Drilling Prognosis
Project Libra
Well: Simoneaux CCS Injector No. 1

Revision 0 – September 19, 2024

		Date
Prepared by:	Eric Burnett – Director of Engineering	**09/19/2024**
Approved by:	William H. George P.E. – Lonquist Sequestration	**11/15/2024**

Introduction:

The Simoneaux CCS Injector No. 1 well will be one of three injectors drilled as part of the Project Libra CCUS development. A 13 ½” surface hole will be drilled to 3,250’ and 9 ⅝” surface casing will be run and cemented to surface. An 8 ¾” hole will be drilled to a TD of 9,975’. An extensive wireline logging suite will be run. 7” long string casing will be run and cemented to surface. Operations will be suspended, and the drilling rig will move off location. The well will be completed with 4 ½” tubing, TEC with P/T gauges, and packer assembly prior to CO_2 injection.

20” Conductor (0’ – 280’):

Drive 20” Conductor

1. MIRU Equipment.
2. P/U Hammer and drive 20” conductor to final penetration.
    a. Estimated total depth is 280’.
    b. Final penetration is estimated at 200 bpf.

Conductor Specs:

Tubular	Depth (feet)	Casing Size (in)	Weight (lb./ft)	Grade	Hole Size (in)
Conductor	0 – 280	20”	129.33	X-42	N/A

13 ½” Surface Hole / 9 ⅝” Surface Casing (280’ – 3,250’):

Drilling 13 ½” Hole

3. MIRU. Do not accept rig until fully rigged up and prepared for spud. Weld riser and flowline on 20” conductor.
4. Mudloggers should be rigged up and will be catching samples from surface to TD. Consult evaluation program for sampling requirements & details.
5. P/U a 13 ½” bit.
6. Drill 13 ½” hole to 3,250’. Drill with water-based mud and keep MW as low as practical. Use soap/SAP as required to prevent bit balling.
7. At TD, circulate the hole clean and condition the mud for logging.
8. Run logs as per the Formation Evaluation program.
    a. Make conditioning trips as required with dumb-iron BHA’s and a used 13 ½” bit.

9. After logging, P/U 13 ½” bit and BHA and TIH.
10. Circulate hole clean and condition hole for casing/cementing.
11. POOH and lay down BHA.

Run & Cement 9 ⅝” Casing

Casing Specs:

Tubular	Depth (feet)	Casing Size (in)	Hole Size (in)	Weight (lb./ft)	Grade	Thread	Collapse/Burst	Tensile Body/Joint (x1000 lbs)
Surface	0 – 3,250	9 ⅝”	13 ½”	40	J-55	LTC	2570 / 3950	520

1. Pilot test the cement blend at least 24 hours prior to cementing. Make sure that cementer uses actual mix water for the test.
2. P/U 9 ⅝” surface casing.
3. P/U shoe track as follows:
    a. Float Shoe
    b. 2 joints 9 ⅝” casing with one centralizer 5' above the Float shoe.
    c. 1 Float Collar
4. Finish running 9 ⅝” surface casing.
5. Install bow spring centralizers every third joint to surface.
6. R/U cementing equipment and cement 9 ⅝” casing.
7. Pump cement. Pump 5 bbls on top of plug prior to displacing. Displace with water-based drilling mud. Use top and bottom non-rotating plugs. Take wet and dry samples. Displace at maximum possible rate. Bump the plug with 500 psi over final displacement pressure.
8. Release pressure. Check float equipment. Record cement volumes and recipes pumped on the Daily Drilling Report.
9. Rough and final cut casing. Install 5 k wellhead.

8 ¾” Hole (3,250’ – 9,975’):

Drilling 8 ¾” Hole

1. N/U and test 5k BOP stack. This interval will be open for a long period of time and BOP’s should be tested every 14 days. If critical operations are expected, consider testing BOP’s earlier to ensure no critical operations are interrupted.

2. Mudloggers will be taking samples for the entire interval. Consult evaluation program for sampling requirements & details.
3. P/U an 8 ¾" Bit & BHA. TIH and tag float equipment. Displace hole to OBM.
4. Test 9-5/8" casing to LDENR standards.
    a. Notify the CES at least 48 hours prior to the casing test
    b. Fill out and submit for CSG-T
5. Drill 8 ¾" hole to TD at 9,975'.
6. At TD, circulate the hole clean and condition the mud for logging.
7. Run logs as per the Formation Evaluation program.
    a. Make conditioning trips as required with dumb-iron BHA's and a used 8 ¾" bit.
8. After logging, P/U 8 ¾" bit and BHA and TIH.
9. Circulate the hole clean and condition mud for cementing.
10. POOH and L/D BHA.

Run & Cement 7" Casing

Casing Specs:

Tubular	Depth (feet)	Casing Size (in)	Hole Size (in)	Weight (lb./ft)	Grade	Thread	Collapse/Burst	Tensile Body/Joint (x1000 lbs)
Protective	0 – 3,260	7"	8 ¾"	26	HCL-80	LTC	5650 / 6340	532
Protective	3260' – 8,100'	7"	8 ¾"	26	25Cr-80	VAM-21	5650 / 6340	532
Protective	8,100' – 9,975'	7"	8 ¾"	26	HCL-80	LTC	5650 / 6340	532

1. Pilot test the cement blend at least 24 hours prior to cementing. Make sure that cement company uses actual mix water for the test.
2. P/U 7" long string casing.
3. P/U shoe track as follows:
    a. Float Shoe
    b. 2 joints 7" casing with one centralizer 5' above the Float shoe.
    c. 1 Float Collar
    d. Install DV tool at 5,000'
4. Finish running 7" surface casing.
5. Install bow spring centralizers every third joint to surface.
6. R/U cementing equipment and cement 7" casing.

7. Pump cement. The 7" will be cemented in 2 stages as per the attached cement program. Bump all plugs with 500psi over circulating pressure.
8. After Stage 1, open the DV to and circulate out any cement and WOC prior to pumping Stage 2. (WOC time will be based on blend test results)
9. After each stage, release pressure. Check float equipment. Record cement volumes and recipes pumped on the Daily Drilling Report.
10. Rough and final cut casing. Install 5 k wellhead.
11. RDMO.
12. Completion operations will be conducted with a workover rig to include the following:
    a. Drill-out DV Tool
    b. Test 7" casing to LDENR standards.
        i. Notify the CES at least 48 hours prior to the casing test.
        ii. Fill out and submit form CSG-T.
    c. Perforate injection interval as determined by open-hole logs.
    d. Install tubing and packer completion assembly
    e. Install 5k wellhead

Drilling Fluids

Diesel oil-based mud will be used in this hole section. Maintain mud weights as low as practical while drilling and weight up only as hole conditions dictate. Pump hi-vis and weighted sweeps as required for hole cleaning. Mud weights should be 9.0 – 9.5 ppg until +/- 9,500'. MW's of up to 10.5 ppg may be required to drill the lower Miocene section to TD.

Drilling Prognosis
Project Libra
Well: Simoneaux CCS Injector No. 2

Revision 0 – September 19, 2024

		Date
Prepared by:	Eric Burnett – Director of Engineering	**09/19/2024**
Approved by:	William H. George P.E. – Lonquist Sequestration	**11/15/2024**

Introduction:

The Simoneaux CCS Injector No. 2 Injection well will be one of three injectors drilled as part of the Project Libra CCUS development. A 13 ½" surface hole will be drilled to 3,250' and 9 ⅝" surface casing will be run and cemented to surface. An 8 ¾" hole will be drilled to a TD of 8,010'. An extensive wireline logging suite will be run. 7" long string casing will be run and cemented to surface. Operations will be suspended, and the drilling rig will move off location. The well will be completed with 4 ½" tubing, TEC with P/T gauges, and packer assembly prior to CO_2 injection.

20" Conductor (0' – 280'):

Drive 20" Conductor

1. MIRU Equipment.
2. P/U Hammer and drive 20" conductor to final penetration.
    a. Estimated total depth is 280'.
    b. Final penetration is estimated at 200 bpf.

Conductor Specs:

Tubular	Depth (feet)	Casing Size (in)	Weight (lb./ft)	Grade	Hole Size (in)
Conductor	0 – 280	20"	129.33	X-42	N/A

13 ½" Surface Hole / 9 ⅝" Surface Casing (280' – 3,250'):

Drilling 13 ½" Hole

3. MIRU. Do not accept rig until fully rigged up and prepared for spud. Weld riser and flowline on 20" conductor.
4. Mudloggers should be rigged up and will be catching samples from surface to TD. Consult evaluation program for sampling requirements & details.
5. P/U a 13 ½" bit.
6. Drill 13 ½" hole to 3,250'. Drill with water-based mud and keep MW as low as practical. Use soap/SAP as required to prevent bit balling.
7. At TD, circulate the hole clean and condition the mud for logging.
8. Run logs as per the Formation Evaluation program.
    a. Make conditioning trips as required with dumb-iron BHA's and a used 13 ½" bit.

9. After logging, P/U 13 ½” bit and BHA and TIH.
10. Circulate hole clean and condition hole for casing/cementing.
11. POOH and lay down BHA.

Run & Cement 9 ⅝” Casing

Casing Specs:

Tubular	Depth (feet)	Casing Size (in)	Hole Size (in)	Weight (lb./ft)	Grade	Thread	Collapse/Burst	Tensile Body/Joint (x1000 lbs)
Surface	0 – 3,250	9 ⅝”	13 ½”	40	J-55	LTC	2570 / 3950	520

1. Pilot test the cement blend at least 24 hours prior to cementing. Make sure that cementer uses actual mix water for the test.
2. P/U 9 ⅝” surface casing.
3. P/U shoe track as follows:
    a. Float Shoe
    b. 2 joints 9 ⅝” casing with one centralizer 5' above the Float shoe.
    c. 1 Float Collar
4. Finish running 9 ⅝” surface casing.
5. Install bow spring centralizers every third joint to surface.
6. R/U cementing equipment and cement 9 ⅝” casing.
7. Pump cement. Pump 5 bbls on top of plug prior to displacing. Displace with water-based drilling mud. Use top and bottom non-rotating plugs. Take wet and dry samples. Displace at maximum possible rate. Bump the plug with 500 psi over final displacement pressure.
8. Release pressure. Check float equipment. Record cement volumes and recipes pumped on the Daily Drilling Report.
9. Rough and final cut casing. Install 5 k wellhead.

8 ¾” Hole (3,250’ – 8,010’):

Drilling 8 ¾” Hole

1. N/U and test 5k BOP stack. This interval will be open for a long period of time and BOP’s should be tested every 14 days. If critical operations are expected, consider testing BOP’s earlier to ensure no critical operations are interrupted.

2. Mudloggers will be taking samples for the entire interval. Consult evaluation program for sampling requirements & details.
3. P/U an 8 ¾" Bit & BHA. TIH and tag float equipment. Displace hole to OBM.
4. Test 9-5/8" casing to LDENR standards.
    a. Notify the CES at least 48 hours prior to the casing test
    b. Fill out and submit for CSG-T
5. Drill 8 ¾" hole to TD at +/- 8,010'.
6. At TD, circulate the hole clean and condition the mud for logging.
7. Run logs as per the Formation Evaluation program.
    a. Make conditioning trips as required with dumb-iron BHA's and a used 8 ¾" bit.
8. After logging, P/U 8 ¾" bit and BHA and TIH.
9. Circulate the hole clean and condition mud for cementing.
10. POOH and L/D BHA.

Run & Cement 7" Casing

Casing Specs:

Tubular	Depth (feet)	Casing Size (in)	Hole Size (in)	Weight (lb./ft)	Grade	Thread	Collapse/Burst	Tensile Body/Joint (x1000 lbs)
Protective	0 – 3,260	7"	8 ¾"	26	HCL-80	LTC	5650 / 6340	532
Protective	3260' – 6,800'	7"	8 ¾"	26	25Cr-80	VAM-21	5650 / 6340	532
Protective	6,800' – 8,010'	7"	8 ¾"	26	HCL-80	LTC	5650 / 6340	532

1. Pilot test the cement blend at least 24 hours prior to cementing. Make sure that cement company uses actual mix water for the test.
2. P/U 7" long string casing.
3. P/U shoe track as follows:
    a. Float Shoe
    b. 2 joints 7" casing with one centralizer 5' above the Float shoe.
    c. 1 Float Collar
    d. Install DV tool at 5,000'
4. Finish running 7" surface casing.
5. Install bow spring centralizers every third joint to surface.
6. R/U cementing equipment and cement 7" casing.

7. Pump cement. The 7" will be cemented in 2 stages as per the attached cement program. Bump all plugs with 500psi over circulating pressure.
8. After Stage 1, open the DV to and circulate out any cement and WOC prior to pumping Stage 2. (WOC time will be based on blend test results)
9. After each stage, release pressure. Check float equipment. Record cement volumes and recipes pumped on the Daily Drilling Report.
10. Rough and final cut casing. Install 5 k wellhead.
11. RDMO.
12. Completion operations will be conducted with a workover rig to include the following:
    a. Drill-out DV Tool
    b. Test 7" casing to LDENR standards.
        i. Notify the CES at least 48 hours prior to the casing test.
        ii. Fill out and submit form CSG-T.
    c. Perforate injection interval as determined by open-hole logs.
    d. Install tubing and packer completion assembly
    e. Install 5k wellhead

<u>Drilling Fluids</u>

Diesel oil-based mud will be used in this hole section. Maintain mud weights as low as practical while drilling and weight up only as hole conditions dictate. Pump hi-vis and weighted sweeps as required for hole cleaning. Mud weights should be 9.0 – 9.5 ppg until +/- 9,500'. MW's of up to 10.5 ppg may be required.

Drilling Prognosis
Project Libra
Well: Simoneaux CCS Injector No. 3

Revision 0 – September 19, 2024

		Date
Prepared by:	Eric Burnett – Director of Engineering	**09/19/2024**
Approved by:	William H. George P.E. – Lonquist Sequestration	**11/15/2024**

STATE OF LOUISIANA
WILLIAM HAROLD GEORGE
License No. 45286
PROFESSIONAL ENGINEER

Introduction:

The Simoneaux CCS Injector No. 3 well will be one of three injectors drilled as part of the Project Libra CCUS development. A 13 ½" surface hole will be drilled to 3,250' and 9 ⅝" surface casing will be run and cemented to surface. An 8 ¾" hole will be drilled to a TD of 6,758'. An extensive wireline logging suite will be run. 7" long string casing will be run and cemented to surface. Operations will be suspended, and the drilling rig will move off location. The well will be completed with 4 ½" tubing, TEC with P/T gauges, and packer assembly prior to CO_2 injection.

20" Conductor (0' – 280'):

Drive 20" Conductor

1. MIRU Equipment.
2. P/U Hammer and drive 20" conductor to final penetration.
    a. Estimated total depth is 280'.
    b. Final penetration is estimated at 200 bpf.

