Salado Draw
Closed Loop Gas Capture Pilot

October 2021

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Contents

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1 Introduction

Challenge:

- 3rd party gas takeaway capacity constraints are a leading cause of production interruptions and well shut-ins in Chevron's "Salado Draw" development

Solution:

- Closed loop gas capture "CLGC" injection provides an alternative solution to flaring and/or shutting in wells in response to gas takeaway market interruptions and capacity constraints.
- CLGC decouples the dependency between 3rd party midstream systems and production operations, enabling a buffer to manage short-term midstream interruptions

Benefits:

- Reduction in Greenhouse gas emissions due to flaring during interruptions.
- Enables the uninterrupted production of oil that would be shut-in during gas takeaway constraints, improving the economic recovery of mineral resources.
- Utilizes existing gas lift infrastructure.

Process overview:

- During 3rd party interruption, wells utilized in CLGC operations will have production valves shut in.
- Gas lift rate will be increased to CLGC target, while measured & metered at the existing gas lift meter and flow controller.
- Injected gas flows down the tubing-casing annulus, through the orifice and unloading valves, entering the tubing, lateral, and fracture network near the wellbore
- When constraint is lifted, injection is ceased, and the well is returned to production operations.

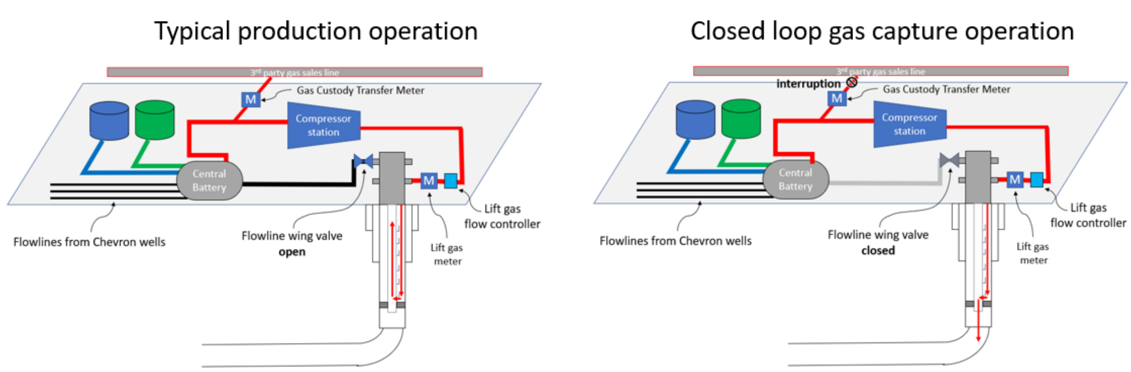


Figure 1. Schematic comparing production vs closed loop cag capture operations

1.1 Pilot project design considerations

Three primary categories or criteria, from broad to narrow, were satisfied in selecting appropriate application of closed loop gas injection.

1. Subsurface
2. Infrastructure
3. Wellbore

1.1.1 Subsurface: Geology and Reservoir

Wells utilized for injection are in a structurally stable area, absent of faulting or structural complexity that could potentially serve as a migration pathway for injected gas out of the reservoir. The injection wells are completed in the informally named Avalon shale, the shallowest hydrocarbon-bearing zone in the Bone Spring Formation. Shown in Figure 2 is the top structure of the Bone Spring Lime.

The injection interval is ~250' thick, overlain by the ~50 thick Bone Spring Limestone. Underlying the injection interval is ~700' of carbonate interbedded with silica-rich mudstones. A structural cross section through the project area, highlighting the injection interval and bounding strata is shown in Figure 3. Low porosity and low permeability of the bounding carbonates prevent migration of injected gas out of the reservoir. Matrix permeability of the injection reservoir is ~400 nanoDarcies to ~5 microDarcies, containing the injected gas to the near-wellbore fracture network.

Static bottom hole pressure is low enough to enable injection into the near-wellbore fracture network utilizing existing gas lift surface pressures. During 2019 slickline static surveys, static pressures ranged from ~550 psi to ~650 psi following 12-hr. pressure build up periods.

Salado Draw Closed Loop Gas Capture Pilot Results
October 2021

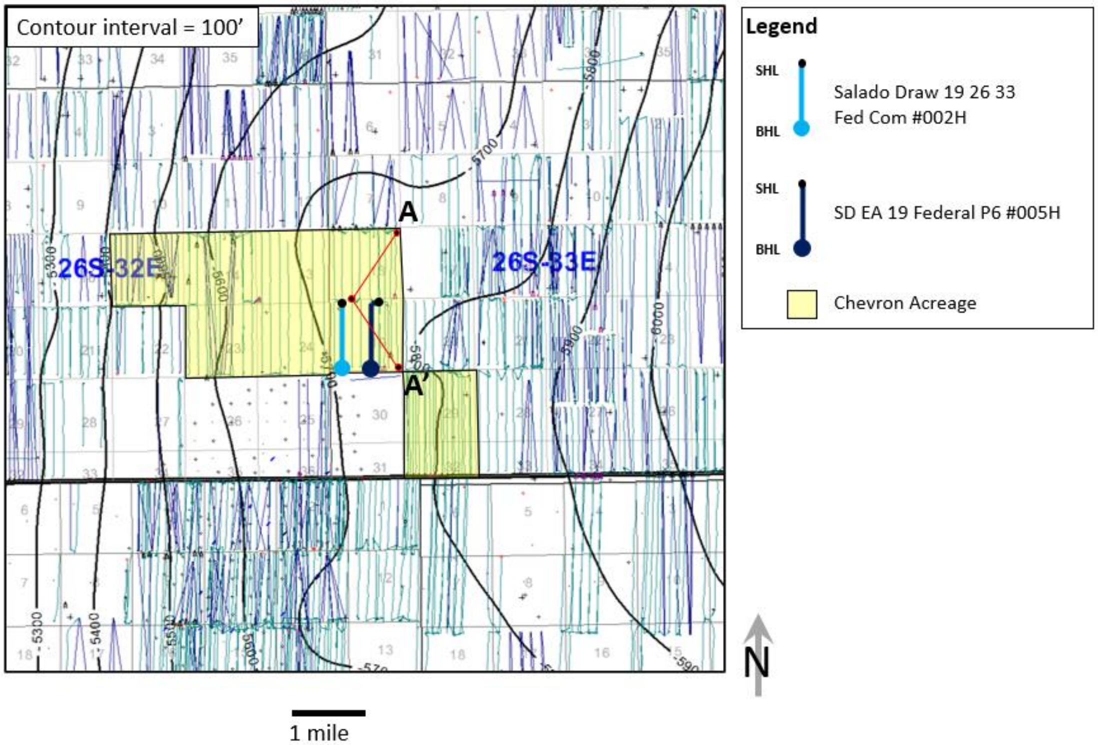


Figure 2. Salado Draw Area – Top Bone Spring Lime Structure (SSTVD)

