INJECTION WELL OPERATIONS PLAN

40 CFR 146.82(a)(7), 146.88

AAC 400-8-1-.15(2)(iv), (2)(v), 400-8-1-.30, 400-8-1-.33

PINE HILLS ALABAMA REGIONAL CO_2 STORAGE HUB

Prepared for

Reliant Southwest Alabama Storage, LLC

By

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February 2026

REVISION HISTORY

Document Version	Description	Dated
v1	Original submission	July 2025
v2	Claimed as PBI [redacted]	February 2026

FACILITY INFORMATION

Facility Name: Pine Hills Sequestration Hub (PHSH)

Facility Operator: Reliant Southwest Alabama Storage, LLC (Reliant)

Claimed as PBI

[redacted]

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List of Abbreviations and Acronyms

ºF	Degrees Fahrenheit
40 CFR	Title 40 of the Code of Federal Regulations
AAC	Alabama Administrative Code
CO	Carbon Monoxide
CO_2	Carbon Dioxide
d	day
DTS	Distributed temperature sensing
EPA	Environmental Protection Agency
ft	feet
H_2	Hydrogen
H_2O	Water
H_2S	Hydrogen Sulfide
INJ	Injector
LKA	Lower Cretaceous A
LKB	Lower Cretaceous B
LLC	Limited liability company
MASP	Max Allowable Surface Pressure
Claimed as PBI [redacted]	[redacted]
Mt	Metric tons
N_2	Nitrogen
NOx	Total Nitrogen Oxides
O_2	Oxygen
PHSH	Pine Hills Sequestration Hub
ppg	pounds per gallon
ppm	parts per million
PS	Pilot Sand
Psi	Pounds per square inch
psia	Pounds per square inch, absolute
Reliant	Reliant Southwest Alabama Storage, Limited Liability Company
SLB	Schlumberger
UIC	Underground injection control
U.S.	United States

6. INJECTION WELL OPERATIONS PLAN

6.1. EXECUTIVE SUMMARY

According to Title 40 of the Code of Federal Regulations (CFR) §146.82/Alabama Administrative Code (AAC) 400-8-1.15, .30, .33, Reliant Southwest Alabama Storage, LLC (Reliant) prepared this document to describe the planned operation of the carbon dioxide (CO_2) injection wells for the Pine Hills Sequestration Hub (PHSH).

6.2. CARBON DIOXIDE STREAM SPECIFICATIONS

The CO_2 delivered to PHSH for geologic storage will be sourced from various regional CO_2 sources, including the J.H. Miller Power Plant as described in the **PHSH Narrative Section 1.1.4**. The CO_2 will enter a header and be piped to the injection well, which is designed to operate continuously.

The PHSH pipeline system is still in the design phase. Therefore, an assumption was made that CO_2 will enter the wellhead at 90 degrees Fahrenheit (ºF) and above the maximum required pressure and will be choked down to the desired injection pressure. This will ensure the CO_2 enters the wellhead in a supercritical phase and remains in this state into the formation. The CO_2 stream is expected to contain minute portions of water and trace components of hydrogen, hydrogen sulfide, and oxygen. This is expected to make the CO_2 composition corrosive; therefore, 22% Chromium material is selected for all components of the well that contact CO_2, such as the wellhead, packer, tubing, and casing within the injection zone. If the CO_2 stream composition changes during the pipeline design or if future corrosion modeling or lab testing shows that other metallurgies, including those with 13%, 15%, or 17% chrome, will meet all of the United States (U.S.) Environmental Protection Agency's (EPA) requirements, they may be used in place of 22% chrome. Please refer to **Table 6-1** for a summary of the expected physical and chemical characteristics of the CO_2 injectate stream. A phase diagram illustrating the supercritical phase boundaries and injection paths is shown in **Figure 6-1.** Please refer to **Section 7.4.1 Carbon Dioxide Stream Analysis** of the **Testing and Monitoring Plan** for additional information on the CO_2 stream and its related testing and monitoring activities.

