CONSTRUCTION DETAILS

Kern River Eastridge CCS Project

Facility Information

Facility name:	Kern River Eastridge CCS
Well:	MC19001INJ
API No.	Not yet assigned
Facility contact:	David Wessels – Project Manager 9525 Camino Media, Bakersfield, CA 93311 David.wessels@chevron.com / 661-412-6039
Well location:	Bakersfield, Kern County, CA 93308
Lat.- Long.:	35.4404°/-118.9983°

Introduction

The well construction details in this document apply to a new CO_2 injection well. The well will be drilled and completed as a Class VI CO_2 injection well.

Well Construction Process

Conductor casing will be set for drilling and cementing the first surface casing.

The first surface casing hole will be drilled to 1,425 ft. The field rules do not allow the surface casing to be drilled deeper than 1,500 ft. Deviation check surveys will be taken while drilling (40 CFR 146.87(a)(1)). Open hole logs including resistivity, spontaneous potential, caliper, and gamma ray will be run prior to running casing (40 CFR 146.87(a)(2)(i)). The first surface casing will be run and cemented to surface. After the cement sets, a cement bond and variable density log and a temperature log will be run (40 CFR 146.87(a)(2)(ii)).

The second surface casing hole section will be drilled to the base of the Freeman-Jewett Silt (confining layer). Deviation check surveys will be taken while drilling (40 CFR 146.87(a)(1)). Open hole logs including resistivity, spontaneous potential, caliper, and gamma ray will be run prior to running casing (40 CFR 146.87(a)(2)(i)). The second surface casing will be run and cemented to surface to isolate the USDW zones as required by 40 CFR 146.86(a)(1) and 40 CFR 146.86(b)(2). After the cement sets, a cement bond and variable density log and a temperature log will be run (40 CFR 146.87(a)(2)(ii)).

The injection casing hole section will be drilled to the base of the 5th Vedder Sand. Deviation check surveys will be taken while drilling (40 CFR 146.87 (1)). Open hole logs including but not limited to resistivity, spontaneous potential, porosity, caliper, gamma ray, and fracture finder logs will be run prior to running casing (40 CFR 146.87(a)(3)(i)). The injection casing will be

run and cemented to surface (40 CFR 146.86(b)(3)). After the cement sets, a cement bond and variable density log, casing inspection log and a temperature log will be run (40 CFR 146.87(a)(3)(ii)).

The injection string casing design will consist of materials compatible with exposure to the injected fluids (40 CFR 146.86(b)(1)). Casing conveyed DAS fiber optics will be run on the injection string casing for testing and monitoring purposes. Refer to the Testing and Monitoring plan or Quality Assurance and Surveillance Plan for more details. The cement and additives will be compatible with the injection and formation fluids as required by 40 CFR 146.86(b)(5). Casing centralizers will be used to centralize the casing to 70% standoff or greater as per 40 CFR 146.86(b)(3). All well construction materials comply with American Petroleum Institute (API) and American National Standards (ANSI) Recommended Practices, Specifications and Standards.

The injection well will be completed by perforating the authorized injection zones. Completion equipment, consisting of packers, monitoring equipment, and tubing will be installed. The flow wetted components of the packer and wellhead will also use material compatible with the injected fluid. Noncorrosive packer fluid treated with corrosion inhibitors and biocide will be circulated in the tubing-by-casing annulus as per 40 CFR 146.88(c).

Well Design

Table 4 shows the proposed casing setting depths and casing specifications.

Directional

The well will be drilled as a directional well. Directional surveys will be taken as the well is drilled. Figure 1 shows the planned directional profile.

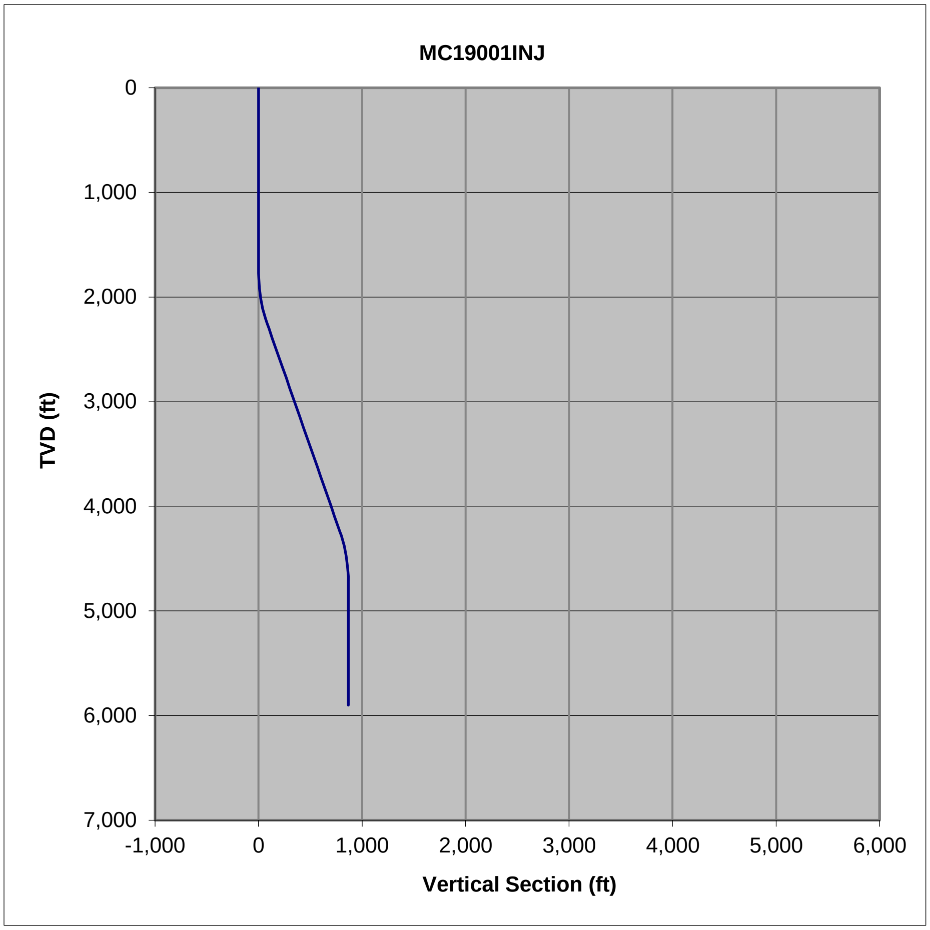

Figure 1: Proposed Directional Plan

Cementing

First Surface Casing

The first surface casing cement will be circulated to surface. Top and bottom wiper plugs will be used to minimize contamination.

The casing will be cemented with a 12 ppg surface casing slurry with the top of cement at surface as required by 40 CFR 146.86(b)(2).

Excess slurry volume of 50 – 100% will be pumped to circulate cement to surface. Excess will depend on hole conditions specific to the well.

Second Surface Casing

The casing will be cemented with a 12 ppg surface casing slurry with the top of cement at surface to isolate the USDW zones as required by 40 CFR 146.86(b)(2).

Excess open hole slurry volume of 50 – 100% will be pumped to circulate cement to surface. Excess volume will depend on hole conditions specific to the well.

Injection Casing

The casing will be cemented to surface as required by 40 CFR 146.86(b)(3) with a CO_2 resistant cement blend. The slurry density will be 13 ppg.

Excess slurry volume of 25 – 50% in the open hole section will be used to circulate cement to surface. An open hole caliper log will be used to estimate the annulus volume and the excess volume will ensure cement to surface.

The casing will be centralized (40 CFR 146.86(b)(3)) to provide 70% or greater stand-off.

Casing conveyed DAS fiber optics will be run for testing and monitoring purposes. Refer to the Testing and Monitoring Plan or Quality Assurance and Surveillance Plan (QASP) for more details.

Cement Bond, Temperature, and Inspection Logs

After the injection string casing has been cemented, a cement bond and variable density log and a temperature log will be run as required by 40 CFR 146.87(a)(3)(ii) to verify an annular seal. A baseline wall thickness inspection log will also be run.

Tubing and Packer

Injection will be through tubing and multiple packers per 40 CFR 146.86(c)(2). Materials for the tubing and packer are shown in Table 5 and Table 6 and were selected for compatibility with the injected fluids and reservoir fluids as required by 40 CFR 146.86(c)(1). The packers will be set in the casing opposite a cemented interval. The setting depths will be selected based on an evaluation of the CBL after the casing is run and cemented.

The tubing size was selected based on the proposed injection rate, composition, reservoir conditions, and monitoring equipment. The fluid flow model PROSPER[1] was used to determine the pressure and temperature profiles for CO_2 injection. PROSPER has PVT correlations that have been validated for CO_2 injection.

Proposed Perforations

Through the project life, Chevron plans to target individual zones within the Vedder Sand with tubing and packer completions, starting with the deepest target and recompleting into increasingly shallower Vedder Sand intervals through time as necessary based upon monitoring data. With each recompletion, Chevron plans to update operating constraints based upon any wellbore changes (e.g., additional perforations for shallower Vedder Sand targets).

Proposed perforations will be selected based on the injection zones in each well.

Table 1 shows the proposed perforations intervals for the wells.

[1] https://www.petex.com

Table 1: Proposed Perforations, Measured Depth

Zone	MC19001INJ Perforations
Top 1st Vedder Perf	5,036
Base 1st Vedder Perf	5,096
Top 2nd Vedder Perf	5,300
Base 2nd Vedder Perf	5,360
Top 3rd Vedder Perf	5,574
Base 3rd Vedder Perf	5,634
Top 4th Vedder Perf	5,843
Base 4th Vedder Perf	5,903

Maximum Surface Pressures and Mechanical Integrity

The operating injection pressure will depend on the reservoir pressure, the properties of the injected fluid, the wellbore friction, and the rate. PROSPER, a modeling software package, was used to determine the pressure and temperature profiles for CO_2 injection. PROSPER has PVT correlations that have been validated for CO_2 injection.

The annulus pressure will be maintained at a pressure higher than the tubing injection pressure as required by 40 CFR 146.88(c). The design surface pressure loads on the injection tubing and tubing by casing annulus are as follows:

- Maximum tubing injection pressure 1,950 psi
- Maximum annulus pressure 2,050 psi

The maximum tubing injection and shut-in pressures are based on PROSPER flow assurance modeling. The maximum annulus pressure is higher than the maximum injection pressure as required by 40 CFR 146.88(c).

After each casing is set and cemented, and after the tubing and packer are installed, they will be pressure tested to a pressure equal to or greater than the design pressure for that component to demonstrate mechanical integrity.

Material Selection

The material selected for the flow wetted well construction components within the reservoir, including the lower tubing and lower injection casing below the packer, is 25 Cr. Glass reinforced epoxy (GRE) lined tubing will be used above the packer as it will be exposed to the CO_2 stream during injection. Standard carbon steel alloy casing will be used for the injection casing above the packer as it is not planned to be exposed to CO_2 during the lifecycle of the well. Modeling results and supporting literature (see References) confirmed an acceptable corrosion rate for 25 Cr material for the life of the project to meet the well materials compatibility requirement in 40 CFR 146.86(b)(1).

Downhole Monitoring

Downhole monitoring equipment includes (a) a dual transducer pressure/temperature gauge run on tubing above packer and (b) distributed acoustic sensor (DAS) cable on the casing.

Safety System for Injection Wells

The well monitoring system will consist of surface sensors for measuring temperature, pressure, and flow rate. Data from the sensors will be collected and stored in a Supervisory Control and Data Acquisition (SCADA) system. Monitored parameters will have high and low alarms that will be activated when a measured parameter is outside its normal operating range. When a critical parameter alarms, such as pressure, the well will be shut in by a fail-safe actuated gate valve that is a component of the injection tree. Operating personnel will be notified that an alarm was activated. The reason for the alarm will be investigated to determine what needs to be done to make sure the well is safe. After any needed repairs or maintenance are conducted, the well will be put back into service.

