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Geologic carbon storage at a one million tonne demonstration project: Lessons learned from the Illinois Basin – Decatur Project

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Abstract

The Illinois Basin – Decatur Project (IBDP) has demonstrated the safety, effectiveness, and efficiency of the process of isolating the carbon dioxide (CO_2) stream from biofuels production and storage in a deep saline reservoir at a depth of more than 2,000 meters. Geologic assessment and controls have proven essential to understanding reservoir conditions and predicting CO_2 behavior. The injectivity and storage capacity of part of the lower Mt. Simon Sandstone at IBDP have been confirmed. Modeling, microseismic event analysis, and MVA continue to provide significant insights into reservoir response to stored CO_2 and the development of commercial-scale project workflows.

Peer-review under responsibility of the organizing committee of GHGT-13.

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1. Introduction

Demonstration of safe geologic storage of carbon dioxide (CO_2) at the near commercial-scale is essential to gain understanding of the workflows needed to go from regional characterization to post-injection site care and closure. The Illinois Basin – Decatur Project (IBDP), located in Decatur, Illinois USA, is a one million tonne deep saline geologic CO_2 storage project led by the Midwest Geologic Sequestration Consortium (MGSC), one of the United States Department of Energy (US DOE) – National Energy Technology Laboratory's Regional Carbon Sequestration Partnerships. IBDP is a fully integrated demonstration project in the largest-capacity saline reservoir in the Illinois Basin. Stored CO_2 is derived from biofuel production at the Archer Daniels Midland (ADM) hosted test site. IBDP is currently in the post-injection monitoring phase, and the project is linked to the Illinois Industrial Sources CCS Project through scientific and permitting-related activities. These projects hold the first-ever United States Environmental Protection Agency (USEPA) Underground Injection Control permits (UIC) for Class VI, specifically developed for the subsurface storage of CO_2, in the United States.

IBDP began in 2007 with a three-year pre-injection characterization and design period, followed by three years of injection and three or more years of scheduled post-injection monitoring. In November 2014, the injection phase was safely and successfully completed with 999,215 tonnes of CO_2 injected at rate of 1,000 tonnes/day into the lower Mt. Simon Sandstone at a depth of 2.1 km. The project infrastructure includes three deep wells (injection (CCS1), monitoring (VW1), geophysical (GM1)), 17 shallow groundwater monitoring wells, microseismic monitoring with downhole 4-component sensors in the injection well, an in-well geophysical monitoring array for repeat plume monitoring using vertical seismic profile (VSP) methods, a compression/dehydration facility, and a 1.9-km pipeline. Wet CO_2 at atmospheric pressure was collected from ethanol fermentation units and delivered to the reservoir as dry supercritical CO_2. The integrated compression/dehydration, pipeline, and injection well system operated 24/7, as planned, with ADM injection operations being fully integrated with the ethanol production facility.

A rigorous and extensive monitoring program includes 3D surface seismic (2 surveys), 3D VSP (6 surveys), soil flux, atmospheric monitoring, shallow groundwater monitoring, and a deep verification well for pressure/temperature and fluid sampling. Monitoring data have been collected during the 18-month pre-injection period, 36-month injection period, and to date, 24 months of the scheduled 36-month post-injection period. Outreach and education programs, in place since 2007, continue to engage local, regional, and international stakeholders through print materials, open houses, presentations, model demonstrations, school visits, teacher professional development, stakeholder meetings, briefings, and public hearings.

This paper will focus on post-injection activities undertaken since injection in CCS1 was completed in November 2014 including extensive data analysis, repeat seismic survey, microseismic monitoring, and monitoring, verification, and accounting (MVA) activities. In January and February 2015, a repeat post-injection surface seismic data acquisition was completed. The data have been processed and compared to the 2011 pre-injection surface seismic survey. A 4-dimensional (4D) analysis of the plume development and location has been conducted. Monitoring of microseismic events and reservoir geomechanical response continues. Additionally, an assessment of monitoring technologies deployed at IBDP is underway to determine scale-up viability for commercial projects.

2. Geologic Modeling

Static (geologic) and dynamic (flow) modeling have been a central part of the IBDP. Leveraging the extensive geophysical site characterization efforts which began in 2009, a 3-dimensional (3D) geological model has been developed and systematically updated as new geological and geophysical data have become available.