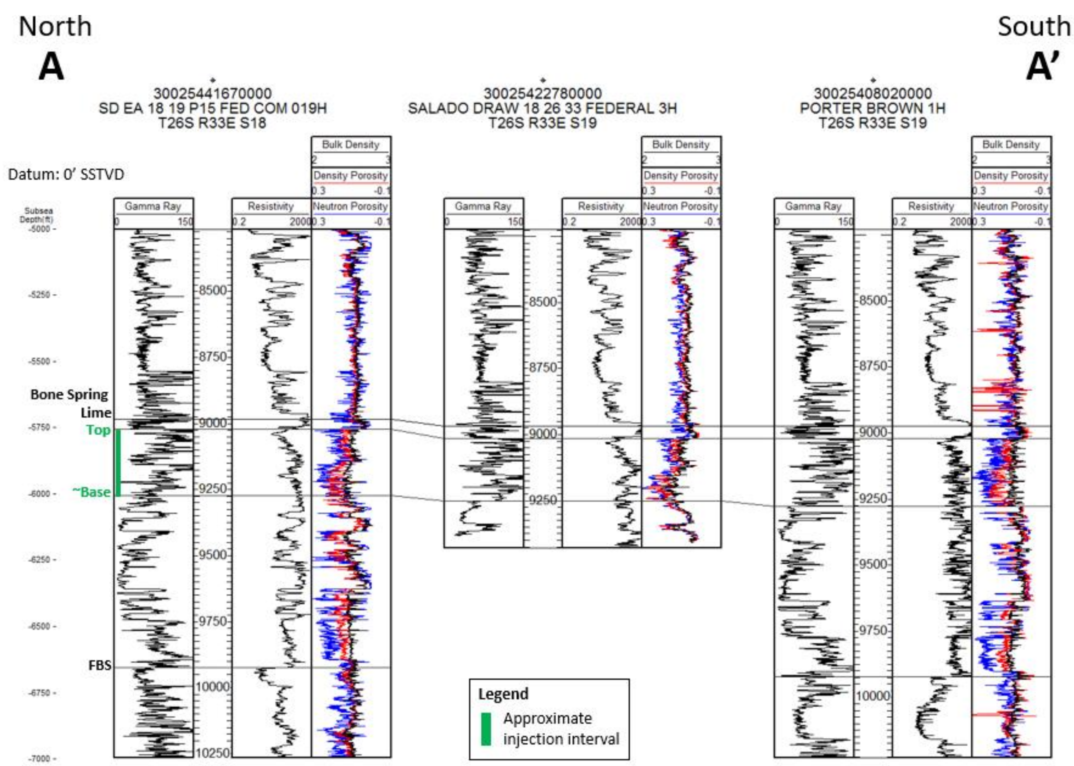


Figure 3. Cross section A-A’ across project area, showing injection interval and over/underlying stratigraphy.

1.1.2 Infrastructure

The CLGC injection pilot utilizes the existing production and lift gas compression and distribution infrastructure, including compressors, piping, and metering/measurement equipment. Well selection ensured existing distribution network would allow movement and accounting of produced gas from producing well, to central tank batteries, through injection network, to injection wells.

1.1.3 Well selection

In addition to the subsurface and infrastructure criteria above, the following considerations were used for well selection.

- Mechanical integrity and basis of design adequate to withstand injection pressures and ensure isolation of fluids in injection reservoir
- Artificial lift type: gas lift
- Stable production history enabling creation of GOR forecast utilized in allocation of native vs recovered injected gas following periods of injection.
- Wells that are already prioritized for shut-in during 3rd party curtailments. We are not shutting in for the purpose of injection, rather utilizing a wellbore for CLGC that would already be slated for shut-in during the constraints.

2 Pilot injection test

2.1 Pilot well candidates

The following wells were selected for the pilot based on the selection criteria outlined above:

Well name	Surface Location	Reservoir
Salado Draw 19 26 33 Federal Com 2H	200’ FNL & 948’ FWL, s.19, T26S/R33E	Bone Spring (Avalon)
SD EA 19 Federal P6 #005H	227’ FNL & 1,747’ FEL, s.19, T26S/R33E	Bone Spring (Avalon)

The selected wells have been on production since 2016. Complete wellbore diagrams are provided in the Appendix.

2.2 Mechanical Integrity & Basis of Design

Burst pressure calculations

Calculations were performed to ensure the production casing burst pressure is, at minimum, 120% of the maximum allowable surface pressure (MASP) plus the hydrostatic pressure from a full column of reservoir fluid.

Min. Burst Rating = 1.2 * [MASP + (TVD * reservoir fluid gradient)] **(eq. 1)**

- Casing burst pressure rating for 5 ½", 20#, P-110 casing = **12,640 psi**

Well	MASP	TVD	Reservoir fluid	Minimum burst rating
Salado Draw 19 26 33 Federal Com 2H	1250 psi	9171'	0.49 psi/ft	6,893 psi (pass)
SD EA 19 Federal P6 #005H	1250 psi	9196'	0.49 psi/ft	6,907 psi (pass)

Table 1: Calculations for minimum required burst pressure of production casing

Mechanical integrity tests (MIT)

Mechanical integrity of each pilot injection well was confirmed by successfully pressure testing the production casing to 110% of MASP (1375 psi) with a full hydrostatic column of fluid from the packer to surface for at least 30 minutes.

Following the pilot, an additional MIT verified mechanical integrity of wells utilized for injection.

Charts results for each MIT are provided in the Appendix.

Cement Bond Log

Cement bond log confirmed isolation of the injection interval. Excerpt of the log showing top of cement is provided in the Appendix.

Well diagrams for the pilot injection wells are provided in the Appendix.

2.3 Pilot objectives

1) Determine gas injection capacity for each well
2) Determine achievable injection rate for each well
3) Determine recovery period of injected gas
4) Assess whether this project can effectively reduce the frequency of well shutdowns and associated lost production due to midstream gas takeaway interruptions.

2.4 Surveillance

The following data were collected throughout the duration of the pilot:

Injection pilot well

- Pressure (continuous)
  - Production casing
  - Tubing/wellhead
  - Intermediate casing
  - Injection pressure
- Bottom hole pressure (retrievable gauges)
- Injection rate
- Cumulative injection volume
- Water chemistry (pre/post injection)
- Gas composition (pre/post injection)
- 3 stream production rates
- Cumulative injected gas recovery
- Acoustic fluid level (casing & tubing)

Direct offset wells to pilot injector

- Pressure (continuous)
  - Production casing
  - Tubing/wellhead
- Water chemistry (pre/post injection)
- 3 stream production rates

2.5 Pilot design

The injection tests are comprised of 4 phases: (1) build up, (2) injection, (3) fall-off, and (4) return to production. Each phase was utilized to collect data in both the pilot injection wells and the direct offset "observation well" located adjacent to the pilot well lateral. The pilot tests were performed in series, on a single injection well. Implementation as a field solution would involve injection into several wells simultaneously.

- **Baseline surveillance**
  - Prior to the initiation of the pilot, a memory pressure-temperature gauge was set in the landing nipple of the pilot injection well. The well is sent into test for 72 hours. Gas, oil, and water samples were collected from the pilot injection well.

- **Phase 1: Build-up**
  - 24 hours prior to injection, the pilot well and the offset observation wells are shut in. This phase is not a critical component of CLGC injection, and typical injection cycles would not include a build-up phase. This step is integrated in the pilot for data collection purposes. The build-up period established a baseline tubing/wellhead pressure build-up profile in the observation wells. During the upcoming injection phase, observed tubing pressures are compared to the build-up profile and

evaluated for deviations, enabling the identification of pressure responses that may indicate potential communication with the offset injection.

- In addition to the data collected in the observation wells, discussed above, acoustic fluid level shots were acquired in the casing and tubing of the injection well. Both production/pressure modeling and tubing fluid levels were utilized for estimation of the static bottom hole pressure prior to injection.