Conductor Specs:

Tubular	Depth (feet)	Casing Size (in)	Weight (lb./ft)	Grade	Hole Size (in)
Conductor	0 – 280	20"	129.33	X-42	N/A

13 ½" Surface Hole / 9 ⅝" Surface Casing (280' – 3,250'):

Drilling 13 ½" Hole

3. MIRU. Do not accept rig until fully rigged up and prepared for spud. Weld riser and flowline on 20" conductor.
4. Mudloggers should be rigged up and will be catching samples from surface to TD. Consult evaluation program for sampling requirements & details.
5. P/U a 13 ½" bit.
6. Drill 13 ½" hole to 3,250'. Drill with water-based mud and keep MW as low as practical. Use soap/SAP as required to prevent bit balling.
7. At TD, circulate the hole clean and condition the mud for logging.
8. Run logs as per the Formation Evaluation program.

   a. Make conditioning trips as required with dumb-iron BHA's and a used 13 ½" bit.
9. After logging, P/U 13 ½" bit and BHA and TIH.
10. Circulate hole clean and condition hole for casing/cementing.
11. POOH and lay down BHA.

Run & Cement 9 ⅝" Casing

Casing Specs:

Tubular	Depth (feet)	Casing Size (in)	Hole Size (in)	Weight (lb./ft)	Grade	Thread	Collapse/Burst	Tensile Body/Joint (x1000 lbs)
Surface	0 – 3,250	9 ⅝"	13 ½"	40	J-55	LTC	2570 / 3950	520

1. Pilot test the cement blend at least 24 hours prior to cementing. Make sure that Halliburton uses actual mix water for the test.
2. P/U 9 ⅝" surface casing.
3. P/U shoe track as follows:
   a. Float Shoe
   b. 2 joints 9 ⅝" casing with one centralizer 5' above the Float shoe.
   c. 1 Float Collar
4. Finish running 9 ⅝" surface casing.
5. Install bow spring centralizers every third joint to surface.
6. R/U cementing equipment and cement 9 ⅝" casing.
7. Pump cement. Pump 5 bbls on top of plug prior to displacing. Displace with water-based drilling mud. Use top and bottom non-rotating plugs. Take wet and dry samples. Displace at maximum possible rate. Bump the plug with 500 psi over final displacement pressure.
8. Release pressure. Check float equipment. Record cement volumes and recipes pumped on the Daily Drilling Report.
9. Rough and final cut casing. Install 5 k wellhead.

8 ¾" Hole (3,250' – 6,758'):

Drilling 8 ¾" Hole

1. N/U and test 5k BOP stack. This interval will be open for a long period of time and BOP's should be tested every 14 days. If critical operations are expected, consider testing BOP's earlier to ensure no critical operations are interrupted.
2. Mudloggers will be taking samples for the entire interval. Consult evaluation program for sampling requirements & details.
3. P/U an 8 ¾" Bit & BHA. TIH and tag float equipment. Displace hole to OBM.
4. Test 9-5/8" casing to LDENR standards.
    a. Notify the CES at least 48 hours prior to the casing test
    b. Fill out and submit for CSG-T
5. Drill 8 ¾" hole to TD at +/- 6,758'.
6. At TD, circulate the hole clean and condition the mud for logging.
7. Run logs as per the Formation Evaluation program.
    a. Make conditioning trips as required with dumb-iron BHA's and a used 8 ¾" bit.
8. After logging, P/U 8 ¾" bit and BHA and TIH.
9. Circulate the hole clean and condition mud for cementing.
10. POOH and L/D BHA.

Run & Cement 7" Casing

Casing Specs:

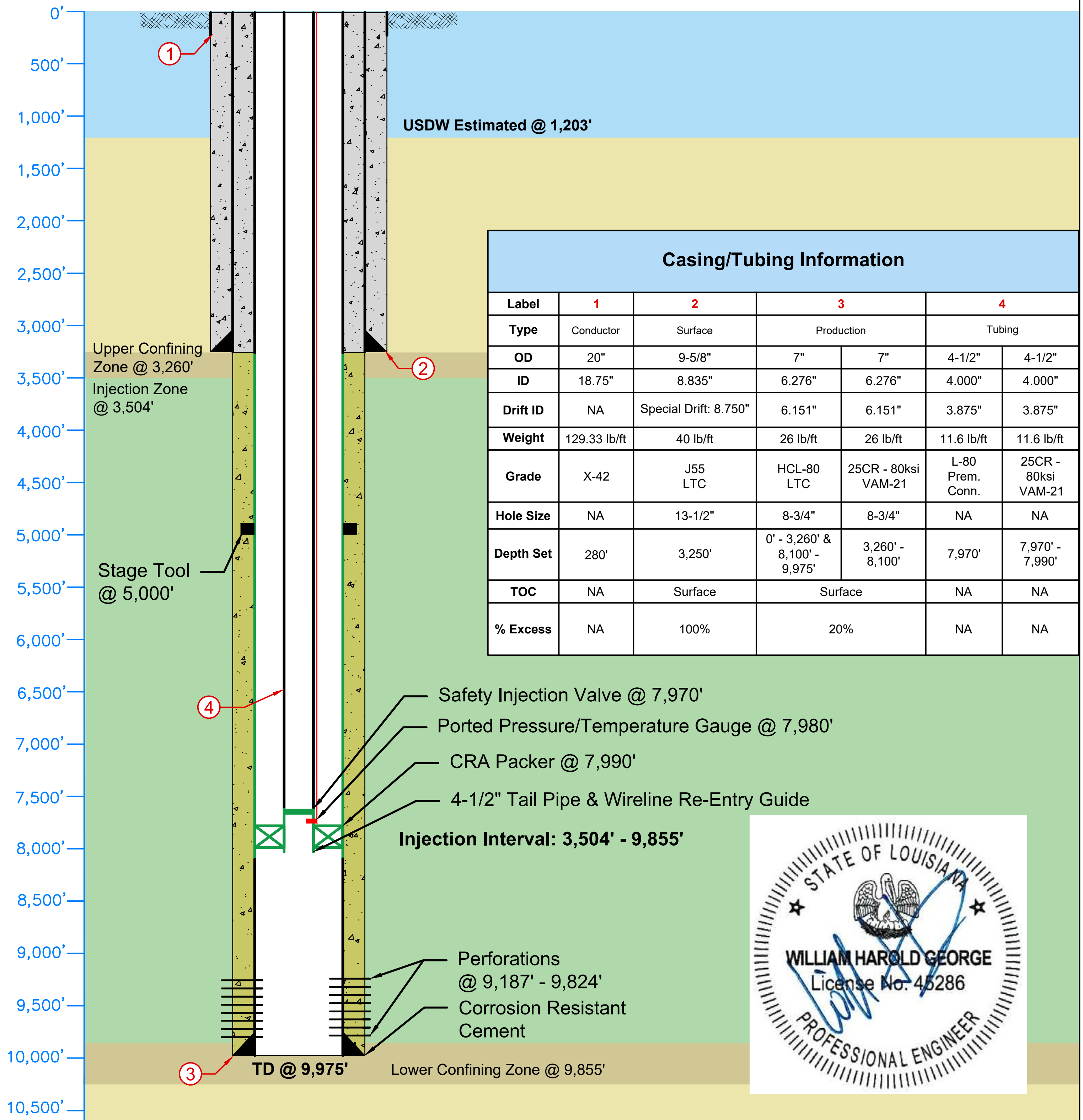
Tubular	Depth (feet)	Casing Size (in)	Hole Size (in)	Weight (lb./ft)	Grade	Thread	Collapse/Burst	Tensile Body/Joint (x1000 lbs)
Protective	0 – 3,260	7"	8 ¾"	26	HCL-80	LTC	5650 / 6340	532
Protective	3,260' – 5,040'	7"	8 ¾"	26	25Cr-80	VAM-21	5650 / 6340	532
Protective	5,040' – 6,758'	7"	8 ¾"	26	HCL-80	LTC	5650 / 6340	532

1. Pilot test the cement blend at least 24 hours prior to cementing. Make sure that cement company uses actual mix water for the test.
2. P/U 7" long string casing.
3. P/U shoe track as follows:
    a. Float Shoe
    b. 2 joints 7" casing with one centralizer 5' above the Float shoe.
    c. 1 Float Collar
    d. Install DV tool at 4,000'
4. Finish running 7" surface casing.

5. Install bow spring centralizers every third joint to surface.
6. R/U cementing equipment and cement 7” casing.
7. Pump cement. The 7” will be cemented in 2 stages as per the attached cement program. Bump all plugs with 500psi over circulating pressure.
8. After Stage 1, open the DV to and circulate out any cement and WOC prior to pumping Stage 2. (WOC time will be based on blend test results)
9. After each stage, release pressure. Check float equipment. Record cement volumes and recipes pumped on the Daily Drilling Report.
10. Rough and final cut casing. Install 5 k wellhead.
11. RDMO.
12. Completion operations will be conducted with a workover rig to include the following:
    a. Drill-out DV Tool
    b. Test 7” casing to LDENR standards.
        i. Notify the CES at least 48 hours prior to the casing test.
        ii. Fill out and submit form CSG-T.
    c. Perforate injection interval as determined by open-hole logs.
    d. Install tubing and packer completion assembly
    e. Install 5k wellhead

Drilling Fluids

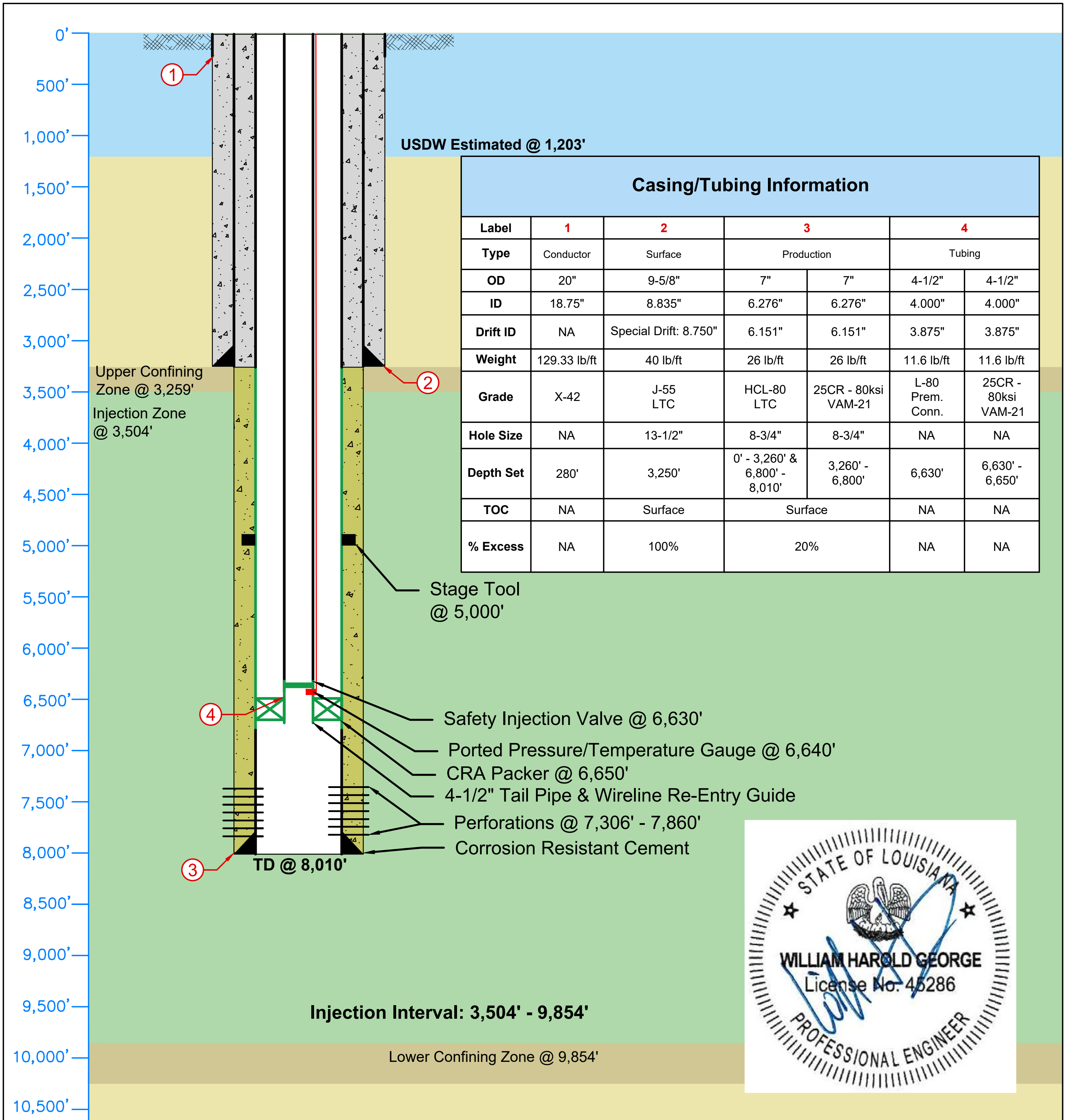
Diesel oil-based mud will be used in this hole section. Maintain mud weights as low as practical while drilling and weight up only as hole conditions dictate. Pump hi-vis and weighted sweeps as required for hole cleaning. Mud weights should be 9.0 – 9.5 ppg until +/- 9,500’. MW’s of up to 10.5 ppg may be required.