2.1. Geologic model

The IBDP static modeling effort has included interpretation of 2D and 3D seismic datasets, integration of geophysical logs and core, and 3D interpolation of reservoir properties guided by advanced seismic inversion products when available. The result has been a continuously improving and increasingly more accurate geologic representation of the injection target zone and overlying formations. Although the original intent was for this static geologic model to be used primarily as the framework for the reservoir simulation model, the static model has provided the geologic context for both geomechanical modeling and the analysis of microseismic observations. Further, the model has been important in the permitting process.

A static model has been prepared with petrophysical modeling describing porosity and permeability for Argenta Formation, Mt. Simon Sandstone, and Eau Claire Formation. Each zone has been further layered to capture vertical heterogeneity. Although cell height varies by zone, grid cell size is 45 m x 45 m over the 24 km x 24 km model area. The static model also includes a structural framework supported by 3D seismic data interpretation extending up to surface level for use in the geomechanical modeling, and downward into a shallow portion of the Precambrian basement to aid the visualization of microseismic events below the storage formation. A predominant aspect of the structural interpretation is the existence of significant paleotopographic variations on the Precambrian basement underlying the Mt. Simon Sandstone (Figure 1a). The geologic model has 11 zones, 126 layers, and approximately 35,000,000 grid cells in the storage formation. Figure 1b shows the well section with porosity logs and velocity functions used for seismic time-depth conversion. The section is flattened on the top of the Eau Claire Formation illustrating Mt. Simon Sandstone thickness variations associated with Precambrian paleotopography.

a. b.

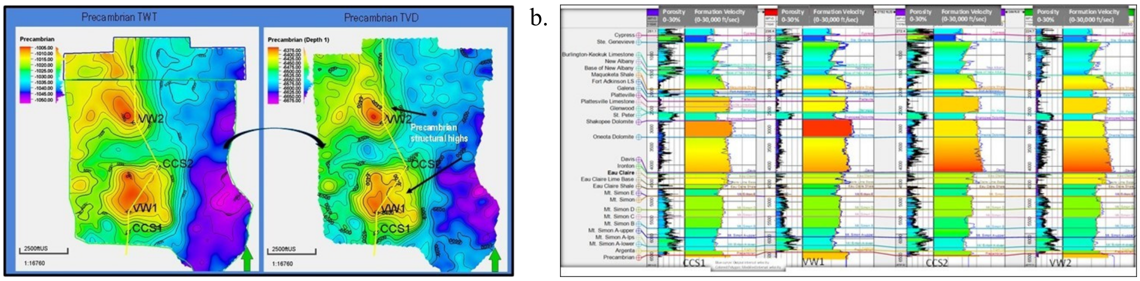

Figure 1: (a) Seismic time (left) and depth (right) at the top of the Precambrian. The yellow line indicates the well cross-section shown in (b). (b) Well cross section (1a) with porosity and velocity functions used for seismic time-depth conversion.

Well log porosity was interpolated throughout the 3D model using the Gaussian Random Function Simulation (GRFS) method, conditioned to a porosity volume computed through 3D seismic data inversion. Because the footprint of the seismic porosity volume is so much smaller than the model area, the spatial structures of the seismic porosity volume were captured through variogram analysis and used to extrapolate the upscaled porosity volume outside the seismic survey footprint. Vertical heterogeneity was re-captured through kriging interpolation with the porosity logs from the site's three wells. Permeability was interpolated from well logs using the GRFS method with co-simulation against the porosity volume. Figure 2 shows a montage of static model components including the Precambrian surface, porosity distribution, seismic reflection and porosity inversion, and wells with injection completions and monitoring ports.

2.2. Flow simulation model

The static model was used as the basis for numerical modeling of pressure and plume behavior for the initial IBDP Class VI injection permit application. A "tartan" style grid was used to provide lateral refinement of grid block size near the well as required for computational accuracy, but increased coarsening away from the well to minimize overall model size. The simulation model was initialized using pressure, temperature, and salinity measurements from CCS1. An infinite acting boundary condition was applied through use of pore volume multipliers at boundary cells.

