CLASS VI PERMIT TESTING AND MONITORING PLAN

[40 CFR 146.90]

LAPIS ENERGY (AR DEVELOPMENT) LP
PROJECT BLUE
EL DORADO, ARKANSAS

Prepared By:
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Revision No. 2 – RAI No. 1
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1.0 FACILITY INFORMATION

Facility/Project Name:	El Dorado Chemical Company / Lapis Energy Project Blue Class VI Injection Wells No. 1 and No. 2
Facility/Project Contact:	Stijn Konings, Chief Geoscientist Lapis Energy LP 2950 N. Harwood St. Dallas, Texas 75201 (972) 757-6529 / skonings@lapisenergy.com
Well Locations:	Union County El Dorado, Arkansas Project Blue Class VI Injection Well No. 1 Latitude Coordinate: 33.26217733 Longitude Coordinate: -92.69162567 Project Blue Class VI Injection Well No. 2 Latitude Coordinate: 33.2621800 Longitude Coordinate: -92.6914510

This Testing and Monitoring Plan (TMP) describes how Lapis Energy will monitor the sequestration project pursuant to 40 CFR §146.90 at the Project Blue site in El Dorado, Arkansas. In addition to demonstrating that the injection wells are operating as expected, the carbon dioxide plume and pressure front are moving as predicted, and there is no endangerment to Underground Sources of Drinking Water (USDW), the monitoring data will be used to validate and guide any required adjustments to the geologic and dynamic models used to predict the distribution of carbon dioxide within the storage complex, supporting the Area of Review (AoR) evaluations and a non-endangerment demonstration. Additionally, the testing and monitoring components include a leak detection plan to monitor and account for any movement of the carbon dioxide outside of the storage complex.

In accordance with 40 CFR §146.90(j), the TMP will be re-evaluated every 5 years (at a minimum), or more frequently at the direction of the Underground Injection Control (UIC) Program Director. The review process will evaluate whether the current plan will require any amendment. All amendments will be approved by the UIC Program Director and incorporated into the currently authorized operating permit.

Results of the testing and monitoring activities described below may also trigger responsive actions according to the Emergency and Remedial Response Plan [40 CFR 146.94(a)].

2.0 OVERALL STRATEGY AND APPROACH

This TMP is adapted for the Project Blue site and considers the following site-specific strategy and approach:

- The design principle is risk-based and adaptive to provide the optimum monitoring results. The risk assessment will be concurrently reviewed and updated along with the regular AoR and TMP updates.
- The Injection Zones targeted for this project are made up of the Lower Hosston and Cotton Valley Formations. Both these formations are comprised of stacked packages of porous and permeable sandstone that are separated by local clay/shale baffles. The initial completion in Project Blue Class VI Injection Well No. 1 (Blue INJ-1) at start of injection is expected to be within the deepest modeled interval of the Cotton Valley (CV1), then recompleted upwards into the CV2, then finally into the CV3. A second shallower Project Blue Injection Well No. 2 (Blue INJ-2) will also be completed at start of injection into the Lower Hosston Injection Zone. Injection well No. 1 and Injection Well No. 2 can be used intermittently, with the constraint that any one of the 4 intervals (CV1, CV2, CV3 and Lower Hosston) will only be used for injection up to the modeled volume of 2.5 MM metric tons. The Lower Hosston in Injection Well No. 2 will probably be used for the first 1-3 years of injection, after which injection will commence in Injection Well No. 1 in CV1. Injection Well No. 2 will then be used as a fall back well for injection when well No. 1 is down, for example when well No. 1 is completing the next interval up, and at the very end of the 20-year project injection timeframe when well No.1 has used up all the 3 interval CO_2 volume allocations.

  The injection period in any single interval can be extended beyond 5 years until a total injected volume of CO_2 is reached of 2.5 MM metric tons, without the combined injection period in all 4 intervals exceeding the project duration of 20 years. The Lower Hosston Formation is overlain by approximately 890 feet of the Upper Hosston Formation, the Sligo Formation, the Pine Island Formation, and the Rodessa Formation. Note that the Pine Island and Rodessa Formations are successively truncated against the Lower Cretaceous Unconformity in the northern portions of the project area.

- The performance of the Lower Hosston Sandstone in accepting injection fluids is well known. This is based on the formation being historically (and currently) being used for injection of Class I wastewaters for over 30 years, with only low-pressure buildup in the permitted injection interval.

- The project area is free of faulting at seismic resolution within the delineated AoR and larger site of investigation performed as part of the site characterization. Several reprocessed two-dimensional seismic lines are located across the immediate project area and were used in the site characterization analysis. Interpretation of the data indicates that there is no faulting across either the Injection Zones or the Confining Zones (*i.e.*, the Sequestration Complex).

- In the Union County area, the multiple sandstones of the Upper Cretaceous contain hydrocarbons. The proximal hydrocarbon production areas are located north, west, and south of the immediate project area. However, most of these wells are less than +/- 3,000 feet in depth and do not penetrate the Injection Zone(s).

- The upper Confining Zone for the sequestration complex is comprised of the Rodessa/Pine Island/Sligo/Upper Hosston and is located between the Lower Hosston and the Upper Cretaceous Unconformity which lies at the base of the Upper Cretaceous section. For this Class VI application, this group of strata is referred to as the Lower Cretaceous Sequence Boundary (LCSB) and this unit is of regional extent and is geologically suited to contain injected CO_2. See Module A – "*Project Narrative*" for additional information.

- The Tokio Formation, directly overlaying the LCSB Confining Zone, is a blanket sandstone unit. This formation in the project area is saline and serves as a buffer aquifer situated between the top of the Sequestration Complex and the USDW.

- The Sparta Formation is the deepest confirmed USDW and is well known as a groundwater resource in southern Arkansas. It is separated from the underlying Cretaceous section by the Midway Shale, an extensive, regional shale that extends throughout the Gulf Coast area. The Sparta Formation (USDW) will be monitored during the baseline, injection, and post-injection phases of the project to confirm that the groundwater resource has not been impacted as a result of the carbon dioxide injection activities.

- The Wilcox Group underlying the Sparta Formation is a known saline aquifer within the area and is also separated from the underlying Cretaceous section by the extensive Midway Shale. The Wilcox Group is utilized as a receiving unit for brine disposal via injection wells (USGS, 1984). There are no known water supply wells or potable use of this aquifer; and therefore, no monitoring of the Wilcox Group is anticipated for this project.

- Natural seismicity in the area is exceedingly low. However, induced seismicity, from hydrocarbon and saltwater injection, is known to have occurred to the southeast of El Dorado in 1983. As part of the site-specific TMP regional seismicity will be monitored annually using public sources for any change in occurrence or frequency of seismic events. Only if a change in frequency of seismic events occurs, will additional site-specific monitoring of local events be undertaken by the Lapis Energy. The University of Memphis Center for Earthquake Research and Information has a permanent helicorder located at the Richland Creek Farm in El Dorado as a part of the Arkansas Seismic Network Project. It records seismicity in the El Dorado, Arkansas area twice per day and may indicate changes in seismicity due to carbon dioxide injection at Project Blue.

- The proposed injection wells will create a composite carbon dioxide plume and an area of elevated pressures surrounding the injection wells. Both the carbon dioxide plume and the AoR perimeter will be reviewed throughout the lifetime of the project to account for the potential to intersect additional existing (legacy) wells. The injected CO_2 is not expected to migrate to any legacy well that could permit vertical migration of CO_2. Monitoring activities will provide:

  a) validation of the magnitude and area of pressure increase during injection, and

  b) documentation of the extent of the carbon dioxide plume during injection and subsequent stabilization during the post-injection monitoring period.

2.1 IN-ZONE (IZ) MONITORING

The proposed in-zone monitoring plan for the project is composed of direct and indirect elements.

2.1.1 Direct Monitoring

The elements parts of the direct monitoring network are listed below in order, from deepest and closest to the Project Blue Injection Wells, to the shallowest and furthest away. The overall concept for the monitoring well plan is shown in cross section view in Figure 1.

The direct monitoring well network locations are shown in Figure 2.

- IZ monitoring at the injection wells will assure that the wells are performing as intended, which is to deliver the carbon dioxide to the subsurface storage intervals (Injection Zones), and measure the pressure response in the reservoir intervals, a key model match parameter. A downhole pressure gauge and injection logging in the constructed injection wells will be used to collect real-time, continuous data that will be used to assess reservoir response to injection. The gauge will be referenced to ground level.
- One new IZ monitoring well will be drilled to validate the model of growth of sequestered carbon dioxide plume and the growth of the AoR over time (location in Figure 2). Real-time, continuous IZ pressure-monitoring will be performed initially outside of the carbon dioxide plume. As shown on Figure 2, the in-zone monitoring well will be placed in the up-dip direction near the northeastern property boundary. A contingent second IZ monitor Well may be placed southwest (down dip) of the injection wells. Overall decision to drill this second IZ monitor well will be based on an assessment after a period of 2-3 years of injection of the ability of the indirect permanently deployed seismic trace array to pick up plume movement.
- Native formation fluid will be sampled during the IZ monitoring well drilling campaign (for each injection zone) for pre-injection site characterization.

The IZ monitoring well(s) will also provide direct measurement for the sequestered plume, when or if the sequestered carbon dioxide plume ever reaches the monitoring well location, using a dual completion system. The reason to go with a dual completion is to have the option to monitor and sample the Lower Hosston injection zone and the Cotton Valley Injection Zones independently. Pressure and temperature will be continuously measured in the Lower Hosston, and separately in the Cotton Valley. Cotton Valley injection zone 1, 2 and 3, will not be monitored individually. A different tracer will be injected in each of the 4 Injection Zones (See Section 9.1.1.) in the injection wells. Even though sampling will be comingled in the In-Zone Monitoring Well for the Cotton Valley, Lapis should still be able to determine which Injection Zones contribute to the CO_2 plume and will monitor all intervals for the duration of injection operations.

Should the IZ well begin to show the presence of carbon dioxide (either by change in downhole pressure and temperature or by surface pressure and temperature), an adaptive fluid sampling program will be triggered in the affected well(s). Adaptive sampling will be set based upon a specific pressure and temperature threshold that is within the gauge accuracy. Formations have natural slight variations which are to be expected. Therefore, Lapis will use a threshold value of a 25 psi over a 30-day average downhole pressure increase vs the average pressure measured during the first year of IZ monitoring well pressure measurements. The 25 psi threshold is about a quarter of the maximum expected pressure increase in the shallowest zone (Module B - Appendix 8.4), or an average 30-day temperature change of 100%, compared to the maximum measured temperature deviation from the average over the first year of IZ monitoring well temperature measurements. The first year IZ monitoring well baseline temperature deviation will be measured from when the injection well temperatures have stabilized after well completion. Similarly, the 30-day temperature change of 100% vs the maximum deviation, should exclude periods in which well work, or other operations are conducted that might temporarily change the downhole temperatures in the well. Once triggered, samples will be taken on a quarterly basis in the IZ monitoring well during the injection period, and annually during the PISC. Work will be conducted by a qualified Vendor and the selected analytical laboratory will be an Arkansas Accredited Laboratory.

- The direct monitoring program will be enhanced with the continuous addition of tracers to the injected carbon dioxide. In order to establish the source of any CO_2 observed in the IZ-monitoring well, the project plans to use up to four unique chemical tracers, one for each injection zone. The selected tracers will be foreign to the system and tracer materials will be inert, non-flammable and non-toxic, and are classed as non-dangerous goods. The targeted tracer concentration within the CO_2 stream has been designed at 10 parts per billion (ppb). This way, the provenance of the sampled CO_2 can be determined: at a particular sampling point, the presence of a tracer will provide insight from which injection zone the sampled CO_2 comes from; the absence of a tracer in any CO_2 sample will indicate a provenance from outside the project injection wells.