Casing/Tubing Information

Label	1	2	3		4	
Type	Conductor	Surface	Production		Tubing	
OD	20"	9-5/8"	7"	7"	4-1/2"	4-1/2"
ID	18.75"	8.835"	6.276"	6.276"	4.000"	4.000"
Drift ID	NA	Special Drift: 8.750"	6.151"	6.151"	3.875"	3.875"
Weight	129.33 lb/ft	40 lb/ft	26 lb/ft	26 lb/ft	11.6 lb/ft	11.6 lb/ft
Grade	X-42	J55 LTC	HCL-80 LTC	25CR - 80ksi VAM-21	L-80 Prem. Conn.	25CR - 80ksi VAM-21
Hole Size	NA	13-1/2"	8-3/4"	8-3/4"	NA	NA
Depth Set	280'	3,250'	0' - 3,260' & 8,100' - 9,975'	3,260' - 8,100'	7,970'	7,970' - 7,990'
TOC	NA	Surface	Surface		NA	NA
% Excess	NA	100%	20%		NA	NA

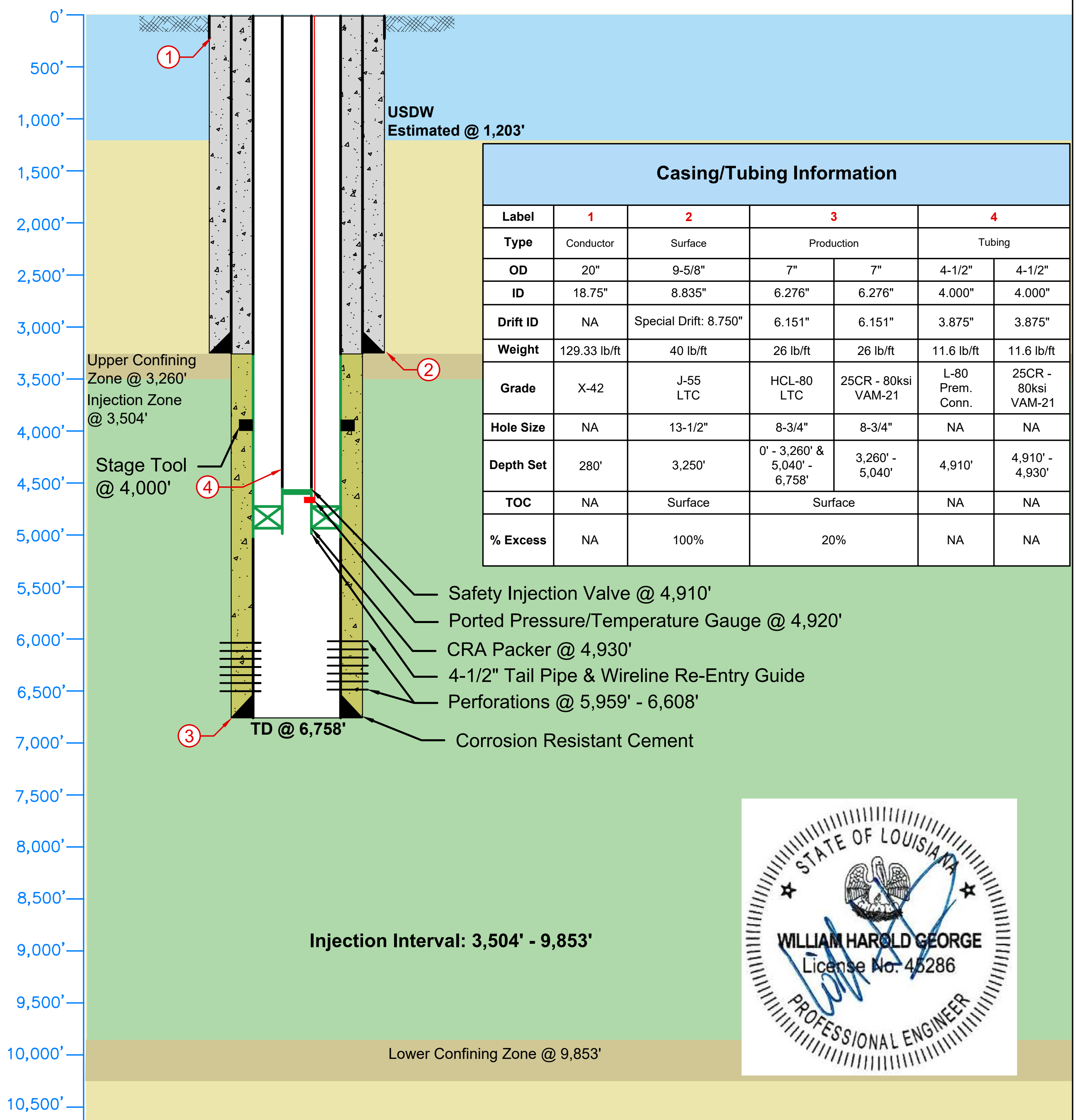
LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	Simoneaux CCS Injector No. 001	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** St. Charles
	Location: 90º 22' 17.226" W, 29º 48' 35.315" N (NAD 27)	**District:**	**Survey:**
	API No:	**Field:**	**Well Type/Status:**
Louisiana License EF-7423	**Serial No:** TBD	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	



Casing/Tubing Information

Label	1	2	3		4	
Type	Conductor	Surface	Production		Tubing	
OD	20"	9-5/8"	7"	7"	4-1/2"	4-1/2"
ID	18.75"	8.835"	6.276"	6.276"	4.000"	4.000"
Drift ID	NA	Special Drift: 8.750"	6.151"	6.151"	3.875"	3.875"
Weight	129.33 lb/ft	40 lb/ft	26 lb/ft	26 lb/ft	11.6 lb/ft	11.6 lb/ft
Grade	X-42	J-55 LTC	HCL-80 LTC	25CR - 80ksi VAM-21	L-80 Prem. Conn.	25CR - 80ksi VAM-21
Hole Size	NA	13-1/2"	8-3/4"	8-3/4"	NA	NA
Depth Set	280'	3,250'	0' - 3,260' & 6,800' - 8,010'	3,260' - 6,800'	6,630'	6,630' - 6,650'
TOC	NA	Surface	Surface		NA	NA
% Excess	NA	100%	20%		NA	NA

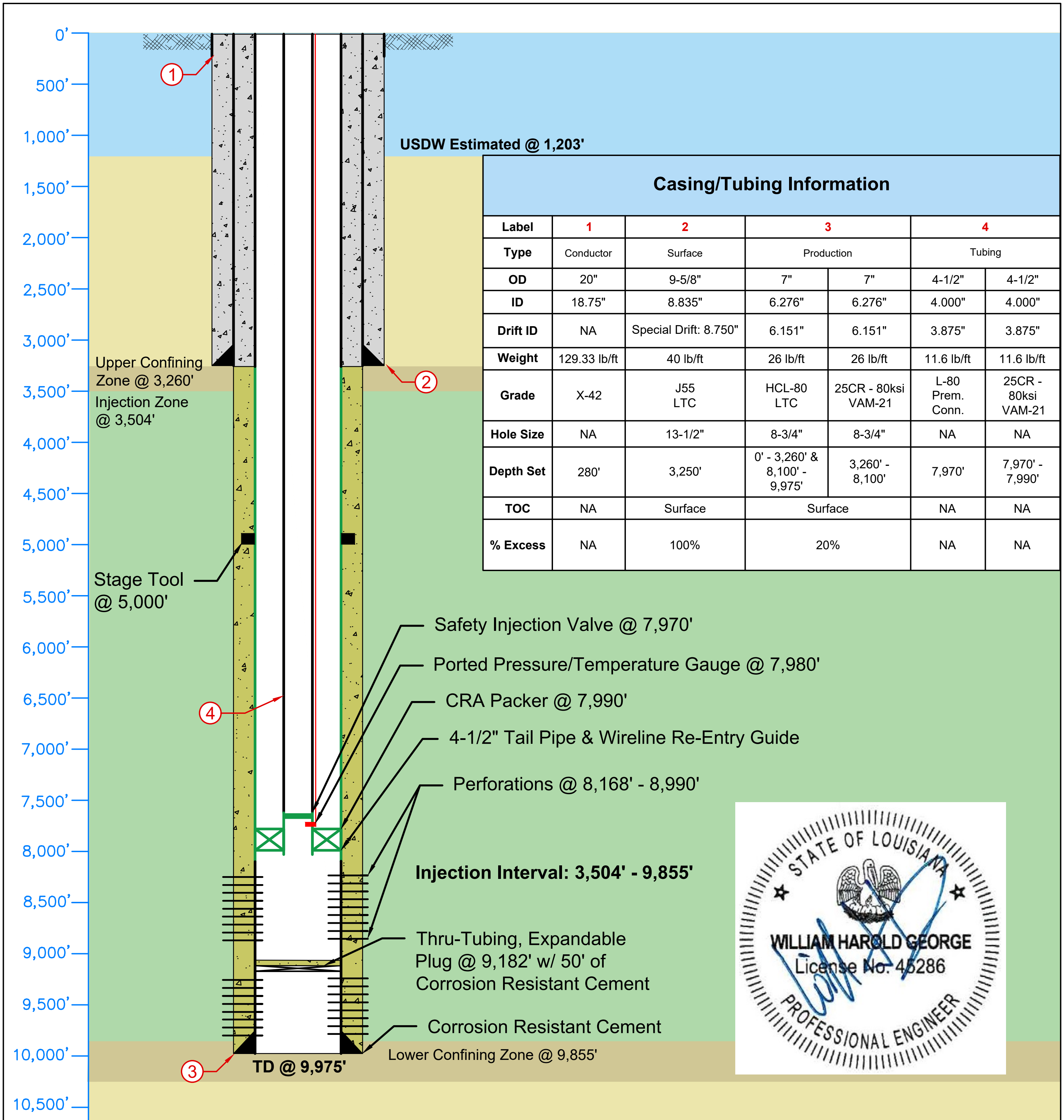
LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	Simoneaux CCS Injector No. 002	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** St. Charles
	Location: 90° 22' 17.510" W, 29° 48' 35.317" N (NAD 27)	**District:**	**Survey:**
	API No: TBD	**Field:**	**Well Type/Status:**
Louisiana License EF-7423	**Serial No:** TBD	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	



Casing/Tubing Information

Label	1	2	3		4	
Type	Conductor	Surface	Production		Tubing	
OD	20"	9-5/8"	7"	7"	4-1/2"	4-1/2"
ID	18.75"	8.835"	6.276"	6.276"	4.000"	4.000"
Drift ID	NA	Special Drift: 8.750"	6.151"	6.151"	3.875"	3.875"
Weight	129.33 lb/ft	40 lb/ft	26 lb/ft	26 lb/ft	11.6 lb/ft	11.6 lb/ft
Grade	X-42	J-55 LTC	HCL-80 LTC	25CR - 80ksi VAM-21	L-80 Prem. Conn.	25CR - 80ksi VAM-21
Hole Size	NA	13-1/2"	8-3/4"	8-3/4"	NA	NA
Depth Set	280'	3,250'	0' - 3,260' & 5,040' - 6,758'	3,260' - 5,040'	4,910'	4,910' - 4,930'
TOC	NA	Surface	Surface		NA	NA
% Excess	NA	100%	20%		NA	NA

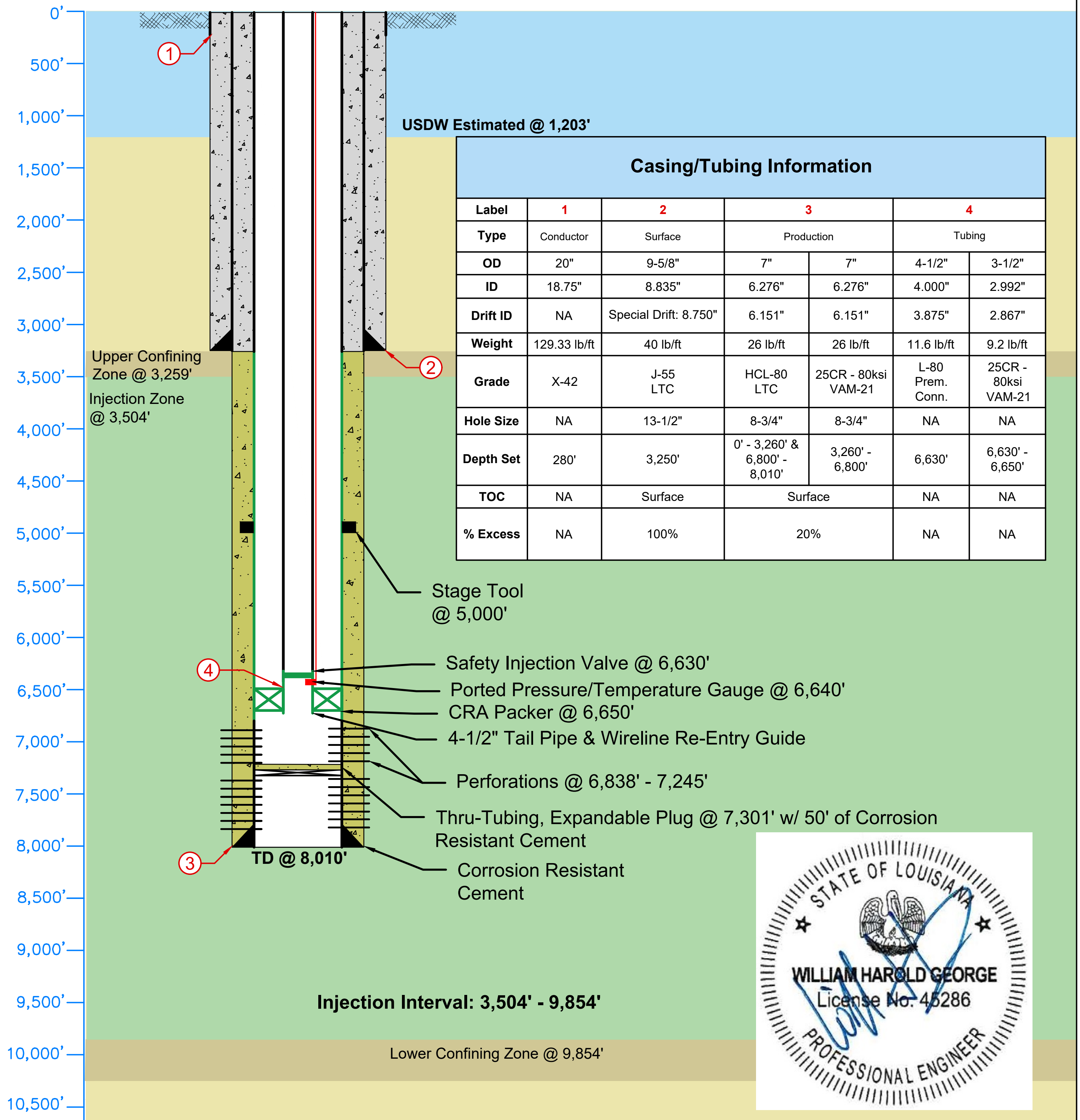
LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	Simoneaux CCS Injector No. 003	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** St. Charles
	Location: 90º 22' 17.793 W, 29º 48' 35.319" N (NAD 27)	**District:**	**Survey:**
	API No: TBD	**Field:**	**Well Type/Status:**
Louisiana License EF-7423	**Serial No:** TBD	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	



Casing/Tubing Information

Label	1	2	3		4	
Type	Conductor	Surface	Production		Tubing	
OD	20"	9-5/8"	7"	7"	4-1/2"	4-1/2"
ID	18.75"	8.835"	6.276"	6.276"	4.000"	4.000"
Drift ID	NA	Special Drift: 8.750"	6.151"	6.151"	3.875"	3.875"
Weight	129.33 lb/ft	40 lb/ft	26 lb/ft	26 lb/ft	11.6 lb/ft	11.6 lb/ft
Grade	X-42	J55 LTC	HCL-80 LTC	25CR - 80ksi VAM-21	L-80 Prem. Conn.	25CR - 80ksi VAM-21
Hole Size	NA	13-1/2"	8-3/4"	8-3/4"	NA	NA
Depth Set	280'	3,250'	0' - 3,260' & 8,100' - 9,975'	3,260' - 8,100'	7,970'	7,970' - 7,990'
TOC	NA	Surface	Surface		NA	NA
% Excess	NA	100%	20%		NA	NA

