Plains CO_2 Reduction (PCOR) Partnership
Energy & Environmental Research Center (EERC)

CLASS VI INJECTION WELL STEP RATE TEST PROCEDURAL RECOMMENDATIONS

Plains CO_2 Reduction (PCOR) Partnership Initiative
White Paper

Prepared for:

Joshua Hull

National Energy Technology Laboratory
U.S. Department of Energy
626 Cochrans Mill Road
PO Box 10940
Pittsburgh, PA 15236-0940

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Prepared by:

Susan L. McKenzie
Catherine R. Stevens
Thomas E. Doll
Kevin C. Connors

Energy & Environmental Research Center
University of North Dakota
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018

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EXECUTIVE SUMMARY

Underground injection control (UIC) Class VI injection well regulations state, "…In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW..." (§146.88(a)). To ensure that the injection pressure does not initiate new fractures or propagate existing fractures in the injection zone(s), regulations apply a percentage of the fracture pressure to set the maximum allowable injection pressure (MAIP) (see Appendix A). Carbon capture and storage (CCS) project operators must determine the fracture pressure prior to initiating Class VI injection well operations. Step rate tests (SRT) are a long-standing best practice for determining the fracture pressure in the injection zone(s).

Class VI injection wells can be regulated by different governing agencies (e.g., the U.S. Environmental Protection Agency, state oil and gas regulatory agencies, or state environmental protection agencies); therefore, the SRT procedural requirements may not be identical. However, governing agencies have the commonality of protecting underground sources of drinking water (USDWs) under the Class VI UIC program.

This white paper provides an SRT method and procedure that has been accepted by regulators for determining the MAIP. An SRT consists of a series of injection rate steps each held for an equal time duration, with each injection rate progressively increased. Results are plotted and analyzed to observe the formation pressure response. An extended injection test at a constant rate followed by a pressure falloff test is recommended after the SRT. It is important that the following SRT methods are understood by CCS project operators and their contractors.

- Why to conduct step rate testing, including:
  - Objectives of an SRT
  - Regulatory requirements for an SRT
- Preplanning considerations prior to conducting the SRT
- Recommended SRT procedures
- SRT analyses to determine fracture pressure

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STEP RATE TEST PROCEDURAL RECOMMENDATIONS

DISCUSSION

The Plains CO_2 Reduction (PCOR) Partnership, funded by the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL), the North Dakota Industrial Commission's Oil and Gas Research Program and Lignite Research Program, and more than 230 public and private partners is accelerating the deployment of carbon capture, utilization, and storage (CCUS) technology. The PCOR Partnership region encompasses ten U.S. states and four Canadian provinces in the upper Great Plains and northwestern regions of North America. The PCOR Partnership is led by the Energy & Environmental Research Center (EERC), with support from the University of Wyoming and the University of Alaska Fairbanks, with the additional inclusion of stakeholders from public and private sectors. The goal of this joint government–industry effort is to identify and address regional capture, transport, use, and storage challenges facing commercial deployment of CCUS throughout the PCOR Partnership region.

Multiple federal and state regulatory agencies as well as professional organizations have prepared guidance documents or technical papers for conducting a step rate test (SRT). This procedure, created by the EERC, factors in extensive knowledge-driven experience, various published papers, as well as the SRT guidance documents from U.S. Environmental Protection Agency (EPA) Regions 5 and 8, which are both referenced in Appendix A.

This Class VI injection well SRT guidance will assist with designing an SRT procedure intended to provide outcomes with a high probability of acceptance by all regulatory agencies. There is no guaranteed procedure for approved SRT results, but proper preplanning can reduce the technical risks associated with the SRT.

Most SRT guidelines require continuous bottomhole pressure (BHP) measurements recorded during the test, commonly obtained using downhole memory pressure gauges. However, this guideline strongly recommends the use of an electronic surface readout display for a direct real-time reading of the BHP to eliminate the procedural risks of not obtaining a stabilized downhole formation pressure for each rate step. Surface pressure readouts also allow real-time evaluations to identify the need for additional rate steps to properly determine the formation parting pressure. Wireline-conveyed electronic gauges also allow pressure gradients to be taken while running in and out of the wellbore for evaluating fluid densities and can also determine the static fluid level in wells that go on a vacuum after being shut-in.

A stabilized downhole pressure for each rate step is necessary for an accurate SRT analysis. Ideally, each rate step duration should reach radial flow, but practically, the duration should be such that the pressure response is not dominated by wellbore storage and is at least transitioning toward radial flow. Wellbore storage occurs when the pressure responses are dominated by wellbore hydraulics, whereas radial flow is indicative of formation reservoir responses. Incremental rate steps that do not achieve a stabilized downhole pressure or have a sufficient number of rate steps to clearly identify the formation parting pressure may be unacceptable to regulators. Utilizing surface readout measurements for BHPs allow for proper BHP monitoring and real-time treatment analysis during the test to ensure stabilized BHPs are obtained before advancing to a higher injection rate step.

In addition to a stabilized downhole pressure, equal duration time steps are necessary for accurate analysis. However, the designed time intervals for the rate steps may need to be extended based on stabilized BHP responses during the test. If the time interval for a rate step is increased, the same time interval needs to be applied for the remaining rate step time intervals in the treatment for consistent formation pressure responses. Multiple variations in the rate step time intervals should be avoided by ensuring best practices for test designs include properly calculated time intervals. Once the formation parting pressure is observed, a *minimum* of two additional steps at progressively higher rates need to be performed in order to confirm the parting pressure has been achieved and to successfully demonstrate the formation parting pressure upon further analyses.

Upon conclusion of the last rate step and once injection has ceased, the wellbore needs to be immediately shut-in near the wellhead and the instantaneous shut-in pressure (ISIP) recorded. The ISIP is the instantaneous shut-in pressure after the initial frictional pressure fluctuation minimizes and pressure begins to stabilize. ISIP provides an indication of the instantaneous system pressure without pipe friction losses. Following the SRT, wellbore isolation should continue while recording the pressure falloff to obtain a static reservoir BHP.

Since regulators set the maximum allowable injection pressure for injection operations based on SRT results of formation parting pressure, the use of surface pressure measurements rather than BHP measurements is not recommended. Surface pressures must be converted into interpreted downhole pressures by including calculated friction and hydrostatic pressures. Risk lies in the calculated and interpreted pressure data not being representative of the actual bottomhole reservoir pressures, especially when involving smaller diameter tubing and friction pressure estimates at the higher injection rates. An example of test results based on surface pressures with no conversion to BHP instead of results based on actual BHPs is illustrated in Appendix B, showing why BHP measurements must be used for a correct SRT analysis.

