Making Climate Change History™

Attachment D: Pre-Operational Testing Program

Claimed as PBI [redacted]

Carbon America

(40 CFR 146.82(a))

Revision	Date	Notes	Written By	Approved By
A	03/12/2024	Issued for Approval		R. Keeling

Claimed as PBI [redacted]

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1. Facility Information

- Facility Name: Claimed as PBI [redacted]
- Well Name:
- Facility Contact:
- Well Location: Claimed as PBI [redacted]

2. Introduction

The testing activities described in this attachment are restricted to the pre-injection phase. Testing and monitoring activities during the injection and post-injection phases are described in **Attachment F: Testing and Monitoring Plan**, along with other non-well related pre-injection baseline activities such as geochemical monitoring. The pre-operational testing program's purpose is to ensure conformance with testing standards listed in 40 CFR 146.87 and construction standards listed in 40 CFR 146.86.

This pre-operational testing program includes various activities to be conducted during the drilling and completion of the Claimed as PBI [redacted] stratigraphic test well, and is further discussed in Section 3. The pre-injection testing plan for the Claimed as PBI [redacted] is discussed in Section 4. Pre-operational testing activities include logging, coring, formation fluid sampling, and other relevant procedures. Logging is used to characterize static reservoir properties (i.e., porosity, permeability) and fluid properties (i.e., saturation). Coring is used to calibrate logging data with physical measurements, and to provide physical core specimens to laboratories where more rigorous testing can occur. Additionally, formation pressure testing determines current reservoir pressure and lends insight into injection and confining zone fracture gradients. Claimed as PBI [redacted] is used to measure formation pressure in permeable zones and to recover fluid samples for lab testing to confirm injection zone brine composition, total dissolved solids (TDS), and salinity values.

Following completion of drilling and testing activities at Claimed as PBI [redacted] a comprehensive report detailing the results will be prepared. This report will be submitted to the U.S. Environmental Protection Agency (EPA) before the commencement of carbon dioxide (CO_2) injection.

Claimed as PBI [redacted] will notify the Underground Injection Control (UIC) Program Director prior to each phase of the pre-operational testing plan to allow for observation. The schedule for these activities will be shared at least 30 days before the first test. Once all pre-operational testing is completed, Claimed as PBI [redacted] will deliver a comprehensive report containing interpretations of each test outcome.

Methods for tests will be consistent with EPA guidance (U.S. EPA, 2013) and testing methods listed in **Attachment F: Testing and Monitoring Plan**.

3. Pre-Injection Testing Plan – Injection Well

The following tests and logs will be conducted during drilling and after casing installation in accordance with the testing required under 40 CFR 146.87(a), (b), (c), and (d).

3.1 Deviation Checks

During the drilling of Claimed as PBI [redacted] deviation measurements will be conducted at a minimum of approximately every Claimed as PBI [redacted] feet (ft). A measurement while drilling (MWD) tool, used to take well path surveys, will be attached to the bottomhole assembly (BHA) just above the drill bit to collect these measurements. Inclination (deviation) and azimuth (direction) will be transmitted to the surface in real-time. A copy of the deviation survey will be provided to the UIC Program Director once performed and analyzed.

3.2 Tests and Logs

3.2.a Wireline Logs to be Performed During Drilling

A tabulated summary of logging and testing activities to be performed is provided in Appendix D-1. Logging and testing results will be provided to the UIC Program Director once performed and analyzed. The following wireline logs will be performed during the drilling of [redacted]

- Surface hole section [redacted] open hole section)

[redacted]

- Injection hole section [redacted] open hole section)

[redacted]

3.2.b To Be Performed During and After Casing Installation

The following wireline logs will be performed in the surface and injection sections of [redacted] after casing installation. Injection section cased hole logs are expected to occur upon installation of the tubing and packer. Results from these tests and logs will be provided to the UIC Program Director once performed and analyzed.

[redacted]

3.2.c Coring Program

The acquisition of [redacted] of whole core is planned in [redacted] totaling approximately [redacted] of whole core collected. Whole core will be acquired to provide fluid and rock property measurements, for well log calibration, and to provide an overall understanding of containment. A detailed core analysis program will be performed in [redacted] and is summarized below. A tabulated summary of the core analysis program to be performed is provided in Appendix D-2. The following whole core segments are planned for collection:

[redacted]

The following is a summary of core analysis to be conducted on each core segment:

[redacted]

- Special core analysis (SCAL) will include:

[redacted]

[redacted]

[redacted]

3.2.d Additional Injection Well Testing

The following additional pre-operational testing will occur when the tubing and packer are installed in [redacted] A summary of the tests and logs will be provided to the UIC Program Director.

- Injection hole section [redacted] cased hole section)

[redacted]

3.2.e Demonstration of Mechanical Integrity

Table D-1 summarizes the mechanical integrity tests (MITs), PFOTs, and injectivity tests to be performed prior to injection.

Table D-1. Pre-Operational Testing Schedule

Class VI Rule Citation	Rule Description	Test Description	Program Period
[redacted]			

Notes: (1) To be conducted if primary external MIT method, temperature logging, cannot be completed.

[redacted] will notify the UIC Program Director at least 30 days prior to conducting the tests and will provide a detailed description of the testing procedure. Notice and the opportunity to witness these tests/logs shall be provided to the UIC Program Director at least 48 hours in advance of a given test/log.

4. Pre-Injection Testing Plan – Deep Monitoring Well [redacted]

The following tests and logs will be conducted in [redacted] during drilling and after casing installation in accordance with EPA guidance (U.S. EPA, 2013).

4.1 Deviation Checks

During the drilling of [redacted] deviation measurements will be conducted at a minimum of approximately every [redacted] An MWD tool, used to take well path surveys, will be attached to the BHA just above the drill bit to collect these measurements. Inclination (deviation) and azimuth (direction) data will be transmitted to the surface in real-time.

4.2 Tests and Logs

4.2.a To Be Performed During Drilling

[redacted]

4.2.b To Be Performed During and After Casing Installation

The following wireline logs will be performed in the surface and long string sections of [redacted] after casing installation. The [redacted] proposed wellbore diagram (WBD) is displayed in Appendix F-3 of **Attachment F: Testing and Monitoring Plan**.

[redacted]

4.2.c Demonstration of Mechanical Integrity

Table D-2 summarizes the MITs to be performed in the deep monitoring well, [redacted] after installation and prior to commencing CO_2 injection operations.

Table D-2. Mechanical Integrity Tests

Test Name	Test Description	Program Period
[redacted]		

Notice and the opportunity to witness all testing and logging shall be provided to the UIC Program Director at least 48 hours in advance of a given test/log.

5. Annulus Pressure Test Procedures for Injection Well

Initial mechanical integrity verification will be demonstrated through the implementation of a SAPT. EPA Region 8 SAPT guidance (Appendix D-3) will be followed as procedure. The SAPT will be executed after the installation of the tubing, packer, downhole equipment, and the wellhead. Before wellhead installation, the annulus will be filled with fluid, as summarized in **Attachment F: Testing and Monitoring Plan**. Subsequently, the SAPT will be conducted by pressurizing the annulus once the well reaches thermal equilibrium. Once this equilibrium is achieved, [redacted] as detailed in Appendix D-3. A calibrated digital gauge will be affixed to the annulus, and the pressure will be systematically monitored for a minimum of 30 minutes. Throughout this duration, casing and tubing pressures will be observed at 5-minute intervals. Upon completion of the test, the casing pressure will be returned to the normal operational level. The test will be deemed successful if the pressure deviation is less than 5% of the initial value. In addition to the standard internal integrity monitoring, [redacted] Once injection begins, continuous monitoring of injection pressure, annular pressure, and annular fluid volumes will be maintained to ensure ongoing well integrity and the maintenance of appropriate annular pressure.

6. Annulus Pressure Test Procedures for Monitoring Well [redacted]

SAPT procedures for [redacted] will be conducted in accordance with SAPT procedures listed in Section 5.

7. Pressure Fall-Off Test Procedures

After tubing and the packer are installed in [redacted] the well will be perforated and an SRT and PFOT will occur. To acquire all necessary data including a pre-injection fracture pressure, a testing procedure incorporating an injectivity test, in this case a step-rate test, will be prescribed, followed by the recording of pressure fall-off data (to assess reservoir parameters such as permeability thickness, transmissibility, skin factor, and well flowing and static pressures). Additionally, if necessary, evidence can be gathered to analyze injectivity degradation with additional tests of injection and pressure falloff.

- [redacted]

Claimed as PBI [redacted]

8. References

U.S. Environmental Protection Agency (U.S. EPA), 2013. Underground Injection Control (UIC) Program Class Six Well Testing and Monitoring Guidance. Office of Water (4606M) EPA 816-R-13-001, March 2013.

Figure

Claimed as PBI

[redacted]

Claimed as PBI

[redacted]

Appendix D-1
Logging and Testing Activities

Claimed as PBI
[redacted]

Claimed as PBI

[redacted]

Appendix D-2
Core Analysis Program

Claimed as PBI
[redacted]

Claimed as PBI

[redacted]

Appendix D-3

Region 8 Standard Annulus Pressure Test (SAPT) Guidance

Claimed as PBI

[redacted]

SUBJECT: **GROUND WATER SECTION GUIDANCE NO. 39**
Pressure testing injection wells for Part I (Internal) Mechanical Integrity

FROM: Tom Pike, Chief
UIC Direct Implementation Section

TO: All Section Staff
Montana Operations Office

Introduction

The Underground Injection Control (UIC) regulations require that an injection well have mechanical integrity at all times (40 CFR 144.28 (f)(2) and 40 CFR 144.51 (q)(1)). A well has mechanical integrity (40 CFR 146.8) if:

(1) There is no significant leak in the tubing, casing or packer; and

(2) there is no significant fluid movement into an underground source of drinking water (USDW) through vertical channels adjacent to the injection wellbore.

Definition: **Mechanical Integrity Pressure Test for Part I.** A pressure test used to determine the integrity of all the downhole components of an injection well, usually tubing, casing and packer. It is also used to test tubing cemented in the hole by using a tubing plug or retrievable packer.

