Attachment 4A: Injection Well #1 Construction
40 CFR 146.82(a)(9), (11), and (12)
Vervain Project, McLean County, Illinois
24 March 2023

Navigator CO_2

Facility Information

Project Name: Vervain

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Project Location: Vervain Injection Well #1
CO_2 Injection Well Location
Latitude 40°17'47.98" N
Longitude 89°15'16.29" W

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List of Acronyms

API	American Petroleum Institute
APT	Annulus Pressure Test
BHP	bottomhole pressure
BOPs	blow out preventers
CBL	cement bond log
CCS	carbon capture and sequestration
DST	drill stem test
EOR	enhanced oil recovery
EPA	Environmental Protection Agency
fbgl	feet below ground level
FOT	fall-off test
HCl	hydrochloric
HF	hydrofluoric
IAC	Indiana Administrative Code
KCl	potassium chloride
LTC	long thread coupling
MAIP	maximum allowable injection pressure
Mtpa	million tonnes per annum
NOV	National Oilwell Varco
NV_INJ1	Vervain Injection Well #1
NV_INJ2	Vervain Injection Well #2
NV_OBS1	Vervain Deep Observation Well
POOH	pull out of hole
ppg	pounds per gallon
SCADA	supervisory control and data acquisition
SDS	safety data sheet
STC	short thread coupling
TD	total depth
USDW	Underground Source of Drinking Water
US	United States
WBM	water-based mud

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Plan revision date: 24 March 2023

Change Log

Item Changed	Date	Version	Description
	3/24/2023	V1.1	Reorder document to better match 40 CFR 146.86
Pg 8 Figure 1	3/24/2023	V1.1	Added a depiction of the downhole P/T gauges to the wellbore schematic
Pg 15 Sec 1.2	3/24/2023	V1.1	Added wording stating all components exposed to wet CO2 will use corrosion resistant materials
Pg 17 Table 6	3/24/2023	V1.1	Added internal and external pressures used to determine casing safety loads shown in Table 6
Pg 18 Sec 1.2.1	3/24/2023	V1.1	Description of CO2 stream temperatures
Pg 20	3/24/2023	V1.1	Corrected differential rating of packer to 10,000 psi
Pg 21 Sec 1.3.6	3/24/2023	V1.1	Added information about formation fluids referenced to the project narrative

1. Injection Well Construction

This section summarizes the methods and materials to be used for the construction of the Vervain Injection Well #1 (NV_INJ1). Schematics of the well that illustrate the construction, are provided within the contents of this document. Please note that these schematics are not meant to portray final products and are subject to change pending availability of materials listed and the completion of well installation. The work will be performed in accordance with guidance documents, approved work plans, and reporting timelines as approved by the United States (US) Environmental Protection Agency (EPA). NV_INJ1 will be constructed with multiple casing strings, each string smaller in diameter than the previous and cemented to surface to provide multiple layers of protection for Underground Sources of Drinking Water (USDWs).

Downhole pressure and temperature gauges will be installed just above the packer [redacted] The downhole pressure gauge will be used to help ensure that the maximum allowable injection pressure (MAIP) does not exceed 90% of the fracture pressure. The downhole temperature gauge will be used to calculate the bottomhole density and volume of the injected fluid. The BHP gauges will be programed to take data at the intervals outlined in the testing and monitoring program section of this application (Attachment 7: Testing And Monitoring, 2023). The data collected from these measurement systems will be collected continuously and sent to a surface SCADA system. More information about these sensors is provided in the Well Operations and Testing and Monitoring Plans (Attachment 6A: NV_INJ1 Well Operations Plan, 2023), (Attachment 7: Testing And Monitoring, 2023).

The injection well proposed in this document will be constructed as a new well. Due to the high potential for lost circulation through the Knox interval an intermediate string [redacted] casing will be run and set in the Davis Formation. The injection well will then be drilled into the Precambrian Granite Basement (basement) with enough hole present such that the basement rock can be properly characterized. It is noted that the Vervain Deep Observation Well (NV_OBS1) will potentially serve to collect the basement characterization data. Should that be the case, NV_INJ1 will not be used to characterize the basement.

Once the basement characterization data has been collected, whether in NV_INJ1, NV_INJ2 or NV_OBS1, the open basement section will be plugged back to the injection zone such that the CO_2 will not be directly injected into the basement. This will be done prior to running and cementing the long string casing in place.

Figure 1 displays a schematic of the proposed well construction for NV_INJ1. Figure 2 displays a schematic of the proposed wellhead for NV_INJ1.

The Lower Mt. Simon Sandstone and the Arkose Sandstone are the targeted injection zone for the project [redacted]. The Upper and Middle Mt. Simon units [redacted] could serve as secondary storage as CO_2 migrates due to density effects. The Eau Claire Shale [redacted] serves as the primary confining layer for the project. The base of the Eau Claire Formation is a siltstone to very fine-grained sandstone known as the Eau Claire Siltstone and is in gradational contact with the Mt. Simon Sandstone.

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[redacted]

Figure 1: NV_INJ1 Injection Well Construction Proposed Schematic

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[redacted]

Figure 2: NV_INJ1 Injection Wellhead Proposed Schematic

1.1. Construction Procedures 40 CFR 146.82(a)(12)]

This section details the procedures that will be followed during the drilling, completion, and testing portions of the NV_INJ1 installation. Note that these procedures are subject to change based upon field conditions and/or the availability of equipment/materials. An updated and detailed procedure will be provided prior to well construction.

1.1.1. Drilling Procedures

1. [redacted] conductor casing will be driven [redacted] into the ground before the drilling rig arrives on location to commence drilling operations.
2. A [redacted] bit will be used to drill [redacted] below the base of the Mahomet Aquifer. Sufficient rat hole should be drilled such that openhole and cased hole logs can be run to assess the entire Mahomet Aquifer.
    a. The drilling mud in this section of the hole will be water-based mud (WBM).
3. At the section TD, the hole will be circulated clean, and the drill string will be POOH.
4. Openhole logs will be run across the openhole interval (conductor casing shoe to the section TD).
    a. Log run details are provided in Section 4.
    b. Cement volumes for this hole section will be determined based on the results of the caliper log.
5. [redacted] surface casing will then be run to the section TD.
    a. The casing will be run as follows (bottom to top):
        i. Float shoe
        ii. One joint of casing
        iii. Float collar
        iv. Casing to surface
    b. One centralizer will be used every third joint to surface.
6. The [redacted]h casing will be cemented [redacted].
    a. Wet samples will be collected during mixing.
    b. After pumping all cement, a plug will be dropped, and the cased hole volume will be displaced with water.
7. After allowing cement to harden approximately 24 hours, cased hole logs will be run to assess the overall bond quality of the cement.
    a. Details on the logs that will be run are provided in Section 4.
8. Once the bond is of sufficient quality, nipple up blow out preventers (BOPs) and test per API Standard 53.
9. Once the BOPs have been nippled up and tested, the casing will be tested to at least twenty percent (20%) greater than the anticipated maximum pressure to which the casing will be exposed for a minimum of thirty (30) minutes with a pressure drop of no more than ten percent (10%).
    a. The pressure to be used for testing will be provided as part of the final installation procedures to be made available prior to the installation of the well.
10. A [redacted] bit will be used to drill [redacted] the Davis Formation at [redacted]. Sufficient rat hole will be drilled such that openhole and cased hole logs can be run to assess the entire intermediate section of the well.
    a. The drilling mud in this section of the hole will be WBM.

   b. Lost circulation is anticipated in the Knox interval. Mud losses will be controlled by various means including LCM and cement plugs as necessary to reach section TD.