The CCS1 completion was modeled as three intervals within the lowest portion of the Lower Mt Simon (A). The simulation model was history matched (calibrated) to the first 15 months of pressure observations from the bottomhole pressure sensor in CCS1 (and five levels of VW1 ranging in depth from the lower Mt. Simon Sandstone to the Eau Claire Shale). Plume and pressure forecasts were run for the three-year injection period and post injection monitoring period. This updated model, seen in Figure 3, was used for preliminary coupled fluid flow-geomechanical model investigations and for investigations of potential relationships between pressure front behavior and observed microseismic events. This model was also used as the basis for a comprehensive sensitivity and uncertainty analysis [1]. The results of this uncertainty analysis were instrumental in the process of history matching the model to 15 months of injector bottom hole and monitoring well pressures as well as RST* reservoir saturation tool observations. The calibrated simulation model is also central to the rock physics based time-lapse seismic integration workflow currently in progress.

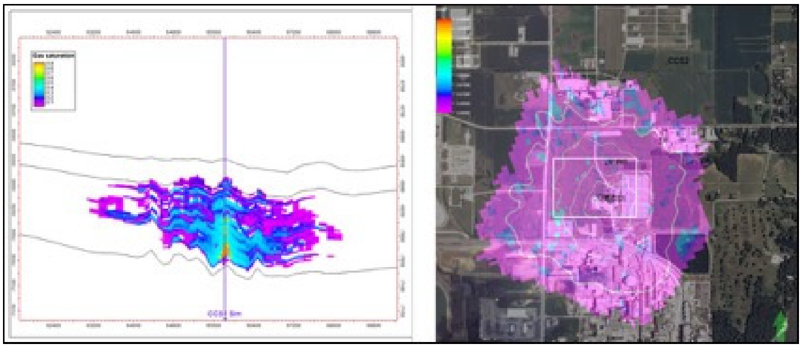

Figure 3: Modeled CO_2 plume at the time of the time-lapse monitor 3D seismic survey in cross section through injector CCS1 (left) and map view (right).

2.3. Time-lapse seismic integration

The IBDP monitoring program included acquisition of 3D seismic surveys before commencement and after completion of CO_2 injection. By comparing the seismic signals before and after injection it is possible to infer the underground movement of the CO_2 plume in space and time in detail. To obtain reliable information of the subsurface CO_2 plume development the seismic signals received at surface must be processed to remove noise and inferences that are not related to sub-surface changes. Because injection induced 4D effects are very subtle, specialized processing techniques are required to maintain data fidelity. Properly processed 4D seismic data may be used in rock physics based workflows for quantitative integration with reservoir simulation results, thus enabling the time-lapse seismic response to be used as a calibration observation for the simulation model.

One method of evaluating time-lapse seismic changes is to compute time shifts in two windows from the 3D seismic volume: one above and one below or including the injection zone. Derivatives of these time shifts are used to compute metrics such as Normalized Root Mean Square (NRMS) and Reliability, which should exhibit anomalies below and within the injection interval but not above it.

Another method of quantifying time-lapse changes between seismic volumes is to perform Non-Rigid Matching (NRM). In the NRM method, using the base survey as a reference the time shift required to match reflection time between volumes is computed. The result of the NRM process is a 3D volume called the displacement field that records the amount of shift needed to match the baseline to monitor at each seismic sample. The displacement field should be non-zero in and below the injection zone.

Figure 4a shows Reliability, NRMS, and NRM displacement field attributes from the IBDP time lapse analysis along with the outline of the modeled CO_2 saturation plume at the time of the monitor survey. Differences between the time-lapse attribute and the modeled plume may be attributed to both the seismic detection limit and error in model predictions due to lack of calibration constraint in the inter-well space. The time-lapse seismic attributes may be used to constrain the reservoir model calibration through a series of informed model updates and rock physics modeling. Reservoir model updates may be informed through the use of specialized attributes which hi-light structural and reservoir property characteristics not yet included in the reservoir model. For example, Figure 4b shows the eXchroma^{SG}* chromatic geology extraction software attribute computed on the base survey at the injection zone in which subtle features are seen with orientation similar to the time-lapse attribute (elongated East to West) but inconsistent with the existing simulation model prediction (approximately radial distribution). The attribute and others will be used to inform reservoir model updates in efforts to reconcile model predictions with time-lapse observations.