Analyzing the SRT data results using more than one method is beneficial if the standard analysis does not provide definitive results. The standard analysis consists of using a Cartesian plot of the ending stabilized BHPs versus the injection rates associated with each rate step to identify the definitive decreasing slope change that indicates enhanced injectivity (see Appendix C). Additional pressure transient analyses will provide stronger validation when the formation fracture pressure outcome is submitted to the regulatory agencies. Appendix C only includes an example of an injectivity analysis using the individual rate steps. Selecting a contractor or pumping service provider with working knowledge of the regional formation parameters (e.g., permeability), software expertise, and the operational capability to conduct the designed SRT test would be beneficial to operators.

Many factors are involved in designing an SRT procedure, although formation permeability is generally most important. Lower permeability reservoirs typically require longer rate step time durations to obtain associated stabilized downhole pressures, whereas in high permeability reservoirs, pressure stabilization occurs quicker, especially at low injection rates. Therefore, the time durations may be shorter. However, higher permeability reservoirs usually require much higher injection rates to obtain the formation parting pressure.

Another important consideration for testing is the precise selection of the perforated interval to define the primary characteristics of the formation. In the initial steps of an SRT, a lower fracture parting pressure may be falsely interpreted if an increase in bottomhole pressure promulgates a secondary tighter section of the reservoir to accept fluid and, therefore, does not create a fracture in either reservoir section. Performing a falloff test immediately following the SRT is beneficial for confirmation that the primary formation parting pressure has been obtained.

SRT pressure and rate design parameter requirements will dictate the type of equipment necessary for conducting and recording the test. All pressure gauge specifications, whether surface or bottomhole, should utilize the narrowest possible pressure differential between the maximum anticipated pressure and maximum gauge pressure. The accuracy and resolution specifications of the pressure gauges must be capable of measuring small pressure changes to obtain accurate formation fracture pressure, the ISIP, and pressure falloff measurements when injection ceases and the wellbore is isolated. A minimum of 0.001-second pressure readings should be used. All pressure gauges should have been calibrated, at a minimum, within the past six months.

Thorough preplanning can eliminate many preventable issues. The following basic considerations should be followed, with more detailed discussion in Appendix D.

SRT Preplanning Considerations

1. Check governing regulatory agency for SRT procedures and/or analysis requirements, either provided on an agency website or via contacting an agency representative.

2. Gather and review known reservoir characteristics of injection formation—geologic characterizations, i.e., estimated permeability and porosity, with the following key notes:
   a. Lower permeability reservoirs require longer time steps to obtain stabilized BHP.
   b. Higher permeability reservoirs require higher injection rates.

3. Test design for the rate steps should contain a minimum of seven rate steps to accurately identify the formation parting pressure. Ensure the initial rates are low enough to establish a linear line below the formation parting pressure when graphing the BHP vs. injection rate Cartesian plot. Include pumping a minimum of two rate steps higher after observing the formation parting pressure to confirm the decreasing slope change has occurred after reaching the formation parting pressure. The number of rate steps, their duration, and the injection rates will vary based on formation geologic characteristics and pressure responses.

4. When available, use the permeability estimated from log analysis, cores, offset wells, or other available sources to simulate the SRT design with applicable software.

5. Proper test fluid/injectate parameters are crucial, e.g., fluid type, quantity, accessibility, material compatibility, and quality control.
   a. Have surplus fluid on-site with a consistent specific gravity and density/viscosity tested and recorded.
   b. Confirm fluid is compatible with the tubulars, reservoir formation, additives, and any previous injection fluids.

6. Continuous fluid flow is necessary for steady rate steps and pressure responses during the test. Prevent operational shutdowns by properly configuring injection lines, storage tanks, shut-in valves, fluid sampling points, and layout of pumping equipment.

7. For best results, multiple zones or perforated intervals should be isolated and tested individually, if practical.

8. Stacked storage sequestration projects may have different formations perforated and require SRTs be conducted on each formation.

9. Detailed wellbore schematics with accurate depths of perforations (open or isolated), tubing, packer, casing/liner, exterior casing monitoring devices, plug back depths, and cementing information are needed.

10. Accurate wellhead configurations are essential, e.g., pressure rating, shut-in valve located near the wellhead, crown valve for use by wireline, annulus valve rating, isolation of surface facilities, and pressure ratings of the injection tubing, casing, and any involved surface equipment.

11. Design the SRT procedure using a table of the planned rate steps and time duration, similar to Table D-1 in Appendix D.
    a. Each rate step should be of equal time duration. However, during the test, the rate step durations may need to be extended to reach a stabilized BHP, and all subsequent rate step durations should be conducted for the same extended period.
    b. If a stabilized BHP is not reached during a rate step, the test results may be inconclusive and unacceptable to the regulator.

12. Use pressure gauges and recording instruments at the surface and a minimum of two downhole pressure gauges.
    a. One downhole pressure gauge should have an electronic surface readout display and the second, a memory gauge, run in tandem for backup.
    b. Record gauge specs, e.g., number, type, location/depth, calibration, minimum/maximum range.
    c. Gauges should have an accurate setting of date and time.

13. Use continuous recording flowmeters, noting type (e.g., inline turbine meter) and location. Request backup rate measurement from the pump truck or by gauging the water storage tanks.

14. Well locations of sufficient size for safe work practices are needed for all the test equipment, test fluid tanks, pumping equipment, lighting, personnel, and vehicles.

15. Safe operating procedures need to be communicated for safety requirements, and test procedure and operations need to be explained to all site personnel.

16. Synchronized rate, pressure, and time stamp readings are crucial. Confirm downhole and surface recording devices have the correct date and time prior to installation.

17. Data transfers and downloading methods need to be determined for both surface and BHPs, injection rates, and time stamp data for real-time data plots and review.

18. Be prepared to determine the length of the shut-in time period according to the SRT results and review of surface readout of BHP for evaluation using pressure transient analysis. Leaving the well shut-in for sufficient time to obtain a static BHP is advised.

19. Plan to conduct a follow-up pressure falloff test consisting of an extended constant rate injection period and pressure falloff period. Acquiring falloff pressure data following a constant rate injection period will likely provide better analysis since multiple injection rate changes do not have to be considered in the falloff analysis (super-positioning of rate changes).
    a. Performing an analysis of test data using reservoir parameter data (e.g., reservoir transmissibility, skin and flow regimes, BHP) obtained from pressure falloff analysis is important for new wells and provides inputs for the Class VI permit application. Falloff tests are also beneficial for existing wells to evaluate wellbore conditions (skin), flow regimes, and BHP measurements.

