities, as well as groundwater contamination risks. The market is beginning to make these products available for CCS.

It should be noted that insurance is different from a bond in that insurance usually has a higher premium, and the funds it disburses do not need to be paid back. Additionally, insurance has a shorter term—currently up to about three years for CCS—and would then need to be renewed. Insurance is best suited to the operational period of a project.

Surety Bonds. Surety bond requirements are common in a number of industries. The mining, oil and gas and waste management industries all have similar obligations that are addressed by bonds:

- The mining industry has to obtain reclamation bonds to insure that they reclaim the land once they have completed mining.
- The oil and gas industry have to obtain well plugging guaranties for their operations.
- The waste management industry has to obtain closure bond to insure that they close a landfill and post closure bonds to insure that they monitor a site in case there is a leak.

A surety bond is a three-party agreement whereby one party, the Surety (usually an insurance company), is bound with another party, the Principal, who in this case would be the firm or entity that is attempting to capture and sequester the CO_2, to a third party, commonly referred to as the Obligee or the Beneficiary. In this instance you would have the Surety guaranteeing the contractual, financial and liability obligations of the CCS party to the public at large or the state. It is important to note that the Surety is only the guarantee company and that the obligation remains with the CCS firm or entity. In other words, the bond will pay upfront costs, but the CCS project sponsor would be required to pay back these funds afterwards.

The Surety guarantees the obligation of another party, in this case the CCS project sponsor, and should the CCS project sponsor not perform, the Surety would step in. The obligations can vary. In the case of landfills, the surety bond guarantees that it will only provide coverage for post closure monitoring. If necessary, the obligation may be extended to cover site monitoring and remediation.

For the Surety to agree to write such an instrument, they would have to underwrite the financial and legal wherewithal of the CCS project sponsor to ensure that they feel comfortable with the CCS operator's ability to perform their obligation. The Surety would also require the CCS operator, and possibly other parties to sign an indemnity agreement to protect the Surety should a claim be made against it. These additional indemnitors may be the power plant owner or another party that has an interest in the project. The Surety will make sure that there is a deep pocket to protect them from a loss.

Surety bonds are basic instruments that, in general, do not have a lot of fine print. By design these bonds are simple instruments that refer to a state or federal statute or an underling contract of the Principal that the bond guarantees. The Surety would normally review the statute or contract before agreeing to provide a bond, which further emphasizes the need for a comprehensive CCS regulatory program because without it, bonds may not be available.

Sureties are only willing to write a guaranty for a finite period of time. Today that period typically maximizes out at three to five years, and would depend on the strength of the indemnitor. The longer the bond runs, the more difficult the bond will be to obtain and the more expensive the bond will be. In the case of CCS, bonds would be needed for a much longer period of time. Therefore, there must be a way for the Surety to extricate itself from the obligation while providing comfort to the Obligee that the latter will not be left with the liabilities. This can be done using a forfeiture type bond form similar to what is presently used in the landfill or hazardous waste area.

Currently, bonds for landfills typically cover monitoring of the site and last for two to five years but can extend to 40 years. One condition of the Surety's obligation to the Obligee is that even if it chooses to cancel the bond, it must ensure that some form of financial assurance remains. If the Principal finds a replacement, either in the form of another bond or a letter of credit, the Principal does not owe the original Surety company anything. Nevertheless, if the Principal is not able to find a replacement, the original Surety company is obligated to set up a trust fund for the remainder of the original bond's duration, and for the same limit amount. In the latter case, the original Surety company may then sue the Principal to pay the former the entire limit amount, even if no claims were made during the bond's duration. Typically, however, the two parties agree to a sum that is lower than the initial limit.

The amount of capacity available in the marketplace will depend upon the strength of the Principal, the underlying guaranty agreement and the term of the bond. In the best scenario, the surety industry could provide several hundred million dollars in capacity for this obligation. For even the strongest Principal, the surety industry may not be able handle this guaranty if the total need for one Principal is more than $500 million. In all cases, the premium on the bond is charged yearly.

In contrast to insurance, which is more appropriate to address operational risks, bonds are typically applied to address risks arising during the closure/post-closure period.

4.3.2.2 Precedent.

<u>Oil, Gas, and Other Mineral Bonds.</u> The OGL and other state oil and gas mineral extraction regulatory programs establish a number of bonding requirements to ensure safe operations and closure (operation bonds), well plugging and abandonment (individual or blanket performance/well bonds) and post closure care ("plug" fund or an equivalent). Performance bonding is also common in the coal industry, where mining permits are typically conditioned on the posting of a bond that may be in the form of a surety bond, cash, or letter of credit and are released in three phases as the state agency approves the heavy earth moving (approximately a 60% release), the planting of vegetation (25%), and the success of that vegetation (15%). The total waiting period post mining is a minimum of five years. To further ensure that required closure activities are implemented, Kentucky and other mining states will deny the issuance of future mining permits to the permittee at other mine sites in their jurisdiction if a bond of any type or in any amount is forfeited for non-performance.[70]

<u>RCRA.</u> Similarly the RCRA statute and regulations establish detailed financial responsibility requirements for hazardous waste landfills that address all aspects of operations, closure and post closure care. Under this approach, operators retain long-term liability and are required during the permit approval process to demonstrate they have sufficient assets in place (e.g., bonds, letters of credit, insurance) to address closure and post closure monitoring requirements.[71]

<u>IOGCC Model Rule.</u> IOGCC has developed a comprehensive set of bonding requirements that utilize industry standard methodologies to calculate bond amounts that are currently employed to regulate different activities such as coal mining (regulated by Surface Mining Control and Recovery Act [SMCRA]) and highway construction.[72] It also establishes requirements that will require CCS operators to pay a tax or fee to a state administrated trust fund to address post closure requirements that address sequestration, integrity, monitoring and long-term maintenance, and care. This tax/fee would be paid on a per-ton-of-injected-CO_2 basis. Monies collected would be deposited in the trust fund and be collected in an amount sufficient to cover the cost related to long-term monitoring, verification, remediation, and capture of CO_2 if any CO_2 were to escape from the sequestration reservoirs.

In developing its recommendations, IOGCC considered a number of options to address monitoring, verification, and remediation during the Post Closure Period:

1. The Texas FutureGen model whereby a state takes a future responsibility for a specific prototype/demonstration project but is not provided a separate funding mechanism.

2. A government insurance fund along the lines of the Federal Flood Insurance program.

3. A private insurance program funded through premiums.

4. A federal statutory program patterned after the Price Anderson Act, which would insulate the CCS project sponsors and CO_2 generators from potential liabilities.

5. The federal superfund model under CERCLA, which raises revenue from a tax on chemical feedstock and establishes a fund to characterize and clean up releases of hazardous substances.

6. The federal Oil Pollution Act of 1990 model that raises revenue from a tax on oil and establishes a fund to clean up oil spills.

7. State acquisition of CO_2 sequestration rights from private parties in the state operation of sequestration activities.

8. The RCRA financial responsibility program model, mentioned earlier, which puts the onus for long-term care on the treatment, storage and disposal facility operator with funding supplied by fees charged to generators for disposal.

IOGCC concluded that the state administered trust fund offered the best option for long-term care. Regarding the RCRA alternative, IOGCC rejected it because it "likely would have onerous implications that could inhibit CO_2 storage projects from occurring."

The IOGCC approach utilizes an existing framework that has been developed by the states to address abandoned and orphaned oil and gas wells, with long-term responsibility passing to the state only after the stability and integrity of the sequestration reservoirs is confirmed after a post operational "closure" of 10 to 29 years. The funding mechanism based on each CO_2 injection tax/fee, offers a secure source of revenue.

This approach is based on sound public policy considerations: it provides strong assurance to the public that post closure requirements will be implemented; it safeguards public safety; and it removes the vagaries and uncertainties associated with private sector implementation of long-term monitoring responsibilities during a Post Closure Period that could extend over several hundred years. In an age when even the largest corporate entities in the world have faltered during times of economic crisis, the guarantee of government stability has a strong intuitive appeal that the public can appreciate and embrace.

Government Sponsored Insurance. Two additional insurance programs are worth mentioning to round out the discussion of relevant precedents:

1. The Terrorist Risk Insurance Act (TRIA) establishes a program within the Treasury Department, under which the federal government shares the risk of loss from future foreign terrorist attacks. If an act, certified to be a foreign act of terrorism, causes losses in excess of $5 million, participating insurers pay a certain amount in claims – a deductible equal to15% of the insurer's directly earned premiums during the preceding year – before federal assistance becomes available. For losses above the deductible, the government covers 90%, while the insurer contributes 10%. Losses covered by the program are capped at $100 billion, and the program permits the government to recoup the amounts paid by virtue of a surcharge on all policyholders.

Commercial property and casualty insurers will collect (by policyholder surcharge) the mandatory and discretionary recoupments and remit them to the federal government. Surcharges cannot exceed three percent of any policy's annual premium. TRIA was recently reauthorized to provide this coverage through 2014.[73]

2. Price Anderson Act. The Price-Anderson Act was enacted in 1957 to provide liability insurance for the nuclear power industry. The act provides no-fault insurance to benefit the public in the event of a nuclear power plant accident the Nuclear Regulatory Commission deems to be an "extraordinary nuclear occurrence." The costs of this insurance, like all the costs of nuclear-generated electricity, are borne by the industry. Nuclear power plants are required to show evidence of financial protection, and licensees must provide a total of more than $10 billion in insurance coverage to compensate the public in the event of a nuclear accident. This protection consists of two tiers. The primary level provides $300 million in liability insurance. This first-level coverage consists of the liability insurance provided by two private insurance pools. The pools are groups of insurance companies pledging assets that enable them to provide substantially higher coverage than an individual company could offer. If this amount is not sufficient to cover claims arising from an accident, secondary financial protection applies. For this second level, each nuclear plant must pay a retrospective premium equal to its proportionate share of the excess loss, up to a maximum of $100.6 million per reactor per accident. This includes a $95.8 million premium and a 5% surcharge that may be applied, if needed, to legal costs. All 104 operating reactors are participating in the secondary financial protection program. The Price-Anderson Act was extended for an additional 20 years by the Energy Policy Act of 2005.[74]

Though beyond the scope of this report, a federal or state statute authorizing a similar approach to address CCS insurance may prove to be a viable way to provide insurance to CCS operators and project sponsors if the private insurance market fails to develop.

4.3.2.3 Policy Options and Recommendations.

1. One option is to adopt the financial responsibility requirements that include the following elements:

    a. Adopt a NYSDEC permit process that requires RCRA type financial security to be provided by the CCS project sponsor (e.g., insurance, letters of credit) to ensure the implementation of operational and closure activities.

        i. It could also be supplemented with requirements for operational and performance bonds. The bonds would be similar to those required for the oil and gas and mining industry, that are not released until closure is implemented and approved. It is recommended that the Obligee (i.e., the state) accept letters of credit as well as insurance and surety bonds, to guaranty these obligations. A bank letter of credit (LOC) with an evergreen clause would work well with the above approach, with the state having the option of calling the LOC should the bond not renew and the Principal not be able to come up with a replacement guaranty.

b. Establish minimum liability insurance requirements as insurance products become available. Permit approval could be made subject to the CCS sponsor providing evidence of adequate liability insurance to be provided before a permit would be granted.
   i. This insurance could be extended to cover post closure liability concerns on a case by case basis as may be appropriate to allay state concerns over taking title to the CO_2 and assuming long-term liability during the post closure period, as provided in (c) below.
   ii. To provide additional incentives, the state could provide a tax credit for CCS liability insurance policies as is provided for Brownfield projects.75
   iii. The state could consider funding the insurance as was done by the state of Illinois (see Section 2.2 of this report).
   iv. If the private insurance market does not develop, consider either working with the federal government to establish a government subsidized insurance program and/or establishing a state sponsored insurance program modeled after TRIA and/or the Price Anderson Act that specifically addresses CCS financial responsibility concerns.

c. Establish CCS Trust Fund requirements, as contemplated by the IOGCC model rule. This approach builds on the existing OGL program, as contemplated by IOGCC: it provides a well funded state administered mechanism to ensure that post closure requirements are fully implemented. The state would assume title to the CO_2 and administer the CCS Trust Fund during the Post Closure Period.
   i. Any State CCS Trust Fund program could be subject to the development of an equivalent federal trust fund program. To the extent a federal program assumed long-term responsibilities and liability during the Post Closure Period, the New York trust fund obligations would be superseded (see Illinois FutureGen statute).

2. Another option would be to require private funding of long-term care by the CCS project sponsor, using the RCRA treatment storage and disposal facility approach. Nevertheless, as noted above, this was rejected by IOGCC; in addition, such an approach could present financial risks and seriously erode public confidence if private party bankruptcy were to occur in the future and/or post closure requirements were not fully implemented.

3. A third option would be to require long-term insurance throughout the Post Closure Period. The downside of this approach is that it remains unknown as to whether any such insurance product will exist in the future. It also raises the same public credibility issue since AIG, the largest insurance carrier in the world, recently required significant government aid to avoid financial collapse.

4. A fourth option would be to work with federal agency counterparts to evaluate the need and feasibility of establishing a government sponsored insurance program consistent with the TRIA and Price Anderson Act precedents discussed above. Implementing such a program at this time would be premature, given the uncertainty regarding the availability of CCS insurance coverage at this time.

4.3.3 Governmental Assistance for Early Mover CCS Projects

4.3.3.1 Overview. CCS projects, particularly those involving coal fired power plants, present a variety of significant financial and market risks that could significantly delay deployment. The characteristics of coal generating plants and carbon markets present multiple hurdles for the development of CCS. Generating power from coal derived fuels is a capital-intensive and requires large investments and long time-frame planning horizons. Full-scale 600-megawatt pulverized coal generating power plants without CCS cost hundreds of millions to billions of dollars to construct. As stated earlier in Sections 1.2 and 4.3, there are significant added costs to a CCS project and "Early Mover" demonstration projects will face a disproportionately increased cost because economies of scale will not be achievable. Plants are constructed for 30 to 40-year operating lives although many plants continue to operate after 50 years or more. Decisions to add or replace capacity and the choice of fuel type depend on electricity demand growth, the need to replace inefficient plants, the capital costs, and operating efficiencies of different options, fuel costs, and emission prices. Decisions are made conservatively after multiple scenarios and sensitivity analyses are evaluated. These uncertain market realities present a variety of significant financial and market risks to a CCS project sponsor and the ratepayers that they will be servicing, and this will have a chilling affect on project development.

One aspect of the financial risk associated with CCS alluded to in Section 1.2, is parasitic load loss for carbon capture and sequestration. At a conventional coal fueled power plant, parasitic load loss, or station service load as it is frequently called, is the power used for office buildings, the lights and computers at a generating plant, and pollution equipment. By contrast, parasitic load loss for CCS plants will be much larger because of the energy needs for the operation of oxygen separation or gasification equipment, compressors, air separation units and injection wells, among other equipment. In a competitive energy market, these significant additional energy costs for CCS projects will seriously affect their economic competitiveness relative to traditional coal plants not using CCS technology. Simply put, even if the significant additional construction cost of a CCS project are fully covered and the facility constructed, CCS power plants will not be able to be continue to operate without substantial subsidies or a carbon revenue stream to fill the funding gap attributable to CCS parasitic power costs.

These economic risks are particularly significant in a market-based environment. For example, the New York Independent System Operator (NYISO) process requires each supplier to bid daily into the NYISO market and the NYISO utilizes those bids to perform a least cost analysis that balances load demand and energy supply for each hour of the day. Facilities located in the NYISO Zone A, which includes many of New York's coal plants, is the lowest priced zone within the eleven zone NYISO system. This fact coupled with the higher costs associated with full CCS could result in a CCS unit not being dispatched when compared to other lower cost units within the bid stack.[76] Accordingly, unless some funding or balancing mechanism is determined, a full-scale CCS application will likely operate at lower than expected capacity factors and higher economic risk due to the higher cost nature of incorporating CCS as compared to other non-CCS units in the system.

CCS projects need carbon trading or other financial support to provide an adequate revenue stream to cover the cost due to parasitic load loss. Carbon trading, however, is in its infancy. In the first three auctions (September and

December 2008 and March 2009) held under RGGI, carbon trading program, the clearing price was below $4/ton of carbon that may not be sufficient to address this cost for CCS, which typically requires CO_2 prices in the $30 range or higher for demonstration projects. There are currently no other mandatory CO_2 trading programs in the U.S. Though there are several federal climate change bills under consideration in Congress, until these bills are enacted, CO_2 trading is unlikely to be significant, and CO_2 credit value will continue to be depressed. This is particularly problematic for early mover demonstration projects that are already negatively impacted by the market realities discussed in the previous subsection. To make matters worse, the 2008 Energy Act, which allows carbon credit subsidies at $20 per ton of sequestered CO_2[77], is only available to CCS projects sequestering greater than 500,000 tons per year. Based on the foregoing short-term economic realities and the absence of federal operating subsides for demonstration-scale projects, regardless of what may develop with federal climate change legislation, early mover projects and/or demonstration scale projects will be delayed and if and when they do move forward, ratepayers will be negatively impacted.

4.3.3.2 Precedent. Governor Paterson, in announcing his support for the demonstration scale CCS Oxy Coal power project in Jamestown, New York recognized the fundamental importance of these economic realities by conditioning his financial support on the development of a price support strategy that will protect the ratepayers in Jamestown. The Jamestown BPU must "establish…that Jamestown ratepayers are protected to the extent practicable from potential long-term operating losses associated with exploring and/or demonstrating the feasibility of CCS."[78]

It is significant to note that the RGGI planning document released in January 2009 specifically identifies geosequestration projects as being eligible for RGGI funding.[79] Though the credit values are currently low, this does represent a potential funding source to address the funding gap facing sponsors of CCS early mover/demonstration projects and the potential adverse economic impacts on ratepayers.

Though it may be reasonable to assume that sponsors of full-scale CCS power projects will be able to address these issues through a federal carbon credit trading program, CCS project sponsors of early mover projects and/or demonstration scale projects will not be able to move these projects forward unless government assistance is provided to offset the sizeable CCS construction and operation costs. Projects that are funded initially as demonstration-scale projects may go bankrupt and be forced to cease operation. To date, power plant owners and CCS developers have been unwilling to take on these risks.[80]

The need for governmental funding for early mover and demonstration scale projects has been recognized by political leaders in the international community:

> The particular characteristics of electricity and climate mitigation markets, as well as the scale of the technology, mean that demonstration will not be funded by the private sector alone. This is a classic example of market failure that is reliant on public policy and law to fix. Some form of partnership is needed where private firms (or consortia) deliver demonstration projects, mixing their own resources with additional public aid that compensates for first mover disadvantages.[81]

4.3.3.3 Policy Options and Recommendations. NYS could consider creating an Early Deployment Fund to cover a specified amount of the projected cost gap due to parasitic load loss for early mover/demonstration scale CCS projects based on financial modeling approaches found to be appropriate and approved by the state. Specific revenue sources could be made available through the NYPA and RGGI auction proceeds. By creating an Early Deployment Fund offering this type of assistance, the funding shortfall resulting from the high parasitic load costs associated with the development of new CCS technologies could be addressed by providing necessary financial incentives to spur on the development of early mover/demonstration power projects in NYS. Such a funding mechanism could encourage CCS project development in a responsible way that will protect the ratepayer from adverse, disproportionate impacts.

4.4 REGULATORY OVERSIGHT

4.4.1 CO_2 Pipelines

4.4.1.1 Overview. There is currently no federal regulation of the siting of CO_2 pipelines and the rates for pipeline transportation of commodities. This is due in large part to the facts that many of them are intrastate pipelines; and that they are used primarily to transport CO_2 for the benefit of the pipeline's owners, which do not typically result in any rate or service disputes.

The Natural Gas Act of 1938 (NGA) vests in FERC the authority to issue "certificates of public convenience and necessity" for the construction and operation of interstate natural gas pipeline facilities. FERC is also charged with extensive regulatory authority over the siting of natural gas import and export facilities, as well as rates for transportation of natural gas and other elements of transportation service. FERC, to date, has declined to take jurisdiction over CO_2 pipelines because CO_2 is not a "natural gas," as defined by the Natural Gas Act.

Similarly, in NYS, Article VII of the PSL authorizes the PSC to license the construction and operation of fuel gas transmission lines of 1,000 feet or more in length. Because CO_2 is not a fuel gas, Article VII does not apply to CO_2 being transported to a sequestration site.

Instead, the construction and operation of CO_2 lines in NYS is regulated by multiple federal, state, and local resource and regulatory agencies that have general authorities over discrete portions of a project. See Table 1 for a listing of permitting authorities. A more detailed discussion of these permitting requirements is presented in the CO_2 Pipeline Permitting Assessment Work Group paper included in Appendix B.

The DOT's Pipeline and Hazardous Material Safety Administration (PHMSA), Office of Pipeline Safety (OPS) administers pipeline safety programs applicable to design, construction, testing, operation, maintenance, and emergency response of pipeline facilities. While the federal government is primarily responsible for developing, issuing, and enforcing pipeline safety regulations, the pipeline safety statutes provide for state assumption of the *intrastate* regulatory, inspection, and enforcement responsibilities under an annual certification if their standards are compatible with minimum United States Department of Transportation (USDOT) standards. Where states have not adopted comparable programs the federal standards are enforceable by USDOT.

In NYS, the PSC is the certified DOT partner agency and administers the 49 CFR Part 195 program for natural gas pipelines, however, the PSC definition of a regulated “gas pipeline” does not does not include pipelines that transport CO_2 and consequently PSC does not currently have express authority to enforce 49 CFR Part 195 with respect to CO_2 pipelines.

4.4.1.2 Precedent. As noted above, licenses for major gas transmission pipelines in New York are obtained through FERC if there is interstate transmission or the PSC, if the project is entirely in the state. Both FERC and the PSC are responsible for determining whether there is a need for a particular project and issuing a certificate of environmental compatibility and public need for the project; however, under current law neither FERC nor PSC licensing processes are applicable to CO_2 transmission projects because CO_2 is not considered a “natural gas.”

Table 1 Potential Permits, Approvals, and Consultations Applicable to the CO_2 Pipeline and Geological Storage

Agency	Permits/Approvals/ Consultations	Applicability
Federal		
NEPA	Environmental Impact Statement or Environmental Assessment	**Entire project.** If project requires a federal permit or receives federal funding
U.S. Army Corps of Engineers	Clean Water Act Section 404 Permit Rivers and Harbors Act Section 10 Permit	**Pipeline.** NWP 12 required if pipeline crosses regulated water body or jurisdictional wetlands
U.S. Environmental Protection Agency	Safe Drinking Water Act Underground Injection Control Permit	Injection Class II wells for a variety of waste fluid disposal, enhanced oil/gas recovery, and hydrocarbon storage needs. Class V experimental technology wells to demonstrate a developing technology may be subject to more flexible, yet fully protective, technical standards
U.S. Environmental Protection Agency	Prevention of Significant Deterioration Permit (State Part 231 Proposed)	**Carbon Capture.** If unit is installed at an existing facility it would result in the reduction of emissions
U.S. Fish and Wildlife Service	Section 7 Endangered Species Act Consultation	**Entire Project.** Consultation required if project is required to obtain federal approval (e.g., disturbance of federal wetland). A take permit would be required if there is a potential to take, or harass a threatened and endangered species
Advisory Council on Historic Preservation	Section 106, National Historic Preservation Act	**Entire Project.** Consultation required if project is required to obtain federal approval
U.S. Department of Transportation, Federal Highway Administration	Federal Highway Encroachment Permit	**Pipeline.** Required in pipeline crosses federal highway
	49CFR Part 195 - Design standards	Applicable to pipeline design standards
State		
State Environmental Quality Review Act	Environmental Assessment Form or Environmental Impact Statement	**Entire Project**. If project requires a state or local action
New York State Historic Preservation Office	Cultural Resources (Section 106/NHPA) Consultation/Clearance	**Entire Project**. Consultation required if state or federal approval is involved
New York State Department of Environmental Conservation	Air Emissions Part 201 Pre-construction Permit	**Carbon Capture.** If unit is installed at an existing facility it would result in the reduction of emissions
	Water Quality Certification (Section 401 Permit)	**Pipeline.** If project crosses federally regulated wetlands or protected streams and/or require permits under §404 CWA (navigable waters) or §10 Rivers and Harbors Act.
	State Pollution Discharge Elimination System (SPDES) Construction General Permit for Storm Water Discharges	**Entire Project**. If project construction disturbs one or more acres

Table 1 Potential Permits, Approvals, and Consultations Applicable to the CO_2 Pipeline and Geological Storage

Agency	Permits/Approvals/ Consultations	Applicability
	Article 15 Protection of Waters; Article 24 Freshwater Wetlands; Article 25 Tidal Wetlands	**Pipeline.** If project involves excavation and fill in navigable waters or otherwise disturbs state regulated wetlands
New York State Department of Environmental Conservation	Well Drilling Permit (Issued to Well Driller/Operator)	**Injection.** Permits required for drilling activities and well plugging
New York State Department of Transportation	State Road Use Permits	**Pipeline.** Permits required if pipeline crosses a state highway
	Highway Work/Utility/Non-utility Permits Consultation	
New York State Department of Agriculture and Markets	Consultation with respect to impacts to agricultural lands	**Entire Project**. Consultation required if project impacts agricultural lands
Local		
County Highway Department	Road use permits	**Pipeline.** If project crosses town/county road
Town/County Planning Board	Building permits/zoning approvals	**Entire Project**. If town/county has enacted local requirements

Under the FERC process, an applicant for a natural gas pipeline would obtain a certificate of need and necessity from FERC, and concurrently, but separately, obtain federal, state and local resource/regulatory agencies permits as may be required for discrete portions of the project subject to their jurisdiction. FERC acts as the lead federal agency under NEPA for all pipeline projects under its jurisdiction and the FERC NEPA document can be used by other permitting agencies in support of their review of individual permit applications. Under Section 7 of the Natural Gas Act, FERC has the authority to authorize the taking of property through eminent domain to facilitate the siting of a project for which a FERC certificate has been issued.

Under the New York's Article VII process, the PSC acts as the sole state licensing entity for a project. Though it does not currently apply to CO_2 pipelines, the current PSC regulatory program offers useful precedent that should be considered, if it were to be expanded to cover this activity. The PSC is required to make a determination of environmental compatibility and public need for a project and coordinate with state and local resource and regulatory agencies to ensure that the substantive requirements of laws and regulations administered by those agencies are met. Once a certificate is obtained from the PSC, the project sponsor is not required to obtain individual project permits from any state or local agencies, although acquisition of permits from federal agencies (e.g., United States Army Corps of Engineers) is still required. The Article VII process supersedes and exempts a project from needing a separate SEQRA review. Unlike the authority issued through FERC approvals, approval through the PSC does not provide applicants with eminent domain authority.

4.4.1.3 Policy Options and Recommendations. The existing permitting structure provides a workable permitting approach for an applicant considering constructing a CO_2 project in the near term. In the long term, however, a statewide permitting program administered by the PSC that is similar to Article VII and is coordinated with SEQRA and the NYSDEC permitting process, may be preferable:

1. One option would be to expand PSC's jurisdiction by amending Article VII as follows:

    a. Grant authority of PSC over CO_2 pipelines, authorizing PSC as the agency responsible for the review and approval of all aspects of an interstate or intrastate pipeline under NYS jurisdiction. Though federal approvals such as a USACE permit for wetland or stream impacts would still need to be obtained separately, state permits could be consolidated and expedited through amended Article VII provisions:

i. The new provisions would set forth standardized requirements regarding the contents of an application;
ii. These provisions would also clarify how the application is to be integrated into the SEQRA process and how the PSC is to coordinate its review functions and be integrated into the SEQRA process. By folding the pipeline review into the SEQRA process, segmentation concerns will be avoided; further, by fully engaging PSC in the SEQRA process as a consulting agency, substantive issues will be properly addressed. Though currently Article VII establishes the PSC as the lead permitting agency to provide “one-stop shopping” for all state and local permits, given the fact that the pipeline is an ancillary part of a larger permit process that involves CO_2 capture and sequestration, deference to SEQRA would seem to be preferable. Requiring duplicative environmental and permit reviews by two separate state agencies would give rise to potential delays and unjustified expense; in this case, NYSDEC is already engaged in the review of both the capture and sequestration portions of the project and therefore appears to be better suited to manage the environmental aspects of the CO_2 pipeline component of the project so long as PSC is allowed to participate fully in the process and lend its expertise in establishing appropriate pipeline specific permit conditions;
iii. Specific requirements would make it clear that CO_2 pipelines are to meet applicable federal and state design standards;
iv. The amended law could specifically incorporate the existing Article VII provisions for shorter pipelines to ensure that the permit process for pipelines falling below the regulatory size threshold, are treated in an expedited manner;
v. Once the SEQRA review is completed, PSC could retain authority to implement pipeline permit conditions and override unreasonably restrictive local requirements. The local agencies would have an opportunity to comment on the project during the SEQRA process and again during the implementation of the PSC two phase approval process, but the final licensing/permitting decisions would lie with the PSC.
vi. In addition, PSC could retain authority to grant Certification once environmental requirements established under SEQRA were agreed to, along with any other substantive requirements established by PSC that were consistent with the SEQRA findings, based on the same two-step PSC approval process currently being employed. During the first phase, the PSC could make a decision on whether or not to issue a license based on conceptual design information and drawings that provide enough detail to evaluate the potential impacts of the project, but not detailed enough to construct the project. After a license has been issued, the second phase could require a review of the applicants Environmental Management & Construction Plan (EM&CP) that includes design details. As is currently the case, a project could not be constructed until the EM&CP has been made available for public comment and approved by the PSC;
vii. To facilitate the pipeline construction, the legislature should consider granting eminent domain authority to an applicant once a certificate has been issued and the applicant has made a demonstra-

tion to PSC that it has exercised all reasonable measures to obtain easement agreements through other means.

2. A second option may be to allow the existing system to remain and allow NYSDEC to deal with issues relating to the pipeline aspects of the project through the existing SEQRA and permit review process.

4.4.2 Risk Assessment and Mitigation

4.4.2.1 Overview. As indicated in Sections 3 and 4.3.1, the threat of statutory and common law liability is a significant concern for persons engaged in CCS activities, particularly those that are engaged in the implementation of demonstration projects where the uncertainties and unknowns associated with the application of new technologies and systems is the greatest. Nevertheless, much progress is being made to identify and further mitigate the potential risks associated with CCS.

Scientists at Massachusetts Institute of Technology and Lawrence Berkeley National Laboratories, and the many scientists comprising the IPCC, among others, have proposed geologic sequestration as a technologically feasible and environmentally responsible means of mitigating GHG emissions. Carbon sequestration partnerships organized by the federal government have also concluded, after analysis of hundreds of saline formations, coal bed seams, and other subsurface reservoirs, that CO_2 may be stored in numerous subsurface basins. Enhanced oil recovery (EOR) projects, while primarily designed to maximize the extraction of oil and gas minerals rather than the long-term storage of CO_2 to mitigate climate change, nonetheless provides useful precedent for developing sequestration projects. EOR involving the transportation, injection, and storage of large quantities of CO_2 has been implemented for the past 30+ years and has demonstrated that it can be accomplished in a safe manner. The developing CCS regulatory framework discussed in this report will provide additional assurance that CCS activities will be implemented in a safe and responsible manner.

4.4.2.2 Precedent. As indicated below, risk assessments conducted to date support the conclusion that the potential risk attendant to CO_2 sequestration activities appears to be small and acceptable. Still, this cannot be assumed and it is appropriate and reasonable to require each proposed sequestration site to be evaluated from a risk perspective on a case by case basis. Approaches to quantifying potential CCS risk and establishing appropriate mitigation measures are being developed and the utility of these approaches needs to be fully assessed. Any site specific assessment of risk requires the collation of geologic, demographic, and engineering data. The health effects data, including the risks of asphyxiation and other consequences of CO_2 over exposure are well understood and do not require reliance on extrapolated dose-response data from animals to man, but also has to be integrated into the site-specific risk assessment process.

4.4.2.3 Risk Assessment. Recently a quantitative safety assessment has been conducted for potential CO_2 sequestration sites on behalf of the DOE for the FutureGen Project[82]. Although the risk assessments done for those sites no doubt are based on site specific factors, which may limit their utility in assessing risk on sites located in NYS, the results of the FutureGen safety assessment use sound, well respected methodologies and are illustrative of the type of concerns that might arise if a similar assessment of CO_2 sequestration activity were conducted on a site in New York. A summary of the risk assessment protocols used on the FutureGen project are provided in Appendix B, Risk Assessment Workgroup Report.

Evolving practice in this area allows a number of critical risk issues to be evaluated and addressed early-on during the site selection process. Rigorous site selection review criteria, also developed from work sponsored by DOE for the FutureGen Project, maximize the likelihood that the geologic conditions at the selected sequestration site will be suitable for the long-term, safe storage of CO_2 and that continued sequestration of CO_2 at the selected site will be protective of human health and the environment. In addition, the permit review processes will also focus on the technology and procedures to be used during all aspects of CCS activities and identify appropriate alternatives if warranted, based on health and safety considerations. If unacceptable risks cannot be addressed, the permit review system allows regulators to deny the permit and prevent project implementation. It is essential that risk management plans for CCS projects take into account the project lifetimes of capture and sequestration[83] and that they are flexible enough to allow alterations to be made to the plan as the project proceeds and project needs change or new information becomes available.

Recently, the DOE's National Energy Technology Laboratory (NETL) reviewed the consequences of release of natural underground stores of CO_2 in volcanic formations near Lake Nyos (Cameroon) and Mammoth Mountain (California). Regarding safety associated with engineered CO_2 sequestration stores they commented:

> The likelihood that any stored CO_2 [from an engineered sequestration project] will escape from the target formation will be very low. A large portion of any CO_2 that does escape will often be dissolved or trapped in the strata that lie above the injection site, prior to reaching the surface. Underground monitoring technologies such as three dimensional seismic surveying will give operators years or even decades of advanced notice that CO_2 could escape the target formations. Geologic sequestration poses no additional risks beyond the daily risks currently associated with CO_2 injection in the oil and gas industries. …All of these projects continue to operate in a safe, effective manner with a low level of environmental safety and health risk. The risk of large, catastrophic releases of CO_2, such as occurred at Lake Nyos and Mammoth Mountain, are virtually non-existent for geologic sequestration.[84]

The EPA considers that risk of asphyxiation and other chronic and acute health effects from airborne exposure resulting from CO_2 injection activities (even in the case of leakage or accidental exposure) is minimal. This finding is based on experience gained in the oil and gas industry, experience from international GS projects, and evaluations of large scale releases of naturally occurring CO_2.[85]

The CAA, in the 1990 CAA Amendments set forth in Section 112 (r) of the CAA and described in Section 3.1.2 of this report, requires owners and operators of stationary sources to identify hazards posed by extremely hazardous substances, by conducting probable risk assessments based on the type and quantity of material handled, transported or stored on site and evaluations of worst-case consequences.

4.4.2.4 Risk Mitigation. Once potential project risks are identified and assessed, it is important to address these risks by developing appropriate risk mitigation measures. For example as part of the 112(r) risk provisions under the CAA, the person conducting the risk assessment is required to develop risk management plans to mitigate the potential occurrence of a catastrophic release, as well as its consequences if such an event were to take place.

As mentioned earlier in this section, the most effective way to reduce risk is ensure that all components of a CCS operation (e.g., capture equipment, pipeline and sequestration site) are properly sited. Actions that further reduce the probability or consequence of a release include:

- Material selection and design criteria that address the conditions of transporting and injecting CO_2;
- Identification of and proper sealing of inactive wells in the vicinity of the project;
- Physical containment and/or leak minimization practices, such as bladders, double walled piping;
- Operating practices, such as following industry-specific guidance and/or stringent Occupational Safety and Health Administration work safety procedures that define safe actions or reduced injection rates;
- Response plans for potential and actual upset conditions;
- Direct and indirect leak detection and monitoring equipment; and/or
- Reduction of injection volumes to mitigate the potential for release.

The SEQRA permitting process in New York, which forces a thorough assessment of project alternatives, will play a significant role in providing assurances, to participating regulatory agencies and the public at large, that risks posed by a particular project will be mitigated to the extent possible.

4.4.2.5 Policy Options and Recommendations. Set forth below are a number of policy options that should be considered to address risk issues associated with CCS projects:

1. One option is to develop a unified approach to evaluating all aspects of project risk. This approach will identify and quantify those risks to the extent practicable; and develop appropriate mitigation measures to minimize potential adverse impacts of potential releases from carbon sequestration facilities, on human health and the environment. Specific activities under this option include the following:

    a. Continue to require rigorous site selection protocols to be applied, similar to those established for the FutureGen project, as a screening tool to maximize the likelihood that the preferred and alternative sequestration sites meet acceptable criteria for the safe sequestration of CO_2.

b. Conduct probabilistic risk assessment activities that are consistent with the approach set forth in Section 112(r) of the CAA, including public participation, hazard assessments, release prevention, emergency response, and mitigation.

c. Obtain the location specific data over time and conduct a quantitative analysis of risk to underground sources of drinking water as described in the proposed rule for Class VI Wells for Geological Sequestration.

d. Conduct routine reviews of risk methodologies to be performed so that state of the art refinements can be integrated into the risk assessment process.

e. Concurrent with the risk assessment work outlined above, require identified risks issues to be adequately addressed and mitigated in a risk management plan.

2. A second option would be to adopt the recommendations outlined in option 1 and to supplement those activities with a comprehensive site-specific health risk assessment that is focused on the first CCS demonstration project(s) in New York. This comprehensive, rigorous site-specific risk assessment methodology would integrate current risk assessment procedures that have been used on other projects. For example, the approach used on the FutureGen projects would be evaluated for applicability and adapted as appropriate, together with other CCA risk assessment procedures and models that have been used on other projects and/or are currently under development. In addition, the comprehensive risk assessment methodology would incorporate decision analysis protocols that would allow the risk assessment team to critically evaluate the various types of decisions to be made (e.g., design, operation, mitigation, response), the potential consequences of those decisions, the possible outcomes and their associated costs. The use of more sophisticated procedures such as these will increase public confidence in the bases for decision making, reduce the likelihood that an inappropriate location for project development would be chosen and provide reassurances to the public that project risks have been properly identified and mitigated. This approach will also allow the reviewing agencies to identify any gaps or inappropriate components of the methodology and develop appropriate refinements and recommendations.

4.4.3 Hydraulic Fracturing

4.4.3.1 Overview. In response to interest in developing the Marcellus Shale on the part of natural gas exploration and production companies and mineral rights owners, NYSDEC is reviewing the use of hydraulic fracturing under the State Environmental Quality Review Act (SEQRA).[86] Specifically, the SEQRA review covers the horizontal drilling and the high-volume hydraulic fracturing (also known as *slick water fracturing*) necessary for developing the Marcellus Shale. Developed in the late 1990s, high-volume hydraulic fracturing uses less gelling agents and a higher proportion of water, but a significantly increased amount of water (while a typical hydraulic fracturing operation will use up to 80,000 gallons, high-volume fracturing can use as much as millions of gallons).[87]

The current regulatory framework for oil and gas wells in NYS consists of regulations under 6NYCRR 550 through 559, the Oil, Gas and Solution Mining Law, and the regulatory program outlined in the final Generic Environmental Impact Statement (GEIS) on the Oil, Gas and Solution Mining Regulatory Program. While 6NYCRR 550 through 559 do not specifically address hydraulic fracturing, general language in the regulations could be interpreted to apply to stimulation, specifically:

- “The drilling, casing and completion program adopted for any well shall be such as to prevent pollution” (Part 554.1 [a])

- “Pollution of the land and/or of surface or ground fresh water resulting from exploration or drilling is prohibited” (Part 554.1 [b])

- “Except as hereinafter provided, sufficient surface casing shall be run in all wells to extend below the deepest potable fresh water level” (Part 554.1 [d])

- “The drilling, casing and completion program adopted for any well shall be such as to prevent the migration of oil, gas or other fluids from one pool or stratum to another” (Part 554.1 [e])

The Final Scope DSGEIS speaks directly to this last bullet as follows:

> Department regulations presently require, and will continue to require, that freshwater aquifers be sealed behind cemented steel pipe before a well is drilled to the depth where hydraulic fracturing will occur, which is typically thousands of feet below the aquifers”.[88]

Additional regulatory procedures included in the 1992 GEIS also include: conditions attached to permits; inspections; and enforcement actions.[89] Well permits, required before site activities can begin, are reviewed by the NYSDEC Division of Mineral Resources in accordance with SEQRA.[90] The GEIS sets parameters that are applicable statewide for SEQRA review of gas well permitting.[91] A proposed mitigation included in the 1992 GEIS is the need to include with a permit application a proposed drilling program that addresses, among other issues, stimulation procedures.[92]

<u>4.4.3.2 Precedent.</u> The legal and regulatory precedent with regard to hydraulic fracturing appears to address the concerns that will apply to hydraulic fracturing for a CS well. The potential issues are broadly addressed in Article 23, Title 3 of the ECL that authorizes NYSDEC to require that wells be drilled, constructed, operated and plugged, and the surrounding land reclaimed, to prevent or *remedy* "the escape of oil, gas, brine or water out of one stratum into another" and "the pollution of fresh water supplies by oil, gas, salt water or other contaminants" [ECL §§23-0305(8)(d) and (g)].[93] Language regarding hydraulic fracturing expressed in the 1992 GEIS is focused entirely on the potential for contamination of surface water and groundwater by frac fluids. Other aspects of the GEIS, regarding well completion, address migration of gas or fluids from one geologic layer to another without specifically addressing the potential for hydraulic fracturing to create migration pathways through cap rock.

EPA's proposed rule for Class VI wells for geologic sequestration recognizes that GS wells may need to be fractured to enhance injectivity:

> There are some circumstances, however, where fracturing of the injection zone would be acceptable provided the integrity of the confining system remains unaffected. For example, hydraulic fracturing is a process where a fluid is injected under high pressure that exceeds the rock strength, and the fluid opens or enlarges fractures in the rock. EPA recognizes that there may be well completions which require intermittent treatments, including hydraulic fracturing of the injection zone, to improve wellbore injectivity. Such stimulation of the injection zone during a well workover (as defined in 40 CFR 144.86(d)) approved by the Director would be permissible.[94]

In addition to state and federal regulations regarding fracturing of bedrock formations, river basin commissions regulate water use. Both the Delaware River Basin Commission (DRBC) and the Susquehanna River Basin Commission (SRBC) cover portions of NYS, regulate water usage, and have developed, or are in the process of developing, rules specifically with regard to the development of gas wells in the Marcellus Shale.

The DRBC's authority extends over eastern portions of New York and Pennsylvania, as well as portions of New Jersey and Delaware that fall within the basin. The DRBC was originally founded in 1961 between the states listed above and the federal government. The three major areas of interest of the DRBC relate to:

- Water withdrawal (e.g., water for hydraulic fracturing);
- Well site development/operation; and
- Wastewater storage, treatment, and disposal.

Relevant DRBC Regulatory Requirements include Section 3.8 of the DRBC Compact "No project having a substantial effect on the water resources…. Unless it shall have been first submitted to and approved by the Commission…"[95] regulations regarding water usage are addressed under Rules of Practice and Procedure and Water Quality Regulations. While DRBC rules do not specifically identify projects based on a water usage threshold, existing DRBC rules are focused on water uses significantly larger than that required for standard hydraulic fracturing, (e.g., groundwater systems that withdraw an average of 10,000 gpd or more during any 30-day period and owners of water supply systems serving an average of 100,000 gpd or more during any 30-day period). No DRBC rules specifically mention hydraulic fracturing or stimulation.

The SRBC recently promulgated a rule specifically identifying natural gas development projects targeting the Marcellus or Utica shale formations as projects requiring review and approval by the SRBC.[96] Under current SRBC regulations however, projects requiring review include those that will consume or divert an average of 20,000 gpd or more over a consecutive 30-day period, or withdrawal an average of 100,000 gpd over a consecutive 30-day period

(18 CFR 806.4). This level of withdrawal and consumption is also considerably higher than the volumes required for standard hydraulic fracturing.

Jamestown is in the Conewango River basin, that drains to the Allegheny River, which then drains to the Ohio River. The Ohio River Valley Water Sanitation Commission (ORSANCO) regulates water quality in the Ohio River and its tributaries. Still, there apparently are no ORSANCO regulations on the development of groundwater wells in the Ohio River basin. A search of the ORSANCO Web page showed no mention of groundwater issues or groundwater regulations.[97]

4.4.3.3 Policy Options and Recommendations. Hydraulic fracturing for carbon sequestration should be conducted in accordance with the SGEIS currently being prepared to address high volume hydraulic fracturing in shale gas plays such as the Marcellus Shale, because the volumes of water in both cases will exceed the 80,000 gallon "high volume" threshold specified in the SGEIS.

Water withdrawal, management, and disposal within the Delaware and Susquehanna river basins are already regulated by the DRBC and SRBC. The use of water related to fracturing projects including those for CS will be subject to approval by the appropriate river basin commission in the same fashion as hydraulic fracturing for natural gas.

Under EPA's proposed Class VI rules, EPA is seeking comment regarding the use of hydraulic fracturing as a method of reservoir stimulation in carbon sequestration injection wells.

Section 5.0
CONCLUSIONS

In order for NYS to move forward with the in-state development of CCS technology, a regulatory framework will need to be developed that provides for the protection of public health and safety as well as the environment while at the same time providing predictability for CCS developers. In addition, a number of issues confronting the deployment of CCS in New York as outlined in this report will need to be addressed by public policymakers.

The following policy options should be considered:

- A comprehensive CCS regulatory program that considers relevant existing NYS statutory and common law precedents in the context of new regulations

- A statutory scheme similar to those endorsed by Wyoming and the IOGCC Model rule, which address property rights issues by identifying the surface owners as having ownership of subsurface pore spaces below their properties

- Identification and creation of a regulatory scheme informed by programs in analogous industries—waste disposal, gas storage, oil, and gas extraction

- A regulatory framework that builds on existing OGL natural gas extraction and storage programs that define spacing units to identify production area boundaries; utilize an integration process to identify ownership interests with access and the injection rights; establish procedures to facilitate mineral storage in reservoir areas and buffer zones; utilize a unitization process to maximize mineral extraction efficiency; establish due process safeguards; establish minimum control thresholds of mineral ownership interests before state permits can be filed by project sponsors; and establish appropriate regulatory procedures (e.g., compulsory integration and eminent domain) that allow pore space owners to earn fair compensation for the use of their property

- A detailed review of other statutes to identify those that should be amended to address CCS projects. For example, Environmental Conservation Law Section 23-0301, Declaration of Policy, is often cited as an appropriate rationale for legislation authorizing the extraction of oil and gas, underground storage of gas, solution mining of salt, and installation of brine disposal wells and geothermal and stratigraphic wells. It may prove helpful to amend the OGL statute to include CCS

- The development of a fair and rational approach to providing compensation for access and use of surface lands for drilling and injection purposes, and the use of underlying pore spaces for CO_2 sequestration

- The development of new state and federal laws that use other proposed or existing laws as models. Illinois and Texas enacted statutes that address CO_2 ownership and liability issues and similar laws can be drafted in New York for "Early Movers," as an incentive to invest in CCS activities. Similarly, precedents from other jurisdictions can be used to limit rights to ownership and compensation, as appropriate.

In addition, it is well documented that CCS will add significant costs to power plant projects that could be so prohibitive as to prevent their commercial development and deployment. Some of the cost barriers to the implementation of a CCS program in New York include the following, regardless of whether the CCS is associated with a Greenfield or retrofit project:

- Highly site-specific costs, varying from less than US $0.50 to more than US $30 per ton of avoided CO_2 capture and sequestration;

- Energy consumption to capture, compress, and sequester CO_2;

- Current lack of market incentives or regulatory certainty;

- Lack of knowledge about available and potential capacity of subsurface rock formations and long-term geographic sequestration suitability; and

- Difficulties associated with matching large CO_2 sources with suitable sequestration reservoirs and the inability to optimize an associated sequestration repository network.[98]

While financial incentives can stimulate the demonstration of CCS, such incentives will not be enough to drive the widespread commercialization of these technologies unless the liability issues are addressed. Special consideration should be given to the "early movers" willing to engage in the first CCS demonstration projects as CCS regulatory programs develop, because they are the ones that will bear the greatest financial liability and technical risk and their successful development of these initial projects is critical for widespread, accelerated CCS project deployment.

Because of the important role that the private sector will play on CCS projects, it is important that public and private partnerships be encouraged by the CCS regulatory program. Both parties must be able to agree on the importance of sharing risk and to find a way to strike a balance between the risks that currently loom large, and the future goals and objectives that both are committed to achieve. The best use of incentives will require flexibility with respect to a range of terms and conditions. A single project may require more than one incentive, depending on the nature and importance of the risks the project faces and the capacity of a project's sponsors to manage them. If we are to meet the global climate change challenge before us, government agencies and private entities must be able to consider and accept a range of alternative approaches to address different risks and achieve their respective goals.

The creation of a CCS Early Deployment Fund could play an important role in helping to reduce uncertainty about budget cycles and provide consistent, large-scale funding to enable critical early deployments of fully integrated CCS projects. Such a Fund would help accelerate the deployment of CCS by: (a) covering the additional cost of CCS technologies, (b) protecting the ratepayers of the community(ies) hosting the first CCS projects and (c) addressing the full range of CCS liability issues. Projects not generating electric power that use petroleum coke or other fossil fuels to produce energy, could also qualify for CCS incentives if they are able to commit to comparable, large-scale CCS activities.[99]

The CCS challenges facing New York are clearly stated in the *Operating Plan for Investments in New York under the* CO_2 *Budget Trading Program and the* CO_2 *Allowance Auction Program:*

> Given the level of sophistication of current and emerging power generation technologies, carbon capture and sequestration are the only means now available to permit continuing use of fossil fuels without releasing climate-changing GHGs into the atmosphere. Current U.S. DOE estimates put New York's onshore sequestration potential at more than three billion tons of CO_2, enough capacity to eliminate all of the state's power plant-generated emissions for nearly 50 years. By capturing and sequestering the lifetime emissions from one 600-megawatt integrated gasification combined-cycle power plant, the release into the atmosphere of more than 150 million tons of CO_2 could be avoided. Before these benefits can be realized, however, capture technologies need to advance and site-specific geological research needs to be conducted to determine the best methods and locations to sequester CO_2. Projects funded through this program will focus on assessing and demonstrating carbon capture, reuse, compression, and transport technologies, characterizing and testing the state's geological sequestration potential, and supporting development of carbon capture and sequestration demonstration projects in New York.[100]

E & E welcomes the opportunity to further assist NYS in developing a successful CCS regulatory framework that will address the numerous legal, permitting and policy issues outlined in this report.

Appendix A

LIST OF WORK GROUP MEMBERS

Appendix B

WORK GROUP REPORTS

Appendix C

ENVIRONMENTAL PERMITTING OF CARBON DIOXIDE CAPTURE AND SEQUESTRATION PROJECTS

ENDNOTES

1 Press release announcing Governor Paterson's support of the Jamestown Oxy-Fuel project, June 6, 2008.

2 Task 4 Milestone 1, scope of work document, NYSERDA and E&E.

3 "Cost and Performance Baseline for Fossil Energy Power Plants Study, Volume 1: Bituminous Coal and Natural Gas to Electricity," Revised Final Report, August 2007, RDS for NETL.

4 Yamagata, B. 2008, "Policies to Promote the Implementation of CCS Power Plants", MIT Carbon Sequestration Forum, Advancing CO2 Capture, Cambridge, MA, MIT.

