INJECTION WELL PLUGGING PLAN
LAC 43:XVII.3631

Magnolia Sequestration Hub

1.0 Facility Information

Facility name: Magnolia Sequestration Project (Magnolia Hub)
Magnolia CCS 1, Magnolia CCS 2, Magnolia CCS 3, and Magnolia CCS 4 Wells

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: Allen Parish, Louisiana
Magnolia CCS 1
30° 40' 56.2474" N, 092° 50' 1.2244" W (NAD 27)
30° 40' 56.9387" N, 092° 50' 1.7707" W (NAD 83)
Magnolia CCS 2
30° 41' 40.1623"N, 092° 50' 23.1767"W (NAD 27)
30° 41' 40.8527" N, 092° 50' 23.7241" W (NAD 83)
Magnolia CCS 3
30° 41' 6.1794" N, 092° 50' 24.1145" W (NAD 27)
30° 41' 6.8705" N, 092° 50' 24.6617" W (NAD 83)
Magnolia CCS 4
30° 41' 38.4597" N, 092° 50' 23.1814" W (NAD 27)
30° 40' 39.1501" N, 092° 50' 23.7288" W (NAD 83)

Pursuant LAC 43:XVII.3631, this Injection Well Plugging Plan describes the actions the Magnolia Sequestration Hub, LLC, will take to plug and abandon the CO_2 injector wells Magnolia CCS 1, Magnolia CCS 2, Magnolia CCS 3, and Magnolia CCS 4. This plan also describes the proposed abandonment of the monitoring wells in Appendix A.

After 15 years of injection, the project will plug and abandon the injector wells Magnolia CCS 1, Magnolia CCS 2, Magnolia CCS 3, and Magnolia CCS 4.

The plugging procedure and materials will be designed to prevent any unwanted fluid movement, resist the corrosive aspects of carbon dioxide (CO_2) with water mixtures, and protect any underground sources of drinking water (USDWs).

In compliance with LAC 443:XVII.3631(A)(4), the Magnolia Sequestration Hub, LLC, will submit the Form UIC-17 to the Louisiana Department of Conservation and Energy (C&E) Office of Conservation and receive written approval from the commissioner before plugging operations begin.

The project will submit a certified Well Closure Report to the C&E within 30 days after plugging each well and will comply with the requirements in LAC 43:XVII.3631(A)(5). Magnolia Sequestration Hub, LLC will retain a copy of the plugging report for a minimum of 10 years following site closure.

2.0 General Tests and Measures Before Plugging and Abandoning CO_2 Injector Wells

Pursuant to LAC 43:XVII.3631(A)(2), the project will perform the following activities prior to plugging each well.

1. Bottomhole pressure (BHP) measurements will be taken using the installed downhole gauges. In case the gauges are not functioning properly, the Magnolia Hub will run downhole pressure gauges during the plug and abandon (P&A) process of the well.
2. After injection has ceased, the well will be flushed with a kill/buffer fluid. A minimum of three tubing volumes will be injected without exceeding the fracture pressure.
3. An annular pressure test will be performed to assess internal mechanical integrity before the tubing and packer are removed from the well.
4. The project will evaluate the external mechanical integrity and condition of the casing using one of the methods described in Section 3.
5. If a loss of mechanical integrity is discovered, the well will be repaired before proceeding further with the plugging operations.
6. All casing in this well will have been cemented to the surface at the time of construction and will not be retrievable at abandonment.
7. A cement retainer will be used to squeeze and isolate the perforated section to prevent flowback of formation fluids that could contaminate the plug. The balanced-plug placement method will be used for the additional cement plugs planned.
8. Heavy gel mud (9.5-10.5 ppg) will be left between cement plugs.
9. All casing strings will be cut off at least 5 ft below the surface and plow line.
10. A blanking plate with the required permit information will be welded on top of the cutoff casing.

3.0 Planned External Mechanical Integrity Test(s)

The Magnolia Sequestration Hub, LLC, will conduct at least one of the tests listed below to verify external mechanical integrity prior to plugging each injection well as required by LAC 43:XVII.3631(A)(2), 3631(A)(3)(b) and specified in LAC 43:XVII.3627:

a. Pulse neutron log
b. Noise log
c. DTS (Distributed Temperature Sensing)/DAS (Distributed Acoustic Sensing) survey
d. Temperature log.

4.0 Information on Plugs

The Magnolia Sequestration Hub, LLC, will use the materials and methods noted in Tables PLB-1 through 4 to plug the CO_2 injector wells. The volume and depth of the plug or plugs will depend on the final geology and downhole conditions of the well as assessed during construction. The cement(s) formulated for plugging will be compatible with the CO_2 stream. The cement

formulation and required certification documents will be submitted to the C&E with the well plugging plan. Magnolia Sequestration Hub, LLC, will report the wet density and retain duplicate samples of the cement used for each plug.

An example of CO_2-resistant cement formulation is provided in Appendix B.

4.1 Magnolia CCS 1 Plug and Abandonment Details

Table PLG-1—Magnolia CCS 1 cement plug information.

Plug No	Type Slurry	ID (in)	Placement Method	Depths top (ft)	Depths bottom (ft)	Density (ppg)	Sacks	Excess (%)	Yield (ft^3/sx)
1	CO2 Resistant Cement	8.535	Squeeze Plug	6650	7040	14.8-15.5	365	150	1.06
2	CO2 Resistant Cement	8.535	Squeeze Plug	6485	6650	14.8-15.5	153	150	1.06
3	CO2 Resistant Cement	8.535	Squeeze Plug	6200	6485	14.8-15.6	265	150	1.06
4	CO2 Resistant Cement	8.535	Balanced Plug	3700	4000	14.8-15.5	132	20	1.06
5	Class G cement with additives	8.535	Balanced Plug	2900	3300	15-15.5	189	20	1.01
6	Class G cement with additives	8.535	Balanced Plug	0	100	15-15.5	44	20	1.01

Notes:

- All plug depths will be adjusted after the well is drilled and completed.
- The plugging procedure will be updated as required by the C&E.
- Formation tops will be adjusted after running openhole electric logs.

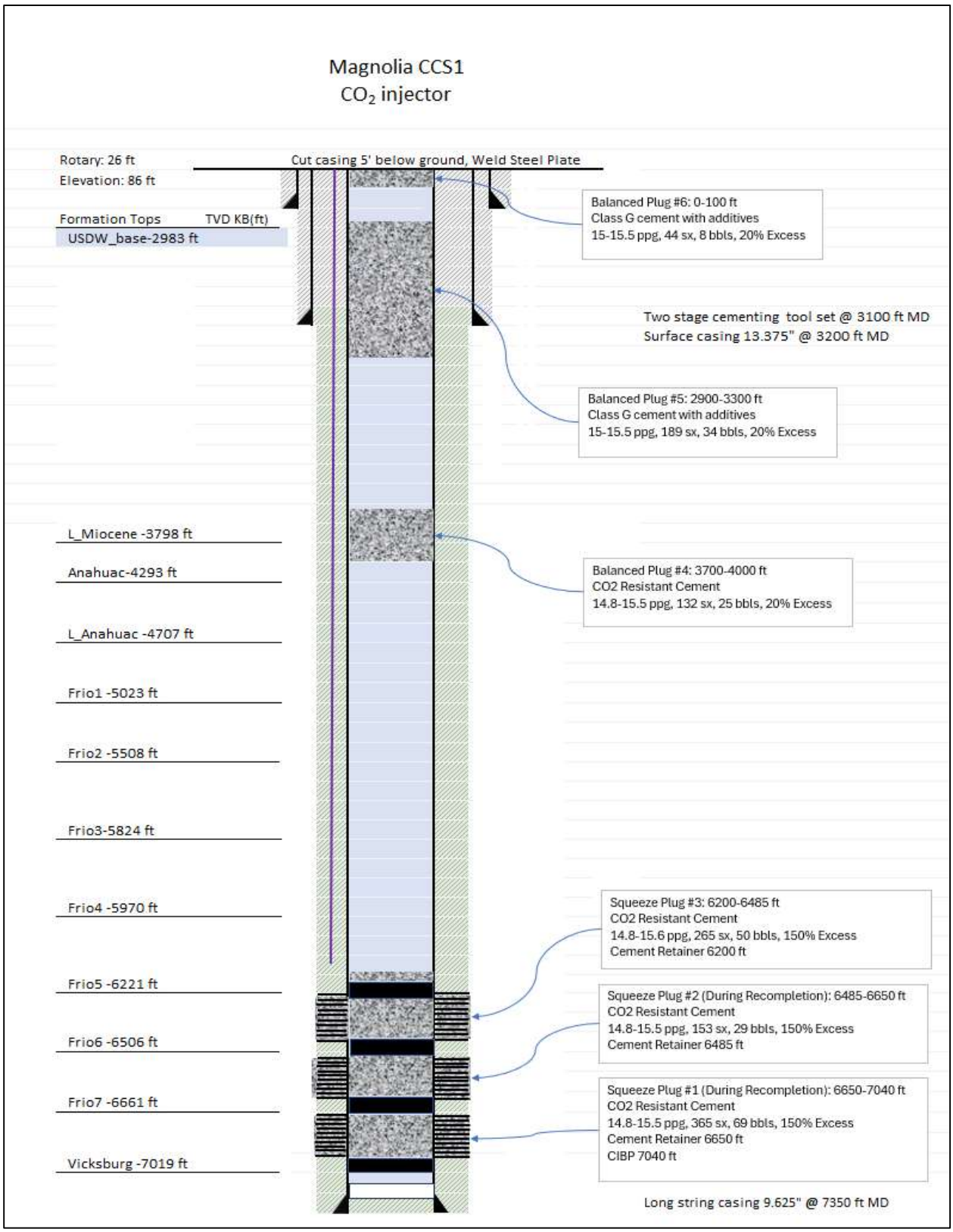

Figure PLG-1—Magnolia CCS 1 injection well plug schematic.

4.2 Magnolia CCS 2 Plug and Abandonment Details

Table PLG-2—Magnolia CCS 2 cement plug information.

Plug No	Type Slurry	ID (in)	Placement Method	Depths top (ft)	Depths bottom (ft)	Density (ppg)	Sacks	Excess (%)	Yield (ft^3/sx)
1	CO2 Resistant Cement	8.535	Squeeze Plug	6490	6880	14.8-15.5	365	150	1.06
2	CO2 Resistant Cement	8.535	Squeeze Plug	6330	6490	14.8-15.5	148	150	1.06
3	CO2 Resistant Cement	8.535	Squeeze Plug	6040	6330	14.8-15.6	270	150	1.06
4	CO2 Resistant Cement	8.535	Balanced Plug	3600	3900	14.8-15.5	132	20	1.06
5	Class G cement with additives	8.535	Balanced Plug	2900	3300	15-15.5	189	20	1.01
6	Class G cement with additives	8.535	Balanced Plug	0	100	15-15.5	44	20	1.01

Notes:

- All plug depths will be adjusted after the well is drilled and completed.
- The plugging procedure will be updated as required by the LA C&E.
- Formation tops will be adjusted after running openhole electric logs.