SRT Procedure

1. Isolate the wellbore prior to testing so the initial BHP represents the static reservoir pressure.
    a. Install crown valve for wireline service provider to install the electronic surface readout BHP gauge and tandem memory gauge.

2. Verify the injection flowmeter setup can provide accurate and instantaneous rate information to confirm stable injection for each rate step and the system has a downloadable recording function.

3. Pressure gauges with temperature gauges:
    a. Run redundant calibrated pressure gauges: One electronic surface readout BHP gauge and a second memory gauge run in tandem, preferably located at the top perforation. Gauge pressure ranges must meet the requirement for the maximum anticipated pressure readings with the accuracy and resolution to measure minimal pressure changes.
        i. Confirm date and time stamps are accurate and synchronized prior to running the pressure gauges into the wellbore.
        ii. The two downhole pressure gauges do not have to be identical.
        iii. Pressure data will be erratic or noisy and could be deemed inadequate if the accuracy and resolution of the gauge is incapable of small pressure changes.

iv. Pressure gauges should be capable of recording pressures at a minimum frequency of 0.01 seconds.

4. Ensure time stamps are accurate and synchronized between all pressure gauges and flowmeters, especially between multiple service providers.
   a. Determine how and where downhole pressures and injection rates will be monitored and recorded during the test.

5. Locate the wellbore isolation valve near the wellhead for an immediate shut-in following the SRT, and assign designated personnel to close the valve simultaneously with injection pump shutdown.

6. Designate personnel to take fluid samples near the start, middle, and end of the SRT for quality control of injection fluid.

7. Rig up wireline. Following necessary wireline safeguards, run in hole with two tandem pressure gauges: one an electronic bottomhole surface readout gauge and the second a backup memory gauge.

8. Manually and electronically record all surface activity to explain any pressure or rate fluctuations during the test. Once the SRT has begun:
   a. Record the time when injection rate changes occur.
   b. Record the time and stabilized surface and BHPs prior to increasing the injection rate.
   c. Record the time of any disruptions that occurred during the test.

9. Upon opening the isolation wellhead valve, record the static BHP reading prior to initiating the SRT. It should be noted that the California Air Resources Board (CARB) requires the recording time frame to be the same length as a designed timestep.

10. Fill the wellbore, if necessary, to catch pressure, note volume required and pressure, and to establish a preinjection rate.

11. Start the SRT, injecting at design Rate 1 for the designed time step duration (Table 1) and successively increasing to the next higher injection rate.

Table 1. SRT Design Recommendation

Time Step Duration, hr	Injection Rate, bpm
Minimum of 0.5 hr	Rate 1
Same Duration as Previous	Rate 2
Same Duration as Previous	Rate 3
–	–
Same Duration as Previous	Rate 7
	Additional rates as designed

a. Ideally, each rate step should be of equal time step duration. However, if a stabilized BHP is not reached during a rate step, the test results may be inconclusive and unacceptable to the regulator.
b. During the test, maintain a Cartesian plot of each stabilized bottomhole injection pressure vs. corresponding injection rate, once obtained (see Appendix B, Figure B-2).
c. Once the formation parting pressure has definitively been observed, proven by at least two injection rate step–pressure combinations greater than the observed formation parting pressure, injection can cease and the isolation valve near the wellhead closed.
d. If the parting pressure was not obtained at the maximum test injection pressure utilized, the test results indicate that the formation is accepting fluids without fracturing.

12. Following simultaneous shut-in of the well after the last rate step, observe and record the ISIP.

13. Continue monitoring the pressure falloff for an extended period, ideally to a static BHP if practical. The goal is to reach radial flow in the reservoir; however, at a minimum, the goal is to exit wellbore storage into the transition period and provide sufficient pressure data to type-curve match data on a log-log plot or perform other pressure transient analyses.

14. Conduct an injection/falloff test consisting of an extended constant rate injection period followed by the immediate isolation of the wellbore to record the pressure falloff. The injection rate should be moderate (approximately 50% of the fracturing rate based on the SRT) and continue for a length of time to accomplish a desired radius of reservoir investigation. The subsequent falloff period should be at least twice as long as the injection period to ensure radial flow pressure response and a reliable calculation of formation permeability, skin damage condition, and possible reservoir discontinuities at greater distances from the well.

SRT Analyses (see Appendix C)

1. Prepare a complete job plot of all continuously recorded pressures and injection rate data.
   a. Identify any anomalies and review notes for explanations.

2. Confirm the injection rates are steady for each rate step.

3. Identify the ending stabilized BHP for each rate step, as shown in Table 2.

Table 2. BHP and Step Rate Recordings

Injection Rate, bpm	Ending Stabilized BHP, psia
Rate 1	BHP 1
Rate 2	BHP 2
Rate 3	BHP 3
–	–
Rate 7	BHP 7
Added Rates as Designed or Required	Added BHP as designed or required

4. Prepare a plot of stabilized BHP vs. injection rate.
   a. Draw a linear line through the initial points.
   b. Identify transition when pressure/rate points no longer align with first linear line.
   c. Draw a second linear line through the latter points corresponding to the rate steps.
   d. Identify when a distinct decreased slope change occurs between the intersecting linear lines and the corresponding BHP.

5. Record the ISIP and static reservoir pressure observed at the end of the test.

6. Conduct advanced pressure transient analysis of individual rate steps and the pressure falloff following the last rate step to confirm the Cartesian plot results.
   a. Use required, specialized pressure transient software.
   b. Compare results with the Cartesian plot analysis of the stabilized BHP vs. injection rate.

REFERENCES

1. U.S. Environmental Protection Agency, 1999, EPA Region 8 step-rate procedure: January 12, 1999, p. 1–6.

2. U.S. Environmental Protection Agency, 1994, EPA UIC Region 5 determination of maximum injection pressure for Class I Wells, January 1994.

3. Felsenthal, M., 1974, Step-rate tests determine safe injection pressures in floods: Oil and Gas Journal, v. 72, no. 43.

APPENDIX A

CLASS VI WELL REGULATORY REQUIREMENTS RELATED TO STEP RATE TESTS

CLASS VI WELL REGULATORY REQUIREMENTS RELATED TO STEP RATE TESTS

U.S. Environmental Protection Agency (EPA): Regulations require operators to determine the fracture pressure but provide no specifics on how to obtain.

EPA regional offices guidance documents for conducting an SRT:

1. EPA Region 8 (serving Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming, and 28 Tribal Nations): www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance.

2. EPA Region 5 (serving Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin, and 35 tribes): www.epa.gov/uic/epa-region-5-guidance-deep-injection-wells.

