Plan revision number: 0
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INJECTION WELL CONSTRUCTION PLAN
40 CFR 146.82(a)(11) and (12), 146.86, 146.87, and 146.88 (a), (b), (c), and (e)

Pelican Sequestration Project

<u>1.0 Facility Information</u>

Facility name: Pelican Sequestration Project
Pelican CCS 1 Well

Facility contact: [redacted] Project Manager
5 Greenway Plaza Houston, TX 77046
[redacted]

Well location: Holden, Livingston Parish, Louisiana
[redacted] (NAD 1927, BLM Zone 15N)

The Pelican CO_2 Sequestration Hub, LLC will construct the injection well according to the procedures below.

The matter of construction details is relevant to the requirements of Environmental Protection Agency (EPA) document 40 CFR Subpart H – Criteria and Standards Applicable to Class VI Wells. The main topics covered in this attachment are special construction requirements, open hole diameters and intervals, casing specifications, tubing specifications, data acquisition and testing plan, and demonstration of mechanical integrity.

2.0 Overview

The Pelican CCS 1 injection well and monitoring wells are designed with the highest standards and best practices for drilling and well construction. The operational parameters and material selection are aimed to ensure mechanical integrity in the system, prevent any endangerment of the USDW, and optimize the operation during the life of the project.

The Pelican CO_2 Sequestration Hub, LLC will drill two new wells as a CO_2 injector, Pelican CCS 1 and Pelican CCS 2, that will target injection in the [redacted] and [redacted] sand. The development scenario for the Pelican CCS 1 proposes an initial completion in [redacted] [redacted], and [redacted] ([redacted] to [redacted] ft estimated measured depth (MD) (see Figure CON-1). After [redacted] injection, the well will [redacted] in the [redacted] and [redacted] sands ([redacted] to [redacted] ft estimated MD) and move the packer above the [redacted]. The [redacted] of the injection period (see Figure CON-2).

There will be [redacted] wells drilled, [redacted], and [redacted]. These wells will target the reservoir section to track CO_2 plume extension and pressure front, as described in the Testing and Monitoring Plan.

Additionally, the Project plans to drill one [redacted] monitoring well, [redacted], targeting the first permeable zone above the [redacted] Shale. This well will track any potential leak in the main confining systems above the injection target.

Two USWD monitoring wells will be drilled to track quality and variations in the Evangeline and Jasper Aquifer that represent the base of the USDW. These are shallow water wells that will be sampled based on the requirements described in the Testing and Monitoring Plan.

3.0 Operating parameters and specifications CO_2 Injector wells

The well is designed to maximize the rate of injection and reduce the surface pressure and friction alongside the tubing, while maintaining the bottomhole pressure below 90% of the frac gradient. The selected design provides enough clearance to deploy the pressure and temperature gauges on tubing and to ensure continuous surveillance of external integrity and conformance through the external fiber optic cable.

Well materials were selected based on the operating conditions expected during the life of the well, as shown in Table CON-1 and Table CON-2, and on CO_2 specifications for the project as shown in Table CON-3. A nodal analysis was used to perform sensitivities on the tubing size, rate of erosion, stresses, and potential movement of the tubulars.

Table CON-1—Operating Parameters – First Completion

Parameter	Value
Perforations Interval (TVDSS ft)	[redacted]
Perforation Interval (TVD estimated ft)	[redacted]
Injection Rate (MMscfd)	[redacted]
Tubing Pressure (psi)	[redacted]
Annular Surface Pressure (psi)	[redacted]
Surface Temperature (°F)	[redacted]
Frac Gradient (psi/ft)	[redacted]
Bottomhole Temperature (°F)	[redacted]

Table CON-2—Operating Parameters – Recompletion

Parameter	Value
Perforations Interval (TVDSS)	[redacted]
Perforation Interval (TVD estimated ft)	[redacted]
Injection Rate (MMscfd)	[redacted]
Tubing Pressure (psi)	[redacted]
Annular Surface Pressure (psi)	[redacted]
Surface Temperature (°F)	[redacted]
Frac Gradient (psi/ft)	[redacted]
Bottomhole Temperature (°F)	[redacted]

Note:

- Annular surface pressure between the tubing and long string will be kept between [redacted] psi to monitor changes during injection. It is not recommended to apply the maximum injection pressure to the tubing-long string casing annulus to avoid unnecessary stress on the cement sheath that could lead to a micro-annulus or microfractures.