- **Phase 2: Injection**
  - Injection is initiated with tubing shut in. Injection rate is incrementally stepped up to the target rate of 2 MMSCF/day during the first day of the pilot. Chevron's Integrated Operations Center (IOC) continuously monitored injection rate, potential deviation from rate setpoint, tubing pressure, production and intermediate casing pressures, and injection system pressure.
  - The compressor discharge pressure is limited to 1250 psi. Alarms and safety shutdowns are in place to prevent exceeding this pressure.
  - Incremental notifications and alarms were configured to ensure significant changes in production or intermediate casing pressure, surface injection pressure, and deviations from injection rate setpoints were immediately identified.
- **Phase 3: Fall-off**
  - Injection is shut-in and the injection well begins a 48-hour fall off period. This phase is not a critical component of CLGC injection. It was included only as a data collection opportunity during the pilot. Typical CLGC cycles would not routinely integrate a fall off phase. Offset observation wells remain shut in during this period.
- **Phase 4: Return to production**
  - The pilot injection well is sent to test and returned to production. Daily, 24-hour well tests are conducted for 7 days, with the option to extend as appropriate. Gas, oil, and water samples are acquired during this post-injection production period. Pre- & post-injection samples are compared to identify any potential changes. Native vs recovered injected gas allocation is estimated as follows:

Recovered injected gas = total gas - (lift gas + native gas) **(eq. 2)**

where,

*native gas (scf.) = oil volume (bbl.) * GOR forecast (scf./bbl.)* **(eq. 3)**

- GOR forecast is generated for each injection well following methodology outlined in SPE-171580-MS.
- For accounting purposes, estimates of native and recovered injected gas are performed on a monthly basis (i.e., monthly oil volume is input

into equation 3). To investigate how recovery profiles may evolve day to day, an assessment using daily data was performed.

3 Injection test results

3.1 Salado Draw 19 26 33 Federal Com 2H

Pre-injection preparation

Following shut-in, an acoustic fluid level shot on the casing-tubing annulus indicated a fluid level below the orifice. Tubing fluid level was recorded at 7324' TVD with ~400 psi tubing pressure. TAM software was utilized to estimate static bottom hole pressure of 1142 psi at 9,143' TVD, (depth of first perforation). At the gauge reference depth of 8662' MD, the estimated pressure derived from the fluid level was ~940 psi.

Injection test

Injection was initiated and ramped up in steps from 0.8 MMCFD, 1.2 MMCFD, and to 2.0 MMCFD. Key injection parameters are below. The pressure and rate profiles throughout the first 3 phases of the injection test are shown in Figure 4.

- Duration:
  - Start of injection: 5/14/2021; 9:52 AM MST
  - End of injection: 5/21/2021; 9:31 AM MST
- Cumulative injected volume: 8,504 MCF
- Injection Rates
  - Max instantaneous: 2.0 MMCF/d
  - Max sustained: ~1.5 MMCF/d
- Injection pressure:
  - Max instantaneous surface at wellhead: 1230 psi
  - Max instantaneous bottom hole: 1685 psi
  - Sustained pressure at max sustained rate: 1200 -1210 psi

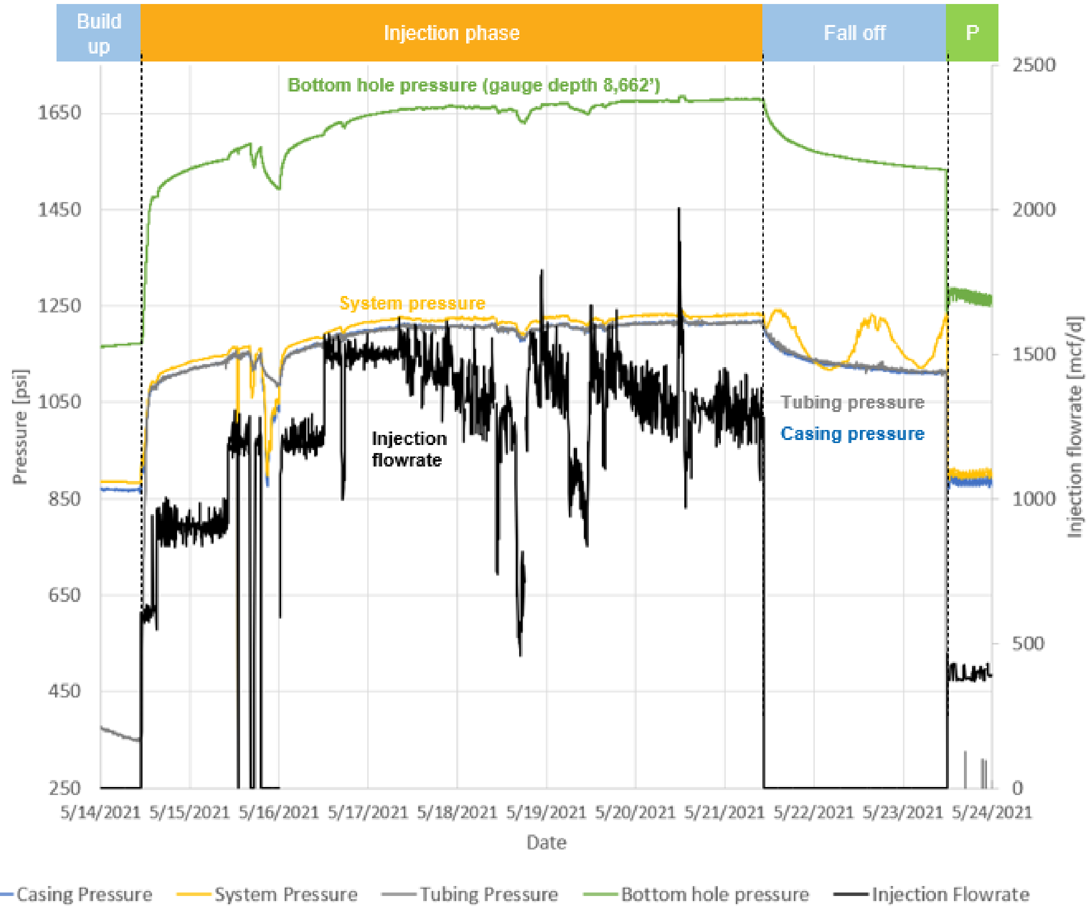


Figure 4. System, wellhead, and casing pressure with injection rate during Phases 1-3 of injection test.

Return to production

Following the 48-hour fall off period, the well was returned to production. Gas lift was initiated at 400 MCFD, consistent with pre-injection baseline rate. Well tests indicated the well was producing 100% water and recycling lift gas. June 4th, the production team increased the gas injection rate to 800 MSCF. The well began to produce hydrocarbons during that day's test. The daily recovery profile for the well on a daily basis is shown in Figure 5. This plot suggests that gas recovery was approximately 11% of the injected volume. An interpretation of this apparent low recovery rate is expanded upon in the discussion section of this report.

