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

APPLICATIONS AND VALUE OF WELL TESTING FOR CARBON DIOXIDE STORAGE SITES

Plains CO_2 Reduction (PCOR) Partnership Initiative
White Paper

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EXECUTIVE SUMMARY

In the context of understanding the deep subsurface and fluid flow within it, well testing is a comparatively old technology. To many people working toward the development of CO_2 storage sites in saline aquifers, the methods for executing a good well test may not be obvious, with the analysis techniques applied to the data even less obvious. Well testing takes time and money to perform in the field, especially during the appraisal stage of development, and clear, precise results from a well test are not guaranteed. It is easy to understand why the benefits of well testing, in both the short and long term, may be overlooked and underprioritized. However, many benefits can be gained by good well testing and data analysis; therefore, it is important that those involved in storage project development and operation understand:

- What well testing is.
- What the objectives are.
- The common types of tests that can be applied to CO_2 storage wells.
- How the tests are conducted.
- What well testing can do to explain and improve project performance.

This brief document will not make anyone an expert in well testing. It is intended to introduce the above-listed items as they apply to testing of wells in saline aquifer CO_2 storage projects. With this introduction, readers will have a better appreciation of well testing and the value it can bring to a CO_2 storage project.

APPLICATIONS AND VALUE OF WELL TESTING FOR CARBON DIOXIDE STORAGE SITES

INTRODUCTION

The Plains CO_2 Reduction (PCOR) Partnership, funded by the National Energy Technology Laboratory (NETL) of the U.S. Department of Energy (DOE), the Oil and Gas Research Program and the Lignite Research Program of the North Dakota Industrial Commission (NDIC), in combination with more than 230 public and private partners, is advancing the commercial deployment of carbon capture, utilization, and storage (CCUS) technology. The PCOR Partnership is focused on a region comprising ten U.S. states and four Canadian provinces in the upper Great Plains and northwestern regions of North America. It is led by the Energy & Environmental Research Center (EERC) of the University of North Dakota, with support from the University of Wyoming and the University of Alaska Fairbanks. The goal of this joint government–industry effort is to accelerate the commercial deployment of CCUS throughout the PCOR Partnership region.

At its core, well testing uses the production or injection of fluids in a well to create a pressure pulse that is carefully measured by pressure gauges placed in the well. The magnitude, duration, and shape of the pressure data response (aka a pressure transient) are combined with fluid rate data and other information about the fluid and rock properties to determine numerical values that describe the flow characteristics of the well/reservoir system. Unfortunately, well testing is a monitoring technology that is easily underappreciated with respect to the appraisal, development, and management of CO_2 storage projects. It is a comparatively old technology that has, perhaps, seen less recent new development compared to other disciplines, such as four-dimensional seismic, three-dimensional geologic modeling, high-resolution numerical simulation, well logging, or remote sensing techniques. All of these other techniques, beyond their scientific fundamentals and advanced computational methods, also carry strong visual presentation impacts thanks to advances in computer graphics. By comparison, well testing often creates the impression of relying on arcane two-dimensional plots and complex equations to provide estimates of fluid flow ability in the formation and parameters such as permeability (k) and formation damage value that are just two of the many inputs needed for the simulation. Formation damage value, also known as skin (S), is an alteration in near-wellbore formation properties (permeability and porosity) due to drilling, production, or injection. When one considers the receivers of the results of well testing are often not well versed in well testing methods and benefits, yet are asked to pay for the test, it is not surprising that the long-term value of well testing can be overlooked.

With the above in mind, this document attempts to provide a concise discussion of the common types of well testing that may be suitable for CO_2 storage projects, how they are executed, the results they provide, and the value those results contribute to the success of the project. This document does not attempt to provide detailed technical review of well testing theory or analysis techniques.

The benefits of a good well testing program are significant and accrue in both the short and long term of a CO_2 storage project's life. It is more than an activity mandated by regulation or a passive part of the monitoring program. As illustrated by numerous circumstances in this document, well testing is a powerful tool that can directly determine initial well and reservoir conditions, explain project performance, and guide development and operating decisions throughout the life of the project.

THE NEED FOR TESTING

First and foremost, well testing is the only method for directly determining the combined responsiveness of the injection well completion, reservoir rock, and fluid flow system. It does this by combining values for rock and fluid properties with measured changes to well pressure in response to changes in fluid injection or production condition (e.g., rate and fluid type). This responsiveness is commonly referred to as the formation permeability and skin factor. Other specifically designed tests may also determine other parameters such as formation fracturing pressure. In addition, well testing investigates a large reservoir area, which may extend hundreds or thousands of feet from the well. Accurate determination of these parameters on a reservoir scale is fundamental to understanding performance during the life of the project and the ability to accurately forecast pressure and plume development prior to injection, during the injection phase, and throughout the postinjection long-term monitoring phase of the project.

Other methods are also used to measure or estimate permeability, including core analysis, modular dynamics testing logging tool tests, and permeability logs calculated from other openhole logging measurements. These measurements are valuable, particularly because they often become available before well testing is performed. But they necessarily focus on small rock samples or small test points in the well that measure parameters only within a few inches or a few feet of reservoir rock. They do not measure bulk reservoir fluid flow performance, generally cannot be repeated over time, and none of them can determine completion skin damage.