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Claimed as PBI [redacted]

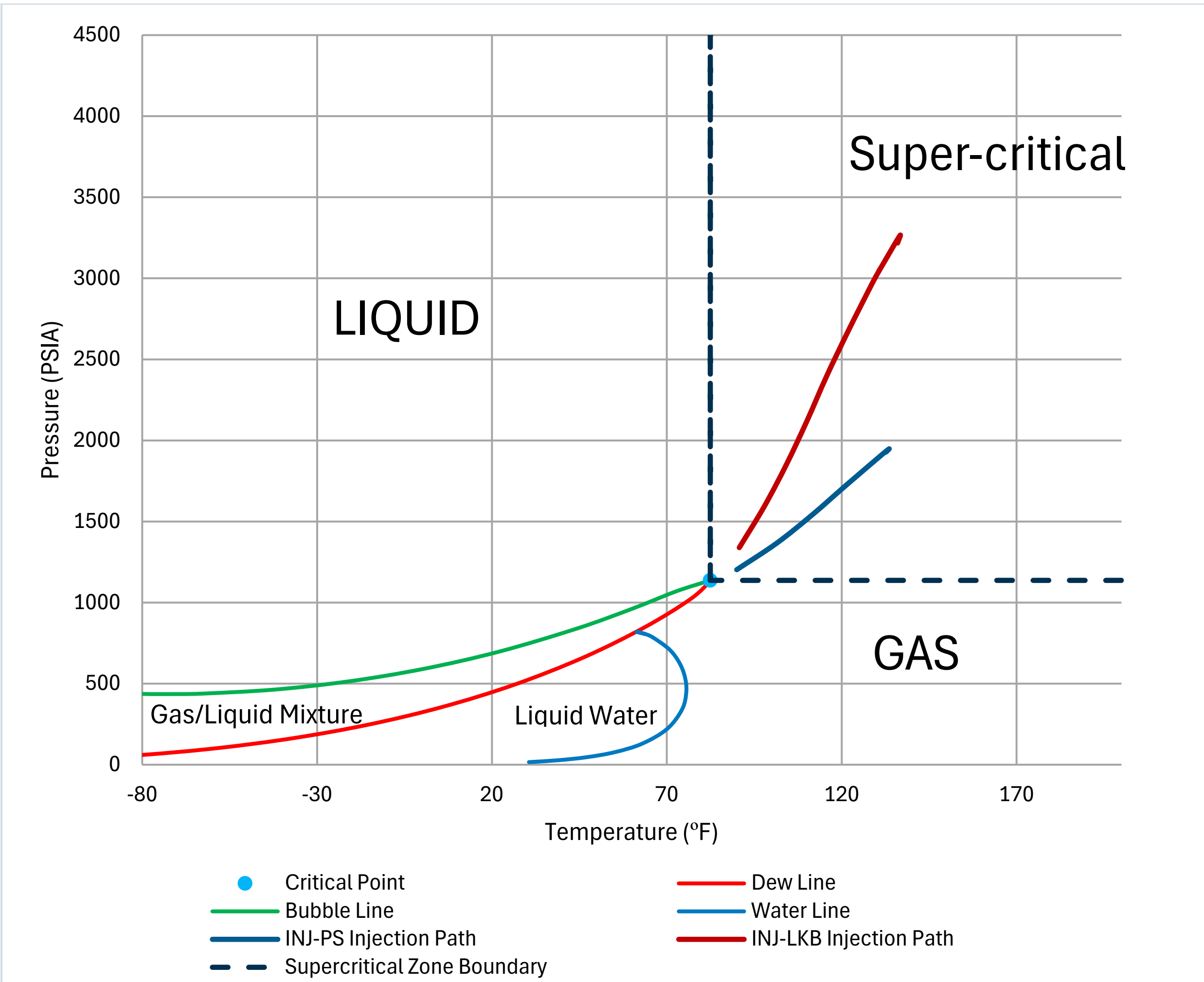

Figure 6-1. Phase Diagram for 95% Carbon Dioxide Stream Purity. PSIA = Pounds per square inch, absolute; ºF = degrees Fahrenheit.

6.3. INJECTION WELL OPERATING CONDITIONS

The PHSH injection wells will be constructed as described in the **Injection Well Construction Plan** and will inject into the Claimed as PBI [redacted]. Injection will be facilitated through a tubing set in the long-string casing with the packer set above perforations in the respective injection zones. Please refer to **Table 6-2** and **Sections 6.3.1. Injection Rates** and **6.3.2. Injection Pressures** for a summary of PHSH's proposed operating conditions in compliance with 40 CFR 146.82(a)(7)/AAC 400-8-1-.15(2)(d)(iv).

Claimed as PBI [redacted]

6.3.1. Injection Rates

The operational injection rate values in **Table 6-2** were calculated using SLB's PipeSIM software. A nodal analysis was performed in PipeSIM, as described in the **Injection Well Construction Plan**, to determine the range of possible injection rates. Claimed as PBI [redacted] wells as described in **Section 1.1.3. Project Timeframe** in the **Project Narrative**. No injection well will exceed the permitted maximum surface pressure or maximum injection rate.