11. At the section TD, the hole will be circulated clean, and the drill string will be pulled out of hole.
12. Openhole logs will be run across the openhole interval (surface casing shoe to the section TD).
    a. Details on the logs that will be run are provided in Section 4.
    b. Cement volumes for this hole section will be determined based on the results of the caliper log.
13. [redacted] intermediate casing will then be run to the section TD.
    a. The casing will be run as follows (bottom to top):
        i. Float shoe
        ii. One joint of casing
        iii. Float collar
        iv. Casing to surface
    b. One centralizer will be used every 3rd joint to surface with one centralizer used every joint for three joints above and below the surface shoe joint.
14. The [redacted] casing will be cemented [redacted].
    a. Wet samples will be collected during mixing.
    b. After pumping all cement, a plug will be dropped, and the cased hole volume will be displaced with water.
15. After allowing cement to harden for approximately 24 hours, cased hole logs will be run to assess the overall bond quality of the cement.
    a. Details on the logs that will be run are provided in Section 4.
16. Once the bond is of sufficient quality, blow out preventers (BOPs) will be nippled up and tested per API Standard 53.
    a. BOPs will already be installed prior to drilling the intermediate hole section. BOPs might need to be changed out and retested to accommodate the [redacted] casing string.
17. After the cement has been allowed to harden for at least 24 hours, the casing will be tested to at least twenty percent (20%) greater than the anticipated maximum pressure to which the casing will be exposed for a minimum of thirty (30) minutes with a pressure drop of no more than ten percent (10%).
18. Once the intermediate string has been set, a [redacted] bit will be used to drill the long string section.
    a. The drilling mud in this section of the hole will be WBM.
    b. While drilling this section, the drilling assembly will be run out of the hole to capture a [redacted] whole core in both the Eau Claire Formation and Mt. Simon Sandstone.
19. At the section TD, the hole will be circulated clean, and the drilling string will be pulled out of hole.
20. Openhole logs will be run across the openhole interval (intermediate casing shoe to the section TD).
    a. Details on the logs that will be run are provided in (Attachment 5: Pre-Op Testing Program, 2023)

   b. Cement volumes for this hole section will be determined based on the results of the caliper log.
21. A drill stem test (DST) tool will be run into the Mt. Simon Sandstone to collect a fluid sample for analysis.
   a. If a DST is not run at this time, the well will be swabbed to collect a representative fluid sample during the well completion operations.
22. A [redacted] string casing will be run [redacted]
   a. The casing will be run as follows (bottom to top):
      i. Float shoe (13Cr80, or similar suitable metallurgy)
      ii. Two joints of casing (13Cr80)
      iii. Float collar (13Cr80, or similar suitable metallurgy)
      iv. 13Cr80 casing [redacted] above the Eau Claire Formation
      v. Stage Tool [redacted].
      vi. L80 steel casing to surface
   b. One centralizer per joint will be utilized for the 13Cr80 casing. One centralizer every third joint will be utilized for the L80 steel casing with one centralizer used every joint for three joints above and below the Stage Tool and the intermediate shoe joint.
23. The [redacted] casing will be cemented using a system that uses either EverCRETE or WellLock as a tail system below the Stage Tool, and [redacted] above the Stage Tool.
   a. The top of the tail cement is targeted to be above the top of the Eau Claire Formation.
   b. Wet samples will be collected during mixing.
   c. After pumping the tail system (Stage 1 cement or resin), a plug will be dropped to open the stage tool, and the lead system (Stage 2 cement) will be pumped to surface. Once completed, a plug will be dropped, and the cased hole will be displaced with water.
24. After the cement and/or resin has been allowed to harden for at least 48 hours, the casing will be tested to at least twenty percent (20%) greater than the anticipated maximum pressure to which the casing will be exposed for a minimum of thirty (30) minutes with a pressure drop of no more than ten percent (10%).
   a. The pressure to be used for testing will be provided as part of the final installation procedures to be made available prior to the installation of the well.
25. The drilling rig will be disassembled. The BOPs will also be nippled down and a Night Cap will be installed.

The subsurface and surface design (casing, cement, and wellhead) exceeds the minimum requirements to sustain the integrity of the confining interval to ensure that the CO_2 remains in the Mt. Simon Sandstone. The final well design meets strength and CO_2 compatibility requirements. This procedure concludes the drilling portion of the well installation.

1.1.2. Well Deviation Survey Plan

The wellbore trajectory will be surveyed every 500 feet of depth to ensure the well has less than 5° inclination. These surveys will be performed using a wireline conveyed, timer-based survey tool. The following presents the survey plan and tolerances:

- If the wellbore trajectory is more than 1° inclination, then the wellbore trajectory will be surveyed every 250 feet of depth.
- If the wellbore trajectory is 2° or more inclination, then the wellbore trajectory will be surveyed every 100 feet.
- This will be repeated until the wellbore is within 1° of inclination.

1.1.3. Completion Procedures

The completion portion of the well installation is detailed below. Note that these procedures are subject to change as based on field conditions or the availability of equipment or materials. A detailed procedure will be provided prior to the installation of the well.

1. A workover rig will be installed, and BOPs will be nippled up. The BOPs will be tested per API Standard 53.
2. Cased hole logs will be run to assess the overall bond quality of the cement.
    b. Details on the logs that will be run are provided in (Attachment 5: Pre-Op Testing Program, 2023).
        i. These logs may or may not be run prior to the workover rig being on location.
        ii. Two runs will likely be performed, 1) under anticipated operation pressure, 2) under no pressure.
3. The Lower Mt. Simon sandstone and the Arkose sandstone will be perforated in select intervals.
    c. It is currently anticipated that the entire Lower Mt. Simon sandstone and the Arkose sandstone intervals will be perforated from the top to the bottom.
    d. This implies a perforated interval [redacted].
4. Following the perforations, acid will be bullheaded into the well to clean up the perforations.
    e. Should the well need to be swabbed for a fluid sample, it would be done at this time.
5. The [redacted] packer assembly will be run in on work string as follows:
    f. Blow-out disk (2k)
    g. 1 joint [redacted]
    h. [redacted] packer
    i. Stinger On/Off tool
    j. Work string
6. Once the packer has been set, the work string will be stung off the packer and run out of hole.
7. The [redacted] injection tubing will be run in the hole as follows:
    k. On/Off tool
    l. Crossover
    m. [redacted] tubing to surface
    n. Crossover
    o. Landing joint
8. Once the injection tubing has been latched onto the packer, the BOPs will be closed, and a preliminary annulus pressure test (APT) will be performed.
    p. The APT will be run as detailed in (Attachment 5: Pre-Op Testing Program, 2023).