2.1.2 Indirect Monitoring

- Indirect monitoring will be used to assess the performance of the sequestration complex to ensure that it is operating as intended. Indirect plume monitoring will be employed in the injection wells and the "in zone" monitoring wells to define the location, extent, and thickness of the sequestered carbon dioxide. Pulsed neutron capture logs will be used to monitor carbon dioxide saturation at the injection wells and in the IZ monitoring well(s). Saturation logging in the IZ monitoring well(s) will help in understanding the larger scale flow distribution in the sequestration complex.
- The areal distribution of the carbon dioxide plume in the Injection Zones will be determined using a time-lapse ray path seismic technique. Substitution of carbon dioxide for brine within sandstones and limestones at similar project depths is well documented to produce a strong change in acoustic impedance (Vasco et al., 2019). Leading-edge techniques for time-lapse imaging of carbon dioxide plumes developed during implementation of the Regional DOE Partnership projects. include time-lapse vertical seismic profiling (Daley and Korneev, 2006; Gupta, et al., 2020), azimuthal vertical seismic profiling (Gordon, et al., 2016), and sparse array walk-away surveys or scalable, automated, semipermanent seismic array "SASSA" (Roach, et al., 2015; Burnison, et al., 2016; Livers, 2017; Adams, et al., 2020).

  Lapis Energy is proposing deployment of an autonomous, real-time permanent source and receiver seismic array within and beyond the expected dimensions of the carbon dioxide plume. The system will use one or more permanent surface sources and an autonomous 6-component receiver array with the receivers emplaced underground. The receivers will be used to monitor ray paths that will allow for dense sampling over time. System flexibility allows for sensors and/or source geometry to be optimally redeployed further away from the injection wells as the plume gets larger. Baseline and subsequent time-lapse surveys will be processed using a technique that will resolve the differences between the surveys, which will be mapped to show the change in plume extent over time. The seismic array will monitor a grid of several 10's of different X,Y locations, resembling a grid of 'pseudo-monitoring well locations' in the form of a single seismic trace per X,Y location repeated over time, aimed at detecting the moment a plume reaches an X,Y location.

2.2 ABOVE CONFINING ZONE (ACZ) MONITORING

- ACZ monitoring will occur in a well drilled and completed in the basal Tokio Sandstone on the El Dorado Chemical Company (EDCC) property. The initial ACZ monitoring zone for the sequestration project is a porous interval in the Tokio Sandstone located at a depth of 2,900 to 3,000 feet below ground level that is located stratigraphically just above the Lower Cretaceous Unconformity. The ACZ monitoring well shall be located near the point of carbon dioxide injection, where elevated formation pressure would be the greatest.
- The ACZ monitoring well will be outfitted with real-time, continuously recording downhole pressure/temperature gauge. The gauge will be referenced to ground level. Native formation water will be sampled initially upon well construction (including testing for dissolved gases) for baseline characterization purposes. An initial baseline characterization of the Tokio will be performed. Quarterly baseline sampling will be performed prior to injection of carbon dioxide.
- The ACZ monitoring will be monitored quarterly following initiation of injection of carbon dioxide in a new zone for two years for any changes in water quality and composition, after which the frequency goes down to yearly. A threshold of a 10 psi over a 30-day average downhole pressure increase vs the average pressure measured during the first year of ACZ monitoring well pressure measurements will be established. Or an average 30-day temperature change of 50%, compared to the maximum temperature deviation from the average during the first year of ACZ monitoring well temperature measurements. The first year ACZ monitoring well baseline temperature deviation will be measured from when the injection well temperatures have stabilized after well completion. Similarly, the 30-day temperature change of 50% vs the maximum deviation, should exclude periods in which well work, or other operations are conducted that might temporarily change the downhole

temperatures in the well. Note that these triggers are more restrictive than in the IZ monitoring well as the formation is not the injection zone, and leakage could be subtle (if present). Once triggered, a sample will be taken to determine if leakage took place. An adaptive fluid sampling (increase in sampling) program, to be agreed upon with the EPA, will be initiated with more frequent monitoring events if the sample indicates CO_2 leakage, e.g. in the form of the detection of tracers in the sample. If the sample does not indicate leakage, sampling will resume at the regular intervals as defined below in Table 5. If pressure caused the false trigger, the pressure baseline will set to the new higher 30-day pressure average, which was causing the trigger. If temperature caused the false trigger a new baseline will be set which equals the maximum temperature deviation over the preceding year (inclusive of the 30-day temperature average which caused the trigger). Field sampling work will be conducted by a qualified Vendor and the selected analytical laboratory will be an Arkansas Accredited Laboratory.

2.3 UNDERGROUND SOURCES OF DRINKING WATER (USDW) MONITORING

Aquifers in the area consist of the Greensand and El Dorado aquifers of the Sparta Formation, which are collectively referred to as the single Sparta Formation USDW. Public water supply in the area is supplied by El Dorado Water Utilities with partial supply from the Greensand and El Dorado aquifers (ADH, 2021). The EDCC owns and operates approximately 3 on-site and 11 off-site water supply wells (WSWs) within the AoR, all screened within the Sparta Formation USDW. Groundwater samples will be collected from a subset of these EDCC wells (WSW4 and WSW6) during the baseline, injection, and post-injection phases of the project. Drilling pad water supply wells will also be sampled during the baseline phase of the CCS project. An adaptive groundwater sampling program (frequency of sampling increases with triggers) will be initiated with more frequent monitoring events and/or additional locations should indications of carbon dioxide leakage be confirmed in the Tokio Sandstone (via the ACZ monitor well) or in the near-surface monitoring points. An adaptive fluid sampling (increase in sampling) program, to be agreed upon with the EPA, will be initiated with more frequent monitoring events if the sample indicates CO_2 leakage, e.g. in the form of the detection of tracers in the sample.

2.4 SAMPLES AND DATA COLLECTION

Lapis Energy will sample and record injection and monitoring operations using a SCADA distributive control system (or similar). Operations will be monitored at a central control room and data will be recorded in real-time. An archiver may be used to reduce the data stream size for long term data storage. To ensure that permit limits are not exceeded, the distributive control system will consist of safe-set controls and alarms that are set to values safely below regulatory requirements. All gauges and equipment related to injection and monitoring operations will be calibrated per each manufacture's specifications and the calibration records will be maintained at the facility.

2.5 REPORTING PROCEDURES

Lapis Energy will report the results of all testing and monitoring activities to the UIC Program Director in compliance with the requirements under 40 CFR §146.91. Table 1 is an overview of the monitoring and reporting frequency program discussed within this plan.

Table 1: Testing and Monitoring reporting overview

Parameters Monitored	Monitoring Program	Monitoring & Reporting Frequency [a]
Carbon Dioxide Stream Analysis [40 CFR §146.90(a)]		
Chemical and physical composition of CO_2 Stream	Compositional analysis of the injected CO_2 stream using non-destructive chromatographic detector	Quarterly or as process changes or additional sources are included in the injection stream. Semi-annual reporting.
Continuous Recording of Operational Procedures [40 CFR §146.88(e)(1), §146.89(b), and §146.90(b)]		
Injection Parameter Monitoring	Pressure and temperature gauge, mass flow meter with alarms for measurements outside of the normal operating conditions	Continuous monitoring. Summary monthly statistics prepared. Semi-annual reporting.
Annulus Pressure Monitoring	Annulus pressure gauge	
	Annular Fluid Volume Measurements	

Parameters Monitored	Monitoring Program	Monitoring & Reporting Frequency [a]
Corrosion Monitoring [40 CFR §146.90(c)]		
Coupon Testing	Flow-through corrosion coupon using injection well construction materials. Utilize corrosion inhibitors in all fluids during well workovers.	Quarterly analysis during injection operations. Additionally, as new sources added to stream.
Above Confining Zone Monitoring ACZMI [40 CFR §146.90(d) and §146.90(f)(3)]		
Tokio Formation	Downhole temperature and pressure Water analyses from the Tokio.	Continuous real time pressure monitoring. Pre-injection: Quarterly. <u>Injection</u>: Quarterly for the 1st 2 years of injection, annually thereafter; adaptive, if triggered Post-Injection: Annually; adaptive, if triggered
USDW Monitoring [40 CFR §146.90(d)]		
Water Supply Wells (Sparta Formation)	Water analysis from USDW Monitoring Wells (EDCC WSWs WSW4 & WSW6) and Drilling Well Pad water supply wells	<u>Baseline:</u> Quarterly <u>Injection:</u> Quarterly for 1st 2 years in new injection zone; annually thereafter; adaptive, if triggered <u>Post-Injection:</u> Annually; adaptive, if triggered
External Mechanical Integrity [40 CFR §146.89(c)] and §146.90]		
Well Integrity	Annulus Pressure Tests, Radioactive Tracer Survey, Temperature Survey	Annually and after all well workover operations that change well configuration.
Pressure Falloff Test [40 CFR §146.90(f)]		
Reservoir transmissivity and pressure.	Pressure Falloff Test, Static and Flowing Bottomhole Pressures	<u>Baseline</u>: test after well completion. Every 5-years thereafter.

Parameters Monitored	Monitoring Program	Monitoring & Reporting Frequency [a]
CO_2 Pressure and Plume Front [40 CFR §146.90(g)]		
Project Blue injection well One IZ monitoring well(s)	Direct Pressure Monitoring	Continuous
Project Blue injection wells Pulsed Neutron Logging. Repeat Seismic	Indirect Monitoring	A base line pulsed neutron and every 5 years thereafter. Seismic via permanently installed array.

[a] Data archiver may be used to reduce data streams

2.6 QUALITY ASSURANCE PROCEDURES

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities, required pursuant to §146.90(k), is provided in Appendix 1 – Quality Assurance and Surveillance Plan (QASP) to this TMP.

3.0 CARBON DIOXIDE STREAM ANALYSIS

Lapis Energy will analyze the composite carbon dioxide stream during the operational period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR §146.90(a). A baseline sample of the carbon dioxide stream will be evaluated and tested prior to initiation of injection operations at the facility.

3.1 CARBON DIOXIDE SAMPLING LOCATION AND FREQUENCY

The injected carbon dioxide will be continuously monitored at the surface for pressure, temperature, and flow volumes. Sampling will be performed upstream or downstream of the flowmeter to analyze the gas composition. Sampling procedures will follow protocols to ensure the sample is representative of the injected carbon dioxide stream.

The frequency of carbon dioxide sampling will be conducted on a quarterly basis commencing with the initiation of injection operations. This equates to a schedule as follows:

1. Sample No. 1: 3 months after start of injection
2. Sample No. 2: 6 months after start of injection
3. Sample No. 3: 9 months after start of injection
4. Sample No. 4: 12 months after start of injection

The schedule will then repeat using this quarterly sample cycle. When known changes to the injected stream occur (*i.e.*, source changes and/or additions/deletions to the existing stream), sampling will also be performed for verification of the chemical and physical properties of the modified stream. This will determine if there are changes to the stream that need to be accounted and tested to update and compare to the baseline conditions. The proposed sample frequency is sufficient to characterize the carbon dioxide stream and account for any potential changes to representative data.

Density measurements at the mass flow meter greater than normal variability and not correlated to thermal variations also will trigger sampling of the injection stream. The isotopic composition of carbon in CO_2 ($\delta C^{12}/C^{13}$) ratio and C^{14} will be measured for baseline and repeated only if new sources are added.

3.2 CARBON DIOXIDE ANALYTICAL PARAMETERS

Lapis Energy will contract a Vendor to analyze the carbon dioxide for the constituents identified in Table 2 using the methods listed (or equivalent). If the constituents are not found in initial analysis or are screened out at the source prior to injection, this will be documented and with the prior approval of the UIC Program Director, they will be removed from the list of analytical parameters.

