9.0 POST-INJECTION SITE CARE AND SITE CLOSURE PLAN
40 CFR 146.93

CASS SEQUESTRATION

Facility Information

Facility name: Cass Sequestration

Facility contact: Maureen Bennett
Cass Sequestration | Senior Environmental Engineer
One Energy Plaza, 400 WCB Detroit, MI 48226
maureen.bennett@dteenergy.com | 313-548-8154

Well name: [redacted]

Well location: CASS COUNTY, INDIANA
[redacted]

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9.0 Post-Injection Site Care and Site Closure (PISC) Plan

9.1 Introduction

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Cass Sequestration, LLC ("Cass Sequestration") will perform to meet the requirements of 40 CFR 146.93.

At the end of the injection period, Cass Sequestration will either submit an amended PISC plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the plan is needed.

Cass Sequestration will monitor groundwater quality and track the position of the carbon dioxide (CO_2) plume and pressure front for five years after the end of injection which is the modeled time for CO_2 plume stabilization and for pressure in the injection zone to decrease to a level at which it no longer poses an endangerment to Underground Sources of Drinking Water (USDW) and the criteria described in Section 9.6 are satisfied.

9.2 Pre- and Post-Injection Pressure Differential (40 CFR 146.93(a)(2)(i)

Pressure behavior of the storage system in response to injection at the proposed [redacted] injection well has been modeled as part of the Area of Review (AoR) delineation (Permit Section 2 - Area of Review and Corrective Action Plan). **Figure 9-1** shows the modeled bottomhole pressure for the gridblock at the top of the completed interval in the computational model during the 12-year injection phase and 50-years post-injection.

The modeling indicated that pressures at the well (where the highest pressures would be created) are expected to decrease rapidly to near pre-injection levels 5 years after the end of injection (**Figure 9-1**). At the end of the injection period (end of year 12), the maximum pressure [redacted] and pressure increase [redacted] is reached. Refer to discussion in Section 9.5 – Alternative Post-Injection Site Care Timeframe, below. Additional detail on the modeled post-injection pressure declines and differentials is presented in Permit Section 2 - AoR and Corrective Action Plan.

[redacted]

Figure 9-1: Pressure time-series data over 12 years injection period followed by 50 years post-injection at the gridblock of the topmost completion in the injection interval. Simulation injection rate is also shown.

9.3 Predicted Position of the CO_2 Plume and Associated Pressure Front at Site Closure (40 CFR 146.93(a)(2)(ii))

A map view of the AoR for this project is shown in **Figure 9-2**. The AoR was determined based on the greater of the regions covered by the maximum extent of the CO_2 saturation plume and the region of pressure increase above a threshold of [redacted] psi (refer to Permit Section 2- AoR and Corrective Action Plan for full details and discussion). **Figure 9-2** shows the outline of the [redacted] psi pressure front is larger than the outline of the maximum extent of the CO_2 saturation plume, and therefore the pressure contour is taken as the project AoR outline.

Figure 9-3 displays the modeled pressure increase (pressure increase above initial pressure) in the injection formation at the end of injection and 5 years after the end of injection. The pressure increase after 12 years of injection at the well is [redacted] psi. **Figure 9-1** and **Figure 9-3** [redacted]

[redacted]

Figure 9-2: Outlines of maximum CO_2 saturation plume and maximum threshold pressure [redacted]. The maximum threshold pressure outline coincides with the outline of the AoR.

[redacted]

Figure 9-3: Cross-sectional view of pressure buildup (pressure in excess of initial pressure), at end of the 12-year injection period (left) and 5 years after end of injection (right). At right, all pressures in excess of [redacted] psi have dissipated.

9.4 Post-Injection Monitoring Plan (40 CFR 146.93(b)(1))

Cass Sequestration will perform groundwater monitoring, storage formation pressure monitoring, and geophysical monitoring, as described in the following sections, during the post-injection phase to meet the requirements of 40 CFR 146.93(b)(1). The monitoring plans will be modified as necessary if potential revisions to regulations and project requirements occur throughout the life of the CCS project to remain in full compliance.

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities during the injection and post-injection phases is provided in Appendix 7A of the Permit Section 7 -Testing and Monitoring Plan.

Initial monitoring activities during the PISC phase are summarized in **Table 9-1**. If results demonstrate a substantial decrease in the potential endangerment of USDWs over time, the frequency of monitoring may be reduced in consultation with the UIC Program Director.

