Policy, Regulatory, Legal, and Permitting Case Study
Subtask 3.2 – Topical Report

March 1, 2017 through May 30, 2019

Christopher Korose[1], John Rupp[2], Sallie Greenberg[1]

[1]Prairie Research Institute
University of Illinois
Urbana-Champaign, IL 61820

[2]School of Public and Environmental Affairs
Indiana University
Bloomington, IN 47405

Report Issued: October 2, 2018

Report Number: DOE/ FE0029445-4
U.S. DOE Cooperative Agreement Number: DE-FE0029445
CARBONSAFE ILLINOIS EAST SUB-BASIN

Principal Investigator: Dr. Hannes Leetaru
Business Contact: Illinois State Geological Survey
615 E. Peabody Drive
Champaign, IL 61820-7406

DISCLAIMER

Executive Summary

This report summarizes the policy, regulatory, legal, and permitting requirements to-date for the siting of a CO_2 injection and storage project in the CarbonSAFE Illinois East Sub-Basin pre-feasibility study area. Where applicable, the East Sub-Basin case study focuses on a proposed carbon capture and storage (CCS) site location in West Terre Haute, Indiana.

Indiana has established the legal mechanisms to obtain rights to the subsurface mineral estate with the expectation to apply to reservoir pore space for CO_2 storage in an analogous manner to storage of natural gas, which is a common practice in Indiana. There is, however, no precedent in Indiana to take liability for stored CO_2.

There are currently no Indiana State incentives for CCS, but at the Federal level, tax credits for carbon capture and storage under 26. U.S. Code § 45Q constitute the greatest incentive targeted at CCS projects. The amendment to these credits put forth in the Bipartisan Budget Act (the FUTURE Act) of 2018 substantially increases the per-ton incentive for CCS—from $22.66 per ton in tax year 2017 up to $50 per ton in tax year 2027, for CO_2 not used as an injectant (i.e. saline storage).

Additional economic opportunities may exist for the provision of CO_2 for potential EOR in the Illinois Basin. Policies that may support the development of CO_2 pipelines and/or CCS projects in Indiana include: 1) Title 41 of the FAST Act (2015), which created a new governance structure, procedures, and funding authorities in order to improve and expedite Federal review and authorization of covered infrastructure projects, including pipelines, and 2) the Eminent Domain for Transportation of Carbon Dioxide by Pipeline (IC 14-39, Indiana State, 2011), which declares pipeline transportation of CO_2 exclusively to a carbon management application, including sequestration, enhanced oil recovery, and deep saline injection as a benefit to the welfare of Indiana and the people.

The US Environmental Protection Agency's (EPA) Underground Injection Control (UIC) Program Class VI rule and permit requirements address all components pertaining to CO_2 injection and monitoring for long-term storage, and outline the minimum technical criteria to protect underground sources of drinking water at, and surrounding, injection well sites. The Class VI requirements also address financial responsibility for corrective action, post-injection site care, and site closure. In addition, UIC Program public notice requirements include that the EPA issue notice of the draft permit preparation to key stakeholders, and open a public comment period of not less than 30 days. A public hearing about the permit would also be held, if specifically requested by the public.

A potential Class VI CO_2 injection well permit for the East Sub-Basin case study site would be obtained through the US EPA Region 5, because the State of Indiana does not have UIC Class VI primacy. Although no CO_2 injection wells have been permitted in Indiana, the US EPA Region 5 (which covers Illinois and Indiana) and the East Sub-Basin CarbonSAFE team (via the Midwest Geological Sequestration Consortium [MGSC]) have Class VI permitting experience from several projects located in Illinois. Based on our experience, applying for a Class VI permit can be an intensive and iterative process requiring clear communication and numerous interactions with EPA staff. In addition to gathering and preparing the data/models and documentation necessary for a permit application's initial submittal, the subsequent public comments, EPA response and review, and answering of any follow-up questions/requests by the EPA could significantly increase the timeframe of draft permit issuance.

