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

Brown Pelican CO_2 Sequestration Project

1.0 Facility Information

Facility name: Brown Pelican CO_2 Sequestration Project
BRP CCS 1, CCS2 and CCS3 Wells

Facility contact: [redacted]

Well location: Penwell, Texas

BRP CCS1	31.76479314	-102.7289311
BRP CCS2	31.76993805	-102.7332448
BRP CCS3	31.76031163	-102.7101566

2.0 Overview

Oxy Low Carbon Ventures, LLC (OLCV) will construct CO_2 injection wells for the Brown Pelican CO_2 Sequestration Project (BRP Project or Project) according to the procedures in this document. The matter of construction details is relevant to the requirements of Environmental Protection Agency (EPA) document 40 CFR Subpart H – Criteria and Standards Applicable to Class VI Wells. The main topics covered in this attachment are special construction requirements, open hole diameters and intervals, casing specifications, tubing specifications, data acquisition and testing plan, and demonstration of mechanical integrity.

The Brown Pelican CCS1, CCS2 and CCS3 (BRP CCS1, BRP CCS2 and BRP CCS3) injection wells are designed with the highest standards and best practices for drilling and well construction. The design parameters and material selection are aimed to ensure mechanical integrity in the system and to optimize the operation during the life of the Project.

3.0 Design Parameters and Specifications

The well was designed to maximize the rate of injection while maintaining the bottomhole pressure below 90% of the fracture gradient. The selected design provides enough clearance to deploy the pressure and temperature gauges on tubing and install a fiber optic cable on the long string casing to ensure continuous surveillance of external integrity and conformance.

Design parameters that will be employed during the life of the well are shown in Table 1, and CO_2 specifications for the Project are shown in Table 2. A nodal analysis was used to perform sensitivities on the tubing size, rate of erosion, and potential movement of the tubulars. The nodal analysis results, operating parameters, and CO_2 specifications were used in selecting materials to be used to construct the well.

Table 1—Design Parameters

Parameter	Value or Range
Injection rate (MTPD)	417-1319
Tubing pressure (psi)	1,000 to 1,800
Annular surface pressure (psi)	0 to 400
Surface temperature (°F)	60 to 90
Bottomhole temperature (°F)	120

Note:
Annular surface pressure between the tubing and long string will be kept between 0 and 400 psi to monitor changes during injection. It is not recommended to apply the maximum injection pressure to the annulus between the tubing and the long string casing to avoid unnecessary stress on the cement sheath, which could lead to a micro-annulus or microfractures.

Table 2—Specification of CO_2 Injectate

Component	Specification
CO_2 content	>95 mol%
Water	<30 lbm/MMscf
Nitrogen	<4 mol%
Sulphur	<35 ppm by weight
Oxygen	<5 mol%
Glycol	<0.3 gal/MMscf
Carbon Monoxide	<4,250 ppm by weight
NOx	<6 ppm by weight
SOx	<1 ppm by weight
Particulates ($CaCO_3$)	<1 ppm by weight
Argon	<1 mol%
Surface pressure	>1,600 psig
Surface temperature	>65°F and <120°F

4.0 Well Design

OLCV plans to construct three CO_2 injector wells: BRP CCS1, BRP CCS2, and BRP CCS3 for the Project. The locations and orientations of those wells are shown in Figure 1 below.

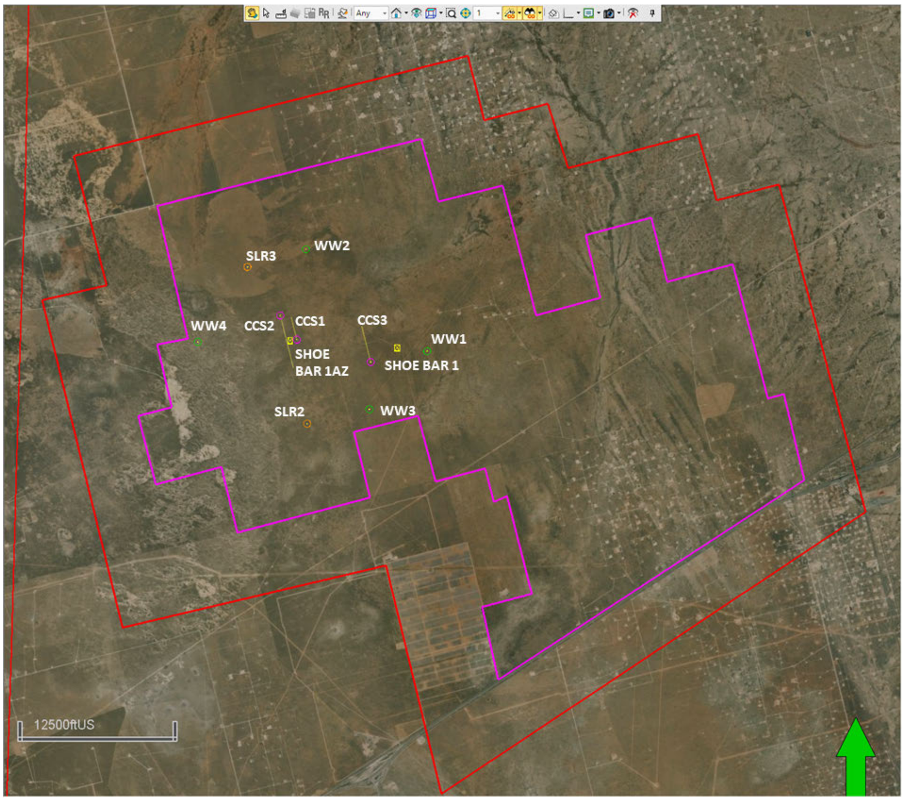

Figure 1—BRP CCS1, BRP CCS2 and BRP CCS3 Well Locations

4.1 BRP CCS1

4.1.1 Design for BRP CCS1

The BRP CCS1 well design includes three main casing sections: 1) surface casing to cover the USDW and provide integrity while drilling to the Injection Zone, 2) intermediate section, and 3) a long string section to acquire formation data and isolate the target formation while running the upper completion equipment. Figure 2 presents wellbore trajectory of BRP CCS1 and Figure 3 is BRP CCS1 well proposed schematic