The project will continue to monitor the well integrity of the injection and the monitoring wells using temperature measurements to ensure that there is no migration of CO_2 up the wellbores, until wells are plugged and abandoned. In addition, the tubing annular pressure and fluid volume in the injection well and injection zone monitoring well (IZM) will be monitored on a continuous basis until the wells are plugged and abandoned. Refer to the Permit Sections 6 -Well Operations Plan and the Permit Section 7 – Testing and Monitoring Plan for more information on the well integrity and operational monitoring plans.

[redacted]

[redacted]

Table 9-1: Summary of initial monitoring activities in the PISC phase of the project.

9.4.1 Schedule for Submitting Post-Injection Monitoring Results (40 CFR 146.93(a)(2)(iv))

All post-injection site care monitoring data and monitoring results collected using the methods described above will be submitted to the EPA in annual reports within 90 days following the anniversary date on which injection ceases. The reports will contain information and data generated during the reporting period (i.e., well-based monitoring data, sample analysis, and the results from updated site models).

9.5 Alternative Post-Injection Site Care Timeframe

An alternative PISC timeframe of 5 years (compared to the default of 50 years) is appropriate based on the results of the detailed geologic analyses and numerical plume and pressure-front modeling. Specifically, the rapid pressure decline and stabilization of the CO_2 plume following the end of injection. The demonstration below is based on the requirements of 40 CFR 146.93(c). All monitoring will continue until the EPA has approved a non-endangerment demonstration per 40 CFR 146.93(b)(3).

Pressure behavior of the system in response to injection at the proposed [redacted] well has been modeled as part of the Area of Review (AoR) delineation (Permit Section 2 - Area of Review and Corrective Action Plan). An extensive suite of site-specific data acquired in the Stratigraphic Test Well (STW) including [redacted] were incorporated into the computational model. A full description of these data is available in Permit Section 5.0 – Pre Operational Testing Plan.

9.5.1 Computational Modeling Results (40 CFR 146.93(c)(1)(i))

Computational modeling at the Cass Sequestration project location has been completed to delineate the plume and pressure front area , and resulting AoR. Refer to Permit Section 2.0 – AoR and Corrective Action Plan, section 2.3.1 for further details. **Figure 9-5** shows the CO_2 saturations in map view and in vertical cross section view at the end of the 12 year injection period, **Figure 9-6** to **Figure 9-8** show the plume 5, 10 and 50 years after the end of injection. These figures illustrate how the CO_2 plume evolves over the alternative PISC timeframe and show the stability of the plume within 5 years of the end of injection.

The computational model is well constrained having been created using data acquired in the drilling and completion of the Logansport #1 STW. To address any residual uncertainty and demonstrate that impact on the Dynamic Reservoir Model (DRM), alternative DRM simulations were completed based on our current understanding of the range of variation of two uncertainty parameters: [redacted] and [redacted]. Each scenario is constrained to the same injection pressure constraints with varied reservoir parameters compared to the base case. [redacted] efer to Permit Section 2.0 – AoR and Corrective Action Plan, section 2.2.2 for further details. A comparison of the modeled downhole pressure from the sensitivity study as it pertains to this alternative PISC timeframe is discussed below in Section 9.5.3

[redacted]

Figure 9-4: Stratigraphic column for Cass Sequestration derived from the STW showing the lowest USDW [redacted] relative to the storage formation (Mt. Simon).

[redacted]

Figure 9-5: [redacted] CO_2 plume after 12 years of injection. The AoR outline is shown in black.

[redacted]

Figure 9-6: [redacted] CO_2 plume after 5 years post injection stop. The AoR outline is shown in black.

[redacted]

Figure 9-7: [redacted] CO_2 plume after 10 years post injection stop. The AoR outline is shown in black.

[redacted]

Figure 9-8: [redacted] CO_2 plume after 50 years post injection stop. The AoR outline is shown in black.

9.5.2 Predicted Timeframe for Pressure Decline (40 CFR 146.93(c)(1)(ii))

Modeling results indicate that pressures at the well (where pressure will be highest) are expected to decrease quickly after the end of injection (**Figure 9-1**). The rate of pressure reduction relative to the maximum pressure at the end of the injection period is shown in **Figure 9-9.**

The pre-injection pressure at the gridblock of the topmost completion in the injection interval [redacted] is [redacted]. Assuming a delta critical pressure threshold of [redacted] psi, the critical pressure threshold at that depth is [redacted] psi. The pressure time series data shown in **Figure 9-1** indicates that the pressure decreases to this threshold after [redacted] post injection and continue to drop thereafter, supporting the alternative PISC timeframe of 5 years. **Figure 9-10** provides a graphical representation of the above description.