Regulatory Requirement

A major reason for well testing is because, in many settings, the regulatory authority requires tests to be performed, often annually. For example, North Dakota requires a pressure falloff or injectivity test prior to injection operations plus a pressure falloff test at least once every 5 years. Beyond traditional well testing, there is also the regulatory requirement to demonstrate that injection operations do not exceed a specified maximum allowed injection pressure to protect the mechanical integrity of the confining overburden. That maximum pressure is most frequently determined by measuring the formation fracturing pressure during a step rate test (SRT). In practice, this requirement also implies continuous recording of pressure measurements for each injection well. In addition to ensuring that operations are performed within the requirements of the storage permit, regulators have their own need for a consistent means of understanding the reservoirs and wells under their purview. While some operators may consider this strictly a compliance issue, the accumulating track record of the performance of their asset is usually helpful when a reservoir or well performance question or problem arises. The benefits of improved reservoir and well understanding via well testing accrue to both operator and regulator.

Monitoring – Baseline and Future Conditions

Well testing data can only be collected at the time of the test and conditions need to be recorded at that time. Later tests cannot recreate the conditions of the past. While this sounds obvious, it is a fundamental principle of CO_2 storage facility monitoring programs. Baseline monitoring measurements are needed before injection operations start to establish the initial conditions of the site. This applies to many data gathering and monitoring technologies, including logs, cores, seismic, and site surface conditions. Well testing is not an exception to this principle.

Knowing the initial bottomhole pressure and fluid gradient prior to injection provides a pressure starting point as well as identifies the reservoir as normally pressured, overpressured, or underpressured. Pressure buildup is an important regulatory requirement, so knowing the starting pressure is important. Obtaining an initial shut-in temperature log is also useful for a baseline. It provides a temperature gradient and a baseline to compare future temperature logs to identify anomalies. Both reservoir pressure and temperature are helpful in estimating the initial reservoir fluid properties.

Saline aquifer systems, by definition, are 100% saturated with formation brine. As soon as CO_2 is injected into the reservoir, the reservoir is no longer a single fluid phase system. The reservoir becomes a multiphase system for which data interpretation becomes more challenging. Therefore, a preinjection test conducted with compatible water (instead of CO_2) is recommended because it is the last opportunity for a true single-phase test that can most accurately describe the initial reservoir conditions. Well testing can also help identify the reservoir flow regimes to describe the reservoir environment impacting CO_2 movement. For example, in a reservoir with a radial or linear flow regime, the presence of reservoir discontinuities such as faults, pinch-outs, or partial reservoir completion effects can be identified by well testing and analysis.

After CO_2 injection begins, all subsequent tests will necessarily be performed in a multiphase CO_2–water-saturated environment. These subsequent tests can be analyzed to describe the current conditions and compared with initial testing to evaluate changes in reservoir properties.

Changing Well and Reservoir Conditions

Reservoir and well conditions change with time. Changes can and do occur rapidly, sometimes within minutes. Those types of changes are typically immediately observed by a substantial change in injection rate or pressure. However, it is more common that change occurs slowly over a longer period of time. It is important to understand how these changes have occurred in order to efficiently respond to them. Many factors may cause loss of injectivity or an increase in injection pressure. For example, periodic versus continuous operation of the well may result in pressure changes downhole and cause formation to sluff into the wellbore, resulting in wellbore fill that isolates portions of the injection interval. Wellbore fill is typically a constant battle in unconsolidated rock. Fluid compatibility is another potential issue if CO_2 results in the formation of particulates that block pore space or forms scale in the perforations.

In this context, CO_2 storage projects can benefit from reviewing the experience of the natural gas storage industry where numerous other mechanisms that affect injection well performance were identified. Natural gas storage was already being conducted at a large scale in many areas of the United States in the 1990s, and storage operations had become routine. However, gas storage wells were observed, on average, to lose a few percent of injectivity/deliverability every year. This obliged gas storage operators to identify wells with declining performance and continually conduct remediation programs to restore their performance. Fortunately, the industry had maintained a history of annual tests of storage wells, and this provided important documentation of the breadth and progression of the issue. DOE funded research to identify the causes of performance decline (Yeager and others, 1997). The research identified several factors that contribute to performance decline in underground gas storage wells and completions:

- Hydrocarbon-based chemicals
  - Compressor oil bypass
  - Chemicals
  - Excess valve grease
  - Excess pipe dope
- Particulate matter
- Inorganic precipitates
- Migration or precipitation of formation solids or minerals
- Bacterial contamination
- Temporary injection of incompatible fluids (i.e., water or completion fluids)

Although the gas was considered “clean and dry” pipeline-quality natural gas and the operation of compressors and wells appeared to be routine, all of the above performance-degrading mechanisms affected storage well performance over time. Additionally, performance declines in underground storage operations were further aggravated as the negative effects had preferentially concentrated themselves in the best, most productive perforation intervals. High performing/ prolific perforation intervals accounted for the most throughput of the wells and were thus most affected by those negative impacts. It is noteworthy that all the performance hazards listed above may also apply to CO_2 storage injection wells.