This guidance addresses making a determination of Part I of Mechanical Integrity (no leaks in the tubing, casing or packer). The Region's policy is: 1) to determine if there are significant leaks in the tubing, casing or packer; 2) to assure that the casing can withstand pressure similar to that which would be applied if the tubing or packer fails; 3) to make the Region's test procedure consistent with the procedures utilized by other Region 8 Primacy programs; and 4) to provide a procedure which can be easily administered and is applicable to all Class I and II wells. Although there are several methods allowed for determining mechanical integrity, the principal method involves running a pressure test of the tubing/casing annulus. Region 8 procedures for running a pressure test is intended to aid UIC field inspectors who witness pressure tests for the purpose of demonstrating that a well has Part I of Mechanical Integrity. The guidance is also intended as a means of informing operators of the procedures required for conducting the test in the absence of an EPA inspector.

Pressure Test Description

Test Frequency

Pressure tests must be run at least once every five years. If for any reason the tubing/packer is pulled, the injection well is required to pass another mechanical integrity test of the tubing casing and packer prior to recommencing injection regardless of when the last test was conducted. The well's test cycle would then start from the date of the new test if the well passes the test and documentation is adequate. Tests may be required on a more frequent basis depending on the nature of the injectate and the construction of the well (see Section guidance on MITs for wells with cemented tubing and regulations for Class I wells). The EPA Region 8 UIC program must be notified of the workover and the proposed date of the pressure test. Tests run by operators in the absence of an EPA inspector must be conducted according to these procedures and recorded on either the MIT Form (attachment) or an equivalent record that contains the same information, and the pressure recording chart documenting the actual annulus test pressures must be submitted with the form.

Region 8 criteria for well testing frequency is as follows:

1. **Class I hazardous waste injection wells**; initially [40 CFR 146.68(d)(1)] and annually thereafter;

2. **Class I non-hazardous waste injection wells**; initially and every two (2) years thereafter, except for old permits (such as the disposal wells at carbon dioxide extraction plants which require a test at least every five years);

3. **Class II wells with tubing, casing and packer**; initially and at least every five (5) years thereafter;

4. **Class II wells with tubing cemented in the hole**; initially and every one (1) or two (2) years thereafter depending on well specific conditions (See Region 8 UIC Section Guidance #36);

5. **Class II wells which have been temporarily abandoned** (TA'd) must be pressure tested after being shut-in for two years; and

6. **Class III uranium extraction wells**; initially.

<u>Test Pressure</u>

To assure that the test pressure will detect significant leaks and that the casing is subjected to pressure similar to that which would be applied if the tubing or packer fails, the tubing/casing annulus should be **<u>tested at a pressure equal to the maximum allowed injection pressure or 1000 psig whichever is less.</u>** **<u>The annular test pressure must, however, have a difference of at least 200 psig either greater or less than the injection tubing pressure.</u>** **<u>Wells which inject at pressures of less than 300 psig must test at a minimum pressure of 300 psig, and the pressure difference between the annulus and the injection tubing must be at least 200 psi.</u>**

<u>Test Criteria</u>

1. The duration of the pressure test is 30 minutes.

2. Both the <u>annulus and tubing pressures should be monitored and recorded every five (5) minutes.</u>

3. If there is a pressure change of 10 percent or more from the initial test pressure during the 30 minute duration, the well has failed to demonstrate mechanical integrity and should be shut-in until it is repaired or plugged.

4. A pressure change of 10 percent or more is considered significant. If there is no significant pressure change in 30 minutes from the time that the pressure source is disconnected from the annulus, the test may be completed as passed.

Recordkeeping and Reporting

The test results must be recorded on the attached form. The annulus pressure should be recorded at five (5) minute intervals. Tests run by operators in the absence of an EPA inspector must be conducted according to these procedures and recorded on the attached form or an equivalent form and a pressure recording chart documenting the actual annulus test pressures must be attached to the submittal. The tubing pressure at the beginning and end of each test must be recorded. The volume of the annulus fluid bled back at the surface after the test should be measured and recorded on the form. This can be done by bleeding the annulus pressure off and discharging the associated fluid into a five gallon container. The volume information can be used to verify the approximate location of the packer.

Procedures for Pressure Test

1. Scheduling the test should be done at least two (2) weeks in advance.

2. Information on the well completion (location of the packer, location of perforations, previous cement work on the casing, size of casing and tubing, etc.) and the results of the previous MIT test should be reviewed by the field inspector in advance of the test. Regional UIC Guidance #35 should also be reviewed. Information relating to the previous MIT and any well workovers should be reviewed and taken into the field for verification purposes.

3. All Class I wells and Class II SWD wells should be shut-in prior to the test. A 12 to 24-hour shut-in is preferable to assure that the temperature of the fluid in the wellbore is stable.

4. Class II enhanced recovery wells may be operating during the test, but it is recommended that the well be shut-in if possible.

5. The operator should fill the casing/tubing annulus with inhibited fluid at least 24 hours in advance, if possible. Filling the annulus should be undertaken through one valve with the second valve open to allow air to escape. After the operator has filled the annulus, a check should be made to assure that the annulus will remain full. If the annulus can not maintain a full column of fluid, the operator should notify the Director and begin a rework. The operator should measure and report the volume of fluid added to the annulus. If not already the case, the casing/tubing valves should be closed, at least, 24 hours prior to the pressure test.

Following steps are at the well:

6. Read tubing pressure and record on the form. If the well is shut-in, the reported information on the actual maximum operating pressure should be used to determine test pressures.

7. Read pressure on the casing/tubing annulus and record value on the form. If there is pressure on the annulus, it should be bled off prior to the test. If the pressure will not bleed-off, the guidance on well failures (Region VIII UIC Section Guidance #35) should be followed.

8. Ask the operator for the date of the last workover and the volume of fluid added to the annulus prior to this test and record information on the form.

9. Hook-up well to pressure source and apply pressure until test value is reached.

10. Immediately disconnect pressure source and start test time (If there has been a significant drop in pressure during the process of disconnection, the test may have to be restarted). The pressure gages used to monitor injection tubing pressure and annulus pressure should have a pressure range which will allow the test pressure to be near the mid-range of the gage. Additionally, the gage must be of sufficient accuracy and scale to allow an accurate reading of a 10 percent change to be read. For instance, a test pressure of 600 psi should be monitored with a 0 to 1000 psi gage. The scale should be incremented in 20 psi increments.

11. Record tubing and annulus pressure values every five (5) minutes.

12. At the end of the test, record the final tubing pressure.

13. If the test fails, check the valves, bull plugs and casing head close up for possible leaks. The well should be retested.

14. If the second test indicates a well failure, the Region should be informed of the failure within 24 hours by the operator, and the well should be shut-in within 48 hours per Headquarters guidance #76. A follow-up letter should be prepared by the operator which outlines the cause of the MIT failure and proposes a potential course of action. This report should be submitted to EPA within five days.

15. Bleed off well into a bucket, if possible, to obtain a volume estimate. This should be compared to the calculated value obtained using the casing/tubing annulus volume and fluid compressibility values.

16. Return to office and prepare follow-up.

Alternative Test Option

While it is expected that the test procedure outlined above will be applicable to most wells, the potential does exist that unique circumstances may exist for a given well that precludes or makes unsafe the application of this test procedure. In the event that these **exceptional or extraordinary** conditions are encountered, the operator has the option to propose an alternative test or monitoring procedures. The request must be submitted by the operator in writing and must be approved in writing by the UIC-Implementation Section Chief or equivalent level of management.

Mechanical Integrity Test
Tubing/Casing Annulus Pressure Test

U.S. Environmental Protection Agency
Underground Injection Control Program
999 18th Street, Suite 200 Denver, CO 80202-2466

EPA Witness: ______________________ Date: ____/____/____
Test conducted by: ______________________
Others present: ______________________

Well Name: ______________________	Type: ER SWD	**Status: AC TA UC**
Field: ______________________		
Location: ________ Sec: ____ T ____ N / S R ____ E / W	County: ______________	State: ______
Operator: ______________________		
Last MIT: ____/____/____	**Maximum Allowable Pressure:** ______________	**PSIG**

Regularly scheduled test? [ ] Yes [ ] No
Initial test for permit? [ ] Yes [ ] No
Test after well rework? [ ] Yes [ ] No

Well injecting during test? If Yes, rate: ______________ bpd
Pre-test annulus pressure: ______________ psig

MIT DATA TABLE	***Test #1***	***Test #2***	***Test #3***
TUBING		***PRESSURE RECORD***	
Initial Pressure	psig	psig	psig
End of test pressure	psig	psig	psig
CASING / TUBING ANNULUS		***PRESSURE RECORD***	
0 minutes	psig	psig	psig
5 minutes	psig	psig	psig
10 minutes	psig	psig	psig
15 minutes	psig	psig	psig
20 minutes	psig	psig	psig
25 minutes	psig	psig	psig
30 minutes	psig	psig	psig
_______ minutes	psig	psig	psig
_______ minutes	psig	psig	psig
RESULT	***[ ] Pass [ ]Fail***	***[ ] Pass [ ]Fail***	***[ ] Pass [ ]Fail***

Does the annulus pressure build back up after the test ? If Yes, ______________ psig.

MECHANICAL INTEGRITY PRESSURE TEST

Additional comments for mechanical integrity pressure test, such as volume of fluid added to annulus and bled back at end of test, reason for failing test (casing head leak, tubing leak, other), etc.:

Signature of Witness: ______________________________

OFFICE USE ONLY - COMPLIANCE FOLLOWUP

Staff ______________________________ Date: ____/____/

Do you agree with the reported test results? [ ] YES [ ] NO

If not, why?

Possible violation identified? [ ] YES [ ] NO

If YES, what

If YES - followup initiated? [ ] YES

[ ] NO - why not?

[ ] Data Entry [ ] Compliance Staff [ ] 2nd Data Entry [ ] Hardcopy Filing

Appendix D-4
Region 8 Step Rate Test (SRT) Guidance

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
999 18TH STREET- SUITE 200
DENVER, CO 80202-2466
Phone 800-227-8917
http://www.epa.gov/region08

STEP-RATE TEST PROCEDURE

Approved January 12, 1999

PURPOSE:

The purpose of this document is to provide a guideline for the acquisition of a Step Rate Test (SRT). Test results may be used by the Region 8 Underground Injection Control (UIC) offices to determine a Maximum Allowable Injection Pressure (MAIP) to provide for the protection of the underground sources of drinking water at an injection well having mechanical integrity. These procedures are consistent with acceptable oilfield practices.

Step rate test results must be documented with service company or other appropriate (acceptable) records and/or charts, and the test should be witnessed by an EPA inspector. Attached is a form that you may copy and use to record data from your test. Arrangements for witnessing the test may be made by contacting the Region 8 UIC offices using the EPA toll-free number 1-800-227-8917.