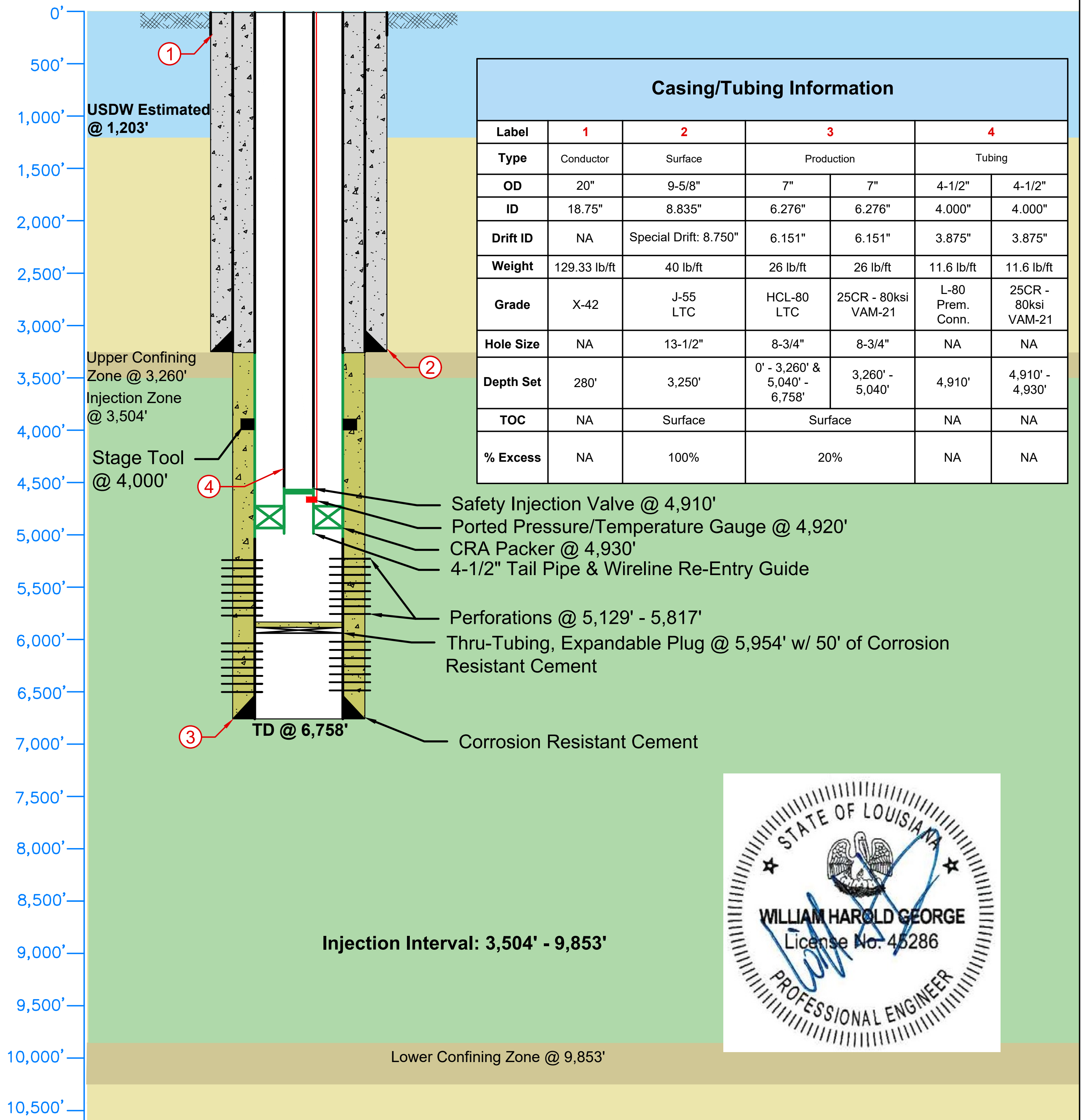
LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	Simoneaux CCS Injector No. 001	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** St. Charles
	Location: 90º 22' 17.226" W, 29º 48' 35.315" N (NAD 27)	**District:**	**Survey:**
	API No:	**Field:**	**Well Type/Status:**
Louisiana License EF-7423	**Serial No:** TBD	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	



Casing/Tubing Information

Label	1	2	3		4	
Type	Conductor	Surface	Production		Tubing	
OD	20"	9-5/8"	7"	7"	4-1/2"	3-1/2"
ID	18.75"	8.835"	6.276"	6.276"	4.000"	2.992"
Drift ID	NA	Special Drift: 8.750"	6.151"	6.151"	3.875"	2.867"
Weight	129.33 lb/ft	40 lb/ft	26 lb/ft	26 lb/ft	11.6 lb/ft	9.2 lb/ft
Grade	X-42	J-55 LTC	HCL-80 LTC	25CR - 80ksi VAM-21	L-80 Prem. Conn.	25CR - 80ksi VAM-21
Hole Size	NA	13-1/2"	8-3/4"	8-3/4"	NA	NA
Depth Set	280'	3,250'	0' - 3,260' & 6,800' - 8,010'	3,260' - 6,800'	6,630'	6,630' - 6,650'
TOC	NA	Surface	Surface		NA	NA
% Excess	NA	100%	20%		NA	NA

LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	Simoneaux CCS Injector No. 002	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** St. Charles
	Location: 90º 22' 17.510" W, 29º 48' 35.317" N (NAD 27)	**District:**	**Survey:**
	API No: TBD	**Field:**	**Well Type/Status:**
Louisiana License EF-7423	**Serial No:** TBD	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	



Casing/Tubing Information

Label	1	2	3		4	
Type	Conductor	Surface	Production		Tubing	
OD	20"	9-5/8"	7"	7"	4-1/2"	4-1/2"
ID	18.75"	8.835"	6.276"	6.276"	4.000"	4.000"
Drift ID	NA	Special Drift: 8.750"	6.151"	6.151"	3.875"	3.875"
Weight	129.33 lb/ft	40 lb/ft	26 lb/ft	26 lb/ft	11.6 lb/ft	11.6 lb/ft
Grade	X-42	J-55 LTC	HCL-80 LTC	25CR - 80ksi VAM-21	L-80 Prem. Conn.	25CR - 80ksi VAM-21
Hole Size	NA	13-1/2"	8-3/4"	8-3/4"	NA	NA
Depth Set	280'	3,250'	0' - 3,260' & 5,040' - 6,758'	3,260' - 5,040'	4,910'	4,910' - 4,930'
TOC	NA	Surface	Surface		NA	NA
% Excess	NA	100%	20%		NA	NA

LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	Simoneaux CCS Injector No. 003	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** St. Charles
	Location: 90° 22' 17.793 W, 29° 48' 35.319" N (NAD 27)	**District:**	**Survey:**
	API No: TBD	**Field:**	**Well Type/Status:**
Louisiana License EF-7423	**Serial No:** TBD	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	

DRILLING FLUIDS AFE BID

NEWPARK FLUIDS SYSTEMS

Lapis Energy AD3 Technologies Libra Injector Well

OBM

Prepared by:
Scott Thomassen

Cover Letter

08/05/2024

RE: **AD3 Technologies**
South Louisiana Strat Well

Mr. Eric Burnett,

Newpark Fluids Systems is pleased to present the following recommended drilling fluids AFE for your South Louisiana Strat Well in St Charles Parish, Louisiana.

Your well estimated cost of **~ 183,627** for a **OBM**, assuming no unusual drilling problems are encountered, and one 24 hr. Mud Engineers, this well take ~21 days. The project will be serviced from Newpark's closest stock point. **Note: Vacuum trucks for liquid OBM is not included in the bid. Estimated cost to customer $45,000 - $50,000, this includes trucking hours delivered and returned.**

Your estimated clean-out of a pre-drilled start well will be ~$58,074, assuming no unusual drilling problems are encountered, and one 24 hr. Mud Engineers, this well take ~7 days.

The AFE does not include OBM lost downhole, or behind casing, higher than expect mud weights and other unforeseen problems that may alter this cost estimate.

Newpark Fluids Systems is committed to providing superior performance and consistent fluids cost through value added engineering and service quality.

Newpark reserves the right to increase the pricing after 30 days, if warranted by supporting documentation, detailed on a line-item basis, and submitted to the customer, prior to the well start.

Regards,

Traddick Scott Thomassen

Scott Thomassen
Project Specialist
985-515-5069
Newpark Fluids Systems

Drilling Fluids Summary

NEWPARK FLUIDS SYSTEMS

MUD TYPE: Low Solids Non-Dispersed Spud Mud

Hole Size (in)	Depth MD (ft)	Mud Density (ppg)	Plastic Viscosity (cP) @ 120°F	Yield Point (lb/100ft^2) @ 120° F	API Fluid Loss (ml)	pH	LGS %
13.5”	0 - 3,500’	9.5	5 - 12	20 - 30	NC - 20	< 9.0	< 6.0

MUD TYPE: OBM

Hole Size (in)	Depth MD (ft)	Mud Density (ppg)	Plastic Viscosity (cP) @ 120°F	Yield Point (lb/100ft^2) @ 120° F	HTHP Fluid Loss (ml)	Oil : Water Ratio	LGS %
8.5”	3,500’ -7,000’	± 10.0	10 - 19	16 - 20	< 6.0 @ 240°F	70:30 - 75:25	< 6.0

Interval (ft)	***From:***	***To:***	***Total Days***	***Total Price (US$)***
Surface	0	3,500	5	$22,776.70
Production	3,500	7000	9	$44,051.79
Total Material and Engineering			***14***	***$66,828.49***
Other Products / Services / Charges	**QTY**	**Price**		**Total Price (US$)**
Shrink Wraps	54	$18.00		$972
Bulk Tank Rig Up / Rig Down	2	$1,200.00		$2,400.00
Freight (Drayage), CWT	4,200	$4.50		$18,900.00
Minimum Freight Charges	3	1,248.00		$3,744.00
Subtotal				**$26,016**
Total Estimated Cost				**$92,844.49**
Total Estimated Diesel Usage	**13,188**	**±3.25/Gallons**	**$42,861.00**	

Drilling Fluids Summary

MUD TYPE: Low Solids Non-Dispersed Spud Mud

Hole Size (in)	Depth MD (ft)	Mud Density (ppg)	Plastic Viscosity (cP) @ 120°F	Yield Point (lb/100ft^2) @ 120° F	API Fluid Loss (ml)	pH	LGS %
13.5"	0 - 3,500'	9.5	5 - 12	20 - 30	NC - 20	< 9.0	< 6.0

MUD TYPE: OBM

Hole Size (in)	Depth MD (ft)	Mud Density (ppg)	Plastic Viscosity (cP) @ 120°F	Yield Point (lb/100ft^2) @ 120° F	HTHP Fluid Loss (ml)	Oil : Water Ratio	LGS %
8.5"	3,500' -8,000'	± 10.0	10 - 19	16 - 20	< 6.0 @ 240°F	70:30 - 75:25	< 6.0

Interval (ft)	*From:*	*To:*	*Total Days*	*Total Price (US$)*
Surface	0	3,500	5	$22,776.70
Production	3,500	8,000	11	$53,874.04
Total Material and Engineering			***16***	***$76,650.74***
Other Products / Services / Charges	**QTY**	**Price**		**Total Price (US$)**
Shrink Wraps	54	$18.00		$972
Bulk Tank Rig Up / Rig Down	2	$1,200.00		$2,400.00
Freight (Drayage), CWT	4200	$4.50		$18,900.00
Minimum Freight Charges	3	1,248.00		$3,744.00
Subtotal				**$26,016.00**
Total Estimated Cost				**$102,666.74**
Total Estimated Diesel Usage	**17.052**	**±3.25/Gallons**	**$55,419.00**	

Drilling Fluids Summary

NEWPARK FLUIDS SYSTEMS

MUD TYPE: Low Solids Non-Dispersed Spud Mud

Hole Size (in)	Depth MD (ft)	Mud Density (ppg)	Plastic Viscosity (cP) @ 120°F	Yield Point (lb/100ft^2) @ 120° F	API Fluid Loss (ml)	pH	LGS %
13.5”	0 - 3,500’	9.5	5 - 12	20 - 30	NC - 20	< 9.0	< 6.0

MUD TYPE: OBM

Hole Size (in)	Depth MD (ft)	Mud Density (ppg)	Plastic Viscosity (cP) @ 120°F	Yield Point (lb/100ft^2) @ 120° F	HTHP Fluid Loss (ml)	Oil : Water Ratio	LGS %
8.5”	3,500’ -10,000’	± 10.0	10 - 19	16 - 20	< 6.0 @ 240°F	70:30 - 75:25	< 6.0

Interval (ft)	*From:*	*To:*	*Total Days*	*Total Price (US$)*
Surface	0	3,500	5	$22,776.70
Production	3,500	10,000	16	$78,314.31
Total Material and Engineering			***21***	***$101,091.01***
Other Products / Services / Charges	**QTY**	**Price**		**Total Price (US$)**
Shrink Wraps	54	$18.00		$972
Bulk Tank Rig Up / Rig Down	2	$1,200.00		$2,400.00
Freight (Drayage), CWT	4,200	$4.50		$18,900.00
Minimum Freight Charges	3	1,248.00		$3,744.00
Subtotal				**$26,016.00**
Total Estimated Cost				**$127,107.01**
Total Estimated Diesel Usage	**24,486**	**±3.25/Gallons**	**$79,579.50**	

Drilling Fluids Summary

NEWPARK FLUIDS SYSTEMS

MUD TYPE: WBM

Hole Size (in)	Depth MD (ft)	Mud Density (ppg)	Plastic Viscosity (cP) @ 120°F	Yield Point ($lb/100ft^2$) @ 120° F	API Fluid Loss (ml)	pH	LGS %
0	0 - 3,500’	9.5	5 - 12	20 - 30	NC - 20	< 9.0	< 6.0

Interval (ft)	*From:*	*To:*	*Total Days*	*Total Price (US$)*
Surface	0	3,500	7	$49,032.71
Total Material and Engineering			***7***	***$49,032.71***
Other Products / Services / Charges	**QTY**	**Price**		**Total Price (US$)**
Shrink Wraps	54	$18.00		$972
Bulk Tank Rig Up / Rig Down	2	$1,200.00		$2,400.00
Freight (Drayage), CWT	1,260	$4.50		$5,670.00
Subtotal				**$9,042.00**
Total Estimated Cost				**$58,074.71**

Personnel and Contacts

	Phone	Email
Longview Dispatch	(903) 297-2210	LDISPATCH@newpark.com
Madisonville Warehouse and Liquid Mud Plant	(281) 881-4554	mwarehouse@newpark.com
Regional Office - Katy	(281) 754-8600	

		Office	Mobile
Nicholas Landwermeyer	VP of NAM Operations		(346) 213-4195
Boone Dubose	Sales Manager - US Land		(512) 750-5480
Carlos Rivas	Sr. Sales Representative		(903) 431-2976-
Scott Thomassen	Technical Manager		(985) 515-5069
Daniel Butts	Field Support		(903) 638-1568

Revision & Peer Review Log

A revision, review, and approval log are below to document changes. AFE is based on information provide on “Initial Well Design—Base Case” Eric Burnett September 02, 2024.