CO_2 storage well performance can also be impacted by the following:

- Excessive increase in reservoir pressure with time
- Change in the distribution of fluids entering the perforations
- Change in wellbore hydraulics due to buildup of scale, rust, or other substances
- Processing plant liquid carryover
- Repeated dehydration and resaturation of the near wellbore area
- Contaminants carried by the injection stream

During the current early stages of commercial CO_2 storage development, it is, perhaps, easy to imagine that injection wells will simply continue operating for many years in the same way as when they were first put into service. However, CO_2 storage wells will likely not be immune to all the issues experienced by the natural gas storage industry. CO_2 storage operators need to maintain a long-term perspective (20–50 years) when considering the performance of their wells. Initial and periodically repeated well tests will be a critical activity for identifying, remediating, and maintaining long-term performance.

Well and Completion Interval Dynamics

A simple injection/falloff test can provide a large amount of useful information about the well/reservoir injection system. However, as the completion intervals become complex, the test results may also become complex and more difficult to interpret. This is because the test results are a composite reflection of all the completion intervals open to flow. For example, the response from 10 feet of perforations in a single, homogeneous 10-foot reservoir should be relatively easy to reliably interpret. On the other hand, a test of five combined perforation intervals spread among three different formations with variable properties may be very difficult to interpret, and other than an overall permeability thickness (*kh*) and overall skin value, little could be definitively said about any of the intervals. Some intervals could have a high skin value and others very little. Some intervals may be completely nonperforming. Downhole crossflow may occur between intervals with varying reservoir properties; crossflow can delay stabilization of the wellbore pressure.

Falloff test results may indicate partial penetration, suggesting wellbore fill or a dual porosity rock type. However, as noted above, the more complex the reservoir or completion or if crossflow occurs between intervals, falloff testing alone may not provide conclusive results without the use of additional tools. Uncertainty in the distribution fractions of the injected CO_2 among the perforation intervals will directly translate into uncertainty about the sizes of the plumes associated with each interval. This will be the case whether the project is injecting into multiple reservoir sections of a single formation or if it is a "stacked storage" project injecting into two or more formations within the stratigraphy at the same geographic location, separated by a combination of confining formations (above and below) with multiple injection reservoirs.

Additionally, wells with high injection or production rates, such as prolific gas production wells, may be subjected to the phenomenon of "rate dependent skin," a condition where the well injectivity index (Q/Delta P) declines even as the injection rate continues to increase. This may also selectively affect some intervals and not others. A single rate injection/falloff test cannot identify this condition. Conversely, injection wells operating near their maximum rate/pressure capacity may cause poor or damaged intervals to open up or develop a flow path through a damaged zone without initiating any hydraulic fracture, thereby actually improving the well's performance. Therefore, it is important to realize that well testing is not a "one-size-fits-all" process and that good test design and execution is critical.

Testing with CO_2 Versus Water

In an appraisal well setting, there are important differences between testing with water and testing with CO_2 as the injection fluid. Water has well-known, stable properties; it is an incompressible fluid, the native fluid of the saline storage formation, and inexpensive. In some cases, water testing can be performed with only surface pressure and temperature recording.

Testing with CO_2 is challenging and requires the use of special pumping and tankage equipment. Fluid properties are much more variable compared to water, the fluid may even change phase during testing operations, and it is more compressible than water. CO_2 is not the native fluid in the reservoir, and unlike water, the saturation of CO_2 will be rapidly changing during the test, introducing relative permeability effects. CO_2 is typically expensive to purchase commercially, whereas water is available at little cost. Because of the low viscosity and density associated with CO_2, it is not a medium that is well suited for performing an SRT. Therefore, clear, limited test objectives and careful design consideration are needed before attempting a CO_2 injection test in an appraisal well.

Once a storage project is in progress and the near wellbore area has a significant buildup of CO_2 saturation, there is a reversal of roles, and water becomes undesirable for testing. The use of water for performing injectivity tests requires pumps and storage tanks to be brought to the well location, whereas CO_2 is readily available from the industrial source and can be delivered at pressure. It is important to note that the rate and pressure flexibility of the permanently installed CO_2 equipment may be somewhat limited. Injection of water will resaturate the injection zone, complicating the pressure response and temporarily inhibiting the well's CO_2 injectivity when storage activities resume. Whereas if CO_2 is used, the formation already has a CO_2 saturation that may not change much during the test, and the incremental cost of test execution versus continuing operations should be small.

Lastly, an adverse reaction to any introduced water can occur, causing swelling of formation clay minerals or other forms of damage. A water–formation compatibility test is recommended to ensure the water used for testing does not harm the formation.

TYPES OF TESTS

Several types of tests are described below. The type of test selected depends upon the data gathering and analysis objectives to be achieved, regulatory requirements, reservoir conditions, existing well equipment, and availability and cost of temporary test equipment.

Injection/Falloff Test

Primary objective: determine the static bottomhole pressure, reservoir permeability, and completion skin. Secondary objective: determine radius of test investigation.