RECOMMENDED TEST PROCEDURES:

1) **Shut in long the well long enough prior to testing** such that the bottom hole pressures approximate shut-in formation pressures. If the shut-in well flows to the surface, the wellhead injection string should be equipped with a gauge, and the static surface pressure read and recorded.

2) **Read and record the elapsed time and pressure values for each time and rate-step. Each rate-step should last exactly as long as the preceding rate-step**. If stabilized pressure values are not obtained within the rate-steps suggested below, the test results may be considered as inconclusive. A series of successively higher injection rates should be determined using guidelines below

Formation Permeability (md)	*Total time per rate-step (min)*
# 5 md	60 min
∃ 10 md	30 min

3) Suggested injection rates:

5% B
10% E
20% E
40% X …of the anticipated maximum injection rate.
60% E
80% E
100% Δ

4) **Control injection rates** with a constant flow regulator that has been tested prior to use. A throttling device is not considered sufficient.

5) **Measure flow rates** with a calibrated turbine flowmeter.

6) **Record injection rates** using a chart recorder or a strip chart.

7) **Measure pressures** with a down hole pressure bomb. If a surface gauge is used, the test pressures must be corrected for the estimated friction loss at each particular flow rate.

8) Measure <u>and record</u> injection pressures with a gauge or recorder (for immediate test results). **Record each time step and corresponding pressure.**

9) If the formation fracture pressure has definitively been exceeded, as evidenced by at least two injection rate-pressure combinations greater than the breakdown pressure, the injection pump can be stopped, and the line valve closed and pressure allowed to bleed-off into the injection zone.

10) **Record the ISIP.** There will occur a significant instantaneous pressure drop (Instantaneous Shut-in Pressure or ISIP), after which the pressure values will level out. This ISIP value must be read and recorded. The ISIP obtained in this manner may be considered to be the minimum pressure required to hold open a fracture in this formation at this well. In the event that the breakdown pressure was not obtained at the maximum test injection pressure utilized, the test results may indicate that the formation is accepting fluids without fracturing.

11) Once the ISIP is obtained, the SRT is concluded.

12) **Plot the injection rates and the corresponding stabilized pressure values.** These are graphically represented as a constant slope straight line to a point at which the formation fracture, or breakdown, pressure is exceeded. The slope of this subsequent straight line should be less than that of the before-fracture straight line (see example).

STEP RATE TEST DATA

Well: ______________________ ***Date:*** ____________ ***Operator:*** ________________________________.

STEP #1 Test Rate (***5%*** *of maximum rate*) ______________ (*bbl/min*)

| **Time** (*min*) : _________ _________ _________ _________ _________ _________ _______ |
| **Pressure** (psi): ________ _________ _________ _________ _________ _________ _____ __ |

STEP #2 Test Rate (***10%*** *of maximum rate*) ______________ (*bbl/min*)

| **Time** (*min*) : _________ _________ _________ _________ _________ _________ _______ |
| **Pressure** (psi): ________ _________ _________ _________ _________ _________ _____ __ |

STEP #3 Test Rate (***20%*** *of maximum rate*) ______________ (*bbl/min*)

| **Time** (*min*) : _________ _________ _________ _________ _________ _________ _______ |
| **Pressure** (psi): ________ _________ _________ _________ _________ _________ _____ __ |

STEP #4 Test Rate (***40%*** *of maximum rate*) ______________ (*bbl/min*)

| **Time** (*min*) : _________ _________ _________ _________ _________ _________ _______ |
| **Pressure** (psi): ________ _________ _________ _________ _________ _________ _____ __ |

STEP #5 Test Rate (***60%*** *of maximum rate*) ______________ (*bbl/min*)

| **Time** (*min*) : _________ _________ _________ _________ _________ _________ _______ |
| **Pressure** (psi): ________ _________ _________ _________ _________ _________ _____ __ |

STEP #6 Test Rate (***80%*** *of maximum rate*) ______________ (*bbl/min*)

| **Time** (*min*) : _________ _________ _________ _________ _________ _________ _______ |
| **Pressure** (psi): ________ _________ _________ _________ _________ _________ _____ __ |

STEP #7 Test Rate (***100%*** *of maximum rate*) ______________ (*bbl/min*)

| **Time** (*min*) : _________ _________ _________ _________ _________ _________ _______ |
| **Pressure** (psi): ________ _________ _________ _________ _________ _________ _____ __ |

ISIP : _________________ (psi)

Notes:

Test Run / Witnessed By: ____.

EXAMPLE

STEP RATE TEST

The following is an example of a Step-Rate Test with tabular and graphic results. The step-rate test data and graphic results of the test are on the following pages.

The operator of Anywell #1 set up a SRT for the following conditions:

A) Maximum anticipated injection rate was **4** bbl/min.

B) Following the recommended test procedures, the operator planned on using these rates for the test:

1) **5**% of 4 bbl/min = **0.2** bbl/min

2) **10**% of 4 bbl/min = **0.4** bbl/min

3) **20**% of 4 bbl/min = **0.8** bbl/min

4) **40**% of 4 bbl/min = **1.6** bbl/min

5) **60**% of 4 bbl/min = **2.4** bbl/min

6) **80**% of 4 bbl/min = **3.2** bbl/min

7) **100**% of 4 bbl/min = **4.0** bbl/min

C) The formation permeability is estimated as **100** md, therefore each step will last for 30 minutes.

For this test, the injection formation broke down at approximately 1200 psi, and the ISIP was listed as 1000 psi.

Because the injection formation will part at 1000 psi, the maximum injection pressure will be held to the ISIP. If the formation had not broken down at 1200 psi, the maximum allowable injection pressure would be the maximum pressure obtained during the test.

EXAMPLE

STEP RATE TEST DATA

Well: Anywell #1 ***Date:*** April 15, 2000 ***Operator:*** Lotsa Oil .

STEP #1 Test Rate (***5%* of maximum rate**) .2 (***bbl/min***)

Time (*min*) :	0	5	10	15	20	25	30
Pressure (psi):	0	90	95	98	99	100	100

STEP #2 Test Rate (***10%* of maximum rate**) .4 (***bbl/min***)

Time (*min*) :	0	5	10	15	20	25	30
Pressure (psi):	80	170	185	195	199	201	202

STEP #3 Test Rate (***20%* of maximum rate**) .8 (***bbl/min***)

Time (*min*) :	0	5	10	15	20	25	30
Pressure (psi):	190	320	385	392	398	403	404

STEP #4 Test Rate (***40%* of maximum rate**) 1.6 (***bbl/min***)

Time (*min*) :	0	5	10	15	20	25	30
Pressure (psi):	380	700	790	792	798	803	805

STEP #5 Test Rate (***60%* of maximum rate**) 2.4 (***bbl/min***)

Time (*min*) :	0	5	10	15	20	25	30
Pressure (psi):	751	990	1032	1093	1155	1188	1202

STEP #6 Test Rate (***80%* of maximum rate**) 3.2 (***bbl/min***)

Time (*min*) :	0	5	10	15	20	25	30
Pressure (psi):	1133	1250	1326	1370	1397	1399	1403

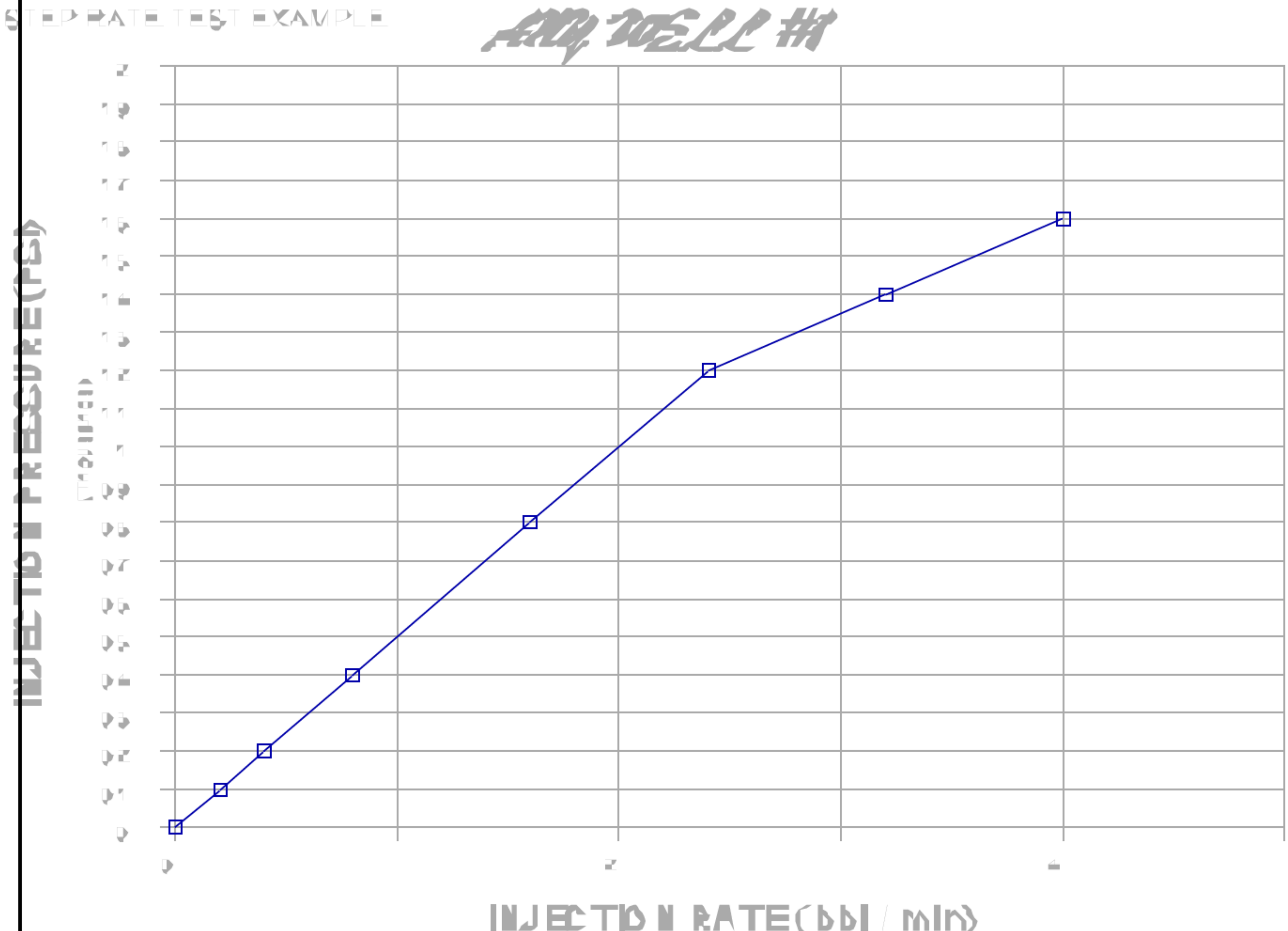
STEP #7 Test Rate (***100%* of maximum rate**) 4.0 (***bbl/min***)

Time (*min*) :	0	5	10	15	20	25	30
Pressure (psi):	1350	1448	1503	1530	1571	1590	1600

ISIP : 1000 (psi)

Notes:

Test Run / Witnessed By: Alan Testor .


