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Integrated CCS for Kansas (ICKan)

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Research Performance Progress Report (Quarterly)

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Signature of submitting official:

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INTRODUCTION

A. OBJECTIVES

This *Phase I- Integrated CCS Pre-Feasibility Study* activity under CarbonSAFE will evaluate and develop a plan and strategy to address the challenges and opportunities for commercial-scale Carbon Capture and Storage (CCS) in Kansas, *ICKan (Integrated CCS for Kansas)*. The objectives of *ICKan* include identifying and addressing the major technical and nontechnical challenges of implementing CO_2 capture and transport and establishing secure geologic storage for CO_2 in Kansas. The study will examine three of Kansas' largest CO_2 point sources and corresponding storage sites, each with an estimated 50+ million tons capacity (of saline aquifer storage), and a local transportation network to connect with nearby geologic storage. The project will also provide high level technical sub-basinal evaluation, building on previous characterization of the regional stacked storage complex.

B. SCOPE OF WORK

ACCS Coordination Team will examine three of Kansas' largest CO_2 point sources and corresponding storage sites, each with an estimated 50+ million tons capacity, and a local transportation network to connect with nearby geologic storage. ICKan will evaluate and develop a plan and strategy to address the challenges and opportunities for commercial-scale CCS in Kansas. The *Team* will identify and address the major technical and nontechnical challenges of implementing capture, transportation, and secure geologic storage of CO_2 in Kansas.

The ICKan and CCS Coordination Team will generate information that will allow DOE to make a determination of the proposed storage complex's level of readiness for additional development under Phase II, by establishing and addressing the key challenges in commercial scale capture, transportation, and storage in this investigation.

C. TASKS TO BE PERFORMED

Task 1.0 – Project Management and Planning Integrated CCS for Kansas (ICKan)
This Task includes the necessary activities to ensure coordination and planning of the project with DOE/NETL and other project participants. These activities include, but are not limited to, the monitoring and controlling of project scope, cost, schedule, and risk, and the submission and approval of required National Environmental Policy Act (NEPA) documentation

This Task includes all work elements required to maintain and revise the Project Management Plan, and to manage and report on activities in accordance with the plan.

Subtask 1.1 - Fulfill requirements for National Environmental Policy Act (NEPA) documentation
Phase I shall not involve work in the field, thus the activities shall have no adverse impact on the environment. Potential future activities that could have negative environmental impact in subsequent project phases will be documented in the Phase I reports.

Subtask 1.2 - Conduct a kick-off meeting to set expectations
The PIs shall layout expectations for adherence to scope, schedule, budget, risk management, and overall project plan in an "all-hands" meeting within the first four weeks of project initiation. The PIs shall provide

protocols and reporting mechanisms for notice of modifications.

Subtask 1.3 - Conduct regularly scheduled meetings and update tracking
The team shall hold regularly scheduled monthly meetings including all personnel and subcontractors via conference calls or online videoconferences. The PIs shall update scope, tasks, schedule, costs, risks, and distribute to the DOE and the project team. Accountability shall be encouraged by the monthly review sessions. The PIs shall hold full CCS team meetings (including CO_2sources and field operators) quarterly.

Subtask 1.4 - Monitor and control project scope
PIs shall evaluate and analyze monthly reports from all team section leads ensuring compliance with the requirements of DOE.

Subtask 1.5- Monitor and control project schedule
PIs shall closely monitor adherence to the project schedule, facilitated by monthly project team meetings. Schedule tracking and modifications shall be provided to the team on a monthly basis. PI will monitor resources to ensure timely completion of tasks.

Subtask 1.6 - Monitor and control project risk
Project risks and mitigation protocol shall be discussed with the team at the beginning of the project to help limit risks being realized and help recognize patterns that could signal increased risk.

Subtask 1.7 - Finalize the DMP. The DMP and its components shall be finalized by the PI. Information acquired, during the project, will be shared via the NETL-EDX data portal including basic and derived information used to describe and interpret the data and supplementary information to a published document. Information will be protected in accordance with the usage agreements and licenses of those who contribute the data.

Subtask 1.8 - Revisions to the PMP after submission
The PMP shall be updated as needed, including:1) details from the negotiation process through consultation with the Federal Project Officer, 2) revisions in schedule, 3) modifications in the budget, 4) changes in scope and tasks, 5) additions or changes in personnel, and 5) other material changes in the project.

Subtask 1.9 - Develop an integrated strategy/business plan for commercial scale CCS
The PIs shall set goals and timelines in early meetings and the team shall develop and build on strategy that will be documented in a business plan.

Task 2.0 – Establish a Carbon Capture and Storage (CCS) Coordination Team
The PIs shall develop a multidisciplinary team capable of addressing technical and non-technical challenges specific to commercial-scale deployment of the CO_2storage project. The Phase I team will 1) determine if any additional expertise and manpower required for Phase II, 2) recommend individuals, groups or institutions to fill any additional needs that are identified, and 3) assist in the recruitment and gaining formal commitments by key individuals or institutions for Phase II.

Subtask 2.1 - Identify additional CCS team members
Identify additional team members required to evaluate; 1) geologic storage complex, 2) large-scale anthropogenic sources and approaches to capturing CO_2, 3) transportation/delivery systems from source to the geologic complexes and injection into the storage reservoir, 4)costs, economics and financial requirements, 5) legal and political challenges, and 6) public outreach for the Phase II effort. Future needs will also be evaluated and additional team members will be selected if there are additional gaps in technical or non-technical areas that would be advisable to fill.

Subtask 2.2 - Identify additional stakeholders that should be added to the CCS team
The team will identify possible additional stakeholders that could include environmental groups, business groups, state legislators, state organizations (commerce), rate-payer organizations, land use and land owner groups.

Subtask 2.3 - Recruit and gain commitment of additional CCS team members identified
A comprehensive review of the gap analyses and develop recommendations of additional individuals, groups or institutions which should be filled before proceeding to Phase II. The CCS team shall identify primary and secondary choices, recruit, and gain commitments for possible participation in Phase II.

Subtask 2.4 - Conduct a formal meeting that includes the Phase I team and committed Phase II team members
A one-day working meeting will be conducted to1) review Phase I preliminary results, 2) present draft plans for Phase II, and3) gather input from recruited potential Phase II members. The meeting shall be held at the KGS or a mutually agreed upon alternate site with an option to participate by videoconferencing.

Task 3.0 – Develop a plan to address challenges of a commercial-scale CCS Project
This application presents three candidate sources and identifies three possible geologic complexes suitable for storage. Phase I work shall determine which are most feasible, and shall identify and develop a preliminary plan to address the unique challenges of each source/geologic complex that may be feasible for commercial-scale CCS (50+ million tonnes captured and stored in a saline aquifer). Reliable and tested approaches, such as Road mapping and related activities (Phaal, et al., 2004, Gonzales-Salavar, et al., 2016; IEA, 2013: DOE, 2003) shall be used to identify, select, and establish alternative technical and non-technical options based on sound, transparent analyses including monitoring for adjustment as the assessment matures.

Subtask 3.1 - Identify challenges and develop a plan to address challenges for CO_2 capture from anthropogenic sources
A plan will be developed that addresses CO_2 capture including use of plant configuration, current and anticipated operating conditions, product distribution (e.g. electrical power grid), and regulatory uncertainty.

Subtask 3.2 - Identify challenges and develop a plan to address challenges for CO_2 transportation and injection
A plan will be developed that describes challenges specific to Kansas to deliver $CO_2$to the injection well(s) including addressing regulations, right of way, pipeline configuration, maintenance, safety, and deliverability.

Subtask 3.3 - Identify challenges and develop a plan to address challenges for CO_2 storage in geologic complexes
The KGS shall evaluate candidate geological complexes for technical risks (capacity, seal, faults, seismicity, pressure, existing wellbores), economics (location/distance, injectivity, availability), and legal (pore space rights, liability) and document the results in a plan.

Task 4.0 – Perform a high level technical sub-basinal evaluation using NRAP and related DOE tools
Three candidate sources and two possible storage complexes were identified. Phase I work shall determine which are most feasible, and will identify and develop a plan to address the unique challenges of each storage complex that may be feasible for commercial-scale CCS (50+ Mt captured and stored in a saline aquifer).Each location will be evaluated using NRAP models and the results shall be submitted to DOE.

Subtask 4.1 - Review storage capacity of geologic complexes identified in this proposal and consider alternatives
Three possible sites in two complexes are in various stages of analysis and each appears to meet the50+Mt storage requirement. They shall be further evaluated and a survey of other potential geologic structures will undergo a rigorous site screening and selection process to determine suitability.

Subtask 4.2 - Conduct high-level technical analysis of suitable geologic complexes using NRAP- IAM-CS and other tools for integrated assessment
The KGS shall evaluate candidate storage complexes in terms of capacity, seal, faults, seismicity, pressure, existing wellbores, and injectivity.

Subtask 4.3 - Compare results using NRAP with methods used in prior DOE contracts including regional and sub-basin CO_2 storage
The CCS team shall use the results of the NRAP models obtained in this study with the regional simulation of CO_2 storage in southern Kansas to provide an assessment of risk to this greater area and compare with findings of project DE-FE0002056, including Pleasant Prairie Field and other potentially prospective storage sites (e.g., Eubank, Cutter, and Shuck fields).

Subtask 4.4 - Develop an implementation plan and strategy for commercial-scale, safe and effective CO_2 storage
A technology roadmap or similar methodology shall be used to convey a detailed realistic implementation plan and strategy that shall utilize the experience gained by the KGS in developing a US EPA Class VI permit. The result shall be based on a sound analysis that meets the goals of stakeholders, defines effective action, and is adaptable and open for review and updates as conditions change, e.g., new technology breakthroughs, incentivizing, and market conditions (McDowall, 2012).

Task 5.0 – Perform a high level technical CO_2 source assessment for capture
An assessment of the capture technologies best suited for efficiency, addressing the concerns of the electric utilities and their operating requirements and economic needs will be performed.

Subtask 5.1 - Review current technologies and CO_2 sources of team members and nearby sources using NATCARB, Global CO_2 Storage Portal, and KDM
The CCS team shall develop an organized electronic clearinghouse of vital information pertaining to the project, ranked by suitability, historical usage records, adaptability, scaling, and demonstration of success, and operations and maintenance requirements.

Subtask 5.2 - Determine novel technologies or approaches for CO_2 capture
CO_2 sources shall carefully be evaluated for suitability with new capture technologies. The evaluation will utilize private research including that sponsored by DOE and results of international efforts and projects such as DOE's Carbon Capture Simulation Initiative (CCSI) to determine the suitability and rational for making decisions to pursue or table the technology.

Subtask 5.3 - Develop an implementation plan and strategy for cost effective and reliable carbon capture
An optimal CCS plan and strategy that best represents the holistic operating environment and requirements of the CO_2 sources will be developed. The team shall develop a means to ensure a mechanism to update and adapt to new disruptive technologies and possibly accommodate them in the design document.

Task 6.0 – Perform a high level technical assessment for CO_2 transportation
The CCS team shall consider best practices in pipeline design to ensure safety, security, and compliance with regulations in force in Kansas and other states were the pipeline may extend.

Subtask 6.1 - Review current technologies for CO_2 transportation
The CCS team shall address the challenges in pipeline transportation and shall catalog and classify the technologies best suited for use in Kansas.

Subtask 6.2 - Determine novel technologies or approaches for CO_2 transportation
The CCS team shall review the challenges and solutions conveyed by current research and development and using a SWOT analysis determine the suitability and rational for making a decision to pursue or table transportation technologies.

Subtask 6.3 - Develop a plan for cost-efficient and secure transportation infrastructure
The CCS team shall develop an optimal plan and strategy for aCO_2distribution system that aligns with the needs of the proposed CO_2 sources and the storage complex put forth by the team.

Task 7.0 – Technology Transfer

Subtask 7.1 - Maintain website on KGS server to facilitate effective and efficient interaction of the team
The KGS shall create and maintain a web site available to both the members of the CCS team and the public. A non-secured site portion of the site shall be dedicated to apprising the public on the status of the on-going project as well as publishing the acquired data. The format of the public site shall be directed toward both technical and non-technical audiences. The public site will contain all non- confidential reports, public presentations, and papers. All data developed by the project or interpretation of existing data, performed by the project, shall be uploaded to EDX (edx.netl.doe.gov).

Subtask 7.2 - Public presentations
Progress and information gained from the study shall be convey to the public when deemed appropriate to enable an understanding of issues, concerns, and solutions for Integrated CCS in Kansas, *ICKan*. A focused dialog with interested stakeholders shall be sought through informational meetings and workshops that correspond with formal reporting to DOE including intermediate results and the final report. Prior to the final report being released, the CCS team shall invite key stakeholders and interest groups to participate in addressing the general topics of CCS and to comment on the plan and strategy through a conference and workshop in order build public support for taking the next steps in ICKan.

Subtask 7.3 - Publications
The CCS team shall publish methodologies, findings, and recommendations.

D. DELIVERABLES

Reports will be submitted in accordance with the attached “Federal Assistance Reporting Checklist” and the instructions accompanying the checklist.

In addition to the reports specified in the "Federal Assistance Reporting Checklist", the Recipient will provide the following to the DOE Project Officer.

Data Submitted to NETL-EDX
Data generated as a result of this project shall be submitted to NETL for inclusion in the NETL Energy Data eXchange (EDX), https://edx.netl.doe.gov/. The Recipient will work with the DOE Project Officer to assess if there is data that should be submitted to EDX and identify the proper file formats prior to submission. All final data generated by this project shall be submitted to EDX including, but not limited to: 1) datasets and files, 2) metadata, 3) software/tools, and 4) articles developed as part of this project.

