Underground Injection Control Program

PERMIT

Class V Experimental
Permit No. CA5060001

Well Names:
SFI-1, SFI-2 and SFI-3
Los Angeles County, California

Table of Contents

Part I. AUTHORIZATION TO CONSTRUCT AND INJECT

City of Los Angeles
Bureau of Sanitation
445 Ferry St.
San Pedro, California 90731

Pursuant to the Underground Injection Control (UIC) regulations of the U.S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (CFR), Parts 124, 144, 145, 146, 147, and 148, is hereby authorized to construct and operate a Class V Experimental municipal biosolids waste injection facility with one injection well and at least two monitoring wells. The wells are to be located within the Terminal Island Plant boundaries.

EPA will grant authorization to inject after the requirements of Part II, Section C.1 of this permit have been met. Injection will be authorized into the Tar, Ranger and Terminal formations for the purpose of injecting slurry mixtures of treated, non-hazardous, municipal sludge and water at pressures sufficient to hydraulically create fractures to demonstrate an experimental technology whereby the solid waste undergoes high-temperature anaerobic biodegradation. Extensive field monitoring, sampling and analysis from the offset monitoring wells will be utilized to quantify at a minimum slurry placement, biodegradation rates, carbon dioxide and methane separation, carbon sequestration and saturation in formation brine, free gas migration, commercial methane production potential and timeframes.

All conditions set forth herein are based on Title 40 Parts 124, 144, 145, 146, 147 and 148 of the Code of Federal Regulations.

This permit consists of twenty-eight(28) pages, and includes all items listed in the Table of Contents. Further, it is based upon representations made by City of Los Angeles (the permittee). It is the responsibility of the permittee to read, understand and comply with all terms and conditions of this permit.

This permit and the authorization to inject are issued for a period of up to five (5) years unless terminated under the conditions set forth in Part III, Section B.1. of this permit.

Issued this 6th day of November, 2006.

This permit shall become effective forty (40) days after the date of issuance.

signed by Alexis Strauss

Alexis Strauss, Director
Water Division, EPA Region IX

Part II. SPECIFIC PERMIT CONDITIONS

A. WELL CONSTRUCTION

1. "Onshore Well Regulations" of the California Code of Regulations
Permittee shall conduct both drilling and plugging operations by following the requirements of this permit and the "Onshore Well Regulations" of the California Code of Regulations, found in Title 14. Natural Resources, Division 2. Department of Conservation, Chapter 4, Article 3, Section 1722-1723 as implemented by the Division of Oil, Gas, and Geothermal Resources (DOGGR).

2. The Construction Plans and Schematics
submitted with the permit application are hereby incorporated into this permit as Appendix A, and shall be binding on the permittee to the extent that the basic construction scheme is accurate pending the exact depths of the geology encountered during the drilling process. The actual depths of the geological zones are expected to occur within close proximity of the proposed depths, as evidenced from knowledge of the geology of the Wilmington Oil Field. Therefore the actual setting depths of the casing strings will vary by a minor amount. These changes will be approved by EPA before they are enacted and are considered minor in this permit. The exact dimensions of the casing strings and tubing may vary by a minor amount because of the dimensions of various tools and equipment that are commercially available. An example would be after determining larger diameter tools are needed to run in the well. The larger diameter of the tools would require the tubing size to increase from 3.5-in. to 4.5-in. to allow for clearance when running those tools, which further causes the casing sizes and ultimately the hole diameter to increase proportionately in order to accommodate that size of tubing. These changes will be approved by EPA before they are enacted and are considered minor in this permit. Notwithstanding any other provisions of this permit, the permittee shall case and cement the wells to prevent the movement of fluids into or above underground sources of drinking water.

   Wells SFI-1, SFI-2, and SFI-3 shall be equipped with retrievable or permanent monitoring systems depending on the role these wells play, i.e. monitoring versus injection. These details are included in Appendix A

   The following specifications apply to the wells:

   a. <u>WELL SFI-1:</u>
   Injection well SFI-1 shall be installed to conduct Phase I operations as outlined in APPENDIX E. In the subsequent Phase II, this well may become the lower of the first two wells if Well SFI-2 encounters the geological formations at a lower depth ("downdip" of Well SFI-1) during drilling. In that case, Well SFI-2 will be more suitable to be converted for

use as the injection well and Well SFI-1 will be converted for use as a monitoring well and their roles as applicable within this permit shall be reversed. This same decision logic shall apply to discovery of geological stratigraphy that would apply to Well SFI-3. Decisions about well conversions must be approved in advance by EPA and are considered minor in this permit.

Location: Latitude (+) 33.7438N; Longitude (-) 118.2649W

Conductor pipe: 20-in OD (26-in. hole), 90 lb/ft, H-40 casing from ground surface to 150 ft. cemented to surface.

Surface Casing: 13-3/8-in. (17-1/2-in. hole) ; 61 lb/ft.; K-55; set at 1,000 ft. Cemented to surface with +/- 400 sacks Class H.

Long String Casing: 9-5/8-in. (12-1/4-in. hole); 40 lb/ft; N-80; set at +/- 5,350ft. Cemented to surface with +/- 1,000 sacks Class H w/10.0 lb/sack Gilsonite.

Fiber optic temperature tool: Halliburton OptoLog DTS (or commercially available equivalent) - Fiber optic temperature sensor shall be installed on the long string casing. At the location of the injection reservoir, it shall be looped to increase resolution.

Pressure-temperature tool: Halliburton CT Permanent Monitoring System shall be attached to the tubing string and run as part of the completion (or commercially available equivalent).

Injection Tubing: 4-5-in.; 12.6 lb/ft; N-80; Atlas Bradford Mod. Buttress tubing set at +/-5,000 ft. with retrievable tension packer.

Annular space between the Injection Tubing and Long String Casing shall be filled with a non-corrosive fluid.

PERFORATIONS (approximate depths expected) are 5,200-5,300 ft.; 8 shots/ft.; 0.75 in. diameter holes. This perforation interval shall reflect the injection zone that is currently authorized in this permit per Part II.A.3. Perforations may be systematically extended uphole within the Tar, Ranger and Terminal sequence of formations which are expected to occur from depths ranging 3,800 - 5,300 ft. These interval changes must be requested in writing and proposed procedures must include plans for placement of cement across the lower perforation interval, testing of the cement plug and perforating the upper interval. These perforation interval changes must be approved by EPA before they are conducted and are considered minor in this permit.

b. MONITORING WELL SFI-2:

Monitoring Well SFI-2 shall be installed prior to Phase II which includes the phase of low solids content slurry injection as outlined in APPENDIX E. This well is intended to be used as a monitoring well, however it may encounter the geological formations at a lower depth, downdip, from that of Well SFI-1. In that case, Well SFI-2 will be more suitable to be converted for use as the injection well and Well SFI-1 will be converted for use as a monitoring well and the roles as applicable within this permit shall be reversed. These decisions and changes must be approved in advance by EPA and are considered minor in this permit.

Location: Well SFI-2 will be drilled from the same surface location as SFI-1, however it will be a directionally drilled hole that is deviated such that the bottom hole location will be approximately 1,000 ft. away and updip (upgradient within the same geological formations encountered at Well SFI-1).

Conductor pipe: 20-in OD (26-in. hole), 90 lb/ft, H-40 casing from ground surface to 150 ft. cemented to surface.

Surface Casing: 13-3/8-in. (17-1/2-in. hole) ; 61 lb/ft.; K-55; set at 1,000 ft. Cemented to surface with +/- 400 sacks Class H.