Figure 9-3 compares the modeled downhole pressure increases (pressure increase above initial pressure) between the end of injection (left panel) and after 5 years post injection (right panel). After 5 years post injection, modeled pressures have decreased beneath the critical pressure threshold across the whole cross section.

Downhole pressures time series data for the modeling sensitivity analysis described in Permit Section 2.0 – AoR and Corrective Action Plan are shown in **Figure 9-11.** The data shows that for each of the sensitivity cases the downhole pressure decreases to less than the critical pressure threshold within 5 years of the end of injection. The high salinity and increased vertical permeability cases have had the largest effect on the predicted pressure decline yet they both decrease to below the critical pressure threshold within 5 years of the end of injection.

This rapid decrease in pressure within the storage formation at the end of the injection period as demonstrated above provides justification for an alternative PISC timeframe of 5 years.

[redacted]

Figure 9-9: Percentage rate of pressure reduction relative to the maximum pressure at the gridblock of the topmost completion at the end of the injection period.

[redacted]

Figure 9-10: Pressure time-series data over 12 years injection period followed by post-injection decrease over a 100 year PISC at the gridblock of the topmost completion in the injection interval. Pre injection pressure and critical pressure threshold shown in black dashed.

[redacted]

Figure 9-11: Pressure time-series data over 12 years injection period followed by post-injection decrease at the gridblock of the topmost completion in the injection interval for each sensitivity simulation. Pre injection pressure and critical pressure threshold shown in black dashed.

9.5.3 Predicted Rate of Plume Migration (40 CFR 146.93(c)(1)(iii))

Figure 9-12 shows the lateral extent of the CO_2 saturation plume outlines at the end of the 12-year injection and 5 and 10 years post injection. **Figures 9-5** to **Figure 9-8** show the vertical distribution of the CO_2 saturation plume for similar time periods. Lateral migration of the plume ceases within 5 years of the end of injection and is maintained within the storage formation throughout injection and the PISC timeframe.

The computational modeling is well constrained having been created using data acquired in the drilling and completion of the STW. Geological parameters (e.g., porosity, permeability), have been calculated based on [redacted] samples, all cross-calibrated, as described in Permit Section 1 – Project Narrative.

To address any residual uncertainty and demonstrate that impact on the DRM, alternative DRM simulations that affect plume mobility were completed based on our current understanding of the range of variation of two uncertainty parameters: [redacted] and [redacted] Each scenario is constrained to the same injection pressure constraints with varied reservoir parameters compared to the base case.

Figure 2-28 in Permit Section 2.0 – AoR and Corrective Action Plan, illustrates the lateral extent of the plume in the base case at the end of a 50-year post-injection period, compared to that of each of the simulated sensitivity runs. [redacted] runs showed minimal difference from the [redacted] while the alternate [redacted]

The rate of movement predicted for the CO_2 plume during the PISC period and lack of interface with sensitive receptors (i.e. artificial penetrations through the caprock) after 5 years post-injection supports a PISC timeframe of 5 years.

[redacted]

Figure 9-12: Overlay of modeled CO_2 plume outline at the end of injection (blue), after 5 years (yellow), and after 10 years (green) post injection.

9.5.4 Site Specific Trapping Processes (40 CFR 146.93(c)(1)(iv-vi))

The computational modeling takes into account the relevant physical and chemical mechanisms governing fluid movement in the subsurface. Specifically, various mechanisms which work to trap CO_2 such that its movement is slowed or stopped. The primary modeled mechanisms for CO_2 trapping are capillary trapping and solubility in water. Capillary trapping (i.e. "residual trapping") refers to CO_2 which is trapped as a residual phase in the otherwise brine-filled pore space, driven by hysteresis. Solubility trapping (i.e. dissolution) refers to CO_2 which dissolves in brine and therefore does not move as a free phase.

Figure 9-13 shows the CO_2 in the injection formation over time based on the state of CO_2 (supercritical phase, capillary trapped and dissolved). During injection, CO_2 is fully in supercritical phase, and so the CO_2 supercritical amount grows steadily and is the most prominent. As that CO_2 plume grows away from the injection well displacing and contacting water from larger and larger regions of the pore volume, the amount of CO_2 dissolved in water grows immediately, then remains relatively constant during injection. But because flow is mainly in one direction (all fluids displacing primarily in a direction away from the well), there is little hysteresis and therefore much smaller growth of the amount of capillary-trapped CO_2.