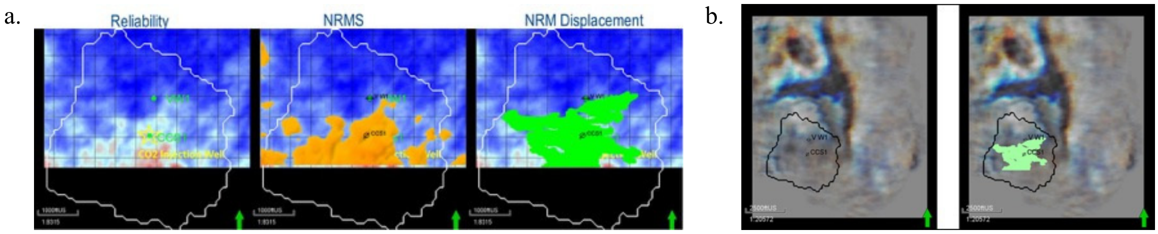

Figure 4: (a) Time-lapse attributes Reliability (left), NRMS (middle), and NRM displacement (right), and model plume outline (white), (b) Base survey eXchroma[SG] attribute at injection interval with modeled plume outline (black) without NRM displacement attribute (left) and with NRM displacement attribute (right).

3. Microseismic Activity at IBDP

Microseismicity was recorded by three vertical arrays: two permanent installations in the injection and geophysical monitoring wells and one temporary (about 1.5 years) in a deep monitoring well with a total of 38 four- or three-component geophones. The two permanent arrays were calibrated using vibrator sweeps and perforation shots in early monitoring well drilling before injection started [2].

3.1. Pre-injection microseismicity

Pre-injection microseismic monitoring covered a 1.5-year time period before injection by the two vertical arrays in the injection and geophysical monitoring wells. The two arrays recorded over 68,000 triggered events. Most were related to surface noise, drilling of another monitoring well, well activities, perforation shots, and distant events attributed to be mine blasts because of distance and time of day. Twenty distant natural earthquakes (12 in the U.S. Geological Survey catalogue) and eight local microseismic events were recorded which appear to be unrelated to well activity and are presumed to be background events. These eight events were located in the Mt. Simon Sandstone and Argenta Formation (unconformably overlies the Precambrian) with six located within 457 m of injection well and two located 1,646-2,408 m from the injection well with a magnitude range from -2.16 to -1.52 and an average of -1.83. Magnitudes recorded from drilling and well activity ranged from -2.6 to -1.6 [2].

3.2. Injection period microseismicity

CO_2 was injected at a near constant rate for three years with short interruptions related to operational issues. The overall average per month for the injection time period was about 30,864 tons (28,000 tonnes) or 35,000 cubic meters. Microseismic events started two months after initiation of injection and during the overall injection time period 4,747 events were located with an average of slightly more than four events per day with an average magnitude of -0.9. Ninety-four percent of events were less than magnitude 0 and only two events were above 1 at 1.08 and 1.14.

Monitoring has shown the CO_2 and formation pore pressure increases are stratified near the base of the Mt. Simon; the location of the injection zone. Thin silty mudstone layers in the Mt. Simon, over 300 m below the Eau Claire seal, form baffles to upward pressure and CO_2 migration. This control on pore pressure increases also represents the upper limit of the microseismic event locations. Close to half the microseismic events are located in the Precambrian crystalline basement while the rest are in the Mt. Simon Sandstone and Argenta Formation, which unconformably overlies the Precambrian; with the smallest number in the thin Argenta Formation. The range of magnitudes of events is also nearly identical in each layer. The Precambrian had the highest magnitudes of 1.08 and 1.14, while magnitude highs of 0.88, 0.76 and 0.66 were recorded in the Argenta Formation and Mt. Simon Sandstone. The maximum event occurred in the 6th month of the 36-month injection. The lowest moment magnitude detected, measurable, and locatable event in all three formations was near -2.0 and below with 95% of microseismicity having magnitudes of 0 and less [3].