Long String Casing: 9-5/8-in. (12-1/4-in. hole); 40 lb/ft; N-80; set at +/- 5,350ft. Cemented to surface with +/- 1,000 sacks Class H w/10.0 lb/sack Gilsonite.

c. MONITORING WELL SFI-3:

Monitoring Well SFI-3 shall be installed prior to Phase III which includes the phase of high solids content slurry injection as outlined in APPENDIX E. The bottom hole location of Well SFI-3 will be determined and approved after considering the geologic, geophysical, fracture simulation, temperature recovery, gas migration modeling, and other data provided from Phase I and Phase II operations and data from Wells SFI-1 and SFI-2. It is also possible that geological and other evidence could indicate that it is more advantageous to reverse the role of SFI-3 with the current injection well as applicable within this permit. This decision must be approved in advance by EPA and is considered minor in this permit.

Conductor pipe: 20-in OD (26-in. hole), 90 lb/ft, H-40 casing from ground surface to 150 ft. cemented to surface.

Surface Casing: 13-3/8-in. (17-1/2-in. hole) ; 61 lb/ft.; K-55; set at 1,000 ft. Cemented to surface with +/- 400 sacks Class H.

Long String Casing: 9-5/8-in. (12-1/4-in. hole) ; 40 lb/ft; N-80; set at +/- 5,350 ft. Cemented to surface with +/- 1,000 sacks Class H w/10.0 lb/sack Gilsonite.

3. Proposed Changes and Workovers
The permittee shall give advance notice to the EPA Region IX Water Division Director (Director) of any planned physical alterations or additions to the permitted wells. Any changes in the well construction not identified within this permit will require prior approval of EPA and a permit modification under the requirements of 40 CFR §144.39. In addition, the permittee shall provide all records of well workovers, logging, or other subsequent test data, including required mechanical integrity testing, to EPA 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.2.

B. CORRECTIVE ACTION

No corrective action for wells located within the Area of Review will be required pursuant to 40 CFR §144.55 and 40 CFR §146.7.

C. WELL OPERATION

1. Prior to Commencing Injection
Injection operations may not commence until construction is complete and the permittee has complied with items (a), (b), (c), (d), (e), (f) and (g) as follows:

a. Permittee shall provide depth of Base of Underground Sources of Drinking Water (USDWs). Permittee shall obtain formation fluid samples and analyze for total dissolved solids content that is less than 10,000 ppm to identify the depth of the lowermost USDW. Well logging information from Well SFI-1 will be used to determine which formations will be sampled.

b. Permittee shall conduct Formation Evaluation wireline logging and sampling operations in Wells SFI-1, SFI-2 and SFI-3 and provide those results. These results shall be used to estimate and report values for hydrocarbon saturation, porosity, lithology, formation dip direction, rock mechanical properties for both the injection zones and confining zones identified within the permitted geological sequence. These results shall be addressed and updated in a report within 60 days of completion of drilling and construction of each well.

i. Spontaneous Potential (SP) logs shall be used in the open hole.

ii. Gamma Ray logs shall be used in the open hole as well as in the cased hole.

iii. Resistivity logs shall be used in the open hole.

iv. Sonic logs shall be used in the open hole.

v. Density logs shall be used in the open hole.

vi. Neutron or Density-Neutron logs shall be used in the open or cased hole.

vii. Dipmeter logs shall be used in the open hole.

viii. Thermal Decay logs shall be used in the open or cased hole.

ix. Mud log sampling shall be conducted during drilling operations and analyzed.

x. Sidewall cores shall be obtained from Well SFI-1 through the entire interval from 3,800 - 5,300 ft. covering the Tar and Ranger zones (within the Repetto Formation), and the Terminal zone (within the Puente Formation) and analyzed for porosity, permeability, saturations of water and oil, and triaxial compression. The formation intervals from which the cores will be taken shall include confining zones (shales) and injection zones (sandstones).

xi. A 30 ft. long conventional (drilled) core shall be obtained from the proposed injection interval (estimated to occur at 5,200 - 5,300 ft.) and analyzed for porosity, permeability, saturations of water and oil, biological constituents, and triaxial compression. A detailed description of the analysis shall also include percent sand, grain size and sedimentary structure, identify basic rock type, oil staining and fluorescence, facies and laboratory remarks.

xii. Cement logging tools shall be of a pad-type, spherically focused cement evaluation tool.

xiii. Fluid samples shall be obtained to gather baseline data on fluid geochemistry and biological constituents. Samples shall be obtained after sufficient backflow has occurred to flush out the effects of drilling and completion. Additional samples shall be procured for participating independent research institutions involved in supportive efforts such as determining the native species of microbes present and identification of those species with potential for biodegradation activity, especially that of methanogenesis. Reports shall be made quarterly regarding details of the sampling program, and updating the results of efforts and progress of the independent research institutions.

xiv. The possibility of shallow expressions of the Palos Verdes fault intersecting the wellbores shall be determined and the results reported using standard geological techniques including using a combination of data obtained by logging and sampling during drilling operations for wells SFI-1, SFI-2, SFI-3, and other data and information including representative wells from the nearby Wilmington Oil Field.

c. The permittee must submit notice of completion of construction including drilling operations, well records and data. After final construction of each well, injection may not commence until the EPA has inspected or otherwise reviewed the well records and data and notified the permittee that it is in compliance with the conditions of the permit.

d. The permittee shall demonstrate that all the wells have mechanical integrity in accordance with Part II, Section C.3 of this permit. The permittee may not commence injection until it has received written notice from the EPA that such a demonstration is satisfactory.

e. The permittee shall supply evidence of Financial Assurance in accordance with Part II, Section F of this permit in a form that is approved by the EPA.

2. Operations

a. Fracture simulation modeling results shall be modified when new data obtained both during the drilling, construction and operation of the wells SFI-1, SFI-2 and SFI-3 and at any time the simulation model's parameter values become more accurately known or measured. The permittee shall include these modified modeling results in the quarterly reports. The reports shall justify and identify the parameters used in the modeling, their values and their accuracy. The report must also interpret possible deviation or discrepancy between predicted and measured data.

b. Reservoir simulation shall be used to estimate and locate gas generation and migration. Permittee shall utilize software with an industry accepted methodology. In the absence of such software, a method of calculation shall be used that is justified and approved by EPA.

3. Mechanical Integrity
The injection well and the monitoring wells have mechanical integrity when there is no significant leak in the casing, tubing or packer and there is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the well bore.

a. <u>Methods for Demonstrating Mechanical Integrity</u>

i. Annular Pressure test:
An annual (every 12 months) demonstration of the absence of significant leaks in the casing, tubing and/or packer shall be made by performing a pressure test on the annular space between the tubing and long string casing of the injection well. This test shall be for a minimum of thirty (30) minutes at a pressure equal to the maximum allowable injection pressure. A well passes the mechanical integrity test (MIT) if there is less than a five (5) percent decrease/increase in pressure over the thirty (30) minute period. A pressure differential of at least 350 pounds per square inch (psi) between the tubing and annular pressures shall be maintained throughout the MIT.

ii. Thermal Monitoring and Analysis:
Injection Well SFI-1 shall be fitted with a fiber optic temperature sensor on the long string casing. Real time temperature data will be continuously recorded and displayed in the operator's control room. Analysis shall include verification that the vertical location of injectate in the near-wellbore region remains within the currently authorized injection zone. Reports shall graphically display monitoring results. A temperature log may be required to be run in the monitoring wells SFI-2 and SFI-3. This shall be determined by EPA and notice shall be given in advance.

iii. Tracer Surveys and Analysis
The permittee shall run either Radioactive Tracer (RAT) logs or Oxygen Activation (OA) logs:

Radioactive Tracer (RAT) surveys shall be conducted monthly in Injection Well SFI-1 for the first three months of operation and quarterly for the remainder of the permit.