Table 2: Summary of potential analytical parameters for CO_2 stream

Parameter	Analytical Method(s)[1]
Carbon Dioxide (CO_2)	ISBT[2] 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD
Oxygen (O_2)	ISBT 4.0 (GC/DID) GC/TCD
Nitrogen (N_2)	ISBT 4.0 (GC/DID) GC/TCD
Hydrogen Sulfide (H_2S)	ISBT 14.0 (GC/SCD)
Sulfur dioxide (SO_2)	ISBT 10.1 (GC/FID)
Methane (CH_4)	ISBT 10.1 (GC/FID)
Total hydrocarbons (C_2H_6, C_3H_8+)	ISBT 10.0 THA (FID)
Hydrogen (H_2)	ISBT 4.0 (GC/DID) GC/TCD
Carbon Monoxide (CO)	ISBT 5.0 Colorimetric ISBT 4.0 (GC/DID)
Nitrogen Oxides (any (NO_x)	ISBT 7.0 Colorimetric
Carbon isotopic composition δC^{13} and C^{14}	Measured once and when a significant new source is added. Used for attribution during monitoring

[1] *An equivalent method may be employed with the prior approval of the UIC Program Director, such as ASTM Standards*

[2] *International Society of Beverage Technologists (ISBT) Carbon Dioxide Guidelines MBAA TQ vol. 39, no. 1, 2002, pp. 32-35 as cited in ISO/TR 27921: 2020(en). Carbon dioxide capture, transportation, and geological storage — Cross Cutting Issues — CO_2 stream composition*

3.3 CARBON DIOXIDE SAMPLING METHODS

Sampling will be performed from a tap located upstream or downstream of the flowmeter and will follow protocols to ensure the sample is representative of the injected carbon dioxide stream. Sample collection procedures will be provided in detail by a certified laboratory Vendor, who will be determined prior to injection authorization. Sampling methods and equipment will meet the standards and limits provided within the attached QASP (Appendix 1).

3.4 CARBON DIOXIDE ANALYSIS PROCEDURES AND CHAIN OF CUSTODY

Samples will be analyzed by a third-party laboratory accredited by the Arkansas Department of Environmental Quality (https://www.adeq.state.ar.us/techsvs/lab_cert/) or the International Organization for Standardization (ISO) using standardized procedures for gas chromatography, mass spectrometry, detector tubes, and photo ionization. Detection limits will be dependent on equipment facilitated for the analytical methods by the selected qualified Vendor. However, all Vendors will meet the minimum levels set forth in the QASP (Appendix 1).

The sample chain-of-custody procedures will be dependent on Vendor selection as they will assume custody of the samples. The procedures will document and track the sample transfer to laboratory, to the analyst, to testing, to storage and to disposal (at a minimum). A sample chain of custody procedures is contained in the QASP (Appendix 1).

4.0 CONTINUOUS RECORDING OF OPERATIONAL PROCEDURES

Lapis Energy will install and use continuous recording devices to monitor injection pressure, injection rate (mass flow), and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the carbon dioxide stream, as required at 40 CFR §146.88(e)(1), §146.89(b), and §146.90(b).

Injection rates and pressures will be monitored such that they do not exceed the values set by the permit. All aspects of the injection process will be monitored, recorded, and if necessary, shut down in the event the normal operating range is exceeded. Surface pressure and temperature will be measured continuously. The injected volume will be determined from a mass flow meter for each well that will be installed on the injection supply line.

4.1 MONITORING LOCATION AND FREQUENCY

Lapis Energy will perform the activities identified in Table 3 to monitor operational parameters and verify internal mechanical integrity of the injection wells. All monitoring will take place at the locations and frequencies shown below.

Table 3: Sampling devices, locations, and frequencies for continuous monitoring

Parameter	Device(s)	Location	Min. Sampling[1] Frequency	Min. Recording[2] Frequency
Injection Pressure (surface)	Pressure Gauge	Wellhead/Flowline	1 minute	30 minutes
Injection Pressure (downhole)	Quartz Pressure Gauge	Near Perforations	1 minute	30 minutes
Injection Rate	Mass Flow Meter/Computer	Flowline	1 minute	30 minutes
Injection Volume	Mass Flow Meter/Computer	Flowline	1 minute	30 minutes
Annulus pressure	Pressure Gauge	Wellhead	1 minute	30 minutes
Annulus fluid volume	Fluid Level Measure	Annulus Tank	1 minute	Daily
CO_2 stream temperature	Mass Flow Meter/Computer	Wellhead/Flowline	1 minute	30 minutes
Downhole Temperature	Temperature Gauge	Near Perforations	1 minute	30 minutes

Parameter	Device(s)	Location	Min. Sampling[1] Frequency	Min. Recording[2] Frequency
If Deployed on Injection Well				
Changes in *Rayleigh* scattering resulting from distributed strain indicative of wave arrival	optical fiber	Installed on outside of casing or tubing	As designed for acoustic survey	As designed for acoustic survey
Changes in *Rayleigh* scattering indicative of temperature change	optical fiber	Installed on outside of casing or tubing	Hourly	Daily

[1] *Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. for example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.*

[2] *Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). for example, the data from the injection pressure transducer might be recorded to a hard drive once every minute. Note a data archiver may be used to reduce data stream size for long term storage.*

Continuously recorded injection parameters will be reviewed and interpreted on a regular basis, to evaluate the injection stream parameters against permit requirements. Trend analysis will also help evaluate the performance (*e.g.,* drift) of the instruments, suggesting the need for maintenance or calibration.

Basic calibration standards, precision, formulas, conversion factors, and tolerances for measuring devices and analysis are included in the QASP (Appendix 1) but will be dependent on specific qualified Vendor selection. Calibrations will be per manufacturers specifications and frequency.

4.2 MONITORING DETAILS

For each of the parameters that are required to be continuously monitored, such as injection pressure, injection rate, injection volume, annular pressure, annulus fluid volume, and carbon dioxide stream temperature, these will be monitored and recorded using a SCADA distributive control system (DCS) or similar. Results of the monitoring activities will be submitted to EPA in a semi-annual report for each of the following parameters:

- Monthly average, maximum, and minimum values for injection pressure, flow rate, and volume [40 CFR §146.91(a)(2)].
- Monthly average, maximum, and minimum values for annulus pressure, in compliance with 40 CFR §146.91(a)(2).
- A description of any event that exceeds operating parameters for annular pressure or injection pressure specified in the permit, in compliance with 40 CFR §146.91(a)(3).
- A description of any event that triggers a shut-off device required pursuant to 40 CFR §146.88(e) and the response taken.
- The monthly volume and/or mass of the carbon dioxide stream injected over the reporting period and volume injected cumulatively over the life of the project [40 CFR §146.91(a)(5)].
- Monthly annulus fluid volume added or gained [40 CFR §146.91(a)(6)].

Automatic alarm and automatic shutoff systems will be designed and installed to trigger an audible alarm in the event that pressures, flow rates, or other parameters, designated by the Executive Director, exceed the normal operating range specified in the injection permit per 40 CFR §146.88(e)(2). If an alarm or shutdown is triggered, Lapis Energy will immediately investigate and identify the cause of the alarm or shutoff (Please see the "*E.4-Emergency and Remedial Response Plan*" [40 CFR §146.94 (a)] submitted in Module E for details).

4.2.1 Injection Rate, Volume, and Pressure Monitoring

Injection rates, volumes, and pressures will be set and limited to safe operating values below those specified in the authorized permit. All gauges, pressure sensing devices, and recording devices will be tested and calibrated as specified by the manufacturer. Test and calibration records will be maintained at the facility. All instruments will be housed in weatherproof enclosures, where appropriate, to limit damage from outside elements and events. The flow meters and pressure gauges will continuously record data that will be sent to a distributive control system.

Downhole flowing pressures into the reservoir will be monitored by a gauge installed near the perforations in the injection well. Gauges will be referenced to ground level at each well. Downhole pressure monitoring will protect the Injection Zone against over-injection as the carbon dioxide becomes denser. If a retrievable gauge is used, pressure gauge(s) will be periodically calibrated according to the manufacturer's instructions and corrected for drift.

If permanent unretrievable downhole gauges are used, those gauges will be calibrated by comparison to a wireline deployed gauge run to the same depth in concert with mechanical integrity testing events. Static gradient stops will be made with the wireline deployed gauge to verify fluid column density for pressure to depth corrections. Downhole pressure gauge data will provide real-time information for verification of model predictions and AoR reevaluations.

4.2.2 Annulus System Monitoring

The purpose of the annulus system is to maintain a positive pressure on the tubing by the casing annulus of at least 100 psi in excess of the tubing pressure. This will prevent fluid movement from the tubing out into the casing, which will prevent contamination of freshwater sands in the event of well casing or injection tubing failure.

The integrity of the well's annulus system is achieved by monitoring of the annulus system at the wellhead. Annulus monitoring equipment used for the injection wells includes an annulus tank, an annulus pump (small volume/high pressure), well flow meters, pressure monitoring cells, and pressure control valves. Alternate annulus construction may use a pressurized nitrogen system to maintain a constant pressure on the annulus. The annulus pressure will be monitored continuously. Deviations from expected changes could indicate a potential loss of mechanical integrity in the well annulus system. Observed deviations will initiate a well shutdown and investigation to determine the root cause of the observed deviation. Details are contained in the "*E.4-Emergency and Remedial Response Plan*" [40 CFR §146.94(a)] in Module E.

Annulus brine tank fluid levels (and volumes) will be monitored for indications of system losses/gains and recorded daily.

5.0 CORROSION MONITORING

Per the requirements of 40 CFR §146.90(c), Lapis Energy will monitor well materials during the operational period. This will be accomplished by using corrosion coupons of well construction materials, which will be monitored for loss of mass and thickness, and will be visually inspected for evidence of cracking, pitting, and other signs of corrosion. This testing will ensure that the well components meet the minimum standards for material strength and performance. The coupon monitoring program is described in the following sections.

5.1 MONITORING LOCATION AND FREQUENCY

Coupon samples of the well construction materials (well casing, tubing, and any other well parts in contact with carbon dioxide, such as the packer and wellhead) will be mounted in a tray located in the common flowline to the injection well, upstream of the flow distribution header. The tray of coupons will be in contact with the carbon dioxide stream during all injection operations. This will ensure that the tray location will provide representative exposure of the samples to the carbon dioxide composition, temperature, and pressures that will be seen at the wellhead and injection tubing. The holders and location of the system will be included in the pipeline design and will allow for continuation of injection during sample removal for testing.

The frequency of corrosion coupon collection and testing will be conducted on a quarterly basis per 40 CFR §146.90(c). Baseline measurements on all coupon samples will be made prior to initiation of injection of carbon dioxide. Commencing with the initiation of injection operations, the initial monitoring event will occur at the end of the first calendar quarter (even if less than 3 months). Subsequent monitoring will occur at the end of each calendar quarter. This equates to a schedule as follows:

- March 31 – End of Calendar 1st Quarter
- June 30 – End of Calendar 2nd Quarter
- September 31 – End of Calendar 3rd Quarter
- December 31 – End of Calendar 4th Quarter

The schedule will then repeat using this quarterly sample cycle for the lifetime of the injection operations. Coupon compositions and details will be specified as part of conveyance pipeline and final well design.

5.2 SAMPLE DESCRIPTION

Lapis Energy is proposing that a corrosion coupon (weight loss) technique will be used for monitoring purposes, as it is the best known and simplest of all corrosion monitoring techniques (the alternative is to use flow line loops). The corrosion monitoring system will be located downstream of all process compression/dehydration/pumping equipment (*i.e.,* at the beginning of the flow distribution header to the injection well). This will allow for monitoring at a single location for the injection well. Corrosion coupons representative of the well construction materials (Table 4) will be inspected, photographed, and weighed prior to placement into the flowline to establish a baseline. Prior to installation of the corrosion monitoring system, the following information will be recorded:

1) Coupon Serial Number;
2) Installation date;
3) Identification of the location of the system; and
4) Orientation of the coupon holder.

The coupon method involves exposing a specimen sample of material (the coupon) to a process environment for a given duration, then removing the specimen for analysis. The corrosion monitoring plan will be implemented following the initial installation of the test coupons in the flowline, as follows:

1) Consult maintenance schedule to determine when to remove test coupons from corrosion monitoring holders (coincident with end of calendar quarter);
2) Remove and inspect coupons on a calendar quarterly basis and quantitatively evaluate for corrosion according to ASTM G1 – 03 (2017) or NACE Standard RP0775-2005 Item No. 21017 standards guidelines;

3) Place coupons in proper receptacle for safe transport to measurement and weighing equipment;

4) Photograph each coupon as received. Visually inspect each corrosion coupon for any pitting, stress corrosion cracking or scale buildup. Analyze corrosion coupons by weighing each coupon (to the nearest 0.0001 gram) and measuring the length, the width, and the height of the coupon (to the nearest 0.0001 inch);

5) Record information for each coupon including the date of measurement, the coupon identity (coupon number and metal grade), and the coupon weight in grams, and include any observations of excessive weight loss or pitting, stress corrosion cracking, or scale buildup;

6) Determine if current the corrosion coupon can be returned to the monitoring test holder, if so, make a note of the coupon return; if not, make a note of the installation of a new coupon.