Title 40 Code of Federal Regulations (CFR) Protection of Environment

§146.87: Logging, sampling, and testing prior to injection well operations.

(d) At a minimum, the owner or operator must determine or calculate the following information concerning the injection and confining zone(s):

(d)(1) Fracture pressure.

(e) Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):

(e)(3) Injectivity tests.

§146.88 Injection well operating requirements:

(a) Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers USDW (underground source of drinking water). Pursuant to requirements at §146.82(a)(9), all stimulation programs must be approved by the Director as part of the permit application and incorporated into the permit.

North Dakota Industrial Commission (NDIC) Oil and Gas Division:

Chapter 43-05-01 Geologic Storage of Carbon Dioxide

43-05-01-11.2. Logging, sampling, and testing prior to injection well operation.

4. At a minimum, the storage operator shall determine or calculate the following information concerning the injection and confining zone:

a. Fracture pressure

43-05-01-11.3. Injection well operating requirements.

43-05-01-11.3.(1.) Except during stimulation, the storage operator shall ensure that injection pressure does not exceed ninety percent of the fracture pressure of the injection zone so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone. Injection pressure must never initiate fractures in the confining zone or cause the movement of injection or formation fluids that endanger an underground source of drinking water. All stimulation programs are subject to the commission's approval as part of the storage facility permit application and incorporated into the permit.

Wyoming Department of Environmental Quality (WDEQ) – Water Quality:

WY Administrative Rules Chapter 24: Class VI Injection Wells and Facilities Underground Injection Control Program (as of July 2022)

Section 17. Logging, Sampling, and Testing Prior to Injection Well Operation.

(d) The owner or operator shall determine fracture pressures of the injection and confining zones and verify hydrogeologic and geomechanical characteristics of the injection zone by conducting a pressure falloff test, any other test requested by the Administrator, and:

(i) A pump test; or

(ii) Injectivity tests.

Section 18. Injection Well Operating Requirements.

(a) The owner or operator shall ensure that injection pressure does not exceed ninety percent (90%) of the fracture pressure of the injection zone(s) to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s).

(i) In no case may injection pressure cause movement of injection or formation fluids in a manner that endangers a USDW, or otherwise threatens human health, safety, or the environment.

(ii) In no case may injection pressure initiate fractures in the confining zones or cause the movement of injectate or formation fluids that endangers a USDW or otherwise threatens human health, safety, or the environment.

California Air Resources Board (CARB): CARB specifically requires SRTs be conducted in each Class VI injection well and lists some specific testing requirements. Carbon Capture and Sequestration Protocol under the Lower Carbon Fuel Standard, August 13, 2018:

C. PERMANENCE REQUIREMENTS FOR GEOLOGIC SEQUESTRATION

C.2.3. Geologic and Hydrologic Evaluation Requirements

(a)(3)(E): Estimation of the injection volume and the maximum allowable injection rate and pressure, such that neither the primary confining layer nor the sequestration zone hydraulically fracture during injection, must be based on step rate test results as in subsection C.2.3.1(h).

C.2.3.1. Formation Testing and Well Logging Program

C.2.3.1(h): Fracture/parting pressure of the sequestration zone and primary confining layer:

1. The CCS Project Operator must perform step rate tests for each CO_2 injection well that is part of the CCS project, and use the results of each test to determine the fracture pressure of the sequestration zone and primary confining layer.
    A. The CCS Project Operator must report the results of all step rate tests for each CO_2 injection well. Such data must be used to determine the maximum allowable injection pressure for the CCS project such that injection will not initiate or propagate faults of fractures in the sequestration zone or primary confining layer; and

B. **Step rate tests must meet the following requirements:**

1. Real-time downhole pressure recording must be employed;
2. Bottom-hole pressure must be recorded at a zero injection rate for at least one full time step before the first step of the step rate test, and before one full time step after the last step of the step rate test; and
3. Step rate test data reported under subsection C.1.1.2 must be raw and unaltered, and include the injection rate, bottom-hole pressure, surface pressure, pump rate volume, and time recorded continuously at a rate of every one second during the step rate test.

APPENDIX B

BOTTOMHOLE VS. UNCORRECTED SURFACE PRESSURE ANALYSIS

BOTTOMHOLE VS. UNCORRECTED SURFACE PRESSURE ANALYSIS

Use bottomhole pressure (BHP), not surface pressure, for this analysis. **Same well, same test, but different results!** The plot of surface pressures shown in Figure B-1 had an increasing or positive slope change, suggesting a loss of injectivity, whereas the BHP plot observed a decreasing or negative slope change, indicative of increased injectivity, as shown in Figure B-2.

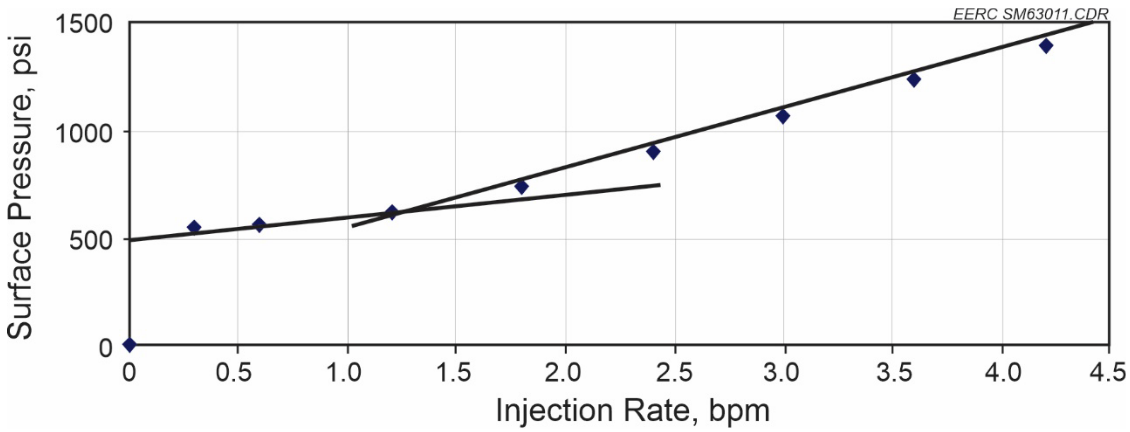

Figure B-1. Injection surface pressure vs. injection rate plot.