General RAT Procedure

1. Run gamma ray log to record baseline readings.
2. Tag 250 bbls of water with Iodine-131 Water Soluble Liquid (I-131 WSL) tracer.
3. Pump at maximum allowable injection rate and pressure - expected to be 15 bpm.
4. Run gamma ray log to record placement of tracer into formation and compare with baseline gamma ray log.
5. If results are inconclusive, pump additional injection water and re-log or repeat previous steps.

Oxygen Activation (OA) logs shall be conducted monthly in Injection Well SFI-1 for the first three months of operation and quarterly for the remainder of the permit.

General OA Procedure

1. Run OA tool in hole to Total Depth. Activate neutron generator. Inject water at maximum rate (15 bpm) until rate has stabilized. Log uphole at 10 ft/min.
2. Stop OA tool at pre-determined depths and perform impulse tests for detecting upward fluid movement behind long string casing.
3. Stop OA tool above injection interval and perform impulse tests at decreasing injection rates. Turn off neutron generator.
4. Stop injection; wait for pressure to become stable. Log uphole to 500 ft recording temperature profile.
5. Wait for 30 min to 1 hour. Run in hole to total depth then log out of hole for recording temperature profile change.

b. <u>Demonstrations of Annular Pressure Test</u>

i. An annular pressure test shall be demonstrated annually (every 12 months) or any time that a workover is conducted, the packer is unseated or the construction of the well is modified.

ii. It shall be the permittee's responsibility to arrange and conduct the annular pressure test demonstrations. The permittee shall notify the EPA of its intent to annually (every 12 months) demonstrate mechanical integrity at least thirty (30) days prior to each demonstration. Results of the test shall be submitted to the EPA as soon as possible but no later than thirty (30) days after the demonstration.

iii. In addition to any demonstration made under items (i) and (ii), the EPA may require a demonstration of annular pressure test at any time during the life of the wells.

iv. Failure to test and submit these results shall constitute a violation of the terms of the permit and may be cause for revocation.

c. <u>Loss of Mechanical Integrity</u>
If (1) a well fails to demonstrate mechanical integrity during any test or (2) a loss of mechanical integrity becomes evident during operation or (3) a significant change in the annulus or injection pressure occurs during normal operating conditions, injection activities shall be terminated immediately and the permittee shall notify the EPA in accordance with Part III, Section E.10 of this permit. Furthermore, operation shall not be resumed until the permittee has taken necessary actions to restore mechanical integrity to the well and EPA gives approval to recommence injection.

4. Injection Zones
Injection shall be permitted and systematically authorized for the Tar, Ranger and Terminal sequence of formations (suitable for use as injection zones and corresponding confining zones) which are expected to occur at depths ranging from 3,800 - 5,300 ft. as indicated from offset well records and logs.

The sequence of formations that are considered to be possibly suitable for use as injection zones shall be evaluated for their ability to provide containment of slurry fracture injection, their volumetric and areal extent of zonal reservoir continuity, their cumulative performance and response to slurry fracture injection, and their pressure influence at the location of the three improperly plugged and abandoned wells (Superior Well B-1, Apex Hards-Warnock Well 1, and SP LA Harbor Well 301) (See Part II.C.4.a.).

Initial injection shall occur at 5,200-5,300 ft. or that equivalent formation depth interval that corresponds to the geological formation (injection zone) encountered at the location of Well SFI-1. However, if this injection interval proves not usable as an injection zone, other injection zones may be systematically considered for injection within the Tar, Ranger and Terminal sequence of formations. These perforation interval or injection zone changes shall be requested in writing and proposed procedures will include plans for placement of cement across the lower perforated injection interval, testing of the cement plug, and perforating the upper injection interval. These injection interval changes must be approved by EPA before they are enacted and are considered minor in this permit. These alterations and other rework operations that may occur later in the course of operation of the wells must be properly reported (EPA Form 7520-12) and the permittee must demonstrate that each well has mechanical integrity in accordance with Part II, Section C.3 before any injection is authorized.

5. Injection Pressure, Fracture Limitation

a. In no case shall pressure in the currently authorized injection zone initiate new fractures or propagate existing fractures in the corresponding confining zone that are permeable and capable of allowing leakage out of that injection zone. Permittee shall obtain authorization to conduct slurry fracture injection in the overlying, sequential injection zone before proceeding.

b. In no case shall injection operations cause the movement of injection or formation fluids into an underground source of drinking water.

c. In no case shall injection operations cause the reservoir pressure of the currently authorized or any previously authorized injection zones to increase at the location of the three improperly plugged and abandoned wells (Superior Well B-1, Apex Hards-Warnock Well 1, and SP LA Harbor Well 301). The predicted reservoir pressures at these locations shall be updated and addressed in the quarterly report using data and information obtained during the various monitoring operations.

d. In no case shall injection pressure propagate fractures downward to within 1,000 ft. proximity of the Palos Verdes fault in the Jurassic formation. If there is evidence that the Palos Verdes fault intersects the injection reservoir and/or the wellbores, the reporting requirements for microseismic and pressure falloff monitoring shall include a discussion that satisfactorily addresses injection related activity that occurs in the proximity of this or any other fault plane.

e. The pressure falloff data shall be sufficient to allow for analysis using radial/linear well test analysis procedures. The proposed procedures and analyses shall be adapted for the specific conditions at this facility, but must generally conform to the EPA Regional Guideline example provided in Appendix F when reporting results.

6. Injection Rate Limitation

   a. The injection rate shall not exceed 15 barrels per minute (bpm) at any time. The average daily rate is expected to be 10 bpm.

   b. The permittee may request an increase in the maximum rate allowed in paragraph (a). Any such request shall be made in writing to the Director.

   c. Any request for an increase in injection rate shall demonstrate to the satisfaction of the Director that the increase will not interfere with the operation of the facility or its ability to meet conditions described in this permit.

7. Injection Fluid Limitation

   a. The permittee shall not inject any hazardous waste as defined by 40 CFR Part 261 at any time.

   b. Injection fluids shall be limited to only waste fluids and slurries formed from combining biosolids authorized by this permit and produced at the following facilities: (1) Hyperion Treatment Plant; (2) Terminal Island Treatment Plant; (3) Carson Treatment Plant; (4) Orange County Treatment Plant. No other sources shall be accepted.

8. Slurry Fracture Injection Process, Related Operations and Analyses
   The demonstration project proposed by the permittee consists of a three phased plan incorporated into this permit as APPENDIX E. PHASE I shall occur for approximately 3 months, PHASE II for 9 months and PHASE III for 4 years.

   a. <u>Slurry Fracture Injection and Step Rate Testing Operations</u>
      These shall consist of injection for five days per week, with extended shut-in periods on each weekend. Permittee shall record and report injection volumes, rates, concentration, density and pressures.

      i. Maximum daily rate of injection shall be determined during field tests during Phases I, II, and III but shall not exceed 15 barrels per minute (bpm). Average daily rate of injection: (10 bpm expected).

      ii. Average and maximum daily injection pressure. Maximum allowable (surface) injection pressure shall be determined during field tests during Phases I, II, and III and is expected to be 6,000 psi. (Average injection pressure: 4,000 psi expected.)

      iii. Average and total daily volumes of injectate: (5,000 barrels (bbls) expected average)

iv. Cumulative volume of injectate.

v. Average and total daily biosolids injection: (100 to 400 wet tons expected)

vi. Cumulative biosolids injection.