Once injection has ceased, the flow regime becomes quite different. Flow is no longer directed forcefully in the radial direction away from the well, but instead moves as the residual pressure field eases, with buoyancy becoming more relatively important. During the post-injection period, CO_2 is not appreciably contacting new brine, so the amount of CO2 trapped by solubility remains basically constant. However, because fluids are now flowing and redistributing based on easing the residual pressure from the injection period and through buoyancy forces, local flow directions will now vary widely: no injection force causing radial flow away from the well, such that buoyancy becomes an important driver. These changes in flow directions and patterns therefore allow for hysteresis, and therefore faster growth of capillary-trapped CO_2 in the post-injection period.

[redacted]

[redacted]

Figure 9-13: Distribution of CO_2 by modeled trapping mechanisms during injection and post injection. Supercritical CO_2 shown in black, capillary trapped CO_2 in red, and dissolved CO_2 in blue.

9.5.5 Confining Zone Characterization (40 CFR 146.93(c)(1)(vii))

[redacted]

[redacted]

[redacted] Further details on the characteristics of the confining zone can be found in Permit Section 1.0 – Project Narrative.

9.5.6 Assessment of Fluid Movement Potential (40 CFR 146.93(c)(1)(viii-ix))

There are no wells within the AoR that penetrate the confining formation (see Permit Section 2.0 – AoR and Corrective Action Plan, section 2.4.2 for further details). The injection well will be constructed in accordance with Permit Section 4.0 – Injection Well Construction Plan and monitored for well integrity throughout the injection period in accordance with Permit Section 7.0 – Testing and Monitoring Plan. The injection well will be plugged and abandoned in accordance with Permit Section 8.0 – Injection Well Plugging Plan soon after the end of injection.

9.5.7 Location of USDWs (40 CFR 146.93(c)(1)(x))

As described in Section 1.2 of the Project Narrative, there is significant thickness between the lowest USDW [redacted] and the injection zone (**Figure 9-4**). As measured at the Logansport #1 STW, the base of the [redacted] is [redacted] above the top of the Mt. Simon storage formation [redacted]. In addition to the analyses described in this section, the significant thickness is another assurance of the limited risk to USDWs and supports the shorter PISC timeframe. In the unlikely event of leakage from the injection zone, monitoring in the Ironton formation at the AZM well is designed to detect potential fluid leakage. Additionally, discussion of the location of USDWs and their relationship to the injection and confining zone is found in Section 1.2.7 of the Project Narrative.

9.6 Non-Endangerment Demonstration Criteria

Prior to approval of the end of the post-injection phase, Cass Sequestration will submit a demonstration of non-endangerment of USDWs to the UIC Program Director, per 40 CFR

146.93(b)(3) . This report will demonstrate USDW non-endangerment based on the evaluation of the site monitoring data used in conjunction with the project's computational model. The report will detail how the non-endangerment demonstration evaluation uses site-specific conditions to confirm non-endangerment. The report will include all relevant monitoring data and interpretations upon which the non-endangerment demonstration is based, model documentation and all supporting data, and any other information necessary for the UIC Program Director to review the assessment. Specific topics to be addressed in the report will include,

- Introduction and Overview
- Summary of Existing Monitoring Data
- Summary of Computational Modeling History
- Evaluation of Reservoir Pressure
- Evaluation of Carbon Dioxide Plume
- Evaluation of Emergencies or Other Events

9.7 Site Closure Plan

Cass Sequestration will conduct site closure activities to meet the requirements of 40 CFR 146.93(e) as described below. Cass Sequestration will submit a final Site Closure Plan and notify the permitting agency at least 120 days prior to intent to close the site. Once the permitting agency has approved closure of the site, Cass Sequestration will plug all remaining monitor wells and submit a site closure report to EPA. The activities described below represent the planned activities based on current available information. The actual site closure plan may employ different methods and procedures. Thus, a final Site Closure Plan will be submitted to the UIC Program Director for approval with the notification of the intent to close the site.

9.7.1 Plugging Monitoring Wells

Prior to plugging wells, the external mechanical integrity of each well will be confirmed by reviewing the DTS temperature profile as compared to previous temperature profiles to ensure that anomalies have not developed.