Table 4: List of equipment coupon with material of construction

Equipment Coupon	**Material of Construction**
Surface Piping	"as built" material in contact with CO_2
Wellhead	Chrome alloy, or "as built" trim material in contact with CO_2
Injection Tubing	Chrome alloy, or "as built" material in contact with CO_2
Packer	Chrome alloy, or "as built" trim material in contact with CO_2

Samples will be collected by trained and authorized personnel and submitted to a third-party analytical laboratory for analysis. Results of the analysis will be compared to the pre-project baseline of the coupons. Basic details regarding the laboratory analysis are explained in the attached QASP, however, specific details will be provided and updated by the selected corrosion laboratory Vendor. Results will be submitted through the GSDT semi-annual reporting portal. The UIC Program Director will independently assess the results of the corrosion monitoring program to assess the integrity of the injection well.

5.3 ALTERNATIVE TESTS

In accordance with 40 CFR §146.90, Lapis Energy may run a casing inspection log(s) to determine the presence, or absence, of corrosion in the protection (longstring) casing whenever the tubing is pulled from the well, or at the request of the UIC Program Director. Proposed casing inspection logs may include multi-finger caliper, ultrasonic imaging, magnetic flux leakage, and electromagnetic imaging tools, as they are the industry standard for determining casing thickness and for identifying internal and external corrosion. The log(s) will be compared to those run during the initial construction of the well (40 CFR §146.87). Additional inspection logging programs may be implemented, should the coupons show undue corrosion in excess of the design-life criteria.

Alternative testing, other than those listed above, may be conducted with the written approval of the UIC Program Director. To obtain approval for alternative testing, ahead of any proposed testing, Lapis Energy will submit a written request to the UIC Program Director setting forth the proposed test and all technical data supporting its use.

6.0 ABOVE CONFINING ZONE (ACZ) MONITORING

6.1 ACZ MONITORING – TOKIO SANDSTONE FORMATION

Lapis Energy will monitor pressure and temperature in a sandstone developed within the basal Upper Cretaceous Tokio Formation , immediately above the Confining Zone. This will allow for early detection of any out-of-zone movement of either carbon dioxide or intraformational fluids above the Confining Zone and out of the sequestration complex. The basal Upper Cretaceous Tokio Sandstone is generally a blanket sand within the area of the injected carbon dioxide plume and the AoR. The Tokio Sandstone will be monitored in a dedicated ACZ monitor well located on the EDCC property, near the Project Blue injection wells. The well will be engineered for continuous monitoring and set up for fluid sampling on a quarterly basis.

The well will be fitted with a real-time, continuously recording downhole pressure/temperature gauge for the Tokio Sandstone. The gauge will be referenced to ground level. Alternately, a “light” fluid column may allow monitoring and recording pressures at surface. The method is dependent on if the monitor well can support a “light” fluid to surface. Native formation water from the Tokio Sandstone will be sampled initially upon well construction (including a quantification of dissolved native gases) for baseline characterization purposes.

Changes in water composition are not expected in the basal Tokio Sandstone. However, the ACZ monitor well will provide direct measurement, when or if, the sequestered carbon dioxide or deeper formation brines ever vertically migrate upwards to the base of monitored interval. Baseline and quarterly fluid sampling will be conducted in the ACZ monitor well. Baseline sampling will be performed prior to initiation of sequestration injection. Should the well begin to exhibit the presence of carbon dioxide (either by change in downhole pressure and temperature or by surface pressure and temperature changes or a change in water quality), an adaptive fluid sampling program will be initiated with more frequent monitoring events. A threshold of a 10 psi over a 30-day average downhole pressure increase vs the average pressure measured during the first year of ACZ monitoring well pressure measurements will be established. Or an average 30-day temperature change of 50%, compared to the maximum temperature deviation from the average during the first year of ACZ monitoring well temperature measurements. The first year ACZ monitoring well baseline temperature deviation will be measured from when the injection well temperatures have stabilized after well completion. Similarly, the 30-day temperature change of 50% vs the maximum deviation, should exclude periods in which well work, or other operations are conducted that might temporarily change the downhole temperatures in the well. Note that these triggers are more restrictive than in the IZ monitoring well as the formation is not the injection zone, and leakage could be subtle (if present). Once triggered, a sample will be taken to determine if leakage took place. An adaptive fluid sampling (increase in sampling) program, to be agreed upon with the EPA, will be initiated with more frequent monitoring events if the sample indicates CO_2 leakage, e.g. in the form of the detection of tracers in the sample. If the sample does not indicate leakage, sampling will resume at the regular intervals as defined below in Table 5. If pressure caused the falls trigger, the pressure baseline will set to the new higher 30-day pressure average, which was causing the trigger. If temperature caused the falls trigger a new baseline will be set which equals the maximum temperature deviation over the preceding year (inclusive of the 30-day temperature average which caused the trigger).

Field sampling work will be conducted by a qualified Vendor and the selected analytical laboratory will be compliant with the Arkansas Laboratory Accreditation Program.

6.1.1 Monitoring Location and Frequency

Per Standard 40 CFR §146.90(d), geochemical and water quality will be monitored within the lower sandstone of the Tokio Formation. Figure 2 and Table 5 show the planned monitoring methods, locations, and frequencies for direct and indirect monitoring of groundwater quality and geochemistry above the Confining Zone, in the porous sandstone of the Tokio Formation, located at a depth of 2,900 to 3,000 feet below ground level. The ACZ monitoring well will be located near the point of carbon dioxide injection, where the elevated formation pressure in the reservoirs is expected to be the greatest during the injection and post-injection phases.

Table 5: Monitoring of groundwater in the Tokio Sandstone (ACZ monitor well)

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Tokio Sandstone	Downhole pressure monitoring	ACZ monitoring well	Near the point of CO_2 injection	Real time daily read out.
	Pulsed Neutron Logging			Baseline log at prior to project start. Repeat surveys if anomaly is observed
	Baseline geochemical sampling			Baseline Sample at prior to project start.
	Follow-up Geochemical testing if signal is observed			Only if anomaly is observed
	Fluid Sampling			Pre-injection: Quarterly. Injection: Quarterly for the 1st 2 years of injection, annually thereafter, adaptive, if triggered Post-Injection: Annually; adaptive, if triggered

Modeling shows that pressure monitoring is a more robust and more diagnostic leakage detection method in deep confined saline aquifers. Under typical low flow gradients in saline formations, a carbon dioxide pressure signal is unlikely to propagate far from the leakage point and would be chemically undetectable. Leakage of brine from one formation to another is also unlikely to be chemically diagnostic. If ambient methane or carbon dioxide is present in the system, carbon dioxide may not be chemically diagnostic either. Lapis Energy will instead measure bottomhole pressure in the onsite ACZ monitoring well, which will be continuously monitored. If leakage trends are detected, follow-up testing, logging, or geochemical measurements will be conducted to assess the change in signal (adaptive monitoring).

The goal of monitoring the unit directly above the Confining Zone is to detect the leakage or upward movement of either formation brine or carbon dioxide from the sequestration complex, should it occur. An initial geochemical description of the fluids will be evaluated prior to injection operations for this interval.

Lapis Energy will also monitor ground water quality and geochemical changes in the Tokio Sandstone above the Confining Zone during the operational and post-operational periods to meet the requirements of 40 CFR §146.90(d). Groundwater sampling methods to be employed, include sampling standard operating procedures as adapted from EPA (2017) or as approved by the UIC Program Director. Sample containers will be new and of an appropriate material and size for the analyte. Sufficient volumes will be collected to complete all the specified analyses in Table 6. Appropriate preservation of each sample container will be completed upon sample collection (see QASP). Chain-of-custody will be documented using a standardized form from the analytical laboratory and will be retained and archived to allow tracking of sample status. This will include any required duplicates collected and appropriate field and trip blanks included for quality assurance. Completing the field chain-of-custody form will be the responsibility of groundwater sampling personnel.

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assurance. Completing the field chain-of-custody form will be the responsibility of groundwater sampling personnel.

The frequency of groundwater quality sampling will be conducted on a quarterly basis. A baseline series of sampled groundwater quality will be established ahead of the initiation of carbon dioxide sequestration. Then, commencing with the initiation of carbon dioxide injection operations, the initial monitoring event will occur at the end of the first calendar quarter (even if less than 3 months). Subsequent monitoring will occur at the end of each calendar quarter. This equates to a schedule as follows:

1. March 31 – End of Calendar 1st Quarter
2. June 30 – End of Calendar 2nd Quarter
3. September 31 – End of Calendar 3rd Quarter
4. December 31 – End of Calendar 4th Quarter

The schedule will then repeat using this quarterly sample cycle for the duration of injection operations.

If a pressure anomaly is detected in the ACZ monitoring well, Lapis Energy will be notified, and the anomaly will be investigated. If it is determined that the anomaly appears to be real and related to project performance, this will trigger additional adaptive geochemical sampling of the formation fluids. The collected samples will be sealed, dated, and sent to an authorized third-party laboratory for analysis. The frequency of enhanced geochemical sampling will be conducted on an "as needed" basis if the pressure signal triggers additional testing.

If pressure and sample analyses confirm potential leakage into the strata overlying the Confining Zone, then injection operations will cease and will trigger the procedures set out in the "*E.4-Emergency Remedial and Response Plan*". Sampling of the near-surface groundwaters will then be initiated as part of the response, to define the impact and reach of the potential leakage above the Confining Zone.

6.1.2 Analytical Procedures

Table 6: Summary of potential analytical and field parameters for the Tokio Sandstone (ACZ monitor well)

Parameters	Analytical Methods
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Sr, and Tl	ICP-MS, EPA Method 6020B
Cations: Ca*, Fe, K*, Mg*, Na*, and Si	ICP, EPA Method 6010D
Anions: Br*, Cl*, F, NO_3, and SO_4*	Ion chromatography, EPA Method 300.0
Alkalinity (total and bicarbonate)*	SM 2320B
Total dissolved solids*	SM 2540C
Water density (lab)	SM 2710F
Water density (field)*	Calculated from Salinity, Temperature, and Pressure
pH (lab)*	SM 4500 H+B
pH (field)*	Standard Method 4500-H+ B-2000
Specific conductance (field)*	Standard Method 2510 B-1997
Temperature (field)*	Thermistor, Standard Method 2550 B-2000
Turbidity (field)*	Nephelometric - Optical, 90° Scatter
Oxidation-Reduction Potential (field)*	Platinum Button; Ag/AgCl Reference
Dissolved Oxygen (field)*	ASTM Method D888-09 (C)
Dissolved Inorganic Carbon (DIC)*	SM 5310B
Isotopic composition of selected major or minor constituents (*e.g.*, $^{228}Ra/^{226}Ra$, $^{87}Sr/^{86}Sr$)	EPA Method 901.1, ICP-MS
$\delta^{18}O$ and $\delta^{2}H$ of H_2O	Analyzed via CRDS
$\delta^{13}C$ of DIC	Gas Bench/CF-IRMS
^{14}C of DIC	AMS
Dissolved CO_2, N_2, Ar, O_2, He, C1-C6+, by headspace*	In-house Lab SOP, similar to RSK-175
$\delta^{13}C$ of dissolved Methane, Ethane, Propane, and CO_2, $\delta^{2}H$ of Methane	High precision (offline) analysis via Dual Inlet IRMS

* *Analytical parameters to be included during the baseline phase, and only as needed during* the *injection and post-injection phases of the project.*

Pre-injection phase fluid sampling and analysis is an integral part of the site characterization activities prior to start of the injection project. It provides a basis to assess data gathered during the injection and post-closure monitoring phases of the project when such a need is identified based on project performance / triggers.