vii. Average and maximum slurry density: (1.0 - 1.5 specific gravity expected)

viii. Viscosity: To be determined

ix. Average solids concentrations: (10 - 40 % by weight is expected per Phase I, II and III procedures)

b. <u>Pressure Monitoring and Analysis</u>

i. Bottom Hole Pressure (BHP) at Injection Well SFI-1 shall be monitored continuously - during injection (pressure elevation occurs) and shut-in periods (pressure Falloff occurs). Injection shall not resume until the BHP Falloff value has dissipated to within 10% of the currently authorized and any previously authorized injection zone's original reservoir pressure.

ii. Permittee shall utilize software with an industry accepted methodology to analyze the BHP Falloff to determine and predict reservoir and fluid flow system behavior in the general area of the injection zone as well as near the Injection Well SFI-1 wellbore.

iii. BHP at Monitoring wells SFI-2 and SFI-3 shall be monitored continuously. Use of these BHP measurements shall include extrapolating and verifying on a weekly basis that injection operations at SFI-1 shall not cause the currently authorized or any previously authorized injection zone's reservoir pressure to increase at the location of the three improperly plugged and abandoned wells (Superior Well B-1, Apex Hards-Warnock Well 1, and SP LA Harbor Well 301).

c. Step-Rate Testing (SRT) and Analysis

i. Permittee shall conduct monthly SRTs at any well used for injection to evaluate formation parting (fracture) pressure and changes in in-situ stresses. The SRT shall be conducted to the maximum allowable injection rate. Modifications to the SRT procedures must be requested in writing in advance and justified based on field observations. These modifications will be considered minor for this permit. The following SRT procedures shall be implemented:

RATE (bbl/min)	DURATION (min)
_0.5	30
_1.0	30
_2.0	30
_4.0	30
_8.0	30
12.0	30
15.0	30

ii. Injection rate shall gradually increase between steps by a gradual increase to the next rate over a 5-minute interval.

iii. Rates are not varied during the last 25 minutes of the 30-minute duration at each step.

iv. Injected volumes are recorded for each step at 15-minute intervals.

v. Scan rate for pressure Falloff monitoring is increased one per minute prior to the end of the SRT.

vi. The wellhead valve is closed just as the pump is stopping to prevent flow-back.

vii. Wells are to remain shut-in for 2 hours after completion of the SRTs before Slurry Fracture Injection operations may resume.

d. Thermal Monitoring and Analysis
Requirements for Well SFI-1 are described in Part II. Section C.3.(a)(ii).

e. Tracer Surveys and Analysis
Requirements for Well SFI-1 are described in Part II. Section C.3.(a)(iii).

f. Microseismic/Tiltmeter Monitoring and Analysis
Permittee shall install and operate a continuous downhole monitoring system with best available technology to provide dimensions and

orientation of the fractures. Wells SFI-1, SFI-2, and SFI-3 shall be equipped with retrievable or permanent monitoring systems depending on the role these wells play. These details are included in Appendix A.

i. Downhole monitoring shall be performed continuously to provide location of seismic events related to fracturing operations within the currently authorized injection zone and within the adjacent geological confining zone as well as the location of fracture lengths, and fracture heights.

ii. Fracture mapping and fracture growth modeling shall be performed in real time using software with an industry accepted methodology.

iii. Slurry Fracture Injection simulation modeling and analysis shall be performed to provide estimates on general fracture size, including at a minimum fracture thickness, length, and height. Permittee shall utilize software with an industry accepted methodology; data shall be provided in a format that is compatible with software that is available to EPA.

g. Biodegradation Process Evaluation and Optimization

Samples shall be procured both for permittee and for participating independent research institutions involved in supportive efforts which have been described as objectives of the experiment. Reports shall be made quarterly regarding details of the sampling program and updating the results of efforts and progress of the independent research institutions. During the operational phases of the project, samples from Monitoring Wells SFI-2 and SFI-3 and Injection Well SFI-1 shall be extracted and tested for geochemical and biological properties in efforts to quantify and identify at a minimum:

i. active species of methanogenic micro-organisms
ii. biosolids compaction behavior and volumetric strains associated with methanogenesis
iii. in-situ biodegradation of biosolids,
iv. in-situ generation and behavior of carbon dioxide (CO_2),
v. in-situ generation and behavior of methane (CH_4),
vi. in-situ generation and behavior of hydrogen sulfide,
vii. dominant biological species,
viii. (frontal extent of biological activity or injectate, and
ix. presence of pathogenic microbial indicators including fecal coliform, salmonella and enteric viruses.

h. Experimental Objectives - Monitoring, Analysis and Application

The Class V Experimental classification of this permit is based on the high level of investigation and analyses of previously unknown, complex in situ processes that are fully expected to continue well beyond the period of injection and emplacement of biosolids within distinct geological formations.

Progress is likewise expected throughout this project regarding theoretical predictive analysis and application techniques as new data are acquired and various reservoir and geological characteristics and properties are obtained and confirmed. Reports addressing these objectives shall be made quarterly. Each quarterly report shall progressively include and address any previous related dialogue between EPA and the permittee. The objectives include:

i. Time needed to elevate temperature after injection.
ii. Biodegradation process evaluation and optimization.
iii. Gas migration process simulation.

D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Monitoring
   Calibration and Maintenance of Equipment:
   All monitoring and recording equipment shall be calibrated and maintained on a regular basis to ensure proper working order of all equipment.

2. Recordkeeping

   a. The permittee shall retain records concerning:

      i. the nature, volume and composition of all injected fluids until three (3) years after all the wells have been plugged and abandoned.

      ii. all monitoring information, including all calibration and maintenance records and all recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit for a period of at least five (5) years after all the wells have been plugged and abandoned.

b. The permittee shall continue to retain the records described in paragraphs (a) (i) and (a) (ii) after the specified retention periods, unless it delivers the records to the Director or obtains written approval from the Director to discard the records.

c. The permittee shall maintain copies (or originals) of all observation records throughout the operating life of the well and make such records available for inspection at the facility. The permittee shall continue to retain such records unless it obtains written approval from the Director to discard the records.

3. Reporting of Results

Quarterly report forms shall be submitted for the reporting periods by the respective due dates as listed below:

Reporting Period	Report Due
Jan, Feb, Mar	Apr 28
Apr, May, June	Jul 28
July, Aug, Sept	Oct 28
Oct, Nov, Dec	Jan 28

Copies of the monitoring results and all other reports required by this permit shall be submitted to the designated project officer at the following address:

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

a. At the beginning of each of the 3 phases, the permittee shall submit daily reports of the Daily Injection Pressure Analysis via phone conversation and e-mail to the designated project officer during each of the three Phases of the project. This frequency shall only be temporary and shall be relaxed over time as determined by results of the analyses and their consistency.

b. The permittee shall submit Quarterly reports including results and discussion of the Slurry Fracture Injection Process, Related Operations and Analyses of Part II, Sections C.8.(a) - (h).

c. A narrative description of all noncompliance that occurred during the Quarterly reporting period. Narrative must summarize all noncompliance submissions reported under Part III, Section E.10 of this permit.

d. The permittee shall include the modified fracture simulation modeling results in the quarterly reports. The reports shall justify and identify the parameters used in the modeling, their values and their accuracy. The report must also interpret possible deviation or discrepancy between predicted and measured data.

E. PLUGGING AND ABANDONMENT

1. "Onshore Well Regulations" of the California Code of Regulations
   Permittee shall conduct both drilling and plugging operations by following the requirements of this permit and the "Onshore Well Regulations" of the California Code of Regulations, found in Title 14. Natural Resources, Division 2. Department of Conservation, Chapter 4, Article 3, Section 1722-1723 as implemented by the Division of Oil, Gas, and Geothermal Resources (DOGGR).