STEP RATE TEST EXAMPLE
INJECTION PRESSURE (PSI)
INJECTION RATE (bbl / min)

Appendix D-5
Region 6 Pressure Fall-Off Test (PFOT) Guidance

Claimed as PBI

[redacted]

EPA Region 6

UIC PRESSURE FALLOFF TESTING GUIDELINE

Third Revision

August 8, 2002

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APPENDIX

EPA Region 6

UIC PRESSURE FALLOFF TESTING GUIDELINE

Third Revision
August 8, 2002

1.0 Background

The Hazardous and Solid Waste Amendments of 1984 to the Resource Conservation and Recovery Act mandated prohibitions on the land disposal of hazardous waste. These prohibitions are known as the land disposal restrictions and EPA promulgated regulations to implement these requirements for injection wells on July 26, 1988. The land disposal restrictions for injection wells are codified in 40 CFR Part 148. In addition to specifying the effective dates of the restrictions on injection of specific hazardous wastes, these regulations outline the requirements for obtaining an exemption to the restrictions.

Facilities that have received an exemption to the land disposal restrictions under 40 CFR Part 148 have demonstrated that, to a reasonable degree of certainty, there will be no migration of hazardous constituents from the injection zone for as long as the waste remains hazardous. As part of this approval, facilities are required by Region 6 to meet approval conditions including annual monitoring in accordance with 40 CFR 148.20(d)(2).

Region 6 has adopted the 40 CFR 146.68(e)(1) requirements for monitoring Class 1 hazardous waste disposal wells. Under 40 CFR 146.68(e)(1), operators are required annually to monitor the pressure buildup in the injection zone, including at a minimum, a shut down of the well for a time sufficient to conduct a valid observation of the pressure falloff curve.

A falloff test is a pressure transient test that consists of shutting in an injection well and measuring the pressure falloff. The falloff period is a replay of the injection preceding it; consequently, it is impacted by the magnitude, length, and rate fluctuations of the injection period. Falloff testing analysis provides transmissibility, skin factor, and well flowing and static pressures. All of these parameters are critical for evaluation of technical adequacy of no migration demonstrations and UIC permits.

2.0 Purpose of Guideline

This guideline has been developed by the Region 6 office of the Evironmental Protection Agency (EPA) to assist operators in planning and conducting the falloff test and preparing the annual monitoring report. Typically, this report should consist of a falloff test and a comparison of the reservoir parameters derived from the test with those of the petition demonstration. Falloff tests provide reservoir pressure data and characterize both the injection interval reservoir and the completion condition of the injection well. Both the reservoir parameters and pressure data are necessary for no migration and UIC permit demonstrations. Additionally, a valid falloff test is a requirement of a no migration petition condition as well as a monitoring requirement under 40 CFR Part 146 for all Class I injection wells. For no migration purposes, the annual report is viewed not as an enforcement tool, but as an annual confirmation that the petition demonstration continues to be valid.

The main body of this guideline contains general information that pertains to the majority of the facilities impacted. Because each site is unique, one guideline cannot be written to encompass all situations. A more detailed discussion of many topics and equations is included in the attached Appendix.

The ultimate responsibility of conducting a valid falloff test is the task of the operator. Operators should QA/QC the pressure data and test results to confirm that the results "make sense" prior to submission of the report to the EPA for review.

3.0 Timing of Falloff Tests and Report Submission

Falloff tests must be conducted within one year from the date of the original petition approval and annually thereafter. The time interval for each test should not be less than 9 months or greater than 15 months from the previous test. This will ensure that the tests will be performed at relatively even intervals throughout the duration of the petition approval period. Operators can, at their discretion, plan these tests to coincide with the performance of their annual state MIT requirements as long as the time requirements are met. The falloff testing report should be submitted no later than 60 days following the test. Failure to submit a falloff test report will be considered a violation of the applicable petition condition and may result in an enforcement action. Any exceptions should be approved by EPA prior to conducting the test.

4.0 Falloff Test Report Requirements

In general, the report to EPA should provide general information and an overview of the falloff test, an analysis of the pressure data obtained during the test, a summary of the test results, and a comparison of the results with the parameters used in the no migration demonstration. Some of the following operator and well data will not change so once acquired, it can be copied and submitted with each annual report. The falloff test report should include the following information:

1. Company name and address
2. Test well name and location
3. The name and phone number of the facility contact person. The contractor contact may be included if approved by the facility in addition to a facility contact person.

4. A photocopy of an openhole log (SP or Gamma Ray) through the injection interval illustrating the type of formation and thickness of the injection interval. The entire log is not necessary.
5. Well schematic showing the current wellbore configuration and completion information:
   - Wellbore radius
   - Completed interval depths
   - Type of completion (perforated, screen and gravel packed, openhole)
6. Depth of fill depth and date tagged.
7. Offset well information:
   - Distance between the test well and offset well(s) completed in the same interval or involved in an interference test
   - Simple illustration of locations of the injection and offset wells
8. Chronological listing of daily testing activities.
9. Electronic submission of the raw data (time, pressure, and temperature) from <u>all</u> pressure gauges utilized on a floppy disk or CD-ROM. A READ.ME file or the disk label should list all files included and any necessary explanations of the data. A separate file containing any edited data used in the analysis can be submitted as an additional file.
10. Tabular summary of the injection rate or rates preceding the falloff test. At a minimum, rate information for 48 hours prior to the falloff or for a time equal to twice the time of the falloff test is recommended. If the rates varied and the rate information is greater than 10 entries, the rate data should be submitted electronically as well as a hard copy of the rates for the report. Including a rate vs time plot is also a good way to illustrate the magnitude and number of rate changes prior to the falloff test.
11. Rate information from any offset wells completed in the same interval. At a minimum, the injection rate data for the 48 hours preceding the falloff test should be included in a tabular and electronic format. Adding a rate vs time plot is also helpful to illustrate the rate changes.
12. Hard copy of the time and pressure data analyzed in the report.
13. Pressure gauge information: (See Appendix, page A-1 for more information on pressure gauges)
   - List all the gauges utilized to test the well
   - Depth of each gauge
   - Manufacturer and type of gauge. Include the full range of the gauge.
   - Resolution and accuracy of the gauge as a % of full range.
   - Calibration certificate and manufacturer's recommended frequency of calibration
14. General test information:
   - Date of the test
   - Time synchronization: A specific time and date should be synchronized to an equivalent time in each pressure file submitted. Time synchronization should also be provided for the rate(s) of the test well and any offset wells.
   - Location of the shut-in valve (e.g., note if at the wellhead or number of feet from the wellhead)

15. Reservoir parameters (determination):
    - C Formation fluid viscosity, $:_f$ cp (direct measurement or correlation)
    - C Porosity, N fraction (well log correlation or core data)
    - C Total compressibility, c_t psi^{-1} (correlations, core measurement, or well test)
    - C Formation volume factor, rvb/stb (correlations, usually assumed 1 for water)
    - C Initial formation reservoir pressure - See Appendix, page A-1
    - C Date reservoir pressure was last stabilized (injection history)
    - C Justified interval thickness, h ft - See Appendix, page A-15
16. Waste plume:
    - C Cumulative injection volume into the completed interval
    - C Calculated radial distance to the waste front, r_{waste} ft
    - C Average historical waste fluid viscosity, if used in the analysis, $:_{waste}$ cp
17. Injection period:
    - C Time of injection period
    - C Type of test fluid
    - C Type of pump used for the test (e.g., plant or pump truck)
    - C Type of rate meter used
    - C Final injection pressure and temperature
18. Falloff period:
    - C Total shut-in time, expressed in real time and)t, elapsed time
    - C Final shut-in pressure and temperature
    - C Time well went on vacuum, if applicable
19. Pressure gradient:
    - C Gradient stops - for depth correction
20. Calculated test data: include all equations used and the parameter values assigned for each variable within the report
    - C Radius of investigation, r_i ft
    - C Slope or slopes from the semilog plot
    - C Transmissibility, kh/: md-ft/cp
    - C Permeability (range based on values of h)
    - C Calculation of skin, s
    - C Calculation of skin pressure drop, $)P_{skin}$
    - C Discussion and justification of any reservoir or outer boundary models used to simulate the test
    - C Explanation for any pressure or temperature anomaly if observed
21. Graphs:
    - C Cartesian plot: pressure and temperature vs. time
    - C Log-log diagnostic plot: pressure and semilog derivative curves. Radial flow regime should be identified on the plot
    - C Semilog and expanded semilog plots: radial flow regime indicated and the semilog straight line drawn
    - C Injection rate(s) vs time: test well and offset wells (not a circular or strip chart)
22. A comparison of all parameters with those used in the petition demonstration, including references where the parameters can be found in the petition.

23. A copy of the latest radioactive tracer run to fulfill the annual mechanical integrity testing requirement for the State and a brief discussion of the results.
24. Compliance with any unusual petition approval conditions such as the submission of an annual flow profile survey. These additional conditions may be addressed either in the annual falloff testing report or in an accompanying document.

5.0 Planning

The radial flow portion of the test is the basis for all pressure transient calculations. Therefore the injectivity and falloff portions of the test should be designed not only to reach radial flow, but to sustain a time frame sufficient for analysis of the radial flow period.