Injection/falloff tests are the simplest types of tests and are the most commonly used test methods in CO_2 storage well evaluations. Saline aquifer reservoir pressures are typically at or near the hydrostatic gradient pressure (also known as normally pressured). In this condition, the well may not naturally flow at an adequate rate to conduct a reliable pressure drawdown/buildup test. Therefore, injection testing methods are preferred. The tests involve an injection period and a shut-in period. Ideally the goal is for each test period to reach "radial flow," where the test is measuring flow conditions in the reservoir and is not influenced by the wellbore or near-wellbore conditions. During the injection period, water is injected at a constant rate for several hours. Rate changes create pressure transients, so maintaining a constant rate or having continuous rate measurements to account for any rate changes is preferred. Water injection is set at a constant rate for a specified length of time, usually several hours, to ensure the injection rate and pressure approach stable conditions. The well is then quickly shut in at the wellhead and the pressure falloff, or decline response, is monitored. As a guideline, pressure falloff periods should be, at a minimum, twice the length of injection periods to ensure that the pressure response data are representative of radial, steady-state flow conditions in the reservoir and are not influenced by the wellbore or near-wellbore conditions. The lower the permeability of the formation, the slower a reservoir reestablishes pressure stability; therefore, the required duration of the pressure falloff is longer, relative to the length of the injection time. Generally, the more time that can be allocated to the pressure falloff period, the better to further investigate the reservoir properties (permeability, radius of investigation, and reservoir boundaries). The radius of investigation into the reservoir is a function of the duration of the injection period and not a function of the injection rate. Nevertheless, the injection rate should be sufficient to create a magnitude of pressure buildup that can be measured during the falloff period and therefore impacted by the transmissibility of the test reservoir. For example, pressure dissipates quicker in higher permeability reservoirs, so a higher injection rate is required to obtain a measurable pressure to measure during the pressure falloff period. It is advisable to select an injection rate that is representative of the expected operating rate of the well, as long as this rate does not exceed 90% of the formation fracture pressure or establishes a pressure differential that is so low that the falloff data become difficult to interpret.

If offset wells are present and completed and operating in the same formation, the injection rate into the offset well should remain constant before and during the injection/falloff test of the test well. Rate changes create pressure transients in the reservoir and offset well rate changes may be observed in the test well and impact the analysis. Confirm that the rate into offset wells will not be impacted when the test well is shut in. If so, the offset well rate data should also be provided so the rate change can be accounted for when analyzing data from the test well.

Step Rate Test

Primary objective: determine reservoir fracturing pressure and maximum safe injection rate. Secondary objective: determine the amount of system pressure drop due to tubing friction effects.

An SRT is normally performed during the appraisal phase of development and is exclusively performed with water. The main objective of an SRT is to determine the fracturing pressure of the reservoir test interval in a controlled and limited environment. The pressure at which a formation fractures is an important parameter for storage development planning since fracturing of the storage formation, particularly the overlying confining layer, should be avoided. Typically, regulators will base a CO_2 storage facility's maximum allowable injection pressure on the fracturing pressure, which is usually determined by an SRT or other methods.

An SRT is performed as a sequence of equally timed injection periods with increasing constant injection rates, or steps. With each step, the injection pressure rises until fracturing pressure is reached; at which time, the pressure no longer increases or increases only marginally even as the injection rate for each step continues to increase. Regulatory agencies may have a recommended SRT procedure that should be considered in the test design. Typically, a minimum of five or six injection rates are used to create an analysis plot. The ending injection pressure at each rate verses the injection rate is plotted to estimate the fracture pressure. A slope change is observed in points before and after fracture pressure has been reached. Once reaching fracturing pressure is confirmed, the test is ended by an abrupt shutdown of pumping and close observation of the initial pressure falloff data. This practice should, within a few seconds, provide an initial shut-in pressure reading for the formation without the masking effects of tubing friction pressure losses in the system. Additionally, the declining shut-in pressure data should be evaluated to confirm fracture closure pressure, thus giving a second indication of the formation fracturing behavior.

SRTs can be challenging to cleanly execute in the field. Real-time surface readout of bottomhole pressure data may not always be available, making the test more difficult to confidently perform. The SRT is frequently the first attempt to establish injection into new perforations in a new well, and the well response can be unpredictable, especially at the start of the test. Injection rates or pressure may be higher or lower than anticipated. Because injection fluid will be moving past the recording gauge, pressure data are often noisy, especially at the higher injection rates. Suitability or capability of the test equipment that was brought on-site can be affected by unpredictable pressures and volumes during testing. In turn, the availability and volume of test water brought on-site can delay testing. If the injection rates needed during test execution are higher than initially anticipated, the injection pumps may be of inadequate capacity to pump the higher rates. The well tubing may be of inadequate capacity to accept the higher rates without excessive friction pressure losses. Additionally, the fracturing response of the formation may or may not be clearly observed or occur at a pressure different than anticipated, causing uncertainty about when to end the test. Any or all of these conditions may be encountered during the SRT, creating execution uncertainty and requiring real-time decision-making. Therefore, good execution of an SRT demands well-considered procedure and equipment selection, contingency planning, and experienced personnel on-site.

Interference Test

Primary objective: establish pressure communication between wells. Secondary objectives: determine interwell reservoir permeability and verifiable radius of test investigation.