2. Notice of Plugging and Abandonment
   The permittee shall notify the Director no less than sixty (60) days before conversion, workover, or abandonment of a well. The Director requires that the plugging and abandonment be witnessed by an EPA representative.

3. Plugging and Abandonment Plans
   The permittee shall plug and abandon the wells as provided in the Plugging and Abandonment Plans in Appendix C. EPA reserves the right to change the manner in which a well will be plugged if the well is modified during its permitted life or if the well is not consistent with EPA requirements for construction or mechanical integrity. The Director may require 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 wells according to the Plugging and Abandonment Plans and Schematics in Appendix C.

4. Plugging and Abandonment Report
   Within thirty (30) days after plugging a well, the permittee shall submit a report on Form 7520-13, provided in Appendix B, 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 Plugging and Abandonment Plans, or (2) where actual plugging differed from the Plugging and Abandonment Plans, a statement specifying the different procedures followed.

5. Cessation of Injection Activities
   After a cessation of injection operations for two (2) years, the permittee shall plug and abandon all three wells in accordance with the Plugging and Abandonment Plans, unless it:

   a. Provides notice to the Director;

b. Has demonstrated that the wells 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 wells will not endanger underground sources of drinking water during the period of temporary abandonment.

F. FINANCIAL RESPONSIBILITY

The permittee is required to demonstrate and maintain financial responsibility and resources sufficient to close, plug, and abandon the underground injection operation as provided in the Plugging and Abandonment Plans.

G. DURATION OF PERMIT

This permit and the authorization to inject are issued for a period of up to five (5) years unless terminated under the conditions set forth in Part III, Section B.1 of this permit.

The Class V Experimental classification of this permit is based on the high level of investigation and analyses of previously unknown, complex in situ processes that are fully expected to continue well beyond the period of injection and emplacement of biosolids within distinct geological formations.

Monitoring and measurements are expected to continue beyond the period of injection. Any records of sampling and analysis conducted after termination of authorization to inject shall be submitted in the quarterly reporting period schedule.

Part III. GENERAL PERMIT CONDITIONS

A. EFFECT OF PERMIT

The permittee is allowed to engage in underground injection well construction and operation in accordance with the conditions of this permit. The permittee 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 (as defined by 40 CFR §144.3) 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 Part 141 or may otherwise adversely affect the health of persons. Furthermore, any underground injection or any other activity not specifically authorized in this permit is prohibited. The permittee must comply with all applicable provisions of the SDWA and 40 CFR Parts 144, 145, 146, and 124. Such compliance does not constitute a defense to any action brought under Section 1431 of the SDWA, 42 U.S.C. § 300i, or any other common law, statute, or regulation other than Part C of the SDWA. 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. Nothing in this permit shall be construed to relieve the permittee of any duties under all applicable laws or regulations.

B. PERMIT ACTIONS

1. Modification, Revocation and Reissuance, and Termination of the Permit
   The Director may, for cause, modify, revoke and reissue, or terminate this permit in accordance with 40 CFR §§124.5, 144.12, 144.39, and 144.40. Also, the permit is subject to minor modifications in accordance with 40 CFR §144.41. The filing of a request for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance by the permittee, does not stay any permit condition. The Director may also modify, revoke and reissue, or terminate this permit in accordance with any amendments to the SDWA if the amendments have applicability to this permit.

2. Transfer of Permit.
   This permit is not transferable.

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 application of such provision to other circumstances and the remainder of this permit shall not be affected thereby.

D. CONFIDENTIALITY

In accordance with 40 CFR §§2 and 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.

E. GENERAL DUTIES AND REQUIREMENTS

1. Duty to Comply
   The permittee shall comply with all applicable UIC Program regulations and all conditions of this permit, except to the extent and for the duration such noncompliance is authorized by an emergency permit issued in accordance with 40 CFR §144.34. Any permit noncompliance constitutes a violation of the Safe Drinking Water Act (SDWA) and is grounds for enforcement action, permit termination, revocation and reissuance, modification, or denial of a permit renewal application. 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 enforcement actions pursuant to RCRA. Any person who willfully violates a permit condition may be subject to criminal prosecution.

3. Need to Halt or Reduce Activity Not a Defense
   It shall not be a defense, for the 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 and 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 (and related appurtenances) 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. Property Rights
This permit does not convey any property rights of any sort, or any exclusive privilege.

7. Duty to Provide Information
The permittee shall furnish to 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.

8. 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 are kept under the conditions of this permit;

   c. Inspect and photograph 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.

9. Signatory Requirements
All applications, reports, or other information submitted to 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. <u>Anticipated Noncompliance</u>
   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. <u>Compliance Schedules</u>
   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 to the Director 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 orally within twenty-four (24) hours from the time the permittee becomes aware of the circumstances. The following information must be reported orally within twenty-four (24) hours:

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

2) 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.

3) Any monitoring or other information which indicates that injection operations at SFI-1 may cause the reservoir pressure to increase at the location of the three improperly plugged and abandoned wells (Superior Well B-1, Apex Hards-Warnock Well 1, and SP LA Harbor Well 301).

4) Any monitoring or other information which indicates that fractures in the immediately overlying confining zone that are permeable and capable of allowing leakage have propagated above the currently authorized injection zone. Permittee shall obtain authorization to conduct slurry fracture injection in the overlying, sequential injection zone before proceeding.

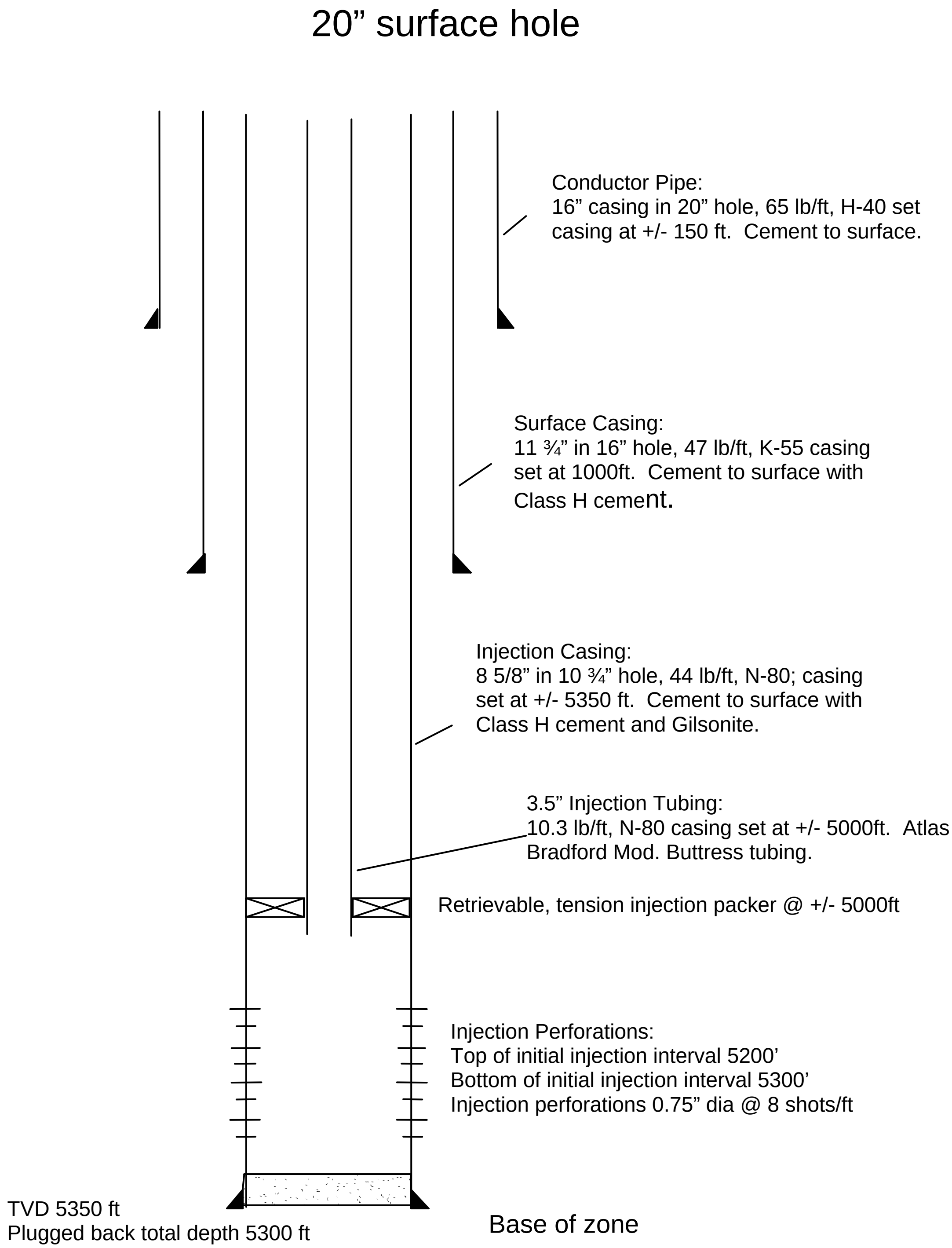
5) Any monitoring or other information which indicates that fractures have propagated downward to within 1,000 ft. proximity of the Palos Verdes fault in the Jurassic formation or if the Palos Verdes fault intersects the injection reservoir and/or the wellbores (above the Jurassic formation).