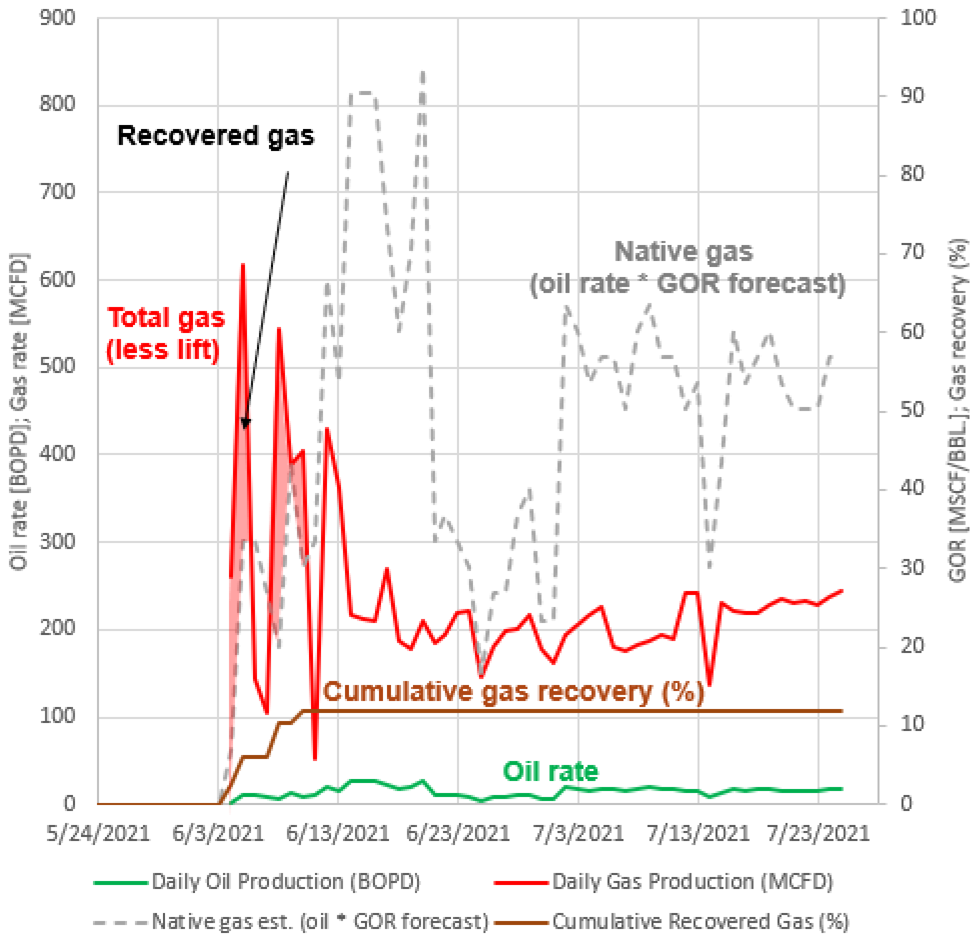


Figure 5. recovery profile for Salado Draw 19 26 33 Fed Com 1H

Intermediate casing pressure

Intermediate casing pressure was continuously monitored. Results are provided in the plot in Figure 6. Pre-injection baseline pressure averaged ~35 psi. Daily thermal cycles of approximately ±10 psi were observed through the duration of the pilot. During the injection phase, a gradual increase of ~10 to ~15 psi was observed during the first 2-3 days of injection. Upon cessation of injection, intermediate casing pressure gradually declined and stabilized at an average of ~40 psi.

The interpretation of the increase in casing pressure during injection is likely related to injection of compressed, warm gas and to a lesser degree, a subtle ballooning of the production casing during injection. The top of cement in the intermediate-production casing annulus is ~3830’ MD. When warm, compressed gas is injected through the production casing, this shallow zone, above the top of cement, is heated above the geothermal gradient, resulting in subtle expansion of gas in the annulus as it is heated by the warmer fluids within the production casing.

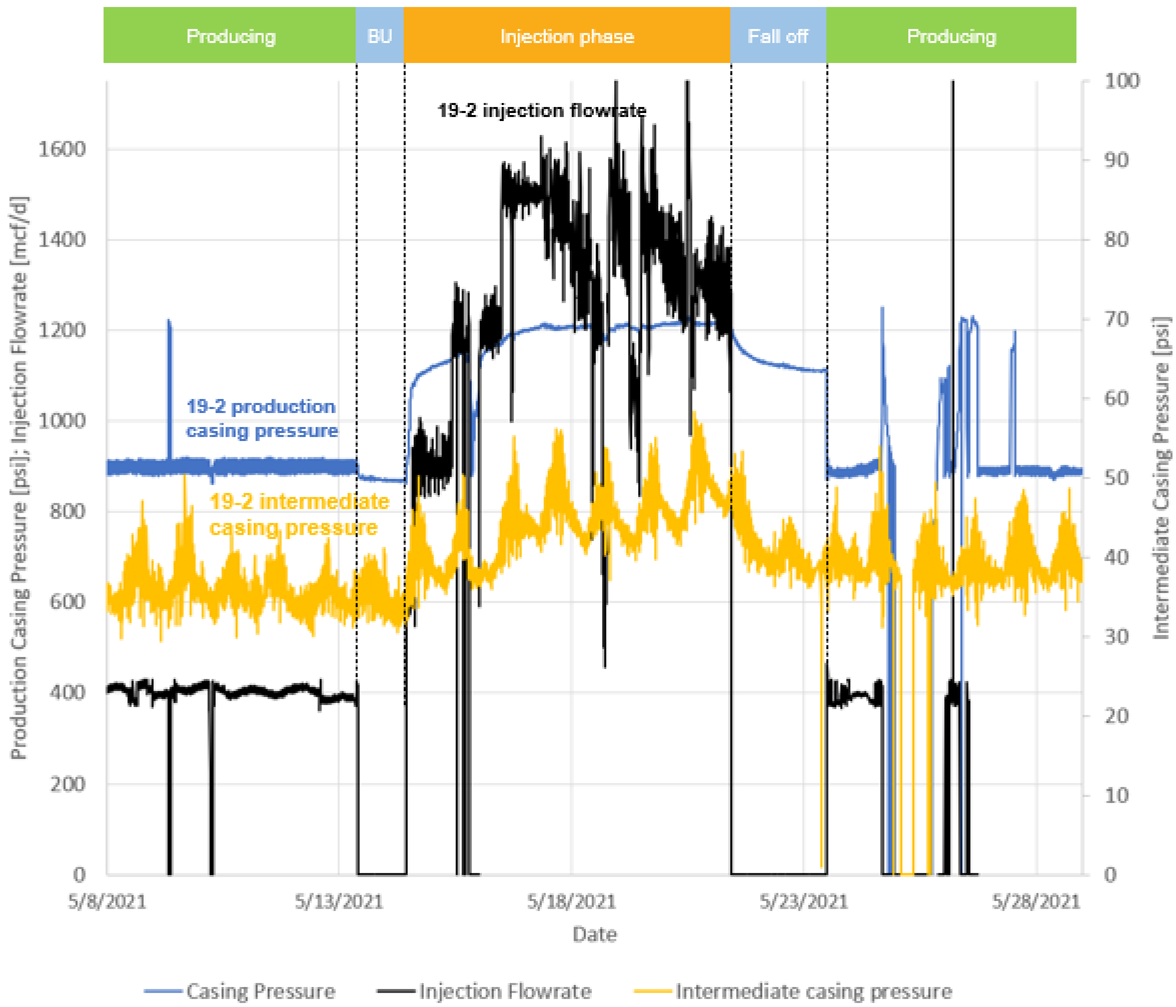


Figure 6. Intermediate casing pressure plot with injection rate and production casing pressure.

Offset well surveillance

Direct offset wells were shut-in 24 hours prior to injection and served as pressure monitoring wells throughout the pilot. Figure 7 shows a plot of the tubing and casing pressures recorded in the offset wells during the pilot. During the initial 24 hours shut in, tubing pressure build-ups provided a baseline to evaluate pressure responses during the injection period. No deviation from the baseline build-up profile was observed.