3.3. Cluster development

Locatable microseismic events started two months after initiation of injection, with two events in the second month and 13 in the third month at a distance of approximately 600 m from the injection well. Subsequent microseismic activity occurred both closer to and at greater distance from the injection well. Event activity did not progress thorugh time with increasing distance from the injection well as was originally anticipated. As injection progressed, clusters of events were identified and several clusters were oriented in the SW-NE direction. As clusters became evident, they were numbered in the sequence of appearance, producing 18 numbered clusters (Figure 5a). Assuming that these clustered events represent activity along pre-existing planes of mechanical weakness, this temporal development can be explained by the relative orientation of each cluster (plane) within the in-situ stress field. Pre-existing weak planes or defects close to 30 degrees from the maximum horizontal stress (SHmax) direction are optimally oriented in the direction expected for strike-slip movements.

a. b.

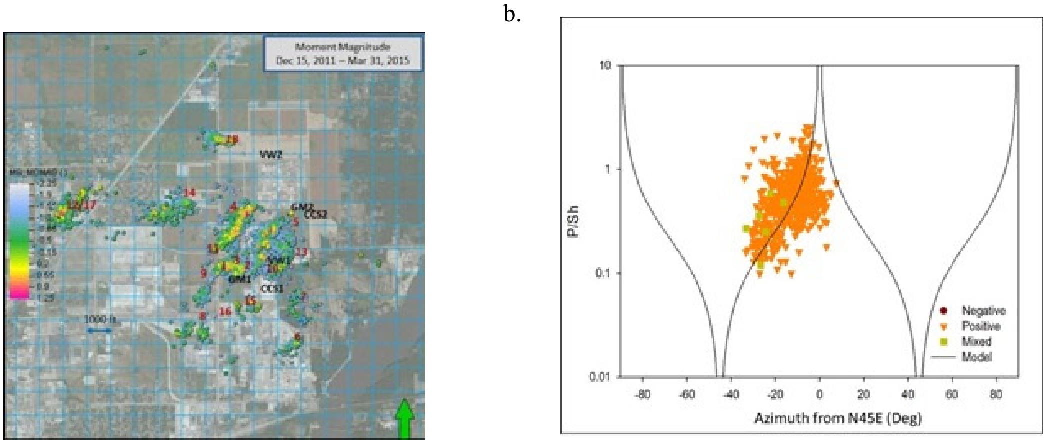

Figure 5: (a) Cumulative event activity as of March 31 2015 with moment magnitude scale. (b) First motion analysis for cluster 4 showing approximately 45-degree strike.

The strike of the planes in relation to the in situ SHmax fits the first motion analysis (Figure 5b) indicating right lateral strike-slip motions on many of the clusters [4]. These planes are interpreted to be the reactivation of pre-existing features as shown by the Gutenberg-Richter plots for all the microseismicity, which show b-values close to 1.

3.4. Post-Injection shut-in microseismicity

Post-injection shut in microseismicity magnitudes ranges from -2.22 to 0.8 with a b-value of about 1; both similar to magnitudes and b-values as during the injection time period. Microseismic events are still being measured and occur throughout all the clusters over time and have decreased since injection ceased, although they have not fallen off in activity in any pattern concerning distance from the injection well as time progresses.

4. Monitoring, Verification, and Accounting Post-Injection Site Care and Permitting

Intensive monitoring of the near-surface environment above the CO_2 plume shows no effects to date on air, water, soil, or land surface, and no effects in the future are expected. Cased-hole logging shows that CO_2 volumes injected remain stored in the lower Mt. Simon Sandstone. Significant geologic characterization of more than 385 m of whole core and 371 sidewall cores has provided significant insights into reservoir heterogeneity and the impact on CO_2 movement through the reservoir, such as zones of low permeability that act as baffles to CO_2 movement. Reservoir simulation suggests that injected CO_2 would not reach the base of the primary seal 100 years after injection ceased. The overall distribution of microseismic events normalized to the injection and post-injection time periods was similar to what the IEAGHG (2013) found for wastewater disposal and enhanced geothermal systems where 70% occurred during injection and 20% occurred during the first quarter length of injection time during post-injection.