6.3.2. Injection Pressures

The operational injection pressures described in **Table 6-2** were calculated using SLB's PipeSIM software. The injection model was used to determine average and maximum surface and downhole pressures. Based on PHSH injection targets, Claimed as PBI [redacted] (**Figure 6-2**) was estimated assuming the maximum allowable bottomhole pressure was reached as the CO_2 entered the injection zone through perforations at the maximum injection rate; the bottomhole pressure was set to 90% of the estimated hydraulic fracture pressure at the top perforation depth. Following 40 CFR 146.88(a)/AAC 400-8-1.33(1), Reliant will ensure downhole pressures do not exceed 90% of the fracture pressure of the injection zone unless performing stimulation activities approved by the United States (U.S.) Environmental Protection Agency (EPA) Region 4 Underground Injection Control (UIC) Program Director and the state of Alabama Oil and Gas Board (AOGB) Supervisor.

The tubing-casing annulus will be filled with a non-corrosive fluid, as described in **Section 4.7 Injection Well Annular Fluid Program** of the **Injection Well Construction Plan**. This fluid will provide a positive pressure differential to ensure the annulus is always pressured above injection pressure. Claimed as PBI [redacted]. Adequate pressure will be held at the wellhead.

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[redacted]

6.4. INJECTION WELL OPERATIONAL MONITORING

Meeting 40 CFR 146.88(e)(1)/AAC 400-8-1-.33(5)(a), continuous recording devices will be deployed on the injection well, within the injection wellbore, and immediately upstream of the injection well on the well pad to monitor operational parameters. Continuous recording devices deployed on or within the injection well include:

- Surface pressure gauges that are ported to the injection tubing and annulus to monitor surface injection pressure and annulus pressure (i.e., internal mechanical integrity), respectively. Please refer to **Sections 7.3.2 Internal Mechanical Integrity** and **7.4.3 Continuous Monitoring of Annulus Pressure and Fluid Volume** of the **Testing and Monitoring Plan** for additional information on injection well internal mechanical integrity testing and monitoring.
- Downhole pressure/temperature gauges to monitor reservoir pressure and temperature, along with the annulus pressure immediately above the packer.
- Distributed temperature sensing (DTS) fiber-optic cables deployed externally along the wellbore to monitor external mechanical integrity. Please refer to **Section 7.3.3 External Mechanical Integrity** for additional information on DTS fiber-optic and external mechanical integrity testing.

Additional recording devices and equipment will be placed immediately upstream of the injection wellhead, such as a flow meter to continuously record injection rate, volume, and temperature, and corrosion coupons that will be sampled quarterly to monitor corrosion of well components (e.g., casing, tubing, packer). For a full description of injection well and project site testing and monitoring activities, please refer to the **Testing and Monitoring Plan**.

Additionally, pursuant to 40 CFR 146.88(e)(2) and (e)(3)/AAC 400-8-1-.33(5)(b), alarms and automatic surface and downhole shut-off systems will be installed on the wellhead so that if parameters exceed their maximum operating limits and/or indicate loss of mechanical integrity, an alarm will sound, injection operations will be shut down, and an investigation into what caused the shutdown will be performed. All automatic shutdowns will be investigated before recommencing injection operations to ensure there are no mechanical integrity issues that may result in leakage. The automatic shut-down valve is shown on the 7 1/16" wing valve, where the pipeline connects to the wellhead on **Figure 4-6**. If an unremedied shutdown is triggered or a loss of mechanical integrity is discovered, Reliant will:

1) Immediately cease injection in the affected well and in any other wells that may exacerbate the leakage risk of the affected well.
2) Notify the UIC Program Director in writing within 24 hours.
3) Take all steps reasonably necessary to determine whether there may have been a release of the CO_2 injectate and/or formation fluids into any unauthorized zone.
4) If it is determined that substantial endangerment to public health or the environment exists from any fluid movement out of the intended storage complex, implement the **Emergency and Remedial Response Plan**.
5) Restore and/or demonstrate mechanical integrity before resuming injection or plugging operations.
6) Report on the new demonstration of mechanical integrity to the UIC Program Director within 30 days of testing.