5 For example, see "Carbon Capture and Sequestration: Framing the Issues for Regulation," Interim Report for the CCSREG Project, Department of Engineering and Public Policy, Carnegie Mellon University (December 2008).

6 See "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells," 73 Fed. Reg. 43492 at 43523 (July 25, 2008).

7 Ibid., at 43503.

8 42 USC 330h-1 of the SDWA provides that states may apply to the EPA for delegated authority to administer the UIC program; those receiving such authority are referred to as "Primacy States." This section requires Primacy States to meet the EPA's minimum federal requirements for UIC programs, including construction, operating, monitoring and testing, reporting, and closure requirements for well owners or operators; the states can seek full program authority or authority to administer portions thereof. (See 73 FR 43523 (July 25, 2008)) If a state does not seek this responsibility or fails to demonstrate that it meets the EPA's minimum requirements, the EPA is required to implement a UIC program for that state by regulation. New York is not currently a Primacy State and has not applied for UIC delegated authority and, therefore, the EPA is required to administer the federal UIC program in New York. Pursuant to 42 USC 300h-2 (d) of the SDWA, until New York applies for primacy, New York is authorized to enact its own, separate CCS underground injection program to protect its groundwater systems, with the understanding that the state program will operate concurrently and in addition to the federal UIC program.

9 See Texas S. B. No. 1461, enacted April 26, 2007.

10 See "Clean Coal FutureGen for Illinois Act," Illinois Public Act 095-0018 (SB 1704 enrolled).

11 Full report of New Mexico sequestration regulation "blueprint" available at: http://www.emnrd.state.nm.us/ocd/documents/CarbonSequestrationFINALREPORT1212007.pdf.

12 See NETL: News Release – "DOE Completes Large-Scale Carbon Sequestration Awards", November 17, 2008.

13 WAS 173-218-115.

14 "Storage of Carbon Dioxide in Geologic Structures: A Legal and Regulatory Guide for States and Provinces", the Interstate Oil and Gas Compact Commission Task Force on Carbon Capture and Geologic Storage, September 25, 2007.

15 Id.

16 Miles v. Home Gas Company, 35 A.D.2d 1042 (1970).

17 International Salt Co. v. Geostow, 878 F.2d 570 (2nd Cir. 1989).

18 See generally Prosser, Torts [4th ed], § 78.

19 Doundoulakis v. Hempstead, 42 N.Y.2d 440, 448 (1977).

20 State v. Schenectady Chemicals, 103 A.D.2d 33, 38 (N.Y. App. Div. 3d Dep't 1984).

21 Doundoulakis v. Town of Hempstead, 42 N.Y.2d 440, 448 (1977).

22 State v. Shore Realty Corp., 759 F.2d 1032, 1051 (2d Cir. N.Y. 1985) (applying New York law).

23 N.Y. NAV. LAW, § 181(1) (2008) ("Any person who has discharged petroleum shall be strictly liable, without regard to fault, for all cleanup and removal costs and all direct and indirect damages, no matter by whom sustained. . . ."); see also Busy Bee Food Stores v. WCC Tank Lining Technology, 202 A.D.2d 898, 899 (N.Y. App. Div. 3d Dep't 1994).

24 Boston v. Dunham, 274 A.D.2d 708, 710 (N.Y. App. Div. 3d Dep't 2000) (establishing that a claimant must fall within the class to be protected by the statute in relying on violation of a statute to prove negligence per se); Sharrow v. N.Y. State Olympic Reg'l Dev. Auth., 193 Misc. 2d 20, 35 (N.Y. Ct. Cl. 2002) (holding that the statutory provisions on which claimants rely must be designed to prevent the type of accident for which claimant seeks recovery); see also RESTATEMENT (THIRD) OF TORTS § 14 (Proposed Final Draft 2005).

25 Another question presented by common law tort actions is the period within which a potential plaintiff would be permitted to bring a cause of action against the owner/operator of the underground storage facility. New York's Statute of Limitations permits an action to be brought three years after discovery of the negligence. Christy v. Harvey, 262 A.D.2d 755 (N.Y. App. Div. 1999). Therefore, the owner/operator of the underground storage facility could be liable potentially indefinitely for CO_2 leaks discovered long after the facility could be operational.

26 In Chance v. BP Chemicals, Inc., 670 N.E.2d 985 (Ohio, 1996), the court held that subsurface rights only include the right to exclude invasion that actually interfere with reasonable and foreseeable uses of the subsurface. On the other hand, there are arguments for maintaining subsurface depths as private property as ever advancing technology reveals new commercially economic value in deep strata, which might not be considered today.

27 See Anthony v. Chevron USA, Inc., 284 F.3d 578 (5th Cir. 2002), rejecting two models presented by plaintiffs to prove that salt water injections had contaminated their aquifer.

28 In Mongrue v. Monsanto Co., 1999 WL 970354 (E.D. La. 1990) the court explained that the regulator does not bar claims of trespass when authorizing the disposal of waste through underground injection wells. Still, the plaintiff has the burden of proof that the migration of injectate interfered with a reasonable and foreseeable use of their property. In Mechlenbacher v. Akzo Nobel Salt, Inc., 71 F.Supp.2d 179, 193 (W.D.N.Y.1999), vacated in part, 216 F.3d 291 (2d Cir. 2000), the United States District Court for the Western District of New York decided that without proof of "actual physical damage to a plaintiff's property, stigma damages alone are too remote and speculative to be recoverable."

29 See CPLR section 214-c, which allows for the statute of limitations to be extended to three years from "the date of discovery of an injury or the date when through the exercise of reasonable diligence such injury should have been discovered." This extension provisions is triggered by an injury to person or property if caused by the "latent effects of exposure to any substance or combination of substances, in any form, upon or within the body or upon or within property"

[30] The minority view is probably most clearly set forth in the Kentucky case of Century Kentucky Natural Gas Co., v. Smallwood, 252 SW2d 204 (Ky. Ct. App. 1952) where the court held: "We conclude that the mineral rather than the surface owner is entitled to rental or royalty accruing under a gas storage lease." The case was later overturned, but on a different issue in Texas American Energy Corp. v. Citizens Fidelity Bank & Trust Co., 736 S.W.2d 25 (Ky. S.Ct. 1987).

[31] Williams & Myers, Oil and Gas Law, Section 1:22, pages 334-335.

[32] For example, see Section 240 of the NYS Labor Law. The leading case in New York regarding common law liability is Basso v. Miller *et al.*, 40 N.Y.2d 233 (1976). The duty of the landowner should not vary with the person using the property, but he should act reasonably to maintain safe conditions in view of all the circumstances, including the likelihood of injury, the seriousness thereof and the burden of avoiding the risk, and the likelihood of the plaintiff's presence should be a primary independent factor in determining foreseeability.

[33] NYSDEC recently issued a proposed Technical Guidance Document to evaluate GHG emissions as part of the SEQRA review process. See Guide for Assessing Energy Use and Greenhouse Gas Emissions in an Environmental Impact Statement, dated September 9, 2008.

[34] Indeck Corinth,L.P. v. David A. Paterson, as Governor; New York State Department of Environmental Conservation; New York State Energy Research and Development Authority; and New York State Public Service Commission (filed January 29, 2009, NYS Supreme Court, Saratoga County).

[35] See the NYSDEC RGGI Web site, http://www.dec.ny.gov/energy/rggi.html. Accessed February 27, 2009.

[36] NYSERDA, "Operating Plan for Investments in New York under the CO2 Budget Trading Program and the CO_2 Allowance Auction Program," (Draft February 25, 2009).

[37] Ibid, page 39.

[38] See 6 NYCRR Parts 200 and 242 CO_2 Budget Trading Program and 21 NYCRR Part 507 RGGI Auction Process.

[39] RGGI Website, http://www.rggi.org/home. Accessed December 30, 2008.

[40] Final Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program. July 1992, Reprinted 2003. Downloaded from http://www.dec.ny.gov/energy/45912.html

[41] Ibid.

[42] Final Scope for Draft Supplemental Generic Environmental Impact Statement (dSGEIS) on the Oil, Gas and Solution Mining Regulatory Program: Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs. Downloaded from: http://www.dec.ny.gov/docs/materials_minerals_pdf/finalscope.pdf

[43] Ibid. Note 40.

[44] Final Scope for Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program: Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs. Executive Summary. Downloaded from: http://www.dec.ny.gov/energy/47554.html

[45] Ibid. Note 40.

[46] Ibid. Note 42.

[47] See 42 U.S.C. § 6973.

[48] EPA, Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 FR 25447 (July 6, 1988).

[49] The exclusion of CO_2 from the solid waste definition seems appropriate in this case. The definition already excludes oil and gas waste and nuclear waste. Similarly, the NYS hazardous waste regulations in 6 NYCRR 371.1(e)(2)(iv) excludes “fly ash, bottom ash waste, slag waste, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels.” Various rationales for excluding these materials from waste regulation include cost, economic impact and /or the applicability of a strong regulatory program to address environmental concerns. All of these rationales could readily be applied in this case to exempt injected supercritical CO_2 from the solid waste definition.

[50] 73 Federal Register 43492 at 43504 (2008).

[51] See Pneumo Abex Corp. v. High Point, Thomasville & Denton R.R. Co., 142 F.3d 769, 775 (4th Cir. 1998) (considering four factors to distinguish between a sale of a useful product and a disposal of a hazardous substance: (1) the intent of the parties as to whether the materials were to be reused entirely or reclaimed and then reused; (2) the value of the materials sold; (3) the usefulness of the materials in the condition in which they were sold; and (4) the state of the products at the time of transfer); *A & W Smelter and Refiners, Inc. v. Clinton*, 146 F.3d 1107, 1112-13 (9th Cir. 1998) (remanding case for factual determining of whether ore containing gold, silver, and small amounts of lead was a useful product or a waste, *i.e.*, whether the materials are the producer’s principal business product or a by-product that the producer intends to dispose); M. STUART MADDEN & GERALD W. BOSTON, LAW OF ENVIRONMENTAL AND TOXIC TORTS 627-28 (3rd ed. 2005) (discussing lack of CERCLA coverage for sale of “useful products”).

[52] Massachusetts v. Environmental Protection Agency, 549 U.S. 497 (It is of interest to note that two federal district court cases (Jastram v. Phillips Petroleum Co., 844 F. Supp. 1139, 1142-43 (E.D.La. 1994) and Eagle-Picher Indus. v. United States E.P.A., 245 U.S. App. D.C. 196, 759 F.2d 922 (D.C. Cir. 1985)) have ruled that primary CERCLA liability does not attach to releases of “pollutants,” but no court rulings have addressed the reach of secondary liability under Section 9604, and certainly have not considered liability under that section for the release of CO_2.)

[53] p.16, World Resource Institute, Guidelines for Carbon Capture, Transport and Storage, 2008.

[54] “Project Developer Interviews: Regulatory measures and financial incentives to accelerate the commercial deployment of advanced coal with carbon capture and storage”, Jennifer Johnson, Great Plains Institute for the Midwestern Governors Association Renewable Electricity and Advanced Coal with Carbon Capture Advisory Group, September 2008.

[55] “Geologic Carbon Sequestration: Property Rights,” presentation paper submitted to the Eighth Annual conference on Carbon Capture and Sequestration –DOE/NETL, May 4-7, 2009, page 5, prepared by Jerry R. Fish, Esq.

[56] Ibid., page 12.

[57] Cost and Performance Baseline for Fossil Energy Power Plants Study, Volume 1: Bituminous Coal and Natural Gas to Electricity,” Revised Final Report, August 2007, RDS for NETL.

[58] NYSDEC Web site, http://www.dec.ny.gov/chemical/8442.html; accessed February 27, 2009.

[59] Kenneth S. Kamlet Introduction: History of Brownfields Regulation, p.2, www.ny-brownfields.com; see also: Kamlet, Kenneth S., "Brownfields Regulation in New York State: A Disappointing Report Card," New York State Bar Association , The Environmental Lawyer, Vol. 22, No.1, Winter 2002, pp 2-24.

[60] The BCP was authorized in statute under Title 14 of Article 27 of the Environmental Conservation Law as part of the 2003 Superfund/Brownfield Law.

[61] The UIC NOPR discussion of liability issues raises the specter of liability under both RCRA and CERCLA. . The analysis provided there also does not preclude the potential for common law liability, noting that UIC requirements are not intended to pre-empt state common law.

[62] Legislative Memorandum prepared in support of Chapter 412, Laws of 1996.

[63] Environmental Conservation Law, Section 56-0509.

[64] Legislative Memorandum prepared in support of Chapter 412, Laws of 1996.

[65] See Energy Research, Development, Demonstration, and Commercial Application Act of 2006, H.R. 5656 (2006).

[66] Amendment to H.R. 5656 offered by Rep. Costello of Illinois (June 27, 2006).

[67] Id. See also Department of Energy Carbon Capture and Storage Research, Development, and Demonstration Act of 2007, H.R. 1933 (April 18, 2007) (bill to amend the Energy Policy Act of 2005 to reauthorize and improve the carbon capture and storage research, development, and demonstration program of the Department of Energy).

[68] See 23 ECL 0305(8)d. General powers provided to NYSDEC by statute to address contamination concerns are set forth at 1 ECL 0101(3)b; 3 ECL 0301(1) (g), (i), and (m). See also 6 NYCRR 556.5 prohibitng pollution of land; and 71 ECL 1305 (2) clarifying that any failure to perform a duty imposed by NYSDEC by permit or order is a criminal offense.

[69] This option contemplates amendment of analogous New York laws; although the amendment of federal laws is beyond the scope of this report, efforts to address these changes on the federal level should be supported by New York State to the extent possible and state legislative changes alone may not be adequate for CCS project sponsors without a change in federal liability.

[70] The Kentucky performance bonding requirements set forth at 405KAR Ch. 10 are representative of the bond release programs used to regulate the closure of coal mines throughout the United States.

[71] 40 CFR 264.140, et seq.

[72] IOGCC model rule, p. 26.

[73] Terrorism Risk Insurance Act of 2002, P.L. 107-297, 116 Stat. 2322, as amended.

[74] Price-Anderson Act, 42 U.S.C. § 2210.

[75] See Title 14 of Article 27 of the ECL and Section 21 of the Tax Law.

[76] If a CCS facility is under a long term contract, it would be placed at the bottom of the generation bid stack each day in the NYISO market. Project revenues could be secured through the commercial contract. In this scenario, the economic and operating dispatch risk would be lower. Nevertheless, the CCS plant would still need to enter into a commercial contract.

[77] Energy Improvement and Extension Act of 2008 (Pub.L. 110-343).

[78] Memorandum of Understanding, dated June 9, 2008, between Empire State Development Corporation and Praxair, Inc.

[79] See Note 9, supra.

[80] There is currently inadequate other funding to compensate for these risks. DOE or other government funding can provide substantial funding support for commercial demonstration projects. DOE, however, typically funds projects only for a limited time period (3 to 5 years) and requires cost sharing. After the demonstration period, and for the remaining thirty or more years of operation, CCS projects would be dependent on carbon revenues from a trading program or other sources.

[81] Excerpt from "Last Chance for Coal – Making Carbon Capture and Storage a Reality", Linda McAvan, MEP (Member of European Parliament).

[82] DOE 2007.

[83] Id, WRI CCS Guidelines, 2008.

[84] NETL 2008.

[85] Ibid. Note 5, at 43497.

[86] Ibid. Note 44.

[87] Ibid. Note 42.

[88] Ibid. Note 42.

[89] Ibid. Note 40.

[90] Protecting the Environment During Well Drilling and Operation: Environmental Protections for Oil and Gas Development. Downloaded from: http://www.dec.ny.gov/energy/1536.html

[91] Ibid. Note 44.

[92] Ibid. Note 40.

[93] Ibid. Note 86.

[94] Ibid. Note 5, at 43510.

[95] Delaware River Basin Compact, United States: Public Law 87-328, approved September 27, 1961.

[96] 73 Fed. Reg. 78618, 78621 (Dec. 23, 2008) (to be codified at 18 CFR Pt. 806).

[97] The Ohio River Valley Water Sanitation Commission. http://www.orsanco.org/default.asp

[98] Bachu, Stefan, Carbon Dioxide Storage in Geological Media: Status and Barriers to Development, Presentation to Alberta Geological Survey and Alberta Energy and Utilities Board.

[99] Final Report of the Advanced Coal Technology Workgroup, January 29, 2008.

[100] NYSERDA, "Operating Plan for Investments in New York under the CO_2 Budget Trading Program and the CO_2 Allowance Auction Program," (April 16, 2009), page 41.

Appendix A

LIST OF WORK GROUP MEMBERS

Appendix A

Workgroup 1 – Municipal CCS Authority (Discontinued; No work group paper prepared)

Tanja Shonkwiler: Duncan, Weinberg, et al.
George Rusk: E & E
Rick Morse: E & E

Workgroup 2 – Liability and Early Mover Incentives

Richard Tisch: Praxair
Christ Wentlent, Doug Roll, Peter Batrowny: AES
Frank Bifera, Diane Mettler: Hiscock & Barclay, et al.
Tanja Shonkwiler: Duncan, Weinberg, et al.
Rick Morse: E & E
George Rusk: E & E
Patrick Maguire: McGriff Insurance Brokers
Peter Magravanis, Natalie Green: Marsh Insurance Brokers

Workgroup 3 – Condemnation/Ownership

F. C. Dayter: F.C. Dayter Law Firm
Ian Miller: E & E
George Rusk: E & E

<u>Observers:</u>
John Martin: NYSERDA
Peter Briggs: NYSDEC
Jennifer Hairie: NYSDEC

Workgroup 4 – Pipeline Right of Way

Tanja Shonkwiler: Duncan, Weinberg, et al.
Scott Turner: Nixon Peabody
Rob Morrison: Praxair
George Rusk: E & E
Janine Whitken: E & E

Workgroup 5 – Risk Assessment

Dante Bonaquist: Praxair
Chris Wentlent: AES
F. C. Dayter: F. C. Dayter Law Firm
George Rusk: E & E
Richard Freeman: E & E
Paul Jonmaire: E & E

<u>Observers:</u>
Veronica Brieno-Rankin: Geoseq, Inc.
Amanda Stevens: NYSERDA
Marilyn Wurth: NYSDEC

Appendix B
WORK GROUP REPORTS

Workgroup 2

CO_2 Sequestration Liability

and Indemnification Issues

January 15, 2009

1.0 INTRODUCTION

The State of New York is taking a leadership role in reducing greenhouse gas emissions through energy efficiency efforts, renewable generation initiatives, and the first mandatory carbon trading program in the United States - the Northeast Regional Greenhouse Gas Initiative.[1]

Ongoing initiatives by the United States Department of Energy (DOE) to reduce carbon dioxide emissions from power plants provide another opportunity for New York to lead in reducing greenhouse gas emissions. One of the ways DOE is working to develop coal-based geologic carbon capture and sequestration (CCS) technologies that will significantly reduce greenhouse gas emissions is by providing funding for projects seeking to demonstrate commercial operation of carbon capture and sequestration. DOE funding provides an opportunity for New York to partner with the federal government in the development of innovative clean-coal technologies that can be used to reduce carbon emissions globally and to set technology standards in the United States. DOE has several ongoing funding initiatives for CCS. DOE's Clean Coal Power Initiative (CCPI), issued in August 2008, provides substantial federal funding for advanced coal-based systems that capture carbon dioxide (CO_2) for sequestration or beneficial reuse. Recently, DOE has also provided funding through: (1) the restructured FutureGen program; (2) loan guarantees and tax credits for CCS projects; (3) funding for sequestration projects through the Regional partnerships; and (4) ongoing funding for various CCS research and development projects.

Clean coal CCS demonstration projects can offer important environmental and economic benefits not only to New York, but globally as well. While New York is acting to reduce greenhouse gas emissions in-state, global emissions of carbon dioxide are increasing at an escalating rate because of the increased construction of new coal plants that lack CCS technology. China and India are building new coal plants at a rate of two each week[2]. The Intergovernmental Panel on Climate Change (IPCC) has estimated that as much as three quarters of the projected increase in energy-related carbon dioxide emitted between now and 2030 will occur in emerging economies such as China. China's coal-related carbon dioxide emissions are projected to grow from 3.8 billion tons in 2004 to 8.8 billion tons in 2030. Addressing these large and escalating emissions from coal-based generation in the developing world is critical to reducing carbon dioxide emissions that have been identified as necessary to mitigate the impacts of climate change. In order to address these emissions, CCS technologies need to be developed for coal plants. Many in the developing world take the position that the United States must provide leadership in developing this technology.

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1 New York is increasing statewide energy efficiency efforts to reduce electric usage by 15% of projected levels by 2015, which is estimated to reduce carbon emissions by approximately 12.8 million tons. New York has committed that 25% of energy used in New York will come from renewable sources by 2015, which is estimated to result in a 7.7 % decrease in carbon dioxide emissions. In cooperation with other Northeastern States, New York has developed and implemented the first mandatory CO_2 trading program in the United States, the Regional Greenhouse Gas Initiative (RGGI), which will reduce CO_2 emissions from electric generating units in New York by a further 10% by 2018.

2 Massachusetts Institute of Technology, "The Future of Coal: Options for a Carbon Constrained World," Executive Summary at ix (2007).

Demonstration CCS project(s) located in New York, such as the proposed Jamestown CCS project (the "Project"), could make New York a center for innovative clean coal technology. Demonstration projects offer the real possibility to spawn larger, successful commercial-scale CCS coal-fired power plants that would significantly reduce emissions of CO_2 to the atmosphere and produce near zero emission rates of criteria pollutants and mercury. Demonstration projects offer not only an opportunity to reduce emissions in New York but also, if replicated globally, to serve as the foundation for CCS technology standards for the United States and the world.

CCS demonstration projects also present an important economic opportunity for New York. The global demand for oxygen supply systems, CCS technology, and compressors could generate hundreds of millions of dollars in annual economic impact and thousands new jobs in future years (2012-2020) throughout New York State. Development of a CCS industry would be particularly important for the economically challenged parts of Upstate New York, where much of New York State's coal-fired generation is located.

While CCS demonstration projects offer significant environmental and economic benefits, there are also challenges to the development of these projects in the near term. Because of the characteristics of electricity and carbon markets, the private sector faces significant hurdles in developing First Mover CCS projects. Coal generating plants are capital-intensive and are constructed on a scale that makes private development without substantial government subsidies unlikely. The lack of liability protection for private parties proposing to finance, build, and operate the first demonstration projects and sequestration sites is an additional and significant challenge that could substantially delay CCS.

Widespread support is developing for liability protection for a small number (a dozen or less) of first demonstration CCS projects if the technology is to progress. The first proposed CCS project in the United States, FutureGen, required indemnification from a guarantor entity. In response, the states of Illinois and Texas, competing for the project, passed legislation that transferred title to and assumed liability for the sequestered gas $_{\text{upon}}$ its injection of the CO_2 into the wellhead or upon its capture, respectively. Liability protection and indemnities from state governments in favor of the participants in CCS demonstration projects are needed to spur private and public partnerships to undertake and implement such projects.

2.0 CCS PROJECTS PRESENT A VARIETY OF SIGNIFICANT FINANCIAL AND MARKET RISKS THAT WILL DELAY CCS DEPLOYMENT

The characteristics of coal generating plants and carbon markets present multiple hurdles for the development of CCS. Generating power using coal is a capital-intensive industry with large investments and long planning horizons. A typical coal generating plant without CCS costs hundreds of millions to billions of dollars to construct. CCS can double these costs for First Mover Projects. Plants are constructed for 30-40 year operating lives; many plants continue to operate after 50 years or more. Decisions to add or replace capacity and the choice of fuel type depend on electricity demand growth, the need to replace inefficient plants, the capital costs and operating efficiencies of different options, fuel costs and emission prices. Decisions are made conservatively after multiple scenarios and sensitivity analyses are evaluated.

One part of the financial risk associated with CCS is parasitic load loss for carbon capture and sequestration. Parasitic load is the amount of energy it takes to operate the generating plant including pollution prevention systems. At a conventional coal plant, parasitic load loss, or station service load as it is frequently called, is the power used for office buildings, the lights and computers at a generating plant, and pollution equipment. Parasitic load loss for CCS plants will be significant and include the energy used to run oxygen separation equipment, compressors, air separation units and injection wells, among other equipment. Collectively, this parasitic load loss is estimated to consume 30% or more of the energy output of a coal plant. Consequently, the output of a CCS plant will be one third or less than a similarly sized conventional coal plant; in other words, the costs of electricity from a CCS plant will be one third or more above the costs of a conventional coal plant. In a competitive market, a plant with CCS will not be economic and will not operate without substantial subsidies or a carbon revenue stream to fill the funding gap.

These economic risks are particularly significant in a market-based environment. For example, the New York Independent System Operator (NYISO) process requires each supplier to bid daily into the NYISO market and the NYISO utilizes those bids to perform a least cost analysis that balances load demand and energy supply for each hour of the day. Facilities located in the NYISO Zone A, which includes many of New York's coal plants, is the lowest priced zone within the eleven zone NYISO system. This fact coupled with the higher costs associated with full CCS could result in a CCS unit not being dispatched compared to other lower cost units within the bid stack.[3] Accordingly, unless some funding or balancing mechanism is determined, a full CCS application will likely operate at lower than expected capacity factors and higher economic risk due to the higher cost nature of incorporating CCS as compared to other non-CCS units in the system.

CCS projects need carbon trading or other financial support to provide an adequate revenue stream to cover these costs. Carbon trading, however, is in its infancy. The Northeast RGGI trading program is beginning this year; the below $4/ton price of carbon does not come near to addressing the costs of CCS, which typically requires CO_2 prices in the $30 or higher range, and higher prices for demonstration projects. There are currently no other mandatory CO_2 trading programs in the U.S. Construction of a CCS project at this time requires owners to assume that there will be a carbon or other revenue stream in the future to cover the high costs of CCS. If the revenue stream does not materialize, these projects may go bankrupt. To date, coal plants have been unwilling to take these risks.[4]

[3] If a CCS facility is under a long term contract, it would be placed at the bottom of the generation bid stack each day in the NYISO market. Project revenues could be secured through the commercial contract. In this scenario, the economic and operating dispatch risk would be lower. However, the CCS plant would still need to enter into a commercial contract.

[4] There is currently inadequate other funding to compensate for these risks. DOE or other government funding can provide substantial funding support for commercial demonstration projects. DOE, however, typically funds projects only for a limited time period (3-5 years) and requires cost sharing. After the demonstration period, and for the remaining thirty or more years of operation, CCS projects would be dependent on carbon revenues from a trading program or other sources.

Need for governmental funding for First Movers has been recognized by political leaders in the international community.

> The particular characteristics of electricity and climate mitigation markets, as well as the scale of the technology, mean that demonstration will not be funded by the private sector alone. This is a classic example of market failure that is reliant on public policy and law to fix. Some form of partnership is needed where private firms (or consortia) deliver demonstration projects, mixing their own resources with additional public aid that compensates for firstmover disadvantages.

Excerpt from "*Last Chance for Coal – Making Carbon Capture and Storage a Reality*", Linda McAvan, MEP (Member of European Parliament).

3.0 LACK OF A REGULATORY AND LIABILITY STRUCTURE FOR CCS CREATES SIGNIFICANT UNCERTAINTIES AND LIABILITY RISKS

Before any large-scale commercial implementation of CCS technologies occurs, states or the federal government must enact laws and promulgate regulations governing all aspects of the CCS process. A regulatory framework is essential to creating technology and safety standards to guide development, manage risk, and protect human health and the environment. This regulatory structure likely should be focused on the unique risks of CCS, including the relatively low-level, but long term risks, associated with CCS.

Until such a regulatory and liability structure is developed, however, First Mover Projects will face uncertainty regarding the appropriate standards of care for their projects. They will also face potential liabilities under existing regulatory and liability structures that were not developed with CCS in mind, but that may, like CERCLA, pose remote risks but ones that could be prohibitive for the Early Mover CCS Projects. Among the potential liability risks associated with CCS for early movers that implement CCS are those related to Underground Injection Control rules under the Safe Drinking Water Act (SDWA), the Resource Conservation and Recovery Act (RCRA), the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), and state common law claims for damages. Because of these uncertainties in the regulatory and liability structure, and because of the lack of commercial insurance, liability protection for a limited number of First Mover projects is essential.

3.1 UNDERGROUND INJECTION CONTROL RULES

Because of the importance of providing a regulatory framework for CCS, the United States Environmental Protection Agency (EPA) published on July 29, 2008 a Notice of Proposed Rulemaking (NOPR) to create a new Class VI injection well for long-term, commercial scale geologic sequestration of carbon dioxide. The NOPR was proposed pursuant to the SWDA, which provides the federal requirements for the protection of underground sources of drinking water (USDWs). With certain exceptions, the underground injection control (UIC) Program regulates underground injection of all fluids, including liquids and gases.

The elements of the NOPR build upon the existing UIC regulatory framework, with modifications based on the unique nature of CO_2 injection for sequestration. The NOPR requires that there be geological site characterization to ensure that sequestration wells are appropriately sited, including a requirement that an "injection zone be of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream" and that the confining zone be "free of transmissive faults and fractures." The NOPR has requirements for well construction to ensure that injectate-compatible materials are utilized and that the wells are constructed in a manner that prevents fluid movement into unintended zones. Periodic (at minimum every ten years and potentially more often) re-evaluation of the area of review around the injection well using computer modeling is required to incorporate monitoring and operational data and to verify that the CO_2 is moving as predicted within the subsurface.

The NOPR sets out requirements for testing of the mechanical integrity of the injection well, ground water monitoring, and tracking of the location of the injected CO_2 to ensure protection of underground sources of drinking water. Extended post-injection monitoring and site care to track the location of the injected CO_2 and monitor subsurface pressures is required. An important element of the NOPR is EPA's proposed treatment of post-injection site care and financial assurance issues for operation of CO_2 injection wells. As part of their initial application, parties would be required to submit a post-injection site care and a site closure plan—which then would be subject to updates and periodic review requirements. Further, the owner or operator ultimately would be required to maintain post-injection site care measures for a fifty (50) year period. This requirement could be shortened upon a finding that movement of a CO_2 plume has ceased and the injectate does not pose a risk to underground drinking water sources. Further, owners or operators would be required to demonstrate and maintain financial responsibility for closure and remediation of a sequestration site. The NOPR includes the general requirement for maintenance of financial assurances to assure that funds will be available for well plugging, site care, closure, and emergency and remedial response. Unlike other category permits, Class VI permits would last for the life of the geologic sequestration project.

While the UIC NOPR is a first step to providing regulatory structure, there are however, significant unresolved regulatory issues. The NOPR is only a proposed, and not a final, rule. The NOPR provides only certain minimal standards and general guidance; specific guidance will be developed in case-by-case permits. There are a variety of areas where the UIC NOPR provides general guidance but little in the way of specifics, including siting criteria, area of review, well construction, monitoring and well-plugging and post-injection cap. EPA states in the NOPR that it "will use data collected from [the Demonstration Projects] to support a decision in the Final Rule."

Under the EPA proposal to establish a new class (Class VI) for CO_2 injection wells under the UIC program, carbon dioxide streams would be defined to exclude hazardous wastes. However, under the proposal, owners and operators will have to characterize their individual CO_2 stream as part of the permit application to determine that the injectate does not contain hazardous wastes, as defined in 40 CFR Part 261. If the injectate is determined to contain hazardous wastes, as defined and regulated under RCRA, then the more stringent UIC Class I requirements apply for injection of hazardous wastes. Hazardous waste disposal wells are regulated under the Safe Drinking Water Act and RCRA. *See* "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells."[5]

The NOPR also leaves open the potential for liability under other federal statutes. In its discussion of CERCLA and RCRA, the NOPR raises the specter of liability under both statutes. Because the UIC requirements do no preempt state common law, a state's tort law can also be a risk for First Mover projects.

3.2 POTENTIAL RCRA LIABILITY

RCRA is designed to provide "cradle-to-grave" controls by imposing management requirements on generators and transporters of hazardous wastes and upon owners and operators of treatment, storage and disposal (TSD) facilities. RCRA applies mainly to active facilities that generate and manage solid or hazardous wastes. TSD facilities must comply with performance standards, including statutory minimum technology requirements, groundwater monitoring, and a prohibition on the land disposal of untreated hazardous wastes. Owners and operators of TSD facilities are required to obtain permits which set the conditions under which they may operate.[6]

Section 7002 of RCRA authorizes suits by any person to restrain anyone who has contributed or is contributing to the past or present handling of any solid or hazardous waste that may present an imminent and substantial endangerment to human health or the environment.[7] Under RCRA, private parties can use Section 7002 to bring a civil action against any violator of RCRA requirements or against the EPA Administrator for failure to undertake a non-discretionary duty. In such a suit, the plaintiff need only establish that there is a reasonable prospect of potentially serious harm[8]. Relief can include an order that the defendant is responsible for site investigation and cleanup costs, as well as attorneys' and experts' fees.

If CO_2, or a trace component of injected CO_2, is considered a hazardous waste and to a lesser extent, if it is a solid waste, RCRA's provisions could impose liability for harm arising from the long-term storage of CO_2, and may also impose stringent handling, storage, and disposal requirements on the CCS process. RCRA defines solid waste as including "any garbage, refuse, and other discarded material, including semisolid or contained gaseous materials, resulting from industrial, . . . commercial operations." This definition, however, could possibly include stored CO_2 in connection with CCS operations because the CO_2 is arguably "discarded material," may be "gaseous" or in "liquid" form, and results from industrial or commercial activities. EPA appears to be leaning towards defining CO_2

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5 73 *Fed. Reg.* 43492 at 43503 (July 25, 2008).

6 For permitted hazardous waste facilities, the New York hazardous waste regulations contain requirements generally similar to the federal RCRA regulations (*see* 40 CFR 264, Subpart F).

7 42 U.S.C. § 6972(a).

8 *See Maine People's Alliance v. Mallinckrodt, Inc.*, 471 F.3d 277 (1st Cir. Me. 2006).

sequestration as a waste in the UIC rules.[9] Characterization as a waste is implied, but not explicitly stated, in the UIC NOPR.[10]

EPA could exclude CO_2 from the definition of solid waste, as it has done for certain oil and gas wastes. The EPA's reasoning was that regulating oil and gas waste as hazardous wastes would "not provide sufficient flexibility to consider costs and avoid the serious economic impacts that regulation would create" for industry. Sequestration may become necessarily linked to the production of electricity from coal so that burdening industry with unduly restrictive regulations could interfere with crucial power generation activity. A policy similar to that used to exempt oil and gas production wastes from the hazardous waste regulations should apply to sequestration.

Hazardous waste is a solid waste that exhibits a hazardous characteristic (ignitability, corrosivity, reactivity, or toxicity) or is a "listed" hazardous waste meaning EPA has placed it on a list of hazardous wastes. Hazardous wastes also include wastes mixed with a listed waste ("mixture rule"), waste "derived from" a listed waste ("derived from rule"), and soil, groundwater, surface water, or debris that is contaminated with a listed hazardous waste ("contained-in rule"). Carbon dioxide is not a listed hazardous waste, and there is no CO_2 stream available for testing for hazardous waste characteristics from a utility plant; however, based on commercial CO_2 streams, it appears unlikely that CO_2 alone would be considered a characteristic hazardous waste, although there is uncertainty about the toxicity characteristic leaching procedure because it may be inapplicable to supercritical CO_2. Contaminates (*e.g.*, hydrogen sulfide (H_2S)) present a risk that injected CO_2 could be considered hazardous and therefore considered a hazardous waste. On the other hand, injected CO_2 could also be excluded from the definition of hazardous waste by EPA pursuant to regulation, as EPA has done with incinerator ash.

In sum, there is regulatory uncertainty regarding the status of CO_2 as a hazardous or solid waste. While RCRA has stringent regulations for hazardous wastes, the regulations applicable to solid waste (Subtitle D regulations) are less stringent. However, if CO_2 is a solid

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9 New York's hazardous waste regulations provide that certain solid wastes are not considered hazardous wastes. For example, Section 371.1(e)(2)(iv) excludes "fly ash waste, bottom ash waste, slag waste, and *flue gas emission control waste generated primarily from the combustion of coal* or other fossil fuels . . ." from the definition of hazardous wastes. *See* 6 NYCRR § 371.1(e)(2) (emphasis added). This provision is analogous to the federal provision found at 40 CFR 261.4(b)(4). A plain reading of these regulations indicates that solid waste constituents derived from combusting coal in CCS would qualify for the exclusion. However, previous EPA rulemakings indicate that exempting coal combustion waste materials from being considered hazardous waste is based, at least in part, on putting the waste material to beneficial use, *e.g.*, using waste fly ash to improve cement products. *See, e.g.*, "Notice of Regulatory Determination on Wastes From the Combustion of Fossil Fuels," 65 *Fed. Reg.* 32214 (May 22, 2000).

10 73 *Fed. Reg.* 43492 at 43503 (July 25, 2008). It is possible that a recycling exemption might apply if a demonstration can be made that supercritical CO_2 is being stored underground for later use. RCRA does not regulate materials that are recycled, reclaimed, or still useful. 40 C.F.R. § 261.2 (2007). However, defining material as recycled under the RCRA may be difficult. The D.C. Circuit Court has held that materials are not waste when they were "destined for beneficial reuse or recycling in a continuous process by the generating industry itself." *American Mining Cong. v. EPA*, 824 F.2d 1177, 1186 (D.C. Cir. 1987). The Court later stated that a material might not be excluded from regulation under the RCRA even when it might eventually be reclaimed. *Id.*

or hazardous waste, then Section 7002 of RCRA could provide a right of action for injunctive relief to compel the remediation of any migration or release of stored CO_2 that presents an imminent and substantial endangerment to human health and the environment.[11]

3.3 POTENTIAL CERCLA RESPONSIBILITY

The Comprehensive Environment Response, Compensation, and Liability Act,[12] commonly referred to as "CERCLA" or "Superfund", was enacted by Congress in 1980. CERCLA's impetus was the emerging realization that inactive hazardous waste sites presented great risk to public health and the environment and that existing law did not address these abandoned disposal sites.

CERCLA was designed to respond to situations involving the past disposal of hazardous substances by casting a broad net of liability over those parties that had any involvement with the generation, transport, arrangement or disposal of hazardous waste. CERCLA provides that any private or government entity may sue to recover for any "release"[13] of a "hazardous substance,"[14] from a "facility,"[15] that results in "response costs,"[16] so long as those costs are incurred in a manner consistent with the "National Contingency Plan."[17] Liability to the federal government under CERCLA is retroactive, joint and several, and is imposed on current as well as past owners and operators of "facilities" where there has been a release of a hazardous substance, as well as on those who have generated or transported hazardous substances. The broad nature of the liability coupled with the ability of private parties to recover under CERCLA has made CERCLA a powerful vehicle for private parties and government to recover costs associated with contamination resulting from a wide-range of harmful substances.

CERCLA applies, however, only to "releases"[18] of a "hazardous substance." As CO_2 is not a listed hazardous substance and probably not a characteristic hazardous waste under RCRA, CERCLA liability for the CO_2, is unlikely although the presence of hazardous substances within the injectate could present potential CERCLA liability risks. EPA, moreover, in the UIC NOPR has suggested that if the injected CO_2 stream contains a hazardous

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11 *See* 42 U.S.C. § 7002.

12 42 U.S.C. §§ 9601 *et seq.*

13 42 U.S.C. § 9601(22) (defining "release").

14 42 U.S.C. § 9601(14) (defining "hazardous substance").

15 42 U.S.C. § 9601(9) (defining "facility").

16 42 U.S.C. § 9601(25) (defining "response").

17 *See* 42 U.S.C. § 9607(a).

18 CERCLA defines a "release" as any spilling, leaking, pumping, pouring emitting, emptying, discharge, injecting, escaping, leaching, dumping, or disposing into the environment. 42 U.S.C. § 9601(22). CERCLA defines "environment" as including the navigable waters, the waters of the contiguous zone, and the ocean waters as well as any other surface water, ground water, drinking water supply land surface or subsurface strata, or ambient air within the United States or under the jurisdiction of the United States. 42 U.S.C. § 9601(8). Based on these definitions, stored CO_2 that migrates to the surface or migrates laterally in the subsurface strata may qualify as a "release" under CERCLA.

substance, such as hydrogen sulfide, there is a risk the injected CO_2 stream would then be considered a hazardous substance and CERCLA liability may apply.[19]

CERCLA also typically does not apply to hazardous substances sold as "useful products" (as opposed to those arranged for disposal) which would mean that CERCLA might not cover stored CO_2 if it was classified as a "commodity" rather than a waste.[20]

Despite the threat of CERCLA liability, there are important reasons why CERCLA sequestration sites are unlikely to pose a significant risk related to liability. Scientists at MIT and Lawrence Berkeley National Laboratories, and the many scientists comprising the Intergovernmental Panel on Climate Change, among others, have proposed geologic sequestration as a technologically feasible and environmentally responsible means of mitigating GHG emissions. Carbon sequestration partnerships organized by the federal government have also concluded, after analysis of hundreds of saline formations, coal bed seams, and other subsurface reservoirs, that CO_2 may be stored in numerous subsurface basins. Enhanced oil recovery projects, while not set up for long term storage of carbon dioxide, nevertheless have demonstrated for the past thirty years or so that such long term CO_2 storage, in fact, occurs. Moreover, there will be many more safeguards in place in connection with the injection and storage of CO_2 than there were with regard to the handling and disposal of hazardous substances in the decades prior to CERCLA. There are also significant potential climate benefits associated with CCS as compared with virtually no benefits associated with the abandoned hazardous waste sites that led to CERCLA.

Nevertheless, because of the far-reaching and significant impacts of CERCLA, and because long term storage of CO_2 in subsurface formations may produce unknown chemical reactions, the risk of CERCLA liability is a significant hurdle for First Mover Projects. These unknown risks are likely to pose problems for financing and funding First Mover CCS projects in the absence of indemnification for such risks.[21]

3.4 RECOVERY FOR HARM UNDER STATE COMMON LAW

In comparison to federal environmental statutes, New York State law, and particularly its common law, present more uncertain liabilities for CCS projects. Unlike the federal environmental statutes, which either do not give states or private parties the right to seek

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19 73 *Fed. Reg.* 43492 at 43504 (2008).

20 *See Pneumo Abex Corp. v. High Point, Thomasville & Denton R.R. Co.*, 142 F.3d 769, 775 (4th Cir. 1998) (considering four factors to distinguish between a sale of a useful product and a disposal of a hazardous substance: (1) the intent of the parties as to whether the materials were to reused entirely or reclaimed and then reused; (2) the value of the materials sold; (3) the usefulness of the materials in the condition in which they were sold; and (4) the state of the products at the time of transfer); *A & W Smelter and Refiners, Inc. v. Clinton*, 146 F.3d 1107, 1112-13 (9th Cir. 1998) (remanding case for factual determining of whether ore containing gold, silver, and small amounts of lead was a useful product or a waste, *i.e.*, whether the materials is the producer's principal business product or a by-product that the producer intends to dispose); M. STUART MADDEN & GERALD W. BOSTON, LAW OF ENVIRONMENTAL AND TOXIC TORTS 627-28 (3rd ed. 2005) (discussing lack of CERCLA coverage for sale of "useful products").

21 The New York Inactive Hazardous Waste Disposal Sites Program, ECL § 27-1301 *et seq.,* generally has a narrower reach than Superfund.

monetary recovery or, in the case of CERCLA, allow only for recovery of response costs, the state common law claims discussed below are available to all affected parties to recover for a fuller range of harms associated with leakage from stored CO_2. These remedies can include compensatory damages, punitive damages, and injunctive relief not available under most federal and state environmental statutes. This means that the New York State common law may play a significant role in presenting liability risks for the long-term storage of carbon dioxide. Notably, even lawful operations that result in harm to public resources or private property can be enjoined or subject to damages based on these actions.[22]

3.4.1 Trespass

A "trespass" is generally defined as a physical and unauthorized invasion of the property of another. A key component in trespass is the element of intent: "[P]roof of trespass requires a showing of willful or intentional conduct that rises to the level of an unlawful invasion of one's property."[23]

Although New York courts have not confronted a trespass case in which CO_2 leaked from one property to another, they have considered underground leakage in other contexts. The leading case on leaching contaminants from one property to another is *Phillips v. Sun Oil*.[24] The element of intent figured prominently in *Phillips*, in which the plaintiff alleged that the defendant's underground gasoline tanks had leaked into the plaintiff's drinking well on his property. The Court in *Phillips* dismissed the claim of trespass, stressing the role played by defendant's intent:

> even when the polluting material has been deliberately put onto, or into, defendant's land, he is not liable for his neighbor's damage therefrom, unless he (defendant) had good reason to know or expect that subterranean and other conditions were such that there would be passage from defendant's to plaintiff's land.[25]

In other words, the trespasser could have intended to place the pollutant on his own property without "good reason to know or expect" that it would migrate.

In several states, courts have held that that a trespass is not actionable in the absence of damage.[26] New York law, by contrast, does not require the property owner to prove that the

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22 *See, e.g.*, *Lugo v. LJN Toys, Ltd.*, 146 A.D.2d 168, 171 (N.Y. App. Div., 1st Dep't 1989) (noting the well-established maxim of New York law that compliance with a statute, while providing some evidence of due care, does not preclude a finding of negligence).

23 *Raiport v. Gowanda Elecs. Corp.*, 190 Misc. 2d 353, 355 (N.Y. Sup. Ct. 2001).

24 307 N.Y. 328 (1954).

25 *Id.* at 331.

26 *See West Edmonds Salt Water Disposal Ass'n v. Rosecrans*, 226 P.2d 965 (Okla. 1950) (injector not liable for damages or injunctive relief for injection of salt water into existing salt water formation that extended under neighboring property because neighbor could not establish damage).

trespass results in monetary damage.[27] However, a New York plaintiff that successfully proves a claim for trespass may collect no more than nominal damages unless he presents to the fact-finder a cogent theory of his damages.[28]

New York law and the law of many other states recognize certain public policy exceptions in connection with the law of trespass when public policy favors the type of activity undertaken that produced the trespass. For instance, a New York court denied injunctive relief to a plaintiff that proved trespass by a city when the city's stormwater project directed runoff onto his property.[29] In rejecting the plaintiff's request that the court enjoin the city from continuing to divert stormwater onto his property, the court found the city's stormwater drainage project to be "necessary to correct a serious threat to public health, safety and welfare."[30] Therefore, New York law is clear that, in considering equitable relief for trespass, the court will balance the particular harm of the trespass against the public good. [31]

Trespass cases of other states involving underground injection have found that public policy supported unitization of areas for oil and gas recovery and secondary recovery operations because they promoted the efficient collection of oil and gas, prevented waste, and avoided the drilling of unnecessary wells.[32] New York has unitization requirements for oil and gas fields and gas storage; a logical extension would be that the public policy benefits of CCS support unitization of the areas needed for such CCS.

New York courts considering trespass claims arising from CCS operations will likely look to the precedent created in other areas, including traditional oil and gas operations. However, they will be called upon to adopt new common law frameworks to address stored CO_2. Public policy favoring reduction of greenhouse gas emission will likely weigh in favor of applying liability sparingly as a common law matter, as New York has done in considering whether to grant equitable relief for the trespass in stormwater cases and as courts in other states have done with respect to traditional oil and gas operations.

3.4.2 Negligence and Negligence *Per se*

Traditional claims for common law negligence and negligence *per se* also provide a potential basis for liability for harm arising from stored CO_2 in connection with CCS operations. A New York plaintiff alleging negligence must prove the following elements: (1) the defendant

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27 *See, e.g.*, *Amodeo v. Town of Marlborough*, 307 A.D.2d 507, 509 (N.Y. App. Div. 3d Dep't 2003).

28 *McDermott v. City of Albany*, 309 A.D.2d 1004, 1006 (N.Y. App. Div. 3d Dep't 2003) (upholding the jury's award of $0.06 in nominal damages for the defendant's trespass when the plaintiff failed to prove monetary damages).

29 *Id.* at 1005-06.

30 *Id.*

31 *Id.*

32 *R.R. Comm'n v. Manziel*, 361 S.W.2d 560 (Tex. 1962) (no liability for authorized injection into adjoining subsurface property because of public policy favoring injection of salt water for secondary recovery of oil); *Phillips Petroleum Co. v. Stryker*, 723 So. 2d 585 (Ala. 1998).

owed a duty of care to the plaintiff; (2) the defendant breached that duty of care; and (3) the breach of that duty was a proximate cause of injury to the plaintiff.[33]

In the context of negligence in connection with stored CO_2, the primary issue of concern would be whether the entity capturing and storing CO_2 breached its duty in storing CO_2. The initial difficulty in determining whether the entity capturing and storing CO_2 breached its duty would be determining what that duty is. Every negligence case involves a balancing of social costs and social benefits associated with the defendant's conduct. It may be very difficult for a plaintiff to establish as a matter of common law the standard of care for selecting a storage site, injecting CO_2, and monitoring it for hundreds of years. In any case dealing with new technologies in a new industry, it can be unclear what the standard of care is.

Although an action sounding in negligence related to the capture and storage of CO_2 underground would be new to New York courts, a similar issue has arisen in the context of pollution of underground water. In one such case, the court held that,

> because of the often unknown courses of subterranean streams or the channel of percolating water, the rule has evolved that for negligence liability to ensue in cases involving the pollution of underground waters, the plaintiff must demonstrate that the defendant failed to exercise due care in conducting the allegedly polluting activity or in installing the allegedly polluting device, and that he or she knew or should have known that such conduct could result in the contamination of the plaintiff's well.[34]

Therefore, the duty owed could be one of "due care" or "reasonable care."[35]

Plaintiffs can also establish negligence under a theory of negligence *per se*. Under negligence *per se*, a plaintiff can establish negligence if he or she can show that the defendant violated a statute or regulation designed to protect against the type of accident the actor's conduct causes and if the accident victim is within the class of persons the statute was designed to protect.[36] Plaintiffs harmed by stored CO_2 could look to violations of standards, such as the UIC regulations, to assert claims of negligence *per se* to obtain traditional common law relief that includes compensatory damages, punitive damages, and injunctive relief. For the UIC

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33 *Akins v. Glens Falls City School Dist.*, 53 N.Y.2d 325, 333 (N.Y. 1981).

34 *Fetter v. De Camp*, 195 A.D.2d 771, 773 (N.Y. App. Div. 3rd Dep't 1993).

35 *See Bunge Corp. v. Manufacturers Hanover Trust Co.*, 65 Misc. 2d 829, 842 (N.Y. Sup. Ct. 1971) (equating "due care" and "reasonable care"); *Shepard v. Beck Bros., Inc.*, 131 Misc. 164, 165 (N.Y. City Ct. 1927) (same).