Interference testing requires the simultaneous use of at least two wells. Injection occurs in one well, and pressure observations are made in the other well(s). The objectives of this test are to directly measure the degree of communication between the wells and calculate the average permeability between them. If communication is not established, then the operation has learned something about formation discontinuities, such as faults or stratigraphic inhomogeneity of the test interval. If more than two wells are used for the test, then directionality of the permeability field (an important influence on the subsequent shape of a CO_2 plume) can be inferred. Interference testing can take a considerable amount of time to produce a solid response at the observation well, depending primarily on the distance between the wells and the permeability. A high injection rate may be required to generate a significant pressure differential in the injection well so that the pressure change can be clearly seen at the observation well. A downhole gauge is usually used in the observation well as the pressure response is often small. A high-resolution gauge (e.g., quartz gauge) is needed to record the pressure response and time lag in both the observer and injection well. The time needed for the radius of investigation in the reservoir to reach the observation well is a function of the duration of the injection period and not a function of the injection rate. However, the magnitude of the observed response is a function of injection rate, distance, and reservoir properties. A larger magnitude of the observed response will make the test easier to interpret. Avoid using a 12-hour test period to help confirm that a small pressure change seen in the observation well is not a tidal effect. Repeatability of the pressure response is recommended and confirms pressure responses seen at the observation well are due to the test well. Adding a second pulse into the procedure is recommended, if possible.

It is critical that the pressure gauge in the monitor well is time synchronized with activities at the injection well. The time lag between when the injection begins and ends relative to the time the pressure pulse is observed in the monitoring well is another indication of the permeability of the reservoir between the wells. Record keeping of the actual time when injection begins and ends can then be compared to time from the pressure gauges. Real-time events also need to be associated with the time increment for the pressure gauge readings.

Isochronal Test

Primary objective: determine advanced well performance characteristics.

Isochronal testing of gas wells and gas storage wells is perhaps less common than in previous years but was once widely required by regulatory authorities. Isochronal testing can be time consuming but generates a wealth of well and reservoir performance knowledge, such as production or injectivity index, rate-sensitive *kh* response, non-Darcy flow behavior, rate-dependent skin, maximum flow potential, and tubing friction pressure losses/optimal tubing size design requirements. Annual or repeated isochronal tests can closely track changes in well/reservoir performance. Although not currently performed on CO_2 injection wells, expanded development of CO_2 storage and the proliferation of CO_2 disposal wells may provide justification for a comeback in its usage. An isochronal test is performed by injecting fluid at four different injection rates of equal duration and interspersed with four pressure falloff periods that are also of equal duration. For example, injection periods at 10%, 25%, 50%, and 75% of estimated maximum injection rate would occur, alternating with monitored shut-in periods to observe pressure falloff. As noted above, isochronal tests can take a long time to execute. Therefore, the modified isochronal test procedure was developed by eliminating the first three falloff periods and only monitoring the final falloff period. This shortens the length of the test and may not severely compromise test results.

Temperature Surveys

> Primary objective: determine initial reservoir temperature and temperature gradients. Secondary objective: determine magnitude of wellbore and near-wellbore cooling caused by injection of large quantities of cooler fluid and the time required to achieve thermal stability.

Temperature gauges are routinely included alongside any use of pressure gauges and may be mandatory by regulation. Temperature logs can also be run independently to identify or track temperature anomalies in wellbores or run along with other types of logs.

Temperature is a necessary input to well test analysis, particularly for determination of fluid properties that are temperature sensitive. When well tests are performed with water, temperature variations are not critical unless the injection water is in danger of freezing. However, when the testing medium is CO_2, tracking fluid temperature is important as CO_2 physical properties are more sensitive to changes in temperature than water. Injection of cold CO_2, which warms up while traveling down the tubing, can cause unexpected variations in fluid density, fluid phase, and wellhead pressure. If temperature gradients in a well are high enough, CO_2 density may actually decline with depth. Seasonal temperature variation of the injection stream can be expected to cause seasonal variation in wellhead injection pressure. Continuous injection of cold fluid does create a region of suppressed reservoir temperature around the wellbore, which may affect injection performance. Therefore, bottomhole temperature monitoring of CO_2 injection wells is needed, and analysis of temperature may be critical to understanding well performance issues.

A baseline temperature survey is important to run the length of the entire wellbore. Though not a well test procedure, future temperature decay surveys can then be compared to the baseline to detect temperature anomalies, possibly from a casing leak or from fluids migrating into formations overlying the designated injection interval during the life of the well. Temperature decay surveys can indicate which perforations are taking injection based on the temperature change across the perforated interval.

Injection Profiles and Pulsed-Neutron Surveys

> Primary objective: determine the distribution of injected fluid along the perforated intervals and the CO_2 saturation within those intervals. Secondary objective: identify migration of CO_2 to nonperforated intervals.

Strictly speaking, injection profiles (spinner surveys or production logs) and pulsed-neutron surveys are logging procedures and not well testing procedures. However, the use of both devices is often combined with well testing operations and, when used together, can be very enlightening.

Pulsed-neutron surveys measure the fluid saturation profile in the well. In a saline aquifer, the baseline survey should naturally indicate 100% water saturation. Repeated surveys after the start of injection will show progressive buildup of CO_2 saturation along the reservoir, at the perforations, perhaps over the full thickness of the injection interval and, importantly, along the outside of the casing if there is any CO_2 outside of the injection intervals that may have migrated vertically. It is important that pulsed-neutron logs be run to a shallow depth to confirm no CO_2 is present along the wellbore. Though the detectable range of saturation profile and saturation percentage depends on the reservoir porosity ranges and logging speed, they are still very important information for ongoing estimations of the size and CO_2 saturation of the developing plume and add valuable input to reservoir simulation efforts.