The US EPA offers guidance documents regarding the specific Class VI permit requirements, and shows a general permitting timeline example from the FutureGen Alliance 2.0 covering one-and-a-half years from permit submittal to issuance. However, the overall permitting process to-date has a high degree of variability, and in MGSC's project experience we observed a more extended timeline to receive Class VI permits for each of two CO_2 injection wells.

Introduction

This report outlines considerations relating to policy, regulatory, legal, and permitting requirements for the siting of a CO_2 injection and storage project in the East Sub-Basin pre-feasibility study area. Where applicable, the East Sub-Basin case study focuses on a proposed site location in West Terre Haute, Indiana.

In 2016, Wabash Valley Resources LLC (WVR, formerly Quasar Syngas LLC) acquired the Wabash Integrated Gasification Combined Cycle (IGCC) Plant north of Terre Haute, Indiana, the initial step in repurposing the facility for the production of ammonia and Direct Reduced Iron (DRI) for the domestic market. Petcoke (or coal) will be converted in the gasifier to syngas and then hydrogen; the hydrogen, in turn, is used to produce ammonia and DRI. The syngas will be purified using the Rectisol process that results in a very pure carbon dioxide (CO_2) stream that can be readily compressed and transported for storage, or other utilization. The East Sub-Basin case study presented herein considers the potential injection of the CO_2 separated at the Wabash plant for geologic storage directly at the plant site—although an additional possibility for revenue generation is to sell the CO_2 for enhanced oil recovery (EOR) in relatively nearby oilfields in the Illinois Basin.

The following sections examine the key policy, regulatory, legal and permitting considerations for siting a geological storage facility at the East Sub-Basin case study site. The considerations include pore space ownership, policies toward project economics, strategies for securing rights-of-way for pipelines, groundwater protection, US Environmental Protection Agency (EPA) Class VI Underground Injection Control (UIC) Program permitting timelines and requirements, public notice and engagement, and the potential for long-term liability assumption.

Summary

Pore space ownership and subsurface rights

WVR is the land owner at the East Sub-Basin case study site adjacent to their Wabash plant, however they are not currently in possession of any lease agreements or outright ownership of the subsurface mineral estate that underlies their real estate position. The owner of the subsurface rights at the site is an entity known to WVR, but remains confidential at this time.

As in most states, Indiana has established the legal mechanisms for entities to obtain the rights to the subsurface mineral estate—and this is expected to apply to the utilization of pore space for CO_2 storage in an analogous manner to storage of natural gas, which is commonly practiced in Indiana. In general, rights to pore space utilization are a private contractual arrangement between the development entity and the mineral estate owner and not regulated by the state agency that oversees subsurface mineral extraction activities. Specific cases in different states are dealt with differently. For example, in the State of Illinois, there is legal guidance around pore-space utilization and long-term liability, and the broader legal and contractual framework is in place for commercial carbon capture and storage (CCS) development. In all cases, the acquisition of these rights can be difficult and potentially project-limiting.

Whereas Indiana does not have a specific suite of statutes or policies designed to directly regulate the practice of carbon capture and storage (CCS), numerous structures are in place that could support an injection project in the state. The Indiana Department of Natural Resources (DNR), Division of Oil and Gas (DOG) regulates subsurface mineral extraction activities in the state, including the storage of natural gas. The State DOG has secured primacy under the EPA to administer the Class II (Oil and Gas Related Injection Wells) portion of the Underground Injection Control program. Additionally, the Indiana Utility Regulatory Commission works with the natural gas storage firms in their management of underground injection, and Indiana Senate Bill No. 22 established that the Commission administers the pipeline safety laws that apply to hazardous liquids and CO_2 fluid.

Policies toward project economics
The following section was excerpted and updated from Topical Report DOE/FE0029445-19 (Trabucchi, 2018, *Summary of Carbon Storage Incentives and Potential Legislation: East Sub-Basin Project*); see DOE/FE0029445-19 for additional details.