Revision Log:

Revision Number	Date	Description
Draft	09/02/2024	1st draft for review
Final		

Peer Review Log:

Revision Number	Date	Reviewed by
Draft	09/02/2024	Nathan Tarver
Draft	09/02/2024	Carlos Rivos
Final		

Multiple String Proposal

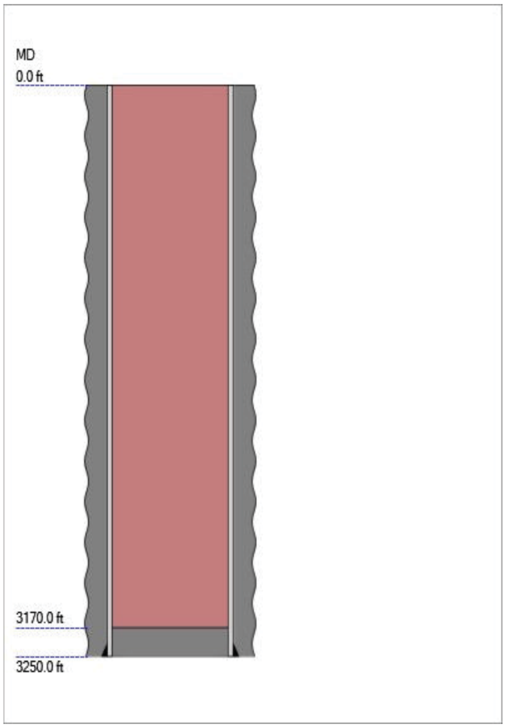
Cementing

Company	LAPIS ENERGY LP
Well Name	Simoneaux CS Injector No 1
County/Parish	St. Charles
Service From District	Shreveport
Proposal Number	v1
Date	10/2/2024
Primary Contact	Lee Reynaud / +1 214 901 6090
Objective	PERMIT VOLUMES - NO PRICING

9 5/8 in Surface Casing Well Data

IMPORTANT

The well data shown on this page is based on information available when this treatment program was prepared. This data must be confirmed on location with the customer representative prior to the treatment. Any changes in the well design need to be reviewed for their impact on the treatment design.



Well Data	
Job Type:	Surface Casing
Total Depth (Measured):	3,250.0 ft
TVD:	3,250.0 ft
BHST (Tubular Bottom Static Temperature):	138.5 degF
BHCT (Tubular Bottom Circulating Temperature):	106.5 degF
Drilling Fluid:	9.50 lb/gal

Open Hole

Excess Type	OH Diameter	MD	Excess Percent	Equiv. OH Diameter	Annular Capacity
Annular	13.500 in	3,250.0 ft	100.0 %	16.488 in	0.174 bbl/ft

Casing

OD, in	Weight, lbm/ft	Grade	Inner Capacity, bbl/ft	Bottom Depth, ft	Casing Capacity, bbl/ft
9 5/8	40.0	K-55	0.076	3,250.0	0.07583

Annular Capacity (no excess)

Fluid Placement

Fluid Name	Volume, bbl	Top of Fluid, ft	Annular Length, ft	Length, ft	Density, lb/gal
9.5 WBM	0.0	0.0	0.0	0.0	9.50
Fresh Water	40.0	0.0	0.0	0.0	8.32
15.6 Type I/II	571.9	0.0	3,250.0	3,330.0	15.60
9.5 WBM	240.4	0.0	0.0	3,170.0	9.50

Total Liquid Volume: 852.3 bbl

9 5/8 in Surface Casing Fluid Systems

Fresh Water	
System	Wash
Density	8.32 lb/gal
Total Volume	40.0 bbl

15.6 Type I/II (2712 sacks, 94.0 lbm per sack of Blend)	
System	Conventional
Density	15.60 lb/gal
Yield	1.18 ft3/sk
Mix Water	5.24 gal/sk
Mix Fluid	5.24 gal/sk
Total Volume	571.9 bbl

Some of the chemicals specified in this program may have toxic properties. All personnel should be familiar with the inherent dangers and appropriate safeguards to prevent accidental injury. Use of these chemicals may be governed by certain laws and regulations and should only be used in accordance with such. Please refer to the MSDS for the recommended safety precautions and required minimum personal protective equipment.

Pumping Schedule

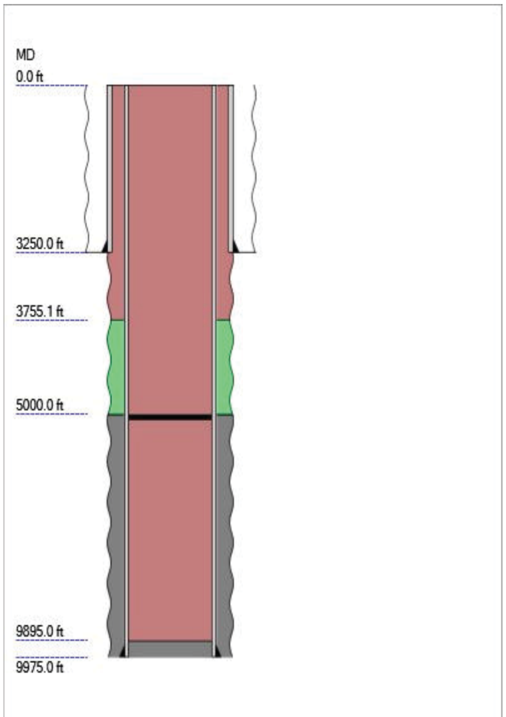
Fluid Placement

Fluid	Flow Rate, bbl/min	Volume, bbl	Stage Time, min	Cumul Volume, bbl	Cumul Time, min	Comments
Fresh Water	5.0	40.0	8.0	40.0	8.0	
15.6 Type I/II	5.0	571.9	114.4	611.9	122.4	
Pause	0.0	0.0	10.0	611.9	132.4	
9.5 WBM	5.0	220.0	44.0	831.9	176.4	
	2.0	20.4	10.2	852.3	186.6	
			Total Fluid Volume:	852.3		
			Total Pump Time:		186.6	

7 in Multi-stage Casing Well Data

IMPORTANT

The well data shown on this page is based on information available when this treatment program was prepared. This data must be confirmed on location with the customer representative prior to the treatment. Any changes in the well design need to be reviewed for their impact on the treatment design.



Well Data

Job Type:	Multi-stage Casing
Total Depth (Measured):	9,975.0 ft
TVD:	9,975.0 ft
BHST (Tubular Bottom Static Temperature):	259.5 degF
BHCT (Tubular Bottom Circulating Temperature):	215.9 degF
Drilling Fluid:	10.00 lb/gal

Open Hole

Excess Type	OH Diameter	MD	Excess Percent	Equiv. OH Diameter	Annular Capacity
Annular	8.750 in	9,975.0 ft	20.0 %	9.060 in	0.032 bbl/ft

Previous Casing

OD, in	Weight, lbm/ft	Grade	Inner Capacity, bbl/ft	Bottom Depth, ft	Casing Capacity, bbl/ft
9 5/8	40.0	K-55	0.076	3,250.0	0.07583

Casing

OD, in	Weight, lbm/ft	Grade	Inner Capacity, bbl/ft	Bottom Depth, ft	Casing Capacity, bbl/ft
7	26.0	L-80	0.038	9,975.0	0.03826

Stage Collar

Measured Depth - Stage 1	9,895.0 ft
Measured Depth - Stage 2	5,000.0 ft

Annular Capacity (no excess)

9 5/8 in Previous CSG :: 7 in CSG:	0.028 bbl/ft

Fluid Placement - Stage 1

Fluid Name	Volume, bbl	Top of Fluid, ft	Annular Length, ft	Length, ft	Density, lb/gal
10.0 OBM	108.0	0.0	3,755.1	3,755.1	10.00
11.0 MUDPUSH Express	40.0	3,755.1	1,244.9	1,244.9	11.00
14.13 EverCRETE Tail	162.9	5,000.0	4,975.0	5,055.0	14.13
10.0 OBM	378.6	0.0	0.0	9,895.0	10.00

Total Liquid Volume: 689.5 bbl

Fluid Placement - Stage 2

Fluid Name	Volume, bbl	Top of Fluid, ft	Annular Length, ft	Length, ft	Density, lb/gal
10.0 OBM	0.0	0.0	0.0	0.0	10.00
11.0 MUDPUSH Express	40.0	0.0	0.0	0.0	11.00
12.0 Poz:H Lead	91.7	0.0	3,250.0	3,250.0	12.00
14.13 EverCRETE Tail	56.2	3,250.0	1,750.0	1,750.0	14.13
10.0 OBM	191.3	0.0	0.0	5,000.0	10.00

Total Liquid Volume: 379.3 bbl

7 in Multi-stage Casing Fluid Systems

11.0 MUDPUSH Express	
System	Conventional
Density	11.00 lb/gal
Total Volume	80.0 bbl

14.13 EverCRETE Tail (972 sacks, 100.0 lbm per sack of Blend)	
System	EverCRETE
Density	14.13 lb/gal
Yield	1.27 ft3/sk
Mix Water	3.85 gal/sk
Mix Fluid	3.90 gal/sk
Total Volume	219.1 bbl

12.0 Poz:H Lead (226 sacks, 84.0 lbm per sack of Blend)	
System	Conventional
Density	12.00 lb/gal
Yield	2.28 ft3/sk
Mix Water	13.05 gal/sk
Mix Fluid	13.07 gal/sk
Total Volume	91.7 bbl

Some of the chemicals specified in this program may have toxic properties. All personnel should be familiar with the inherent dangers and appropriate safeguards to prevent accidental injury. Use of these chemicals may be governed by certain laws and regulations and should only be used in accordance with such. Please refer to the MSDS for the recommended safety precautions and required minimum personal protective equipment.

Pumping Schedule

Stage: 1

Fluid Placement

Fluid	Flow Rate, bbl/min	Volume, bbl	Stage Time, min	Cumul Volume, bbl	Cumul Time, min	Comments
11.0 MUDPUSH Express	5.0	40.0	8.0	40.0	8.0	
14.13 EverCRETE Tail	5.0	162.9	32.6	202.9	40.6	
Pause	0.0	0.0	10.0	202.9	50.6	
10.0 OBM	5.0	360.0	72.0	562.9	122.6	
	2.0	18.6	9.3	581.5	131.9	
			Total Fluid Volume:	581.5		
			Total Pump Time:		131.9	

Stage: 2

Fluid Placement

Fluid	Flow Rate, bbl/min	Volume, bbl	Stage Time, min	Cumul Volume, bbl	Cumul Time, min	Comments
11.0 MUDPUSH Express	5.0	40.0	8.0	40.0	8.0	
12.0 Poz:H Lead	5.0	91.7	18.3	131.7	26.3	
14.13 EverCRETE Tail	5.0	56.2	11.2	188.0	37.6	
Pause	0.0	0.0	10.0	188.0	47.6	
10.0 OBM	5.0	170.0	34.0	358.0	81.6	
	2.0	21.3	10.7	379.3	92.2	
			Total Fluid Volume:	379.3		
			Total Pump Time:		92.2	

Multiple String Proposal

Cementing

Company	LAPIS ENERGY LP
Well Name	Simoneaux CS Injector No 2
County/Parish	St. Charles County
Service From District	Shreveport
Proposal Number	v0.2 - Update Production annular excess to 20%
Date	10/14/2024
Primary Contact	Lee Reynaud / +1 214 901 6090
Objective	PERMIT VOLUMES - NO PRICING

SLB submits this document with the benefit of its judgment, experience, and good oilfield practices. This information is provided in accordance with generally accepted industry practice, relying on facts or information provided by others, limitations, computer models, measurements, assumptions and inferences that are not infallible. Calculations are estimates based on provided information. All proposals, recommendations, or predictions are opinions only. NO WARRANTY IS GIVEN CONCERNING ACCURACY OR COMPLETENESS OF DATA, INFORMATION PRESENTED, EFFECTIVENESS OF MATERIAL, PRODUCTS OR SUPPLIES, RECOMMENDATIONS MADE, OR RESULTS OF THE SERVICES RENDERED. Freedom from infringement of any intellectual property rights of SLB or others is not inferred and no intellectual property rights are granted hereby.

9 5/8 in Surface Casing Well Data

IMPORTANT

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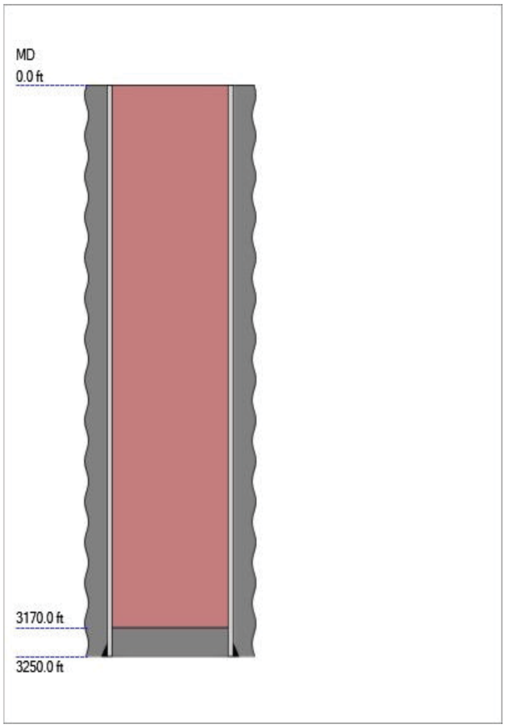

Well Data

Job Type:	Surface Casing
Total Depth (Measured):	3,250.0 ft
TVD:	3,250.0 ft
BHST (Tubular Bottom Static Temperature):	138.5 degF
BHCT (Tubular Bottom Circulating Temperature):	106.5 degF
Drilling Fluid:	9.50 lb/gal

Open Hole

Excess Type	OH Diameter	MD	Excess Percent	Equiv. OH Diameter	Annular Capacity
Annular	13.500 in	3,250.0 ft	100.0 %	16.488 in	0.174 bbl/ft

Casing

OD, in	Weight, lbm/ft	Grade	Inner Capacity, bbl/ft	Bottom Depth, ft	Casing Capacity, bbl/ft
9 5/8	40.0	K-55	0.076	3,250.0	0.07583

Annular Capacity (no excess)

Fluid Placement

Fluid Name	Volume, bbl	Top of Fluid, ft	Annular Length, ft	Length, ft	Density, lb/gal
9.5 WBM	0.0	0.0	0.0	0.0	9.50
Fresh Water	40.0	0.0	0.0	0.0	8.32
15.6 Type I/II	571.9	0.0	3,250.0	3,330.0	15.60
9.5 WBM	240.4	0.0	0.0	3,170.0	9.50

Total Liquid Volume: 852.3 bbl

9 5/8 in Surface Casing Fluid Systems

Fresh Water	
System	Wash
Density	8.32 lb/gal
Total Volume	40.0 bbl

15.6 Type I/II (2712 sacks, 94.0 lbm per sack of Blend)	
System	Conventional
Density	15.60 lb/gal
Yield	1.18 ft3/sk
Mix Water	5.24 gal/sk
Mix Fluid	5.24 gal/sk
Total Volume	571.9 bbl

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Pumping Schedule

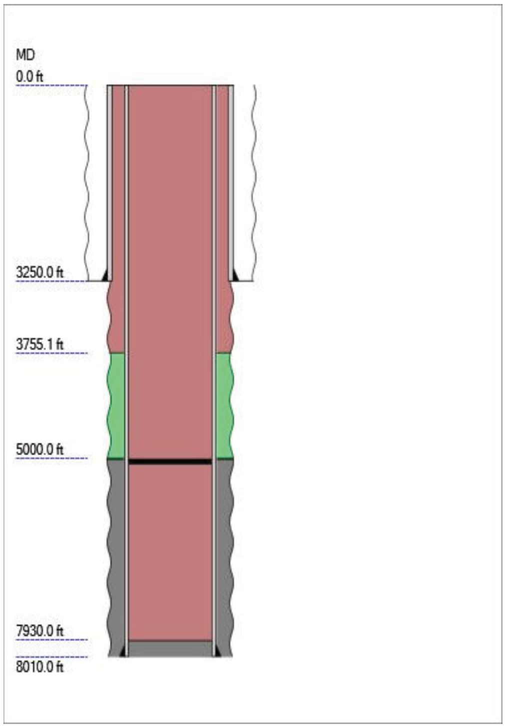
Fluid Placement

Fluid	Flow Rate, bbl/min	Volume, bbl	Stage Time, min	Cumul Volume, bbl	Cumul Time, min	Comments
Fresh Water	5.0	40.0	8.0	40.0	8.0	
15.6 Type I/II	5.0	571.9	114.4	611.9	122.4	
Pause	0.0	0.0	10.0	611.9	132.4	
9.5 WBM	5.0	220.0	44.0	831.9	176.4	
	2.0	20.4	10.2	852.3	186.6	
			Total Fluid Volume:	852.3		
			Total Pump Time:		186.6	

7 in Multi-stage Casing Well Data

IMPORTANT

The well data shown on this page is based on information available when this treatment program was prepared. This data must be confirmed on location with the customer representative prior to the treatment. Any changes in the well design need to be reviewed for their impact on the treatment design.