9. After the APT has been successfully completed, the [redacted] tubing will be stung off the packer and the annulus will be displaced with the treated annulus fluid.
    q. This treated annulus fluid will be comprised of one, or more, of the following:
        i. Fresh water
        ii. Packer fluid
        iii. Inhibiters
        iv. Biocide
        v. Scale reducer
10. Once this annulus fluid has been pumped, the [redacted] tubing will be stung onto the packer, and the tubing will be landed in the tubing hanger.
11. After the tubing hanger is landed, a final APT will be run.
12. The BOPs will be nippled down, and the wellhead will be installed.
13. Following the installation of the wellhead.
14. The workover rig will be rigged down, and the well installation will be considered complete.

1.1.4. Testing Procedure

The testing portion of the well installation is detailed below. Note that these procedures are subject to change as based on field conditions or the availability of equipment or materials. A detailed procedure will be provided prior to the installation of the well. These procedures are consistent with those provided in Section 4. Testing will use the permanent downhole pressure gauges.

1. Rig up pump truck and the associated auxiliary equipment. Ensure proper fluid is on location for injection testing.
2. Pressure test pump truck equipment.
3. Blow out the burst disk.
4. Run step-rate test as detailed in (Attachment 5: Pre-Op Testing Program, 2023).
5. Run FOT as detailed in (Attachment 5: Pre-Op Testing Program, 2023).
6. Rig-down pump truck.
7. Secure the well.

1.2. Hole Sections and Cement Information 40 CFR 146.86 (b)

Table 1 provides a summary of the open-hole sections of the NV_INJ1 well construction. All depths provided in the table are in reference to feet below ground level (fbgl).

Table 1: Openhole Section Diameters and Intervals

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Table 2 provides a summary of the casing strings to be used in construction of the injection well. All casing (weight, grade, and threading) to be used will conform with American Petroleum

Institute (API) standards. All components selected for construction that will be exposed to wet carbon dioxide (CO_2) will use corrosion resistant materials. The casing and cementing plans are designed to ensure the injected CO_2 stays within the Mt. Simon Sandstone and prevents upward migration of injection zone fluids from reaching the deepest USDW (the St. Peter Sandstone).

Table 2: Casing String Setting Depths, Diameters, and Specifications

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[redacted]

Table 3 provides a summary of the cement systems for use on the casing strings during the injection well construction. All cement systems used will conform with API standards. Note that the excess cement pumped is subject to change pending field results. Cement will be pumped with the following open-hole excess:

- Surface – 100% excess
- Intermediate – 50% excess
- Long string – 30% excess

The well design uses CO_2 resistant cement or resin for the long string. Two options are introduced in this section: EverCRETE CO_2 resistant cement system from Schlumberger and WellLock™ or ThermaLock™ resin systems from Halliburton. These systems are stable in extreme acidic conditions, highly resistant to the CO_2 stream and formation fluids in the Mt. Simon Sandstone, and of sufficient quality to maintain integrity over the design life of the NV_INJ1 injection well.

Table 3: Cement System Details for each Hole Section.

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[redacted]

The surface and intermediate casing cement systems will provide the required isolation of the deepest USDW. The deepest USDW is anticipated to be in the St. Peter Formation as defined by the Illinois State Geological Survey (Attachment 1: Project Narrative, 2023). The intermediate casing and cement will isolate the deepest USDW from the CO_2 injected into the Mt. Simon Sandstone. The cement and cement system used will conform with API standards.

The quality of the bond between the cement, casing, and borehole will be verified by the cased hole logs that will be run after each string of casing is cemented in place (Attachment 5: Pre-Op Testing Program, 2023). The long string lead cement system used will conform with API standards. The tail cement system will be either an EverCRETE or WellLock system.

As with the surface cement section, the quality of the bond between the cement, casing, and borehole will be verified using cased hole logs (Attachment 5: Pre-Op Testing Program, 2023). These cased hole logs include cement bond log (CBL) with radial arms, Ultrasonic Cement Evaluation, Temperature, and Pulsed Neutron. Table 4 provides a summary of the tubing and packer system to be used in the construction of NV_INJ1.

The 13-Chrome (13Cr80) casing string has been confirmed as suitable for CO_2 service by the engineers at Sumitomo who produce the casing tubulars (Nippon Steel, 2022). 13Cr80 casing, or a suitable replacement, will be used during well construction. The manufacturers of the pipe, Nippon Steel, have confirmed the materials as suitable for routine, or flowback operations. [redacted]

Table 4: Tubing and Packer Setting Depth, Diameters, and Specifications

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[redacted]

The tubing will consist of internally coated carbon steel tubing provided by Tuboscope™, a National Oilwell Varco (NOV) product. This coating consists of TK-15XT and has been field-proven to be suitable for more extreme cases of EOR. Material specifications and suitability for use documentation is provided in this document (Tuboscope - NOV Wellbore Technologies, 2017).

The Signature F™ Injection packer system from Baker Hughes will be used for this project. The packer can be used with either a retrievable or permanent configuration and will be internally and externally coated with chrome and nickel to resist corrosion effects of the CO_2 stream. The Baker Hughes engineers confirmed that the chrome/nickel plating is suitable for the required service. Materials specifications and suitability for use document is provided in this document (Baker Hughes, a GE Company, 2019).

1.2.1. Casing and Cementing

Design analysis was performed to evaluate the casing selection. This analysis included reviewing the burst, collapse, tensile loads, and a Von Mises analysis, using Lame's equations, that were anticipated to be experienced as a part of the casing installation and normal well operation. Prior to performing any analyses on design criteria, an 80% derating factor was applied to the pipe ratings. This 80% derating equates to a base 1.2 safety factor.

The equation to determine the safety factor is provided below,

$$SF = \frac{Pipe\ Rating}{Load}$$

In addition to this derating, additional, standard derating was performed. The yield strength of the pipe was derated based on applied tensile loading, this consisted of a biaxial analysis. This is consistent with the method presented in API Bulletin 5C3, Formulas and Calculations for Casing, Tubing, Drill pipe and Line Pipe Properties (American Petroleum Institute, 1994). Cyclical loading was considered in the analysis performed by Baker (Baker Hughes InQuest TUBEMOVE, 2022).

This derating is only considered when evaluating collapse parameters under tension. Compressive analysis was not performed on the casing strings, as they are not anticipated to undergo any major compressive loads except for when being run in-hole. Standard API equations were used to calculate all design ratings and loads. The safety factors utilized for analysis are provided in Table 5.

Table 5: Casing Safety Factors for Design.

Burst	Collapse	Tensile
1.2	1.2	1.5

The results of the analyses are provided in Table 6.

Table 6: Casing Safety Factor Loads for Design.

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[redacted]

Sensitive, Confidential, or Privileged Information [redacted] It is not anticipated that this temperature differential is of a large enough magnitude to impact the performance of the casing and cement over the life of the project. Table 7 and Table 8 provide casing and tubing details and design parameters, respectively.

