UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, REGION IX (EPA)
UNDERGROUND INJECTION CONTROL (UIC) PROGRAM

# FINAL PERMIT

Class IID Water Injection Well

Permit No. NN207000003

Well Name: West Bisti SWD #1

San Juan County, New Mexico

Navajo Nation

Lease No. NMSF-078155

Issued to:

Dugan Production Corporation
Attn: Mr. Kurt Fagrelius
709 East Murray Drive
P.O. Box 420
Farmington, NM 87499-0420

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## PART I. AUTHORIZATION TO OPERATE AND INJECT

Pursuant to the Underground Injection Control Regulations of the U. S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations, Parts 124, 144, 145, 146, 147, and 148,

Dugan Production Corporation
Attn: Mr. Kurt Fragelius
709 East Murray Drive
Farmington, NM 87499-0420

is hereby authorized to drill, construct, and operate a new Class IID water injection well, to be known as the West Bisti SWD (Salt Water Disposal) #1. The well will be located on Indian lands in Section 35, T26N, R13W, at thirty-six (36) degrees twenty-seven (27) minutes forty-two (42) seconds latitude and one-hundred-eight (108) degrees eleven (11) minutes nine (9) seconds longitude, in San Juan County, New Mexico.

Injection shall be for the purpose of disposing of produced water from the Gallup Sandstone and Fruitland Coal formations into the Entrada Sandstone, in accordance with conditions set forth herein; the source of the produced water is from current and future wells operated by the Permittee

All conditions set forth herein refer to Title 40 Parts 124, 144, 145, 146, 147, and 148 of the Code of Federal Regulations and are regulations that are in effect on the date that this permit becomes effective.

This permit consists of a total of twenty (20) pages and includes all items listed in the Table of Contents. Further, it is based upon representations made by the Permittee and on other information contained in the administrative record. It is the responsibility of the Permittee to read and understand all provisions of this permit.

This permit and the authorization to inject are issued for a period of ten (10) years unless terminated under the conditions set forth in Part III, Section B of this permit. The permit will expire upon delegation of primary enforcement responsibility for the UIC Class II Program to an appropriate agency of the Navajo Nation, unless that agency has the appropriate authority and chooses to adopt and enforce this permit as a Tribal permit. The permit shall be reviewed by EPA every 5 years.

Issued this 2nd day of November 2007

This permit shall become effective 11/2/07

for Karen Schwinn
Alexis Strauss
Director, Water Division

# PART II. SPECIFIC PERMIT CONDITIONS

## A. WELL CONSTRUCTION

1. Casing and Cementing. The construction details submitted with the permit application are incorporated into this permit as APPENDIX C (Well Schematic), and shall be binding on the Permittee. The well will be cased and cemented to prevent the movement of fluids in the casing wellbore annulus, from the casing shoe at approximately 7165 feet to the surface. The casing shall be maintained throughout the operating life of the well. Advanced notice of casing and cementing operations will be given to EPA[1] so that an EPA representative may be present to monitor those operations. Final construction details will be provided in a modified well schematic after drilling and well construction is complete, within thirty (30) days of well completion.

2. Formation Logging and Testing. A Dual Induction Log (DIL) will be run from total depth (TD) to surface and Gamma Ray/Compensated Neutron Log/Compensated Density Logs (GR/CNL/CDL), Micro Log (ML), AND Cement Bond Log/Gamma Ray (CBL/GR) logs will be run from TD to the bottom of surface casing. Static formation pressure of the Morrison/Entrada injection zone will be measured prior to injection and annually after a well shut-in period of at least seventy-two (72) hours duration, and will be reported to the Director[2] within thirty (30) days of the measurement. A pressure fall-off test will be conducted within thirty (30) days of commencing injection, for the determination of hydraulic conductivity of the injection zone. The Region 9 EPA guidance document for conducting a fall-off test can be found in Appendix D. The test results and evaluation will be reported to the Director within five (5) days of the test and will be subject to the Director's review and approval. Advance notice of logging and fall off test operations shall be given to the Director, so that an EPA representative may be present to witness/monitor those operations.

3. Monitoring Devices. The operator shall install and maintain in good operating condition:

   (a) A tap on the discharge line between the injection pump and the wellhead for the purpose of obtaining representative samples of the injection fluids;

   (b) Two one-half (½) inch FIP (female) fittings, isolated by plug or globe valves, and positioned to provide for either (1), the permanent attachment of one-half (½) inch MIP (male) gauges, or (2), the attachments for equivalent "quick-disconnect" gauges at the wellhead on the injection tubing and on the tubing/casing annulus. The gauges used shall be of a design to provide (1), a full pressure range of 100 percent greater than the anticipated operating pressure, and (2), a certified deviation accuracy of five (5) percent or less throughout the operating pressure range;

[1] "EPA" refers to the Ground Water Office Manager, U.S. Environmental Protection Agency Region IX, with the associated address shown in part II.D.4
[2] "Director" refers to the Water Division Director, EPA Region IX

(c) A flow meter with measured cumulative volumes that are certified for a deviation accuracy of five (5) percent or less throughout the range of injection rates allowed by the permit.

4. Proposed Changes and Workovers. The Permittee shall give advance notice to the Director, as soon as possible, of any planned physical alterations or additions to the permitted injection well. Any changes in the well construction will require prior approval of the Director and a permit modification under the requirements of 40 CFR Part 144.39.

In addition, the Permittee shall provide all records of well completions, workovers, logging, or other subsequent test data, including required mechanical integrity testing, to the Director within thirty (30) days of completion of the activity. Appendix B contains samples of the appropriate reporting forms. Demonstration of mechanical integrity shall be performed within thirty (30) days of completion of workovers or alterations and prior to resuming injection activities in accordance with Part II, Section C.1.(a) of this permit.

## B. CORRECTIVE ACTION

No corrective action will be required on the other wells within the area of review (AOR) since those wells do not penetrate the injection zone. The AOR will be reevaluated upon completion of the well and annually thereafter and may be enlarged if the zone of endangering influence (ZEI), to be calculated from log and formation pressure data, exceeds the one-half mile radius of the AOR. Additional wellbores that may penetrate the expanded AOR will then be considered for corrective action in accordance with the provisions of 40 CFR §§ 144.55 and 146.7.

## C. WELL OPERATION

1. Mechanical Integrity.

(a) Method for Demonstrating Mechanical Integrity.

(i) All injection wells must have and maintain mechanical integrity consistent with 40 CFR §146.8. The Permittee must show that there are no significant leaks in the casing and tubing and that there is no significant fluid movement into any Underground Sources of Drinking Water (USDWs, per 40 CFR §144.3) through vertical channels adjacent to the injection wellbore or into the casing/wellbore annulus.

(ii) The Permittee will demonstrate that no significant leaks exist by means of a shut-in annular pressure test. The casing/tubing annulus must hold a pressure equal to the maximum allowable injection pressure for a period of thirty (30) minutes with no more than a five (5) percent change in pressure and a differential of at least three hundred (300) psig pressure must be maintained between the tubing and casing/tubing annulus for the duration of the test.

(iii) The Permittee will fulfill the requirements listed in 40 CFR §146.8 for demonstrating the absence of fluid movement into an underground source of drinking water (USDW) through vertical channels adjacent to the injection wellbore. The Permittee will run a cement bond log to demonstrate the isolation of the injection interval and other formations from underground sources of drinking water. USDWs will be protected by means of cementing the long string casing/wellbore annulus from total depth (TD) feet to the surface and placement and cementing of surface casing from approximately 480 feet to surface, in addition to the installation of tubing and packer assemblies through which injection will occur.

(b) <u>Prohibition Without Demonstration</u>. Injection into this well may continue after the effective date of this permit only if:

(i) the well has passed a mechanical integrity test (MIT) in accordance with Part II Section C.1.(a) of this permit and

(ii) the Permittee has received written notice from the Director that the MIT demonstration is satisfactory.

The Permittee shall notify the Director of intent to demonstrate mechanical integrity at least thirty (30) days prior to an official test, unless shorter notice is approved by the Director.