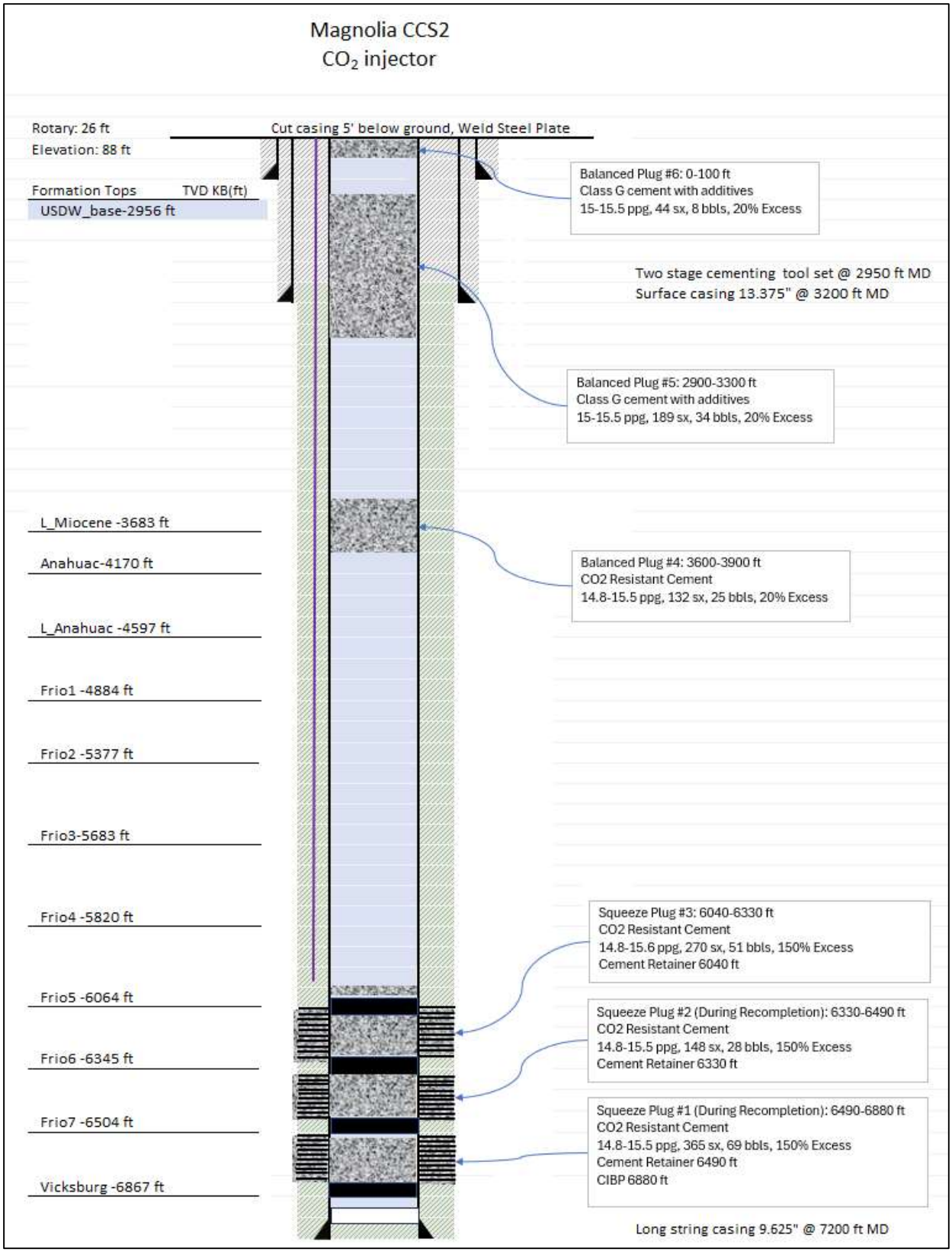

Figure PLG-2—Magnolia CCS 2 injection well plug schematic.

4.3 Magnolia CCS 3 Plug and Abandonment Details

Table PLG-3—Magnolia CCS 3 cement plug information.

Plug No	Type Slurry	ID (in)	Placement Method	Depths top (ft)	Depths bottom (ft)	Density (ppg)	Sacks	Excess (%)	Yield (ft^3/sx)
1	CO2 Resistant Cement	8.535	Squeeze Plug	5770	6175	14.8-15.5	381	150	1.06
2	CO2 Resistant Cement	8.535	Squeeze Plug	5455	5770	14.8-15.5	296	150	1.06
3	CO2 Resistant Cement	8.535	Squeeze Plug	4960	5455	14.8-15.6	466	150	1.06
4	CO2 Resistant Cement	8.535	Balanced Plug	3700	4000	14.8-15.5	132	20	1.06
5	Class G cement with additives	8.535	Balanced Plug	2900	3300	15-15.5	189	20	1.01
6	Class G cement with additives	8.535	Balanced Plug	0	100	15-15.5	44	20	1.01

Notes:

- All plug depths will be adjusted after the well is drilled and completed.
- The plugging procedure will be updated as required by the LA C&E.
- Formation tops will be adjusted after running openhole electric logs.

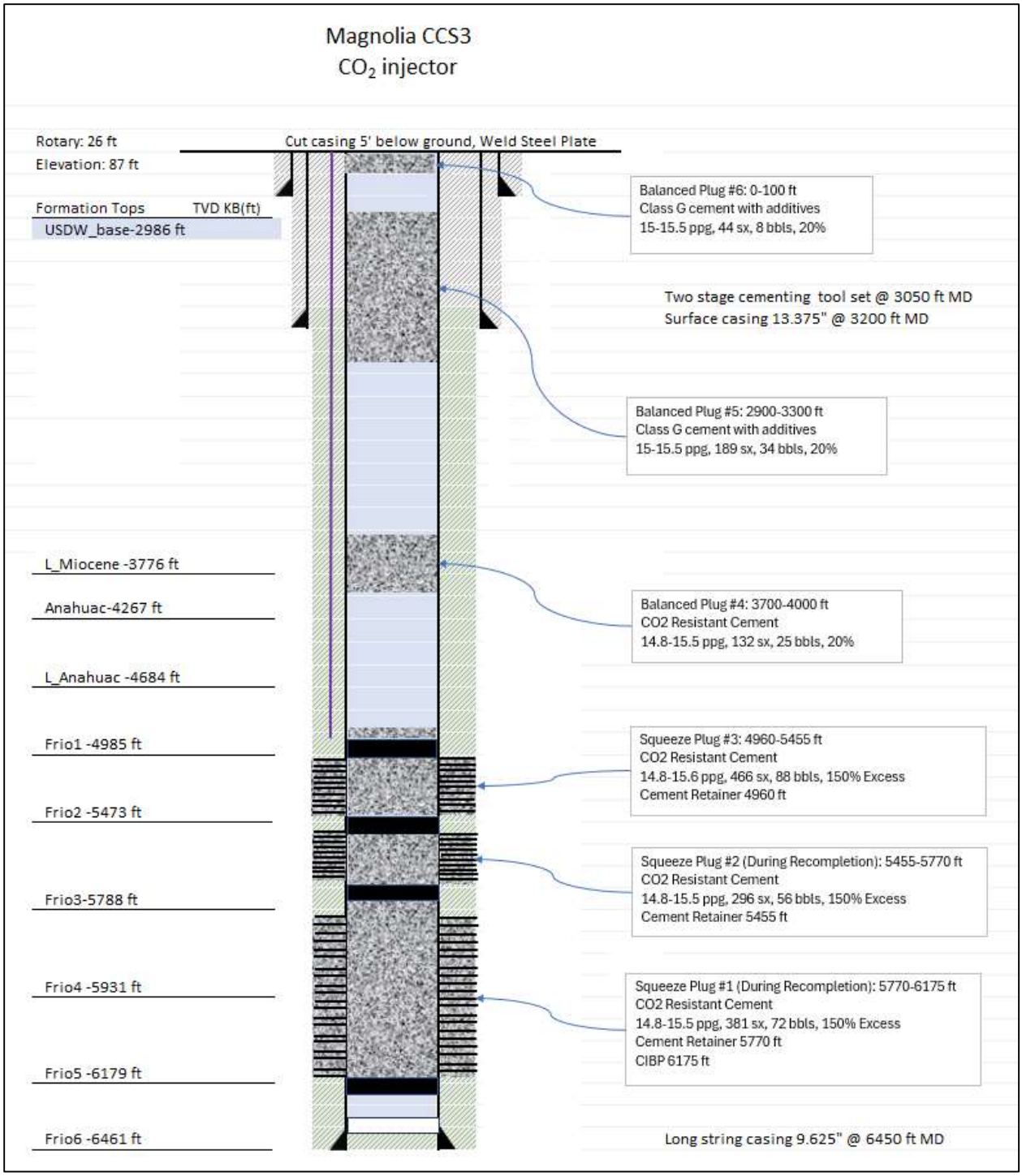

Figure PLG-3—Magnolia CCS 3 injection well plug schematic.

4.4 Magnolia CCS 4 Plug and Abandonment Details

Table PLG-4—Magnolia CCS 4 cement plug information.

Plug No	Type Slurry	ID (in)	Placement Method	Depths top (ft)	Depths bottom (ft)	Density (ppg)	Sacks	Excess (%)	Yield (ft^3/sx)
1	CO2 Resistant Cement	8.535	Squeeze Plug	5665	6060	14.8-15.5	370	150	1.06
2	CO2 Resistant Cement	8.535	Squeeze Plug	5360	5665	14.8-15.5	286	150	1.06
3	CO2 Resistant Cement	8.535	Squeeze Plug	4860	5360	14.8-15.6	466	150	1.06
4	CO2 Resistant Cement	8.535	Balanced Plug	3600	3900	14.8-15.5	132	20	1.06
5	Class G cement with additives	8.535	Balanced Plug	2900	3300	15-15.5	189	20	1.01
6	Class G cement with additives	8.535	Balanced Plug	0	100	15-15.5	44	20	1.01

Notes:

- All plug depths will be adjusted after the well is drilled and completed.
- The plugging procedure will be updated as required by the LA C&E.
- Formation tops will be adjusted after running openhole electric logs.