Other key deliverable include:

- Task 1.0–Project Management Plan
- Task 1.10 – Technical report on *Integrated Strategy For Commercial-Scale CCS Project*
- Task 2.0 – Commitment letters from fully formed *CCS Coordination Team*
- Task 3.0 – Technical report on *Plan to Address Challenges of the Commercial-Scale CCS Project*
- Task 4.0 – Technical report on *High-Level Sub-Basinal Evaluations*
- Task 5.0 – Technical report on *High-Level CO_2 Source Assessment for Capture*
- Task 6.0 – Technical report on *High-Level Assessment for CO_2 Transportation*
- Initial Business Plan that describes the selected source, capture technology, transportation route, and injection site(s), in a saline aquifer, with anticipated surface and subsurface infrastructure requirements. Additionally, a data gap analysis should be performed and include a discussion on the missing data and how the identified data gaps will be filled. There should be a discussion on non-technical issues such as outreach, political aspects of the project, legal requirements such as pore space ownership, permitting requirements, and the ownership of the CO_2/liability throughout the process of capturing, transportation and injection. An economic analysis should be performed that includes anticipated costs for filling in data gaps, anticipated capital expenditures, construction costs, and future system operational expenditures for the proposed CCS system. There should be a list of anticipated sources of funding and strategies to pay for the installation and the operation of the CCS system. The business plan should also have discussions on how the costs of oil will affect the financing of the project and at what price point will it be economically feasible.

E. BRIEFINGS/TECHNICAL PRESENTATIONS

The Recipient shall prepare detailed briefings for presentation to the Project Officer at a location(s) to be designated by the Project Officer, which may include the Project Officer's facility located in Pittsburgh, PA or Morgantown, WV. The Recipient shall make a presentation to the NETL Project Officer/Manager at a project kick-off meeting held within ninety (90) days of the project start date. At a minimum, annual briefings shall also be given by the Recipient to explain the plans, progress, and results of the technical effort and a final project briefing prior to the close of the project shall also be given.

The Recipient shall also provide monthly E-mail updates on the status of the project to the FPM.

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Accomplishments

Task 1.0 – Project Management and Planning Integrated CCS for Kansas

Subtask 1.1 - Fulfill requirements for National Environmental Policy Act documentation

Completed in Q1.

Subtask 1.2 - Conduct a kick-off meeting to set expectations

Completed in Q1.

Subtask 1.3 - Conduct regularly scheduled meetings and update tracking

KGS Team Meetings:
The monthly team meeting was held on 1/8/2017. Topics focused primarily on LRPP and included other technical updates. Frequent individual meetings are held on an as-needed basis throughout the course of the reporting period as well.

Full Team Meeting:
The all team Quarterly meeting was held 12/14/2017.

Other:
The KGS team met with Battelle and EERC in Lincoln, Nebraska on 12/5/2017 to discuss combining projects in the next phase.

Subtask 1.4 - Monitor and control project scope

The KGS held regular monthly and bimonthly meetings with the team to discuss the status of deliverables and evaluate tasks. Participants provided a brief overview of their work and discussed steps forward.

Subtask 1.5 - Monitor and control project schedule

The project schedule was reviewed during monthly and bimonthly meetings with the team.

Subtask 1.6 - Monitor and control project risk

Risks were evaluated in an ongoing basis within normal workflow. Larger concerns were presented in team meetings where in-depth discussions could be held.

Subtask 1.7 - Finalize the DMP.

Completed in previous quarter.

Subtask 1.8 - Revisions to the PMP after submission

Nothing to report.

Subtask 1.9 - Develop an integrated strategy/business plan for commercial scale CCS

This topic was discussed in follow up meetings to prepare for Phase II. New collaborations and partnerships were formed as the group established stakeholders. Work is ongoing.

Task 2.0 – Establish a Carbon Capture and Storage (CCS) Coordination Team

The Integrated CCUS for Kansas and Nebraska Integrated Carbon Capture and Storage Pre-Feasibility Study, led by Energy & Environmental Research Center, Phase I projects joined Battelle Memorial Institute's Integrated Mid-Continent Carbon Stacked Storage Hub (DE-FE0029264), in a single CarbonSAFE Phase II proposal. Possible gaps in the CCS coordination team for the combined project were identified in a December 5, 2017 meeting of the three projects in held in Lincoln, Nebraska, and in subsequent conference calls. ICKan secured additional industry partners and stakeholder as well as commitments from key Phase I partners.

Subtask 2.1 - Identify additional CCS team members

Completed in Q3.

Subtask 2.2 - Identify additional stakeholders that should be added to the CCS team

Completed in Q3.

Subtask 2.3 - Recruit and gain commitment of additional CCS team members identified

Completed in Q3.

Subtask 2.4 - Conduct a formal meeting that includes the Phase I team and committed Phase II team members

This is no longer applicable as defined in the proposal because ICKan joined Battelle and EERC in a Phase II proposal. However, a full ICKan project meeting will be held in Q4 that will include all ICKan Phase I participants as well as newly recruited industry partners and stakeholders.

Significant activities and accomplishments in the reporting period for Task 2 include the following:

- Finalized the collaboration plans for the joint application and, as part of the three joint projects, determined gaps in the joint CCS team that the ICKan would fill.
- Recruited new ICKan-related industry partners and stakeholders and retained key Phase I partners and stakeholders through commitment letters or letters of support for the joint Phase II proposal. Letters of support from Phase I participants include Westar Energy, Sunflower Electric, Kansas City Board of Public Utilities, CHS Refinery, and Casillas Petroleum; and commitment letters from Great Plains Institute, Improved Hydrocarbon Recovery, Depew Gillen Rathbun & McInteer, and The Linde Group. A new partner added and commitment letter received for Phase two is from Berexco, LLC, the operator of the Patterson site, chosen as the primary saline storage site for the joint Phase II application. Merit Energy, Kansas Independent Oil and Gas Association, and Kansas Ethanol are new Phase II stakeholders that have provided a letter of support. The State of Kansas Governor has also provided the joint project a letter of support for Phase II.

Goals and objectives for the next Quarter:

In Q4 the ICKan project will conduct an "all ICKan project" meeting that will also include new Phase II partners and stakeholders.

Products for Task 2.0:

Letters of support and commitment letters for Phase II proposal.

Task 3.0 – Develop a plan to address challenges of a commercial-scale CCS Project

Subtask 3.1 - Identify challenges and develop a plan to address challenges for CO2 capture from anthropogenic sources

A plan will be developed that addresses CO_2 capture, including use of plant configuration, current and anticipated operating conditions, product distribution (e.g. electrical power grid), and regulatory uncertainty.

The ICKan proposal presented three candidate sources for CO_2 capture. The objective of Phase I work is to determine which are most feasible, and to identify and develop a preliminary plan to address the unique challenges of each source that may be feasible for commercial-scale CCS (50+ million tonnes captured and stored in a saline aquifer). Although no time frame was defined by FOA15824 for the processing of 50 million tonnes, the ICKan project set 2.5 million tonnes/year over a 20-year period as a target.

Summary of Activities:
A preliminary economic analysis was conducted to evaluate a range of likely costs of CO2 capture at the CHS refinery and Westar's Jeffrey Energy Center.

Significant Results/Key Outcomes:

Preliminary report on the cost of CO2 capture at two ICKan industrial sites

A preliminary economic analysis was conducted to evaluate a range of likely costs of capture based on the solvent-based Linde-BASF PCC technology at the two leading candidates for anthropogenic CO_2 source. The team considered cost sensitivity to capital costs of equipment, costs of installation, steam and power demand and costs, and options for waste heat recovery at the power plant

For the power plant, it is necessary to explain the increase in parasitic electrical energy demand in the base and upside case. Since the power plant does not change its size or produce more steam for CO_2 capture, Linde has calculated the reduction in the electrical output of the plant due to the repurposing of steam for solvent regeneration. This loss in power output is included as a cost to the plant. Since the cost of power is typically lower than the cost of steam, this approach favors the cost of captured CO_2. In the downside case, the cost of power demand and the cost of steam demand is considered separately.

The matrix of variables considered for both the Jeffries Westar Energy Center and the CHS refinery is shown below in Tables 1 and 2 respectively.

		Upside	Base	Downside
Capital Costs		- 40%	0%	0%
Costs of Integration		0%	+ 10%	+ 10%
Power plant parasitic electrical loss	kWh/t CO_2	305	305	129
Cost of power	$/MWh	$44.3	$44.3	$65.0
Waste heat recovery	MW	17.4	0	0

Table 1. Matrix of variables investigated for carbon capture costs at the Jeffries Westar Energy Center

		Upside	Base	Downside
Capital Costs		- 40%	0%	0%
Carbon capture electrical demand	kWh/t CO_2	123	123	135
Carbon capture steam demand	t steam/ hr	91	91	100
Cost of power	$/MWh	$44.3	$44.3	$65.0
Cost of steam	$/ t steam	$11.1	$11.1	$13.5

Table 2. Matrix of variables investigated for carbon capture costs at the CHS refinery

Results and Discussion

The results of the sensitivity analysis are given below as a range of costs. The results indicate that solvent-based carbon capture at the CHS refinery is less economically attractive than at a power plant. This is expected due to the higher rate of capture at the Jeffries' power plant as well as the potential for waste heat recovery to meet the demands of the capture plant. For better economics, other capture options such as membrane-based technologies or PSA/VSA-based technologies, should be evaluated.

In the best-case scenario, the costs of CO_2 capture at the Jeffries Westar Energy Center is below the DOE target for retrofit of existing pulverized coal (PC) plants with carbon capture ($45/t CO_2) [Table 3]. Linde has shown that under certain configurations for a greenfield site, their solvent-based technology with BASF can be as low as $40/t CO_2.

		Cost of Capture	
Facility	Capture Rate	Best Case	Worst Case
	t.p.a	/tCO_2	/tCO_2
Jeffries power plant	670,800	$43	$73
CHS SMR refinery	2,687,500	$60	$94

Table 3. Range of costs for CO_2 capture using the Linde-BASF solvent-based carbon capture technology at the two sources of anthropogenic CO_2

Goals and objectives for the next Quarter:
During the next quarter, the team will integrate the costs for capture into the integrated project economics.

Products for Subtask 3.1:
Preliminary economic analysis presented in this quarterly report.

Subtask 3.2 - Identify challenges and develop a plan to address challenges for CO_2 transportation and injection (non-technical)

Subtask 3.3 - Identify challenges and develop a plan to address challenges for CO_2 storage in geologic complexes (non-technical)

Note - The SOPO combined technical and non-technical aspects of the Phase I project in Task 3, in particular Subtasks 3.2 and 3.3. To simplify for reporting and for the reader, the technical and non-technical are discussed separately. Furthermore, the non-technical subject matter pertaining to Subtasks 3.2 and 3.3 have considerable overlap and will be combined for this and future reports.

<u>Subtasks 3.2 and 3.3 Non-Technical Section:</u>

Overview

The ICKan Legal, Regulatory and Public Policy team (LRPP), is comprised of attorneys from Depew Gillen Rathbun & McInteer (DGRM), public policy experts from Great Plains Institute and the Kansas Geological Survey outreach manager. In this quarter LRPP continued their dialogues with State and Federal regulators and agencies, worked towards a better understanding of Class VI wells, and developed a preliminary plan to address business and contractual requirements to address technical and financial risks.

Significant activities and accomplishments in the reporting period for Subtasks 3.2 and 3.3 include the following:

1. Continued discussions with the State regulatory agencies Kansas Corporation Commission and Kansas Department of Health and Environment on CCS in Kansas and provided an update on CarbonSAFE Phase II plans (Stover and Rick Brunetti, Chief, Division of Air, Kansas Department of Health and Environment, 1/5/2018; Stover and Jeff McClanahan, Director, Division of Utilities, Kansas Corporation Commission, 1/6/2018; Stover and Ryan Hoffman, Director, Division of Conservation, Kansas Corporation Commission, 1/12/2018).
2. Met with EPA Region VII Administrator Jim Gulliford to discuss CCS Research needs and Class VI permitting requirements (Mandel (KGS Director), Bidgoli, and Stover, 11/8/2017).
3. Continued work on Class VI applications, including teleconference with Battelle (Andrew Duguid) and ADM (Scott McDonald), Midwest Geologic Sequestration Consortium, on their experience with Class VI well permit, which was ultimately successful (Bidgoli, Holubnyak, Stover, 1/24/2018).
4. DGRM developed a preliminary document, a plan to address business and contractual requirements to address technical and financial risks.

Goals and objectives for the next Quarter (non-technical)**:**

- Continue discussions with the State regulatory agencies Kansas Corporation Commission and Kansas Department of Health and Environment on proposed statute and public utility model for transportation and/or geologic storage.
- Refine proposed direction for public policy on liability, and ownership of transported CO2 and storage of CO2.

Products for Subtasks 3.2 and 3.3 (non-technical)**:**

- Draft plan, written by DGRM: Appendix A, Anticipated business and contractual requirements to address technical and financial risks.

Subtasks 3.2 and 3.3 Technical Section:

Subtask 3.2 - Identify challenges and develop a plan to address challenges for CO2 transportation and injection *(Technical)*

The likely mode of transportation for large-scale CCS is via pipelines. Because of the long history (40+ years) of CO2 transportation, and even a longer history of transporting high pressure natural gas, there are no significant technical challenges to transporting CO2 via pipelines. Non-technical challenges are covered separately.

Summary of significant activities: None to report

Significant Results/Key Outcomes: NA

Goals and objectives for the next Quarter: NA

Subtask 3.3- Identify challenges and develop a plan to address challenges for CO2 storage in geologic complexes *(Technical)*

Summary of significant activities:

- Key risks were defined for the Patterson geologic site, part of the North Hugoton Storage Complex (NHSC) during the process of the high-level technical evaluation.

Significant Results/Key Outcomes:

- Injection simulations for two more geologic sites within the NHSC, Patterson and Pleasant Prairie, demonstrate >50Mt CO2 storage capacity. The Patterson site was chosen as the primary Phase II injection site.

Goals and objectives for the next Quarter:

- Develop plans to address technical risks for the Patterson site.