(c) <u>Subsequent Mechanical Integrity Demonstrations</u>

(i) A demonstration of mechanical integrity in accordance with provisions of EPA REGION IX MECHANICAL INTEGRITY TEST (MIT) PART I: REQUIREMENTS FOR INTERNAL TEST, a copy of which is contained in Appendix D attached hereto, shall be conducted at least once every five (5) years during the life of the well. Mechanical integrity shall also be demonstrated within thirty (30) days of the time that a workover is conducted or the seal is broken at the wellhead assembly, the construction of the well is modified, or when a loss of mechanical integrity becomes evident during operation.

(ii) It shall be the Permittee's responsibility to arrange and conduct the mechanical integrity demonstrations. The Permittee shall notify the Director of intent to demonstrate mechanical integrity at least thirty (30) days in advance of the demonstration, or a shorter time if approved by the Director. A subsequent notification must be given to the Navajo Nation UIC office at least seventy-two (72) hours in advance of the MIT in order to arrange for a representative to witness the MIT. Results of the test shall be submitted to the Director as soon as possible, but not later than sixty (60) days after the demonstration.

(iii) In addition to any demonstration made under paragraph (I) above, the Director may require a demonstration of mechanical integrity at any time during the permitted life of the well.

(d) Loss of Mechanical Integrity. The Permittee shall notify the Director, in accordance with Part III, Section E, paragraph 10 of this permit, under any of the following circumstances:

(i) the well fails to demonstrate mechanical integrity during a test, or

(ii) a loss of mechanical integrity becomes evident during operation, or

(iii) a significant change in the annulus or injection pressure occurs during normal operating conditions.

Furthermore, in the event of (i), (ii), or (iii), injection activities shall be terminated immediately and operation shall not be resumed until the Permittee has taken necessary actions to restore mechanical integrity to the well and the Director gives approval to recommence injection

2. Injection Interval(s). Injection shall be permitted for the Entrada Sandstone in the approximate gross subsurface interval of 6915 to 7115 feet, subject to minor modification after reviewing the well logs. Enlarging or changing the injection interval outside of that interval is considered a major permit modification and will require public notice and the Director's approval. Any alteration of the injection interval and other rework operations must be properly reported (EPA Form 7520-12, see Appendix B) and the well must demonstrate mechanical integrity before injection is resumed.

3. Injection Pressure Limitation(s). The injection pressure shall not exceed a surface (wellhead) injection pressure determined from a calculation of maximum allowable injection pressure equal to 0.2 psi/foot multiplied by the actual depth to the top of the injection interval. The actual formation fracture pressure may be determined from a fracture treatment of the injection zone, if undertaken by the operator; the maximum allowable injection pressure may be adjusted downward at that time, depending on the results of that determination. The maximum allowable injection pressure may be increased only if a valid step-rate test has been conducted and approved by the EPA. Appendix D contains acceptable step-rate reference materials. The test will be evaluated and a maximum allowable injection pressure will be determined by EPA, the results of which will be incorporated into this permit as the maximum allowable injection pressure. This will be considered a minor permit modification and will not be open for further public comment.

4. Injection Volume (Rate) Limitation.

(a) The maximum injection rate shall be limited to 6000 barrels per day, subject to the maximum allowable injection pressure. The average injection rate will be 5000 barrels per day.

(b) The Permittee may request an increase in the average and maximum rates allowed in paragraph (a). Any such request shall be made in writing and shall be appropriately justified to the Director.

(c) Should any increase in rate be requested, the Permittee shall demonstrate to the satisfaction of the Director that the increase in volume will not cause migration of formation or injected fluids into any USDW above or below the injection zone, nor cause any injected fluids to move beyond the Area of Review.

5. Injection Fluid Limitation.

   (a) The Permittee shall not inject any hazardous wastes as defined by the Resource Conservation and Recovery Act (RCRA, see 40 CFR §261) at any time during the operation of the facility.

   (b) The well shall be used only for the injection of water produced in connection with the Gallup formation oil and Fruitland Coal seam gas production in the area, and produced only from wells owned and operated by the Permittee.

   (c) Fluids to be injected other than those described in paragraph (b) above shall be limited to occasional minor amounts of well treatment fluids such as dilute acids and corrosion inhibiting fluids. Injection of any fluids other than those described in paragraph (b) above shall be reported to the Director within thirty (30) days.

## D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Injection Well Monitoring Program. Samples and measurements shall be representative of the monitored activity. The Permittee shall utilize the applicable analytical methods described in Table I of 40 CFR §136.3 or, in certain circumstances, other methods that have been approved by the EPA Administrator. Monitoring shall consist of:

   (a) Annually, or whenever there is a change in injection fluids, the following analyses of injection fluids shall be performed:

      (i) Total Dissolved Solids;
      (ii) Major ions;
      (iii) pH;
      (iv) Specific Conductance;
      (v) Specific Gravity: and
      (vi) Viscosity.

   (b) Annually, measurement of static reservoir pressure; and

   (c) Weekly, observations of injection pressure, annulus pressure, flow rate and cumulative volume. Written records of these weekly observations shall be made at least monthly.

2. Monitoring Information. Records of any monitoring activity required under this permit shall include:

   (a) Date, exact place, and the time of sampling or field measurements;

   (b) Name of individual(s) who performed sampling or measurements;

   (c) Exact sampling method(s) used;

(d) Date(s) the laboratory analyses were performed;

(e) Name of individual(s) who performed the analyses;

(f) Types of analyses; and

(g) Results of analyses.

3. Recordkeeping.

**The Permittee shall retain the following records and shall have them available at all times for examination at the lease facility**:

(a) Information on the nature and composition of all injected fluids until three (3) years after the plugging and abandonment has been carried out in accordance with the Plugging and Abandonment Plan shown in Appendix A,

(b) All monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation and copies of all reports required by this permit, for a period of at least five (5) years from the date of the sample, measurement or report throughout the operating life of the well,

(c) Monthly records of weekly observation records as required in Part II, Section D.1(c),

(d) Records and results of MITs or any other tests required by the Director, and

(e) Any well workover records.

The Permittee shall continue to retain such records, including those corresponding to the retention periods specified in paragraphs (a) and (b), unless it delivers the records to the Director or obtains written approval from the Director to discard the records.

4. Reporting.

Annually, the Permittee shall submit a report to the Director summarizing the results of the monitoring required by Part II, Sections A.2, D.1 and 2 of this permit. The results of annual measurement of static reservoir pressure and monthly records of flow rates, volumes, pressures, and injected fluid, and any major changes in the characteristics or sources of injected fluid shall be included in the Annual Report. The first Annual Report shall cover the period from the effective date of the permit through December 31, 2007 and shall be submitted by January 31, 2008. Subsequently, the Annual Report shall cover the period of January 1 through December 31, and shall be submitted by January 31 of the following year. Appendix B contains Form 7520-11, which may be copied and used to submit the annual summary of monitoring.

Monitoring reports and all other reports required by this permit shall be submitted to the following address:

U.S. Environmental Protection Agency, Region IX
Ground Water Office Manager (Mail Code WTR-9)
75 Hawthorne Street
San Francisco, CA 94105-3901

Copies of all reports shall also be provided to the following:

Underground Injection Control Program
Navajo Nation EPA
P.O. Box 1999
Shiprock, NM 87420

## E. PLUGGING AND ABANDONMENT

1. Notice of Plugging and Abandonment. The Permittee shall notify the Director forty-five (45) days before further conversion, workover, or abandonment of the well. The Director may require that the plugging and abandonment be witnessed by an EPA representative.

2. Plugging and Abandonment Plan. The Permittee shall plug and abandon the well as provided in the Plugging and Abandonment Plan and Schematic diagram in Appendix A. The EPA reserves the right to change the manner in which the well will be plugged if the well is modified during its permitted life or if the well is not made consistent with EPA requirements for construction and mechanical integrity. The Director may ask the Permittee to estimate and to update the estimated plugging cost periodically. Such estimates shall be based upon costs which a third party would incur to plug the well according to the plan.

3. Cessation of Injection Activities. After a cessation of operations of two (2) years, the Permittee shall plug and abandon the well in accordance with the Plugging and Abandonment Plan, unless it:

   (a) has provided notice to the Director;

   (b) has demonstrated that the well will be used in the future, and

   (c) has described actions or procedures, satisfactory to the Director that will be taken to ensure that the well will not endanger underground sources of drinking water during the period of temporary abandonment.