ii. A written submission of all noncompliance as described in paragraph (c) (1) shall also be provided to the Director 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 noncompliance, including exact dates and times; 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.

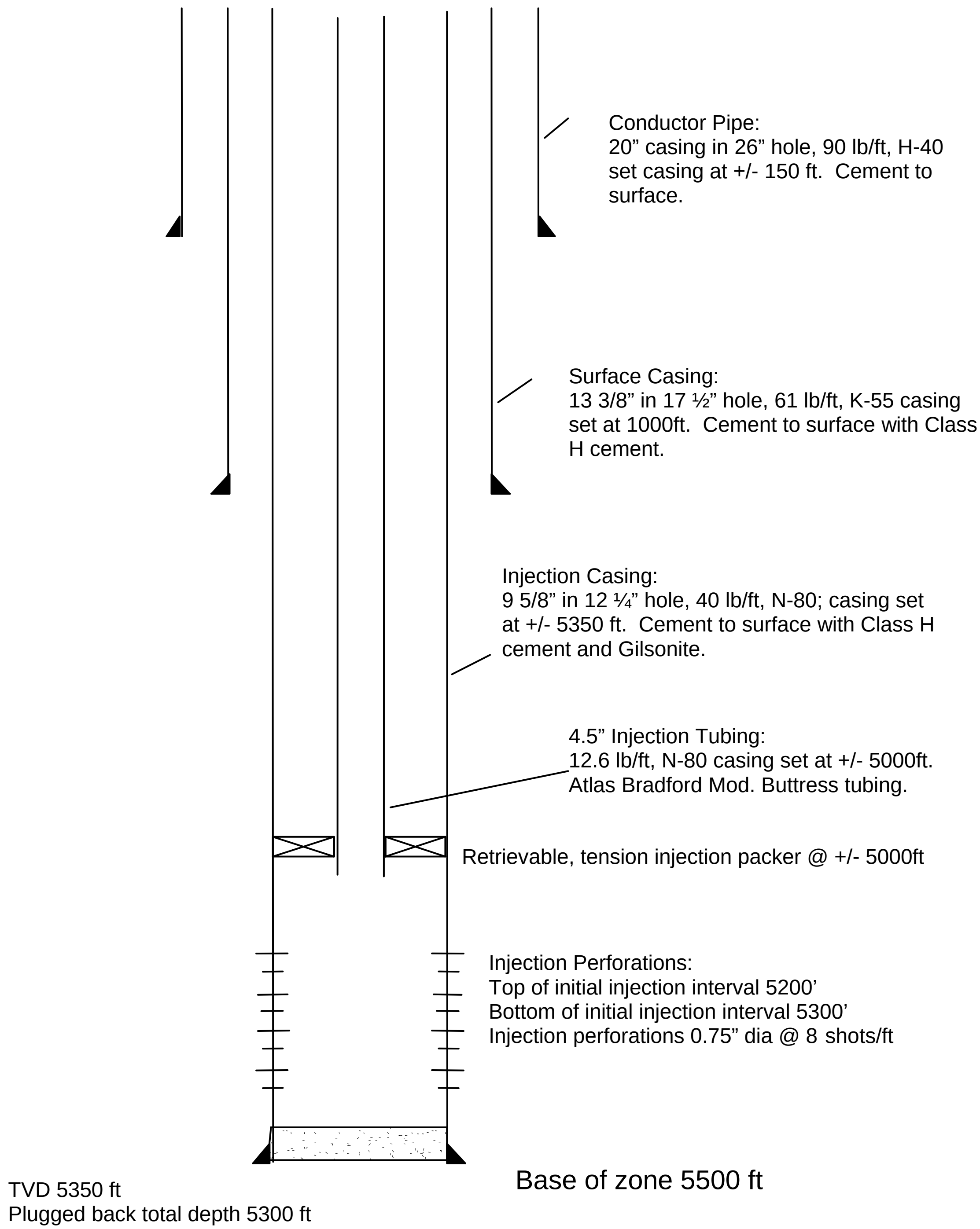
d. Other Noncompliance
At the time monitoring reports are submitted, the permittee shall report in writing all other instances of noncompliance not otherwise reported. The permittee shall submit the information listed in Part III, Section E.10. (c) of this permit.

e. Other Information
If the permittee becomes aware that it failed to submit all relevant facts in the permit application, or submitted incorrect information in the 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 facts or information becomes known.

APPENDIX A - WELL CONSTRUCTION PLANS AND SCHEMATICS



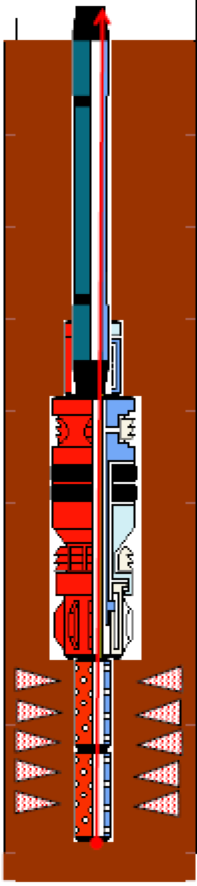
26” surface hole



(3) Schematic drawing for inclusion in Appendix A

HALLIBURTON

CUSTOMER:	Terralog Technologies USA, Inc.	Ticket No:	
WELL NAME:	Slurry Frac Injection Wells	Date:	15/Jun/2005
TEST:			