A landing nipple profile will be installed near the packer to allow setting a plug or other downhole safety device if required for well maintenance and servicing. Figure 2 shows a schematic of the safety system.

The detailed design, equipment specification, and selection will be completed and submitted to the EPA prior to project startup.

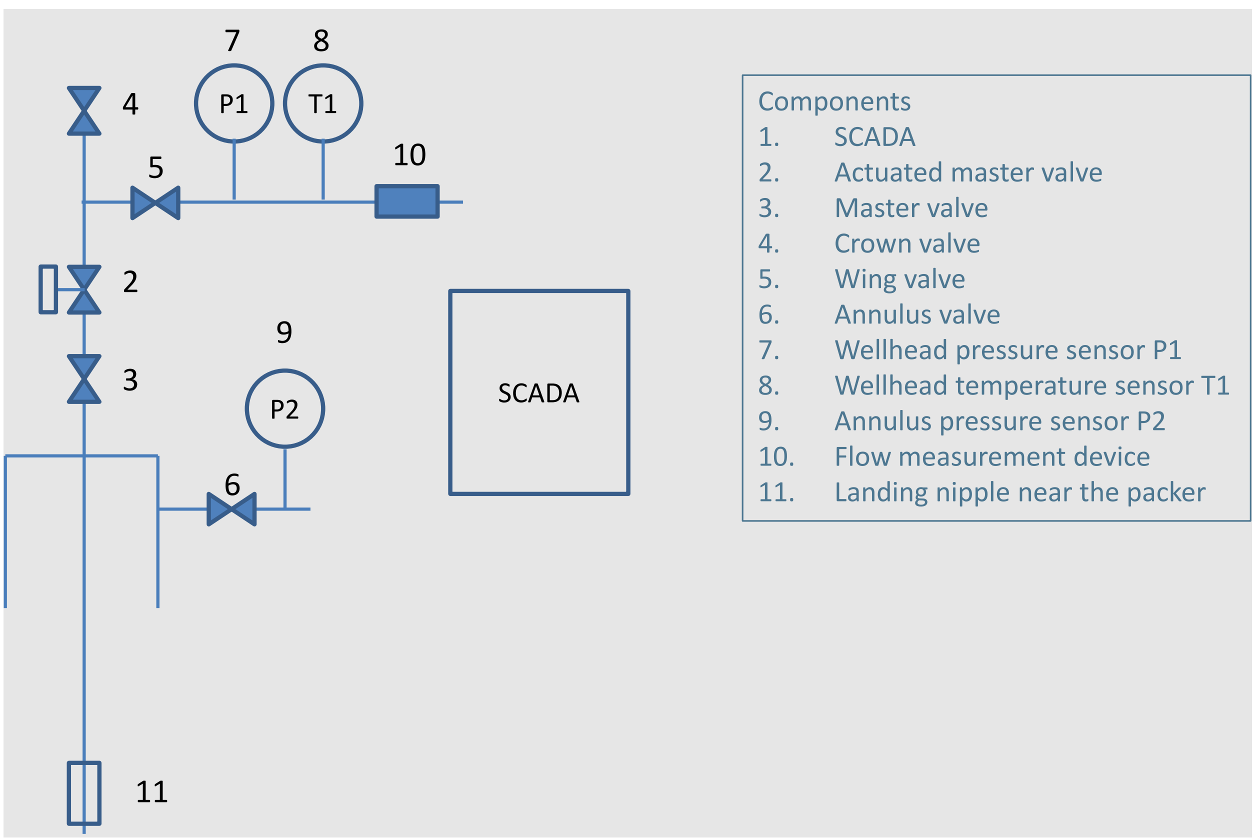

Figure 2: Safety System

Injection Well Casing and Tubing Design

The casings and tubing have been designed to withstand all expected loads during the life of the well including the maximum injection and annulus pressure loads. The materials selected for these items, as shown in Table and Table , were based on corrosion analysis for compatibility with the injected fluids and reservoir fluids. The tubular design also takes into consideration the expected temperature profile. The upper casing section will be carbon steel with a corrosion resistant alloy (CRA) lower section. The upper tubing section will be carbon steel lined with a glass reinforced epoxy (GRE) for compatibility with the injected and reservoir fluids per 40 CFR 146.86(b)(1). The flow wetted lower part of the injection casing, tubing, and packer will be CRA materials.

The tubing and casing loads were evaluated and compared to the strengths to determine an appropriate well design including safety factors. Table 2 shows the design factors (minimum safety factors) used in the analysis.

Table 2: Design Factors

Failure Mode	Casing	Tubing
Triaxial (1)	1.20	1.20
Burst (2)	1.20	1.20
Collapse (3)	1.00	1.10
Axial – Tension (4)	1.30	1.30
Axial – Compression (4)	1.30	1.30
Notes: (1) VME Criterion (YS derated for temperature) (2) API Minimum Internal Yield Pressure (3) API (Tension adjusted) Collapse (4) API Pipe Body Yield Strength		

Injection Well Construction Details

Table 3: Open Hole Diameters and Intervals

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor	Surface – 84	26	
First Surface	Surface – 1,425	17.5	Depth limited by field rules.
Second Surface	Surface – 4,879	12.25	Cemented to surface to isolate the USDW.
Injection string	Surface – 6,040	8.75	

Table 4: Casing Specifications

Name	Setting Depth (ft)	Outside Diameter (in.)	Inside Diameter (in.)	Weight (ppf)	Grade	Connection	Burst Strength (psi)	Collapse Strength (psi)	Tensile Strength (lbf)
Conductor	84	20							
First Surface Casing	1,425	13.375	12.615	54.5	K55	API	2,730	1,130	853,240
Second Surface Casing	4,879	9.625	8.921	36	K55	API	3,520	2,020	564,000
Injection casing section 1	4,350	7	6.366	23	L80	Premium (1)	6,340	3,830	532,440
Injection casing section 2	6,040	7	6.366	23	25Cr80	Premium (1)	6,340	3,830	532,440
Notes: (1) Connection with metal-to-metal seals and full pipe body strength.									

Table 5: Tubing Specifications

Name	Setting Depth (ft)	Outside Diameter (in.)	Inside Diameter (in.)	Weight (ppf)	Grade	Connection	Burst strength (psi)	Collapse strength (psi)	Tensile strength (lbf)
Injection tubing Section 1	4,879	4.5	4.000	11.6	L80 (GRE)	Premium (1)	7,780	6,350	267,040
Injection tubing Section 2	5,849	4.5	4.000	11.6	25Cr80	Premium (1)	7,780	6,350	267,040
Notes: (1) Connection with metal-to-metal seals and full pipe body strength.									

Table 6: Packer Information

Item	Value
Packer Setting Depth	4,936 ft, 5,200 ft, 5,474 ft, 5,743 ft
Packer material	Same CRA material as the tubing and casing or a CRA such as Alloy 718
Packer element material	HNBR
Packer type	Hydraulic set retrievable packer
Maximum casing ID	6.366 in. (nominal ID for 7 in. 23 ppf casing)
Minimum casing ID	6.241 in. (drift diameter for 7 in. 23 ppf casing)
Packer / seal assembly ID	4.5 in.
Packer rating	Differential pressure ±10,000 psi, axial capacity ±150,000 lbf, based on the packer loads
Maximum packer to casing forces	97,000 lbf Upward 102,000 lbf Downward

Injection Well Construction Diagram

Figure 3 shows the wellbore schematic for the design with the injection string casing set through the injection zone with the proposed completion equipment.

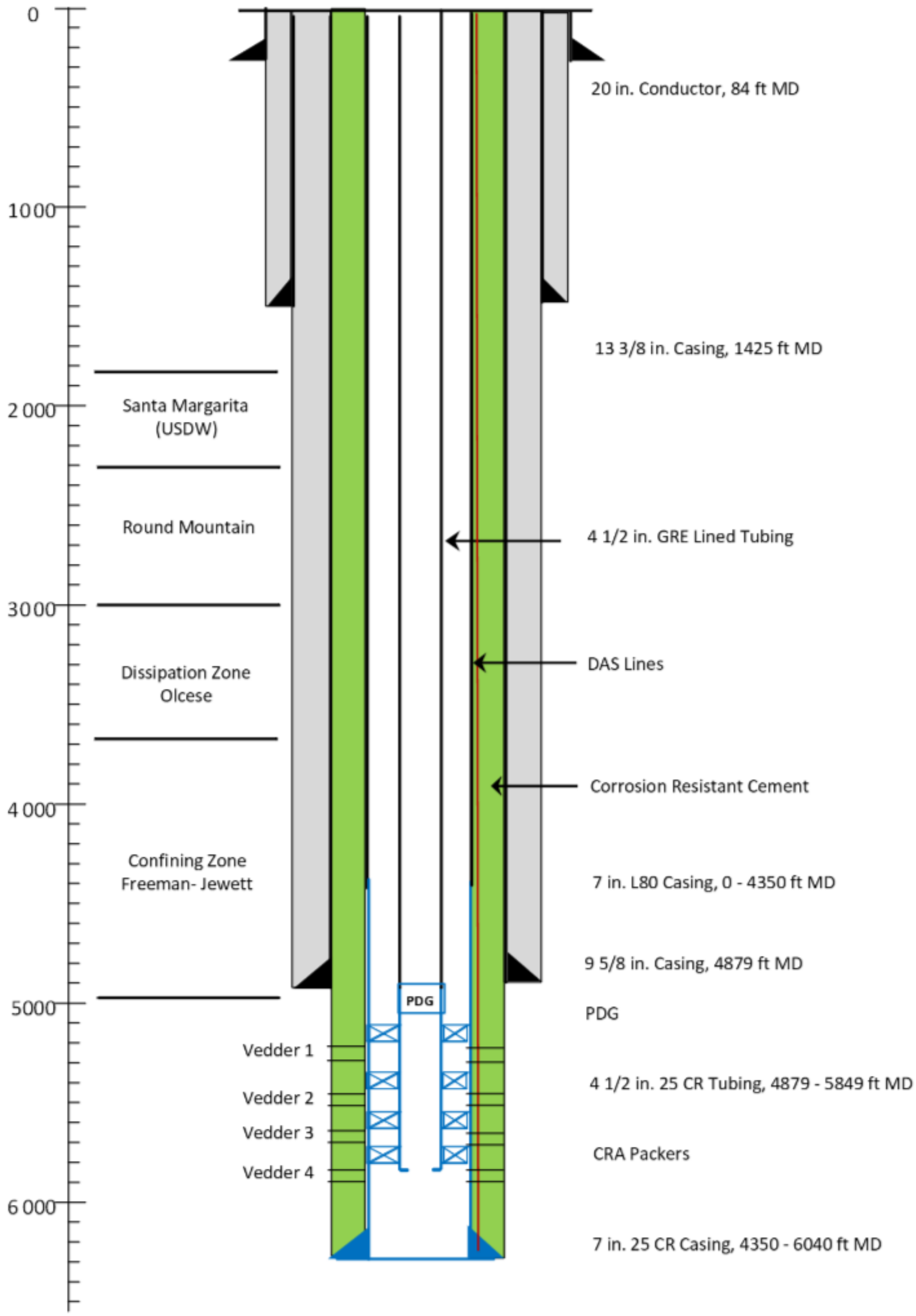

Figure 3: Proposed Wellbore Schematic

References

1 Y. Xiang, M. Xe and Y.-S. Choi, "State of the art overview of pipeline steel corrosion in impure dense CO2 for CCS transportation: mechanism and models," *Corrosion Engineering, Science and Technology,* vol. 52, no. 7, pp. 485-509, 2017.

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9 Y. Xiang, M. Xu and Y.-S. Choi, "State-of-the-art overview of pipeline steel corrosion in impure dense CO2 for CCS transportation: mechanisms and models," *Corrosion Engineering, Science and Technology,* vol. 52, no. 7, pp. 485-509, 2017.