4. Plugging and Abandonment Report. Within sixty (60) days after plugging the well, the Permittee shall submit a report on Form 7520-14 (Appendix B), or an equivalent form, to the Director. The report shall be certified as accurate by the person who performed the plugging operation and the report shall consist of either: (1) a statement that the well was plugged in accordance with the plan, or (2) where actual plugging differed from the plan, a statement specifying the different procedures followed.

## F. FINANCIAL RESPONSIBILITY

1. Demonstration of Financial Responsibility.

The Permittee is required to maintain financial responsibility and resources to close, plug, and abandon the injection well as provided in the plugging and abandonment plan and in accordance with 40 CFR §144.52(a)(7). The Permittee shall not substitute an alternative demonstration of financial responsibility from that which the Director has approved, unless the Permittee has previously submitted evidence of that alternative demonstration to the Director and the Director has notified the Permittee in writing that the alternative demonstration is acceptable.

(a) Plugging and abandonment costs for the subject well are covered by an Irrevocable Standby Letter of Credit (Wells Fargo Bank, N.A. #NZS592729) in the amount of $36,000 and an associated standby trust agreement. The beneficiary of said financial instrument is the U.S. Environmental Protection Agency.

(b) The financial responsibility mechanism shall be reviewed and updated periodically, upon request of the Director. The Permittee may be required to change to an alternate method of demonstrating financial responsibility, such as a surety bond or trust fund which names EPA as the beneficiary. Any such change must be approved in writing by the Director prior to the change.

2. Insolvency of Financial Institution.

The Permittee must submit an alternate instrument of financial responsibility acceptable to the Director within sixty (60) days after either of the following events occurs:

(a) The trustee financial institution issuing the financial instrument files for bankruptcy; or

(b) The authority of the trustee institution to act as trustee, or the authority of the institution issuing the financial instrument, is suspended or revoked.

Failure to submit an acceptable financial demonstration will result in the termination of this permit pursuant to 40 CFR §144.40(a)(1).

3. Insolvency of Owner or Operator.

An owner or operator must notify the Director by certified mail of the commencement of voluntary or involuntary proceedings under U.S. Code Title 11 (Bankruptcy), naming the owner or operator as debtor, within ten (10) business days after the commencement of the proceeding. A guarantor of a corporate guarantee must make such a notification if he/she is named as debtor, as required under the terms of the guarantee.

# PART III. GENERAL PERMIT CONDITIONS

## A. EFFECT OF PERMIT

The Permittee is allowed to engage in underground injection in accordance with the conditions of this permit. The Permittee, as authorized by this permit, shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR §142 or otherwise adversely affect the health of persons.

Any underground injection activity not authorized in this permit or otherwise authorized by permit or rule is prohibited. Issuance of this permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local law or regulations. Compliance with the terms of this permit does not constitute a defense to any enforcement action brought under the provisions of Section 1431 of the Safe Drinking Water Act (SDWA) or any other law governing protection of public health or the environment for any imminent and substantial endangerment to human health or the environment, nor does it serve as a shield to the Permittee's independent obligation to comply with all UIC regulations.

## B. PERMIT ACTIONS

1. Modification, Revocation and Re-issuance, or Termination.

The Director may, for cause or upon request from the Permittee, modify, revoke and reissue, or terminate this permit in accordance with 40 CFR Sections 124.5, 144.12, 144.39, and 144.40. The permit is also subject to minor modifications for cause as specified in 40 CFR §144.41. The filing of a request for a permit modification, revocation and re-issuance, or termination or the notification of planned changes or anticipated noncompliance on the part of the Permittee does not stay the applicability or enforceability of any permit condition.

2. Transfers.

This permit may only be transferred after notice is provided to the Director and the Permittee complies with the requirements of 40 CFR §144.38. The Director may require modification or revocation and re-issuance of the permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the SDWA.

## C. SEVERABILITY

The provisions of this permit are severable, and if any provision of this permit or the application of any provision of this permit to any circumstance is held invalid, the remainder of this permit shall not be affected.

## D. CONFIDENTIALITY

In accordance with 40 CFR Part 2 and 40 CFR §144.5, any information submitted to EPA pursuant to this permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR Part 2 (Public Information). Claims of confidentiality for the following information will be denied:

1. The name and address of the Permittee, or
2. Information which deals with the existence, absence, or level of contaminants in drinking water.

## E. GENERAL DUTIES AND REQUIREMENTS

1. Duty to Comply. The Permittee shall comply with all conditions of this permit, except to the extent and for the duration such noncompliance is authorized by an emergency permit. Any permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action, permit termination, revocation and re-issuance, or modification. Such noncompliance may also be grounds for enforcement action under the Resource Conservation and Recovery Act (RCRA).

2. Penalties for Violations of Permit Conditions. Any person who violates a permit requirement is subject to civil penalties, fines, and other enforcement action under the SDWA and may be subject to such actions pursuant to RCRA. Any person who willfully violates permit conditions may be subject to criminal prosecution.

3. Need to Halt or Reduce Activity not a Defense. It shall not be a defense, for a Permittee in an enforcement action, that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

4. Duty to Mitigate. The Permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit.

5. Proper Operation and Maintenance. The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control which are installed or used by the Permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this permit.

6. Duty to Provide Information. The Permittee shall furnish the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The Permittee shall also furnish to the Director, upon request, copies of records required to be kept by this permit.

7. Inspection and Entry. The Permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

   (a) enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records are kept under the conditions of this permit;

   (b) have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;

   c) inspect at reasonable times any facilities, equipment (including monitoring and control equipment) practices, or operations regulated or required under this permit; and

   (d) sample or monitor, at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location.

8. Records of the Permit Application. The Permittee shall maintain records of all data required to complete the permit application and any supplemental information submitted for a period of five (5) years from the effective date of this permit. This period may be extended by request of the Director at any time.

9. Signatory Requirements. All reports or other information requested by the Director shall be signed and certified by a responsible corporate officer or duly authorized representative according to 40 CFR §144.32.

10. Reporting of Noncompliance.

   (a) Anticipated Noncompliance. The Permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

   (b) Compliance Schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted no later than thirty (30) days following each schedule date.

   c) Twenty-four Hour Reporting.

      (i) The Permittee shall report to the Director any noncompliance which may endanger health or the environment. Information shall be provided within twenty-four (24) hours from the time the Permittee becomes aware of the circumstances by telephoning the EPA project officer. The following information shall be included in the verbal report:

(A) Any monitoring or other information which indicates that any contaminant may cause endangerment to an underground source of drinking water.

(B) Any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between underground sources of drinking water.

(ii) A written submission shall also be provided within five (5) days of the time the Permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause; the period of non compliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

(d) Other Noncompliance. The Permittee shall report all other instances of noncompliance not otherwise reported at the time monitoring reports are submitted. The reports shall contain the information listed in Part II, Section D.1 and 2 of this permit.

(e) Other Information. Where the Permittee becomes aware that it failed to submit all relevant facts in the permit application, or submitted incorrect information in a permit application or in any report to the Director, the Permittee shall submit such facts or information within two (2) weeks of the time such information becomes known.

APPENDIX A - Plugging and Abandonment Plan (s)

OMB No. 2040-0042 Approval Expires 4/30/07

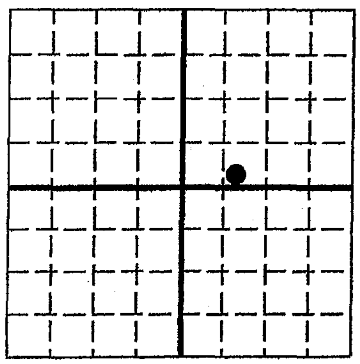
EPA

United States Environmental Protection Agency
Washington, DC 20460

# PLUGGING AND ABANDONMENT PLAN

| Name and Address of Facility | Name and Address of Owner/Operator |
|---|---|
| West Bisti SWD #1<br>Sec. 35, T26N, R13W, 2500' FNL-1855' FEL | Dugan Production Corp.<br>709 E. Murray Dr., Farmington, NM 87401 |

**Locate Well and Outline Unit on Section Plat - 640 Acres**




| State | County | Permit Number |
|---|---|---|
| NM | San Juan | |

**Surface Location Description**

1/4 of ___ 1/4 of SW 1/4 of NE 1/4 of Section 35 Township 26N Range 13W

**Locate well in two directions from nearest lines of quarter section and drilling unit**

Surface 2500' FNL & 1855' FEL of Sec. 35, T26N, R13W

Location ___ ft. frm (N/S) ___ Line of quarter section

and ___ ft. from (E/W) ___ Line of quarter section.