At the Federal level, tax credits for carbon capture and storage under 26. U.S. Code § 45Q constitute the greatest incentive targeted at CCS projects. The amendment to these credits put forth in the Bipartisan Budget Act (the FUTURE Act) of 2018 substantially increases the per-ton incentive for carbon capture and storage. Previous incentives were limited to \$20 per ton of CO_2 not used as an injectant (i.e. saline storage) or \$10 per ton of CO_2 used as an injectant (i.e. enhanced oil recovery) and limited to a cap of 75 million metric tons for which the credits could be claimed. Under the FUTURE Act, the incentives for CO_2 storage have escalated to \$12.83 per ton and \$22.66 per ton (for injectant and non-injectant cases, respectively) in tax year 2017; these incentives increase up to \$35 per ton and \$50 per ton (for injectant and non-injectant cases, respectively) in tax year 2027. In addition, the FUTURE Act removed the "cap" on tons of qualified carbon oxide eligible for the credit, increasing the certainty of the availability of these credits in future years. Non-electric-generating facilities that capture at least 100,000 metric tons of qualified carbon oxide, that would otherwise be emitted each taxable year, are eligible for the amended 45Q tax credits; electric generating units are bound to the original program's minimum of 500,000 metric tons of qualified carbon oxide capture in order to be eligible for credits.

In addition, the Federal government offers tax credits under 26 U.S. Code § 48A and 48B. The investment tax credits therein apply to qualifying advanced coal projects, including those that capture and store qualified carbon dioxide. These credits must be applied for on a competitive basis, and are awarded by the Secretary of the Treasury, potentially limiting the extent to which they can be relied upon for an affirmative business case. Notably, the 48A and 48B tax credits have in-service deadlines of five years and seven years, respectively, constraining the types of projects that may be able to receive these credits.

Preliminary research suggests that no meaningful state-level tax credits or R&D incentives for CCS exist that would be relevant to the East Sub-Basin case study site's business scenario. Research suggests that any revenue-positive business case for the East Sub-Basin site likely will need to be supported by Federal tax credits, and/or the sale of CO_2 for enhanced oil recovery (EOR). Business case development for the project is most likely to be influenced by the value of the increased tax credits under 26 U.S. Code § 45Q, especially given the revision (by 2018's FUTURE Act) increasing the per-ton tax credit over time. In addition, business case development may also take into consideration the feasibility of the East Sub-Basin site to qualify for 26 U.S. Code § 48A or 48B tax credits for advanced coal or gasification projects, respectively, to the extent the project is capable of meeting the year-in-service deadlines for carbon capture and storage associated with these credits.

Strategies for securing rights-of-way for pipelines
At the East Sub-Basin case study site, the separated CO_2 will be compressed and dehydrated as necessary at the plant source. Midwest Geological Sequestration Consortium (MGSC) experience at the Archer Daniels Midland site in Decatur, IL and on similar projects for commercial clients indicates compression and dehydration costs at the case study site will be about \$55M for 1 MT/year to about \$70M for 1.6 MT/year. WVR's planned injection location at the site would be about 200 yards from the separation facility and thus a pipeline would not be required for on-site injection.

However, additional economic opportunities may exist for the provision of CO_2 for potential EOR in the Illinois Basin. There is an existing propane pipeline from the study site directly to Robinson, IL, in the heart of oil production in the Illinois Basin. This pipeline can potentially be repurposed to transport CO_2. Additionally, several north-south oriented pipeline corridors also exist east and west of the case study site that go through the oil field region in the Illinois Basin. Existing pipeline, rail, electrical transmission, and interstate highway corridors are among the more promising pipeline routing options. By leveraging existing corridors or repurposing existing pipelines, financial, environmental, and social benefits can be achieved, which help minimize the impact of any new potential pipeline construction.