Table CON-3—CO_2 Specification for Pelican CCS 1

Component	Specification
CO_2 (% mol)	[redacted]
Water (lbs/MMCF)	[redacted]
Nitrogen (% mol)	[redacted]
Oxygen (ppm by wgt)	[redacted]
Hydrogen (% mol)	[redacted]
SOx (ppm by wgt)	[redacted]
NOx (ppm by wgt)	[redacted]
Hydrogen Sulfide (ppm by wgt)	[redacted]
Hydrocarbons (%mol)	[redacted]
Carbon Monoxide (ppm by wgt)	[redacted]
Glycol (gal/MMSCF)	[redacted]
Ammonia (ppm by wgt)	[redacted]
Argon (%mol)	[redacted]
Sulfur (ppm by wgt)	[redacted]

4.0 Well design CO_2 Injector Wells

Pelican CCS 1 - CO2 Injector

[redacted]

Figure CON-1—Pelican CCS 1 Well Proposed Schematic – First Completion

Pelican CCS 1 - CO2 Injector

[redacted]

Figure CON-2—Pelican CCS 1 Well Proposed Schematic – [redacted]

The Pelican CCS 1 well design includes two main sections: 1) surface casing and 2) long string section to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, and isolate the target formation while running the upper completion.

The [redacted] surface section will be drilled to [redacted] ft to cover base of the USDW, estimated at [redacted] ft, and to provide mechanical integrity on the surface shoe to continue the next section. While drilling, a deviation survey will be taken every [redacted] ft. Once total depth (TD) is reached, the well will be circulated and conditioned to run open hole electric logs according to the testing program. Then, [redacted] casing will be run and cemented to the surface with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the Project Manager will inform the EPA Director, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the Director. After the tail cement reaches at least [redacted] psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test the BOP, test the casing, and pick up the drilling assembly. After drilling out the shoe track, an additional [redacted] ft of new formation will be drilled to execute a Formation Integrity Test (FIT) with a minimum mud equivalent weight of [redacted] ppg.

A [redacted] hole will be drilled from [redacted] ft to TD while taking deviation surveys every [redacted] ft. Once TD is reached, the well will be circulated and conditioned to run open hole electric logs and acquire samples based on the testing program. During this run, [redacted] logs will be acquired over the previously set [redacted] surface casing. Then, the long string of [redacted] casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to ensure good cement from bottom to surface. The depth of the divi-tool or stage tool will be adjusted based on actual conditions of the well after drilled.

After the tail slurry cement develops a minimum compressive strength of [redacted] psi, Section B of the wellhead will be installed, and the DTS/DAS cable will be connected to the surface equipment. Once the cable has been installed and tested, the team will install the tubing head and the rest of the tree.

During the completion operations, the rig will test the casing to [redacted] psi, condition the long string with a bit and scraper, run a [redacted] log to evaluate cement bonding and casing conditions, perforate the injection zone, and run the upper completion. The [redacted] tubing and packer completion will be run to approximately [redacted] ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to [redacted] psi on surface to validate the mechanical seal and integrity in the annular between the tubing and casing. The well will be tested for injectivity with a step rate test procedure and a fall off test before starting injection.

Materials and metallurgy selections in well construction provide protection from corrosion and assurance of external and internal mechanical integrity. The injection casing materials were selected based on corrosion modeling with OLI software and materials testing as well as best practices to be able to withstand downhole and surface operating conditions based on the projected CO_2 specifications and reaction with the formation waters.

The tubing was selected as carbon steel [redacted] metallurgic and will be coated internally with a [redacted] product since the expected CO_2 stream that is in contact with the internal ID of the tubing will be mainly dehydrated, reducing the risk of corrosion, in comparison with the bottom section of the wellbore that will be in contact with the formation waters. Tail pipes below the packers were selected with special metallurgic to prevent damage should formation water enter the well during short periods of shut down.

The injection packer elements in contact with the fluid will be [redacted]. Cables are selected with [redacted] and [redacted] proposed for the application. The annular of the injection well will be filled with packer fluid to prevent corrosion.

Cement across injection zone will be formulated to avoid degradation of the properties due to the effect of carbonic acid and provide protection to the casing as well.

The tables listed below provide further details regarding the Pelican CCS 1 well. Table CON-4 contains the open hole diameters and intervals, Table CON-5 lists the casing specifications and Table CON-6 details the casing material properties.

Table CON-4—Open Hole Diameters and Intervals

Name	Depth Interval (ft)	Open Hole Diameter (inches)	Comment
Surface Section	[redacted]	[redacted]	Cover USDW
Long String Section	[redacted]	[redacted]	To Total Depth

Notes:

- The well total depth (TD) includes a minimum [redacted] ft of rat hole below [redacted] Basal Shale.
- The USDW depth will be confirmed with open hole logs. The USDW is estimated at 2770 ft.

Table CON-5—Casing Specifications

Name	Depth Interval (ft)	OD (inches)	ID (inches)	Drift (inches)	Weight (lb./ft)	Grade (API)	Coupling
Surface String	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Long String	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Long String	[redacted] [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted] [redacted]	[redacted]

Table CON-6—Casing Material Properties

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes:

- A stage tool will be located at [redacted] ft in the [redacted] casing to perform the two-stage cementing job.
- The centralization program will aim at 90% standoff and be adjusted using the field data for deviation, caliper, and hole conditions.
- DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-7 and Table CON-9 contain the upper completion specifications and Table CON-8 and Table CON-10 show the tubing material properties. Table CON-11 shows the specification of the injection packer.