**TYPE OF AUTHORIZATION**

- XX Individual Permit
- ☐ Area Permit
- ☐ Rule

Number of Wells ___

Lease Name

**WELL ACTIVITY**

- ☐ CLASS I
- XX CLASS II
  - XX Brine Disposal
  - ☐ Enhanced Recovery
  - ☐ Hydrocarbon Storage
- ☐ CLASS III

Well Number West Bisti SWD #1

**CASING AND TUBING RECORD AFTER PLUGGING**

| SIZE | WT (LB/FT) | TO BE PUT IN WELL (FT) | TO BE LEFT IN WELL (FT) | HOLE SIZE |
|---|---|---|---|---|
| 8-5/8 | 24# | 480' | 480' | 12-1/4" |
| 5-1/2 | 15.5# | 6400' | 6400' | 7-7/8" |
| 5-1/2 | 17# | 765' | 765' | 7-7/8" |
| | | | | |

**METHOD OF EMPLACEMENT OF CEMENT PLUGS**

- XX The Balance Method
- ☐ The Dump Bailer Method
- ☐ The Two-Plug Method
- ☐ Other

| CEMENTING TO PLUG AND ABANDON DATA: | PLUG #1 | PLUG #2 | PLUG #3 | PLUG #4 | PLUG #5 | PLUG #6 | PLUG #7 |
|---|---|---|---|---|---|---|---|
| Size of Hole or Pipe in which Plug Will Be Placed (inche | 5-1/2" | 5-1/2" | 5-1/2 | 5-1/2 | 5-1/2 | 5-1/2 | 5-1/2 |
| Depth to Bottom of Tubing or Drill Pipe (ft | 6965' | 5790' | 4645' | 2590' | 1245' | 895' | 530' |
| Sacks of Cement To Be Used (each plug) | 17-sks | 17-sks | 17-sks | 34-sk | 17-sk | 17-sks | 55-sks |
| Slurry Volume To Be Pumped (cu. ft.) | 20-cf | 20-cf | 20-cf | 120-cf | 20-cf | 20-cf | 65-cf |
| Calculated Top of Plug (ft.) | 6865' | 5690' | 4545' | 1990' | 1145' | 795' | Surface |
| Measured Top of Plug (if tagged ft.) | --- | --- | --- | --- | --- | --- | --- |
| Slurry Wt. (Lb./Gal.) | 15.6# | 15.6# | 15.6# | 15.6# | 15.6# | 15.6# | 15.6# |
| Type Cement or Other Material (Class III) | Type 5 | Type 5 | Type5 | Type 5 | Type5 | Type5 | Type 5 |

**LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)**

| From | To | From | To |
|---|---|---|---|
| Proposed Perf | | | |
| 6915' | 7115' | | |
| | | | |
| | | | |

Estimated Cost to Plug Wells

$30,050.00

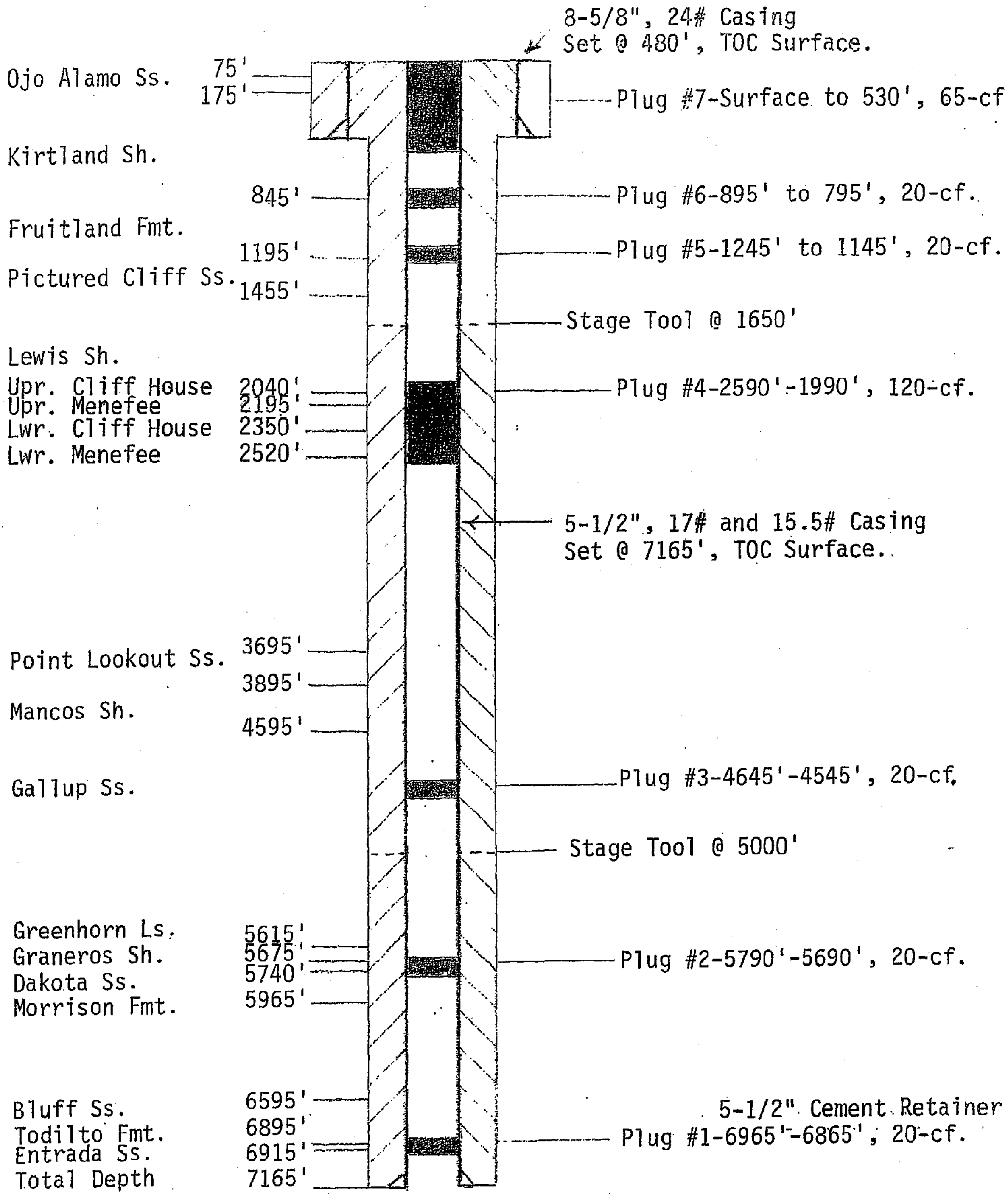
## Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

| Name and Official Title (Please type or print) | Signature | Date Signed |
|---|---|---|
| Kurt Fagrelius, VP Exploration | Kurt Fagrelius | 2-2-2007 |

EPA Form 7520-14 (Rev. 8-01)

**Well-Bore Diagram of Plugging and Abandonment Plan**




Dugan Production Corp.
West Bisti SWD #1
Sec. 35, T26N, R13W
2500' FNL and 1855' FEL
San Juan County, New Mexico

Salt Water Disposal Application

APPENDIX B - Reporting Forms and Instructions

1. EPA Form 7520 -7:APPLICATION TO TRANSFER PERMIT
2. EPA Form 7520-10:WELL COMPLETION REPORT
3. EPA Form 7520-11:ANNUAL WELL MONITORING REPORT
4. EPA Form 7520-12:WELL REWORK RECORD
5. EPA Form 7520-14:PLUGGING AND ABANDONMENT PLAN

OMB No. 2040-0042 Approval Expires 4/30/07

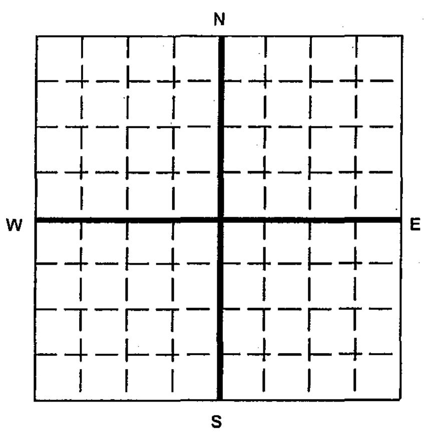
EPA

United States Environmental Protection Agency
Washington, DC 20460

# Application To Transfer Permit

| Name and Address of Existing Permittee | Name and Address of Surface Owner |
|---|---|
| | |

Locate Well and Outline Unit on Section Plat - 640 Acres




| State | County | Permit Number |
|---|---|---|
| | | |

Surface Location Description

___ 1/4 of ___ 1/4 of ___ 1/4 of ___ 1/4 of Section ___ Township ___ Range ___

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface
Location ___ ft. frm (N/S) ___ Line of quarter section
and ___ ft. from (E/W) ___ Line of quarter section.