The Indiana DNR oversees the application process for issuance of a certificate of authority to construct, operate, and maintain a pipeline and the explicit use of eminent domain to the owner or operator of the pipeline. In 2011, the of Indiana state passed the Eminent Domain for Transportation of Carbon Dioxide by Pipeline (IC 14-39) which declares pipeline transportation of CO_2 exclusively to a carbon management application, including sequestration, enhanced oil recovery, and deep saline injection as a benefit to the welfare of Indiana and the people (Indiana State, 2011).

At the federal level, there are several policies that may support the development of CO_2 pipelines and/or CCUS projects. Title 41 of the FAST Act (2015) created a new governance structure, procedures, and funding authorities in order to improve and expedite Federal review and authorization of covered infrastructure projects, including pipelines. Additionally, the USE IT Act is a bill (introduced in March of 2018) to support carbon dioxide utilization, capture research, and the development of CCUS projects; the bill would clarify that CCUS projects and CO_2 pipelines are eligible for the permitting review process established by the FAST Act.

The Indiana Utility Regulatory Commission administers the pipeline safety laws that apply to hazardous liquids and carbon dioxide fluid, and pipeline design for CO_2 transportation is governed by US DOT/PHMSA regulation. CO_2 pipelines generally operate in the supercritical region and may have an upstream pressure as high as 2,000 psig, and delivery pressure around 1,400 psig. Recent cost estimates for CO_2 pipelines are approximately $80,000 per inch per mile—e.g. for a 12 inch pipeline, costs are expected to be on the order of $1 million per mile.

<u>Groundwater protection, and US Environmental Protection Agency Class VI Underground Injection Control permitting timelines and requirements</u>

Groundwater protection is addressed by the Safe Drinking Water Act, and is regulated through the US EPA's Underground Injection Control (UIC) program. Protection of underground sources of drinking water (USDWs), in the context of CO_2 injection for geological storage, is achieved by geological characterization and validation of the storage complex site reservoir and seal integrity, and also through successful UIC Class VI well permitting and proper injection well construction.

The State of Indiana does not have UIC Class VI (or Class I) primacy (Figure 1), therefore a potential Class VI CO_2 injection well permit for the East Sub-Basin case study site in Terre Haute would be obtained through the US EPA Region 5, which covers Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin.

The US EPA UIC Program Class VI rule (Code of Federal Regulations [CFR] Title 40, parts 124, 144, 145, 146, and 147) specifically applies to CO_2 injection for long-term storage, and outlines the minimum technical criteria to protect USDWs at, and surrounding, injection well sites. The Class VI rule and permit requirements address: well siting and construction, the unique properties of CO_2 and conditions for large-volume injection, subsurface modeling and establishing the Area of Review, reporting, and injection well testing, operation, and monitoring; the Class VI requirements also address financial responsibility for corrective action, post-injection site care, and site closure. To help address specific permitting requirements, the US EPA provides UIC Program Class VI guidance documents in these topical areas.