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Kern River Eastridge CCS Project

Facility Information

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Well: ANO9004INJ
API No. Not yet assigned

Facility contact: David Wessels – Project Manager
9525 Camino Media, Bakersfield, CA 93311
David.wessels@chevron.com / 661-412-6039

Well location: Bakersfield, Kern County, CA 93308
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Introduction

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The second surface casing hole section will be drilled to the base of the Freeman-Jewett (confining layer). Deviation check surveys will be taken while drilling (40 CFR 146.87(a)(1)). Open hole logs including resistivity, spontaneous potential, caliper, and gamma ray will be run prior to running casing (40 CFR 146.87(a)(2)(i)). The second surface casing will be run and cemented to surface to isolate the USDW zones as required by 40 CFR 146.86(a)(1) and 40 CFR 146.86(b)(2). After the cement sets, a cement bond and variable density log and a temperature log will be run (40 CFR 146.87(a)(2)(ii)).

The injection casing hole section will be drilled to the base of the 5th Vedder Sand. Deviation check surveys will be taken while drilling (40 CFR 146.87 (1)). Open hole logs including but not limited to resistivity, spontaneous potential, porosity, caliper, gamma ray, and fracture finder logs will be run prior to running casing (40 CFR 146.87(a)(3)(i)). The injection casing will be

run and cemented to surface (40 CFR 146.86(b)(3)). After the cement sets, a cement bond and variable density log, casing inspection log and a temperature log will be run (40 CFR 146.87(a)(3)(ii)).

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Well Design

Table 4 shows the proposed casing setting depths and casing specifications.

Directional

The well will be drilled as a directional well. Directional surveys will be taken as the well is drilled. Figure 1 shows the planned directional profile.

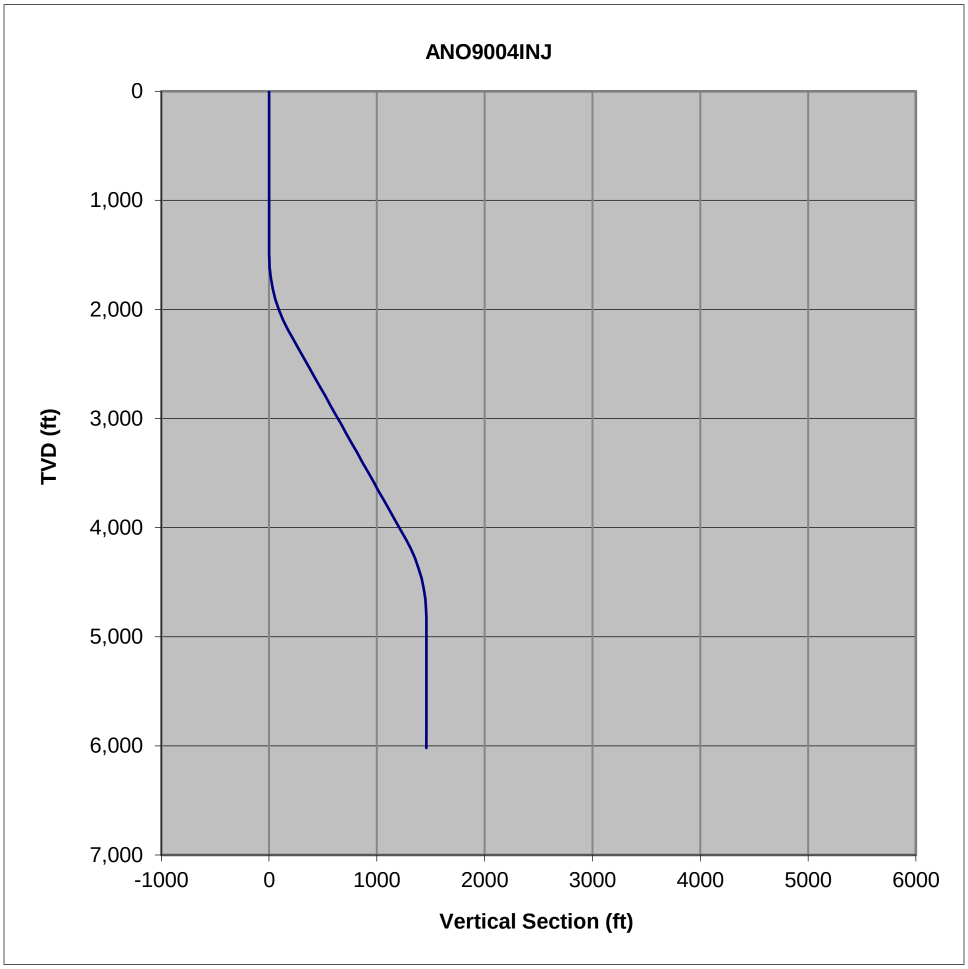

Figure 1: Proposed Directional Plan

Cementing

First Surface Casing

The first surface casing cement will be circulated to surface. Top and bottom wiper plugs will be used to minimize contamination.

The casing will be cemented with a 12 ppg surface casing slurry with the top of cement at surface as required by 40 CFR 146.86(b)(2).

Excess slurry volume of 50 – 100% will be pumped to circulate cement to surface. Excess will depend on hole conditions specific to the well.

Second Surface Casing

The casing will be cemented with a 12 ppg surface casing slurry with the top of cement at surface to isolate the USDW zones as required by 40 CFR 146.86(b)(2).

Excess open hole slurry volume of 50 – 100% will be pumped to circulate cement to surface. Excess volume will depend on hole conditions specific to the well.

Injection Casing

The casing will be cemented to surface as required by 40 CFR 146.86(b)(3) with a CO_2 resistant cement blend. The slurry density will be 13 ppg.

Excess slurry volume of 25 – 50% in the open hole section will be used to circulate cement to surface. An open hole caliper log will be used to estimate the annulus volume and the excess volume will ensure cement to surface.

The casing will be centralized (40 CFR 146.86(b)(3)) to provide 70% or greater stand-off.

Casing conveyed DAS fiber optics will be run for testing and monitoring purposes. Refer to the Testing and Monitoring Plan or Quality Assurance and Surveillance Plan for more details.

Cement Bond, Temperature, and Inspection Logs

After the injection string casing has been cemented, a cement bond and variable density log and a temperature log will be run as required by 40 CFR 146.87(a)(3)(ii) to verify an annular seal. A baseline wall thickness inspection log will also be run.

Tubing and Packer

Injection will be through tubing and multiple packers per 40 CFR 146.86(c)(2). Materials for the tubing and packer are shown in Table 5 and Table 6 and were selected for compatibility with the injected fluids and reservoir fluids as required by 40 CFR 146.86(c)(1). The packers will be set in the casing opposite a cemented interval. The setting depths will be selected based on an evaluation of the CBL after the casing is run and cemented.

The tubing size was selected based on the proposed injection rate, composition, reservoir conditions, and monitoring equipment. The fluid flow model PROSPER[1] was used to determine the pressure and temperature profiles for CO_2 injection. PROSPER has PVT correlations that have been validated for CO_2 injection.

Proposed Perforations

Through the project life, Chevron plans to target individual zones within the Vedder Sand with tubing and packer completions, starting with the deepest target and recompleting into increasingly shallower Vedder Sand intervals through time as necessary based upon monitoring data. With each recompletion, Chevron plans to update operating constraints based upon any wellbore changes (e.g., additional perforations for shallower Vedder Sand targets).

Proposed perforations will be selected based on the injection zones in each well.

[1] https://www.petex.com

Table 1 shows the proposed perforations intervals for the wells.

Table 1: Proposed Perforations, Measured Depth

Zone	ANO9004INJ Perforations
Top 1st Vedder Perf	5,357
Base 1st Vedder Perf	5,417
Top 2nd Vedder Perf	5,609
Base 2nd Vedder Perf	5,669
Top 3rd Vedder Perf	5,864
Base 3rd Vedder Perf	5,924
Top 4th Vedder Perf	6,168
Base 4th Vedder Perf	6,228

Maximum Surface Pressures and Mechanical Integrity

The operating injection pressure will depend on the reservoir pressure, the properties of the injected fluid, the wellbore friction, and the rate. PROSPER, a modeling software package, was used to determine the pressure and temperature profiles for CO_2 injection. PROSPER has PVT correlations that have been validated for CO_2 injection.

The annulus pressure will be maintained at a pressure higher than the tubing injection pressure as required by 40 CFR 146.88(c). The design surface pressure loads on the injection tubing and tubing by casing annulus are as follows:

- Maximum tubing injection pressure 1,950 psi
- Maximum annulus pressure 2,050 psi

The maximum tubing injection and shut-in pressures are based on PROSPER flow assurance modeling. The maximum annulus pressure is higher than the maximum injection pressure as required by 40 CFR 146.88(c).

After each casing is set and cemented, and after the tubing and packer are installed, they will be pressure tested to a pressure equal to or greater than the design pressure for that component to demonstrate mechanical integrity.

Material Selection

The material selected for the flow wetted well construction components within the reservoir, including the lower tubing and lower injection casing below the packer, is 25 Cr. Glass reinforced epoxy (GRE) lined tubing will be used above the packer as it will be exposed to the CO_2 stream during injection. Standard carbon steel alloy casing will be used for the injection casing above the packer as it is not planned to be exposed to CO_2 during the lifecycle of the well.

Modeling results and supporting literature (see References) confirmed an acceptable corrosion rate for 25 Cr material for the life of the project to meet the well materials compatibility requirement in 40 CFR 146.86(b)(1).

Downhole Monitoring

Downhole monitoring equipment includes (a) a dual transducer pressure/temperature gauge run on tubing above packer and (b) distributed acoustic sensor (DAS) cable on the casing.

Safety System for Injection Wells

The well monitoring system will consist of surface sensors for measuring temperature, pressure, and flow rate. Data from the sensors will be collected and stored in a Supervisory Control and Data Acquisition (SCADA) system. Monitored parameters will have high and low alarms that will be activated when a measured parameter is outside its normal operating range. When a critical parameter alarms, such as pressure, the well will be shut in by a fail-safe actuated gate valve that is a component of the injection tree. Operating personnel will be notified that an alarm was activated. The reason for the alarm will be investigated to determine what needs to be done to make sure the well is safe. After any needed repairs or maintenance are conducted, the well will be put back into service.

A landing nipple profile will be installed near the packer to allow setting a plug or other downhole safety device if required for well maintenance and servicing. Figure 2 shows a schematic of the safety system.

The detailed design, equipment specification, and selection will be completed and submitted to the EPA prior to project startup.