Task 4.0 – Perform a high level technical sub-basinal evaluation using NRAP and related DOE tools

Subtask 4.1 - Review storage capacity of geologic complexes identified in this proposal and consider alternatives

In the proposal we identified three possible sites in two complexes that were in various stages of analysis and each appeared to meet the 50+Mt storage requirement. Post award, they were to be evaluated further and a survey of other potential geologic structures were to be screened and evaluated for suitability.

Overview:

Two geologic complexes identified in the proposal as potential sites for storing >50 million tonnes (Mt) are the Pleasant Prairie field geologic site, considered the primary storage site, and the Davis Ranch and John Creek fields, in the Forest City Basin (FCB) storage complex, considered a secondary site. Preliminary capacity evaluation for the FCB indicated it not capable of storing >50Mt CO2 (Q1 ICKan report). In the process of evaluating the Pleasant Prairie site, four separate geologic structures were identified as each having potential for storing 50Mt. The four structures, aligned on the same regional geologic structure, are similar in size, have >100 ft of closure, and similar geologic histories. The four potential sites, Rupp, Patterson, Lakin and Pretty Prairie are in what we have named North Hugoton Storage Complex (NHSC) [Figure 1]. CO2 injection simulation studies are now complete for the Lakin (reported in Q2 ICKan report), Pleasant Prairie and Patterson sites, and underway on the Rupp. Because the Patterson site has been determined to be the primary site for a Phase II proposal, this report will focus on simulation results for this site. The other three sites in the NHSC will be considered alternative sites.

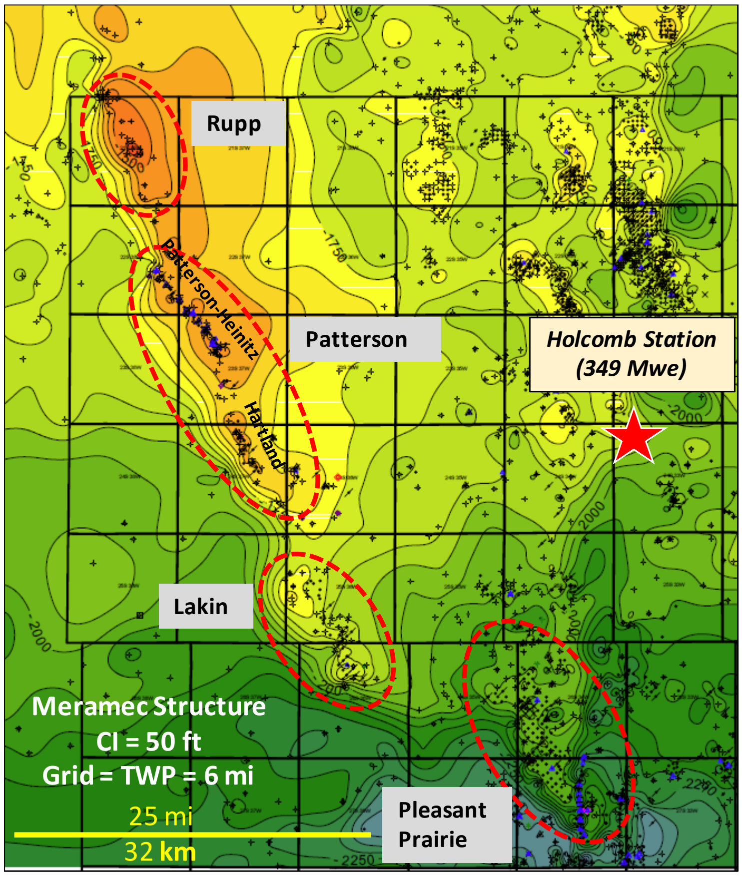

Figure 1. Location of four plausible storage sites within the North Hugoton Storage Complex. Map is the structure on the top of the Meramec (Mississippian). Patterson is the primary site and the others are alternative sites.

Summary of significant activities:

- The Patterson and Pleasant Prairie sites were characterized, modeled and simulated for storage capacity and injectivity.

Rupp site was characterized and modeled. CO2 injection simulations for storage capacity and injectivity were initiated.

Significant Results/Key Outcomes:

- A high-level evaluation of the storage capacity and injectivity in saline aquifers beneath the Patterson and Pleasant Prairie sites indicating a storage capacity is in excess of 50Mt. See discussion of modeling and simulation results under Subtask 4.2.
- A total of four storage sites in the NHSC are each likely to be capable of storing >50Mt CO_2 (Table 4).

Storage Complex	Geologic Site	Volume Stored (Mt)	Injection Wells	Years of Injection	Comments
North Hugoton	**Rupp**	?	?	?	> 50 Mt minimum anticipated
	Patterson	60.7	4	30	> 50 Mt minimum
	Lakin	30.8	3	25	Likely to exceed 50 Mt
	Pleasant Prairie	67.4	3	20	> 50 Mt minimum
Forest City Basin	**Davis Ranch - John Creek**	24.6	6	25	Cannot meet 50Mt minimum

Table 4. Summary of CO2 injection simulations performed at five geologic sites considered. The Patterson site is considered the primary injection site for Phase II, and the Rupp, Lakin and Pleasant Prairie sites are alternatives.

Goals and objectives for the next Quarter:

- The primary goal for the next quarter is to complete technical reports for all geologic sites modeled.

Products for Subtask 4.1:

- Preliminary simulation results for injectivity and storage capacity for the Patterson and Pleasant Prairie sites, each meeting the minimum 50 Mt storage criteria.

Subtask 4.2 - Conduct high-level technical analysis of suitable geologic complexes using NRAP- IAM-CS and other tools for integrated assessment

The KGS shall evaluate candidate storage complexes in terms of capacity, seal, faults, seismicity, pressure, existing wellbores, and injectivity.

Summary of significant activities:
Table 5 summarizes activities and work completed by the ICKan technical team related to Subtasks 4.1 and 4.2.

Storage Complex	North Hugoton				FCB
Geologic Site	Rupp	Patterson	Lakin	Pleasant Prairie	Davis Ranch - John Creek
Volumetric Capacity					
Data gather and process	complete	complete	complete	complete	complete
Well log anslysis and tops	complete	complete	complete	complete	complete
Petrophysics	complete	complete	complete	complete	complete
2D models	complete	complete	complete	complete	complete
3D models	complete	complete	complete	complete	complete
Volumetric (capacity)	Q4	complete	complete	complete	complete
Simulate for injectivity	Q4	complete	complete	complete	complete
Technical Risks					
Seals - geochemistry	complete	complete	complete	complete	complete
Seals - petrophysical	NA	partial (Q4,5)	NA	partial (Q4,5)	NA
Fault leakage	NA	Q4,5	NA	partial (Q4,5)	NA
Seismicity	NA	Q4,5	NA	Q4	NA
Wellbores	NA	partial (Q4,5)	NA	NA	NA
Implementation Plan					
Injection plan	NA	Q4,5	NA	NA	NA
Monitor plan	NA	Q4,5	NA	NA	NA

Table 5. Summary of technical analysis activities and work completed on potential geologic sites. Shaded entries are work completed in the quarter covered by this report. "Partial" indicates work begun, but not completed in Q3. Q4 or Q4,5 indicates the project quarter in which the specific work is to be completed. NA indicates analysis that will not be completed because the site is an alternative site or the sites was determined incapable of storing 50Mt CO_2.

Significant Results/Key Outcomes:

Key outcome 1: Patterson site high-level technical analysis (capacity, injectivity, seals)

The high-level technical analysis of the Patterson confirms that it is capable of storing in excess of 50Mt injected over a 30-year period. The simulation documented in this report indicates that at least 61 Mt could be injected into four wells and stored within the three target zones (Osage, Viola, and Arbuckle).

Setting

The Patterson site is situated in southwest Kansas at the northern end of the giant Hugoton Gas Field and is comprised of three oil pools, Patterson, Heinitz, and Hartland. The three pools share a closed structure (Patterson site) that is part of the NHSC (Figures 1 and 2). The four geologic sites are on a prominent northwest-southeast structural trend, have the same geologic history, and the same saline aquifer reservoirs beneath them. Three stratigraphic intervals are considered for CO2 storage, the Mississippian Osage, Middle-Ordovician Viola, and Cambro-Ordovician Arbuckle (Figure 3). All three have regional lateral extent and appear to be separated by vertical barriers to fluid migration (Spergen, Kinderhook, and Simpson dense carbonate and thin shales). The Morrow shale (Pennsylvanian) on top of the Meramec (Mississippian) is a regional top seal for the oil and gas accumulations in the Mississippian.

Saline aquifer reservoirs in the Osage and Viola consist of thick (>100ft), vertically continuous, laterally extensive porous carbonate, primarily medium-crystalline sucrosic dolomite with good intercrystalline porosity and varying amounts of chert. The Arbuckle storage reservoir consists of stacked thin beds of porous dolomite over the 570-foot-thick Arbuckle, separated by thin intervals of tight carbonate. Although they do not appear to be well- connected vertically, drill stem tests in the Arbuckle, albeit limited in number prove otherwise with fluid recoveries averaging over 2000 feet of saltwater in one-hour flow tests.

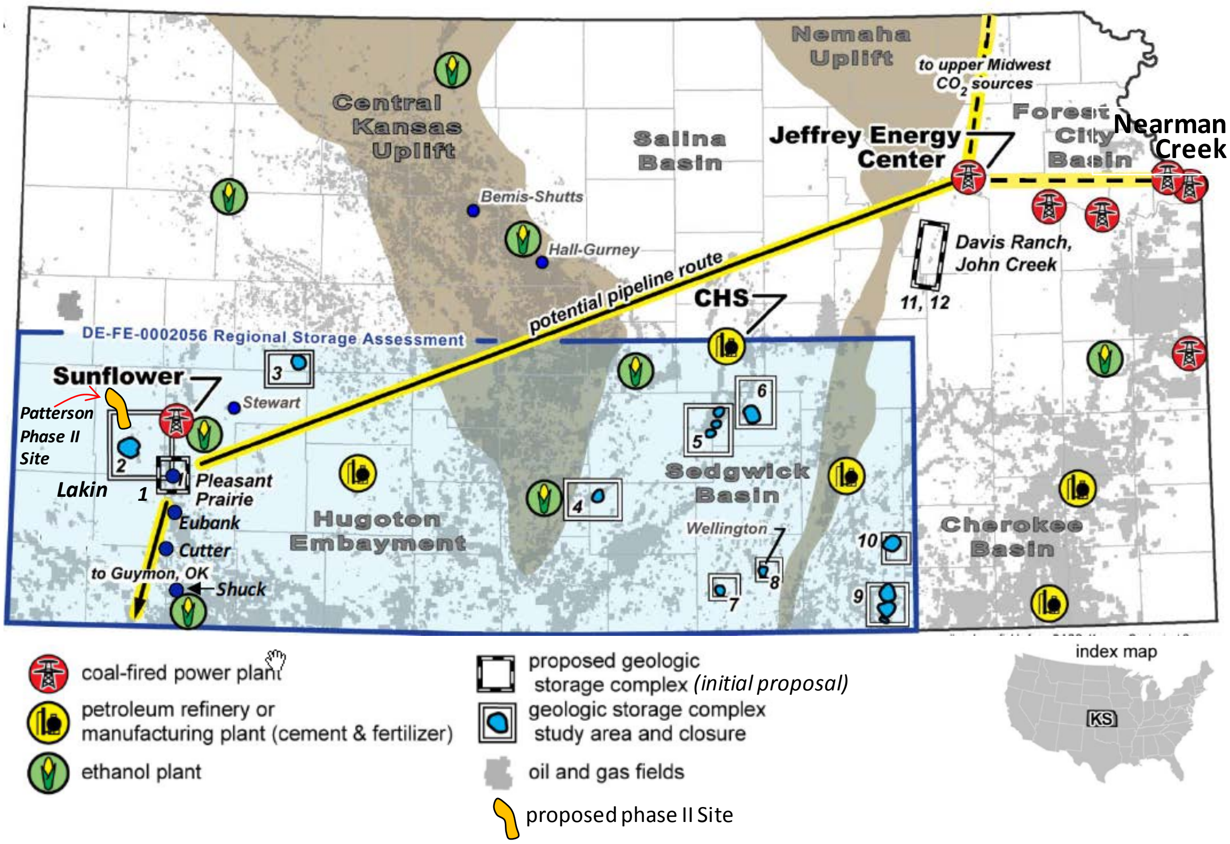

Figure 2. Kansas map showing location of the Patterson site, other possible CO_2 injections sites (numbered 1-12), CO_2 sources, possible CO2 pipeline routes, DE-FE0002056 study areas (blue), and oil fields. (Figure modified from ICKan proposal SF 424 R&R, 2016).