Table 7: Casing and Tubing details

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[redacted]

Table 8: Casing and Tubing Design Parameters

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[redacted]

1.3. Additional Design Considerations 40 CFR 146.86 (c)

Table 6 provides information on the design ratings for the injection tubing and packer. This section discusses the application of these design ratings to ensure the suitability of the construction materials for this project.

A safety factor of 20% has been used to evaluate the materials of construction. As such, all ratings have been derated to 80% of their initial ratings. All comparative evaluations detailed in this section are in reference to these derated values.

[redacted]

[redacted] As such, the well and analysis of well conditions have been performed based on this consideration.

1.3.1. Injection Pressure Considerations

[redacted]. This proposed value is discussed in further detail in the Well Operations section of this permit application (Attachment 6A: NV_INJ1 Well Operations Plan, 2023). The injection pressure will not exceed 90% of the formation fracture pressure and for purposes of this application a safety factor of 80% is assumed, [redacted]

Table 9: Bottomhole Pressure Considerations.

[redacted]

The maximum allowable bottomhole injection pressure is approximately 51.4% of the derated burst rating of the tubing. This assumes the annulus space is evacuated, which is an extremely improbable event.

[redacted]

The maximum allowable bottomhole injection pressure is approximately 32% of the differential pressure rating for the packer elements. This assumes the annulus space is evacuated, which is an extremely improbable event. Based on these worst-case analyses, the tubing and packer to be used for this project are acceptable.

1.3.2. Annulus Pressure Considerations

[redacted]. Based on this range, the maximum proposed annular pressure downhole will be calculated based on the hydrostatic pressure of [redacted] KCl brine (with additives) at the packer added to the maximum anticipated annular pressure.

[redacted]

The tubing is sufficiently designed such that the worst-case scenario is less than the derated collapse rating.

Additionally,

[redacted]

The packer is sufficiently designed such that the worst-case scenario occurs at a pressure that is less than the rated pressure differential of the packer elements.

During operations, this worst-case scenario of an evacuated portion of the well is extremely improbable.

1.3.3. Formation Pressure Considerations (During Initial Completions)

Prior to the start of injection operations, the injection zone will be in a static state, which means that the formation pressure should be considered in the design criteria. [redacted]

[redacted]

The packer is sufficiently designed such that the worst-case scenario of pressure differentials prior to injection beginning is approximately 16% of the rated pressure differential of the packer elements.

Further, when examining the collapse rating in a worst-case scenario during initial completion,

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The injection tubing is sufficiently designed such that the worst-case scenario during the initial completion is 81% of the derated collapse rating of the pipe.

1.3.4. Tensile Loading Considerations

Sensitive, Confidential, or Privileged Information [redacted]

1.3.6. Corrosion Considerations

Sensitive, Confidential, or Privileged Information [redacted] All components selected for construction that will be exposed to wet CO_2 will use corrosion resistant materials. Verification of the suitability for these components is provided with this document and referenced in previous sections and subsections.

Refer to the corrosion monitoring in testing and monitoring plan for corrosion monitoring of the materials of construction (Attachment 7: Testing And Monitoring, 2023). In addition, regular sampling and monitoring of the CO_2 stream will be performed, as detailed in the testing and monitoring plan.

Details and specifications of the corrosivity of the CO_2 and projected chemical content, temperature and density have been provided within the AoR, well operations, and testing and monitoring sections of this permit application.

1.3.7. Operational Considerations

Emergency shut-down equipment will be used at the surface for this project. Details on this equipment are provided in the well operation section as well as the testing and monitoring section (Attachment 6A: NV_INJ1 Well Operations Plan, 2023), (Attachment 7: Testing And Monitoring, 2023).

Surface monitoring equipment, as detailed in the testing and monitoring section, will be connected to the surface Supervisory Control and Data Acquisition (SCADA) system.

Permanent downhole gauges used to monitor pressure and temperature at the packer will be utilized for this project. These gauges will be in a gauge mandrel above the packer. These gauges will transmit data through a wire, run up the annulus, to the SCADA system.

Tubulars have been designed such that logging tools and other equipment needed for routine and annual monitoring will be able to pass through with no restrictions.

2. Proposed Stimulation Program [40 CFR 146.82(a)(9)]

Based on analysis from the ADM CCS1 well in Illinois, it is unlikely that any well stimulation, such as hydraulic fracturing, will be required upon initial completion of the injection well. If there appears to be significant reduction in actual permeability and porosity compared to the analyzed core data and information gathered during the fluid injection test, then a stimulation program may be considered.

Routine well or formation remediation might be necessary to reduce lost injectivity due to routine injection operations. Lost injection capacity may be due to geochemical reactions, scale build-up, or pore throat plugging amongst other things.

Should injection capacity be diminished enough to impact the effectiveness of the well, chemical or mechanical remediation may be required. Such remediation may occur using one, or more of the following methods:

- Bullhead acid stimulation – an acid such as hydrochloric (HCl) acid will be used in a dilute concentration (i.e., 7.5%-15%) with other potential additives (citric acid, scale reducer, defoamer, etc.).
    - Acid will be pumped down the injection string and be allowed to soak in the near wellbore area before being pushed into formation or flushed back up to surface.
- Bullhead acid stimulation with mud acid – HCl and hydrofluoric (HF) acid mix will be used with potential additives.
- Coil tubing acid stimulation – HCl will be used with potential additives.

    - Coil tubing will be used to nitrify and place the acid over specific intervals. Acid will be allowed to soak and will be pushed into the formation or flushed back up to surface.
- Coil tubing acid stimulation with mud acid – HCl and HF acid mix will be used with potential additives.
- Coil tubing chemical treatment – should certain precipitates require treatment using fluids other than acid, targeted chemical remediation will be performed.
- Coil tubing clean out – mechanical cleaning of scale and buildup from the cased hole interval
    - Samples of this scale/buildup may be taken to design effective treatment strategies
- Reperforating.

Note that this list is not intended to be an exhaustive list of potential treatment methods, chemical treatments, or chemical additives.

If it is determined that stimulation is needed to increase permeability of the injection zone, then a proposed stimulation procedure will be submitted in writing to the Director at least 30 days in advance. This proposal will have a description of the treatment, chemicals to be used, and procedures to be followed. A safety data sheet will be provided for all chemicals used during stimulation activities.

All chemical treatments will be performed at working pressures less than the determined fracture pressure of the formation unless otherwise specified. The safe working pressure will be determined using hydrostatic pressure calculations, equipment ratings, materials of construction, and other pertinent details. Details on such calculations will be provided in the notification of stimulation activities.