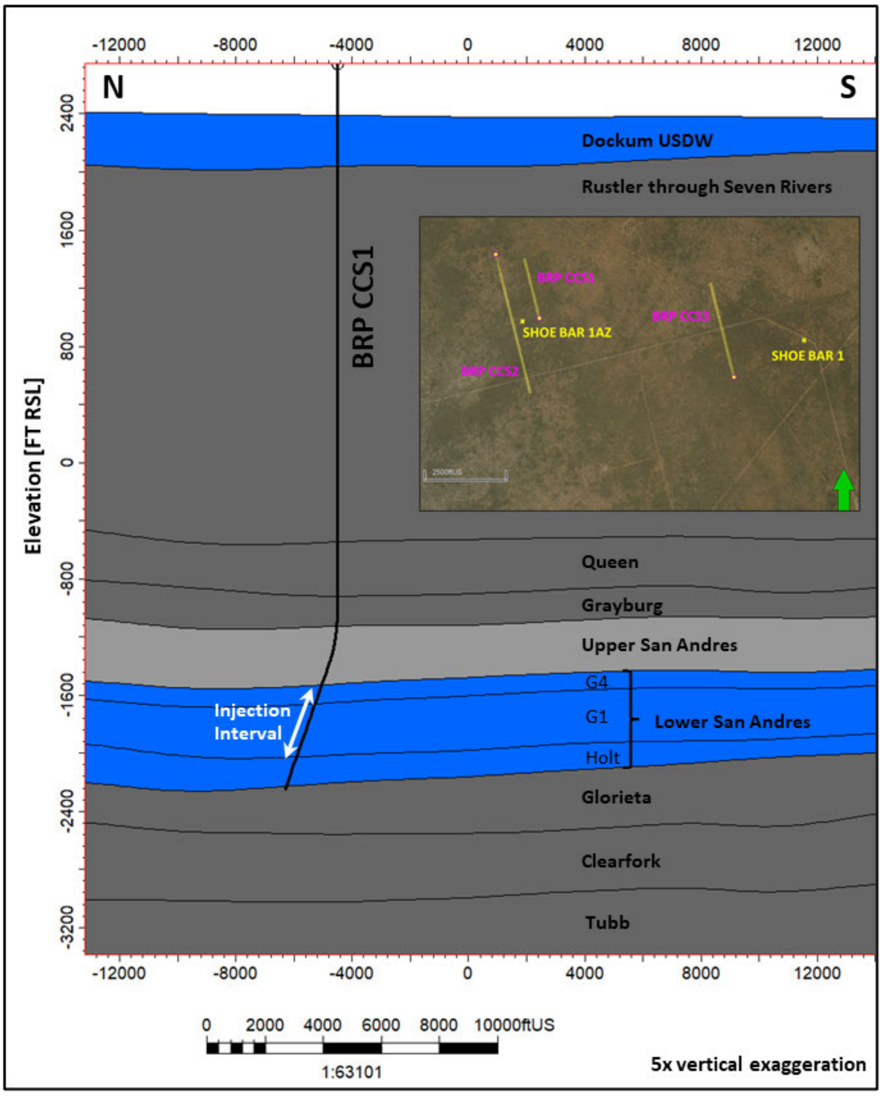

Figure 2—Wellbore trajectory of BRP CCS1 with completion interval in sub-zone G4-G1 highlighted in white.

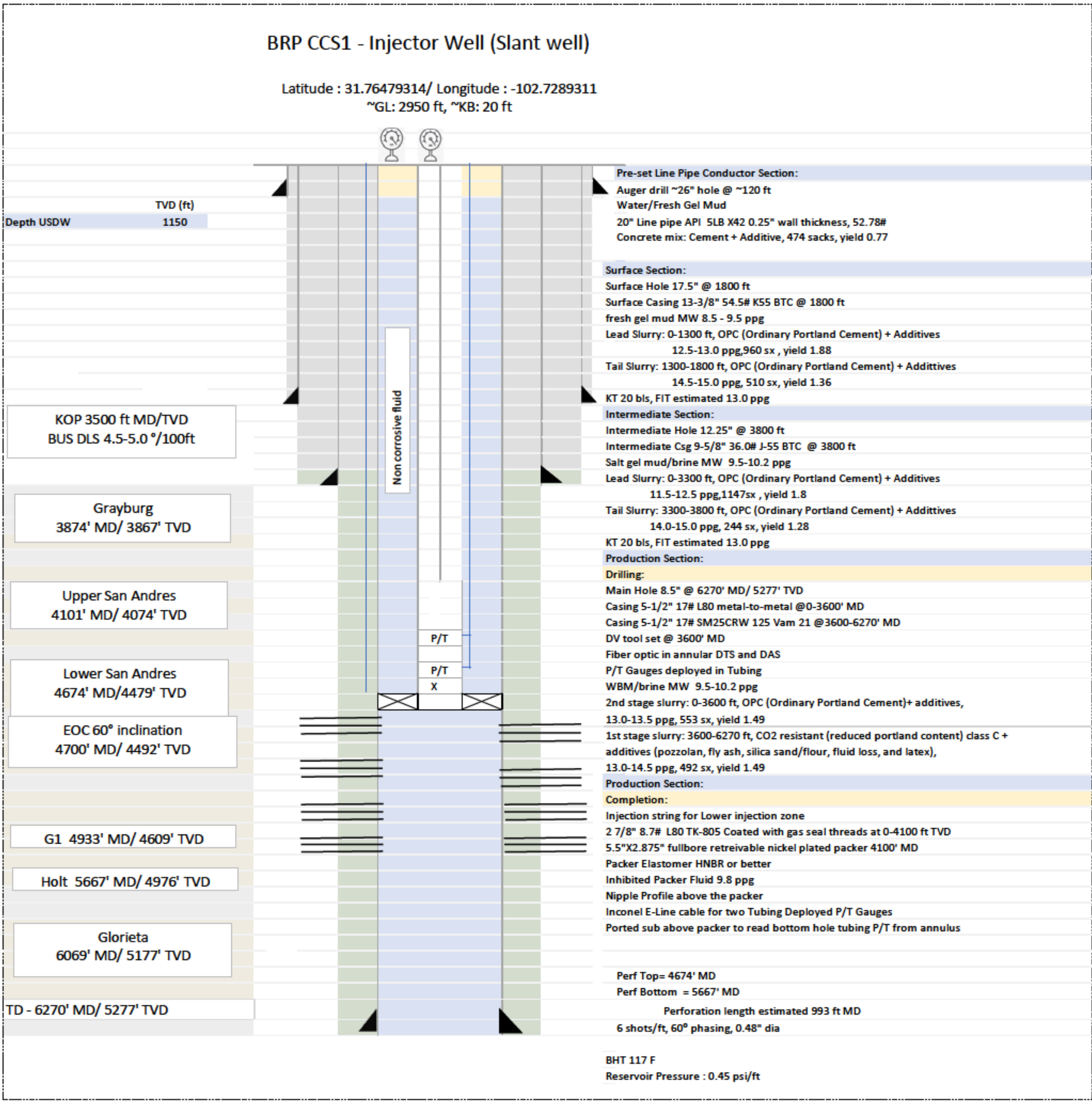

Figure 3—BRP CCS1 well proposed schematic

Details of BRP CCS1 well design are provided in the following tables. Table 3 contains the open hole diameters of each section, Table 4 lists the casing specifications, and Table 5 details the casing material properties. In addition, Table 7 contains the upper completion equipment specifications, and Table 8 shows the tubing material properties.

Table 3—Open Hole Diameters and Intervals for BRP CCS1

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor Section	0 to 120	26	Auger drill
Surface section	0 to 1,800	17 ½	Below base of USDW
Intermediate section	1,800 to 3800	12 ¼	Intermediate section
Long string section	3800 to 6270	8 ½	To total depth (TD)

Notes:

- The well TD includes a minimum 80 ft of cement shoe track, and 100 ft casing rat hole for completion operations in the Glorieta Formation.
- The USDW depth will be confirmed with open hole logs.

Table 4—Casing Specifications for BRP CCS1

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lbm/ft)	Grade (API)	Coupling
Pre-set conductor	0 to 120'	20	19.5	19.25	52.78	5LB X42	weld
Surface string	0 to 1,800	13 3/8	12.615	12.459	54.5	K-55	BTC
Intermediate string	0 to 3,800	9 5/8	8.921	8.765	36	J-55	BTC
Long string	0 to 3,600	5 1/2	4.892	4.767	17	L80	LTC or Vam 21
Long string	3,600 to 6,270	5 1/2	4.892	4.767	17	SM25CRW-125*	Vam 21

*Casing material selection

Table 5—Casing Material Properties for BRP CCS1

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)
20 in conductor	0 to 120	-	-	-
13 3/8 -in. 54.5# K-55 BTC	0 to 1,800	2,730	1,130	853
9 ⅝-in. 36# J-55 BTC	0 to 3,800	3,520	2,020	564
5 ½ -in. 17# L80	0 to 3,600	7,740	6,290	397
5 ½ -in. 17# SM25CRW-125	3,600 to 6,270	12,090	7,890	829

Notes:

- A stage tool will be located at ~3,000 to 4,000 ft in the 5-1/2-in. casing to perform the two-stage cement job.
- The centralization program will aim at 70- 90% standoff and will be adjusted using the field data for deviation, caliper, and hole conditions.
- DTS/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