**Well Activity**

- ☐ Class I
- ☐ Class II
  - ☐ Brine Disposal
  - ☐ Enhanced Recovery
  - ☐ Hydrocarbon Storage
- ☐ Class III
- ☐ Other

**Well Status**

- ☐ Operating
- ☐ Modification/Conversion
- ☐ Proposed

**Type of Permit**

- ☐ Individual
- ☐ Area

Number of Wells ___

Lease Number ___ Well Number ___

| Name(s) and Address(es) of New Owner(s) | Name and Address of New Operator |
|---|---|
| | |

*Attach to this application a written agreement between the existing and new permittee containing a specific date for transfer of permit responsibility, coverage, and liability betweend them.*

*The new permittee must show evidence of financial responsibility by the submission of a surety bond, or other adequate assurance, such as financial statements or other materials acceptable to the Director.*

## Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

| Name and Official Title *(Please type or print)* | Signature | Date Signed |
|---|---|---|
| | | |

## PAPERWORK REDUCTION ACT

The public reporting and record keeping burden for this collection of information is estimated to average 5 hours per response. Burden means the total time, effort, or financial resource expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal Agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822), 1200 Pennsylvania Ave., NW., Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed forms to this address.

## Well Class and Type Code

| | |
|---|---|
| **Class I** | Wells used to inject waste below the deepest underground source of drinking water. |
| **Type "I"** | Nonhazardous industrial disposal well |
| **"M"** | Nonhazardous municipal disposal well |
| **"W"** | Hazardous waste disposal well injecting below USDWs |
| **"X"** | Other Class I wells (not included in Type "I," "M," or "W") |
| **Class II** | Oil and gas production and storage related injection wells. |
| **Type "D"** | Produced fluid disposal well |
| **"R"** | Enhanced recovery well |
| **"H"** | Hydrocarbon storage well (excluding natural gas) |
| **"X"** | Other Class II wells (not included in Type "D," "R," or "H") |
| **Class III** | Special process injection wells. |
| **Type "G"** | Solution mining well |
| **"S"** | Sulfur mining well by Frasch process |
| **"U"** | Uranium mining well |
| **"X"** | Other Class III wells (not included in Type "G," "S," or "U") |
| **Other Classes** | Wells not included in classes above.<br>Class V wells which may be permitted under § 144.12<br>Wells not currently classified as Class I, II, III, or V |

OMB No. 2040-0042 Approval Expires 4/30/07

EPA

United States Environmental Protection Agency
Washington, DC 20460

# COMPLETION REPORT FOR BRINE DISPOSAL, HYDROCARBON STORAGE, OR ENHANCED RECOVERY

| Name and Address of Existing Permittee | Name and Address of Surface Owner |
|---|---|
| | |

Locate Well and Outline Unit on Section Plat - 640 Acres

N

W E

S

| State | County | Permit Number |
|---|---|---|
| | | |

Surface Location Description

☐ 1/4 of ☐ 1/4 of ☐ 1/4 of ☐ 1/4 of Section ☐ Township ☐ Range ☐

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface
Location ☐ ft. frm (N/S) ☐ Line of quarter section
and ☐ ft. from (E/W) ☐ Line of quarter section.

WELL ACTIVITY

- ☐ Brine Disposal
- ☐ Enhanced Recovery
- ☐ Hydrocarbon Storage

TYPE OF PERMIT

- ☐ Individual
- ☐ Area

Number of Wells ☐

Estimated Fracture Pressure of Injection Zone

| Anticipated Daily Injection Volume (Bbls) | | Injection Interval | |
|---|---|---|---|
| Average | Maximum | Feet | to Feet |
| | | | |

| Anticipated Daily Injection Pressure (PSI) | | Depth to Bottom of Lowermost Freshwater Formation (Feet) |
|---|---|---|
| Average | Maximum | |
| | | |

Type of Injection Fluid *(Check the appropriate block(s))*

☐ Salt Water ☐ Brackish Water ☐ Fresh Water
☐ Liquid Hydrocarbon ☐ Other

| Lease Name | Well Number |
|---|---|
| | |

Name of Injection Zone

| Date Drilling Began | Date Well Completed |
|---|---|
| | |

Permeability of Injection Zone

Date Drilling Completed

Porosity of Injection Zone

| CASING AND TUBING | | | CEMENT | | HOLE | |
|---|---|---|---|---|---|---|
| OD Size | Wt/Ft - Grade - New or Used | Depth | Sacks | Class | Depth | Bit Diameter |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |

| INJECTION ZONE STIMULATION | | WIRE LINE LOGS, LIST EACH TYPE | |
|---|---|---|---|
| Interval Treated | Materials and Amount Used | Log Types | Logged Intervals |
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |

Complete Attachments A -- E listed on the reverse.

## Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

| Name and Official Title *(Please type or print)* | Signature | Date Signed |
|---|---|---|
| | | |

## ATTACHMENTS

A. Present a schematic or other appropriate drawing of the surface and subsurface construction details of the well as built.

B. Describe the method and results of mechanical integrity testing.

C. Present the results of that portion of those logs, test, and cores which specifically relate to (1) underground sources of drinking water and the confining zone(s) and (2) the injection and adjacent formations.

D. Present the status of corrective action on defective wells in the area of review.

E. Provide to EPA, with the completion report, one final print of all geophysical logs run.

### PAPERWORK REDUCTION ACT

OMB No. 2040-0042 Approval Expires 4/30/07

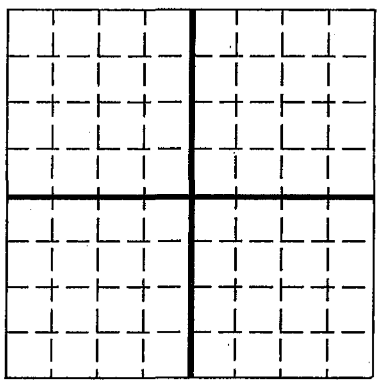
EPA

United States Environmental Protection Agency
Washington, DC 20460

# ANNUAL DISPOSAL/INJECTION WELL MONITORING REPORT

| Name and Address of Existing Permittee | Name and Address of Surface Owner |
|---|---|
| | |

Locate Well and Outline Unit on Section Plat - 640 Acres




| State | County | Permit Number |
|---|---|---|
| | | |

Surface Location Description

☐ 1/4 of ☐ 1/4 of ☐ 1/4 of ☐ 1/4 of Section ☐ Township ☐ Range ☐

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface

Location ☐ ft. frm (N/S) ☐ Line of quarter section

and ☐ ft. from (E/W) ☐ Line of quarter section.

| WELL ACTIVITY | TYPE OF PERMIT |
|---|---|
| ☐ Brine Disposal | ☐ Individual |
| ☐ Enhanced Recovery | ☐ Area |
| ☐ Hydrocarbon Storage | Number of Wells ☐ |

Lease Name ☐ Well Number ☐

| | INJECTION PRESSURE | | TOTAL VOLUME INJECTED | | TUBING -- CASING ANNULUS PRESSURE (OPTIONAL MONITORING) | |
|---|---|---|---|---|---|---|
| MONTH YEAR | AVERAGE PSIG | MAXIMUM PSIG | BBL | MCF | MINIMUM PSIG | MAXIMUM PSIG |
| | | | | | | |
| | | | | | | |
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## Certification

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| Name and Official Title *(Please type or print)* | Signature | Date Signed |
|---|---|---|
| | | |

**PAPERWORK REDUCTION ACT**

The public reporting and record keeping burden for this collection of information is estimated to average 25 hours annually for operators of Class I wells and 5 hours annually for operators of Class II wells. Burden means the total time, effort, or financial resource expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal Agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822), 1200 Pennsylvania Ave., NW, Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed forms to this address.