The Well Plugging Plan for the injection well can be found in Permit Section 8. The same approach will be used to plug the IZM and AZM wells. Plugging and abandonment of these wells will meet all requirements set forth by the Class VI regulations. The open hole storage formation of the well will be plugged using a retainer method and the upper portions of the well will be cemented with a balance plug method. In addition, the portion of the casing within the storage formation in the IZM well will be plugged using CO_2-resistant cement. The wells will have the casing cut off 5 ft below grade and a steel cap will be welded to the top of the deep casing string. The cap will have the well identification (ID) number and the date of plugging and abandonment inscribed on it. The following provides a preliminary plan for plugging the IZM and AZM wells. Preliminary wellbore designs for the IZM and AZM wells are shown in Permit Section 7 – Testing and Monitoring Plan.

1. Conduct and document a safety meeting.
2. Move-in (MI) workover unit and ancillary equipment onto well site and rig up (RU). Nipple up and test blow out preventors (BOPs), pressure test equipment and ensure proper operation.
3. Verify wellhead tubing and casing-annulus pressures are at zero.
4. Record bottom-hole pressure from downhole gauge (if final pressure has not already been determined) and calculate kill fluid density.
5. Fill tubing with kill weight brine as determined by the final pressure measurement. Inject two tubing volumes of kill weight brine. Monitor tubing and casing pressure for 1 hour.
6. If the well is not dead or the pressure cannot be bled off the tubing, rig up slickline and set plug in lower profile nipple below packer. Unstab the tubing and circulate tubing and annulus with kill weight fluid until well is dead.
7. Remove packer (in IZM) and pull out of hole with injection tubing laying it down. NOTE: Ensure that the well is over-balanced so there is no backflow due to formation pressure and there are always at least two well control barriers in place.
8. Trip into hole with work string and cement retainer. Set retainer above the open hole section of the well and prepare for cement plugging operations. Pump required number of sacks of CO_2-resistant cement through the retainer ensuring bottom-hole pressure remains below reservoir fracture pressure. Once the squeeze volume of cement has been pumped through the retainer or calculated bottom hole pressure has reached maximum allowable pressure, pull the tubing stinger out of the retainer and displace remaining volume of cement on top of the retainer.
9. Trip workstring out of well and remove stinger from end of tubing.
10. Trip tubing string to intermediate casing shoe depth and prepare to set balanced cement plug. Pump CO_2 resistant cement using a balanced plug method to set 100 ft of cement across casing shoe.
11. Trip tubing string to lowest USDW depth and prepare to set balanced cement plug. Pump CO_2 resistant cement using a balanced plug method to set 100 ft of cement across lowest USDW.

12. Trip tubing string up hole to surface casing shoe depth and prepare to set balanced cement plug. Pump Type 1L cement using a balanced plug method to set 100 ft of cement across casing shoe.
13. Trip tubing string up hole to a depth of 500 ft and prepare to set surface cement plug. Pump Type 1L cement to fill the casing from a depth of 500 ft to surface.
14. Ensure cement is visible at surface. Cut the casing string off at 5 ft below grade and weld a steel plate, (with well ID, permit number, and date of abandonment on it) to the casing strings
15. Backfill the well cellar.
16. Rig down and move off pulling unit and all remaining equipment.

Following the plugging and abandonment of the monitoring wells, the above ground infrastructure, such as wellheads, monitoring equipment, etc., will be removed, and the area around the wells will be regraded to follow the natural topography of the surrounding area (currently agricultural fields), unless the surface owner desires the well pad be left in place. The ground will be replanted with either native vegetation or be converted back to agricultural land, as warranted relative to the surface owner's desire.

9.7.2 Site Closure Report

A site closure report will be prepared and submitted to the EPA within 90 days following site closure, documenting the following:

- Documentation of appropriate injection and monitoring well plugging (40 CFR 146.93(f)(1))
- Notifications to state as required by 40 CFR 146.93(f)(2)
- Records regarding the nature, composition, volume of the injected CO_2, and post-injection monitoring.
- Project-owned groundwater monitoring wells may be converted to use as groundwater wells if desired by the surface owner.

Cass Sequestration will record a notation to the property's deed on which the injection well was located that will indicate the following:

- That the property was used for CO_2 sequestration
- The volume of fluid injected
- The formation into which the fluid was injected, and the period over which the injection occurred.

- The name of the State agency, local authority, and/or Tribe with which the survey plat was filed,
- The address of the Environmental Protection Agency Regional Office to which the survey plat was submitted

The site closure report will be submitted to the permitting agency and maintained by the owner or operator for a period of 10 years following site closure. Additionally, the owner or operator will maintain the records collected during the post-injection period for a period of 10 years after which these records will be delivered to the UIC Program Director.

9.7.3 Quality Assurance and Surveillance Plan (QASP)

The QASP is presented in Appendix A of the Permit Section 7-Testing and Monitoring Plan.