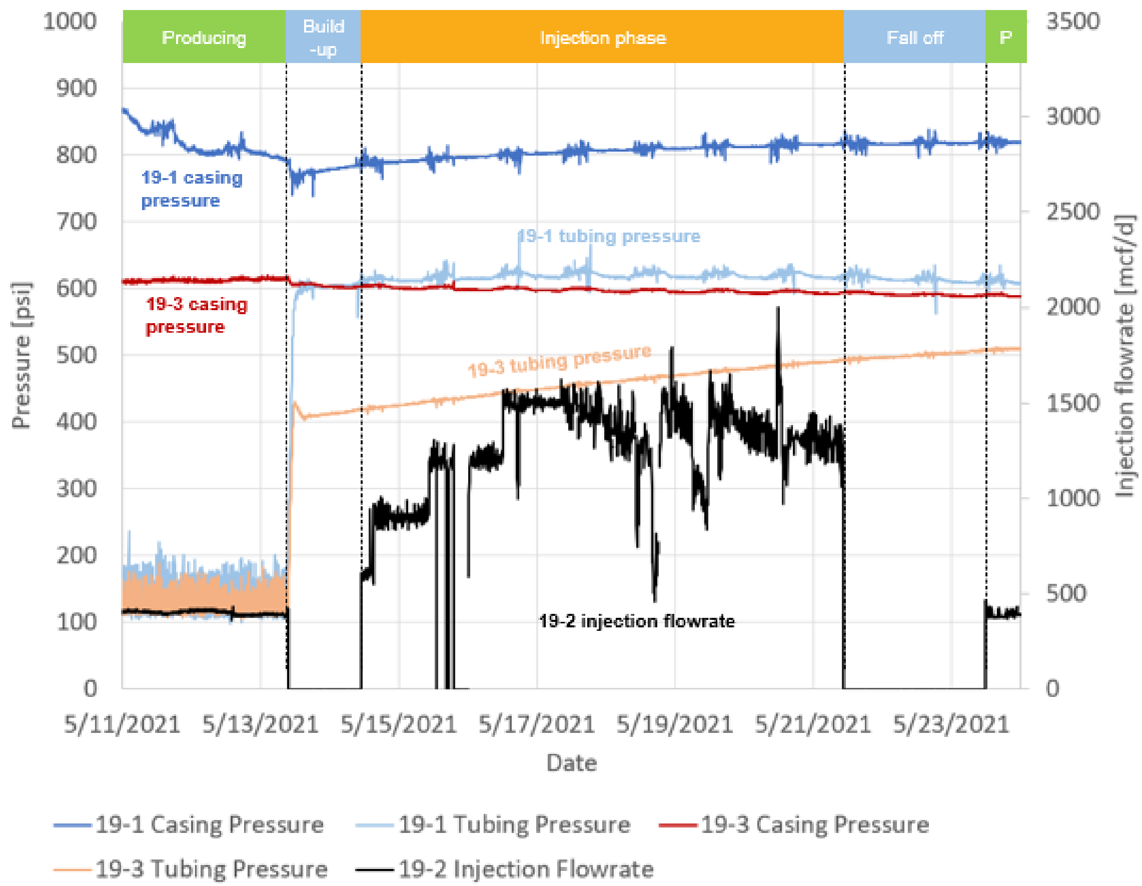


Figure 7. Offset well pressure monitoring.

3.2 SD EA 19 Federal P6 #005H

Prior to initiation of the injection test, production rates indicated an increase in liquid rate, primarily water. Production modeling was performed, indicating an increase in FBHP to more than 1500 psi. This was nearly 1000 psi higher than the 549 psi FBHP measured by gauge measurement in 7/2019. A memory pressure gauge was set in the well and it was returned to production. Following several weeks of monitoring with attempts to increase gas lift rate to unload the well, modeling continued to suggest pressures remained above the injection bottom hole pressure achievable with surface compression equipment utilized in the pilot. The memory gauge was pulled, confirming both the modeling and that bottom hole pressures exceed injection pressures.

The decision was made to cancel the injection test into the second well. Further investigation into the timing and cause of the increase in bottom hole pressures in expanded upon in the discussion section.

4 Discussion

4.1 Reservoir conditions

Both pilot wells discovered bottom hole pressures higher than pressures measured in 7/2019 bottom hole pressure surveys. Initially, observations and production characteristics suggested these wells were potentially affected by fracture driven interactions. I.e., increased water production and bottom hole pressure associated with decrease in gas rate, oil rate, and GOR. No offset completion activity was discovered during the months surrounding the observed changes.

The change in time production was pinpointed to June 2020, following an extended full-field shut-in. These production changes are presented in the plots in Figure 8. Water analyses conducted prior to and following this change suggests influx of non-native water into the Avalon. Chloride concentrations of produced water sampled from Salado Draw 19 26 33 Fed Com 2H, shown in Figure 9, decreased from a baseline of ~120,000-130,000 mg/L down to ~90,000-100,000 mg/L. Timing of the change in produced water chemistry is bracketed between 7/2019 and 4/2021. In addition to the change in Chloride concentration, other ions and ion ratios indicate that a potentially non-native water is being produced. The step change in production that began in June 2020 suggests water influx may have initiated at that time.

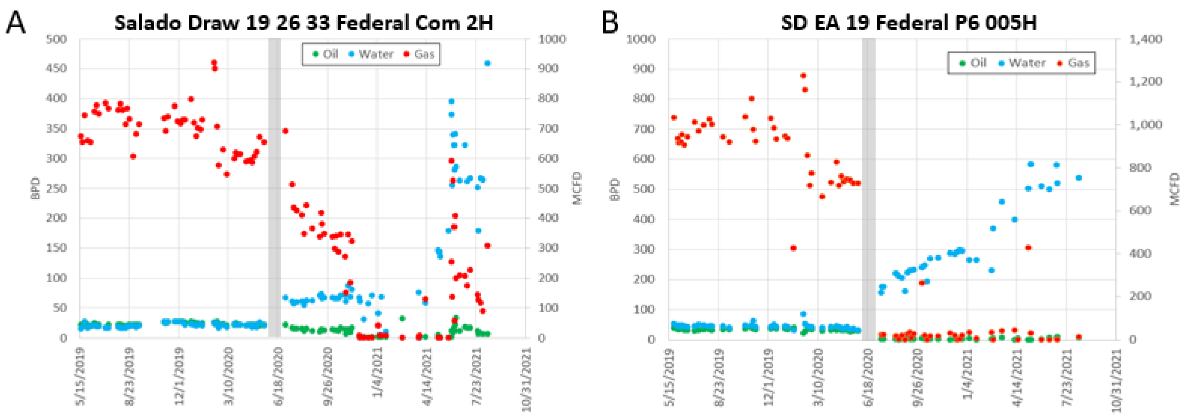


Figure 8. Production changes following extended shut-in. Shut-in timing indicated by grey vertical bar.

The cause of the change in water chemistry and increased pressure and water production rates remains under investigation at the time of this report. Upper Avalon wells operated by Chevron, in s.29 & s.32, T26S/R33E, southeast of the project area have produced at high water cut (>90%) throughout their production history, with flowing bottom hole pressures holding above 2000 psi after nearly 6 years on production. Water influx related to high-rate shallow water disposal has been hypothesized by operators as a potential driver in high water production in Avalon wells.