An initial formation fluid sample will be collected from the basal Tokio ACZ monitoring well prior to injection operations. The initial fluid sample will provide the baseline measurements. Table 6 identifies the parameters to be monitored and the analytical methods that Lapis Energy will use.

The initial parameters identified in Table 6 may be revised to include additional components for testing, dependent on the initial geochemical evaluation. When the fluid samples are collected, then they will be sent to a third-party laboratory accredited by the Arkansas Department of Environmental Quality or ISO for analysis.

6.1.3 Sampling Methods

The sampling system used to sample and quantify dissolved gases and the aqueous phases in equilibrium with those gases will be supplied by a third-party Vendor (Schlumberger, Expro, or equivalent Vendor using downhole PVT sampler or equivalent tool). Bottomhole samples are preferred, however, surface samples may be used for expediency.

The sampling protocol will be similar to the following:

1) Purge the casing volume to bring fresh fluids that have not reacted with casing and tubing to the sample point within the wellbore;
2) Deploy commercial downhole sampler on slickline to collect a fluid sample at pressure and then close to retain gas phases as sample is transported to the surface;
3) Conserve gas volumes as samples are stepped to atmospheric pressure for shipping and analysis;
4) Filter and preserve samples following protocols for brine sampling;
5) All sample containers will be labeled with durable labels and indelible markings;

6) A unique sample identification number and the sampling date will be recorded on each sample container; and
7) The sample container will be sealed and sent to an authorized third-party laboratory.

Repeat sampling and frequency to be determined based on results.

6.1.4 Analysis Procedures and Chain of Custody

Samples will be analyzed by a third-party laboratory accredited by the Arkansas Department of Environmental Quality or ISO using standardized procedures for gas, major, minor and trace element compositions. Detection limits will be dependent on equipment used for the analytical methods by the selected qualified Vendor and meet the minimum levels set forth in the QASP.

The sample chain-of-custody procedures will be dependent on Vendor selection as they will assume the custody of the samples. The procedures will document and track the sample transfer to laboratory, to the analyst, to testing, to storage, to disposal (at a minimum). A sample chain-of-custody procedure is illustrated in Appendix 1.

6.2 USDW MONITORING – EL DORADO CHEMICAL COMPANY WATER SUPPLY WELLS

The primary goal of the USDW monitoring program is to confirm protection of groundwater that can potentially be used as a drinking water resource. The Greensand and El Dorado aquifers of the Sparta Formation are known sources of drinking water within the AoR (ADH, 2021); and therefore, will be monitored during the baseline, injection, and post-injection phases of the project, in accordance with applicable regulations and guidelines set forth by the EPA UIC program for Class VI injection well sites (40 CFR §146.90(d); EPA, 2013a;b; EPA, 2016).

The Wilcox Group underlying the Sparta Formation is a known saline aquifer within the area (USGS, 1984). There are no known existing or proposed facility WSWs or potable use of this aquifer. Therefore, no monitoring of the Wilcox Group is proposed for Project Blue.

6.2.1 Monitoring Location and Frequency

The EDCC has fourteen WSWs within the AoR (see Figure 3), all screened within the Sparta Formation. However, several of the wells are currently out of active service. A subset of the WSWs is proposed for monitoring the injection and post-injection phases. Proposed sampling wells are WSW4 and WSW6, located on the eastern part of the facility and the western part of the facility (see Figure 3). In addition to the WSWs, Lapis Energy is planning to drill water source wells on each project drill pad (injection well pad and deep monitoring well pad). In addition a third USDW Monitor Well will be drilled on the southern portion of the plant (see Figure 3). This southerly well may source water for the contingent second Deep IZ Monitor Well, should it be drilled at a later stage. Groundwater samples will be collected from these five wells (see Figure 3) for water quality testing during the baseline, injection, and post-injection phases of the project. Table 7 shows the planned monitoring methods, locations, and frequencies for ground water quality and geochemical monitoring of the Sparta Formation aquifers.

Table 7: Monitoring of groundwater quality and geochemical parameters in the Sparta Formation USDW – EDCC WSWs and other USDW Monitoring Wells

Target Formation	Monitoring Phase	Suggested Monitoring Location(s)	Spatial Coverage	Frequency
Sparta Formation: Greensand and El Dorado aquifers	Baseline	EDCC WSWs: On-Site: WSW Nos. 4 & 6 Drilling Pad Wells: Injection Well Pad, Northern IZ Well Pad, Southerly Water Well.	Over area of review	Quarterly for at least 1 year for WSW 4&6 and for at least a year or as long as possible for the drilling Pad Wells, starting when they have been completed.
	Injection	EDCC WSWs: On-Site: WSW Nos. 4 & 6 Drilling Pad Wells: Injection Well Pad, Northern IZ Well Pad, Southerly Water Well.	Within estimated 100-year plume extent	Quarterly during first 2 years of injection in new injection zone. Annually thereafter.
	Post-Injection	EDCC WSWs: On-Site: WSW Nos. 4 & 6 Drilling Pad Wells: Injection Well Pad, Northern IZ Well Pad, Southerly Water Well.	Within estimated 100-year plume extent	Annually during post-injection site closure phase.

USDW groundwater samples will be collected manually from select EDCC WSWs (WSW4 & WSW6) on a quarterly basis during the baseline phase of at least 1 year. Baseline sampling in the three new water wells will commence once they are completed, at the same frequency as WSW4 & WSW6. Specific wells to be monitored will be based upon accessibility and location within the delineated AoR. Commencing with the initiation of injection operations in each *new* injection zone (*i.e.*, Cotton Valley and then the Lower Hosston) quarterly monitoring will be conducted during the first 2 years, with annual monitoring conducted thereafter until injection into the next zone is initiated. The initial injection monitoring event for each new injection zone will occur at the end of the first calendar quarter (even if less than 3 months). Subsequent monitoring will occur at the end of each calendar quarter. This equates to a schedule as follows:

- March 31 – End of Calendar 1st Quarter
- June 30 – End of Calendar 2nd Quarter
- September 31 – End of Calendar 3rd Quarter
- December 31 – End of Calendar 4th Quarter

Following the second year in each new injection zone, annual monitoring will be conducted at the end of each calendar year (*i.e.*, by December 31). For post-injection closure sampling, the frequency of sampling will continue to be performed on an annual basis for a determined post-site care closure timeframe.

6.2.2 Analytical Procedures

USDW monitoring programs can entail an array of analytical components, some of which may be prone to false-positive indications of carbon dioxide leakage. These false positives often reflect the natural variability in groundwater geochemistry in space and time, which are unrelated to carbon dioxide injection and storage activities. As such, this USDW monitoring program has been designed to improve the ability to discern natural vs anthropogenic sources of carbon dioxide based on the geochemical patterns observed before, during, and after the injection operations. Table 8 identifies the parameters to be monitored and the analytical methods that Lapis Energy will use for USDW groundwater sampling and testing of existing EDCC WSWs (WSW4 and WSW6), the drilling well pads, and the new southerly USDW Monitor well.

Table 8: Summary of potential analytical and field parameters for groundwater samples - EDCC WSWs and other USDW Monitoring Wells

Parameters	Analytical Methods
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Sr, and Tl	ICP-MS, EPA Method 6020B
Cations: Ca*, Fe, K*, Mg*, Na*, and Si	ICP, EPA Method 6010D
Anions: Br*, Cl*, F, NO_3, and SO_4*	Ion chromatography, EPA Method 300.0
Alkalinity (total and bicarbonate)*	SM 2320B
Total dissolved solids*	SM 2540C
Water density (lab)	SM 2710F
Water density (field)*	Calculated from Salinity, Temperature, and Pressure
pH (lab)*	SM 4500 H+B
pH (field)*	Standard Method 4500-H+ B-2000
Specific conductance (field)*	Standard Method 2510 B-1997
Temperature (field)*	Thermistor, Standard Method 2550 B-2000
Turbidity (field)*	Nephelometric - Optical, 90° Scatter
Oxidation-Reduction Potential (field)*	Platinum Button; Ag/AgCl Reference
Dissolved Oxygen (field)*	ASTM Method D888-09 (C)
Dissolved Inorganic Carbon (DIC)*	SM 5310B
Isotopic composition of selected major or minor constituents (*e.g.*, $^{228}Ra/^{226}Ra$, $^{87}Sr/^{86}Sr$)	EPA Method 901.1, ICP-MS
$\delta^{18}O$ and $\delta^{2}H$ of H_2O	Analyzed via CRDS
$\delta^{13}C$ of DIC	Gas Bench/CF-IRMS
^{14}C of DIC	AMS
Dissolved CO_2, N_2, Ar, O_2, He, C1-C6+, by headspace*	In-house Lab SOP, similar to RSK-175
$\delta^{13}C$ of dissolved Methane, Ethane, Propane, and CO_2, $\delta^{2}H$ of Methane	High precision (offline) analysis via Dual Inlet IRMS

* *Analytical parameters to be included during the baseline phase, and only as needed during the injection and post-injection phases of the project.*

At the conclusion of baseline monitoring, the range of naturally occurring groundwater conditions during the baseline timeframe will be characterized, and protocols for carbon dioxide leakage detection during the injection phase (*e.g.*, the initiation of adaptive sampling when certain threshold concentrations are exceeded) will be developed. Shallow formations have natural slight variations over time due to mineralogy and movement of fluid. Adaptive sampling triggers will be set once the baseline of parameters of the formation fluids has been established. The adaptive sampling program will be based upon the sample results and agreed upon with the EPA. The samples will be analyzed for the tracers used in the CO_2 injection stream.

An anomalous detection of carbon dioxide above background levels in the USDW "does not necessarily demonstrate that USDWs have been endangered, but it may indicate that a leakage pathway or conduit exists" (EPA, 2013b). The continuous addition of tracer to the injected CO_2 will also aid in the evaluation of whether the CO_2 is natural or part of the sequestered plume. Therefore, if it is determined that a departure between observed and baseline parameter patterns appears to be related to a potential carbon dioxide leak from the target reservoir, additional testing of the USDW and the Lower Wilcox zone may be conducted.

Note that the ACZ monitoring well, will have a dual completion. Apart from the Tokio, it will also have the ability to sample the Wilcox. Unless a leak is confirmed in the Tokio, no regular sampling is planned for the Wilcox. If a leak (and tracer is detected in the Tokio), the Wilcox will be included in the adaptive sampling program, to detect if CO_2 has migrated upwards. The adaptive sampling program will be agreed upon with the EPA.

The elements of the USDW monitoring program may be modified throughout the baseline, injection, and post-injection operational phases of the project, as needed, and with approval of the UIC Program Director, as more data and information become available for the Project Blue site.

6.2.3 Sampling Methods

Groundwater sampling will be conducted in general accordance with operating procedures set forth in EPA Method SESDPROC-301-R4 (EPA, 2017). Groundwater samples will be collected into appropriate lab-supplied, method-specific sample containers, properly preserved (as needed), and shipped within 24 hours of collection for laboratory analysis. Groundwater samples for the analysis of cations will be field-filtered utilizing a 0.45 µm flow-through filter cartridge and preserved using appropriate techniques. Prior to sample collection, filters will be purged with a minimum of 100 mL of well water (or more if required by the filter manufacturer). All sample containers will be labeled with durable labels and indelible markings, and a unique sample identification number and sampling date will be recorded on the sample containers.

6.2.4 Analysis Procedures and Chain of Custody

Groundwater samples will be submitted for various geochemical and isotopic analyses by a third-party laboratory accredited by the Arkansas Department of Environmental Quality or ISO using standardized procedures. Detection limits will be dependent on equipment facilitated for the analytical methods by the selected qualified Vendor and meet the minimum levels set forth in Appendix 1.

The sample chain-of-custody procedures will be dependent on Vendor selection as they will assume custody of the samples. The procedures will document and track the sample transfer to laboratory, to the analyst, to testing, to storage, to disposal (at a minimum). A sample chain-of-custody procedure is contained in the attached QASP (Appendix 1). Sample chain-of-custodies will include any required duplicates collected and appropriate field and trip blanks included for quality assurance.