Table CON-7—Upper Completion Specifications – Initial Completion

Name	Depth Interval (ft)	OD (inches)	ID (inches)	Drift (inches)	Weight (lb./ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Packer	[redacted]						
Injection tubing (Tail pipe)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table CON-8—Tubing Material Properties – Initial Completion

Tubing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowable Bending	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table CON-9—Upper Completion Specifications – Re-Completion

Name	Depth Interval (ft)	OD (inches)	ID (inches)	Drift (inches)	Weight (lb./ft)	Grade (API)	Coupling
Injection Tubing (Coated TK-805)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Packer	[redacted]						
Injection tubing (Tail Pipe)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table CON-10—Tubing Material Properties – Re-Completion

Description	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowable Bending	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes:

- Pressure and temperature gauges will be tubing-deployed above and below casing. Cable material will be [redacted] and gauge carriers will be CO_2-resistant material.
- Approximately [redacted] ft of tail pipe will be left below the packer.
- The annular space between the [redacted] tubing and [redacted] casing will be filled with inhibited packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-11—Packer Specifications

Packer type and material	Nominal casing weight (ppf)	Packer main body outer diameter (inch)	Packer main body inner diameter (inch)	Temperature rating (°F)	Pressure rating (psi)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Burst Pressure (psi)	Collapse Pressure (psi)	Tensile Strength (ksi)	Comments
[redacted]	[redacted]	[redacted]	[redacted]

Finally, Table CON-12 outlines the cementing program and Table CON-13 shows the mud program details.

Table CON-12—Cementing Program

Section	Type	Depths (ft)	Density (ppg)	Sacks	Excess
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The stage tool is estimated at [redacted] ft, but the depth will be adjusted based on final drilling conditions.

Table CON-13—Mud Program

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb./ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

5.0 Blowout preventer and wellhead requirements

5.1 Blowout preventer equipment (BOPE)

- BOPE must be API-monogramed and adhere to API Standard 53 and Specifications 16A and 16C, as a minimum, and meet or exceed all applicable regulatory specifications.

- BOPE other than annular preventers must have a minimum working pressure exceeding the maximum anticipated surface pressure (MASP).
- All BOPE stacks must incorporate a set of blind or blind/shear rams.
- All rigs must have a calibrated trip tank. The trip tank and trip sheet are used to measure the fluid required to fill or displace from the hole during all tripping operations including casing or completion string running.
- A Full Opening Safety Valve (FOSV) and an Inside BOP Safety Valve (IBOPSV) must be always available on the rig floor for each drill pipe, drill collar size, and connection type in use.
- If a wireline lubricator is utilized for wireline operations, it shall not be the type that slips into and is held by the annular preventer or rams. A hydraulic cutter or other means of safely cutting the wireline must be available if a lubricator is not in use.

5.2 Choke manifolds and kill line

- The choke manifold must be API-monogrammed, meet API SPEC 16C as a minimum, and meet or exceed all applicable regulatory specifications.
- All BOPE must include a choke manifold with at least one remotely operated choke and one manual choke installed.
- Flare/vent lines must be as long as practical (a minimum of 150 ft from the well center), as straight as possible (without sumps, collection areas, or uphill flow areas to prevent fluid buildup and resulting backpressure) and be securely anchored.

5.3 Closing units

- BOPE closing units must adhere to API Spec 16D and API STD 53 as a minimum and meet or exceed all applicable regulatory specifications.
- BOPE control systems must include full controls on the closing unit and at least one remote control station. One control station must be located within 10 ft of the driller's console.
- BOPE closing units must have two separate charging pumps with two independent power sources, as specified in API Spec 16D, or have N_2 bottle backup.

5.4 Pressure testing

- BOPE components (including the BOP stack, choke manifold, and choke lines) must be pressure tested at the following frequency:
  - When installed. If the BOPE is stump tested, only the new connections are required to be tested at installation.
  - Before 21 days have elapsed since the last BOPE pressure test. When the 21-day test is due soon, consider testing the BOPE prior to drilling any H_2S, abnormal pressure, or lost return zones to avoid having to test while drilling these intervals.
  - Anytime a BOPE connection seal is broken, the break must be pressure tested.

5.5 CO_2 Injector Well - Wellhead mechanical drawing

Figure CON-3 below is a basic mechanical drawing of the wellhead to be used for the Pelican CCS 1 well.