Table 6—Direction design for BRP CCS1

Name	MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	Dogleg (°/100ft)	Description
SHL	0	0	0	0	0.00	Surface hole location
KOP	3500	0	346	3500	0.00	Kick of point
EOC	4700	60	346	4492	5.00	End of curve
Well TD	6270	60	346	5277	0.00	Tangent section

Table 7—Upper Completion Equipment Specifications for BRP CCS1

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lbm/ft)	Grade (API)	Coupling
Injection (Coated TK-805) tubing	0 to 4,100	2 7/8	2.441	2.347	6.5	L80	Special
Packer	Nickel-plated / HNBR (RGD) elastomers						

Table 8—Tubing Material Properties for BRP CCS1

Tubing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Ksi)
2 7/8-in. 6.5# L80 Special – Coated TK-805	0 to 4,100	10,570	11,170	80

Notes:

- Pressure and temperature gauges will be tubing-deployed above and below casing. Cable material will be Inconel®, and gauge carriers will be CO_2-resistant material.
- The internal diameter of the tubing will be slightly reduced due to the TK-805 coating to be applied.
- The annular space between the 2 7/8-in. tubing and 5 1/2-in. casing will be filled with packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

4.1.2 Proposed Drilling Procedure for BRP CCS1

The next section is the drilling procedure for BRP CCS1.

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1 Distributed acoustic sensing (DAS) and distributed temperature sensing (DTS)

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4.1.3 Proposed Completion Procedure for BRP CCS1

During the completion operations, the rig will test the casing to 500 psi, condition the long string casing with a bit and scraper, run a CBL-VDL-USIT-CCL[2] log to evaluate cement bonding and casing conditions, perforate the Injection Zone, and run the upper completion equipment. The 2 7/8-in. tubing and packer completion will be run to approximately 4,100 ft, in conjunction with an electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid, and the packer will be set. Once the packer is set, an annular pressure test will be performed to 500 psi to validate the mechanical seal. A leak-off test followed by a pressure fall-off test will be performed before starting injection.

A detailed proposed procedure follows:

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[2] Cement bond long (CBL), variable density log (VBL), ultrasonic imager tool (USIT), casing collar locator (CCL)

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4.2 BRP CCS2

The BRP CCS2 well design includes three main casing sections: 1) surface casing to cover the USDW and provide integrity while drilling to the Injection Zone, 2) intermediate section, and 3) a long string section to acquire formation data and isolate the target formation while running the upper completion equipment. Figure 4 presents wellbore trajectory of BRP CCS2 and Figure 5 is BRP CCS2 well proposed schematic

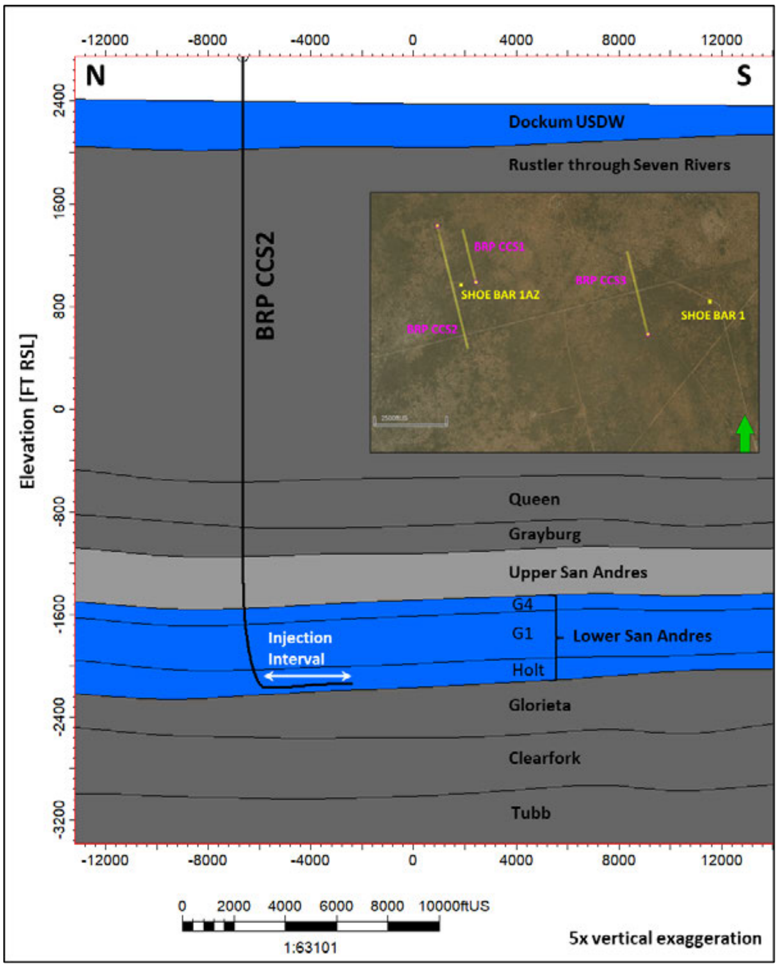

Figure 4—Wellbore trajectory of BRP CCS2 horizontal well with completion interval in sub-zone Holt highlighted in white.