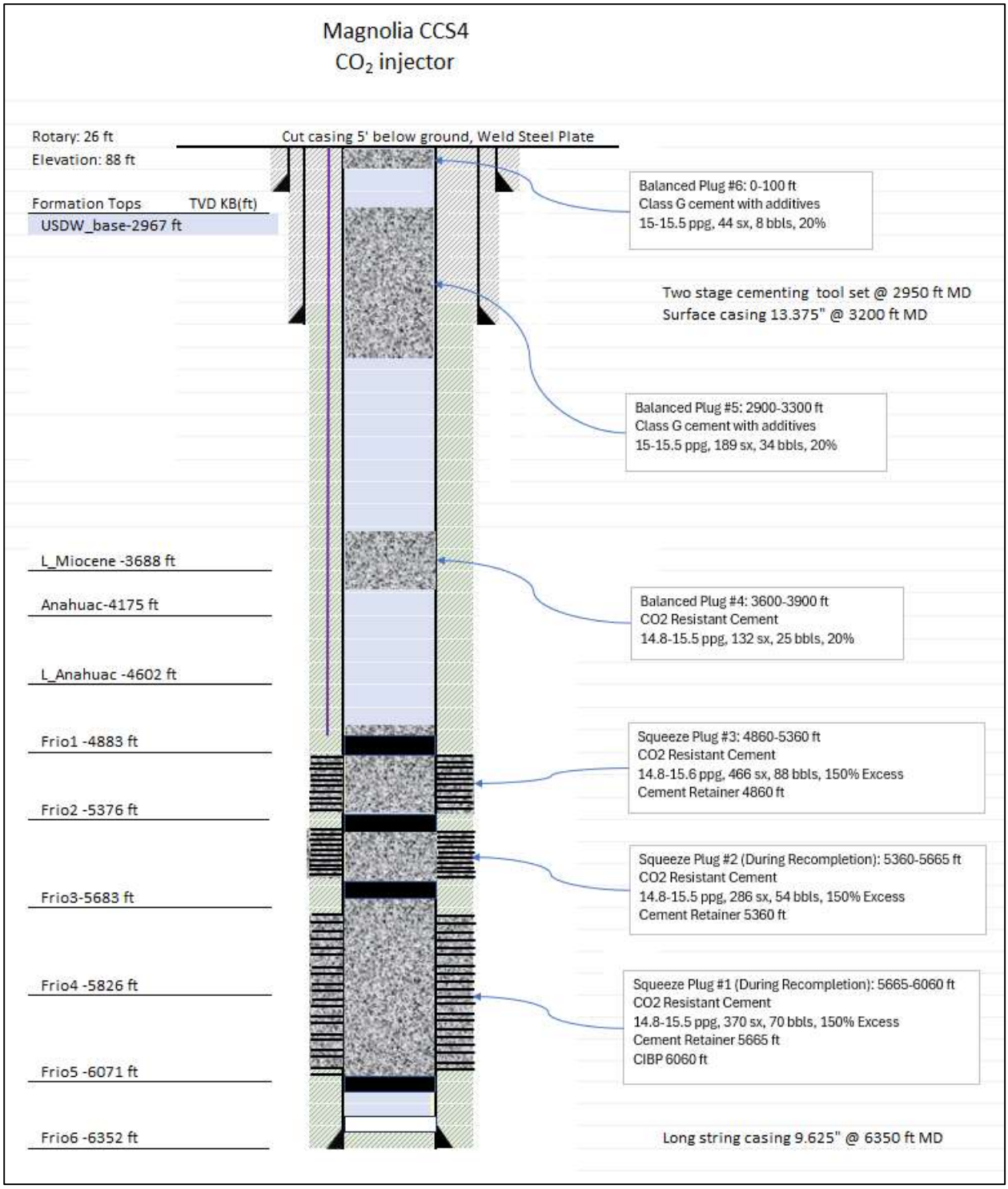

Figure PLG-4—Magnolia CCS 4 injection well plug schematic.

5.0 Narrative Description of Plugging Procedures for CO_2 Injector Wells

5.1 Notifications, Permits, and Inspections

In compliance with LAC 443:XVII.3631(A)(4), the Magnolia Sequestration Hub, LLC, will submit the Form UIC-17 to the C&E and receive written approval from the commissioner before plugging the well.

5.2 Magnolia CCS 1 Plugging Procedure

1. Move the rig onto the Magnolia CCS 1 site and rig up (RU). All CO_2 pipelines will be marked and noted by the rig supervisor prior to moving in.
2. Conduct and document a safety meeting.
3. Record the BHP from the downhole gauge, perform a DTS survey through the fiber optic cable installed alongside the casing, and calculate the kill fluid density. If the fiber optic cables are not functioning, skip this step and proceed with the methods described above for mechanical integrity evaluation after the tubing is pulled.
4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well with at least three times the tubing volume of kill/buffer fluid with the density determined using the BHP measurement. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing and annular pressure continuously.
5. Test the casing annulus to 500 psi and monitor for 30 minutes. If the pressure decreases more than 5% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure.

   Note: If a failure in the long-string casing is identified, the Magnolia Hub will prepare a plan to repair the well before it is plugged and abandoned.
6. If both the casing and tubing are controlled, then nipple up the blowout preventers (BOPs).
7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft above the packer. Circulate with kill mud. Then pull the work string out of the hole and proceed recovering the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.
8. Pick up the work string and trip in hole with the bit to condition the wellbore.
9. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below:
   a. Pulse neutron log
   b. Noise log
   c. Temperature log
   d. DTS/DAS temperature survey (no need for logging unit)

Rig down the logging unit.

10. Trip in hole with the work string and cement retainer to the top of plug #3 at 6,200 ft (plugs #1 and #2 were set during the recompletions). Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
11. Plug #3: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze and seal the perforations in the injection zone of the FRIO formation from 6,200-6,485 ft. Disconnect from the retainer and check the flow. Spot 20 ft of 14.8-15.5 ppg CO_2-resistant slurry on top of the cement retainer at 6,200 ft. Pull up above the plug and circulate heavy mud 9.5-10.5 ppg. Pressure test the plug to 500 psi for 30 minutes. Pull up out of the hole.
12. Plug #4: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the Lower Miocene (3,700-4,000 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
13. Plug #5: Set a balanced plug with 15-15.5 ppg Class G cement slurry to cover the surface casing shoe, and the base of the USDW (2,900-3,300 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
14. Plug #6: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-100 ft).
15. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will require C&E approval and will be described in the plugging report.

5.3 Magnolia CCS 2 Plugging Procedure

1. Move the rig onto the Magnolia CCS 2 site and rig up. All CO_2 pipelines will be marked and noted by the rig supervisor prior to moving in.
2. Conduct and document a safety meeting.
3. Record the BHP from the downhole gauge, perform a DTS survey through the fiber optic cable installed alongside the casing, and calculate the kill fluid density. If the fiber optic cables are not functioning, skip this step and proceed with the methods described above for mechanical integrity evaluation after the tubing is pulled.
4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well with at least three times the tubing volume of kill/buffer fluid with the density determined using the BHP measurement. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing and annular pressure continuously.
5. Test the casing annulus to 500 psi and monitor for 30 minutes. If the pressure decreases more than 5% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure.

Note: If a failure in the long-string casing is identified, the Magnolia Hub will prepare a plan to repair the well before it is plugged and abandoned.

6. If both the casing and tubing are controlled, then nipple up the blowout preventers (BOPs).
7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft above the packer. Circulate with kill mud. Then pull the work string out of the hole and proceed recovering the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.
8. Pick up the work string and trip in hole with the bit to condition the wellbore.
9. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below:
   a. Pulse neutron log
   b. Noise log
   c. Temperature log
   d. DTS/DAS temperature survey (no need for logging unit)

   Rig down the logging unit.
10. Trip in hole with the work string and cement retainer to the top of plug #3 at 6,040 ft (plugs #1 and #2 were set during the recompletions). Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
11. Plug #3: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze and seal the perforations in the injection zone of the FRIO formation from 6,040-6,330 ft. Disconnect from the retainer and check the flow. Spot 20 ft of 14.8-15.5 ppg CO_2-resistant slurry on top of the cement retainer at 6,040 ft. Pull up above the plug and circulate heavy mud 9.5-10.5 ppg. Pressure test the plug to 500 psi for 30 minutes. Pull up out of the hole.
12. Plug #4: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the Lower Miocene (3,600-3,900 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
13. Plug #5: Set a balanced plug with 15-15.5 ppg Class G cement slurry to cover the surface casing shoe, and the base of the USDW (2,900-3,300 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
14. Plug #6: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-100 ft).
15. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will require C&E approval and will be described in the plugging report.

5.4 Magnolia CCS 3 Plugging Procedure

1. Move the rig onto the Magnolia CCS 3 site and rig up. All CO_2 pipelines will be marked and noted by the rig supervisor prior to moving in.
2. Conduct and document a safety meeting.
3. Record the BHP from the downhole gauge, perform a DTS survey through the fiber optic cable installed alongside the casing, and calculate the kill fluid density. If the fiber optic cables are not functioning, skip this step and proceed with the methods described above for mechanical integrity evaluation after the tubing is pulled.
4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well with at least three times the tubing volume of kill/buffer fluid with the density determined using the BHP measurement. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing and annular pressure continuously.
5. Test the casing annulus to 500 psi and monitor for 30 minutes. If the pressure decreases more than 5% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure.

   Note: If a failure in the long-string casing is identified, the Magnolia Hub will prepare a plan to repair the well before it is plugged and abandoned.
6. If both the casing and tubing are controlled, then nipple up the blowout preventers (BOPs).
7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft above the packer. Circulate with kill mud. Then pull the work string out of the hole and proceed recovering the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.
8. Pick up the work string and trip in hole with the bit to condition the wellbore.
9. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below:
   a. Pulse neutron log
   b. Noise log
   c. Temperature log
   d. DTS/DAS temperature survey (no need for logging unit)

   Rig down the logging unit.

10. Trip in hole with the work string and cement retainer to the top of plug #3 at 4,960 ft (plugs #1 and #2 were set during the recompletions). Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
11. Plug #3: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze and seal the perforations in the injection zone of the FRIO formation from 4,960-5,455 ft. Disconnect from the retainer and check the flow. Spot 20 ft of 14.8-15.5 ppg CO_2-resistant slurry on top of the cement retainer at 4,960 ft. Pull up above the plug and circulate heavy mud 9.5-10.5 ppg. Pressure test the plug to 500 psi for 30 minutes. Pull up out of the hole.
12. Plug #4: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the Lower Miocene (3,700-4,000 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
13. Plug #5: Set a balanced plug with 15-15.5 ppg Class G cement slurry to cover the surface casing shoe, and the base of the USDW (2,900-3,300 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
14. Plug #6: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-100 ft).
15. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will require C&E approval and will be described in the plugging report.