The Post Injection Site Care (PISC) period monitoring includes permit and non-permit related activities necessary to successfully meet research, compliance, and project objectives. Permit-required PISC monitoring is being conducted as specified in the final USEPA UIC Class VI permit Post Injection Site Care Plan and Quality Assurance and Surveillance Plan. Other non-permit required monitoring is being conducted to maintain the integrity of pre-injection and injection monitoring datasets to meet the project objectives to demonstrate that CO_2 injection and storage has had no significant environmental impacts. A significant decrease in scope and frequency of scientific monitoring not related to the permit is planned during the PISC period especially in the 2016-2017 timeframe, provided no indications of leakage are identified.

Post-injection monitoring activities for the IBDP site include conducting and/or supporting near-surface (e.g., shallow groundwater, soil CO_2 flux, soil gas) techniques. PISC monitoring activities deeper in the subsurface (>500 ft) include geophysical surveys to characterize CO_2 plume movement, as well as, monitoring properties such as temperature and pressure in the IBDP injection and verification wells, cased-hole logging, fluid sampling, well integrity testing, and continuous microseismic monitoring.

4.1. Compliance monitoring framework

The permitting framework under which the IBDP operates has changed from state- to federally-governed during the course of the project. The IBDP injection into the Mt. Simon Sandstone reservoir began in November 2011 under a UIC Class I - Non-Hazardous permit (number UIC-012-ADM) issued by the Illinois Environmental Protection Agency (IEPA) and was concluded on November 24, 2014 with a total of 999,215 tonnes injected. The IEPA Class I UIC permit did not make a distinction between monitoring to be conducted during the different phases of the project (i.e., pre-injection, injection and post- injection).

At the cessation of injection, a new USEPA Class VI UIC permit for well CCS1 was issued, which guides the PISC monitoring for the injection well (permit number IL-115-6A-0002). The Class VI permit went into effect on February 12, 2015 and superseded the Class I permit which was terminated on July 3, 2015.

With the finalized Class VI permit, additional monitoring requirements were applied to the project. The CCS1 Class VI permit considered different monitoring strategies and frequencies during phases of the IBDP and was aligned with a Class VI permit for CCS2, the injection well for the adjacent Illinois Industrial Carbon Capture and Sequestration (IL-ICCS) Project. For the remainder of the paper, ‘permit’ refers exclusively to a Class VI permit unless indicated otherwise. The CCS1 and CCS2 permits refer to an ‘interim period’ which relates to the time after CCS1 concludes injection up to when CCS2 begins injection. The PISC and Site Closure Plan “describes the activities that ADM [the operator] will perform to meet the requirements of 40 CFR 146.93. The CCS1 well is related to the CCS2 well at the IL-ICCS project (EPA permit No: IL-115-6A-0001). Delineation of the area of review (AoR) for CCS1 incorporates injection activities at CCS2 (i.e., the two wells will create a single CO_2 plume and pressure front). Therefore, post-injection monitoring and an ultimate non-endangerment demonstration for the two wells/projects are closely tied.”

As part of the CCS1 permit, the operator is required to monitor groundwater quality and track the position of the CO_2 plume and pressure front until site closure is authorized at CCS2. While a default length of the PISC period is 50 years under UIC Class VI rules, an alternative PISC monitoring timeframe of 10 years was approved by USEPA. However, the operator may not cease post-injection monitoring until a demonstration of non-endangerment of underground sources of drinking water (USDWs) for CCS1 has been approved by the UIC Program Director pursuant to 40 CFR 146.93(b)(3) and the conditions the CCS2 permit. Following approval for site closure for CCS1, the operator will plug all monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

4.2. Monitoring program modifications

The IBDP monitoring program has been systematically modified in response to the changing monitoring needs during different phases of the project. Most recently in response to entering the PISC period and the finalization of Class VI compliance requirements, the number of monitoring locations, sampling frequencies, and specific sampling parameters has been adapted to those needs. In some cases, monitoring efforts have been concluded (e.g., soil flux monitoring, soil gas monitoring), and in others, monitoring efforts have been increased (e.g., increase in the number of parameters monitored in fluid samples). Overall, the tendency is for reduction of monitoring efforts in the PISC. For example, In Year 1 (2015) of the IBDP PISC, most near-surface monitoring was conducted at the same frequencies used during the pre-injection and injection phases of the project (Table 1). However, during Years 2 (2016) and 3 (2017), sampling will be less frequent (unless anomalous conditions are observed) and several monitoring methods will conclude.