36 *Boston v. Dunham*, 274 A.D.2d 708, 710 (N.Y. App. Div. 3d Dep't 2000) (establishing that a claimant must fall within the class to be protected by the statute in relying on violation of a statute to prove negligence per se); *Sharrow v. N.Y. State Olympic Reg'l Dev. Auth.*, 193 Misc. 2d 20, 35 (N.Y. Ct. Cl. 2002) (holding that the statutory provisions on which claimants rely must be designed to prevent the type of accident for which claimant seeks recovery); *see also* RESTATEMENT (THIRD) OF TORTS § 14 (Proposed Final Draft 2005).

regulations, courts will have to address whether the regulations are limited to protecting drinking water impacts, or can also be used to set the standard of care for other harms.[37]

3.4.3 Nuisance

Nuisance law might provide another means for holders of property rights to recover for harm resulting from the long-term storage of carbon dioxide. Nuisance law is based on the principle that a defendant may not engage in activity that unreasonably interferes with public rights or a private party's interest in land. A private nuisance is invasion of another's interest in the private use and enjoyment of land and may be brought by anyone with an ownership or possessory interest in land.[38] In New York, a private nuisance requires proof of an interference: (1) substantial in nature; (2) intentional in origin; (3) unreasonable in character; (4) that impairs plaintiff's right to use and enjoy plaintiff's land; and (5) that is caused by the defendant's conduct.[39]

Migrating or leaking CO_2 that harms nearby soil, surface water, groundwater, mineral, or other resources, or interferes with human health could constitute a nuisance. This could result in an injunction or could also result in an award of monetary damages for harm associated with the release.[40] Potentially such injunctive or monetary relief could be awarded under a nuisance theory even if the CCS project or storage area was in full compliance with all federal or state permits.[41] As previously stated, a court will balance the harm to the plaintiff against the benefits of stored CO_2 in determining whether a nuisance exists and if it does, the appropriate remedy. Under such a balancing, it may be that the public interest associated with storing CO_2 would be significant if the technology is seen as playing a significant role in efforts to reverse climate change.

3.4.4 Strict Liability for Abnormally Dangerous Activities

The common law doctrine of strict liability allows for liability even where the defendant did not intend to interfere with a legally protected interest or did not act unreasonably or breach any duty of care in causing the harm. Instead, the justification for imposing liability is that, when the defendant has engaged in an activity for profit that causes harm, the defendant is in the best position to bear the loss.

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37 Another question presented by common law tort actions is the period within which a potential plaintiff would be permitted to bring a cause of action against the owner/operator of the underground storage facility. New York's Statute of Limitations permits an action to be brought three years after discovery of the negligence. *Christy v. Harvey*, 262 A.D.2d 755 (N.Y. App. Div. 3d Dep't 1999). Therefore, the owner/operator of the underground storage facility could be liable potentially indefinitely for CO_2 leaks discovered long after the facility could be operational.

38 *See* RESTATEMENT (SECOND) OF TORTS §§ 821D-828.

39 *Weinberg v. Lombardi*, 217 A.D.2d 579 (N.Y. App. Div. 2d Dep't 1995).

40 *Wheeler v. Leb. Valley Auto Racing Corp.*, 303 A.D.2d 791, 794 (N.Y. App. Div. 3rd Dep't 2003).

41 *See, e.g.*, *Yugler v. Pharmacia & Upjohn Co.*, 225 N.Y.L.J. 80 (2001); *see also Lugo v. LJN Toys, Ltd.*, 146 A.D. 2d 168, 171 (N.Y. App. Div 1st Dep't 1989).

An activity is "abnormally dangerous" and thus subject to strict liability based on a judicial balancing of several factors, some of which may make it more difficult for a plaintiff to establish strict liability for the release of stored CO_2.[42] In New York, the factors to be weighed include the following: (1) the existence of a high degree of risk of some harm to the person, chattel, or lands of others; (2) likelihood that the harm that will result from the activity will be great; (3) inability to eliminate the risk of harm by the exercise of reasonable care; (4) the extent to which the activity is not a matter of common usage; (5) the inappropriateness of the activity to the place where it is carried on; and (6) the extent to which the value of the activity to the community is outweighed by its dangerous attributes.[43]

Some examples of abnormally dangerous activities in New York include disposal of hazardous wastes at a landfill site,[44] hydraulic dredging and landfilling,[45] and allowing corroding tanks to hold significant quantities of hazardous waste.[46] In addition, the New York Legislature, in its Navigation Law, has created a cause of action in strict liability for harm to public health and the environment for the release of petroleum or oil that contaminated groundwater.[47]

Whether courts will find the long-term storage of CO_2 associated with CCS to be subject to strict liability under the Restatement factors is unknown. The answers may vary by geographic location. Courts will have to answer whether the storage of large quantities of CO_2 a "matter of common usage" or "appropriate" for a given location. The demands of addressing climate change may alter that equation. In terms of the value to the community, the value of stored CO_2 may be significant if it has a measurable impact on reducing greenhouse gas emissions. Another important consideration is that, unlike solid and hazardous waste releases underground from an activity, CCS has an important environmental benefit in reducing atmospheric greenhouse gas emissions. Given this important social value, the argument for strict liability may be weakened.

Under any of the trespass, nuisance, and strict liability theories described above, parties responsible for the long-term storage of CO_2 may be liable for remediation costs,[48] diminution in value to private or public property (*i.e.*, stigma damages),[49] lost profits,[50] personal injury,[51] and other damages flowing from harm to human health and the environment.

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42 *See generally* Prosser, Torts [4th ed], § 78.

43 *Doundoulakis v. Hempstead*, 42 N.Y.2d 440, 448 (1977).

44 *State v. Schnectady Chemicals*, 103 A.D.2d 33, 38 (N.Y. App. Div. 3d Dep't 1984).

45 *Doundoulakis v. Town of Hempstead*, 42 N.Y.2d 440, 448 (1977).

46 *State v. Shore Realty Corp.*, 759 F.2d 1032, 1051 (2d Cir. N.Y. 1985) (applying New York law).

47 N.Y. NAV. LAW, § 181(1) (2008) ("Any person who has discharged petroleum shall be strictly liable, without regard to fault, for all cleanup and removal costs and all direct and indirect damages, no matter by whom sustained. . . ."); *see also Busy Bee Food Stores v. WCC Tank Lining Technology*, 202 A.D.2d 898, 899 (N.Y. App. Div. 3d Dep't 1994).

48 *Oliver Chevrolet, Inc. v. Mobil Oil Corp.*, 249 A.D.2d 793, 795 (N.Y. App. Div. 3d Dep't 1998).

49 *Fisher v. Qualico Contr. Corp.*, 98 N.Y.2d 534, 539 (2002).

50 *Leo v. General Electric Co*., 145 A.D.2d 291, 294 (N.Y. App. Div. 2d Dep't 1989)

51 *Rogers v. Dorchester Associates*, 32 N.Y.2d 553, 564 (1973).

4.0 LACK OF SEQUESTRATION INSURANCE OR OTHER LIABILITY PROTECTION MAKES DEVELOPING CCS PROJECTS COMMERCIALLY IMPRACTICABLE FOR EARLY MOVERS

In addition to the technical and financial risks associated with parasitic load loss, First Mover CCS plants confront the risk of sequestration liability. While the risks across the industry associated with sequestration are small, for each individual plant the impacts of liability are potentially significant. An analogy to the CCS liability risk and insurance is the risk from driving an automobile. Statistically, each day of driving an automobile presents a tiny risk of an accident. As a percentage of annual miles driven in the U.S., only a very small number of cars are involved in accidents. However, the damages from even one accident could exceed the financial capability of a given driver to pay. In order to address this liability we have liability insurance for cars. The liability insurance premium is low due to the safety of driving cars with a lot of drivers paying the premiums.

Similarly, liability insurance is needed to protect the owner/operator, and the technology or service providers, against the above potential liabilities that may arise from CCS. While we believe that the likelihood of an event arising causing personal injury, property damages, or environmental harm arising from CCS will be quite small, the injuries or damages that might result could be significant. Early Movers should not bear the costs of such risks. The state of Illinois addressed this issue, in part, in its FutureGen legislation by requiring their Department of Commerce and Economic Opportunity to procure an insurance policy, if available, that insures the operator against certain losses, including any public liability arising from post-injection escape of the sequestered gas. However, there is currently no commercially reasonable insurance available for sequestration demonstration projects and, even if the state of New York were to indemnify the participants for claims caused by sequestered gas, the lack of available commercial insurance would present another challenge – financial impacts to bond holders. If no commercial insurance can be obtained, or only certain aspects of the CCS facilities are eligible for insurance, *i.e.*, because they are risks not underwritten by any carrier even with reinsurance, uninsured risks may be a risk to bond holders (bond holders would not be paid or have their bonds redeemed from available funds) if there is a failure of the CCS facilities to function properly or if liability from injury or property damage would cause money revenues to be materially reduced. A standard default provision for bonds is the failure to maintain insurance once obtained and in force at bond closing. Failure to maintain insurance may cause an early extraordinary redemption of all outstanding bonds.

Separate from indemnity for risks associated with CCS potential liabilities, because of the long term nature of CCS risk (carbon dioxide may be stored underground for thousands of years or more) there is a need to transfer ownership of the sequestered gas and the attendant liabilities to the state government - an entity which, for reasons set forth above and in consideration of its greater longevity than private commercial parties or municipal entities, should bear certain liability and indemnification obligations on behalf of the Early Movers.

5.0 FEDERAL AND STATE LEGISLATIVE EFFORTS TO LIMIT LIABILITY FOR FIRST MOVERS

At both the federal and state levels, there have been efforts to encourage the development of CCS through the enactment of significant limitations on liability for harm associated with the long-term storage of CO_2. Recent efforts to do so are instructive and show recognition of the importance of liability in the development of this new technology. As shown below, much of this legislation significantly limits project owners' and operators' liability for the long-term storage of CO_2.

For example, in 2006, the U.S. House of Representatives considered a bill to authorize and appropriate funds for the FutureGen project "to demonstrate the feasibility of the commercial application of advanced clean coal energy technology, including carbon capture and geological sequestration, for electricity generation."[52] One of the failed amendments to that bill was to allow the Secretary of the Department of Energy to "indemnify the consortium and its member companies for liability associated with the first-of-a-kind sequestration component of the project," with indemnity extending to any legal liability arising out of "the storage or unintentional release, of sequestered emissions."[53] The proposed indemnification contained exceptions for gross negligence and intentional misconduct, and limited the U.S. Government's aggregate liability to $500,000,000 for a single incident.[54]

Without the aforementioned failed amendment, FutureGen participants looked to the states for liability protection. During the competition for the FutureGen Project, the states of Illinois and Texas passed legislation that provided for the transfer of title to the injected CO_2 to the state or one of its subdivisions, at no cost, either at the injection of the CO_2 into the wellhead of the injection well (Illinois) or upon its capture (Texas).[55] The legal effect was significant: the states would assume potential liabilities which otherwise would fall on owners or operators of the project, including, but not limited to, release to the surface of the CO_2 or migration of the sequestered gas underground.

In addition, legislation passed in Texas provided that the owner and operator of the project would be relieved of liability for any act or omission related to the CO_2 injection location and the means of the CO_2 injection if the owner or operator complied with the terms of an injection permit and requirements. In 2007, Illinois passed liability protection legislation so as to be in a better position to compete with Texas for the FutureGen project. It specifically requires the state to indemnify and defend the operator from public liability actions (not separately

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52 *See* Energy Research, Development, Demonstration, and Commercial Application Act of 2006, H.R. 5656 (2006).

53 Amendment to H.R. 5656 offered by Rep. Costello of Illinois (June 27, 2006).

54 *Id. See also* Department of Energy Carbon Capture and Storage Research, Development, and Demonstration Act of 2007, H.R. 1933 (April 18, 2007) (bill to amend the Energy Policy Act of 2005 to reauthorize and improve the carbon capture and storage research, development, and demonstration program of the Department of Energy).

55 Before CO_2 can be sequestered underground, it must be compressed into a supercritical liquid and then pumped through the injection well into porous formations at least several thousand feet below the surface. This extreme depth is required to assure that the CO_2 remains in this dense, supercritical state.

covered by insurance), defined as civil liability arising out of the storage, escape, release, or migration of the sequestered gas, but excluding liability resulting from the construction, operation, or other pre-injection activity. The only limits on the state's indemnity for the operator's liability are in cases of intentional or willful misconduct by the operator or if the loss stemmed from the operator's failure to comply with applicable state or federal laws, rules, or regulations for the carbon capture and storage of the sequestered gas. If federal indemnification was put in place, the State indemnification was reduced proportionately.

The Illinois Attorney General, subject to timely notice, is required to defend actions against the Alliance; if the Attorney General is conflicted, private counsel could be hired and the State would pay reasonable fees. The legislation provides for streamlined permitting and establishes State court jurisdiction for actions related to liability. The Illinois incentives package also included a $17 million direct grant from the Illinois Coal Development Fund, an estimated $15 million sales tax exemption on materials and equipment purchased through local enterprise zones, and $50 million for below-market rate loans through state finance agencies.

6.0 METHODS FOR LIMITING LONG-TERM CCS LIABILITY

Because most states, including New York, do not have rules for CCS in place, the potential long-term liability issues associated with CCS is a major hurdle to many companies that would like to research commercially viable ways of capturing and sequestering CO2, particularly CO2 associated with emissions from coal-fired power plants. New York, however, does have a regulatory scheme that could be adapted to CCS.

6.1 The 1996 Bond Act

The 1996 Bond Act, codified as ECL Article 56, provides funding to assist municipalities with the completion of Environmental Restoration Projects ("ERP"). The ERP law provides funding, limited liability and indemnification to the municipality, successors in title, lessees and lenders in order to promote the clean up and redevelop contaminated sites. ECL 56-0509.

The ERP limited liability provision provides that municipalities, successors in title, lessees and lenders:

> shall not be liable to the state upon any statutory or common law cause of action, or to any person upon any statutory cause of action arising out of the presence of any contamination in or on property.

The ERP indemnification provision provides that:

> The state shall indemnify and save harmless any municipality, successor in title, lessee, or lender identified in paragraph (a) of subdivision one of this section in the amount of any judgment or settlement, obtained against such municipality, successor in title, lessee, or lender in any court for any common law cause of action arising out of the presence of any contamination in or on property at anytime before the effective date of a

contract entered into pursuant to this title.

The Legislature determined that the preservation, enhancement, restoration and improvement of the quality of the State's environment is one of the government's most fundamental obligations - therefore, the Legislature, by passing the 1996 Bond Act, authorized: State financial assistance to develop and implement ERP projects; limits to liability associated with such projects; and indemnification for any legal actions brought against the municipality, successor in title, lessee or lender associated with the clean up of the subject property.

The Legislature also stated that it believes that New York State has a responsibility toward future generations and to encourage "pollution reducing technologies." The Senate and Assembly Memorandum in Support of the 1996 Bond Act states that:

> This Bond Act will help fulfill our responsibility to the future of our State's environment and the health of future generations. A tremendous opportunity exists for the state to set an example for the twenty-first century by making an investment in air quality projects. There are many important initiatives that New York State can undertake that will simultaneously serve to address ongoing environmental degradation while encouraging the development of pollution reducing technologies.

6.2 Limited Liability Associated with CCS

Similar to the reasons that the State provides funding, limited liability and indemnification to municipalities, successors in title, lessees and lenders in order to promote the clean up of contaminated sites, the State could provide the same type of limited liability and indemnification for the capture, transport and storage of carbon dioxide. In addition to the reasons behind the State funding and liability regime associated with ERPs, there are also other reasons for the State to provide assistance for overcoming this significant issue.

A CCS project being conducted on a small electric generating facility provides a great opportunity for the State to encourage clean energy technologies and promote low carbon electric generation in New York, and across the world. As New York State is aware, climate change is a global problem and with a large amount of coal-fired power plants located in the U.S., China and around the world, finding a way to capture and sequester the CO2 emissions associated with these facilities is necessary to reduce CO2 emissions and mitigate the impact of climate change. Similar to the reasons behind the ERP, that municipalities often lack the funding necessary to clean up brownfield sites, it is already extremely difficult for an entity that is trying to develop new clean energy technologies to pay for the costs associated with a new technology like CCS, but for the entity to also be potentially liable for any future costs that may arise makes it almost prohibitive to develop such technologies.

The work that has already been done on both the federal and state level can be used by the state of New York to establish industry partnerships and a liability regime associated with carbon dioxide capture and sequestration.

Workgroup 3

Condemnation and Ownership

Issues and Recommendations

January 15, 2009

1.0 Carbon Capture and Sequestration

Carbon capture and sequestration (CCS) is an emerging technology by which carbon dioxide ("CO2") that normally would be released into the atmosphere by coal-fired power plants, oil refineries or other large-scale commercial projects would be captured, pressurized into a "supercritical" liquid, transported, and then injected into suitable deep, underground geologic formations. Many geological formations may be suitable for CO2 storage, including depleted oil and gas fields, saline formations (deep rock layers saturated with brine with an impermeable layer), or un-minable coal beds.

CCS is widely considered to be a promising means to alleviate concerns over climate change. The United States Department of Energy ("DOE") reported that: "Given the magnitude of carbon reductions needed to stabilize the atmosphere, capture and sequestration could be a major tool for reducing carbon emissions to the atmosphere from fossil fuels; in fact sequestration may be essential for the continued large-scale use of fossil-fuels."[1]

While CO2 has long been injected underground for enhanced oil or gas recovery, sequestration for large-scale disposal and/or long-term storage is a relatively new technology with only a limited number of commercial operations around the world. As such, legal statutes, relevant common law and regulatory framework are underdeveloped and rarely extend beyond basic, first-order issues. True, there may be legal trends among certain jurisdictions, and arguably analogous industries such as oil and gas and natural gas storage from which to draw comparisons. But, to potential operators and investors, this translates to uncertainty, and uncertainty often means shepherding investment capital to safer pastures.

Indeed, in 2008 the Midwestern Governors Association's Energy Security and Climate Stewardship Platform conducted seven interviews with project developers and industry experts. Areas identified as top priorities included:

(1) The need for a climate framework so industry can adapt to the rules vs. operating in an environment of uncertainty; and
(2) The need for a legal and regulatory framework that addresses issues related to: pore space ownership and mechanisms for acquiring property rights.[2]

2.0 Property Rights and Ownership Issues

A CO2 sequestration project requires the permitting of an injection well and the utilization of both the surface (injection well, compressors, pipeline) and subsurface strata (a reservoir consisting of geologic formations, voids and/or pore space). This may implicate

[1] DOE: "Carbon Sequestration, State of the Science: A working paper for roadmapping future carbon sequestration R&D, February 1999.
[2] "Project Developer Interviews: Regulatory measures and financial incentives to accelerate the commercial deployment of advanced coal with carbon capture and storage", Jennifer Johnson, Great Plains Institute for the Midwestern Governors Association Renewable Electricity and Advanced Coal with Carbon Capture Advisory Group, September 2008.

numerous property interests including those of surface owners, mineral owners, lessees of solid minerals and oil and gas, holders of easements, owners of future interests and adjacent property owners.

One facet of property rights relates to potential claims for liability for the areas where the CO2 would be injected and isolated, and areas where CO2 migration may occur. Another equally important facet relates to gaining access to both the surface and subsurface.

Indeed, according to one power company official, "This property rights issue is different from liability-related issues, since it could prevent CO2 from being injected in the ground in the first place. If they cannot get access rights to the formation, they cannot do a project."[3] Notably, where the acquisition of rights is deemed necessary or simply desirable, of equal concern is the identification of the proper party from whom permission is sought.

A critical decision of any CCS operator then is what, if any, property rights need to be acquired. Presently, there is much uncertainty. The industry is in its infancy. Detailed regulatory frameworks have not been developed. Legal precedent is limited. Further, laws and decisions vary from state to state. Absent statutory or regulatory clarification, these matters will be likely resolved via litigation in state courts, with the likely results of delay, expense and a lack of national uniformity.

3.0 Injection Wells

3.1 The Permitting Process

Underground injection refers to the placement of fluids and gases into the subsurface through a well bore. It is used to isolate more than 50% of the liquid hazardous waste and a large percentage of the nonhazardous industrial waste generated in the United States. Underground injection plays a vital role in petroleum production, food and chemical production, mining, manufacturing and the remediation of ground water contamination.

Injection wells must be permitted pursuant to the federal Underground Injection Control Program (UIC) of the Safe Drinking Water Act (SDWA). Enacted in 1984, the SDWA directed the Environmental Protection Agency (EPA) to set and maintain health-based standards for contaminants in drinking water. In the 1980's, the Act was amended to include the UIC program that consists of promulgated regulations. Primacy of enforcement has been delegated to 34 states.

The UIC establishes 5 classes of injection wells and sets minimal requirements for siting, testing, installing, operating, monitoring, reporting and abandonment. Class I wells include the injection of hazardous and non-hazardous industrial and municipal wastes into isolated formations beneath the lowermost underground source of drinking water. Class I wells are the most strictly regulated. Operators must demonstrate that their hazardous injectate will not

[3] United States Governmental Accountability Office, "Climate Change: Federal Actions Will Greatly Affect the Viability of Carbon Capture and Storage as a Key Mitigation Option", September 2008.

migrate from the injection zone as long as it remains hazardous. Continuous monitoring is also required.

Class II wells involve the re-injection of substances including brine and CO2 for the enhancement of production in oil and gas wells. Class III wells involve the injection of fluids associated with solution mining of minerals. Class IV wells cover the injection of hazardous or radioactive wastes into or above underground sources of drinking water within one-quarter of a mile of USDW and are now banned. Class V wells consist of all underground injection not included in Classes I – IV. They are typically shallow, on-site disposal systems such as dry wells, and leach fields. Class V also encompasses experimental technology wells.

While the EPA has concluded that geologic sequestration of carbon dioxide through well injection meets the definition of "underground injection" of the SDWA, under what class of injection well CO2 sequestration would fall is currently not clear.[4] On July 25, 2008, EPA published a proposed rule proposing to use its authority under the SDWA to regulate the injection of CO2 for geologic sequestration on a commercial level through its existing UIC program. It would establish a new Class VI for dedicated CCS projects.

Pending comment and approval of a new rule, the EPA urges regional administrators and state regulators to consider permitting proposed CO2 sequestration projects as Class V experimental wells, as distinct from enhanced recovery wells. Accordingly, the EPA issued a Class V Experimental Technology Underground Control Permit in January 2008 for a CO2 field geologic demonstration test at the northern rim of the Michigan Basin conducted by the Midwest Regional Carbon Sequestration Project. Injection began in late February. About 10,000 tons of CO2 were injected over a six-week period.

Neither the current UIC program nor the newly proposed rule however, addresses the issues of property rights, nor liability for property damage or accidents. Neither mandates that a permit holder control the reservoir, pore neither space nor adjacent lands. Neither specifies a containment time for injected waste, with the exception of Class I hazardous wells, which can have no migration within the geological formation for at least 10,000 years.

The central focus of the EPA's existing and proposed UIC program then is the prevention of contamination of underground sources of drinking water from injection. As such, without additional federal or state guidance a CCS operator is faced with a significant decision on how best to proceed with little statutory guidance.

3.2 The Waste Disposal Approach

With UIC permit in hand, a project operator may decide to begin CO2 injections without seeking landowner permission from anyone outside the owners of the land where the injection well and facilities physically sit. The UIC program does not require the acquisition of subsurface rights to obtain injection permits, and the issuance of the permit does not convey any property rights. In New York, State Pollution Discharge Elimination System (SPDES) permits, or the

[4] See letter of July 2006 of the EPA by Cynthia C. Dougherty, Director, Office of Ground Water and Drinking Water to State/Regional UIC Contact.

like, may need to be obtained to maintain reasonable standards of purity in state waters, particularly if CO_2 is considered a pollutant. Permission from landowners where abandoned wells are situated may also be needed to test mechanical integrity to avoid escape routes for the CO_2.

While a state well drilling permit is required for any brine disposal well in New York deeper than 500 feet, current regulations do not require an operator to acquire property rights in the expected reservoir. However, at the time of application for the well drilling permit, an applicant must affirm under penalty of perjury that it possesses the right to access property and drill at the location described on the application. In New York, the EPA permit review may require parameters for protection of groundwater aquifers. In addition, regardless of well depth, the NYSDEC Division of Water must be contacted for determination of whether a SPDES permit is necessary to operate a brine disposal well.

Such business decisions are not uncommon in the realm of UIC disposal wells where the acquisition of rights to pore space are not mandated. In fact, a business decision to proceed based only on a UIC permit may avoid great time and expense in title work, disputes over contested issues of property ownership, negotiation of rights, and compensation to landowners.

However, a decision not to seek property rights does not come without risk or uncertainty. At the forefront is the risk of litigation for claims of negligence, trespass, assumpsit, strict liability and nuisance. Additional claims may arise. For example, the federal Resource Conservation and Recovery Act, 42 U.S.C. Sections 6901 et seq., authorizes suits by any person to restrain those who contribute to the past or present handling of any solid or hazardous waste that may present an imminent and substantial endangerment to human health or the environment.

3.3 Potential Claims

3.3.1 Negligence

Negligence is the failure to exercise reasonable care under the circumstances. It comprises the bulk of tortuous litigation. It requires proof of a duty of care, breach of that duty, causation and damages. It can be used to seek remedies for injuries to both property and persons.

Plaintiffs can also establish negligence under a theory of negligence per se. Plaintiffs would need to show that the defendant violated a statute or regulation designed to protect against the type of accident caused by the actor’s conduct and that the accident victim is within the class of persons the statute was designed to protect.

3.3.2 Strict Liability

Strict liability claims are generally reserved for abnormally dangerous activities such as blasting or transportation of hazardous or toxic wastes. Proven claims result in automatic liability no matter the amount of care exercised by the defendant. Proof would be needed that CO_2

injection activities constitute an abnormally dangerous activity and that the activity caused compensable damage.

3.3.3 Trespass

Trespass is generally defined as a physical and unauthorized entry on to the property of another. A valid claim requires proof of unauthorized entry, intent, and in some jurisdictions, damages. The injection of CO2 into pore space where permission is not sought may constitute an unauthorized entry. The eventual migration of CO2 to adjoining lands may constitute further invasion depending on the intent of the actor. In Phillips v. Sun Oil, 307 NY 328 (1954), for example, the court dismissed a claim of trespass involving the leakage of gas from underground storage tanks into the drinking well of neighboring property. The court held that the actor must have had “good reason to know or expect the subterranean and other conditions were such that there would be passage from defendant’s to plaintiff’s land”. The remedy for trespass typically included the diminution of value of a property or the costs of restoration.

In several states, the courts have held that a trespass is not actionable in the absence of damage. In the much anticipated decision of Coastal Oil & Gas v. Garza Energy, 05-0466, (Texas 2008), the Texas Supreme Court recently overturned a claim of trespass. The claim stemmed from the hydrofacing of a gas well, which resulted in the fracturing of the subsurface of the plaintiff’s adjoining property. Plaintiff’s sole claim of damages was for lost natural gas, which was drained from his property into the defendant’s well. The Texas high court held that the rule of capture precluded any damages and in the absence of damages, the trespass claim also falls. An immediate hurdle faced by a plaintiff would be proof as to the value of pore space. One potential argument in support of compensable damage would be the lost opportunity to lease the pore space for exploration rights, disposal or storage. Notably, New York law does not require the property owner to prove that the trespass results in monetary damage. However, a successful New York plaintiff would be limited to the recovery of nominal damages in the absence of proof of actual damages.[5]

3.3.4 Assumpsit

In some jurisdictions, plaintiffs may elect to waive the tort of trespass and sue under assumpsit (a breach or nonperformance of a simple contract, express or implied) on the theory that by injecting into the subsurface the injector assumes an implied contractual duty to pay rental for the right to inject into the subsurface. Similar to claims of unjust enrichment, this option may be selected to avoid difficulties in proving trespass.

3.3.5 Nuisance

Nuisance is the unreasonable interference with the enjoyment of one’s property. Unreasonable interference and damages must be proven. Nuisance claims are typically remedied through an injunction (a court order commanding or forbidding a party from taking an action) or

[5] See McDermott v. City of Albany, 309 AD2d 1004 (3rd Dept. 2003), upholding the jury’s award of 6 cents in nominal damages for the defendant’s trespass where the plaintiff failed to prove monetary damages.

monetary damages for property damage. In the case of CCS, an order to halt CO2 injection could result.

3.4 Defenses to Claims

Notably, a CCS operator would not be without potential defenses. However, they are untested in the realm of CO2 injection. Potential defenses include:

3.4.1 The Negative Rule of Capture

This rule provides that just as an owner may capture such oil or gas that migrates from adjoining property to a well on his own land under the "rule of capture", so may he inject into a geologic formation substances which might migrate to the property of others.

Under this rule, permission need only be sought from the owner(s) of the surface and subsurface of the land where the injection well was physically located. The consent of owners of land encompassing the subsurface formation would not be necessary, as they have no legal standing. Moreover, liability for migration of injected substances is virtually eliminated in exchange for public policy preferences chosen in adoption of the rule - encouraging enhanced oil and gas recovery where substances are injected underground to further production, or perhaps in the case of carbon sequestration, a public policy preference of reducing climate change.

The negative rule of capture however is not widely adopted. Case law in some states suggests limitations of the rule even where it had been followed in the past.

3.4.2 Limitations on the Boundaries of Property Ownership

An ancient Latin maxim of property law, *cujus est solum, ejus est usque ad coelum et ad inferos*, provides that "[t]o whomsoever the soil belongs, he owns also to the sky and to the depths." This doctrine has been modified by modern courts, including the United States Supreme Court, which concluded that the notion that land ownership extends infinitely upward, "had no place in the modern world" given the advent of air flight. Similarly, some courts have limited the depth to which subsurface rights exist in light of modern day of disposal wells. In Chance v. BP Chemicals, Inc., 670 N.E.2d 985 (Ohio, 1996), the court held that subsurface rights only include the right to exclude invasion that actually interfere with reasonable and foreseeable uses of the subsurface. On the other hand, there are arguments for maintaining subsurface depths as private property as ever advancing technology reveals new commercially economic value in deep strata, which might not be considered today. The "center of the earth to the heavens" approach has also been limited by the public trust doctrine, which has been utilized to protect navigable waterways and tidal areas for the common use of the public.

If courts imposed such limitations on the boundaries of property rights, the injection and/or migration of CO2 at deep depths would not arguably violate any viable property rights.

3.4.3 Insufficiency of Claims and Inadequacy of Proof

A CO2 injection operator may object to the sufficiency of a legal claim or adequacy of proof of landowners. As plaintiffs, landowners must prove that have an interest in the allegedly affected property. The lack of clarity as to who owns the pore space may prove burdensome. In addition, even where ownership can be established, rights may be limited at depths deep below the surface of the land.

Further, landowners bear the legal burden and cost of proving a physical invasion - that CO2 from a specific project did in fact migrate to their properties and that its source was that of the project. Physical proof of migration may be daunting given the depth of the injections, elapsed time and lack of access to scientific knowledge. Further, admissible proof must often come in the form of experts hired to develop complex theoretical models that are normally developed after much expense and rest on assumptions that are often the fodder of extensive cross-examination.[6]

Further, landowners bear the burden of proving that they were damaged. One prominent issue is whether subsurface voids have any legally recognized value. Under common law, pore space may not have any recoverable value to a landowner absent a reasonably foreseeable expectation of using the deep pore spaces at the time of the invasion. In Mongrue v. Monsanto Co., 1999 WL 970354 (E.D. La. 1990) the court explained that the regulator does not bar claims of trespass when authorizing the disposal of waste through underground injection wells. However, the plaintiff has the burden of proof that the migration of injectate interfered with a reasonable and foreseeable use of their property. In Mechlenbacher v. Akzo Nobel Salt, Inc., 71 F.Supp.2d 179, 193 (W.D.N.Y.1999), vacated in part, 216 F.3d 291 (2d Cir. 2000), the United States District Court for the Western District of New York decided that without proof of "actual physical damage to a plaintiff's property, stigma damages alone are too remote and speculative to be recoverable." As the CCS industry develops, suitable pore space may be in higher demand with resultant recognition of market value.

Without legally recognized value, there would generally be no damage and consequently no viable claim. Such actions could be summarily dismissed without trial. Even if pore space value is recognized under the applicable law, it may be minimal. As such, only nominal value may be recoverable in a lawsuit or eminent domain proceedings. The potential of recovering only nominal damages may make the pursuit of claims cost prohibitive and/or simply unattractive to plaintiff attorneys.

3.4.4 Legislative Efforts to Limit Liability

Efforts to encourage the development of CCS through the proposal and/or enactment of statutes limiting liability have been made at both the federal and state levels. Successful legislation may serve as additional defenses to CC operators.

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[6] See Anthony v. Chevron USA, Inc., 284 F.3d 578 (5th Cir. 2002), rejecting two models presented by plaintiffs to prove that salt water injections had contaminated their aquifer.

On February 27, 2003, the federal government announced FutureGen, a $1 billion initiative to create a coal-based power plant focused on demonstrating a revolutionary clean coal technology that would produce hydrogen and electricity and mitigate greenhouse gas emissions. In 2006 the United States House of Representatives considered a bill to authorize and appropriate funds for the FutureGen project. "to demonstrate the feasibility of the commercial application of advanced clean coal energy technology, including carbon capture and geological sequestration, for electricity generation."[7]

One of the proposed amendments allowed the Secretary of the Department of Energy to indemnify companies for liability associated with first-of-a-kind sequestration components. The proposed indemnity provisions extended to any legal liability arising out of the storage or unintentional release of sequestered emissions, with exceptions for gross negligence and intentional misconduct and limitations on the United States Government's aggregate liability for $500 million for a single incident.[8]

On the state level, Illinois and Texas both passed legislation as a result of competition for selection for the FutureGen Project. Both states transferred title to injected CO2 to the state or one of its subdivisions, at no cost, either at the injection of the CO2 into the wellhead of the injection well (Illinois) or upon its capture (Texas). In addition, Texas legislation relieved the owner and operator of a project from liability for any act or omission related to the CO2 injection location and the means of injection if the owner or operator complied with the terms of the injection permit. Illinois passed legislation requiring the state to indemnify and defend the operator from public liability actions not separately covered by insurance, defined as civil liability arising out of the storage, escape, release, or migration of sequestered CO2.

3.5 The Permission Based Approach

As an alternative approach, an operator holding the required UIC permit may decide to seek permission from landowners prior to initiating CO2 injection. This may be the safer of approaches. However, a multitude of issues and uncertainty accompany this approach as well.

One major obstacle is the time, effort and money needed to acquire rights to land. The amounts of CO2 estimated to be injected in a commercial facility vastly exceed most waste disposal facilities. As such, miles of land and multitudes of various landowners and mineral rights owners might come into play. Moreover, without a right of condemnation, it may simply prove impossible to obtain necessary property rights where land and/or mineral rights owners refuse to grant permission.

A second obstacle is the lack of legal clarity as to property ownership rights. The ascertainment of who to contact may be relatively straightforward where the lands contemplated for use in a CO2 sequestration project are owned by landowners in fee simple - that is, in total, without any conditions. In those cases, rights to both the surface and subsurface of each parcel could be obtained from one source – the landowners.

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[7] See Energy Research, Development, and Commercial Application Act of 2006, H.R. 5656 (2006).
[8] Id.

Many lands however, are composed of split estates where the rights to subsurface minerals have been deeded or leased the rights to subsurface minerals to a third party. Conflicts between estates arise. Does the surface estate retain ownership in the pore space or does it pass to the mineral estate? If the pore space stays with the surface owner, what rights, if any, are given to the mineral estate to allow access and mineral extraction? Who then is to be contacted for negotiation or condemnation proceedings? The surface estate owner? The mineral estate owner? Both?

Ownership issues are complicated further by the fact that with the exception of federal lands, the rules concerning surface and subsurface property rights, if developed at all, are largely governed by state law and differ across jurisdictions. Moreover, the applicable law within the jurisdiction may be based on the type of geologic formation chosen for sequestration.

For example, where captured CO2 is to be stored in depleted oil and gas reservoirs it is generally agreed that oil and gas law provides the best guidance for issues regarding real property. The states however, are divided on basic tenets of oil and gas law:

The American Rule

The majority of states follow the "American Rule", which provides that the subsurface geologic formations and pore space are owned by the surface owner. The mineral estate is limited to the minerals. This view would theoretically eliminate the need to obtain rights from the owners of the mineral estate for use of the subsurface formation or pore space.

A CCS operator still faces complications however. The holders of mineral rights are viewed by virtually all states as dominant to the rights of the surface estate. As such, the mineral rights holder has the right to use the surface and subsurface to the extent reasonable for the extraction of the minerals. Interference with those rights, such as the use of pore space when minerals are still recoverable, may result in a lawsuit. Accordingly, the identification of and negotiation with mineral estate holders may be prudent and/or necessary.

An example is the California case of Cassinos v. Union Oil Company, 14 Cal.App.4th 1770 (Court of Appeal, Second District, 1993) a suit was brought by the mineral rights owner against an adjacent property owner who had injected off-site wastewater via an oil well. The wastewater migrated into the mineral estate. The appellate court affirmed a determination by the lower court holding that a subsurface migration of fluids into a mineral estate without consent of that estate constitutes a trespass.

The English Rule

A minority of states hold that the mineral rights estate owns the geologic storage formation and pore space. The minority view is probably most clearly set forth in the Kentucky case of Century Kentucky Natural Gas Co., v. Smallwood, 252 SW2d 204 (Ky. Ct. App. 1952) where the court held: "We conclude that the mineral rather than the surface owner is entitled to rental or royalty accruing under a gas storage lease." The case was later overturned, but on a different issue in Texas American Energy Corp. v. Citizens Fidelity Bank & Trust Co., 736

S.W.2d 25 (Ky. S.Ct. 1987). This view has been endorsed by the authors of an oft-cited oil and gas legal treatise.[9]

This approach may eliminate some of the dominant estate issues encountered under the American Rule. However, CCS efforts under the English Rule would no doubt still require negotiation with surface owners as surface access for facilities, wells and pipeline would remain necessary.

The discernment of relevant property rights becomes more complex when the storage reservoir is a deep saline aquifer. There, ownership of the underground formation may rest on groundwater law that varies greatly from state to state. Further, the withdrawal of water, and not the injection of matter into depleted aquifers, has been the focus of regulations and litigation.

Additional Considerations

A CCS operator may encounter additional issues regarding property rights. Even if it is settled that pore space belongs to say the surface estate, can the pore space be decoupled from the surface estate and sold or leased separately? Further, energy exploration companies may have obtained mineral, oil and/or gas leases purporting to include rights to storage and pore space bringing a third party into the equation. Interference with those that hold rights to minerals, oil and/or gas may also be of concern. In the New York case of International Salt Co. v. Geostow, 878 F.2d 570 (2nd Cir. 1989), a federal court found that the surface owners were precluded from executing a waste storage contract with a third party to use the excavated space created by the salt mining activities because there still remained minerals in place and the International Salt Company required use of the previously mined sections as a means of access to the un-mined portions of their mineral property.

4.0 Regulatory Approaches

Apart from increased clarity surrounding property rights, the orderly implementation of CCS may require the implementation of a regulatory regime designating the extent to which the storage reservoir (and possibly buffer zones) CCS must be controlled by the operator and granting the powers of eminent domain or similar processes to gain control of property where negotiations prove futile.

4.1 Natural Gas Storage

An examination of the regulation of underground gas storage provides insights for a potential regulatory framework for CCS. At the beginning of 2006, 123 natural gas companies operated 394 gas storage sites located in the lower 48 states. Almost all of the underground

[9] Williams & Myers, Oil and Gas Law. The severance of the mineral estate from the surface estate "should be construed as granting exclusive rights to the subterranean strata for all purposes relating to minerals, whether 'native' or 'injected', absent contrary language in the instrument several such minerals." Section 1:22, pages 334-335.

natural gas storage fields in the Northeast were developed from depleted natural gas production fields in New York, Pennsylvania and West Virginia.[10]

Many states have enacted statutes and regulations providing not only for safety but a framework under which property concerns are addressed. In New York for example, written approval must be received from the State Geologist along with an underground storage permit. Applications for permits must include a map showing the locations and boundaries of the proposed underground storage reservoir and buffer zone limits. An operator must submit an affidavit that it has acquired at least 75% of the storage rights in the reservoir and buffer zones. The applicant must further agree as a condition to the issuance of the permit that it will acquire the remaining 25% of the storage rights in the reservoir and buffer zone. Moreover, the statute grants the operator the power to acquire the rights to properties subject to the eminent domain procedure law if reasonable efforts fail to obtain the property.[11]

The New York statutory regime also provides some insight on property valuation. It states that the value of any property acquired includes the value of any commercially recoverable native oil, gas and salt in place to the extent that the holder of the property interest being acquired has a right thereto.[12]

The insights gained from natural gas storage regulatory frameworks are not comprehensive however. For example, New York case law on pore space ownership in a split estate is undeveloped. As such, questions remain as to the identity of the proper party for negotiation of property rights and condemnation, if necessary.

Further, eminent domain may not be legally permissible or recommended in the CCS realm. First, the law of eminent domain requires a public use, benefit or purpose be served by the proposed acquisition.[13] While natural gas storage has generally been viewed as serving such a purpose, the courts may not view the sequestration of CO2 in the same manner, arguments as to the benefits to the global climate to the contrary.

In addition, given the public's general current wariness with CCS, the introduction of eminent domain powers may increase public resistance to the industry.[14]

4.2 The Unitization Approach

Unitization is the treatment of oil and gas producing fields as a unit in which property owners share in the proceeds generated from production by an energy exploration company. Many states have enacted mandatory unitization laws.

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[10] "U.S. Underground Natural Gas Storage Developments: 1998-2005", Energy Information Administration, Office of Oil and Gas, October 2006.
[11] Environmental Conservation Law, Title 13, "Underground Storage of Gas".
[12] Environmental Conservation Law, Section 13-1303 (5).
[13] See, for example, Keegan v. City of Hudson, 23 AD3d 742 (3rd Dept. 2005).
[14] See Congressional Research Service Report to Congress, "Community Acceptance of Carbon Capture and Sequestration Infrastructure: Siting Challenges", July 29, 2008.

Often, unitization laws prescribe the specific property area where the reservoir of oil or gas is deemed to exist. Further, the operator is required to have obtained permission to drill from a majority of the landowners in the unit. Where permission is not obtainable, some states have enacted compulsory integration provisions, where the subject land is incorporated into the unit, with the landowner electing available methods of compensation.

Such an approach might prove useful to CCS in that it would provide guidance as to whether, and to what extent, property rights need to be obtained. It may also prove helpful as a defense to suits from adjoining landowners in the case of migration.[15]

Still, to be truly useful to the industry, additional clarity would be needed on the issue of pore space ownership. Further, the vast size of prospective CCS projects may, as a practical matter, prevent the acquisition of required property rights. An additional drawback is the extent to which regulatory time and resources must be utilized to establish and/or approve units. Finally, compulsory integration may arouse the same negative public connotations as eminent domain.

5.0 State Legislative and Regulatory Initiatives

5.1 Wyoming

In March 2008, Wyoming became the first state to enact comprehensive legislation that designs a framework for storing CO2. House Bill 90 required the Wyoming Department of Environmental Quality to expand the Underground Injection Control program to include carbon sequestration and to develop rules to regulate sequestration activities. The Wyoming Board of Oil and Gas was granted jurisdiction over the subsequent extraction of sequestered carbon for commercial or industrial purposes.

House Bill 90 also dealt with landowner rights, albeit in a broad fashion. Permit applicants must demonstrate that they have "all legal rights, including but not limited to the right to surface use, necessary to sequester carbon dioxide and associated constituents into the proposed geologic sequestration site". Further, applicants must, among other requirements, provide proof of notice to surface owners, mineral claimants, mineral owners, lessees and other owners of record of the project and provide further notice within thirty days of when any excursion of CO2 is discovered.

House Bill 89 addressed the ownership of pore space. The law established that pore space is owned by the surface owner. In addition, a conveyance of the surface ownership constitutes a conveyance in all strata below the surface unless the ownership interest in the pore space has been previously conveyed or is explicitly excluded. Further, transfers of pore space after July 1, 2008 are null and void at the option of the owner of the surface if the transfer document does not

[15] See Philips Petroleum Co. v. Stryker, where the Alabama Supreme Court reversed a finding of damages to a landowner's reservoir that bordered a unitized enhanced oil recovery project. The court held that under Alabama law, the adjacent landowner could have petitioned for inclusion into the unitized project to protect his underlying reservoir.

contain a specific description of the pore space being transferred. The law would not affect the common law related to mineral estate dominance.

Notably, the Wyoming legislation did not set forth who or what entity would be liable if carbon sequestered underground migrated beyond its permitted perimeter.

5.2 Montana

According to Representative Brady Wiseman, a member of the Montana Energy & Telecommunications Interim Committee, Montana intends to do nothing legislatively in 2008. Mr. Wiseman cites issues with unproven technology, unclear lines of responsibility and liability and high costs of deterrents.[16] In November 2008 the U.S. Department of Energy did award $66.9 million dollars through its Regional Carbon Sequestration Partnership Program, to the Big Sky Regional Sequestration Partnership to conduct a large-volume test in the Nugget Sandstone formation to demonstrate the ability of a geologic formation to safely, permanently and economically store more than two million tons of $CO2$.[17]

5.3 Oklahoma

Despite a proposed bill which would have required the development of a CCS permitting regime and the transfer of well ownership to the state and a release from liability ten (10) years after closure, the version of the bill that became law only mandated a task force to the Governor which was to provide permitting guidelines by December 2008.

5.4 Washington

In 2008 the State of Washington amended its laws regarding Class V wells to provide for specific requirements for wells used to inject CO2 for permanent geologic sequestration. The legislation addressed a multitude of issues including geologic sequestration well standards and permit application requirements (including the submittal of a map showing the boundaries of the project calculated to include an area containing 95% of the injected CO2 mass one hundred years after completion or the plume boundary at the point in time when expansion is less than one percent per year, whichever is greater or another method approved by the department). However, no provisions were included regarding pore space ownership or requirements to obtain surface and subsurface rights.[18]

5.5 IOGCC Proposal

The Interstate Oil and Gas Compact Commission (IOGCC) Task Force on Carbon Capture and Geologic Storage included representatives from IOGCC member states and international affiliate provinces, state and provincial oil and gas agencies, U.S. Department of Energy-sponsored Regional Carbon Sequestration Partnerships, the Association of American

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[16] NewWest.Net, "Montana Legislature Won't Tackle Carbon Sequestration, And That's a Good Thing", Rep. Brady Wiseman, September 8, 2008.
[17] See NETL: News Release – "DOE Completes Large-Scale Carbon Sequestration Awards", November 17, 2008.
[18] WAS 173-218-115

State Geologists and independent experts. Its 2007 Phase II report was the culmination of a two-phase, five-year effort.[19]

The Task Force Report produced a model legal and regulatory regime for the geologic storage of CO2. Among its conclusions the Task Force found that control of the reservoir and associated pore space used for CO2 storage is necessary to allow for the orderly development of a storage project. Therefore, the Task Force determined that control of the necessary storage rights should be required as part of the initial storage site licensing. Its Model General Rules and Regulations propose the required acquisition of these storage rights and contemplates use of state natural gas storage eminent domain powers or oil and gas unitization processes to gain control of the entire storage reservoir.

A major issue confronted by the Task Force was how to deal with long-term monitoring and liability issues. The creation of an industry-funded and state-administered trust fund was considered by the Task Force to be the most effective and responsive "care-taker" program to provide the necessary oversight after injection activities cease and the injection well was plugged.

The Task Force also considered the best venue for geologic storage regulation. It concluded that the federal UIC Program may be applicable at the discretion of a state program, but that limitations of the program make it applicable only to the operational phase of a storage project. Given the proposed long-term "care-taker" role of the states, the states were viewed as best position to provide the "necessary 'cradle to grave' regulatory oversight of geologic storage of CO2."[20]

6.0 Proposed Goals and Recommended Actions

Goals:

Reduce the environment of legal and regulatory uncertainty currently faced by potential operators and investors.

[19] "Storage of Carbon Dioxide in Geologic Structures: A Legal and Regulatory Guide for States and Provinces", The Interstate Oil and Gas Compact Commission Task Force on Carbon Capture and Geologic Storage, September 25, 2007.
[20] Id.

Recommendations:

Consider a legislative fix to property rights issues, primarily the identification of the ownership of pore space.

Identify the most appropriate regulatory scheme for CCS following a review of analogous industries - waste disposal, gas storage, oil and gas unitization.

Give strong consideration to the implementation of a regulatory framework akin to natural gas storage requiring property rights for reservoir areas and buffer zones, and granting the right of eminent domain or unitization.

Conduct a detailed review of state statutes to identify those that might be amended to benefit CCS. For example, Environmental Conservation Law Section 23-0301, Declaration of Policy, is often cited in support of acts in furtherance of the oil and gas industry. Underground storage of gas, solution mining of salt, brine disposal wells and geothermal and stratigraphic wells are referenced in the same statute. It may prove beneficial to amend the statute to include CCS.

Prepared by F. Charles Dayter, Esq.
*Prepared for the NYSERDA Workgroup 3.
This is not offered nor is it intended to be legal advice.

Workgroup 4

CO_2 Pipeline Permitting

Issues and Recommendations

January 15, 2009

1.0 Overview

Introduction

Industry and policy experts are evaluating a number of potential approaches to reducing manmade contributions to global warming from U.S. sources. One approach is carbon capture and sequestration (CCS) – capturing CO_2 at its source (e.g., a power plant) and storing it indefinitely (e.g., underground) to avoid its release to the atmosphere. A common requirement among the various techniques for CCS is a dedicated pipeline network for transporting $CO_2$from capture sites to storage sites.

CCS science and associated technology are still in the early stages of development. One of the unknowns is whether ultimately there will be a large number of sequestration sites located geographically close to CO_2 source facilities, or a smaller number of more centralized, or more distant, sequestration locations.

If CO_2 can be sequestered near where it is produced then CO_2 pipelines should evolve in a decentralized way, with individual facilities developing direct pipeline connections to nearby sequestration sites. The resulting network would consist of many relatively short and unconnected intrastate pipelines. Alternatively, if only very large, centralized sequestration sites are developed, the result might be a network of interconnected long distance interstate pipelines.

Currently there are several regional CO_2 pipelines are operating in the southwestern US. They include the Canyon Reef Carriers in Texas (built in 1970 and operated by Kinder Morgan), the Bravo Dome Pipeline in New Mexico (built in 1984 and operated by BP Amoco), and the Cortez Pipeline in Texas and New Mexico (built in 1984 and operated by Kinder Morgan). These pipelines are used to inject CO_2 into storage sites for Enhanced Oil Recovery (EOR). (See figure 1)

The purpose of this paper is to:

- Provide background information on the history of CO_2 transmission in the U.S.
- Summarize the existing regulatory structure applicable to the permitting of an intrastate pipeline used to transport CO_2 from capture site to storage site, specifically in NYS.
- Summarize existing regulatory requirements applicable to the design of a CO_2 pipeline
- Evaluate alternatives to the existing permitting programs that could be used to improve the NYS permitting process
- Make recommendations for future legislative action, as appropriate.

In order to simplify the discussion is assumed that the CO_2 pipeline can be permitted separately from the generation, capture and sequestration components of a CCS project.

2.0 History of CO_2 Regulation

2.1 Federal Regulation

There is currently no federal regulation of siting and rates for CO_2 pipelines due in large part to the fact that many of them are intrastate and that they often transport CO_2 for the benefit of the pipeline's owners (so there are no rate or service disputes). The Natural Gas Act of 1938 (NGA) vests in FERC the authority to issue "certificates of public convenience and necessity" for the construction and operation of interstate natural gas pipeline facilities. FERC is also charged with extensive regulatory authority over the siting of natural gas import and export facilities, as well as rates for transportation of natural gas and other elements of transportation service.