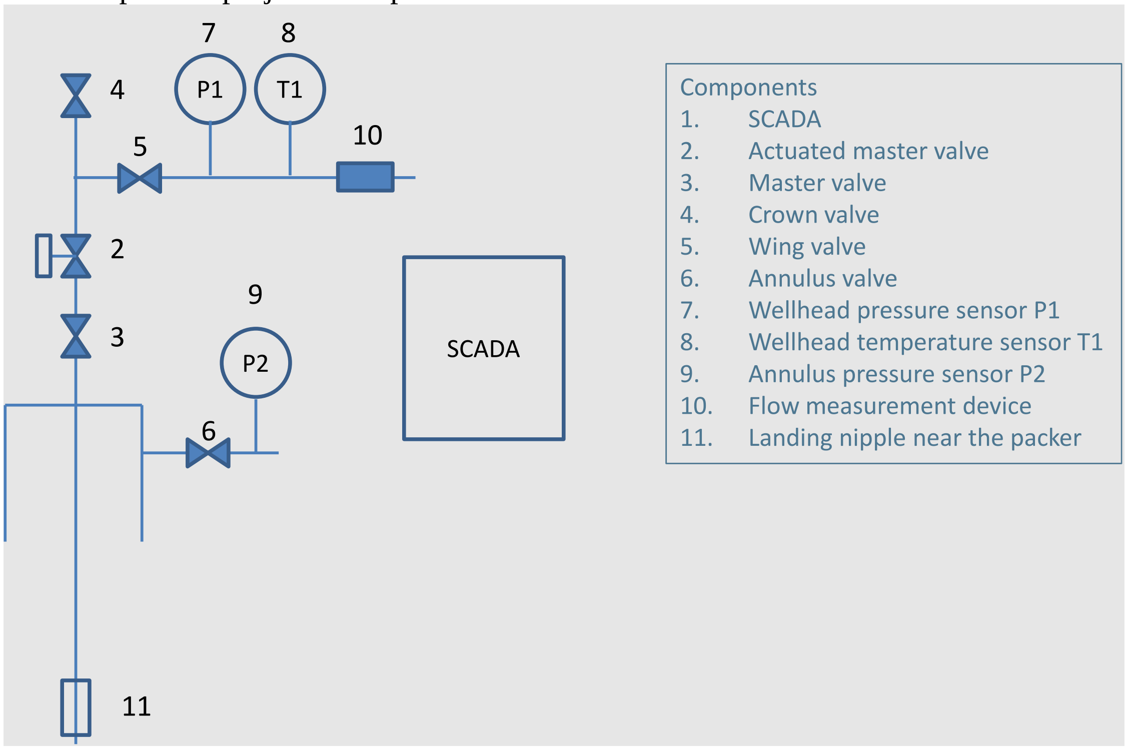

Figure 2: Safety System

Injection Well Casing and Tubing Design

The casings and tubing have been designed to withstand all expected loads during the life of the well, including the maximum injection and annulus pressure loads. The materials selected for these items, as shown in Table 4 and Table 5, were based on corrosion analysis for compatibility with the injected fluids and reservoir fluids. The tubular design also takes into consideration the expected temperature profile. The upper casing section will be carbon steel with a corrosion resistant alloy (CRA) lower section. The upper tubing section will be carbon steel lined with a glass reinforced epoxy (GRE) for compatibility with the injected and reservoir fluids per 40 CFR 146.86(b)(1). The flow wetted lower part of the injection casing, tubing, and packer will be CRA materials.

The tubing and casing loads were evaluated and compared to the strengths to determine an appropriate well design including safety factors. Table 2 shows the design factors (minimum safety factors) used in the analysis.

Table 2: Design Factors

Failure Mode	Casing	Tubing
Triaxial (1)	1.20	1.20
Burst (2)	1.20	1.20
Collapse (3)	1.00	1.10
Axial – Tension (4)	1.30	1.30
Axial – Compression (4)	1.30	1.30
Notes: (1) VME Criterion (YS derated for temperature) (2) API Minimum Internal Yield Pressure (3) API (Tension adjusted) Collapse (4) API Pipe Body Yield Strength		

Injection Well Construction Details

Table 3: Open Hole Diameters and Intervals

Name	**Depth Interval** (ft)	**Open Hole Diameter** (in.)	**Comment**
Conductor	Surface – 84	26	
First Surface	Surface – 1,500	17.5	Depth limited by field rules.
Second Surface	Surface – 5,174	12.25	Cemented to surface to isolate the USDW.
Injection string	Surface – 6,373	8.75	

Table 4: Casing Specifications

Name	**Setting Depth (ft)**	**Outside Diameter (in.)**	**Inside Diameter (in.)**	**Weight (ppf)**	**Grade**	**Connection**	**Burst Strength (psi)**	**Collapse Strength (psi)**	**Tensile Strength (lbf)**
Conductor	84	20							
First Surface Casing	1,500	13.375	12.615	54.5	K55	API	2,730	1,130	853,240
Second Surface Casing	5,174	9.625	8.921	36	K55	API	3,520	2,020	564,000
Injection casing section 1	4,650	7	6.366	23	L80	Premium (1)	6,340	3,830	532,440
Injection casing section 2	6,373	7	6.366	23	25Cr80	Premium (1)	6,340	3,830	532,440
Notes: (1) Connection with metal-to-metal seals and full pipe body strength.									

Table 5: Tubing Specifications

Name	Setting Depth (ft)	Outside Diameter (in.)	Inside Diameter (in.)	Weight (ppf)	Grade	Connection	Burst strength (psi)	Collapse strength (psi)	Tensile strength (lbf)
Injection tubing Section 1	5,257	4.5	4.000	11.6	L80 (GRE)	Premium (1)	7,780	6,350	267,040
Injection tubing Section 2	6,189	4.5	4.000	11.6	25Cr80	Premium (1)	7,780	6,350	267,040
Notes: (1) Connection with metal-to-metal seals and full pipe body strength.									

Table 6: Packer Information

Item	Value
Packer Setting Depth	5,257 ft, 5,509 ft, 5,764 ft, 6,068 ft
Packer material	Same CRA material as the tubing and casing or a CRA such as Alloy 718
Packer element material	HNBR
Packer type	Hydraulic set retrievable packer
Maximum casing ID	6.366 in. (nominal ID for 7 in. 23 ppf casing)
Minimum casing ID	6.241 in. (drift diameter for 7 in. 23 ppf casing)
Packer / seal assembly ID	4.5 in.
Packer rating	Differential pressure ±10,000 psi, axial capacity ±150,000 lbf, based on the packer loads
Maximum packer to casing forces	97,000 lbf Upward 104,000 lbf Downward

Injection Well Construction Diagram

Figure 3 shows the wellbore schematic for the design with the injection string casing set through the injection zone with the proposed completion equipment.

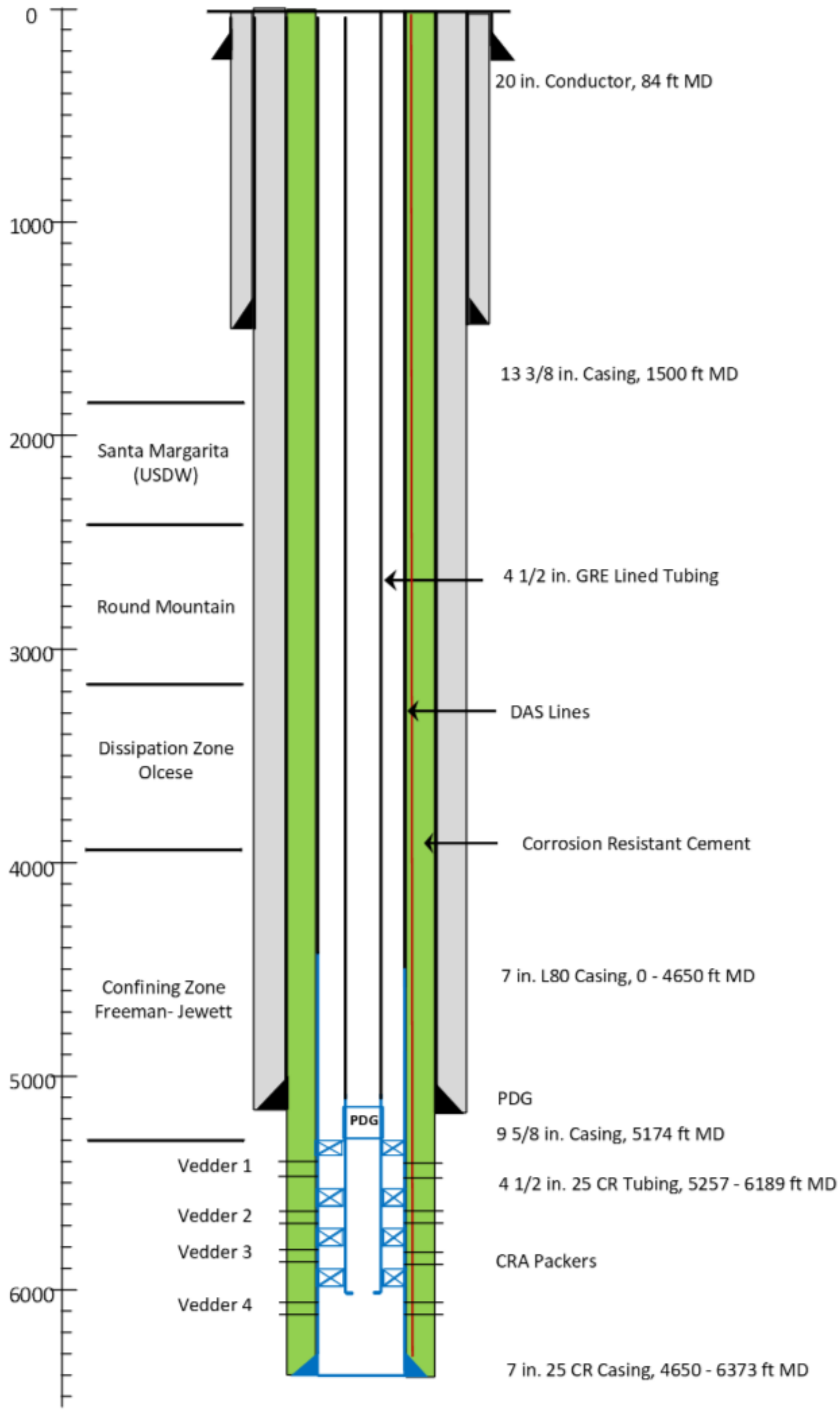

Figure 3: Proposed Wellbore Schematic

References

1 Y. Xiang, M. Xe and Y.-S. Choi, "State of the art overview of pipeline steel corrosion in impure dense CO2 for CCS transportation: mechanism and models," *Corrosion Engineering, Science and Technology,* vol. 52, no. 7, pp. 485-509, 2017.

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14 Y. Song, A. Palencsar and T. Hemmingsen, "Effect of O2 and Temperature on Sour Corrosion," in *NACE Corrosion Conference & Expo; Paper No. 11077*, 2011.

CONSTRUCTION DETAILS

Kern River Eastridge CCS Project

Facility Information

Facility name: Kern River Eastridge CCS
Well: MC19002INJ
API No. Not yet assigned

Facility contact: David Wessels – Project Manager
9525 Camino Media, Bakersfield, CA 93311
David.wessels@chevron.com / 661-412-6039

Well location: Bakersfield, Kern County, CA 93308
Lat.- Long.: 35.4401°/-118.9981°

Introduction

The well construction details in this document apply to a new CO_2 injection well. The well will be drilled and completed as a Class VI CO_2 injection well.

Well Construction Process

Conductor casing will be set for drilling and cementing the first surface casing.

The first surface casing hole will be drilled to 1,425 ft. The field rules do not allow the surface casing to be drilled deeper than 1,500 ft. Deviation check surveys will be taken while drilling (40 CFR 146.87(a)(1)). Open hole logs including resistivity, spontaneous potential, caliper, and gamma ray will be run prior to running casing (40 CFR 146.87(a)(2)(i)). The first surface casing will be run and cemented to surface. After the cement sets, a cement bond and variable density log and a temperature log will be run (40 CFR 146.87(a)(2)(ii)).

The second surface casing hole section will be drilled to the base of the Freeman-Jewett (confining layer). Deviation check surveys will be taken while drilling (40 CFR 146.87(a)(1)). Open hole logs including resistivity, spontaneous potential, caliper, and gamma ray will be run prior to running casing (40 CFR 146.87(a)(2)(i)). The second surface casing will be run and cemented to surface to isolate the USDW zones as required by 40 CFR 146.86(a)(1) and 40 CFR 146.86(b)(2). After the cement sets, a cement bond and variable density log and a temperature log will be run (40 CFR 146.87(a)(2)(ii)).

The injection casing hole section will be drilled to the base of the 5th Vedder Sand. Deviation check surveys will be taken while drilling (40 CFR 146.87 (1)). Open hole logs including but not limited to resistivity, spontaneous potential, porosity, caliper, gamma ray, and fracture finder logs will be run prior to running casing (40 CFR 146.87(a)(3)(i)). The injection casing will be

run and cemented to surface (40 CFR 146.86(b)(3)). After the cement sets, a cement bond and variable density log, casing inspection log and a temperature log will be run (40 CFR 146.87(a)(3)(ii)).