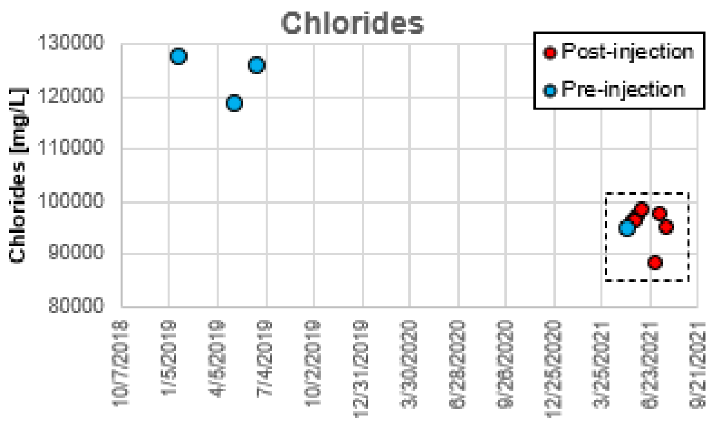
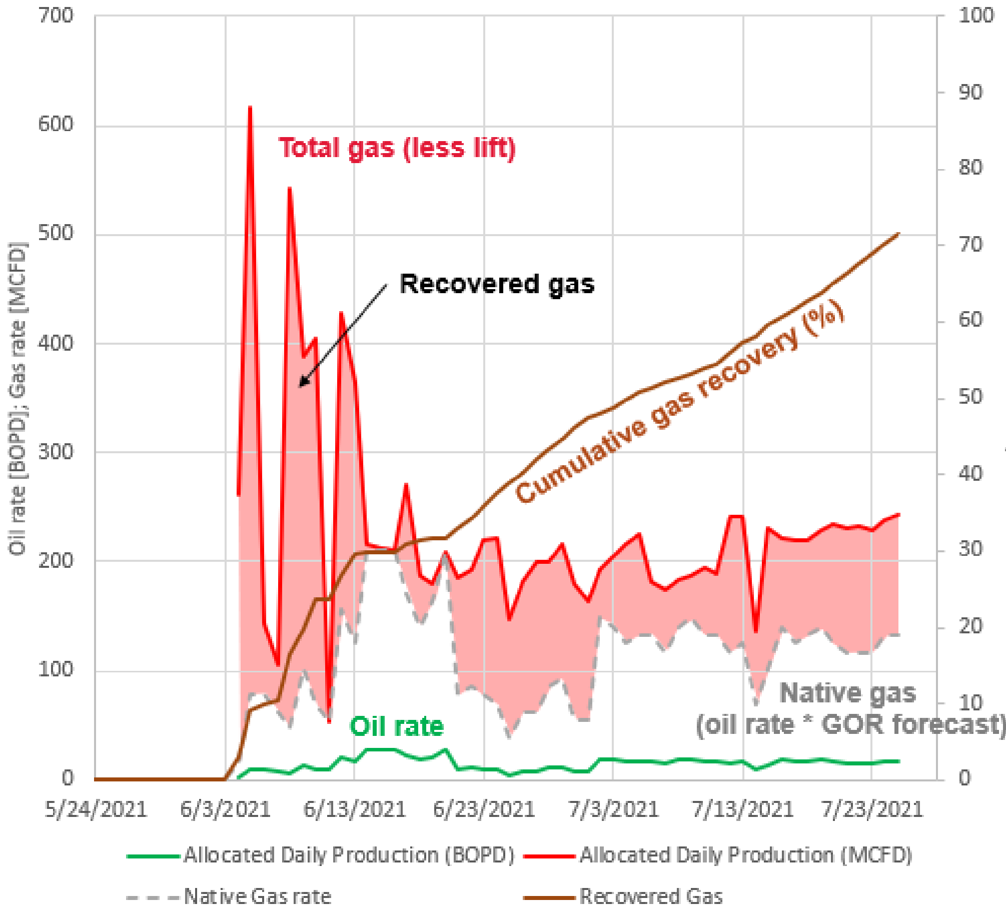


Figure 9. Salado Draw 19 26 33 Federal Com 2H produced water chloride concentration

4.2 Gas recovery

As discussed above, the change in reservoir conditions resulting from water influx has caused the producing GOR of the pilot wells to decrease. GOR forecasts utilized for accounting were developed from the long, stable production histories of each of the pilot wells. These recent, significant changes in production caused the pre-injection producing GOR to fall significantly below the established forecast GOR. As a result, the native gas production as derived in equation 3, was potentially over-estimated and recovered injected volumes utilized for accounting were likely under-estimated.

Re-calibrating the GOR forecast to post June 2020 well performance and GOR resulted in a recovery profile shown in Figure 10. This recalibration suggests recovery of ~70% as of 60 days following return to production.



The GOR forecast of 30,000 scf./bbl. utilized to estimate native gas was developed from the long-term production history of the well, forecasted forward. This initial forecast was utilized for all gas accounting and royalty calculations as it favored native gas production. Due to several operational changes and reservoir conditions, the well has in recent times been producing at a lower GOR significantly below the long-term forecast.

This pilot highlighted the dynamic fluid property changes in unconventional reservoirs, even in wells with years of stable, predictable production history. Due to the dynamic nature of the wells, the plan is to use near-term GOR trends for the wells used for injection to estimate native vs recovered injected gas.

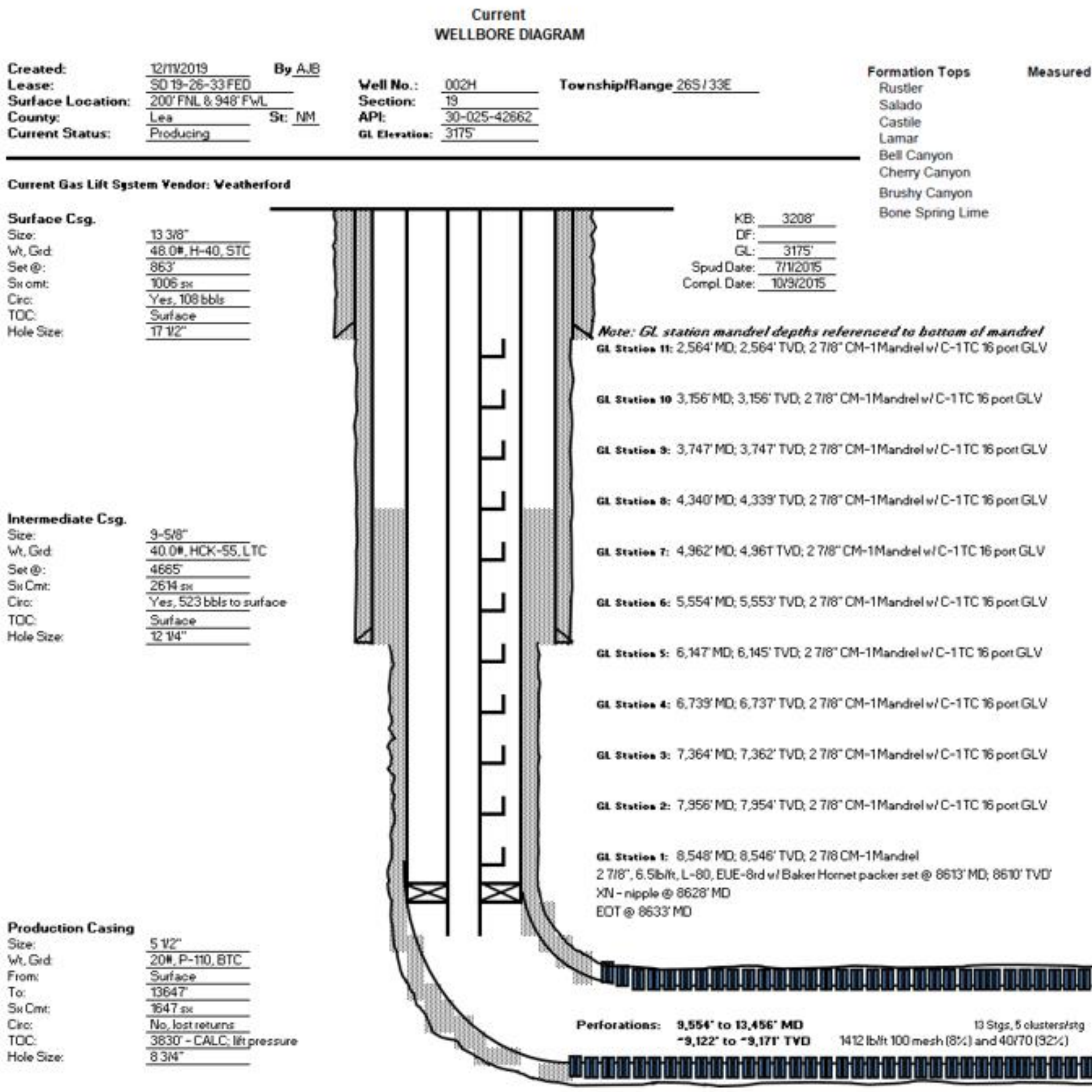
5 Conclusion

- Utilizing several injection wells concurrently, sufficient gas handling can be achieved utilizing this solution to prevent flaring and/or frequent shutdowns.
- Surface injection pressures below 1250 psi are sufficient for injection
- No significant effect on pilot well or offset monitoring wells
- No indication of adverse effects to reservoir

The pilot test results suggest that all stages of CLGC injection can be safely and successfully performed. CLGC can be integrated as a short-term solution to midstream gas handling constraints.