In December of 1978, the Cortez Pipeline Company (operating in Texas and New Mexico) sought a declaratory order from FERC that the construction and operation of a proposed interstate pipeline transporting a gas comprising of 98% CO_2 and 2% methane would not be within the Commission's jurisdiction. Cortez argued that the gas in question was not "natural gas" as the term is defined in Section 2(5) of the NGA, so a proposed pipeline to transport this gas was not under FERC's NGA jurisdiction. FERC agreed with Cortez and issued a declaratory order disclaiming jurisdiction over the proposed pipeline because CO2 is not a "natural gas," as defined by the Natural Gas Act and therefore the regulation of CO2 was not within its jurisdiction.

Jurisdiction over rate regulation for "other" types of pipelines resides with the Surface Transportation Board (STB). The STB is an independent regulatory agency administratively affiliated with the Department of Transportation. In 1980, after FERC issued its CO_2 ruling, Cortez went to the ICC (the predecessor to the STB) to seek a declaratory order similar to the one issued by FERC stating that the pipeline would not be subject to the ICC's jurisdiction either. Like FERC the ICC also declined to take jurisdiction over CO_2 pipelines. They found that Congress intended to exclude all types of gas, including CO_2, from ICC regulation but noted that the U.S. Department of Transportation did have jurisdiction over the pipeline's compliance with applicable safety standards.

Given the reluctance of FERC and the STB to exercise jurisdiction over CO_2 pipelines the regulation of existing CO_2 pipelines (except pipeline safety) has been left to the regulatory structures of the states where they are located.

2.2 State Regulation

In New York State Article VII of the Public Service Law (PSL) is the statute under which the construction and operation of major utility transmission facilities is licensed. A "major utility transmission facility" is defined as a) an electric transmission line of 125 kV or more and of a mile or more in length and b) a fuel gas transmission line of a 1000 feet or more in length used to transport fuel gas at pressures of 125 psi and above. PSL

§ 120(2). Because CO_2 is not a fuel gas, Article VIII does not give the Public service Commission jurisdiction over CO_2 being transported to a sequestration site. Instead, the construction and operation of CO_2 lines in New York is regulated by multiple federal, state and local resource and regulatory agencies that have general authorities over discreet portions of a project.

2.3 Emerging Legislation

There has been considerable debate in Congress over the past few years on the capture and sequestration aspects of carbon sequestration, and there is an understanding that a national CCS program could require the construction of a substantial network of interstate CO_2 pipelines, however, to date there has been little focus on transportation. Proposed S. 2144 and S. 2191 would require the Secretary of Energy to study the feasibility of constructing and operating such a network of pipelines. Proposed S. 2323 would require carbon sequestration projects to evaluate the most cost-efficient ways to integrate CO_2 sequestration, capture, and transportation. Proposed S. 2149 would allow seven-year accelerated depreciation for qualifying CO_2 pipelines. P.L. 110-140, signed by President Bush on December 19, 2007, requires the Secretary of the Interior to recommend legislation to clarify the issuance of CO_2 pipeline rights-of-way on public land.

Given that traditional federal and state gas pipeline regulatory authorities do not currently have jurisdiction to regulate the transport of CO_2 in New York and that it is unlikely that there will be federal CO_2 transportation regulation for many years there is a need for state policy makers to begin to understand the existing regulatory structure and consider the need for the enacting of new legislation to improve this process if New York wants to promote the development of CSS technologies within the next few years.

3.0 Existing Licensing Program for CO_2 Pipelines in New York

Licenses for major gas transmission pipelines in NY are obtained through the Federal Energy Regulatory Commission (FERC) if there is interstate transmission, or the New York Public Service Commission (NYSPSC) if the project is entirely in NY. Both FERC and the PSC are responsible for determining whether there is a need for a particular project and issuing a license/certificate of environmental compatibility and public need for the project; however under current law neither FERC nor PSC licensing processes are applicable to CO_2 transmission projects because CO_2 is not considered a "natural gas."

Under the FERC process, an applicant for a natural gas pipeline would obtain a certificate of need and necessity from FERC, and concurrently, but separately, obtain federal, state and local resource/regulatory agencies permits as may be required for discreet portions of the project subject to their jurisdiction. FERC acts as the lead federal agency under NEPA for all pipeline projects under its jurisdiction and the FERC NEPA document can be used by other permitting agencies in support of their review of individual permit applications. Under Section 7 of the Natural Gas Act, FERC has the authority to authorize the taking of property through eminent domain to facilitate the siting of a project for which a FERC certificate has been issued.

Under the PSC (Article VII) process, the PSC acts as the sole state licensing entity for a project. The PSC is required to make a determination of environmental compatibility and public need for a project and coordinate with state and local resource and regulatory agencies to ensure that the substantive requirements of laws and regulations administered by those agencies are met. Once a certificate is obtained from the PSC, the project sponsor is not required to obtain individual project permits from any state or local agencies, although acquisition of permits from federal agencies (e.g. United States Army Corps of Engineers) is still required. The Article VII process supersedes and exempts a Project from needing a separate SEQRA review. Unlike the authority issued through FERC approvals, approval through the PSC does not provide applicants with eminent domain authority.

Because neither FERC nor the PSC have jurisdiction over CO_2, no license comparable to what would be required for a natural gas pipeline is required for a CO_2 transmission project in NY. Instead, the project would be subject to a comprehensive environmental review under SEQRA/NEPA and federal, state and local resource/regulatory agencies permits would be required for discreet portions of the project subject to their jurisdiction. Any of these permitting agencies could act as the lead agency for the SEQRA/NEPA review.

Potential federal, state and local permitting processes are discussed below.

3.1 Federal Permits/Approvals Potentially Applicable to the Project

NEPA requires federal agencies to integrate environmental values into their decision making processes by considering the environmental impacts of their proposed actions and reasonable alternatives. Under NEPA, a federal agency issuing an approval for a project (e.g. permit or funding authorization) is required to prepare a written environmental assessment (EA) to determine whether or not a federal undertaking would significantly affect the environment. If the answer is no, the agency can issue a finding of no significant impact (FONSI). If the EA determines that the environmental consequences of a proposed federal undertaking may be significant, an EIS must be prepared which incorporates greater public involvement and provides the opportunity for public review and comment prior to issuance a decision on a Project. The public, other federal agencies and outside parties may all provide input into the preparation of an EIS, and then comment on the draft EIS when it is completed. An EIS also requires a detailed evaluation of alternatives to the proposed action.

If a CO_2 pipeline is proposed as part of a larger CCS, the NEPA review may need to address potential impacts from the whole project. Depending on the length and location of the proposed CO_2 pipeline, the facility generating the CO_2 could have significantly greater potential environmental impact and impact the overall schedule and level of effort required to gain approval. Depending on the route, a CO_2 pipeline project could potentially require additional federal approvals associated with siting and construction as illustrated in Table 1.

3.2 State Permits

SEQRA is the state equivalent of NEPA. If a state approval (including funding approval) is required for a project, a coordinated review to assess environmental impacts is required. One of the state or local agencies from which a project approval is required is designated as the lead agency and that agency is responsible for evaluating project impacts in accordance with the requirements of SEQRA. The lead agency may either issue a negative declaration, or require a preparation of and EIS (if there is a potential for a significant impact). The scope of the EIS must include all components of the project for which the approvals are required (i.e. capture, transport and sequestration). If an EIS has been prepared under NEPA, a state agency has no obligation to prepare a separate EIS under SEQRA.

Depending on the route a CO_2 pipeline project could potentially require additional state approvals as illustrated in Table 1.

3.3 Local Permits

Local road use and building permits and zoning approvals may also be required to comply with town and county laws. Requirements will vary depending on the location of the project. These approvals are also subject to SEQRA. For many projects of local significance, a local (rather than state) agency assumes the role of lead agency. Required local approvals are listed in Table 1.

3.4 Summary of Existing NY/Federal CO_2 Permitting Program

The permitting process for each CO_2 gas pipeline will vary depending on the resources impacted and the local building and zoning requirements of the locality where it will be constructed. Most projects will require an approval that would trigger the preparation of an EIS under SEQRA. The EIS would evaluate the environmental consequences associated with the capture, transport and sequestration of CO_2. In conjunction with the preparation of the EIS, an applicant would also be required to make individual applications and receive the appropriate approvals from each of the agencies having jurisdiction over the project. No agency can issue an approval until the requirements of SEQRA (state and local) or NEPA (federal) have been met.

None of the permitting agencies currently have eminent domain authority to facilitate the siting of a CO_2 project; however if the project sponsor is a municipality it would likely have eminent domain authority under existing municipal law.

Table 1 summarizes permits, approvals, consultations potentially applicable to CO_2 pipelines in New York, including federal, state and local regulatory programs with uncertain jurisdiction over CO_2 pipelines.

Table 1: POTENTIAL PERMITS, APPROVALS, AND CONSULTATIONS APPLICABLE TO THE CO_2 PIPELINE

AGENCY	PERMITS/APPROVALS/ CONSULTATIONS	APPLICABILITY
FEDERAL		
Federal Energy Regulatory Commission	Federal Certificate of Public Convenience and Necessity	Not applicable to CO_2 pipelines; FERC has declined to take jurisdiction over CO_2
U.S. Army Corps of Engineers (USACE)	Clean Water Act Section 404 Permit Rivers and Harbors Act Section 10 Permit	NWP 12 required if pipeline crosses regulated water body or jurisdictional wetlands
U.S. Fish and Wildlife Services (USFWS)	Section 7 Endangered Species Act Consultation Section 7/10 Take Permit	Consultation required if project is required to obtain NWP12. A take permit would be required if there is a potential to take, or harass a T&E species
Advisory Council on Historic Preservation	Section 106, National Historic Preservation Act	Consultation required if project is required to obtain NWP12
U.S. Department of Transportation, Federal Highway Administration	Federal Highway Encroachment Permit	Required in pipeline crosses federal highway
NEPA lead Agency	EIS or EA	If project includes a non-exempt federal action
STATE		
New York State Public Service Commission	Article VII Certificate of Environmental Compatibility and Public Need	Not applicable to CO_2 pipelines
New York State Historic Preservation Office	Cultural Resources (Section 106/NHPA) Consultation/Clearance	Consultation required if state or federal approval is involved
New York State Department of Environmental Conservation	Threatened and Endangered Species Consultation Water Quality Certification (Section 401 Permit) State Pollution Discharge Elimination System (SPDES) Construction General Permit for Stormwater Discharges	Section 401 WQC required as part of the Section 404 permit process. Article 15, 24, and/or 25 Permits required if project crosses regulated wetlands or protected streams

Table 1: POTENTIAL PERMITS, APPROVALS, AND CONSULTATIONS APPLICABLE TO THE CO_2 PIPELINE

AGENCY	PERMITS/APPROVALS/ CONSULTATIONS	APPLICABILITY
	Article 15 Protection of Waters; Article 24 Freshwater Wetlands Article 25 Tidal Wetlands	
New York State Department of Transportation	State Road Use Permits Highway Work/Utility/Non-utility Permits Consultation	Permits required if pipeline crosses a state highway
New York State Department of Agriculture and Markets	Consultation with respect to impacts to agricultural lands	Consultation required if project impacts Ag lands
SEQRA Lead Agency	EIS	If project requires a state or local action
LOCAL		
County Highway Department	Road use permits	If project crosses town/county road
Town/County Planning Board	Building permits/ Zoning approvals	If town/County has enacted local requirements

4.0 Pipeline Design Requirements

The DOT regulates the design and construction of interstate pipelines in the United States. The pipeline program is administered through DOT's Pipeline and Hazardous Material Safety Administration (PHMSA), Office of Pipeline Safety (OPS). OPS develops regulations and other approaches to risk management to assure safety in design, construction, testing, operation, maintenance, and emergency response of pipeline facilities. Regulations applicable to CO_2 pipelines are found at 49CFR Part 195. State authorities may adopt additional or more stringent safety standards for intrastate pipeline facilities and intrastate pipeline transportation if those standards are compatible with minimum DOT standards. In New York, the PSC is the certified DOT partner agency and administers the 49 CFR Part 195 program.

49 CFR Part 195 addresses day to day operations of a hazardous liquid pipeline and defines requirements for design, construction testing, operations and maintenance, operator qualifications, and integrity management. § 195.452 addresses pipeline integrity management in high consequence areas. High consequence areas are areas of higher population density, environmentally sensitive areas, unusually sensitive areas like drinking water sources, and navigable waterways. The pipeline operator must determine

the risks to integrity to which the covered segments are exposed. Each segment must be thoroughly inspected or tested to determine an integrity 'baseline' condition, then re-inspected or tested at frequencies that take into consideration the severities of the threats to which it is exposed. The criteria for determining when pipe defects must be repaired in "high consequence areas" are much more restrictive than criteria applied to similar defects in other pipeline segments. Operators are also required to implement additional measures to prevent or mitigate the threats to high consequence segments that go beyond the requirements for other segments.

A pipeline operator's integrity management program must include a quality control plan that covers not only its own integrity management processes and procedures, but also the processes and procedures used by contractors it may hire to perform integrity management activities. Both pipeline operator and contractor supervisors and personnel must be specifically trained and qualified to perform integrity management activities. The pipeline operator must track a range of performance metrics to demonstrate compliance with the IM rule, many of which are reported semi-annually to PHMSA and state regulatory agencies.

5.0 ALTERNATIVES

This section identifies three alternatives to the existing permitting programs that could be implemented to improve the NYS permitting process, and evaluates the advantages and disadvantages of each. The three alternatives are:

- Develop a state licensing program modeled after the FERC process and adopt DOT standards for CO_2 pipeline safety and design

- Develop state licensing process modeled after Article VII that would give complete CO_2 pipeline licensing authority to the PSC

- Permit a project under the existing NEPA/SEQRA framework

Under each of these alternatives CO_2 pipelines are already required to meet (49 CFR Parts 190 – 195) DOT pipeline design standards.

5.1 Develop a State Licensing Program Modeled after the FERC Process and Adopt DOT Standards for CO_2 Pipeline Safety and Design

5.1.1 Discussion

The FERC process could be used as a model for drafting New York state legislation for the regulation of intrastate CO_2 pipelines. Under this approach, PSC would be responsible for licensing CO_2 projects. An applicant for a CO_2 pipeline would obtain a certificate of need from the PSC and then separately obtain federal, state and local resource/regulatory agencies permits as may be required for discreet portions of the project. PSC would act as the lead agency under SEQRA and the PSC SEQRA document would be used by other state and local permitting agencies in support of their review of individual permit applications. Federal agencies would still need to issue permits as required for impacts to resource areas under their jurisdiction and confirm that a proposed project adheres to the requirements of NEPA prior to issuing a permit. If the FERC model were adopted PSC would also be given the authority to authorize the taking of property through eminent domain to facilitate the siting of a project for which a PSC Certificate has been issued.

5.1.2 Advantages to Adopting the Federal Model

- The FERC model provides a clear process for applicants to follow in order to determine whether their project is in the public interest, but still provides state and federal resource agencies and local jurisdictions the opportunity to comment on a Project an participate in the SEQRA process and to retain permitting authority for portions of the project under their normal jurisdiction. This model would take advantage of the existing SEQRA process to insure that environmental and social costs and benefits are thoroughly evaluated and make the licensing application and review process consistent no matter what jurisdiction the application is made in because PSC will always be the Lead Agency.

- By insuring that PSC is the lead Agency for all projects the FERC model can better take state energy needs into account in determining the need for a project than the current approach. This will minimize the potential for a local bias to influence the granting of a project approval based on non technical considerations. The FERC model and the Article VII model (discussed below) are similar in this regard. The existing NEPA/SEQRA process leaves policy level decision with local permitting agencies or resource agencies who are often making decisions on a matter outside of their area of expertise.

- The FERC model would insure that a lead agency (PSC) that would have sufficient resources to consistently and diligently review all projects. In the existing process local agencies may not have sufficient staff or resources with expertise in energy and policy matters to adequately review applications.

- Eminent domain authority can be used as a last resort to facilitate routing if there is local or landowner opposition.

5.1.2 Disadvantages

- If the FERC model is adopted the state process for permitting a CO_2 pipeline would be different from the Article VII process currently used for permitting a natural gas pipeline located wholly within New York. (The Article VII process makes the PSC the Lead Agency for purposes of the review of an application but does not rely on SEQRA to do so; does not give PSC eminent domain authority; and does not require that an applicant obtain separate local and state approvals.)

- Stakeholder groups, both public and regulatory, may not be in favor of giving eminent domain authority to the PSC for CO_2 pipeline projects.

- Local policy interests may have lesser weight in the approval process than broader state policy concerns.

5.2 Develop State Licensing Process Similar to Article VII that would Give Complete CO_2 Pipeline Licensing Authority to the PSC

5.2.1 Discussion

Article VII of the Public Service Law (PSL) is the statute under which the construction and operation of major utility transmission facilities are permitted in New York. "Major utility transmission facility" is defined as: a fuel gas transmission line of 1000 feet or more in length used to transport fuel gas at pressures of 125 psi and above (PSL § 120(2)). Because CO_2 is not a fuel gas, Article VII would need to be amended to extend its coverage to CO_2 being transported to a sequestration site. Article VII standardizes requirements regarding the contents of an application and requires that pipelines meet applicable federal and state design standards. It does not provide eminent domain authority pursuant to the issuance of a Certificate. (Note, however, that for transmission projects being constructed by a municipality, the municipality may have eminent domain authority within areas under its jurisdiction.)

Assuming the NYS legislature was to expand the PSC's jurisdiction under the Article VII to include CO_2 pipelines, PSC would be responsible for the review and approval of all aspects of an interstate pipeline under NYS's jurisdiction. Federal approvals such as a USACE permit for wetland or stream impacts would still need to be obtained separately, while state permits would not. Article VII establishes the PSC as the lead permitting agency, providing "one-stop shopping" for all State and local permits, and authorizes the Public Service Commission to override unreasonably restrictive local requirements. Article VII also provides an expedited process for certain shorter pipelines.

If a proposed CO_2 pipeline project were required to obtain Certification through Article VII, the substantive evaluation of potential environmental impact of the construction and operation of this pipeline would be similar to that required under the NEPA/SEQRA process embodies in existing law except that the Article VII process involves a two-step approval process. During the first phase, the PSC makes a decision whether or not to issue a license based on conceptual design information and drawings that provide enough detail to evaluate the potential impacts of the project, but not detailed enough to construct the project. After a license has been issued, the applicant is required to prepare an Environmental Management &Construction Plan (EM&CP) that includes design details. A project cannot be constructed until the EM&CP has been made available for public comment and approved by the PSC.

As mentioned above, the Article VII process eliminates the need for an applicant to obtain additional state and local approvals for components of the project that are subject to the jurisdiction of local permitting agencies and state resource agencies. These agencies would have an opportunity to comment on the project but the final licensing/permitting decisions would lie with the PSC.

The major difference between this approach and the FERC model discussed above is that under the Article VII model an applicant would still need to obtain state and local permits for the project and PSC does not have eminent domain authority. The FERC model also requires that the initial permit application include more detail regarding the project design than is required under Article VII.

5.2.2 Advantages to Adopting the Article VII Model

- Like the FERC approach discussed above an Article VII-like process would provides more certainty and consistency to applicants than the existing one, as there would be a standardized application process and single state approval authority. An advantage of the Article VII process as compared with the FERC model is that the PSC has more experience in implementing an Article VII approach than it does under a model that would be based on SEQRA

- The PSC may be better able to take state energy needs into account in its decision making than local agencies. PSC has years of experience making decisions regarding the transportation of electricity and natural gas and it is likely that CO2 transport will involve similar issues

- The PSC has more resources and expertise available to review applications than resource or local agencies.

- For projects that would require approvals from multiple agencies the Article VII process can likely be completed in less time than under either the FERC or existing NEPA/SEQRA approaches.

5.2.3 Disadvantages

- There are no current plans for the State to amend Article VII to include CO_2 transport. Recent efforts to reauthorize Article X have met with a great deal of resistance.

- Local policy interests may have lesser weight in the approval process than broader state policy concerns.

- Article VII does not include eminent domain authority. The inclusion of eminent authority in any proposed legislation would make it more controversial and could significantly delay the adoption of new legislation

5.3 Permit a Project under the Existing NEPA/SEQRA Framework

5.3.1 Discussion

As discussed in Section 1.0, under the current permitting process for any given CO_2 pipeline would vary depending on the resources impacted and the building and zoning requirements of the locality where it will be constructed. Most projects would require a number of approvals that would trigger the designation of a lead agency and the preparation of an EIS under SEQRA/NEPA. For smaller local projects that may fall under a single jurisdiction, Lead Agency status would likely be assumed by the local municipality that would need to issue either building or zoning permits for the construction of a CO_2 pipeline. For larger projects that cross multiple jurisdictions, and potentially cross more sensitive wetland and water body resources, the NYSDEC, or the USACE may want to become the lead agency. The EIS would evaluate the environmental consequences associated with the capture, transport and sequestration of CO_2. In conjunction with the preparation of the EIS, an applicant would also be required to make individual applications and receive the appropriate approvals from each of the agencies having jurisdiction over the project. Although there are time limits for the review and approval of an EIS under both SEQRA and NEPA and, for most of the individual permits that are required, the complexity of the permitting process and number of agencies involved would likely result in a significantly longer application process than under FERC or Article VII procedures. The current program provides each regulatory agency the opportunity to make decisions over issues within its specialized area of expertise.

5.3.2 Advantages

- No legislative changes are required to permit a project under the existing program. Applicants are aware of the rules and can plan accordingly.

- For small projects the local agency where the project is going to be developed may be in the best position to make decisions regarding the balancing of costs and benefits of the project to the public.

5.3.3 Disadvantages

- A number of approvals are required from independent permitting entities. As a result there is a potential for project delays while all required approvals are obtained and multiple opportunities for opponents of a project to challenge agency approvals.

- For large projects that cross multiple jurisdictions and have regional policy implications a state agency with specialized expertise may be in the best position to make decisions regarding the balancing of costs and benefits of the project to the public.

- NIMBY concerns have the potential to prevent the approval of projects that are otherwise consistent with state energy policies.

- Local permitting agencies may not have the resources or technical expertise to make informed decisions regarding the application of new energy projects.

- Lack of a statewide process and a single decision maker with respect to critical issues of necessity and environmental compatibility may result in inconsistencies in the application requirements and review criteria.

5.4 Summary Comparison of Environmental Requirements

A comparison of FERC, Article VII, and the existing SEQRA processes is presented in Table 3 below:

Table `3. Comparison of FERC, Article VII and NYS SEQRA Permitting Processes for CO2 Pipelines

Issue		Article VII	FERC
Lead Agency	No specific designation of lead agency. Determination based on specific permits required.	PSC designated as lead agency.	PSC would be lead agency.
Permitting Agencies	Multiple state federal and local permitting authorities.	Certificate issued by PSC covers all state permits issued.	Multiple state federal and local permitting agencies.
SEQRA/NEPA applicability	SEQRA/NEPA review required	NEPA review required	SEQRA/NEPA review required
Eminent Domain	No eminent domain authority to acquire necessary rights of way	No eminent domain authority to acquire necessary rights of way	Eminent domain authority available for lands for which reasonable easement agreements can not be reached.

Table `3. Comparison of FERC, Article VII and NYS SEQRA Permitting Processes for CO2 Pipelines

Issue		Article VII	FERC
Application processing time	SEQRA approval process likely to take at least 12 – 18 months after complete DEIS is submitted to lead agency. No expedited review of local, state and federal permits.	License is generally issued 12 months after complete application is submitted. No state or local permits required. No expedited review of federal permits.	For smaller projects that can be analyzed with an EA, Certificate is generally issued **6 months** after complete application is submitted to FERC. For larger projects requiring an EIS, Certificate is generally issued 10 months after complete application is submitted to FERC. FERC requires significant stakeholder outreach during the EIS process, which typically facilitates review of individual local, state and federal permits

Table `3. Comparison of FERC, Article VII and NYS SEQRA Permitting Processes for CO2 Pipelines

Issue		Article VII	FERC
Application requirements	Level of design detail required in SEQRA document and permit applications likely to vary depending on agency issuing approval.	Level of design detail in initial PSC application minimal. Detailed construction drawings required after certificate is issued but before construction.	Scope of environmental review requires detailed design data in order to address specific effects of construction, operation (including maintenance and malfunctions), and termination of the project, as well as cumulative effects
Public Comment	Public notice and comment opportunity	Public notice and comment opportunity	Public notice and comment opportunity
Legislative action required	Does not require legislative change	Requires legislative change	Requires legislative change
Key decision makers	Need and compatibility decisions made by resource or local agencies	Need and compatibility decisions made by PSC	Need and compatibility decisions made by PSC

6.0 CONCLUSIONS & RECOMMENDATIONS

The existing permitting structure provides a workable permitting approach for an applicant considering constructing a CO_2 project in the near term. In the long term, a comprehensive statewide permitting program administered by the PSC may be preferable.

The comprehensive program should include:

- Uniform requirements for application contents;
- A comprehensive application process similar to Article VII that, at a minimum, places project need and environmental compatibility approval authority in a single entity (the PSC). Although Article VII also gives the PSC the authority to apply all substantive requirements of existing laws and regulations, and issue a comprehensive license after consulting with resource agencies and local regulatory agencies, this additional element may not be critical to an applicant. The FERC process leaves permitting authority with resource and local agencies and still seems to be workable.
- The level of detail required for an application should be similar to what is currently required under Article VII and detailed construction drawings should not be required until the EM&CP phase; and
- Authorize the PSC to exercise eminent domain authority in certain limited instances.

Work Group 5
Summary of
CCS Human Health Risk Assessment and Mitigation
January 15, 2009

1.0 Introduction

New or developing technologies that could be subject to governmental regulation benefit from *a priori* evaluations not only of the engineering associated with construction and operation of the technology but also what public health or environmental impacts might be associated with the activity. For a given design of a technology, should quantitative analysis of potential public health impacts, for instance, indicate that risk could occur at societal unacceptable levels, the technology could be altered to the point that benefits balance any remaining risk. The discussion below address show one might quantitatively assess public health impacts, and provides some results from a preliminary CCS safety assessment.

2.0 Risks Posed by Carbon Capture and Sequestration (CCS)

The capture and geological storage of carbon (in the form of the greenhouse gas carbon dioxide - CO_2) is one of the models being investigated and in some cases already practiced for diminishing possible greenhouse gas impacts on the global environment. Rather than being discharged to ambient air, CO_2 emitted from a process (such as coal-fired electricity generation) can be collected at a discharge site, processed to make it suitable for transportation (e.g., concentrating and pressurizing the gas to produce a supercritical fluid), and injected underground into stable geologic formations where it could remain for millennia or through natural processes be converted slowly into stable rock. Figure 1 gives an overview of the process and presents possible steps at which releases could occur.

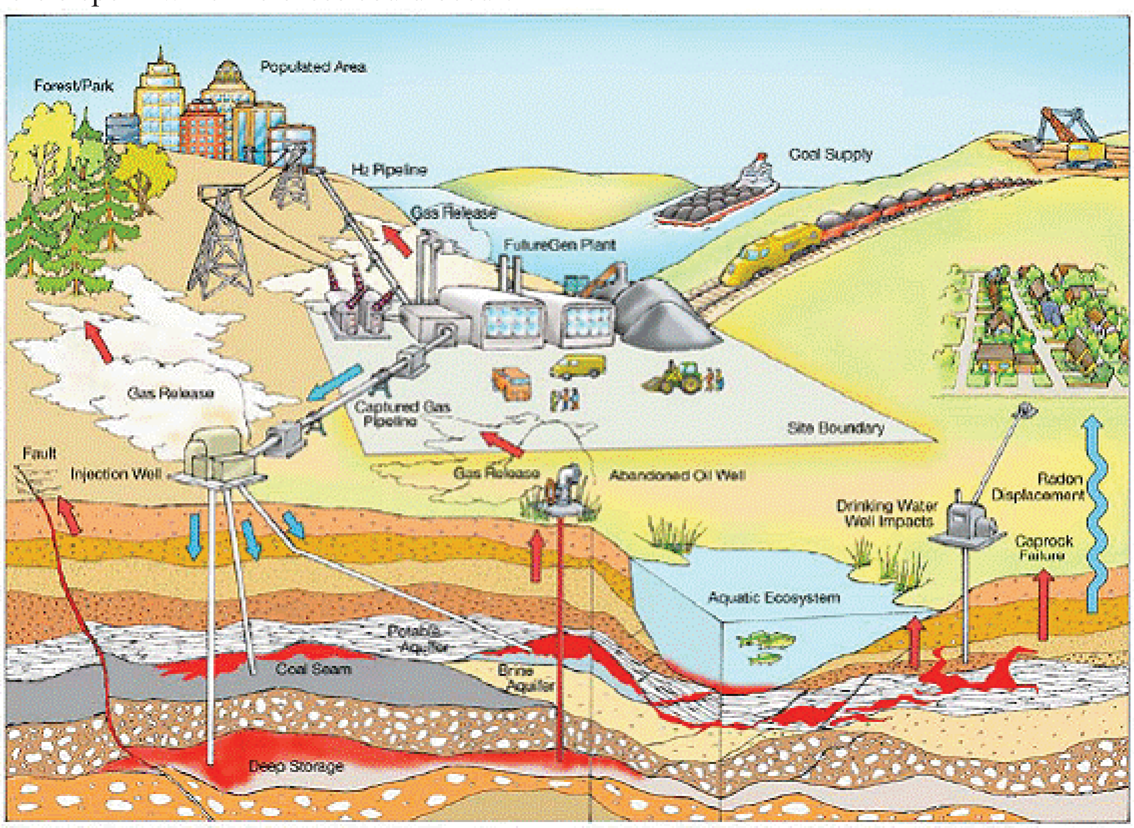


Figure 1 – Conceptual Model for Carbon Capture and Sequestration process. (Taken from DOE 2007)

When considering the use of CCS technology, an assessment for the carbon capture and sequestration process would include containment failures at any and all of the steps depicted in Figure 1. As depicted in Figure 1, CO_2 released from a power generation station that is produced from coal would have to be captured and pressurized[1] so that it could be transported to a deep well injection site. CO_2 released during capture and pressurization due to accidents or equipment malfunction would be released directly to the atmosphere. When using carbon capture technology pressurized gas is transported by a pipeline to and stored at a distant deep well injection site. Releases from the pipeline (due to rupture, puncture, or equipment malfunction) or from storage at the injection site would result in CO_2 being released directly to the environment. As indicated in Figure 1 there are various methods for the underground sequestration of CO_2 (two which, injection into a coal seam or into a deep non-potable saline aquifer may not be appropriate for New York State sites). The injection well could be placed into a geologically stable and well confined deep storage location. Releases of the stored supercritical fluid over time (which might be considered as several millennia), could occur through known or unknown wells which penetrate the formation or from faults that either exist in the confining layer or are induced by the increased pressure from the sequestration. Whatever the mechanism of release, consideration should also be given to the possibility that as the sequestered supercritical CO_2 escapes it could push radon gas out from deep stores into the environment[2]. Other areas that should be considered in a risk assessment of a CCS project should include mobilizations of metals from the sequestration site and the possible contamination of potable water sources.

3.0 Risks Assessment: Regulatory Requirements and Methodologies

Risk assessment is a commonly applied tool for regulatory agencies, including setting standards for use of food additives, clean up of hazardous waste sites, setting drinking water standards, and exposure to chemicals from accidental releases.

Under the Clean Air Act (CAA), in the 1990 Clean Air Act Amendments, Congress added Section 112(r) requiring owners and operators of stationary sources to identify hazards, and prevent and minimize the effects of accidental releases wherever extremely hazardous substances are present at their facility. Section 112(r) encompasses both the General Duty Clause of Section 112(r)(1) and the Risk Management Program of Section 112(r)(7).

The General Duty Clause applies to any facility were extremely hazardous substances are present. The Risk Management Program (RMP) applies to a subset of these facilities were certain substances above a threshold level. The Risk Management Program is a regulatory program developed by EPA, found at 40 C.F.R. Part 68, which emphasizes hazard assessment, prevention and response. Information on the Risk Management Program, provided by EPA's

[1] A gas at elevated pressure and temperature becomes "supercritical" above its "critical point" and exists in a state where vapor and liquid phases are in equilibrium. For CO_2 the critical point is 304°K (31°C) and 73 atm (73 times normal atmospheric pressure of 14.7 pounds per square inch).
[2] DOE 2007 determined, based on an existing sequestration site, that radon levels at ground surface were indistinguishable from background. The radon pathway was not carried forward in their risk assessment.

Chemical Emergency Preparedness and Prevention Office (CEPPO) is available at the following web site.

The General Duty Clause refers to the release of "extremely hazardous substances," but these are not defined in the statute. EPA has adopted a broad interpretation of the term "extremely hazardous substances" that includes various lists of hazardous substances, toxic substances, and chemicals that it has identified in its regulations relating to the statute. By way of further guidance, the legislative history broadly describes the category as including any substance which has the capacity to cause death, injury, or property damage due to short-term exposure because of its toxicity, reactivity, flammability, volatility, or corrosivity. CO2 is neither reactive, flammable, volatile, nor corrosive. However, the Material Safety Data Sheet for CO2 provides toxicity information, and the potential for CO2 to be toxic is discussed below.

The RMP Rule applies to facilities (both public and private) that manufacture, process, use, store, or otherwise handle hazardous air pollutants (HAP) at or above specified threshold quantities. There are 188 substances designated as HAPs for their effects on human health and ecosystems. CO2 is not listed as one of 188 substances designated as HAPs.

The Rule requires all regulated facilities to prepare and execute a risk management program which contains the following elements:

- A hazard assessment to determine the consequences of worst case scenario and other accidental release scenarios on public and environmental receptors and provide a summary of the facility's five year accident history of accidental releases.
- An accidental release prevention program designed to detect, prevent and minimize accidental releases.
- An emergency response program designed to deal with any accidental release in order to protect both human health and the environment.
- A risk management plan (RMP) which summarizes the facility's risk management program and which must be submitted to a central point that will be designated by EPA. All RMPs will be made available to appropriate State and local agencies and the public.

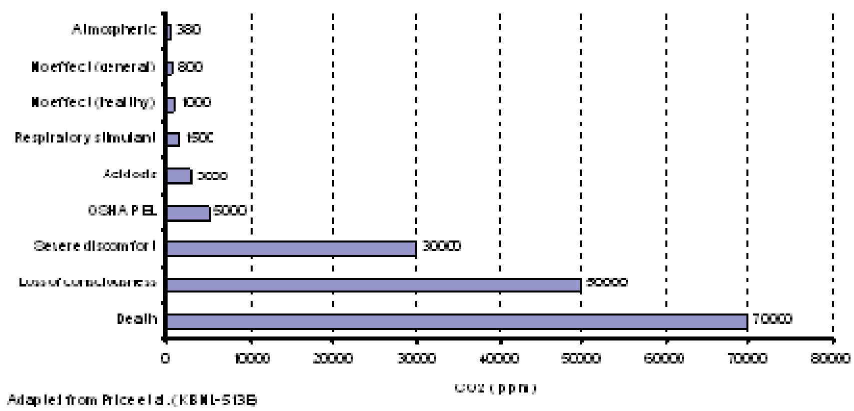
When performing a risk assessment there are two basic components. These are:

(1) toxicity assessment; and
(2) exposure assessment.

These two components are evaluated independently and integrated with each other into a risk assessment. The toxicity component links potential adverse health effects to levels of the toxicant and duration of exposure. Traditionally a dose response curve is developed wherein various toxic responses are linked to levels of exposure. Figure 2 shows CO2 dose response information. The air we breathe out contains about 4%, or 4000 ppm carbon dioxide. Power plant emissions are typically up to about 14% or 14,000 ppm. However, the capture and compression process increases CO2 concentrations significantly, to 80 to 90% depending on the capture mechanism, or 800,000 to 900,000 ppm. At high concentrations, CO2 is an asphyxiant. It can inhibit the normal mechanisms for transport of oxygen to tissues and can result in transient symptoms (headache or difficulty breathing at ~20,000 parts per million volume or ppmv) or life-threatening conditions (unconsciousness or death at concentrations of 70,000 ppmv or greater.

The second component is the exposure component of a risk evaluation. There are numerous potential points (sources) that would need to be considered for both probability and estimation of the amount of a potential CO_2 release. This component of the evaluation also includes identification of migration pathways and an identification of potential receptors culminating in an estimated level and duration of exposure. The estimated exposure levels at the receptor would be integrated with the established toxicity criteria to produce a risk estimate.

Figure 2
Carbon Dioxide Dose-Response



During operation of CCS, the potential for releases of CO2 includes pre-sequestration activities of handling, storage and transport and post sequestration potential for releases to the surface or to drinking water from the underground storage formations. The geologic formation where the supercritical fluid is stored also will vary depending upon location but should be the most stringently controlled factor for the sequestration process. General requirements would include sufficient pressure at depth to keep CO_2 in a supercritical state, sufficient impermeable overlay material to retard upward migration of the stored supercritical fluid, geologic stability of the overlaying material, and lack of faults or fissures that would allow the supercritical fluid to escape. There are CO_2 sequestration projects operating at the present time which demonstrate qualitatively the safety of underground CO_2 storage. These include the Sleipner Field in the North Sea where CO_2 from a coal-fired power plant is sequestered in a deep saline aquifer, the Weyburn field in Canada where CO_2 is injected underground for enhanced oil recovery, and the San Juan basin in New Mexico where underground CO_2 injection is used to enhance coal bed methane recovery. Friedman (2004) describes a qualitative risk assessment approach for evaluating leakage during gasification of underground coal seams that could be applicable to CO2 sequestration. It would be expected that release, if any, from underground gas stores would be slow over the anticipated lifetime of the storage location (in most cases thousands of years) and would occur through existing or undiscovered wells that penetrate the overlayment, existing or induced faults in the overlayment, or through failures at the injection well head. Though not impossible, it would be expected that these releases would occur at much lower rates than what would be expected for pipeline releases[3] but would be expected to occur over a longer timeline.

Another site-specific factor that would have to be considered in an assessment of CCS would be the process that captures the gas. For instance, the oxycoal process produces mainly CO_2 and water (other contaminants such as hydrogen sulfide [H_2S] are separated in scrubbers) (Eriksson et al 2006). On the other hand, a coal-fired power plant using an integrated gasification combined cycle (IGCC) process may release other chemicals of potential concern (COPCs) (e.g., H_2S, sulfur oxides [SO_x], nitrogen oxides [NO_x], carbon monoxide, methane, elemental mercury, and cyanide) (DOE, 2007). Thus, the assessment for CCS would have to take into account contaminant gases, if any, in the CO_2 stream that is separated. Each of the gases listed above would be assessed based on systemic toxicity rather than carcinogenicity. That is, the gases listed above interfere with some physiologic process and result in injuring the cell which is either lost or replaced.

A quantitative assessment should be based on as much empirical information as possible and if mathematical modeling is required, the assumptions of those models must fit the conditions at the location chosen for sequestration. A list of data potential needs is provided in Table 1.

[3] The DOE 2007 risk assessment used pipeline CO_2 release rates of 3,500 to 7,950 kg/s for ruptures and 81.4 kg/s for punctures. Release rates for sequestered CO_2 from wells or faults were 1.9 and 0.0013 kg/s, respectively.

Table 1

Data Elements Necessary for Quantitative Safety Assessment of CO_2 Sequestration

Site area	Deep oil and gas wells within plume	Air dispersion model
Site elevation	Estimate of undocumented deep wells	Flow estimates from failed pipeline or wellhead
Site topography	Number of production wells	Distance to population center
Sensitive receptors	Number of faults extending into injection zone	Empirical data on loss rates from underground supercritical gas stores (reservoir volume, flux rate, primary and secondary seals, secondary porous zone, groundwater, vadose zone, surface water, faults, wells within plume, radon)
Wetlands	Pipeline diameter	Benchmark toxicity values of sequestered supercritical fluid(s)
Soil type	Pipeline pressure	
Shallow groundwater resources	Pipeline temperature	
Surface water resources	Pipeline length	
Aquatic ecology	Release rate for pipeline puncture	
Terrestrial ecology	Release rate for pipeline rupture	
Site present land use	Release rate for wellhead failure	
Number of injection wells	Local meteorology	
Distance to injection well(s)		
Depth to injection target		
Thickness of injection target		
Caprock thickness		
Plume radii over time		

The exposure component of the risk evaluation would also consider the probability of a potential CO2 release. For instance, the frequencies of a pipeline puncture or pipeline ruptures have to be quantified. Data are available to do this (Gale and Davison, 2004). A release rate through a pipeline puncture or rupture has to be determined (Kruse and Tekiela 1996). Air concentrations of the released gas in the breathing zone of human beings in the immediate area or at distances downwind which might represent actual population areas have to be determined (Cameron-Cole 2005). Finally, an estimate of risk has to be determined based on the receptor's possible exposure to the gas and known estimate of a concentration of that gas where an adverse effect of exposure to the gas is likely to occur. The risk would integrate the estimated concentration at the receptor and the appropriate toxicity safety criterion.

In the parlance of risk assessment, risk for non-carcinogens such as CO_2 is expressed as a hazard index (HI).

- If the HI is less than 1, then the exposure concentration is less than a concentration known to be safe, so there is no excess potential risk. For instance if the normal concentration of CO_2 in air is 380 ppm and the concentration of CO_2 expected to cause headache is 20,000, then the HI is 0.02 (380 ÷ 20,000) and the exposure could be considered safe (there would be only a 2 in 100 chance that a person would suffer a headache due to CO_2).

- If the HI is greater than 1, then there is an increased possibility that an adverse effect might occur. For instance, if someone is exposed to 70,000 ppm CO_2 for a short period they could suffer a headache and be rendered unconscious; the HI for this exposure would be 3.5 (70,000 ÷ 20,000) and the exposure would be considered unsafe (they would be 3½ times more likely to suffer a headache).

4.0 Risk Assessment Example

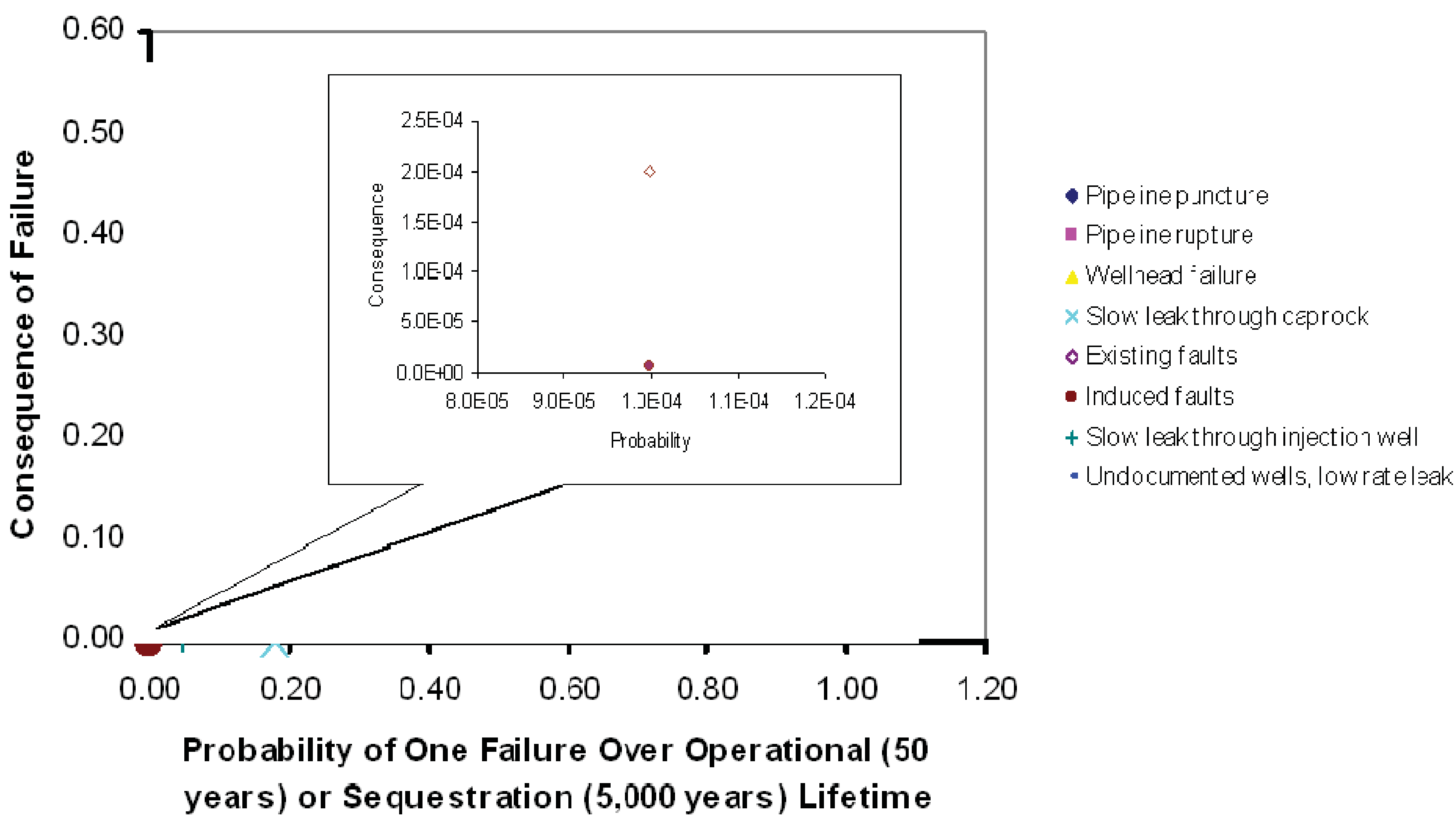
A quantitative risk assessment was conducted for potential CO_2 sequestration sites on behalf of the United States Department of Energy (DOE) for the FutureGen Project (DOE, 2007). Although there probably are a number of significant deviations from what might occur at a site in New York State, the results of the FutureGen safety assessment are illustrative of what a risk assessment might predict for a CO_2 sequestration activity. Briefly, the characteristics of the potential sequestration activity were,

- An IGCC 275 megawatt power plant that produces 1.1 to 2.8 million tons per year of CO_2 for injection below ground,
- CO_2 and H_2S as the chemicals of concern,
- 12.8 inch to 19.5 inch pipelines under 2,200 pounds per square inch pressure that have lengths of 0.5 mile to 62 miles, and
- Injection wells into sedimentary structures that are 2,950 feet to 7,000 feet below surface with sealing surfaces that are between 300 and 700 feet thick.

From existing data, failure rates for the pipelines were estimated as were release rates from the pipeline failures. An analog database of CO_2 emission fluxes was constructed from 28 sites where deep-sourced flux values were measured. Data from the natural gas storage industry were used to predict the frequency of well head failure events and CO_2 fluxes from deep storage sites. Toxicity benchmarks were taken from governmental standards and guidelines.

Figure 2 is an example of the quantitative results obtained from the FutureGen risk assessment. For a number of events that were evaluated in the risk assessment, Figure 2 plots the anticipated frequency with which an event might occur on the horizontal axis and the severity of the consequence of that event occurring (in terms of the hazard index for that event) along the vertical axis. Plots such as this are beneficial in that risk relationships are more evident. If an event occurs at a low frequency and the consequences from that event are small, the point representing that event would tend to be closer to the origin of the graph. Conversely, an event with a high probability of occurrence that has a large consequence would be expected to be indicated on the upper right-hand corner of the figure. So the figure is a representation of the degree to which various events contribute to risk for a particular activity or site. Results shown in Figure 2 are based on release of and exposure to CO_2.

Figure 2 Risk Diagram For Predicted Pre- and Post-Sequestration Failures at Tuscola, IL



The pre-sequestration events shown in Figure 2 (pipeline puncture, pipeline rupture, and wellhead failure) show low frequencies of occurrence but have hazard indices for CO_2 exposure that are higher than those calculated for post-sequestration events. The data represent exposures to pipeline workers at 250 meters (825 feet) from the failure location for XX minutes (pipeline rupture and wellhead failure) or XX hours (pipeline puncture). The probabilities of a failure for these events over a 50 year operational lifetime ranged from 0.1 or 1 in ten (pipeline rupture) to 0.001 or 1 in a thousand (wellhead failure). But the consequences of the event were larger (but still the resulting exposures produce a HI of less than 1) than those of post-sequestration events. HI values for pipeline puncture, pipeline rupture, and wellhead failure were 0.4, 0.5, and 0.07, respectively. The event with the highest probability of at least one failure and the highest consequence was a pipeline rupture.

Post-sequestration events (slow leak through caprock, leak through existing or induced faults, slow leak through the injection well, and low rate leaks from undocumented wells) are also shown in Figure 2. The risks shown are for the general population located above the reservoir of sequestered supercritical CO_2. What Figure 2 shows for these data is that over an assumed sequestration lifetime of 5,000 years there is a higher probability that at least one release could occur but the consequences of such releases are quite small compared to that for the pre-sequestration events. Even though the risk assessment predicted with near certainty that over the 5,000 year sequestration lifetime there would be a slow leak through undocumented wells (probability of 0.99), the consequences of that event were predicted to be quite small resulting in a HI of 0.01. Leakage of supercritical CO_2 through the caprock had a probability of occurring at least once over 5,000 years of 0.18 but the risk attendant to this event was the lowest risk calculated in the risk assessment (a HI of 0.000008 or $8x10^{-6}$ or 8 in a million). For CO_2 leaks through existing or induced faults, probability of occurrence and consequence were both small; the inset on Figure 2 explodes these values which are close to the origin. The probability of leaks through faults was $1x10^{-4}$, and the HIs for existing and induced faults were $4x10^{-4}$ and $2x10^{4}$, respectively. It also appears from Figure 2 that slow leaks through the injection well have a small probability of occurring and a small risk.

Three additional release CO_2 release scenarios were not evaluated quantitatively in the FutureGen risk assessment (DOE 2007) but rather were addressed qualitatively. The release scenarios and their qualitative evaluation were:

- Catastrophic release due to caprock failure – Based on the empirical database constructed for the risk assessment, the occurrence of such an event was considered to be vanishingly remote. The database noted no such events occurring in sedimentary basins, no such events at underground natural gas storage sites, and no evidence that CO_2 eruptive release can be powered by the mechanical energy of compression.
- Rapid release through the injection well or undocumented wells – It was assumed these type releases would be detected and mitigated quickly and would thus be active for only short periods of time (½ to 5 days).

5.0 Risk Management and Mitigation

Risk assessments provide information to help risk managers decide (a) whether a risk is acceptable and (b) determine whether mitigation measures are necessary. Issues associated with unacceptable levels of risk identified in a risk assessment provide the information risk managers require to decide what approaches must be taken to ensure adequate environmental protection. The approaches could include alterations of site processes, changes in the parameters of site selection; even to the point of not proceeding with the project should other solutions not provide adequate protection. Risk management plans for CCS projects should be flexible (i.e. alterable as the project proceeds) and should consider the lifetimes of capture and sequestration (WRI, 2008).

As noted in results of the example risk assessment shown in Figure 2, risk attendant to the transport and injection of supercritical CO_2 were greatest; mitigation measures for these aboveground activities have been discussed in the paper on Pipeline Permitting. For the risk issues identified for sequestration (none of which rose to unacceptable levels), the following table identifies possible mitigation measures:

Risk Scenario	Possible Mitigation Option
Leaks through faults	Lower reservoir pressure by removing sequestered gas
	Create hydraulic barrier by increasing pressure upstream of leak
	Install sealer to block leaks
Leaks through active or abandoned wells	Use standard well recompletion techniques (e.g., replacing injection tubing and packers)
	Regrout well with cement
	Abandon unrepairable wells
	Create hydraulic barrier by increasing pressure upstream of leak
	Install sealer to block leaks
Leak into vadose zone and accumulation in soil	Passive remediation (e.g., diffusion or barometric pumping to deplete from vadose zone). May not be good for ongoing releases.
	Remediate acidified soils with lime. Create hydraulic barrier by increasing pressure upstream of leak Install sealer to block leaks

Adapted from WRI 2008

6.0 Conclusions and Recommendations

In sum, risk attendant to CO_2 sequestration activities appears to be small and acceptable but generalizations cannot be made regarding individual sequestration sites. Approaches to quantifying CCS risk are available and the utility of available approaches needs to be determined. Any assessment of risk has to be site specific and requires the collation of much geologic and engineering data. The health effects data are by and large sound and devoid of many simplifying assumptions that have to made when extrapolating dose-response data from animals to man.