The injection string casing design will consist of materials compatible with exposure to the injected fluids (40 CFR 146.86(b)(1)). Casing conveyed DAS fiber optics will be run on the injection string casing for testing and monitoring purposes. Refer to the Testing and Monitoring plan or Quality Assurance and Surveillance Plan (QASP) for more details. The cement and additives will be compatible with the injection and formation fluids as required by 40 CFR 146.86(b)(5). Casing centralizers will be used to centralize the casing to 70% standoff or greater as per 40 CFR 146.86(b)(3). All well construction materials comply with American Petroleum Institute (API) and American National Standards (ANSI) Recommended Practices, Specifications and Standards.

The injection well will be completed by perforating the authorized injection zones. Completion equipment, consisting of packers, monitoring equipment, and tubing will be installed. The flow wetted components of the packer and wellhead will also use material compatible with the injected fluid. Noncorrosive packer fluid treated with corrosion inhibitors and biocide will be circulated in the tubing-by-casing annulus as per 40 CFR 146.88(c).

Well Design

Table 4 shows the proposed casing setting depths and casing specifications.

Directional

The well will be drilled as a directional well. Directional surveys will be taken as the well is drilled. Figure 1 shows the planned directional profile.

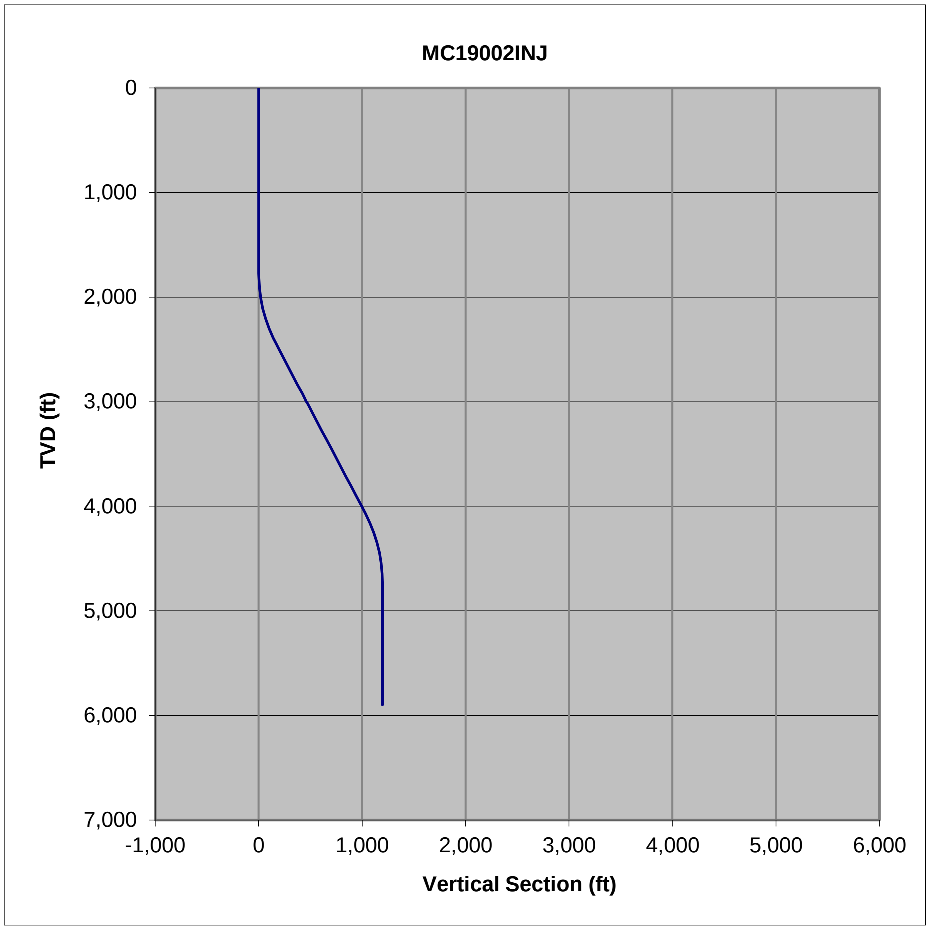

Figure 1: Proposed Directional Plan

Cementing

First Surface Casing

The first surface casing cement will be circulated to surface. Top and bottom wiper plugs will be used to minimize contamination.

The casing will be cemented with a 12 ppg surface casing slurry with the top of cement at surface as required by 40 CFR 146.86(b)(2).

Excess slurry volume of 50 – 100% will be pumped to circulate cement to surface. Excess will depend on hole conditions specific to the well.

Second Surface Casing

The casing will be cemented with a 12 ppg surface casing slurry with the top of cement at surface to isolate the USDW zones as required by 40 CFR 146.86(b)(2).

Excess open hole slurry volume of 50 – 100% will be pumped to circulate cement to surface. Excess volume will depend on hole conditions specific to the well.

Injection Casing

The casing will be cemented to surface as required by 40 CFR 146.86(b)(3) with a CO_2 resistant cement blend. The slurry density will be 13 ppg.

Excess slurry volume of 25 – 50% in the open hole section will be used to circulate cement to surface. An open hole caliper log will be used to estimate the annulus volume and the excess volume will ensure cement to surface.

The casing will be centralized (40 CFR 146.86(b)(3)) to provide 70% or greater stand-off.

Casing conveyed DAS fiber optics will be run for testing and monitoring purposes. Refer to the Testing and Monitoring Plan or QASP for more details.

Cement Bond, Temperature, and Inspection Logs

After the injection string casing has been cemented, a cement bond and variable density log and a temperature log will be run as required by 40 CFR 146.87(a)(3)(ii) to verify an annular seal. A baseline wall thickness inspection log will also be run.

Tubing and Packer

Injection will be through tubing and multiple packers per 40 CFR 146.86(c)(2). Materials for the tubing and packer are shown in Table 5 and Table 6 and were selected for compatibility with the injected fluids and reservoir fluids as required by 40 CFR 146.86(c)(1). The packers will be set in the casing opposite a cemented interval. The setting depths will be selected based on an evaluation of the CBL after the casing is run and cemented.

The tubing size was selected based on the proposed injection rate, composition, reservoir conditions, and monitoring equipment. The fluid flow model PROSPER[1] was used to determine the pressure and temperature profiles for CO_2 injection. PROSPER has PVT correlations that have been validated for CO_2 injection.

Proposed Perforations

Through the project life, Chevron plans to target individual zones within the Vedder Sand with tubing and packer completions, starting with the deepest target and recompleting into increasingly shallower Vedder Sand intervals through time as necessary based upon monitoring data. With each recompletion, Chevron plans to update operating constraints based upon any wellbore changes (e.g., additional perforations for shallower Vedder Sand targets).

Proposed perforations will be selected based on the injection zones in each well.

Table 1 shows the proposed perforations intervals for the wells.

[1] https://www.petex.com

Table 1: Proposed Perforations, Measured Depth

Zone	MC19002INJ Perforations
Top 1st Vedder Perf	5,161
Base 1st Vedder Perf	5,221
Top 2nd Vedder Perf	5,427
Base 2nd Vedder Perf	5,487
Top 3rd Vedder Perf	5,690
Base 3rd Vedder Perf	5,750
Top 4th Vedder Perf	5,970
Base 4th Vedder Perf	6,030

Maximum Surface Pressures and Mechanical Integrity

The operating injection pressure will depend on the reservoir pressure, the properties of the injected fluid, the wellbore friction, and the rate. PROSPER, a modeling software package, was used to determine the pressure and temperature profiles for CO_2 injection. PROSPER has PVT correlations that have been validated for CO_2.

The annulus pressure will be maintained at a pressure higher than the tubing injection pressure as required by 40 CFR 146.88(c). The design surface pressure loads on the injection tubing and tubing by casing annulus are as follows:

- Maximum tubing injection pressure 1,950 psi
- Maximum annulus pressure 2,050 psi

The maximum tubing injection and shut-in pressures are based on PROSPER flow assurance modeling. The maximum annulus pressure is higher than the maximum injection pressure as required by 40 CFR 146.88(c).

After each casing is set and cemented, and after the tubing and packer are installed, they will be pressure tested to a pressure equal to or greater than the design pressure for that component to demonstrate mechanical integrity.

Material Selection

The material selected for the flow wetted well construction components within the reservoir, including the lower tubing and lower injection casing below the packer, is 25 Cr. Glass reinforced epoxy (GRE) lined tubing will be used above the packer as it will be exposed to the CO_2 stream during injection. Standard carbon steel alloy casing will be used for the injection casing above the packer as it is not planned to be exposed to CO_2 during the lifecycle of the well. Modeling results and supporting literature (see References) confirmed an acceptable corrosion rate for 25 Cr material for the life of the project to meet the well materials compatibility requirement in 40 CFR 146.86(b)(1).

Downhole Monitoring

Downhole monitoring equipment includes (a) a dual transducer pressure/temperature gauge run on tubing above packer and (b) distributed acoustic sensor (DAS) cable on the casing.

Safety System for Injection Wells

The well monitoring system will consist of surface sensors for measuring temperature, pressure, and flow rate. Data from the sensors will be collected and stored in a Supervisory Control and Data Acquisition (SCADA) system. Monitored parameters will have high and low alarms that will be activated when a measured parameter is outside its normal operating range. When a critical parameter alarms, such as pressure, the well will be shut in by a fail-safe actuated gate valve that is a component of the injection tree. Operating personnel will be notified that an alarm was activated. The reason for the alarm will be investigated to determine what needs to be done to make sure the well is safe. After any needed repairs or maintenance are conducted, the well will be put back into service.

A landing nipple profile will be installed near the packer to allow setting a plug or other downhole safety device if required for well maintenance and servicing. Figure 2 shows a schematic of the safety system.

The detailed design, equipment specification, and selection will be completed and submitted to the EPA prior to project startup.