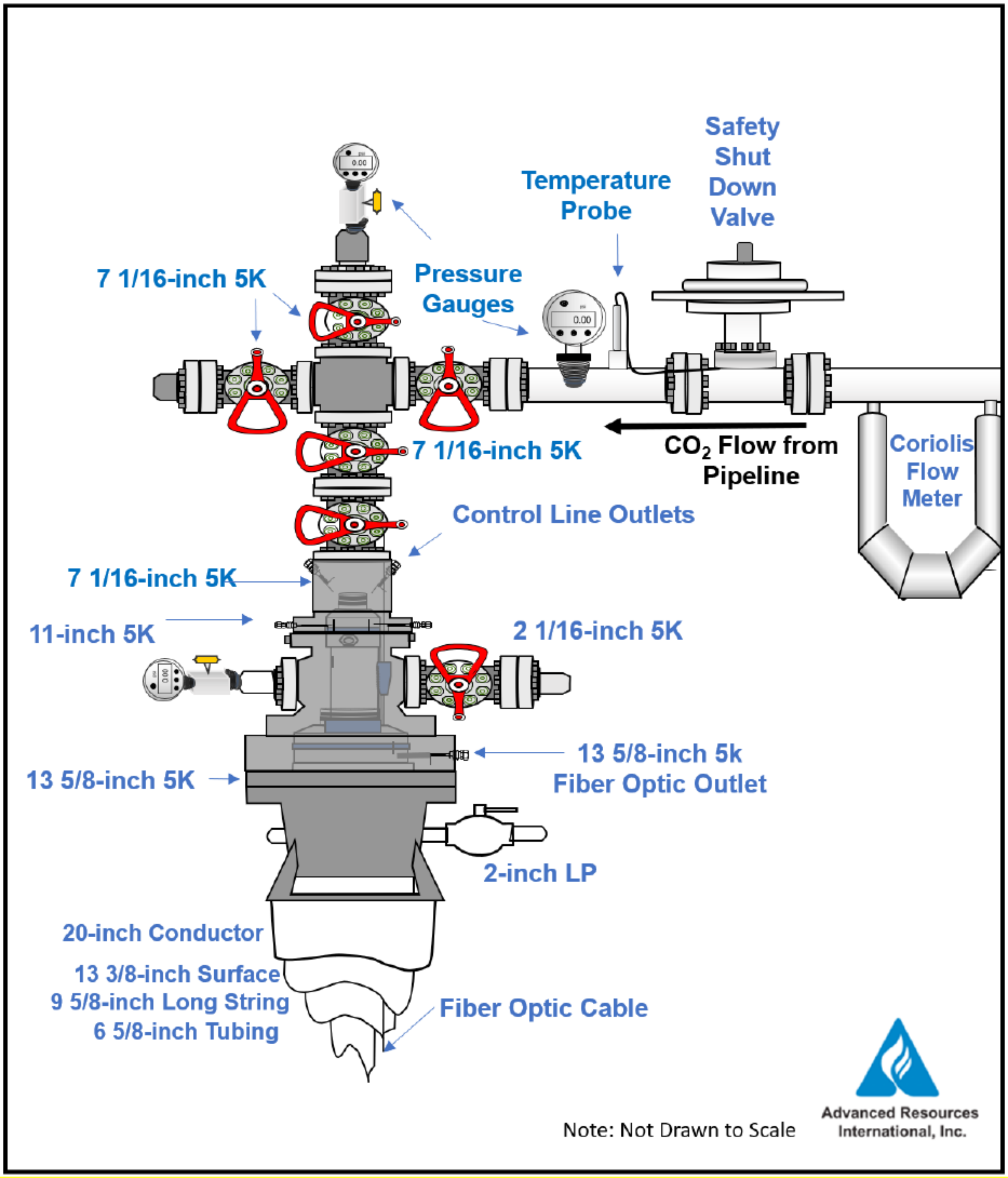

Figure 6-3: Design schematic of the PHSH wellhead, Christmas tree, automatic shut down valves, and monitoring technology.

6.5. INJECTION WELL WORKOVER AND MAINTENANCE

Reliant will perform routine maintenance to ensure injection wells maintain mechanical integrity throughout the lifespan of PHSH, per 40 CFR 146.88(d)/AAC 400-8-1-333(4). Well maintenance and workovers will be part of normal operations to keep the injection well in a safe operating condition. Procedures for well maintenance will vary depending on the nature of the maintenance required. However, all maintenance and workover operations will be monitored to ensure there is no loss of mechanical integrity; the injection well is designed to allow for the installation of a temporary plug above the packer assembly so that the tubing can be removed and replaced, if required, while keeping a barrier in place. Additionally, the bottomhole pressure and temperature gauge is set above the packer to allow for replacement, if required, without removing the packer from the well.