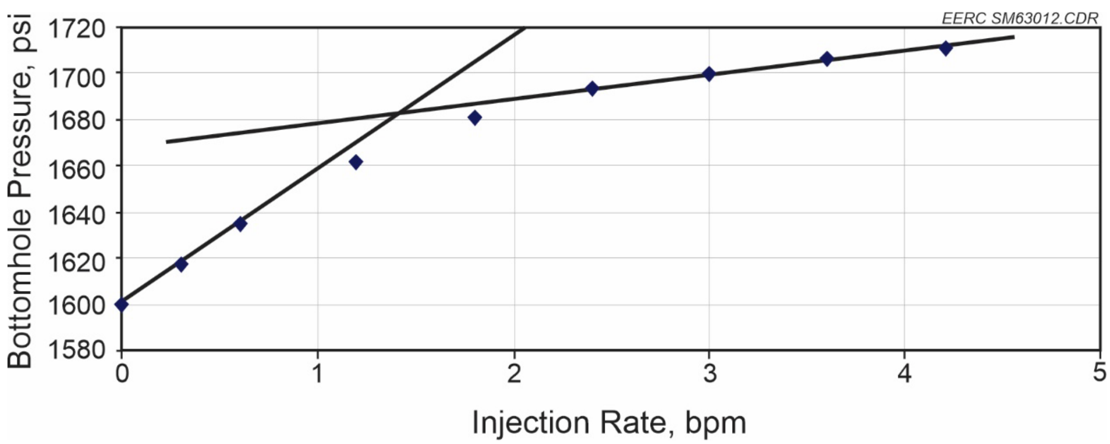

Figure B-2. Injection BHP vs. injection rate plot.

Note: The use of a more accurate downhole recorded pressure data when analyzing the step rate test is recommended. Any surface pressure obtained must be converted to BHP prior to plotting. This requires adding in the hydrostatic pressure and subtracting the friction pressure (of which may be substantial at higher injection rates) from the measured surface pressure.

Use of a surface readout of the BHP gauge allows on-site analysis of a test by verifying that the downhole pressure has stabilized prior to moving to the next rate step. If pressure transient software is available, a log-log plot of the pressure and derivative can be plotted to determine if the rate step was of sufficient duration to exit wellbore storage.

APPENDIX C

STEP RATE TEST ANALYSIS

STEP RATE TEST ANALYSES

Typical analysis of a step rate test (SRT):

1. Prepare a Cartesian overview plot of the bottomhole pressure (BHP) vs. time data.

2. Add when rate changes were initiated.

3. Identify the final stabilized pressure prior to increasing the rate for the next rate step. It should be noted that in this example, not all rates reached a stabilized pressure (Figure C-1).

4. Prepare a plot of the final stabilized BHP vs. injection rate for each rate step. A fracture will enhance injectivity and cause a decrease in slope. The stabilized pressures for rates preceding the formation parting pressure should form a straight line (Figure C-2).

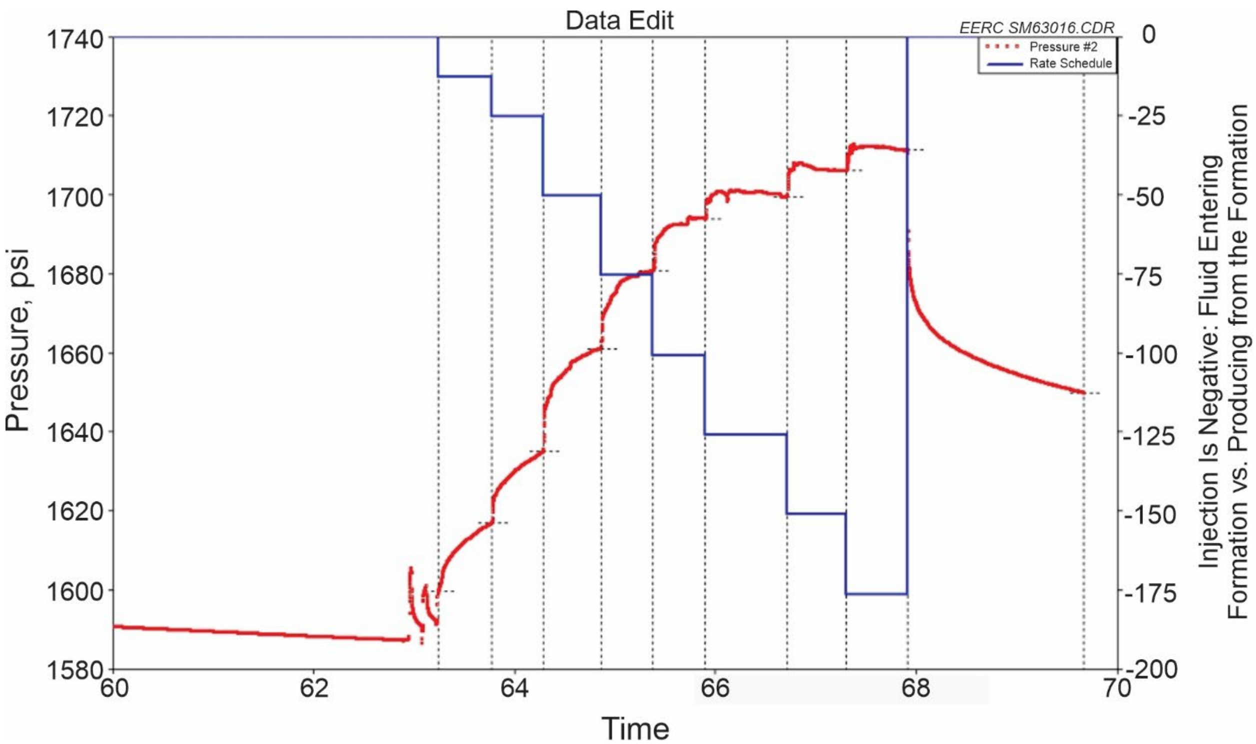

Figure C-1. Injection BHP vs. time and rate vs. time.