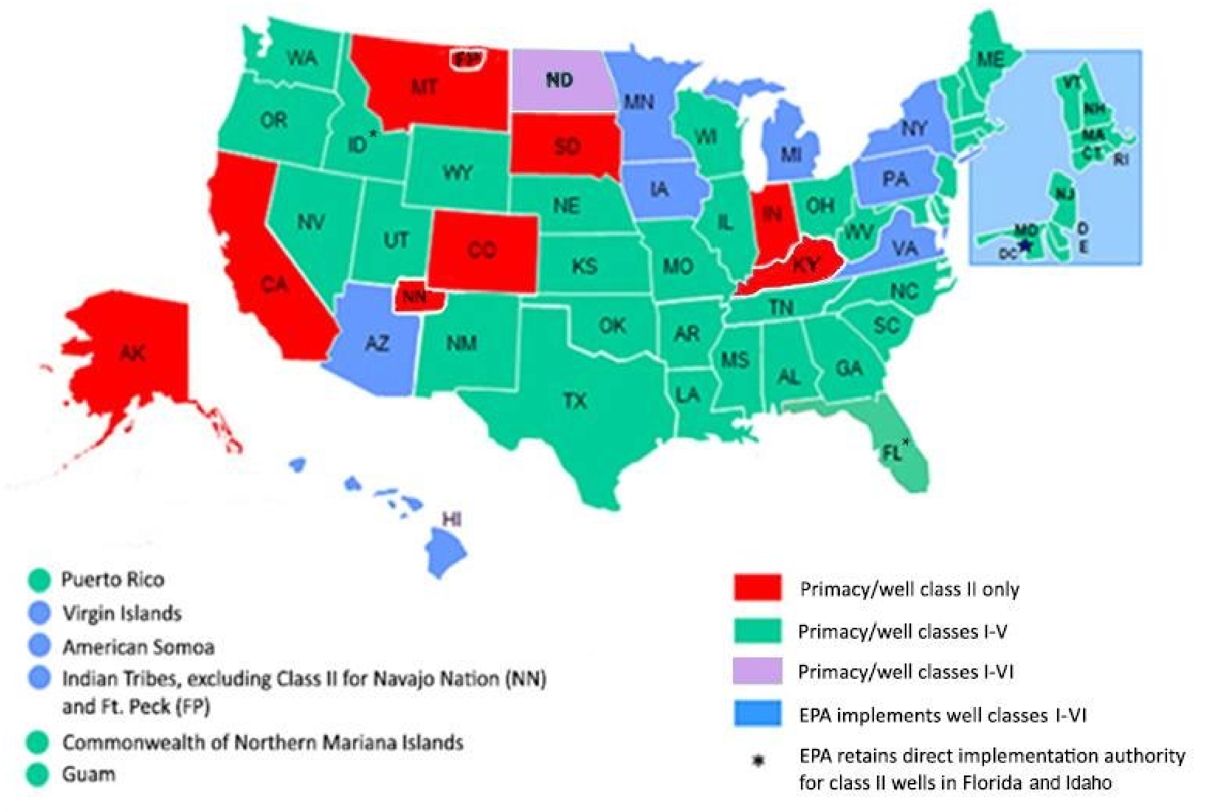

Figure 1. States, territories, and tribes with primacy. Thirty-four states and three territories have EPA-approved primacy programs for well classes I, II, III, IV and V. Additionally, seven states and two tribes have applied for and received primacy approval for Class II wells only. North Dakota is the only state with primary enforcement authority for UIC Class VI wells. EPA directly implements the Class VI program in all other states, territories, and tribes.
From https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program .

One key aspect of UIC Class VI permitting requirements is demonstration and assurance of financial responsibility to provide long term monitoring of a site post injection, which can be managed several different ways (trust, bond, insurance, etc.) The US EPA states that the financial instrument(s) must be sufficient to cover the cost of: (a) corrective action, (b) injection well plugging, (c) post-injection site care and site closure, and (d) emergency and remedial response—all meeting UIC Program Class VI rule requirements.

The EPA also details that the permitting criteria for Class VI wells include: extensive site characterization requirements, and comprehensive monitoring requirements that address all aspects of well integrity, CO_2 injection and storage, and ground water quality during the injection operation and the post-injection site care period. Reporting and recordkeeping requirements call for the provision of project-specific information to continually evaluate Class VI operations and confirm USDW protection. In addition, the injection well construction requires materials that are compatible with and can withstand contact with CO_2 over the life of a geological storage project. After injection is completed, the EPA stipulates 50 years of post-injection site care, unless an alternative timeline can be demonstrated from data analysis and modeling.