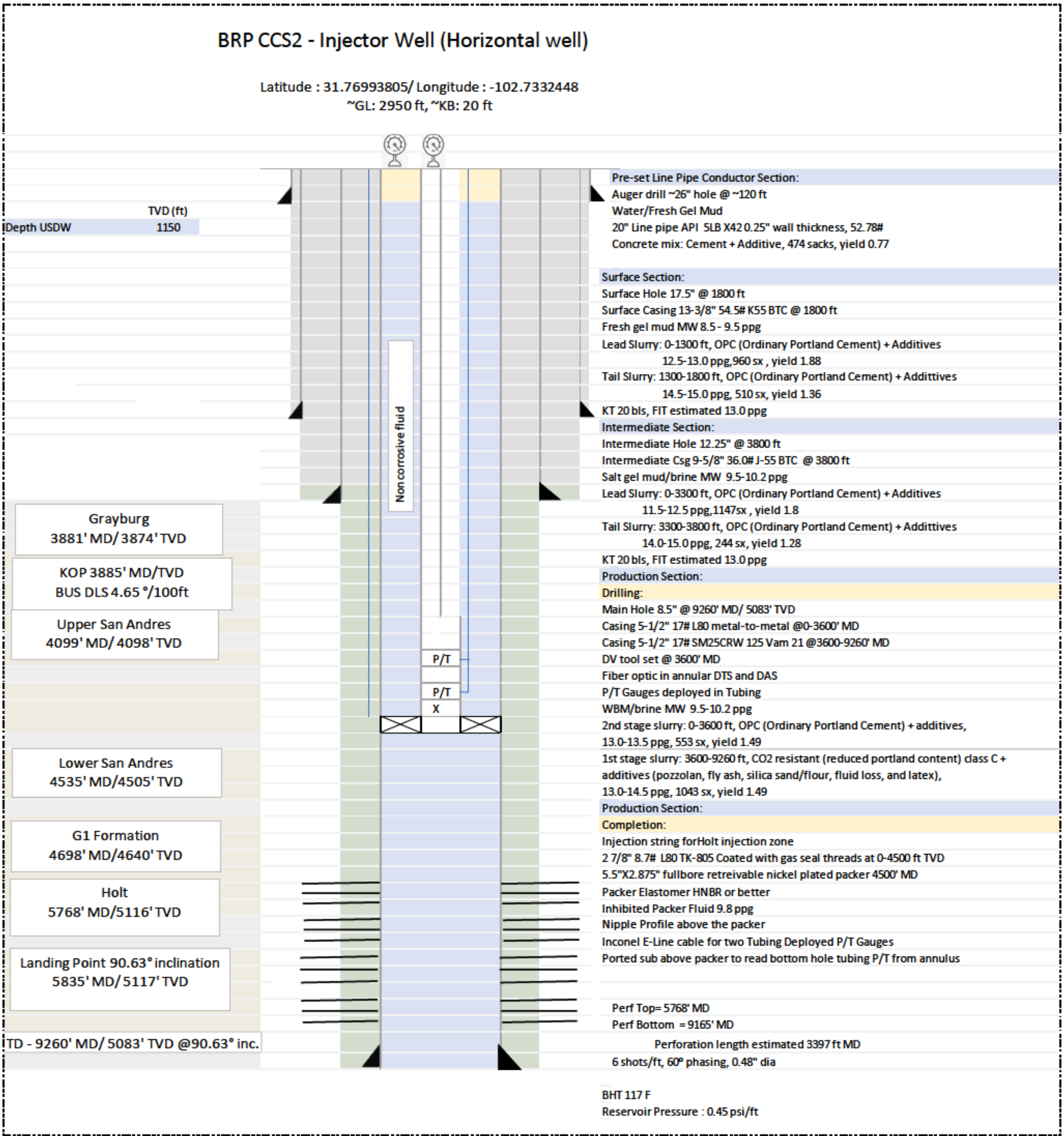

Figure 5—BRP CCS2 well proposed schematic

4.2.1 Design for BRP CCS2

Details regarding the BRP CCS2 well design are provided in the following tables. Table 9 contains the open hole diameters of each section, Table 10 lists the casing specifications, and Tables 11 details the casing material properties. In addition, Table 13 contains the upper completion equipment specifications, and Table 14 shows the tubing material properties.

Table 9—Open Hole Diameters and Intervals for BRP CCS2

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor Section	0 to 120	26	Auger drill
Surface section	0 to 1,800	17 ½	Below base of USDW
Intermediate section	1,800 to 3800	12 ¼	Intermediate section
Long string section	3800 to 9260	8 ½	To total depth (TD)

Notes:

- The well TD includes a minimum 80 ft of cement shoe track in the Holt Formation.
- The USDW depth will be confirmed with open hole logs.

Table 10—Casing Specifications for BRP CCS2

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lbm/ft)	Grade (API)	Coupling
Pre-set conductor	0 to 120'	20	19.5	19.25	52.78	5LB X42	weld
Surface string	0 to 1,800	13 3/8	12.615	12.459	54.5	K-55	BTC
Intermediate string	0 to 3,800	9 5/8	8.921	8.765	36	J-55	BTC
Long string	0 to 3,600	5 1/2	4.892	4.767	17	L80	LTC or Vam 21
Long string	3,600 to 9,260	5 1/2	4.892	4.767	17	SM25CRW-125*	Vam 21

*Casing material selection

Table 11—Casing Material Properties for BRP CCS2

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)
20 in conductor	0 to 120	-	-	-
13 3/8 -in. 54.5# K-55 BTC	0 to 1,800	2,730	1,130	853
9 ⅝-in. 36# J-55 BTC	0 to 3,800	3,520	2,020	564
5 ½ -in. 17# L80	0 to 3,600	7,740	6,290	397
5 ½ -in. 17# SM25CRW-125	3,600 to 9,260	12,090	7,890	829

Notes:

- A stage tool will be located at ~3,000 to 4,000 ft in the 5-1/2-in. casing to perform the two-stage cement job.
- The centralization program will aim at 70- 90% standoff and will be adjusted using the field data for deviation, caliper, and hole conditions.
- DTS/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

Table 12—Direction design for BRP CCS2

Name	MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	Dogleg (°/100ft)	Description
SHL	0	0	0	0	0.00	Surface hole location
KOP	3885	0	346	3885	0.00	Kick of point
LP	5835	90.67	166	5117	4.64	Landing point
Well TD	9260	90.53	166	5083	0.00	Lateral section

Table 13—Upper Completion Equipment Specifications for BRP CCS2

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lbm/ft)	Grade (API)	Coupling
Injection (Coated TK-805) tubing	0 to 4,500	2 7/8	2.441	2.347	6.5	L80	Special
Packer	Nickel-plated / HNBR (RGD) elastomers						

Table 14—Tubing Material Properties for BRP CCS2

Tubing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Ksi)
2 7/8-in. 6.5# L80 Special – Coated TK-805	0 to 4,500	10,570	11,170	80

Notes:

- Pressure and temperature gauges will be tubing-deployed above and below casing. Cable material will be Inconel®, and gauge carriers will be CO_2-resistant material.
- The internal diameter of the tubing will be slightly reduced due to the TK-805 coating to be applied.
- The annular space between the 2 7/8-in. tubing and 5 1/2-in. casing will be filled with packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

4.2.2 Proposed Drilling Procedure for BRP CCS2

The next section is the drilling procedure for BRP CCS2.

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4.2.3 Proposed Completion Procedure for BRP CCS2

During the completion operations, the rig will test the casing to 500 psi, condition the long string casing with a bit and scraper, run a CBL-VDL-USIT-CCL[4] log to evaluate cement bonding and casing conditions, perforate the Injection Zone, and run the upper completion equipment. The 2 7/8-in. tubing and packer completion will be run to approximately 4,500 ft, in conjunction with an electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid, and the packer will be set. Once the packer is set, an annular pressure test will be performed to 500 psi to validate the mechanical seal. A leak-off test followed by a pressure fall-off test will be performed before starting injection.

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4.3 BRP CCS3

4.3.1 Design for BRP CCS3

The BRP CCS3 well design includes three main casing sections: 1) surface casing to cover the USDW and provide integrity while drilling to the Injection Zone, 2) intermediate section, and 3) a long string section to acquire formation data and isolate the target formation while running the upper completion equipment. Figure 6 presents wellbore trajectory of BRP CCS3 and Figure 7 is BRP CCS3 well proposed schematic.