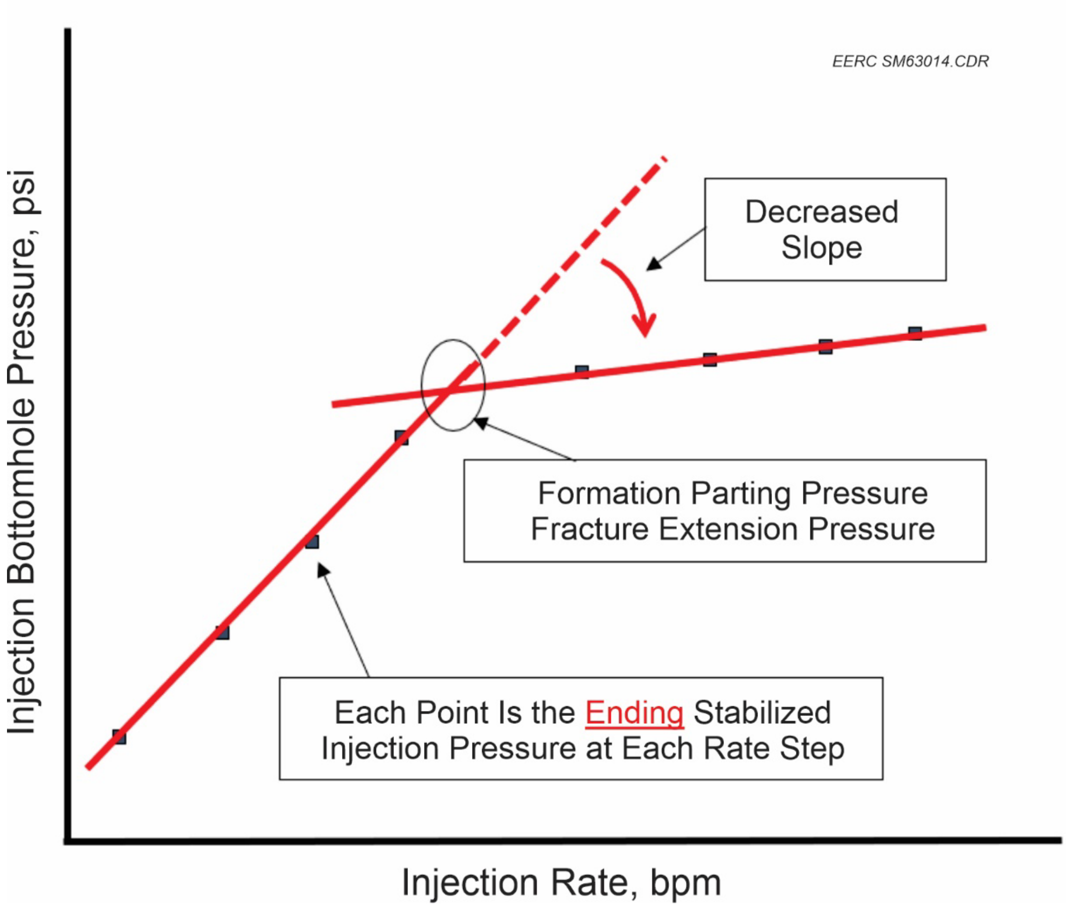

Figure C-2. Cartesian plot of injection BHP vs. injection rate.

Example of Using One Type of Pressure Transient Analysis to Evaluate the SRT:

Conduct advanced pressure transient analysis to confirm the Cartesian plot results:

- Requires use of specialized pressure transient software to account for the rate changes that occur during the SRT: Construct a log-log diagnostic plot and analyze each rate step. Identify which rate steps exhibit a linear flow regime on both the pressure derivative plot and derivative of the linear flow plot (BHP vs. SQRT of time).

- Determine the skin value associated with each rate step to identify fractured rate steps (skin values of −5 to −6 suggest a stimulated or fractured reservoir).

- Compare results with Cartesian plot analysis of the stabilized BHP vs. injection rate.

Use of pressure transient software allows type curve matching the pressure and pressure derivative on the log-log plot to obtain a skin value. A skin value of −5 to −6 suggests a stimulated or fractured well. Analysis of each injection rate step and downhole pressure data can support the SRT fracture pressure determination (Figure C-3).

Adding the derivative of the linear plot of pressure vs. the square root of a designated rate step provides further indication of a linear flow regime of the linear flow if that derivative is flat (Figure C-4).

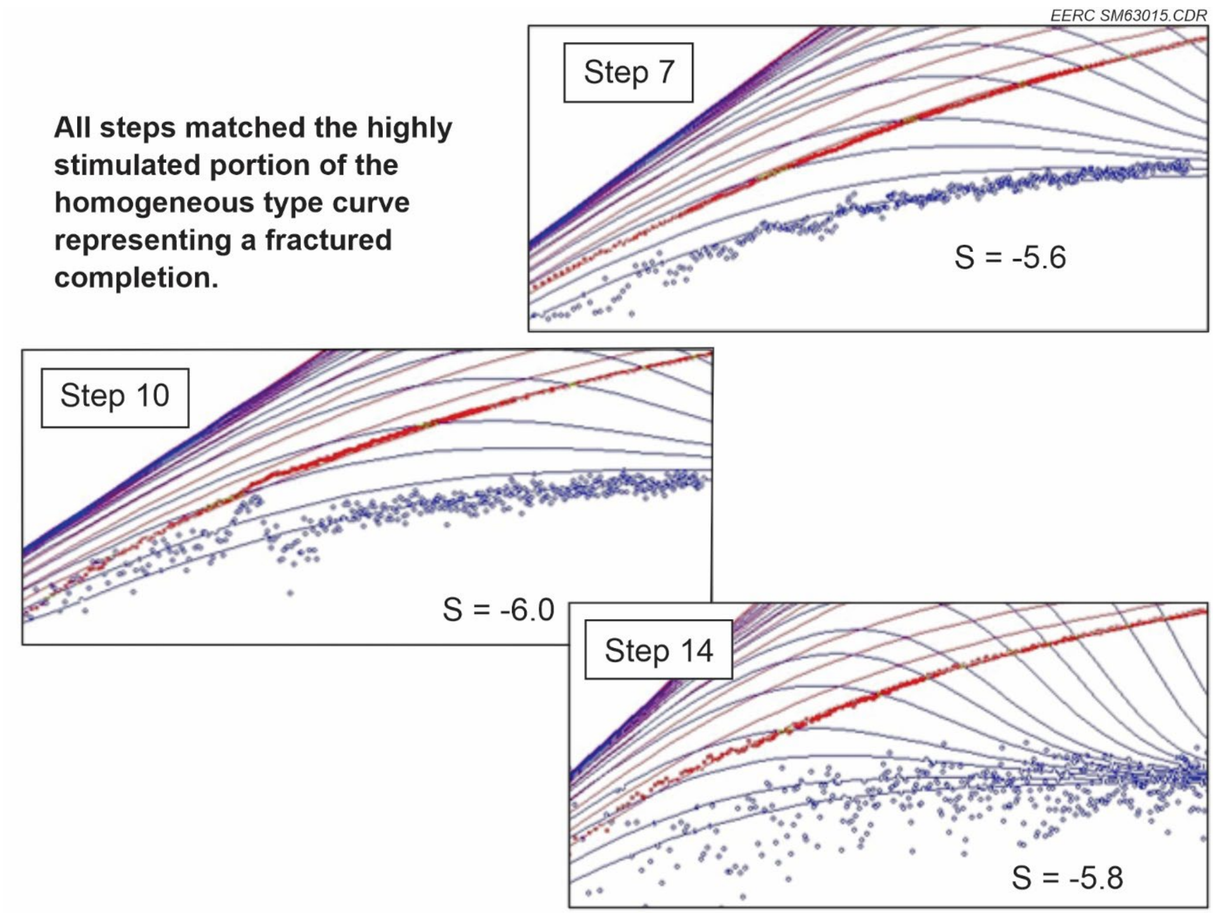

Figure C-3. Type curve matching of the pressures.