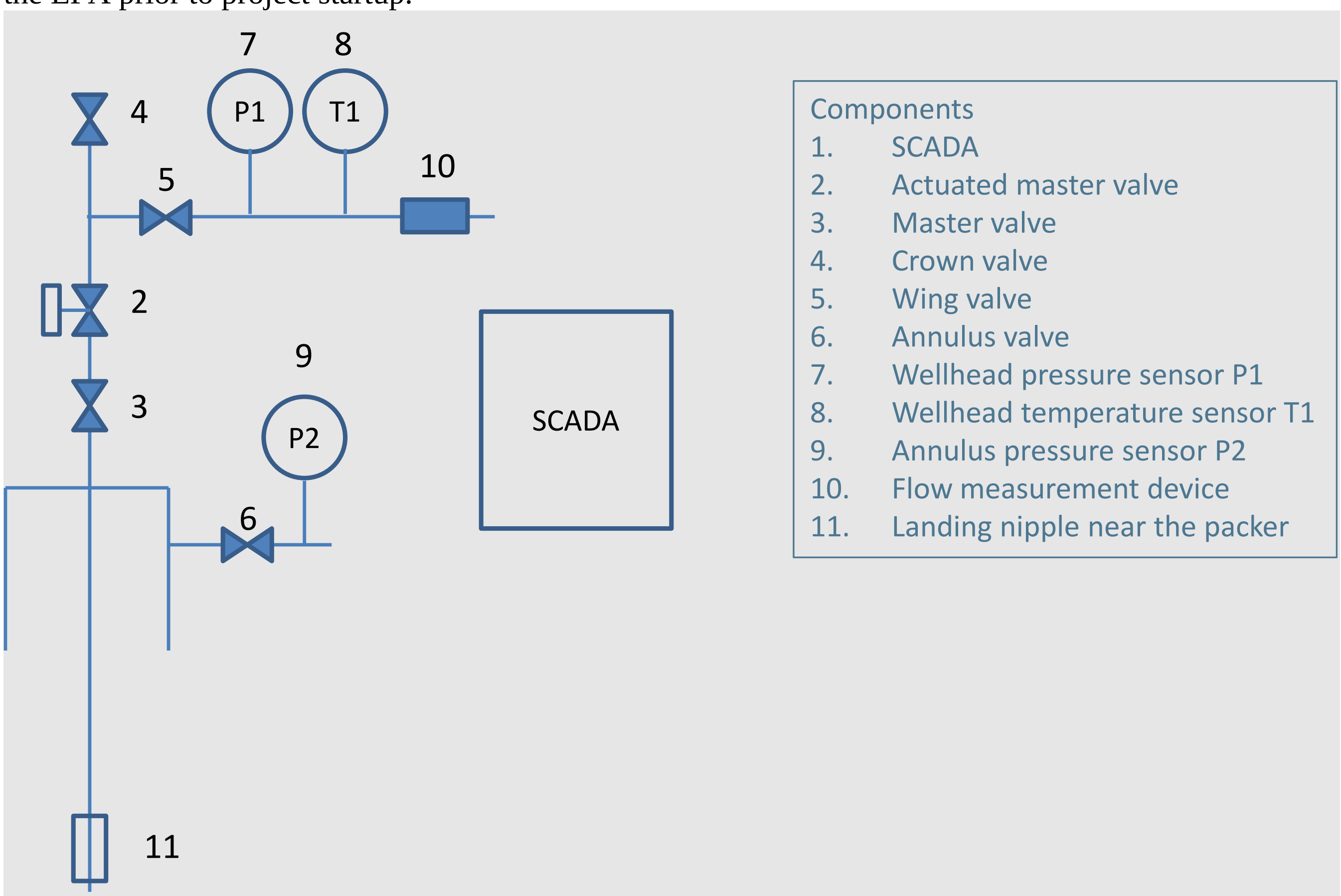

Figure 2: Safety System

Injection Well Casing and Tubing Design

The casings and tubing have been designed to withstand all expected loads during the life of the well including the maximum injection and annulus pressure loads. The materials selected for these items, as shown in Table 4 and Table 5, were based on corrosion analysis for compatibility with the injected fluids and reservoir fluids. The tubular design also takes into consideration the expected temperature profile. The upper casing section will be carbon steel with a corrosion resistant alloy (CRA) lower section. The upper tubing section will be carbon steel lined with a glass reinforced epoxy (GRE) for compatibility with the injected and reservoir fluids per 40 CFR 146.86(b)(1). The flow wetted lower part of the injection casing, tubing, and packer will be CRA materials.

The tubing and casing loads were evaluated and compared to the strengths to determine an appropriate well design including safety factors. Table 2 shows the design factors (minimum safety factors) used in the analysis.

Table 2: Design Factors

Failure Mode	Casing	Tubing
Triaxial (1)	1.20	1.20
Burst (2)	1.20	1.20
Collapse (3)	1.00	1.10
Axial – Tension (4)	1.30	1.30
Axial – Compression (4)	1.30	1.30
Notes: (1) VME Criterion (YS derated for temperature) (2) API Minimum Internal Yield Pressure (3) API (Tension adjusted) Collapse (4) API Pipe Body Yield Strength		

Injection Well Construction Details

Table 3: Open Hole Diameters and Intervals

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor	Surface – 84	26	
First Surface	Surface – 1,425	17.5	Depth limited by field rules.
Second Surface	Surface – 5,006	12.25	Cemented to surface to isolate the USDW.
Injection string	Surface – 6,169	8.75	

Table 4: Casing Specifications

Name	Setting Depth (ft)	Outside Diameter (in.)	Inside Diameter (in.)	Weight (ppf)	Grade	Connection	Burst Strength (psi)	Collapse Strength (psi)	Tensile Strength (lbf)
Conductor	84	20							
First Surface Casing	1,425	13.375	12.615	54.5	K55	API	2,730	1,130	853,240
Second Surface Casing	5,006	9.625	8.921	36	K55	API	3,520	2,020	564,000
Injection casing section 1	4,500	7	6.366	23	L80	Premium (1)	6,340	3,830	532,440
Injection casing section 2	6,169	7	6.366	23	25Cr80	Premium (1)	6,340	3,830	532,440
Notes: (1) Connection with metal-to-metal seals and full pipe body strength.									

Table 5: Tubing Specifications

Name	Setting Depth (ft)	Outside Diameter (in.)	Inside Diameter (in.)	Weight (ppf)	Grade	Connection	Burst strength (psi)	Collapse strength (psi)	Tensile strength (lbf)
Injection tubing Section 1	5,006	4.5	4.000	11.6	L80 (GRE)	Premium (1)	7,780	6,350	267,040
Injection tubing Section 2	5,976	4.5	4.000	11.6	25Cr80	Premium (1)	7,780	6,350	267,040
Notes: (1) Connection with metal-to-metal seals and full pipe body strength.									

Table 6: Packer Information

Item	Value
Packer Setting Depth	5,061 ft, 5,327 ft, 5,590 ft, 5,870 ft
Packer material	Same CRA material as the tubing and casing or a CRA such as Alloy 718
Packer element material	HNBR
Packer type	Hydraulic set retrievable packer
Maximum casing ID	6.366 in. (nominal ID for 7 in. 23 ppf casing)
Minimum casing ID	6.241 in. (drift diameter for 7 in. 23 ppf casing)
Packer / seal assembly ID	4.5 in.
Packer rating	Differential pressure ±10,000 psi, axial capacity ±150,000 lbf, based on the packer loads
Maximum packer to casing forces	97,000 lbf Upward 102,000 lbf Downward

Injection Well Construction Diagram

Figure 3 shows the wellbore schematic for the design with the injection string casing set through the injection zone with the proposed completion equipment.

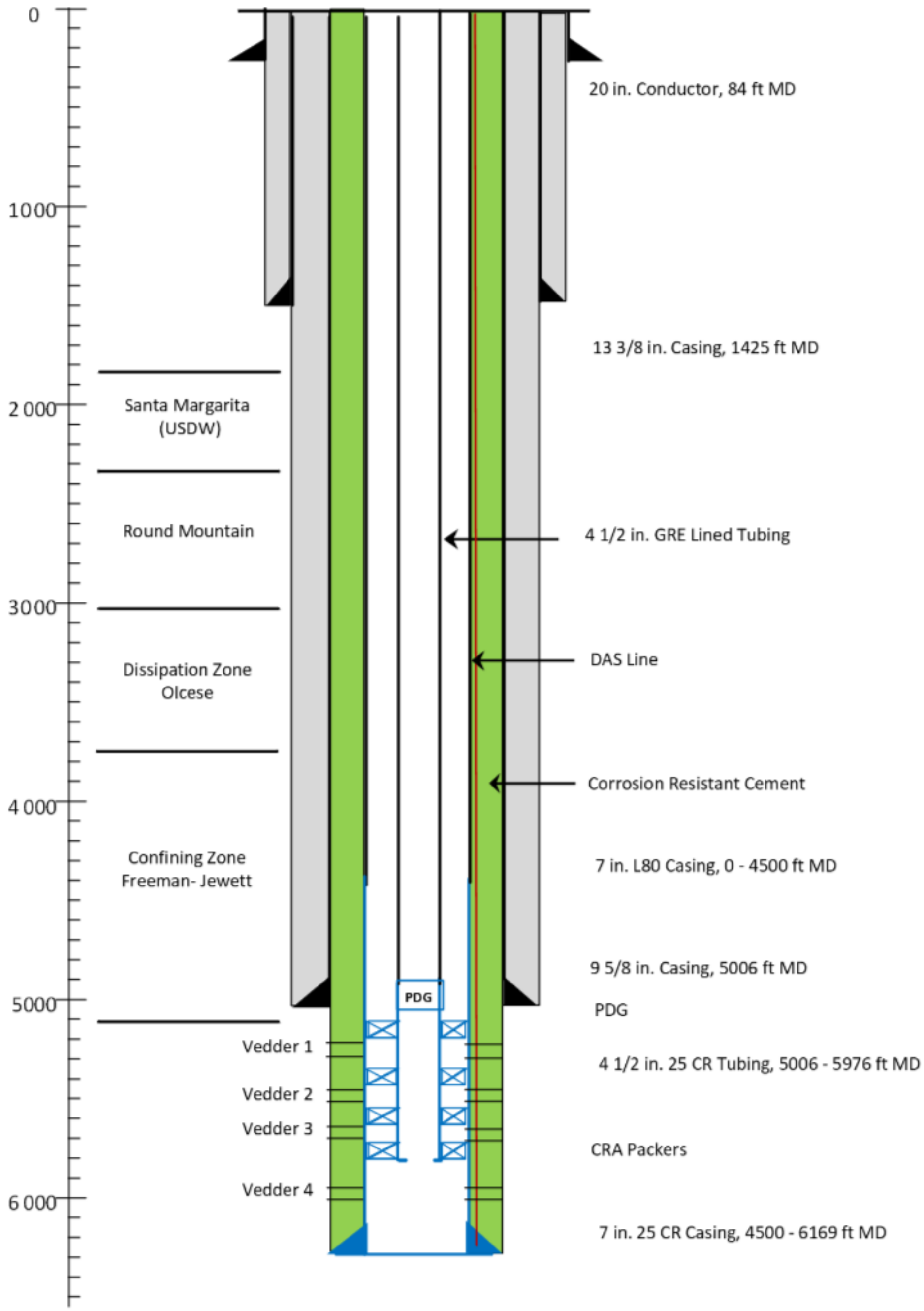

Figure 3: Proposed Wellbore Schematic

References

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CONSTRUCTION DETAILS

Kern River Eastridge CCS Project

Facility Information

Facility name:	Kern River Eastridge CCS
Well:	ANO9005INJ
API No.	Not yet assigned

Facility contact:	David Wessels – Project Manager 9525 Camino Media, Bakersfield, CA 93311 David.wessels@chevron.com / 661-412-6039

Well location:	Bakersfield, Kern County, CA 93308
Lat.- Long.:	35.4462°/-119.0010°

Introduction

The well construction details in this document apply to a new CO_2 injection well. The well will be drilled and completed as a Class VI CO_2 injection well.

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The second surface casing hole section will be drilled to the base of the Freeman-Jewett (confining layer). Deviation check surveys will be taken while drilling (40 CFR 146.87(a)(1)). Open hole logs including resistivity, spontaneous potential, caliper, and gamma ray will be run prior to running casing (40 CFR 146.87(a)(2)(i)). The second surface casing will be run and cemented to surface to isolate the USDW zones as required by 40 CFR 146.86(a)(1) and 40 CFR 146.86(b)(2). After the cement sets, a cement bond and variable density log and a temperature log will be run (40 CFR 146.87(a)(2)(ii)).

The injection casing hole section will be drilled to the base of the 5th Vedder Sand. Deviation check surveys will be taken while drilling (40 CFR 146.87 (1)). Open hole logs including but not limited to resistivity, spontaneous potential, porosity, caliper, gamma ray, and fracture finder logs will be run prior to running casing (40 CFR 146.87(a)(3)(i)). The injection casing will be

run and cemented to surface (40 CFR 146.86(b)(3)). After the cement sets, a cement bond and variable density log, casing inspection log and a temperature log will be run (40 CFR 146.87(a)(3)(ii)).

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Well Design

Table 4 shows the proposed casing setting depths and casing specifications.

Directional

The well will be drilled as a directional well. Directional surveys will be taken as the well is drilled. Figure 1 shows the planned directional profile.