Well Data	
Job Type:	Multi-stage Casing
Total Depth (Measured):	8,010.0 ft
TVD:	8,010.0 ft
BHST (Tubular Bottom Static Temperature):	224.2 degF
BHCT (Tubular Bottom Circulating Temperature):	183.7 degF
Drilling Fluid:	10.00 lb/gal

Open Hole

Excess Type	OH Diameter	MD	Excess Percent	Equiv. OH Diameter	Annular Capacity
Annular	8.750 in	8,010.0 ft	20.0 %	9.060 in	0.032 bbl/ft

Previous Casing

OD, in	Weight, lbm/ft	Grade	Inner Capacity, bbl/ft	Bottom Depth, ft	Casing Capacity, bbl/ft
9 5/8	40.0	K-55	0.076	3,250.0	0.07583

Casing

OD, in	Weight, lbm/ft	Grade	Inner Capacity, bbl/ft	Bottom Depth, ft	Casing Capacity, bbl/ft
7	26.0	L-80	0.038	8,010.0	0.03826

Stage Collar

Measured Depth - Stage 1	7,930.0 ft
Measured Depth - Stage 2	5,000.0 ft

Annular Capacity (no excess)

9 5/8 in Previous CSG :: 7 in CSG:	0.028 bbl/ft

Fluid Placement - Stage 1

Fluid Name	Volume, bbl	Top of Fluid, ft	Annular Length, ft	Length, ft	Density, lb/gal
10.0 OBM	108.0	0.0	3,755.1	3,755.1	10.00
11.0 MUDPUSH Express	40.0	3,755.1	1,244.9	1,244.9	11.00
14.13 EverCRETE Tail	99.8	5,000.0	3,010.0	3,090.0	14.13
10.0 OBM	303.4	0.0	0.0	7,930.0	10.00

Total Liquid Volume: 551.2 bbl

Fluid Placement - Stage 2

Fluid Name	Volume, bbl	Top of Fluid, ft	Annular Length, ft	Length, ft	Density, lb/gal
10.0 OBM	0.0	0.0	0.0	0.0	10.00
11.0 MUDPUSH Express	40.0	0.0	0.0	0.0	11.00
12.0 Poz:H Lead	91.7	0.0	3,250.0	3,250.0	12.00
14.13 EverCRETE Tail	56.2	3,250.0	1,750.0	1,750.0	14.13
10.0 OBM	191.3	0.0	0.0	5,000.0	10.00

Total Liquid Volume: 379.3 bbl

7 in Multi-stage Casing Fluid Systems

11.0 MUDPUSH Express	
System	Conventional
Density	11.00 lb/gal
Total Volume	80.0 bbl

14.13 EverCRETE Tail (692 sacks, 100.0 lbm per sack of Blend)	
System	EverCRETE
Density	14.13 lb/gal
Yield	1.27 ft3/sk
Mix Water	3.85 gal/sk
Mix Fluid	3.90 gal/sk
Total Volume	156.0 bbl

12.0 Poz:H Lead (226 sacks, 84.0 lbm per sack of Blend)	
System	Conventional
Density	12.00 lb/gal
Yield	2.28 ft3/sk
Mix Water	13.05 gal/sk
Mix Fluid	13.07 gal/sk
Total Volume	91.7 bbl

Some of the chemicals specified in this program may have toxic properties. All personnel should be familiar with the inherent dangers and appropriate safeguards to prevent accidental injury. Use of these chemicals may be governed by certain laws and regulations and should only be used in accordance with such. Please refer to the MSDS for the recommended safety precautions and required minimum personal protective equipment.

Pumping Schedule

Stage: 1

Fluid Placement

Fluid	Flow Rate, bbl/min	Volume, bbl	Stage Time, min	Cumul Volume, bbl	Cumul Time, min	Comments
11.0 MUDPUSH Express	5.0	40.0	8.0	40.0	8.0	
14.13 EverCRETE Tail	5.0	99.8	20.0	139.8	28.0	
Pause	0.0	0.0	10.0	139.8	38.0	
10.0 OBM	5.0	285.0	57.0	424.8	95.0	
	2.0	18.4	9.2	443.2	104.2	
			Total Fluid Volume:	443.2		
			Total Pump Time:		104.2	

Stage: 2

Fluid Placement

Fluid	Flow Rate, bbl/min	Volume, bbl	Stage Time, min	Cumul Volume, bbl	Cumul Time, min	Comments
11.0 MUDPUSH Express	5.0	40.0	8.0	40.0	8.0	
12.0 Poz:H Lead	5.0	91.7	18.3	131.7	26.3	
14.13 EverCRETE Tail	5.0	56.2	11.2	188.0	37.6	
Pause	0.0	0.0	10.0	188.0	47.6	
10.0 OBM	5.0	170.0	34.0	358.0	81.6	
	2.0	21.3	10.7	379.3	92.2	
			Total Fluid Volume:	379.3		
			Total Pump Time:		92.2	

Multiple String Proposal

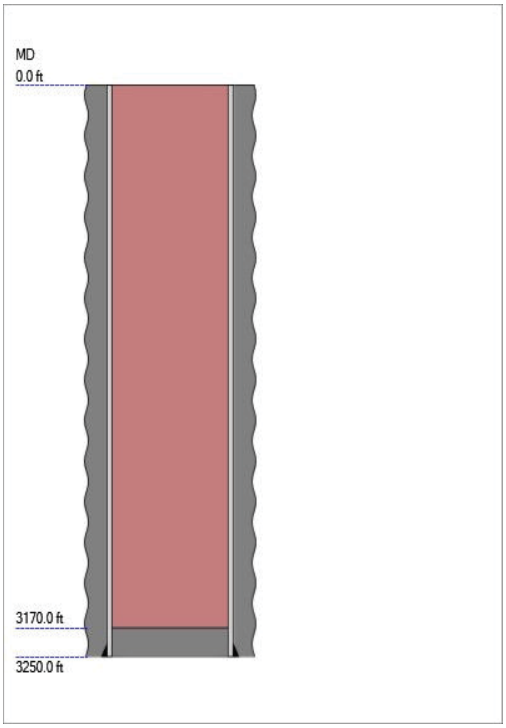
Cementing

Company	LAPIS ENERGY LP
Well Name	Simoneaux CS Injector No 3
County/Parish	St. Charles County
Service From District	Shreveport
Proposal Number	v0
Date	10/3/2024
Primary Contact	Lee Reynaud / +1 214 901 6090
Objective	PERMIT VOLUMES - NO PRICING

9 5/8 in Surface Casing Well Data

IMPORTANT

The well data shown on this page is based on information available when this treatment program was prepared. This data must be confirmed on location with the customer representative prior to the treatment. Any changes in the well design need to be reviewed for their impact on the treatment design.



Well Data	
Job Type:	Surface Casing
Total Depth (Measured):	3,250.0 ft
TVD:	3,250.0 ft
BHST (Tubular Bottom Static Temperature):	138.5 degF
BHCT (Tubular Bottom Circulating Temperature):	106.5 degF
Drilling Fluid:	9.50 lb/gal

Open Hole

Excess Type	OH Diameter	MD	Excess Percent	Equiv. OH Diameter	Annular Capacity
Annular	13.500 in	3,250.0 ft	100.0 %	16.488 in	0.174 bbl/ft

Casing

OD, in	Weight, lbm/ft	Grade	Inner Capacity, bbl/ft	Bottom Depth, ft	Casing Capacity, bbl/ft
9 5/8	40.0	K-55	0.076	3,250.0	0.07583

Annular Capacity (no excess)

Fluid Placement

Fluid Name	Volume, bbl	Top of Fluid, ft	Annular Length, ft	Length, ft	Density, lb/gal
9.5 WBM	0.0	0.0	0.0	0.0	9.50
Fresh Water	40.0	0.0	0.0	0.0	8.32
15.6 Type I/II	571.9	0.0	3,250.0	3,330.0	15.60
9.5 WBM	240.4	0.0	0.0	3,170.0	9.50

Total Liquid Volume: 852.3 bbl

9 5/8 in Surface Casing Fluid Systems

Fresh Water	
System	Wash
Density	8.32 lb/gal
Total Volume	40.0 bbl

15.6 Type I/II (2712 sacks, 94.0 lbm per sack of Blend)	
System	Conventional
Density	15.60 lb/gal
Yield	1.18 ft3/sk
Mix Water	5.24 gal/sk
Mix Fluid	5.24 gal/sk
Total Volume	571.9 bbl

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Pumping Schedule

Fluid Placement

Fluid	Flow Rate, bbl/min	Volume, bbl	Stage Time, min	Cumul Volume, bbl	Cumul Time, min	Comments
Fresh Water	5.0	40.0	8.0	40.0	8.0	
15.6 Type I/II	5.0	571.9	114.4	611.9	122.4	
Pause	0.0	0.0	10.0	611.9	132.4	
9.5 WBM	5.0	220.0	44.0	831.9	176.4	
	2.0	20.4	10.2	852.3	186.6	
			Total Fluid Volume:	852.3		
			Total Pump Time:		186.6	

7 in Multi-stage Casing Well Data

IMPORTANT
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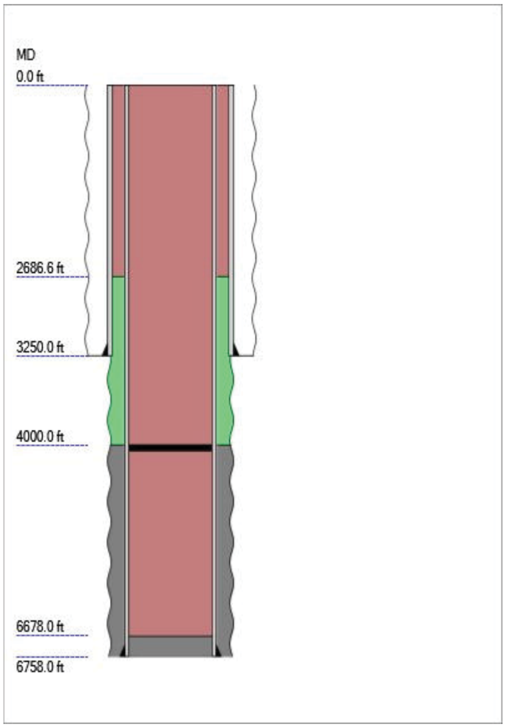

Well Data	
Job Type:	Multi-stage Casing
Total Depth (Measured):	6,758.0 ft
TVD:	6,758.0 ft
BHST (Tubular Bottom Static Temperature):	201.6 degF
BHCT (Tubular Bottom Circulating Temperature):	163.9 degF
Drilling Fluid:	10.00 lb/gal

Open Hole

Excess Type	OH Diameter	MD	Excess Percent	Equiv. OH Diameter	Annular Capacity
Annular	8.750 in	6,758.0 ft	20.0 %	9.060 in	0.032 bbl/ft

Previous Casing

OD, in	Weight, lbm/ft	Grade	Inner Capacity, bbl/ft	Bottom Depth, ft	Casing Capacity, bbl/ft
9 5/8	40.0	K-55	0.076	3,250.0	0.07583

Casing

OD, in	Weight, lbm/ft	Grade	Inner Capacity, bbl/ft	Bottom Depth, ft	Casing Capacity, bbl/ft
7	26.0	L-80	0.038	6,758.0	0.03826

Stage Collar

Measured Depth - Stage 1	6,678.0 ft
Measured Depth - Stage 2	4,000.0 ft

Annular Capacity (no excess)

9 5/8 in Previous CSG :: 7 in CSG:	0.028 bbl/ft

Fluid Placement - Stage 1

Fluid Name	Volume, bbl	Top of Fluid, ft	Annular Length, ft	Length, ft	Density, lb/gal
10.0 OBM	75.8	0.0	2,686.6	2,686.6	10.00
11.0 MUDPUSH Express	40.0	2,686.6	1,313.4	1,313.4	11.00
14.13 EverCRETE Tail	91.7	4,000.0	2,758.0	2,838.0	14.13
10.0 OBM	255.5	0.0	0.0	6,678.0	10.00

Total Liquid Volume: 463.0 bbl

Fluid Placement - Stage 2

Fluid Name	Volume, bbl	Top of Fluid, ft	Annular Length, ft	Length, ft	Density, lb/gal
10.0 OBM	0.0	0.0	0.0	0.0	10.00
11.0 MUDPUSH Express	40.0	0.0	0.0	0.0	11.00
12.0 Poz:H Lead	91.7	0.0	3,250.0	3,250.0	12.00
14.13 EverCRETE Tail	24.1	3,250.0	750.0	750.0	14.13
10.0 OBM	153.1	0.0	0.0	4,000.0	10.00

Total Liquid Volume: 308.9 bbl

7 in Multi-stage Casing Fluid Systems

11.0 MUDPUSH Express	
System	Conventional
Density	11.00 lb/gal
Total Volume	80.0 bbl

14.13 EverCRETE Tail (514 sacks, 100.0 lbm per sack of Blend)	
System	EverCRETE
Density	14.13 lb/gal
Yield	1.27 ft3/sk
Mix Water	3.85 gal/sk
Mix Fluid	3.90 gal/sk
Total Volume	115.8 bbl

12.0 Poz:H Lead (226 sacks, 84.0 lbm per sack of Blend)	
System	Conventional
Density	12.00 lb/gal
Yield	2.28 ft3/sk
Mix Water	13.05 gal/sk
Mix Fluid	13.07 gal/sk
Total Volume	91.7 bbl

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Pumping Schedule

Stage: 1

Fluid Placement

Fluid	Flow Rate, bbl/min	Volume, bbl	Stage Time, min	Cumul Volume, bbl	Cumul Time, min	Comments
11.0 MUDPUSH Express	5.0	40.0	8.0	40.0	8.0	
14.13 EverCRETE Tail	5.0	91.7	18.3	131.7	26.3	
Pause	0.0	0.0	10.0	131.7	36.3	
10.0 OBM	5.0	235.0	47.0	366.7	83.3	
	2.0	20.5	10.3	387.2	93.6	
			Total Fluid Volume:	387.2		
			Total Pump Time:		93.6	