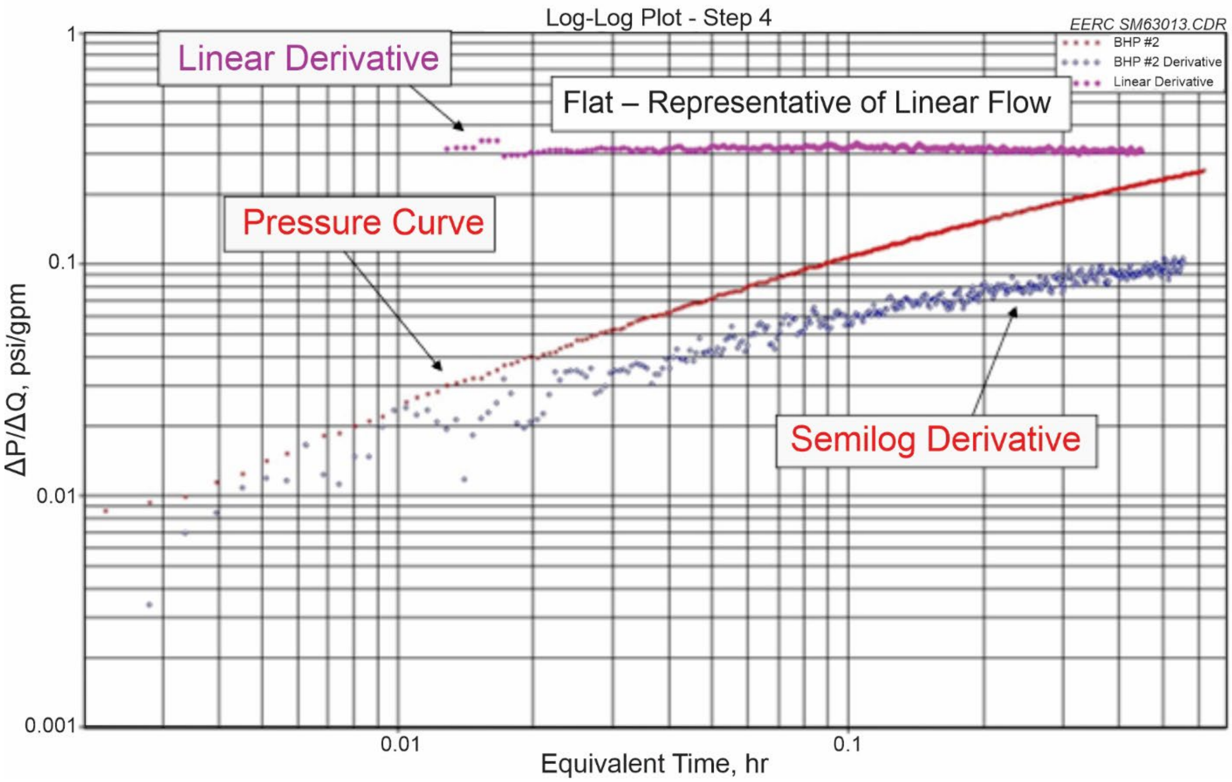

Figure C-4. Derivative of the linear plot of pressure vs. the square root of time for a designated rate step.

APPENDIX D

DETAILED PREPLANNING CONSIDERATIONS

DETAILED PREPLANNING CONSIDERATIONS

Below are considerations for both new and existing wells. Use as appropriate for the specific well:

1. Check that all regulatory procedural or analysis requirements will be satisfied. For example:
   a. The California Air Resources Board (CARB) requires bottomhole pressure (BHP) measurement at zero injection rate for at least one full time step before injecting and has specific gauge and meter calibration requirements.
   b. U.S. Environmental Protection Agency (EPA) Region 8 Step Rate Test (SRT) Guidelines require recording and reporting the instantaneous shut-in pressure (ISIP) following the last rate step. The ISIP is typically recorded but requires an isolation valve close to the wellhead and a pressure gauge with continuous recording capability.

2. Review geologic and reservoir characteristics:
   a. Identify the formation type(s) being tested, e.g., sandstone, carbonate, and dolomite.
      i. Lower permeability formations require lower injection starting rates and a longer duration rate step to reach a stabilized BHP.
      ii. Higher permeability formations may reach a stabilized pressure sooner but require higher injection rates to build pressure in the reservoir and operational limitations may not allow a formation parting pressure to be reached.
   b. Estimate a permeability range of the test formation(s) from reliable sources.
      i. Logs, cores, regional data, and offset wells.

3. Design a table of the proposed injection rates and rate step duration for calculating the minimum amount of test fluid required.
   a. The table should have at least seven injection rate steps.
      i. Injection rates must start low enough so the first three rates have pressure responses below the formation parting pressure.
         - Plot rate vs. pressure points real-time. Points need to establish a linear line on the Cartesian plot.
   b. It should be noted in the design procedure that the rate time step duration may be extended in order to reach a stabilized BHP for each rate step as shown in Table D-1, with required fluid volumes modified accordingly.
      i. If a rate time step duration is extended, all subsequent rate steps shall be conducted for the same extended period, accounting for additional time required to reach a stabilized pressure at each rate step.
   c. Literature[1] example for injection rates, rate step duration, and similar information is included in EPA Region 8 SRT Guidelines dated January 12, 1999, as shown in Table D-2.

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[1] Felsenthal, M., 1974, Step-rate tests determine safe injection pressures in floods: Oil and Gas Journal, v. 72, no. 43.

Table D-1. EPA Region 8 Step Rate Duration Recommendations

Test Design Values[1]	
Average k_{air}	Recommended minimum time for each step
5 mD	60 min
10 mD or Larger	30 min

[1] Felsenthal, M., 1974, Step-rate tests determine safe injection pressures in floods: Oil and Gas Journal, v. 72, no. 43.

d. EPA Region 6 "Watch Your Step" training course recommended starting with an injection rate below a 0.5 psi/ft gradient since regional fracture gradients were in the range of 0.7 psi/ft or starting with injection rates of 5% or 10% of the upper target injection rate, as shown in the example in Table D-2.