OMB No. 2040-0042 Approval Expires 4/30/07

EPA

United States Environmental Protection Agency
Washington, DC 20460

# WELL REWORK RECORD

| Name and Address of Permittee | Name and Address of Contractor |
|---|---|
| | |

Locate Well and Outline Unit on Section Plat - 640 Acres

N

W E

S

| State | County | Permit Number |
|---|---|---|
| | | |

Surface Location Description

☐ 1/4 of ☐ 1/4 of ☐ 1/4 of ☐ 1/4 of Section ☐ Township ☐ Range ☐

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface
Location ☐ ft. frm (N/S) ☐ Line of quarter section
and ☐ ft. from (E/W) ☐ Line of quarter section.

| WELL ACTIVITY | | TYPE OF PERMIT |
|---|---|---|
| ☐ Brine Disposal | Total Depth Before Rework | ☐ Individual |
| ☐ Enhanced Recovery | Total Depth After Rework | ☐ Area |
| ☐ Hydrocarbon Storage | Date Rework Commenced | Number of Wells ☐ |
| Lease Name | Date Rework Completed | Well Number |

WELL CASING RECORD -- BEFORE REWORK

| Casing | | Cement | | Perforations | | Acid or Fracture Treatment Record |
|---|---|---|---|---|---|---|
| Size | Depth | Sacks | Type | From | To | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |

WELL CASING RECORD -- AFTER REWORK *(Indicate Additions and Changes Only)*

| Casing | | Cement | | Perforations | | Acid or Fracture Treatment Record |
|---|---|---|---|---|---|---|
| Size | Depth | Sacks | Type | From | To | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |

| DESCRIBE REWORK OPERATIONS IN DETAIL USE ADDITIONAL SHEETS IF NECESSARY | WIRE LINE LOGS, LIST EACH TYPE | |
|---|---|---|
| | Log Types | Logged Intervals |
| | | |
| | | |
| | | |
| | | |

## Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possiblity of fine and imprisonment. (Ref. 40 CFR 144.32)

| Name and Official Title *(Please type or print)* | Signature | Date Signed |
|---|---|---|
| | | |

EPA Form 7520-12 (Rev. 8-01)

## PAPERWORK REDUCTION ACT

The public reporting and record keeping burden for this collection of information is estimated to average 4 hours per response annually. Burden means the total time, effort, or financial resource expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal Agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822), 1200 Pennsylvania Ave., NW., Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed forms to this address.

OMB No. 2040-0042 Approval Expires 4/30/07

EPA

United States Environmental Protection Agency
Washington, DC 20460

# PLUGGING AND ABANDONMENT PLAN

| Name and Address of Facility | Name and Address of Owner/Operator |
|---|---|
| | |

Locate Well and Outline Unit on Section Plat - 640 Acres

N

W E

S

| State | County | Permit Number |
|---|---|---|
| | | |

Surface Location Description

__ 1/4 of __ 1/4 of __ 1/4 of __ 1/4 of Section __ Township __ Range __

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface
Location __ ft. frm (N/S) __ Line of quarter section
and __ ft. from (E/W) __ Line of quarter section.

| TYPE OF AUTHORIZATION | WELL ACTIVITY |
|---|---|
| ☐ Individual Permit | ☐ CLASS I |
| ☐ Area Permit | ☐ CLASS II |
| ☐ Rule | ☐ Brine Disposal |
| Number of Wells __ | ☐ Enhanced Recovery |
| | ☐ Hydrocarbon Storage |
| | ☐ CLASS III |
| Lease Name | Well Number |

CASING AND TUBING RECORD AFTER PLUGGING

| SIZE | WT (LB/FT) | TO BE PUT IN WELL (FT) | TO BE LEFT IN WELL (FT) | HOLE SIZE |
|---|---|---|---|---|
| | | | | |
| | | | | |
| | | | | |
| | | | | |

METHOD OF EMPLACEMENT OF CEMENT PLUGS

- ☐ The Balance Method
- ☐ The Dump Bailer Method
- ☐ The Two-Plug Method
- ☐ Other

| CEMENTING TO PLUG AND ABANDON DATA: | PLUG #1 | PLUG #2 | PLUG #3 | PLUG #4 | PLUG #5 | PLUG #6 | PLUG #7 |
|---|---|---|---|---|---|---|---|
| Size of Hole or Pipe in which Plug Will Be Placed (inche | | | | | | | |
| Depth to Bottom of Tubing or Drill Pipe (ft | | | | | | | |
| Sacks of Cement To Be Used (each plug) | | | | | | | |
| Slurry Volume To Be Pumped (cu. ft.) | | | | | | | |
| Calculated Top of Plug (ft.) | | | | | | | |
| Measured Top of Plug (if tagged ft.) | | | | | | | |
| Slurry Wt. (Lb./Gal.) | | | | | | | |
| Type Cement or Other Material (Class III) | | | | | | | |

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

| From | To | From | To |
|---|---|---|---|
| | | | |
| | | | |
| | | | |
| | | | |

Estimated Cost to Plug Wells

## Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possiblity of fine and imprisonment. (Ref. 40 CFR 144.32)

| Name and Official Title *(Please type or print)* | Signature | Date Signed |
|---|---|---|
| | | |

## Paperwork Reduction Act Notice

The public reporting and record keeping burden for this collection of information is estimated to average 19.5 hours annually for operators of Class I wells, 6 hours annually for operators of Class II wells, and 8 hours annually for operators of Class III wells. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR Part 9 and 48 CFR Chapter 15.

Please send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Office of Environmental Information, Collection Strategies Division, U.S. Environmental Protection Agency (2822), Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Officer for EPA. Please include the EPA ICR number and OMB control number in any correspondence.

APPENDIX C – Well Schematic(s)
Permit application Exhibits M-1 and M-2, Injection Well Data Sheets with Wellbore Schematic

Dugan Production Corp.
West Bisti SWD #1
Sec. 35, T26N, R13W
2500' FNL and 1855' FEL
San Juan County, New Mexico
Salt Water Disposal Application

# EXHIBIT M-1.

## INJECTION WELL DATA SHEET

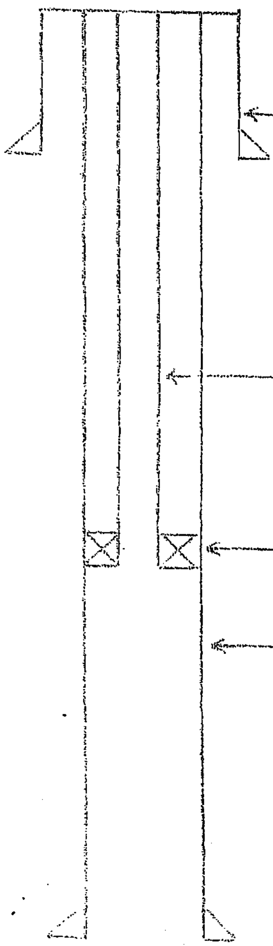
OPERATOR: Dugan Production Corp.

WELL NAME & NUMBER: West Bisti SWD #1

WELL LOCATION:

| FOOTAGE LOCATION | UNIT LETTER | SECTION | TOWNSHIP | RANGE |
|---|---|---|---|---|
| 2500' FNL and 1855' FWL | G | 35 | 26N | 13W |

### *WELLBORE SCHEMATIC*



8-5/8", 24# Casing
Set @ 480', TOC @ Surface

Stage Tool @ 1650'

Stage Tool @ 5000'

Internal Plastic Coated
2-7/8", 6.4# EUE Tubing

Baker Model AD-1 Tension Packer
Set @ 6865'

5-1/2", 17# and 15.5# Casing
Set @ 7165', TOC Surface

Perforate 6915' - 7115'

Total Depth 7165'

### *WELL CONSTRUCTION DATA*

**Surface Casing**

Hole Size: 12-1/4"    Casing Size: 8-5/8"

Cemented with: 220 sx. *or* 300 $ft^3$

Top of Cement: Surface    Method Determined: Will Circulate

**Intermediate Casing**

Hole Size: ____    Casing Size: ____

Cemented with: ____ sx. *or* ____ $ft^3$

Top of Cement: ____    Method Determined: ____

**Production Casing**

Hole Size: 7-7/8"    Casing Size: 5-1/2"

Cemented with: 750 sx. *or* 1540 $ft^3$

Top of Cement: Surface    Method Determined: Will Circulate

Total Depth: 7165'

**Injection Interval**

6915 feet to 7115

(Perforated or Open Hole; indicate which)

EXHIBIT M-2.