3. References

American Petroleum Institute. (1994). *API BULL 5C3. 6th Edition.* API.
(2023). *Attachment 1: Project Narrative.* Class VI Permit Application Narrative; Vervain.
(2023). *Attachment 2: AoR and Corrective Action.* Class VI Permit Application Area Of Review And Corrective Action Plan; Vervain.
(2023). *Attachment 5: Pre-Op Testing Program.* Class VI Permit Application Pre-Operational Formation Testing Program; Vervain.
(2023). *Attachment 6A: NV_INJ1 Well Operations Plan.* Class VI Permit Application Injection Well #1 Operations Plan; Vervain.
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Attachment 4B: Injection Well #2 Construction
40 CFR 146.82(a)(9), (11), and (12)
Vervain Project, McLean County, Illinois
24 March 2023

Navigator CO_2

Facility Information

Project Name:	Vervain
Project Operator:	Heartland Greenway Carbon Storage, LLC
Project Contact:	Tyler Durham, SVP and Chief Development Officer 13333 California St., Suite 202, Omaha, NE 68154 Phone: 402-520-7089 Email: tdurham@navco2.com
Project Location:	Vervain Injection Well #2 CO_2 Injection Well Location Latitude 40°18’8.36” N Longitude 89°14’32.73” W

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List of Acronyms

API	American Petroleum Institute
APT	Annulus Pressure Test
BHP	bottomhole pressure
BOPs	blow out preventers
CBL	cement bond log
CCS	carbon capture and sequestration
DST	drill stem test
EOR	enhanced oil recovery
EPA	Environmental Protection Agency
fbgl	feet below ground level
FOT	fall-off test
HCl	hydrochloric
HF	hydrofluoric
IAC	Indiana Administrative Code
KCl	potassium chloride
LTC	long thread coupling
MAIP	maximum allowable injection pressure
Mtpa	million tonnes per annum
NV_INJ1	Vervain Injection Well #1
NV_INJ2	Vervain Injection Well #2
NV_OBS1	Vervain Deep Observation Well
POOH	pull out of hole
ppg	pounds per gallon
SCADA	supervisory control and data acquisition
SDS	safety data sheet
STC	short thread coupling
TD	total depth
USDW	Underground Source of Drinking Water
US	United States
WBM	water-based mud

Change Log

Item Changed	Date	Version	Description
	3/24/2023	V1.1	Reorder document to better match 40 CFR 146.86
Pg 8 Figure 1	3/24/2023	V1.1	Added a depiction of the downhole P/T gauges to the wellbore schematic
Pg 15 Sec 1.2	3/24/2023	V1.1	Added wording stating all components exposed to wet CO2 will use corrosion resistant materials
Pg 17 Table 6	3/24/2023	V1.1	Added internal and external pressures used to determine casing safety loads shown in Table 6
Pg 18 Sec 1.2.1	3/24/2023	V1.1	Description of CO2 stream temperatures
Pg 20	3/24/2023	V1.1	Corrected differential rating of packer to 10,000 psi
Pg 21 Sec 1.3.6	3/24/2023	V1.1	Added information about formation fluids referenced to the project narrative

1. Injection Well Construction

This section summarizes the methods and materials to be used for the construction of the Vervain Injection Well #2 (NV_INJ2). Schematics of the well that illustrates the construction, are provided within the contents of this document. Please note that these schematics are not meant to portray final products and are subject to change pending availability of materials listed and the completion of well installation. The work will be performed in accordance with guidance documents, approved work plans, and reporting timelines as approved by the United States (US) Environmental Protection Agency (EPA). NV_INJ2 will be constructed with multiple casing strings, each string smaller in diameter than the previous and cemented to surface to provide multiple layers of protection for Underground Sources of Drinking Water (USDWs).

Downhole pressure and temperature gauges will be installed just above the packer [redacted]. The downhole pressure gauge will be used to help ensure that the maximum allowable injection pressure (MAIP) does not exceed 90% of the fracture pressure. The downhole temperature gauge will be used to calculate the bottomhole density and volume of the injected fluid. The BHP gauges will be programed to take data at the intervals outlined in the testing and monitoring program section of this application (Attachment 7: Testing And Monitoring, 2023). The data collected from these measurement systems will be collected continuously and sent to a surface SCADA system. More information about these sensors is provided in the Well Operations and Testing and Monitoring Plans (Attachment 6B: NV_INJ2 Well Operations Plan, 2023), (Attachment 7: Testing And Monitoring, 2023).

The injection well proposed in this document will be constructed as a new well. Due to the high potential for lost circulation through the Knox interval an intermediate string [redacted] will be run and set in the Davis Formation. The injection well will then be drilled into the Precambrian Granite Basement (basement) with enough hole present such that the basement rock can be properly characterized. It is noted that the deep observation well (NV_OBS1) will potentially serve to collect the basement characterization data. Should that be the case, NV_INJ2 will not be used to characterize the basement.

Once the basement characterization data has been collected, whether in NV_INJ1, NV_INJ2 or NV_OBS1, the open basement section will be plugged back to the injection zone such that the CO_2 will not be directly injected into the basement. This will be done prior to running and cementing the long string casing in place.

Figure 1 displays a schematic of the proposed well construction for NV_INJ2. Figure 2 displays a schematic of the proposed wellhead for NV_INJ2.

The Lower Mt. Simon Sandstone and the Arkose Sandstone are the targeted injection zone for the project [redacted]. The Upper and Middle Mt. Simon [redacted] could serve as secondary storage as CO_2 migrates due to density effects. The Eau Claire Shale [redacted] serves as the primary confining layer for the project. The base of the Eau Claire Formation is a siltstone to very fine-grained sandstone known as the Eau Claire Siltstone and is in gradational contact with the Mt. Simon Sandstone.

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[redacted]

Figure 1: NV_INJ2 Injection Well Construction Proposed Schematic

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[redacted]

Figure 2: NV_INJ2 Injection Wellhead Proposed Schematic

1.1. Construction Procedures 40 CFR 146.82(a)(12)]

This section details the procedures that will be followed during the drilling, completion, and testing portions of the NV_INJ2 installation. Note that these procedures are subject to change based upon field conditions and/or the availability of equipment/materials. An updated and detailed procedure will be provided prior to well construction.

1.1.1. Drilling Procedures

1. [redacted] conductor casing will be driven [redacted] into the ground before the drilling rig arrives on location to commence drilling operations.
2. A [redacted] bit will be used to drill [redacted] below the base of the Mahomet Aquifer. Sufficient rat hole should be drilled such that openhole and cased hole logs can be run to assess the entire Mahomet Aquifer.
    a. The drilling mud in this section of the hole will be water-based mud (WBM).
3. At the section TD, the hole will be circulated clean, and the drill string will be POOH.
4. Openhole logs will be run across the openhole interval (conductor casing shoe to the section TD).
    a. Log run details are provided in Section 4.
    b. Cement volumes for this hole section will be determined based on the results of the caliper log.
5. [redacted] surface casing will then be run to the section TD.
    a. The casing will be run as follows (bottom to top):
        i. Float shoe
        ii. One joint of casing
        iii. Float collar
        iv. Casing to surface
    b. One centralizer will be used every third joint to surface.
6. The [redacted] casing will be cemented [redacted].
    a. Wet samples will be collected during mixing.
    b. After pumping all cement, a plug will be dropped, and the cased hole volume will be displaced with water.
7. After allowing cement to harden approximately 24 hours, cased hole logs will be run to assess the overall bond quality of the cement.
    a. Details on the logs that will be run are provided in Section 4.
8. Once the bond is of sufficient quality, nipple up blow out preventers (BOPs) and test per API Standard 53.
9. Once the BOPs have been nippled up and tested, the casing will be tested to at least twenty percent (20%) greater than the anticipated maximum pressure to which the casing will be exposed for a minimum of thirty (30) minutes with a pressure drop of no more than ten percent (10%).
    a. The pressure to be used for testing will be provided as part of the final installation procedures to be made available prior to the installation of the well.
10. A [redacted] bit will be used to drill [redacted] the Davis Formation [redacted] Sufficient rat hole will be drilled such that openhole and cased hole logs can be run to assess the entire intermediate section of the well.
    a. The drilling mud in this section of the hole will be water-based mud (WBM).