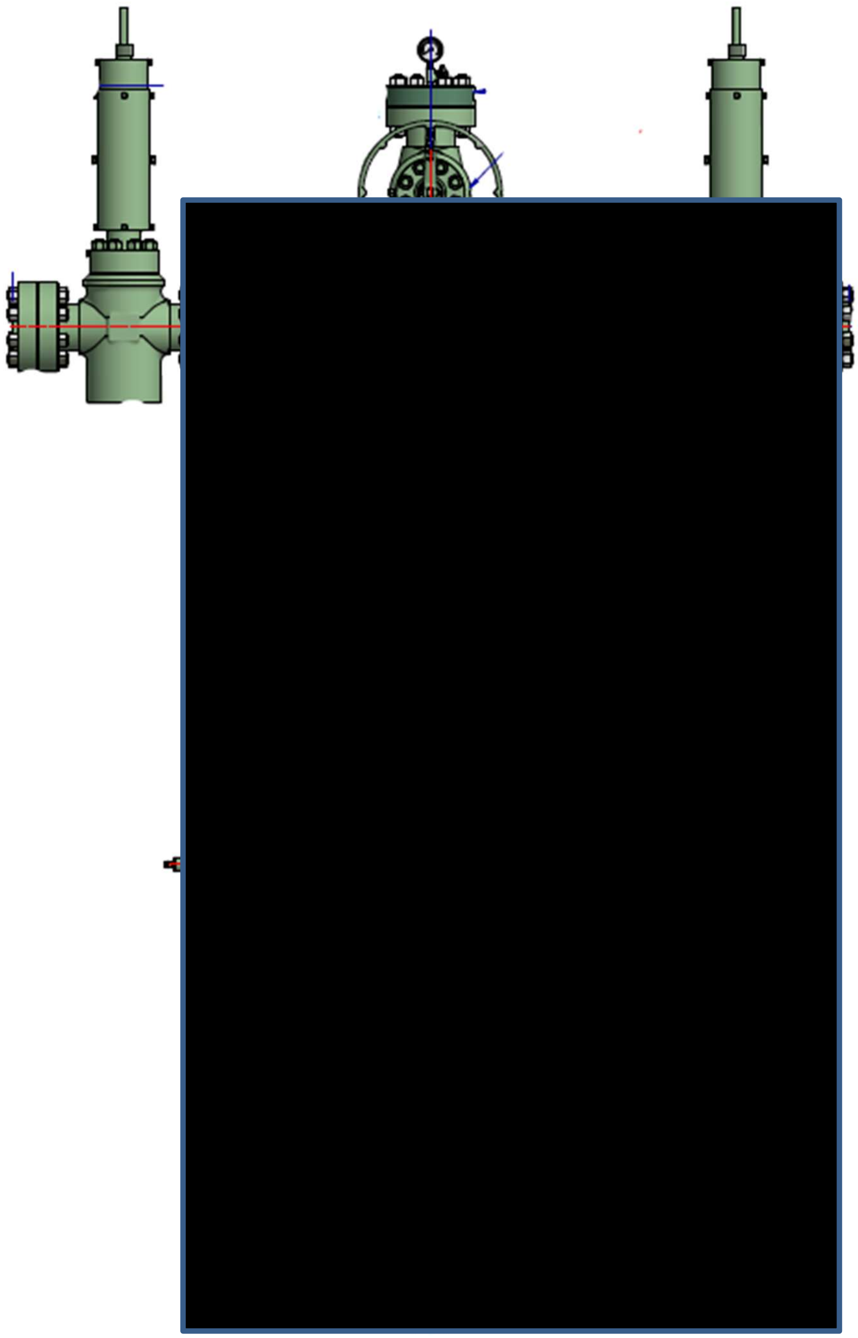

Figure CON-3—Schematic Diagram of Pelican CCS 1 Well

6.0 Recompletion Pelican CCS 1:

After [redacted] of injection. Pelican CCS 1 will be recompleted by isolating the original perforations and adding [redacted] and [redacted] Zone.

Proposed procedure for recompletion:

1. Move in rig onto the Bluebonnet CCS 1 site and rig up (RU). All CO_2 pipelines will be marked and noted by the rig supervisor prior to moving in. Conduct and document a safety meeting.
2. Record the bottomhole pressure (BHP) from the downhole gauge, perform DST survey through fiber optic installed alongside the casing, and calculate kill fluid density.
3. Test the pump and line to [redacted] psi. [redacted] the tubing volume with kill fluid with the density determined using the bottomhole pressure measurement. Monitor the tubing pressure and annular pressure continuously.
4. Test casing annulus to [redacted]. If the pressure decreases more than 5% in 30 minutes, bleed the pressure, check surface lines and connections, and repeat the test.
5. If both the casing and tubing are static, then nipple up the blowout preventers (BOPs).
6. Pull out of the hole and lay down tubing, packer, cable, and sensors.
7. Pick up the work string and trip in hole (TIH) with the bit to condition the wellbore.
8. Pull out of the hole and rig up the logging unit. Run casing inspection log. Set cast iron bridge plug at [redacted] ft. Rig down wireline.
9. Run in the hole with cement retainer and work string and set at [redacted] ft.
10. Rig up cement equipment, test lines, mix and pump cement to squeeze the perforations. Details and Volume of the squeeze is presented in Table CON-14
11. Pull out of the hole work string and wait for the cement to set.
12. Run in the hole with work string and bit and drilled out cement retainer and 200 ft of cement to provide rat hole.
13. Pull out work string and bit.
14. Perforate reservoir from [redacted].
15. Run upper completion as defined in previous section.

Table CON-14—Detail of the squeeze job on CCS 1 on bottom perforations.