General Operational Concerns
Successful well testing involves the consideration of many factors, most of which are within the operator's control. Some considerations in the planning of a test include:

- C Adequate storage for the waste should be ensured for the duration of the test
- C Offset wells completed in the same formation as the test well should be shut-in, or at a minimum, provisions should be made to maintain a constant injection rate prior to and during the test
- C Install a crown valve on the well prior to starting the test so the well does not have to be shut-in to install a pressure gauge
- C The location of the shut-in valve on the well should be at or near the wellhead to minimize the wellbore storage period
- C The condition of the well, junk in the hole, wellbore fill or the degree of wellbore damage (as measured by skin) may impact the length of time the well must be shut-in for a valid falloff test. This is especially critical for wells completed in relatively low transmissibility reservoirs or wells that have large skin factors.
- C Cleaning out the well and acidizing may reduce the wellbore storage period and therefore the shut-in time of the well
- C Accurate recordkeeping of injection rates is critical including a mechanism to synchronize times reported for injection rate and pressure data. The elapsed time format usually reported for pressure data does not allow an easy synchronization with real time rate information. Time synchronization of the data is especially critical when the analysis includes the consideration of injection from more than one well.
- C Any unorthodox testing procedure, or any testing of a well with known or anticipated problems, should be discussed with EPA staff prior to performing the test.
- C Other pressure transient tests may be used in conjunction or in place of a falloff test in some situations. For example, if surface pressure measurements must be used because of a corrosive wastestream and the well will go on vacuum following shut-in, a multi-rate test may be used so that a positive surface pressure is maintained at the well.

- If more than one well is completed into the same reservoir, operators are encouraged to send at least two pulses to the test well by way of rate changes in the offset well following the falloff test. These pulses will demonstrate communication between the wells and, if maintained for sufficient duration, they can be analyzed as an interference test to obtain interwell reservoir parameters.

<u>Site Specific Pretest Planning</u>

1. Determine the time needed to reach radial flow during the injectivity and falloff portions of the test:
   - Review previous welltests, if available
   - Simulate the test using measured or estimated reservoir and well completion parameters
   - Calculate the time to the beginning of radial flow using the empirically-based equations provided in the Appendix. The equations are different for the injectivity and falloff portions of the test with the skin factor influencing the falloff more than the injection period. (See Appendix, page A-4 for equations)
   - Allow adequate time beyond the beginning of radial flow to observe radial flow so that a well developed semilog straight line occurs. A good rule of thumb is 3 to 5 times the time to reach radial flow to provide adequate radial flow data for analysis.

2. Adequate and consistent injection fluid should be available so that the injection rate into the test well can be held constant prior to the falloff. This rate should be high enough to produce a measurable falloff at the test well given the resolution of the pressure gauge selected. The viscosity of the fluid should be consistent. Any mobility issues (k/:) should be identified and addressed in the analysis if necessary.

3. Bottomhole pressure measurements are usually superior to surface pressure measurements because bottomhole measurements tend to be less noisy. Surface pressure measurements can be used if positive pressure is maintained at the surface throughout the falloff portion of the test. The surface pressure gauge should be located at the wellhead. A surface pressure gauge may also serve as a backup to a downhole gauge and provide a monitoring tool for tracking the test progress. Surface gauge data can be plotted during the falloff in a log-log plot format with the pressure derivative function to determine if the test has reached radial flow and can be terminated. Note: Surface pressure measurements are not adequate if the well goes on a vacuum during the test. (See Appendix, page A-2 for additional information concerning pressure gauge selection.)

4. Use two pressure gauges during the test with one gauge serving as a backup, or for verification in cases of questionable data quality. The two gauges do not need to be the same type. (See Appendix, page A-1 for additional information concerning pressure gauges.)

6.0 Conducting the Falloff Test

1. Tag and record the depth to any fill in the test well

2. Simplify the pressure transients in the reservoir
   - Maintain a constant injection rate in the test well prior to shut-in. This injection rate should be high enough and maintained for a sufficient duration to produce a measurable pressure transient that will result in a valid falloff test.
   - Offset wells should be shut-in prior to and during the test. If shut-in is not feasible, a constant injection rate should be recorded and maintained during the test and then accounted for in the analysis.
   - Do not shut-in two wells simultaneously or change the rate in an offset well during the test.

3. The test well should be shut-in <u>at the wellhead</u> in order to minimize wellbore storage and afterflow. (See Appendix, page A-3 for additional information.)

4. Maintain accurate rate records for the test well and any offset wells completed in the same injection interval.

5. Measure and record the viscosity of the injectate periodically during the injectivity portion of the test to confirm the consistency of the test fluid.

7.0 Evaluation of the Falloff Test

1. Prepare a Cartesian plot of the pressure and temperature versus real time or elapsed time.
   - Confirm pressure stabilization prior to shut-in of the test well
   - Look for anomalous data, pressure drop at the end of the test, determine if pressure drop is within the gauge resolution

2. Prepare a log-log diagnostic plot of the pressure and semilog derivative. Identify the flow regimes present in the welltest. (See Appendix, page A-6 for additional information.)
   - Use the appropriate time function depending on the length of the injection period and variation in the injection rate preceding the falloff (See Appendix, page A-10 for details on time functions.)
   - Mark the various flow regimes - particularly the radial flow period
   - Include the derivative of other plots, if appropriate (e.g., square root of time for linear flow)
   - If there is no radial flow period, attempt to type curve match the data

3. Prepare a semilog plot.
   C Use the appropriate time function depending on the length of injection period and injection rate preceding the falloff
   C Draw the semilog straight line through the radial flow portion of the plot and obtain the slope of the line
   C Calculate the transmissibility, kh/:
   C Calculate the skin factor, s, and skin pressure drop, ΔP_{skin}
   C Calculate the radius of investigation, r_i

4. Explain any anomalous results.

8.0 Comparison of Falloff Results to No Migration Petition Data

A comparison between the falloff test results and the parameters used in the no migration petition demonstration should be made. Specifically, the following should be demonstrated:

C Both the flowing and static bottom hole pressures measured during the test should be corrected for skin and be at or below those which were predicted to occur by the pressure buildup model in the approvided no migration petition for the same point in time. (See Appendix, page A-13)

C It should be shown that the (kh/:) parameter group calculated from the current falloff data is the same or greater than that employed in the pressure buildup modeling.

9.0 Technical References

1. SPE Textbook Series No. 1, “Well Testing,” 1982, W. John Lee
2. SPE Monograph 5, “Advances in Well Test Analysis,” 1977, Robert Earlougher, Jr.
3. SPE Monograph 1, “Pressure Buildup and Flow Tests in Wells,” 1967, C.S. Matthews and D.G. Russell
4. “Well Test Interpretation In Bounded Reservoirs,” Hart’s Petroleum Engineer International, Spivey, and Lee, November 1997
5. “Derivative of Pressure: Application to Bounded Reservoir Interpretation,” SPE Paper 15861, Proano, Lilley, 1986
6. “Well Test Analysis,” Sabet, 1991
7. “Pressure Transient Analysis,” Stanislav and Kabir, 1990
8. “Well Testing: Interpretation Methods,” Bourdarot, 1996
9. “A New Method To Account For Producing Time Effects When Drawdown Type Curves Are Used To Analyze Pressure Buildup And Other Test Data,” SPE Paper 9289, Agarwal, 1980

10. “Modern Well Test Analysis – A Computer-Aided Approach,” Roland N. Horne, 1990
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12. EPA Region 6 Falloff Guidelines
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14. “Guidelines Simplify Well Test Interpretation,” Oil and Gas Journal, Ehlig-Economides, Hegeman, and Vik, July 18, 1994
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16. Pressure-Transient Test Design in Tight Gas Formations, SPE Paper 17088, W.J. Lee, October 1987
17. “Radius-of-Drainage and Stabilization-Time Equations,” Oil and Gas Journal, H.K. Van Poollen, Sept 14, 1964
18. “Effects of Permeability Anisotropy and Layering On Well Test Interpretation,” Hart’s Petroleum Engineer International, Spivey, Aly, and Lee, February 1998
19. “Three Key Elements Necessary for Successful Testing,” Oil and Gas Journal, Ehlig-Economides, Hegeman, Clark, July 25, 1994
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22. “Fundamentals of Type Curve Analysis,” Hart’s Petroleum Engineer International, Spivey, and Lee, September 1997
23. “Identifying Flow Regimes In Pressure Transient Tests,” Hart’s Petroleum Engineer International, Spivey and Lee, October 1997
24. “Selecting a Reservoir Model For Well Test Interpretation,” Hart’s Petroleum Engineer International, Spivey, Ayers, Pursell,and Lee, December 1997
27. “Use of Pressure Derivative in Well-Test Interpretation,” SPE Paper 12777, SPE Formation Evaluation Journal, Bourdet, Ayoub, and Pirard, June 1989
28. “A New Set of Type Curves Simplifies Well Test Analysis,” World Oil, Bourdet, Whittle, Douglas, and Pirard, May 1983

APPENDIX

Initial Formation Reservoir Pressure from Falloff Testing

For use in the no migration demonstration pressure buildup modeling:

- Some predictive models calculate a pressure buildup while other models calculate a specific pressure based on an initial reservoir pressure assigned to the model. No wellbore skin should be assumed in the demonstration. Historical falloff flowing pressure data used for comparison with model results should be corrected for skin effects
- The initial pressure should represent the initial reservoir pressure prior to initiation of injection in the model.
- Direct bottomhole static measurements are best. If no measurements are available, or are questionable, attempt to correct static surface pressures to bottomhole conditions. Use site specific information if available. Alternatively, the facility can reference a technical paper that may discuss the initial pressure of the injection interval at another location in the same area or an initial static pressure measurement from an offset injection well.
- Review historical measured static pressures. The initial reservoir pressure should be lower than the measured static pressures following injection at the well.

For use in Cone of Influence (COI) calculations in both no migration demonstrations and UIC permits:

- P^* is the false extrapolated pressure obtained from the semilog straight line at a time of 1 hour and is often used as the average reservoir pressure
- P^* is only applicable for a new well in an infinite acting reservoir
- EPA Region 6 does not recommend using P^* for the average reservoir pressure. For long injection periods, P^* will differ significantly from $\overline{P}$, the average reservoir pressure
- Use the final shut-in pressure, if the well reaches radial flow, for the cone of influence calculation

Pressure Gauge Usage and Selection

<u>Usage</u>

- EPA recommends that two gauges be used during the test with one gauge serving as a backup.
- As a general rule, downhole pressure measurements are less noisy and are preferred. Surface pressure measurements can be employed if positive pressure is maintained at the surface throughout the test. Surface gauges are insufficient if the well goes on a vacuum.
- Surface pressure gauges may be impacted by the fluctuations in ambient temperature that can occur over the course of a normal day. If unchecked, this aspect of these gauges can result in erroneous pressure readings. Insulating the gauges appears to be an effective countermeasure for temperature fluctuations in many instances.