Recently, the Department of Energy's National Energy Technology Laboratory (NETL) reviewed the consequences from natural underground stores of CO_2 in volcanic formations near Lake Nyos (Cameroon) and Mammoth Mountain (California) (NETL 2008). Regarding safety associated with engineered CO_2 sequestration stores they commented:

> *The likelihood that any stored CO_2 [from an engineered sequestration project] will escape from the target formation will be very low. A large portion of any CO_2 that does escape will often be dissolved or trapped in the strata that lie above the injection site, prior to reaching the surface. Underground monitoring technologies such as three dimensional seismic surveying will give operators years or even decades of advanced notice that CO_2 could escape the target formations. Geologic sequestration poses no additional risks beyond the daily risks currently associated with CO_2 injection in the oil and gas industries. ... All of these projects continue to operate in a safe, effective manner with a low level of environmental safety and health risk. The risk of large, catastrophic releases of CO_2, such as occurred at Lake Nyos and Mammoth Mountain, are virtually non-existent for geologic sequestration.*

Recommendations:

- Develop a unifying risk assessment methodology to quantify potential human health and ecological impacts due to releases from carbon sequestration activities (more than just a facility). Allow for stakeholder comment on the proposed methodology and address any public concerns.
- As pilot sequestration sites are developed, obtain the location specific data that will be required for a quantitative analysis of risk.
- Perform pilot risk analyses for initial CO2 sequestering projects in New York State (such as Jamestown) to identify any gaps or inappropriate components to the initially developed risk methodology
- Routinely review the risk analysis methodology in order that improvements might be implemented as the state-of-the-art progresses.

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Appendix C

ENVIRONMENTAL PERMITTING OF CARBON DIOXIDE CAPTURE AND SEQUESTRATION PROJECTS

002595_NY13_04-B2743

Environmental Permitting of Carbon Dioxide Capture and Sequestration Projects

March 2009

Prepared for:

NYSERDA
Agreement No. 10498
Natural Gas and Petroleum Exploration and Production, Emissions Reduction, and Carbon Sequestration

Prepared by:

ECOLOGY AND ENVIRONMENT, INC.
368 Pleasant View Drive
Lancaster, New York 14086

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1 Regulatory Overview for Environmental Permitting for Carbon Capture and Sequestration Projects

1.1 Background

There has been a great deal of interest in the development of commercial-scale carbon c and sequestration (CCS) projects and technologies in response to the global awareness of the need to reduce greenhouse gas (GHG) emissions. The anticipated application of a commercial-scale CCS project would involve:

- The capture of carbon dioxide (CO_2) gases at the generation source;
- The transport of CO_2 to a sequestration site; and
- The injection of the CO_2 for long-term storage in a saline aquifer.

Ecology and Environment, Inc. (E & E) has prepared this overview of the permitting requirements that would be applicable to a CSS project constructed and operated in New York State (NYS) under existing law.

At present there are no commercial-scale CSS projects operating anywhere in the country. The United States Department of Energy (DOE) is, however, sponsoring seven regional partnerships to advance carbon sequestration technologies nationwide, summarized in Table 1-1. Two of these partnerships have projects that are fully permitted. A number of other projects are in the permitting/planning phase. These demonstration projects generally do not involve on-site capture or a CO_2 pipeline. Typically the CO_2 is delivered by truck to the storage site where it is injected into the aquifer.

There are also a number operating facilities where CO_2 is injected into oil fields in order to facilitate the recovery of oil. None of these "enhanced oil recovery operations" are located in NYS. At these facilities CO_2 is transported via pipeline and injected into underground formations in accordance state permitting requirements.

Table 1-1 DOE Sponsored CO_2 Sequestration Projects

Regional Organization	Project Name	Description	Total CO_2 Sequestered (tons)	Depth (feet)	UIC Permit Status
WESTCARB	Colorado Plateau	Arizona utilities will conduct injection testing of CO_2 into saline formations (Naco/Martin) in northern Arizona	2,200	4,000	Class V UIC Application filed with EPA (Region 9 as of October 2008)
Midwest Geologic Sequestration Consortium	Appalachian Basin	Injection testing into deep saline formation at First Energy RE Burger Plant, Shadyside, Ohio	1,100 to 3,700	5,900 to 8,300	Permit obtained for injection test from Ohio EPA. Currently awaiting Draft Permit Class V UIC from EPA Region 4
Southeast Regional Partnership on Carbon Sequestration	Mississippi Salt Bain	Injection testing into deep saline formation at Mississippi Power Company Plant Daniel (1,000-megawatt coal fired power plant)	3,000	9,500	Class V UIC permit issued by Mississippi Department of Environmental quality in 2007
Big Sky Sequestration Partnership	Grande Ronde Basalt Formation	Basalt Sequestration Pilot Test	3,000	~3,700	Class V well registration package was prepared and submitted to Washington Department of Environment Class V UIC Application to be submitted in the third quarter of 2009
Midwest Geologic Sequestration Consortium	Michigan Basin	Injection of CO_2 into deep saline reservoirs	~12,000	~6,000	Class V UIC permit issued by EPA Region 5
Midwest Geologic Sequestration Consortium	Cincinnati Arch Geological Test	Injection of CO_2 into a deep regional saline formation (Mt. Simon/Sandstone)	1,100 to 3,300	3,500	Class V UIC Permit Application submitted to EPA Region IV in May 2008

1.2 CCS Process Description

This subsection provides a description of each of the three phases of the CSS process addressed as part of the permitting analysis.

CO_2 Capture

Available technology captures about 85 to 95% of the CO_2 present in power plant flue gas. The CO_2 capture equipment requires a significant amount of electricity to operate and reduces the overall efficiency of power generation. A power plant equipped with a CCS would need approximately 10 to 40% more energy than a plant of equivalent output without CCS, in order to power the capture and compression equipment. The additional electrical requirements can be met by the power plant with a reduction in the amount of electricity produced for sale, or it can be met with additional fuel and without a reduction in electricity produced for sale. The increase in fuel generation needed to power the CSS equipment will result in a proportionate increase solid wastes and other byproducts of energy production.

CO_2 capture options are described as precombustion, post combustion, and oxygen-based combustion. In pre-combustion CO_2 capture, the CO_2 is recovered before the fuel is burned or otherwise completely converted to CO_2. This includes gasification and Integrated Gasification Combined Cycle power plants. Post-combustion capture involves the removal of CO_2 from flue gas produced by combustion. Existing power plants use air, which is 79% nitrogen, for combustion and generate a flue gas that is at atmospheric pressure and typically has a CO_2 concentration of less than 15%. The low relative concentration requires significant additional processing to increase the CO_2 concentration adequately for compression and transport. Oxycombustion is combustion with nearly pure oxygen (greater than 95%) mixed with recycled flue gas to maintain similar conditions as with air combustion. The nearly pure oxygen is produced from a cryogenic air separation unit.

Another way to classify CO_2 capture is by the underlying mechanism of capture. Mechanisms currently available for CO_2 capture are: absorption, adsorption, membranes, cryogenic distillation, biomimetic approaches, chemical looping, and direct decarbonization. Of these, the capture mechanisms that are being applied on a commercial scale are primarily physical/chemical absorption and distillation. The absorption process uses solvents, such as methanol, polyethylene glycol, amines, and similar proprietary chemicals.

CO_2 Pipelines

Pipelines are the most common method that will be used for transporting large quantities of CO_2 over long distances at commercial and large pilot facilities. CO_2 pipelines are operated at ambient temperature and high pressure, with primary compressor stations located where the CO_2 is captured or injected and booster compressors located as needed farther along the pipeline. In overall construction, CO_2 pipelines are similar to natural gas pipelines, requiring the same attention to design, monitoring for leaks, and protection against overpressure.

CO_2 Injection and Sequestration

Design of CO_2 injection is based on technologies that have been developed and refined by the oil and gas and chemical manufacturing industries over the past several decades. The CO_2 is injected to depths greater than 2,625 feet, such that a sufficiently high pressure and temperature would be maintained to keep the CO_2 in a supercritical, or fluid-like state. CO_2 is sequestered in geological formations by a combination of trapping mechanisms, including physical and geochemical processes.

1.3 Potentially Applicable Federal and State Regulatory Requirements

The permits and approvals potentially applicable to CCS projects under existing regulatory requirements are summarized in Table 1-2. The applicability of these regulatory programs to the components of CCS is described below. This analysis assumes that the source of the CO_2 has the required permits to operate without CCS and new and modified permits are required for the additional equipment. The process of obtaining approvals under these regulatory programs is described in Section 2.

General Requirements

NEPA requires federal agencies to integrate environmental values into their decision making processes by considering the environmental impacts of their proposed actions and reasonable alternatives. New York's State Environmental Quality Review Act (SEQRA) is the state equivalent of the National Environmental Policy Act of 1969 (NEPA). Under both NEPA and SEQRA an agency issuing an approval for a project (e.g., permit or funding authorization) is required to conduct an evaluation to determine whether or not a project would significantly affect the environment. The scope of this evaluation encompasses all of the components of the project (i.e., capture, transport, and sequestration). If the agency determines, based on an initial review of the project, that the environmental consequences of a proposed project may be significant, an environmental impact statement (EIS) must be prepared, The public, other federal state and local agencies and outside parties may all provide input into the preparation of an EIS, and then comment on the draft EIS when it is completed. An EIS also requires a detailed evaluation of alternatives to the proposed action.

Construction and operation of the project would also be subject to other general state, federal, and local requirements designed to protect public health and safety, special resources, and resource areas including:

- Wetlands and waterbodies;
- Cultural resources;
- Endangered species;
- Stormwater discharges;
- Zoning;
- Well drilling; and
- Road use.

CCS Capture Requirements

There are currently no mandatory federal limits or reporting requirements for CO_2 emissions. Electric generating units reporting sulfur dioxide (SO_2) and oxides of nitrogen (NO_x) emissions under the acid rain cap-and-trade program of the Clean

Air Act (CAA) also report CO_2 emissions as part of the continuous emission monitoring requirements.

NYS is a member of the Regional Greenhouse Gas Initiative (RGGI), a historic agreement that addresses climate change by establishing a cap-and-trade program for CO_2 emissions from electricity-generating units. The New York State Department of Environmental Conservation (NYSDEC) has proposed regulations to implement the RGGI program through air emission permits. Each year, actual emissions will be summarized and reported. Owners of electric generating units must purchase adequate allowances for each ton of CO_2 actually emitted.

The operation of CCS equipment will result in reductions in air emissions and potential changes in water use, wastewater discharges, and use of hazardous substances, which may trigger requirements for new or modified permits. Prior to installing the capture equipment the facility would be required to prepare an application to modify its existing permit. Modifications would need to be made to both the state facility permit and the PSD permit, which in NYS is issued by the United States Environmental Protection Agency (EPA). The application that would support the request for the modification would include a description of the capture process and equipment, new and revised emissions, and new and revised operating conditions.

Potential changes in water use, wastewater discharges, and use of hazardous substances will be dependent on the capture mechanism and equipment. For example, removing incompressible components of the flue gas may be accomplished with water-based processes that generate wastewater. The heat generated from the compression process will likely require additional raw water supply to cool equipment. Because most power plants have an existing authorization to withdraw cooling water, a new authorization is not anticipated. However, it may be necessary to evaluate the impacts of the increased withdrawal. In addition, post combustion capture options include use of ammonia or MEA (amine scrubbing). Ammonia is a hazardous air pollutant, which is regulated by the Occupational Safety and Health Administration (OSHA) and the EPA if it is stored and handled in threshold quantities. Other capture solvents are also categorized as hazardous and may require special storage and handling.

Pipeline Requirements

There are no federal or state permitting requirements that apply specifically to the siting of CO_2 pipelines. Natural gas transmission projects are typically permitted by Federal Energy Regulatory Commission (FERC) if the transmission line travels interstate and the host state if the project is located wholly in a single state. To date, FERC has declined to extend its regulatory authority beyond natural gas pipelines leaving pipelines that transport CO_2 unregulated at the federal level. Similarly the NYS Public Service Commission (PSC) has regulatory authority over intrastate natural gas transmission projects but that authority does not extend to intrastate CO_2 pipelines.

The siting of the pipeline would, however, be addressed in the environmental studies required to be completed as part of the NEPA/SEQRA review and approval process discussed above. In addition the design of a CO_2 pipeline operating at high pressures would likely be required to comply with United States Department of Transportation (DOT) pipeline design requirements for hazardous liquids.

Pipeline design standards are developed and implementation of those standards is monitored by the DOT's Pipeline and Hazardous Material Safety Administration (PHMSA), Office of Pipeline Safety (OPS). OPS develops regulations and other approaches to risk management to assure safety in design, construction, testing, operation, maintenance, and emergency response of pipeline facilities (including facilities transporting CO_2). Regulations applicable to natural gas and CO_2 pipelines are found at 49 CFR Part 195. The pipeline safety statutes provide for state assumption of the intrastate regulatory, inspection, and enforcement responsibilities under an annual certification if their standards are compatible with minimum DOT standards. Where states have not adopted comparable programs the federal standards are enforceable by DOT.

In NYS, the PSC is the certified DOT partner agency and administers the 49 CFR Part 195 program for natural gas pipelines, however, the PSC definition of a regulated "gas pipeline" does not does not include pipelines that transport CO_2. Consequently the PSC does not currently have authority to enforce 49 CFR Part 195 with respect to CO_2 pipelines.

49 CFR Part 195 addresses day to day operations of a hazardous liquid pipeline and defines requirements for design, construction testing, operations and maintenance, operator qualifications, and integrity management. Section 195.452 addresses pipeline integrity management in high consequence areas. High consequence areas are areas of higher population density, environmentally sensitive areas, unusually sensitive areas like drinking water sources and navigable waterways. The pipeline operator must determine the risks to integrity to which the covered segments are exposed. Each segment must be thoroughly inspected or tested to determine an integrity "baseline" condition, then re-inspected or tested at frequencies that take into consideration the severities of the threats to which it is exposed. The criteria for determining when pipe defects must be repaired in "high consequence areas" are much more restrictive than criteria applied to similar defects in other pipeline segments. Operators are also required to implement additional measures to prevent or mitigate the threats to high consequence segments that go beyond the requirements for other segments.

A pipeline operator's integrity management program must include a quality control plan that covers not only its own integrity management processes and procedures, but also the processes and procedures used by contractors it may hire to perform integrity management activities. Both pipeline operator and contractor supervisors and personnel must be specifically trained and qualified to perform integrity management activities. The pipeline operator must track a range of performance metrics to demonstrate compliance with the IM rule, many of which are reported semiannually to PHMSA and state regulatory agencies.

Pipelines that transport CO_2 in the supercritical state are not subject to DOT requirements, but as a practical matter, and in accordance with industry standards, companies constructing any CO_2 pipeline would need to design the project to meet DOT standards.

Injection and Sequestration Requirements

Injection wells must be permitted by the EPA pursuant to the federal Underground Injection Control Program (UIC) of the Safe Drinking Water Act (SDWA) and well drilling activities must be permitted by NYSDEC pursuant to the state Oil and Gas Mining Program.

The central focus of the UIC program is the prevention of contamination of underground sources of drinking water from injection. The UIC establishes five classes of injection wells and sets requirements for siting, testing, installing, operating, monitoring, reporting and abandonment. The March, 2007 EPA Memorandum: Using the Class V Experimental Technology Well Classification for Pilot Geologic Sequestration Projects – UIC Program Guidance (UICPB #83) provides the EPA's rationale for using the existing well classifications to bridge the gap between pilot and commercial-scale CCS projects.

On July 25, 2008, EPA published a proposed rule to regulate the injection of CO_2 for geologic sequestration on a commercial level through its existing UIC program. It would establish a new Class VI for dedicated CCS projects. The requirements of the proposed new rule are very similar to the existing requirements for Class V wells, which is consistent with EPA's intent to ensure protection of drinking water supplies. Currently, the EPA permits injection wells for the purposes of injecting CO_2 as either a Class II Well for Enhanced Oil Recovery or Class V Well for CO_2 Injection.

The NYSDEC well drilling permit program is designed to protect the environment during drilling of wells. Drilling permits mandate a casing and cementing program for each well, setbacks from municipal water wells, surface water bodies and streams and require proper disposal for all wastes and proper containment of drilling fluids. The types of wells requiring permitting in Section 23-0102, Article 23 of the Environmental Conservation Law are listed below:

- All oil wells, regardless of depth;
- All gas wells, regardless of depth;

- All wells, regardless of depth, associated with underground storage in caverns or reservoirs of gas, liquefied petroleum gas, oil, petroleum products, and petroleum byproducts;
- All solution salt mining wells, regardless of depth;
- Stratigraphic wells deeper than 500 feet; and
- Geothermal wells, including:
  - Wells deeper than 500 feet for finding or producing hot water or steam,
  - Wells deeper than 500 feet for injecting fluids to recover heat from the surrounding geologic materials (including geothermal heat pump wells deeper than 500 feet), and
  - Brine disposal wells deeper than 500 feet.

Well permitting in NYS is generally oriented towards the oil and gas industry, with authority for injection of CO_2 being the responsibility of the EPA. However, the Division's expertise in evaluating drilling programs and well spacing will be invaluable during the CCS project. There are numerous oil and gas wells throughout the state and the Division of Mineral Resources will ensure that future gas wells do not penetrate or impact the planned CO_2 storage reservoir through the evaluation of future permits. Through the state well permitting process, the Division will also ensure that the placement (both vertically and horizontally) do not impact existing natural gas operations in the area, as well as regulate that each well is drilled and completed in a safe and effective manner.

Table 1-2 Potential Permits, Approvals, and Consultations Applicable to CCS

Agency	Permits/Approvals/ Consultations	Applicability
FEDERAL		
NEPA	EIS or EA	Entire project - If project requires a federal permit or receives federal funding
U.S. Army Corps of Engineers (USACE)	Clean Water Act Section 404 Permit Rivers and Harbors Act Section 10 Permit	Pipeline - NWP 12 required if pipeline crosses regulated water body or jurisdictional wetlands
U.S. Environmental Protection Agency (EPA)	Safe Drinking Water Act Underground Injection Control Permit	Injection-Class V experimental technology wells to demonstrate a developing technology may be subject to more flexible, yet fully protective, technical standards (as well as proposed Class VI Well standards)
U.S. Environmental Protection Agency (EPA)	Prevention of Significant Deterioration Permit/Modification (State Part 231 Proposed)	Carbon Capture – If unit is installed at an existing facility it would result in an overall reduction of emissions; individual increases or decreases in emissions must be evaluated for applicability thresholds

Table 1-2 Potential Permits, Approvals, and Consultations Applicable to CCS

Agency	Permits/Approvals/ Consultations	Applicability
U.S. Fish and Wildlife Services (USFWS)	Section 7 Endangered Species Act Consultation	Entire project - Consultation required if project is required to obtain federal approval (e.g. disturbance of federal wetland). A take permit would be required if there is a potential to take, or harass a T&E species
Advisory Council on Historic Preservation	Section 106, National Historic Preservation Act	Entire project - Consultation required if project is required to obtain federal approval
U.S. Department of Transportation, Federal Highway Administration	Federal Highway Encroachment Permit 49CFR Part 195 - Design standards	Pipeline -Required in pipeline crosses federal highway Applicable to pipeline design standards
STATE		
State Environmental Quality Review Act	Environmental Assessment Form or Environmental Impact Statement	Entire project - If project requires a state or local action
New York State Historic Preservation Office	Cultural Resources (Section 106/NHPA) Consultation/Clearance	Entire project - Consultation required if state or federal approval is involved
New York State Department of Environmental Conservation	Air Emissions Part 201 Preconstruction Permit/Title V Operating Permit Modification Water Quality Certification (Section 401 Permit) State Pollution Discharge Elimination System (SPDES) Construction General Permit for Stormwater Discharges Article 15 Protection of Waters; Article 24 Freshwater Wetlands; Article 25 Tidal Wetlands	Carbon Capture - If unit is installed at an existing facility it would result in an overall reduction of emissions; each pollutant must be considered for increases or decreases for applicability thresholds Pipeline - if project crosses federally regulated wetlands or protected streams Entire project - If project construction disturbs one or more acres Pipeline - If project disturbs state regulated wetland
New York State Department of Environmental Conservation	Well Drilling Permit (Issued to Well Driller/Operator)	Injection – Permit required for drilling activities
New York State Department of State	State Pollution Discharge Elimination System (SPDES) Permit for Industrial Discharges	Capture/Compression – If new wastewater stream or change in wastewater discharge characteristics

Table 1-2 Potential Permits, Approvals, and Consultations Applicable to CCS

Agency	Permits/Approvals/ Consultations	Applicability
New York State Department of State	Coastal Consistency Certification	Pipeline or Injection – unlikely to affect coastal zone since impacts are temporary and below ground
New York State Department of State	Water Withdrawal Registration	Capture/Compression – If new or increased water withdrawal which would result in a water loss of over 5 MGD
New York State Department of Transportation	State Road Use Permits Highway Work/Utility/Non-utility Permits Consultation	Pipeline - Permits required if pipeline crosses a state highway
New York State Department of Agriculture and Markets	Consultation with respect to impacts to agricultural lands	Entire project - Consultation required if project impacts Agricultural lands
LOCAL		
County Highway Department	road use permits	Pipeline - If project crosses town/county road
Town/County Planning Board	Building permits/ Zoning approvals	Entire Project - If town/county has enacted local requirements

2 Permitting Roadmap for CCS

The Permitting Roadmap for CCS describes the major environmental approvals identified in Table 1-2 that are anticipated to be required to construct and operate a commercial scale CCS project in New York under existing regulatory programs. The major approvals and permits are:

- NEPA/SEQR review;
- Air permit modification;
- Stormwater permit for discharges during construction;
- Wastewater permit modification for new or modified discharges during operation;
- UIC and NYS well permit for injection well installation and operation;
- DOT permits for road crossings; and
- Federal and state wetlands permits.

Described below for each major approval or permit are the process and substantive information requirements.

2.1 National Environmental Protection Act (NEPA)/State Environmental Quality Review Act (SEQRA)

For the purposes of NEPA/SEQRA review, the "Project" will include the construction and operation of CO_2 capture equipment at an existing permitted facility, the construction and operation CO_2 transport pipeline, and the construction and operations CO_2 injection wells for long-term storage in an underground formation. For projects which oxidize a carbon based fuel, it is anticipated that the CO_2 produced will be purified and compressed for transport and beneficial reuse or sequestration (storage). The CO_2 will be stored in a supercritical (almost liquid) state, approximately 7,000 feet or more below the ground contained beneath a layer of solid cap rock. The unique aspects of these project components in the NEPA/SEQRA process are discussed below.

2.1.1 Scoping

Scoping is a critical first step in any application of NEPA/SEQRA, and particularly on a project that has the potential to be of significant interest to the community. Scoping also provides an opportunity to identify critical issues that may need to be addressed in community outreach efforts. Given the high level of public interest expected for implementation of a major new technology and regulatory applications, a corresponding level of commitment to public outreach should be part of any CCS permitting effort.

One key purpose of scoping is to identify and describe the studies that will be performed to prepare the draft EIS. It is anticipated that key studies of interest and importance to NEPA/SEQRA review process are:

- Air quality analysis including GHG impact analysis;
- Emissions modeling;
- Land use analysis;
- Biological resources surveys and impact analysis;
- Geological surveys and impact analyses for siting and injection;
- Socioeconomic analysis;
- Health and safety analysis; and
- Transportation analysis.

2.1.2 Preparation of a Draft EIS

The draft EIS must include a description of the Project, its purpose, public need and benefits, a discussion of alternatives, a description of the environmental setting of areas to be affected, an evaluation of the potential significant adverse environmental impacts, and a discussion of potential mitigation measures.

The type and extent of studies that will need to be undertaken for a CSS project will be determined by the NEPA/SEQRA lead agency on a project specific basis based on the size, location and stakeholder interest in a project. Key areas and the type of analysis anticipated are described below.

Global Climate

The contribution to global climate impacts from anthropogenic CO_2 is the driver for considering capture and sequestration of CO_2. A new resource area is recommended to distinguish this issue from traditional air quality impact analyses. This analysis should include a Greenhouse Gas Impact Analysis which fully assesses impacts and mitigation of greenhouse gas emissions. The methodology for the analysis should be based on NYSDEC guidance, voluntary GHG reporting programs, and published literature on life cycle GHG analyses.

Air Quality

The air quality analysis will demonstrate the overall reduction in emissions from implementation of CCS. There may be increases and decreases in individual pollutants that will require discussion and comparison with regulatory thresholds for allowable increases. The application for modification of the existing Title V Operating permit will be the basis for this evaluation. It is anticipated that modeling of CO_2 emissions will be required to address potential releases from the generating facility and the CO_2 pipeline or sequestration site. A modeling protocol and air dispersion modeling analysis in accordance with NYSDEC requirements may be necessary.

Land Use
An analysis will be required to determine if the CCS Project is consistent with current land use in the area and with local and regional land use plans. The NYS Department of Agriculture and Markets (NYSDAM) will be involved in reviewing construction projects affecting farmland to ensure that impacts to agricultural resources are minimized and/or properly mitigated. Although the NYSDAM does not issue a formal authorization for linear projects, they provide input to lead agencies recommending best management practices (BMPs) for the protection of agricultural resources. Department staff review proposed routing to determine if agricultural land will be crossed by the project, and review proposed construction plans to determine potential impacts to agricultural resources. Under PSC permitting, NYSDAM is a statutory party to all Article VII gas proceedings. For federally regulated pipelines, NYSDAM typically participates as a "Cooperating Agency" in all FERC proceedings for gas pipelines that impact agricultural land.

Water Resources
This analysis should include an assessment of the potential for the project construction and operation to impact water resources, including wetlands and water bodies. In addition, this analysis should identify the additional water use associated with CO_2 capture, compression, and transport.

The discussion should address temporary and permanent impacts from pipeline and well construction and operation and whether state or federal permits are required.

Groundwater in the region of the anticipated CO_2 storage area will also be characterized as part of the UIC Permit Application. Short and long-term impacts of CO_2 storage in saline aquifers should be described based on the anticipated volume of CO_2 storage.

Geology and Soils
This analysis should summarize the in-depth studies that will be performed for the UIC Permit Application in order to determine the suitability of the proposed injection site for long-term storage.

Noise
This analysis should address impacts from the addition of CO_2 capture, compression, transport, and injection equipment to nearby receptors and the noise impacts that will result from construction and operation of the project. The addition of pumps and compressors may increase overall noise from an existing facility. The increase should be evaluated relative to allowable increases under local noise ordnances and NYSDEC guidance.

Socioeconomics
This analysis should address the potential socioeconomic costs and benefits of the project to the local community and the region in terms of tax base, job creation, and community character. The analysis should include the capital and oper-

ating cost of CCS, as well as the potential benefits under government incentive programs or carbon markets.

Cultural Resources Assessment
This analysis should address the potential for impacts to cultural resources due to the construction and operation of the project. The focus of this study will be on the siting and construction of the pipeline.

Public Health and Safety Review
This analysis should address the potential public health and safety concerns associated with the project. During operation of CCS, the potential for releases of CO_2 includes pre-sequestration activities of handling, storage and transport, and post sequestration potential for releases to the surface or to drinking water from the underground storage formations. Currently, there is no standard protocol for evaluating CCS risks; however, there are many existing templates applicable to storage, transport, and handling of similar substances, including natural gas and petroleum. A protocol should be developed for systematically identifying probability and consequence of CO_2 releases, as well as prevention and mitigation techniques.

Transportation Analysis
This analysis should address transportation impacts associated with the construction of the project including the capacity of existing roads and bridges to handle the heavy equipment that will be needed to support construction equipment.

2.1.3 Public Outreach
Public outreach should be initiated early in the permitting process. This will serve to maximize public knowledge of the project, identify issues of concern, and build community acceptance. A Public Involvement Plan should be developed to proactively include the community in the permitting process. The plan should identify potential stakeholders and points of contact. Information about the Project can be shared informally in periodic phone calls or more formally at group meetings through presentations. Meeting summaries should be prepared to ensure timely responses to comments. The Public Involvement Plan should include at least one Public Meeting or Open House in addition to the Scoping Meeting. Comments and questions should be documented to ensure responses are provided directly or through the draft EIS. Fact sheets and/or news articles should be prepared in advance. The key topics for fact sheets would include descriptions of the proposed carbon capture technology, description of the proposed geological sequestration site, and the environmental review process

2.2 Air Permit

Air Permit Modification
Until CO_2 is a regulated pollutant under the CAA or under New York Environmental Statues, the air permit will address emissions of criteria and other regulations pollutants. It is anticipated that a modification to any existing air permits will

be required to address new emission control equipment, changes in operating scenarios, and changes in emissions in accordance with Part 201 and 40 CFR 60. Any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant requires approval under the CAA and its implementing regulations. However, it is anticipated that implementation of CCS would result in a significant net decrease in all regulated pollutants.

Because emissions from the operating mode with CCS are anticipated to be extremely low or near zero, it is not anticipated that Prevention of Significant Deterioration (PSD) review will be applicable for this operating scenario. The assumptions regarding the duration of operating scenarios with and without CCS could affect PSD applicability for the facility. For example, the integration of capture, compression, and injection equipment will likely have an associated availability that is less than 100% of the time that power is produced. The regulatory applicability analysis should include the quantitative analysis to make this demonstration of PSD applicability.

BACT Review

On December 18, 2008, Stephen Johnson, EPA Administrator, issued a memorandum regarding EPA's interpretation of regulations that determine pollutants covered by the federal PSD Permit Program. The memo clarified that CO_2 is not "subject to regulation" under the PSD program, including the requirement to install the best available control technology (BACT), because existing regulations currently only require monitoring and reporting but do not require control of emissions of CO_2. According to the memo, the intent of the Clean Air Act and subsequent regulations have been implemented consistently for pollutants subject emission or other regulatory limits, not just monitoring or reporting requirements. EPA concludes that CO_2 is only subject to monitoring provisions, and therefore is not subject to BACT.

Accidental Release

The General Duty Clause of Section 112(r) of the Clean Air Act applies to any facility were extremely hazardous substances are present, and could be applicable to substances used in the capture process or potentially to CO_2 after capture and compression. CO_2 is neither reactive, flammable, volatile, nor corrosive; however, if contaminants are present in quantities greater than the thresholds considered toxic under 40 CFR 261, it may be necessary to assess the potential for releases under the General Duty Clause. Though this requirement is generally not part of new permit applications or permit modifications, its applicability should be considered for new material used in the CCS process.

2.3 General Stormwater Permit for Construction Activities and Industrial Activities

Construction of the CCS system will include clearing, grading, and excavation which have the potential to impact surface water through erosion from stormwater runoff. During operation, stormwater impacts include erosion from stormwater runoff, and the potential for spills of chemicals or petroleum stored on site.

A completed Notice of Intent (NOI) for Stormwater Discharges from Construction Activities General Permit and a Stormwater Pollution Prevention Plan (SWPPP) will be required to address such discharges from projects that disturb more than one acre of land. A general permit issued by NYSDEC authorizes stormwater discharges to surfaces waters during pipeline construction activities. A condition of the stormwater permit is that the project applicant has a SWPPP in place prior to initiating construction activities. The SWPPP must include Water Quality and Quantity Control and Erosion and Sediment Control (E&SC) plans in accordance with the NYS Stormwater Management Design Manual (NYSDEC 2003) and NYS Standards and Specifications for Erosion and Sediment Control (NYSDEC 2005).

The pipeline and CO_2 storage site will include underground piping, pipe connections, well heads and potentially a small utility shed to house controls. For small projects, the limited size of the pipeline and sequestration well field may not require stormwater conveyances, and would not cause a point source discharge to waters of the United States. In this case, the pipeline and injection well field would not require coverage under the SPDES Multi-Sector General Permit for Stormwater Discharges Associated with Industrial Activity (GP-0-06-002).

2.4 State Pollution Discharge Elimination System (SPDES) Permit for Industrial Discharge Modification

Existing projects will be operating under a State Pollutant Discharge Elimination System Permit for industrial and stormwater discharges. It may be necessary to modify the existing SPDES permit depending on the characteristics of new wastewater streams or changes in characteristics of existing streams associated with carbon capture and compression equipment.

The characterization of wastewater should be based on preliminary engineering data, including the proposed water balance and related water quality design data. Based on this characterization and review of applicable federal, state, and local regulations, it may be determined that the existing SPDES must be modified. If additional chemical substances are anticipated in the discharge, application for their approval must be made in accordance with NYSDEC's Water Treatment Chemical (WTC) Usage Notification Requirements for SPDES permitees.

Although the SPDES permit is a permit to discharge wastewater from the facility, it also addresses water intake structures and Section 316(b) of the Clean Water Act. Given the assumption of an existing facility, and the small relative increase in water supply needed for additional cooling capacity, changes to the intake structure are not expected from the implementation of CCS. Similarly, the additional heat discharged is not expected to affect the thermal discharge characteristics regulated under Section 316(a) of the Clean Water Act. However, a site specific determination is necessary.

2.5USEPA Underground Injection Control Permit and NYSDEC Well Drilling Permit

EPA UIC Permit

An EPA Underground Injection Control (UIC) permit will be required before CO_2 can be injected into the ground. To date, CO_2 injection wells have been considered to be either Class II or Class V injection wells. A Class II well is defined as a well used to inject brines and other fluids associated with oil and gas production, and hydrocarbons for storage beneath the lowermost underground source of drinking water (USDW). A Class V well is defined as any injection wells not included in Classes I-IV. In general, Class V permits have been issued for wells that inject non-hazardous fluids into or above USDWs and are typically shallow, on-site disposal systems.

In July 2008, EPA proposed new regulations that would apply to injection wells used for the geological sequestration of CO_2. The proposed regulations add a new classification (Class VI) for CO_2, injection wells and describe siting requirements.

Under the proposed regulations Class VI wells must be designed to ensure that sound science is used to evaluate the fate and transport of CO_2. The UIC application must:

- Address potential acute and chronic health risks from the migration of CO_2;
- Characterize the CO_2 stream prior to permit issuance; and
- Evaluate the displacement of native fluids and chemical constituents, the movement of possibly hazardous impurities in injected fluids, and potential leaching and mobilization of naturally occurring metals and minerals in the injection and confining formations associated with CO_2 injection for the potential to endanger USDWs.

Since the purpose of the proposed new regulations is to address commercial-scale operation of CCS, the requirements of that rule are most relevant to this permitting roadmap and are described below.

Demonstration of the Appropriateness of Injection Sites

The appropriateness of injection sites selected for pilot CO_2 injection must be demonstrated with respect to the goals of the Project. The application must present geological evaluations to demonstrate that an adequate receiving and confining system for a CO_2 injection site exists with sufficient depth, areal extent, thickness, porosity, and permeability; no major non-sealing faults; a confining system of sufficient regional thickness and competency; and a secondary containment system which could include buffer aquifers and/or thick, impermeable confining rock layers.

Other factors include potential reactions between injected CO_2 and the rocks and fluids in the injection zone may impact injectivity. Analytical or numerical models of CO_2 containment or transport must be used to make these demonstrations.

The area of review (AoR) and test modeling/monitoring of CO_2 movement must be based on a zone of pressure influence, which also will consider some or all of the following:

- Reservoir transmissibility;
- Injection rate;
- Duration of CO_2 injection;
- Total injection volume;
- Boundary conditions (e.g., pinchout or sealing fault);
- Pressure-volume-temperature (PVT) behavior; and
- Injection depth.

Description of Injection Well Construction

The application must include a description of the injection well construction, including construction materials, casing, and cement appropriate to the geologic environment, the properties of CO_2, and the anticipated life of the project.

Injection Well Operation and Monitoring Program

The application must include a description of the planned operating procedures and how USDWs will be protected. Monitoring parameters (e.g., injection pressure, volume, and rate) that help gather the data needed to understand the behavior and potential leakage of CO_2 and impacts of CO_2 injection on well materials and receiving formations will be defined.

Site Closure

The application must include a site closure plan. As with other injection operations, CO_2 injection projects must be closed and abandoned in a manner that is protective of USDWs.

Well Drilling Permits

The CCS project will also require a NYSDEC well drilling permit pursuant to Section 23-0102, Article 23 of the Environmental Conservation Law. Drilling permits typically mandate well construction requirements, setbacks from municipal water wells, surface water bodies and streams, and require proper disposal for all wastes and proper containment of drilling fluids.

NYSDEC will issue its well permit after the EPA issues a UIC permit. NYSDEC will be a participating agency in the UIC permit review and will have an opportunity to raise any concerns it has to the EPA so they can be addressed as UIC permit conditions.

The permitting of the injection well will require close coordination between the EPA and NYSDEC.

2.5 Federal and State Wetlands Permits

In NYS most CO_2 pipelines more than 1-mile long will cross or impact one or more wetlands. Assuming this to be the case, as part of the project permitting process an applicant will be required to survey the pipeline route corridor and identify all wetlands within the corridor. In order to obtain a permit to disturb the wetlands, the project sponsor will be required to prepare an application that quantifies the amount of disturbance and evaluates potential impacts to biological and cultural resources. Mitigation, including offset mitigation may be required depending on the nature and extent of the potential impacts.

Wetlands fall under the jurisdiction of both NYSDEC and the United States Army Corps of Engineers. These agencies require the submission of a single Joint Permit Application (JPA) but there is an independent review of the JPA by each agency. The issuance of a wetland permit is contingent on the completion of the NEPA/SEQRA review process described above.

2.6 Other Permits

Local Building Permits

The construction of all parts of the project will be required to comply with state and local building codes and zoning regulations. Construction permits are typically issued after the review of design drawings by a town engineer.

The DOT, PHMSA, OPS regulates the design certain pipelines. Regulated pipelines are required to be designed in accordance with DOT standards. The program is administered through an inspection program.

State and Federal DOT Highway Permits

United States Department of Transportation permits will be required if pipeline a pipeline crosses federal highway. Similarly a NYSDOT permit may be required if the pipeline crosses a state highway.

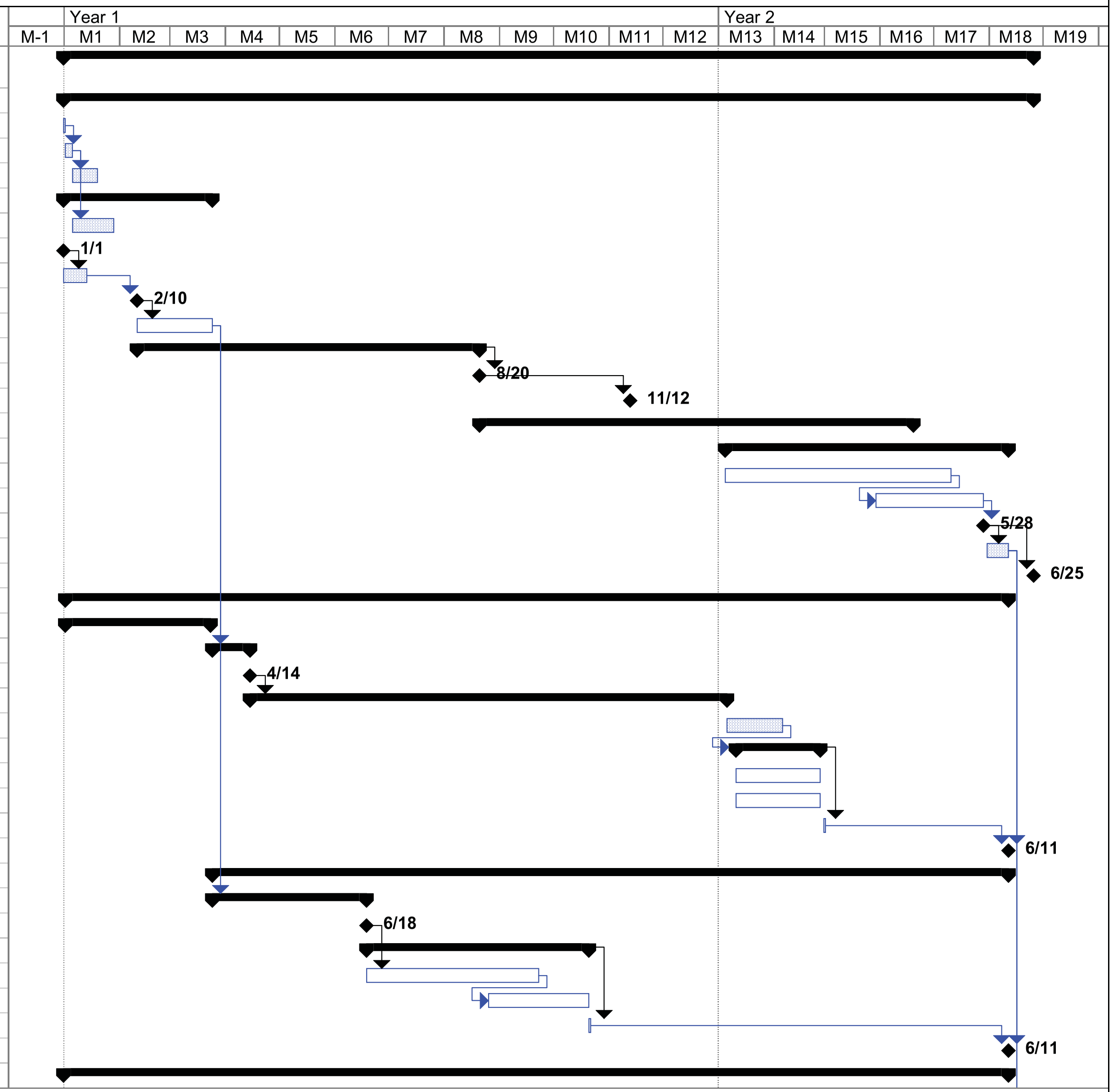
Local highway permits may also be required for actions affecting control of right of way, work within the right of way, or for special hauling. The local highway permit process would generally follow the state highway process, with the local agency as the process lead.

3 Anticipated Schedule for Permitting

It is anticipated that it will take between 12 and 18 months from the time the NEPA/SEQRA scoping process begins until the major environmental permits described above are obtained for a CSS project. Because of the need to integrate environmental information that will be obtained during the studies described above it is imperative that engineering and environmental teams be well coordinated. It is also important to coordinate permitting activities amongst the multiple federal, state, and local agencies with approval authority over the project. The schedule for any particular project will depend on a number of site-specific factors, including availability of environmental, engineering and design data and community interest. An anticipated project schedule is provided as Figure 3-1.

Figure 3-1 ENVIRONMENTAL PERMITTING OF CCS DRAFT GENERIC SCHEDULE

ID	Task Name
1	**ENVIRONMENTAL PERMITTING OF CCS**
2	**Task 1: State Environmental Quality Review**
3	Initiate Project
4	***Agency pre-application meetings***
5	Prepare Environmental Assessment Form
6	**1.1 Scoping**
7	Develop Draft Scoping Document
8	Submit Draft Scoping Document for Lead Agency review
9	Lead Agency Review and Approval
10	***Scoping Meeting***
11	Compile and Review Scoping Comments
12	**1.2 DEIS**
56	***Submit DEIS***
57	Open House(s) and Public Hearing
58	**1.4 Lead/Agency Review and Comment on DEIS**
61	**1.5 Finalize EIS**
62	Response to Comments
63	Prepare Final EIS
64	*Notice of Completion of Final EIS*
65	*Agency Findings*
66	***Final Decision***
67	**Task 2: State Air/Federal PSD/NSR Permit Modification**
68	**Air Quality Modeling Protocol**
73	**Prepare Application**
76	***Submit Air Permit Mod Application***
77	**Agency Review, Comment, and Draft Permit**
84	***Pubic comment period / hearing***
85	**Response to comments**
86	**DEC responses to comments**
87	**EPA responses to comments**
88	**Draft Air Permit**
89	***Air Permit Issued***
90	**Task 3: Water Discharge Permits/Modification**
91	**Prepare Application**
96	***Submit Wastewater and Storm Water Applications***
97	**Agency Review, Comment, and Draft Permit**
98	Agency Review
99	Respond to Agency comments
100	**Draft Stormwater/Wastewater Permits**
101	***Stormwater/Wastewater Permits Issued***
102	**Task 4: Injection Well Permits**

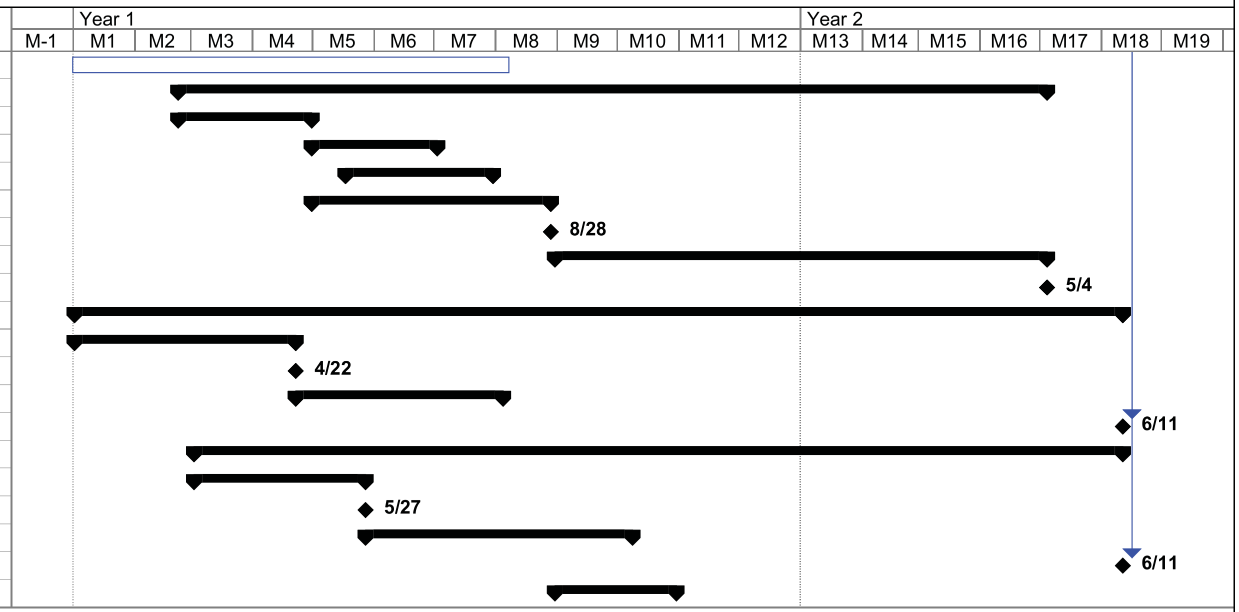


Project: Carbon Capture and Sequestration
Date: Wed 4/15/09

Task | Progress | Milestone ◆ | Summary

Figure 3-1 ENVIRONMENTAL PERMITTING OF CCS
DRAFT GENERIC SCHEDULE

ID	Task Name
103	Geological Studies
104	UIC Permit Application
105	Demonstration of Appropriate Site
107	Injection Well Design and Operation Plan
110	CO2 Fate and Transport Modeling
113	Draft UIC Application
118	*Submit UIC Application*
119	Agency Review, Comment, and Draft Permit
123	*UIC Permit Issued*
124	State Well Permit
125	Prepare Application
129	*Submit Application*
130	Agency Review, Comment, and Draft Permit
133	*DEC Well Permit Issued*
134	Task 5 Wetland Permits
135	USACOE/NYS Application
141	*Submit USACE/NYS Applications*
142	Agency Review, Comment, and Draft Permit
145	*USACOE/NYS Wetland Permit Issued*
146	Task 6 Other Permits



Project: Carbon Capture and Sequestration
Date: Wed 4/15/09

Task | Progress | Milestone ◆ | Summary

END NOTES

[1] Press release announcing Governor Paterson's support of the Jamestown Oxy-Fuel project, June 6, 2008.

[2] Task 4 Milestone 1, scope of work document, NYSERDA and E&E.

[3] "Cost and Performance Baseline for Fossil Energy Power Plants Study, Volume 1: Bituminous Coal and Natural Gas to Electricity," Revised Final Report, August 2007, RDS for NETL.

[4] Yamagata, B. 2008, "Policies to Promote the Implementation of CCS Power Plants", MIT Carbon Sequestration Forum, Advancing CO2 Capture, Cambridge, MA, MIT.

[5] For example, see "Carbon Capture and Sequestration: Framing the Issues for Regulation," Interim Report for the CCSREG Project, Department of Engineering and Public Policy, Carnegie Mellon University (December 2008).

[6] See "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells," 73 Fed. Reg. 43492 at 43523 (July 25, 2008).

[7] Ibid., at 43503.

[8] 42 USC 330h-1 of the SDWA provides that states may apply to the EPA for delegated authority to administer the UIC program; those receiving such authority are referred to as "Primacy States." This section requires Primacy States to meet the EPA's minimum federal requirements for UIC programs, including construction, operating, monitoring and testing, reporting, and closure requirements for well owners or operators; the states can seek full program authority or authority to administer portions thereof. (See 73 FR 43523 (July 25, 2008)) If a state does not seek this responsibility or fails to demonstrate that it meets the EPA's minimum requirements, the EPA is required to implement a UIC program for that state by regulation. New York is not currently a Primacy State and has not applied for UIC delegated authority and, therefore, the EPA is required to administer the federal UIC program in New York. Pursuant to 42 USC 300h-2 (d) of the SDWA, until New York applies for primacy, New York is authorized to enact its own, separate CCS underground injection program to protect its groundwater systems, with the understanding that the state program will operate concurrently and in addition to the federal UIC program.

[9] See Texas S. B. No. 1461, enacted April 26, 2007.

[10] See "Clean Coal FutureGen for Illinois Act," Illinois Public Act 095-0018 (SB 1704 enrolled).

[11] Full report of New Mexico sequestration regulation "blueprint" available at: http://www.emnrd.state.nm.us/ocd/documents/CarbonSequestrationFINALREPORT1212007.pdf.

[12] See NETL: News Release – "DOE Completes Large-Scale Carbon Sequestration Awards", November 17, 2008.

[13] WAS 173-218-115.

[14] "Storage of Carbon Dioxide in Geologic Structures: A Legal and Regulatory Guide for States and Provinces", the Interstate Oil and Gas Compact Commission Task Force on Carbon Capture and Geologic Storage, September 25, 2007.

[15] Id.

[16] Miles v. Home Gas Company, 35 A.D.2d 1042 (1970).

[17] International Salt Co. v. Geostow, 878 F.2d 570 (2nd Cir. 1989).

[18] See generally Prosser, Torts [4th ed], § 78.

[19] Doundoulakis v. Hempstead, 42 N.Y.2d 440, 448 (1977).

[20] State v. Schenectady Chemicals, 103 A.D.2d 33, 38 (N.Y. App. Div. 3d Dep't 1984).

[21] Doundoulakis v. Town of Hempstead, 42 N.Y.2d 440, 448 (1977).