5.5 Magnolia CCS 4 Plugging Procedure

1. Move the rig onto the Magnolia CCS 4 site and rig up. All CO_2 pipelines will be marked and noted by the rig supervisor prior to moving in.
2. Conduct and document a safety meeting.
3. Record the BHP from the downhole gauge, perform a DTS survey through the fiber optic cable installed alongside the casing, and calculate the kill fluid density. If the fiber optic cables are not functioning, skip this step and proceed with the methods described above for mechanical integrity evaluation after the tubing is pulled.
4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well with at least three times the tubing volume of kill/buffer fluid with the density determined using the BHP measurement. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing and annular pressure continuously.
5. Test the casing annulus to 500 psi and monitor for 30 minutes. If the pressure decreases more than 5% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure.

   Note: If a failure in the long-string casing is identified, the Magnolia Hub will prepare a plan to repair the well before it is plugged and abandoned.

6. If both the casing and tubing are controlled, then nipple up the blowout preventers (BOPs).
7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft above the packer. Circulate with kill mud. Then pull the work string out of the hole and proceed recovering the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.
8. Pick up the work string and trip in hole with the bit to condition the wellbore.
9. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below:
   a. Pulse neutron log
   b. Noise log
   c. Temperature log
   d. DTS/DAS temperature survey (no need for logging unit)

   Rig down the logging unit.
10. Trip in hole with the work string and cement retainer to the top of plug #3 at 4,860 ft (plugs #1 and #2 were set during the recompletions). Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
11. Plug #3: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze and seal the perforations in the injection zone of the FRIO formation from 4,860-5,360 ft. Disconnect from the retainer and check the flow. Spot 20 ft of 14.8-15.5 ppg CO_2-resistant slurry on top of the cement retainer at 4,860 ft. Pull up above the plug and circulate heavy mud 9.5-10.5 ppg. Pressure test the plug to 500 psi for 30 minutes. Pull up out of the hole.
12. Plug #4: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the Lower Miocene (3,600-3,900 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
13. Plug #5: Set a balanced plug with 15-15.5 ppg Class G cement slurry to cover the surface casing shoe, and the base of the USDW (2,900-3,300 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
14. Plug #6: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-100 ft).
15. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will require C&E approval and will be described in the plugging report.

The proposed plugging and abandonment procedures and schematics for the monitoring wells, Magnolia MLR 1, Magnolia MLR 2, Magnolia MLR 3, YAMS MLR 004, Magnolia AZC 1, Magnolia ACZ 2, Magnolia USDW 1, and Magnolia USDW 2 are included in Appendix A.

Appendix A: Monitoring and USDW Well P&A

A.1 Magnolia MLR 1 Details

Table PLG-5—Magnolia MLR 1 cement plug information.

Plug No	Type Slurry	ID (inches)	Placement Method	Depths top (ft)	Depths bottom (ft)	Density (ppg)	Sacks	Excess (%)	Yield (ft^3/sx)
1	CO2 Resistant Cement	4.778	Squeeze Plug	4815	5820	14.8-15.5	296	150	1.06
2	CO2 Resistant Cement	4.778	Squeeze Plug	5820	6825	14.8-15.5	296	150	1.06
3	CO2 Resistant Cement	4.778	Balanced Plug	3600	3900	14.8-15.5	42	20	1.06
4	Class G cement with additives	4.778	Balanced Plug	2900	3300	15-15.5	61	20	1.01
5	Class G cement with additives	4.778	Balanced Plug	0	100	15-15.5	17	20	1.01

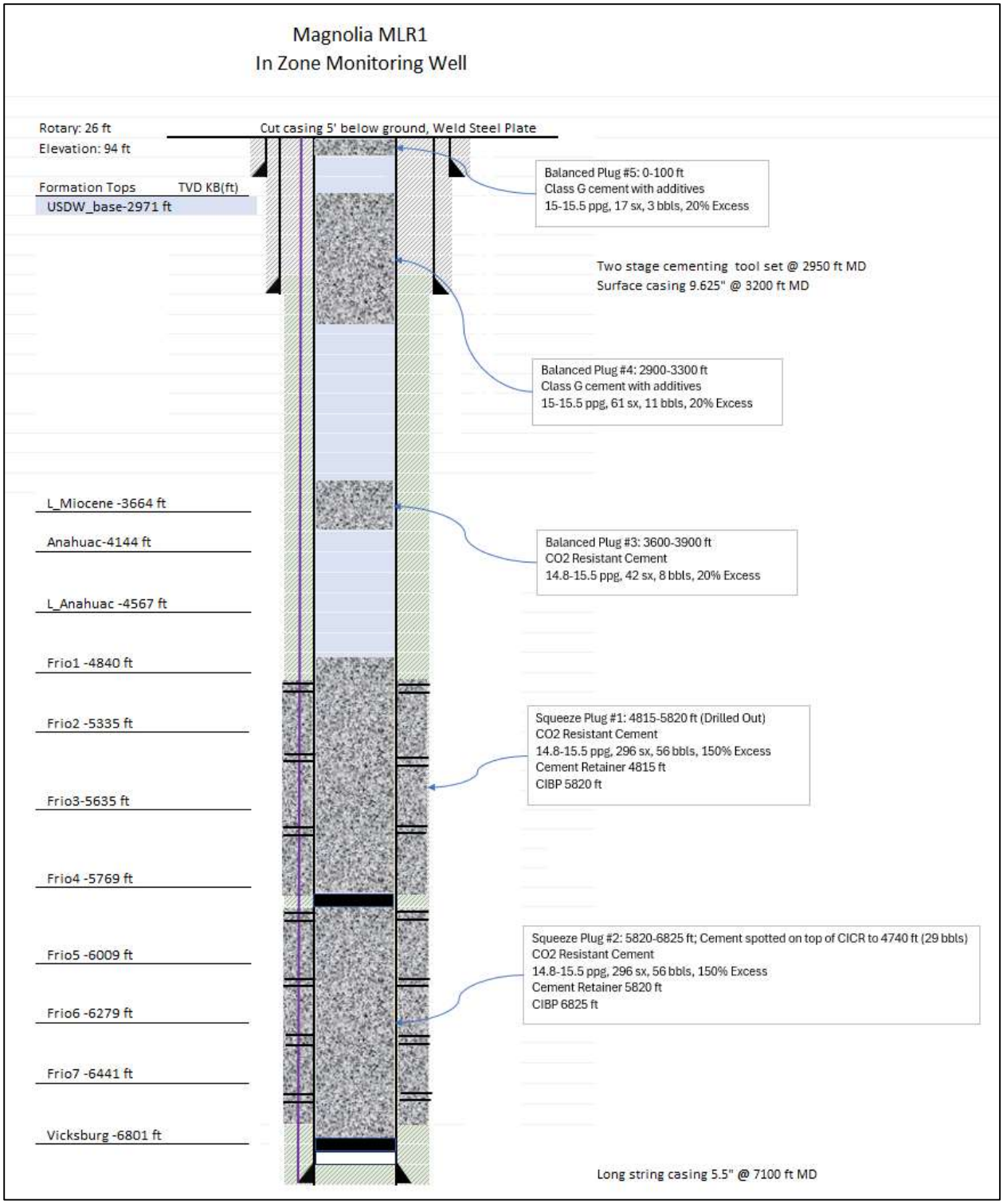

Figure PLG-5: Magnolia MLR 1 plug design and schematic.

Plugging Procedure

1. Move the rig onto the Magnolia MLR 1 site and rig up (RU).
2. Conduct and document a safety meeting.
3. Record the BHP from the downhole gauge, perform a DTS survey through the fiber optic cable installed alongside the casing, and calculate the kill fluid density. If the fiber optic cables are not functioning, skip this step and proceed with the methods described above for mechanical integrity evaluation after the tubing is pulled.
4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well with at least three times the tubing volume of kill/buffer fluid with the density determined using the BHP measurement. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing and annular pressure continuously.
5. Test the casing annulus to 500 psi and monitor for 30 minutes. If the pressure decreases more than 5% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure.

   Note: If a failure in the long-string casing is identified, the Magnolia Hub will prepare a plan to repair the well before it is plugged and abandoned.
6. If both the casing and tubing are controlled, then nipple up the blowout preventers (BOPs).
7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft above the packer. Circulate with kill mud. Then pull the work string out of the hole and proceed recovering the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.
8. Pick up the work string and trip in hole with the bit to condition the wellbore.
9. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below:
   a. Pulse neutron log
   b. Noise log
   c. Temperature log
   d. DTS/DAS temperature survey (no need for logging unit)

   Rig down the logging unit.
10. Set a cast iron bridge plug (CIBP) at 5,820 ft
11. Trip in hole with the work string and cement retainer to the top of plug #1 at 4,815 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
12. Plug #1: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze and seal the perforations in the injection zone of the FRIO formation from 4,815-5,820 ft. Disconnect from the retainer

and check the flow. Spot 20 ft of 14.8-15.5 ppg CO_2-resistant slurry on top of the cement retainer at 4,815 ft. Pressure test the plug to 500 psi for 30 minutes. Pull up out of the hole.

13. Pick up bit and trip in hole to the cast iron cement retainer (CICR) at 4,815 ft. Wait for the cement from plug #1 to develop 1000 psi compressive strength according to the laboratory test and drill out the CICR and cement down to CIBP at 5,820. Test the casing to 500 psi and monitor for 30 minutes. If the pressure decreases more than 5% in 30 minutes, bleed the pressure, check surface lines and connections, and repeat the test. Then release the pressure. If the casing fails the pressure test, re-squeeze plug #1.
14. Drill out the CIBP and continue cleaning the well down to 6,825 ft. Circulate the well clean. Pull out of the hole and lay down bit.
15. Set a CIBP at 6,825 ft.
16. Trip in hole with the work string and cement retainer to the top of plug #2 at 5,820 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
17. Plug #2: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze and seal the perforations in the injection zone of the FRIO formation from 5,820-6,825 ft. Disconnect from the retainer and check the flow. Spot 14.8-15.5 ppg CO_2-resistant slurry from the top of the cement retainer to 4,740 ft. Pull up above the plug and circulate heavy mud 9.5-10.5 ppg. Pressure test the plug to 500 psi for 30 minutes. Pull up out of the hole.
18. Plug #3: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the Lower Miocene (3,600-3,900 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
19. Plug #4: Set a balanced plug with 15-15.5 ppg Class G cement slurry to cover the surface casing shoe, and the base of the USDW (2,900-3,300 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
20. Plug #5: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-100 ft).
21. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well serial number and data of plug and abandonment.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will require C&E approval and will be described in the plugging report

A.2 Magnolia MLR 2 Details

Table PLG-6—Magnolia MLR 2 cement plug information.