Shallow groundwater monitoring began at the IBDP site in March 2009. A total of 17 wells at 11 locations were installed at depths ranging from 10 to 100 meters. Four of the 17 wells are used for compliance monitoring to meet conditions of the IEPA UIC Class I and USEPA UIC Class VI permits. The remaining 13 wells are referred to as the 'research' wells. Monthly sampling results from the research wells during the pre-injection and injection phases of the project were valuable in characterizing the local hydrogeology and the variability of near surface groundwater quality and levels through a range of seasonal and annual weather patterns. Research wells continued to be monitored on a monthly basis initially during Year 1 of the PISC, but frequencies were reduced to quarterly thereafter. These wells will ultimately be plugged and abandoned according to state requirements in at the end of the project or transferred to ADM for their use.

Soil flux monitoring began at the IBDP site in the summer of 2009. Weekly measurements have been collected from approximately April through December each year from a point network of over 100 locations to characterize the variability of soil CO_2 fluxes throughout the study area during the project. Monitoring of soil fluxes was concluded in December 2015. Soil flux monitoring has been essential to identify the natural variability of soil CO_2 fluxes during the project, but as a leak detection tool, it will be of lower priority at IBDP than other monitoring methods.

Soil gas sampling was initiated at the IBDP site during the summer of 2011 and includes a total of 24 sites with up to 3 sampling depths at 0.3, 0.6, and 1.2 m, respectively for each location. Sampling frequency was initially quarterly, but was reduced to a semi-annual/annual frequency due to field conditions, sampling logistics, and cost. Soil gas sampling was concluded in September 2016.

Frequencies of deeper monitoring techniques have also been modified throughout the project life cycle. Since August 2009, pulsed neutron logging has been done eight times in IBDP deep wells. Analysis of the pulsed neutron logs has proven to be a reliable tool to identify the presence of CO_2 behind the well casing.

Annual pulsed neutron logging will be completed on each of the IBDP wells (CCS1, VW1 and GM1) during the PISC period. That frequency is greater than is required in the final IBDP UIC Class VI permit but is necessary to ensure the scientific project objectives are met. For the IBDP wells CCS1 and VW1, the permit requires logging runs once during the interim period and once in IBDP PISC Year 2. Continuation of pulsed neutron logging through the post-injection period is expected to show dissipation and buoyancy effects of the plume, understanding of which will be essential to demonstrate compliance with the Class VI requirements and a final determination of non-endangerment to groundwater resources.

Fluid sampling has occurred in the IBDP VW1 well beginning in May 2011 with well swabbing as part of the well completion. The Westbay multilevel groundwater characterization and monitoring system installation finished in June 2011. Since then, ten 'Westbay' sampling events have occurred on an approximately annual to semi-annual basis as well as sampling opportunities that arose from well operation and maintenance. A total of 11 fluid sampling events have occurred. VW1 sampling will continue on an annual or semi-annual basis as operations allow.

For the CCS1 UIC Class VI permit, VW1 sampling is required once during the interim period, and annually during the first three years of CCS2 injection. That frequency is to be used for sampling from one zone in the Ironton-Galesville Formation (i.e., above the primary seal) and one zone in the Mt. Simon Sandstone (i.e., in the injection reservoir). Fluid sampling from other operable zones in VW1 (e.g., Zones 4-11) is planned on an annual to semi-annual basis for the IBDP PISC in order to more fully monitor fluid chemistry in and above the injection reservoir.

Table 1. Frequencies of compliance and other monitoring at the IBDP site
([1] UIC Class 1 permit requirement, [2] UIC Class VI permit requirement).