The initial parameters identified in Table 8 may be revised and include additional components for testing dependent on the initial geochemical evaluation.

7.0 EXTERNAL MECHANICAL INTEGRITY TESTING (MIT)

To verify external mechanical integrity in the injection wells, Lapis Energy will conduct the tests presented in Table 9, during the injection phase, as required by 40 CFR 146.89(c) and 146.90 per the frequency indicated. A demonstration of mechanical integrity will be made at least once a year during injection operations and will include an Annulus Pressure Test and either an approved tracer survey or temperature/noise log.

7.1 TESTING LOCATION AND FREQUENCY

The integrity of the long-string casing, the injection tubing, and the annular seal shall be tested by means of an approved pressure test. The integrity of the bottom-hole cement may be tested by means of a temperature survey or an approved tracer survey. Alternatively, a noise log may be run in the well to demonstrate containment within the permitted Injection Zones. Pulsed neutron logging will be run to verify the mechanical integrity of the near-well area behind the casing of the injection wells.

Table 9: Mechanical Integrity Testing – Injection Well

Test Description	Location	Frequency
Temperature/Noise log or Tracer Survey	Injection Well	Annually
Pulsed Neutron Log	Injection Well	Periodically
Annulus Pressure Test	Injection Well	Annually

Mechanical Integrity Tests (MITs) will be run after the initial construction of the well, prior to the initiation of injection operations. During injection operations, an MIT will be performed on an annual basis, within 45 days of the anniversary of the preceding year's test and will be submitted in a report within 30 days. Lapis Energy will notify the UIC Program Director ahead of testing. This schedule will be repeated through the duration of injection operations and prior to plugging operations. Should the well require a workover, an MIT will also be performed prior to placing the well back into service with notification in writing in 30 days ahead of planned operations. If at any time, a well fails to maintain integrity, Lapus will cease injection into the well and report to the UIC Program Director within 24 hours as required by 40 CFR 146.91(c)(4).

7.2 TESTING DETAILS

Prior to running an MIT, the wellbore may be displaced with water or brine. In either case, the well will be allowed to thermally stabilize prior to all testing operations. It is recommended that the well be shut-in for 36 hours to allow temperature effects to dissipate. The external MIT logs will be run in the injection wells.

7.2.1 Temperature Survey

A baseline differential temperature survey will be run in the well after allowing the well a period of time to reach approximate static conditions. The temperature log will be one of the approved logs for detecting fluid movement outside of the well pipe. A baseline survey will be run during completion operations, which will provide an initial baseline temperature curve for future comparisons. The log will include both an absolute temperature curve and a differential temperature curve. The well should be shut-in for at least 36 hours to allow temperature stabilization of the well prior to running the temperature survey.

If a distributed temperature sensing fiber is run in the injection well, the fiber will be used for the temperature testing; otherwise, a wireline truck will be used.

If wireline operations are conducted, the temperature will be logged from the surface down to the total depth of the well. Recommended line speed for the logging operations is 30 to 40 feet per minute. A correlation log(s) will be presented in Track 1 and the two temperature curves will be presented in Tracks 2 and 3. The temperature log tracks will be scaled to approximately 20° F per track. The differential curve will be scaled in a manner appropriate to the logging equipment design but will be sensitive enough to readily indicate temperature anomalies. In general, the procedure for wireline operations will be as follows:

1) Attach a temperature probe and casing collar locator (CCL) to the wireline.

2) After a minimum of 36 hours of well static conditions, begin the temperature survey. The tools will be lowered into the well at 30 to 40 feet/minute, recording the temperature in wellbore. The temperature survey will be run to the deepest attainable depth (top of solids fill) in the wellbore. The wireline may be flagged, if needed, to assist in depth correlation.

3) Following completion of the survey, the wireline tools will be retrieved from the wellbore.

A temperature log run will be considered successful if there are no unexplained temperature anomalies observed outside of the permitted injection zone.

If temperature anomalies are observed outside of the permitted zone, additional logging may be conducted to determine whether a loss of mechanical integrity or loss of containment has occurred. Depending on the nature of the suspected movement, radioactive tracer, noise, oxygen activation, or other logs approved by the UIC Program Director may be required to further define the nature of the fluid movement or to diagnose a potential leak.

7.2.2 Radioactive Tracer Survey

A Radioactive Tracer Survey (RTS) may be run as an alternative to a temperature survey. The tool consists of a gamma ray detector above an ejector port and one or two gamma ray detectors below the ejector port. In order to run the RTS, the wellbore annulus will need to be flushed with brine. Therefore, the test will be conducted using brine to convey the radioactive tracer material down the well. The tool will continuously record the gamma ray API units during tracer fluid injection. The upper detector will be recorded in Track 1 at a scale of 0 to 100 or 150 API units, and the lower detector(s) will be recorded in Tracks 2 and 3 at a higher (less sensitive) scale, typically 0 to 1,000 API units.

Prior to testing, an initial gamma ray baseline log will be recorded from at least 100 feet above the injection tubing packer to the total depth of the well. The initial gamma ray survey can be made under low flow conditions or static well conditions.

For depth correlation, a concurrent casing collar locator log will be run on the wireline tool string. Two, five (5) minute time drive, statistical checks will be run prior to the ejection of tracer fluid One of the statistical checks will be run in the confining unit immediately above the uppermost perforation in the well. The second check will be run at the depth of the Injection Zone. The baseline log and the statistical checks will be used to determine the baseline background radiation prior to the ejection of the tracer fluid.

Brine injection will be initiated or increased during testing operations. During the survey, brine injection rates will be set at the rate at which the fluid will be under laminar flow conditions, while remaining within the maximum permitted operating parameters anticipated for the well. The volume of the tracer fluid slug will be sufficient to cause a gamma curve deflection on the order of 25x background reading as the ejected slug passes the lower detector(s). This would typically be a full-scale deflection.

A constant injection (moving) survey will be run from above the packer down to the perforations to check for leaks between those two points. This survey will consist of ejecting a tracer slug above the packer, verifying the tracer slug ejection, dropping the tool down through the slug, and logging up through the slug to above where the slug was first ejected. Then, the tool will be successively dropped down through the slug again and logging will continue upward to above where the slug was encountered on the previous pass. This process will be repeated a minimum of two times, until the slug flows out into the formation. If necessary, the injection rate may be adjusted to accomplish this test.

A stationary survey will be run approximately 20 feet or less above the top of the perforated interval to check for upward fluid migration outside of the cemented casing. The flow during the stationary survey will be at sufficient rates to approximate the normal operating conditions anticipated for the well. The stationary survey procedure consists of setting the tool and logging on time drive, ejecting a slug, verifying the ejection, and waiting an appropriate amount of time to allow the slug to exit the wellbore and return through channels outside of the pipe, if present. The time spent at the station will vary but should be at least twice the time estimated to detect the tracer fluid if channeling exists, or 15 minutes, whichever is greater. If tracer fluid is detected channeling outside of the pipe at any time during the stationary survey, the survey may be stopped, and the movement of the tracer fluid will be documented by logging up on depth drive, until the tracer exits the channel. The stationary survey will be repeated at least once.

Additional stationary or moving surveys may be required, depending upon well construction, test results, or to investigate known problem conditions. At least two repeatable logs of every tracer survey, moving and stationary, should be run. On completion of the tracer surveys, a final background gamma log will be run for comparison with the initial background log. In general, the test procedure will be as follows:

1) Attach radioactive tracer tools, including the casing collar locator (CCL), the gamma ray detectors, and the ejector modules to the wireline. Lower the tools into wellbore to the deepest attainable depth (top of solids fill). Record the depth of solids fill in the well, if any. Correlate the tools to depth with the injection packer and any other cased-hole log(s) that are run in the well.

2) A baseline gamma log will be run from the deepest attainable depth to approximately 100 feet above the packer. Statistical tool checks will be conducted 10 feet above the set depth of the injection packer and approximately 15 feet above the top perforation. (*Specific depths will be identified and updated after injection well completion*).

3) With the tool set a minimum of 100 feet above the packer, start injecting brine fluid at approximately 50 gallons per minute (gpm) or the defined acceptable rate. Eject a slug of tracer material and verify ejection.

4) Lower the tool through the slug and log up through the slug. Repeat the slug-tracking sequence, following the slug down the tubing and into the Injection Zone until the slug has been dissipated.

Note: It is desired to achieve a minimum of three or more passes below the injection packer before the radioactive slug exits the perforations. Adjust or reduce injection rate, if needed, to achieve this objective.

5) Repeat Steps 3 and 4.

6) Position the RTS tool's lower detector approximately 15 feet above the top perforation. Initiate and maintain injection at approximately 250 gpm or the defined acceptable rate.

7) Eject a slug of tracer material and record on time drive for a minimum of 15 minutes to determine if upward flow around the casing occurs.

8) Repeat Step 7.

9) Cease pumping, lower the tool to the deepest attainable depth, and run a repeat baseline gamma ray log to verify that the radiation level has returned to baseline background radiation levels.

10) Dump the remaining radioactive tracer material from the tool and pump the remaining test fluid to flush the tracer material from the wellbore.

11) Retrieve the wireline tools from the wellbore and rig down wireline unit.

A successful pressure test will "PASS" if the radioactive iodine material stays within the Injection Zone(s) and within the sequestration complex.

If the radioactive anomalies are observed outside of the permitted zones, this would represent a "Fail" of the test. This could be presented as detecting the radioactive material moving upwards of the formation. If this is encountered, the tool will be moved upwards with a time drive until the material cannot be detected anymore, to analyze the material's maximum extent of movement.

Additional logging will then be conducted to determine whether a loss of mechanical integrity or containment has occurred. Depending on the nature of the suspected movement, a temperature, oxygen activation, or other logs approved by the UIC Program Director may be required to further define the nature of the fluid movement or to diagnose a potential leak.

7.2.3 Pulsed Neutron Logging

Pulsed neutron logging will be run to verify the mechanical integrity of the near-wellbore area behind the casing in the injection wells. A baseline survey will be run during completion operations (with the well in completion configuration) and will provide an initial baseline log for future comparisons. Should the downhole well completion change at any time, a new baseline log will be run. The pulsed neutron survey will be run from the Wilcox Formation below a depth of 2,400 feet below ground down to the total depth of the well and will be run in gas-sigma-hydrogen mode. The sigma measurement is used to determine porosity, differentiate between saline water and carbon dioxide, and calculate formation saturation in the Injection Zones. Lapis Energy will run the Pulsed Neutron log every 5 years throughout the life of the injection wells. The UIC Program Director may require more frequent monitoring to further define the nature of potential fluid movement along the casing-borehole wall or to diagnose potential leaks.

7.2.4 Annulus Pressure Test

In conjunction with annual mechanical integrity testing, an annulus pressure test of the casing by the tubing annulus will be made.

Pressures will be recorded on a time-drive recorder for at least 60 minutes in duration and the chart or digital printout of times and pressures will be certified as true and accurate. The pressure scale on the chart will be low enough to readily show a five percent change from the starting pressure. In general, the test procedure will be as follows:

1) Connect a high-resolution pressure transducer to the annulus and increase the annulus pressure to at least 200 pounds per square inch gauge (psig) over the permitted maximum tubing/injection pressure. Conduct the Annulus Pressure Test (APT) by holding annular pressure a minimum of 100 psi above the well's maximum permitted surface injection pressure for a minimum of 60 minutes.
2) At the conclusion of the APT, the annular pressure will be lowered to the well's normal, safe differential pressure value and pressure recording equipment will be removed from the well system.

A successful pressure test will "PASS" if the pressure holds to +/-5 percent of the starting pressure. If the test is unable to hold pressure for the selected time period, the test will be considered a "FAIL". The test will then be repeated and if the well continues to "FAIL", the construction of the well may have lost mechanical integrity. Additional tests at progressively lower pressures may be run to identify the pressure at which the annulus can hold a differential. Continuous monitoring of the annulus system will be reviewed to identify if there is any data that may lead to a potential leak and assist in diagnosing potential issues with the annulus.