Plug No	Type Slurry	ID (inches)	Placement Method	Depths top (ft)	Depths bottom (ft)	Density (ppg)	Sacks	Excess (%)	Yield (ft^3/sx)
1	CO2 Resistant Cement	4.778	Squeeze Plug	4690	5680	14.8-15.5	291	150	1.06
2	CO2 Resistant Cement	4.778	Squeeze Plug	5680	6670	14.8-15.5	291	150	1.06
3	CO2 Resistant Cement	4.778	Balanced Plug	3500	3800	14.8-15.5	42	20	1.06
4	Class G cement with additives	4.778	Balanced Plug	2900	3300	15-15.5	61	20	1.01
5	Class G cement with additives	4.778	Balanced Plug	0	100	15-15.5	17	20	1.01

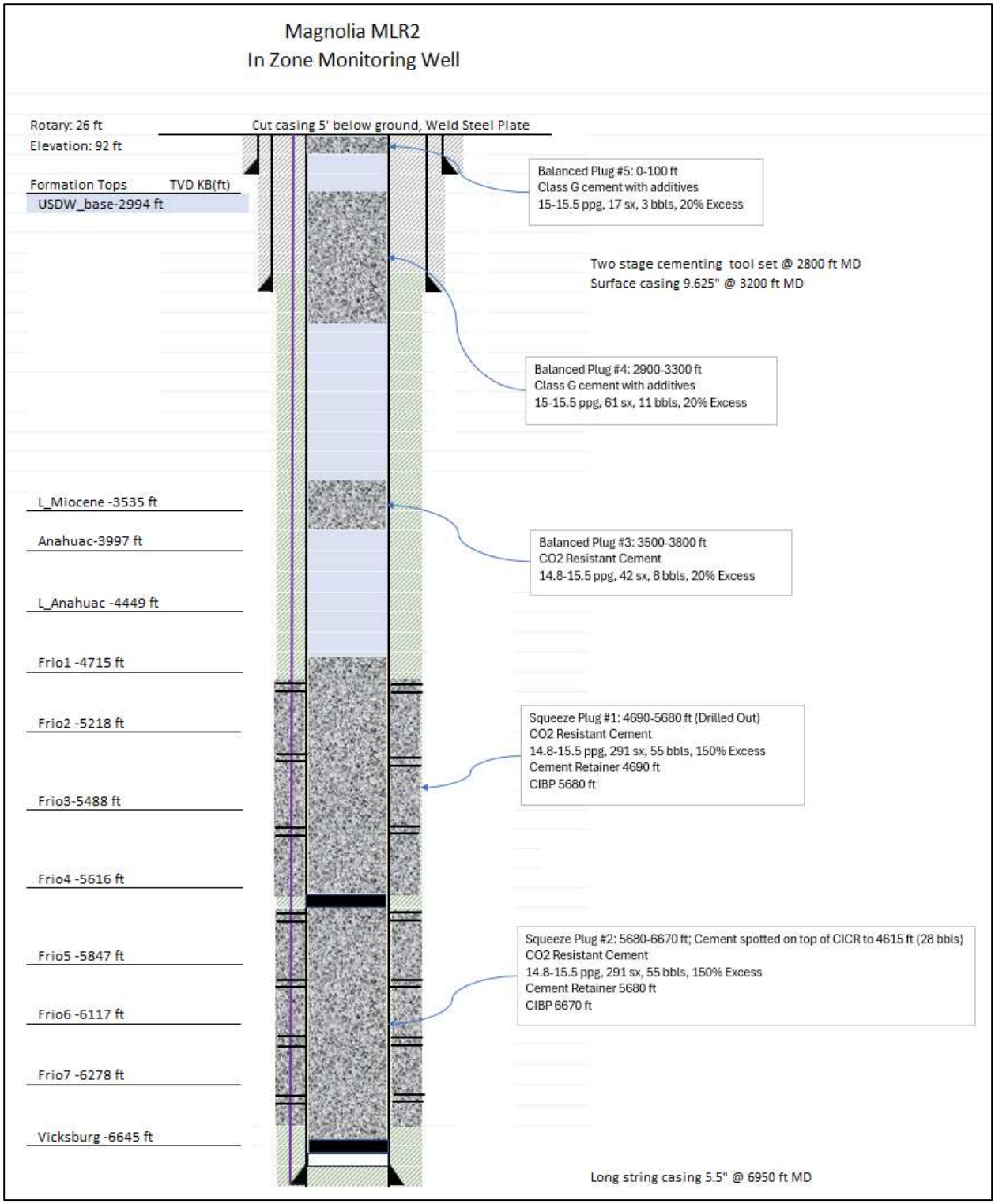

Figure PLG-6—Magnolia MLR 2 plug design and schematic.

Plugging Procedure

1. Move the rig onto the Magnolia MLR 2 site and rig up (RU).
2. Conduct and document a safety meeting.
3. Record the BHP from the downhole gauge, perform a DTS survey through the fiber optic cable installed alongside the casing, and calculate the kill fluid density. If the fiber optic cables are not functioning, skip this step and proceed with the methods described above for mechanical integrity evaluation after the tubing is pulled.
4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well with at least three times the tubing volume of kill/buffer fluid with the density determined using the BHP measurement. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing and annular pressure continuously.
5. Test the casing annulus to 500 psi and monitor for 30 minutes. If the pressure decreases more than 5% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure.

   Note: If a failure in the long-string casing is identified, the Magnolia Hub will prepare a plan to repair the well before it is plugged and abandoned.
6. If both the casing and tubing are controlled, then nipple up the blowout preventers (BOPs).
7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft above the packer. Circulate with kill mud. Then pull the work string out of the hole and proceed recovering the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.
8. Pick up the work string and trip in hole with the bit to condition the wellbore.
9. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below:
   a. Pulse neutron log
   b. Noise log
   c. Temperature log
   d. DTS/DAS temperature survey (no need for logging unit)

   Rig down the logging unit.
10. Set a cast iron bridge plug (CIBP) at 5,680 ft
11. Trip in hole with the work string and cement retainer to the top of plug #1 at 4,690 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
12. Plug #1: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze and seal the perforations in the injection zone of the FRIO formation from 4,690-5,680 ft. Disconnect from the retainer

and check the flow. Spot 20 ft of 14.8-15.5 ppg CO_2-resistant slurry on top of the cement retainer at 4,690 ft. Pressure test the plug to 500 psi for 30 minutes. Pull up out of the hole.

13. Pick up bit and trip in hole to the cast iron cement retainer (CICR) at 4,690 ft. Wait for the cement from plug #1 to develop 1000 psi compressive strength according to the laboratory test and drill out the CICR and cement down to CIBP at 5,680. Test the casing to 500 psi and monitor for 30 minutes. If the pressure decreases more than 5% in 30 minutes, bleed the pressure, check surface lines and connections, and repeat the test. Then release the pressure. If the casing fails the pressure test, re-squeeze plug #1.
14. Drill out the CIBP and continue cleaning the well down to 6,670 ft. Circulate the well clean. Pull out of the hole and lay down bit.
15. Set a CIBP at 6,670 ft.
16. Trip in hole with the work string and cement retainer to the top of plug #2 at 5,680 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
17. Plug #2: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze and seal the perforations in the injection zone of the FRIO formation from 5,680-6,670 ft. Disconnect from the retainer and check the flow. Spot 14.8-15.5 ppg CO_2-resistant slurry from the top of the cement retainer to 4,615 ft. Pull up above the plug and circulate heavy mud 9.5-10.5 ppg. Pressure test the plug to 500 psi for 30 minutes. Pull up out of the hole.
18. Plug #3: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the Lower Miocene (3,500-3,800 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
19. Plug #4: Set a balanced plug with 15-15.5 ppg Class G cement slurry to cover the surface casing shoe, and the base of the USDW (2,900-3,300 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
20. Plug #5: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-100 ft).
21. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with well serial number and data of plug and abandonment.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will require C&E approval and will be described in the plugging report.

A.3 Magnolia MLR 3 Details

Table PLG-7—Magnolia MLR 3 cement plug information.

Plug No	Type Slurry	ID (in)	Placement Method	Depths top (ft)	Depths bottom (ft)	Density (ppg)	Sacks	Excess (%)	Yield (ft^3/sx)
1	CO2 Resistant Cement	4.778	Squeeze Plug	4504	5466	14.8-15.5	281	150	1.06
2	CO2 Resistant Cement	4.778	Squeeze Plug	5466	6428	14.8-15.5	281	150	1.06
3	CO2 Resistant Cement	4.778	Balanced Plug	3400	3700	14.8-15.5	42	20	1.06
4	Class G cement with additives	4.778	Balanced Plug	3000	3500	15-15.5	72	20	1.01
5	Class G cement with additives	4.778	Balanced Plug	0	100	15-15.5	17	20	1.01