   b. Lost circulation is anticipated in the Knox interval. Mud losses will be controlled by various means including LCM and cement plugs as necessary to reach section TD.
11. At the section TD, the hole will be circulated clean, and the drill string will be pulled out of hole.
12. Openhole logs will be run across the openhole interval (surface casing shoe to the section TD).
    a. Details on the logs that will be run are provided in Section 4.
    b. Cement volumes for this hole section will be determined based on the results of the caliper log.
13. 13.375-inch intermediate casing will then be run to the section TD.
    a. The casing will be run as follows (bottom to top):
        i. Float shoe
        ii. One joint of casing
        iii. Float collar
        iv. Casing to surface
    b. One centralizer will be used every 3rd joint to surface with one centralizer used every joint for three joints above and below the surface shoe joint.
14. The [redacted] casing will be cemented [redacted].
    a. Wet samples will be collected during mixing.
    b. After pumping all cement, a plug will be dropped, and the cased hole volume will be displaced with water.
15. After allowing cement to harden for approximately 24 hours, cased hole logs will be run to assess the overall bond quality of the cement.
    a. Details on the logs that will be run are provided in Section 4.
16. Once the bond is of sufficient quality, blow out preventers (BOPs) will be nippled up and tested per API Standard 53.
    a. BOPs will already be installed prior to drilling the intermediate hole section. BOPs might need to be changed out and retested to accommodate the [redacted] casing string.
17. After the cement has been allowed to harden for at least 24 hours, the casing will be tested to at least twenty percent (20%) greater than the anticipated maximum pressure to which the casing will be exposed for a minimum of thirty (30) minutes with a pressure drop of no more than ten percent (10%).
18. Once the intermediate string has been set, a [redacted] bit will be used to drill the long string section.
    a. The drilling mud in this section of the hole will be WBM.
    b. While drilling this section, the drilling assembly will be run out of the hole to capture a [redacted] whole core in both the Eau Claire Formation and Mt. Simon Sandstone.
19. At the section TD, the hole will be circulated clean, and the drilling string will be pulled out of hole.
20. Openhole logs will be run across the openhole interval (intermediate casing shoe to the section TD).
    a. Details on the logs that will be run are provided in (Attachment 5: Pre-Op Testing Program, 2023)

   b. Cement volumes for this hole section will be determined based on the results of the caliper log.
21. A drill stem test (DST) tool will be run into the Mt. Simon Sandstone to collect a fluid sample for analysis.
   a. If a DST is not run at this time, the well will be swabbed to collect a representative fluid sample during the well completion operations.
22. A [redacted] string casing will be run to [redacted]
   a. The casing will be run as follows (bottom to top):
      i. Float shoe (13Cr80, or similar suitable metallurgy)
      ii. Two joints of casing (13Cr80)
      iii. Float collar (13Cr80, or similar suitable metallurgy)
      iv. 13Cr80 casing [redacted]
      v. Stage Tool set [redacted].
      vi. L80 steel casing to surface
   b. One centralizer per joint will be utilized for the 13Cr80 casing. One centralizer every third joint will be utilized for the L80 steel casing with one centralizer used every joint for three joints above and below the Stage Tool and the intermediate shoe joint.
23. The [redacted] casing will be cemented using a system that uses either EverCRETE or WellLock as a tail system below the Stage Tool, [redacted] above the Stage Tool.
   a. The top of the tail cement is targeted to be above the top of the Eau Claire Formation.
   b. Wet samples will be collected during mixing.
   c. After pumping the tail system (Stage 1 cement or resin), a plug will be dropped to open the stage tool, and the lead system (Stage 2 cement) will be pumped to surface. Once completed, a plug will be dropped, and the cased hole will be displaced with water.
24. After the cement and/or resin has been allowed to harden for at least 48 hours, the casing will be tested to at least twenty percent (20%) greater than the anticipated maximum pressure to which the casing will be exposed for a minimum of thirty (30) minutes with a pressure drop of no more than ten percent (10%).
   a. The pressure to be used for testing will be provided as part of the final installation procedures to be made available prior to the installation of the well.
25. The drilling rig will be disassembled. The BOPs will also be nippled down and a Night Cap will be installed.

The subsurface and surface design (casing, cement, and wellhead) exceeds the minimum requirements to sustain the integrity of the confining interval to ensure that the CO_2 remains in the Mt. Simon Sandstone. The final well design meets strength and CO_2 compatibility requirements. This procedure concludes the drilling portion of the well installation.

1.1.2. Well Deviation Survey Plan

The wellbore trajectory will be surveyed every 500 feet of depth to ensure the well has less than 5° inclination. These surveys will be performed using a wireline conveyed, timer-based survey tool. The following presents the survey plan and tolerances:

- If the wellbore trajectory is more than 1° inclination, then the wellbore trajectory will be surveyed every 250 feet of depth.
- If the wellbore trajectory is 2° or more inclination, then the wellbore trajectory will be surveyed every 100 feet.
- This will be repeated until the wellbore is within 1° of inclination.

1.1.3. Completion Procedures

The completion portion of the well installation is detailed below. Note that these procedures are subject to change as based on field conditions or the availability of equipment or materials. A detailed procedure will be provided prior to the installation of the well.