Stage: 2

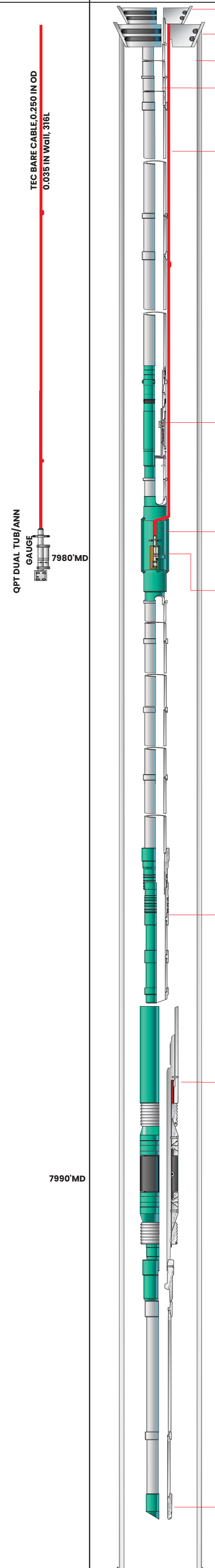
Fluid Placement

Fluid	Flow Rate, bbl/min	Volume, bbl	Stage Time, min	Cumul Volume, bbl	Cumul Time, min	Comments
11.0 MUDPUSH Express	5.0	40.0	8.0	40.0	8.0	
12.0 Poz:H Lead	5.0	91.7	18.3	131.7	26.3	
14.13 EverCRETE Tail	5.0	24.1	4.8	155.8	31.2	
Pause	0.0	0.0	10.0	155.8	41.2	
10.0 OBM	5.0	135.0	27.0	290.8	68.2	
	2.0	18.1	9.0	308.9	77.2	
			Total Fluid Volume:	308.9		
			Total Pump Time:		77.2	

Proposed Well Completion

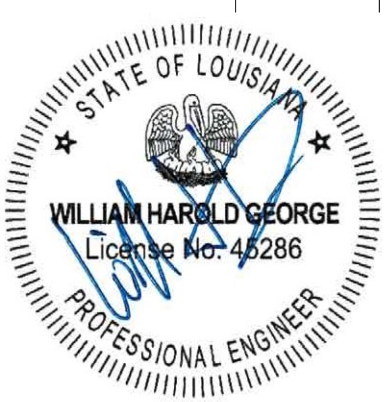
Customer:			Date: 11/7/2024
Country: USA	Field: Libra	Sales Rep: Duane Martin	Baker Hughes
Prepared For: Lipsa Energy	Lease: Libra	Drawn By: Joel Mathew	
Quotation No.	Well No. Simoneaux CCS Injector# 1	Drawing No. Deep Injector Well	

	4.5" Injection String Control Lines	Well Schematic	Description	Material#



Description	Material#
4.50IN 11.6# Hanger w/Feed-through Port for TEC	
7.0IN 26# Hanger	
7.0IN 26# Casing	
4.50IN 11.6# L-80 Tubing	
1 TEC BARE CABLE,0.250 IN OD; 0.035 IN Wall, 316L	
2 4.500 IN INJECTION WIRELINE SAFETY VALVE FMJ-14 T/M W/ MODEL N EQUALIZING SUB W/B PROFILE 25CR80 3.838 IN OD 3.812 IN SEAL BORE 1.906 IN ID	H808890025_MOD
3 SureSENS DUAL GAUGE CARRIER 4.5" 11.6LB/FT 25 CHROME 80 BXB VAM21 TUB/ANN SENSING 6.070IN OD 3.865IN ID 36.00IN LG	H308090153_MOD
4 SureSENS QPT ELITE DUAL GAUGES (TUB/ANN) 10K PSI 150C, INC 718	H307570135
	H801990230_MOD
5 BAKER GBH-22 LOCATOR TUBING SEAL ASSEMBLY W/2 SEAL UNITS 192-47 90HD NITRILE BONDED SEAL BPS-E102 (H002) 90HD NIT BND 4.967 IN TOOL OD 4.755 IN SEAL OD 3.875 IN ID 39.267 IN LG 25CR80 32-300 DEGF WK TEMPERATURE 4.500 IN 11.60 LB/FT VAM 21 BOX UP 1/2 MULESHOE	H450010026_MOD
6 BAKER SIGNATURE SERIES PACKER F 587-475-400 W/BOTTOM GUIDE 06.625 IN 17.0 LB/FT CSG; 07.000 IN 26.0-29.0 LB/FT CSG F/6.276 IN MAX CSG ID F/6.095 IN MIN CSG ID 5.875 IN OD 4.000 IN ID 4.000 IN SEAL BORE 4.750 IN ALT SEAL BORE 25CR80 NITRILE PE 70 HD PERMANENT NITRILE PE 70-275 DEGF WK TEMPERATURE 5.125 IN BAKER LH SQUARE THREAD BOX UP 4.500 IN 11.60 LB/FT VAM21 BOX DOWN BOTTOM GUIDE: H02432225T	H432080138_MOD
	H02432225N_MOD
	H801990225_MOD
7 WIRELINE ENTRY GUIDE 4.500 IN 11.60 LB/FT VAM 21 UP 1/2 MULESHOE BLANK DOWN 4.932 IN OD 3.942 IN ID 11.000 IN LG	H469210269_MOD

Tubemove calculation will need to be performed to determine the length requirement on LTSA and packer body

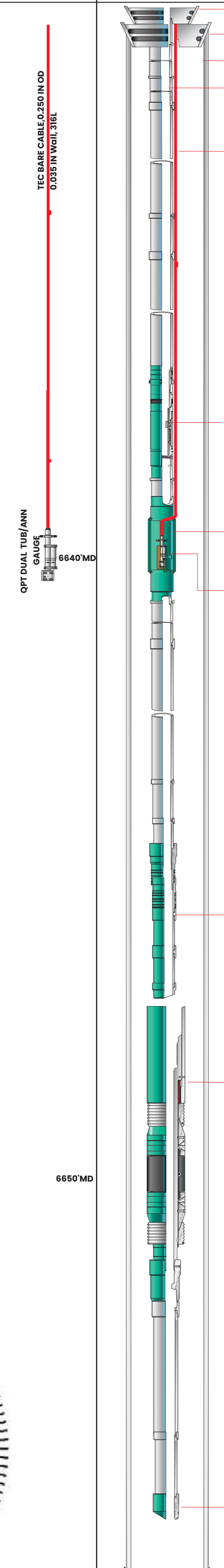


Proposed Well Completion

Customer:		Date: 11/7/2024
Country: USA	Field: Libra	Sales Rep: Duane Martin
Prepared For: Lipsa Energy	Lease: Libra	Drawn By: Joel Mathew
Quotation No.	Well No. Simoneaux CCS Injector# 2	Drawing No. Mid Injector Well

Baker Hughes

4.5" Injection String Control Lines	Well Schematic	Description	Material#
		4.50IN 11.6# Hanger w/Feed-through Port for TEC	
		7.0IN 26# Hanger	
		7.0IN 26# Casing	
		4.50IN 11.6# L-80 Tubing	
		1 TEC BARE CABLE,0.250 IN OD; 0.035 IN Wall, 316L	
		2 4.500 IN INJECTION WIRELINE SAFETY VALVE FMJ-14 T/M W/ MODEL N EQUALIZING SUB W/B PROFILE 25CR80 3.838 IN OD 3.812 IN SEAL BORE 1.906 IN ID	H808890025_MOD
		3 SureSENS DUAL GAUGE CARRIER 4.5" 11.6LB/FT 25 CHROME 80 BXB VAM21 TUB/ANN SENSING 6.070IN OD 3.865IN ID 36.00IN LG	H308090153_MOD
		4 SureSENS QPT ELITE DUAL GAUGES (TUB/ANN) 10K PSI 150C, INC 718	H307570135
			H801990230_MOD
		5 BAKER GBH-22 LOCATOR TUBING SEAL ASSEMBLY W/2 SEAL UNITS 192-47 90HD NITRILE BONDED SEAL BPS-E102 (H002) 90HD NIT BND 4.967 IN TOOL OD 4.755 IN SEAL OD 3.875 IN ID 39.267 IN LG 25CR80 32-300 DEGF WK TEMPERATURE 4.500 IN 11.60 LB/FT VAM 21 BOX UP 1/2 MULESHOE	H453010076_MOD
		6 BAKER SIGNATURE SERIES PACKER F 587-475-400 W/BOTTOM GUIDE 06.625 IN 17.0 LB/FT CSG; 07.000 IN 26.0-29.0 LB/FT CSG F/6.276 IN MAX CSG ID F/6.095 IN MIN CSG ID 5.875 IN OD 4.000 IN ID 4.000 IN SEAL BORE 4.750 IN ALT SEAL BORE 25CR80 NITRILE PE 70 HD PERMANENT NITRILE PE 70-275 DEGF WK TEMPERATURE 5.125 IN BAKER LH SQUARE THREAD BOX UP 4.500 IN 11.60 LB/FT VAM21 BOX DOWN BOTTOM GUIDE: H02432225T	H450010026_MOD
			H02432225N_MOD
			H801990225_MOD
		7 WIRELINE ENTRY GUIDE 4.500 IN 11.60 LB/FT VAM 21 UP 1/2 MULESHOE BLANK DOWN 4.932 IN OD 3.942 IN ID 11.000 IN LG	H469210269_MOD



Tubemove calculation will need to be performed to determine the length requirement on LTSA and packer body

STATE OF LOUISIANA
WILLIAM HAROLD GEORGE
License No. 45286
PROFESSIONAL ENGINEER

Proposed Well Completion

Customer:

Date: 11/7/2024

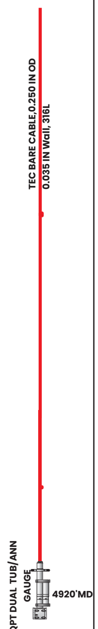
Country: USA | Field: Libra | Sales Rep: Duane Martin

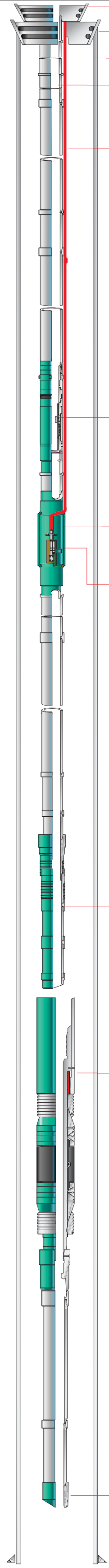
Prepared For: Lipsa Energy | Feetase: Libra | Drawn By: Joel Mathew

Quotation No. | Well No. Simoneaux CCS Injector # 3 | Drawing No. Shallow Injector Well

Baker Hughes

	4.5" Injection String Control Lines	Well Schematic	Description	Material#





Description	Material#
4.50IN 11.6# Hanger w/Feed-through Port for TEC	
7.0IN 26# Hanger	
7.0IN 26# Casing	
4.50IN 11.6# L-80 Tubing	
(1) TEC BARE CABLE,0.250 IN OD; 0.035 IN Wall, 316L	
(2) 4.500 IN INJECTION WIRELINE SAFETY VALVE FMJ-14 T/M W/ MODEL N EQUALIZING SUB W/B PROFILE 25CR80 3.838 IN OD 3.812 IN SEAL BORE 1.906 IN ID	H808890025_MOD
(3) SureSENS DUAL GAUGE CARRIER 4.5" 11.6LB/FT 25 CHROME 80 BXB VAM21 TUB/ANN SENSING 6.070IN OD 3.865IN ID 36.00IN LG	H308090153_MOD
(4) SureSENS QPT ELITE DUAL GAUGES (TUB/ANN) 10K PSI 150C, INC 718	H307570135
	H801990230_MOD
(5) BAKER GBH-22 LOCATOR TUBING SEAL ASSEMBLY W/2 SEAL UNITS 192-47 90HD NITRILE BONDED SEAL BPS-E102 (H002) 90HD NIT BND 4.967 IN TOOL OD 4.755 IN SEAL OD 3.875 IN ID 39.267 IN LG 25CR80 32-300 DEGF WK TEMPERATURE 4.500 IN 11.60 LB/FT VAM 21 BOX UP 1/2 MULESHOE	H450010026_MOD
(6) BAKER SIGNATURE SERIES PACKER F 587-475-400 W/BOTTOM GUIDE 06.625 IN 17.0 LB/FT CSG; 07.000 IN 26.0-29.0 LB/FT CSG F/6.276 IN MAX CSG ID F/6.095 IN MIN CSG ID 5.875 IN OD 4.000 IN ID 4.000 IN SEAL BORE 4.750 IN ALT SEAL BORE 25CR80 NITRILE PE 70 HD PERMANENT NITRILE PE 70-275 DEGF WK TEMPERATURE 5.125 IN BAKER LH SQUARE THREAD BOX UP 4.500 IN 11.60 LB/FT VAM21 BOX DOWN BOTTOM GUIDE: H02432225T	H432080138_MOD
	H801990225_MOD
(7) WIRELINE ENTRY GUIDE 4.500 IN 11.60 LB/FT VAM 21 UP 1/2 MULESHOE BLANK DOWN 4.932 IN OD 3.942 IN ID 11.000 IN LG	H469210269_MOD

Tubemove calculation will need to be performed to determine the length requirement on LTSA and packer body

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PACECCS

LSB Libra Project

Flow Assurance Study Steady-state Results Summary

11th Nov 2024 Rev.4

Study Objectives

❖ This revision of the results summary is revised based on the 4.5-in tubing size.

The objectives of the steady-state study are listed as follows:

- To determine the maximum pump discharge pressure during normal steady-state operation;
- To assess the hydraulic capacity of the 16-inch CO_2 injection pipeline;
- To calculate the flowing wellhead conditions over injection lifetime;
- To evaluate the system sensitivity to ambient temperatures (summer and winter conditions);
- To understand the system sensitivity to inlet temperatures (i.e. pump discharge temperatures);
- To identify any risks associated with normal steady-state operation;
- To access the system pressure differences between 4.5" and 5.5" tubing size.

Study Summary

The main conclusions of the study are summarised as follows:

- The maximum pump discharge pressure is 2555 psia during the year of 2037 based on an inlet temperature of 85 °F and worst-case CO_2 compositions, with the shortest well for each injector.
- The hydraulic capacity of the 16” pipeline is 13 MTPA based on the CO_2 pump discharge temperature of 85 °F and maximum ambient conditions.
- In the later stage of field life, there is a risk of two-phase flow at the top of the well inj#3. The margin between the flowing wellhead conditions and the saturation line may be too small to reliably address the potential uncertainties in the thermodynamic models currently available for predicting the behaviour of the CO_2 stream. It is recommended to inject the CO_2 to shorter injection zones of inj#3 or at a higher inlet temperature to avoid the likelihood of gas breakout during the winter months in the late life.

Study Parameters

The following parameters have been considered in the steady-state study:

- CO_2 inlet temperatures (pump discharge temperatures):
  - Base case: inlet temperature to be ambient temperatures: 85 ºF (summer) and 50 ºF (winter);
- CO_2 fluid compositions: pure CO_2 and worst-case composition (97 mol% CO_2).
- Injection depths and pressures across 20 years of injection:
  - Perforation 1: year 2027-2029;
  - Perforation 2: year 2037-2039; and
  - End of injection: year 2046.
- Field CO_2 injection rate: 4 MTPA (design) and up to 14 MTPA.