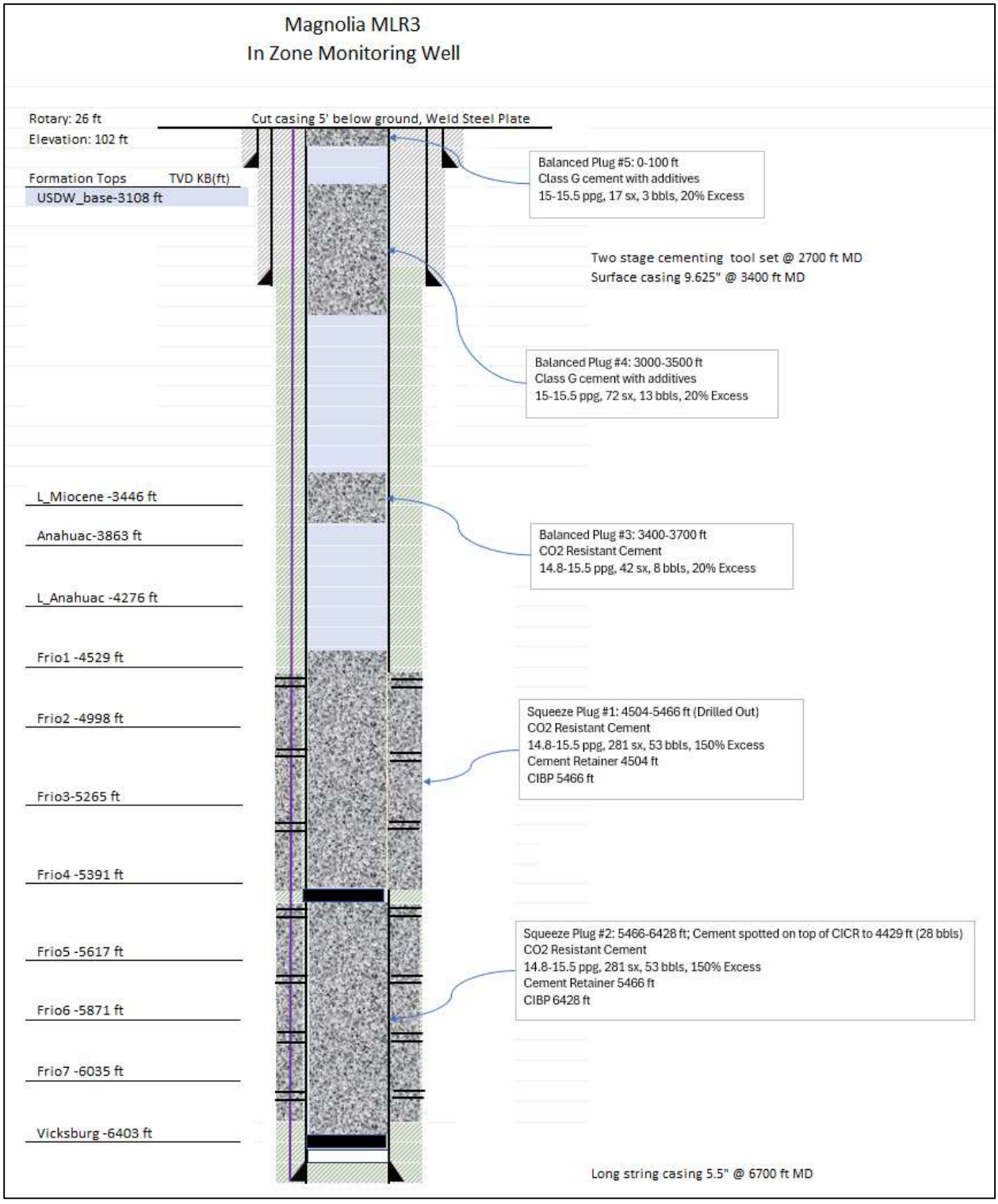

Figure PLG-5—Magnolia MLR 3 plug design and schematic.

Plugging Procedure

1. Move the rig onto the Magnolia MLR 3 site and rig up (RU).
2. Conduct and document a safety meeting.
3. Record the BHP from the downhole gauge, perform a DTS survey through the fiber optic cable installed alongside the casing, and calculate the kill fluid density. If the fiber optic cables are not functioning, skip this step and proceed with the methods described above for mechanical integrity evaluation after the tubing is pulled.
4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well with at least three times the tubing volume of kill/buffer fluid with the density determined using the BHP measurement. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing and annular pressure continuously.
5. Test the casing annulus to 500 psi and monitor for 30 minutes. If the pressure decreases more than 5% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure.

   Note: If a failure in the long-string casing is identified, the Magnolia Hub will prepare a plan to repair the well before it is plugged and abandoned.
6. If both the casing and tubing are controlled, then nipple up the blowout preventers (BOPs).
7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft above the packer. Circulate with kill mud. Then pull the work string out of the hole and proceed recovering the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.
8. Pick up the work string and trip in hole with the bit to condition the wellbore.
9. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below:

   a. Pulse neutron log
   b. Noise log
   c. Temperature log
   d. DTS/DAS temperature survey (no need for logging unit)

   Rig down the logging unit.
10. Set a cast iron bridge plug (CIBP) at 5,466 ft
11. Trip in hole with the work string and cement retainer to the top of plug #1 at 4,504 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
12. Plug #1: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze and seal the perforations in the injection zone of the FRIO formation from 4,504-5,466 ft. Disconnect from the retainer

and check the flow. Spot 20 ft of 14.8-15.5 ppg CO_2-resistant slurry on top of the cement retainer at 4,504 ft. Pressure test the plug to 500 psi for 30 minutes. Pull up out of the hole.

13. Pick up bit and trip in hole to the cast iron cement retainer (CICR) at 4,504 ft. Wait for the cement from plug #1 to develop 1000 psi compressive strength according to the laboratory test and drill out the CICR and cement down to CIBP at 5,466. Test the casing to 500 psi and monitor for 30 minutes. If the pressure decreases more than 5% in 30 minutes, bleed the pressure, check surface lines and connections, and repeat the test. Then release the pressure. If the casing fails the pressure test, re-squeeze plug #1.
14. Drill out the CIBP and continue cleaning the well down to 6,428 ft. Circulate the well clean. Pull out of the hole and lay down bit.
15. Set a CIBP at 6,428 ft.
16. Trip in hole with the work string and cement retainer to the top of plug #2 at 5,466 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
17. Plug #2: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze and seal the perforations in the injection zone of the FRIO formation from 5,466-6,428 ft. Disconnect from the retainer and check the flow. Spot 14.8-15.5 ppg CO_2-resistant slurry from the top of the cement retainer to 4,429 ft. Pull up above the plug and circulate heavy mud 9.5-10.5 ppg. Pressure test the plug to 500 psi for 30 minutes. Pull up out of the hole.
18. Plug #3: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the Lower Miocene (3,400-3,700 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
19. Plug #4: Set a balanced plug with 15-15.5 ppg Class G cement slurry to cover the surface casing shoe, and the base of the USDW (3,000-3,500 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
20. Plug #5: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-100 ft).
21. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with well serial number and data of plug and abandonment.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will require C&E approval and will be described in the plugging report.

A.4 YAMS MLR 004 Details

Table PLG-8—YAMS MLR 4 cement plug information.

Plug No	Type Slurry	ID (in)	Placement Method	Depths top (ft)	Depths bottom (ft)	Density (ppg)	Sacks	Excess (%)	Yield (ft^3/sx)
1	CO2 Resistant Cement	4.778	Squeeze Plug	5084	6108	14.8-15.5	302	150	1.06
2	CO2 Resistant Cement	4.778	Squeeze Plug	6108	7132	14.8-15.5	302	150	1.06
3	CO2 Resistant Cement	4.778	Balanced Plug	3800	4100	14.8-15.5	42	20	1.06
4	Class G cement with additives	4.778	Balanced Plug	3000	3300	15-15.5	44	20	1.01
5	Class G cement with additives	4.778	Balanced Plug	0	100	15-15.5	17	20	1.01

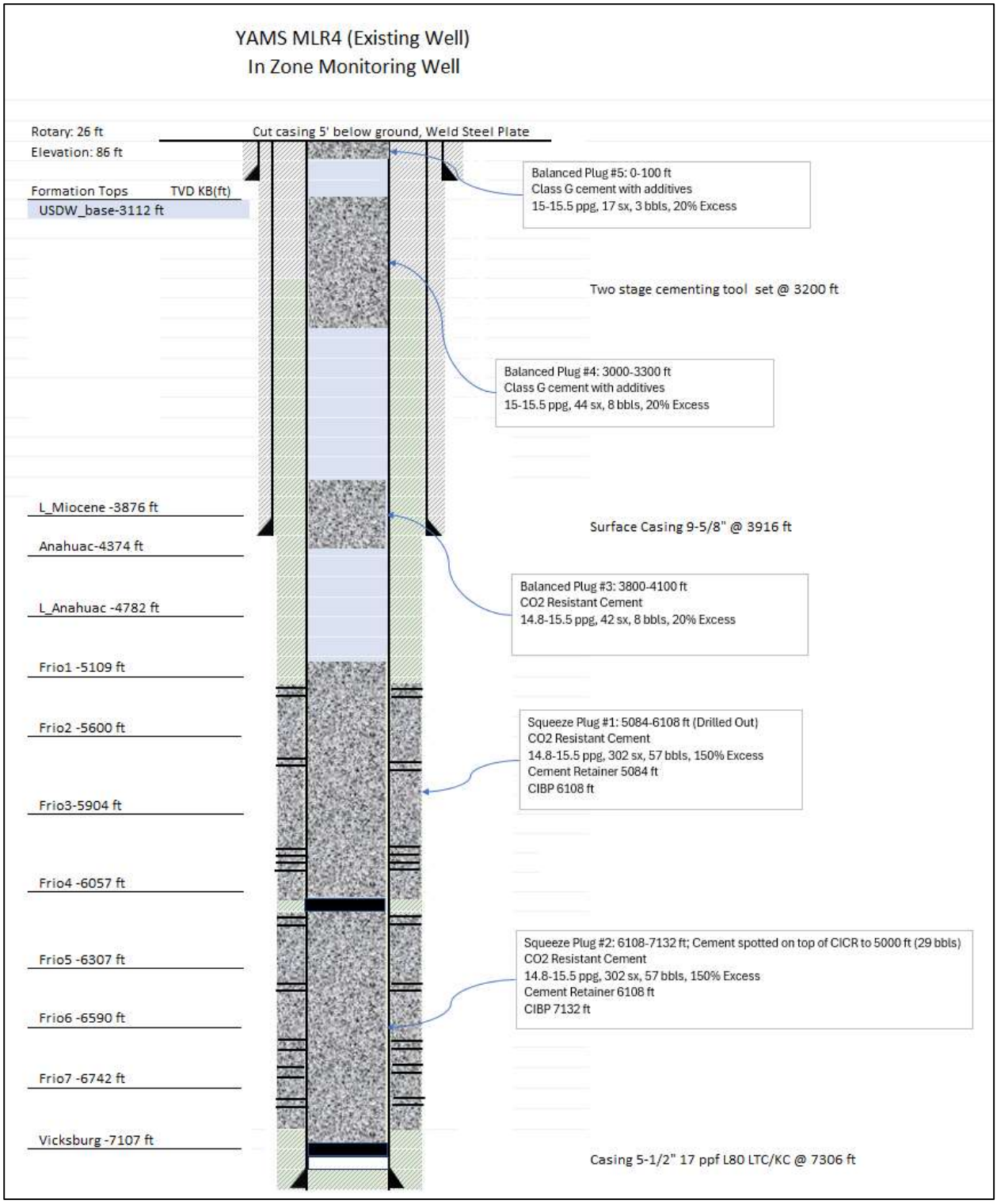

Figure PLG-8—YAMS MLR 4 plug design and schematic.

Plugging Procedure

1. Move the rig onto the YAMS MLR 4 site and rig up (RU).
2. Conduct and document a safety meeting.
3. Record the BHP from the downhole gauge and calculate the kill fluid density.
4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well with at least three times the tubing volume of kill/buffer fluid with the density determined using the BHP measurement. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing and annular pressure continuously.
5. Test the casing annulus to 500 psi and monitor for 30 minutes. If the pressure decreases more than 5% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure.