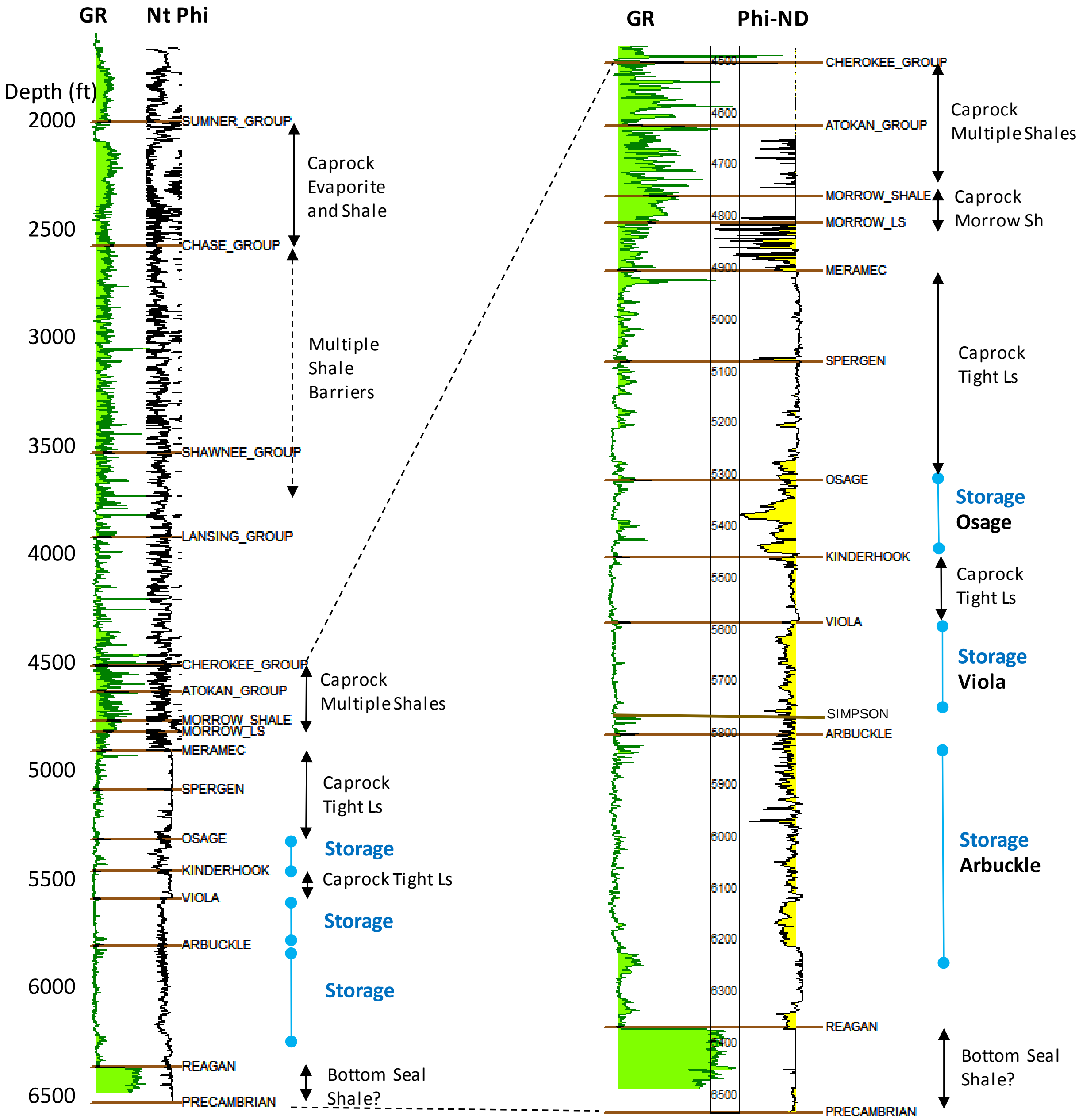

Figure 3. Generalized stratigraphic column for the Patterson site area. Wireline log of a key well in the Patterson site, the Longwood Gas Unit #2. Log on the left is from below surface casing to TD (1900-6530 ft). An enlarged section of the well is on the right. In both figures gamma ray (GR) is color-filled to accentuate shale. The porosity curve on the left figure is Neutron Porosity (Nt Phi) while in the right figure it is an average of neutron and density porosity and is color filled to accentuate porous intervals.

Workflow

A simple, un-faulted 3D static model was built for a 920 mi^2 (2400 km^2) area and then a smaller area was cut out of the model for simulation (Figure 4). A conventional workflow (Figure 5) for building a 3D static model was deployed: 1) gather, prepare and analyze well-scale well data from public sources and operator-partner data, 2) build 2D structure and isopach maps with Geoplus Petra™, 3) develop petrophysical relationships to estimate permeability knowing porosity, 4) build a larger-area 3D static property model populated with porosity and permeability for the Osage, Viola and Simpson, 5) upscale the model to reduce cell counts for simulation, and 6) cut out and export smaller field-scale model for simulation.

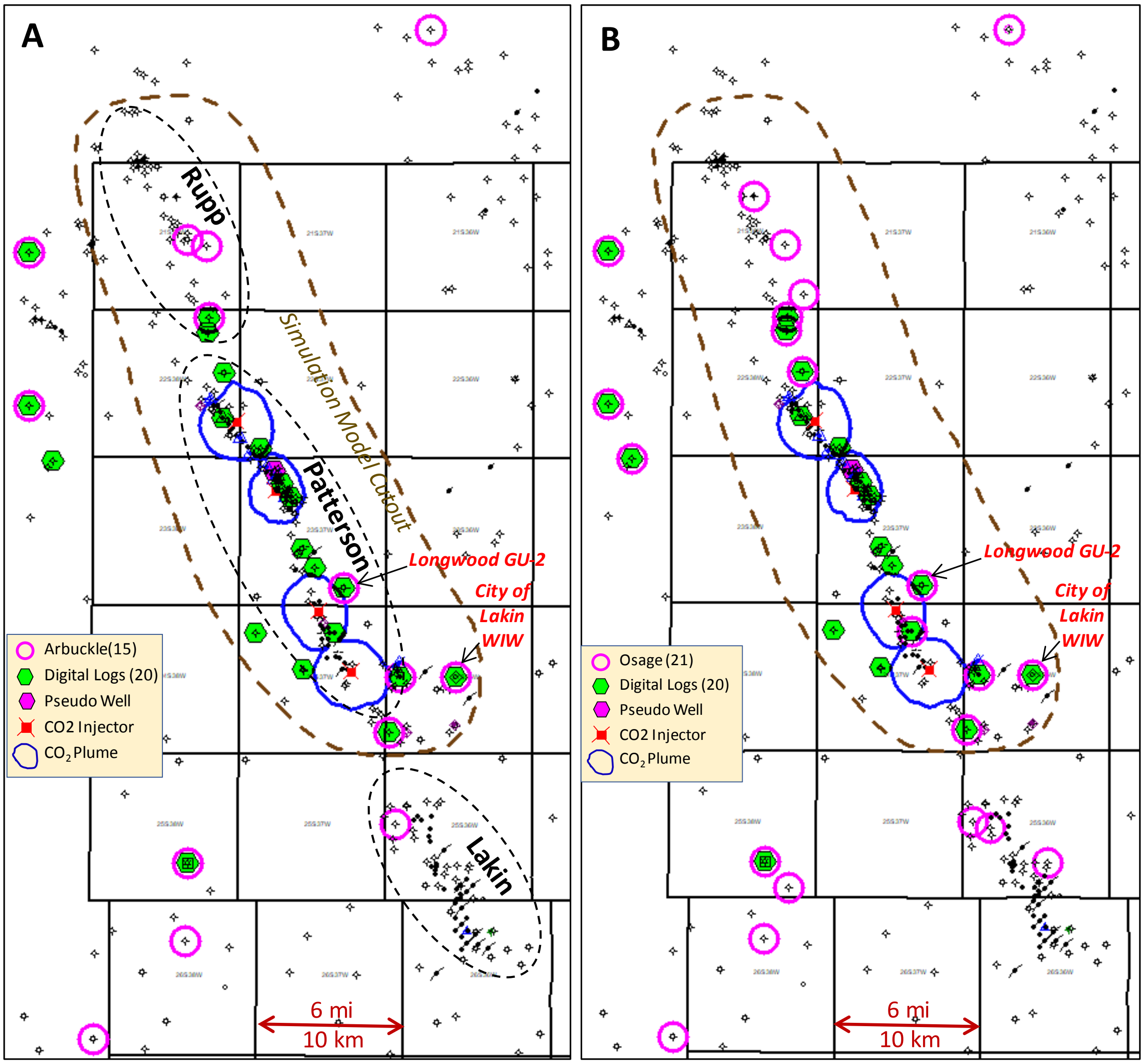

Figure 4. A Plat showing locations of 363 "deep" wells and 4 hypothetical CO2 injection wells and their CO2 plume extents within the bounds of the static geomodel. The simulation model was cut out of the static model (brown dashed line). 15 wells that have penetrated the Arbuckle are circled. B. Same plat except the 21 circled wells are Osage penetrations.

Well data

There are 363 wells deeper than 4,500 ft in the model area (Figure 4) and 1952 shallow wells (<4500 ft), the vast majority being shallow gas wells with depths under 3200 feet. The shallow gas wells are completed in the Chase and Council Grove Groups and are part of the shallow Hugoton-Panoma gas field.

Of the 363 wells, 361 penetrate the top of the Meramec, but relatively few penetrate the prospective saline storage zones, Osage, Viola, and Arbuckle, because there is no production below the upper 150 feet of the Meramec. Raster log images are available for most wells in the immediate vicinity of the simulation model and formation tops were picked for all wells with penetrations below the Meramec. Only 21 wells penetrated the Osage, 20 cut the Viola and 14 penetrated the Arbuckle. Modern logs, having a minimum neutron and density porosity and gamma ray, were digitized for 20 wells yielding coverage for the Osage (12 wells), Viola, (9 wells) and Arbuckle (8 wells). Although the data is sparse, porous intervals in the three candidate injection zones are laterally extensive. However, because of the long distance (10 miles) between Arbuckle well data in the Longwood GU-2 well and the next well with Arbuckle to the northwest, a pseudo well with Longwood GU-2 properties was inserted midway in the data gap to aid in modeling (Figure 4).

Petrophysics

Porosity input for the geomodel was the average of neutron and density porosity and gamma ray at the half-foot scale for the 20 wells with modern logs (Figure 4) from the Morrow to total depth. Permeability was calculated in the geomodel using porosity-permeability transform equations derived from available empirical data.

Empirical data utilized in petrophysical analysis at the Patterson site includes limited core data from the Longwood GU-2 well, engineering injection/falloff test in the City of Lakin WIW, both within the bounds of the reservoir simulation (Figure 4), and extensive data from Berexco KGS-Cutter 1 well, located 30 miles south of the Patterson site. Conventional core analysis for plugs and whole core in the Longwood well provide nearly full coverage in the Osage, but limited coverage in the Viola and Arbuckle. Initial porosity-permeability transform equations (Table 6) for the Osage were based on core from the Longwood well while transforms for all other zones (Meramec, Spergen, Warsaw, Kinderhook, Viola, Simpson and Arbuckle) were based on KGS-Cutter 1 data.

Zone	Permeability from Porosity (and GR for Arbuckle)
Meramec	Kxy=87.768*Porosity^2.0923
Spergen	Kxy=212571*Porosity^4.377
Warsaw	Kxy=452218* Porosity ^5.0603
Osage	Kxy=331.31* Porosity ^2.9257
Kinderhook	Kxy=157.2* Porosity ^2.1019
Viola	Kxy=4160* Porosity ^3.2036
Simpson	Kxy=40647* Porosity ^3.7804
Arbuckle	Kxy=1000000000*GR ^(-4.84)* Porosity^(9.37*(GR^(-0.486))))

Table 6. Porosity-permeability transforms derived from empirical data utilized in the Patterson geomodel.

In the simulation model, adjustments (increases) to permeability were made for the Osage and Arbuckle, justified by reservoir performance data that demonstrates reservoir-scale permeability data is significantly greater than matrix permeability at the core scale. Maximum injection rate in the City of Lakin well injection/falloff test in the Arbuckle was 4831 barrels of water per day on a vacuum, yielding a calculated average permeability of 1.43 Darcy over a 690-ft interval, a thousand times the average permeability using the transform in Table 6. The permeability transform based on core data for the Osage in table 3 is less than 1/10th that of a transform based on the KGS-Cutter #1 data, both likely to be significantly lower than reservoir-scale data. Merit Energy obtains >2000 barrels of water per day from the Osage water supply wells for their Victory field area just southeast of the NHSC area in Figure 1, requiring much greater permeability than the average of 1.34 mD for core data from the Longwood #2 well.

Detailed discussions of permeability for the Patterson area will be provided in the Patterson technical report.

3D static model

Static model construction will be discussed in detail in the Patterson technical report. A single 3D cellular model covering both the Rupp and Patterson geologic sites was constructed (Figure 5). The model was upscaled before parts of the model were extracted for CO2 injection simulations in separate studies.

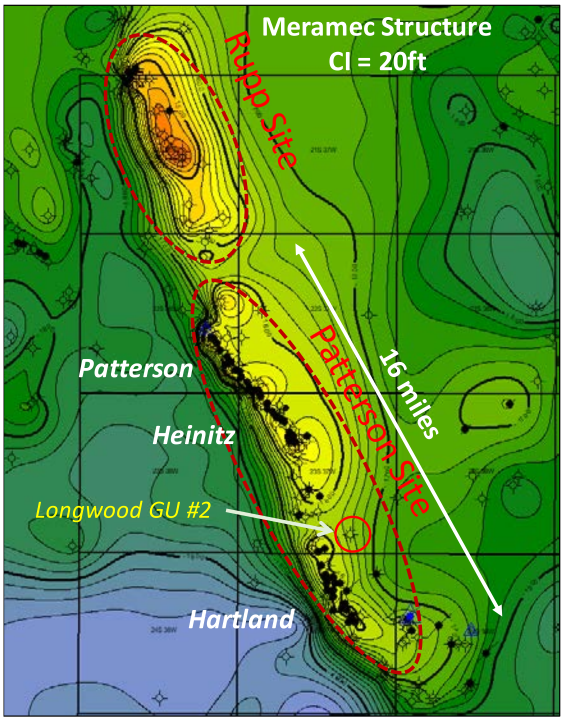

Figure 5. Structure map on top of the Meramec (Mississippi) covering the area modeled for the Rupp and Patterson geologic sites.

Simulation model

Dynamic Modeling of CO_2 Injection at Patterson Field
The key objectives of the dynamic modeling were to determine the volume of CO2 stored, resulting rise in pore pressure and the extent of CO2 plume migration in the Patterson filed structure. Simulations were conducted using the Computer Modeling Group (CMG) GEM simulator, a full equation of state compositional reservoir simulator with advanced features for modeling the flow of three-phase, multi-component fluids that has been used to conduct numerous CO2 studies (Chang et al., 2009; Bui et al., 2010).