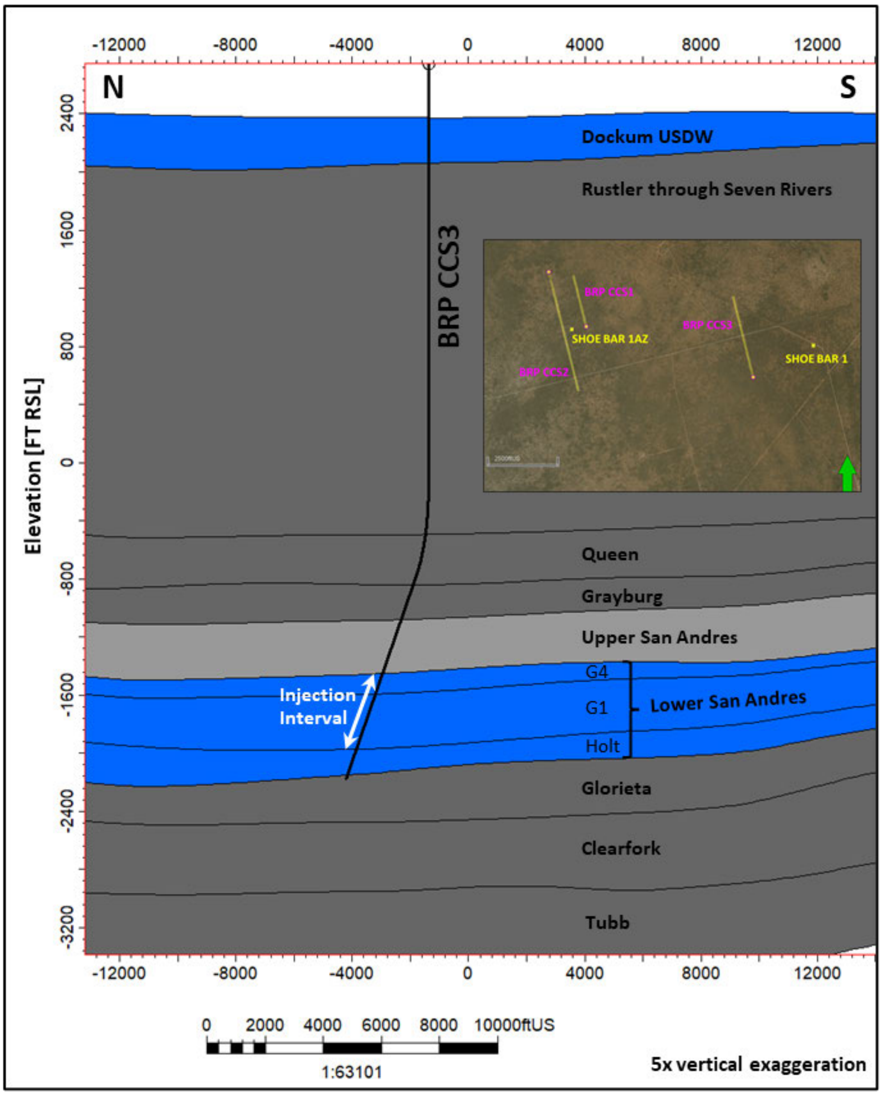

Figure 6—Wellbore trajectory of BRP CCS3 with completion interval in sub-zone G4-G1 highlighted in white

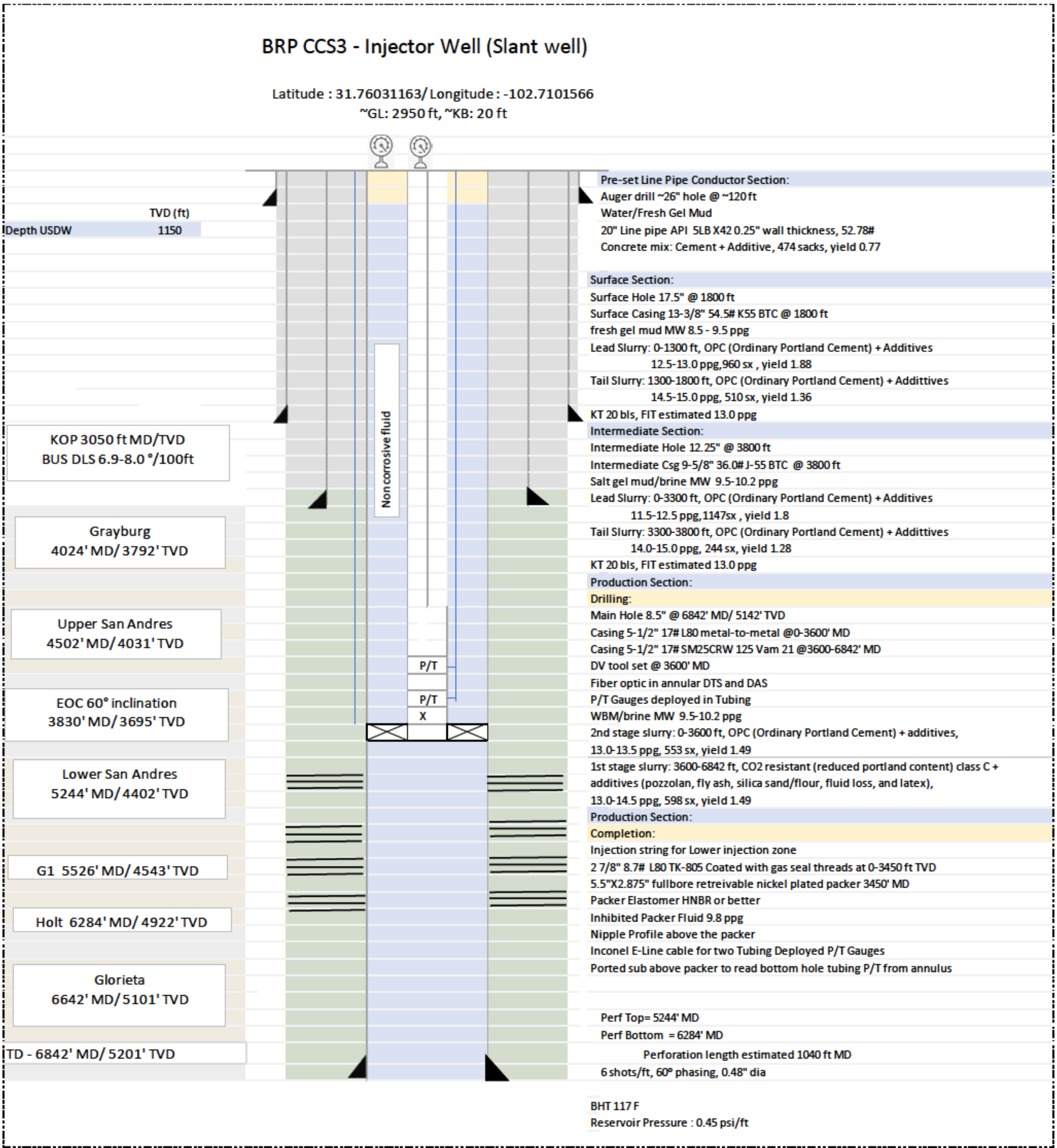

Figure 7—BRP CCS3 well proposed schematic

Details of BRP CCS3 well design are provided in the following tables. Table 15 contains the open hole diameters of each section, Table 16 lists the casing specifications, and Table 17 details the casing material properties. In addition, Table 19 contains the upper completion equipment specifications, and Table 20 shows the tubing material properties.

Table 15—Open Hole Diameters and Intervals BRP CCS3

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor Section	0 to 120	26	Auger drill
Surface section	0 to 1,800	17 ½	Below base of USDW
Intermediate section	1,800 to 3,800	12 ¼	Intermediate section
Long string section	3,800 to 6,842	8 ½	To total depth (TD)

Notes:

- The well TD includes a minimum 80 ft of cement shoe track, and 100 ft casing rat hole for completion operations in the Glorieta Formation.
- The USDW depth will be confirmed with open hole logs.

Table 16—Casing Specifications BRP CCS3

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lbm/ft)	Grade (API)	Coupling
Pre-set conductor	0 to 120'	20	19.5	19.25	52.78	5LB X42	weld
Surface string	0 to 1,800	13 3/8	12.615	12.459	54.5	K-55	BTC
Intermediate string	0 to 3,800	9 5/8	8.921	8.765	36	J-55	BTC
Long string	0 to 3,600	5 1/2	4.892	4.767	17	L80	LTC or Vam 21
Long string	3,600 to 6,842	5 1/2	4.892	4.767	17	SM25CRW-125*	Vam 21

*Casing material selection

Table 17—Casing Material Properties for BRP CCS3

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)
20 in conductor	0 to 120	-	-	-
13 3/8 -in. 54.5# K-55 BTC	0 to 1,800	2,730	1,130	853
9 ⅝-in. 36# J-55 BTC	0 to 3,800	3,520	2,020	564
5 ½ -in. 17# L80	0 to 3,600	7,740	6,290	397
5 ½ -in. 17# SM25CRW-125	3,600 to 6,842	12,090	7,890	829

Notes:

- A stage tool will be located at ~3,000 to 4,000 ft in the 5-1/2-in. casing to perform the two-stage cement job.
- The centralization program will aim at 70- 90% standoff and will be adjusted using the field data for deviation, caliper, and hole conditions.
- DTS/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

Table 18—Direction design for BRP CCS3

Name	MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	Dogleg (°/100ft)	Description
SHL	0	0	0	0	0.00	Surface hole location
KOP	3050	0	346	3050	0.00	Kick of point
EOC	3830	60	346	3695	7.69	End of curve
Well TD	6842	60	346	5201	0.00	Tangent section

Table 19—Upper Completion Equipment Specifications

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lbm/ft)	Grade (API)	Coupling
Injection (Coated TK-805) tubing	0 to 3450	2 7/8	2.441	2.347	6.5	L80	Special
Packer	Nickel-plated / HNBR (RGD) elastomers						

Table 20—Tubing Material Properties

Tubing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Ksi)
2 7/8-in. 6.5# L80 Special – Coated TK-805	0 to 3450	10,570	11,170	80

Notes:

- Pressure and temperature gauges will be tubing-deployed above and below casing. Cable material will be Inconel®, and gauge carriers will be CO_2-resistant material.
- The internal diameter of the tubing will be slightly reduced due to the TK-805 coating to be applied.
- The annular space between the 2 7/8-in. tubing and 5 1/2-in. casing will be filled with packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

4.3.2 Proposed Drilling Procedure for BRP CCS3

The next section is the drilling procedure for BRP CCS3.