   Note: If a failure in the long-string casing is identified, the Magnolia Hub will prepare a plan to repair the well before it is plugged and abandoned.
6. If both the casing and tubing are controlled, then nipple up the blowout preventers (BOPs).
7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft above the packer. Circulate with kill mud. Then pull the work string out of the hole and proceed recovering the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.
8. Pick up the work string and trip in hole with the bit to condition the wellbore.
9. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below:

   a. Pulse neutron log
   b. Noise log
   c. Temperature log

   Rig down the logging unit.
10. Set a cast iron bridge plug (CIBP) at 6,108 ft
11. Trip in hole with the work string and cement retainer to the top of plug #1 at 5,084 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
12. Plug #1: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze and seal the perforations in the injection zone of the FRIO formation from 5,084-6,108 ft. Disconnect from the retainer and check the flow. Spot 20 ft of 14.8-15.5 ppg CO_2-resistant slurry on top of the cement retainer at 5,084 ft. Pressure test the plug to 500 psi for 30 minutes. Pull up out of the hole.
13. Pick up bit and trip in hole to the cast iron cement retainer (CICR) at 5,084 ft. Wait for the cement from plug #1 to develop 1000 psi compressive strength according to the laboratory test

and drill out the CICR and cement down to CIBP at 6,108. Test the casing to 500 psi and monitor for 30 minutes. If the pressure decreases more than 5% in 30 minutes, bleed the pressure, check surface lines and connections, and repeat the test. Then release the pressure. If the casing fails the pressure test, re-squeeze plug #1.

14. Drill out the CIBP and continue cleaning the well down to 7,132 ft. Circulate the well clean. Pull out of the hole and lay down bit.
15. Set a CIBP at 7,132 ft.
16. Trip in hole with the work string and cement retainer to the top of plug #2 at 6,108 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
17. Plug #2: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze and seal the perforations in the injection zone of the FRIO formation from 6,108-7,132 ft. Disconnect from the retainer and check the flow. Spot 14.8-15.5 ppg CO_2-resistant slurry from the top of the cement retainer to 5,000 ft. Pull up above the plug and circulate heavy mud 9.5-10.5 ppg. Pressure test the plug to 500 psi for 30 minutes. Pull up out of the hole.
18. Plug #3: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the Lower Miocene and surface casing shoe (3,800-4,100 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
19. Plug #4: Set a balanced plug with 15-15.5 ppg Class G cement slurry to cover the base of the USDW (3,000-3,300 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
20. Plug #5: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-100 ft).
21. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with well serial number and data of plug and abandonment..

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will require C&E approval and will be described in the plugging report

A.5 Magnolia ACZ 1 Details

Table PLG-9—Magnolia ACZ 1 cement plug information.

Plug No	Type Slurry	ID (in)	Placement Method	Depths top (ft)	Depths bottom (ft)	Density (ppg)	Sacks	Excess (%)	Yield (ft^3/sx)
1	Class G cement with additives	4.778	Squeeze Plug	3315	3640	15-15.5	100	150	1.01
2	Class G cement with additives	4.778	Balanced Plug	2900	3200	15-15.5	44	20	1.01
3	Class G cement with additives	4.778	Balanced Plug	0	100	15-15.5	17	20	1.01

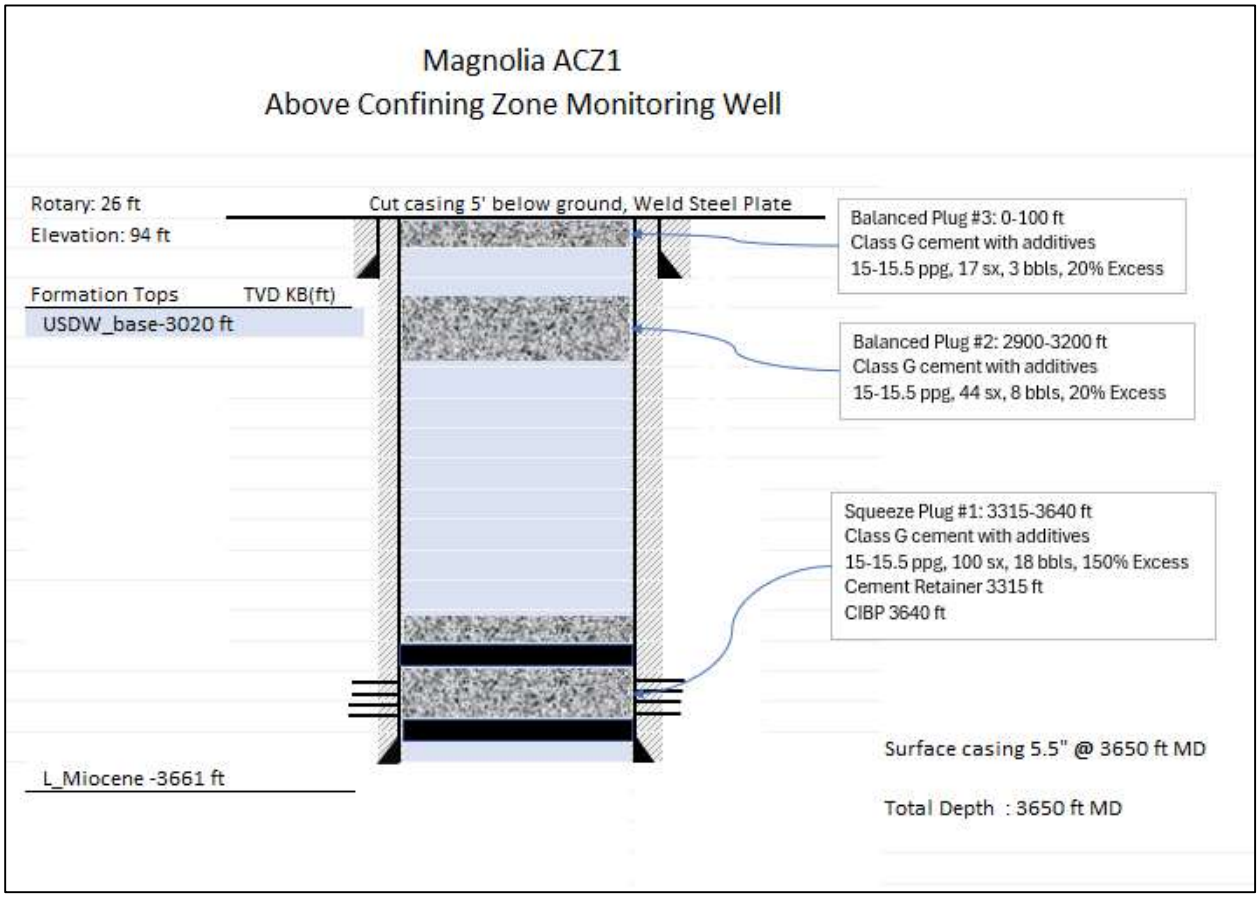

Figure PLG-9—Magnolia ACZ 1 plug design and schematic.

Plugging Procedure

1. Move the rig onto the Magnolia ACZ 1 site and rig up.
2. Conduct and document a safety meeting.
3. Calculated the BHP from the downhole or surface gauges and calculate the kill fluid density.
4. Test the pump and surface lines to 5,000 psi.
5. Test the casing annulus to 500 psi and monitor it for 30 minutes. If the pressure decreases more than 5% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure. Note: If a failure in the long-string casing is identified, the Magnolia Hub will prepare a plan to repair the well before plugging and abandonment.
6. If both the casing and tubing are controlled, then nipple up the BOPs.
7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft MD above the packer. Circulate with kill mud. Then pull the work string up the hole and proceed to recover the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.
8. Pick up the work string and trip in hole with the bit to condition the wellbore.
9. Set a CIBP at 3,640 ft.
10. Trip in hole with the work string with a cement retainer to the top of plug #1 at 3,315 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
11. Plug #1: Mix and pump 15-15.5 ppg Class G cement to squeeze and seal the perforations above the confining zone from 3,315-3,640 ft. Disconnect from the retainer and check the flow. Spot 20 ft of 15-15.5 Class G cement on top of the retainer at 3,315 ft. Circulate heavy mud (9.5-10.5 ppg). Pressure test the plug to 500 psi for 30 minutes. Pull out of the hole.
12. Plug #2: Set a balanced plug with 15-15.5 ppg Class G to cover the base of the USDW (2,900-3,200 ft). Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
13. Plug #3: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-100 ft).
14. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with well serial number and data of plug and abandonment.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will require C&E approval and will be described in the plugging report.

A 6 Magnolia ACZ 2 Details

Table PLG-10— Magnolia ACZ 2 cement plug information.

Plug No	Type Slurry	ID (in)	Placement Method	Depths top (ft)	Depths bottom (ft)	Density (ppg)	Sacks	Excess (%)	Yield (ft^3/sx)
1	Class G cement with additives	4.778	Squeeze Plug	3300	3640	15-15.5	106	150	1.01
2	Class G cement with additives	4.778	Balanced Plug	2900	3200	15-15.5	44	20	1.01
3	Class G cement with additives	4.778	Balanced Plug	0	100	15-15.5	17	20	1.01

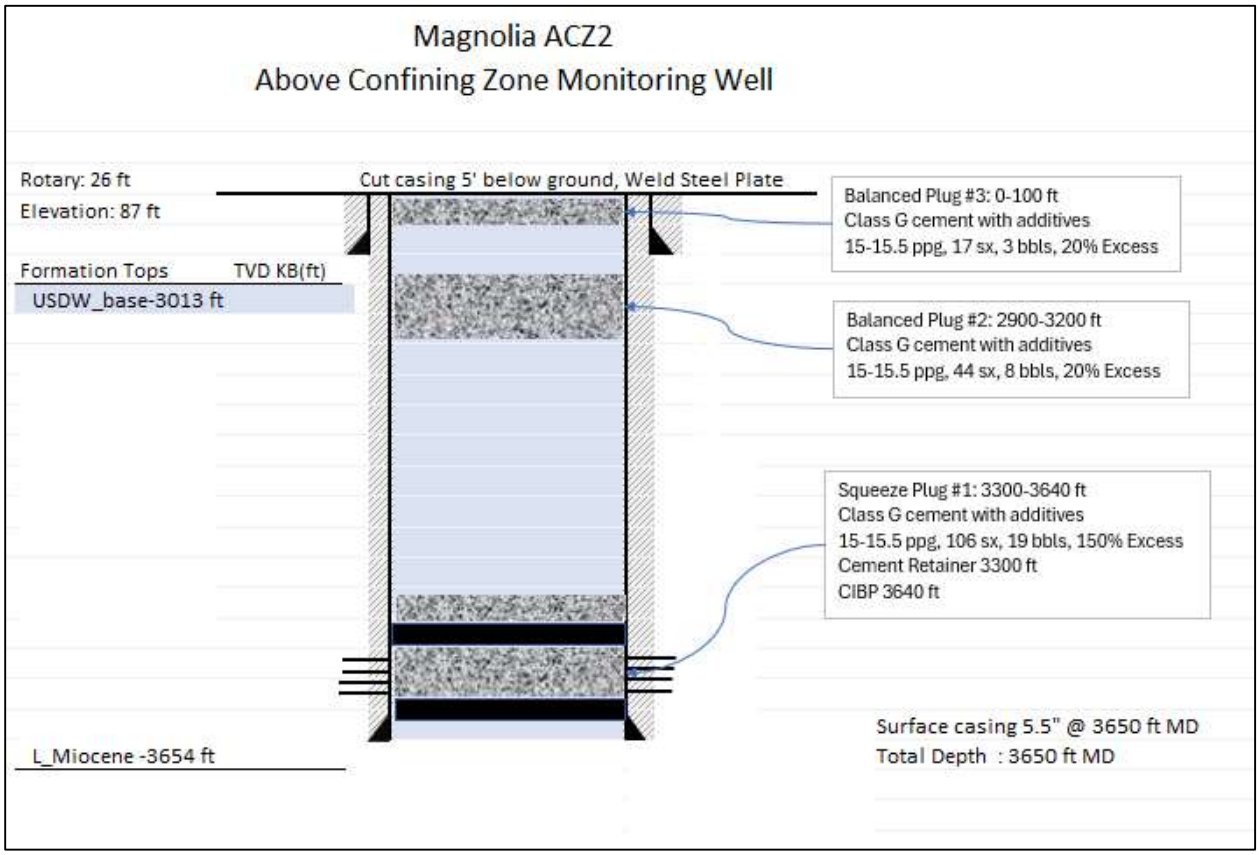

Figure PLG-10—Magnolia ACZ 2 plug design and schematic.