- A surface or bottomhole surface readout gauge (SRO) allows tracking of pressures in real time. Analysis of this data can be performed in the field to confirm that the well has reached radial flow prior to ending the test.
- The derivative function plotted on the log-log plot amplifies noise in the data, so the use of a good pressure recording device is critical for application of this curve.
- Mechanical gauges should be calibrated before and after each test using a dead weight tester.
- Electronic gauges should also be calibrated according to the manufacturer's recommendations. The manufacturer's recommended frequency of calibration, and a copy of the gauge calibration certificate should be provided with the falloff testing report demonstrating this practice has been followed.

Selection

- The pressures must remain within the range of the pressure gauge. The larger percent of the gauge range utilized in the test, the better. Typical pressure gauge limits are 2000, 5000, and 10000 psi. Note that gauge accuracy and resolution are typically a function of percent of the full gauge range.
- Electronic downhole gauges generally offer much better resolution and sensitivity than a mechanical gauge but cost more. Additionally, the electronic gauge can generally run for a longer period of time, be programmed to measure pressure more frequently at various intervals for improved data density, and store data in digital form.
- Resolution of the pressure gauge must be sufficient to measure small pressure changes at the end of the test.
- The type of wastestream injected may prevent the use of a downhole gauge unless brine from offsite is brought in and used for the test. This may be cost prohibitive.

Test Design

General Operational Considerations

- The injection period controls what is seen on the falloff since the falloff is replay of the injection period. Therefore, the injection period must reach radial flow prior to shut-in of the well in order for the falloff test to reach radial flow

- Ideally to determine the optimal lengths of the injection and falloff periods, the test should be simulated using measured or estimated reservoir parameters. Alternatively, injection and falloff period lengths can be estimated from empirical equations using assumed reservoir and well parameters.

- The injection rate dictates the pressure buildup at the injection well. The pressure buildup from injection must be sufficient so that the pressure change during radial flow, usually occurring toward the end of the test, is large enough to measure with the pressure gauge selected.

- Waste storage and other operational issues require preplanning and need to be addressed prior to the test date. If brine must be brought in for the injection portion of the test, operators should insure that the fluid injected has a consistent viscosity and that there is adequate fluid available to obtain a valid falloff test. The use of the wastestream as the injection fluid affords several distinct advantages:
  1. Brine does not have to be purchased or stored prior to use.
  2. Onsite waste storage tanks may be used.
  3. Plant wastestreams are generally consistent, i.e., no viscosity variations

- Rate changes cause pressure transients in the reservoir. Constant rate injection in the test well and any offset wells completed in the same reservoir are critical to simplify the pressure transients in the reservoir. Any significant injection rate fluctuations at the test well or offsets must be recorded and accounted for in the analysis using superposition.

- Unless an injectivity test is to be conducted, shutting in the well for an extend period of time prior to conducting the falloff test reduces the pressure buildup in the reservoir and is not recommended.

- Prior to conducting a test, a crown valve should be installed on the wellhead to allow the pressure gauge to be installed and lowered into the well without any interruption of the injection rate.

- The wellbore schematic should be reviewed for possible obstructions located in the well that may prevent the use or affect the setting depth of a downhole pressure gauge. The fill depth in the well should also be reported. The fill depth may not only impact the depth of the gauge, but usually prolongs the wellbore storage period and depending on the type of fill, may limit the interval thickness by isolating some of the injection intervals. A wellbore cleanout or stimulation may be needed prior to conducting the test for the test to reach radial flow and obtain valid results.

- The location of the shut-in valve can impact the duration of the wellbore storage period. The shut-in valve should be located near the wellhead. Afterflow into the wellbore prolongs the wellbore storage period. The injection pipeline leading to the well can act as an extension to the well if the shut-in valve is not located near the wellhead. Operators should report the location of the shut-in valve and its distance from the wellhead, in the test report.

- The area geology should be reviewed prior to conducting the test to determine the thickness and type of formation being tested along with any geological features such as natural fractures, a fault, or a pinchout that should be anticipated to impact the test.

Wellbore and Reservoir Data Needed to Simulate or Analyze the Falloff Test

- Wellbore radius, r_w - from wellbore schematic
- Net thickness, h - See Appendix, page A-15
- Porosity, N - log or core data
- Viscosity of formation fluid, $:_f$ - direct measurement or correlations
- Viscosity of waste, $:_{waste}$ - direct measurement or correlations
- Total system compressibility, c_t - correlations, core measurement, or well test
- Permeability, k - previous welltests or core data
- Specific gravity of injection fluid, s.g. - direct measurement
- Injection rate, q - direct measurement

Design Calculations

When simulation software is unavailable the test periods can be estimated from empirical equations. The following are set of steps to calculate the time to reach radial flow from empirically-derived equations:

1. Estimate the wellbore storage coefficient, C (bbl/psi). There are two equations to calculate the wellbore storage coefficient depending on if the well remains fluid filled (positive surface pressure) or if the well goes on a vacuum (falling fluid level in the well):

   a. Well remains fluid filled:

   $$C = V_w \cdot c_{waste}$$

   where, V_w is the total wellbore volume, bbls
   c_{waste} is the compressibility of the injectate, psi^{-1}

   b. Well goes on a vacuum:

   $$C = \frac{V_u}{\frac{r \cdot g}{144 \cdot g_c}}$$

   where, V_u is the wellbore volume per unit length, bbls/ft
   D is the injectate density, psi/ft
   g and g_c are gravitational constants

2. Calculate the time to reach radial flow for both the injection and falloff periods. Two different empirically-derived equations are used to calculate the time to reach radial flow, $t_{radial\ flow}$, for the injectivity and falloff periods:

   a. Injectivity period:

   $$t_{radial\ flow} > \frac{(200000 + 12000s) \cdot C}{\frac{k \cdot h}{m}} \quad hours$$

   b. Falloff period:

   $$t_{radial\ flow} > \frac{170000 \cdot C \cdot e^{0.14 \cdot s}}{\frac{k \cdot h}{m}} \quad hours$$

   The wellbore storage coefficient is assumed to be the same for both the injectivity and falloff periods. The skin factor, s, influences the falloff more than the injection period.

Use these equations with caution, as they tend to fall apart for a well with a large permeability or a high skin factor. Also remember, the welltest should not only reach radial flow, but also sustain radial flow for a timeframe sufficient for analysis of the radial flow period. As a rule of thumb, a timeframe sufficient for analysis is 3 to 5 times the time needed to reach radial flow.

3. As an alternative to steps 1 and 2, to look a specific distance "L" into the reservoir and possibly confirm the absence or existence of a boundary, the following equation can be used to estimate the time to reach that distance:

$$t_{boundary} = \frac{948 \cdot f \cdot m \cdot c_t \cdot L_{boundary}}{k} \quad hours$$

where, $L_{boundary}$ = feet to boundary
$t_{boundary}$ = time to boundary, hrs

Again, this is the time to reach a distance "L" in the reservoir. Additional test time is required to observe a fully developed boundary past the time needed to just reach the boundary. As a rule of thumb, to see a fully developed boundary on a log-log plot, allow at least 5 times the time to reach it. Additionally, for a boundary to show up on the falloff, it must first be encountered during the injection period.

4. Calculate the expected slope of the semilog plot during radial flow to see if gauge resolution will be adequate using the following equation:

$$m_{semi\log} = \frac{162.6 \cdot q \cdot \mathrm{B}}{\frac{k \cdot h}{m}}$$

where, q = the injection rate preceding the falloff test, bpd
B = formation volume factor for water, rvb/stb (usually assumed to be 1)

<u>Considerations for Offset Wells Completed in the Same Interval</u>

Rate fluctuations in offset wells create additional pressure transients in the reservoir and complicate the analysis. Always try to simplify the pressure transients in the reservoir. Do not simultaneously shut-in an offset well and the test well. The following items are key considerations in dealing with the impact of offset wells on a falloff test:

- Shut-in all offset wells prior to the test
- If shutting in offset wells is not feasible, maintain a constant injection rate prior to and during the test
- Obtain accurate injection records of offset injection prior to and during the test
- At least one of the real time points corresponding to an injection rate in an offset well should be synchronized to a specific time relating to the test well

- Following the falloff test in the test well, send at least two pulses from the offset well to the test well by fluctuating the rate in the offset well. The pressure pulses can confirm communication between the wells and can be simulated in the analysis if observed at the test well. The pulses can also be analyzed as an interference test using an Ei type curve.
- If time permits, conduct an interference test to allow evaluation of the reservoir without the wellbore effects observed during a falloff test.

Falloff Test Analysis

In performing a falloff test analysis, a series of plots and calculations should be prepared to QA/QC the test, identify flow regimes, and determine well completion and reservoir parameters. Individual plots, flow regime signatures, and calculations are discussed in the following sections.

<u>Cartesian Plot</u>

- The pressure data prior to shut-in of the well should be reviewed on a Cartesian plot to confirm pressure stabilization prior to the test. A well that has reached radial flow during the injectivity portion of the test should have a consistent injection pressure.

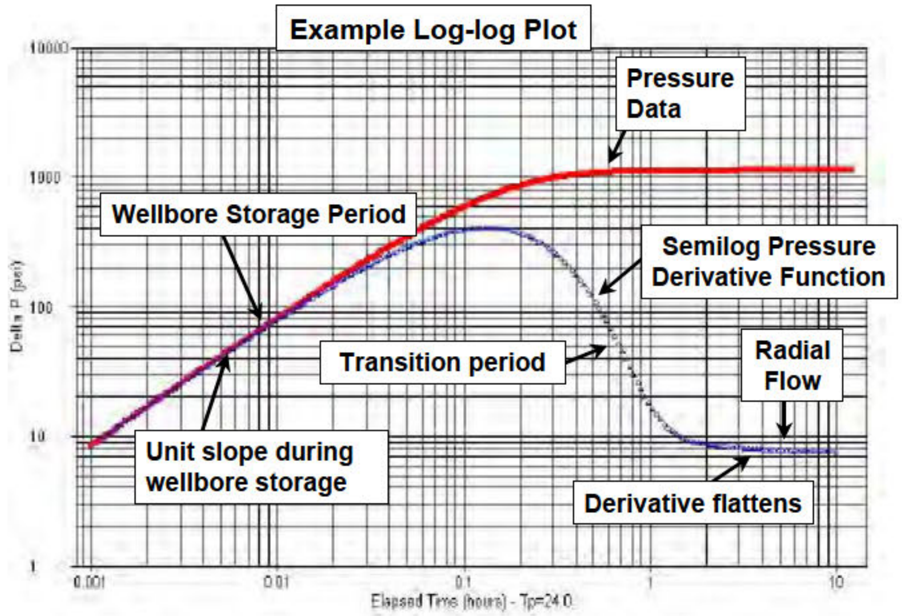
- A Cartesian plot of the pressure and temperature versus real time or elapsed time should be the first plot made from the falloff test data. Late time pressure data should be expanded to determine the pressure drop occurring during this portion of the test. The pressure changes should be compared to the pressure gauges used to confirm adequate gauge resolution existed throughout the test. If the gauge resolution limit was reached, this timeframe should be identified to determine if radial flow was reached prior to reaching the resolution of the pressure gauge. Pressure data obtained after reaching the resolution of the gauge should be treated as suspect and may need to be discounted in the analysis.