<u>Initial reservoir conditions and simulation constraints</u>
The initial conditions specified in the reservoir model are specified in Table 7. The simulations were conducted assuming isothermal conditions. Although isothermal conditions were assumed, a thermal gradient of 0.008 °C/ft was considered for specifying petrophysical properties that vary with layer depth

and temperature such as CO2 relative permeability, CO2 dissolution in formation water, etc. The original static pressure in the injection zone was set to reported field test pressures and the Arbuckle pressure gradient of 0.48 psi/ft was assumed for specifying petrophysical properties. Perforation zone was set at top 35 ft of in all three injection intervals: Osage, Viola, and Arbuckle. Injection rate was assigned according to maximum calculated based on well tests and reservoir properties. Boundary conditions were selected as open Carter-Tracy aquafer with leakage allowed.

Injection Interval	**Osage**	**Viola**	**Arbuckle**
Temperature	60 °C (140 °F)	61 °C (142 °F)	62 °C (144 °F)
Pressure	1,650 psi (11.38 MPa)	1,700 psi (11.5 MPa)	1,800 psi (11.72 MPa)
Max. BHP	2250 psi ()	2300 psi	2400 psi
TDS	100 g/l	140 g/l	180 g/l
Formation Top	5,260 ft	5,500 ft	5,740 ft
Formation Base	5,400 ft	5,700 ft	6,340 ft
Perforation Zone	110 ft	200 ft	150 ft
Injection Period		30 years	
Number of wells		4	
Injection Rate	3,050 T/day	1,400 T/day	1,080 T/day
Total CO_2 injected	33.5 MT	15.3 MT	11.8 MT

Table 7. Model input specification and CO_2 injection rates

Four wells were completed in the main part of the Patterson structure and were “perforated” in the Mississippi Osage, Viola, and Arbuckle. No flow boundary conditions were specified above and below the injection zones as indicated by brine chemistry. Additional work is underway to support these assumptions. CO2 was injected at rates determined by the petrophysical conditions at each injection site and within each perforated interval. The lateral boundary conditions were set as an infinite-acting Carter-Tracy aquifer (Dake, 1978; Carter and Tracy, 1960) with leakage.

Simulation results

Figure 6 shows the maximum lateral migration of the CO2 plume approximately 100 years after cessation of CO2 injection activities at Patterson Field. The plume grows rapidly during the injection phase and is largely stabilized 20-30 years after the end of injection period. CO2 travels throughout the reservoir for additional several years and enters stabilization phase after several years post injection commencement. Significant amount of CO2 (~30%) is dissolved in water over the period of 50 years past injection commencement.

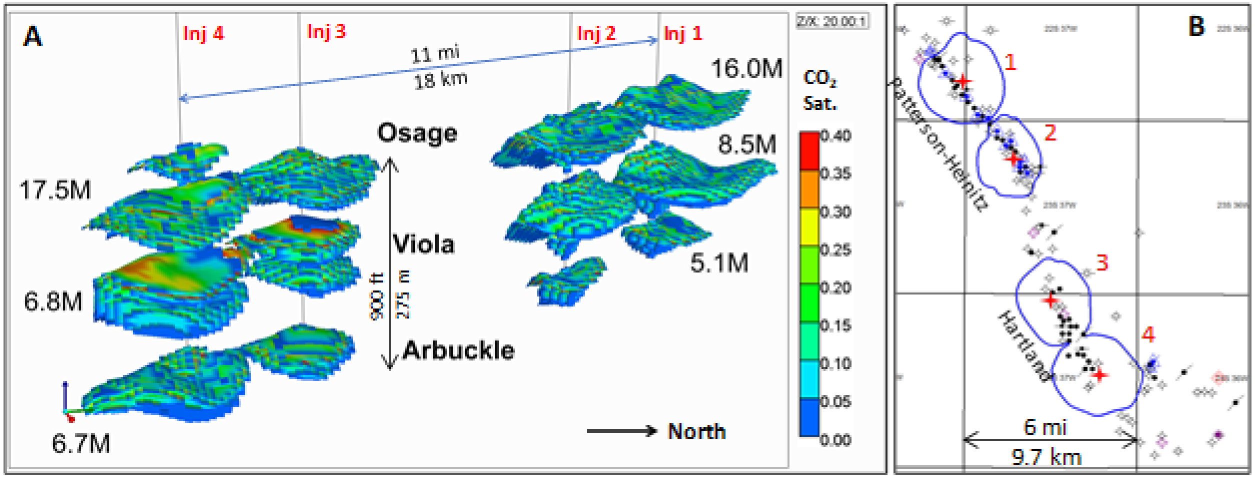

Figure 6. Dynamic simulation results showing CO2 plumes after vertically stacked injection in the Arbuckle, Viola, and Osage. A. 3D view of CO2 plumes in stacked saline aquifers with CO2 volume stored for each plume (million tonnes). B. Plate showing aerial extent of plumes for the four injectors and 132 wells that penetrate the Morrow caprock (~4800 ft)

Figure 7 presents the distribution of reservoir pore-pressure at the maximum point of CO2 injection. The pressure increases are estimated to be below 500 psi on commencement of injection and then pressure gradually drops after the commencement of the injection as the capillary effects are overcome. The pressure decreases to almost pre-injection levels after approximately 15-20 years as illustrated in Figure 8.

Figure 9 illustrates modeled cumulative injection volumes obtained via injection by 4 injection wells completed at Osage, Viola, and Arbuckle intervals. Maximum combined injection rate for 4 wells modeled for Patterson Site is 5,800 metric tonnes/day. The cumulative injected CO2 estimate for the Patterson Site is 60.7 M metric tonnes; however, the injection strategy could be optimized to inject even higher amount of CO2 at this site.

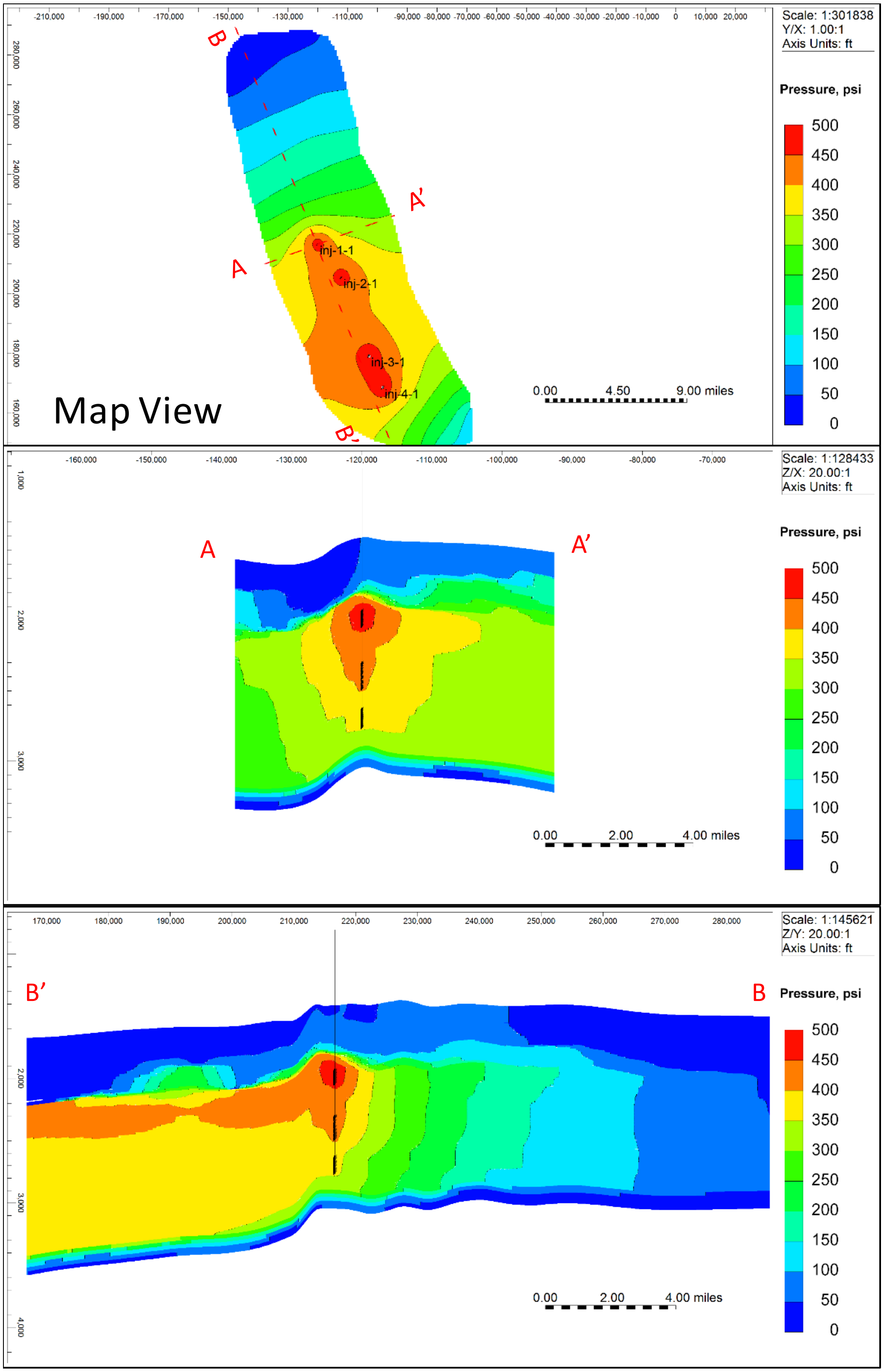

Figure 7. Maximum reservoir pressure increase as a result of CO_2 injection

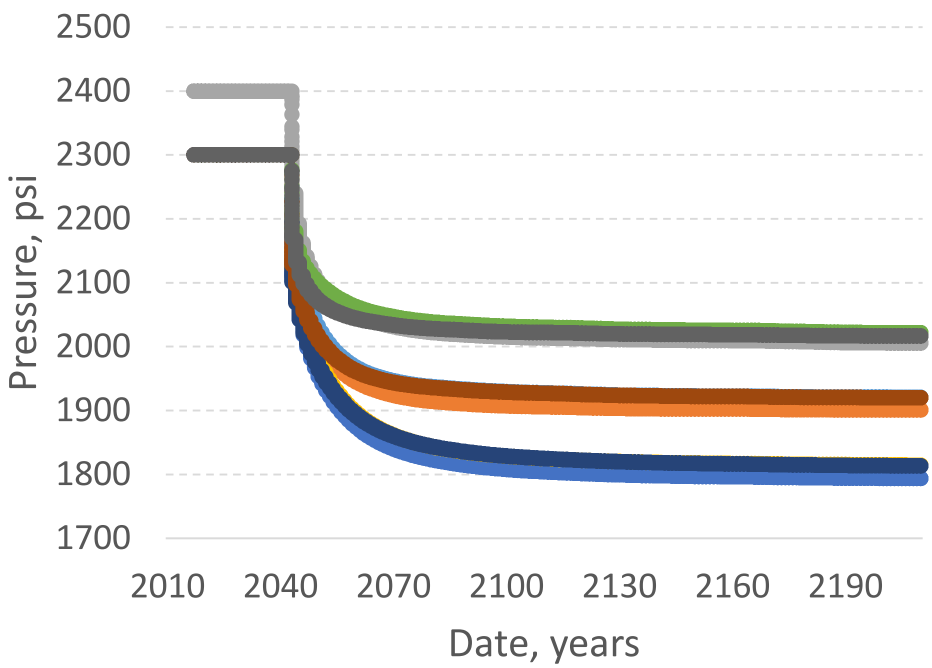

Figure 8. Bottom-hole pressure profiles for CO2 injection in four wells and three injection intervals.

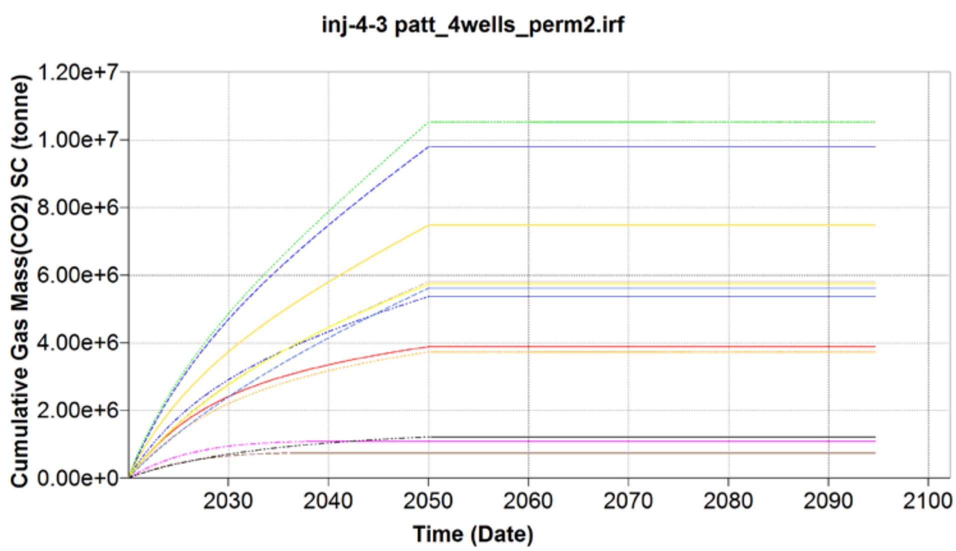

Figure 9. Cumulative CO2 injection volumes in four wells and three injection intervals.

Summary/Discussion

For CO2 injection simulations at the Patterson site, four wells were placed in close proximity to the apex of the linear closed structure where there was higher porosity and permeability indicated in the 3D static model in the three storage zones, the Osage, Viola, and Arbuckle (Figure 1). A fully-compositional simulation using CMG Gem software was performed. Injection was restricted to a delta P of 600 psi above reservoir pressure and a maximum of 2400 psi in the Arbuckle, approximately equal to hydrostatic pressure and 2100 psi under fracture pressure (assuming 0.75 psi/ft). Daily injection rates were 1.6, 1.3, 1.5, and 1.4 kilotonnes/day for 30 years, storing 60.7 tonnes. Maximum plume diameter averages 2.9 miles (4.6 km) 100 years after injection ceased.