1. A workover rig will be installed, and BOPs will be nippled up. The BOPs will be tested per API Standard 53.
2. Cased hole logs will be run to assess the overall bond quality of the cement.
    b. Details on the logs that will be run are provided in (Attachment 5: Pre-Op Testing Program, 2023).
        i. These logs may or may not be run prior to the workover rig being on location.
        ii. Two runs will likely be performed, 1) under anticipated operation pressure, 2) under no pressure.
3. The Lower Mt. Simon sandstone and the Arkose sandstone will be perforated in select intervals.
    c. It is currently anticipated that the entire Lower Mt. Simon sandstone and the Arkose sandstone intervals will be perforated from the top to the bottom.
    d. This implies a perforated interval [redacted].
4. Following the perforations, acid will be bullheaded into the well to clean up the perforations.
    e. Should the well need to be swabbed for a fluid sample, it would be done at this time.
5. The [redacted] packer assembly will be run in on work string as follows:
    f. Blow-out disk (2k)
    g. 1 joint [redacted]
    h. [redacted] packer
    i. Stinger On/Off tool
    j. Work string
6. Once the packer has been set, the work string will be stung off the packer and run out of hole.
7. The [redacted] injection tubing will be run in the hole as follows:
    k. On/Off tool
    l. Crossover
    m. [redacted] tubing to surface
    n. Crossover
    o. Landing joint
8. Once the injection tubing has been latched onto the packer, the BOPs will be closed, and a preliminary annulus pressure test (APT) will be performed.
    p. The APT will be run as detailed in (Attachment 5: Pre-Op Testing Program, 2023)

9. After the APT has been successfully completed, the [redacted] tubing will be stung off the packer and the annulus will be displaced with the treated annulus fluid.
    q. This treated annulus fluid will be comprised of one, or more, of the following:
        i. Fresh water
        ii. Packer fluid
        iii. Inhibiters
        iv. Biocide
        v. Scale reducer
10. Once this annulus fluid has been pumped, the [redacted] tubing will be stung onto the packer, and the tubing will be landed in the tubing hanger.
11. After the tubing hanger is landed, a final APT will be run.
12. The BOPs will be nippled down, and the wellhead will be installed.
13. Following the installation of the wellhead.
14. The workover rig will be rigged down, and the well installation will be considered complete.

1.1.4. Testing Procedure

The testing portion of the well installation is detailed below. Note that these procedures are subject to change as based on field conditions or the availability of equipment or materials. A detailed procedure will be provided prior to the installation of the well. These procedures are consistent with those provided in Section 4. Testing will use the permanent downhole pressure gauges.

1. Rig up pump truck and the associated auxiliary equipment. Ensure proper fluid is on location for injection testing.
2. Pressure test pump truck equipment.
3. Blow out the burst disk.
4. Run step-rate test as detailed in (Attachment 5: Pre-Op Testing Program, 2023).
5. Run FOT as detailed in (Attachment 5: Pre-Op Testing Program, 2023).
6. Rig-down pump truck.
7. Secure the well.

1.2. Hole Sections and Cement Information 40 CFR 146.86 (b)

Table 1 provides a summary of the open-hole sections of the NV_INJ2 injection well construction. All depths provided in the table are in reference to feet below ground level (fbgl).

Table 1: Openhole Section Diameters and Intervals

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[redacted]

Table 2 provides a summary of the casing strings to be used in construction of the injection well. All casing (weight, grade, and threading) to be used will conform with American Petroleum

Institute (API) standards. All components selected for construction that will be exposed to wet carbon dioxide (CO_2) will use corrosion resistant materials. The casing and cementing plans are designed to ensure the injected CO_2 stays within the Mt. Simon Sandstone and prevents upward migration of injection zone fluids from reaching the deepest USDW (the St. Peter Sandstone).

Table 2: Casing String Setting Depths, Diameters, and Specifications

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[redacted]

Table 3 provides a summary of the cement systems for use on the casing strings during the injection well construction. All cement systems used will conform with API standards. Note that the excess cement pumped is subject to change pending field results. Cement will be pumped with the following open-hole excess:

- Surface – 100% excess
- Intermediate – 50% excess
- Long string – 30% excess

The well design uses CO_2 resistant cement or resin for the long string. Two options are introduced in this section: EverCRETE CO_2 resistant cement system from Schlumberger and WellLock™ or ThermaLock™ resin systems from Halliburton. These systems are stable in extreme acidic conditions, highly resistant to the CO_2 stream and formation fluids in the Mt. Simon Sandstone, and of sufficient quality to maintain integrity over the design life of the NV_INJ2 injection well.

Table 3: Cement System Details for each Hole Section.

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[redacted]

The surface and intermediate casing cement systems will provide the required isolation of the deepest USDW. The deepest USDW is currently anticipated to be in the St. Peter Formation as defined by the Illinois State Geological Survey (Attachment 1:Project Narrative, 2023). The intermediate casing and cement will isolate the deepest USDW from the CO_2 injected into the Mt. Simon Sandstone. The cement and cement system used will conform with API standards.

The quality of the bond between the cement, casing, and borehole will be verified by the cased hole logs that will be run after each string of casing is cemented in place (Attachment 5: Pre-Op Testing Program, 2023). The long string lead cement system used will conform with API standards. The tail cement system will be either an EverCRETE or WellLock system.

As with the surface cement section, the quality of the bond between the cement, casing, and borehole will be verified using cased hole logs (Attachment 5: Pre-Op Testing Program, 2023). These cased hole logs include a cement bond log (CBL) with radial arms, Ultrasonic Cement Evaluation, Temperature, and Pulsed Neutron. Table 4 provides a summary of the tubing and packer system to be used in the construction of NV_INJ2.

The 13-Chrome (13Cr80) casing string has been confirmed as suitable for CO_2 service by the engineers at Sumitomo who produce the casing tubulars (Nippon Steel, 2022). 13Cr80 casing, or a suitable replacement, will be used during well construction. The manufacturers of the pipe, Nippon Steel, have confirmed the materials as suitable for routine, or flowback operations. [redacted]

Table 4: Tubing and Packer Setting Depth, Diameters, and Specifications

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[redacted]

The tubing will consist of internally coated carbon steel tubing provided by Tuboscope™, a National Oilwell Varco (NOV) product. This coating consists of TK-15XT and has been field-proven to be suitable for more extreme cases of EOR. Material specifications and suitability for use documentation is provided in this document (Tuboscope - NOV Wellbore Technologies, 2017).

The Signature F™ Injection packer system from Baker Hughes will be used for this project. The packer can be used with either a retrievable or permanent configuration and will be internally and externally coated with chrome and nickel to resist corrosion effects of the CO_2 stream. The Baker Hughes engineers confirmed that the chrome/nickel plating is suitable for the required service. Materials specifications and suitability for use document is provided in this document (Baker Hughes, a GE Company, 2019).

1.2.1. Casing and Cementing

Design analysis was performed to evaluate the casing selection. This analysis included reviewing the burst, collapse, tensile loads, and a Von Mises analysis, using Lame's equations, that were anticipated to be experienced as a part of the casing installation and normal well operation. Prior to performing any analyses on design criteria, an 80% derating factor was applied to the pipe ratings. This 80% derating equates to a base 1.2 safety factor.

The equation to determine the safety factor is provided below,

$$SF = \frac{Pipe\ Rating}{Load}$$

In addition to this derating, additional, standard derating was performed. The yield strength of the pipe was derated based on applied tensile loading, this consisted of a biaxial analysis. This is consistent with the method presented in API Bulletin 5C3, Formulas and Calculations for Casing, Tubing, Drill pipe and Line Pipe Properties (American Petroleum Institute, 1994). Cyclical loading was considered in the analysis performed by Baker (Baker Hughes InQuest TUBEMOVE, 2022).

This derating is only considered when evaluating collapse parameters under tension. Compressive analysis was not performed on the casing strings, as they are not anticipated to undergo any major compressive loads except for when being run in-hole. Standard API equations were used to calculate all design ratings and loads. The safety factors utilized for analysis are provided in Table 5.