- Falloff tests conducted in highly transmissive reservoirs may be more sensitive to the temperature compensation mechanism of the gauge because the pressure buildup response evaluated is smaller. Region 6 has observed cases in which large temperature anomalies were not properly compensated for by the pressure gauge, resulting in erroneous pressure data and an incorrect analysis. For this reason, the Cartesian plot of the temperature data should be reviewed. Any temperature anomalies should be noted to determine if they correspond to pressure anomalies.

- Include the injection rate(s) of the test well 48 hours prior to shut-in on the Cartesian plot to illustrate the consistency of the injection rate prior to shut-in and to determine the appropriate time function to use on the log-log and semilog plots. (See Appendix, page A10 for time function selection)

Log-log Diagnostic Plot

- Plot the pressure and semilog derivative versus time on a log-log diagnostic plot. Use the appropriate time function based on the rate history of the injection period preceding the falloff. (See Appendix, page A-10 for time function selection) The log-log plot is used to identify the flow regimes present in the welltest. An example log-log plot is shown below:



Identification of Test Flow Regimes

- Flow regimes are mathematical relationships between pressure, rate, and time. Flow regimes provide a visualization of what goes on in the reservoir. Individual flow regimes have characteristic slopes and a sequencing order on the log-log plot.

- Various flow regimes will be present during the falloff test, however, not all flow regimes are observed on every falloff test. The late time responses correlate to distances further from the test well. The critical flow regime is radial flow from which all analysis calculations are performed. During radial flow, the pressure responses recorded are representative of the reservoir, not the wellbore.

- The derivative function amplifies reservoir signatures by calculating a running slope of a designated plot. The derivative plot allows a more accurate determination of the radial flow portion of the test, in comparison with the old method of simply proceeding 1½ log cycles from the end of the unit slope line of the pressure curve.

- The derivative is usually based on the semilog plot, but it can also be calculated based on other plots such as a Cartesian plot, a square root of time plot, a quarter root of time plot, and the 1/square root of time plot. Each of these plots are used to identify specific flow regimes. If the flow regime characterized by a specialized plot is present then when the derivative calculated from that plot is displayed on the log-log plot, it will appear as a "flat spot" during the portion of the falloff corresponding to the flow regime.

- Typical flow regimes observed on the log-log plot and their semilog derivative patterns are listed below:

Flow Regime	Semilog Derivative Pattern
Wellbore Storage	Unit slope
Radial Flow	Flat plateau
Linear Flow	Half slope
Bilinear Flow	Quarter slope
Partial Penetration	Negative half slope
Layering	Derivative trough
Dual Porosity	Derivative trough
Boundaries	Upswing followed by plateau
Constant Pressure	Sharp derivative plunge

Characteristics of Individual Test Flow Regimes

- Wellbore Storage:
  1. Occurs during the early portion of the test and is caused by the well being shut-in at the surface instead of the sandface
  2. Measured pressure responses are governed by well conditions and are not representative of reservoir behavior and are characterized by both the pressure and semilog derivative curves overlying a unit slope on the log-log plot
  3. Wellbore skin or a low permeability reservoir results in a slower transfer of fluid from the well to the formation, extending the duration of the wellbore storage period
  4. A wellbore storage dominated test is unanalyzable

- Radial Flow:
  1. The pressure responses are from the reservoir, not the wellbore
  2. The critical flow regime from which key reservoir parameters and completion conditions calculations are performed
  3. Characterized by a flattening of the semilog plot derivative curve on the log-log plot and a straight line on the semilog plot

- Spherical Flow:
  1. Identifies partial penetration of the injection interval at the wellbore
  2. Characterized by the semilog derivative trending along a negative half slope on the log-log plot and a straight line on the 1/square root of time plot
  3. The log-log plot derivative of the pressure vs 1/square root of time plot is flat

- Linear Flow
  1. May result from flow in a channel, parallel faults, or a highly conductive fracture
  2. Characterized by a half slope on both the log-log plot pressure and semilog derivative curves with the derivative curve approximately 1/3 of a log cycle lower than the pressure curve and a straight line on the square root of time plot.
  3. The log-log plot derivative of the pressure vs square root of time plot is flat

- Hydraulically Fractured Well
  1. Multiple flow regimes present including wellbore storage, fracture linear flow, bilinear flow, pseudo-linear flow, formation linear flow, and pseudo-radial flow
  2. Fracture linear flow is usually hidden by wellbore storage
  3. Bilinear flow results from simultaneous linear flows in the fracture and from the formation into the fracture, occurs in low conductivity fractures, and is characterized by a quarter slope on both the pressure and semilog derivative curves on the log-log plot and by a straight line on a pressure versus quarter root of time plot
  4. Formation linear flow is identified by a half slope on both the pressure and semilog derivative curves on the log-log plot and by a straight line on a pressure versus square root of time plot
  5. Psuedo-radial flow is analogous to radial flow in an unfractured well and is characterized by flattening of semilog derivative curve on the log-log plot and a straight line on a semilog pressure plot

- Naturally Fractured Rock
  1. The fracture system will be observed first on the falloff test followed by the total system consisting of the fractures and matrix.
  2. The falloff analysis is complex. The characteristics of the semilog derivative trough on the log-log plot indicate the level of communication between the fractures and the matrix rock.

- Layered Reservoir
  1. Analysis of a layered system is complex because of the different flow regimes, skin factors or boundaries that may be present in each layer.
  2. The falloff test objective is to get a total tranmissibility from the whole reservoir system.
  3. Typically described as commingled (2 intervals with vertical separation) or crossflow (2 intervals with hydraulic vertical communication)

<u>Semilog Plot</u>

- The semilog plot is a plot of the pressure versus the log of time. There are typically four different semilog plots used in pressure transient and falloff testing analysis. After plotting the appropriate semilog plot, a straight line should be drawn through the points located within the equivalent radial flow portion of the plot identified from the log-log plot.

- Each plot uses a different time function depending on the length and variation of the injection rate preceding the falloff. These plots can give different results for the same test, so it is important that the appropriate plot with the correct time function is used for the analysis. Determination of the appropriate time function is discussed below.

- The slope of the semilog straight line is then used to calculate the reservoir transmissibility - kh/μ, the completion condition of the well via the skin factor - s, and also the radius of investigation - r_i of the test.

<u>Determination of the Appropriate Time Function for the Semilog Plot</u>
The following four different semilog plots are used in pressure transient analysis:

1. Miller Dyes Hutchinson (MDH) Plot
2. Horner Plot
3. Agarwal Equivalent Time Plot
4. Superposition Time Plot

These plots can give different results for the same test. Use of the appropriate plot with the correct time function is critical for the analysis.

- The MDH plot is a semilog plot of pressure versus Δt, where Δt is the elapsed shut-in time of the falloff.
    1. The MDH plot only applies to wells that reach psuedo-steady state during injection. Psuedo-steady state means the pressure response from the well has encountered all the boundaries around the well.
    2. The MDH plot is only applicable to injection wells with a *very* long injection period at a constant rate. This plot is not recommended for use by EPA Region 6.

- The Horner plot is a semilog plot of pressure versus $(t_p+\Delta t)/\Delta t$. The Horner plot is only used for a falloff preceded by a single constant rate injection period.
    1. The injection time, $t_p=V_p/q$ in hours, where V_p=injection volume since the last pressure equalization and q is the injection rate prior to shut-in for the falloff test. The injection volume is often taken as the cumulative injection since completion.
    2. The Horner plot can result in significant analysis error if the injection rate varies prior to the falloff.

- The Agarwal equivalent time plot is a semilog plot of the pressure versus Agarwal equivalent time, Δt_e.
    1. The Agarwal equivalent time function is similar to the Horner plot, but scales the falloff to make it look like an injectivity test.
    2. It is used when the injection period is a short, constant rate compared to the length of the falloff period.
    3. The Agarwal equivalent time is defined as: $\Delta t_e=\log(t_p \Delta t)/(t_p+\Delta t)$, where t_p is calculated the same as with the Horner plot.

C The superposition time function accounts for variable rate conditions preceding the falloff.

1. It is the most rigorous of all the time functions and is usually calculated using welltest software.
2. The use of the superposition time function requires the operator to accurately track the rate history. As a rule of thumb, at a minimum, the rate history for twice the length of the falloff test should be included in the analysis.

The determination of which time function is appropriate for the plotting the welltest on semilog and log-log plots depends on available rate information, injection period length, and software:

1. If there is not a rate history other than a single rate and cumulative injection, use a Horner time function
2. If the injection period is shorter than the falloff test and only a single rate is available, use the Agarwal equivalent time function
3. If you have a variable rate history use superposition when possible. As an alternative to superposition, use Agarwal equivalent time on the log-log plot to identify radial flow. The semilog plot can be plotted in either Horner or Agarwal time if radial flow is observed on the log-log plot.

<u>Parameter Calculations and Considerations</u>

C Transmissibility - The slope of the semilog straight line, m, is used to determine the transmissibility (kh/:) parameter group from the following equation:

$$\frac{k \cdot h}{m} = \frac{162.6 \cdot q \cdot \mathrm{B}}{m}$$

where, q = injection rate, bpd (negative for injection)
B = formation volume factor, rvb/stb (Assumed to be 1 for formation fluid)
m = slope of the semilog straight line through the radial flow portion of the plot in psi/log cycle
k = permeability, md
h = thickness, ft (See Appendix, page A-15)
: = viscosity, cp

C The viscosity, :, is usually that of the formation fluid. However, if the waste plume size is massive, the radial flow portion of the test may remain within the waste plume. (See Appendix, page A-14)

1. The waste and formation fluid viscosity values usually are similar, however, if the wastestream has a significant viscosity difference, the size of the waste plume and distance to the radial flow period should be calculated.
2. The mobility, k/:, differences between the fluids may be observed on the derivative curve.

C The permeability, k, can be obtained from the calculated transmissibility (kh/:) by substituting the appropriate thickness, h, and viscosity, :, values.