# INJECTION WELL DATA SHEET

Tubing Size: 2-7/8" Lining Material: Plastic

Type of Packer: Baker Model AD-1 set in tension (5-1/2")

Packer Setting Depth: 6865' (50' above uppermost perforation)

Other Type of Tubing/Casing Seal (if applicable): ____

## Additional Data

1. Is this a new well drilled for injection? X Yes ____ No

   If no, for what purpose was the well originally drilled? ____

2. Name of the Injection Formation: Entrada Sandstone

3. Name of Field or Pool (if applicable): Not Applicable

4. Has the well ever been perforated in any other zone(s)? List all such perforated intervals and give plugging detail, i.e. sacks of cement or plug(s) used. New well, will be drilled for purpose of injection into Entrada Ss., no other zones will be perf'd.

5. Give the name and depths of any oil or gas zones underlying or overlying the proposed injection zone in this area: Fruitland Coal 800', Gallup Ss. 4600'.

Dugan Production Corp.
West Bisti SWD #1
Sec. 35, T26N, R13W
2500' FNL and 1855' FEL
San Juan County, New Mexico
Salt Water Disposal Application

APPENDIX D – Reference Materials.

1. MECHANICAL INTEGRITY TEST (MIT) PART I: REQUIREMENTS FOR INTERNAL TEST
2. REGION 9 UIC PRESSURE FALLOFF REQUIREMENTS
3. REGION 9 STEP RATE TEST POLICY – reference Society of Petroleum Engineers (SPE) Paper #16798, Systematic Design and Analysis of Step-Rate Tests to Determine Formation Parting Pressure

# U.S.E.P.A. REGION IX
# MECHANICAL INTEGRITY TEST (MIT)
# PART I: REQUIREMENTS FOR INTERNAL TEST

The U. S. Environmental Protection Agency (EPA) Region 9 requirements described below are effective as of May 1, 1992. For further reference, consult 40 CFR §146.8(b). Part I MIT may be demonstrated by one of two methods:

METHOD A

1) An annular pressure demonstration is performed at the system's maximum water injection pressure (pressure must be at least 300 psig).
2) The system's wells are tested at least once every five years or whenever packer reseating is needed. A test ensuing from packer reseating will be regarded as an official MIT demonstration.
3) Casing annuli and injections are monitored **monthly** and the results are included in the annual report to the director.

METHOD B

1) Test pressure is to be 1000 psig (it is not necessary to test to maximum water injection pressure).
2) Water injection pressure tests are conducted at least once every three years or whenever packer reseating is needed (see Method A (2)).
3) Casing annuli and injection pressure are monitored **weekly** and the results are included in the annual report to the director.

In applying either Method A or Method B, the operator must adhere to the following EPA specifications:

- All tests must last at least 30 minutes, during which time the pressure should not increase or decrease by more than 5%.
- A minimum differential pressure of 300 psig between tubing and tubing-casing annulus is to be maintained throughout the MIT.
- The EPA will consider alternative test parameters and frequencies when requested in writing. Requirements might be less stringent, for example, where there are no Underground Sources of Drinking Water (USDWs).
- The 30 days minimum notification period specified in federal regulations may be shortened by the EPA Regional Administrator. MIT information will be accepted as valid **only** if EPA has been given at least 14 days notice to make arrangements to witness the MIT.
- If a well fails the MIT, the well is to be shut in immediately and steps for remediation taken as soon as possible. The operator will still be bound to report any noncompliance as required in 40 CFR §144.28(b).
- Remediation may consist of squeeze cementing holes in the casing, running a liner inside the casing, or setting tandem packers to isolate a hole in the casing when it is not practical to squeeze the hole and the hole poses no danger to any USDWs. These and other alternatives will be considered on a case-by-case basis.
- If mechanical integrity is not achieved within the specified time period, the EPA may undertake an enforcement action. Time extensions to achieve compliance are permissible, but they must be justified and requested in writing.

# EPA Region 9
# UIC PRESSURE FALLOFF REQUIREMENTS

## Condensed version of the EPA Region 6
# UIC PRESSURE FALLOFF TESTING GUIDELINE
**Third Revision**

**August 8, 2002**

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# APPENDIX

# REQUIREMENTS

### UIC PRESSURE FALLOFF TESTING GUIDELINE
### Third Revision
### August 8, 2002

## 1.0 Background

Region 9 has adopted the Region 6 UIC Pressure Falloff Testing Guideline requirements for monitoring Class 1 Non Hazardous waste disposal wells. Under 40 CFR 146.13(d)(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.

**All of the following parameters (Test, Period, Analysis) are critical for evaluation of technical adequacy of UIC permits:**

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.

## 2.0 Purpose of Guideline

This guideline has been adopted by the Region 9 office of the Evironmental Protection Agency (EPA) to assist operators in **planning and conducting** the falloff test and preparing the **annual monitoring report**.

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 UIC permit demonstrations. Additionally, a valid falloff test is a monitoring requirement under 40 CFR Part 146 for all Class I injection wells.

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 annually. 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.

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 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:

(1) general information and an overview of the falloff test,
(2) an analysis of the pressure data obtained during the test,
(3) a summary of the test results, and
(4) a comparison of those results with previously used parameters.

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 <u>in addition</u> 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:
    - X Wellbore radius
    - X Completed interval depths
    - X Type of completion (perforated, screen and gravel packed, openhole)
6. **Depth of fill depth and date tagged.**
7. **Offset well information:**
    - X Distance between the test well and offset well(s) completed in the same interval or involved in an interference test
    - X 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 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)
    - X List all the gauges utilized to test the well
    - X Depth of each gauge
    - X Manufacturer and type of gauge. Include the full range of the gauge.
    - X Resolution and accuracy of the gauge as a % of full range.
    - X Calibration certificate and manufacturer's recommended frequency of calibration
14. **General test information:**
    - X Date of the test
    - X 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 <u>and any offset wells</u>.
    - X Location of the shut-in valve (e.g., note if at the wellhead or number of feet from the wellhead)
15. **Reservoir parameters (determination):**
    - X Formation fluid viscosity, $\mu_f$ cp (direct measurement or correlation)
    - X Porosity, $\varphi$ fraction (well log correlation or core data)
    - X Total compressibility, $c_t$ $psi^{-1}$ (correlations, core measurement, or well test)
    - X Formation volume factor, rvb/stb (correlations, usually assumed 1 for water)
    - X Initial formation reservoir pressure - See Appendix, page A-1
    - X Date reservoir pressure was last stabilized (injection history)
    - X Justified interval thickness, h ft - See Appendix, page A-15
16. **Waste plume:**
    - X Cumulative injection volume into the completed interval
    - X Calculated radial distance to the waste front, $r_{waste}$ ft
    - X Average historical waste fluid viscosity, if used in the analysis, $\mu_{waste}$ cp

17. **Injection period:**
    - X Time of injection period
    - X Type of test fluid
    - X Type of pump used for the test (e.g., plant or pump truck)
    - X Type of rate meter used
    - X Final injection pressure and temperature
18. **Falloff period:**
    - X Total shut-in time, expressed in real time and $\Delta t$, elapsed time
    - X Final shut-in pressure and temperature
    - X Time well went on vacuum, if applicable
19. **Pressure gradient:**
    - X Gradient stops - for depth correction
20. **Calculated test data:** include all equations used and the parameter values assigned for each variable within the report
    - X Radius of investigation, $r_i$ ft
    - X Slope or slopes from the semilog plot
    - X Transmissibility, $kh/\mu$ md-ft/cp
    - X Permeability (range based on values of h)
    - X Calculation of skin, s
    - X Calculation of skin pressure drop, $\Delta P_{skin}$
    - X Discussion and justification of any reservoir or outer boundary models used to simulate the test
    - X Explanation for any pressure or temperature anomaly if observed
21. **Graphs:**
    - X Cartesian plot: pressure and temperature vs. time
    - X Log-log diagnostic plot: pressure and semilog derivative curves. Radial flow regime should be identified on the plot
    - X Semilog and expanded semilog plots: radial flow regime indicated and the semilog straight line drawn
    - X Injection rate(s) vs time: test well and offset wells (not a circular or strip chart)
22. **A copy of the latest radioactive tracer run** and a brief discussion of the results.