The US EPA Region 5 (which includes Illinois and Indiana) has extensive experience reviewing and issuing Class VI permits, and has issued six Class VI permits—resulting in two injection wells—as of

June, 2017, all of which are in Illinois (US EPA, 2017). The team involved in the current East Sub-Basin assessment has more than 15 years of permitting experience, and is one of the few experienced in applications for US EPA Class VI permits. Based on experience gained from the Illinois Basin – Decatur Project (IBDP) and the Illinois Industrial Carbon Capture and Storage (IL-ICCS) project, applying for a Class VI permit can be an intensive and iterative process requiring clear communication and numerous interactions with EPA staff. Since there have been no Class VI permits applied for in the state of Indiana, there would need to be clear communication between the storage site operator and/or East Sub-Basin project team, Indiana DNR, and the US EPA Region 5. In addition to gathering and preparing the data/models and documentation necessary for a permit application's initial submittal, the subsequent public comments, EPA response and review, and answering of any follow-up questions/requests by the EPA could significantly increase this timeframe before a draft permit is issued. Public notice requirements and general permitting timelines are further addressed in the following section of this report.

Locke et al. (2017) state that:

> Typically, a Class VI permit would be issued in stages. The first stage provides the operator the authority to drill and test the injection well in accordance with the permit. Once the well is drilled and tested, a completion report with final well [as-built] specifications and test data would be submitted to the regulatory agency for review. Authorization to inject CO_2 would only be approved as part of the final stage after a review of the completion report, adjustments to project and monitoring program design based on the new information gained during drilling of the injection well, and responses by the applicant to any additional requests by the US EPA.

In a scenario where a site operator was considering the injection of 50 million tonnes of CO_2 over 25 years using multiple injection wells, permitting complexities could result because area permits are not granted by the US EPA, and thus each injection well would require a unique Class VI permit.

Public notice and engagement

In their Quick Reference Guide for Public Participation (2011), the US EPA state that:

> While owners or operators submitting a Class VI permit application do not have specific requirements for public involvement, they may choose to work with the UIC Program Director during the development and execution of a public participation plan for their Class VI permit application (especially in providing background information on the proposed Class VI injection well(s)). The owner or operator may choose to inform the public about the proposed Class VI injection well(s) to solicit community input and to help facilitate increased community acceptance of the proposed Class VI injection well(s).

Strategies for public and stakeholder engagement and outreach will be addressed in a separate East Sub-Basin report. However, formal public notice requirements pertaining to well permitting are highlighted herein.

For an initial feasibility study at the East Sub-Basin case study site, a geological exploration (non-oil/gas) well permit could be obtained through the Indiana DNR, and formal public notice need not be given; this exploration well would need to be plugged and abandoned. At the time of this report, potentially converting an exploration well to other use(s) is less clear, from a regulatory standpoint, and may involve initially permitting the well for its ultimate intended use (e.g. Class VI monitoring well or Class I waste injection well).

For the potential case of a Class VI CO_2 injection well permit (or a Class I waste injection well), the public notice requirements under the UIC program include that the EPA issue notice of the draft permit preparation to key stakeholders, and open a public comment period of not less than 30 days. The EPA would also provide at least 30-days' advance notice and hold a public hearing regarding the permit application, if a hearing is specifically requested by the public.

The EPA compiles and responds to all public comments on the permit application. Following a public hearing, there would then be another comment period and subsequent responses from the EPA. Pending no major permit modifications or appeals (which would necessitate other comments/responses), the permit requestor should generally plan for 3-4 months to be dedicated solely to the public notice and comment periods, including a potential public hearing.

Although each potential geological storage project and/or Class VI injection permit application will have its own unique circumstances, the US EPA's timeline and public notice schedule from the FutureGen Alliance 2.0 permit application is presented below (Table 1) as a general example covering one-and-a-half years (assuming there are no appeals to the permit). However, the overall permitting process to-date has a high degree of variability, and in MGSC's project experience we observed a more extended timeline to receive permits for injection wells CCS1 (IBDP) and CCS2 (IL-ICCS). After permit completeness review and technical review, the IL-ICCS Class VI process from submittal to issuance took over three years. The earlier IBDP permit process began before federal EPA Class VI rules were finalized in December 2010. The IBDP received a Class I (non-hazardous) injection well (CCS1) permit from the Illinois EPA. A Class VI permit was later acquired by the IBDP for post-injection site care at the CCS1 well, and this permit was submitted and issued in coordination with the nearby IL-ICCS project's injection well (CCS2) Class VI permit.