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4.3.3 Proposed Completion Procedure for BRP CCS3

During the completion operations, the rig will test the casing to 500 psi, condition the long string casing with a bit and scraper, run a CBL-VDL-USIT-CCL[5] log to evaluate cement bonding and casing conditions, perforate the Injection Zone, and run the upper completion equipment. The 2 7/8-in. tubing and packer completion will be run to approximately 3450 ft, in conjunction with an electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid, and the packer will be set. Once the packer is set, an annular pressure test will be performed to 500 psi to validate the mechanical seal. A leak-off test followed by a pressure fall-off test will be performed before starting injection.

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4.4 Material Selection

Casing string materials for the injection wells are selected based on the risk of corrosion with the casing in the zones where no risk of CO_2 in contact with the casing is made of alloy steel as shown in the well schematics and the zone where casing will be in contact with the CO_2 and formation water will be of corrosion resistant alloy (CRA). This covers the primary casing below the packer and 3 to 5 joints above the packer being of corrosion resistant alloy and the remaining is of alloy steel.

Appendix A discusses the material selection process.

4.5 Cement Program

To ensure long term barrier integrity under anticipated CO_2 conditions at and near the Injection Zone, modifications have been made to the slurry design(s) which improve chemical and mechanical resistance to the effects of carbonic acid exposure. These are and will be referenced as '*CO_2 Resistant Slurries*.' The modifications, while may vary slightly due to well conditions, formation pressures and strengths, etc. all contain the following composition adjustments when compared to conventional and/or ordinary Portland cement (OPC).

Additional discussion about the cement selection and additives is in Appendix B

Table 21—Cementing Program for BRP CCS1

Section	Type	Depths (ft)	Density (ppg)	Sacks	Excess
20 in	concrete blend	0 to 120	-	474	100%
17 ½ -in.	OPC (Ordinary Portland Cement) with additives	0 to 1,300	12.5-13.0	960	100%
	OPC (Ordinary Portland Cement) with additives	1,300 to 1,800	14.5-15.0	510	100%
12 ¼-in.	OPC (Ordinary Portland Cement) with additives	0 to 3,300	11.5-12.5	1147	100%
	OPC (Ordinary Portland Cement) with additives	3,300 to 3,800	14.0-15.0	244	100%
8 ½ -in.	OPC (Ordinary Portland Cement) with additives	0 to 3,600	13.0-13.5	553	0%
	Class C reduced Portland content with additives (pozzolan, fly ash, silica sand/flour)*	3,600 to 6,270	13.0-14.5	492	20-30%

Table 22—Cementing Program for BRP CCS2

Section	Type	Depths (ft)	Density (ppg)	Sacks	Excess
20 in	concrete blend	0 to 120	-	474	100%
17 ½ -in.	OPC (Ordinary Portland Cement) with additives	0 to 1,300	12.5-13.0	960	100%
	OPC (Ordinary Portland Cement) with additives	1,300 to 1,800	14.5-15.0	510	100%
12 ¼-in.	OPC (Ordinary Portland Cement) with additives	0 to 3,300	11.5-12.5	1147	100%
	OPC (Ordinary Portland Cement) with additives	3,300 to 3,800	14.0-15.0	244	100%
8 ½ -in.	OPC (Ordinary Portland Cement) with additives	0 to 3,600	13.0-13.5	553	0%
	Class C reduced Portland content with additives (pozzolan, fly ash, silica sand/flour)*	3,600 to 9,260	13.0-14.5	1043	20-30%

Table 23—Cementing Program for BRP CCS3

Section	Type	Depths (ft)	Density (ppg)	Sacks	Excess
20 in	concrete blend	0 to 120	-	474	100 %
17 ½ -in.	Class C cement with additives	0 to 1,300	12.5-13.0	960	100%
	Class C cement with additives	1,300 to 1,800	14.5-15.0	510	100%
12 ¼-in.	Class C cement with additives	0 to 3,300	11.5-12.5	1147	100%
	Class C cement with additives	3,300 to 3,800	14.0-15.0	244	100%
8 ½ -in.	Class C cement with additives	0 to 3,600	13.0-13.5	553	0%
	Class C reduced Portland content with additives (pozzolan, fly ash, silica sand/flour)*	3,600 to 6,842	13.0-14.5	598	20-30%

Notes:

- The slurry design might change in density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the Injection, Upper Confining, and USDW zones.

4.6. Mud Program

Table 24--Mud Program for BRP CCS1

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lbm/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½ - in	Fresh water gel	0 to 1,800	8.5 to 9.5	12 to 14	14 to 18	40 to 50	<20	<8
12 ¼-in	Fresh gel mud/ Brine water inhibited	0 to 3,800	9.5 to 10.2	14 to 18	16 to 18	40 to 50	<6	<3
8 1/2-in	Brine water inhibited	3,800 to 6,270	9.5 to 10.2	14 to 18	16 to 18	40 to 50	<6	<3

Table 25--Mud Program for BRP CCS2

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lbm/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½ - in	Fresh water gel	0 to 1,800	8.5 to 9.5	12 to 14	14 to 18	40 to 50	<20	<8
12 ¼-in	Fresh gel mud/ Brine water inhibited	0 to 3,800	9.5 to 10.2	14 to 18	16 to 18	40 to 50	<6	<3

8 1/2-in	Brine water inhibited	3,800 to 9,260	9.5 to 10.2	14 to 18	16 to 18	40 to 50	<6	<3

Table 26--Mud Program for BRP CCS3

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lbm/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½ -in	Fresh water gel	0 to 1,800	8.5 to 9.5	12 to 14	14 to 18	40 to 50	<20	<8
12 ¼-in	Fresh gel mud/ Brine water inhibited	0 to 3,800	9.5 to 10.2	14 to 18	16 to 18	40 to 50	<6	<3
8 1/2-in	Brine water inhibited	3,800 to 6,842	9.5 to 10.2	14 to 18	16 to 18	40 to 50	<6	<3

5.0 Data Acquisition and Testing Plan Summary

Comprehensive details on pre-operational testing are provided in the Pre-Operational Testing Plan that is part of this application. The information below summarizes key components of the plan.

The CO_2 Injection well testing program is designed to obtain the chemical and physical characteristics of the Injection and Upper Confining zone(s). This program includes a combination of logging, sidewall coring, formation hydrogeologic testing, and other activities performed during the construction of the CO_2 injection wells.

This pre-operational testing program will determine or verify the depth, thickness, mineralogy, lithology, porosity, permeability, and geomechanical information of the Injection Zone, the overlying Upper Confining Zone, and other relevant geologic formations. In addition, formation fluid characteristics of the Injection Zone will be obtained to establish baseline data against which future measurements may be compared after the start of injection operations. Table 27 lists the wireline logs and tests proposed for the BRP CCS1, BRP CCS2, and BRP CCS3. Consult Table 14 of the Pre-Operations Plan or Table 6 in the QASP for details on fluid analyses.