[22] State v. Shore Realty Corp., 759 F.2d 1032, 1051 (2d Cir. N.Y. 1985) (applying New York law).

[23] N.Y. NAV. LAW, § 181(1) (2008) ("Any person who has discharged petroleum shall be strictly liable, without regard to fault, for all cleanup and removal costs and all direct and indirect damages, no matter by whom sustained. . . ."); see also Busy Bee Food Stores v. WCC Tank Lining Technology, 202 A.D.2d 898, 899 (N.Y. App. Div. 3d Dep't 1994).

[24] Boston v. Dunham, 274 A.D.2d 708, 710 (N.Y. App. Div. 3d Dep't 2000) (establishing that a claimant must fall within the class to be protected by the statute in relying on violation of a statute to prove negligence per se); Sharrow v. N.Y. State Olympic Reg'l Dev. Auth., 193 Misc. 2d 20, 35 (N.Y. Ct. Cl. 2002) (holding that the statutory provisions on which claimants rely must be designed to prevent the type of accident for which claimant seeks recovery); see also RESTATEMENT (THIRD) OF TORTS § 14 (Proposed Final Draft 2005).

[25] Another question presented by common law tort actions is the period within which a potential plaintiff would be permitted to bring a cause of action against the owner/operator of the underground storage facility. New York's Statute of Limitations permits an action to be brought three years after discovery of the negligence. Christy v. Harvey, 262 A.D.2d 755 (N.Y. App. Div. 1999). Therefore, the owner/operator of the underground storage facility could be liable potentially indefinitely for CO_2 leaks discovered long after the facility could be operational.

[26] In Chance v. BP Chemicals, Inc., 670 N.E.2d 985 (Ohio, 1996), the court held that subsurface rights only include the right to exclude invasion that actually interfere with reasonable and foreseeable uses of the subsurface. On the other hand, there are arguments for maintaining subsurface depths as private property as ever advancing technology reveals new commercially economic value in deep strata, which might not be considered today.

[27] See Anthony v. Chevron USA, Inc., 284 F.3d 578 (5th Cir. 2002), rejecting two models presented by plaintiffs to prove that salt water injections had contaminated their aquifer.

[28] In Mongrue v. Monsanto Co., 1999 WL 970354 (E.D. La. 1990) the court explained that the regulator does not bar claims of trespass when authorizing the disposal of waste through underground injection wells. However, the plaintiff has the burden of proof that the migration of injectate interfered with a reasonable and foreseeable use of their property. In Mechlenbacher v. Akzo Nobel Salt, Inc., 71 F.Supp.2d 179, 193 (W.D.N.Y.1999), vacated in part, 216 F.3d 291 (2d Cir. 2000), the United States District Court for the Western District of New York decided that without proof of "actual physical damage to a plaintiff's property, stigma damages alone are too remote and speculative to be recoverable."

[29] See CPLR section 214-c which allows for the statute of limitations to be extended to three years from "the date of discovery of an injury or the date when through the exercise of reasonable diligence such injury should have been discovered." This extension provisions is triggered by an injury to person or property if caused by the "latent effects of exposure to any substance or combination of substances, in any form, upon or within the body or upon or within property"

[30] The minority view is probably most clearly set forth in the Kentucky case of Century Kentucky Natural Gas Co., v. Smallwood, 252 SW2d 204 (Ky. Ct. App. 1952) where the court held: "We conclude that the mineral rather than the surface owner is entitled to rental or royalty accruing under a gas storage lease." The case was later overturned, but on a different issue in Texas American Energy Corp. v. Citizens Fidelity Bank & Trust Co., 736 S.W.2d 25 (Ky. S.Ct. 1987).

[31] Williams & Myers, Oil and Gas Law, Section 1:22, pages 334-335.

[32] For example, see Section 240 of the NYS Labor Law. The leading case in New York regarding common law liability is Basso v. Miller *et al*., 40 N.Y.2d 233 (1976). The duty of the landowner should not vary with the person using the property, but he should act reasonably to maintain safe conditions in view of all the circumstances, including the likelihood of injury, the seriousness thereof and the burden of avoiding the risk, and the likelihood of the plaintiff's presence should be a primary independent factor in determining foreseeability.

[33] NYSDEC recently issued a proposed Technical Guidance Document to evaluate GHG emissions as part of the SEQRA review process. See Guide for Assessing Energy Use and Greenhouse Gas Emissions in an Environmental Impact Statement, dated September 9, 2008.

[34] Indeck Corinth,L.P. v. David A. Paterson, as Governor; New York State Department of Environmental Conservation; New York State Energy Research and Development Authority; and New York State Public Service Commission (filed January 29, 2009, NYS Supreme Court, Saratoga County).

[35] See the NYSDEC RGGI Web site, http://www.dec.ny.gov/energy/rggi.html. Accessed February 27, 2009.

[36] NYSERDA, "Operating Plan for Investments in New York under the CO2 Budget Trading Program and the CO_2 Allowance Auction Program," (Draft February 25, 2009).

[37] Ibid, page 39.

[38] See 6 NYCRR Parts 200 and 242 CO_2 Budget Trading Program and 21 NYCRR Part 507 RGGI Auction Process.

[39] RGGI Website, http://www.rggi.org/home. Accessed December 30, 2008.

[40] Final Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program. July 1992, Reprinted 2003. Downloaded from http://www.dec.ny.gov/energy/45912.html

[41] Ibid.

[42] Final Scope for Draft Supplemental Generic Environmental Impact Statement (dSGEIS) on the Oil, Gas and Solution Mining Regulatory Program: Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs. Downloaded from: http://www.dec.ny.gov/docs/materials_minerals_pdf/finalscope.pdf

[43] Ibid. Note 40.

[44] Final Scope for Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program: Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs. Executive Summary. Downloaded from: http://www.dec.ny.gov/energy/47554.html

[45] Ibid. Note 40.

[46] Ibid. Note 42.

47 See 42 U.S.C. § 6973.

48 EPA, Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 FR 25447 (July 6, 1988).

49 The exclusion of CO_2 from the solid waste definition seems appropriate in this case. The definition already excludes oil and gas waste and nuclear waste. Similarly, the NYS hazardous waste regulations in 6 NYCRR 371.1(e)(2)(iv) excludes "fly ash, bottom ash waste, slag waste, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels." Various rationales for excluding these materials from waste regulation include cost, economic impact and /or the applicability of a strong regulatory program to address environmental concerns. All of these rationales could be readily applied in this case to exempt injected supercritical CO_2 from the solid waste definition.

50 73 Federal Register 43492 at 43504 (2008).

51 See Pneumo Abex Corp. v. High Point, Thomasville & Denton R.R. Co., 142 F.3d 769, 775 (4th Cir. 1998) (considering four factors to distinguish between a sale of a useful product and a disposal of a hazardous substance: (1) the intent of the parties as to whether the materials were to reused entirely or reclaimed and then reused; (2) the value of the materials sold; (3) the usefulness of the materials in the condition in which they were sold; and (4) the state of the products at the time of transfer); *A & W Smelter and Refiners, Inc. v. Clinton*, 146 F.3d 1107, 1112-13 (9th Cir. 1998) (remanding case for factual determining of whether ore containing gold, silver, and small amounts of lead was a useful product or a waste, *i.e.*, whether the materials is the producer's principal business product or a by-product that the producer intends to dispose); M. STUART MADDEN & GERALD W. BOSTON, LAW OF ENVIRONMENTAL AND TOXIC TORTS 627-28 (3rd ed. 2005) (discussing lack of CERCLA coverage for sale of "useful products").

52 Massachusetts v. Environmental Protection Agency, 549 U.S. 497 (It is of interest to note that two federal district court cases (Jastram v. Phillips Petroleum Co., 844 F. Supp. 1139, 1142-43 (E.D.La. 1994) and Eagle-Picher Indus. v. United States E.P.A., 245 U.S. App. D.C. 196, 759 F.2d 922 (D.C. Cir. 1985)) have ruled that primary CERCLA liability does not attach to releases of "pollutants" but no court rulings have addressed the reach of secondary liability under Section 9604, and certainly have not considered liability under that section for the release of CO_2.)

53 p.16, World Resource Institute, Guidelines for Carbon Capture, Transport and Storage, 2008.

54 "Project Developer Interviews: Regulatory measures and financial incentives to accelerate the commercial deployment of advanced coal with carbon capture and storage", Jennifer Johnson, Great Plains Institute for the Midwestern Governors Association Renewable Electricity and Advanced Coal with Carbon Capture Advisory Group, September 2008.

55 "Geologic Carbon Sequestration: Property Rights," presentation paper submitted to the Eighth Annual conference on Carbon Capture and Sequestration –DOE/NETL, May 4-7, 2009, page 5, prepared by Jerry R. Fish, Esq.

56 Ibid., page 12.

57 Cost and Performance Baseline for Fossil Energy Power Plants Study, Volume 1: Bituminous Coal and Natural Gas to Electricity," Revised Final Report, August 2007, RDS for NETL.

58 NYSDEC Web site, http://www.dec.ny.gov/chemical/8442.html; accessed February 27, 2009.

[59] Kenneth S. Kamlet Introduction: History of Brownfields Regulation, p.2, www.ny-brownfields.com; see also: Kamlet, Kenneth S., "Brownfields Regulation in New York State: A Disappointing Report Card," New York State Bar Association , The Environmental Lawyer, Vol. 22, No.1, Winter 2002, pp 2-24.

[60] The BCP was authorized in statute under Title 14 of Article 27 of the Environmental Conservation Law as part of the 2003 Superfund/Brownfield Law.

[61] The UIC NOPR discussion of liability issues raises the specter of liability under both RCRA and CERCLA. . The analysis provided there also does not preclude the potential for common law liability, noting that UIC requirements are not intended to pre-empt state common law.

[62] Legislative Memorandum prepared in support of Chapter 412, Laws of 1996.

[63] Environmental Conservation Law, Section 56-0509.

[64] Legislative Memorandum prepared in support of Chapter 412, Laws of 1996.

[65] See Energy Research, Development, Demonstration, and Commercial Application Act of 2006, H.R. 5656 (2006).

[66] Amendment to H.R. 5656 offered by Rep. Costello of Illinois (June 27, 2006).

[67] Id. See also Department of Energy Carbon Capture and Storage Research, Development, and Demonstration Act of 2007, H.R. 1933 (April 18, 2007) (bill to amend the Energy Policy Act of 2005 to reauthorize and improve the carbon capture and storage research, development, and demonstration program of the Department of Energy).

[68] See 23 ECL 0305(8)d. General powers provided to NYSDEC by statute to address contamination concerns are set forth at 1 ECL 0101(3)b; 3 ECL 0301(1) (g), (i), and (m). See also 6 NYCRR 556.5 prohibitng pollution of land; and 71 ECL 1305 (2) clarifying that any failure to perform a duty imposed by NYSDEC by permit or order is a criminal offense.

[69] This option contemplates amendment of analogous New York laws; although the amendment of federal laws is beyond the scope of this report, efforts to address these changes on the federal level should be supported by New York State to the extent possible and state legislative changes alone may not be adequate for CCS project sponsors without a change in federal liability.

[70] The Kentucky performance bonding requirements set forth at 405KAR Ch. 10 are representative of the bond release programs used to regulate the closure of coal mines throughout the United States.

[71] 40 CFR 264.140, et seq.

[72] IOGCC model rule, p. 26.

[73] Terrorism Risk Insurance Act of 2002, P.L. 107-297, 116 Stat. 2322, as amended.

[74] Price-Anderson Act, 42 U.S.C. § 2210.

[75] See Title 14 of Article 27 of the ECL and Section 21 of the Tax Law.

[76] If a CCS facility is under a long term contract, it would be placed at the bottom of the generation bid stack each day in the NYISO market. Project revenues could be secured through the commercial contract. In this scenario, the economic and operating dispatch risk would be lower. However, the CCS plant would still need to enter into a commercial contract.

[77] Energy Improvement and Extension Act of 2008 (Pub.L. 110-343).

[78] Memorandum of Understanding, dated June 9, 2008, between Empire State Development Corporation and Praxair, Inc.

[79] See Note 9, supra.

[80] There is currently inadequate other funding to compensate for these risks. DOE or other government funding can provide substantial funding support for commercial demonstration projects. DOE, however, typically funds projects only for a limited time period (3 to 5 years) and requires cost sharing. After the demonstration period, and for the remaining thirty or more years of operation, CCS projects would be dependent on carbon revenues from a trading program or other sources.

[81] Excerpt from "Last Chance for Coal – Making Carbon Capture and Storage a Reality", Linda McAvan, MEP (Member of European Parliament).

[82] DOE 2007.

[83] Id, WRI CCS Guidelines, 2008.

[84] NETL 2008.

[85] Ibid. Note 5, at 43497.

[86] Ibid. Note 44.

[87] Ibid. Note 42.

[88] Ibid. Note 42.

[89] Ibid. Note 40.

[90] Protecting the Environment During Well Drilling and Operation: Environmental Protections for Oil and Gas Development. Downloaded from: http://www.dec.ny.gov/energy/1536.html

[91] Ibid. Note 44.

[92] Ibid. Note 40.

[93] Ibid. Note 86.

[94] Ibid. Note 5, at 43510.

[95] Delaware River Basin Compact, United States: Public Law 87-328, approved September 27, 1961.

[96] 73 Fed. Reg. 78618, 78621 (Dec. 23, 2008) (to be codified at 18 CFR Pt. 806).

[97] The Ohio River Valley Water Sanitation Commission. http://www.orsanco.org/default.asp

[98] Bachu, Stefan, Carbon Dioxide Storage in Geological Media: Status and Barriers to Development, Presentation to Alberta Geological Survey and Alberta Energy and Utilities Board.

[99] Final Report of the Advanced Coal Technology Workgroup, January 29, 2008.

[100] NYSERDA, "Operating Plan for Investments in New York under the CO_2 Budget Trading Program and the CO_2 Allowance Auction Program," (April 16, 2009), page 41.

Conclusions

- Cur ent state of egulatory uncertainty leads to cost uncertainty
- A ew subsidized projects are moving forward, but conventionally financed power projects with CCS are at a standstill
- Situation will likely change with federal climate change egulations, so planning and permitting can continue

Appendix 5.

Cost Benefit Report

002595_NY13_06-B2883

Task 6
Evaluation of Costs and Potential Benefits for Carbon Capture and Sequestration

May 2010

Prepared for:

John Martin

NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY
Agreement No. 10498
Natural Gas and Petroleum Exploration and Production, Emissions Reduction, and Carbon Sequestration

Prepared by:

ECOLOGY AND ENVIRONMENT, INC.
368 Pleasant View Drive
Lancaster, New York 14086

NOTICE

ABSTRACT

Evaluation of Costs and Potential Benefits of Carbon Capture and Sequestration

The costs of carbon capture and storage (CCS) are recognized as a significant challenge to development and commercial applications addressing control of anthropogenic carbon dioxide (CO_2) emissions. The objective of this analysis is to estimate the costs of implementing CCS in New York State (NYS). The analysis presents a review of available literature regarding similar cost studies completed by leading CCS researchers that provides relevant insights on the costs of implementing CCS systems. For this analysis, the "Project" consists of a 100 MW-e nameplate (gross) capacity Oxy-Coal Circulating Fluidized Bed (CFB) capable of capturing over 98% of the CO_2 produced by the plant and resulting in minimal emissions of sulfur oxides (SO_x), nitrogen oxides (NO_x), and mercury. The capital and O&M costs are total lifecycle costs. The analysis is based on the "with CCS" and "without CCS" framework. Potential financial revenues and public economic benefits are estimated, including avoided health and environmental damages. Costs represent discounted lifecycle costs over a 30-year period using discount rates of 4.5% and 8.5%. For a modeled 100 MW plant size with CCS, public benefits would exceed total lifecycle costs under discount rates of 4.5% and 8.5%. Implementing CCS systems would improve environmental quality and avoid the economic and social damages from air emissions because these pollutants would be reduced through plant processes, captured and stored. The sensitivity analysis evaluates the effect of varying the size of federal grants on the cost of electricity from the Project.

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List of Abbreviations and Acronyms

¢/kWh	cents per kilowatt hour
$/kW	dollars per kilowatt
$/kWh	dollars per kilowatt hour
$/MWh	dollars per megawatt hour
$/MMBTU	dollars per million British thermal units
$/ton	dollars per ton
ACES	American Clean Energy and Security Act of 2009
ASU	air separation unit
BTU/kWh	British thermal units per kilowatt hour
C$	Canadian dollars
CCS	carbon capture and storage
CFB	circulating fluidized bed
CFG	Coal fired generation
CO_2	carbon dioxide
COE	cost of electricity
CPU	CO_2 processing unit
DOE	(United States) Department of Energy
DOT	(United States) Department of Transportation
DSS	DSS Management Consultants
ECAR	East Central Area Reliability Coordination Agreement
ECBM	enhanced coal bed methane recovery
EOR	enhanced oil recovery
EGR	enhanced gas recovery
FGD	flue gas desulfurization
FOAK	first of a kind
GEE	GE Energy
GHG	greenhouse gas

List of Abbreviations and Acronyms (cont.)

HF	hydrogen fluoride
HHV	higher heating value
IGCC	integrated gasification-combined cycle
ITM	ion transport membrane
kg/h	kilograms per hour
km	kilometer
kWe	kilowatt electric
kWh	kilowatt hour
LBMP	locational-based marginal price
LCOE	levelized cost of electricity
MES	Minimum efficient scale
MIT	Massachusetts Institute of Technology
MMV	measuring, monitoring, and verification
MW	megawatt
MWe	Megawatts electric
NERC	North American Electric Reliability Council
NETL	National Energy Technology Laboratory
NGCC	natural gas combined cycle
NOAK	nth of a kind
NO_X	nitrogen oxide
NPV	net present value
NYISO	New York Independent System Operator
NYS	New York State
O&M	operation and maintenance
Oxy-PC	pulverized coal oxy-combustion
PC	pulverized coal
PM	particulate matter
psia	pounds per square inch absolute
psig	pounds per square inch gauge
REC	Renewable Electricity Credit
RGGI	Regional Greenhouse Gas Initiative
ROW	right of way

List of Abbreviations and Acronyms (cont.)

SC	supercritical
SCPC	supercritical pulverized coal
SO_X	sulfur oxide
TLCC	Total Lifecycle Costs
TPC	total plant cost
tpy	tons per year
TSM	transportation, storage and monitoring
UCAP	unforced capacity
US$	United States dollars
USC	ultra-supercritical
WTP	willingness to pay
VSL	value of a statistical life

1 Summary

The costs of carbon capture and storage (CCS) are recognized as a significant challenge to development and commercial applications addressing control of anthropogenic carbon dioxide (CO_2) emissions. The objective of this analysis is to estimate the costs of implementing CCS in New York State (NYS). The analysis presents a review of available literature regarding similar cost studies completed by leading CCS researchers that provides relevant insights on the costs of implementing CCS systems. In addition, an analysis of the likely costs and benefits of CCS is developed for a hypothetical project.

Section 2 presents a detailed analysis of studies that evaluated the design cost of implementing CCS systems for mostly commercial-scale power plants. The studies compared pre-combustion (integrated gasification combined cycle [IGCC]), post-combustion, and oxy-combustion processes that precede sequestration. The most expensive CO_2 capture total plant cost (TPC, in absolute terms) was supercritical pulverized coal (SCPC) ($3,080/kWe), closely followed by pulverized coal (PC) subcritical and supercritical. The greatest change in TPC amongst all the processes (i.e., the delta between without and with capture) was for natural gas combined cycle (NGCC) Advanced F Class, a 111% increase in TPC. The range in cost increases between without and with capture was between a low of 32% (IGCC: GEE) and the high noted. The average increase in TPC costs was 65% across all plant processes.

Section 3 provides an overview of the cost and benefit analysis for a hypothetical new coal fired power plant with CCS. For this analysis, the "Project" consists of a 100 MW-e nameplate (gross) capacity Oxy-Coal Circulating Fluidized Bed (CFB) capable of capturing over 98% of the CO_2 produced by the plant and resulting in minimal emissions of sulfur oxides (SO_x), nitrogen oxides (NO_x), and mercury. The cost benefit analysis summarizes the incremental cost of implementing CCS and is illustrative of the cost to implement CCS at similar sized power plants under current and anticipated regulatory and market conditions. The analysis uses relevant information sourced from the scientific literature, regional utility and power pool market relationships for key inputs and outputs, prior studies performed by the Department of Energy, and confidential information obtained from project developers. The benefits are based on financial revenues from power sales, potential carbon revenue streams under various legislative scenarios, and economic benefits based on the avoided costs of health and property damages associated with reductions in emissions. These latter economic benefits would arise with CCS plant configurations.

The total lifecycle capital and operational and maintenance (O&M) cost estimates presented in Section 4 are based on an order of magnitude or planning level basis. The capital and O&M costs are total lifecycle costs (TLCC) that consider all significant dollar costs over the life of the project assets (NREL 1995). The hypothetical or conceptual costs adapted for this study's estimate were originally based on process inputs, components and technology associated with a smaller scale plant (i.e., < 100 MW-e). To account for variation in TLCC with increases in plant scale, a scaling function sourced from the scientific literature (Belfer Center 2009) was used to estimate the total plant costs associated with this larger 100 MWe plant scale. Appendix A describes the cost scaling procedure that was applied.

The analysis in Section 4 is based on the "with CCS" and "without CCS" framework. This standard project evaluation framework compares the gross costs and benefits with CCS to the base reference case without these CCS plant components and systems. The differences between the "with" and "without" CCS cases represent the incremental net costs attributable to the CCS process improvements and enabling infrastructure. Both long-term O&M and projected financial revenues have been estimated based on a 30-year planning horizon and take into consideration the parasitic loss of power from gross generation capacity necessary to run the CCS systems and infrastructure.

The Project with CCS would add between $178 and $206 million to total capital costs compared to the base reference case without CCS. On a total plant cost basis, (TPC, in $/kWe) the Project with CCS would cost an additional $1,784 – $2,056/kWe. The gross TPC with CCS at 100 MW is below the literature values for First of a Kind (FOAK) plants with CCS that averaged about $6,500/kWe, and slightly above the average TPC for Nth of a Kind (NOAK) plants. The most expensive CO2 capture TPC (in absolute terms) for NOAK plants was SCPC ($3,080/kWe).

The levelized cost of electricity (LCOE), calculated based on TLCC, i.e., total lifecycle capital, O&M, fuel, other long-term running costs and annual electricity production over a 30-year planning horizon was estimated to be $0.107 and $0.126/kWh for the Project using discount rates of 4.5% and 8.5% respectively. These values correspond to incremental LCOE (above the reference or base without capture plant) of between $0.033 and $0.044/kWh. These incremental costs fall within the incremental cost range for NOAK plants (between $0.03-$0.05/kWh) reported in the literature and are consistent with the recent NOAK plant CCS cost studies.

Using the 8.5% discount rate the cost of CO_2 avoided was calculated to be $45 per ton. Using a 4.5% discount rate, a rate close to the cost of capital associated with tax-exempt financing for a public sponsoring entity or utility, the cost of CO_2 avoided was calculated to be $33/ton. From the FOAK studies surveyed in the literature, the cost of abatement was estimated to be $120 to $180 per ton. For commercial-scale NOAK plants the cost of abatement was estimated to be between $35 and $70 per ton of CO_2 avoided (Belfer 2009). The estimated cost of abatement would place the Project within the low end of the range of the NOAK plant averages reported in the literature.

In addition to the lifecycle costs, potential financial revenues and public economic benefits are also estimated in Section 5. Public economic benefits include avoided health and environmental damages from the CCS process that also significantly reduces harmful criteria air pollutants (i.e., NO_x, SO_2 and PM). This analysis explicitly takes into account the environmental externalities associated with coal-fired power generation and accounts for these social and environmental costs in measuring the public benefits to be realized from CCS. A benefits transfer procedure was applied to estimate these avoided negative effects based on the Damage Function Approach used to estimate health and environmental damages associated with air pollutant emissions from coal fired power plants. A comparable regional study was the basis for the benefits transfer technique used to adapt the damage function to the Project.

Section 6 compares the lifecycle costs and benefits for the Project "with" and "without" CCS to illustrate the incremental net benefits. Costs represent discounted lifecycle costs over a 30-year period using discount rates of 4.5% and 8.5%. Economic benefits include the sum of avoided health damages and avoided materials/crop damages adapted from the benefits transfer technique. Total benefits include the sum of financial revenues and economic benefits. Net benefits are equal to total benefits less total costs.

The analysis makes clear that the key feasibility drivers that can spur CCS implementation are the federal policies that would encourage carbon abatement and renewable energy. For all the climate legislation scenarios considered, the former Lieberman-Warner proposal would result in the most favorable outcome. Under this scenario, the implementation of CCS would result in a cumulative incremental net present value benefit of between $1.0 to 1.9 billion over the 30 year planning horizon based on discount rates of 4.5% and 8.5%. Lieberman Warner provides for both offset allowances for each ton of CO_2 sequestered and CCS bonus allowances for the first 10 years of operations. This bill feature makes a large difference over time and was also included in the Bingamen Specter bill. The results of these bonus allowances show positive cumulative net present value revenues available to offset TLCC. The Revised Dingell Boucher legislation results reflect the relatively larger fixed credit value per ton of CO_2 for the first 10 years of the pro-forma modeling of operations. Under Revised Dingell Boucher legislation the Project receives $90/ton of CO_2 sequestered for first 10 years of operation. This credit value is significantly higher than projected credit values for other legislative proposals. Revised RGGI positive net present values reflect the New York State provision of a $40/ton subsidy (from recycled CO_2 auction allowance proceeds) for the first 10 years of operation. The current version of Waxman-Markey (ACES) results in the least amount of net benefits compared to the other alternatives, primarily because no surplus marketable emission reduction CO_2 credits would be generated for the Project due to the 200-MW nameplate capacity eligibility requirement. The estimated renewable energy credits (RECs) earned from the portion of electricity output generated through renewable biomass fuel do not serve to fully offset compliance costs over the entire planning horizon.

The sensitivity analysis evaluates the effect of the different size federal grants on the cost of electricity from the Project. Using a discount rate of 8.5%, a grant of \$100 million would result in an incremental LCOE of \$0.030/kWh. Compared to the no-grant case, this reduction is equivalent to a reduction of approximately \$0.014 /kWh. Grant sizes moving close to one half of the total capital costs would reduce the incremental LCOE from CCS to under \$0.02 /kWh.

2 Literature Review of CCS Costs

2.1 Overview

The literature review highlights studies that evaluated the design cost of implementing CCS systems for mostly commercial-scale power plants. The studies compared pre-combustion (integrated gasification combined cycle [IGCC]), post-combustion, and oxy-combustion processes that precede sequestration. The capture and sequestration technologies have varying effects on plant energy efficiencies and total and incremental costs. The CO_2 capture rates considered in these analyses range from 85 to 88% for pre-combustion, from 86 to 88% for post-combustion, and 93% for oxy-combustion.

CCS includes CO_2 capture, separation, compression, transport, injection at the storage site, and measurement, monitoring, and verification (MMV). Collectively, these elements are called the CCS value chain. To complicate the cost comparisons, some studies have focused exclusively on the capital costs of capture and separation alone, while some have concentrated solely on the costs of pipeline transportation and injection. Transportation of CO_2 via pipeline is a mature technology. The modeling of these relatively smaller costs uses natural gas pipeline costs because pipeline materials and gas throughput requirements and characteristics are similar (McCoy 2008). Parameterized performance models have been developed based on pipeline length, diameter, and pressurized flow rates.

Since capture costs are the largest and most uncertain of the total lifecycle cost components of CCS (i.e., up to 80% of the entire value chain), researchers have compared plant capital construction costs (dollars per kilowatt [$/kW]) for capture process differences to deliver the same output, in megawatts (MW). For these comparisons the plant efficiency losses (unique to a technology/capture process) required to capture up to 90% of the CO_2 from the CCS systems are documented. Since the high costs of carbon capture can act as a disincentive to early movers, researchers have also evaluated the relative costs of “partial-capture” (Hildebrand and Herzog 2008). The background construction materials and fuel markets driving costs are highly volatile and dynamic. Because of these fluctuating trends, the cost estimates have to be placed in their proper time context. The literature review summaries work in reverse chronological order to highlight the most recent cost information.

Tables 2-1 and 2-2 compare performance and cost metrics by plant process starting with the most recent study results. Table 2-1 compares traditional air-fired power plants. Table 2-2 shows a comparison of oxy-combustion and IGCC power plants because both technologies use oxygen for combustion. Based on the sources surveyed, the highest potential cost impact occurs for CCS for post combustion control. The variability within pulverized coal technology is very high. Generally, CO_2 capture lowers plant efficiencies (between 7 and 12%, higher heating value [HHV] basis) and CCS raises capital costs (total plant costs [TPCs]) by between 32% and 111% on average, compared to reference plants without CCS. The parasitic loss requires greater fuel consumption (i.e., increase in coal feed by 25 to 37% kilograms per hour [kg/h]), is cost punitive, and requires an over-sizing of the plant to achieve the same net electricity output. In terms of the levelized cost of electricity (LCOE), the average incremental cost including CO_2 capture compared to the base reference plant costs (without CCS) varies between \$0.03 and \$0.05 cents per kilowatt hour (kWh) higher, with the average being close to \$0.04 cents per kWh higher across all plant processes. The lowest increase in incremental costs compared to base reference plant processes without CO_2 capture was shown in the IGCC case studies.

Figure 2-1 shows the breakdown in LCOE by lifecycle cost component for the non-IGCC processes. Levelized capital costs account for the greatest share of LCOE followed by fuel and operation and maintenance costs (O&M). Figure 2-1 shows that capital costs can absorb between 4 and 6 cents per kWh (¢/kWh) of the LCOE with capture, in most cases adding approximately 2 ¢/kWh above the base case. Fuel is the next largest cost component followed by long-term lifecycle O&M or running costs.

2.2 Discussion of Studies Reviewed

Massachusetts Institute of Technology (MIT) researchers Hamilton, Herzog, and Parsons provide an updated cost estimate and financial analysis (in 2007 United States dollars [US$]) for new supercritical pulverized coal (SCPC) plants with CCS systems reported in ***Optimization of Carbon Capture Percentage for Technical and Economic Impact of Near-Term CCS Implementation at Coal-Fired Power Plants*** (MIT 2008). The update was provided in a high construction cost environment based on pre-recession level global demand for raw materials, capital equipment, and labor inputs for power plants. A comparison of several previous cost estimates including the authors' earlier updated estimates from the ***Future of Coal: Options for a Carbon Constrained World*** (MIT 2007) are also presented. Surveyed costs, from both design studies and actual plant cost estimates were provided for IGCC and oxy-combustion technologies as well. The cost estimates are all presented based on the nth plant-level design basis criteria normalized to the commercial plant size of 500 megawatts electric (MWe). The nth of a kind (NOAK) plant criteria used by researchers is based on mature plants operating at a size allowing for learning and scale economies. Most of the "nth of a kind" studies have been normalized to a commercial-scale plant centering on 500 MWe.

Table 2-1 Post Combustion: Comparison of Carbon Capture and Storage Cost Studies

	MIT 2008		MIT 2007							
	Supercritical pulverized coal (SCPC)		Subcritical PC		Supercritical PC		Ultra-supercritical PC		Subcritical CFB	
Plant Process	without Capture	with CO_2 Capture	without Capture	with CO_2 Capture	without Capture	with CO_2 Capture	without Capture	with CO_2 Capture	without Capture	with CO_2 Capture
Plant Capacity Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Primary fuel	Illinois # 6 coal	Illinois # 6 coal	Illinois # 6 coal	Illinois # 6 coal	Illinois # 6 coal	Illinois # 6 coal	Illinois # 6 coal	Illinois # 6 coal	Illinois # 6 coal	Illinois # 6 coal
Performance Metrics										
Net plant output – MW	500	500	500	500	500	500	500	500	500	500
Net Plant Heat Rate (HHV) (Btu/kWh)	8,868	11,652	9,950	13,600	8,870	11,700	7,880	10,000	9,810	13,400
Net Plant Thermal Efficiency (HHV) (%)	38.5%	29.3%	34.3%	25.1%	38.5%	29.3%	43.3%	34.1%	34.8%	25.5%
Energy Penalty[1]		-9.2%		-9.2%		-9.2%		-9.2%		-9.3%
CO_2 emitted (kg/kWh)	0.83	0.109	0.931	0.127	0.83	0.109	0.74	0.094	1.03	0.141
Cost Metrics										
Discount rate, %	8.14%	8.14%	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%
Cost year	2007	2007	2007	2007	2007	2007	2007	2007	2007	2007
Capital Structure (Debt/Equity, %)	45/55	45/55	55/45	55/45	55/45	55/45	55/45	55/45	55/45	55/45
Total Plant Cost (TPC, $/kW-e)	$1,910	$3,080	$1,280	$2,230	$1,330	$2,140	$1,360	$2,090	$1,330	$2,270
% Δ in TPC		61.3%		74.2%		60.9%		53.7%		70.7%
TSM included in cost?		No		No		No		No		
Capital	$0.039	$0.062	$0.026	$0.045	$0.027	$0.043	$0.028	$0.042	$0.027	$0.046
Fuel	$0.016	$0.021	$0.015	$0.020	$0.013	$0.018	$0.012	$0.015	$0.010	$0.013
O&M	$0.008	$0.017	$0.008	$0.016	$0.008	$0.016	$0.008	$0.016	$0.010	$0.019
Total	$0.063	$0.100	$0.048	$0.082	$0.048	$0.077	$0.047	$0.073	$0.047	$0.078
Δ in Total LCO		$0.0376		$0.033		$0.029		$0.027		$0.031
% Δ in Total LCOE		60.0%		68.6%		60.9%		56.5%		66.5%

Notes:
1. Percentage decrease in efficiency due to CO2 capture relative to base case (w/out capture)

Key:

$/kWe = Dollars per kilowatt electric.
Btu/kWh = British thermal units per kilowatt hour.
CFB = Circulating fluidized bed.
CO_2 = Carbon dioxide.
HHV = Higher heating value.
kg/kWh = Kilograms per kilowatt hour.
LCOE = Levelized cost of electricity.
MIT = Massachusetts Institute of Technology.
MWe = Megawatt electric.
NETL = NationalEnergy Technology Laboratory.
O&M = Operation and maintenance.
PC = Pulverized coal.
SCPC = Supercritical pulverized coal.
TPC = Total plant cost.
TSM = Transportation, storage and materials.

Table 2-1 Post Combustion: Comparison of Carbon Capture and Storage Cost Studies

	NETL 2007 (continued)					
	PC subcritical		PC: supercritical		NGCC: Advanced F Class	
Plant Process	without Capture	with CO_2 Capture	without Capture	with CO_2 Capture	without Capture	with CO_2 Capture
Plant Capacity Factor	85%	85%	85%	85%	85%	85%
Primary fuel	Illinois # 6 coal	Illinois # 6 coal	Illinois # 6 coal	Illinois # 6 coal	Illinois # 6 coal	Illinois # 6 coal
Performance Metrics						
Net plant output – MWe	550	550	550	546	560	482
Net Plant Heat Rate (HHV) (Btu/kWh)	9,276	13,724	8,721	12,534	6,719	7,813
Net Plant Thermal Efficiency (HHV) (%)	36.8%	24.9%	39.1%	27.2%	50.8%	43.7%
Energy Penalty \1		-11.9%		-11.9%		-7.1%
CO_2 emitted (kg/kWh)	0.855	0.126	0.804	0.115	0.362	0.042
Cost Metrics						
Discount rate, %	8.79%	9.67%	8.79%	9.67%	8.79%	9.67%
Cost year	2007:Jan	2007:Jan	2007:Jan	2007:Jan	2007:Jan	2007:Jan
Capital Structure (Debt/Equity, %)	50/50	45/55	50/50	45/55	50/50	45/55
Total Plant Cost (TPC, \$/kW-e) %	\$1,549	\$2,895	\$1,575	\$2,870	\$554	\$1,172
Δ in TPC		86.9%		82.2%		111.6%
TSM included in cost?		yes\4		yes\4		yes\4
Capital						
Fuel						
O&M						
Total	\$0.064	\$0.119	\$0.063	\$0.115	\$0.068	\$0.0974
Δ in Total LCOE		\$0.055		\$0.052		\$0.029
% Δ in Total LCOE		85.6%		81.4%		42.4%

Table 2-2 Pre-Combustion (IGCC) and Oxy-combustion: Comparison of Carbon Capture and Storage Cost Studies

Plant Process	NETL 2008		NETL 2007			
	Oxy-combustion (average)		IGCC: GEE\3		IGCC: CoP\3	
	without Capture	with CO_2 Capture[2]			without Capture	with CO_2 Capture
Plant Capacity Factor	85%	85%	80%	80%	80%	80%
Primary fuel	Illinois # 6 coal	Illinois # 6 coal	Illinois # 6 coal	Illinois # 6 coal	Illinois # 6 coal	Illinois # 6 coal
Performance Metrics						
Net plant output - MWe	550	550	623	518	640	556
Net Plant Heat Rate (HHV) (Btu/kWh)	8,662	11,195	8,681	10,757	8,922	10,505
Net Plant Thermal Efficiency (HHV) (%)	39.4%	30.6%	39.3%	31.7%	38.2%	32.5%
Energy Penalty[1]		-8.8%		-7.6%		-5.7%
CO_2 emitted (kg/kWh)	0.800	0.058	0.785	0.115	0.796	0.093
Cost Metrics						
Discount rate, %	8.79%	8.79%	9.67%	9.67%	9.67%	9.67%
Cost year	2007	2007	2007:Jan	2007:Jan	2007:Jan	2007:Jan
Capital Structure (Debt/Equity, %)	50/50	50/50	45/55	45/55	45/55	45/55
TPC ($/kW-e)	$1,579	$2,663	$1,733	$2,431	$1,813	$2,390
% Δ in TPC		68.6%		40.3%		31.8%
TSM included in cost?		yes		yes[4]		yes[4]
Levelized Cost of Electricity (LCOE, $/kWh, 20-year period)						
	without Capture	**with CO_2 Capture**	**without Capture**	**with CO_2 Capture**	**without Capture**	**with CO_2 Capture**
Capital	$0.035	$0.063				
Fuel	$0.019	$0.026				
O&M	$0.010	$0.014				
Total	$0.063	$0.102	$0.075	$0.106	$0.078	$0.103
Δ in Total LCOE		$0.039		$0.030		$0.025
% Δ in Total LCOE		61.7%		40.4%		31.9%

Table 2-2 (continued) Pre-Combustion (IGCC) and Oxy-combustion: Comparison of Carbon Capture and Storage Cost Studies

Plant Process	IGCC: Shell	
Plant Capacity Factor	80%	80%
Primary fuel	Illinois # 6 coal	Illinois # 6 coal
Performance Metrics		
Net plant output – Mwe	636	517
Net Plant Heat Rate (HHV) (Btu/kWh)	8,304	10,674
Net Plant Thermal Efficiency (HHV) (%)	41.1%	32.0%
Energy Penalty [1]		-9.1%
CO_2 emitted (kg/kWh)	0.752	0.090
Cost Metrics		
Discount rate, %	9.67%	9.67%
Cost year	2007:Jan	2007:Jan
Capital Structure (Debt/Equity, %)	45/55	45/55
Total Plant Cost (TPC, $/kW-e)	$1,977	$2,668
% Δ in TPC		35.0%
Transport, Storage & Monitoring (TS&M) included in cost?		yes [4]
Levelized Cost of Electricity (LCOE, $/kWh, 20-year period)		
	w/out Capture	w/ CO_2 Capture
Capital		
Fuel		
O&M		
Total	$0.081	$0.110
Δ in Total LCOE		$0.030
% Δ in Total LCOE		37.1%

Notes:
1. Refers to Case 1, Air-fired SC without CO_2 Capture.
2. Refers to average of Cases 3 through 7, where 3 = air fired CO_2 capture (SC/air), 4 = air fired CO_2 capture (USC/air), 5 = Oxygen-fired cryogenic (SC/ASU), 6 = Oxygen-fired cryogenic (USC/ASU), 7 = Oxygen-fired ITM (SC/ITM).
3. GE Energy.
4. Based on CO_2 transported 80 kilometers (50 miles) via pipeline to a suitable geologic formation field for injection into a saline formation.

Key:

CO_2 = Carbon dioxide.
GEE = GE Energy, CoP = Conoco Phillips
HHV = Higher heating value.
kg/kWh = Kilograms per kilowatt hour.
NETL = National Energy Technology Laboratory.
O&M = Operation and maintenance.
TPC = Total plant cost.
TSM = Transportation, storage and materials.

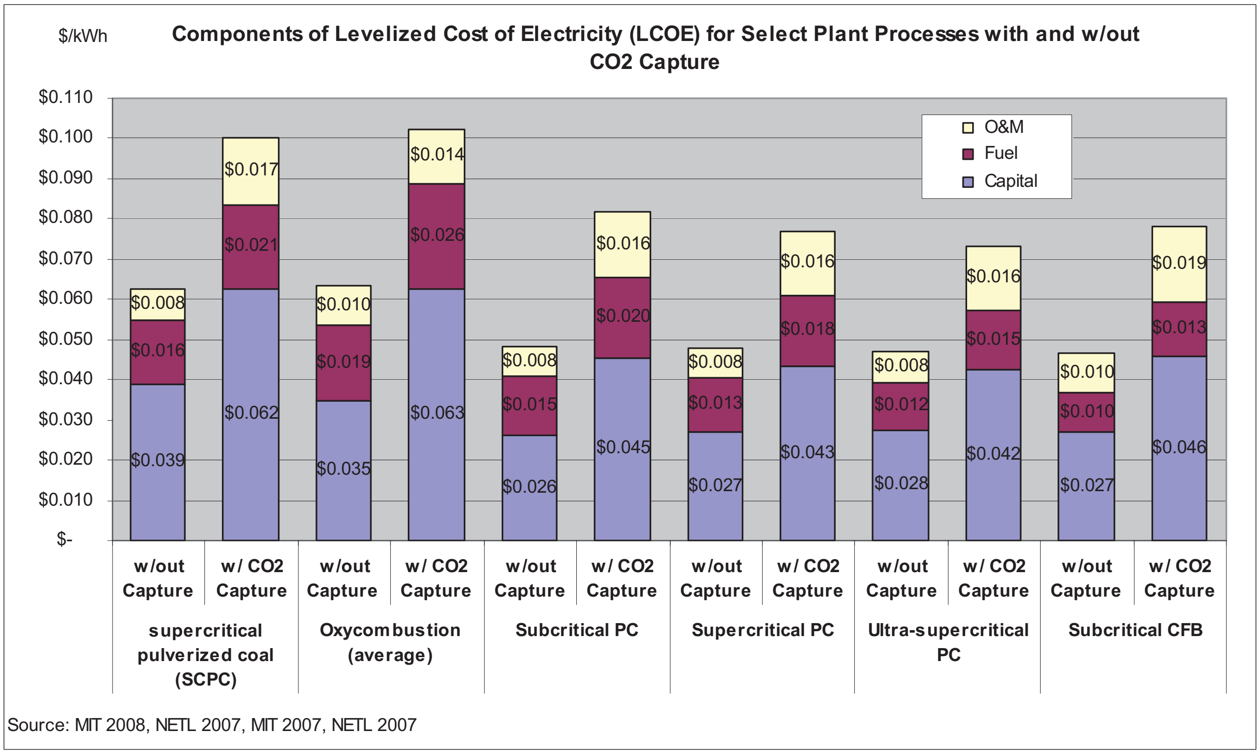


Figure 2-1 Components of Levelized Cost of Electricity (LCOE) for Select Plant Processes with and without CO_2 Capture

The studies provide cost estimates for the reference plant (without CCS) and the total plant cost with CO_2 capture plant. In addition, the LCOE, in either dollars per megawatt-hour ($/MWh) or cents per kWh, are provided and are broken out by capital costs, O&M, and fuel. The researchers estimated that the total plant cost (SCPC) with the CO_2 capture plant at $3,080/kWe, compared to the reference plant cost of $1,910 /kWe (see Table 2-1). The total LCOE was estimated at $100.3 $/MWh with capture, and $62.6 $/MWh without capture, for a difference of $0.0377 kWh. There was a considerable difference in thermal efficiency (HHV) 8,868 BTU/kWh (reference) versus 11,652 BTU/kWh (with CCS) to achieve the 90% capture. Emission rates were also provided with CO_2 90% capture of 0.109 kilograms per kilowatt-hour (kg/kWh; with CCS) versus a CO_2 emission rate of 0.830 (kg/kWh) for the base reference plant.

The MIT 2008 study also compared the updated cost estimates provided above with other cost studies that included nth plant design estimates as well as actual plant estimates for SCPC, SCPC with CCS, IGCC, IGCC with CCS and pulverized coal oxy-combustion (Oxy-PC), and show a wide cost range indicating a lack of consensus on power plant costs with CCS. For example, a comparison of just the SCPC with CCS shows a range between $ 3,071/kW and $5,000/kW (the latter is an actual plant estimate using sub-bituminous coal fuel). On average, the incremental total plant costs ($/kWe, with CCS less reference plant) were $841/kW higher for IGCC compared to $1,212/kW higher for SCPC plants.

In ***The Value of Post Combustion Carbon Dioxide and Capture and Storage Technologies in a World with Uncertain Greenhouse Gas Emission Constraints,*** Wise and Dooley, researchers from the Joint Global Change Research Institute of the Pacific Northwest National Laboratory (PNNL 2009) evaluated the relative performance of IGCC with CCS and pulverized coal (PC) with CCS systems in a competitive, emission-constrained electricity market. The researchers focused on the relative technical and economic merits of deploying post-combustion CO_2 capture technologies within the East Central Area Reliability Coordination Agreement (ECAR) regional electricity system (east-central Midwest region). The ECAR region hosts the largest CO_2 emitters within the North American Reliability Council (NARC) system and is dominated by coal-fired capacity. Using several models developed by Battelle (i.e., Battelle CO_2-GIS [Dahowski et al. 2005] and the Battelle Carbon Management Electricity Model, [Wise and Dooley 2005]), the cost of CO_2 transport, storage, and MMV was projected to be between $12 to $15 per tonne of CO_2 (or $13 to $17 per ton) within the ECAR region. The Pacific Northwest National Library (PNNL) focused on dispatch costs that only included the variable operational and fuel costs (PNNL 2009).

McCoy developed a suite of models to be used for estimating the project-specific cost of CO_2 transport and storage in his thesis on ***The Economics of CO_2 Transport by Pipeline and Storage in Saline Aquifers and Oil Reservoirs*** (McCoy 2008). Engineering-economic models of pipeline CO_2 transport, CO_2-flood EOR, and aquifer storage were developed for this purpose and sensitivity analyses of key variables were measured. The cost of CO_2 pipeline transport was shown to be sensitive to the region of construction and the length and design capacity of the pipeline. The cost of CO_2 storage in saline aquifers was shown to be most sensitive to factors affecting site characterization cost. Applying the cost models, the estimated construction cost of a 100-kilometer (km; 62-mile), 16-inch pipeline in the Midwest, was $36 million (constant 2004 dollars). A 16-inch pipeline could transport approximately 5 million tonnes of CO_2 per year, which would be approximately the maximum annual emissions of a 600-MW (net) pulverized coal-fired plant with 90% CO_2 capture. O&M costs (without a booster compression station) were estimated to be approximately 6% of the total cost per ton of transportation (McCoy 2008).

Hildebrand and Herzog (MIT 2008) focus on the optimization of the carbon capture percentage and near-term economic and technical impacts. The recent focus was driven by findings showing that full capture is too expensive and untested for near-term full-scale deployment. The researchers argue that because the capital cost of a coal-fired power plant with full capture CCS is significantly greater than the cost of the same plant without capture early movers are deterred from implementation. Capture can represent a 60% increase in costs for a PC plant, and at least 30% for an IGCC. In contrast, partial capture for both PC and IGCC represents a smaller total capital investment because smaller or fewer pieces of equipment are necessary and the parasitic energy loss is reduced. Hildebrand and Herzog (MIT 2008) argue that 45 to 65% capture reduces CO_2 emissions levels to a parity level with emissions from natural gas power plants and would allow near–

term electrical generating needs to be met by coal with a climate impact similar to natural gas. While the researchers did not provide actual cost data from simulation models with partial CCS, they relate how MIT is developing models to approximate relevant technical and economic aspects of partial capture for Greenfield PC plants (subcritical and supercritical) and IGCC plants with different gasifier vendors. These models are based on the "end point" data of no capture and full capture from the National Energy Technology Laboratory's (NETL's) "Cost and Performance Baseline for Fossil Energy Plants" (see below, NETL 2007). The same plant specifications and assumptions are used except that plant capacity, not net output, is held constant across capture levels. Spreadsheet models were developed to approximate corresponding data for the full range of capture from 0% to 90% for Greenfield PC and IGCC plants. Hildebrand and Herzog (2008) make the point that full capture CCS can potentially lead to regional cost shifts along the ordered dispatch curve, such that coal fired plants become relatively expensive and are no longer the least cost base load providers. These cost shifts can potentially lead to stranded costs arising from large-scale deployment of full capture CCS investments.

Carbon Capture and Storage: Assessing the Economics, (McKinsey 2008) focused on the costs and economics of implementing CCS in Europe. McKinsey (2008) looked out to the year 2030 and reviewed the incremental costs of CCS (including total capital and long-term O&M costs) compared to a reference state-of-the-art non-CCS power plant with the same net power output and using the same fuel. The analysis was based on a bottom-up review of the main plant technologies currently under development for capture; post combustion, pre-combustion, and oxy-fuel. The results reported did not refer to any specific process or type of power plant. McKinsey 2008 found that the cost of an early commercial-scale project (i.e., those that would be implemented shortly after 2020) would be between €35 to 50 per tonne ($51 to $73) of CO_2 abated. The cost range fell to between €30 to 45 per tonne for mature commercial phase (post 2030). The early demonstration phase cost range was between €60 to 90 ($88 to $132) ton per of CO_2 abated. McKinsey reported that the capture process alone accounted for two thirds of the cost for early commercial phase (€30/tonne), while transport accounted for 11% (€5/tonne) and geological storage was 22% (€10/tonne) (McKinsey 2008).

NETL evaluated the relative plant performance and costs of a PC plant (TPCs: net present value (NPV), $/kW, LCOE, $/ton) for air and oxygen-fired combustion with and without CO_2 capture (NETL 2008). Several process technologies were compared to the base reference case:

- Case 1: Air-fired supercritical (SC) system without CO_2 capture

- Case 2: Air-fired ultra-supercritical (USC) system without CO_2 capture

- Cases 3 and 4 were based on air-fired SC or USC systems with Econamine CO_2 capture

- Case 5: Oxygen-fired SC system

- Case 6: USC systems both with air separation units (ASUs) and CO_2 capture; and

- Case 7: O_2 fired SC with ion transport membrane (ITM) and CO_2 capture.

ITM technology has the potential to help produce oxygen more economically and efficiently. The technology was developed by Air Products Inc. for use in IGCC plants. The process is capable of high mass transfer per unit area and is 100% selective to oxygen (i.e., no other ion can pass through). No external source of electrical power is required (EPRI 2009).

Adding CO_2 capture results in a substantial auxiliary power load in both conventional air-fired amine CO_2 capture cases as well as in oxy-combustion cases. The auxiliary power load is higher in oxy-combustion cases, relative to air-fired, due to the power consumed by the ASU. Total plant costs (excluding transport, storage, and monitoring) ranged from \$2,386/kW (Case 7) to \$2,855/kW (Case 3). Total plant costs necessary to maintain a nominal plant output of 550 MW ranged from \$1.3 billion (2007\$) for Case 7 to \$1.57 billion for Case 3.