Geochemistry

There are only isolated salinity and total dissolved solids (TDS) analyses in the Patterson geologic site region (Patterson, Heinitz, and Hartland oil pools). Most of these are isolated drill-stem tests with limited recovery of formation water. Lacking these direct salinity measurements, well-log techniques can be employed to determine salinities. These techniques are outlined in Doveton (2004) and in this particular region around the Patterson site, the deep induction resistivity log and neutron-density porosity measurements are utilized. In order that the apparent resistivity (Rwa) of the water can be determined by well-log analysis, no hydrocarbons can be present in the porous zones analyzed. Off-structure wells are thus better for this type of analysis. In addition, the zone being analyzed cannot be too shaly, thus all depth intervals with 50 or greater API gamma-ray units were ignored. The minimum porosity (average of the neutron and density measurements) considered for analysis is 8%, and the minimum thickness of the porous zone has to be 2 feet or greater, otherwise the induction log focal area will also read higher than normal resistivity due to the effects of the induction device also reading any non-porous strata adjacent to the porous zones of interest.

Salinity by depth is plotted for three deep wells analyzed in Figure 10. If the porous zones in each well were in vertical communication by either fluid-transmitting faults or stratigraphic contact, then a steady increase in salinity with depth would be expected, because highly saline water, being denser would sink, or seek out, the lowest level to which it could settle. Concomitantly less-saline (and less dense) water would be displaced upward. However, water within the Viola and Arbuckle in all three wells decreases in salinity with depth within each unit. Physical separation, or impermeability of the nonporous units between porous zones in each unit is thus indicated. Porous zones in the Mississippian (Meramec, Spergen, Warsaw, Osage) of each well are more vertically isolated than in the sub-Mississippian units. The varying salinity of each of these porous zones in the Mississippian implies that they are also isolated from each other. The Osage appears to have the most laterally contiguous porous zones of the Mississippian sub-units.

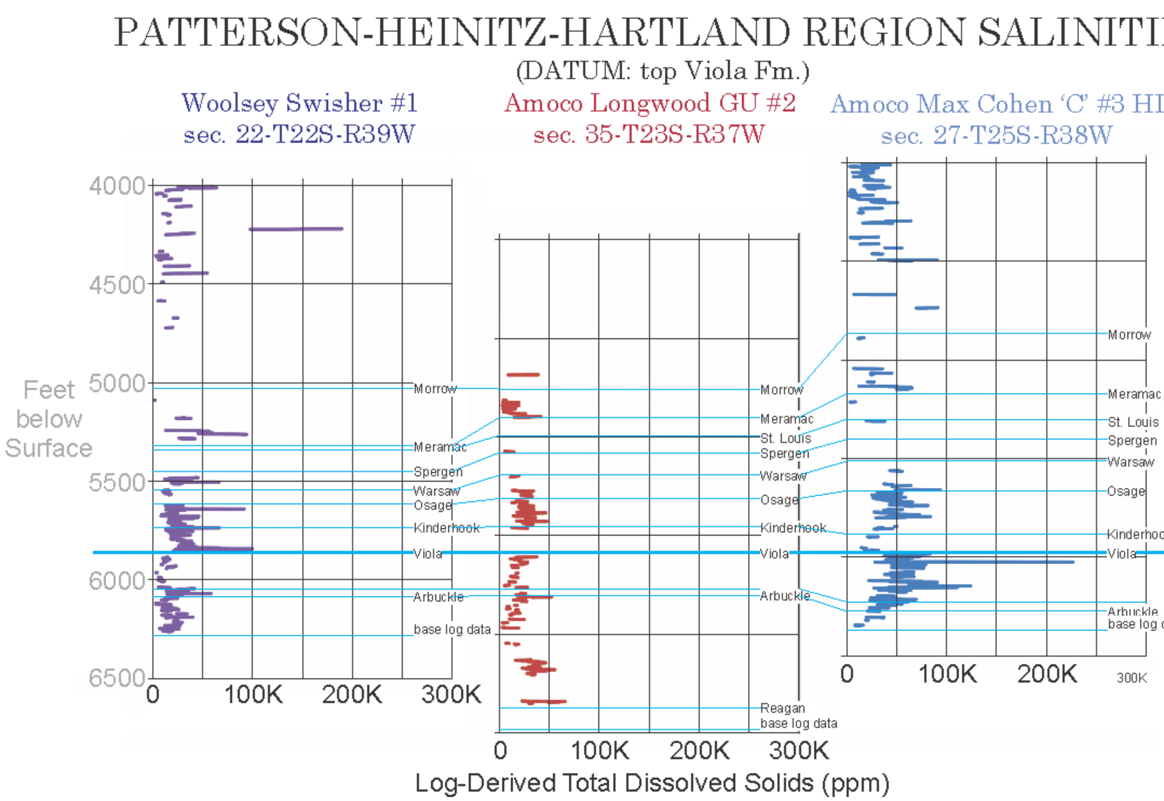

Figure 10. Salinity vs. depth plots for three wells in the Patterson site area. Cross section datum is the top of the Viola.

In general, salinity increases regionally southward toward the Cohen well. The Longwood well generally has the least porosity. Some zones in the Pennsylvanian above the Morrow in all three wells can have relatively fresh water (5,000 - 10,000 ppm TDS). The reason for this is unclear, but perhaps these porous zones are physically isolated from ion-contributing shales, or perhaps are subject to be washed by relatively fresh water coming in from near the surface. Like the salinity that characterizes to Mississippian, salinity in the Arbuckle is relatively low (~25,000 ppm TDS). This salinity level exceeds that of the maximum for potable water (i.e., 10,000 ppm TDS), but is less than that of sea-water (i.e., 34,000 ppm TDS).

Key outcome 2: Pleasant Prairie site high-level technical analysis (capacity, injectivity, seals).

A characterization, 3D modeling and reservoir simulation study was completed for the Pleasant Prairie site (Figures 1 and 11). Dynamic modeling resulted in 67.4 million tonnes could be injected into three wells over a twenty-year period in three saline storage zones, the Osage, Viola, and Arbuckle (Figure 12). The Pleasant Prairie Technical report is slated to be completed in the next quarter.

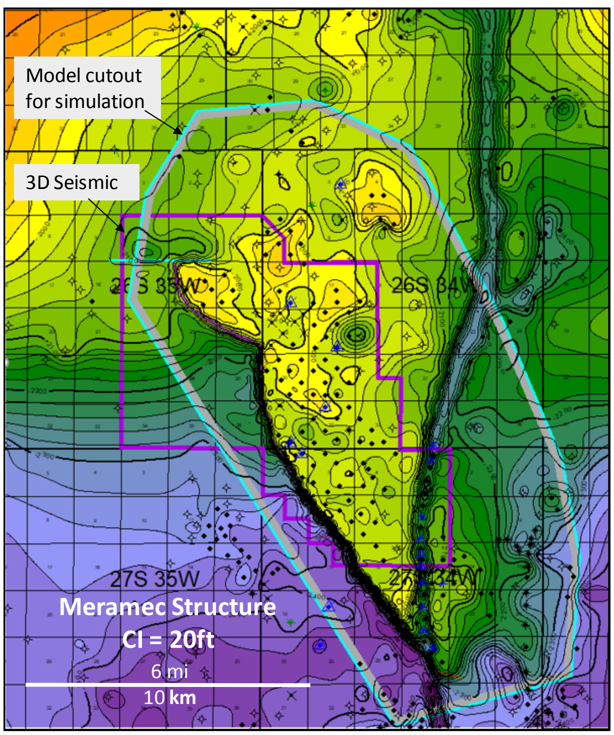

Figure 11. Structure map on top of the Meramec (Mississippian) over the Pleasant Prairie field.

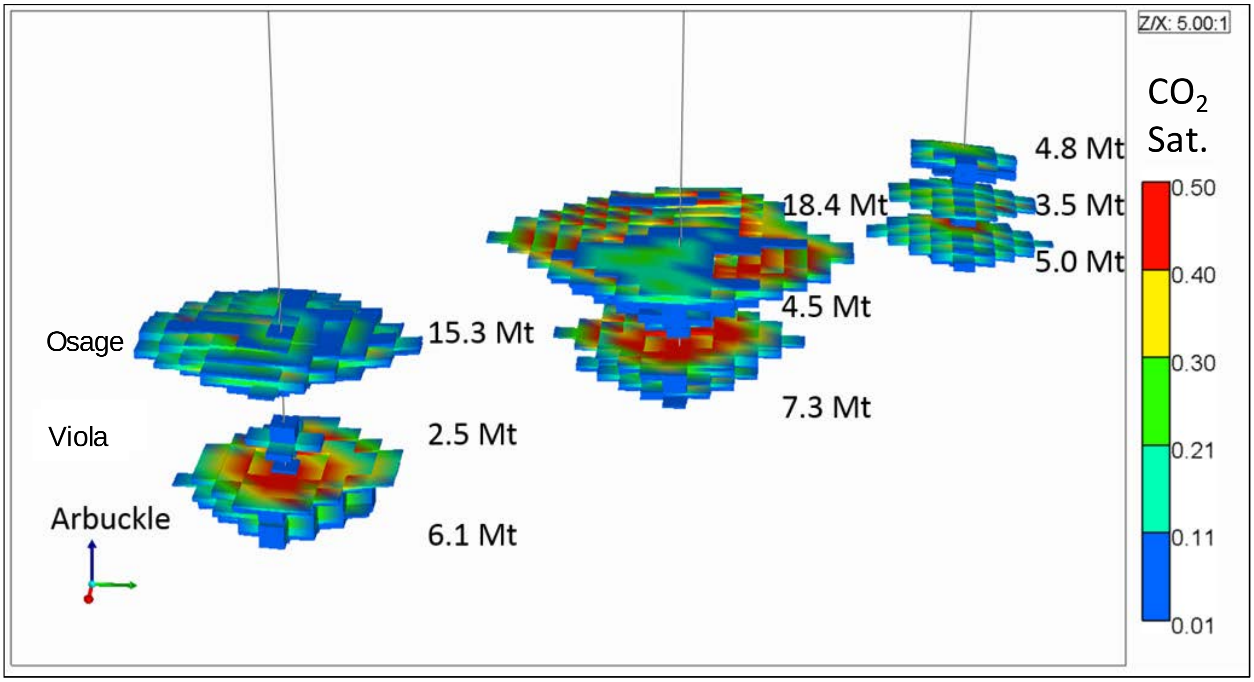

Figure 12. Dynamic simulation results showing CO2 plumes after 20 years of injection in the Arbuckle, Viola, and Osage. Numbers are CO2 volume stored for each plume (million tonnes).

Key outcome 3: Rupp site high-level technical analysis underway.

Although the Rupp is not considered the primary injection site it is being evaluated as an alternative site, as a part of the NHSC. The site was characterized and modeled concurrently with the Patterson site. Dynamic modeling is currently underway and to be completed in the next quarter.

Goals and objectives for the next Quarter:

- Complete dynamic modeling at the Rupp site.
- Complete initial draft of high-level technical evaluation reports for the Patterson. Rupp, and Pleasant Prairie sites. Complete technical risk assessments for the Patterson site.

Products for Subtask 4.2:

- Partial draft of the Patterson site high-level technical analysis (capacity, injectivity, seals) presented in the body of this report.
- Pleasant Prairie sits preliminary injection and storage capacity documented through simulations.

Subtask 4.3 - Compare results using NRAP with methods used in prior DOE contracts including regional and sub-basin CO_2 storage

Significant accomplishments: Nothing to report.

References:

Bui, L. H., Tsau, J. S., and Willhite, G. P., 2010, Laboratory investigations of CO2 near-miscible application in Arbuckle Reservoir: SPE Improved Oil Recovery Symposium held in Tulsa, Oklahoma, 24–28 April 2010, SPE Publication 129710.

Carter, R. D., and Tracy, G. W., 1960, An improved method for calculating water influx: Petroleum Transactions, AIME, vol. 219, p. 415–417.

Chang, K. W., Minkoff, S. E., and Bryant, S. L., 2009, Simplified model for CO2 leakage and its attenuation due to geological structures: Energy Procedia, v. 1, p. 3,453–3460.

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Task 5.0 – Perform a high level technical CO2 source assessment for capture

An assessment of the capture technologies best suited for efficiency, addressing the concerns of the electric utilities and their operating requirements and economic needs will be performed.

Subtask 5.1- Review current technologies and CO_2 sources of team members and nearby sources using NATCARB, Global CO_2 Storage Portal, and KDM

The CCS team shall develop an organized electronic clearinghouse of vital information pertaining to the project, ranked by suitability, historical usage records, adaptability, scaling, and demonstration of success, and operations and maintenance requirements.

Summary of Activities: Completed in Q1

Significant Results/Key Outcomes: Completed in Q1

Subtask 5.2- Determine novel technologies or approaches for CO_2 capture

Goals and Objectives: CO_2 sources shall carefully be evaluated for suitability with new capture technologies. The evaluation will utilize private research including that sponsored by DOE and results of international efforts and projects such as DOE's Carbon Capture Simulation Initiative (CCSI) to determine the suitability and rational for making decisions to pursue or table the technology.

Summary of Activities: Completed in Q2.

Significant Results/Key Outcomes: Completed in Q2.

Subtask 5.3- Develop an implementation plan and strategy for cost effective and reliable carbon capture

Goals and Objectives: An optimal CCS plan and strategy that best represents the holistic operating environment and requirements of the CO_2 sources will be developed. The team shall develop a means to ensure a mechanism to update and adapt to new disruptive technologies and possibly accommodate them in the design document.

Summary of Activities: Completed in Q2

Significant Results/Key Outcomes: Completed in Q2

Goals and objectives for the next Quarter:
During the next two quarters, the team will consolidate data and preliminary reports into a comprehensive final report.