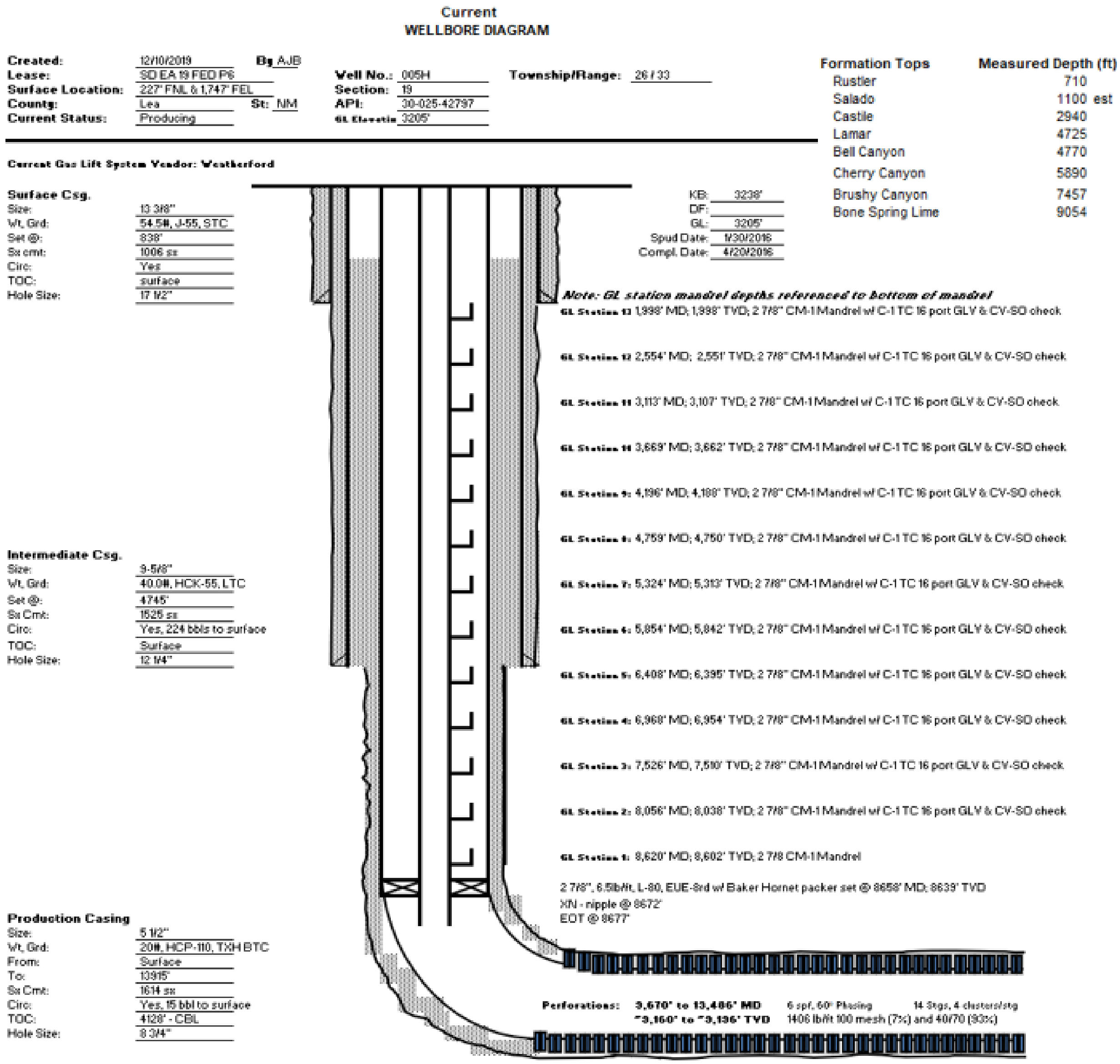
Appendix A:

Salado Draw 19 26 33 Federal Com 2H – wellbore diagram

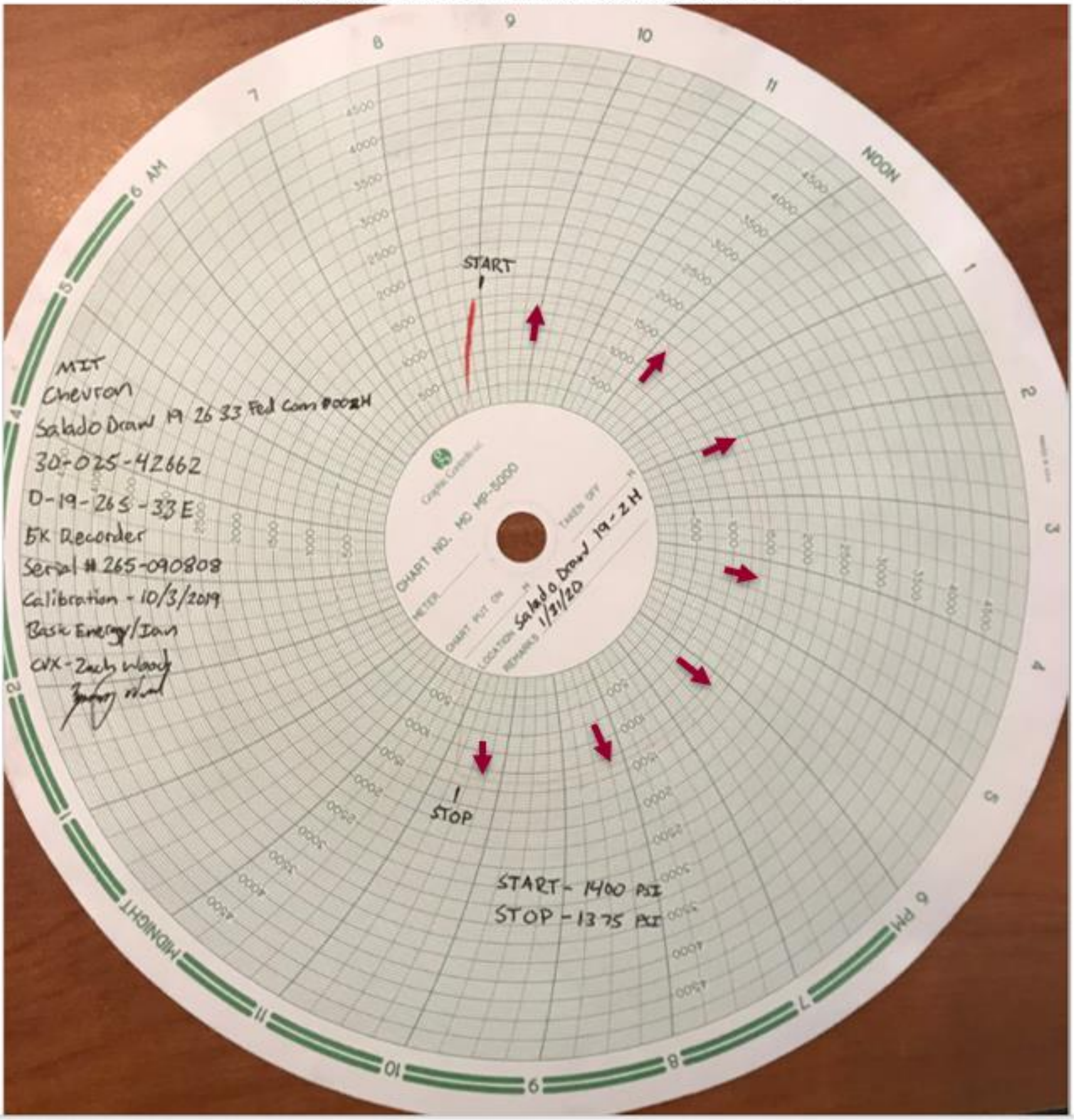


Salado Draw Closed Loop Gas Capture Pilot Results
October 2021

SD EA 19 Federal P6 #005H – wellbore diagram



Salado Draw 19 26 33 Federal Com 2H



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October 2021

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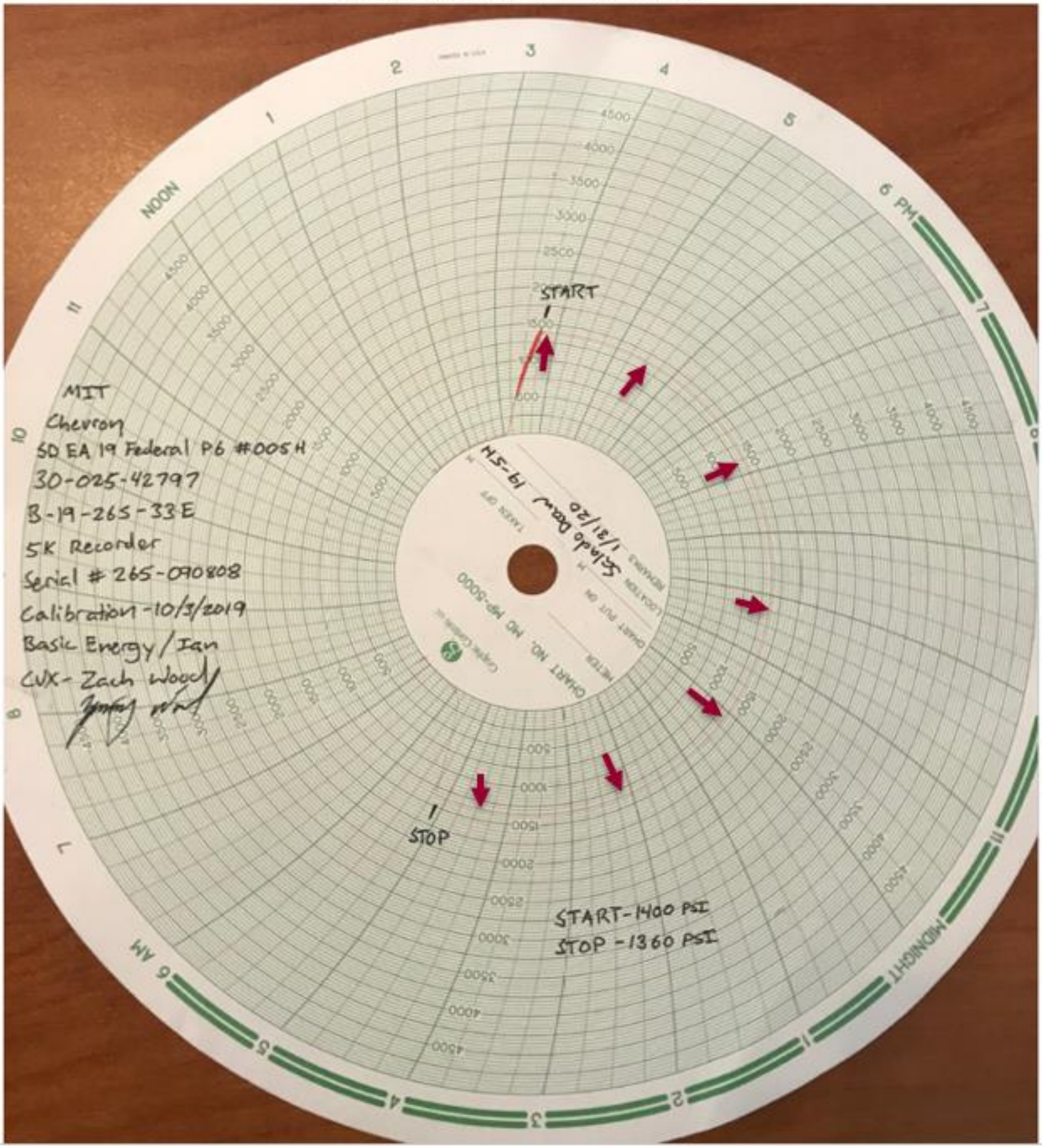
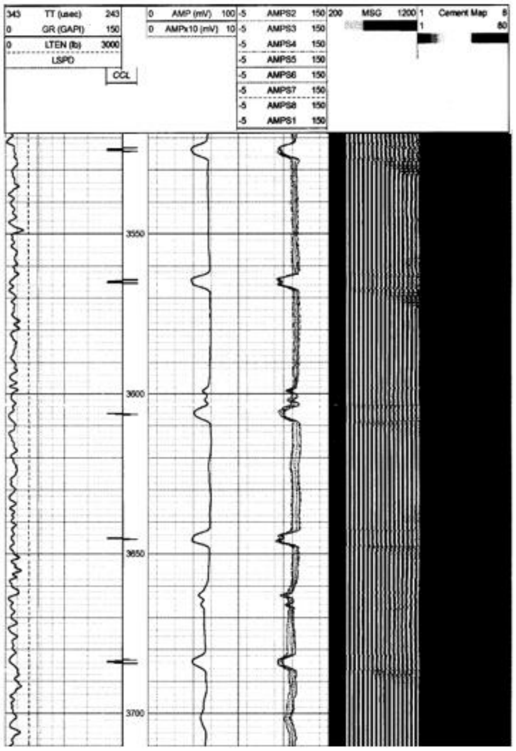
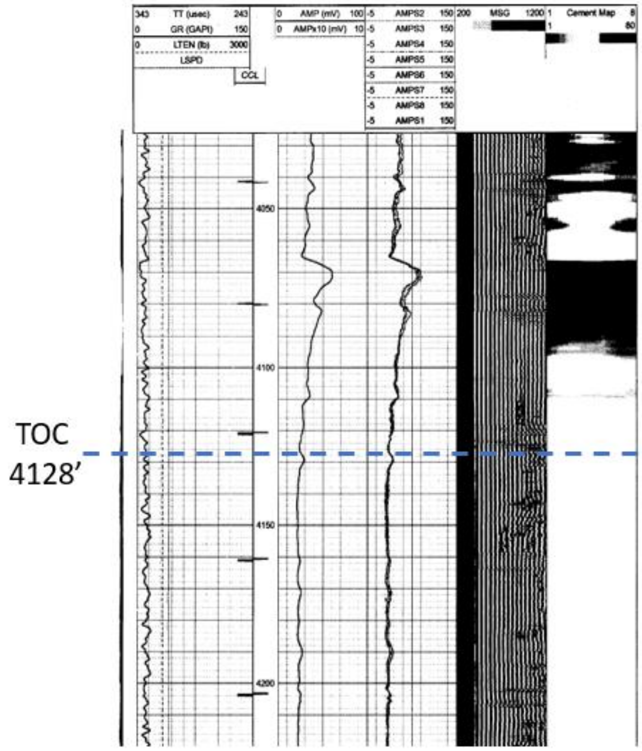


SD EA 19 Federal P6 5H excerpts – *full log provided in digital format*

Excerpt showing free pipe response



Excerpt showing top of cement



Salado Draw 19 26 33 Federal Com 2H. Post pilot MIT result.

References

Yu, Shaoyong "A New Methodology to Forecast Solution Gas Production in Tight Oil Reservoirs." Paper presented at the SPE/CSUR Unconventional Resources Conference – Canada, Calgary, Alberta, Canada, September 2014. doi: https://doi.org/10.2118/171580-MS