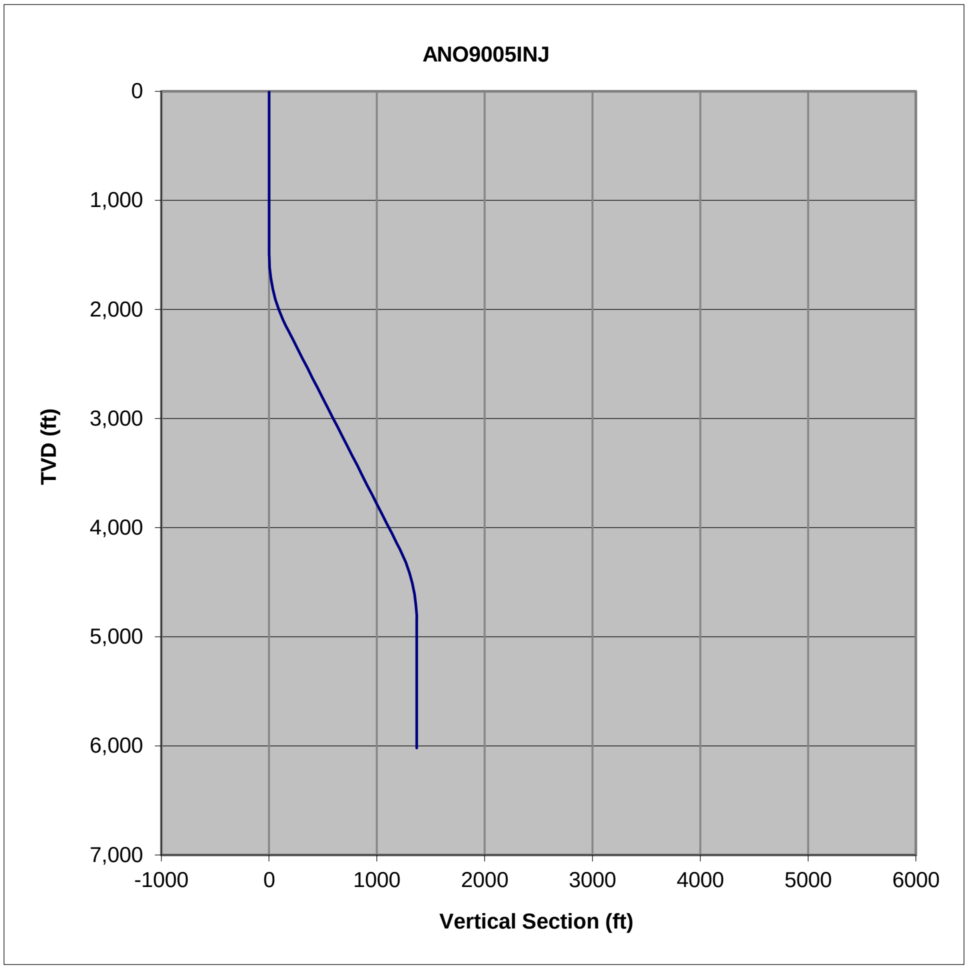

Figure 1: Proposed Directional Plan

Cementing

First Surface Casing

The first surface casing cement will be circulated to surface. Top and bottom wiper plugs will be used to minimize contamination.

The casing will be cemented with a 12 ppg surface casing slurry with the top of cement at surface as required by 40 CFR 146.86(b)(2).

Excess slurry volume of 50 – 100% will be pumped to circulate cement to surface. Excess will depend on hole conditions specific to the well.

Second Surface Casing

The casing will be cemented with a 12 ppg surface casing slurry with the top of cement at surface to isolate the USDW zones as required by 40 CFR 146.86(b)(2).

Excess open hole slurry volume of 50 – 100% will be pumped to circulate cement to surface. Excess volume will depend on hole conditions specific to the well.

Injection Casing

The casing will be cemented to surface as required by 40 CFR 146.86(b)(3) with a CO_2 resistant cement blend. The slurry density will be 13 ppg.

Excess slurry volume of 25 – 50% in the open hole section will be used to circulate cement to surface. An open hole caliper log will be used to estimate the annulus volume and the excess volume will ensure cement to surface.

The casing will be centralized (40 CFR 146.86(b)(3)) to provide 70% or greater stand-off.

Casing conveyed DAS fiber optics will be run for testing and monitoring purposes. Refer to the Testing and Monitoring Plan or QASP for more details.

Cement Bond, Temperature, and Inspection Logs

After the injection string casing has been cemented, a cement bond and variable density log and a temperature log will be run as required by 40 CFR 146.87(a)(3)(ii) to verify an annular seal. A baseline wall thickness inspection log will also be run.

Tubing and Packer

Injection will be through tubing and multiple packers per 40 CFR 146.86(c)(2). Materials for the tubing and packer are shown in Table 5 and Table 6 and were selected for compatibility with the injected fluids and reservoir fluids as required by 40 CFR 146.86(c)(1). The packers will be set in the casing opposite a cemented interval. The setting depths will be selected based on an evaluation of the CBL after the casing is run and cemented.

The tubing size was selected based on the proposed injection rate, composition, reservoir conditions, and monitoring equipment. The fluid flow model PROSPER[1] was used to determine the pressure and temperature profiles for CO_2 injection. PROSPER has PVT correlations that have been validated for CO_2 injection.

Proposed Perforations

Through the project life, Chevron plans to target individual zones within the Vedder Sand with tubing and packer completions, starting with the deepest target and recompleting into increasingly shallower Vedder Sand intervals through time as necessary based upon monitoring data. With each recompletion, Chevron plans to update operating constraints based upon any wellbore changes (e.g., additional perforations for shallower Vedder Sand targets).

Proposed perforations will be selected based on the injection zones in each well.

[1] https://www.petex.com

Table 1 shows the proposed perforations intervals for the wells.

Table 1: Proposed Perforations, Measured Depth

Zone	ANO9005INJ Perforations
Top 1st Vedder Perf	5,311
Base 1st Vedder Perf	5,371
Top 2nd Vedder Perf	5,564
Base 2nd Vedder Perf	5,624
Top 3rd Vedder Perf	5,819
Base 3rd Vedder Perf	5,879
Top 4th Vedder Perf	6,121
Base 4th Vedder Perf	6,181

Maximum Surface Pressures and Mechanical Integrity

The operating injection pressure will depend on the reservoir pressure, the properties of the injected fluid, the wellbore friction, and the rate. PROSPER, a modeling software package, was used to determine the pressure and temperature profiles for CO_2 injection. PROSPER has PVT correlations that have been validated for CO_2 injection.

The annulus pressure will be maintained at a pressure higher than the tubing injection pressure as required by 40 CFR 146.88(c). The design surface pressure loads on the injection tubing and tubing by casing annulus are as follows:

- Maximum tubing injection pressure 1,950 psi
- Maximum annulus pressure 2,050 psi

The maximum tubing injection and shut-in pressures are based on PROSPER flow assurance modeling. The maximum annulus pressure is higher than the maximum injection pressure as required by 40 CFR 146.88(c).

After each casing is set and cemented, and after the tubing and packer are installed, they will be pressure tested to a pressure equal to or greater than the design pressure for that component to demonstrate mechanical integrity.

Material Selection

The material selected for the flow wetted well construction components within the reservoir, including the lower tubing and lower injection casing below the packer, is 25 Cr. Glass reinforced epoxy (GRE) lined tubing will be used above the packer as it will be exposed to the CO_2 stream during injection. Standard carbon steel alloy casing will be used for the injection casing above the packer as it is not planned to be exposed to CO_2 during the lifecycle of the well. Modeling results and supporting literature (see References) confirmed an acceptable corrosion rate for 25 Cr material for the life of the project to meet the well materials compatibility requirement in 40 CFR 146.86(b)(1).

Downhole Monitoring

Downhole monitoring equipment includes (a) a dual transducer pressure/temperature gauge run on tubing above packer and (b) distributed acoustic sensor (DAS) cable on the casing.

Safety System for Injection Wells

The well monitoring system will consist of surface sensors for measuring temperature, pressure, and flow rate. Data from the sensors will be collected and stored in a Supervisory Control and Data Acquisition (SCADA) system. Monitored parameters will have high and low alarms that will be activated when a measured parameter is outside its normal operating range. When a critical parameter alarms, such as pressure, the well will be shut in by a fail-safe actuated gate valve that is a component of the injection tree. Operating personnel will be notified that an alarm was activated. The reason for the alarm will be investigated to determine what needs to be done to make sure the well is safe. After any needed repairs or maintenance are conducted, the well will be put back into service.

A landing nipple profile will be installed near the packer to allow setting a plug or other downhole safety device if required for well maintenance and servicing. Figure 2 shows a schematic of the safety system.

The detailed design, equipment specification, and selection will be completed and submitted to the EPA prior to project startup.

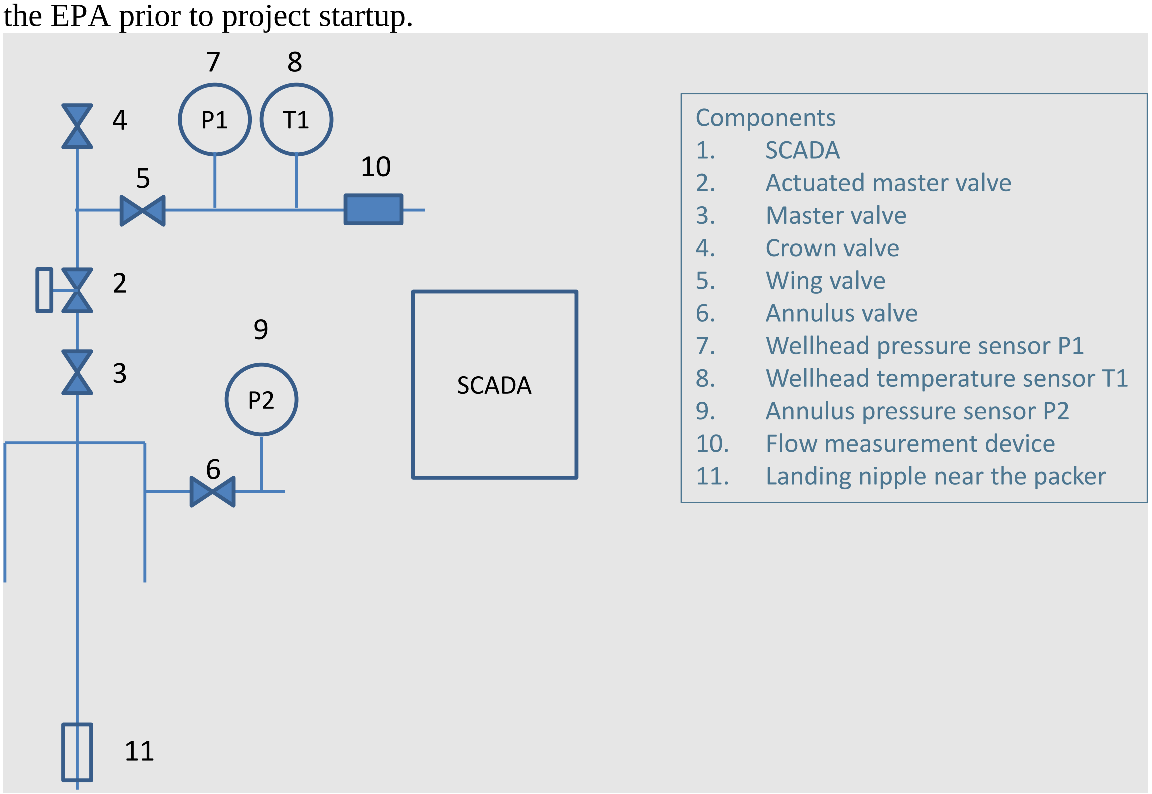

Figure 2: Safety System

Injection Well Casing and Tubing Design

The casings and tubing have been designed to withstand all expected loads during the life of the well including the maximum injection and annulus pressure loads. The materials selected for these items, as shown in Table 4 and Table 5, were based on corrosion analysis for compatibility with the injected fluids and reservoir fluids. The tubular design also takes into consideration the expected temperature profile. The upper casing section will be carbon steel with a corrosion resistant alloy (CRA) lower section. The upper tubing section will be carbon steel lined with a glass reinforced epoxy (GRE) for compatibility with the injected and reservoir fluids per 40 CFR 146.86(b)(1). The flow wetted lower part of the injection casing, tubing, and packer will be CRA materials.