The incremental additions to the LCOE compared to the base Case 1 were between 50 and 60% higher than the non-CO_2 capture case, ranging from 3.27 ¢/kWh (Case 6) to 4.59 ¢/kWh (Case 3) higher. The added costs exceed the United States Department of Energy (DOE) goals of achieving no more than a 20% increase in LCOE with CO_2 capture. For Case 1, the reference case without capture, the total LCOE was 6.32 ¢/kWh. For CO_2 capture, the DOE goal would mean a maximum incremental addition of 1.26 ¢/kWh or a total of 7.58 ¢/kWh with CO_2 capture. Cases 3 through 7 mostly fall within a total LCOE band of close to 10 ¢/kWh, with a high close to 11¢/kWh (Case 3). Figure 2-2 reproduces the components of the LCOE for each case and shows the relative incremental cost burdens (in ¢/kWh) resulting from each process.

NETL (2008) researchers then evaluated the impact on LCOE from the following options that would lower the capital costs. These options included:

1. Eliminating the flue gas desulfurization (FGD) unit. If NOx and SO_2 could be co-sequestered with CO_2, an oxy-combustion system might not require an FGD unit.
2. Eliminating the 15% boiler process contingency that was included in the capital costs to account for the lack of commercial-scale operating experience with an oxy-combustion boiler. If the technology is demonstrated at the estimated cost, the process contingencies can be eliminated.
3. Sensitivities associated with a reduction in capital and operating cost for the ASU (NETL 2008).

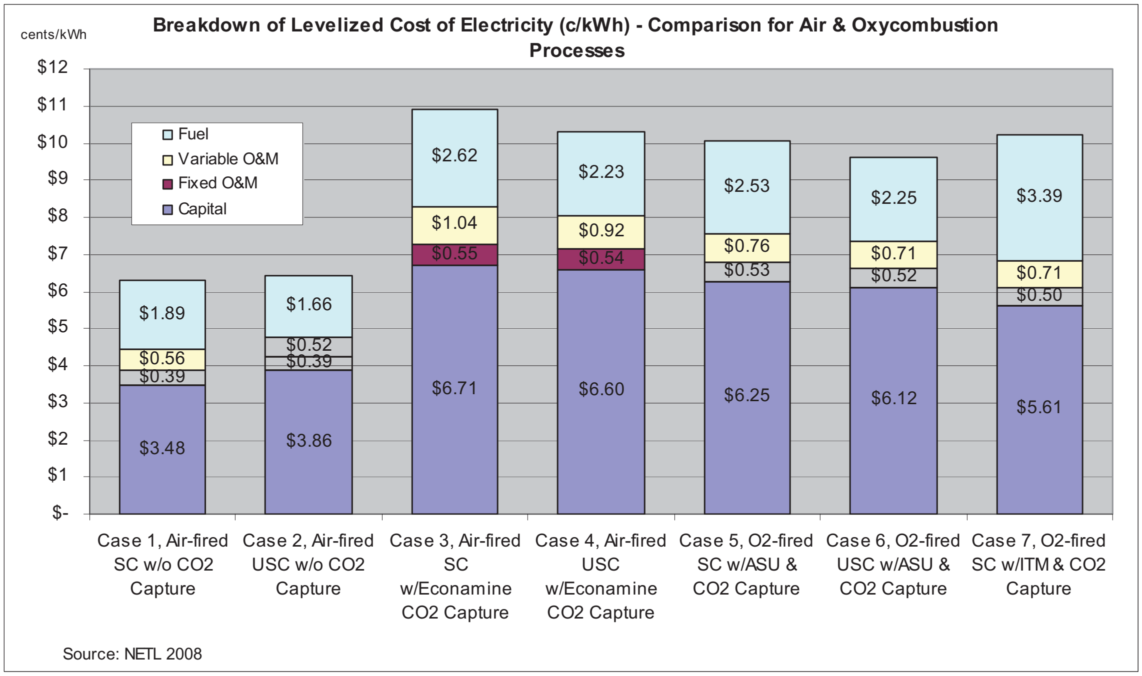


Figure 2-2 Breakdown of Levelized Cost of Electricity (c/kWh) - Comparison for Air and Oxy-combustion Processes

Transportation, storage, and monitoring (TSM) costs represent marginal increases to the LCOE. In terms of the total LCOE per each case, TSM added fractions of a cent per kWh to the total cost. For example Case 6 with and without TSM was (¢9.98/kWh – ¢9.59/kWh = ¢0.39/kWh) while Case 3 was (¢11.3/kWh-10.91=¢0.39/kWh). Average LCOE components for oxy-combustion Cases 3 through 7 showed that CO_2 transport accounted for 2.5% of the total LCOE, CO_2 storage was 0.4%, CO_2 monitoring 0.8%, and LCOE without TSM (primarily capture) was 96% on a total LCOE basis.

As part of the study entitled ***The Future of Coal: Operations for a Carbon Constrained World*** (MIT 2007), MIT researchers compared air-fired technologies costs and performance both with and without capture. The comparisons were based on a 500 MWe net output plant being fed by Illinois No. 6 bituminous coal. The cost results were provided for both TPC ($/kW), LCOE, and costs per ton (avoided and captured). With capture, total plant costs (in 2005 $/kW) varied from a low of $2,090/kW (for USC PC with capture) to $2,230/kW for subcritical PC with capture. Incremental increases in the cost of electricity (COE; with CCS less without CCS) were also the highest using subcritical PC with capture (equivalent to $0.0332 /kWh = 0.0816- 0.0484 $/kWh) and were lowest with ultra-supercritical PC with capture ($0.0265 /kWh = 0.07.34 – 0.0469 $/kWh)

NETL contracted with Parsons Corporation to produce the ***Cost and Performance Baseline for Fossil Energy Plants***, of which Volume 1 focused on Bituminous Coal and Natural Gas (NETL 2007). NETL 2007 is the benchmark study for costs and performance baselines between non-capture and with CCS fossil energy plants. Costs and performance measures were estimated for IGCC, PC, and NGCC using steady state simulations with data from design/build utility projects (Greenfield) and a nominal net plant output of 550 MW. Energy efficiency (HHV basis) showed energy penalties ranging between 6.2% and 9.1% between "non-capture" and "with capture" configurations. The study estimated and compared total plant costs (TPC 2007 US$), LCOE, and the cost of CO_2 removed and avoided (dollars per ton [$/ton]). Power plants were modeled using the Aspen Plus Modeling Program (NETL 2007). PC plant configurations were the costliest in terms of TPC (e.g., $2,883/kW with CCS, compared to $1,562/kW without CCS), while IGCC plants were 13% lower ($2,496/kW with CCS, $1,841/kW without CCS). NGCC was the least cost configuration ($1,172/kW with CCS, $554/kW without CCS). LCOE calculations were based on 20-year levelized costs assuming investor owned utility financing.

LCOE calculations also included the cost of CO_2 TSM assuming a transport distance of 50 miles for storage in a geologic formation with 30 years of monitoring. TSM costs are relatively de minimis (contributing $0.04/kWh). Expressed in $/kWh, total CCS costs for PC configuration were the highest at $0.117/kWh, ($0.064/kWh without), followed by IGCC ($0.106/kWh with CCS, $0.078/kWh without CCS), and NGCC ($0.097 with, $0.068 without CCS). Natural gas combined cycle (NGCC) and IGCC plant configuration with CCS would add close to $0.03/kWh while PC would add slightly over $0.05/kWh to LCOE. Total CCS cost comparisons (including capture, compression, and TSM) ranged from $30/ton for IGCC to $70/ton for NGCC, with PC at ($45/ton; NETL 2007).

Realistic Costs of Carbon Capture, Energy Technology Innovation Policy A joint project of the Science, Technology and Public Policy Program and the Environment and Natural Resources Program (Belfer Center 2009), recently examined realistic costs for carbon capture and storage that is directly relevant to the comparisons between NOAK and first of a kind plants (FOAK).[1] The authors examined the costs for pre-combustion capture with compression (i.e., excluding costs of transport and storage and any revenue from EOR associated with storage) and compared FOAK plant to a NOAK plant with more mature technologies. For FOAK plants using solid fuels, the levelized cost of electricity on a 2008 basis was found to be approximately 10¢/kWh higher with capture than for conventional plants (with a range of 8 to 12 ¢/kWh). Costs of abatement are found typically to be approximately $150 per ton of CO_2 avoided (with a range of $120 to $180/ton of CO_2 avoided). For NOAK plants, the additional cost of electricity with capture is approximately 2 to 5¢/kWh, with abatement costs of the range of $35 to 70/ton of CO_2 avoided. Costs of abatement with carbon capture for other fuels and technologies are also estimated for NOAK plants. The costs of abatement are calculated with reference to conventional SCPC plant for both emissions and costs of electricity. Estimates for both FOAK and NOAK are mainly based on cost data from 2008. The estimates for FOAK and NOAK costs appear to be

[1] FOAK or "first of a kind" means a first plant to be built using a particular technology, while NOAK or "nth of a kind" assumes a large number of plants allowing for substantial learning and thus significant cost reductions.

broadly consistent in light of estimates of the potential for cost reductions with increased experience. Cost reductions are expected from increasing scale, learning in relation to individual components, and technological innovation for improved plant integration.

2.3 Summary Figures of Plant Performance and Costs from Literature CCS Studies

The following figures show performance metrics and cost comparisons for implementing CCS for the full range of plant processes and technologies reviewed in the literature search. The figures show the value ranges and deltas between with capture and without carbon capture plant metrics.

2.3.1 Plant Performance

Figure 2-3 compares the net plant thermal efficiency. The difference between the with capture and the without capture plants represents the energy penalty, or the percentage decrease in efficiency due to CO_2 capture relative to the base case (without capture). The energy penalty was close to 9% (on average, across all processes), with the exception of IGCC: GE Energy (GEE), with a low energy penalty estimate of 5.7%, and a high penalty estimate of 11.9% for PC subcritical and PC supercritical.

Figure 2-4 compares the CO_2 emission rates for the “with capture” and “without capture” cases. The largest capture percentage difference in emission rates was for the oxy-combustion process average (93%), with most capture emission rates averaging between 86% and 88%.

2.3.2 Costs

TPC in dollars per kWe are shown in Figure 2-5. The most expensive CO_2 capture TPC (in absolute terms) was SCPC ($3,080/kWe), closely followed by PC subcritical and supercritical. The greatest change in TPC amongst all the processes (i.e., the delta between without and with capture) was for NGCC Advanced F Class, a 111% increase in TPC. The range in cost increases between without and with capture was between a low of 32% (IGCC: GEE) and the high noted. The average increase in TPC costs was 65% across all plant processes.

Figure 2-6 shows a comparison of the LCOE across all plant processes. The average increase in LCOE was 68% across all processes, approximately an additional $0.035 /kWh compared to the base case without capture lifecycle costs. The most expensive LCOE in absolute terms was for PC subcritical and PC supercritical plant processes ($0.119 /kWh and $0.115 /kWh). The greatest increase in LCOE between the without and with capture plant costs was also for PC subcritical and supercritical (86% and 81% or $0.055 /kWh and $0.052/kWh).

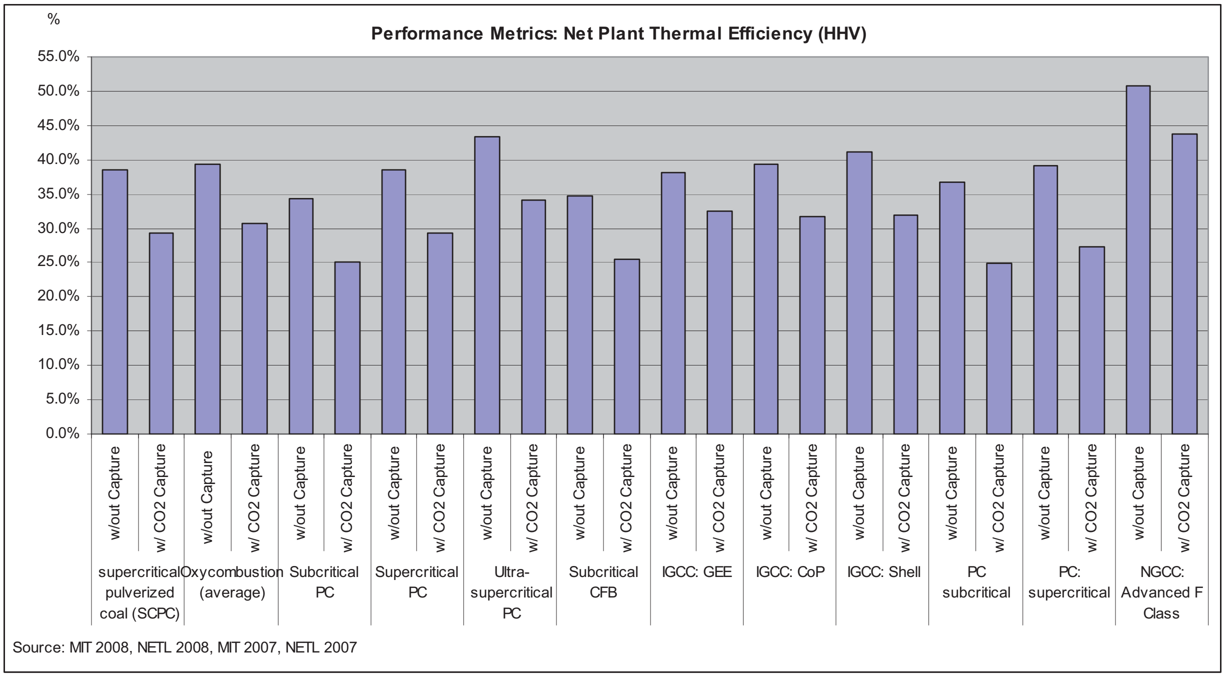


Figure 2-3 Performance Metrics: Net Plant Thermal Efficiency (HHV)

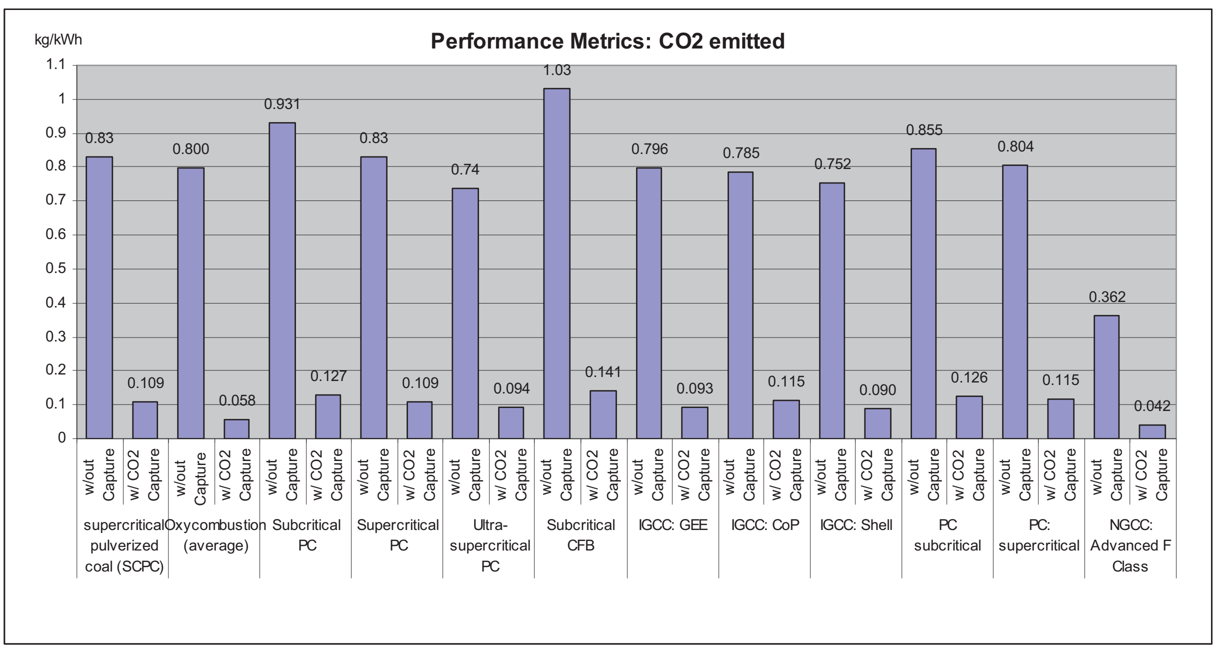


Figure 2-4 Performance Metrics: CO_2 Emitted

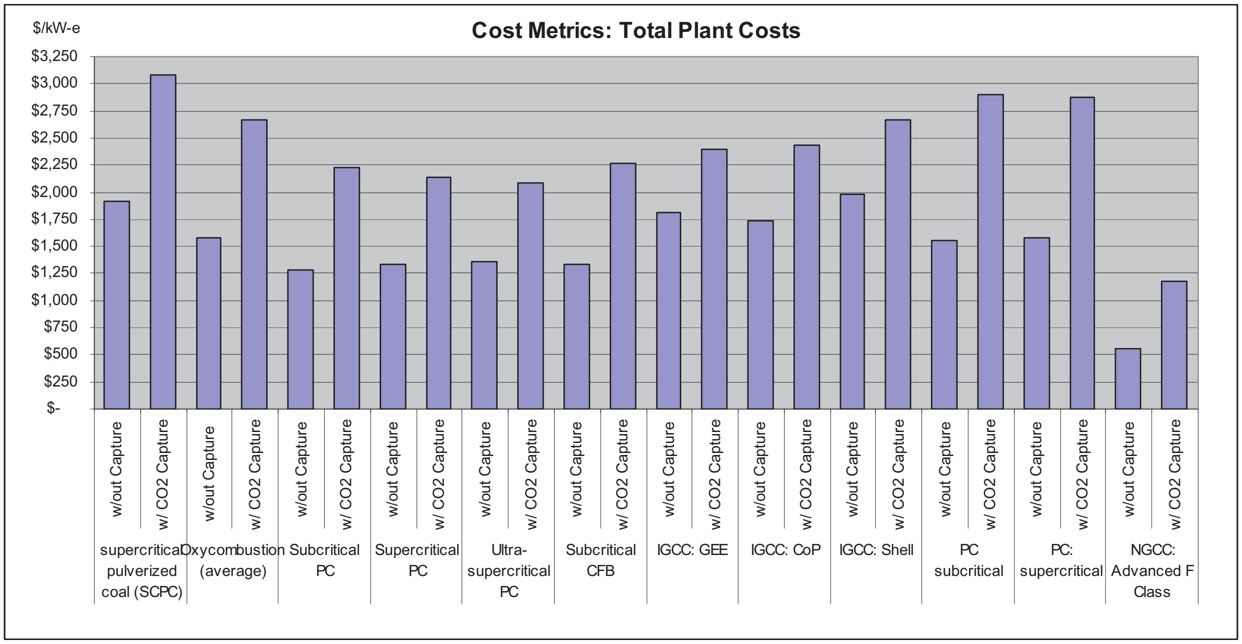


Figure 2-5 Cost Metrics: Total Plant Costs

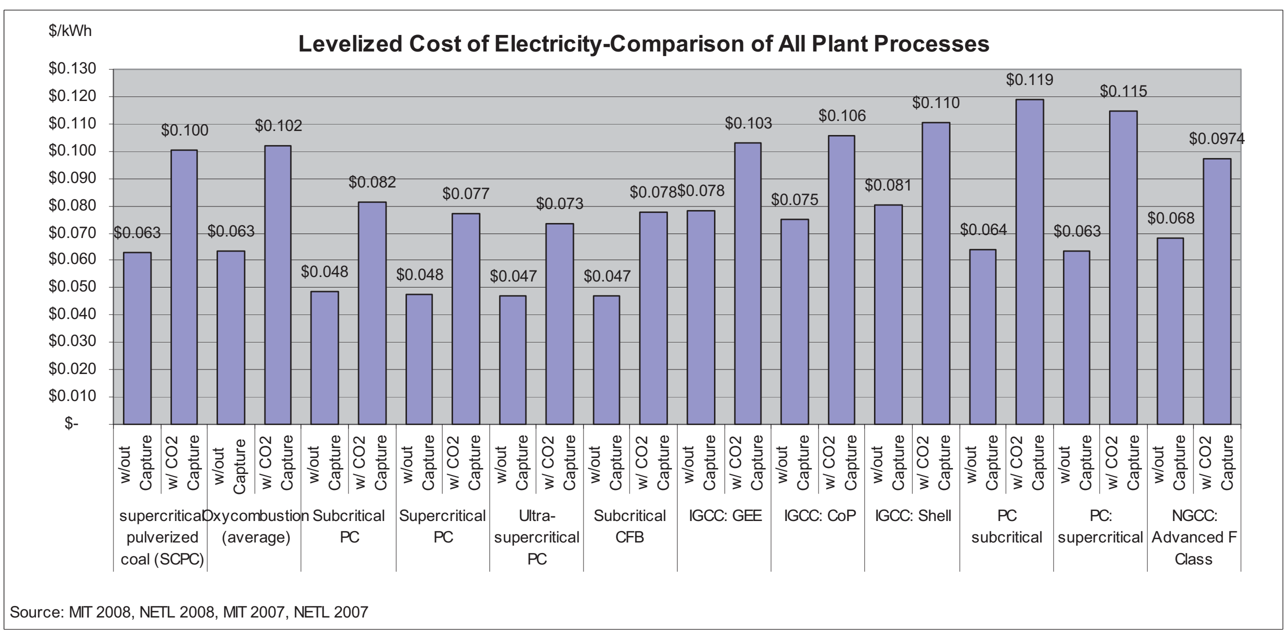


Figure 2-6 Levelized Cost of Electricity-Comparison of All Plant Processes

3 Cost and Benefit Analysis Overview

The "Project" consists of a 100 MW-e nameplate (gross) capacity Oxy-Coal Circulating Fluidized Bed (CFB) with CCS capable of capturing over 98% of the CO_2 produced. Approximately 781,000 tons per year (steady state, tpy) of CO_2 would be transported via pipeline to a suitable injection field for sequestration in a deep saline formation. The cost benefit analysis summarizes the incremental cost of implementing CCS.

3.1 Macroeconomic Context of Project Cost Estimates

Commodity prices have fallen markedly from their pre-recession peaks as the economy has experienced a collapse in demand from the recession. Figure 3-1 compares the United States index of industrial production (physical output) to the Commodity Research Bureau's spot market commodity price index.

The capital costs presented in this section reflect cost estimates completed during a macroeconomic climate when commodity prices were significantly higher. Still, because cost estimates are generally finalized with more detail and precision during the engineering design phase, the planning level costs presented here have been retained. Modeling the costs based on material inputs reflecting greater demand is one way of providing a conservative cost estimate scenario for decision makers that provides a more realistic estimate of the cost of electricity that is closer to price behavior under normal, average steady state economic growth conditions.

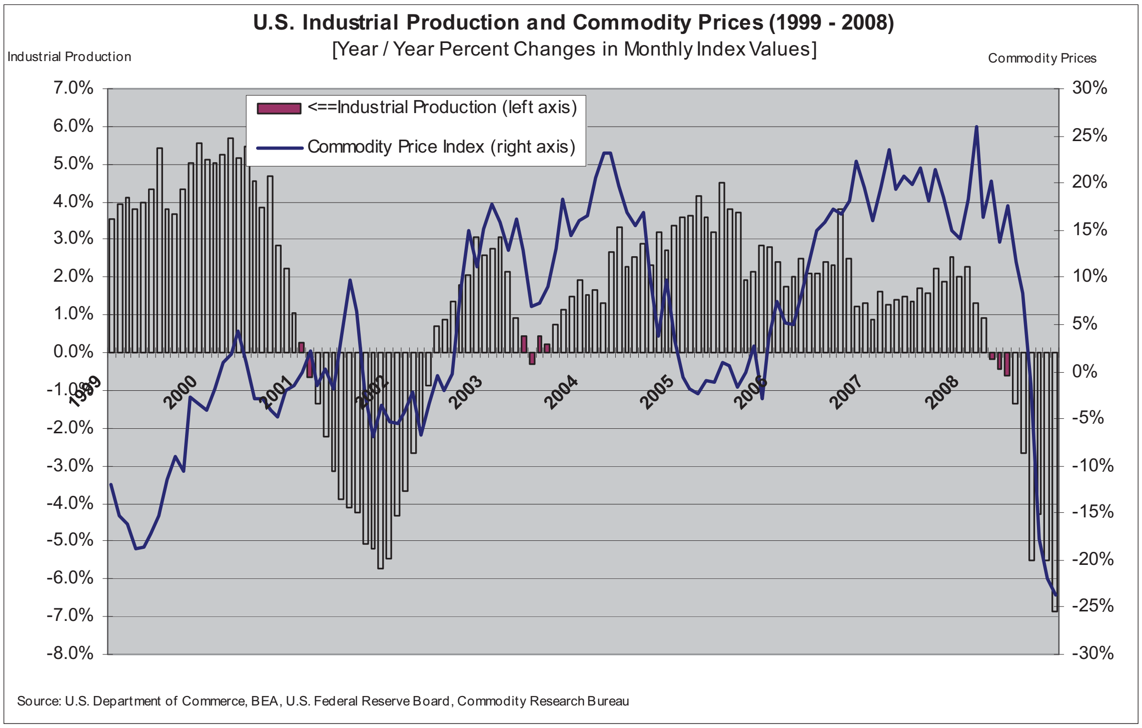


Figure 3-1 United States Industrial Production and Commodity Prices

Figure 3-1 shows that prices for raw materials reflecting basic commodities that would be procured to construct any power plant have fluctuated within a wide range over the last few years in response to business cycles. As a consequence, the projected costs for inputs and raw materials may be significantly different when resource cost estimates are finalized and ultimately when inputs are procured and resources are mobilized. For the purposes of this analysis, the majority of construction activities were modeled to occur between 2012 and 2014 (see explanation under Project Construction Schedule).

3.2 Current and Future Regulatory Climate

The assumptions applied for completing the cost and potential benefit estimates reflect current plans for addressing carbon abatement and mitigation through various cap and trade programs. The scenarios below also include past proposed legislation that has now been superseded by the proposed American Clean Energy and Security Act of 2009 (ACES; Waxman-Markey). The reason for including the modeled financial impacts from past climate change CO_2 allowance proposals is to simulate a range of potential outcomes and to highlight some of the favorable features of select legislation demonstrated through the pro-forma financial modeling exercise. Because there is uncertainty in how the final version of ACES-Waxman-Markey will survive final passage and the bicameral conference committee process, the analysis below includes the past bills as a form of scenario analysis that effectively covers a range of carbon crediting (emission allowance and compliance) scenarios.

Under ACES, the threshold size for receiving emission allowances for sequestration is 200-MW nameplate capacity. Consequently, should this threshold capacity not be lowered (to include up to 100-MW size facilities), the sponsors of the Project with CCS pay for the right to emit residual emissions not sequestered and receive no emission allowance benefits from the tons stored. To the extent that biomass would be used (with coal) in the fuel feedstock, the Oxy-Coal facility would be eligible for federal renewable energy credits (RECs) in proportion to the power generated from this renewable fuel source.

The crediting scenarios include the following national proposals put forth in the Waxman-Markey, Bingaman-Specter, Lieberman-Warner, and Dingell-Boucher proposed acts and plans. In addition, the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowance program is also modeled. The programs have identified unit values or values per emission reduction credit that have been projected over the planning horizon using both interpolation and unit price escalation. The programs reviewed all have unique various features that have been factored into the analysis because, in most cases, they will result in a marketable additional revenue stream. Still, under the current version of ACES the project sponsors would have to pay for the right to emit residual emissions that have not been sequestered, a future running annual cost. Still, since the modeled Project could also potentially use between 10 and 20% biomass feedstock in their operational model, the plant would be eligible to earn annual federal RECs under ACES.

3.3 Assumptions and Parameters Used

Numerous operational, financial, and engineering assumptions have been applied in the cost, revenue, and economic benefit analysis. Select key plant and project-level assumptions applied in simulating the Project are presented in Table 3-1.

Table 3-1 Assumptions and Parameters Used in Cost Benefit Analysis

Assumption/Parameter	With CCS Project
Gross Capacity- MWe (condensing steam turbine generator)	100
CCS Parasitic Load- MWe	30
Availability Starting	2017
Availability	90.0%
Gross Heat Rate BTU/kWh	9,815
Coal Cost $/ton	$43.29
NYISO LBMP Price Forecast- Average Zone A $/MWh	$104.39
CO_2 Allowances Scenarios	Multiple
Annual CO_2 emissions sequestered (tons, yr. 2020)	780,884
Project evaluation lifetime, n=	30 years
Discount Rate – Low	4.5%
Discount Rate – High	8.5%

3.4 Methodology

The costs and potential benefits were evaluated using standard evaluation techniques widely used in engineering, financial, and economic analysis. The lifecycle cost and benefit resource streams were compared over a 30-year planning horizon that coincides with the economic life of the project assets. Two nominal discount rates were used to discount the future benefit and cost streams to their present values, a low of 4.5% and a high of 8.5%. The analysis was conducted in nominal terms and TLCC and projected revenues were escalated for inflation. The low discount rate was based on the expected yield on the municipal bond that could be used to co-finance the Project assuming it is sponsored by a public entity eligible for tax-exempt financing. The high discount rate reflects an average weighted average cost of capital (including a mix of debt and private equity funds) that was sourced from the range of studies surveyed in the literature review and presented in Section 2. The full integrated cost benefit comparison was based on the Project "with CCS" and "without CCS".

4 Costs

This section presents the planning level capital and O&M costs for the Project with and without CCS.

4.1 Project Construction Schedule

The construction schedule is based on a realistic assumption of at least four to five years. This amount of time would be necessary to build the CCS systems and modify the base plant. The five-year planning horizon is factored in to design, engineering, and financing decisions. The analysis assumes that the Project with CCS would be built over the period spanning 2010 to 2014, with the bulk of capital construction spending occurring in years four and five of this period.

4.2 Capital Costs

Table 4-1 shows the capital cost breakdown by main project component. Specific cost items and the assumptions and parameters used to estimate these costs are described in more detail in the following subsections. Some described costs below are not specifically isolated or called out within Table 4-1 but are included within main category groups.

Table 4-1 Breakdown of Project Elements[1]- Capital Costs by Component

Component	Millions of ($)	%
Air Separation Unit	$65.0	28.8
CO2 Processing Unit	$67.2	29.8
Pipeline	$29.5	13.1
Sequestration	$37.6	16.7
Financing	$18.3	8.1
Project Management	$7.7	3.4
Total:	$225.4	100.0

Notes:
1. Excludes the cost of the power plant (CFB) estimated at $199.4 million.

4.2.1 Land Acquisitions

For the NYS based CCS Project, under a public ownership model, the best practices siting criteria for the pipeline and sequestration site prioritize the use of existing ROWs and sites that will not encroach upon private lands. A representative target site considered for cost estimation purposes, would most likely not include surface features that would preclude the development of a well field and would be remote from urban areas, parks, preserves, and similar land uses. The ideal site would also be located near existing pipeline routes and provide controlled access. To defray TLCC, the cost for land acquisition would most likely not factor in as a potential cost issue, and would be avoided as a component of the proposed Project, given the likely municipal sponsorship and use of public lands.

For a private project, the siting criteria for the CO_2 pipeline and sequestration site will be very similar, except that the same opportunity to use large tracts of isolated public lands would most likely not be available. The cost of land acquisition for a private developer could become a significant cost issue for a variety of reasons, including current values and compensation to owners.

4.2.2 Access and Easements

Under the current development concept for the Project, the siting criteria will minimize the need for access agreements or easements. Obtaining access and easements is not generally a significant cost component of a project. Still, there are situations where inability to obtain easements requires relocation of part or all of a project component. The costs and schedule impact of this occurrence are site and project specific.

4.2.3 Permitting

The cost to permit CCS will depend on many site-specific conditions, particularly geologic conditions and community acceptance. Assuming an 18-month permitting schedule, the range of permitting costs for CCS are estimated to range from \$1M to \$3M under reasonable conditions and significantly more if conditions are not favorable.

4.2.4 Air Separation Unit (ASU)

For the oxy-combustion process, the ASU separates the oxygen from the nitrogen in air and provides the oxygen for the combustion process. The ASU is a cryogenic process specifically designed for the unique needs of oxy-coal combustion, while minimizing parasitic power. The ASU has three essential sub-processes: feed air compression and purification; heat exchange between incoming air and outgoing product and waste streams; and cryogenic distillation.

Post combustion processes do not require an ASU. Still, to achieve the high concentration of CO_2 necessary for compression and transport, post-combustion processes must separate CO_2 from other combustion gases.

4.2.5 Power Plant

The Power Plant includes all equipment to receive and process fuel to produce electricity, from the point of coal delivery to the exhaust stack. For a Greenfield project installing CCS, the power plant will be the largest cost component, regardless of the type of boiler.

4.2.6 CO_2 Processing Unit

The CO_2 Processing Unit (CPU) is a refrigeration and distillation unit that produces a high purity (99.8%) CO_2 product at 2,000 pounds per square inch absolute (psia) that is ready for pipeline transport for sequestration. The overall recovery of CO_2 from this system is designed to be greater than 98%, while a significant reduction in atmospheric emissions of criteria pollutants is achieved. Purification includes removal of water, particulates, atmospheric gases (i.e., nitrogen, oxygen, argon), acid gases (i.e., SO_x, NO_x, hydrogen fluoride(HF), as well as other trace impurities including carbon monoxide, volatile organic compounds, and volatile metals, such as mercury.

For post combustion and IGCC projects, CO_2 capture occurs with physical and chemical solvents. At this time, amine based and chilled ammonia processes are being developed for commercial implementation. The processing is a cooling and absorption process designed to capture 90% of CO_2 emissions.

4.2.7 Pipeline

The CO_2 pipeline is assumed to be approximately 10.5 miles long following an existing ROW. Because operating pressure of the CO_2 pipeline will exceed 900 pounds per square inch gauge (psig), it will fall under the United States Department of Transportation (DOT) rules governing the transportation by pipeline as prescribed in Code of Federal Regulations, Title 49, Chapter I, Part 195, Transportation of Hazardous Liquids by Pipeline.

The pipeline design will be guided by the American Society of Mechanical Engineers, B31.4 Standard, *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids*. The carbon steel piping will be nominally 10 inches in diameter, 0.50-inch wall thickness, electric resistance welded type manufacture, compliant with American Petroleum Institute 5L, Specification for Line Pipe. The pipe will have a maximum allowable operating pressure of 2,000 psig and be capable of flowing 1,300 tons per day of a 99.9% CO_2 fluid. The pipeline will be cathodically protected with an impressed current system designed to the National Association of Corrosion Engineers, RP-01-69 standards to protect against corrosion.

4.2.8 Sequestration

The sequestration system will be designed to inject more than 781,000 tpy (CO_2) in these formations at steady state operations (i.e., by 2017). In addition, comprehensive site characterization and monitoring programs will be completed to ensure the CO_2 is securely sequestered in the deep rock formations.

Initial geological evaluation, including analysis of available geologic investigations, evaluation of existing 2-D seismic data, and preliminary reservoir modeling using available data, are key data inputs to verifying the suitability for long-term sequestration.

4.2.9 Testing, Monitoring, Evaluation and Verification

Monitoring activities focus on the injection system operation, CO_2 in the deep reservoir, and leakage. Methods include primary, secondary, and potential additional techniques as described in DOE guidance documents on monitoring, verification, and accounting of CO_2 stored in deep geologic formations.

Wellhead monitoring and injection controls are assumed at each wellhead using several sensors: coriolis mass flow meter, injection pressure sensor, injection temperature sensor, annulus pressure sensor, wellhead corrosion sensor or coupon, and down-hole pressure and temperature sensors. Deep saline formations will be primarily monitored with deep wells surrounding the storage site drilled to rock units above the sandstone. These wells will be used for continuous pressure measurements as well as periodic wireline logging and brine sampling for geochemical indicators of CO_2 leakage. Geophysical methods such as cross-well seismic, vertical seismic profiling, and 4-D seismic surveying will be considered for determining CO_2 distribution in the subsurface.

It is assumed that the monitoring will include a series of shallow groundwater monitoring wells that will also be installed and regularly monitored at each injection site.

4.2.10 Decommissioning

Decommissioning will be accomplished by ensuring that future monitoring activities can take place in an operating and management environment that facilitates environmental stewardship. The main activities associated with decommissioning (site closure) consist of well plugging and abandonment, final wellbore assessment (through surface and subsurface means), certification of site closure, and demonstration of non-endangerment.

It is important to note and communicate to the public that decommissioning does not necessarily end with the cessation of injection and storage activities. Even after plugging and abandonment, long-term monitoring and evaluation are necessary to ensure that public health, safety, and environmental protection are not compromised by any unforeseen contingencies that would result in the loss of CO_2 subsurface retention. The back-end costs of site closure will relate to the materials and procedures used, such as the use, for example, of Portland cement to plug the wells and the manpower and costs associated with various testing, monitoring, and evaluation procedures (WRI 2008).

Site closure is certified when there has been a demonstration that the CO_2 is properly contained within the confining zone and will not endanger public health and the environment. Guidelines to follow that relate to measuring, monitoring and verification (MMV) and certification are reproduced below. Satisfactory completion of post-injection monitoring requires a demonstration with a high degree of confidence that the storage does not endanger human health or the environment. This process includes demonstrating the following:

1. Estimated magnitude and extent of the project footprint (CO_2 plume and area of elevated pressure), based on measurements and modeling

2. CO_2 movement and pressure changes match model predictions

3. The estimated location of the detectable CO_2 plume based on measurement and modeling (measuring magnitude of saturation within the plume or mapping the edge of it)

4. Either (a) no evidence of significant leakage of injected or displaced fluids into formations outside the confining zone, or (b) the integrity of the confining zone

5. Based on the most recent geologic understanding of the site, including monitoring data and modeling, the injected or displaced fluids are not expected to migrate in the future in a manner that encounters a potential leakage pathway; and

6. Wells at the site are not leaking and have maintained integrity.

Project operators who have demonstrated non-endangerment are assumed to be released from responsibility for any additional post-closure MMV, and will plug and abandon any wells used for post-injection monitoring. At this point, the sequestration site can be certified as closed, and project operators are assumed to be released from any financial assurance instruments held for site closure.

4.2.10 Financing

The analysis assumed that a public finance model would be used to finance CCS in NYS. While numerous financial structures are possible, including the use of public private partnerships, the financial modeling was based on the use of federal grants, tax-exempt bonds and internally generated funds from the rate base. Financing costs represents the interest during construction (capitalized interest) associated with the municipal bond, the proceeds of which would be applied under a public finance model. Over the long-term horizon during operations, financing represents interest and principal payments (debt service).

4.3 Lifecycle Operational and Maintenance Costs (O&M)

Lifecycle O&M costs and the material inputs were estimated based on a combination of operational experience with the existing regional power plant (and material inputs and markets) as well as engineering estimates for long-term sustainment costs associated with CCS. The assumptions used reflect operational experience with day to day market activities for procuring the resources and practical experience with these resource markets. The projection assumptions and growth rates applied reflect reasonable or conservative estimates for how resource prices and costs are likely to behave over the planning horizon. The quantities of materials are based on engineering and operational projections for throughput requirements under 90% availability operating assumptions.

4.3.1 Fuels

Annual fuel expenses are variable and are projected to vary with the CFB plant's gross power output. Coal is the largest component of annual O&M, estimated at 23% of total annual lifecycle costs. Coal will be delivered by truck and/or rail and stored in silos, as is the usual practice. The projected tons of coal used are a function of the plant's gross production and heat rate operating assumptions. The tons of coal consumed annually, was estimated based on projected gross production (MWh) and a coal usage factor in tons per MWh estimated to be 0.4703. The unit price of coal ($/ton) was escalated for inflation over the forecast period. The underlying real price of coal forecast reflects industry assumptions and projections for this resource. The nominal price of coal, in dollars per ton is projected to be $51.25/ton by 2017, rising to $61.13/ton by 2025, and to $83.8/ton by 2039.

The annual cost of natural gas was also projected based on natural gas price forecasts in dollars per million British thermal units $/MMBTU reflecting industry assumptions and was also escalated for inflation. The quantity of natural gas consumed annually was based on projected gas quantities (in MMBTU) and an 82% efficiency factor.

4.3.2 Labor

Annual labor expenses are fixed and do not vary with plant output. Annual incremental labor expenses associated with CCS labor are projected based on staffing of 15 persons for this function. Combined annual labor costs for CFB and CCS represent 4.6% of lifecycle annual costs.

4.3.3 Carbon Capture

Annual CO_2 O&M costs were calculated based on a percentage of the total capital costs for the combined ASU and CPU. The annual costs were also escalated for inflation. Carbon capture O&M costs represent approximately 4.4% of total annual lifecycle costs.

4.3.4 Sequestration

The annual O&M cost for CO_2 sequestration was estimated to be $3 million per annum and was escalated for inflation over the projection period. These costs include testing and monitoring during the operating life of the project and decommissioning.

4.4 Cost Summary

Table 4-2 shows the estimated lifecycle costs for Project with CCS. The table includes the main cost and performance metrics that are reported in other CCS studies for comparison as well as the "with" and "without capture" or incremental cost differences from implementing CCS at two discount rates.

Total capital costs are the same as those displayed in Table 4-1 but are presented in cumulative discounted present value terms, as these costs would be incurred between 2010 and 2014. The Project with CCS would add between $178 and

\$206 million to total capital costs compared to the base reference case without CCS.

On a total plant cost basis, (TPC, in \$/kWe) the Project with CCS would cost an additional \$1,784 – \$2,056/kWe. The gross TPC with CCS at 100 MW is below the literature values for FOAK plants with CCS that averaged about \$6,500/kWe, and slightly above the average TPC for NOAK plants shown in Figure 2-5. The most expensive CO2 capture TPC (in absolute terms) for NOAK plants was SCPC (\$3,080/kWe).

Table 4-2 Project Cost and Performance Metrics

Cost Metric	With CO_2 capture	Without capture	Difference
Total Capital Costs (millions, \$) \1			
@ 4.5% discount rate	\$358.8	\$153.2	\$205.6
@ 8.5% discount rate	\$311.1	\$132.7	\$178.4
Total Plant Costs (TPC, \$/kWe)			
@ 4.5% discount rate	\$3,588	\$1,532	\$2,055.5
@ 8.5% discount rate	\$3,111	\$1,327	\$1,783.7
Total Lifecycle Costs (TLCC, millions, \$) \1			
@ 4.5% discount rate	\$985.1	\$682.3	\$302.8
@ 8.5% discount rate	\$666.3	\$432.3	\$234.0
Levelized Cost of Electricity (\$/kWh)			
LCOE @ 4.5% discount rate	\$0.107	\$0.074	\$0.033
LCOE @ 8.5% discount rate	\$0.126	\$0.082	\$0.044
Levelized Cost of Electricity (\$/MWh)			
LCOE @ 4.5% discount rate	\$107	\$74	\$33
LCOE @ 8.5% discount rate	\$126	\$82	\$44
Electricity Production (MWh)			
Steady State Year (MWh/yr)	551,880	788,400	(236,520)
Cumulative (MWh, n=30)	13,748,820	19,517,280	(5,768,460)
CO_2 (tons)			
Steady State Year (MWh/yr)	15,936	796,821	(780,884)
Cumulative (MWh, n=30)	680,839	19,725,735	(19,044,897)
Tons/MWh	0.0289	1.0107	(0.98)
Cost of CO_2 Avoided (\$/ton) =			
@ 4.5% discount rate	\$33		
@ 8.5% discount rate	\$45		

Key:
\$/kWe = Dollars per kilowatt electric.
\$/kWh = Dollars per kilowatt hour.
\$/MWh = Dollars per megawatt hour.
LCOE = Levelized cost of electricity.
MWh = Megawatt hour.
MWh/yr = Megawatt hours per year.

Notes: [1] cumulative present value of annual costs (2009-2039)

The LCOE (that takes into account TLCC, i.e., total lifecycle capital, O&M, fuel, other long-term running costs and annual electricity production) over a 30-year planning horizon was estimated to be $0.107 and $0.126/kWh for the Project using discount rates of 4.5% and 8.5% respectively. These values correspond to incremental LCOE (above the reference or base without capture plant) of between $0.033 and $0.044/kWh. These incremental costs fall within the incremental cost range for NOAK plants (between $0.03-$0.05/kWh) reported in the literature and are consistent with the recent NOAK plant CCS cost studies.

The cost of CO_2 avoided (cost of avoided emissions or cost of abatement) was calculated using the following formula:

$$Cost\ of\ CO_2\ avoided = \frac{\left(LCOE_{with\ \ capture} - LCOE_{w/\,out\ capture}\right)\frac{\$}{MWh}}{\frac{\left(Q_{CO2\ w/\,out\ capture} - Q_{CO2\ with\ \ capture}\right)ton}{MWh}}$$

Where, LCOE is equal to the levelized cost of electricity and Q_{CO2} is equal to the quantity (tons) of CO_2. MWh is equal to megawatt hours. Table 4-2 shows that using the 8.5% discount rate (e.g., the discount rate closest to the cost of capital used in other comparable cost studies and project evaluations) the cost of CO_2 avoided was calculated to be $45 per ton. Using a 4.5% discount rate, the cost of capital associated with tax-exempt financing for a public sponsoring entity or utility, the cost of CO_2 avoided was $33/ton. From the FOAK studies surveyed in the literature, the cost of abatement was estimated to be $120 to $180 per ton. For commercial-scale NOAK plants, the cost of abatement was estimated to be between $35 and $70 per ton of CO_2 avoided (Belfer 2009). The estimated cost of abatement would place the Project within the low end of the range of the NOAK plant averages reported in the literature.

4.5 Observations

The analysis for the Project compares well with the analyses reviewed in Section 2 with some notable exceptions. The Project is for a smaller scale (100 MW gross) compared to the NOAK plants surveyed in the literature that were profiled at 500 MW corresponding to Nth of a kind plant criteria (i.e., mature plants operating at a sufficient size to achieve learning and scale economies). Still, the estimates show that the 100 MW scale compared to smaller plants can achieve some cost savings related to increased scale. This result shows that the Project would also be able to benefit from economies of scale (declining long-run average lifecycle costs) similar to a larger commercial-scale plant operating in the 500-MW gross range.

As noted in the literature review in Section 2, the CCS cost ranged from $30/ton to $70/ton for NOAK plants depending on the technology and for $120 to $180/ton for FOAK plants. The Project CO_2 abatement costs per ton were estimated to be within the range for the NOAK average (i.e., $35 - 70/ton). For comparison, Figure 4-1 reproduces a net cost curve showing the net cost of employing

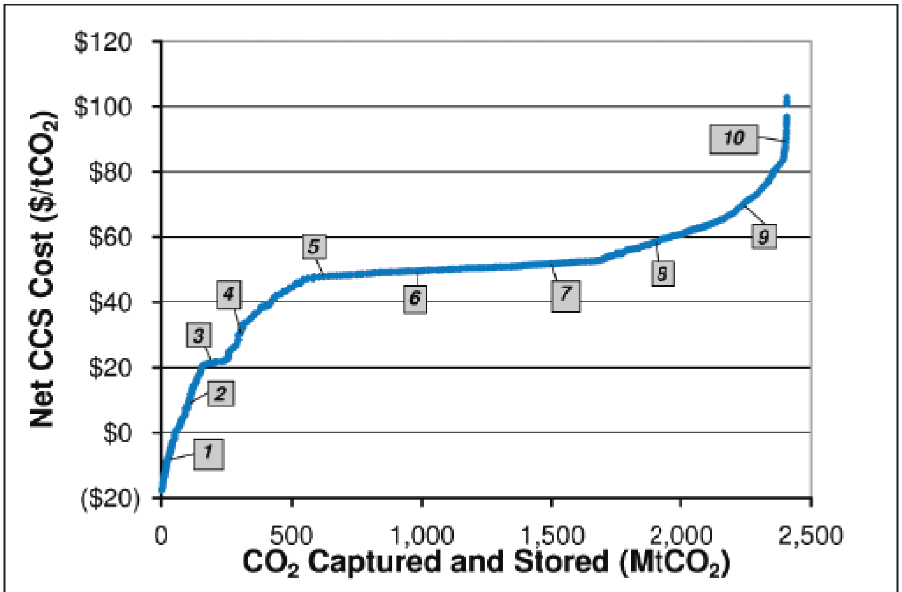
CCS for various technologies at various scales. The model used to build the cost curve is called *Battelle CO2-GIS* (Dahowski et al. 2005). Each point on the curve represents the levelized cost ($/t$CO_2$) for a specific existing large CO_2 point source to employ CCS, capture its CO_2 and ready it for transport; transport it via pipeline to a suitable storage reservoir; inject the CO_2 into the reservoir, and MMV that the injected CO_2 remains within the target reservoir. Any revenues available from value added reservoirs (EOR, enhanced coal bed methane recovery [ECBM]) are also factored into the net cost curve (Battelle 2006).

The net cost per ton of CO_2 sequestered for the Project would fall within points 4 and 5 on Figure 4-1. The net costs per ton for Point 5 correspond to a larger coal fired power plant within 25 miles of a deep saline storage reservoir, a favorable finding. The calculated cost per ton of CO_2 sequestered of $33 - 45/ton (at discount rate of 4.5% and 8.5%) is close to this range segment. While the evaluated scale does not reach the minimum efficient scale (MES), the 100 MW scale does provide significant cost advantages over smaller scale plants as Appendix A also shows.[2] The Figure 4-1 net cost curve adjusted for cost escalation since 2006 shows that plant scale and any available direct process revenues (i.e., EOR/ECBM) can also be significant factors in lowering net costs per ton. Point 3 on the figure represents the large-scale coal fired plant with ECBM and point 5 is the large-scale coal-fired plant without ECBM revenue offsets. The ECMB difference between points 3 and 5 is close to $30/ton all else equal.

[2] The minimum efficient scale is the smallest output for a firm at which long run average costs are minimized.

THE NET COST OF EMPLOYING CCS WITHIN THE UNITED STATES—CURRENT SOURCES AND TECHNOLOGY

The ten marked points on the curve are characterized below the graph by their different circumstances related to use of CCS technologies.



1	**High purity ammonia plant** / nearby (<10 miles) EOR opportunity
2	**High purity natural gas processing facility** / moderately distant (~50 miles) EOR opportunity
3	**Large, coal-fired power plant** / nearby (<10 miles) ECBM opportunity
4	**High purity hydrogen production facility** / nearby (<25 miles) depleted gas field
5	**Large, coal-fired power plant** / nearby (<25 miles) deep saline formation
6	**Coal-fired power plant** / moderately distant (<50 miles) depleted gas field
7	**Iron & steel plant** / nearby (<10 miles) deep saline formation
8	**Smaller coal-fired power plant** / nearby (<25 miles) deep saline basalt formation
9	**Cement plant** / distant (>50 miles) deep saline formation
10	**Gas-fired power plant** / distant (>50 miles) deep saline formation

Source: Battelle, 2006

Figure 4-1 Net Cost of Employing CCS within the United States

5 Benefits

This section describes the incremental financial revenues and public economic benefits that would be attributable to the Project with CCS, measured over its useful life.