Plug No	Type Slurry	ID (inches)	Placement Method	Depths top (ft)	Depths bottom (ft)	Density (ppg)	Sacks	Yield
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

7.0 Additional Wells Construction Details

7.1 CO_2 Injector Well – Pelican CCS 2

Figure CON-4 shows well construction details of Pelican CCS 2 Injector well during Original Completion. And Figure CON-5 shows well construction details for Pelican CCS 2 CO_2 Injector well after recompletion at [redacted] of injection.

Pelican CCS 2 - CO_2 Injector

[redacted]

Figure CON-2—Pelican CCS 2 Well Proposed Schematic – First Completion

Pelican CCS 2- CO_2 Injector

[redacted]

7.2 Monitoring wells

Well construction schematics for the [redacted], as well as the USDW monitoring wells are detailed in the Testing and Monitoring Plan Attachment.

INJECTION WELL CONSTRUCTION PLAN
40 CFR 146.82(a)(11) and (12), 146.86, 146.87, and 146.88 (a), (b), (c), and (e)

Pelican Sequestration Project

1.0 Facility Information

Facility name: Pelican Sequestration Project
Pelican CCS 2 Well

Facility contact: [redacted], Project Manager
5 Greenway Plaza Houston, TX 77046
[redacted]

Well location: Holden, Livingston Parish, Louisiana
[redacted] (NAD 1927, BLM Zone 15N)

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The Pelican CO_2 Sequestration Hub, LLC will drill two new wells as a CO_2 injector, Pelican CCS 1 and Pelican CCS 2, that will target injection in the [redacted] and [redacted] sand. The development scenario for the Pelican CCS 1 proposes an initial completion in [redacted], and [redacted] ([redacted] to [redacted] ft estimated measured depth (MD) (see Figure CON-1). After [redacted] injection, the well will [redacted] in the [redacted] and [redacted] sands ([redacted] to [redacted] ft estimated MD) and move the packer above the [redacted]. The [redacted] of the injection period (see Figure CON-2).

There will be [redacted] wells drilled, [redacted], and [redacted]. These wells will target the reservoir section to track CO_2 plume extension and pressure front, as described in the Testing and Monitoring Plan.

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Well materials were selected based on the operating conditions expected during the life of the well, as shown in Table CON-1 and Table CON-2, and on CO_2 specifications for the project as shown in Table CON-3. A nodal analysis was used to perform sensitivities on the tubing size, rate of erosion, stresses, and potential movement of the tubulars.

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Annular Surface Pressure (psi)	[redacted]
Surface Temperature (°F)	[redacted]
Frac Gradient (psi/ft)	[redacted]
Bottomhole Temperature (°F)	[redacted]

Table CON-2—Operating Parameters – Recompletion

Parameter	Value
Perforations Interval (TVDSS)	[redacted]
Perforation Interval (TVD estimated ft)	[redacted]
Injection Rate (MMscfd)	[redacted]
Tubing Pressure (psi)	[redacted]
Annular Surface Pressure (psi)	[redacted]
Surface Temperature (°F)	[redacted]
Frac Gradient (psi/ft)	[redacted]
Bottomhole Temperature (°F)	[redacted]

Note:

- Annular surface pressure between the tubing and long string will be kept between [redacted] psi to monitor changes during injection. It is not recommended to apply the maximum injection pressure to the tubing-long string casing annulus to avoid unnecessary stress on the cement sheath that could lead to a micro-annulus or microfractures.

Table CON-3—CO_2 Specification for Pelican CCS 1

Component	Specification
CO_2 (% mol)	[redacted]
Water (lbs/MMCF)	[redacted]
Nitrogen (% mol)	[redacted]
Oxygen (ppm by wgt)	[redacted]
Hydrogen (% mol)	[redacted]
SOx (ppm by wgt)	[redacted]
NOx (ppm by wgt)	[redacted]
Hydrogen Sulfide (ppm by wgt)	[redacted]
Hydrocarbons (%mol)	[redacted]
Carbon Monoxide (ppm by wgt)	[redacted]
Glycol (gal/MMSCF)	[redacted]
Ammonia (ppm by wgt)	[redacted]
Argon (%mol)	[redacted]
Sulfur (ppm by wgt)	[redacted]

4.0 Well design CO_2 Injector Wells

Pelican CCS 2 - CO2 Injector

[redacted]

Figure CON-1—Pelican CCS 2 Well Proposed Schematic – First Completion

Pelican CCS 2- CO_2 Injector

[redacted]

Figure CON-2—Pelican CCS 2 Well Proposed Schematic – After Recompletion

The Pelican CCS 2 well design includes two main sections: 1) surface casing and 2) long string section to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, and isolate the target formation while running the upper completion.

The [redacted] surface section will be drilled to [redacted] ft to cover base of the USDW, estimated at [redacted] ft, and to provide mechanical integrity on the surface shoe to continue the next section. While drilling, a deviation survey will be taken every [redacted] ft. Once total depth (TD) is reached, the well will be circulated and conditioned to run open hole electric logs according to the testing program. Then, [redacted] casing will be run and cemented to the surface with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the Project Manager will inform the EPA Director, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the Director. After the tail cement reaches at least [redacted] psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test the BOP, test the casing, and pick up the drilling assembly. After drilling out the shoe track, an additional [redacted] ft of new formation will be drilled to execute a Formation Integrity Test (FIT) with a minimum mud equivalent weight of [redacted] ppg.