## 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

- X Adequate storage for the waste should be ensured for the duration of the test

- X 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
- X 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
- X The location of the shut-in valve on the well should be at or near the wellhead to minimize the wellbore storage period
- X 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.
- X Cleaning out the well and acidizing may reduce the wellbore storage period and therefore the shut-in time of the well
- X 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.
- X 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.
- X 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.

## Site Specific Pretest Planning

1. Determine the time needed to reach radial flow during the injectivity and falloff portions of the test:
    - X Review previous welltests, if available
    - X Simulate the test using measured or estimated reservoir and well completion parameters
    - X 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)
    - X 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 ($k/\mu$) should be identified and addressed in the analysis if necessary.

3. Bottomhole pressure measurements are required. (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
   - X 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.
   - X 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.
   - X 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 at the wellhead 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.
   - X Confirm pressure stabilization prior to shut-in of the test well
   - X 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.)

- X 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.)
- X **Mark the various flow regimes** - particularly the radial flow period
- X Include the derivative of other plots, if appropriate (e.g., square root of time for linear flow)
- X If there is no radial flow period, attempt to type curve match the data

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

4. Explain any anomalous results.

## 8.0 Technical References


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# APPENDIX

## Pressure Gauge Usage and Selection

Usage

- X EPA recommends that two gauges be used during the test with one gauge serving as a backup.
- X **Downhole pressure measurements** are less noisy and are required.
- X A 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.
- X 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.
- X Mechanical gauges should be **calibrated** before and after each test using a dead weight tester.
- X 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

- X 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.
- X 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.
- X Resolution of the pressure gauge must be sufficient to measure small pressure changes at the end of the test.

## Test Design

### General Operational Considerations

- X 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
- X 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.

- X 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.

- X 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

- X 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.

- X 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.

- X 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.

- X 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.

- X 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.
- X 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

- X Wellbore radius, $r_w$ - from wellbore schematic

X Net thickness, h - See Appendix, page A-15
X Porosity, $\varphi$ - log or core data
X Viscosity of formation fluid, $\mu_f$ - direct measurement or correlations
X Viscosity of waste, $\mu_{waste}$ - direct measurement or correlations
X Total system compressibility, $c_t$ - correlations, core measurement, or well test
X Permeability, k - previous welltests or core data
X Specific gravity of injection fluid, s.g. - direct measurement
X 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:

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

   where, $V_u$ is the wellbore volume per unit length, bbls/ft
   $\rho$ 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:

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

   b. Falloff period:

   $$t_{radial\,flow} > \frac{170000 \cdot C \cdot e^{0.14 \cdot s}}{\frac{k \cdot h}{\mu}} \; hours$$

   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:

$$t_{boundary} = \frac{948 \cdot \phi \cdot \mu \cdot c_t \cdot L_{boundary}}{k} \quad hours$$

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:

$$m_{semilog} = \frac{162.6 \cdot q \cdot B}{\frac{k \cdot h}{\mu}}$$

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

## Considerations for Offset Wells Completed in the Same Interval

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:

X Shut-in all offset wells prior to the test
X If shutting in offset wells is not feasible, maintain a constant injection rate prior to and during the test
X Obtain accurate injection records of offset injection prior to and during the test
X 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
X **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.

X 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.

### Cartesian Plot

X 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.

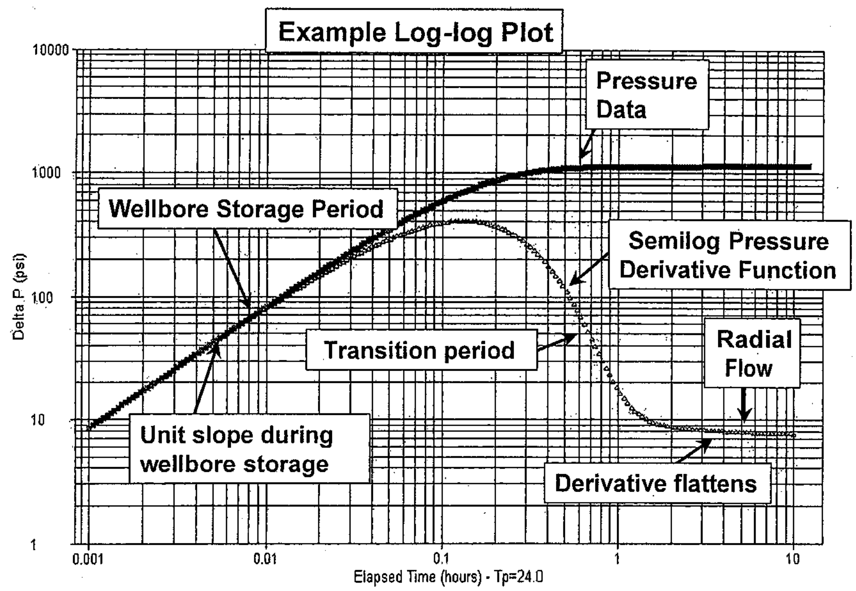
X A Cartesian plot of the pressure and temperature versus real time or elapsed time should be the first plot made from the falloff test data. Late time pressure data should be expanded to determine the pressure drop occurring during this portion of the test. The pressure changes should be compared to 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.

X **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.**

X 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

X 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

X 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.

X 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.

X 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.

X 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.

X **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

X **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

X **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

X **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

X **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

X **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

X **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.

X **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)

## Semilog Plot

X 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.

X 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.

X 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.

**Determination of the Appropriate Time Function for the Semilog Plot**

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.

X 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.

X 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.

X The **Agarwal equivalent time plot** is a semilog plot of the pressure versus Agarwal equivalent time, $\Delta t_e$.
   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.

X 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.

## Parameter Calculations and Considerations

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

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

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)

$\mu$ = viscosity, cp

X The viscosity, $\mu$, 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, $k/\mu$, differences between the fluids may be observed on the derivative curve.

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

**Skin Factor**

X 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. Region 6 has seen instances in which large zones of alteration were suspected of being present.

X 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.

X The skin factor is calculated from the following equation:

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

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

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

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

k = permeability, md

φ = 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 $\Delta t$=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**

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

X 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).

X 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, $\Delta t_e$, at the end of the falloff as the length of the injection period preceding the shut-in to calculate $r_i$.

X 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:

$$r_i = \sqrt{0.00105 \frac{k \cdot t}{\phi \cdot \mu \cdot c_t}} \equiv \sqrt{\frac{k \cdot t}{948 \cdot \phi \cdot \mu \cdot c_t}}$$

**Effective Wellbore Radius**

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

X The effective wellbore radius is calculated from the following:

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

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

**Reservoir Injection Pressure Corrected for Skin Effects**

X The pressure correction for wellbore skin effects, $\Delta P_{skin}$, 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

X The adjusted injection pressure, $P_{wfa}$ is calculated by subtracting the $\Delta P_{skin}$ 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, $\Delta t=0$, and is determined by the following:

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

X 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.

**Determination of the Appropriate Fluid Viscosity**

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

X This is only needed in cases where the mobility ratios are extreme between the wastestream, $(k/\mu)_w$, and formation fluid, $(k/\mu)_f$. 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.

X 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.

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

$$r_{waste\ plume} = \sqrt{\frac{0.13368 \cdot V_{waste\,injected}}{\pi \cdot h \cdot \phi}}$$

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
$\varphi$ = porosity, fraction

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

$$t_w = \frac{126.73 \cdot \mu_w \cdot c_t \cdot V_{waste\,injected}}{\pi \cdot k \cdot h}$$

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
$\mu_w$ = viscosity of the historic waste plume at reservoir conditions, cp
$c_t$ = total system compressibility, psi$^{-1}$

X 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**

X 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.

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

X 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.

X 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**

X 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.

X All data should be submitted on a CD-ROM 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 CD, 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

X 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.

X 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.

X 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.

X 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.

X The data that is obtained from pressure transient testing should be compared to permit parameters. Test derived transmissibilities and static pressures can confirm compliance with non-endangerment (Area Of Review) conditions.