Table 5: Casing Safety Factors for Design.

Burst	Collapse	Tensile
1.2	1.2	1.5

The results of the analyses are provided in Table 6.

Table 6: Casing Safety Factor Loads for Design.

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[redacted]

Sensitive, Confidential, or Privileged Information [redacted]. It is not anticipated that this temperature differential is of a large enough magnitude to impact the performance of the casing and cement over the life of the project. Table 7 and Table 8 provide casing and tubing details and design parameters, respectively.

Table 7: Casing and Tubing details

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Table 8: Casing and Tubing Design Parameters

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1.3. Additional Design Considerations 40 CFR 146.86 (c)

Table 6 provides information on the design ratings for the injection tubing and packer. This section discusses the application of these design ratings to ensure the suitability of the construction materials for this project.

A safety factor of 20% has been used to evaluate the materials of construction. As such, all ratings have been derated to 80% of their initial ratings. All comparative evaluations detailed in this section are in reference to these derated values.

[redacted]

[redacted] As such, the well and analysis of well conditions have been performed based on this consideration.

1.3.1. Injection Pressure Considerations

[redacted]. This proposed value is discussed in further detail in the Well Operations section of this permit application (Attachment 6B: NV_INJ2 Well Operations Plan, 2023). The injection pressure will not exceed 90% of the formation fracture pressure and for purposes of this application a safety factor of 80% is assumed, [redacted]

Table 9: Bottomhole Pressure Considerations.

[redacted]

The maximum allowable bottomhole injection pressure is approximately 51.5% of the derated burst rating of the tubing. This assumes the annulus space is evacuated, which is an extremely improbable event.

[redacted]

The maximum allowable bottomhole injection pressure is approximately 32% of the differential rating for the packer. This assumes the annulus space is evacuated, which is an extremely improbable event. Based on these worst-case analyses, the tubing and packer to be used for this project are acceptable.

1.3.2. Annulus Pressure Considerations

The proposed operating annular pressure range at surface [redacted]. Based on this range, the maximum proposed annular pressure downhole will be calculated based on the hydrostatic pressure of [redacted] KCl brine (with additives) at the packer added to the maximum anticipated annular pressure.

[redacted]

The tubing is sufficiently designed such that the worst-case scenario is less than the derated collapse rating.

Additionally,

[redacted]

The packer is sufficiently designed such that the worst-case scenario occurs at a pressure that is less than the rated pressure differential.

During operations, this worst-case scenario of an evacuated portion of the well is extremely improbable.

1.3.3. Formation Pressure Considerations (During Initial Completions)

Prior to the start of injection operations, the injection zone will be in a static state, which means that the formation pressure should be considered in the design criteria. [redacted]

[redacted]

The packer is sufficiently designed such that the worst-case scenario of pressure differentials prior to injection beginning is approximately 16% of the rated pressure differential of the packer.

Further, when examining the collapse rating in a worst-case scenario during initial completion,

[redacted]

The injection tubing is sufficiently designed such that the worst-case scenario during the initial completion is 81% of the derated collapse rating of the pipe.

1.3.4. Tensile Loading Considerations

[redacted]

1.3.6. Corrosion Considerations

[redacted] All components selected for construction that will be exposed to wet CO_2 will use corrosion resistant materials. Verification of the suitability for these components is provided with this document and referenced in previous sections and subsections.

Refer to the corrosion monitoring in testing and monitoring plan for corrosion monitoring of the materials of construction (Attachment 7: Testing And Monitoring, 2023). In addition, regular sampling and monitoring of the CO_2 stream will be performed, as detailed in the testing and monitoring plan.

Details and specifications of the corrosivity of the CO_2 and projected chemical content, temperature and density have been provided within the AoR, well operations, and testing and monitoring sections of this permit application.

1.3.7. Operational Considerations

Emergency shut-down equipment will be used at the surface for this project. Details on this equipment are provided in the well operation section as well as the testing and monitoring section (Attachment 6B: NV_INJ2 Well Operations Plan, 2023), (Attachment 7: Testing And Monitoring, 2023).

Surface monitoring equipment, as detailed in the testing and monitoring section, will be connected to the surface Supervisory Control and Data Acquisition (SCADA) system.

Permanent downhole gauges used to monitor pressure and temperature at the packer will be utilized for this project. These gauges will be landed in a gauge nipple above the packer. These gauges will transmit data through a wire, run up the annulus, to the SCADA system.

Tubulars have been designed such that logging tools and other equipment needed for routine and annual monitoring will be able to pass through with no restrictions.

2. Proposed Stimulation Program [40 CFR 146.82(a)(9)]

Based on analysis from the ADM CCS1 well in Illinois, it is unlikely that any well stimulation, such as hydraulic fracturing, will be required upon initial completion of the injection well. If there appears to be significant reduction in actual permeability and porosity compared to the analyzed core data and information gathered during the fluid injection test, then a stimulation program may be considered.

Routine well or formation remediation might be necessary to reduce lost injectivity due to routine injection operations. Lost injection capacity may be due to geochemical reactions, scale build-up, or pore throat plugging amongst other things.

Should injection capacity be diminished enough to impact the effectiveness of the well, chemical or mechanical remediation may be required. Such remediation may occur using one, or more of the following methods:

- Bullhead acid stimulation – an acid such as hydrochloric (HCl) acid will be used in a dilute concentration (i.e., 7.5%-15%) with other potential additives (citric acid, scale reducer, defoamer, etc.).
    - Acid will be pumped down the injection string and be allowed to soak in the near wellbore area before being pushed into formation or flushed back up to surface.
- Bullhead acid stimulation with mud acid – HCl and hydrofluoric (HF) acid mix will be used with potential additives.
- Coil tubing acid stimulation – HCl will be used with potential additives.

    - Coil tubing will be used to nitrify and place the acid over specific intervals. Acid will be allowed to soak and will be pushed into the formation or flushed back up to surface.
- Coil tubing acid stimulation with mud acid – HCl and HF acid mix will be used with potential additives.
- Coil tubing chemical treatment – should certain precipitates require treatment using fluids other than acid, targeted chemical remediation will be performed.
- Coil tubing clean out – mechanical cleaning of scale and buildup from the cased hole interval
    - Samples of this scale/buildup may be taken to design effective treatment strategies
- Reperforating.

Note that this list is not intended to be an exhaustive list of potential treatment methods, chemical treatments, or chemical additives.

If it is determined that stimulation is needed to increase permeability of the injection zone, then a proposed stimulation procedure will be submitted in writing to the Director at least 30 days in advance. This proposal will have a description of the treatment, chemicals to be used, and procedures to be followed. A safety data sheet will be provided for all chemicals used during stimulation activities.

All chemical treatments will be performed at working pressures less than the determined fracture pressure of the formation unless otherwise specified. The safe working pressure will be determined using hydrostatic pressure calculations, equipment ratings, materials of construction, and other pertinent details. Details on such calculations will be provided in the notification of stimulation activities.

3. References

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