5.1 Financial Revenues

5.1.1 Electricity Sales

The Project would generate electricity sales revenues from the net kWh generated. To calculate these projected revenues, the projected peak and off-peak average New York Independent System Operator (NYISO) Zone A Locational-Based Marginal Price (LBMP) in \$/MWh was multiplied by the projected annual net MWh over the planning horizon. The calculation takes into account both peak and off-peak sales to the regional power pool, Zone A. For the without CCS project scenario, the same projected prices in (\$/MWh) were applied to the gross MWh inclusive of the parasitic losses. The parasitic MWh losses with CCS translate directly into smaller total energy sales revenues, all else equal, when comparing the base case “with CCS” to the “without CCS” scenario.

5.1.2 CFB Unforced Capacity (UCAP) Revenues

CFB unforced capacity (UCAP) revenues were projected by multiplying the projected CFB UCAP Sales (annual MW) by the average price in (\$/MW).

5.1.3 District Heating Revenues

District heating sales were calculated by multiplying the projected annual district heating sales (in MMBTU) by the projected price in \$/MMBTU. The average hourly district heating load (MMBTU) was annualized by a factor of (24 x 365).

5.1.4 SO_2 Allowance Revenues

SO_2 allowance revenues were calculated by multiplying the projected price per SO_2 allowance by the number of projected allowances available for sale in a given year. The allowances available for sale were calculated by subtracting the SO_2 allowances needed from the original federal allowances allocation.

5.1.5 CO_2 Revenues

Several cap and trade schemes or scenarios were modeled in order to depict the potential revenue/cost streams, under the “with CCS” scenario. The Waxman-Markey proposed legislation (ACES 2009) as mentioned in its present form was applied in the analysis but would not benefit the Project (in terms of adding a future incremental carbon credit revenue stream) because of the 200-MW eligibility threshold. The national scenarios are contingent upon which national carbon abatement legislation will be enacted. It should be noted that this draft is based on climate change legislation that may in fact be slightly different or revised in its final form, given that the scenarios were developed based on the last Congressional session and prior administration. Nevertheless, for the purposes of the feasibility study's cost benefit analysis, all seven options have been modeled and present a range of net benefit alternatives. The alternatives have not been probability weighted. Although Waxman-Markey will supersede the former bills, the former proposals have also been modeled to show the range of outcomes under varying carbon crediting schemes and to highlight how sensitive the net benefits are to emission allowance assumptions.

Previous and Current Federal Legislative and Regional Initiatives

Several legislative efforts have been proposed that would result in curtailment of CO_2 emissions. The recent past efforts are summarized and compared with the current ACES, H.R. 2454, also known as Waxman Markey. These bills are summarized in Table 5-1.

Table 5-1 Proposed Federal Climate Change Legislation Applicable to CCS Projects and Regional GHG Reduction Initiatives

Initiative	Features
Bingaman-Specter Bill	- CCS bonus allowances for first 10 years of operation - Offset allowance for each ton of CO_2 sequestered - Some free allowances to lower cost of compliance
Lieberman-Warner Bill	- CCS bonus allowances first 10 years of operation - Some free carbon allowances to defray cost of compliance
Dingell-Boucher Bill As Is	- Project not eligible for CCS subsidy ($90/ton) or for any free carbon allowances to defray cost of compliance - Carbon allowance prices same as those under Lieberman-Warner
Revised Dingell Boucher	- Lowers eligibility threshold to 30 MW or less - Plant receives $90/ton of CO_2 sequestered for first 10 years of operation - Project receives no free carbon allowances to help defray costs of compliance
RGGI	- Project receives no free carbon allowances (all allowances are auctioned) - Benefits only derived from reduction in emissions needed to be covered by allowance purchases (avoided costs). Project still pays compliance costs for "with CCS" emissions
Revised RGGI	- Assumed that New York State provides a $40/ton subsidy (from recycled CO_2 auction allowance proceeds) for first 10 years of operation - Project receives no free allowances as all emission allowances are auctioned

Table 5-1 Proposed Federal Climate Change Legislation Applicable to CCS Projects and Regional GHG Reduction Initiatives

Initiative	Features
Current Waxman Markey	- Eligibility threshold is 200 MW nameplate capacity - Co-firing of renewable biomass with fossil fuels renders project eligible for federal RECs. RECs based on proportion of electricity attributable to the renewable energy resource or other qualifying energy resource. - No allowance benefits because of threshold disqualifying small projects (<200 MW). Benefits only derived from reduction in emissions needed to be covered by allowance purchases. Project still pays compliance costs for "with CCS" emissions

Key:
CCS = Carbon capture and sequestration.
CO_2 = Carbon dioxide.
MW = Megawatt.
REC = Renewable electricity credits
RGGI = Regional greenhouse gas initiative.

5.1.6 Commercial CO_2 Sales for Industrial Applications

It is possible that the Project could support commercial sales of CO_2 from a surface based outlet prior to underground injection and sequestration. Sales of this form of CO_2 could be trucked to other industrial site locations for beneficial reuse and industrial applications in facilities, such as refineries, for example. The present draft has not measured or projected any of these potential monetized industrial sales. If these sales are to be considered, then the tons of CO_2 to be sequestered must be adjusted or discounted (where applicable) to avoid double counting associated with the potential sale of CO_2 credits (certified emission reduction credits).

5.1.7 Revenues from Value Added Reservoirs (EOR/ECBM/EGR)

The western New York region is characterized by large, active, gas producing deposits with unexploited reserves. While enhanced oil and gas recovery is possible, the region's gas industry economics would most likely favor drilling new gas wells at relatively shallower depths, instead of trying to recover oil/gas or coal bed methane from depleted wells at greater depths (Lukert 2009). For this reason, potential revenues from EOR/EGR have not been estimated or quantified and applied to offset costs.

Nevertheless, in other parts of the United States the economics may favor recovery from particular reservoirs that have been designated as "value added reservoirs." This is particularly the case in the West Texas region (Permian Basin) that is characterized by older, depleted oil wells. Roughly half of the world's CO_2 floods are in the Permian basin, not far from some of the biggest natural sources of CO_2 in the United States. Some industry estimates put incremental recovery from CO_2—floodable reservoirs in the Permian basin alone—at 500 million to 1 billion barrels (DOE/NETL 2006).

It is noted that the fastest-growing technique for EOR, CO_2 flooding, accounted for approximately 4% of the nation's oil production in 2006. Flooding a natural gas reservoir with CO_2 moves previously bypassed natural gas to producing wells by pressurizing and/or displacing it—although this EGR technique is not widely used (DOE/NETL 2006). Coal bed methane is also extracted from un-mineable coal seams in the Permian basin.

5.2 Economic Benefits

Economic benefits are based on the avoided health and environmental damages associated with reducing pollutants in the atmosphere. The term "economic benefits" is used here to mean the full range of benefits to society or monetized benefits to the health and welfare of the Project beneficiaries, as opposed to the financial benefits or returns to the project sponsors (called financial revenues). A full cost benefit analysis, integrates these economic benefits (and costs) where they would not be considered in a financial cash flow analysis.

The objective of CCS is to reduce emissions of CO_2 to address the contribution of anthropogenic CO_2 emissions to global climate change. In addition to CO_2, the process technologies for oxycombustion will also result in the incidental benefits of substantially reducing criteria air pollutants. Therefore CCS includes the potential for an improvement in regional ambient air quality. The analysis estimates the effect of reduced emissions of SO_X, NO_X, and particulate matter ($PM_{2.5,\ 10}$) enabled by the implementation of CCS infrastructure and systems. To measure these non-market benefits (i.e., avoided damages), a technique called benefits transfer (see Box Insert) was applied. A non-market benefit does not have a market price but nevertheless can be highly valued by the Project beneficiaries. Ignoring these benefits effectively applies a zero price to this benefit or resource. The benefits transfer technique involved the adaptation of a Damage Function Approach study's results from a similar region and locality (Southern Ontario Province, City of Hamilton) after making certain adjustments to the study's findings that considered the regional differences compared to the Project evaluation, location and valuation timing.

What is Benefits Transfer?
Benefits transfer involves the transfer or application of existing estimates of nonmarket values to a new study that is different from the study for which the values were originally estimated. The case for which the existing estimates were obtained is often referred to as the "study case," while the case under consideration for a new policy (or application) is termed "the policy case," Applications of benefit transfer to value health effects have also been completed in numerous studies. For example, the United States Environmental Protection Agency's (EPA's) analysis of the benefits and costs of the Clean Air Act (EPA 1997, EPA 1999) relied on this method. The advantages of applying benefits transfer relates to avoiding the cost and time of engaging in original primary research. Still, estimates derived from benefits transfer may not be as accurate as primary research tailored specifically to the new policy case (EPA 2000).

The adapted study was prepared for the Ontario Ministry of Energy and is called *Cost Benefit Analysis: Replacing Ontario's Coal-Fired Electricity Generation* ("the Ontario Study") (DSS 2005). The purpose of this study was to produce estimates of the physical and economic damages associated with air pollution emissions from alternative means of replacing coal-fired electricity generation (CFG) capacity in Ontario. The alternatives that were studied included an all gas option, nuclear/gas, and stringent controls. Because a power plant with CCS would effectively result in near-zero emissions, the emissions profile changes between the baseline coal-fired generation and the nuclear option alternative was the closest proxy used in the benefits transfer for the Project. The Ontario Study stringent controls option did not involve Oxy-Coal technology or CO_2 sequestration.

The Ontario study applied the Damage Function Approach that is widely used by researchers to estimate the avoided health and environmental damages from improving ambient air quality. The Ontario Study employed air modeling to determine the impact of air pollutants on the air quality where sensitive receptors (people, structures, crops, systems) are located. The emissions profiles were connected to changes in ambient air quality taking into account background pollution levels, atmospheric and physical processes, and climate. Based on wind patterns, the study found that closing down the coal-fired generation facilities would improve air quality in most parts of southern Ontario.

There are basically four steps required to complete the Damage Function Approach to estimate avoided damages from CCS:

1. Estimate ambient air pollution levels to which the population at risk will be exposed for both the baseline and with controls (in this case CCS) scenario. This step involves translating emissions into changes in ambient air quality through meteorological modeling and the application of a pollutant transport, dispersion and chemical transformation model;

2. Evaluate the demographics of the potentially exposed population (age profiles that consider sensitive receptors, young, and seniors etc., and other receptors such as crops/materials), apply dose response functions to estimate health and environmental impacts on receptors;

3. Evaluate the relative risks and calculate the incidence of specific health outcomes for exposed populations; and other environmental impacts (damages to crops and materials soiling etc.);

4. Calculate the economic costs associated with each type of illness (morbidity) and the willingness to pay (WTP) for reductions in the risk of premature mortality (called the Value of a Statistical Life [VSL]). Calculate the economic costs associated with crop damages and materials soiling caused by the pollutants. It should be noted that the averted risks from premature mortality are the largest share of monetary damages associated with these studies reflecting the high willingness to pay to avoid premature mortality (VSL) from the surveyed respondents.

An additional reason why the Ontario Study has general applicability is because it applied the results of a VSL survey completed in the city of Hamilton, Ontario, by Krupnick (Krupnick et al. 2002). Many potential host communities within New York State possess demographic and economic characteristics that are similar in nature to the City of Hamilton, Ontario.

Assuming that the stakeholder valuation of improved health and environmental quality is similar, and that the willingness to pay for reductions in the risk of premature death is comparable in magnitude across NYS, the Ontario Study was applied in this exercise to recognize these CCS benefits. The benefits transfer steps used to adjust the DSS Management Consultants (DSS) Study findings and to apply them to the Project are described below.

5.2.1 Health Damages

The DSS study provided measures of health damages for premature deaths, hospital admissions, emergency room visits, and minor illnesses in 2004 Canadian dollars (C$) and in 2004 C$ on an annual or levelized unit cost basis (i.e., 2004 C$/MWh). These values were escalated to present value (C$ 2008) terms and then converted to United States dollars (US$) using the average United States/Canadian dollar exchange rate. The largest component of health damages is for premature deaths. With the valuation of health damages expressed on a unit value basis (US$/MWh) the valuation factor could then be applied to the Project's output in MWh to calculate the annual avoided damages under the with CCS scenario. This procedure assumes that many variables that could influence these damages are similar in nature to the Southern Ontario situation. Among these variables are coal fired generation (CFG) plant age, stack height, emission intensity, atmospheric transformation and dispersion, deposition on receptors, population density and the physical impacts resulting from concentration response relationships. While not all of these elements will be exactly comparable to NYS, by not including this measure of avoided damages risks effectively ignoring these benefits from the Project, a material omission. The regional adaptation using the benefits transfer technique addresses this shortcoming.

5.2.2 Environmental Damages

In the original DSS Study, environmental damages consisted of damages from greenhouse gas emissions (proxied by GHG Permits), other criteria air pollutants (SO_X, NO_X, and PM), and their impact on crop damages and materials soiling. Since CO_2 allowances were already measured and in some instances valued above (see Section 5.1.5, CO_2 Revenues), GHG damages functions from the Ontario study were not transferred to NYS, but were netted out. To avoid double counting only the remaining criteria air pollutant damage functions (SO_X, NO_X, PM) from the Ontario study were transferred. The annual levelized damages for combined crop losses and materials soiling were escalated for inflation and converted to United States dollars. The unit factor (in US$/MWh) was then applied to the projected output to measure annual damages that would be avoided under the Project with CCS scenario. The damage function unit factors applied (i.e., $/MWh) worked out to be U.S. $88.2/MWh for health damages and U.S. $12.3/MWh for environmental damages. On a per kWh basis, these combined damages totaled $0.1005/kWh. For the benefits transfer applied to this CCS Project evaluation, the avoided costs associated with potential health damages averted worked out to be equivalent to $0.0882 /kWh, while crop damages and material soiling worked out to be equivalent to $0.012 / kWh.

A recent comprehensive study commissioned by the National Research Council entitled, “The Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use” found that the mean damages from four criteria air pollutants (SO2, NOX, PM2.5 and PM10) associated with emissions from 406 coal fired power plants was equivalent to 4.4 U.S. cents (2007 $) per kWh (NRC 2009). The NRC 2009 study’s distribution of damages for the 406 coal fired plants reported that the 75th percentile damage estimate was $0.06 /kWh, while the 95th percentile unit damage estimate was $0.13/kWh. The regional damages estimate adapted from the Southern Ontario study would correspond to the upper range of these national damage estimates and is consistent with the NRC’s findings that plants with the largest damages per kWh are concentrated in the Northeast and the Midwest. Figure 5-1 below shows the results of this study escalated to reflect 2009 price levels (NRC 2009).

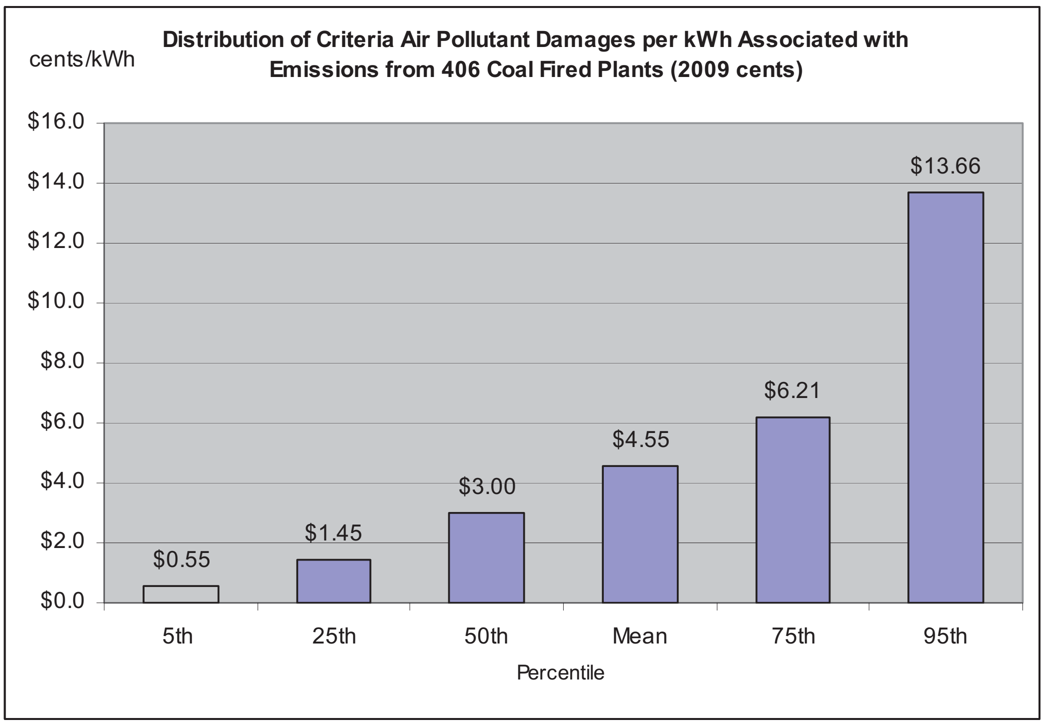


Figure 5-2 Source: NRC 2009

5.3 Project Scenario Benefit Policy Differences

Under the policy scenarios modeled (including both past and current climate change legislation), the main CO_2 crediting differences relate to the ability of the plant operator (sponsor/owner) to convert the sequestered CO_2 into a meaningful financial revenue stream to defray lifecycle costs. Under the current version of

ACES (Waxman-Markey), instead of generating a surplus quantity of marketable certified emission reduction credits (excess allowances) with CCS, the Project operators would need to purchase allowances to cover their compliance obligations for the residual 2% of non-sequestered CO_2 emissions after CCS implementation. At the 100 MW scale, while only 2%, the larger scale of output and resulting CO_2 emissions translates into a net cost stream under ACES. Assuming biomass is consistently used in co-firing generators, the RECs generated would not serve to fully offset these lifecycle compliance obligations over the entire planning horizon.

Without the CCS framework, the value of the avoided health and environmental damages (from all capture process avoided and dedicated sequestered emissions) would not be realized as a benefit to the region. The main benefits would be limited to energy sales from the larger gross annual sales output, which does not reflect the parasitic loss sustained under the Project with CCS scenario. External damages would still be imposed on the region and CO_2 emissions would continue to contribute to the formation of GHG.

6 Net Benefits

6.1 Comparison of Lifecycle Costs to Benefits

The following tables (6-1 through 6-4) compare the lifecycle costs and benefits in both cumulative discounted dollars and levelized cents per kWh for both the "with" and "without" CCS scenarios to illustrate how incremental net benefits vary under the range of discount rates. The incremental net costs and benefits are shown in the "difference" column (3). Costs represent discounted lifecycle costs (capital costs plus O&M) over a 30-year period using discount rates of 4.5% and 8.5% respectively. Total financial revenues include the sum of energy sales for a modeled CFG/CFB facility providing co-generated district heating.[3] . The tables illustrate the potential loss in direct energy sales revenue attributable to the parasitic loss in power consumed with CCS. The public benefits from CCS are measured by the widest measure of economic benefits representing the avoided social costs of implementing these systems. Economic benefits include the sum of avoided health damages and avoided materials/crop damages associated with pollutant emissions under the "without CCS" model. Total benefits include the sum of financial revenues and economic benefits. Net benefits are equal to total benefits less total costs.

By comparing the total economic benefits (the widest measure of avoided social costs) to financial costs and revenues associated with implementing CCS, policy and decision-makers can then compare a range of subsidies associated with different Climate Change bills to see which CO_2 net allowance streams are equivalent to, or exceed the net public benefits. The comparisons can show how much each bill's subsidy "buys" in terms of net public benefits. The public cost benefit results first address whether CCS plant projects deserve subsidy on economic benefit grounds. The data and assumptions applied in this analysis, under discount rates of 4.5% and 8.5%, demonstrated that the answer is "yes", net economic benefits exceeded incremental total lifecycle costs over the 30 year planning horizon.

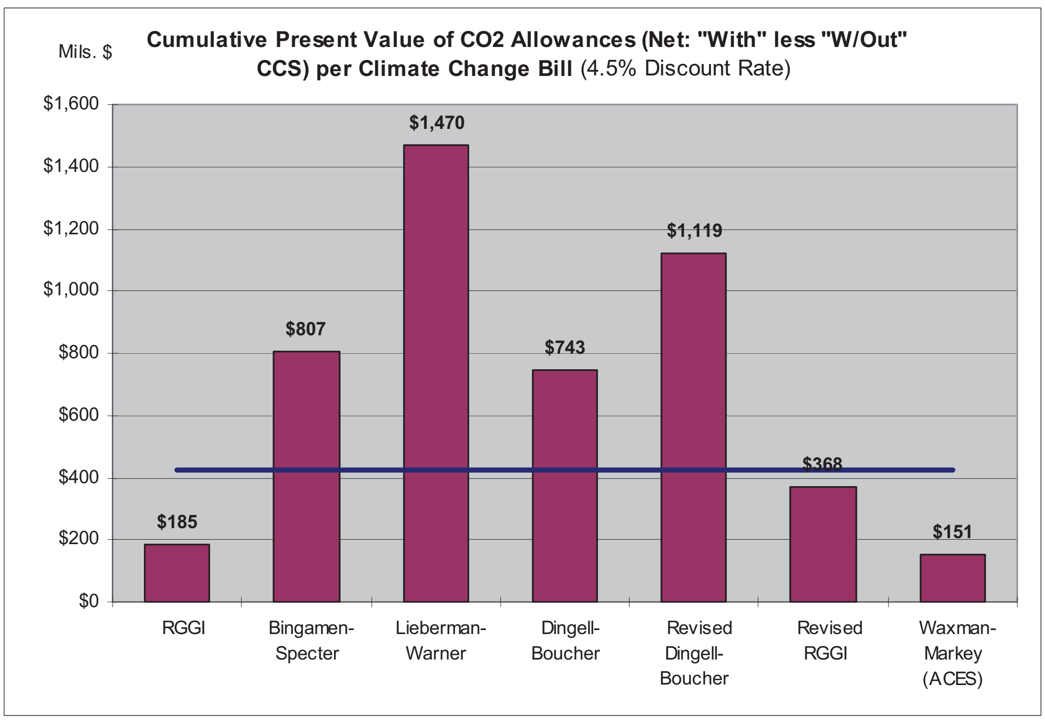
Secondly, the comparisons can be used to compare how each bill's cumulative net CO_2 allowance stream compares to the cumulative net economic benefits measured with CCS over time. The bottom half of the table plots the cumulative net economic benefits (solid blue line) against the cumulative net present value CO_2 allowance revenue streams that would be realized under each bill. Because the net economic benefits exceed the lifecycle costs, the CCS project deserves a public

[3] Energy sales were modeled to include CFB UCAP revenues, district heating revenues, and SO2 allowances.

subsidy. The CCS systems enabled by a public subsidy would improve environmental quality and result in avoided social and economic damages to NYS thereby justifying public involvement to correct the externality associated with conventional CFG.

Table 6-1 CCS Net Economic Benefits Comparison - Cumulative Net Present Values (in millions of 2009 dollars, *i* = ***4.5%***)

	With CCS (1)	Without CCS (2)	Net Difference (3)=(1) – (2)
A. Financial Costs[1]			
Capital Costs	$358.8	$153.2	$205.6
O&M Costs	$626.4	$529.1	$97.3
Total:	$985.1	$682.3	$302.8
B. Financial Revenues:			
Total Energy Sales[2]	$723.7	$927.3	-$203.6
C. Economic Benefits (Avoided Social Costs)[3]			
Health Damages	$815.2	0	$815.2
Crops & Material Damages	$114.1	0	$114.1
Total:	$929.3	0	$929.3
D. Net Benefits [= A – (B+C)][4]	$667.9	$245.0	$422.8



Notes:
1 Costs represent discounted total lifecycle costs (TLCC) over a 30-year period using a 4.5% discount rate.
2 Total energy sales is the sum of energy sales, CFB UCAP revenues, district heating revenues and SO_2 allowances
3 Represents the sum of avoided health damages (=$88.2/MWh) & avoided materials soiling and crop damages (=$12.3/MWh). These cumulative present values were estimated using the following equation:

Table 6-1 CCS Net Economic Benefits Comparison - Cumulative Net Present Values (in millions of 2009 dollars, *i* **= *4.5%***)

	With CCS	Without CCS	Net Difference

$$EconomicBenefits = \sum_{i=1}^{n=30} \frac{MWh_t \times Damages\ per\ MWh_t}{1+i^{\,n}}$$

Total benefits include the sum of financial revenues and economic benefits.

[4] Net benefits are equal to total benefits less total costs.

Table 6-1 shows that under the 4.5% discount rate scenario, 4 out of the 6 Climate Change legislative CO_2 allowance scenarios modeled would exceed the quantified economic benefits estimated for the 100 MW CCS plant. The cumulative lifetime allowances under Revised RGGI would be slightly below the identified net economic benefits.

The analysis makes clear that the key feasibility drivers that can spur CCS implementation are the federal policies that would encourage carbon abatement and renewable energy. For all the climate legislation scenarios considered, the former Lieberman-Warner proposal would exceed the net economic benefits by the widest margin. Lieberman Warner provides for both offset allowances for each ton of CO_2 sequestered and CCS bonus allowances for the first 10 years of operations. This bill feature makes a large difference over time and was also included in Bingamen Specter. The Revised Dingell Boucher legislation results reflect the relatively larger fixed credit value per ton of CO_2 for the first 10 years of the pro-forma modeling of plant operations. Under the Revised Dingell Boucher legislation the Project would receive $90/ton of CO_2 sequestered for the first 10 years of operation. This credit value is significantly higher than credit values for other legislation that start from a much lower base and are then escalated over the planning horizon.

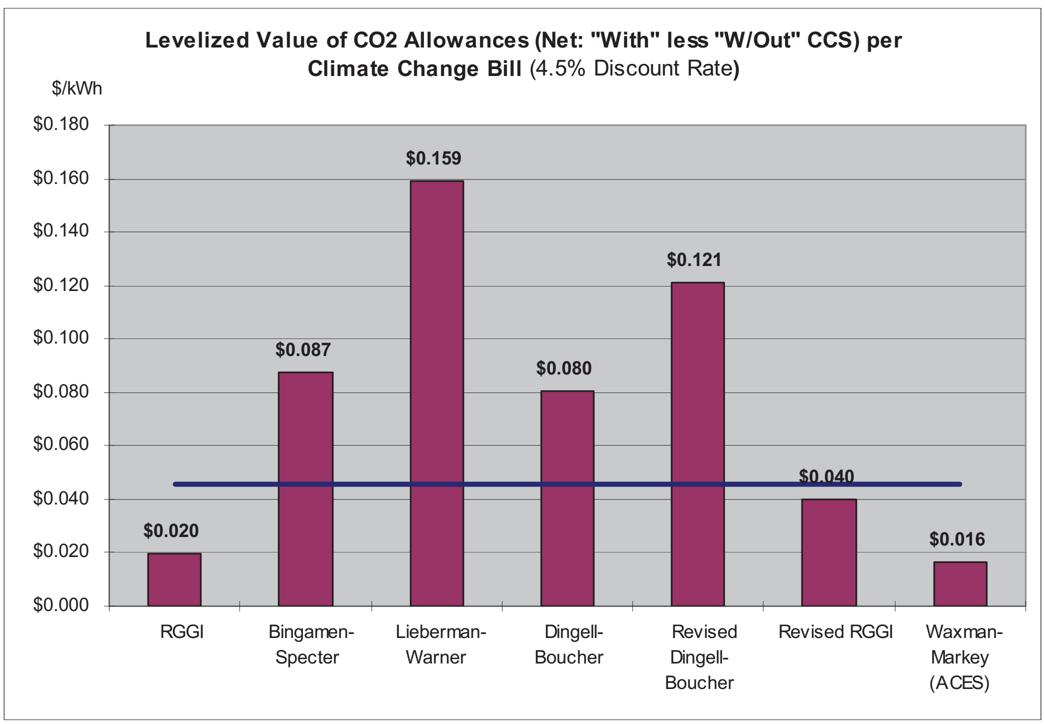
The lower cumulative present value net costs for RGGI reflect the compliance costs paid on the non-sequestered CO_2 output. Revised RGGI positive net present values reflect the New York State provision of a $40/ton subsidy (from recycled CO_2 auction allowance proceeds) for the first 10 years of operation.

The current version of Waxman-Markey (ACES) results in the least amount of net benefits on balance, compared to the other alternatives. Net benefits under ACES are lowest primarily because no surplus marketable emission reduction CO_2 credits would be generated for the 100-MW gross plant design due to the 200-MW nameplate capacity eligibility requirement. The RECs earned from the portion of electricity output generated through renewable biomass fuel do not serve to fully offset compliance costs over the entire planning horizon.

Table 6-2 shows the economic benefits (avoided health and environmental damages = social costs of CFG) expressed on a levelized $/kWh basis. These avoided costs were equivalent to $0.100 / kWh. A sensitivity analysis showed that achieving the required net economic benefits from implementing CCS for NYS would need to value avoided economic damages at the equivalent of $0.07 / kWh (and above) to be economically feasible. Given the benefits transfer analysis completed, these benefits are realistically attainable within the Northeast given the CFG generation operating history and infrastructure already in place.

Table 6-2 CCS Net Economic Benefits Comparison - Cumulative Net Present Values Expressed in Levelized Costs/Benefits per kWh (in 2009 dollars per kWh, *i* = ***4.5%***)

	With CCS (1)	Without CCS (2)	Net Difference (3)=(1) – (2)
A. Financial Costs[1]			
Capital Costs	$0.039	$0.017	$0.022
O&M Costs	$0.068	$0.057	$0.011
Total:	$0.107	$0.074	$0.033
B. Financial Revenues:			
Total Energy Sales[2]	$0.078	$0.100	-$0.022
C. Economic Benefits (Avoided Social Costs)[3]			
Health Damages	$0.088	0	$0.088
Crops & Material Damages	$0.012	0	$0.012
Total:	$0.100	0	$0.100
D. Net Benefits [= A–(B+C)][4]	$0.072	$0.026	$0.046



Notes:

1 Costs represent discounted total lifecycle costs (TLCC) over a 30-year period using a 4.5% discount rate.

2 Total energy sales is the sum of energy sales, CFB UCAP revenues, district heating revenues and SO_2 allowances

3 Represents the sum of avoided health damages (=$88.2/MWh) & avoided materials soiling and crop damages (=$12.3/MWh). These cumulative present values were estimated using the following equation:

$$EconomicBenefits = \sum_{i=1}^{n=30} \frac{MWh_t \times Damages\ \ per\ \ MWh_t}{1+i^n}$$

Table 6-2 CCS Net Economic Benefits Comparison - Cumulative Net Present Values Expressed in Levelized Costs/Benefits per kWh (in 2009 dollars per kWh, *i* = ***4.5%***)

	With CCS	Without CCS	Net Difference

Total benefits include the sum of financial revenues and economic benefits.

[4] Net benefits are equal to total benefits less total costs.

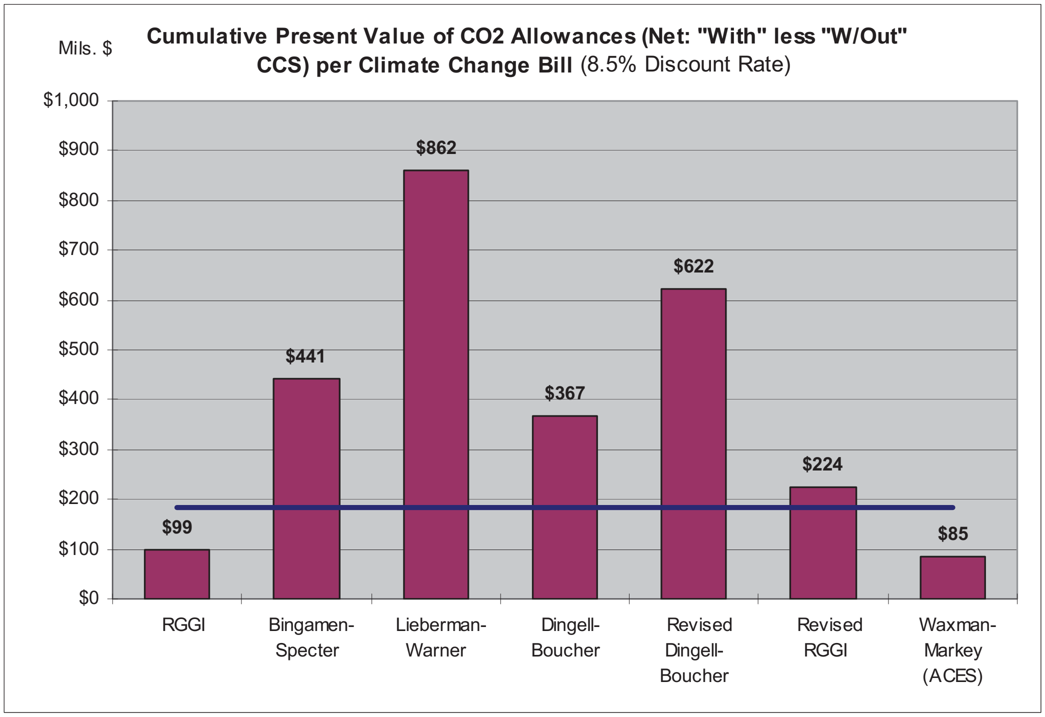
Tables 6-3 and 6-4 show the net economic benefit comparisons using an 8.5% discount rate. Table 6-3 shows the CCS net economic benefits in cumulative discounted dollar terms, while Table 6-4 shows the corresponding benefits and costs expressed in cents per kWh. Table 6-3 and 6-4 show slightly lower net economic benefits compared to the 4.5% discount rate scenario. Still, the $185 million in cumulative net economic benefits that would be gained from CCS are meaningful and justify the public subsidy.

Table 6-3 CCS Net Economic Benefits Comparison - Cumulative Net Present Values (in millions of 2009 dollars, *i* = **8.5%**)

	With CCS (1)	Without CCS (2)	Net Difference (3)=(1) – (2)
A. Financial Costs[1]			
Capital Costs	$311.1	$132.7	$178.4
O&M Costs	$355.2	$299.5	$55.7
Total:	$666.3	$432.3	$234.0
B. Financial Revenues:			
Total Energy Sales[2]	$393.2	$504	-$110.4
C. Economic Benefits (Avoided Social Costs)[3]			
Health Damages	$464.5	0	$464.5
Crops & Material Damages	$65.0	0	$65.0
Total:	$529.5	0	$529.5
D. Net Benefits [= A – (B+C)][4]	$256.3	$71.3	$185.0

Table 6-3 CCS Net Economic Benefits Comparison - Cumulative Net Present Values (in millions of 2009 dollars, *i* **= 8.5%**)

	With CCS	Without CCS	Net Difference



Notes:
[1] Costs represent discounted total lifecycle costs (TLCC) over a 30-year period using a 4.5% discount rate.
[2] Total energy sales is the sum of energy sales, CFB UCAP revenues, district heating revenues and SO_2 allowances
[3] Represents the sum of avoided health damages (=$88.2/MWh) & avoided materials soiling and crop damages (=$12.3/MWh). These cumulative present values were estimated using the following equation:

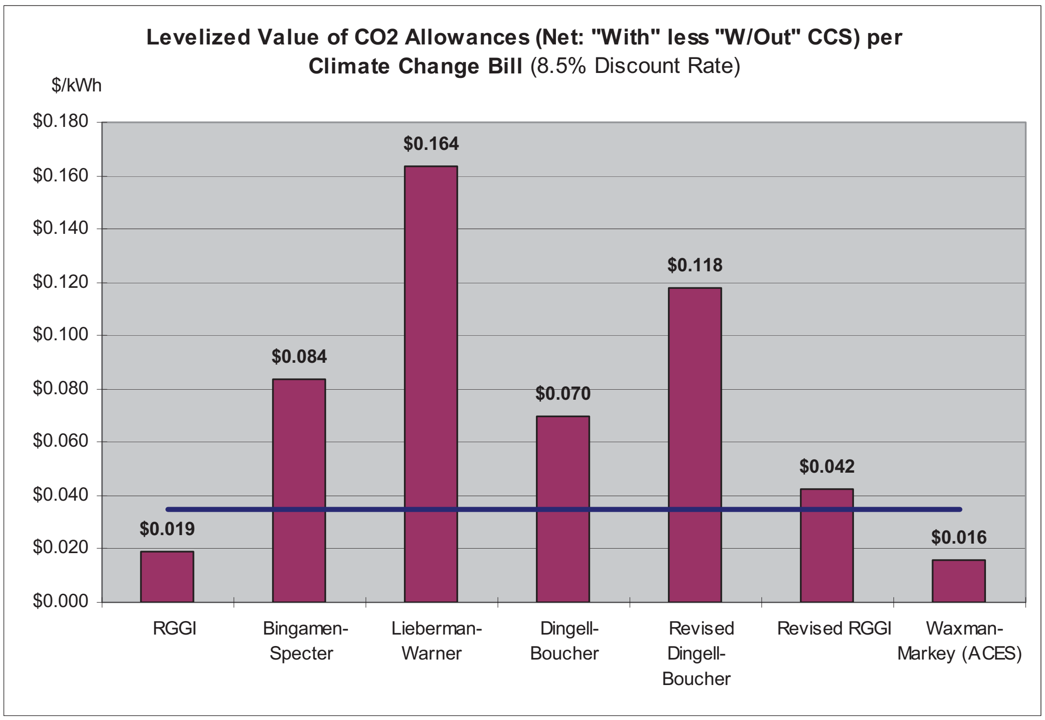
$$EconomicBenefits = \sum_{i=1}^{n=30} \frac{MWh_t \times Damages\ \ per\ \ MWh_t}{1+i^n}$$

Total benefits include the sum of financial revenues and economic benefits.
[4] Net benefits are equal to total benefits less total costs.

Under the 8.5% discount rate scenario, the revised RGGI cumulative $C0_2$ allowance stream would slightly exceed the value of the cumulative net economic public benefits. The net economic benefits under the 8.5% discount rate worked out to be 3.5 cents per kWh, compared to 4.6 cents per kWh under the 4.5% scenario.

Table 6-4 CCS Net Economic Benefits Comparison - Cumulative Net Present Values Expressed in Levelized Costs/Benefits per kWh (in 2009 dollars per kWh, *i* = ***8.5%***)

	With CCS (1)	Without CCS (2)	Net Difference (3)=(1) – (2)
A. Financial Costs[1]			
Capital Costs	$0.059	$0.025	$0.034
O&M Costs	$0.067	$0.057	$0.011
Total:	$0.126	$0.082	$0.044
B. Financial Revenues:			
Total Energy Sales[2]	$0.075	$0.096	-$0.021
C. Economic Benefits (Avoided Social Costs)[3]			
Health Damages	$0.088	0	$0.088
Crops & Material Damages	$0.012	0	$0.012
Total:	$0.100	0	$0.100
D. Net Benefits [= A–(B+C)][4]	$0.049	$0.014	$0.035



Notes:

1 Costs represent discounted total lifecycle costs (TLCC) over a 30-year period using a 4.5% discount rate.

2 Total energy sales is the sum of energy sales, CFB UCAP revenues, district heating revenues and SO_2 allowances

3 Represents the sum of avoided health damages (=$88.2/MWh) & avoided materials soiling and crop damages (=$12.3/MWh). These cumulative present values were estimated using the following equation:

$$EconomicBenefits = \sum_{i=1}^{n=30} \frac{MWh_t \times Damages\ \ per\ \ MWh_t}{1 + i^n}$$

Total benefits include the sum of financial revenues and economic benefits.

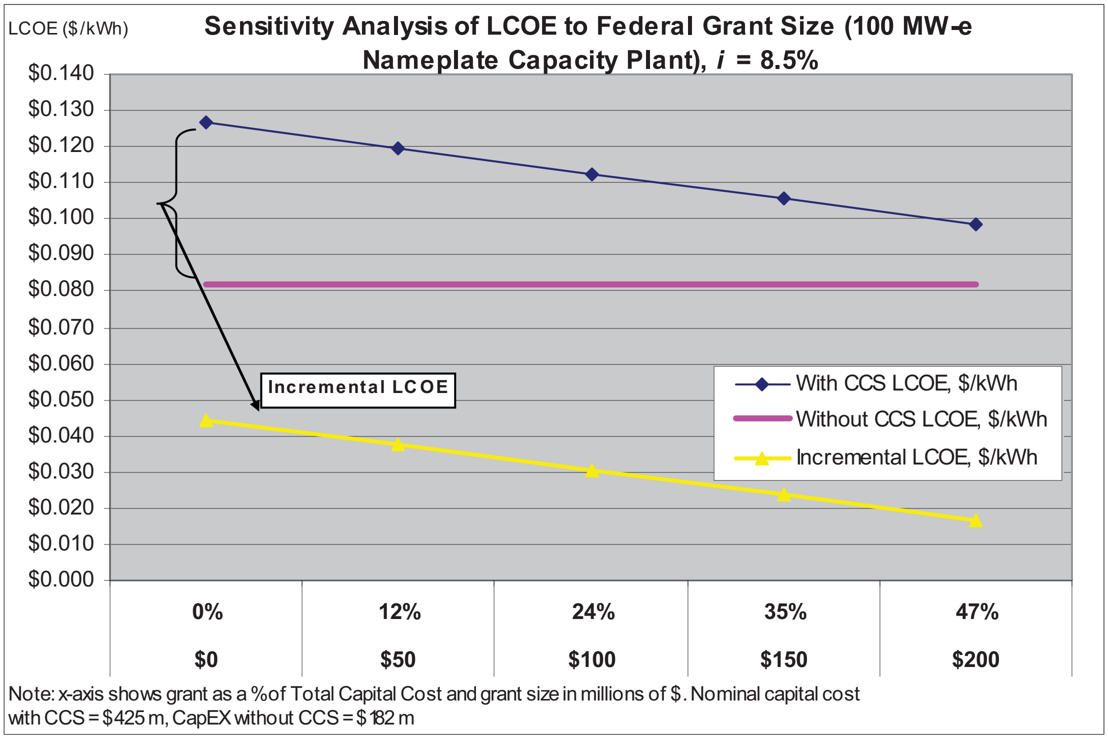
4 Net benefits are equal to total benefits less total costs.

Under both the 4.5% and the 8.5% discount rate scenarios, both the original RGGI scheme, and the Waxman-Markey (ACES) bill resulted in cumulative CO_2 allowance streams that were below the cumulative net economic benefits provided by a CFG/CFB plant with CCS.

6.2 Sensitivity Analysis

In addition to the federal regulatory incentives evaluated above geared toward long-term operational sustainability, other variables that can influence the Project's net benefits are the discount rate, capital costs, the construction environment and revenue assumptions. One of the key barriers toward future implementation of CCS is the potential impact on the incremental cost of electricity. A critical incentive to spur implementation is the federal grant program available for demonstration projects. Federal grants would effectively reduce the high upfront capital costs of implementation and reduce the impact on the cost of electricity to ratepayers. The above unabridged analysis reported key cost metrics (i.e., TLCC, TPC and LCOE) without factoring in the potential for federal grants to offset capital construction costs. Since the size of these grants can vary, a sensitivity analysis is provided below that compares the LCOE to the percentage of federal grant upfront funding that would effectively lower capital costs. The analysis was completed for discount rates of 4.5% and 8.5%.

Figure 6-2 shows the LCOE on the y-axis. The x-axis shows both the size of the grant (in millions of $) corresponding to the LCOE, and the grant size as a percent of the total capital costs. Using a discount rate of 8.5%, a grant of $100 million would result in an incremental LCOE of $0.030/kWh. Compared to the no-grant case, this reduction is equivalent to a reduction of approximately $0.014 /kWh. Grant sizes moving close to one half of the total capital costs would reduce the incremental LCOE from CCS to under $0.02 /kWh.



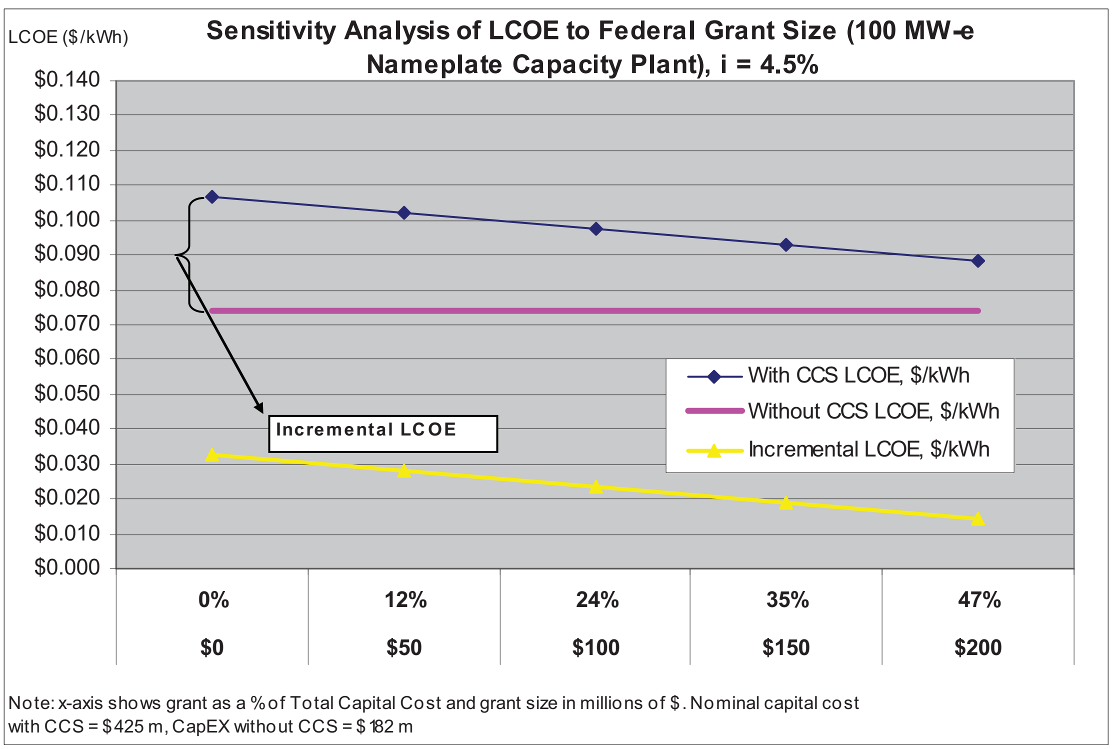


Figure 6-2 Sensitivity of LCOE to Size of Federal Grant

7 Conclusion

The data and analysis presented above show that implementation of CCS has the potential to add significant value depending on the incentives provided by legislation and the development of a carbon market. Under the best-case scenarios, implementation of CCS would enable relatively cheap, abundant coal resources to continue to generate electricity and process steam in an environmentally sustainable manner. Under scenarios that do not provide significant incentives, or grants, the cost (or revenue requirements) to implement CCS are estimated to be approximately 44% to 54% higher on a LCOE ($/kWh) basis.

Still, significant public benefits in the form of reduced GHG, and improved ambient air quality contribute to avoided health and environmental damages. These public benefits are not captured in the traditional LCOE evaluation metric but show that CCS would be viable and beneficial to NYS. Explicitly considering these public benefits are necessary to justify public policy decisions and subsidies to support CCS development. The implementation of CCS using the oxycombustion capture process would reduce potentially harmful emissions of NO_X, SO_X, and PM, which result in the degradation of regional ambient air quality. Removing these harmful emissions would result in avoided health and environmental damages to the surrounding population and host environments.

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Appendix A: Cost Scaling Method

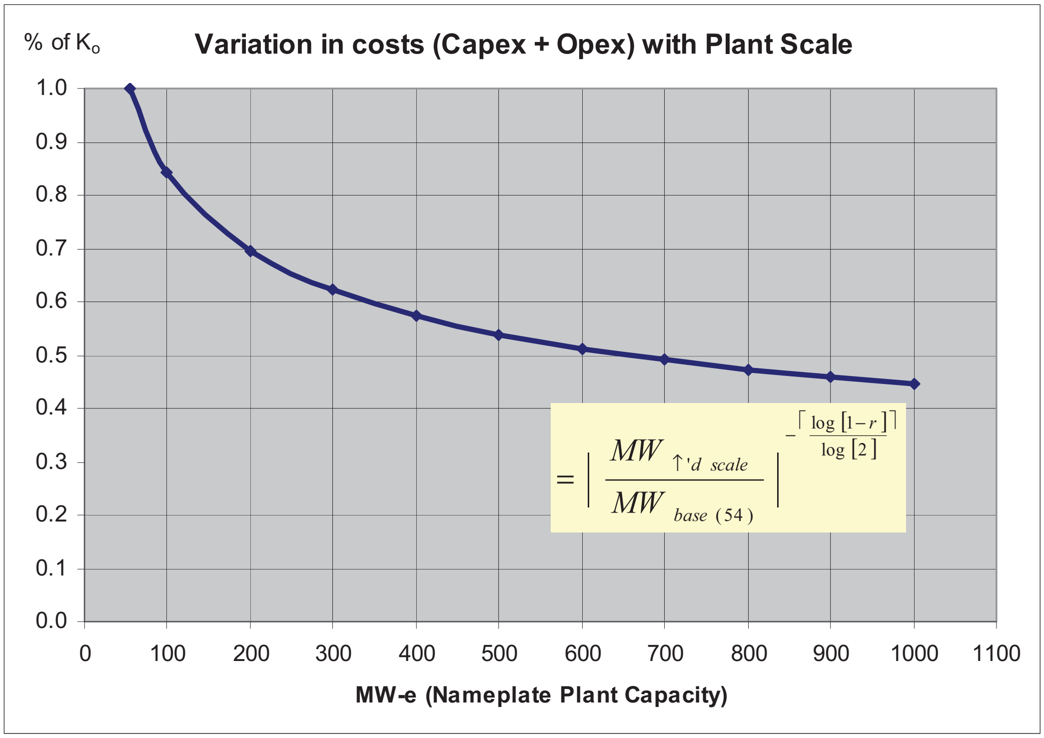
The method applied to scale the original costs (i.e., the total lifecycle costs associated with a 54 MW-e plant with CCS) to the TLCC associated with a 100 MW-e CCS project was based on a procedure outlined by Al-Juaied and Whitmore, the authors of the study called “Realistic Costs of Carbon Capture”, (Belfer Center 2009). The authors provided a cost function that was applied to estimate the variation in costs with scale. Lifecycle costs (both capital and operational & maintenance) are estimated to fall by a certain percentage doubling of capacity. The cost function applied is reproduced below:

$$= K_O \, x_n^{-\left[\frac{\log[1-r]}{\log[2]}\right]}$$

Where:
K_0 is the cost of the original non-scaled unit, x_n is the scale factor relative to the original unit, in this case MWe, , and “r” represents the average reduction in capital costs for a doubling of scale. Substituting in the MW scale factor for x_n results in:

$$= K_O \left(\frac{MWe_{\uparrow'd\ scale(100)}}{MWe_{base(54)}} \right)^{-\left[\frac{\log[1-r]}{\log[2]}\right]}$$

Applying the scale factor across an increasing range of plant sizes shows that the greatest incremental cost reductions associated with increases in plant scale are realized along the most immediate plant size range of the cost function (i.e., between 54 and 300 MW). Figure A shows the pattern of the scaling factor function for a range of plant scales, starting at (or indexed to) 54 MWe = 1.00, or 100% of lifecycle capital and operational and maintenance costs for this plant size.


% of K$_o$
Variation in costs (Capex + Opex) with Plant Scale
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
0
100
200
300
400
500
600
700
800
900
1000
1100
MW-e (Nameplate Plant Capacity)
$= \left(\frac{MW_{\uparrow'd\ scale}}{MW_{base\ (54)}} \right)^{-\left[\frac{\log[1-r]}{\log[2]}\right]}$

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