Skin Factor

C In theory, wellbore skin is treated as an infinitesimally thin sheath surrounding the wellbore, through which a pressure drop occurs due to either damage or stimulation. Industrial injection wells deal with a variety of waste streams that alter the near wellbore environment due to precipitation, fines migration, ion exchange, bacteriological processes, and other mechanisms. It is reasonable to expect that this alteration often exists as a zone surrounding the wellbore and not a skin. Therefore, at least in the case of industrial injection wells, the assumption that skin exists as a thin sheath is not always valid. This does not pose a serious problem to the correct interpretation of falloff testing except in the case of a large zone of alteration, or in the calculation of the flowing bottomhole pressure. The Region has seen instances in which large zones of alteration were suspected of being present.

C The skin factor is the measurement of the completion condition of the well. The skin factor is quantified by a positive value indicating a damaged completion and a negative value indicating a stimulated completion.

1. The magnitude of the positive value indicating a damaged completion is dictated by the transmissibility of the formation.
2. A negative value of -4 to -6 generally indicates a hydraulically fractured completion, whereas a negative value of -1 to -3 is typical of an acid stimulation in a sandstone reservoir.
3. The skin factor can be used to calculate the effective wellbore radius, r_{wa} also referred to the apparent wellbore radius. (See Appendix, page A-13)
4. The skin factor can also be used to correct the injection pressure for the effects of wellbore damage to get the actual reservoir pressure from the measured pressure.

C The skin factor is calculated from the following equation:

$$s = 1.1513\left[\frac{P_{1hr} - P_{wf}}{m} - \log\left(\frac{k \cdot t_p}{(t_p + 1) \cdot f \cdot m \cdot c_t \cdot r_w^2}\right) + 3.23\right]$$

where, s = skin factor, dimensionless

P_{1hr} = pressure intercept along the semilog straight line at a shut-in time of 1 hour, psi

P_{wf} = measured injection pressure prior to shut-in, psi

: = appropriate viscosity at reservoir conditions, cp (See Appendix, page A-14)

m = slope of the semilog straight line, psi/cycle

k = permeability, md

N = porosity, fraction

c_t = total compressibility, psi^{-1}

r_w = wellbore radius, feet

t_p = injection time, hours

Note that the term $t_p/(t_p + \Delta t)$, where Δt=1 hr, appears in the log term. This term is usually assumed to result in a negligible contribution and typically is taken as 1 for large t. However, for relatively short injection periods, as in the case of a drill stem test (DST), this term can be significant.

Radius of Investigation

- The radius of investigation, r_i, is the distance the pressure transient has moved into a formation following a rate change in a well.

- There are several equations that exist to calculate the radius of investigation. All the equations are square root equations based on cylindrical geometry, but each has its own coefficient that results in slightly different results, (See Oil and Gas Journal, Van Poollen, 1964).

- Use of the appropriate time is necessary to obtain a useful value of r_i. For a falloff time shorter than the injection period, use Agarwal equivalent time function, Δt_e, at the end of the falloff as the length of the injection period preceding the shut-in to calculate r_i.

- The following two equivalent equations for calculating r_i were taken from SPE Monograph 1, (Equation 11.2) and Well Testing by Lee (Equation 1.47), respectively:

$$r_i = \sqrt{0.00105 \frac{k \cdot t}{f \cdot m \cdot c_t}} \equiv \sqrt{\frac{k \cdot t}{948 \cdot f \cdot m \cdot c_t}}$$

Effective Wellbore Radius

- The effective wellbore radius relates the wellbore radius and skin factor to show the effects of skin on wellbore size and consequently, injectivity.

- The effective wellbore radius is calculated from the following:

$$r_{wa} = r_w e^{-s}$$

- A negative skin will result in a larger effective wellbore radius and therefore a lower injection pressure.

Reservoir Injection Pressure Corrected for Skin Effects

- The pressure correction for wellbore skin effects, ΔP_{skin}, is calculated by the following:

$$\Delta P_{skin} = 0.868 \cdot m \cdot s$$

where, m = slope of the semilog straight line, psi/cycle
s = wellbore skin, dimensionless

- The adjusted injection pressure, P_{wfa} is calculated by subtracting the ΔP_{skin} from the measured injection pressure prior to shut-in, P_{wf}. This adjusted pressure is the calculated reservoir pressure prior to shutting in the well, Δt=0, and is determined by the following:

$$P_{wfa} = P_{wf} - \Delta P_{skin}$$

C From the previous equations, it can be seen that the adjusted bottomhole pressure is directly dependent on a single point, the last injection pressure recorded prior to shut-in. Therefore, an accurate recording of this pressure prior to shut-in is important. Anything that impacts the pressure response, e.g., rate change, near the shut-in of the well should be avoided.

<u>Determination of the Appropriate Fluid Viscosity</u>

C If the wastestream and formation fluid have similar viscosities, this process is not necessary.

C This is only needed in cases where the mobility ratios are extreme between the wastestream, $(k/:)_w$, and formation fluid, $(k/:)_f$. Depending on when the test reaches radial flow, these cases with extreme mobility differences could cause the derivative curve to change and level to another value. Eliminating alternative geologic causes, such as a sealing fault, multiple layers, dual porosity, etc., leads to the interpretation that this change may represent the boundary of the two fluid banks.

C First assume that the pressure transients were propagating through the formation fluid during the radial flow portion of the test, and then verify if this assumption is correct. This is generally a good strategy except for a few facilities with exceptionally long injection histories, and consequently, large waste plumes. The time for the pressure transient to exit the waste front is calculated. This time is then identified on both the log-log and semilog plots. The radial flow period is then compared to this time.

C The radial distance to the waste front can then be estimated volumetrically using the following equation:

$$r_{waste\ plume} = \sqrt{\frac{0.13368 \cdot V_{waste\ injected}}{p \cdot h \cdot f}}$$

where, $V_{waste\ injected}$ = cumulative waste injected into the completed interval, gal
$r_{waste\ plume}$ = estimated distance to waste front, ft
h = interval thickness, ft
N = porosity, fraction

C The time necessary for a pressure transient to exit the waste front can be calculated using the following equation:

$$t_w = \frac{126.73 \cdot m_w \cdot c_t \cdot V_{waste\ injected}}{p \cdot k \cdot h}$$

where, t_w= time to exit waste front, hrs
$V_{waste\ injected}$ = cumulative waste injected into the completed interval, gal
h = interval thickness, ft

k = permeability, md
μ_w = viscosity of the historic waste plume at reservoir conditions, cp
c_t = total system compressibility, psi^{-1}

- The time should be plotted on both the log-log and semilog plots to see if this time corresponds to any changes in the derivative curve or semilog pressure plot. If the time estimated to exit the waste front occurs before the start of radial flow, the assumption that the pressure transients were propagating through the reservoir fluid during the radial flow period was correct. Therefore, the viscosity of the reservoir fluid is the appropriate viscosity to use in analyzing the well test. If not, the viscosity of the historic waste plume should be used in the calculations. If the mobility ratio is extreme between the wastestream and formation fluid, adequate information should be included in the report to verify the appropriate fluid viscosity was utilized in the analysis.

Reservoir Thickness

- The thickness used for determination of the permeability should be justified by the operator. The net thickness of the defined injection interval is not always appropriate.

- The permeability value is necessary for plume modeling, but the transmissibility value, kh/μ, can be used to calculate the pressure buildup in the reservoir without specifying values for each parameter value of k, h, and μ.

- Selecting an interval thickness is dependent on several factors such as whether or not the injection interval is composed of hydraulically isolated units or a single massive unit and wellbore conditions such as the depth to wellbore fill. When hydraulically isolated sands are present, it may be helpful to define the amount of injection entering each interval by conducting a flow profile survey. Temperature logs can also be reviewed to evaluate the intervals receiving fluid. Cross-sections may provide a quick look at the continuity of the injection interval around the injection well.

- A copy of a SP/Gamma Ray well log over the injection interval, the depth to any fill, and the log and interpretation of available flow profile surveys run should be submitted with the falloff test to verify the reservoir thickness value assumed for the permeability calculation.

Use of Computer Software

- To analyze falloff tests, operators are encouraged to use well testing software. Most software has type curve matching capabilities. This feature allows the simulation of the entire falloff test results to the acquired pressure data. This type of analysis is particularly useful in the recognition of boundaries, or unusual reservoir characteristics, such as dual porosity. It should be noted that type curve matching is not considered a substitute, but is a compliment to the analysis.

- All data should be submitted electronically with a label stating the name of the facility, the well number(s), and the date of the test(s). The label or READ.Me file should include the names of all the files contained on the diskette, along with any necessary explanations of the information. The parameter units format (hh:mm:ss, hours, etc.) should be noted for the pressure file for synchronization to the submitted injection rate information. The file containing the gauge data analyzed in the report should be identified and consistent with the hard copy data included in the report. If the injection rate information for any well included in the analysis is greater than 10 entries, it should also be included electronically.

Common Sense Check

- After analyzing any test, always look at the results to see if they "make sense" based on the type of formation tested, known geology, previous test results, etc. Operators are ultimately responsible for conducting an analyzable test and the data submitted to the regulatory agency.

- If boundary conditions are observed on the test, review cross-sections or structure maps to confirm if the presence of a boundary is feasible. If so, the boundary should be considered in the AOR pressure buildup evaluation for the well.

- Anomalous data responses may be observed on the falloff test analysis. These data anomalies should be evaluated and explained. The analyst should investigate physical causes in addition to potential reservoir responses. These may include those relating to the well equipment, such as a leaking valve, or a channel, and those relating to the data acquisition hardware such as a faulty gauge. An anomalous response can often be traced to a brief, but significant rate change in either the test well or an offset well.

- Anomalous data trends have also been caused by such things as ambient temperature changes in surface gauges or a faulty pressure gauge. Explanations for data trends may be facilitated through an examination of the backup pressure gauge data, or the temperature data. It is often helpful to qualitatively examine the pressure and/or temperature channels from both gauges. The pressure data should overlay during the falloff after being corrected for the difference in gauge depths. On occasion, abrupt temperature changes can be seen to correspond to trends in the pressure data. Although the source of the temperature changes may remain unexplainable, the apparent correlation of the temperature anomaly to the pressure anomaly can be sufficient reason to question the validity of the test and eliminate it from further analysis.

- The data that is obtained from pressure transient testing should not collect dust, but be compared to petition or permit parameters. Test derived transmissibilities and static pressures can confirm compliance with no migration and non-endangerment (AOR) conditions.