Table 27—Wireline Logs and Tests in the CO_2 injector wells

Method	Interval Section(s)	Purpose
Open Hole Logs, Surveys and Sampling During Construction		
Deviation survey	Every 100 ft while drilling as minimum, from surface to TD	Define well trajectory, displacement, and tortuosity
Wireline- Spontaneous Potential	Surface, Intermediate, Production	Correlation log, volume of shale indicator, estimate salinity
Wireline – Resistivity	Surface, Intermediate, Production	Fluid identification, estimate salinity, correlation log
Wireline – Caliper	Surface, Intermediate, Production	Identify borehole enlargement and calculate cement volume
Wireline -Gamma ray	Intermediate, Production	Define stratigraphy, correlation log, shale indicator
Wireline -Magnetic resonance image	Production	Estimate porosity, pore size distribution, permeability index
Wireline -Sonic Scanner	Intermediate, Production	Estimate mechanical properties, validation of velocity model, well tie to seismic
Wireline - Spectral gamma ray	Intermediate, Production	Define uranium rich formation, clay indicator
Wireline - Density / neutron	Intermediate, Production	Estimate porosity, mineralogical characterization
Wireline -High-definition image	Production	Identify fracture, structural information, minimum stress orientation
Wireline - Litho-scanner or an equivalent Elemental Capture Spectroscopy	Production	Identify mineralogy
Wireline - Formation Dynamics Testing	Production	Measure formation pressures, fluid sampling, mini-frac testing
Mud Logging	Surface to TD (every 30 ft)	Identify lithology, hydrocarbon shows, gases composition
Cased Hole Logs and surveys Before Injection		
Wireline - CBL-VDL-USIT-CCL	Surface, Intermediate, Production	Cement bond, casing integrity. Validate external mechanical integrity
Annulus Pressure Test - Long string casing	Annular between tubing and long string	Validate internal mechanical integrity between the tubing, long-string, and packer
Wireline - Activate pulsed neutron – Long string casing	Surface, Intermediate, Production	CO_2 saturation, baseline for monitoring
Wireline - Temperature Log	Surface, Intermediate, Production	Measure baseline temperature profile on the well from surface to top of perforation
Fiber Optic - DAS, DTS survey	Surface, Intermediate, Production	Measure baseline temperature profile on the well from surface to top of perforation. Acquire baseline 3D VSP survey for monitoring plume migration over time

In addition to the logging and testing listed above, OLCV will perform mini-fracs in distinct porosity / permeability packages within the proposed Injection Zone and Upper and Lower Confining Zones. Thin intervals that are interpreted to have limited horizontal extent will not be tested. The interval for mini-frac will be selected upon review of logging data. The Fracture Extension Pressure will be interpreted by qualified OLCV reservoir and completions engineers to determine injection limits throughout the Injection Zone.

In addition to Mini-fracs, the Project will utilize the MDT tool to collect reservoir pressures and acquire fluid samples in the Injection Zone. Based on data from the Shoe Bar 1 and Shoe Bar 1AZ, OLCV anticipates encountering three distinct porosity zones. OLCV will collect fluid samples in each of these porosity zones. The final sampling depths will be selected after reviewing logs for the specific Injector well. The fluid and dissolved gas samples will be transported under pressure to a third-party lab for comprehensive analysis. See Table 14 in the Pre-Operational Testing Plan or Table 6 in the Quality Assurance and Surveillance Plan for details on the analytical program for fluids and dissolved gasses.

Fluid level testing will be conducted following well completion. The test will measure static fluid level using an echometer. See Section 3.12 of the Pre-Operations plan for details on the echometer tool.

An injection test will be performed in the Lower San Andres after the injection well is complete, including perforation of the Injection Zone and installation of the injection tubing and packer. The pre-operation injectivity testing will serve as the baseline for future pressure fall-off testing. The purpose of conducting an injectivity test is to verify or establish the injection well operating parameters and constrain the inputs used for dynamic injection simulation modeling.

The injection testing will comprise of a period (typically 12-24hrs) of injection at constant rate (typically 0.5-2bpm) subject to a maximum bottom pressure (less than the estimated fracture gradient for the perforated interval). This is followed by a shut-in/pressure fall off period (typically 24-48hrs) for monitoring. The injection period will be used to establish/monitor well injectivity performance and the fall off analysis will indicate the well/reservoir flow regime, average reservoir flow characteristics and the presence (if any) of reservoir baffles/boundaries/interwell interference. The tests will be planned to cover the entire perforated interval of the injector well. Injection profile logs will be run if needed to monitor the distribution of fluid and check of out of zone injection/non-contributing layers.

The results of the testing program will be documented in a report and submitted to the US Environmental Protection Agency (EPA) after the well construction and testing activities have been completed, but before the start of CO_2 injection operations.

The permittee shall submit to the Program Director for review all pre-injection testing procedures for logging, sampling, and testing, as required by 40 CFR §146.87. This information, along with the schedule for such testing, shall be submitted no later than 30 days before performing the first test. The permittee shall submit any changes to the schedule 30 days before the next scheduled test, and testing shall not proceed without the Program Director's approval of the schedule.

6.0 Demonstration of Mechanical Integrity and Baseline for Monitoring

Table 28 below summarizes the tests that will be conducted at the injection well before the start of injection to prove mechanical integrity.

Table 27—Summary of Pre-Injection Testing at Injection Well Site

Test	Comments
Annulus pressure test	MIT – Internal
CBL-VDL-USIT-temperature log	MIT – External
Pressure fall-off test	Formation and well testing
Leak-off test	Fracture gradient / MASP
Pulsed neutron (through tubing)	Baseline for CO_2 saturation
CIL electromagnetic (through tubing)	Baseline

Notes:

- CIL: Casing Inspection Log
- Details for the tests and procedures are described in the QASP attachment to this permit.

7.0 Blowout Preventer and Wellhead Requirements

7.1 Blowout Preventer Equipment (BOPE)

- BOPE shall be API-monogramed and adhere to API Standard 53 and Specifications 16A and 16C at a minimum and shall meet or exceed all applicable regulatory specifications.
- BOPE other than annular preventers shall have a minimum working pressure exceeding the maximum anticipated surface pressure (MASP).
- All BOPE stacks shall incorporate a set of blind rams.
- Blind rams shall be located in the lower ram cavity of a two-ram stack or the middle ram cavity of a three-ram stack.
- Choke and kill line outlets shall be located below the blind rams on either a two-ram or three-ram stack.
- All rigs shall have a calibrated trip tank. The trip tank and trip sheet are used to measure the fluid required to fill or displace fluid from the hole during all tripping operations, including when running the casing or completion string. Trip sheets shall include the number of joints or stands run into or pulled from the hole vs. the calculated and actual displacements per step and a running total as a minimum.
- A full-opening safety valve (FOSV) and an inside-BOP safety valve (IBOPSV) shall be always available on the rig floor for each drill pipe and drill collar size and connection type in use. The FOSV is used to stab into the string and shut off flow through the drill string. The IBOPSV is used above the FOSV to prevent backflow through the drill string. These valves shall remain in the fully open position until installed. **Note:** This requirement is in addition to any integral safety valve in the top drive system inclusive of casing running operations. In the event of a power failure on a

variable frequency drive (VFD) rig, it is impossible to slack off and make up the top drive to the string; therefore, there is a need for additional independent stabbing valve(s) to be available on the floor always.

- If a wireline lubricator is utilized for wireline operations, it shall not be the type that slips into and is held by the annular preventer or rams. A hydraulic cutter or other means of safely cutting the wireline shall be available if a lubricator is not in use.