A [redacted] hole will be drilled from [redacted] ft to TD while taking deviation surveys every [redacted] ft. Once TD is reached, the well will be circulated and conditioned to run open hole electric logs and acquire samples based on the testing program. During this run, [redacted] logs will be acquired over the previously set [redacted] surface casing. Then, the long string of [redacted] casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to ensure good cement from bottom to surface. The depth of the divi-tool or stage tool will be adjusted based on actual conditions of the well after drilled.

After the tail slurry cement develops a minimum compressive strength of [redacted] psi, Section B of the wellhead will be installed, and the DTS/DAS cable will be connected to the surface equipment. Once the cable has been installed and tested, the team will install the tubing head and the rest of the tree.

During the completion operations, the rig will test the casing to [redacted] psi, condition the long string with a bit and scraper, run a [redacted] log to evaluate cement bonding and casing conditions, perforate the injection zone, and run the upper completion. The [redacted] tubing and packer completion will be run to approximately [redacted] ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to [redacted] psi on surface to validate the mechanical seal and integrity in the annular between the tubing and casing. The well will be tested for injectivity with a step rate test procedure and a fall off test before starting injection.

Materials and metallurgy selections in well construction provide protection from corrosion and assurance of external and internal mechanical integrity. The injection casing materials were selected based on corrosion modeling with OLI software and materials testing as well as best practices to be able to withstand downhole and surface operating conditions based on the projected CO_2 specifications and reaction with the formation waters.

The tubing was selected as carbon steel [redacted] metallurgic and will be coated internally with a [redacted] product since the expected CO_2 stream that is in contact with the internal ID of the tubing will be mainly dehydrated, reducing the risk of corrosion, in comparison with the bottom section of the wellbore that will be in contact with the formation waters. Tail pipes below the packers were selected with special metallurgic to prevent damage should formation water enter the well during short periods of shut down.

The injection packer elements in contact with the fluid will be [redacted]. Cables are selected with [redacted] and [redacted] proposed for the application. The annular of the injection well will be filled with packer fluid to prevent corrosion.

Cement across injection zone will be formulated to avoid degradation of the properties due to the effect of carbonic acid and provide protection to the casing as well.

The tables listed below provide further details regarding the Pelican CCS 1 well. Table CON-4 contains the open hole diameters and intervals, Table CON-5 lists the casing specifications and Table CON-6 details the casing material properties.

Table CON-4—Open Hole Diameters and Intervals

Name	Depth Interval (ft)	Open Hole Diameter (inches)	Comment
Surface Section	[redacted]	[redacted]	Cover USDW
Long String Section	[redacted]	[redacted]	To Total Depth

Notes:

- The well total depth (TD) includes a minimum 600 ft of rat hole below Frio Basal Shale.
- The USDW depth will be confirmed with open hole logs. The USDW is estimated at 2852 ft.

Table CON-5—Casing Specifications

Name	Depth Interval (ft)	OD (inches)	ID (inches)	Drift (inches)	Weight (lb./ft)	Grade (API)	Coupling
Surface String	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Long String	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Long String	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table CON-6—Casing Material Properties

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
13 ⅜" 61# K55 BTC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9 ⅝" 53.5# L80 Premium connection	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9 5/8" 53.5# 2507 80 ksi Premium Connection	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes:

- A stage tool will be located at [redacted] ft in the [redacted] casing to perform the two-stage cementing job.
- The centralization program will aim at 90% standoff and be adjusted using the field data for deviation, caliper, and hole conditions.
- DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-7 and Table CON-9 contain the upper completion specifications and Table CON-8 and Table CON-10 show the tubing material properties. Table CON-11 shows the specification of the injection packer.

Table CON-7—Upper Completion Specifications – Initial Completion

Name	Depth Interval (ft)	OD (inches)	ID (inches)	Drift (inches)	Weight (lb./ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Packer	[redacted]						
Injection tubing (Tail pipe)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table CON-8—Tubing Material Properties – Initial Completion

Tubing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowable Bending	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table CON-9—Upper Completion Specifications – Re-Completion

Name	Depth Interval (ft)	OD (inches)	ID (inches)	Drift (inches)	Weight (lb./ft)	Grade (API)	Coupling
Injection Tubing (Coated TK-805)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Packer	[redacted]						
Injection tubing (Tail Pipe)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table CON-10—Tubing Material Properties – Re-Completion

Description	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowable Bending	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes:

- Pressure and temperature gauges will be tubing-deployed above and below casing. Cable material will be [redacted] and gauge carriers will be CO_2-resistant material.
- Approximately [redacted] ft of tail pipe will be left below the packer.
- The annular space between the [redacted] tubing and [redacted] casing will be filled with inhibited packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-11—Packer Specifications

Packer type and material	Nominal casing weight (ppf)	Packer main body outer diameter (inch)	Packer main body inner diameter (inch)	Temperature rating (°F)	Pressure rating (psi)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Burst Pressure (psi)	Collapse Pressure (psi)	Tensile Strength (ksi)	Comments
[redacted]	[redacted]	[redacted]	[redacted]

Finally, Table CON-12 outlines the cementing program and Table CON-13 shows the mud program details.