Regulatory Compliance Monitoring		
Method	Frequency (Pre-injection and Injection Phases)	Frequency (Post-injection Phase)
Pressure and Temperature Monitoring in CCS1	Continuous[1]	Continuous[2]
Passive Seismic Monitoring	Not required	Continuous[2]
Pulsed Neutron Logging in CCS1 and VW1	Annual[1]	Once in interim period, once in Year 2 (2016) [2]
Shallow Groundwater Sampling – Compliance Wells	Quarterly[1]	Quarterly[2]
Ironton-Galesville Fluid Sampling (1 zone above reservoir)	Not required	Annually[2]
Mt. Simon Sandstone Fluid Sampling (1 zone in reservoir)	Not required	Annually[2]
Other Monitoring		
Method	Frequency (Pre-injection and Injection Phases)	Frequency (Post-injection Phase)
Passive Seismic Monitoring	Continuous	In UIC Class VI permit
Pulsed Neutron Logging in CCS1 and VW1	In UIC Class I permit	Annual
Soil CO_2 Flux – Point network	Weekly	Monthly through December 2015, then terminated.
Soil CO_2 Flux – Multiplexer	Every 30 minutes when operational	Deployed in 2015, but not anticipated in 2016 or 2017.
Soil Gas Sampling	Semi-Annually to Annually	Annually for up to 2 years maximum (2015 and 2016).
Shallow Groundwater Sampling – Compliance Wells	Monthly	Reduced to quarterly compliance frequency.
Shallow Groundwater Sampling – Research Wells	Monthly	Monthly during 2015, no more than quarterly in 2016. Concludes by 2017.
Deep Fluid Sampling in VW1 (for zones not required by UIC Class VI permit)	Semi-Annually to Annually	Semi-Annually to Annually for up to 3 years maximum.

5. Lessons Learned

Microseismic

1. Microseismic baseline activities need to be monitored prior to injection and continued to be monitored in the injection and post-injection phases fully understand reservoir response and residual stress.
2. Interpretation of microseismic data can be labor intensive and changes in the model may necessitate reinterpretation of the entire data set.

Modeling

1. Knowledge of key reservoir characteristics evolves with additional data and site specific experience. Modeling workflows should take into account the need for rapid iteration with systematic improvement.

2. Processes such as induced microseismicity may require increased spatial model discretization for specialized dynamic process modeling. Static models should be developed at high spatial resolution to allow maintenance of fine discretization as required through selective upscaling.
3. While coarse simulation grids are computationally convenient and may adequately estimate pressure, CO_2 plume geometry can be dominated by thin high permeability zones, requiring fine vertical discretization to history match saturation observations in monitoring wells.
4. Because some reservoir features which control plume geometry are not visible in well logs or seismic, calibration of the reservoir model to all available (pressure and saturation) observations distributed spatially (Laterally as well as vertically) is important.

Monitoring

1. Monitoring programs should be designed in order to meet regulatory requirements and minimize potential negative project outcomes (i.e., reduce project risk).
2. Monitoring programs must be well integrated with other project components.
3. Monitoring efforts and information should undergo periodic project-wide reviews. Depending on the size and duration of the project, external reviews may also be beneficial.
4. Program and data reviews should be the basis for optimizing monitoring program components for each phase of a project (e.g., pre-injection, injection, and post-injection) and program adjustments (e.g., reduction of monitoring intensity during later phases of the project, especially during the PISC period).

6. Conclusions

Experience gained through the IBDP show that large injection demonstrations like this (e.g., >1Mt) are necessary to adequately address issues of expanding CCS to full commercial-scale. While many of the fundamental technologies applied at the IBDP have been proven effective in the oil and gas sector, interdependencies between operational and technical objectives unique to CO_2 sequestration required the development of fit-for-purpose integrated systems and operational procedures. Existing drilling, completion, seismic surveying, and microseismic monitoring methods have been adapted as needed for the challenges posed by the industrial site environment.

A combination of real-time, near-real-time, and scheduled periodic data acquisition systems have developmentally advanced to fulfill the various operational and regulatory monitoring and reporting requirements. Data analysis methods have been established to deal with acquisition and processing of noise sensitive seismic and microseismic data in the challenging industrial site environment. Permitting under different primacy and rules specific to well class has resulted in significant learnings about the interface between project, regulator, and community. In conclusion, in addition to the many lessons learned through challenges encountered at the IBDP, the scale and duration of the project has provided the opportunity to investigate and implement solutions to some of these challenges.

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