Plugging Procedure

1. Move the rig onto the Magnolia ACZ 2 site and rig up.
2. Conduct and document a safety meeting.
3. Calculated the BHP from the downhole or surface gauges and calculate the kill fluid density.
4. Test the pump and surface lines to 5,000 psi.
5. Test the casing annulus to 500 psi and monitor it for 30 minutes. If the pressure decreases more than 5% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure. Note: If a failure in the long-string casing is identified, the Magnolia Hub will prepare a plan to repair the well before plugging and abandonment.
6. If both the casing and tubing are controlled, then nipple up the BOPs.
7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft MD above the packer. Circulate with kill mud. Then pull the work string up the hole and proceed to recover the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.
8. Pick up the work string and trip in hole with the bit to condition the wellbore.
9. Set a CIBP at 3,640 ft.
10. Trip in hole with the work string with a cement retainer to the top of plug #1 at 3,300 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
11. Plug #1: Mix and pump 15-15.5 ppg Class G cement to squeeze and seal the perforations above the confining zone from 3,300-3,640 ft. Disconnect from the retainer and check the flow. Spot 20 ft of 15-15.5 Class G cement on top of the retainer at 3,300 ft. Circulate heavy mud (9.5-10.5 ppg). Pressure test the plug to 500 psi for 30 minutes. Pull out of the hole.
12. Plug #2: Set a balanced plug with 15-15.5 ppg Class G to cover the base of the USDW (2,900-3,200 ft). Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
13. Plug #3: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-100 ft).
14. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with well serial number and data of plug and abandonment.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will require C&E approval and will be described in the plugging report.

A.7 Magnolia USDW 1 Details

Table PLG-11—Magnolia USDW 1 cement plug information.

Plug No	Cement Slurry	ID (inches)	Placement Method	Depths top (ft)	Depths bottom (ft)	Density (ppg)	Sacks	Excess (%)	Yield (ft^3/sx)
1	Class A or C	4.950	Balanced Plug	1300	2600	15	206	20	1.01
2	Class A or C	4.950	Balanced Plug	0	1300	15	206	20	1.01

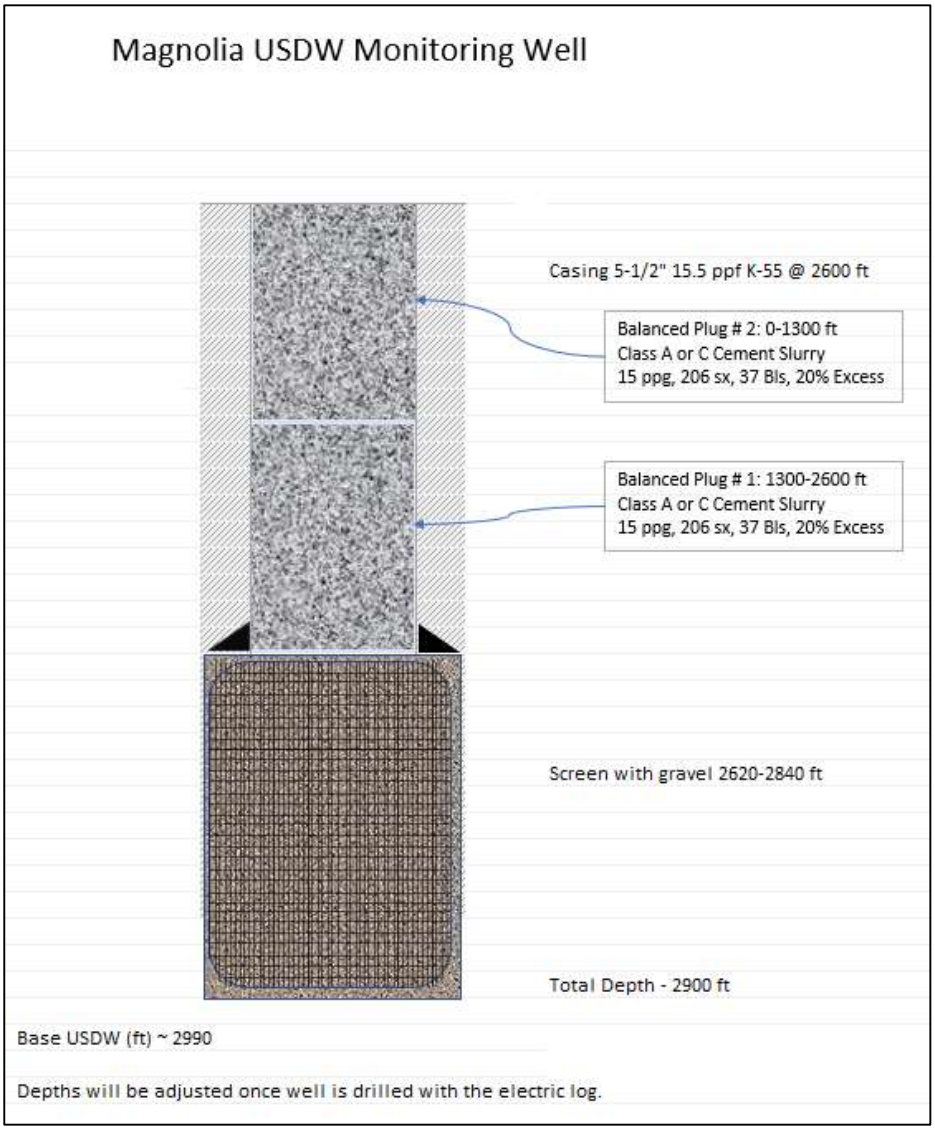

Figure PLG-11—Magnolia USDW 1 cement plug information.

Plugging procedure

1. Move the rig onto Magnolia USDW 1 site and rig up.

2. Conduct and document a safety meeting.
3. Record the surface pressure.
4. Test the pump and surface lines to 5,000 psi.
5. Kill the well if necessary.
6. Pull out of the hole and lay down tubing and pump.
7. Trip in hole with the work string to 2,600 ft.
8. Plug #1: Set a balanced plug with 15-15.5 ppg Class A or C cement slurry 1,300-2,600 ft. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
9. Plug #2: Set a balanced plug with 15-15.5 ppg Class A or C cement slurry 0-1,300 ft.
10. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with well serial number and data of plug and abandonment.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will require C&E approval and will be described in the plugging report.

A.8 Magnolia USDW 2 Details

Table PLG-12—Magnolia USDW 2 cement plug information.

Plug No	Cement Slurry	ID (inches)	Placement Method	Depths top (ft)	Depths bottom (ft)	Density (ppg)	Sacks	Excess (%)	Yield (ft^3/sx)
1	Class A or C	4.950	Balanced Plug	1300	2600	15	206	20	1.01
2	Class A or C	4.950	Balanced Plug	0	1300	15	206	20	1.01

Figure PLG-12—Magnolia USDW 2 cement plug information.

Plugging procedure

1. Move the rig onto Magnolia USDW 2 site and rig up.

2. Conduct and document a safety meeting.
3. Record the surface pressure.
4. Test the pump and surface lines to 5,000 psi.
5. Kill the well if necessary.
6. Pull out of the hole and lay down tubing and pump.
7. Trip in hole with the work string to 2,600 ft.
8. Plug #1: Set a balanced plug with 15-15.5 ppg Class A or C cement slurry 1,300-2,600 ft. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
9. Plug #2: Set a balanced plug with 15-15.5 ppg Class A or C cement slurry 0-1,300 ft.
10. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with well serial number and data of plug and abandonment.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will require C&E approval and will be described in the plugging report.

Appendix B: Example of CO_2 Resistant Cement Formulation for Plug and Abandonment.

HALLIBURTON

Gulf of Mexico, Broussard

Lab Results- Stage 1

Job Information

Request/Slurry		Rig Name		Date	
Submitted By		Job Type	Production Casing	Bulk Plant	
Customer	Occidental Petroleum Corp.	Location		Well	

Well Information

Casing/Liner Size	5.5 in	Depth MD	8579 ft	BHST	93°C / 200°F
Hole Size	8.5 in	Depth TVD	8579 ft	BHCT	63°C / 145°F
Press.	4813 psi				

Drilling Fluid Information

Mud Supplier Name	Mud Trade Name	Density	9.5 lbm/gal

Cement Information - Tail Design ✓

Conc	UOM	Cement/Additive	Description
		CorrosaCem	Blend Name
20 - 50	%	>Prairie State Poz	Fly Ash
40 - 70	%	> Texas LeHigh A	API Class A Portland Cement
100	% BWOC	Cement Blend	
2.11	gal/sack	Field (Fresh) Water	
0.1 – 0.5	% BWOC	D-Air 5000	Defoamer
0.1 – 0.8	% BWOC	HR-5 (PB)	Retarder
0.02 – 0.1	gps	Stabilizer 434D	
1.0 - 3.0	gps	Latex 3000	Liquid SBR Latex
0.1 – 0.5	lb/sk	WellLife 1094 (PB)	Polyolefin Fiber
1.0 – 5.0	%BWOC	Microbond M	Expansion Additive

Cement Properties

Slurry Density	14.0 - 15.5	lbm/gal
Slurry Yield	1.06	ft3/sack
Water Requirement	2.11	gal/sack
Total Mix Fluid	4.19	gal/sack

Figure PLG-13—Example CO_2 resistant cement formulation for plug and abandonment. Additives such as WellLife and Microbond M may not be required for abandonment plugs.