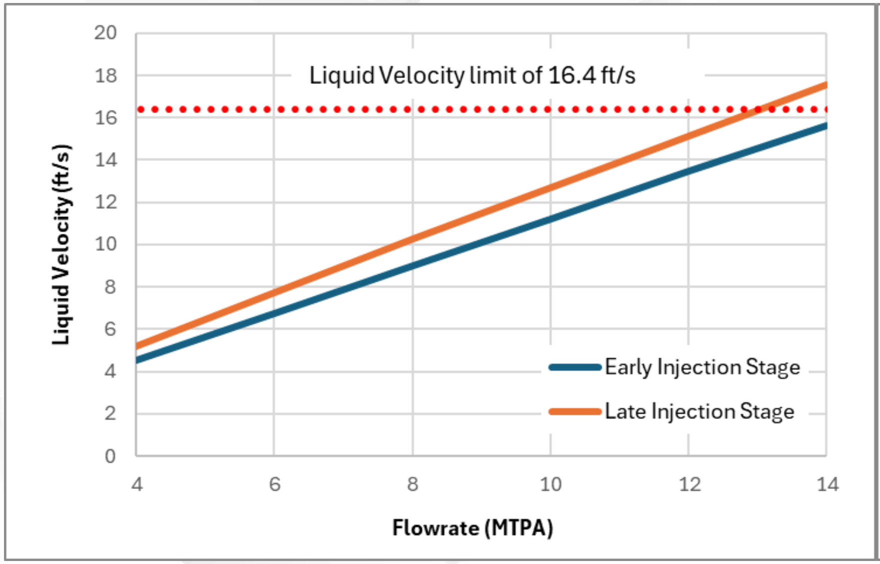
Pump Discharge Pressures

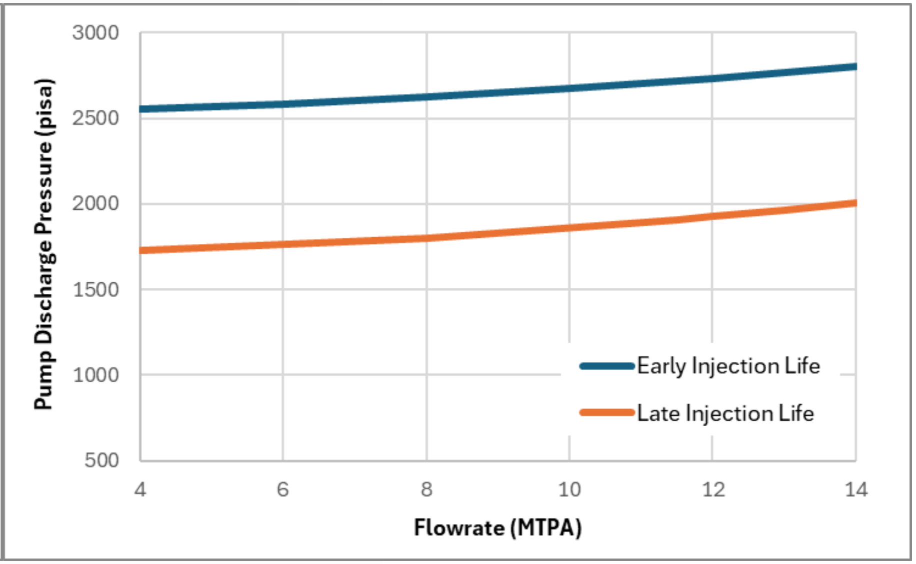
- The maximum pump discharge pressures have been calculated using the inlet temperatures of 85 ºF (summer conditions) and worst-case CO_2 compositions, with the shortest well for each injector.
- The minimum pump discharge pressures have been calculated based on the inlet temperatures of 50 ºF (winter conditions) and pure CO_2, with the deepest well for each injector.
- The maximum pump discharge pressure required is 2555 psia – at injection year 2037.

Injection Year	Maximum Pump Discharge Pressure (psia)	Minimum Pump Discharge Pressure (psia)
2027	2524	1755
2028	2503	1730
2029	2495	1713
2037	2555	1901
2038	2513	1850
2039	2490	1822

16” Injection Pipeline Hydraulic Capacity

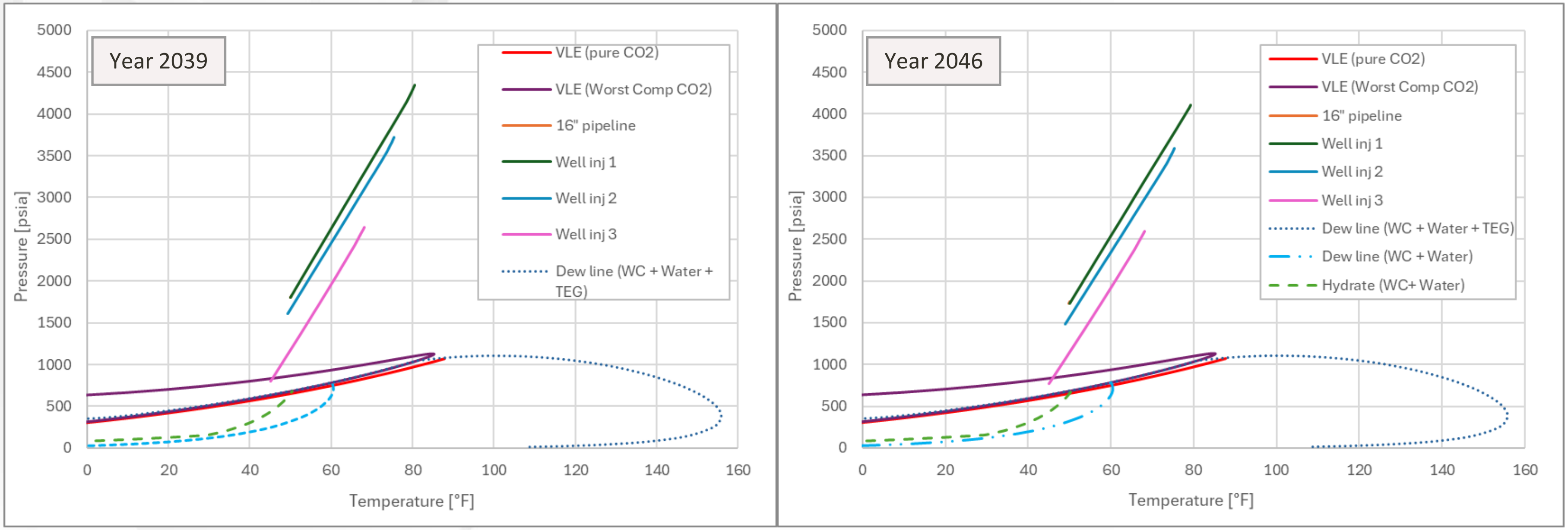
- The hydraulic capacity of the 16” pipeline has been assessed based on the base case conditions, i.e. CO_2 pump discharge temperature of 85 °F and summer ambient conditions.
- The hydraulic capacity of the 16” pipeline is 13 MTPA. This is determined based on a maximum liquid velocity limit of 16.4 ft/s (i.e. 5 m/s).
- The capacity of the 16” pipeline can be greater during early injection phase because the liquid velocity is lower due to higher density of the CO_2 stream. However, the required pump discharge pressures are significantly higher during the early injection stage.
- It should be noted that the maximum injection flowrate should also be limited by the storage capacity.





Late Injection Phase

- The wellbore pressure and temperature profiles for the year 2039 and year 2046, presented below, reflects minimum ambient conditions and pure CO_2 with the deepest wells for each injector.
- In the later stage of field life, there is a risk of two-phase flow at the top of the well inj#3. The margin between the flowing wellhead conditions and the saturation line may be too small to reliably address the potential uncertainties in the thermodynamic models currently available for predicting the behaviour of the CO_2 stream.
- It is recommended to inject the CO_2 to shorter injection zones of inj#3 or at a higher inlet temperature to avoid gas breakout during the winter months in the late injection stage.



Normal Operating Wellhead Conditions

- Wellhead conditions for a pump discharge temperature of 50 °F are based on winter ambient conditions with pure CO_2 and deepest wells, while those for discharge temperature of 85 °F correspond to summer ambient conditions and worst-case CO_2 composition with the shortest wells.

Injection Year	Pump Discharge Temperature (°F)	Inj1 Wellhead Pressure (psia)	Inj1 Wellhead Temperature (°F)	Inj2 Wellhead Pressure (psia)	Inj2 Wellhead Temperature (°F)	Inj3 Wellhead Pressure (psia)	Inj3 Wellhead Temperature (°F)
2027	85	2520	85.0				
2028	85	2490	84.9	2213	82.0		
2029	85	2472	84.8	2194	81.8	1374	70.5
2037	85	2532	84.8	2121	80.5	1260	68.1
2038	85	2489	84.8	2288	82.7	1260	68.4
2039	85	2467	84.8	2219	82.1	1292	69.1

Injection Year	Pump Discharge Temperature (°F)	Inj1 Wellhead Pressure (psia)	Inj1 Wellhead Temperature (°F)	Inj2 Wellhead Pressure (psia)	Inj2 Wellhead Temperature (°F)	Inj3 Wellhead Pressure (psia)	Inj3 Wellhead Temperature (°F)
2027	50	1752	50.0				
2028	50	1715	49.9	1699	49.9		
2029	50	1693	49.9	1679	49.8	778	45.2
2037	50	1881	49.9	1599	48.9	819	45.0
2038	50	1829	49.9	1680	49.4	816	45.1
2039	50	1802	49.9	1602	49.2	798	45.0

4.5in vs 5.5in Tubing Size

- A sensitivity analysis was performed for a 5.5-inch tubing size. The table below compares the pump discharge pressures and wellhead pressures for both tubing sizes for the injection year of 2037, assuming an inlet temperature of 85 °F and worst-case CO_2 compositions, with the shortest well for each injector.
- The smaller 4.5-inch tubing size has a significantly higher-pressure requirement for the injection.

Tubing Size	Pump Discharge Pressure (psia)	Inj1 Wellhead Pressure (psia)	Inj2 Wellhead Pressure (psia)	Inj3 Wellhead Pressure (psia)
4.5 inch	2555	2532	2121	1260
5.5 inch	2032	2007	1671	1135

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Thank You

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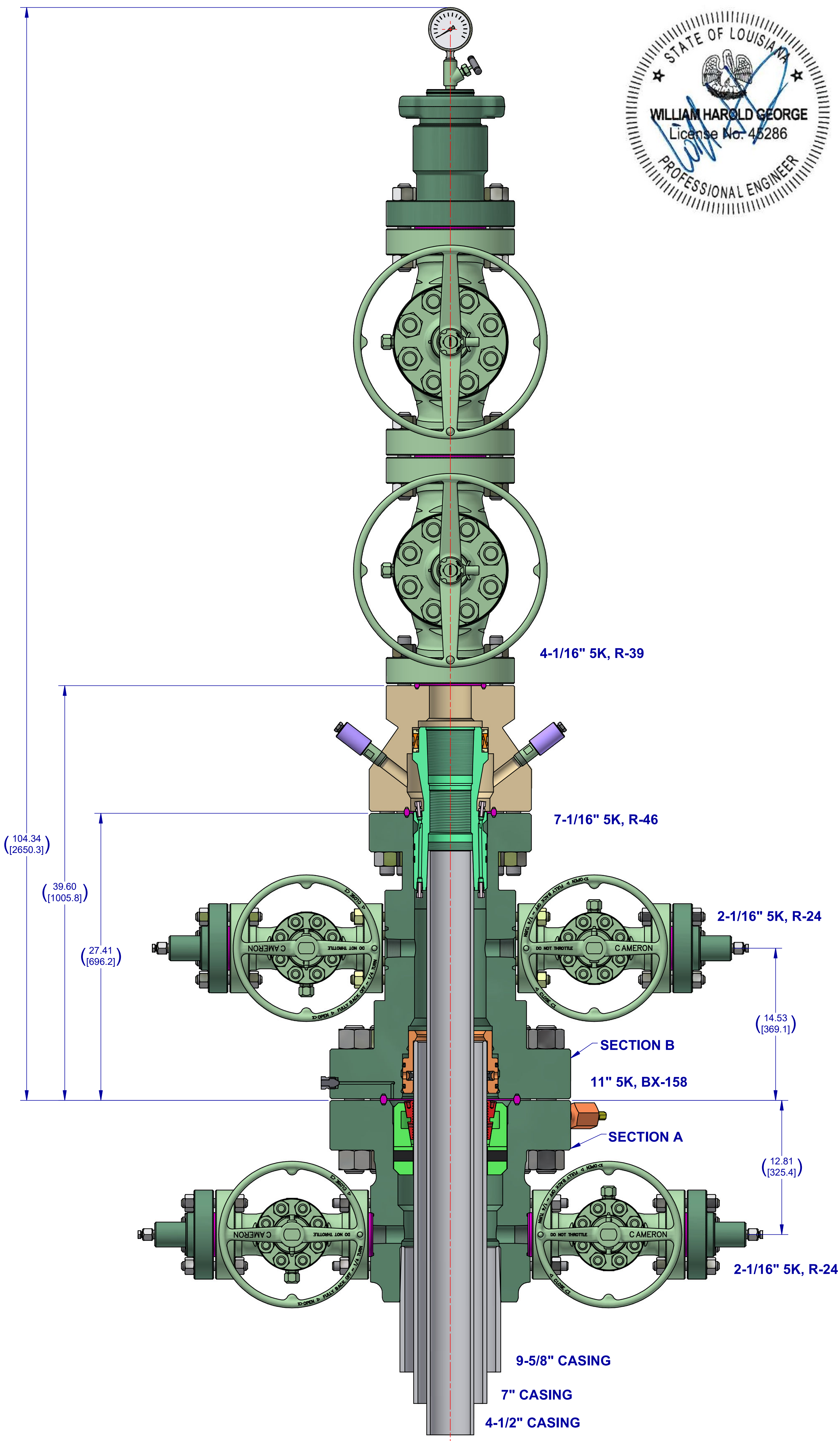

Notes:

1. THIS IS A PROPOSAL DRAWING AND DIMENSIONS SHOWN ARE SUBJECT TO CHANGE DURING THE FINAL DESIGN PROCESS.

2. DIGITALLY ENABLED SOLUTIONS, CHOKES AND ESD'S AVAILABLE ON REQUEST

CONFIDENTIAL				
SURFACE TREATMENT	DO NOT SCALE		slb	SURFACE SYSTEMS
	DRAWN BY: D. GOTTUNG	DATE 8 Oct 24		
MATERIAL & HEAT TREAT	CHECKED BY: D. GOTTUNG	DATE 8 Oct 24	SIMONEAUX INJECTOR WELL	
	APPROVED BY: JC GONZALEZ	DATE 8 Oct 24		
ESTIMATED WEIGHT: 5021.1 LBS 2277.6 KG	INITIAL USE B/M: EWR: 650657648		SHEET 1 OF 1	SD-053434-260-02 REV: 01

INVENTOR - D