Table CON-12—Cementing Program

Section	Type	Depths (ft)	Density (ppg)	Sacks	Excess
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The stage tool is estimated at [redacted] ft, but the depth will be adjusted based on final drilling conditions.

Table CON-13—Mud Program

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb./ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

5.0 Blowout preventer and wellhead requirements

5.1 Blowout preventer equipment (BOPE)

- BOPE must be API-monogramed and adhere to API Standard 53 and Specifications 16A and 16C, as a minimum, and meet or exceed all applicable regulatory specifications.

- BOPE other than annular preventers must have a minimum working pressure exceeding the maximum anticipated surface pressure (MASP).
- All BOPE stacks must incorporate a set of blind or blind/shear rams.
- All rigs must have a calibrated trip tank. The trip tank and trip sheet are used to measure the fluid required to fill or displace from the hole during all tripping operations including casing or completion string running.
- A Full Opening Safety Valve (FOSV) and an Inside BOP Safety Valve (IBOPSV) must be always available on the rig floor for each drill pipe, drill collar size, and connection type in use.
- If a wireline lubricator is utilized for wireline operations, it shall not be the type that slips into and is held by the annular preventer or rams. A hydraulic cutter or other means of safely cutting the wireline must be available if a lubricator is not in use.

5.2 Choke manifolds and kill line

- The choke manifold must be API-monogrammed, meet API SPEC 16C as a minimum, and meet or exceed all applicable regulatory specifications.
- All BOPE must include a choke manifold with at least one remotely operated choke and one manual choke installed.
- Flare/vent lines must be as long as practical (a minimum of 150 ft from the well center), as straight as possible (without sumps, collection areas, or uphill flow areas to prevent fluid buildup and resulting backpressure) and be securely anchored.

5.3 Closing units

- BOPE closing units must adhere to API Spec 16D and API STD 53 as a minimum and meet or exceed all applicable regulatory specifications.
- BOPE control systems must include full controls on the closing unit and at least one remote control station. One control station must be located within 10 ft of the driller's console.
- BOPE closing units must have two separate charging pumps with two independent power sources, as specified in API Spec 16D, or have N_2 bottle backup.

5.4 Pressure testing

- BOPE components (including the BOP stack, choke manifold, and choke lines) must be pressure tested at the following frequency:
    - When installed. If the BOPE is stump tested, only the new connections are required to be tested at installation.
    - Before 21 days have elapsed since the last BOPE pressure test. When the 21-day test is due soon, consider testing the BOPE prior to drilling any H_2S, abnormal pressure, or lost return zones to avoid having to test while drilling these intervals.
    - Anytime a BOPE connection seal is broken, the break must be pressure tested.

5.5 CO_2 Injector Well - Wellhead mechanical drawing

Figure CON-3 below is a basic mechanical drawing of the wellhead to be used for the Pelican CCS 1 well.