Injection profiling may consist of a spinner survey, radioactive tracer velocity shots, or radioactive slug chases or combination of surveys. During injection, injection profiles make detailed flow measurements along the perforation intervals to determine the fraction of flow that is entering the formation on a nearly foot-by-foot basis. Such information may not be necessary if the well has a single, 10-foot interval of perforations. But for wells with multiple sets of perforations into multiple sand bodies, and perhaps multiple formations, an understanding of where the injected fluid is going is critical information. Nonperforming injection intervals can be identified through injection profiles. Additionally, well test estimates of permeability and skin can be refined and distributed among the multiple zones. When added to simulation efforts, injection profiles add valuable data to aid in estimating the size of the plume for each interval and help determine the size of the project footprint.

TEST METHODS

Common Assumptions for Testing

Well tests, regardless of their design or intent, share a few common assumptions that help ensure the test data collected are as reliable and easy to interpret as possible:

- The reservoir is homogeneous.

- Bottomhole pressure and temperature gauges are superior to surface data, although surface data at the tubing and casing annulus should also be collected. Instantaneous surface readout of bottomhole data is preferred over memory gauges.

- Always use two pressure gauges, so if one fails, there is a backup. Collect and report temperature data with the pressure data.

- Injection testing typically involves high-pressure pumping at the surface. Appropriate safety equipment, safety meetings, and safe operating procedures should be a requirement to protect all personnel and equipment from injury or damage. Proper planning is needed prior to conducting a test. Planning should provide adequate fluids be available for storage and injecting, any offset wells have been considered, and shut-in valves are operational and located as close to the wellhead as practical.

- Injection rates should be held constant, except for a short period of time where pumping equipment is adjusted to achieve the desired initial rate. Pump pressure should be allowed to fluctuate naturally. After a few minutes, the injection rate should not change and maintained constant for the specific test period duration.

- Transition from injection periods to shut-in periods (and shut-in to injection) should be done as quickly and sharply as practically possible.

- Pressure falloff periods should be, at a minimum, twice the length of injection periods. The lower the permeability, the slower a reservoir reestablishes pressure stability, and falloff periods need to be longer than 2× the injection period.

- The radius of investigation for an injection test is a function of, among other variables, the length of the test period. It is not a function of the injection rate.

- Field preparation time, duration of injection and falloff periods, plus well rig operations can add up to a considerable amount of total time. The required time will be reflected in testing costs as well as demands on operational equipment, services, supplies, personnel, and supervision.

Test Planning Checklist

Wellbore Configuration: depths, tubular dimensions, well configuration, obstructions, fill depth, proper crown valve is installed, allowing pressure gauges to be run in the well days before testing begins.

Injectivity Period: constant rate as possible, record rates, sufficient test duration, adequate injection fluid and storage capacity, injection fluid compatibility with reservoir rocks and reservoir fluids, pumps capable for anticipated rates and pressures.

Falloff Period: measure time and pressure data, sufficient test duration.

Instrumentation: Use two gauges, check gauge resolution and accuracy to confirm gauge is capable of measuring anticipated pressure changes.

General Information: reservoir thickness, porosity, fluid viscosity.

Appraisal Wells Versus Monitoring Wells Versus Injection Wells

While testing fundamentals may not change among different types of wells, testing objectives and procedures can be different, depending on the well type.

An appraisal well or stratigraphic well is often the first well drilled at a potential storage site. Maximum data collection followed by plug and abandonment may be the priorities. In this case, testing may be performed using temporary equipment of a retrievable packer on drill pipe or drill stem testing (DST) equipment. If there are multiple intervals of interest, a sequence of independent interval tests can be performed, starting with the deepest interval and plugging back the well before beginning work on the next interval higher up. Typically, an SRT followed by an injection/falloff test is performed for each interval. The well may be temporarily or permanently abandoned after testing is complete. The process is time- and labor-intensive. It is also costly, particularly if the drilling rig remains over the well. A more economical approach of releasing the drilling rig and using a smaller workover rig to perform the testing is common. Nevertheless, a multizone testing program is expensive and time-saving efficiencies are always in competition with the preferred length of the test program.

Appraisal wells may be designed with the intent of later use as a monitoring or injection well, but this demands additional planning, cost, and certainty at a very early point in the project's life. A well drilled specifically for monitoring purposes may be drilled with smaller diameters. Federal, state, and provincial standards may be followed in designing the monitoring wells. Perforations may be of limited length and in only one interval to minimize uncertainty of the pressure response in the well. In this case, a single injection/falloff test, and possibly an interference test with other well(s), can be performed to better understand the reservoir permeability and its distribution. An SRT may not be needed or desired in a monitoring well.

CO_2 injection wells must be designed and constructed to federal, state, and provincial standards. Injection wells must also be constructed to meet continuous monitoring requirements and repeated periodic well tests. Depending on project design and performance needs, an injector may have only a single set of perforations or it may have multiple sets of perforations spanning hundreds of feet in the wellbore. Therefore, initial testing programs can be quite variable. They can be performed similarly to what was described for appraisal wells with temporary plug backs, or they can first run the permanent completion tubing and packer in the hole and then perforate and test. The former process may gather more data but exposes the well to more operational risk. The later process has the advantage of baseline testing in a well with its permanent operational configuration but at the expense of testing flexibility. Only a single test can be performed that may have to cover multiple perforated intervals. This opens the possibility for uncertainty in test results. An SRT followed by an injection/falloff or interference test is a common industry approach for CO_2 well test procedures. If multiple intervals are perforated, the inclusion of a baseline spinner survey to identify the relative contribution of each interval is recommended.