DESCRIPTION	Supplier or Serial No.	CONNECTION TOP	CONNECTION BOTTOM	OD (in)	ID (in)	LENGTH (m)	DEPTH (m)
4.5" Inj. Tubing 12.6# N-80 w/ FiberTube and heavy Duty Collar Protectors	HES						
4.5" Inj. Tubing 12.6# N-80 w/ FiberTube and heavy Duty Collar Protectors				4.5"	3.958"		
4.5" Inj. Tubing 12.6# N-80 w/ FiberTube and heavy Duty Collar Protectors				4.5"	3.958"		
4.5" Inj. Tubing 12.6# N-80 w/ FiberTube and heavy Duty Collar Protectors				4.5"	3.958"		5,000.000
					Above Packer Seat:		
	HES					Pkr. Seat	5,000.000
					Below Packer Seat:		
4.5" Inj. Tubing Slotted or perforated 12.6# N-80 w/ FiberTube and heavy Duty Collar Protectors	HES			4.500	3.958"		5,350.000
4.5" Inj. Tubing Slotted or perforated 12.6# N-80 w/ FiberTube and heavy Duty Collar Protectors	HES			4.500	3.958"		5,350.000

Figure 1: Schematic for Halliburton's Fiber Optic tool

Part II. Section C. Part7.(f): Array configurations for construction details

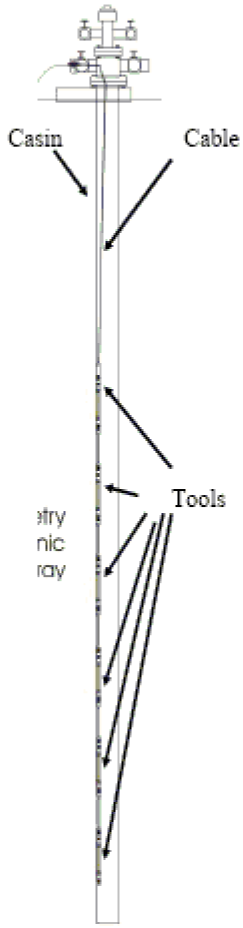


Figure 7 and Figure 7 are the configuration details for wireline deployed multi-level array tiltmeters and wireline deployed multi-level geophones. Both figures are provided by Pinnacle.

Figure 7: Wireline Deployed multi-level tiltmeters

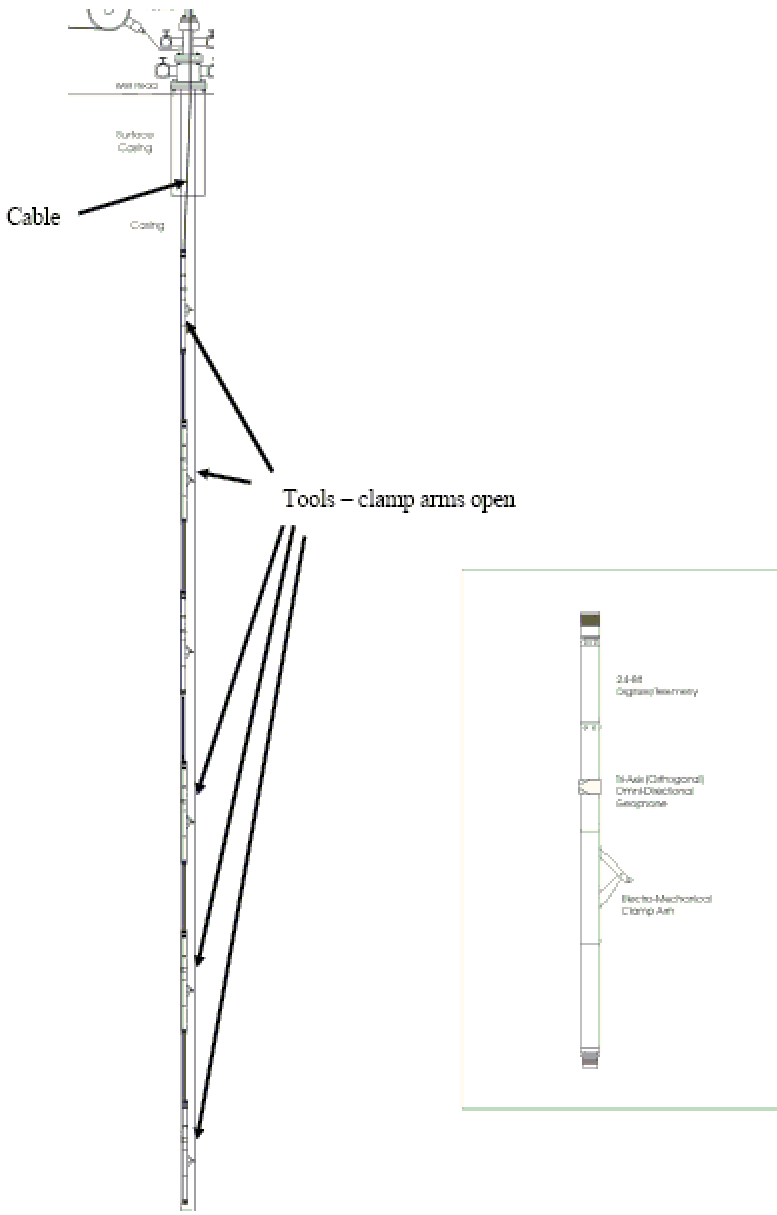


Figure 8: Wireline Deployed Geophones

APPENDIX B - REPORTING FORMS

Forms can be obtained on the web at

http://www.epa.gov/safewater/uic/7520s.html

or

http://www.epa.gov/
and enter “UIC Reporting Forms” into the Search box.

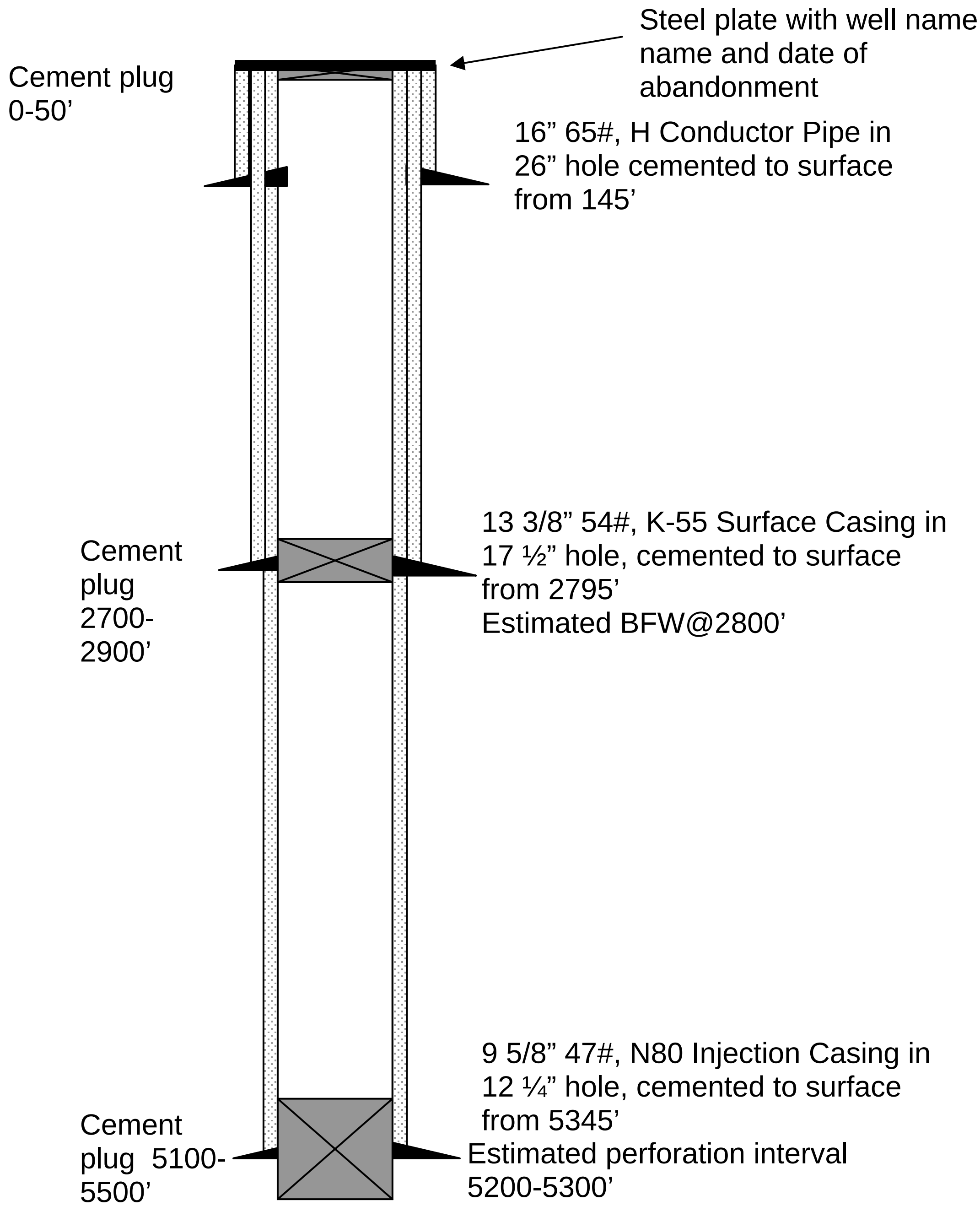
The forms that need to be obtained are:

7520-6 - Permit Application
7520-7 - Application to Transfer Permit
7520-8 - Injection Well Monitoring Report
7520-9 - Completion Form For Injection Wells
7520-10 - Completion Report For Brine Disposal, Hydrocarbon Storage, or Enhanced Recovery
7520-11 - Annual Disposal/Injection Well Monitoring Report
7520-12 - Well Rework Record
7520-14 - Plugging and Abandonment Plan
7520-16 - Inventory of Injection Wells

APPENDIX C - PLUGGING AND ABANDONMENT PLANS AND SCHEMATICS

Upon completion of injection activities the wells shall be abandoned according to State and Federal regulations to ensure protection of Underground Sources of Drinking Water.

WELL PLUGGING AND ABANDOMENT SCHEMATIC



All cement plugs shall meet EPA and DOGGR P&A standards, cement plugs shall have max liquid permeability of 0.1md and attain compressive strength of >=1000lb psi within 24 hrs. All cement test data will be submitted to EPA and DOGGR and conducted according to DOGGR guidelines. Spaces in between cement plugs will be filled with drilling mud with corrosion inhibitor added, consistent with DOGGR requirements and field practices

APPENDIX D - FINANCIAL RESPONSIBILITY

The mechanisms for financial responsibility as required in Part II.F of this permit shall be submitted to the Director prior to receiving authorization to inject.

APPENDIX E - STEP-BY-STEP PROCESS and MILESTONES for FIELD EXPERIMENT

Step-by-Step Process and Milestones for Field Experiment

To Demonstrate:

Biosolids Treatment, Methane Generation and CO2 Sequestration Through Deep Well Injection and Biodegradation

June 24, 2005

Prepared by

Terralog Technologies USA, Inc.
332 E. Foothill Boulevard, Arcadia, CA 91006

PHASE I TO DEMONSTRATE SLURRY INJECTIVITY AND EVALUATE FORMATION RESPONSE (~ 3 MONTHS)

1.1. Drill well, characterize geology and geochemistry (3 weeks)
1.1.1 Collect and analyze cuttings and fluid samples
1.1.2 Evaluate geophysical logs
1.1.3 Install permanent/continuous temperature monitoring system
1.1.4 Install permanent/continuous pressure monitoring system
1.1.5 Install retrievable down-hole tiltmeter system
1.2 Test and evaluate the formation properties with water (1 week)
1.2.1 Step-rate test to determine in-situ stress
1.2.2 Injection and fall-off test to determine permeability to water
1.3 Short-term slurry injection tests (1 week)
1.3.1 1-hr slurry injection test to demonstrate injectivity
1.3.2 4-hr slurry injection test with extended fall-off (1.5 days)
1.3.3 8-hr slurry injection test with extended fall-off (2 days)
1.3.4 Evaluate formation transport properties to slurry
1.3.5 Evaluate containment with temperature and pressure analysis
1.4 Multiple episodic slurry injection tests (6 weeks)
1.4.1 2 wks of 8-hr slurry injection episodes at low concentration
1.4.2 2 wks of 8-hr slurry injection episodes at moderate concentration
1.4.3 2 wks of 8-hr slurry injection episodes at high concentration
1.4.4 Step-rate test to evaluate in-situ stress
1.4.5 Evaluate containment with temperature and tracer surveys
1.4.6 History match fracture simulation to field data
1.4.7 Evaluate process zone dimensions and optimum offset well location
1.5 Diagnose and Report

MILESTONES AND DECISION POINTS
Milestone #1: Demonstrate Slurry Injectivity and Evaluate Formation Response
Milestone #2: Demonstrate Vertical Containment in Target Interval
Milestone #3: Identify Optimum Location for 2nd Well

PHASE II TO DEMONSTRATE THERMAL TREATMENT, GAS GENERATION, AND CO2 SEQUESTRATION (~9 MONTHS)
2.1 Drill and test offset monitoring and sampling well
2.1.1 Collect and analyze cuttings and fluid samples
2.1.2 Evaluate geophysical logs
2.1.3 Evaluate lithology and structure and update reservoir model
2.1.4 Install permanent/continuous temperature monitoring system
2.1.5 Install permanent/continuous pressure monitoring system
2.1.6 Step-rate test to determine in-situ stress
2.1.7 Injection and fall-off test to determine permeability to water
2.1.8 Slurry injection tests and transport property evaluation

2.2 Slurry injection monitoring and sampling from each well

2.2.1 Down-hole tiltmeter survey from each well to characterize fracture dimensions and orientation
2.2.2 Microseismic monitoring survey from each well
2.2.3 Pressure interference tests between wells to evaluate transport
2.2.4 Update reservoir transport model
2.2.5 Alternate injection and monitoring as appropriate between wells
2.2.6 Monthly fluid and gas sampling and analysis from each well
2.2.7 History match reservoir model with field observations and simulate long-term injection, gas generation, and migration

2.3 Diagnose and Report

PHASE III TO QUANTIFY LONG-TERM METHANE GENERATION AND CO2 SEQUESTRATION (~4 YEARS)

3.1.1 Install optimally located well #3 for gas recovery and additional monitoring for large-scale injection
3.1.2 Collect and analyze cuttings and fluid samples
3.1.3 Evaluate geophysical logs
3.1.4 Pressure interference tests between wells to evaluate transport
3.1.5 Update reservoir transport model
3.1.6 Alternate injection and monitoring as appropriate between wells
3.1.7 Monthly fluid and gas sampling and analysis from each well

3.2 Diagnose and Report

MILESTONES AND DECISION POINTS

Milestone #1: Demonstrate Continued Containment in Permitted Interval
Milestone #2: Demonstrate Thermal Treatment, Gas Generation and CO2 Sequestration in Deep Subsurface
Milestone #3: Quantify Long-term Gas Generation and CO2 Sequestration

APPENDIX F - FALLOFF TESTING GUIDELINES

If you are viewing this online please refer to the separate file labeled:

Appendix F Falloff Testing Guidelines.pdf