Products for Subtask 5: None to report.

Task 6.0 – Perform a high level technical assessment for CO2 transportation

Subtask 6.1 - Review current technologies for CO_2 transportation

Nothing to report.

Subtask 6.2- Determine novel technologies or approaches for CO_2 transportation

Nothing to report.

Subtask 6.3 - Develop a plan for cost-efficient and secure transportation infrastructure

Overview:

Understanding the economics of transporting CO2 from anthropogenic sources in the most optimal manner is a key component of the ICKan project. In December, 2017, three Phase I pre-feasibility projects agreed to combine efforts for a single, Phase II proposal with Battelle as the lead. The combined project involves the ICKan Project (KGS, FE0029474), and two others, Nebraska Integrated Carbon Capture and Storage Pre-Feasibility Study (Energy and Environmental Research Center, **FE0029186**), and the Midcontinent Stacked Carbon Storage Hub Project (Battelle, **FE0029264**). In the current quarter, several possible source-geologic site scenarios for the combined Phase II project were evaluated.

Summary of significant activities:

- Contributed to a white paper published online: Capturing and Utilizing CO2 from Ethanol: Adding Economic Value and Jobs to Rural Economies and Communities While Reducing Emissions (State CO2 Workgroup, 2017).
- Performed cost and economic analyses for several capture and transportation infrastructure scenarios under consideration in a combined Phase II proposal, named Midcontinent Stacked Carbon Storage Hub Project.

Significant Results/Key Outcomes:

Key outcome: Cost analysis and economics of capture and transportation scenarios for the Midcontinent Stacked Carbon Storage Hub Project (IMSCS-HUB)

Introduction
In the last quarterly report (ICKan Q2), we reported results of economic analyses for a variety of possible ICKan CO2 pipeline transportation systems, but not the capture component. The analysis took into account capital and operating costs for 22-year projects, two years for construction and 20 years of operations, and the cost of capital (required rate of return). The scenarios were compared in terms of the "price" for which the CO2 would need to be sold for the rate of return required. In this report, the cost of CO2 capture was added to economic analysis for six possible scenarios under the Midcontinent Stacked Carbon Storage Hub Project (IMSCS-HUB), which combines three Phase I projects.

Six Scenarios Analyzed
Cost and economic analysis of capture, compression, and transportation was conducted for five source-sink and pipeline routing scenarios envisioned for the IMSCS-HUB Project, and one regional-scale scenario (Table 8). For the five IMSCS-HUB scenarios, ethanol-derived CO_2 sources analyzed include the ADM plant in Columbus, NE; the Valero plant in Albion, NE; the Cargill plant in Blair, NE; also referred to as the Columbus-Albion-Blair plants (CAB). Power plant-derived CO_2 sources include NPPD's Gerald Gentleman Station (GGS) and Sunflower Electric's Holcomb Station. Scenario 6 represents a regional scenario derived from a white paper released by the State CO_2-EOR Deployment Working Group (2017) wherein CO_2 from 34 ethanol plants in the Midwest is transported through Nebraska, Kansas, and Oklahoma to the northern extent of the Permian Basin pipeline infrastructure. This represents a large-scale regional scenario that could be leveraged by the IMSCS-HUB Project to achieve commercial status.

Scenario	Source(s)	Site(s)	Pipeline Length	Pipeline Route
1	CAB ethanol plants	Patterson	481	From sources to storage site via oilfields
2	CAB ethanol plants	Sleepy Hollow	344	From sources to storage site via oilfields
3	CAB ethanol plants	Sleepy Hollow	295	Direct from sources to storage site
4	GGS power plant	Sleepy Hollow	79	Direct from source to storage site
5	Holcomb Station	Patterson	28	Direct from source to storage site
6	34 ethanol plants	Permian Basin	1,546	Direct from sources to Permian Basin

Table 8. CO_2 source-sink pairs and pipeline routing scenarios evaluated for the IMSCS-HUB Project. Patterson is an ICKan defined site in southwest Kansas and Sleepy Hollow is an IMCS-HUB site in southwest Nebraska.

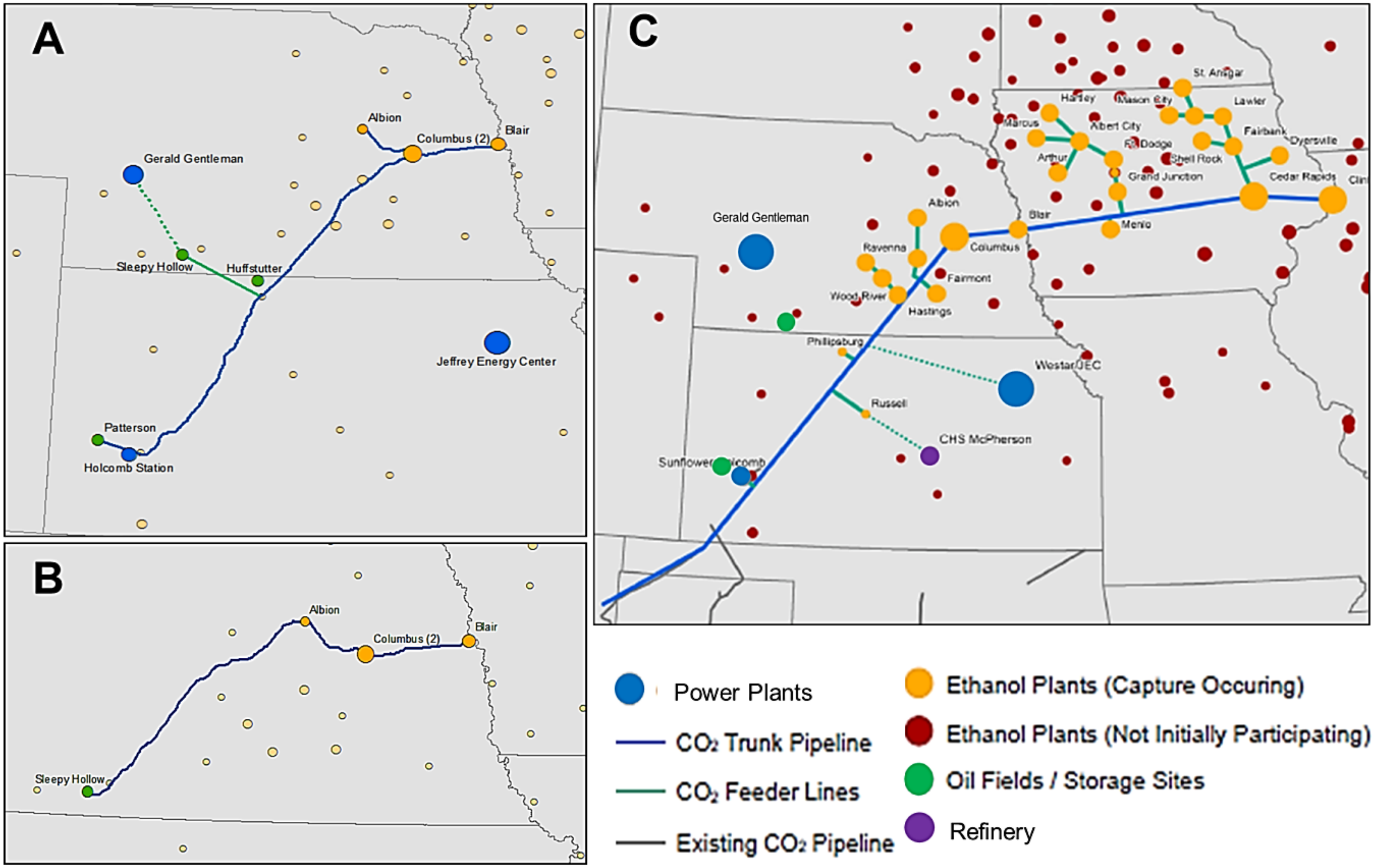

Figure 13. Map showing source-sinks pairs and pipeline routes for (A) scenarios 1, 2, 4, and 5, (B) scenario 3, and (C) scenario 6 (Figure Credit: Great Plains Institute (GPI) and Improved Hydrocarbon Recovery, LLC). Ethanol plant production capacity is represented by the relative size of each circle from 40 to 250 million gallons per year (DOE-EIA, 2017; State CO_2-EOR Deployment Workgroup, 2017.

Analysis:

The pipeline routing analysis for Figures 13a and 13b was conducted by IMSCS-HUB team members at Los Alamos National Laboratory using the SIMCCS economic-engineering optimization model for Carbon Capture and Storage (CCS) infrastructure. The model included identification of all major permit and regulatory requirements and regulatory gaps relevant to the constriction, ownership, and operation of the pipeline system. Major environmental considerations were also identified for the potential pipeline routes to selected areas in southwest Kansas and southwest-central Nebraska. For the analysis of the regional-scale scenario (Figure 13c), the National Energy Technology Laboratory's (NETL) CO_2 Transport Cost Model (Grant et al., 2013; Grant and Morgan, 2014) was modified by ICKan team members at Great Plains Institute (GPI) to calculate costs for multiple pipeline segments (Dubois et al., 2017). Model output includes capital costs for materials, labor, right-of-way negotiations, CO_2 surge tanks, pipeline control systems, and pumps. Operational costs include pipeline operation and maintenance (O&M), equipment and pumps, and electricity costs for pumps, by segment. Pipeline network scenarios were mapped in ESRI's ArcGIS to determine the route, length, and volume of each segment of the network. Pipeline segment lengths specified were 110% of straight-line distances to account for route departures. Ethanol CO_2 production was set at 90 percent of plant potential based on nameplate ethanol production volumes derived from Energy Information Agency (EIA) tables (DOE-EIA, 2017). Resulting cost estimates (Table 9) are in line with a CO_2-EOR industry rule of thumb of $100,000 per inch-mile.

Estimating the capital and operating costs for CO_2 capture, compression, and dehydration (CCD) from fermenters in an ethanol plant is problematic because of the paucity of publicly available data. There are only three commercial-scale ethanol plant operations that currently process and deliver CO_2 via pipelines for injection into geologic targets, and capital expenditures (CapEx) and operating expenses (OpEx) are not publicly available for the three privately operated facilities. CapEx estimates were derived from results reported for ADM's Industrial Carbon Capture and Storage (ICCS) Project (McKaskle, 2016) and other DOE-funded projects (IMCCS, 2010; ICCSND, 2017), and then adjusted based on expert opinion from the ICKan Project partners. A simple linear regression equation (Equation 1) was derived by cross-plotting CapEx estimates and ethanol plant size in MGY for the three examples:

$$\text{CapEx (\$Million)} = 0.15 * \text{Plant Size [million gallons per year (MGY)]} + 9$$

Operating expense for capture, compression, and dehydration from ethanol plants in this study is $8.58 per metric tonne processed. Operating costs are derived from the two DOE final reports and are applied in a linear fashion for all CO_2 volumes. By far, the largest contributor to OpEx is energy costs which are directly proportional to CO_2 volumes compressed. Savings due to economies of scale for larger-sized ethanol plants have not been taken into account.

Power plant capital and operating costs are currently being estimated by Linde for the ICKan project and will be applied as those data become available. For now, power plant capture capital costs were scaled in proportion to Petra Nova's unofficial total costs of $1 billion for capturing, compressing and transporting 1.4 million tonnes (Mt) per year. Operating costs for post-combustion capture (PCC) are not available and were not included in the operating costs. Compression operating costs at the capture site were estimated to be $8.58/tonne, the same as that for CO_2 derived from ethanol production.

For the economic analysis, the CO_2 capture equipment and pipelines are modeled as 22-year projects with a 2-year construction phase (2022-2023) and 20 years of operation and amortization beginning at 2024. A 6.7% rate of return (ROR) on the investment was required. The price for CO_2 required at the outlet to cover all capital and operating costs and the cost of capital over the 20-year operational life were calculated.

Results:

Three economic scenarios are presented and expressed in terms of cost per tonne of CO_2 delivered, 1) with no subsidies, 2) 45Q credits for 100% EOR, and 3) 45Q credits for 100% saline storage. Section 45Q credits start at value of $12.83/tonne CO_2 (EOR) and $22.66/tonne CO_2 (saline storage) in 2017 and ramp linearly to $35/t CO_2 (EOR) and $50/t CO_2 (saline storage) in 2026. The recently expanded and extended Section 45Q tax credits can be applied for 12 of the 20-year operations period in the economic model and would amount to approximately $26/tonne net credit for the EOR case and $36.tonne net for the saline storage case.

Saline storage (cases 4 and 5) is not an economic proposition even with Section 45Q tax credits without additional subsidy from other sources. The four ethanol source scenarios (cases 1, 2, 3, and 6) have relatively low delivery costs when 45Q EOR credits are applied (<$27/tonne). If the CO2 were to be sold at Permian-market rates (0.02*$WTI/mcf), $21-$29/t CO_2 for West Texas Intermediate (WTI) oil prices of $55-$75 per barrel, capture and transportation could be profitable. Profits from the sale of CO2 for EOR could subsidize CO_2 for saline storage in stacked storage operations like those proposed in the ICKan and IMSCS-HUB projects. A distinct advantage of the IMSCS-HUB Project is that the technology for ethanol-based CO_2 capture and transport for EOR is currently economically feasible and can be commercially deployed today to subsidize ethanol CO_2 saline storage, and provide scalable infrastructure needed to integrate CO_2 capture from power plants in the future.