4. If possible, simulate the SRT using a range of permeabilities determined from regional sources (log analysis, cores, regional data, offset wells, and pretreatment calculated permeability) to provide pressure estimates based on the range of permeabilities. Use the results to determine a minimum injection rate and appropriate time step duration.

5. Test fluid: fluid quantity, accessibility, materials compatibility, and testing.
   a. Calculate the *minimum* amount of test fluid needed based on the injection rate and time step duration. Additional test fluids *must* be available (1.5 times minimum quantities), as the higher injection rate time steps will likely take longer to reach a stabilized pressure and/or additional rate steps may also be needed.
   b. Confirm lines from tanks are accurately configured so injection fluid flow during the test will not be disrupted.
   c. Confirm the test fluid is compatible with the tubulars, formation, and any previously injected fluids. Any restrictions by the metals/materials installed in Class VI wells should be identified and considered.
   d. Consider additional fluid needs for any additional testing scheduled following the SRT, for example, an extended falloff test.
   e. Take fluid samples during the test to confirm test fluid consistency.

Table D-2. EPA Region 8 Injection Rate Recommendations

Example Rule of Thumb Test Rates[1]	
Time Step Duration, hr	**Injection Rate, bpm**
Minimum of 0.5 hr from Test Design Table	5% of desired maximum test rate
–	10% of desired maximum test rate
–	20% of desired maximum test rate
–	40% of desired maximum test rate
–	60% of desired maximum test rate
–	80% of desired maximum test rate
–	100% of desired maximum test rate

[1] Felsenthal, M., 1974, Step-rate tests determine safe injection pressures in floods: Oil and Gas Journal, v. 72, no. 43.

6. Perforated interval(s):
   a. Ideally, isolate and test only one perforated interval at a time for best results and best estimate of the formation parting pressure.
      i. Problems associated with multiple perforated intervals open during the SRT, such as pressure increases during the test, may indicate a second set of perforations may start taking fluid, indicating an increase in injectivity. However, neither zone may have reached the formation parting pressure though the Cartesian plot of data may indicate otherwise. This error could result in the maximum allowable pressure being lower than the actual value. The maximum allowable pressure is designated by a percentage of the formation parting pressure, set by the regulatory agency.
   b. For new wells, isolating specific perforations to get the best SRT results and accurate formation parting pressure may be worth consideration. Additional perforations in the same interval could be added later.
   c. For existing wells, e.g., an enhanced oil recovery (EOR) well converted to Class VI:
      i. Identify perforations and any past stimulation treatments on the well.
         1. If well was fractured, determine if proppant was used. It takes less pressure to reopen an existing fracture.

7. Carbon capture and storage (CCS) projects may use stacked storage or multiple formations within a project area for CO_2 sequestration. Each formation will require its own SRT to determine the individual formation parting pressure unless communication with all applicable regulators has been confirmed otherwise.
   a. Use of regional well data from a stratigraphic well may be acceptable by the regulatory agency.
      i. It should be noted that CARB does not have Class VI permitting authority of the well but does have additional requirements for wells associated with projects seeking carbon credit incentives through the California Low Carbon Fuel Standards.

8. Wellbore schematic with complete well history (note pertinent minimum inside diameter [ID] tubular restrictions):
   Open perforations
      i. Depth, orientation, spacing, and size
      ii. Any previous treatments—stimulations, acid matrix, cleanouts, or diversions
   a. Squeezed or isolated perforations
      i. Depth, date perforated or reperforated
      ii. Date squeezed or isolated
      iii. Cement volumes
   b. Casing and liner sizes, type, weight, and depths
      i. Depth of differential valve (DV) tool and cementing record
      ii. Depth to top of cement of each cementing stage
   c. Type and depth of any exterior casing measurement devices
   d. Tubing size, depth, weight, ID, grade, and connection
      i. Design the tubing to accomplish the lowest possible friction pressure to ensure achievable injection rates by the service pump equipment

        ii. Design tubing to withstand the maximum injection pressure
    e. Depth of packer, bridge plug, cement retainer, etc., in the wellbore
        i. Setting configuration of packer—compression, neutral, and tension
        ii. Minimum ID restriction
        iii. Pressure differential rating

9. Wellbore configuration:
    a. Confirm an isolation valve is located near the wellhead so the well can be immediately shut-in and the ISIP accurately identified.
    b. Confirm a crown valve is installed to allow wireline to run in the hole with pressure gauges, one being an electronic surface readout BHP gauge.
        i. Confirm the lubricator sufficiently seals at higher pressures to prevent leakoff occurrences that could mask identifying the ISIP.
    c. Confirm annulus valve and gauge exceed anticipated maximum pressures during the test to prevent packer failure.
    d. Confirm isolation of the surface facilities from high pressure used for testing.

10. Pressure gauges:
    a. Use two BHP gauges, one an electronic continuous surface readout BHP gauge and a second memory gauge run in tandem to serve as a backup.
    b. Have a surface pressure gauge recording also available for use by personnel to confirm equipment limitations are not exceeded and to check surface pressures.
    c. All pressure gauges should be correctly date and time synchronized.
    d. BHP gauge selection should be based on the highest anticipated pressure.
        i. Select a pressure gauge range as low as possible for anticipated pressures with the accuracy and resolution to measure small changes in pressures when well is isolated to record the ISIP and pressure falloff.
        ii. Erratic or noisy pressure data will result if the pressure gauge reaches its resolution limits; having a pressure gauge with a very low percent of full-range accuracy and resolution will provide as much pressure data as possible for analysis.
            1. Higher permeability reservoirs require higher resolution to measure smaller changes in pressure (critical for falloff testing).
        iii. Confirm all pressure gauges have been recently calibrated to manufacturer specifications and calibration reports are provided.
        iv. It should be noted that CARB has specific gauge and meter calibration requirements that must be considered if CARB is applicable to the sequestration project.

11. Injection pumps and injection rate recording:
    a. Confirm injection pumps can maintain constant injection rates at the minimum and maximum designs with corresponding injection pressures.
    b. Use pumping equipment with continuous rate recording capability.
        i. Constant injection rates are required to obtain a stabilized pressure.

12. Synchronized rate and pressure readings: confirm downhole and surface recording devices have correct date and time prior to installation.

13. Confirm the well location size is sufficient to safely position test equipment, storage tanks, pumping equipment, wireline, lighting, vehicles, etc. Lighting equipment will likely be needed and should be set up prior to the test.

14. Confirm road access and surfaces are adequate to handle the equipment being brought in for the test.

15. Determine how and where recorded BHPs and injection rate data will be downloaded and monitored during the test so changes to the procedure can be made, if necessary.