8.0 TRANSIENT PRESSURE FALLOFF TEST

Lapis Energy will perform pressure falloff tests during the injection phase, to meet the requirements of 40 CFR §146.90(f). Pressure falloff testing will be conducted upon the completion of the injection well to characterize the baseline formation properties and to determine the near-well reservoir conditions that may impact the injection of carbon dioxide.

8.1 FALLOFF TESTING LOCATION AND FREQUENCY

Lapis Energy will perform an initial (baseline) pressure falloff test in the injection well using either formation brine or municipal water mixed with a clay stabilizer (to avert clay swelling). This will provide the baseline characterization of the transmissibility of fluid into the Injection Zone(s). The pressure falloff test will be repeated using carbon dioxide within the first 60 days of initiation of injection operations. This will allow for a comparison to the baseline fluid-to-fluid test with the changes in the injection fluid from brine water to carbon dioxide.

A pressure falloff test will be performed at least once every five years (within +/-45 days of the anniversary of the previous test) for the lifetime of injection operations. Periodic testing is expected to provide insight into the performance of the storage complex and potentially aid in assessing the dimensions of the expanding carbon dioxide plume, based on the expected lateral change from supercritical carbon dioxide near the wellbore and native formation brine beyond the plume. The UIC Program Director may request more frequent testing, which will be dependent on test results or other variables. A final pressure falloff test will be run after the cessation of injection into the injection well.

8.2 FALLOFF TESTING DETAILS

Testing procedures will follow the methodology detailed in "*EPA Region 6 UIC Pressure Falloff Testing Guideline-Third Revision (August 8, 2002)*"[1]. Bottomhole pressure measurements near the perforations are preferred due to phase changes within the column of carbon dioxide in the tubing. A surface pressure gauge may also serve as a monitoring tool for tracking the progress of the falloff test.

The pressure gauge can be either installed as part of the completion or can be deployed via a wireline truck. If a wireline truck deployed gauge will be used, the wireline should be corrosion resistant, and the deployed gauges should consist of a surface read-out gauge with a memory backup. Examples of standard gauge specifications are presented in Table 10.

Table 10: Wireline Pressure Gauge specification examples

Pressure Gauge	Property	Value
Surface Readout Pressure Gauge	Range Resolution	0 – 10, 000 psi/356 °F +/-0.01 psi/0.01 °F
	Accuracy	+/-0.03% of full scale (+/-3 psi/+/-0.1 °F)
	Manufacturer's Recommended Calibration Frequency	Minimum Annual
Memory Pressure Gauge	Range Resolution	0 – 10, 000 psi/356 °F +/-0.01 psi/0.01 °F
	Accuracy	+/-0.03% of full scale (+/-3 psi/+/-0.1 °F)
	Manufacturer's Recommended Calibration Frequency	Minimum Annual

The general testing procedure is as follows and presumes that a wireline truck deployed unit is used for the testing: NOTE: a dedicated downhole monitoring gauge may be used if they provide data of sufficient quality:

1) Mobilize the wireline unit to the injection well and rig up on the wellhead.
2) Rig up a wireline lubricator that contains a calibrated downhole surface-readout pressure gauge (SRO) and that has a memory gauge installed in the tool string as a backup to the adapter above the crown valve. Each gauge should have an operating range of 0 - 10,000 psi. Reference the elevation of gauge to both kelly bushing (KB) elevation and elevation above ground level.
3) Open the crown valve, record the surface injection pressure. While maintaining a constant rate of injection, run the wireline with the SRO down the well to just above the shallowest perforations in the completion. Steady rates of injection should be

maintained for at least 24 hours ahead of the planned shut-in of the injection well. Any offset injection well(s) should be either shut-in ahead of the testing or should maintain a constant rate of injection for the entire duration of the testing. This will minimize cross-well interference effects.

4) With the SRO positioned just above the perforations, monitor the bottom-hole injection pressure response for ±1 hour to allow the gauge to stabilize to wellbore temperature and pressure conditions. Ensure that the injection rate and pressure are stable.

5) Cease injection as rapidly as possible (controlled quick shut-in). Starting with the valve closest to the wellhead, close the control valve and the manual flowline valve at the well site (so that wellbore storage effect in early time is minimized, the order of closing is important). Conduct the pressure falloff test for approximately 24 hours, or until bottomhole pressures have stabilized.

6) Lock out all valves on the injection annulus pressure system to ensure that the annulus pressure cannot be changed during the falloff test period. Ensure that the valves located on the flow line to the injection well are closed and locked out to prevent flow to the well during the falloff test period.

7) After 24 hours, download the pressure data and make a preliminary field analysis of the falloff test data using computer-aided transient test software to estimate if, or when, radial flow conditions might be reached. If sufficient data acquisition is confirmed, end the falloff test. If additional data is required, extend the falloff test until radial flow conditions are confirmed. After the confirmation of sufficient data acquisition, end the falloff test.

8) Pull the SRO tool up the well by 1,000 feet and stop to allow the gauge to stabilize (5 minutes each stop). Record stabilized temperature and pressure. Repeat the process to collect stabilized pressure data (5-minute stops) at 1,000-foot intervals and in the lubricator.

In performing a falloff test analysis, a series of plots and calculations will be prepared to QA/QC the test, to identify flow regimes, and to determine well completion and reservoir parameters. It will also be used to compare formation characteristics, such as transmissivity and skin factor of the near wellbore, for changes over time. Skin effects due to drilling and completion (possible damage from perforation) will be assessed for the well's injectivity and for potential well cleanouts in the future. These tests can also measure drops in pressure due to potential damage/leakage over time. With CO_2 injection, it is anticipated that drops in pressure may indicate multiple fluid phases. The analysis will be designed to consider all parameters.

8.3 TEST ANALYSIS AND REPORTING

In order to make the proper assessment, multi-phase flow conditions will be considered. Results of the pressure fall-off test may trigger a reevaluation of the AoR. Testing methods, results, and interpretation will be submitted electronically within 30 days of the test per 40 CFR 146.91(e) and 146.91(b)(3)

Each submission will include the following.

1) Location, test name and the date and time of the shut-in period;
2) Bottom hole pressure and temperature depths;
3) Records of gauges;
4) Raw test data in a tabular format (if required by the UIC Program Director);
5) Measured injection rates and pressure data from the test well and any off-set wells completed in the same zone and including data prior to the shut-in period;
6) Pressure gauge information (make, model, manufacturer, etc.);
7) Diagnostic curves of test results, noting any flow regimes;
8) Description of quantitative analysis of pressure-test results, type of software used and any multi-phase effects;
9) Calculated parameter values such as transmissivity, permeability, and skin factor;
10) Analysis and comparison of calculated parameter values to previous testing values;
11) Identification of data gaps if any exist; and

12) Identified necessary changes to the project and the TMP to ensure continued protection of USDWs

Testing procedures, testing equipment, tolerances and specifications, and calibration details are included in the QASP, which is contained in Appendix 1.

9.0 CARBON DIOXIDE PLUME AND PRESSURE FRONT TRACKING

Lapis Energy will employ both direct (Table 11) and indirect (Table 12) methods to track the geometry and extent of the carbon dioxide plume with time and the areal distribution in pressures within and above the sequestration complex to meet the requirements of 40 CFR 146.90(g).

Table 11: Pressure-Front and Plume-Front Monitoring - Direct

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
PRESSURE-FRONT MONITORING-DIRECT				
Injection Zone - Lower Hosston - Cotton Valley	Pressure & Temperature	Injection Wells & 1 monitor well	Injection Well Field & Up dip of injection wells.	Continuous
ACZ -Tokio Sandstone	Downhole Pressure & Temperature	1 ACZ monitor well	Near point of injection	Continuous
PLUME-FRONT MONITORING-DIRECT				
Injection Zone - Lower Hosston - Cotton Valley	Fluid Sampling	1 IZ monitor well	Up dip of injection wells	Injection: Quarterly, once triggered Post-Injection: Annually; adaptive, if triggered
ACZ -Tokio Sandstone	Fluid Sampling	1 ACZ monitor well	Near point of injection	Quarterly for the 1st 2 years, annually thereafter; adaptive, if triggered Post-Injection: Annually; adaptive, if triggered
USDW -Sparta	Fluid Sampling	EDCC WSW's	<u>Baseline:</u> AoR <u>Injection:</u> Projected 50-year plume extent <u>Post-Injection:</u> Projected 50-year plume extent	<u>Baseline:</u> Quarterly <u>Injection:</u> Quarterly for 1st 2 years in new injection zone; annually thereafter; adaptive, if triggered <u>Post-Injection:</u> Annually; adaptive, if triggered

Table 12: Pressure Front and Plume Front Monitoring - Indirect

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
PRESSURE-FRONT MONITORING-INDIRECT				
Sequestration Complex	Time-lapse Seismic	Injection Wells	CO_2 Plume	If applicability can be demonstrated after one year of injection: Pre-injection: At least one baseline survey Injection: Once a month or more. Post Injection: annually; adaptive if triggered
PLUME-FRONT MONITORING-INDIRECT				
Injection Zone - Lower Hosston - Cotton Valley	Pulsed Neutron	Injection Wells & 1 Monitor Well	Injection Well Field & Up and down dip of Injection Wells.	Every 5 years in Injection Wells. Adaptive, if triggered at monitor well.
ACZ -Tokio Sandstone	Pulsed Neutron	1 ACZ Monitor Well	Near point of injection	Adaptive, if triggered at monitor well.*(i.e. if CO_2 or Tracer is seen in the well)*
Sequestration Complex	Time-lapse Seismic	Injection Wells	CO_2 Plume	Pre-injection: At least one baseline survey Injection: Once a month or more. Post Injection: annually; adaptive if triggered

9.1 PLUME FRONT MONITORING

9.1.1 Direct Monitoring Details

Direct monitoring in the up dip IZ monitoring well completed across the Injection Zones will be used to detect and define the dimensions of the carbon dioxide plume during well operations (see Figure 2 for the location of the IZ monitor well). The IZ monitor well is optimally located in the direct plume path of the sequestered carbon dioxide and north-northeast of the Injection Wells.

Real-time, continuous pressure-monitoring will be performed in the well and the well will be completed to allow for fluid sampling, if needed. The potential parameters to be analyzed as part of fluid sampling in the Injection Zones and associated analytical methods are presented in Table 13.

Table 13: Summary of potential analytical and field parameters for fluid sampling in the Injection Zones

Parameters	Analytical Methods
Dissolved CO_2 gas by headspace	Gas Chromatography (GC)
Dissolved CH_4 gas by headspace Hydrocarbons	Gas Chromatography (GC) Gas Chromatography (GC)
Dissolved inorganic carbon	Combustion
Bicarbonate	Titration
δD CH_{24}	Gas chromatography combustion isotope ratio mass spectrometry (GC/C/IRMS)
δC^{13} CO_2	Gas chromatography combustion isotope ratio mass spectrometry (GC/C/IRMS)
δC^{13} CH_4	Gas chromatography combustion isotope ratio mass spectrometry (GC/C/IRMS)
C^{14} CO_2	Accelerated mass spectrometry (AMS).
C^{14} Methane	Accelerated mass spectrometry (AMS).
Isotopic composition of selected major or minor constituents (*e.g.*, $Sr^{87/86,}$ S)	Multicollector-Inductively Coupled Plasma Mass Spectrometer (MC-ICPMS)
Cations: Al, As, B, Ba, Ca, Cd, Cr, Cu, Fe, K, Li, Mg, Mn, Na, Pb, Sb, Se, Si, Ti, Zn,	ICP-MS or ICP-OES, ASTM D5673, EPA 200.8 Ion Chromatography, EPA Method 200.8, ASTM 6919
Anions: Br, Cl, F, NO_3, SO_4,	Ion Chromatography, EPA Method 300.8, ASTM 4327
Total Dissolved Solids	EPA 160.1, ASTMN D5907-10
Alkalinity	EPA 310.1
pH (field)	EPA Method 150.1
Specific Conductance (field)	EPA 120.1, ASTM 1125
Temperature (field)	Thermocouple
Hardness	ASTM D1126
Turbidity	EPA 180.1
Specific Gravity	Modified ASTM 4052
Density	Modified ASTM 4052

Quality assurance procedures for these methods are presented in Appendix 1.