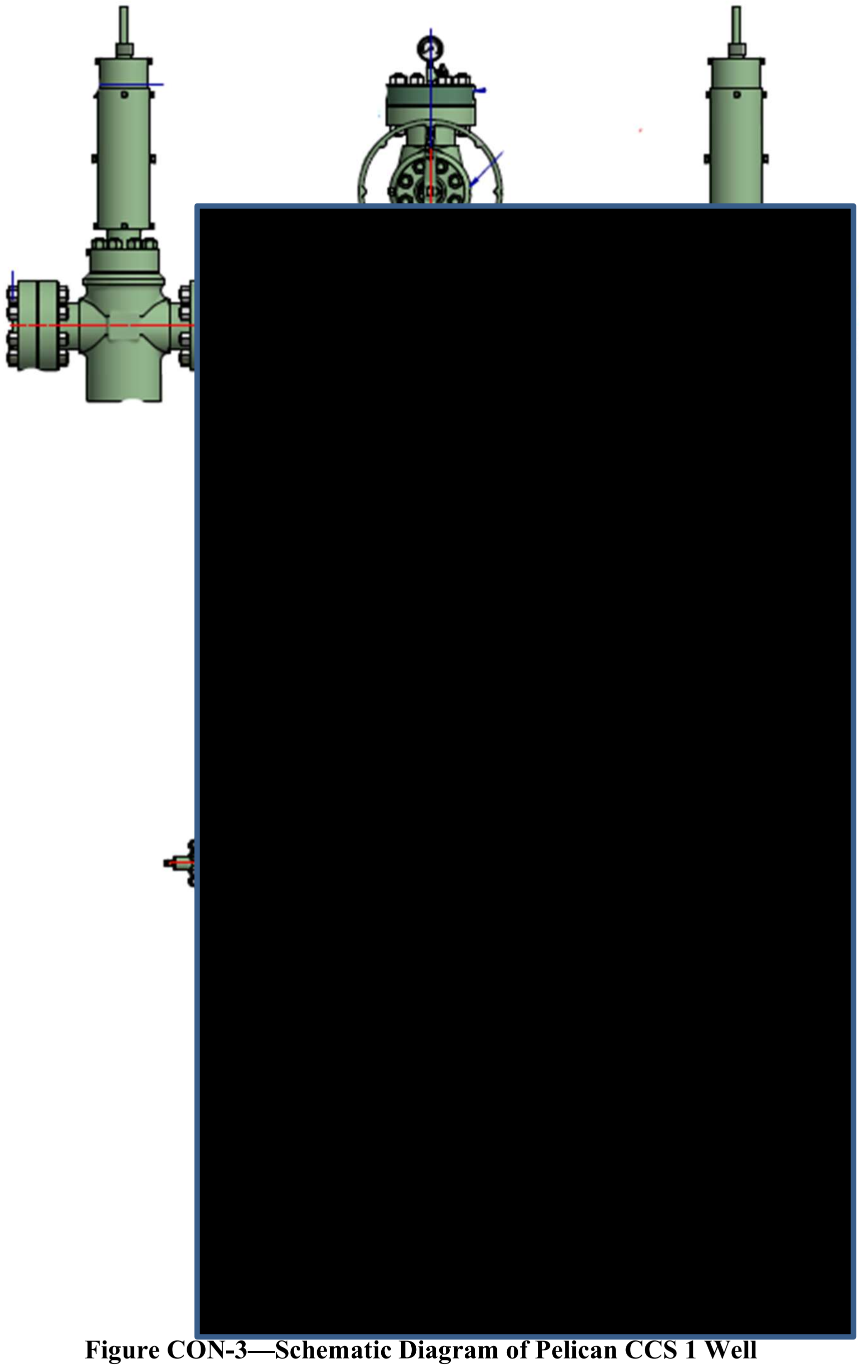

Figure CON-3—Schematic Diagram of Pelican CCS 1 Well

6.0 Recompletion Pelican CCS 1:

After 6.7 years of injection. Pelican CCS 2 will be recompleted by isolating the original perforations and adding Frio 1and Anahuac Zone.

Proposed procedure for recompletion:

1. Move in rig onto the Bluebonnet CCS 2 site and rig up (RU). All CO_2 pipelines will be marked and noted by the rig supervisor prior to moving in. Conduct and document a safety meeting.
2. Record the bottomhole pressure (BHP) from the downhole gauge, perform DST survey through fiber optic installed alongside the casing, and calculate kill fluid density.
3. Test the pump and line to [redacted] psi. [redacted] the tubing volume with kill fluid with the density determined using the bottomhole pressure measurement. Monitor the tubing pressure and annular pressure continuously.
4. Test casing annulus to [redacted]. If the pressure decreases more than 5% in 30 minutes, bleed the pressure, check surface lines and connections, and repeat the test.
5. If both the casing and tubing are static, then nipple up the blowout preventers (BOPs).
6. Pull out of the hole and lay down tubing, packer, cable, and sensors.
7. Pick up the work string and trip in hole (TIH) with the bit to condition the wellbore.
8. Pull out of the hole and rig up the logging unit. Run casing inspection log. Set cast iron bridge plug at [redacted] ft. Rig down wireline.
9. Run in the hole with cement retainer and work string and set at [redacted] ft.
10. Rig up cement equipment, test lines, mix and pump cement to squeeze the perforations. Details and Volume of the squeeze is presented in Table CON-14
11. Pull out of the hole work string and wait for the cement to set.
12. Run in the hole with work string and bit and drilled out cement retainer and 200 ft of cement to provide rat hole.
13. Pull out work string and bit.
14. Perforate reservoir from [redacted].
15. Run upper completion as defined in previous section.

Table CON-14—Detail of the squeeze job on CCS 2 on bottom perforations.

Plug No	Type Slurry	ID (inches)	Placement Method	Depths top (ft)	Depths bottom (ft)	Density (ppg)	Sacks	Yield
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

7.0 Additional Wells Construction Details

7.1 CO_2 Injector Well – Pelican CCS 1

Figure CON-4 shows well construction details of Pelican CCS 2 Injector well during Original Completion. And Figure CON-5 shows well construction details for Pelican CCS 2 CO_2 Injector well after recompletion at [redacted] of injection.

Pelican CCS 1 - CO2 Injector

[redacted]

Figure CON-2—Pelican CCS 1 Well Proposed Schematic – First Completion

Pelican CCS 1 - CO2 Injector

[redacted]

Figure CON-3—Pelican CCS 1 Well Proposed Schematic – Recompletion

7.2 Monitoring wells

Well construction schematics for the [redacted], as well as the USDW monitoring wells are detailed in the Testing and Monitoring Plan Attachment.