Pressure Measurement

Memory gauges, surface readout, and external casing gauges are several options to consider when selecting pressure gauges for well testing and monitoring. Bottomhole pressure and temperature gauges are always preferable to surface-only recorders to maximize data accuracy. This is especially true when conducting an SRT where large pressure losses from tubing friction can significantly mask the formation response. Memory gauges are most common for individual well tests. Memory gauges run on batteries and are programmable for settings of sample speed, sample start time, or end time. Data are stored in the device, and when the gauge is retrieved, the data are downloaded in a spreadsheet-readable format. This type of gauge is reliable, and its use is offered as a moderately priced field service. The main disadvantages to memory gauges are that the user does not know if the gauges have failed during the test period, resulting in no data collection and that there is no real-time response, so the operator cannot see the pressure response during the test to help with decision-making. Also, because of battery operation and data storage capacity limits, memory gauges are not desirable for long-term or permanent downhole monitoring solutions. The gauges need to be periodically retrieved from the well using surface retrieval equipment, and normal well operation is stopped while this process is ongoing. Memory gauges are flexible in their deployment. They can be run into a well on wireline and suspended at any depth; they can be hung in an appropriate landing nipple and the wireline removed from the well during testing. They can be placed in a custom carrier sub, attached to the work string, and run in the hole with the tubing. They can also be used in surface applications by attaching them to the wellhead to record wellhead or annulus pressure.

Surface readout, or real-time, gauges overcome the disadvantages of memory gauges by providing continuous data to the surface during the test. Gauge failures are immediately detected and the instantaneous downhole response information is helpful in making decisions during test execution, especially for an SRT in determining the formation fracture pressure. The gauges are connected to an electric line to provide power and data transmission. The electric line can reside inside the well tubing or tied to the outside of the tubing with a special connector (e.g., gauge mandrel) to the gauge sensors, which must be able to read fluid pressure inside the well. Surface readout gauges can be used for longer-term monitoring needs. Surface readout gauges are a more expensive solution than memory gauges and are more complex to install, but project circumstances may dictate their necessity.

External casing gauges are intended for permanent monitoring installations and are perhaps best suited for use in observation wells. These devices are mounted outside the well production casing along with a data transmission cable or fiber-optic line and are run in the hole with the casing and then cemented in place. These devices allow for permanent continuous pressure and temperature reporting and multiple sensors can be placed at any depth above the perforations for monitoring of strata above the injection intervals. Recent developments make it possible for sensors to also be placed close to or below perforated intervals with a low risk of perforating charges severing the communication line, although such a procedure may put added cost and other limitations on the perforating operation. However, long-term, high-quality performance of these devices is not guaranteed. They can sustain damage during installation; fail before the expected end of their useful life; or provide a signal that is masked, attenuated, or otherwise affected because of the cement surrounding the sensor. Baseline comparisons of external gauges with traditional downhole gauges to verify performance is recommended. If an external casing gauge fails, there are no repair options, and an alternative monitoring method must be devised.

Always use two gauges for testing so a backup exists in case one fails. Reservoir environment will influence the accuracy and resolution of the pressure gauge needed for testing. Confirm the pressure gauges have been recently calibrated and capable of measuring anticipated pressure changes. For example, tighter formations will experience larger pressure increases or drops whereas high-permeability rock may only have a few psi of pressure change and require a gauge with much higher pressure gauge accuracy and resolution to measure the pressure falloff.

Flow Rate Measurement

Reliable well testing requires accurate measurement of flow rates. Three methods measure flow rate: pump stroke counters on the pump trucks, the in-line flowmeter near the wellhead, and the water tank gauges. At least two of the three should be employed during an injection test.

A calculation based on the pump stroke rate is a common method to determine injection rate. However, the pumps may not be 100% efficient or the calculation may be otherwise inaccurate.

In-line flow meters, normally provided by the pumping service company, may be more accurate. However, they are subjected to hard use in the field, and their maintenance and accuracy may be difficult to verify. Gauging the water tanks with a measuring device can provide a cross check to ensure the other methods are reasonable, but the job requires diligence and good note keeping by the assigned person. No one method alone is precise enough to provide robust flow rate measurement data.

Annulus Pressure Measurement and Monitoring

Monitoring of annulus pressure during an injection test has two primary functions: to provide evidence of hydraulic pressure support of the injection string, which may experience high pressure on the inside, and to detect tubing/packer leaks. A static pressure test of the tubing/casing annulus is a routine part of pretest preparations and can alert operators to tubing/packer leaks. After a successful pressure test, an acceptable operating pressure range for the annulus during the test is determined. The maximum allowed pressure may be set as slightly below the tested pressure and a minimum allowed pressure may be set at a few hundred psi to prevent vacuum conditions from occurring. The annulus pressure should be maintained constant to minimize casing ballooning. During the test, the annulus pressure gauge is monitored for unusual changes. If necessary, the bleed-off valve can be opened if the pressure approaches its allowed maximum. Annulus pressure can decline if cold, low-pressure fluid is pumped down the tubing, so the ability is needed to temporarily pump small volumes of compatible fluid into the annulus to maintain a suitable pressure. If extra fluid is added to the annulus because of cold operating conditions, extra vigilance is needed to avoid unwanted pressure increase when the well eventually warms up to its normal thermal gradient. Use of a memory gauge attached to the annulus can be helpful by creating an additional stream of data for comparison, particularly if an unusual event occurs or if the well is equipped with external casing gauges set above the packer depth.