A contingency deep IZ monitoring well may be located down dip of the Injection Wells somewhere near the southwestern facility boundary. The installation of this well is wholly contingent on the operations of the indirect monitoring methods as detailed in Section 9.1.2. The exact location will be chosen based on rig accessibility. Real-time, continuous pressure monitoring will be performed in the well, if constructed, which will also be configured to allow for fluid sampling, if needed, in the event carbon dioxide reaches the wellbore.

The direct monitoring program will be enhanced with the continuous addition of tracers to the injected carbon dioxide. This will entail the continuous introduction of a reservoir and CO_2 compatible chemical tracer into the injected CO_2 at the wellhead or flow line. The tracer will be foreign to the system and monitoring for its presence will be performed with samples taken from observation monitoring wells or from liquids reaching the surface in an uncontrolled manner. In order to establish the source of any CO_2 leakage from each formation, the project plans to use up to four unique chemical tracers. These tracers are all from the same chemical family and can all be simultaneously detected in the presence of each other. The targeted tracer concentration within the CO_2 stream has been designed at 10 parts per billion (ppb). The potential chemical tracers will include four of the following:

- Tracerco T-350 CAS 355-02-2
- Tracerco T-400b CAS 335-27-3
- Tracerco T-400c CAS 374-77-6
- Tracerco T-450a CAS 423-02-9
- Tracerco T-450b CAS 374-59-4
- Tracerco T-450c CAS 374-76-5

All tracer materials are inert, non-flammable and non-toxic, and are classed as non-dangerous goods. Analysis of the resulting tracer concentration from samples gathered enables flow characteristics to be determined so that mitigation can be carried out to reduce or stop the leakage from occurring. Lapis Energy will use multiple tracers, which will be changed following a recompletion of the deep Injection Well and in the shallower Hosston Injection Well. For each injection zone, a specific tracer (potential list above) will be used and thus become a specific signature. In this way, the provenance of the CO_2 can be determined, which may provide insight to how the tracer arrived at a particular sampling point, whether it be within the Injection Zone or at some other location. If no tracer is found in a CO_2 sample, this will indicate that the sampled CO_2 is foreign to the project injection area. Hydraulic pump systems are typically used and give the ability of gas or electrically driven hydraulic metering pumps for continuous (or pulse) injection. In the case of electric pumps, these can be integrated into the control DCS system to change speed of tracer addition with changing flow rates of the CO_2 into the disposal well. A sampling frequency from observation/monitoring wells to meet project requirements will follow the water sampling plan. Note that sampling frequency is not as critical when using continuous injection of tracer into the CO_2 as a constant concentration will be present and a tracer pulse cannot be missed.

Vapor samples will be collected into activated charcoal tubes using an air sampling device that provides passage of a consistent air sample volume. Each activated charcoal tube shall be subjected to thermal desorption followed by Gas Chromatography coupled with Mass Spectrometry with a limit of detection of 1 part per trillion. Analyzed samples will include IZ Well(s), the ACZ monitoring wells (Tokio Sand), and the shallow groundwater monitoring wells.

Additionally, each IZ monitor well will also have a transmitter gauge at surface to continuously record tubing pressure. Experience from previously implemented carbon capture and sequestration projects indicates that carbon dioxide will rapidly evacuate the wellbore fluids in a monitoring well that is open to an Injection Zone, which will result in increased wellhead pressures due to the lighter column of gas replacing the displaced brine fluid column.

9.1.2 Indirect Monitoring Details

Indirect plume monitoring in the Injection Zones will include pulsed neutron capture logging to monitor the lateral and vertical saturation in carbon dioxide in the Injection Wells and in the Deep Monitor Well. The tool incorporates a pulsed neutron generator and a dual-detector spectrometry system to measure elemental concentrations, including carbon and oxygen, and the formation neutron-capture cross section (sigma) during a single trip in the well. The sigma measurement is used to determine porosity and differentiates between saline water and other fluids to calculate formation saturations. Where formation water is fresh or of unknown salinity, saturation is determined from the C/O ratio measurement, which is salinity independent. Schedule for running pulsed neutron tools in the wells is included in Section 7.2.3 Pulsed Neutron Logging.

Lapis Energy is also considering the use of certain time-lapse seismic techniques for indirect monitoring. The displacement of brine by injected carbon dioxide within sedimentary strata at similar project depths is well documented to produce a strong negative change in acoustic impedance (Vasco et al., 2019). This change in impedance can be detected by many time-lapse seismic methods. Leading-edge techniques for time-lapse imaging of carbon dioxide plumes include time-lapse vertical seismic profiling (Daley and Korneev, 2006; Gupta, et al., 2020), azimuthal vertical seismic profiling (Gordon, et al., 2016), sparse array walk-away surveys or scalable, automated, semipermanent seismic array "SASSA" (Roach, et al., 2015; Burnison, et al., 2016; Livers, 2017; Adams, et al., 2020).

Permanent seismic monitoring techniques are robust and documented in monitoring plume growth and less invasive from a surface footprint Harvey et al., 2021). Lapis Energy is anticipating deployment of an autonomous, real-time permanent source and receiver array within and beyond the dimensions of the carbon dioxide plume. The system will use one or more permanent surface sources and an autonomous 6-component receiver array with the receivers emplaced underground. The receivers will be to monitor ray paths that will allow for dense sampling over time. System flexibility allows for sensors and/or source geometry to be optimally redeployed further away from the injection wells as the plume gets larger. Baseline and subsequent time-lapse surveys will be processed using a technique that will resolve the differences between the surveys, which will be mapped to show the change in plume extent over time.

9.2 PRESSURE FRONT MONITORING

Table 14 presents the methods that Lapis Energy will use to monitor the position of the pressure front, including the activities, locations, and frequencies that will be employed.

Quality assurance procedures for these methods are presented in Appendix 1.

Direct pressure monitoring in the Injection Zones will be used to measure the injection induced pressure buildup with time in the sequestration complex. Pressure monitoring using down-hole pressure/temperature gauges, will be conducted in each active injection well. Gauges will be referenced to ground level at each well. These monitor points will be used to evaluate the pressure buildup with time within the injection well field. Additionally, direct pressure and temperature monitoring will be conducted in the project IZ monitor well located up dip of the injection well. Real-time, continuous pressure and temperature monitoring will be performed in each well. These two monitor points will be used to evaluate the rate and magnitude of pressure decay with distance away from the injection well field.

Lapis is not aware of the existence of any quantitative indirect subsurface pressure measurement technologies. Large changes in pressure can sometimes be qualitatively detected using time lapse seismic (Wang and Nur, 1989). Given the subsurface pressure changes because of the CO_2 injection are relatively small, an indirect pressure response might not be observed. Nevertheless, during the first year of injection Lapis will evaluate if the onsite permanent seismic CO_2 plume monitoring array can detect pressure induced reflectivity changes as well. In addition, during the first year of injection Lapis will activate the array for permanent passive seismicity monitoring (except during periods of active seismic CO_2 plume measurements and periods of array maintenance). At the end of the year Lapis will compare in a qualitative manner the active and passive seismic observations with the direct pressure measurements in the in-zone monitoring well DM-2 and the simulation model. The results will be presented to the EPA. If a reasonable correlation can be obtained between the direct pressure measurements and seismic observations, Lapis will continue the indirect pressure measurements for the remainder of the injection phase of the project.

Table 14: Summary of monitoring intervals depths

Monitoring Zone	Expected Depth Range (feet BGL)	Up Dip Monitor	Down Dip Monitor
ACZ -Tokio Sandstone	2,900 to 3,000	-Not Monitored-	-Not Monitored-
Injection Zone - Lower Hosston - Cotton Valley	3,900 to 6,350	3,900 to 6,350	3,900 to 6,350

These measured pressures from the injection wells and the offset monitor locations will be used to assess the performance of the Injection Zones to ensure that the project is operating as permitted and will form the basis for the periodic re-evaluation of the extent of the AoR. Recorded pressures at the injection wells and the monitor locations will be compared to model predictions to determine if actual data deviate from baseline predictions. Significant departures of actual pressure data above model predictions will be used to trigger an adaptive re-assessment of the AoR, in addition to the minimum 5-year re-assessment time frame specified for periodic review. In addition to the assessment of the AoR, real-time data from the overlying monitoring will also be re-evaluated to ensure continued containment of the injected carbon dioxide within the sequestration complex.

The locations of the Project Blue injection wells and IZ monitoring well are shown in Figure 2. The anticipated plume geometry and the AoR Pressure Front with time are presented in the "*Area of Review and Corrective Action Plan*" submitted in Module B.

The downhole pressure and temperature data will be transmitted to the distributed control system for evaluation and storage. A data archiver may be used to permanently store data sets for later recovery.

10.0 SEISMICITY MONITORING

Natural seismicity in the project area is exceedingly low and of low magnitude (https://earthquake.usgs.gov/earthquakes/search/).

Induced seismicity risk is also low because of the high transmissivity of the Injection Zone(s), and the distance of the project from any nearby known faults. Additionally, injection rates and pressures will be maintained at 90 percent of (or less than) the fracture pressure. Previous measurements of induced seismicity in Department of Energy supported research projects along the Gulf Coast (the Mississippi Cranfield Project, for example), have not detected induced seismicity events resulting from the injection of large volumes of carbon dioxide.

Only 10 events (magnitude greater than 2.5 and less than 3.6) have been recorded in Union County since 1900 and have only occurred in the last 40-years. The first event was in 1983 with a magnitude of 3 and the last was in 2020 with a magnitude of 2.76 (Table 15).

Table 15: Seismic Event History – Union County

Date	Magnitude	Location
05/11/2020	2.76	13 km SSE of El Dorado, Arkansas
02/24/2020	2.79	12 km ENE of Junction City, Arkansas
05/16/2007	3.0	5 km SW of El Dorado, Arkansas
12/17/2001	2.8	3 km WSW of El Dorado Arkansas
03/03/2001	3.0	2 km SSE of El Dorado, Arkansas
12/24/1997	2.6	7 km W of El Dorado, Arkansas
01/09/1997	2.8	6 km E of El Dorado, Arkansas
06/10/1994	3.2	4 km W of Junction City, Arkansas
12/12/1988	2.5	20 km E of Emerson, Arkansas
12/09/1983	3.0	6 km W of El Dorado, Arkansas

As part of the monitoring program Lapis will continue to check the regional and local seismicity annually for events through the United States Geological Society (USGS) National Earthquake Database. This provides data on location and depth of events in real time. Lapis will search for events greater than 2.5 within a 100-mile radius (160 Km) annually. If events occur in Union County, Lapis will evaluate their location and depth. If more than two events occur greater than a magnitude of 2.5, Lapis will monitor the National Earthquake database on a quarterly basis. If no events occur within 2 years, Lapis will revert to an annual monitoring system basis.

Only if a seismic event with a magnitude of 2.5 or greater occurs within a two-mile radius of the Lapis injection wells, will additional site-specific monitoring of seismicity be undertaken by Lapis Energy. The Lapis permanent seismic CO_2 plume monitoring array can also measure passive seismicity. In the scenario of a magnitude 2.5 event, the array will be activated for a period of 2 years following the event, for permanent passive seismicity monitoring, except during periods of active seismic CO_2 plume measurements and periods of array maintenance. Annually Lapis will provide a report to the EPA detailing all events with a magnitude greater than 1.5, measured by the on-site passive seismicity monitoring. If within the 2-year period a seismic event takes place with a magnitude of 2.5 or greater within a two-mile radius of the injection wells the onsite passive seismicity monitoring will be extended by another 2 years, from the date of the occurrence of the seismic event.

11.0 APPENDIX: QUALITY ASSURANCE AND SURVEILLANCE PLAN

The QASP is submitted as Appendix 1 to this Testing and Monitoring Plan.

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