Parameters	Scenarios and Costs Summary					
	1	2	3	4	5	6
CO_2 Volume (Mt/yr)	1.96	1.96	1.96	2	1	9.9
Pipeline Distance (miles)	481	344	295	79	28	1546
Maximum Diameter (inches)	12	12	12	12	6	20
Pipeline CapEx ($M)	$439	$303	$272	$80	$23	$1,857
Pipeline Annual OpEx ($M)	$6.10	$4.40	$3.70	$1.20	$0.80	$47
Capture/Compression CapEx ($M)	$132	$132	$132	$1,143	$571	$809
Cap/Comp Annual OpEx ($M)	$16.80	$16.80	$16.80	$17.20	$8.60	$84.50
Total Project CapEx ($M)	$571	$435	$404	$1,223	$594	$2,666
Total Project Annual OpEx ($M)	$22.90	$21.20	$20.50	$18.40	$9.40	$131.50
Economics - Capture and Transportation	CO_2 Price Required for 6.67% Rate of Return					
Pipeline Total ($/tonne)	$33.40	$24.48	$22.13	$4.98	$3.35	$31.99
Cap/Comp Total ($/tonne)	$17.72	$18.30	$18.44	$71.49	$71.91	$20.44
No Subsidies Combined Total ($/tonne)	$51	$43	$41	$76	$75	$52
With 45Q Credits for EOR ($/tonne)	$26	$17	$15	$51	$50	$27
With 45Q Credits for Saline Storage ($/tonne)	$15	$6	$4	$40	$39	$16

Table 9. Summary of estimated costs and economics for capture, compression and transportation with and without 45Q tax credits for the 6 scenarios. Costs are in millions of dollars ($M) unless otherwise specified.

Products for Subtask 6.3:

Cost analysis and economics of capture and transportation scenarios for the Midcontinent Stacked Carbon Storage Hub Project (IMSCS-HUB)

References

Dubois, M. D. McFarlane and T. Bidgoli, 2017, CO2 Pipeline Cost Analysis Utilizing and Modified FE/NETL Cost Model Tool, poster presented at the Carbon Storage and Oil and Natural Gas Technologies Review Meeting, Pittsburgh PA, August 3, 2017.

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Grant, T. and D. Morgan, 2014, FE/NETL CO2 Transport Cost Model. National Energy Technology Laboratory. DOE/NETL-2014/1667. https://www.netl.doe.gov/research/energy-analysis/analytical-tools-and-data/co2-transport. Accessed 6/28/2017.

Integrated Mid-Continent Carbon Capture, Sequestration & Enhanced Oil Recovery Project, final report for DOE Project # DE-FE-0001942, August 31, 2010.

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McKaskle, R. (2017) Trimeric Corporation, Insights into Costs of CCS gained from the IBDP, 2016 Midwest Carbon Sequestration Science Conference, May 17, 2016.

State CO2-EOR Deployment Workgroup, 2017, Capturing and Utilizing CO2 from Ethanol: Adding Economic Value and Jobs to Rural Economies and Communities While Reducing Emissions. http://www.betterenergy.org/sites/default/files/Capturing%20and%20Utilizing%20CO2%20from%20Ethanol.pdf

Task 7.0 – Technology Transfer

The ICKan project focused on additional targets for the CO_2 sequestration, including the Patterson site described under tasks 4 and 5. A search area was created to search for wells and the available data in the Kansas Geological Survey Database. All available field information was provided by the operator, Berexco, LLC. The project web page provided direct access to the wells in the study areas. The web page URL is http://www.kgs.ku.edu/PRS/ICKan/Summary/.

Subtask 7.1- Maintain website on KGS server to facilitate effective and efficient interaction of the team

The ICKan Project Well Data Summary Web Page provides a publicly available database for users to view and download data collected from the ICKan project. This paged is updated on a regular basis and maintained by John Victorine with contributions from others.

Subtask 7.2 - Public presentations

Updates posted to the ICKan project page (http://www.kgs.ku.edu/PRS/ICKan/presentations.html).

Subtask 7.3 - Publications

The group contributed extensively to the State CO_2-EOR Work Group and GPI white paper published recently: Capturing and Utilizing CO_2 from Ethanol: Adding Economic Value and Jobs to Rural Economies and Communities While Reducing Emissions. Work done for CarbonSAFE ICKan was leveraged to illustrate the economic case for large-scale infrastructure to capture and transport Ethanol CO_2 for EOR and storage (pp 16-20 and 27-28). The white paper was used extensively to bolster the lobbying efforts by GPI, NEORI, the State Working Groups, as well as others.

This effort was instrumental in securing the passage of the extended and expanded 45Q. The body of ICKan work, including the 9/21 Wichita meeting, contributed to technical work that went into materials used by those "working the halls" to get 45Q passed. The 9/21 meeting provided a forum that created a nucleus of support for 45Q that helped get our Kansas Governor and the Kansas delegation on board. The decade or so of work by all of the KGS staff is foundational, enabling Kansas to respond. GPI has been invaluable to the project, and within the context of the KGS collaboration with GPI, have assisted in GPI's leadership role through the State Work Group and NEORI, the leaders in supporting the initiative to get 45Q expanded and extended. Work completed by both technical (KGS, Linde, IHR) and non-technical (KGS, GPI, and DGR&M) groups have prepped Kansas for the move beyond a paper study.

Appendix A: Anticipated business contractual requirements necessary to address technical and financial risks

What business contractual requirements this project will require depends, in the first instance, on the business model for CCS the project ultimately embraces. Experience in other states suggests two potential general models: the public utility model and the private party model. In the public utility model, the transportation, disposal, and storage of CO_2 would be accomplished by one or more public utilities. Variations of the model may include a single public utility that is responsible for capture, transportation, disposal, and storage of captured CO_2, or separate utilities individually responsible for transportation and storage. Under a private party model, separate private firms would independently conduct the capture, transportation, disposal, and storage of CO_2.

The business contractual requirements necessary to address project risks would be greater under a private party model because custody of the CO_2 would potentially change hands among a succession of persons. Whereas under a public utility model, and particularly where a single public utility conducts all operations downstream of the generator, the number of persons involved in the chain of custody would be fewer.

Regardless of which model ultimately emerges in this project, the business contractual requirements we anticipate to fully address technical and financial project risks fall into five broad categories: (1) capture, (2) transportation, (3) disposal and storage, (4) long-term liability, and (5) title to CO_2. We will survey the likely business contractual requirements in each category below.

I. Capture

Under either a public utility or private party paradigm, there are conceivably two alternative business arrangements for capture of CO_2. Either the generator will install, operate, and maintain the capture technology at the generation facility, or a third-party contractor will do so. There are few, if any, contractual considerations in the former scenario because the generator will bear all of the risks associated with capture. Where capture is conducted by a third-party, however, a contractual relationship between generator and capture contractor will need to address the risks of technical failure. In particular, the parties' contract must allocate the responsibility for maintenance and repairs, and the liability associated with system failure. System failure liability could include civil penalties for violation of applicable air permits and costs of plant downtime caused by a system failure. A full understanding of the potential technical and financial risks of capture is possible only after a thorough study of the methods and technology under Phase II. Additionally, any contractual relationship between a generator and capture contractor will need to address compensation for the contractor's services and title and responsibility for the captured CO_2 (the latter concern is addressed in section V, below).

II. Transportation

Once the CO_2 is sequestered at the generation plant, it will need to put into a pipeline for transportation to the ultimate storage site. The possible business models for pipeline transportation of CO_2 are myriad, especially under a private party model, and accordingly it is impossible at this stage to precisely anticipate, or briefly summarize, all of the contractual considerations that could arise. It is reasonable to predict the following issues.

Generator and transporter will need to agree on whether title and responsibility for the CO_2 is transferred and, if so, where the transfer occurs. This is addressed in section V, below.

Assuming the CO_2 remains the generator's property, the parties will need to price the transportation. The price will likely include charges for maintenance, compression, treatment and processing, and regulatory compliance (e.g., LDAR), incurred by the transporter. The price may vary based on either the volume delivered to the pipeline, the distance the CO2 is transported, any potential gas quality issues that may need to be addressed, or a permutation of these factors. Alternatively, if the generator sells the CO2 to the transporter, the parties will need to price the CO2. Any pricing mechanism would likely begin with the prevailing market price for CO2 (if any) and deduct costs of transportation.

The parties will allocate liability for shrinkage or loss of the CO2 stream during transportation. How parties allocate this risk may depend on which retains title to the CO2. This could include regulatory fines, penalties, and response costs.

The parties will allocate the technical risks associated with quality of the CO2. These risks may include the pH balance of the CO2 stream, as well as the presence of other impurities or contaminants which may be present, and its possible effects on the physical line. In addressing this issue, the parties are likely to adopt gas-quality criteria in their contract that the CO2 must satisfy as a condition to transportation through the pipeline.

Under one possible business model, portions of the CO2 stream may be diverted for sale to third parties for various industrial applications, notably tertiary oil recovery. Sales of CO2 to third parties will involve contracts which both transfer title to the CO2 and allocate the risks of subsequent transportation and application of the CO2. The sale of portions of the CO2 stream may also effect contractual relations between the transporter and generator if title to the CO2 remains with the generator.

The transporter and the owner of the pipeline facility may be separate entities under some business models. In this case, there would be a contractual relationship between the two allocating the costs and risks of use of the physical pipeline.

The owner of the pipeline will obviously need to first construct the line. The construction process would begin with right-of-way acquisition, which will entail consensual easement agreements with landowners as well as easements obtained by condemnation.

III. Disposal and Storage

The contractual considerations surrounding disposal and storage of captured CO2 begin with acquisition of rights in storage formation. Kansas law appears to hold that title to subsurface pore space remains with the surface estate despite severance of the mineral estates. *See Dick Props., LLC v. Paul H. Bowman Tr.*, 43 Kan. App. 2d 139, Syl. ¶ 6, 221 P.3d 618 (2010). Lacking clear legal authority for this proposition, however, contracts for the acquisition of rights in the storage formation may need to address pore-space ownership among the various surface and mineral estate owners to reduce the risk of the disposal and storage firm committing pore-space trespass. Further, because storage formations may span many acres of surface land, it is usually necessary to obtain consent and transfer of rights from numerous owners of contiguous land. The public utility model is an attractive vehicle for such purposes because a utility can possess the power to condemn the rights of contiguous landowners for storage purposes. Absent statutory authority in Kansas for condemnation of saline storage formations, disposal and storage firms would need to obtain contractual agreements with all owners of the contiguous acreage needed for a storage formation. The significant associated costs would be contractually allocated among the disposal and storage firms and the titleholder of the CO2 (likely the generator).

Disposal will require a regulatory permit for a Class VI Underground Injection well. In Kansas, this is administered through the U.S. Environmental Protection Agency. Class VI disposal well regulations, effective since 2011, have six phases of regulations and monitoring, from amalgamation of storage rights to post-closure long term monitoring. Contractual agreements will need to clarify whom is applying for what phases, whom is responsible for the costs associated with meeting the performance standards of the permit, and for providing the financial assurance to protect or remediate a drinking water source, if necessary.

The separate acts of disposal and storage may not be conducted by one firm under some business models. Consequently, where the two activities are undertaken independently of one another, a contractual relationship will need to exist between the two firms. The relationship will need to address compensation, liability for plugging and abandonment of injection wells, and liability for leakage including proximate property damage and personal injury. These risks could arise in a number of foreseeable scenarios including migration or escape of CO2 into adjacent geologic formations or formations underlying land not included in the storage site (which we refer to as "pore-space trespass"), accidental release of CO2 into formations bearing underground drinking water, and even accidents from the pressurized pipeline transportation or injection of gaseous CO2. Under some circumstances, this may include the cost of regulatory compliance, fines, and penalties. These same risk allocations will need to be made between the disposal firm and the transporter under a contractual relationship governing delivery of the CO2 at the tail end of the pipeline.

Whichever party or parties among generator, transporter, disposal firm, and storage firm, bears the risks of casualty loss from leakage will likely seek to reduce or eliminate these risks through insurance. One (of several) possible contractual insurance arrangements may involve the penultimate custodian of the CO2 (most likely the storage firm) purchasing a policy of casualty or general liability insurance covering operation of the storage site under which the generator is additional named insured. The costs of such an insurance policy would likely be allocated between the primary and additional insureds through the price charged for storage (or, alternatively, the price paid for the CO2 by the storage firm).

IV. Storage Site Closure and Long-Term Liability

Several states have codified a procedure by which the state ultimately takes responsibility for monitoring and liability of a closed storage site. Kansas does not appear to have adopted such a procedure; consequently, storage firms and generators would need to contractually limit their long-term liability for closed storage sites, likely through private insurance. The most likely form of insurance would be a single premium tail or cost cap policy. It is unclear, however, whether there is an insurance market for long-term risks associated with closed CO2 storage sites. For the project to be feasible, it is probable a statutory regime shifting responsibility for monitoring and long-term liability to the state would need to be passed. The specific long-term risks associated with a closed CO2 storage field are similar to those associated with an operational site (e.g., pore-space trespass, drinking water contamination, and pressurized injection wells and surface equipment).

V. Title to CO_2

Underpinning all of the preceding categories of business contractual requirements is title to the CO2 stream. Kansas has two pertinent statutes. K.S.A. 65-3418 governs vesting of title to solid waste. Solid waste is a broadly defined statutory term that likely encompasses captured CO2. Under the statute, title to the solid waste vests in the owner of the solid waste (the generator). The solid waste remains property of the generator, and the generator remains liable for the waste, notwithstanding any contractual arrangements between the generator and third parties. However, title to the solid waste is transferred to the resource recovery facility (the storage facility so long as the storage is conducted in accordance with applicable law. If, however, the storage is not properly operated, liability for the CO2 rests with the storage facility and the generator. K.S.A. 65-3442 sets forth a similar risk-allocation scheme for hazardous waste.

Because the solid waste transfer statutes likely apply to captured CO_2, the generator is likely to be ultimately responsible for risks associated with the CO_2 throughout the capture and transportation phases of the CO_2 stream. The storage firm will become liable for the CO_2 stream upon receipt but will probably share that liability with the generator. Therefore, the generator is likely to purchase private insurance, naming the generator as an additional insured, and price the costs of such insurance into its compensation for storage services (or, under a model in which the storage firm purchases the CO_2, price the costs into the consideration paid for the CO_2).