Flowback Monitoring

At the conclusion of an injection or pressure test, the residual wellhead pressure may be released by opening the well to flow. Assuming the reservoir is normally pressured and a hydrostatic fluid column in the tubing exists, the residual pressure should dissipate quickly with minimum test water flowing back. However, this is not always the case, and flowback can be vigorous and last for hours. If vigorous flowback occurs, estimations of flowback rate, pressure, and duration are appropriate. Wastewater tanks should be periodically gauged to estimate the produced fluid volume. Check the flowback water for signs of produced formation sand or fine particles. If solids are present in the water, collection of a sample for possible future analysis is appropriate. If the water appears clean during flowback, it may be returned to the storage tanks as refill for the next test, saving considerable water-hauling costs.

Test Preparation, Execution, and Posttest

During the appraisal and construction phases of a CO_2 storage project, it is possible that the project operator may not have much experience with the design, execution, and interpretation of a well test. Under those circumstances, it is highly recommended that the operator engage the services of a reputable consulting or engineering firm familiar with well testing practices, field operations, and data analysis methods. The selected consulting or engineering firm may serve as a general contractor (GC) for the well test work.

For the test preparation, the GC needs adequate time to determine the operator's needs, review existing data, design a draft test procedure, contact suppliers and service providers for preliminary scheduling and costs, and reconcile those variables with the operator. Local market conditions for field services and prices can vary substantially. Details of the services to be provided, particularly equipment capabilities, piping layout and connections, and data measurement and recording, need to be clearly determined and understood among the service provider's personnel to avoid delays during the hours of rigging up before the start of the test. If there is a drilling or workover rig at the wellsite, the test's timing may depend on the rig's activity schedule (e.g., day operation or 24-hour operation). Coordination of the test preparation phase should be in the hands of experienced personnel. The entire process of preparing for the test may take several weeks. The GC needs to understand the parameters that need to be recorded to meet regulations and to have a conclusive test result. The final product of this phase will be the final test procedure and may include the list of selected service providers and estimated cost.

During the test execution, which may require several hours to several days, an engineer should be on-site to verify that the equipment on-site is suitable for the execution of the test, all monitoring tools are working, all personnel are available, and the test procedure is followed. Small variations to the procedure are a common occurrence, particularly during an SRT. Major departures to the test procedure are rare and should be agreed upon in advance by all parties involved. In general, the final responsibility for the execution of the test lies with the operator or the operator's specific designee. Engineers or consultants on-site during test execution perform an advisory role for the operator and should provide information and opinions to assist the operator with their decision-making.

During the posttest period, the data generated by several service providers should be collected and transmitted to the operator in a complete and timely fashion. The pumping service, wireline and wireline tool service, pressure/flow recording service, and site consultants may all have important data to provide to the operator. There should be a clear understanding in advance of the chain of custody of the data, the method of transfer, and the degree of confidentiality with which it shall be handled.

After the data are collected, analysis of the data may be performed by one or several parties, as determined by the operator. Analysis of data requires special software to build the necessary plots needed for analysis. Interpretation of data requires some pressure transient knowledge to interpret. If expertise is not available in-house, use of an outside consultant is recommended. Second opinions of analysis results may be needed or required by regulation.

SUMMARY

Well testing has played a vital role in understanding the performance of wells and reservoirs for many decades. The advent of commercial CO_2 storage projects opens the era of a new class of wells and reservoir performance evaluations, but the importance of well testing is not diminished for these projects. Arguably, well testing is as important as ever, especially for those projects that will be closely examined and continuously monitored by regulators, investors, academics, and the public.

The experience of the natural gas storage industry in the 1990s is instructive for the new CO_2 storage industry. The gas storage industry learned that well performance may not remain constant over many years of service and that a long list of hazards can impact continuing performance. Observation and diagnosis of these and other hazards are greatly aided by well tests performed as baseline measurements and subsequent tests. CO_2 storage operators should anticipate that maintaining long-term performance of their wells will likely require a program of continued monitoring, testing, problem diagnosis, and remediation.

Several types of tests can be used in CO_2 storage wells. The most common types of tests include injection/falloff tests to determine permeability and skin factor, SRTs to determine formation fracturing pressure, and interference tests to estimate reservoir continuity between two wells.

Testing of a new well determines parameters of the initial permeability of the bulk reservoir rock in its native saturation condition plus the degree of formation skin damage that may have been caused by completion or other operations. An initial test before the start of CO_2 injection is the only opportunity to obtain this baseline data. All tests made after injection starts will be complicated by the presence of both water and CO_2 in the reservoir. In the case of wells with multiple perforation intervals, a well test conducted with the help of other tools, such as pulsed-neutron, injection profiling, or temperature decay log, can determine the profile of flow into the various perforated intervals. This is critical information for describing the relative sizes of the CO_2 plumes that will develop in the reservoir(s) and the overall project footprint size.

Successful test execution and good data collection require appropriate test design, attention to execution details, and good field reporting to ensure that the various data sources and events are time-sequenced and understood to make the data analysis as easy and as accurate as possible.

REFERENCES

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