The tubing and casing loads were evaluated and compared to the strengths to determine an appropriate well design including safety factors. Table 2 shows the design factors (minimum safety factors) used in the analysis.

Table 2: Design Factors

Failure Mode	Casing	Tubing
Triaxial (1)	1.20	1.20
Burst (2)	1.20	1.20
Collapse (3)	1.00	1.10
Axial – Tension (4)	1.30	1.30
Axial – Compression (4)	1.30	1.30
Notes: (1) VME Criterion (YS derated for temperature) (2) API Minimum Internal Yield Pressure (3) API (Tension adjusted) Collapse (4) API Pipe Body Yield Strength		

Injection Well Construction Details

Table 3: Open Hole Diameters and Intervals

Name	**Depth Interval** (ft)	**Open Hole Diameter** (in.)	**Comment**
Conductor	Surface – 84	26	
First Surface	Surface – 1,500	17.5	Depth limited by field rules.
Second Surface	Surface – 5,154	12.25	Cemented to surface to isolate the USDW.
Injection string	Surface – 6,373	8.75	

Table 4: Casing Specifications

Name	**Setting Depth (ft)**	**Outside Diameter (in.)**	**Inside Diameter (in.)**	**Weight (ppf)**	**Grade**	**Connection**	**Burst Strength (psi)**	**Collapse Strength (psi)**	**Tensile Strength (lbf)**
Conductor	84	20							
First Surface Casing	1,500	13.375	12.615	54.5	K55	API	2,730	1,130	853,240
Second Surface Casing	5,154	9.625	8.921	36	K55	API	3,520	2,020	564,000
Injection casing section 1	4,600	7	6.366	23	L80	Premium (1)	6,340	3,830	532,440
Injection casing section 2	6,326	7	6.366	23	25Cr80	Premium (1)	6,340	3,830	532,440
Notes: (1) Connection with metal-to-metal seals and full pipe body strength.									

Table 5: Tubing Specifications

Name	Setting Depth (ft)	Outside Diameter (in.)	Inside Diameter (in.)	Weight (ppf)	Grade	Connection	Burst strength (psi)	Collapse strength (psi)	Tensile strength (lbf)
Injection tubing Section 1	5,211	4.5	4.000	11.6	L80 (GRE)	Premium (1)	7,780	6,350	267,040
Injection tubing Section 2	6,142	4.5	4.000	11.6	25Cr80	Premium (1)	7,780	6,350	267,040
Notes: (1) Connection with metal-to-metal seals and full pipe body strength.									

Table 6: Packer Information

Item	**Value**
Packer Setting Depth	5,211 ft, 5,464 ft, 5,719 ft, 6,021 ft
Packer material	Same CRA material as the tubing and casing or a CRA such as Alloy 718
Packer element material	HNBR
Packer type	Hydraulic set retrievable packer
Maximum casing ID	6.366 in. (nominal ID for 7 in. 23 ppf casing)
Minimum casing ID	6.241 in. (drift diameter for 7 in. 23 ppf casing)
Packer / seal assembly ID	4.5 in.
Packer rating	Differential pressure ±10,000 psi, axial capacity ±150,000 lbf, based on the packer loads
Maximum packer to casing forces	96,000 lbf Upward 104,000 lbf Downward

Injection Well Construction Diagram

Figure 3 shows the wellbore schematic for the design with the injection string casing set through the injection zone with the proposed completion equipment.

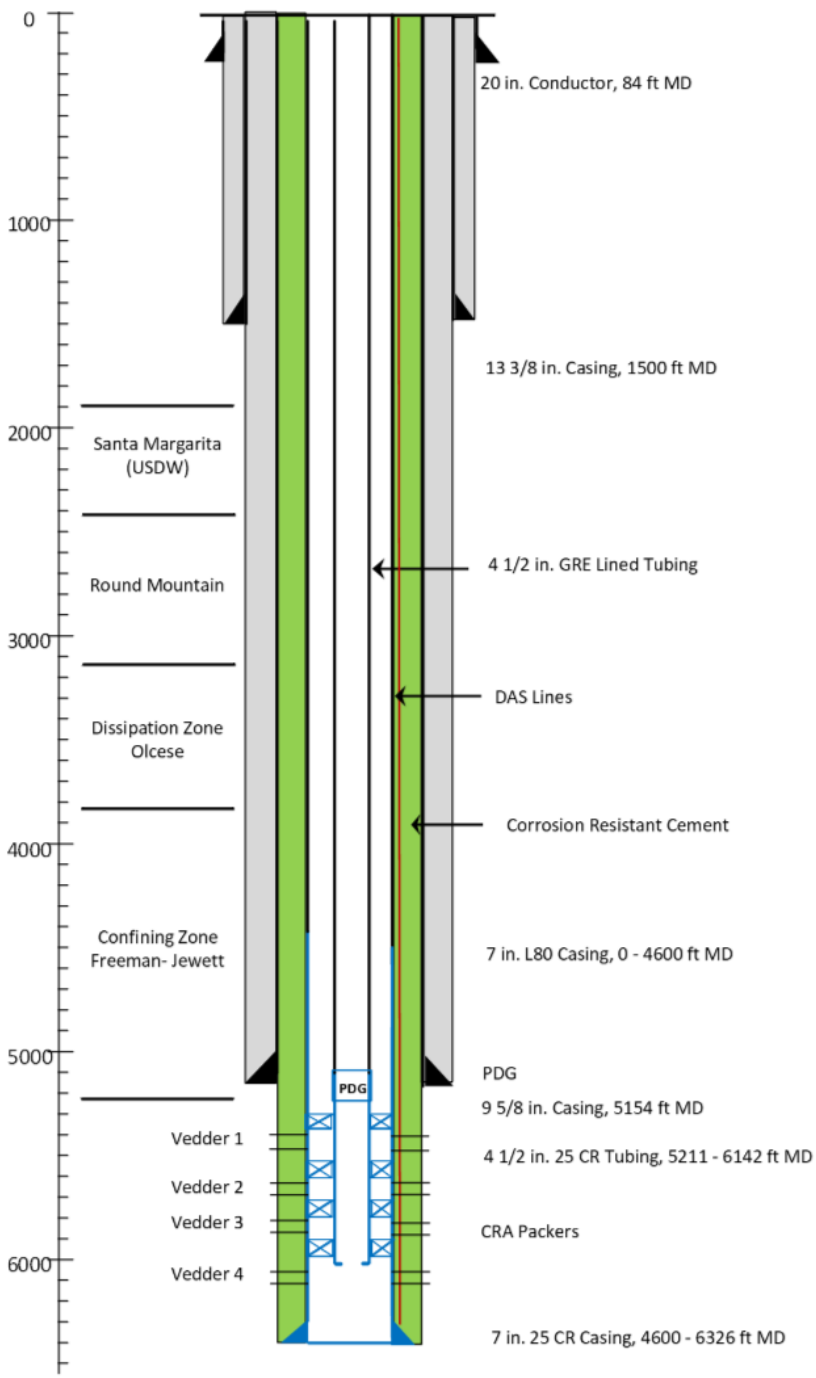

Figure 3: Proposed Wellbore Schematic

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<u>STIMULATION PROGRAM</u>
<u>40 CFR 146.82(a)(9)</u>

Kern River Eastridge CCS

Facility Information

Facility name:	Kern River Eastridge CCS MC19001INJ, ANO9004INJ, MC19002INJ, ANO9005INJ
Facility contact:	David Wessels – Project Manager 9525 Camino Media, Bakersfield, CA 93311 David.wessels@chevron.com / 661-412-6039
Well location:	Bakersfield, Kern County, CA 93308 35.4404°/-118.9983°; 35.4465°/-119.0012°; 35.4401°/-118.9981°; 35.4462°/-119.0010°

Near-wellbore maintenance may be necessary to enhance the injectivity potential of the injection zone. Near-wellbore maintenance may involve but is not limited to flowing fluids into or out of the well, increasing or connecting pore spaces in the injection formation, or other activities that are intended to allow the injectate to move more readily into the injection formation. Near-wellbore maintenance does not include hydraulic fracturing. Advance notice of all proposed near-wellbore maintenance activities will be provided to the Underground Injection Control (UIC) Program Director, as detailed below, prior to conducting the near-wellbore maintenance. Chevron U.S.A., Inc. (Chevron) will describe any fluids to be utilized for near-wellbore maintenance activities and Chevron will demonstrate that the activities will not interfere with containment. Chevron will submit proposed procedures for all near-wellbore maintenance activities to the UIC Program Director in writing at least 30 days in advance, per 40 CFR 146.91(d)(2). Within the 30-day notice period, the Environmental Protection Agency (EPA) may: deny the near-wellbore maintenance; approve the near-wellbore maintenance as proposed; or approve the near-wellbore maintenance with conditions. Chevron will carry out the near-wellbore maintenance procedures, including any conditions, as approved or set forth by EPA.

Introduction/Purpose

It is anticipated that the target injection zone will require near-wellbore maintenance to dissolve drilling mud, carbonate and other minerals introduced to the near-wellbore region during drilling, completion, and injection operations. The objective of the near-wellbore maintenance program is to increase injectivity by removing skin that is degrading the permeability in the near-wellbore region and returning the near-wellbore region to native conditions.

Near-Wellbore Maintenance Fluids

Exact near-wellbore maintenance program design will depend on final drilling program fluid design, final open hole logs, analysis of the chemical constituents of the injection gas, formation mineral content obtained from wellbore or offset well core studies, and injectivity trends as a function of time. Chevron anticipates using several stages, executed sequentially at volumes of 15-25 gallons per foot of open perforation, per stage. The first stage would likely be 1-15% hydrochloric acid. The second stage would likely contain a combination of hydrochloric and hydrofluoric acid totaling 6-12% HCl / 1.5-3% HF. The final stage would likely be a neutralizing clay stabilizer, such as 2-4% ammonium chloride.

Additives

The near-wellbore maintenance program may utilize additives to aid the maintenance plan, including but not limited to acids, corrosion inhibitors, biocides, clay stabilizers, gelling agents, demulsifiers, chelating agents, mutual solvents, iron sequestrants, retarders, surfactants, soluble diversion balls, and/or mechanical divertors.

Diverters

The near-wellbore maintenance treatment may utilize diverters to aid with the treatment plan, including but not limited to: soluble diversion balls, mechanical divertors, and/or gelling agents. This may be utilized to deliver acid to the intended perforations. The specific near-wellbore maintenance design and method for conveying the fluids to the formation will dictate the diverter requirements.

Near-Wellbore Maintenance Procedures

Below is a tentative generic near-wellbore maintenance procedure. The final procedure will depend upon final well construction fluids and perforated lengths.

1. Obtain necessary permits for well work.
2. Move in and rig up coiled tubing unit.
3. Run into the well with coiled tubing and wash nozzle.
    a. Establish injection with inert fluid.
4. Once the wash nozzle is at the top perforation, begin pumping stages while reciprocating the wash nozzle up and down across the perforation interval.
    a. Pump treatment stage. Treatment fluid requirements and volumes will be determined based upon final exposed perforation length and well specific requirements for treatment.
    b. Flush fluid into the perforations with neutralizing stage. Flush fluid and volumes will be determined based upon final well configuration.
    c. Several stages may be utilized to treat the target injection zone. A short soaking period may be utilized in between stages to effectively treat the injection zone.
    d. Continuously monitor pressure and do not exceed the fracture gradient of the formation.
5. Pull out of well with coiled tubing.

6. Rig down and move off coil tubing unit and equipment.
7. Return the well to injection.