- Pressure-energized metal ring gaskets shall be used on flanged well-control equipment. These gaskets shall not be reused on equipment that will be nippled-up on the wellbore.

7.2 Choke Manifolds and Kill Line

- The choke manifold shall be API-monogrammed, meet API SPEC 16C as a minimum, and meet or exceed all applicable regulatory specifications.

- All BOPE shall include a choke manifold with at least one remotely operated choke and one manual choke installed. The control panel shall contain calibrated drill pipe and casing pressure gauges that shall be both accurate and properly maintained. The choke manifold casing pressure should have the capability of being recorded on the drilling rig's recorder. If necessary, for clear dialogue, an electronic means of direct communication with the driller should be in place. This equipment shall be tested and its calibration checked at each casing shoe and at every BOPE test, and results shall be logged on every BOPE test report.

- Flare / vent lines shall be as long as practical, a minimum of 150 ft from the well center, as straight as possible, without sumps, collection areas, or uphill flow areas (to prevent fluid buildup and resulting backpressure) and shall be securely anchored.

7.3 Closing Units

- BOPE closing units shall adhere to API Spec 16D and API STD 53 as a minimum and meet or exceed all applicable regulatory specifications.

- BOPE control systems shall include full controls on the closing unit and at least one remote control station. One control station shall be located within 10 ft of the driller's console.

- BOPE closing units shall have two separate charging pumps with two independent power sources, as specified in API Spec 16D, or have nitrogen bottle backup.

- When pumps are inoperative, BOPE closing units shall have sufficient usable hydraulic fluid volume to close one annular preventer, close all ram preventers, and open one HCR valve against zero wellbore pressure with 200 psi remaining pressure above the pre-charge pressure.

7.4 Pressure Testing

- BOPE components (including the BOP stack, choke manifold, and choke lines) shall be pressure tested at the following frequency:
  - When installed. If the BOPE is stump tested, only the new connections are required to be tested at installation.
  - Before 21 days have elapsed since the last BOPE pressure test. When the 21-day test is due soon, consider testing the BOPE prior to drilling H_2S, abnormal pressure, or any lost return zones to avoid having to test while drilling these intervals.
  - Anytime a BOPE connection seal is broken, the connection shall be pressure tested after reassembly and before use.
  - When utilizing tapered strings, variable bore-type rams and annular preventers shall be pressure tested with all tubing or drill pipe sizes anticipated to be used.
- BOPE shall be tested using a test plug or other means to isolate the casing and open hole from the test pressures. The casinghead valve shall be opened and monitored to avoid exerting BOPE test pressure on the casing or open hole.
- BOPE components shall first be low-pressure tested to between 250 and 350 psi. If the pressure exceeds 350 psi during this test, the pressure shall be bled off to 0 psi and the test restarted. Pressuring up beyond 350 psi can induce a seal and give a false test result.
- BOPE components, excluding the annular preventer, shall be tested to the lesser of rated working pressure (RWP) or wellhead RWP if less than BOPE RWP. The annular preventer shall be tested to 70% of its RWP. In all cases, the test pressure shall not exceed the RWP of any of the components being tested.
- Use of a cup tester should be avoided. If a cup tester is utilized for BOP testing, consideration shall be given to casing burst pressure and possible pressure applied to the casing string or open hole below the cup tester in the event of a leaking cup tester.
- An accumulator closing test shall be performed after the initial nipple-up of the BOP, after any repairs that required isolation or partial isolation of the system, or at initial nipple-up on each well.
- During drilling, the pipe rams shall be functionally operated at least once every 24 hours. The blind rams shall be functionally operated each trip out of the wellbore.

7.5 Wellhead Schematic

Figure 8 below is a schematic diagram of the wellhead to be used for the BRP CCS1, BRP CCS2 and BRP CCS3 wells.

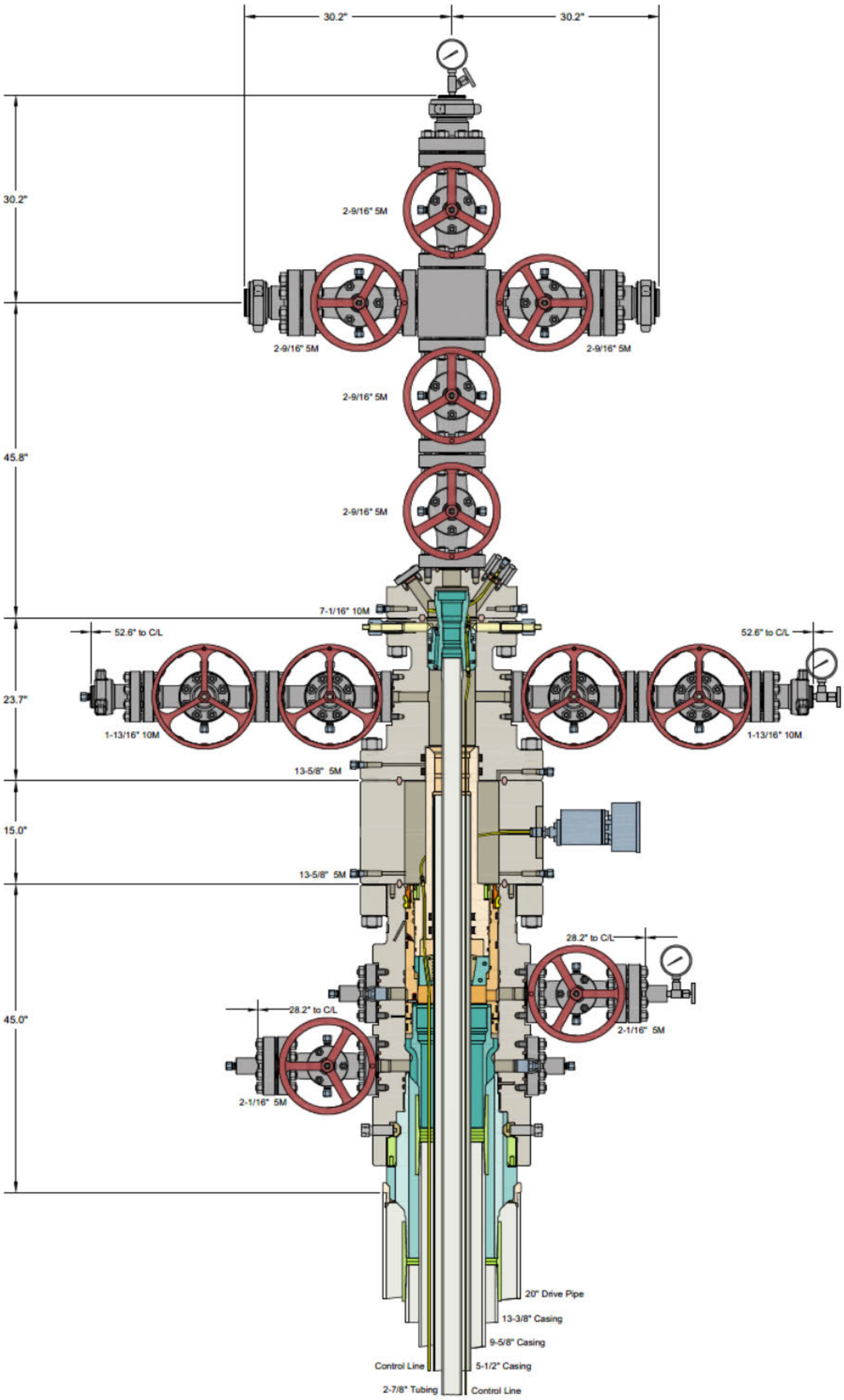

Figure 8—Schematic diagram of BRP CCS1 and BRP CCS2 wellhead