Table 1. UIC Permitting Process, FutureGen Alliance 2.0 Permit Application,
from: https://archive.epa.gov/region5/water/uic/futuregen/web/html/index.html

UIC Permitting Process Action	Date
Receive the permit application	March 2013
Conduct a completeness review, and request additional information if necessary	April 2013
Conduct a technical review, and request additional information if necessary	May 2013 - March 2014
Complete technical review, make a draft decision and announce the draft decision and public comment period	March 31, 2014
Accept public input by mail and online	Through May 15, 2014
Hold public hearing	May 7, 2014
Compile the public comments received	May 16 - August 29
Conduct additional technical review of the permit application if relevant technical issues were raised in comments	May 16 - August 29
Prepare responses to comments received	May 16 - August 29
Issue final decision	August 29, 2014
If the final decision is appealed, respond to the appeal	October 31, 2014
In cases of appeal, the Environmental Appeals Board issues decision	April 28, 2015

Potential for long-term liability assumption

There is no precedent in Indiana to take liability for stored CO_2. In some states, there is legal guidance around long-term liability, and the broader legal and contractual framework is in place for commercial CCS development. The State of Illinois was willing to assume ownership and liability for stored CO_2, albeit specifically for the FutureGen project (Illinois General Assembly, 2007).

References

Federal Register, 2010, Rules and Regulations Part III – Environmental Protection Agency, US Code of Federal Regulations 40, Parts 124, 144, 145 et al., Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells; Final Rule, Federal Register Vol. 75, No. 237, available from: https://www.gpo.gov/fdsys/pkg/FR-2010-12-10/pdf/2010-29954.pdf .

Fixing America's Surface Transportation (FAST) Act, 2015, Title 41 (FAST-41), United States Code 42 § 4370m, available at: https://www.permits.performance.gov/tools/fast-41 .

Illinos General Assembly, 2007, Public Act 095-0018, Clean Coal FutureGen for Illinois Act, http://www.ilga.gov/legislation/publicacts/fulltext.asp?Name=095-0018 .

Locke, R.A. et al., 2017, Regulatory uncertainty and its effects on monitoring activities of a major demonstration project: The Illinois Basin – Decatur Project case, 13th International Conference on Greenhouse Gas Control Technologies, GHGT-13, 14-18 November 2016, Lausanne, Switzerland, 11p.

Trabucchi, Chiara, 2018**,** Summary of Carbon Storage Incentives and Potential Legislation: East Sub-Basin Project, US Department of Energy, Topical Report DOE/FE0029445-19, 11p.

US Environmental Protection Agency, Geologic Sequestration of Carbon Dioxide, Underground Injection Control (UIC) Program Class VI guidance documents, available from: https://www.epa.gov/uic/final-class-vi-guidance-documents .

US Environmental Protection Agency, 2011, Quick Reference Guide for Public Participation (2011), available at: https://www.epa.gov/sites/production/files/2015-07/documents/uic-quick-reference-guide_public-participation_final-508.pdf .

US Environmental Protection Agency, 2017, Underground Injection Control (UIC), UIC Injection Well Inventory, State FY 2017 UIC Inventory Information, available at: https://www.epa.gov/uic/uic-injection-well-inventory, accessed September 27, 2018.

US Senate Committee on Environment and Public Works, 2018, Bipartisan Group of Senators Introduce Bill to Promote Carbon Capture Research and Development, press release March 22, 2018, available at: https://www.epw.senate.gov/public/index.cfm/2018/3/bipartisan-group-of-senators-introduce-bill-to-promote-carbon-capture-research-and-development .